

City of Hercules

*111 Civic Drive
Hercules, CA 94547*



Meeting Agenda

Tuesday, July 25, 2017

7:00 PM

Closed Session - 6:00 P.M.

Regular Meeting - 7:00 P.M.

Council Chambers

City Council

*Mayor Myrna de Vera
Vice Mayor Chris Kelley
Council Member Dan Romero
Council Member Gerard Boulanger
Council Member Roland Esquivias*

*David Biggs, City Manager
Patrick Tang, City Attorney
Lori Martin, City Clerk*

Cablecast live on Comcast Channel 28, AT&T Channel 99 and webcast live via the City's website at www.ci.hercules.ca.us

I. SPECIAL MEETING - CLOSED SESSION – 6:00 P.M. CALL TO ORDER - ROLL CALL

II. PUBLIC COMMUNICATION - CLOSED SESSION ITEMS

III. CONVENE INTO CLOSED SESSION

The Hercules City Council will meet in Closed Session regarding the following:

1. Pursuant to Government Code Section 54957(b) PUBLIC EMPLOYEE PERFORMANCE EVALUATION - Title: City Manager (Discuss Annual Evaluation Per Employment Agreement)
2. Pursuant to Government Code Section 54956.9, Conference with Legal Counsel - Potential Litigation - Exposure to litigation in one (1) case.

IV. REGULAR MEETING – 7:00 P.M. CALL TO ORDER - ROLL CALL

V. REPORT ON ACTION TAKEN IN CLOSED SESSION

VI. PLEDGE OF ALLEGIANCE

VII. MOMENT OF SILENCE

VIII. INTRODUCTIONS/PRESENTATIONS

1. Present Proclamation to the Celebrate Hercules Association Committee for their efforts on the 4th Annual 4th of July Celebrate Hercules Event

Attachments: [Proclamation](#)

IX. AGENDA ADDITIONS/DELETIONS

X. PUBLIC COMMUNICATIONS

This time is reserved for members of the public to address issues not included in the agenda. In accordance with the Brown Act, Council will refer to staff any matters brought before them at this time, and those matters may be placed on a future agenda.

Individuals wishing to address the City Council are asked to complete a form indicating the name and address of the speaker and the general topic to be addressed. Speakers must make their comments from the podium and will be allowed 3 minutes to discuss their concerns. All public comments are recorded and become part of the public record. A limit of 30 minutes will be devoted to taking public comment at this point in the agenda. If any speakers remain at the conclusion of the initial 30 minute period, time will be reserved at the conclusion of the meeting to take the remaining comments.

XI. PUBLIC HEARINGS - None.**XII. CONSENT CALENDAR****1. Minutes**

Recommendation: Approve Minutes for the Regular City Council meeting of July 11, 2017.

Attachments: [Agenda Item Review and Approval Form](#)
 [City Council Minutes of July 11, 2017](#)

XIII. DISCUSSION AND/OR ACTION ITEMS**1. Community Choice Energy (CCE) Program**

Recommendation: Receive Report, Discuss, and Provide Direction, if any.

Attachments: [Agenda Item Review and Approval Form](#)
 [Staff Report - CCE Program](#)
 [CCE Technical Study](#)
 [CCE Technical Study Appendices](#)
 [October 2016 Staff Report re Solar Choice](#)
 [June 26 Staff Report CCE Technical Study MOU](#)

2. Electing City Council Members as an Approved Employee Group the Ability to Obtain Health Benefits from the City's CalPERS Medical Plan

Recommendation: Adopt two (2) CalPERS Resolutions which will add City Council members as an authorized employee group to the City's health and benefit plans through CalPERS.

Attachments: [Agenda Item Review and Approval Form](#)
 [Staff Report - CalPERS Resolutions - Council Benefits](#)
 [Resolution - Hercules - 701 NonPERS Council](#)
 [Resolution - Hercules - 005 PERS Council](#)

3. Contract Amendment No. 2 with WSP USA

Recommendation: Approve contract amendment No. 2 with WSP USA for \$25,704 for a total not to exceed contract amount of \$63,154 to conduct a feasibility study for remedial work within Refugio Creek associated with the Path to Transit project and perform site inspections and maintenance prior to the remediation.

Attachments: [Agenda Item Review and Approval Form](#)
[Staff Report - WSP Amend No 2](#)
[Attachment 1 - Figures 1-5](#)
[Attachment 2 - Resolution](#)
[Attachment 3 - Contract Amendment No.2](#)
[Attachment 4 - Proposal](#)

4. **Part-Time Employees Salary Adjustment to Provide a Cost of Living Adjustment and to Address New Minimum Wage as of January 1, 2018 and Approve New Job Classification for Administrative Engineering/Planning Intern**

Recommendation: Adopt a Resolution approving a new salary schedule for part-time employees to provide a 3.8% cost of living adjustment and to comply with the new minimum wage as of January 1, 2018 and creating the Administrative Engineering/Planning Intern job classification.

Attachments: [Agenda Item Review and Approval Form](#)
[Staff Report - Part-Time Employees Salary Adjustment](#)
[Resolution](#)
[Exhibit A - Part-Time Salary Schedule](#)
[Exhibit B - Administrative Intern Job Description](#)

5. **Temporary Waiver of Business Licenses for Fee Class Contractors and City Professional Services Contractors.**

Recommendation: Approve a Resolution establishing a temporary waiver of business licenses for fee class contractors (up to \$20,000 per year in value) and City professional services contractors.

Attachments: [Agenda Item Review and Approval Form](#)
[Staff Report](#)
[Resolution - Business License Pilot Temp Waiver](#)

XIV. PUBLIC COMMUNICATIONS

This time is reserved for members of the public who were unavailable to attend the Public Communications period during Section X of the meeting, or were unable to speak due to lack of time. The public speaker requirements specified in Section X of this Agenda apply to this Section.

XV. CITY COUNCIL/CITY MANAGER/CITY ATTORNEY ANNOUNCEMENTS, COMMITTEE, SUB-COMMITTEE AND INTERGOVERNMENTAL COMMITTEE REPORTS AND FUTURE AGENDA ITEMS

This is the time for brief announcements on issues of interest to the community. In accordance with the provisions of the Brown Act, matters which do not appear on this agenda but require City Council discussion may be either (a) referred to staff or other resources for factual information or (b) placed on a future meeting agenda.

XVI. ADJOURNMENT

The next Regular Meeting of the City Council will be held on Tuesday, August 8, 2017 at 7:00p.m. in the Council Chambers.

Agendas are posted in accordance with Government Code Section 54954.2(a) or Section 54956. Members of the public can view electronic agendas and staff reports by accessing the City website at www.ci.hercules.ca.us and can receive e-mail notification of agenda and staff report postings by signing up to receive an enotice from the City's homepage. Agendas and staff reports may also be obtained by contacting the Administrative Services Department at (510) 799-8215

(Posted: July 20, 2017)

THE HERCULES CITY COUNCIL ADHERES TO THE FOLLOWING POLICIES, PROCEDURES AND REGULATIONS REGARDING CITY COUNCIL MEETINGS

1. SPECIAL ACCOMMODATIONS: In compliance with the Americans with Disabilities Act, if you require special accommodations to participate at a City Council meeting, please contact the City Clerk at 510-799-8215 at least 48 hours prior to the meeting.

2. AGENDA ITEMS: Persons wishing to add an item to an agenda must submit the final written documentation 12 calendar days prior to the meeting. The City retains the discretion whether to add items to the agenda. Persons wishing to address the City Council otherwise may make comments during the Public Communication period of the meeting.

3. AGENDA POSTING: Agendas of regular City Council meetings are posted at least 72 hours prior to the meeting at City Hall, the Hercules Swim Center, Ohlone Child Care Center, Hercules Post Office, and on the City's website (www.ci.hercules.ca.us),

4. PUBLIC COMMUNICATION: Persons who wish to address the City Council should complete the speaker form prior to the Council's consideration of the item on the agenda.

Anyone who wishes to address the Council on a topic that is not on the agenda and is relevant to the Council should complete the speaker form prior to the start of the meeting. Speakers will be called upon during the Public Communication portion of the meeting. In accordance with the Brown Act, the City Council may not take action on items not listed on the agenda. The Council may refer to staff any matters brought before them at this time and those matters may be placed on a future agenda.

In the interests of conducting an orderly and efficient meeting, speakers will be limited to three (3) minutes. Anyone may also submit written comments at any time before or during the meeting.

5. CONSENT CALENDAR: All matters listed under Consent Calendar are considered to be routine and will be enacted by one motion. There will be no separate discussion of these items unless requested by a member of the Council or a member of the public prior to the time the City Council votes on the motion to adopt.

6. LEGAL CHALLENGES: If you challenge a decision of the City Council in court, you may be limited to raising only those issues you or someone else raised at the meeting or in written correspondence delivered at, or prior to, the meeting. Actions challenging City Council decisions shall be subject to the time limitations contained in Code of Civil Procedure Section 1094.6.



Legislation Details (With Text)

File #: 17-298 **Version:** 1 **Name:**

Type: Closed Session **Status:** Agenda Ready

File created: 7/17/2017 **In control:** City Council

On agenda: 7/25/2017 **Final action:**

Title: Pursuant to Government Code Section 54957(b) PUBLIC EMPLOYEE PERFORMANCE EVALUATION - Title: City Manager (Discuss Annual Evaluation Per Employment Agreement)

Sponsors:

Indexes:

Code sections:

Attachments:

Date	Ver.	Action By	Action	Result
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Pursuant to Government Code Section 54957(b) PUBLIC EMPLOYEE PERFORMANCE EVALUATION - Title: City Manager (Discuss Annual Evaluation Per Employment Agreement)



Legislation Details (With Text)

File #: 17-300 **Version:** 1 **Name:**

Type: Closed Session **Status:** Agenda Ready

File created: 7/18/2017 **In control:** City Council

On agenda: 7/25/2017 **Final action:**

Title: Pursuant to Government Code Section 54956.9(a), Conference with Legal Counsel - Potential Litigation - Exposure to litigation in one (1) case.

Sponsors:

Indexes:

Code sections:

Attachments:

Date	Ver.	Action By	Action	Result
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Pursuant to Government Code Section 54956.9, Conference with Legal Counsel - Potential Litigation - Exposure to litigation in one (1) case.



Legislation Details (With Text)

File #: 17-294 **Version:** 1 **Name:**

Type: Introductions/Presentation **Status:** Agenda Ready

File created: 7/17/2017 **In control:** City Council

On agenda: 7/25/2017 **Final action:**

Title: Present Proclamation to the Celebrate Hercules Association Committee for their efforts on the 4th Annual 4th of July Celebrate Hercules Event

Sponsors:

Indexes:

Code sections:

Attachments: [Proclamation](#)

Date	Ver.	Action By	Action	Result
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Present Proclamation to the Celebrate Hercules Association Committee for their efforts on the 4th Annual 4th of July Celebrate Hercules Event

**PROCLAMATION RECOGNIZING CELEBRATE HERCULES ASSOCIATION
FOR THE 4TH OF JULY CELEBRATION EVENT 2017**

WHEREAS, the most recent 4th of July Celebration was held in 2017; and

WHEREAS, special thanks is due to Celebrate Hercules Association for hosting the 4th of July Celebration and for making the 4th of July Celebration in 2017 another successful event in Hercules; and

WHEREAS, Celebrate Hercules Association is a 501c3 organization and all donations made are tax deductible; and

WHEREAS, proceeds from this year's event will go to creating a memorial to honor all Veterans here in Hercules; and,

WHEREAS, the chairpersons for the event were Bill Shea, Event Director and Race Event Chairperson; Dee Lopez, Parade and Festival in the Park Chairperson; Steve Kirby, Master of Ceremonies and Entertainment Chairperson; and Rob Baldwin, Logistics Chairperson; and

WHEREAS, Celebrate Hercules Association and other community groups including the Friends of the Senior Center and the Police Explorers all played important roles in a successful day of events; and

WHEREAS, major corporate sponsors of \$1,000 or more for the celebration were Phillips 66, Ledcor, Bio-Rad, Lewis Homes, Kaiser Permanente, Print em all, Vincent Chen DDS and Eden Housing; and

WHEREAS, there were numerous community sponsors for the celebration in the sponsor categories of \$500 - \$999, under \$500 and In Kind Donations; and

WHEREAS, the 2017 4th of July Celebration Event included a 5k run event, 1 mile fun run or walk event, kids run for 3-7 year olds, the traditional 4th of July parade, the Festival in the park with a kids zone and live music and entertainment at Refugio Park; and

WHEREAS, there were approximately 400 runners, 55 parade entries, 50 vendors in the park, 30 committee members, 150 community volunteers on the 4th and over 3,000 participants that enjoyed the race, parade and festival in the park.

NOW, THEREFORE, BE IT PROCLAIMED that I, Myrna L. de Vera, Mayor of the City of Hercules, on behalf of the entire City Council and the Hercules community, do recognize the entire Celebrate Hercules Association and others for their dedication and hard work for the benefit of the community.

In witness whereof, I hereunto set my hand and cause the Seal of the City of Hercules to be affixed this 25th day of July 2017.

Myrna L. de Vera, Mayor



Legislation Details (With Text)

File #: 17-296 **Version:** 1 **Name:**

Type: Consent **Status:** Agenda Ready

File created: 7/17/2017 **In control:** City Council

On agenda: 7/25/2017 **Final action:**

Title: Minutes
Recommendation: Approve Minutes for the Regular City Council meeting of July 11, 2017.

Sponsors:

Indexes:

Code sections:

Attachments: [Agenda Item Review and Approval Form](#)
[City Council Minutes of July 11, 2017](#)

Date	Ver.	Action By	Action	Result
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Minutes

Recommendation: Approve Minutes for the Regular City Council meeting of July 11, 2017.

AGENDA ITEM REQUEST FORM

Department: Administrative Services

Department Director: Lori Martin

Phone: 799-8215

Meeting Date: July 25, 2017

Final Decision Date Deadline:

SUBJECT:

City Council Meeting Minutes for the July 11, 2017 Regular City Council Meeting

INDICATE APPROPRIATE BODY

☒ City Council

☐ Successor Agency to the Redevelopment Agency

☐ Public Finance Authority

☐ Finance Commission

☐ Planning Commission

☐ Community/Library Services Commission

☐ Oversight Board

☐ Other _____

ITEM

☐ Presentation/Introduction

☐ Study Session

☐ Grant Application/Acceptance

☐ Public Hearing

☐ Resolution

☐ Video/PowerPoint

☒ Consent Calendar

☐ Ordinance

☐ Discussion Action

☐ Contract/Agreement

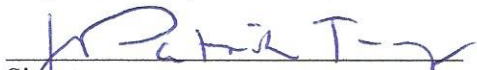
RECOMMENDED ACTION:

Approve the City Council meeting minutes of July 11, 2017.

☐ Copy of executed Resolution/Ordinance/Contract/Application required immediately upon approval.

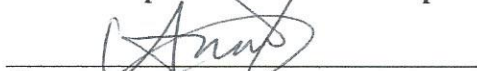
REVIEWED AND APPROVED FOR AGENDA:

City Attorney (if Contract, Ordinance or Resolution)


Signature

7-20-17
Date

Finance Department for Fiscal Impact


Signature

7/20/17
Date

City Manager


Signature

7/20/17
Date

AGENDA ITEM NO:

**CITY OF HERCULES
CITY COUNCIL MINUTES**

**July 11, 2017
6:00 p.m. Closed Session
7:00 p.m. Regular Meeting**

I. ROLL CALL – CALL TO ORDER – 6:00 P.M.

Present: Council Members Boulanger, Esquivias, Romero, Vice Mayor Kelley and Mayor de Vera
Absent: None.

II. PUBLIC COMMUNICATION – CLOSED SESSION ITEMS

Speakers: Pil Orbison.

III. CONVENE INTO CLOSED SESSION

1. Pursuant to Government Code Section 54957.6 CONFERENCE WITH LABOR NEGOTIATORS – City Negotiators: David Biggs, City Manager; Annie To, Director of Finance; Lori Martin, Director of Administrative Services relative to the following employee groups:

- Hercules Police Officers Association

2. Pursuant to Government Code Section 54957(b) PUBLIC EMPLOYEE PERFORMANCE EVALUATION – Title: City Manager (Discuss Annual Evaluation Per Employment Agreement).

3. Pursuant to Government Code Section 54957(b) PUBLIC EMPLOYEE DISCIPLINE/DISMISSAL/RELEASE - RETIREMENT

IV. REGULAR MEETING – 7:07 P.M.

RECONVENE TO OPEN SESSION - ROLL CALL

Present: Council Members Boulanger, Esquivias, Romero, Vice Mayor Kelley, Mayor de Vera

Absent: None.

V. REPORT ON ACTION TAKEN IN CLOSED SESSION

Action: City Attorney Tang announced that there is no final or reportable actions on Closed Session Items 1 or 2. City Attorney Tang reported action taken on Item 3 stating that City Council discussed a disability retirement application of a Police Officer and approved by a unanimous vote to approve a Resolution required by CalPERS to grant the Police Officer an Industrial Disability Retirement and advance his disability retirement payments consistent with State law until such time as CalPERS can issue the disability payments. City Attorney Tang stated that the Resolution approved by City Council is available upon request. City Attorney Tang reported that a motion was moved by Council Member Romero and seconded by Vice Mayor Kelley and the motion carried unanimously to approve the Resolution for Disability Retirement.

VI. PLEDGE OF ALLEGIANCE

VII. MOMENT OF SILENCE

Action: Mayor de Vera called for a moment of silence for the military plane crash in Mississippi that killed 16 people.

VII. INTRODUCTIONS/PRESENTATIONS – None.

1. Present Certificate of Appreciation to the Celebrate Hercules Association Committee for their efforts on the 4th Annual Celebrate Hercules 4th of July Event

Action: Mayor de Vera tabled this item to the July 25th Council meeting.

VIII. AGENDA ADDITIONS/DELETIONS

Action: City Manager Biggs identified the supplemental material provided prior to the meeting.

IX. PUBLIC COMMUNICATIONS

Speakers: Bob Polacchi, Pil Orbison

X. PUBLIC HEARINGS

1. Mandatory Garbage/Solid Waste Disposal Delinquent Accounts

Recommendation: Conduct a public hearing and upon conclusion, adopt a Resolution confirming the report of delinquent accounts and placing liens on said properties and special assessments upon property taxes pursuant to Hercules Municipal Code Section 5-1.01 to 5-2.16, Mandatory Garbage/Solid Waste Disposal.

Action: Mayor de Vera opened the public hearing at 7:20 p.m. Mayor de Vera closed the public hearing at 7:20 p.m. with no comments offered from the public.

Speakers: Janna Coverston.

Action: Moved by Council Member Romero, seconded by Council Member Boulanger to adopt Resolution 17-051. The motion carried by the following vote:

Aye: 5 – Council Members Boulanger, Esquivias, Romero, Vice Mayor Kelley, Mayor de Vera

XI. CONSENT CALENDAR

Action: Council Member Romero requested to pull Items 1 and 2 from Consent Calendar and vote on each individually.

1. Approval of Minutes

Recommendation: Approve Minutes for the City Council Meeting of June 13, 2017.

Action: Moved by Vice Mayor Kelley, seconded by Council Member Esquivias to approve the City Council meeting minutes of June 13, 2017. The motion carried by the following vote:

Ayes: Council Members: Esquivias, Boulanger, Vice Mayor Kelley, Mayor de Vera.

Nays: Council Member Romero.

2. Ordinance 502 Amending Hercules Municipal Code Title 7, Chapter 1 to Allow the City to Require the Addition of City Communications Infrastructure as a Condition of Approval of Any Permit Issued for an Excavation Project

Recommendation: Waive the second reading and adopt Ordinance 502 amending Hercules Municipal Code Title 7, Chapter 1.

Action: Council Member Romero recommended an amendment to Section 7-1.323(j)(1) of the Ordinance to change the language to reflect the City Manager may exempt projects and amend Section 7-1.323(j)(2) and (3) to City Manager instead of Director.

Action: Moved by Council Member Romero, seconded by Vice Mayor Kelley to adopt Ordinance 502 as amended. The motion carried by the following vote:

Ayes: Council Members: Esquivias, Boulanger, Romero, Vice Mayor Kelley, Mayor de Vera.

XII. DISCUSSION AND/OR ACTION ITEMS

1. Approve Memorandum of Understanding with the Hercules Police Officers Association

Recommendation: Adopt a Resolution Approving a Memorandum of Understanding with the Hercules Police Officers Association.

Speakers: None.

Action: Moved by Vice Mayor Kelley, seconded by Council Member Esquivias to adopt Resolution 17-052. The motion carried by the following vote:

Ayes: Council Members: Esquivias, Boulanger, Romero, Vice Mayor Kelley, Mayor de Vera.

2. Award a Construction Contract to O.C. Jones & Sons for the 2017 Pavement Maintenance Project

Recommendation: Adopt a Resolution authorizing the City manager to execute a construction contract in the amount of \$689,906 for the 2017 Pavement Maintenance Project and authorizing an additional expenditure of up to \$68,990 for a 10% contingency on said construction contract.

Action: Moved by Council Member Esquivias, seconded by Council Member Boulanger to adopt Resolution 17-053. The motion carried by the following vote:

Ayes: Council Members: Esquivias, Boulanger, Romero, Vice Mayor Kelley, Mayor de Vera.

3. Receive and File the Finance Commission's Annual Report on Measure B/O and C/A for FY 2015-16

Recommendation: Receive and file the report.

Speaker: Stanley Tom.

Action: The Finance Commission's Annual Report on Measure B/O and C/A was received and filed.

4. City Council 2017 Regular Meeting Dates

Recommendation: Review the schedule of City Council regular meeting dates for 2017 and consider cancelling the November 28th meeting due to the Thanksgiving Holiday closure schedule.

Action: By consensus City Council cancelled the regular meeting date of November 28, 2017. The regular meeting dates of August 22nd and December 26th remain cancelled and if needed may call a special meeting in December 2017.

5. **Consider Possible Reinstatement of City Council Health Benefits**

Recommendation: Receive report, discuss options, and if applicable, adopt a Resolution reinstating City Council medical insurance benefits.

Speakers: Mary Tobin Kelly, Sherry McCoy, John Delgado, Pil Orbison, Selina Williams, Lauren Barton.

Action: Moved by Council Member Romero, seconded by Council Member Boulanger to adopt Resolution 17-054 reinstating City Council health benefits at the Kaiser single level, annual cost not to exceed approximately \$45,000, and an opt out provision of 50%.

Action: A substitute motion was made and moved by Mayor de Vera, seconded by Vice Mayor Kelley to not reinstate the City Council health benefits. The motion failed by the following vote:

Ayes: Vice Mayor Kelley, Mayor de Vera.

Nays: Council Members: Boulanger, Esquivias, Romero

Action: Council Member Romero amended his motion to include language in the Resolution to allow a Council Member to waive health benefits and waive the opt-out provision of 50%, seconded by Council Member Boulanger. The motion passed by the following vote:

Ayes: Council Members: Esquivias, Boulanger, Romero.

Nays: Vice Mayor Kelley, Mayor de Vera.

6. **Receive Report on Strategic Planning Workshop and Hercules Strategic Plan 2017**

Recommendation: Receive and file report on Strategic Planning Workshop and adopt the Hercules Strategic Plan 2017.

Action: City Council discussed and made minor amendments to the plan and by consensus would like to review the strategic plan again prior to the next budget season and once a 5 year financial forecast report is provided.

Action: Moved by Vice Mayor Kelley, seconded by Council Member Esquivias to receive and file the report by Management Partners and accept the initial Hercules Strategic Plan 2017 as amended. The motion passed by the following vote:

Ayes: Council Members: Esquivias, Vice Mayor Kelley, Mayor de Vera.

Nays: Council Member Boulanger

Abstain: Council Member Romero

Action: Mayor de Vera recessed the meeting at 10:22 p.m.

Action: Mayor de Vera reconvened the City Council meeting at 10:28 p.m.

7. **Approve City Council Rules of Procedure, Sections 2.8, 4.7 and 6 and Review Sections 7 and 8**

Recommendation: Approve City Council Rules of Procedure, Section 2.8., 4.7 and 6 amended at the May 23, 2017 City Council meeting and review and recommend changes to Sections 7 and 8, if any.

Action: City Council made additional amendments to Section 2.8. No further amendments were recommended to Sections 4.7 and 6 and approved Sections 4.7 and 6 as presented. In addition, amendments were made to Sections 7 and 8 by consensus of the City Council.

Action: Moved by Council Member Romero, seconded by Vice Mayor Kelley to approve Sections 2.8, 4.7 and 6 as amended and to review additional redlined version of amendments

made to Sections 7 and 8 and to do a first review of Sections 9 – 11 at the August 8, 2017 City Council meeting. The motion passed by the following vote:

Ayes: Council Members: Esquivias, Boulanger, Romero, Vice Mayor Kelley, and Mayor de Vera.

8. Designation of Voting Delegate and Alternates for the League of California Cities Annual Conference and Business Meeting

Recommendation: Discuss and appoint a voting delegate and alternate(s) for the League of California Cities Annual Conference and Business Meeting to be held September 13-15, 2017 in Sacramento, CA.

Action: By consensus of City Council Mayor de Vera was appointed the voting delegate for the League of California Cities business meeting with Council Member Esquivias as Alternate 1 and Council Member Boulanger as Alternate 2.

9. Receive Report Regarding an Update on Current Development Sites within the City of Hercules

Action: City Manager Biggs gave a Power Point presentation on current, pending and public development sites within the City of Hercules.

Action: The report was received and filed.

XIII. PUBLIC COMMUNICATIONS (continued)

Speakers: None.

XIV. CITY COUNCIL/CITY MANAGER ANNOUNCEMENTS AND CITY COUNCIL COMMITTEE, SUB-COMMITTEE AND INTERGOVERNMENTAL COMMITTEE REPORTS

Action: Members of the City Council and staff reported on events and committee meetings.

XV. ADJOURNMENT.

Mayor de Vera adjourned the meeting at 10:56 p.m.

Myrna L. de Vera, Mayor

ATTEST:

Lori Martin, MMC
Administrative Services Director/City Clerk



Legislation Details (With Text)

File #: 17-295 **Version:** 1 **Name:**
Type: Discussion/Action Item **Status:** Agenda Ready
File created: 7/17/2017 **In control:** City Council
On agenda: 7/25/2017 **Final action:**
Title: Community Choice Energy (CCE) Program
Recommendation: Receive Report, Discuss, and Provide Direction, if any.

Sponsors:

Indexes:

Code sections:

Attachments: [Agenda Item Review and Approval Form](#)
[Staff Report - CCE Program](#)
[CCE Technical Study](#)
[CCE Technical Study Appendices](#)
[October 2016 Staff Report re Solar Choice](#)
[June 26 Staff Report CCE Technical Study MOU](#)

Date	Ver.	Action By	Action	Result
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Community Choice Energy (CCE) Program

Recommendation: Receive Report, Discuss, and Provide Direction, if any.

AGENDA ITEM REQUEST FORM

Department: City Manager's Office

Department Director: David Biggs

Phone: 799-8216

Meeting Date: July 25, 2017

Final Decision Date Deadline: July 25, 2017

SUBJECT:

Community Choice Energy (CCE) Program

INDICATE APPROPRIATE BODY

☒ City
Council

☐ Successor Agency to the
Redevelopment Agency

☐ Public Finance
Authority

☐ Finance
Commission

☐ Planning
Commission

☐ Community/Library
Services Commission

☐ Oversight Board

☐ Other _____

ITEM

☐ Presentation/Introduction

☐ Study Session

☐ Grant Application/Acceptance

☐ Public Hearing

☐ Resolution

☐ Video/PowerPoint

☐ Consent Calendar

☐ Ordinance

☒ Discussion Action

☐ Contract/Agreement

RECOMMENDED ACTION:

Receive Report, Discuss, and Provide Direction, if any.

☐ Copy of executed Resolution/Ordinance/Contract/Application required immediately upon approval.

REVIEWED AND APPROVED FOR AGENDA:

City Attorney (if Contract, Ordinance or Resolution)

W. D. H. T. - r
Signature

7.20.17
Date

Finance Department for Fiscal Impact

[Signature]
Signature

7/20/17
Date

City Manager

David Biggs
Signature

7/20/17
Date

AGENDA ITEM NO:



ACTION/DISCUSSION ITEM NO. XIII.1

STAFF REPORT TO THE CITY COUNCIL

DATE: Regular Meeting of July 25, 2017

TO: Members of the City Council

SUBMITTED BY: David Biggs, City Manager

SUBJECT: Community Choice Energy (CCE) Program

RECOMMENDATION: Receive Report, Discuss, and Provide Direction, if any.

COMMISSION/SUBCOMMITTEE ACTION AND RECOMMENDATION: Not applicable.

FISCAL IMPACT OF RECOMMENDATION: Joining a Community Choice Energy (CCE) program is projected to result in similar or lower electricity rates than charges by PG & E for comparable services. There may not be any direct up-front costs for the City to join My Clean Energy (MCE) other than staff time and some in-lieu services like office space if the City were able to join during an inclusion period like the one which just ended where MCE waived the not to exceed \$15,000 cost of a technical analysis; however, that is a decision which would have to be made by the MCE Board. MCE absorbs all of the initial launch expenses as it relates to consumer outreach and communication. Staff participation in a MCE Technical Advisory Committee and a Council Member serving as a Board Member would be on-going.

DISCUSSION: On June 26, 2016, the City Council approved a Memorandum of Understanding with the County and other cities to conduct a technical study to evaluate the costs and benefits of establishing or joining a joint powers authority Community Choice aggregation energy program (Attachment 1). The City of Hercules participated in the technical study and did not contribute to the cost. The technical study was completed in draft form in December, 2016, and it analyzed three options: create a new CCE program in Contra Costa County; join an existing program like My Clean Energy (MCE) or a program in formation; or remain with PG & E. The final technical study is attached (Attachment 2) including the technical appendixes (Attachment 3). In May, 2017, the County Board of Supervisor's elected to join MCE and as a result of the technical study and this decision, many other Contra Costa County jurisdictions have taken action to join MCE.

MCE provided incentives to communities who joined prior to June 30, 2017, namely the waiver of the technical analysis cost. Other priorities and workload issues did not allow for the City of Hercules

to take up the matter prior to June 30, 2017. Set forth below is a list of the cities which have joined MCE as provided by MCE:

Existing Members

Richmond
San Pablo
El Cerrito
Lafayette
Walnut Creek

Membership Requested/Pending MCE Board Approval

Contra Costa County (unincorporated)
Concord
Danville
Martinez
Moraga
Oakley
Pittsburg
Pinole
San Ramon

Antioch, Brentwood, Pleasant Hill, and Orinda, like Hercules, have not yet made a decision. The City of Clayton has determined they will not be joining MCE.

Should the City Council wish to join MCE, it would require that the matter be agendized to allow the City Council to introduce an Ordinance approving the Marin Clean Energy Joint Powers Agreement and for a resolution to be adopted requesting membership in Marin Clean Energy and to approve related actions. This would allow MCE to undertake a membership analysis and if favorable, MCE would approve the City's membership and we would become part of the Joint Powers Authority. Currently, given the number of communities which have joined recently, MCE advises that it is uncertain as to when Hercules could join the program if we applied.

A number of items of importance relate to this possible action. It should be noted that CCE programs operate on an opt-out basis. If the City Council approves the program, then MCE would become the default service provider for electricity in Hercules. However, customers can opt-out and continue to purchase their energy from PG & E. Prior to the beginning of MCE's operation, all electricity customers will receive at least four (4) "opt-out" notices during a 60 day period when anyone can opt-out of the program at no cost. Once the program is operational, then there is an additional 60-day period during which any customers can opt-out at no cost. After that, customers may opt-out for a nominal fee. After opting-out, the customer is prohibited from returning to MCE for a period of one year.

On September 27, 2016, the City Council approved the procurement of electricity for certain city facilities through the PG & E Solar Choice program (Attachment 4). Should the City elect to join MCE, the City could opt-out of the MCE program and could continue with PG & E for those facilities and services already enrolled in the Solar Choice program. This question would need to be addressed prior to the MCE services being offered in Hercules and during the opt-out period.

In addition, the City's unfavorable experience with the formation and subsequent dissolution of its own Hercules Municipal Utility (HMU) may require an enhanced level of communication and outreach to our residents to ensure the different nature of the CCE programs are understood.

Considerable background information is available in the attachments to this staff report. To the extent desired or required, Staff is prepared to provide additional information and to address any of the Council's questions as part of the matter being brought back for possible action at a future meeting.

ATTACHMENTS:

1. Staff report re Memorandum of Understanding.
2. CCE Technical Study
3. CCE Technical Study Appendices
4. Staff report re PG & E Solar Choice

Technical Study for Community Choice Energy Program in Contra Costa County

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List of Acronyms

AAEE	Additional Achievable Energy Efficiency
CAISO	California Independent System Operator
CBA	Collective Bargaining Agreement
CCA	Community Choice Aggregation
CCE	Community Choice Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
EE	Energy Efficiency
EBCE	East Bay Community Energy
ESPs	Energy Service Providers
FY	Fiscal Year
GHG	Greenhouse Gas
GRP	Gross Regional Product
GWh	Gigawatt-hour (= 1,000 MWhs)
IOU	Investor-Owned Utility
I/T	Information Technology
JEDI	Jobs and Economic Impact (model)
JPA	Joint Powers Authority
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
PCIA	Power Charge Indifference Adjustment
PEIR	Programmatic Environmental Impact Report
PG&E	Pacific Gas & Electric
REC	Renewable Energy Credit
REMI	Regional Economic Modeling Inc
RPS	Renewable Portfolio Standard
SB 350	Senate Bill 350
TURN	The Utility Reform Network

Executive Summary

Main Findings

1. This study finds that the jurisdictions in Contra Costa County studied¹ in this report have several options for implementing a Community Choice Energy (CCE) program that would likely result in lower greenhouse gas (GHG) emissions, increased local renewable energy generation, and increased local job creation compared to remaining with current electricity service from the Pacific Gas and Electric Company (PG&E).
2. The electricity rates charged under various CCE scenarios available to the jurisdictions covered in this study would likely be similar or less than the rates charged by PG&E for comparable service. The degree to which CCE rates are reduced below comparable PG&E rates depends in large part on the extent to which the CCE pursues policy objectives other than rate minimization in its energy procurement practices. Competing policy objectives may include increasing the supply of locally generated renewable energy, promoting energy efficiency, and maximizing local employment generated from a CCE program.
3. This study finds that Contra Costa County includes enough technically feasible locations to meet a significant proportion of electricity demand for the area studied through locally generated renewable energy. Forty percent of the technically feasible sites fall within the Northern Waterfront Economic Development Initiative area.
4. The implementation of a CCE program within the studied area is projected to create between 500 and 700 new jobs within Contra Costa County compared to remaining with current PG&E service, depending on the CCE option implemented.
5. This study compares three CCE program alternatives to current PG&E service and identifies the tradeoffs associated with these four alternatives. The decision of which program alternative to implement will require policy makers to balance costs and potential risks and benefits of each option, which are described in detail.

Purpose of this Study

Community Choice Energy is described in State law as “Community Choice Aggregation.” California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California to provide the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses. On March 15, 2016, the Contra Costa County (County) Board of Supervisors directed County staff to work with cities within the County to obtain electrical load data from PG&E for conducting a technical study of options for

¹ The communities constituting the “Contra Costa CCE” throughout the report are Antioch, Brentwood, Clayton, Concord, Danville, Hercules, Martinez, Moraga, Oakley, Orinda, Pinole, Pittsburg, Pleasant Hill, San Ramon, and unincorporated County. They do not include those communities already being served by the Community Choice Aggregator, MCE (El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek).

implementing CCE within the County’s unincorporated area and the 14 cities within the County not currently participating in a CCE program. The Board of Supervisors further directed the CCE technical study to compare alternatives for implementing CCE (i.e., establishing a Contra Costa County-Only CCE or joining one of the neighboring CCEs – MCE, formerly Marin Clean Energy, or East Bay Community Energy) to the option of remaining with PG&E.

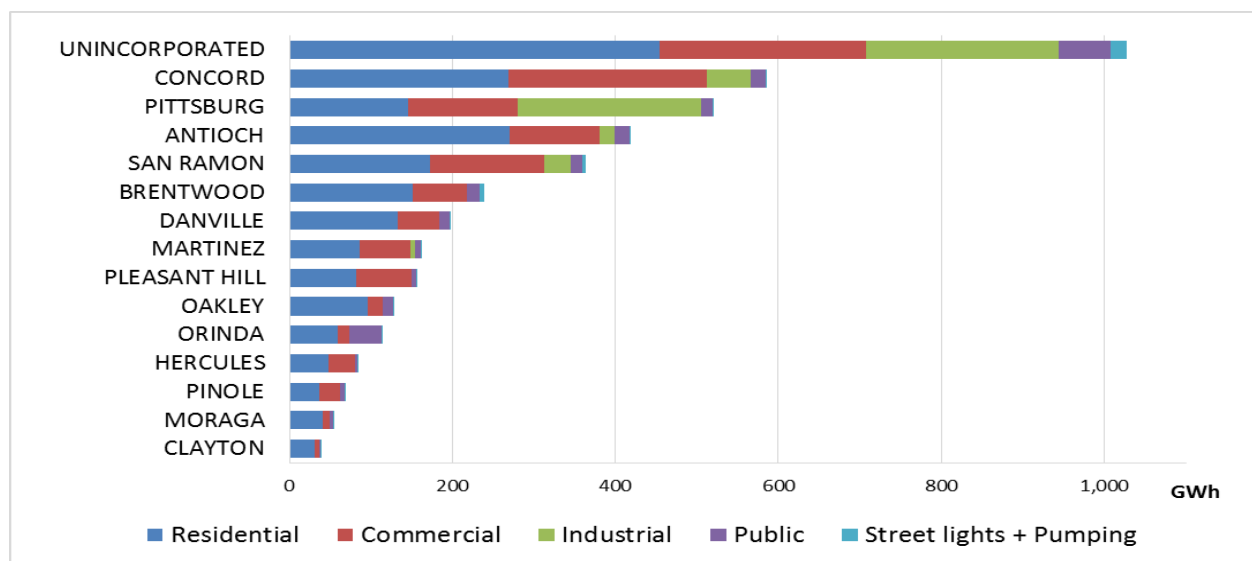
To assess whether a stand-alone CCE is “feasible” in Contra Costa County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

- Quantifies the electric loads that a Contra Costa County CCE would serve;
- Includes analysis of in-county renewable generation;
- Compares the rates that could be offered by the CCE to PG&E’s rates;
- Calculates the macroeconomic development and employment benefits of CCE formation; and
- Compares the benefits and risks of forming a CCE or joining a neighboring CCE versus remaining on PG&E bundled service.

Loads and Forecast

Figure ES-1 provides a snapshot of Contra Costa County bundled electric load in 2015 by city and by rate class.² As the figure shows, total bundled electricity load in 2014 from Contra Costa County was approximately 4,000 GWh. The unincorporated areas of the County represented 25% of County load, and the cities of Concord and Pittsburg were together responsible for another 25%. Residential and commercial customers made up most the County load, with smaller contributions from the industrial and public sectors.

² “Bundled” load includes only load for which PG&E supplies the power; it excludes load from Direct Access customers, load in the jurisdiction of another CCE provider, and load met by customer self-generation. This excludes load originating in the cities of El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek, which are served by MCE.

Figure ES-1. PG&E's 2015 Bundled Load in Contra Costa County

CCE Power Supplies

The CCE's primary function is to procure supplies to meet the electrical loads of its customers. By law, the CCE must also supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS) requires 33% renewable energy supply by 2020, increasing to 50% by 2030. The CCE may additionally choose to source a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio. The CCE may also use its procurement function to meet other objectives, such as sourcing a portion of its supply from local projects to promote economic development in the County. The four supply scenarios considered in this analysis are summarized in Table ES-1.

Table ES-1: Four Scenarios Modeled³

Scenario:	1	2	3	4
% RPS-Eligible in 2020	33%	50%	33%	50%
% RPS-Eligible in 2030	50%	80%	50%	80%
Share of RPS-Eligible from Local Resources	0%	0%	50%	50%

³ Customer-sited solar is not considered RPS-eligible in California and is not included in the RPS procurement in these scenarios. Customer-sited solar is incorporated in this analysis as a reduction to the CCE's load.

Local Renewable Development

The CCE may choose to contract with or develop renewable projects within Contra Costa County to promote economic development or reap other benefits. This study found 1,395 parcels that met the established criteria and 1,875 individual sites within the identified parcels where either a solar shade structure, large rooftop, or ground mounted system could be developed. Table ES-2 shows the total solar PV generation capacity within the County based on the methodology and assumptions in Chapter 3.

Table ES-2. Total PV Solar Generation Potential and Build Cost

	Ground Mount	Shade Structure	Roof Mounted	Total
PV Capacity (MW)	1,891	1,320	144	3,355
PV Production (GWh)	3,025	2,113	230	5,369
Build Cost (\$ Millions)	\$3,417	\$3,977	\$371	\$7,660
Build Cost (\$/Watt)	\$1.99	\$3.10	\$2.62	\$2.56
No of PV Systems	845	886	144	1,875

CCE Rate Analysis Results

Scenarios 1 and 3 (Simple Renewable Compliance)

In Scenario 1, the CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% proposed target between 2030 and 2038. Annual GHG emissions are 50% lower on average than PG&E's forecasted annual GHG emissions by assuming a fraction of the non-RPS power is provided by large hydroelectric resources.

Figure ES-2 summarizes the results of Scenario 1. The figure shows the total average cost of the Contra Costa County CCE to serve its customers (vertical bars) and the comparable PG&E generation rate (line).⁴ Of the CCE cost elements, the greatest cost is for non-renewable generation (including large hydroelectric), followed by the cost for renewable generation, which increases over the years per the RPS requirements. Another important CCE customer cost is the Power Charge Indifference Adjustment (PCIA), which is the mandated charge that State regulators require PG&E to impose on all CCE customers.⁵

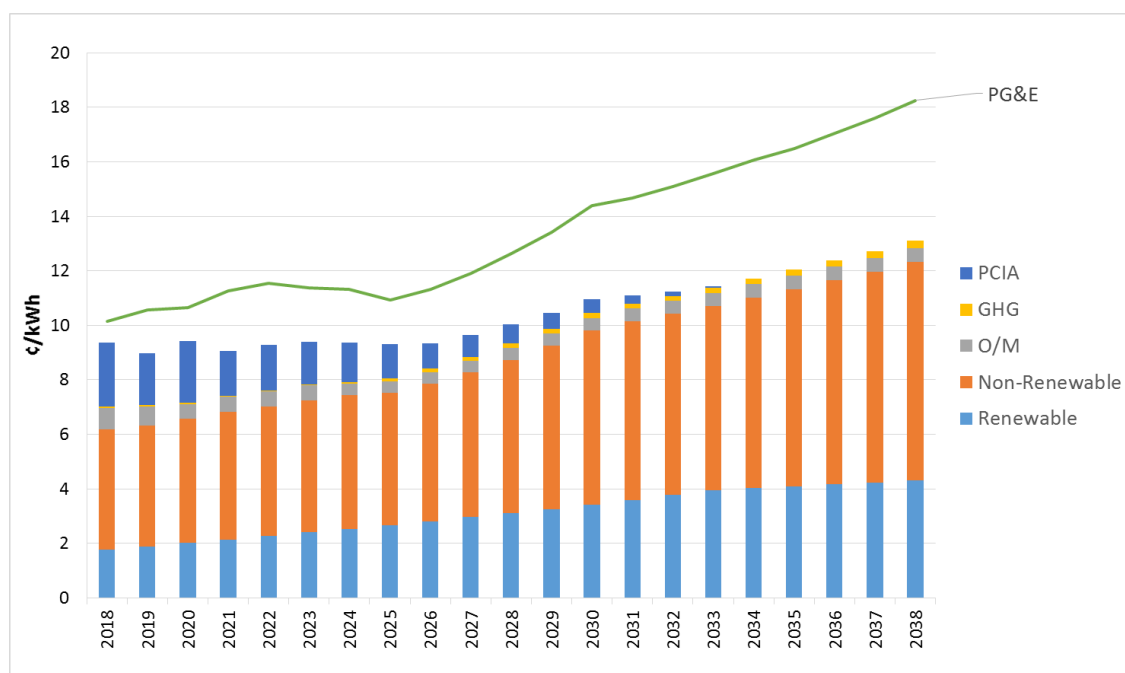
⁴ All rates are in nominal dollars. Note that these are NOT the full rates shown on PG&E bills. They are only the generation portion of the rates. Other parts of the rate, such as transmission and distribution, are not included, as customers pay the same charges for these components regardless of who is providing their power.

⁵ Per current regulations, the PCIA fee is expected to decrease in most years beginning in 2019 and to have less of an impact on CCE customer rates over time as resources expire from PCIA eligibility for CCE customers. However, given that PCIA regulations are subject to change, the possibility that PCIA rates may not decrease as expected is considered in the High PCIA scenario.

Under Scenario 1, the differential between PG&E generation rates and the average cost for the Contra Costa County CCE to serve its customers (*aka* the CCE rates) is positive in each year (i.e., CCE rates are lower than PG&E rates). As a result, Contra Costa County CCE customers' average generation rate (including contributions to the CCE's reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year.

Scenario 3 is the same as Scenario 1 except that by 2028 one-half of the renewable power is provided by local resources. The differential between PG&E generation rates and Contra Costa County CCE customer rates in Scenario 3 is lower than in Scenario 1; the expected Contra Costa County CCE rates continue to be lower than the forecast PG&E generation rates for all years from 2018 to 2038.

Figure ES-2. Scenario 1 Forecast Average CCE Cost and PG&E Rates, 2018-2038



Scenarios 2 and 4 (Accelerated RPS)

Under Scenario 2, the Contra Costa County CCE starts with 50% of its load being served by renewable sources in 2017, and increases this at a quick pace to 80% renewable energy content by 2030. Scenario 4 is the same as Scenario 2 except that by 2027 one-half of the renewable power is provided by local resources.

The differential between PG&E generation rates and Contra Costa County CCE customer rates in Scenarios 2⁶ and 4 is narrower than in Scenarios 1 and 3. Still, the expected Contra Costa County CCE rates continue to be lower on average than the forecast PG&E generation rates for all years from 2018 to 2038. However, for Scenario 4—very high local renewable penetration—

⁶ After 2033, the Contra Costa County CCE rates are lower for Scenario 2 than Scenario 1.

the modeling suggests that the CCE might not be able to beat PG&E rates in the 2025-2030 timeframe. (See Chapter 3 for details).

Greenhouse Gas Emissions

Under Scenarios 1 and 3, we include enough GHG-free hydroelectric power so that the Contra Costa County CCE's GHG emissions rate is about half of PG&E's GHG emissions rate. This requires using large hydroelectric power for 35% of the CCE's generation portfolio, on average, from 2018 to 2038. Though this large hydroelectric power would not qualify for RPS requirements, it is considered a non-GHG emitting resource.⁷ Under Scenarios 2 and 4 these additions of large hydro power are not needed once the high renewable targets are met. The result is a portfolio that averages 20% large hydro from 2018 to 2038.

Tables ES-4 shows GHG emissions from 2018-2038 for the Contra Costa County CCE in each Scenario and what PG&E's emissions would be for the same load if no CCE were formed. Overall, the CCE is projected to reduce GHG emissions from the County by about half. This result is due in large part to not only the assumed renewable generation, but also the hydroelectric power assumed to be part of the CCE's supply mix.

Note that the analysis assumes "normal" hydroelectric output for PG&E. During the drought years, PG&E's hydro output has been at about 50% of normal, and the utility has made up these lost megawatt-hours through additional gas generation. This means that the "normal" PG&E emissions shown here are lower than the "current" emissions. If, as is expected by many experts, the recent drought conditions are closer to the "new normal", then PG&E's GHG emissions in the first 8 years would be approximately 30% higher. Depending on whether the CCE were similarly affected by limited hydroelectric supply, the CCE's emissions may increase as well.

Table ES-4. Comparative GHG total emissions for PG&E and Contra Costa CCE

GHG emissions	PG&E (KTonnes) ⁸	Contra Costa CCE (KTonnes)	Savings (%)
Scenario 1	5,882	2,957	50%
Scenario 2	5,882	2,693	54%
Scenario 3	5,882	2,957	50%
Scenario 4	5,882	2,693	54%

⁷ While there is a limited supply of uncontracted large hydroelectric power, other operating CCEs have been successful in procuring this resource. To account for the limited supply, we added a 10% premium to the cost of this power.

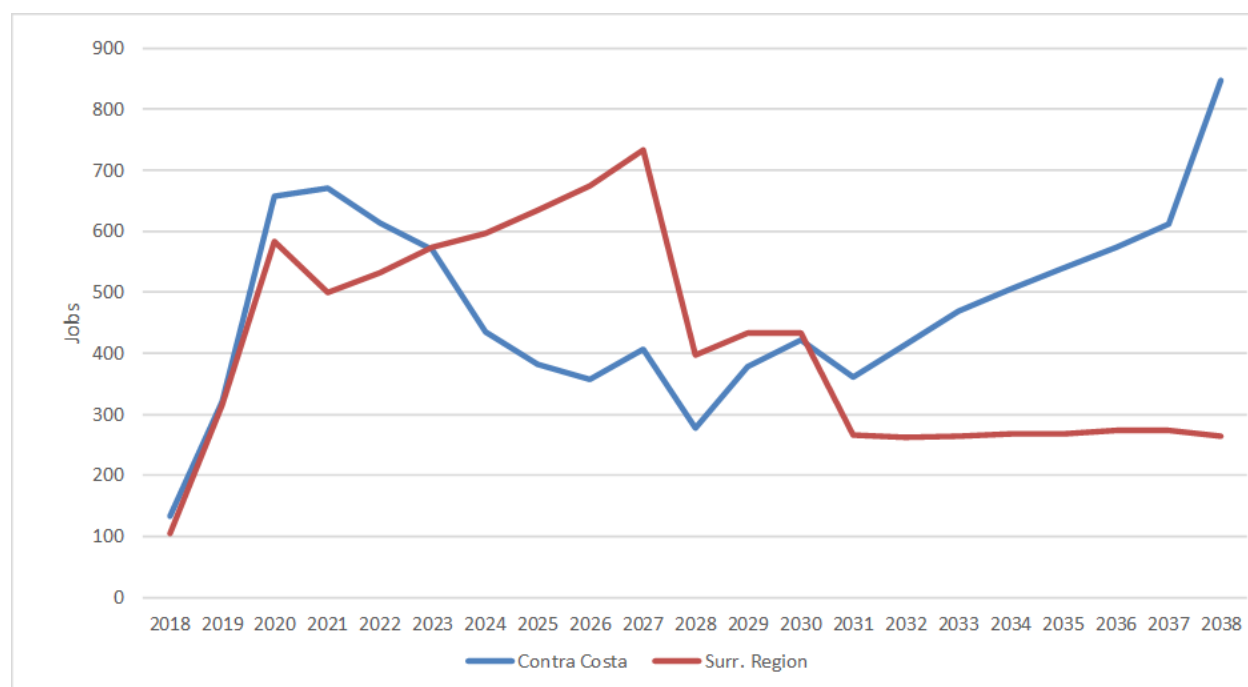
⁸ Thousands of metric tons.

Macroeconomic and Job Impacts

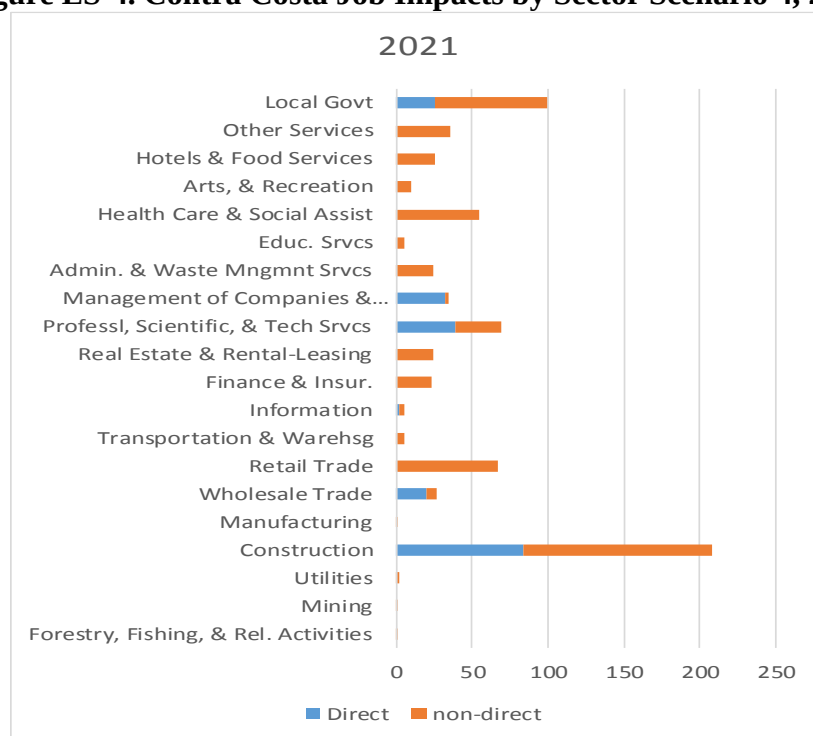
The local economic development and jobs impacts for the four scenarios were analyzed using the dynamic input-output macroeconomic model developed by Regional Economic Models, Inc. (REMI). The model accounts for not only the impact of direct CCE activities (e.g., local project installations for two of the four scenarios, program administration), but also how the rate savings that County households and businesses might experience with a CCE ripple through the local economy, creating more jobs and regional economic growth.

A CCE can also offer positive economic development and employment benefits to the County. The CCE could create approximately 500 to 700 additional annual jobs on average in the County plus an additional 50 to 400 jobs in the neighboring counties, depending on the scenario. The job impacts include not just the stimulus from program-related effects but jobs resulting from *multiplier effects* and *competitiveness effects*. Scenario 4 – with the smallest of *net* rate savings for the County’s electric customers contains the largest investment for small solar across the local economy. Figure ES-3 illustrates this through high-level results expressed as annual job changes for the Scenario 4.

Figure ES-3. Scenario 4 Regional Annual Jobs Impacts, 2018 to 2038



The economic activity generated by the CCE results in incremental employment in a variety of sectors. Figure ES-4 shows the estimated job impacts (direct and indirect) by sector for Scenario 4 in 2021 (the year in which the CCE’s assumed solar investment is maximum).

Figure ES-4. Contra Costa Job Impacts by Sector Scenario 4, 2021

Comparative Analysis of CCE Options

Having the County and cities within the County form their own Joint Powers Authority (JPA) and CCE Program is not the only possibility for CCE participation. First, the County and/or its cities may join MCE (formerly Marin Clean Energy). In fact, five cities in the County—El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek—are already members of MCE. These cities joined between 2012 and 2016, and have full standing on MCE’s board of directors. Second, the County and/or its cities could join East Bay Community Energy (Alameda County, EBCE). While this CCE has just been formed—the JPA board met for the first time in January 2017—it intends to begin delivery of power in early 2018. Furthermore, the County and each city need not join one or the other CCE *en masse*, but instead can join one or the other CCEs individually (or neither).

Table ES-5 below provides a qualitative summary of the differences and similarities among these options. While a quantitative comparison would appear to provide more rigor, in this case it would provide only false precision. First and foremost, two of the potential CCE options are with entities which, while potentially viable, do not yet exist. Without power contracts, portfolios, or procurement guidelines and policies, it would be unwise to claim that EBCE or a potential Contra Costa-only CCE would have rates or greenhouse gas emissions higher or lower than the other. Comparisons against MCE can be somewhat more reasonably asserted; however, MCE’s stated goals—greater renewable energy content, lower greenhouse gas emissions, local generation, and comparable rates—are nearly identical to those stated by EBCE, making long-range rate and emissions distinctions immaterial. Thus, the qualitative comparisons provided in

the table do not provide sharp distinctions between the CCE options.⁹ All these options are expected to provide similar rates and GHG emissions, with differences arising from variations in the priorities and procurement decisions of the individual governance boards. What truly distinguishes these options are primarily governance options (i.e., in-county only versus shared with other entities) and the amount of risk assumed (i.e., developing or signing on with a new CCE versus joining one with a record of satisfactory performance).

Table ES-5. Comparison of Contra Costa CCE Options

Criterion	Form CCCo JPA	Join MCE	Join EBCE	Stay with PG&E
Rates	Likely lower	Likely Lower	Likely Lower	Base
GHG Reduction Potential Over Forecast Period	Some	Some	Some	Base
Local Control/Governance	Greatest	Some	Some	None
Local Economic Benefit Potential	Greatest	Some	Some	Minimal
Start Up Costs/Cost to Join	Low, but greater risk ¹⁰	None	None	None
Level of Effort	Greatest	Minimal	Greater	None
Program Risks	Greatest	Minimal	Some	Base
Timing (earliest)	Late-2018	Late-2017	Mid-2018	N/A

⁹ Differences between the CCE options and the option to stay with PG&E are more marked and better quantifiable, given that information on PG&E's power portfolios, procurement plans, and costs are at least partially available through various filings and applications PG&E has made before the CPUC. The comparisons provided above between the CCE's rates and PG&E's rates takes advantage of this information and market data on power procurement costs to develop quantitative comparisons between the CCE and PG&E options.

¹⁰ Start-up costs incurred by the County or others are likely to be reimbursed by the JPA.

Conclusions

Overall, a CCE in Contra Costa County appears feasible. Given current and expected market and regulatory conditions, a Contra Costa County CCE should be able to offer its residents and businesses electric rates that are less than those available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of local renewable energy are assumed in the CCE portfolio, combined with other negative factors such as higher PCIA rates, higher prices for local renewable power, or lower PG&E costs, do PG&E's rates become consistently more favorable than the CCE's.

A Contra Costa County CCE would also be well positioned to help facilitate greater amounts of renewable generation to be installed in the County. Because the CCE would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would occur with a CCE in the County than without it.

The CCE can also reduce the amount of greenhouse gases emitted in the County if the CCE prioritizes this goal. Because PG&E's supply portfolio has significant carbon-free generation (from large hydroelectric and nuclear generators), the CCE would need to contract for significant amounts of hydroelectric or other carbon-free power above and beyond the required qualifying renewables to reduce the County's GHG footprint from electricity use. This analysis assumes that the CCE procures enough GHG-free generation to halve PG&E's GHG emissions rate, subject to constraints on the minimum share of market supplies in the CCE portfolio.

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 700 new jobs in the County plus additional jobs in neighboring counties. What may be surprising is that many of the economic benefits can come from reduced rates: residents and, more importantly, businesses can spend and reinvest their bill savings, and thus generate greater economic impacts.

While the analytical focus of this report has been on a stand-alone Contra Costa County CCE, that is not the only choice for Contra Costa communities (not already in MCE). Overall, there is insufficient data to suggest that a stand-alone Contra Costa CCE would offer lower rates or greater GHG savings than joining MCE or EBCE. Either forming or joining a CCE would likely offer modestly lower rates, more local economic development, and similar or lower GHG emissions than remaining with PG&E. Joining MCE would likely result in the quickest and least risky path to CCE implementation, however at a loss of local input into CCE policy formation. Because it has yet to be formed, joining with EBCE would take longer than joining the already-established MCE, but would offer greater input into the CCE's policies and formation.

Although all the CCE program options available to the jurisdictions studied would likely provide both environmental and economic benefits compared to PG&E, continuing service from PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service. PG&E is an experienced power provider and is regulated by the State. Furthermore, remaining with PG&E does not require the jurisdiction to take any action. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a higher PCIA rate.

Chapter 1: Introduction

On March 15, 2016, the Contra Costa County (County) Board of Supervisors directed County staff to work with cities within the County to obtain electrical load data from the Pacific Gas and Electric Company (PG&E) for the purpose of conducting a technical study of options for implementing Community Choice Energy (CCE) within the County's unincorporated area and the 14 cities within the County not currently participating in a CCE program. The Board of Supervisors further directed the CCE technical study to compare the following alternatives for implementing CCE to the option of remaining with current electrical service from PG&E:

1. Form a new Joint Powers Authority (JPA) of the County and interested cities within Contra Costa County for the purpose of CCE;
2. Form a new JPA in partnership with Alameda County and interested cities in both counties; and
3. Join the existing CCE program initiated in Marin County, known as Marin Clean Energy (MCE).

The County and the 14 Contra Costa cities not currently participating in a CCE program all authorized the collection of load data from PG&E for this technical study. In addition, the County and the cities of Brentwood, Clayton, Concord, Martinez, Pleasant Hill, Pittsburg, and San Ramon, and the Towns of Danville and Moraga, contributed funding for the completion of this study.

What is a CCE?

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation (also known as Community Choice Energy or "CCE") in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses.

Under existing rules administered by the California Public Utilities Commission (CPUC), PG&E must use its transmission and distribution system to deliver the electricity supplied by a CCE in a non-discriminatory manner. That is, it must provide these delivery services at the same price and at the same level of reliability to customers taking their power from a CCE as it does for its own full-service customers. By state law, PG&E also must provide all metering and billing services such that customers receive a single electric bill each month from PG&E, which would differentiate the charges for generation services provided by the CCE from the charges for PG&E delivery services. Money collected by PG&E on behalf of the CCE must be remitted in a timely fashion (e.g., within 3 business days).

As a power provider, the CCE must abide by the rules and regulations placed on it by the State and its regulating agencies, such as maintaining demonstrably reliable supplies, fully cooperating with the State's power grid operator, and meeting renewable procurement requirements. However, the State has no rate-setting authority over the CCE; the CCE may set rates as it sees fit so as to best serve its constituent customers.

Per California law, when a CCE is formed all the electric customers within its boundaries will be placed, by default, onto CCE service. However, customers retain the right to return to PG&E service at will, subject to whatever administrative fees the CCE may choose to impose.

California currently has five active CCE Programs: MCE, serving Marin County and selected neighboring jurisdictions, including five cities in Contra Costa County; Sonoma Clean Power, serving Sonoma County; CleanPowerSF, serving San Francisco City and County; Peninsula Clean Energy, serving San Mateo County; and Lancaster Choice Energy, serving the City of Lancaster (Los Angeles County). Numerous other local governments are also investigating CCE formation, including Alameda County; Los Angeles County; Monterey Bay region; Santa Barbara, San Luis Obispo and Ventura Counties; ; the City of Davis and Yolo County; and Humboldt County to name a few.

Assessing CCE Feasibility

In order to assess whether a CCE is “feasible” in Contra Costa County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

- Quantifies the electric loads that a Contra Costa County CCE would serve;
- Estimates the costs to start-up and operate the CCE;
- Considers four scenarios with differing assumptions concerning the amount of GHG-free power and local renewable power being supplied to the CCE so as to assess the costs, greenhouse gas emissions reductions, and local economic development opportunities possible with the CCE;
- Includes analysis of in-county renewable generation;
- Compares the rates that could be offered by the CCE to PG&E’s rates;
- Quantitatively explores the rate competitiveness of the four scenarios to key input variables, such as the cost of natural gas;
- Calculates the macroeconomic development and employment benefits of CCE formation; and
- Compares the benefits and risks of forming a CCE or joining a neighboring CCE versus remaining on PG&E bundled service.

For comparison, the differences in the results between this study and that conducted for Alameda County will be described and underlying reasons explained.

The communities constituting the “Contra Costa CCE” in this study are: Antioch, Brentwood, Clayton, Concord, Danville, Hercules, Martinez, Moraga, Oakley, Orinda, Pinole, Pittsburg, Pleasant Hill, San Ramon, and unincorporated County. They do not include the communities already being served by the Community Choice Energy provider MCE (El Cerrito, Lafayette, San Pablo, Richmond and Walnut Creek).

This study was conducted by MRW & Associates, LLC (MRW). MRW was assisted by Sage Renewables, which conducted the local renewable energy potential study, and by Economic Development Research Group, which conducted the macroeconomic and jobs analysis contained in the study.

This study is based on the best information available at the time of its preparation, using publicly available sources for all assumptions to provide an objective assessment regarding the prospects of CCE operation in the County. It is important to keep in mind that the findings and recommendations reflected herein are substantially influenced by current market conditions within the electric utility industry, which are subject to sudden and significant changes.

Chapter 2: Economic Study Methodology and Key Inputs

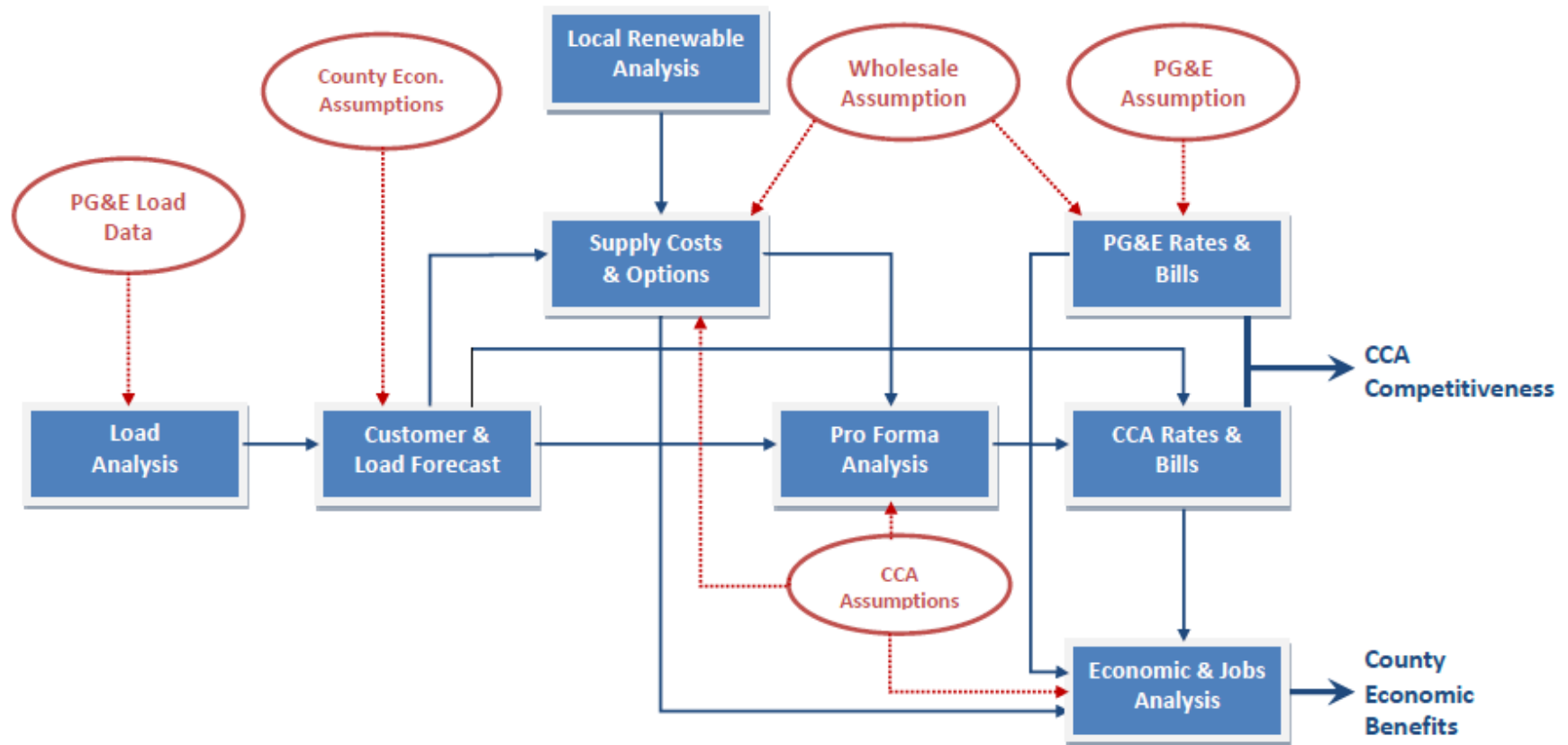
This Chapter summarizes the key inputs and methodologies used to evaluate the cost-effectiveness and cost-competitiveness of a Contra Costa CCE relative to PG&E under different scenarios.¹¹ It considers the regulatory requirements that a Contra Costa County CCE would need to meet (e.g., compliance with renewable portfolio standard (RPS) requirements), the resources that the County has available or could obtain to meet these requirements, and the PG&E rates against which the CCE would compete. It also describes the pro forma analysis methodology that is used to evaluate the financial feasibility of the CCE.

The load and rate forecasts go out twenty years—through 2038. While all forecasting contains an element of uncertainty, the years beyond 2030 are particularly uncertain and should be seen as broadly indicative and not predictive.

Understanding the interrelationships of all the tasks and using consistent and coherent assumptions throughout are critical to developing a meaningful analysis. Figure 1 shows the analysis elements (blue boxes) and major assumptions (red ovals) and how they relate to each other. As the figure illustrates, there are numerous interrelationships between the tasks. For example, the load forecast is a function of not only the load analysis, but also of projections of economic activity in the County.

Two important points are highlighted in this figure. First, it is critical that wholesale power market assumptions are consistent between the CCE and PG&E. While there are reasons that one might have lower or higher costs than the other for a particular product (e.g., CCEs can use tax-free debt to finance generation projects while PG&E cannot), both will participate in the wider Western U.S. gas and power markets and therefore will be subject to the same underlying market forces. Applying different power cost assumptions to the CCE than to PG&E, such as simply escalating PG&E rates while deriving the CCE rates using a bottom-up approach, would produce erroneous results. Second, virtually all elements of the analysis feed into the economic and jobs assessment. As is described in detail in Chapter 5, this Study uses a state-of-the art macroeconomic model that can account for numerous activities in the economy, which allows for a much more comprehensive—and accurate—assessment than a simple input-output model.

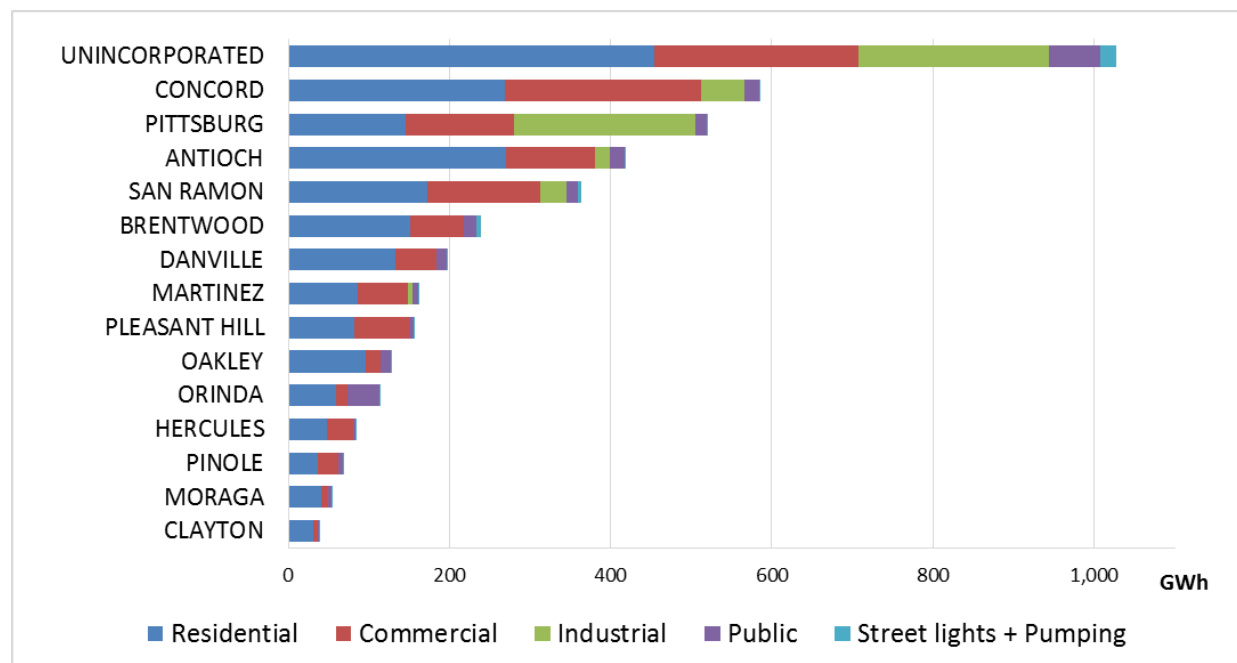
¹¹ The relative costs and merits of joining CCEs in neighboring counties are addressed in Chapter 7.)

Figure 1. Task Map

Contra Costa County Loads and CCE Load Forecasts

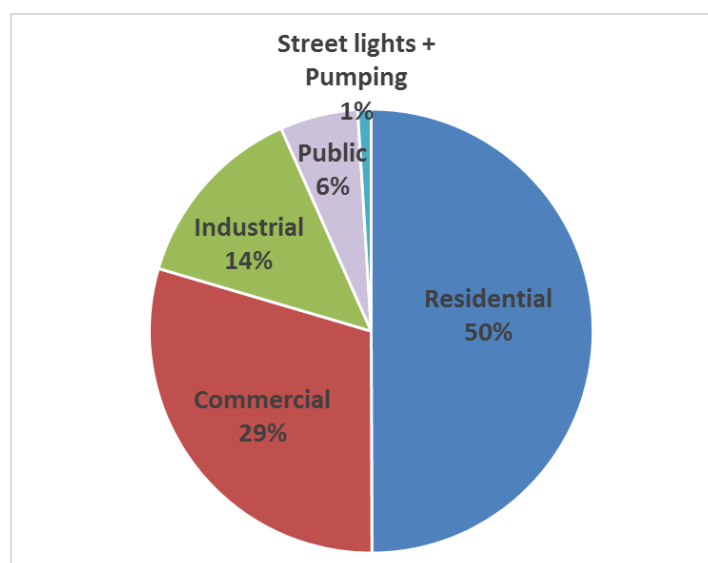
MRW used PG&E bills from 2015 for all PG&E bundled service customers within the Contra Costa County region as the starting point for developing electrical load and peak demand forecasts for the Contra Costa County CCE program.¹² Figure 2 provides a snapshot of Contra Costa County bundled load in 2015 by city and by rate class. PG&E's total electricity load in 2015 from these customers was approximately 4,000 GWh.¹³ The unincorporated areas of the County represented 25% of County load, and the cities of Concord and Pittsburg were together responsible for another 25%. Residential and commercial customers made up most of the County load, with smaller contributions from the industrial and public sectors (Figure 3). This same sector-level distribution of load is also apparent at the jurisdictional level for most cities (Figure 2), except for the City of Pittsburg, which has a significant industrial-sector footprint.

Figure 2. PG&E's 2015 Bundled Load in Contra Costa County by Jurisdiction and Rate Class



¹² Detailed monthly usage data provided by PG&E to Contra Costa County. "Bundled" load includes only load for which PG&E supplies the power; it excludes load from Direct Access customers, load in the jurisdiction of another CCE provider, and load met by customer self-generation. This excludes load originating in the cities of El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek, which are served by MCE.

¹³ As determined from bill data provided by PG&E.

Figure 3. PG&E's 2015 Bundled Load in Contra Costa County by Rate Class

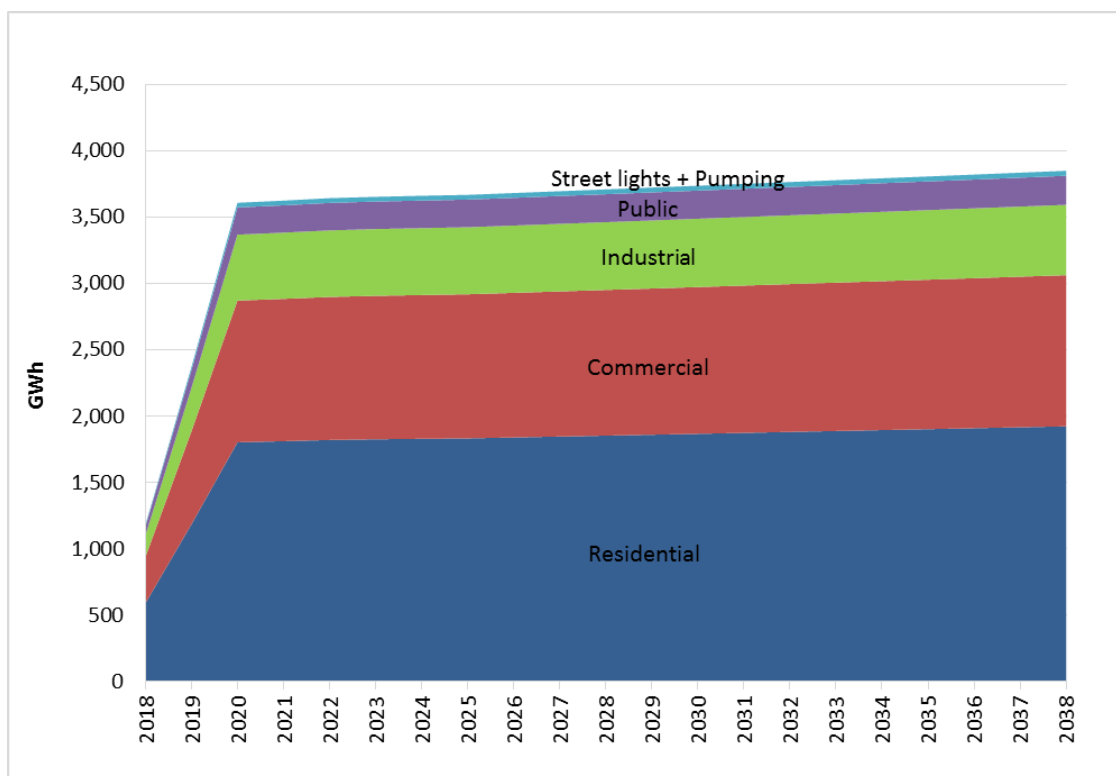
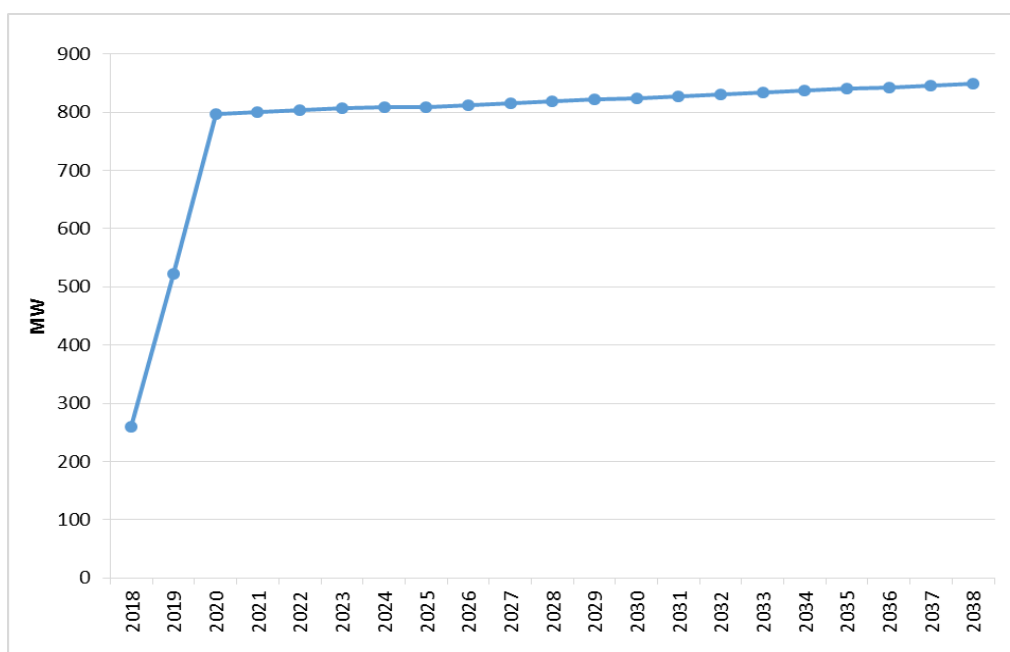
To estimate CCE loads from PG&E's 2015 bundled loads, MRW assumed a CCE participation rate of 85% (i.e., 15% of customers opt to stay with PG&E) and a three-year phase in period from 2018 to 2020, with 33% of potential CCE load included in the CCE in 2018, 67% in 2019, and 100% in 2020. To forecast CCE loads through 2038, MRW used a 0.4% annual average growth rate, consistent with the California Energy Commission's most recent electricity demand forecast for PG&E's planning area.¹⁴ The CCE load forecast is summarized in Figure 4, which shows annual projected CCE loads by class.

To estimate the CCE's peak demand in 2015,¹⁵ MRW multiplied the load forecast for each customer class by PG&E's 2015 hourly ratio of peak demand to load for that customer class.¹⁶ MRW extended the peak demand forecast to 2038 using the same growth rates used for the load forecast. The peak demand forecast is summarized in Figure 5.

¹⁴ California Energy Commission. Form 1.1c California Energy Demand Updated Forecast, 2015 - 2025, Mid Demand Baseline Case, Mid AAEE Savings. January 20, 2015
http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/LSE_and_BA/

¹⁵ Peak demand is the maximum amount of power the CCE would use at any time during the year. It is measured in megawatts (MW). The CCE must have enough power plants on (or contracted with) at all times to meet 115% of the expected peak demand.

¹⁶ Data obtained from PG&E's dynamic load profiles for Public, Industrial, Commercial, and Residential customers (https://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml) and static load profiles for Pumping and Streetlight customers (https://www.pge.com/nots/rates/2016_static.shtml#topic2).

Figure 4: CCE Load Forecast by Class, 2018-2038¹⁷**Figure 5. CCE Peak Demand Forecast, 2017-2038**

¹⁷ Load forecasted assumes 85% participation and three-year phase-in.

CCE Supplies

The CCE's primary function is to procure supplies to meet the electrical loads of its customers. This requires balancing energy supply and demand on an hourly basis. It also requires procuring generating capacity (i.e., the ability to provide energy when needed) to ensure that customer loads can be met reliably.¹⁸ In addition to meeting the energy and capacity needs of its customers, the CCE must meet other procurement objectives. By law, the CCE must supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS) requires 33% renewable energy supply by 2020, increasing incrementally to 50% by 2030. According to PG&E's Diablo Canyon nuclear plant retirement application, PG&E may commit to purchasing additional renewable supply, targeting up to 55% of the total generation between 2030 and 2038, which the CCE would presumably at least match. The CCE may additionally choose to source a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio. The CCE may also use its procurement function to meet other objectives, such as sourcing a portion of its supply from local projects to promote economic development in the County.

The Contra Costa County CCE would be taking over these procurement responsibilities from PG&E for those customers who do not opt out of the CCE to remain bundled customers of PG&E. To retain customers, the CCE's offerings and rates must compete favorably with those of PG&E.

The CCE's specific procurement objectives, and its strategy for meeting those objectives, will be determined by the CCE through an implementation plan, startup activities, and ongoing management of the CCE. A primary purpose of this portion of the study is to assess the feasibility of establishing a CCE to serve Contra Costa County based on a forecast of costs and benefits. This forecast requires making certain assumptions about how the CCE will operate and the objectives it will pursue. To address the uncertainty associated with these assumptions, we have evaluated four different supply scenarios and have generally made conservative assumptions about the ways in which the CCE would meet the objectives discussed above. In no way does this study prescribe actions to be taken by the CCE should one be established.

The four supply scenarios that we considered in this analysis are summarized in Table 1 and are described as follows:

1. **Minimum RPS Compliance:** The CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% RPS target after 2030. Annual GHG emissions from the CCE portfolio are halved relative to PG&E's bundled portfolio

¹⁸ The California Public Utilities Commission requires that CCEs and other load serving entities demonstrate that they have procured resource adequacy capacity to meet at least 115% of their expected peak load. Because Contra Costa County falls within the Greater Bay Area Local Reliability Area, the Contra Costa County CCE must also meet its share of local resource adequacy requirements.

through the addition of large hydroelectric power purchases, subject to a constraint that 5% of the CCE supply come from non-renewable market sources.^{19,20}

2. **Accelerated RPS:** The CCE's supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by 2030. As in Scenario 1, the remaining supply is a mix of hydroelectric power and market purchases aimed at halving PG&E's annual emissions subject to a 5% minimum supply from market purchases.
3. **Minimum RPS Compliance plus Local:** The CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% RPS target after 2030. In addition, 50% of the total RPS generation is provided by local resources by 2030. Large hydroelectric and market supplies, and thus GHG emissions, are the same as in Scenario 1.
4. **Accelerated RPS plus Local:** The CCE's supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by 2030. In addition, 50% of the total RPS generation is provided by local resources by 2030. Large hydroelectric and market supplies, and thus GHG emissions, are the same as in Scenario 2.

Table 1: RPS-Eligible Procurement and GHG Emissions in Each Scenario²¹

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Percent RPS-Eligible in 2020	33%	50%	33%	50%
Percent RPS-Eligible in 2030	50%	80%	50%	80%
Share of RPS-Eligible from Local Resources	0%	0%	50%	50%
GHG Emissions compared to PG&E	50% Lower	54% Lower	50% Lower	54% Lower

¹⁹ For all scenarios we assume a minimum 5% non-renewable market supply to reflect operating constraints that require flexible, dispatchable generation on the system and in local areas. The CCE may be able to reduce emissions further through the use of energy storage or other measures to reduce the need for non-renewable power supplies, likely at additional cost.

²⁰ The availability and cost risks of large hydropower are discussed in Chapter 6, Impact of High CCE Penetration on Low-Carbon (Hydro) Resources.

²¹ Customer-sited solar is not considered RPS-eligible in California and is not included in the RPS procurement in these scenarios. Customer-sited solar is incorporated in this analysis as a reduction to the CCE's load.

To evaluate these scenarios, we assumed a simple portfolio consisting of RPS-eligible resources and additional GHG-free resources in an amount dictated by the particular scenario, with the balance of supply provided by non-renewable wholesale market purchases. In each case, we assumed that the RPS portfolio was predominately supplied with solar and wind resources, which are currently the low-cost sources of renewable energy. We assumed that solar and wind each contribute 45% of the renewable energy supply on an annual basis. To provide resource diversity and partly address the need for supply at times when solar and wind production are low, we assumed the remaining 10% of renewable supply would be provided by higher-cost baseload renewable resources, such as geothermal or biomass.

In the early years, the CCE would have to purchase its required renewable power from the market and existing resources. However, the study assumes that the CCE would contract with new renewable resources, such that by 2030 most of its renewable power would come from new resources. Figures 6 and 7 show the assumed build-out of these new resources under the first (Minimum RPS Compliance) and the fourth (Accelerated RPS plus Local) scenarios described above.

Figure 6. Scenario 1 CCE Build-Out

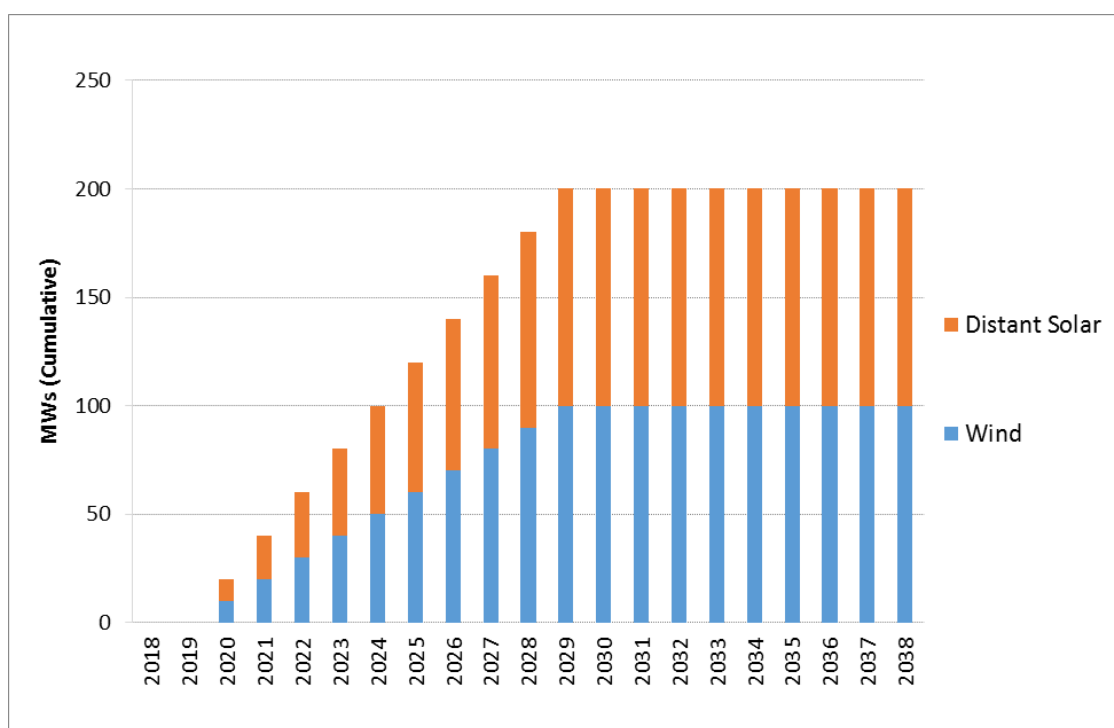
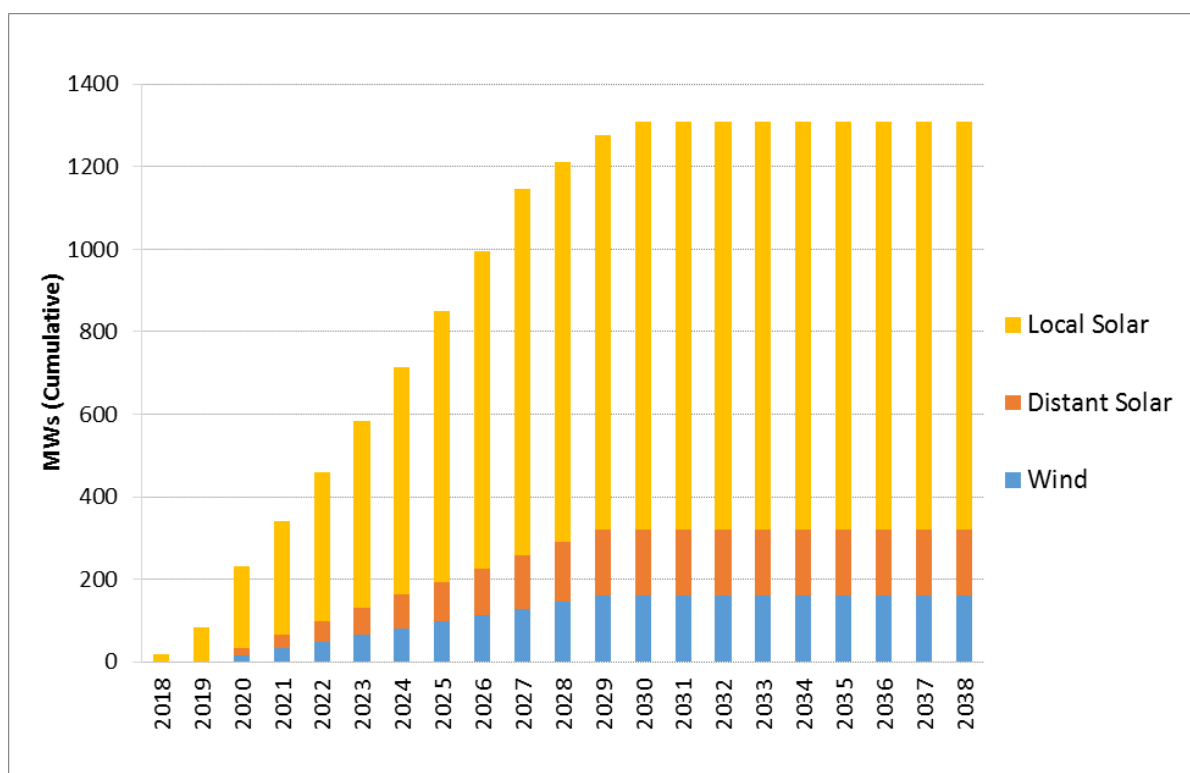
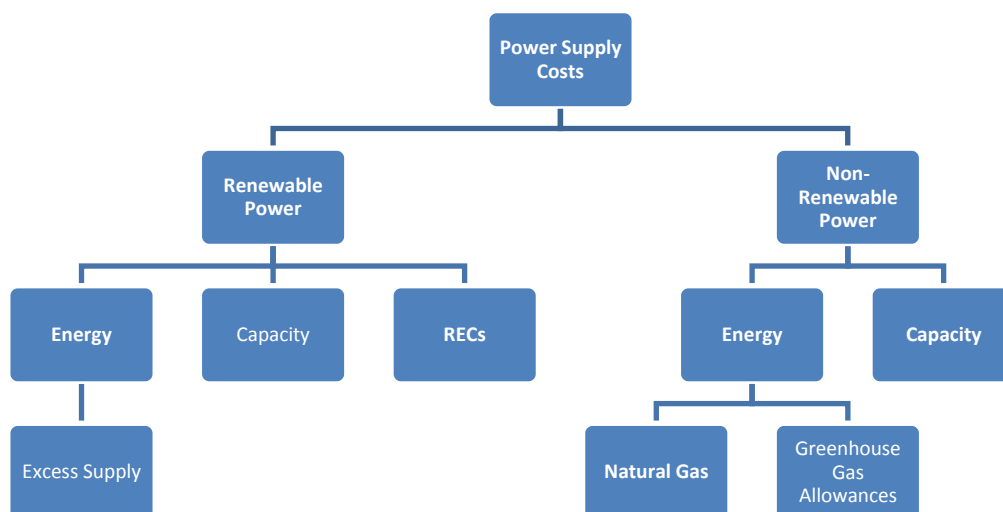


Figure 7. Scenario 4 CCE Build-Out

Power Supply Cost Assumptions

As discussed above, the CCE would procure a portfolio of resources to meet its customers' needs, which would consist of a mix of renewable and non-renewable (i.e., wholesale market) resources. As shown in Figure 8, the products to be purchased by the CCE consist generally of energy, capacity, and renewable attributes (which for counting purposes take the form of renewable energy credits, or Category 1 RECs).²²

²² RECs are typically bundled with energy deliveries from renewable energy projects, with each REC representing 1 MWh of renewable energy. A limited number of unbundled RECs may be used to meet RPS requirements. For the purpose of this study we have not considered unbundled RECs and have rather estimated costs based on renewable energy contracts where the RECs are bundled.

Figure 8. Power Supply Cost Elements

The CCE will procure supplies from the same competitive market for resources as PG&E. Thus, we assume that the costs for renewable and non-renewable energy and for resource adequacy (RA) capacity for the CCE are the same as for new purchases made by PG&E (discussed further in our forecast of PG&E rates). Wholesale market prices for electricity in California are largely driven by the cost of operating natural gas power plants, as these plants typically have the highest operating costs and are the marginal units. Market prices are a function of the efficiency of the marginal generators, the price of natural gas, and the cost of GHG allowances. MRW developed forecasts of these elements to derive a power price forecast to determine costs for the CCE and PG&E. Large hydroelectric power prices are based on the market price forecast with a 10% premium to reflect the value of GHG benefits, flexibility, and increasing demand from load serving entities seeking clean power like the CCE. Capacity prices are based on prices for RA contracts reported by the CPUC and on the cost to build a new combustion turbine power plant.

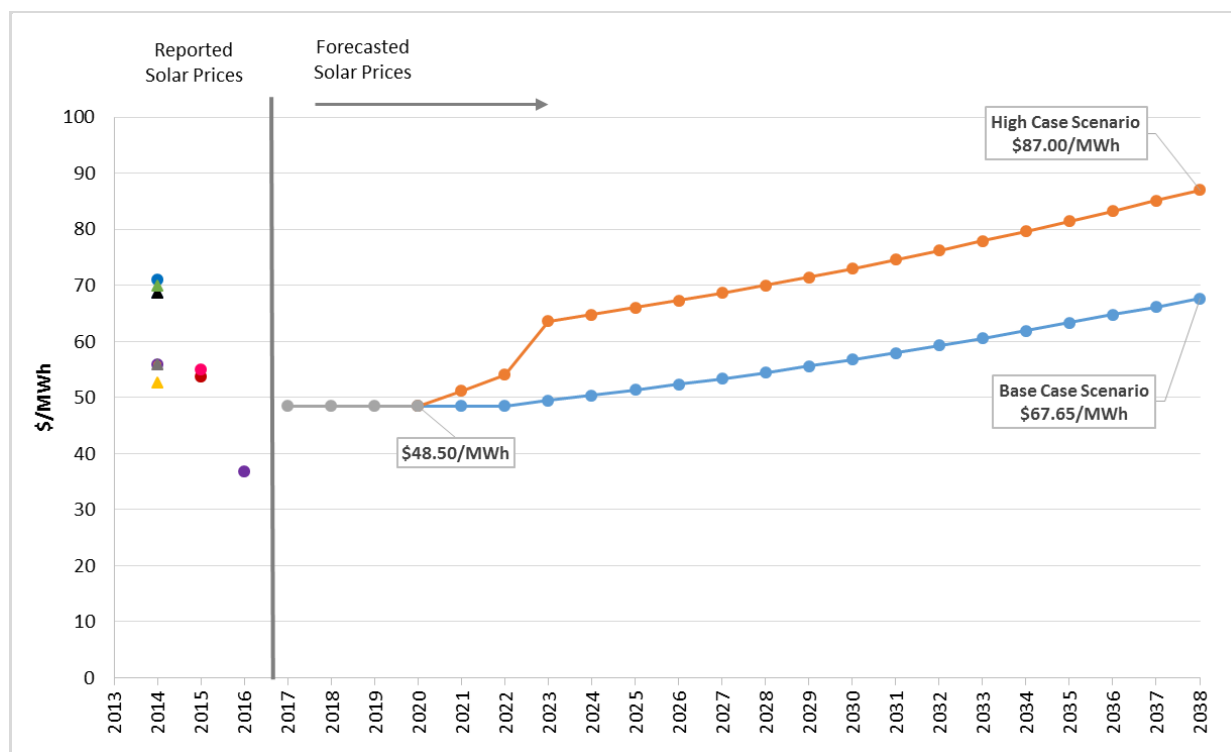
MRW developed a forecast of non-local utility scale renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and CCEs in 2015 and early 2016, finding an average price of \$49/MWh for the solar contracts, \$55/MWh for wind power and \$80/MWh for geothermal.²³ We used these prices as the starting point for our forecast of CCE renewable energy procurement costs. For geothermal, which is a

²³ MRW relied exclusively on prices from municipal utilities and CCEs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in *California Energy Markets*, an independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

relatively mature technology, we assumed that new contract prices would simply escalate with inflation.

Solar and wind prices are a function of technology costs, which have generally been declining over time; financing costs, which have been very low in recent years; and tax incentives, which significantly reduce project costs, but phase out over time. In the near-term we would not expect prices to increase as technology costs and continued tax incentives provide downward pressure and likely offset any increase in financing costs or other competitive pressure from an increasing demand for renewable energy in California. For utility scale wind prices, we relied on an expert elicitation survey²⁴ developed by Lawrence Berkeley National Laboratory (LBNL). According to this survey, wind prices will decrease 24% by 2030 and 35% by 2050.²⁵ For solar, we held prices constant in nominal dollars through 2020. Beyond 2020, with increasing competitive pressure due to the drive to a 50% RPS and the anticipated phase-out of federal tax incentives (offset in part by declining technology costs), we would expect prices to increase somewhat and have assumed they escalate at the rate of inflation. In addition, we also considered a high solar cost scenario based on work performed by LBNL on the value of tax incentives. In the high scenario, we assume that costs increase with the phase-out of federal tax incentives, without being offset by declining technology costs. Figure 9 shows the resulting solar price forecasts for the two scenarios.

Figure 9. Large-Scale Non-Local Solar Price Forecast



²⁴ “Expert Elicitation Survey of Future Wind and Energy Costs,” *Nature Energy*, September 12, 2016.

²⁵ Relative to the 2014 wind prices. MRW also added the annual inflation increase.

Local Solar Analysis

Pivotal to the evaluation of the local economic impacts of a Contra Costa CCE is an understanding of how much renewable energy can be developed within the County. This assessment focused on identifying local solar photovoltaic (PV) siting potential. Wind and biomass energy were also evaluated, but were determined to be less feasible for Contra Costa County.

The solar PV assessment is based on a comprehensive desktop review of countywide parcel data, geographic features, and solar energy potential. Table 2 shows the total solar PV generation capacity within the County based on the methodology and assumptions described below.

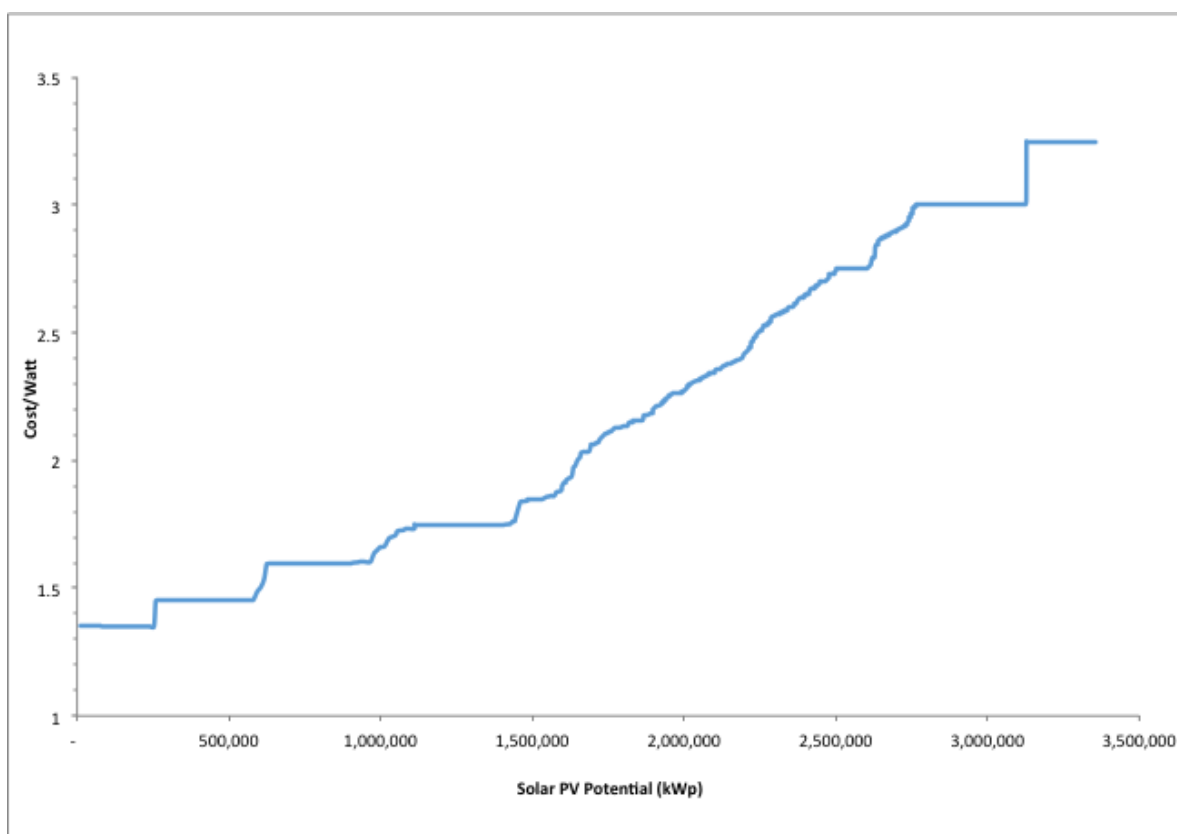
Table 2. Total PV Solar Generation Potential and Build Cost

	Ground Mount	Shade Structure	Roof Mounted	Total
PV Capacity (MW²⁶)	1,891	1,320	144	3,355
PV Production (GWh)	3,025	2,113	230	5,369
Build Cost (\$ Millions)	\$3,417	\$3,977	\$371	\$7,660
Build Cost (\$/Watt)	\$1.99	\$3.10	\$2.62	\$2.56
No. of PV Systems	845	886	144	1,875

Generation capacity was determined for the three types of possible solar PV installations: Ground-Mount, Shade Structure/Carport, and Roof Mount. The findings show that the County has a solar PV generation capacity of 3,355 MW and annual solar electricity production potential of 5,369 GWh. Figure 10 shows the aggregate Solar PV supply curve for all County jurisdictions.

Note that the costs shown in Table 2 and Figure 10 are “build costs.” Additional soft costs, particularly the acquisition or opportunity cost of the land upon which the ground-mount solar is located, are highly site-specific and not included in these values. These can add up to 50% to the cost of local solar projects, and are accounted for in the CCE scenario modeling.

²⁶ Local solar PV capacity measured at the panel (i.e., pre-inverter).

Figure 10. Aggregate Solar PV Supply Build Cost Curve, All County***Siting Analysis***

To assess the potential locations in Contra Costa County where solar PV could be developed, this study utilized a Geographic Information System (GIS)-based desktop review, incorporating aerial imagery and land-based data. The collected data was analyzed and potential solar PV development sites were identified from criteria established through industry knowledge and input from County stakeholders.

The agreed upon criteria are as follows:

- The minimum acceptable parcel size is three acres. Smaller parcels will not be able to hold an economically viable project. If a potential solar PV system size is below 500 kW it was excluded from the list of potentially feasible sites and overall solar energy capacity.²⁷ Again, this measure ensures only realistic and economically feasible sites are identified.
- Based on input from the County, only specific tax codes and zoning areas were evaluated. For example, areas such as Open Space or Parks have sufficient land area for solar PV

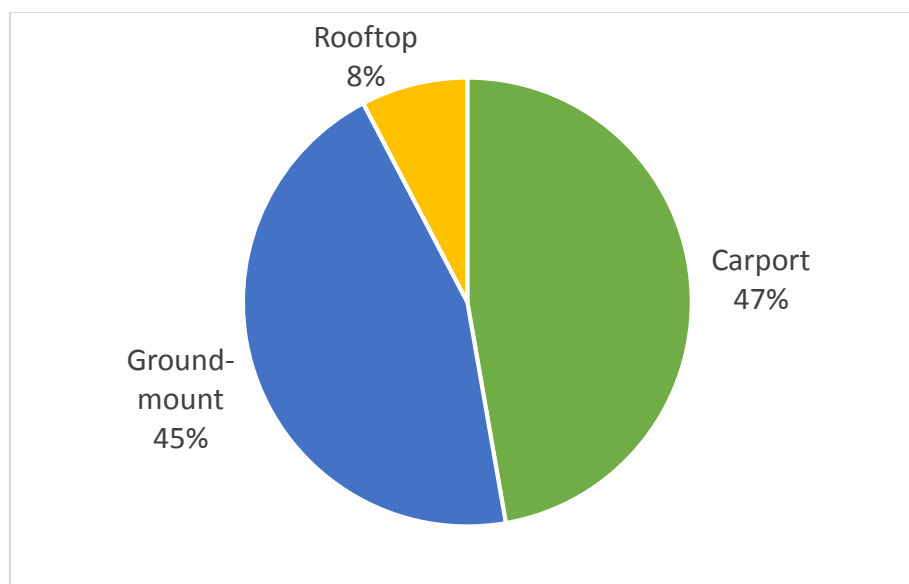
²⁷ Residential and other small rooftop solar are accounted for in the California Energy Commission sales forecast used to develop the CCE's demand forecast.

projects, but zoning restrictions would not allow for the development of these projects, and these areas were removed from the approved scope.

- In addition to size and tax/zoning code designations, areas with poor ground quality (marshland), excessive tree density, or excessive sloping would prohibit cost-effective solar PV development and were removed from the analysis.
- Lastly, sites with existing solar were removed from the pool of potential parcels/sites.

Within each identified parcel is the potential for three different types of solar PV development. On impervious land, such as a parking lot, it was assumed that solar PV carports would be installed. On grassland or bare land areas, this analysis assumed a ground-mounted solar PV system would be installed. Lastly, roof-mounted solar PV was assumed for any buildings found in the parcel data that matched the approved criteria. Countywide, 92% of potential installation sites were found to be either carport or ground-mount sites, with only 8% of the sites amenable to roof-mounted PV (Figure 11). The size of the estimated solar PV system was found by analyzing the total land area against the needed land required for solar PV development.

Figure 11. Potential Solar PV Sites by Installation Type



This study found 1,395 parcels that met the established criteria and 1,875 individual sites within the identified parcels where either a solar shade structure, rooftop, or ground-mounted system could be developed. Table 3 shows the individual sites organized by type of solar PV system for each jurisdiction in Contra Costa County.²⁸

This assessment also calculated the amount of solar energy production for each of the potential sites identified. The amount of energy production was found by multiplying the estimated system size by an average solar yield. The average solar energy yield was created by designing sample projects that matched the estimated system size in the solar software platform Helioscope. Because Contra Costa County has a variety of solar exposure, multiple sites across the County were designed/tested to find an average yield. Based on our testing, the average yield for Contra Costa County is 1,600 (kWh/kW). The resulting amount of potential PV production per jurisdiction is also provided in Table 3.

²⁸ For maps, please see

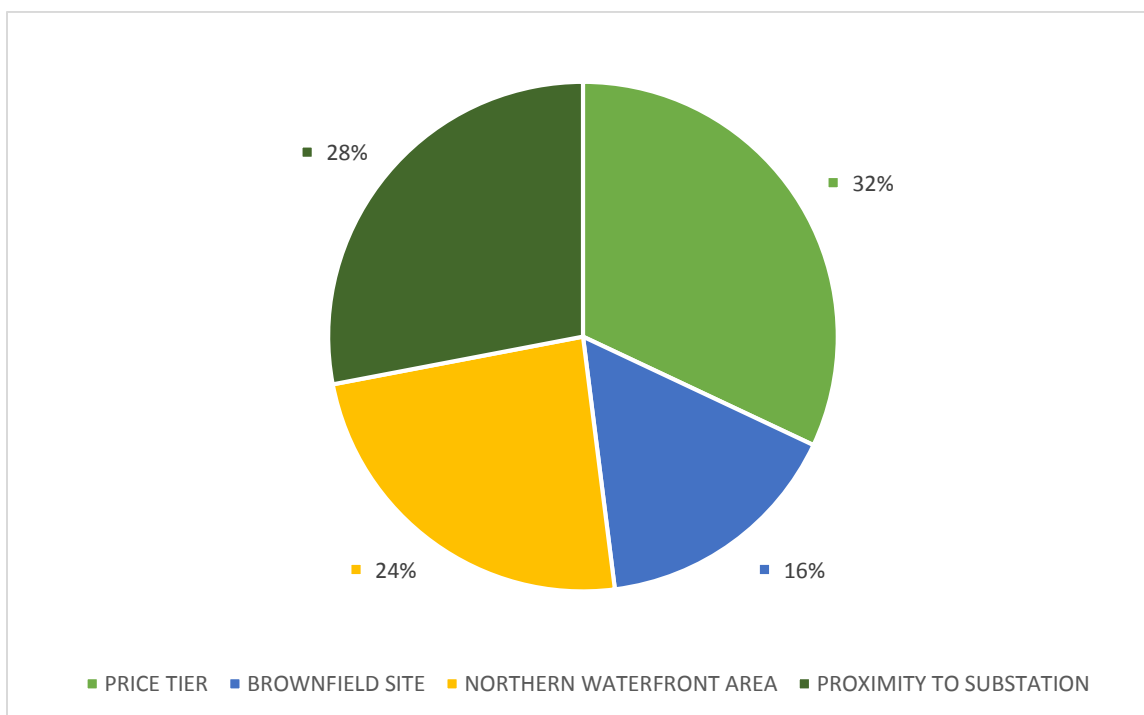
<https://www.dropbox.com/s/cb3rig66shny68j/Contra%20Costa%20CCE%20Solar%20Siting%20DRAFT%20Report%20SA%202016-11-15%20Reduced%20Size.pdf?dl=0>.

Table 3. Potential PV Production and Build Cost by Location

Jurisdiction	PV Potential (MW)	PV Production (GWh)	Build Cost (\$ Millions)
Alamo	14	23	\$30,779,000
Antioch	462	739	\$1,010,374,000
Brentwood	287	460	\$599,685,000
Clayton	38	62	\$71,171,000
Concord	370	593	\$900,603,000
Crockett	58	93	\$125,187,000
Danville	80	129	\$177,801,000
El Cerrito	29	48	\$73,161,000
El Sobrante	19	31	\$42,020,000
Hercules	90	144	\$200,511,000
Lafayette	8	13	\$23,641,000
Martinez	313	502	\$654,701,000
Moraga	24	39	\$55,957,000
Oakley	121	194	\$285,786,000
Orinda	22	36	\$43,554,000
Pinole	47	77	\$126,870,000
Pittsburg	314	502	\$705,202,000
Pleasant Hill	60	96	\$164,364,000
Port Costa	8	13	\$13,501,000
Richmond	502	804	\$1,261,541,000
Rodeo	35	57	\$85,874,000
San Pablo	191	307	\$459,784,000
San Ramon	158	254	\$384,634,000
Walnut Creek	95	152	\$269,795,000
Grand Total	3,355	5,369	\$7,766,496,000

Ranking

After the feasible solar sites and the corresponding solar PV capacity were identified, each site was ranked. The ranking was weighted based on how important it was to the actual feasibility of developing the site for solar PV and based on input from County stakeholders. The ranking consisted of the following measures as shown in the figure below.

Figure 12. Weighted Ranking Categories

An overall ranking score was then applied to each individual site to illustrate the best and worst sites for solar PV development. Sites were then grouped in tiers one through five, with one being the best. In addition to the ranking score, industry knowledge indicates the best sites to develop a feasible solar PV project will be larger than 1 MW, located on government land, and will be a ground-mounted solar array, the most cost-effective installation type. The table below shows the key characteristics of the ranking analysis.

Table 4. Ranking Values for All Sites

Ranking Tier	Sum of PV Production (GWh)	Sum of Total Price	Average Build Price per Watt
1	1,309	\$1,591,810,000	\$2.13
2	1,167	\$1,578,770,000	\$2.37
3	1,105	\$1,622,236,000	\$2.57
4	868	\$1,251,547,000	\$2.56
5	919	\$1,722,142,000	\$3.07

Local Solar Modeled in the CCE Scenarios

To estimate the contribution of local solar to a Contra Costa CCE's supply costs, we used the supply curve shown in Figure 10. To translate the \$/kW costs in the figure to \$/MWh generation costs, we used the pro forma model contained in the CPUC's RPS Calculator and the cost and performance assumptions provided by Sage for the County. For example, the lowest-cost projects at \$1,350/kW were estimated to have a generation cost of \$98/MWh (\$68/MWh for build costs and \$30/MWh for soft and land acquisition/opportunity costs).

The generation cost was assumed to scale with installed cost. Because it is unlikely that all the identified sites would be developed in order of their increasing cost (and some sites may never be developed regardless of economics), we assumed that 50% of the capacity identified in the cost curve would be developed for the purpose of conservatively estimating average costs at each level of local solar penetration. We calculated the average price for the cumulative developed capacity forecast for each year (again, counting only 50% of the capacity of each developed project towards the cumulative total). For Scenarios 3 and 4, we assumed that 50% of the CCA's RPS supply would be provided by local solar by 2027, adding 620 MW of local solar under Scenario 3 and 990 MW under Scenario 4 by 2030. (Scenarios 1 and 2 do not include any local solar.)

Greenhouse Gas Costs

MRW estimated that the price of GHG allowances would equal the auction floor price stipulated by the California Air Resources Board's cap-and-trade regulations, consistent with recent auction outcomes.²⁹

Table 5. GHG Allowances price³⁰

	2017	2018	2019	2025	2030	2035	2038
\$/tonne	13.2	14.7	15.9	24.4	34.7	49.8	61.8

Total GHG costs were calculated by multiplying the allowance price by the amount of carbon emitted per megawatt-hour for each assumed resource. For "system" purchases, MRW assumed that the GHG emissions corresponded to a natural gas generator operating at the market heat rate. This worked out to be, on average over 2018-2038, approximately \$1.5/MWh delivered.³¹

Other CCE Supply Costs

The CCE is expected to incur additional costs associated with its procurement function. For example, if the CCE relies on a third-party energy marketing company to manage its portfolio it will likely incur broker fees or other expenses equal to roughly 5% of the forecasted contract costs. The CCE would also incur costs charged by the California Independent System Operator

²⁹ California Code of Regulations, Title 17, Article 5, Section 95911. Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

³⁰ For 2017, the amount listed corresponds to the GHG allowance price for PG&E according to the most recent ERRR 2017 update. Pacific Gas & Electric ERRR 2017, A.16-06-003, Testimony November 2, 2016, Table 12-1.

³¹ The amount of GHG emissions will depend on the generation portfolio. \$1.50/MWh corresponds to the GHG emissions costs under Scenario 1.

(CAISO) for ancillary services (activities required to ensure reliability) and other expenses. MRW added 5.5% to the CCE's power supply cost to cover these CAISO costs. Finally, we added an expense associated with managing the CCE's renewable supply portfolio. Based on an analysis of the expected CCE load shape and the typical generation profile of California solar and wind resources, we observed that there will be hours in which the expected deliveries from renewable contracts will be greater than the CCE's load in that hour. This results from the amount of renewable capacity that must be contracted to meet annual RPS targets and the variability in renewable generation that leads to higher deliveries in some hours and lower deliveries in other hours. When high renewable energy deliveries coincide with low loads, the CCE will need to sell the excess energy, likely at a loss, or curtail deliveries, and will potentially have to make up those renewable energy purchases during higher load hours to comply with the RPS. The result is that the procurement costs will be somewhat higher than simply contracting with sufficient capacity to meet the annual RPS.

PG&E Rate and Exit Fee Forecasts

MRW developed a forecast of PG&E's bundled generation rates and CCE exit fees in order to compare the projected rates that customers would pay as Contra Costa County CCE customers to the projected rates and fees they would pay as bundled PG&E customers.

PG&E Bundled Generation Rates

To ensure a consistent and reliable financial analysis, MRW developed a 20-year forecast of PG&E's bundled generation rates using market prices for renewable energy purchases, market power purchases, greenhouse gas allowances, and capacity that are consistent with those used in the forecast of Contra Costa County CCE's supply costs. MRW additionally forecast the cost of PG&E's existing resource portfolio, adding in market purchases only when necessary to meet projected demand. MRW assumed that near-term changes to PG&E's generation portfolio would be driven primarily by increases to the Renewable Portfolio Standard requirement in the years leading up to 2030 and by the retirement of the Diablo Canyon nuclear units at the end of their current license periods in 2024 and 2025. More information about this forecast is provided in Appendix B.

MRW forecasts that, on average, PG&E's generation rates will increase faster than inflation through 2038, with 2038 rates more than 20% higher than today's rates when considered on a constant dollar basis (i.e., assuming zero inflation). Underlying this result are three distinct rate periods:

1. An initial period of faster rate growth from 2018 to 2022 (1% annually above inflation);
2. A period of rate decline from 2023 to 2025 (3.5% annually below inflation), primarily due to the retirement of Diablo Canyon³²; and
3. A period of steeper rate growth between 2026 and 2030 (3.5% annually above inflation), primarily due to the replacement of Diablo Canyon with more expensive resources: energy efficiency, renewable generation, and fuel-fired generation. In addition, the retirement of Diablo Canyon increases the demand in capacity with a consequent increase

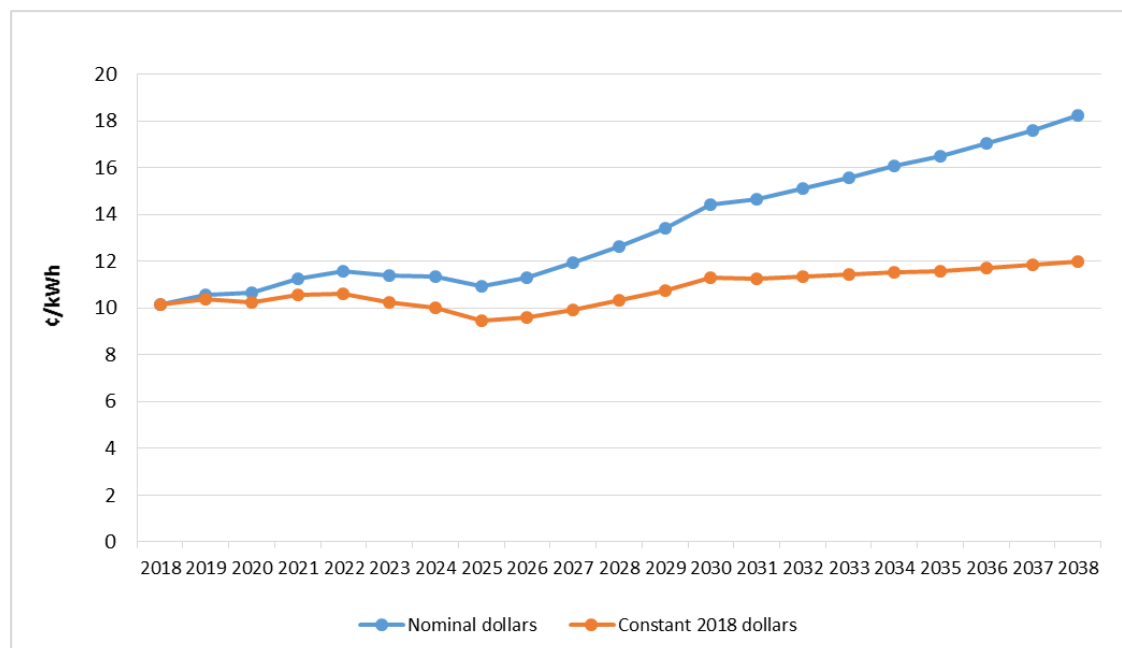
³² More information can be found in Appendix C

in capacity prices.

4. A final period of moderate rate growth through 2038 (1% annually above inflation), primarily due to the replacement of high-cost renewable power contracts currently in PG&E's portfolio with new lower-priced contracts (reflecting the significant fall in renewable power prices in recent years).

PG&E's bundled generation rates in each year of MRW's forecast are shown in Figure 13, on both a nominal and constant-dollar basis.

Figure 13: PG&E Bundled Generation Rates, nominal and constant-dollar forecasts



PG&E Exit Fee Forecast

In addition to the bundled rate forecast, MRW developed a forecast of the Power Charge Indifference Adjustment (“PCIA”), which is a PG&E exit fee that is charged to CCE customers. The PCIA is intended to pay for the above-market costs of PG&E generation resources that were acquired, or which PG&E committed to acquire, prior to the customer’s departure to CCE. The total cost of these resources is compared to a market-based price benchmark to calculate the “stranded costs” associated with these resources, and CCE customers are charged what is determined to be their fair share of the stranded costs through the PCIA.

MRW forecasted the PCIA charge by modeling expected changes to PCIA-eligible resources and to the market-based price benchmark through 2038, using assumptions consistent with those used in the PG&E rate model. Based on our modelling, we expect the PCIA to decline in most years until it drops off completely around 2034. MRW’s forecast of the residential PCIA charge through 2038 is summarized in Table 6.

Table 6. PG&E Residential PCIA Charges

	2018	2019	2020	2025	2030	2035	2038
¢/kWh	2.4	1.9	2.3	1.3	0.5	0.0	0.0

In its Diablo Canyon retirement application, PG&E proposed an additional exit fee, dubbed the “Clean Energy Charge” (CEC) which CCE customers would pay to offset some of the incremental costs PG&E would incur for developing its greener portfolio. This proposal was later withdrawn. Furthermore, no party participating in the proceeding supported this charge. Because of the lack of support for the “CEC,” and the fact that PG&E’s application would have allowed CCEs to get out of the charge by procuring renewable power above and beyond the RPS requirement, we do not quantify or include this hypothetical charge in the analysis.

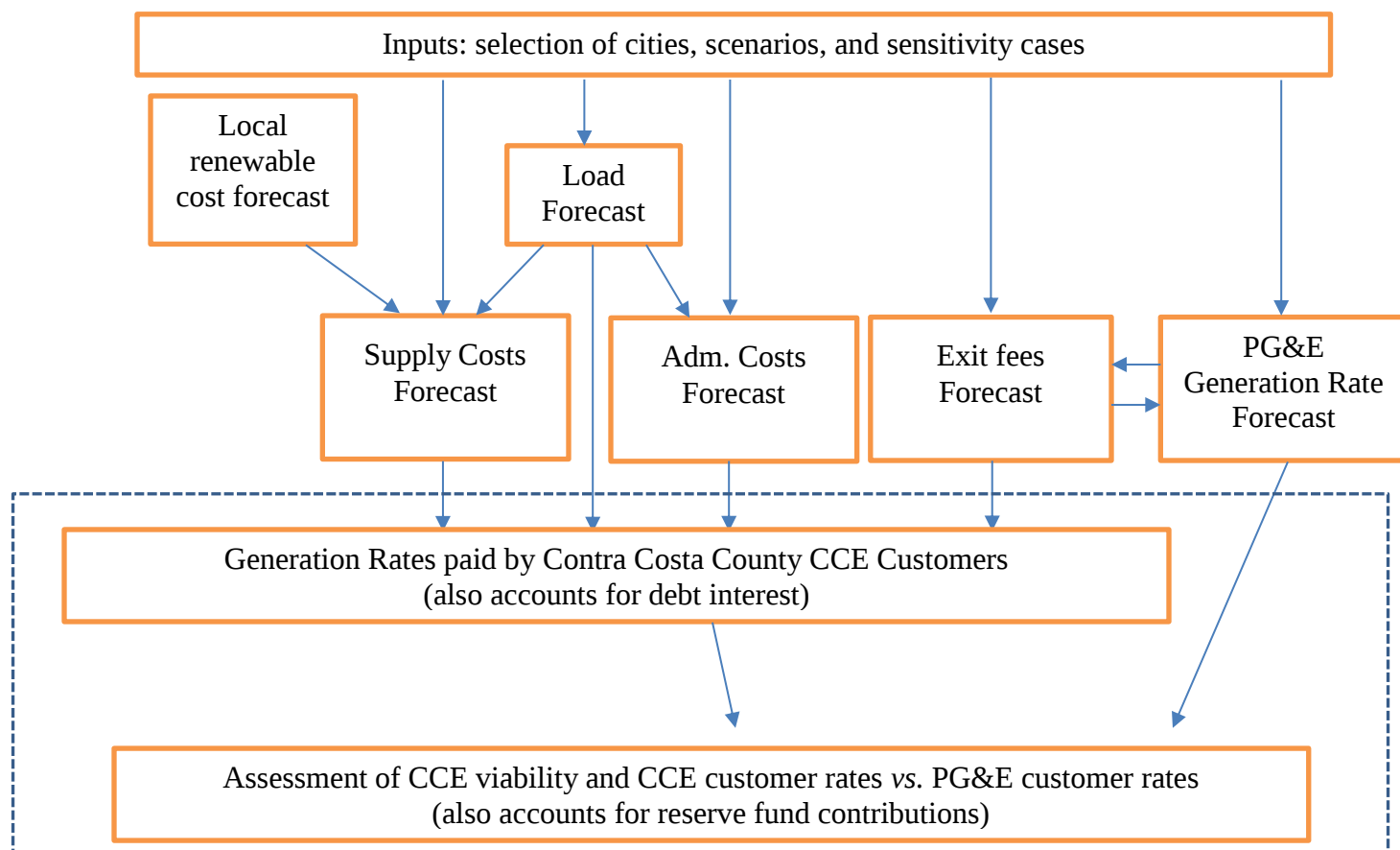
Pro Forma Elements and CCE Costs of Service

MRW conducted a pro forma analysis to evaluate the expected financial performance of the CCE and the CCE’s competitive position *vis a vis* PG&E. The analysis was conducted on a forward-looking basis from the expected start of CCE operations in 2018 through the year 2038, with several cases considered to address uncertainty in future circumstances.

Pro Forma Elements

Figure 14 provides a schematic of the pro forma analysis, outlining the input elements of the analysis and the output results. The analysis involves a comparison between the generation-related costs that would be paid by Contra Costa County CCE customers and the generation-related costs that would be paid by PG&E bundled service customers. Costs paid by CCE customers include all CCE-related costs (i.e., supply portfolio costs and administrative and general costs) and exit fee payments that CCE customers will be required to make to PG&E.

As discussed in previous sections, supply portfolio costs are informed and affected by CCE loads, by the requirements the CCE will need to meet (or will choose to meet) such as with respect to renewable procurement, and by CCE participation levels, which can vary depending on whether or not all cities in the County choose to join the CCE. Administrative and general costs are discussed further below.

Figure 14. Pro forma Analysis

Startup Costs

Table 7 shows the estimated CCE startup costs. They are based on the experience of existing CCEs as well as other CCE technical and feasibility assessments. Working capital is set to equal one hundred days of CCE revenue³³, or approximately \$22 million. This amount would cover the timing lag between when invoices for power purchases (and other account payables) must be remitted and when income is received from the customers. Initially, the working capital is provided to the CCE on credit from a bank. Typical power purchase contracts require payment for the prior month's purchases by the 20th of the current month. Customers' payments are typically received 60 to 90 days from when the power is delivered.

These startup costs are assumed to be financed over 5 years at 5% interest.

³³ The working capital has been calculated in base to Scenario 1.

Table 7. Estimated Start-Up Costs

Item	Cost
Technical Study	\$200,000
JPA Formation/Development	\$100,000
Implementation Plan Development	\$50,000
Power Supplier Solicitation & Contracting	\$75,000
Staffing	\$700,000
Consultants and Legal Counsel	\$400,000
Marketing & Communications	\$250,000
PG&E Service Fees	\$75,000
CCA Bond	\$100,000
Miscellaneous	\$300,000
Total	\$2,250,000
Working Capital	\$21,500,000
Total	\$23,750,000

Administrative and General Cost Inputs

Administrative and general costs cover the everyday operations of the CCE, including costs for billing, data management, customer service, employee salaries, contractor payments, and fees paid to PG&E. MRW conducted a survey of the financial reports of existing CCEs to develop estimates of the costs that would be faced by a Contra Costa County CCE. Administrative and general costs are phased in from 2018 to 2020, as the CCE operations expand to cover the entire territory of the County; after that, costs are escalated by 2% each year to account for the effects of inflation.

Administrative and general costs are unchanged under the three renewable level scenarios, but do vary based on how many cities join the CCE and the number of participating customer accounts. As previously mentioned, a 15% opt-out rate has been assumed for customer participation.

Cost of Service Analysis and Reserve Fund

To determine annual CCE costs and the rates that would need to be charged to CCE customers to cover these costs, MRW summed the two categories of CCE costs (i.e., supply portfolio costs, and administrative and general costs) and added in debt financing to cover start-up costs and initial working capital. Financing was assumed to be for a five-year period at an interest rate of 5%. These costs were divided by projected CCE loads to develop the average rate the CCE would need to charge customers to cover its costs (“minimum CCE rate”).

To establish the Contra Costa County CCE rate, MRW adjusted the minimum CCE rate, if needed, based on the competitive position of the CCE. In particular, when the total CCE

customer rate (i.e., the minimum CCE rate plus the PG&E exit fee) was below the projected PG&E generation rate,³⁴ MRW increased the minimum CCE rate up to the amount needed to meet the reserve refund targets while still maintaining a discount. MRW used the surplus CCE revenue from these rate increases (“Reserve Fund”) in order to maintain Contra Costa County CCE competitiveness with PG&E rates in years in which total CCE customer rates would otherwise be higher than PG&E generation rates.³⁵

³⁴ For this analysis, MRW used the average of the projected PG&E generation rates across all rate classes, weighted by the projected Contra Costa County CCE load in each rate class.

³⁵ MRW applied a Reserve Fund cap of 15% of the annual operating cost. After this cap was reached, no further rate increases were applied for the purpose of Reserve Fund contributions.

Chapter 3: Cost and Benefit Analysis

As described in the prior chapter, as part of the pro forma analysis, MRW calculated Contra Costa County CCE rates that would, where feasible, cover CCE costs and maintain long-term competitiveness with PG&E. This chapter uses those rates to compare the costs and benefits of the Contra Costa County CCE across four scenarios: (1) Minimum RPS Compliance, (2) Accelerated RPS, (3) Minimum RPS Compliance plus Local Procurement, and (4) Accelerated RPS plus Local Procurement. Costs and benefits are evaluated by comparing total CCE customer rates (including PG&E exit fees) to PG&E generation.

Scenario 1 (Minimum RPS Compliance)

Under Scenario 1, the Contra Costa County CCE meets all RPS requirements (including California State Senate Bill 350 and Diablo Canyon retirement proposal requirements), and 35% of the total load over the 20-year period is met through large hydroelectricity.³⁶

CCE Average Costs

Figure 15 summarizes the results of this scenario. The vertical bars represent the total Contra Costa County CCE customer rate and the green line represents a comparable PG&E generation rate.³⁷ Non-renewable generation (including large hydroelectric) is responsible for the bulk of the CCE's costs. Renewable generation costs will continue to increase throughout the forecast period due to the increasing RPS standards. Regarding customer costs, the PCIA exit fee is expected to decrease after 2020. Finally, the GHG allowance purchases represent a small portion of the total costs because 60% of the non-renewable generation is met by hydroelectricity. This non-carbon emitting resource therefore limits the need to purchase GHG allowances.

Note that this figure and the analogous ones to follow do not account for contributions to a rate reserve fund or other potential CCE activities such as energy efficiency or other community programs.

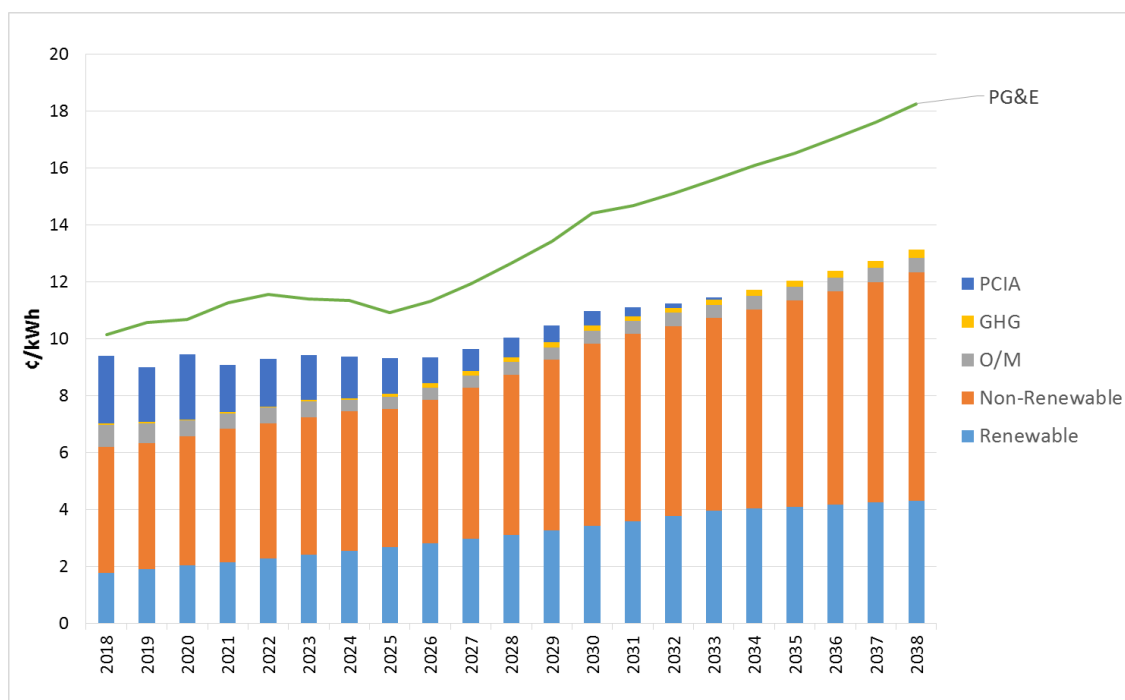
Under Scenario 1, the differential between PG&E generation rates and Contra Costa County CCE customer rates is positive in each year (i.e., CCE rates are lower than PG&E rates). As a result, Contra Costa County CCE customers' average generation rates (including contributions to the reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year. The annual differential between the PG&E rate and the total CCE customer rate is expected to vary significantly over the course of this period (Figure 15). During the initial period from 2018-2022, the differential between the two rates increases (i.e., the CCE becomes more cost-competitive) as PG&E's rates rise, and the exit fees charged to Contra Costa County CCE customers fall as PG&E-owned gas plants expire from PCIA eligibility. Beginning in 2024, the rate differential narrows due to a decrease in PG&E generation rates stemming from the closure of the Diablo Canyon nuclear plant. After 2026, the difference between the two rates is

³⁶ 60% of the non-RPS generation in average for 2018-2038.

³⁷ All rates are in nominal dollars.

expected to increase as PG&E's generation rates continue to increase and exit fees decline with the expiration of additional resources from PCIA eligibility.

Figure 15. Scenario 1 Forecast Average CCE Cost and PG&E Rates, 2018-2038³⁸



Residential Bill Impacts

Table 8 shows the average annual savings for residential customers under Scenario 1. The average annual bill for the residential customer on the Contra Costa County CCE program will be on average 8% lower than the same bill on PG&E rates. Note that these rate impacts assume that a rate stabilization reserve is funded during the first few years of the CCE's existence.

Table 8. Scenario 1 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E (\$)	Bill with Contra Costa County CCA (\$)	Savings (\$)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	124	5	4%
2030	500	189	171	18	10%
2038	500	254	227	27	11%

³⁸ This chart does not include the reserve fund.

Greenhouse Gas Emissions

Under Scenario 1, we model the Contra Costa County CCE to be 50% below PG&E's GHG emission rate. It can meet this goal by using large hydroelectric power to meet 35% of its resource needs (60% of the non-RPS load). Though this large hydro power would not qualify for RPS requirements, it is nevertheless a non-carbon emitting resource.

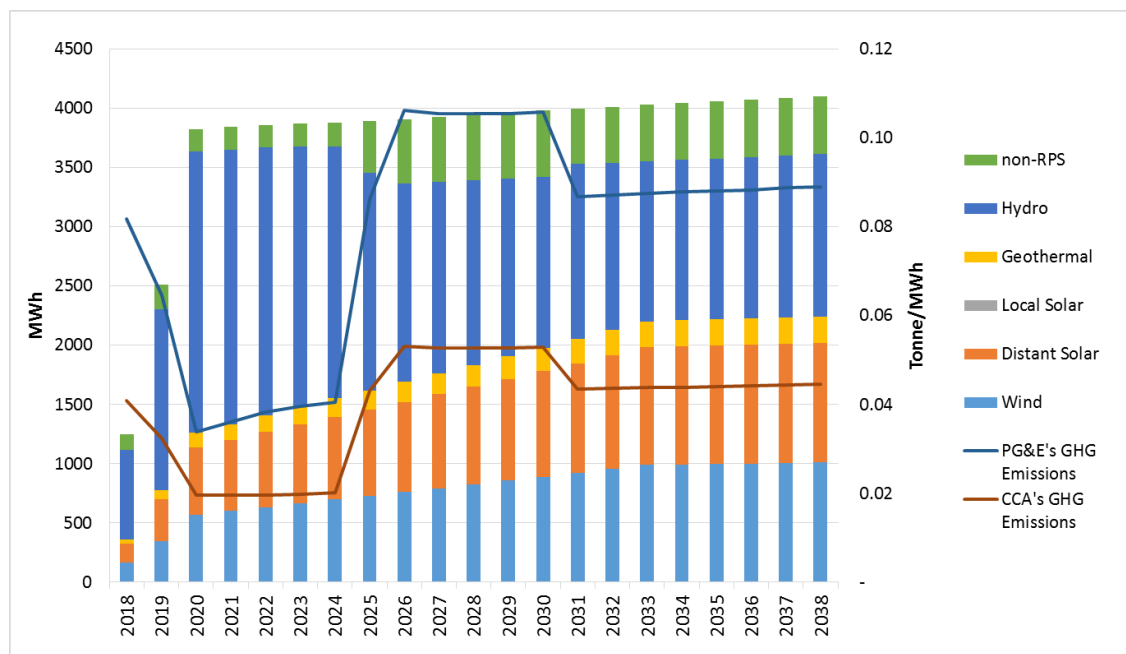
Figure 16 shows the Contra Costa CCE's generation portfolio mix (vertical bars) and GHG emissions rate (brown line) under Scenario 1, along with PG&E's GHG emissions rate for comparison (blue line). Additional GHG savings can occur if additional renewables are added to the portfolio (see Scenarios 2 and 4) or if a greater fraction of GHG-free resources (like large hydro) is used.

PG&E GHG emissions are relatively low due to the diversity in PG&E's electric mix. In addition to renewable generation, over 40% of PG&E's supply portfolio is made up of nuclear and large hydroelectric generation, both of which are considered GHG-free generation technologies. PG&E's GHG emissions rate is expected to fall between 2018 and 2020 due to increases in RPS procurement. In 2025, the retirement of the Diablo Canyon nuclear generation plant is expected to more than double PG&E's GHG emission rate as the utility increases its gas-fired generation to make up for a share of the loss.³⁹ In the following years PG&E's GHG emissions are expected to decrease as PG&E ramps up renewable procurement to meet its mandated RPS goals and the additional RPS procurement required under the Diablo Canyon retirement proposal.⁴⁰ In this scenario, the CCE's emissions rate is set to be approximately 50% of PG&E's in each year, subject to a 5% minimum supply from market purchases.

³⁹ Even if PG&E replaces the nuclear generation with renewable power and other GHG-free resources, as proposed, the new renewable resources will need to be balanced by flexible resources, which are likely to be at least in part provided by fossil-fueled power and which will therefore increase PG&E's GHG emissions.

⁴⁰ Starting in 2030, the required RPS increases from 50% to 55% under PG&E's proposal.

Figure 16. Scenario 1 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) (“Normal” PG&E Hydro Conditions)



Scenario 2 (Accelerated RPS)

Scenario 2, from a renewable procurement perspective, is a more aggressive scenario. Under this scenario, the Contra Costa County CCE starts with 50% of its load served by renewable sources in 2018, and rapidly increases to 80% of its load served by renewable sources in 2030. In addition, between 2018 and 2038 Contra Costa County will provide an average of 20% of its supply through large hydroelectric sources⁴¹.

CCE Average Costs

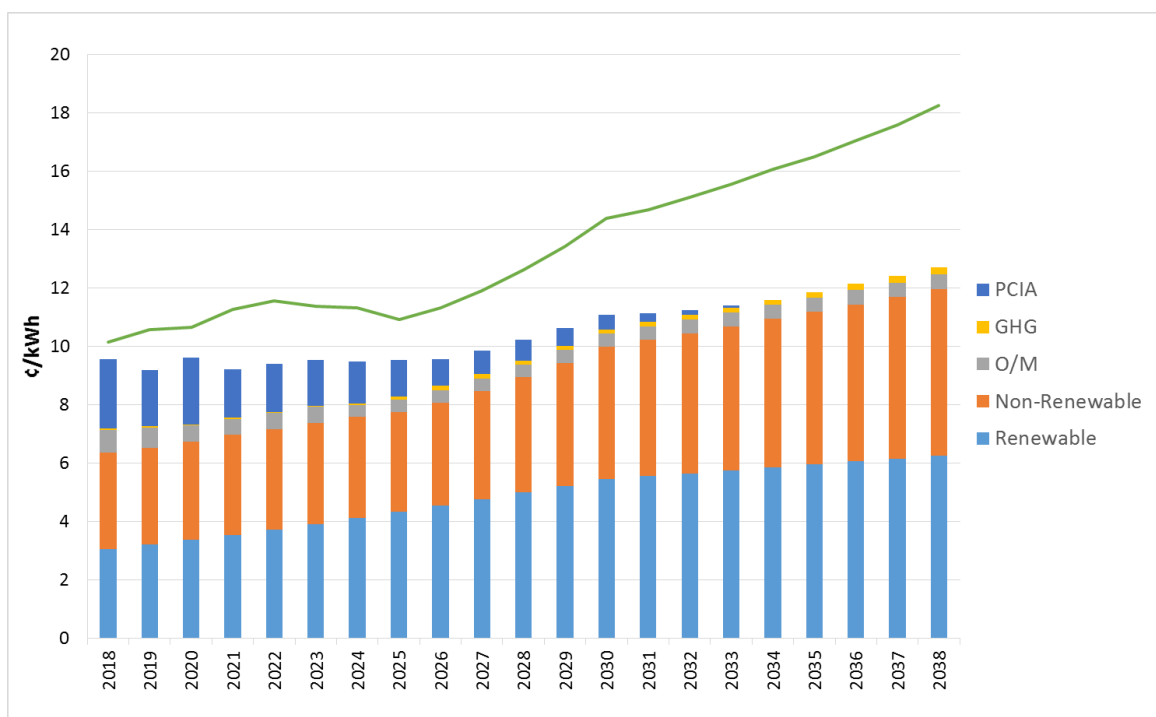
Figure 17 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. In this scenario, the renewable power cost is the single largest element of the CCE rate, reflecting the higher renewable content of this scenario. Non-renewable generation and the PCIA exit fee are the second and third most expensive components, respectively. As in Scenario 1, the PCIA exit fee is expected to decrease in most years beginning in 2020. Because of this scenario's larger share of GHG-free generation between 2028 and 2038, the GHG allowance purchases are an even lower portion of the total costs.

Compared to Scenario 1, Scenario 2 exhibits a lower differential between PG&E's and the CCE's customer generation rates between 2018 and 2033. After 2033, the price of renewable generation is expected to undercut the wholesale electricity market for non-RPS supplies, rendering a higher

⁴¹ 50% of the non-RPS generation for 2018-2028.

differential in Scenario 2 than in Scenario 1. With respect to PG&E's rates, this differential will continue to follow a similar pattern: positive for all years from 2018 to 2038. And as was the case in Scenario 1, Scenario 2 enables the CCE to reliably price its average generation rates lower than those of PG&E.

Figure 17. Scenario 2 Forecast Average CCE Cost and PG&E Rates, 2018-2038⁴²



Residential Bill Impacts

Table 9 summarizes the average annual savings for residential customers under Scenario 2. For the 2018-2038 period, the average annual bill for a residential customer of the Contra Costa County CCE program will be 8% lower than the same bill under PG&E rates. This is a little less than, but close to, the bill savings under Scenario 1. Note that these rate impacts assume that a rate stabilization reserve is funded during the first few years of the CCE's existence. Thus, even though a "gap" between the CCE costs and PG&E rates can be seen in Figure 17, the bill savings in 2018 is zero, as the additional CCE funds are assumed to go to the reserve rather than as a customer bill savings.

⁴² This chart does not include the reserve fund.

Table 9. Scenario 2 Savings for Residential CCE Customers

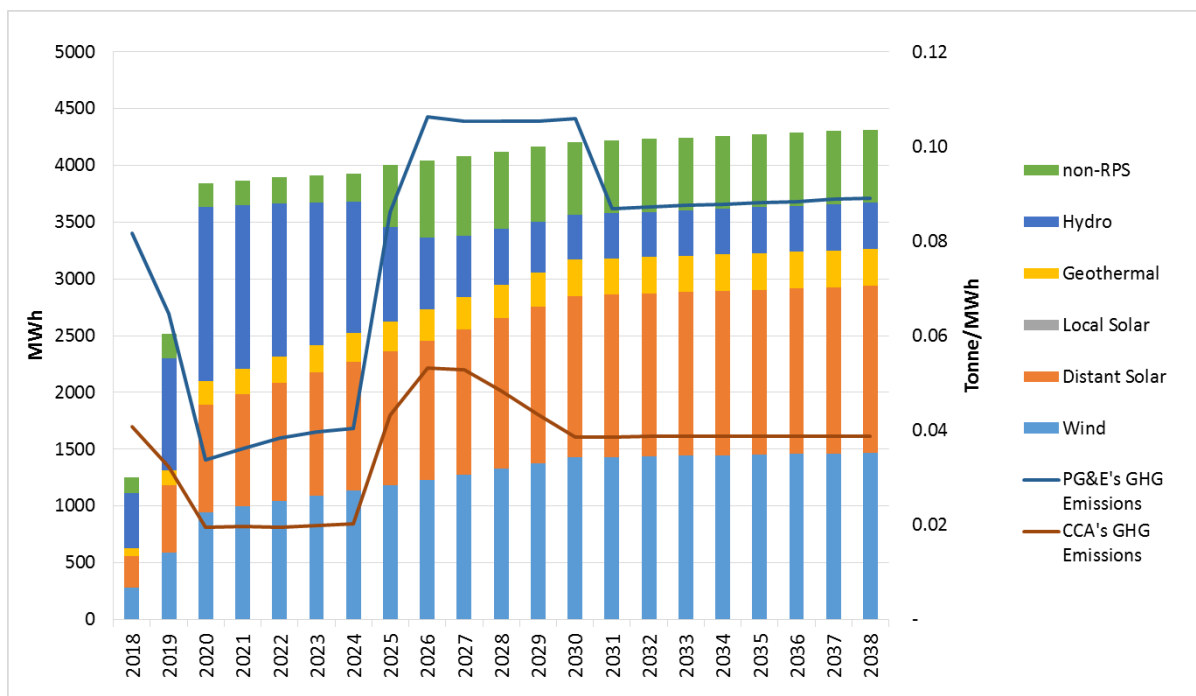
Residential	Monthly Consumption (kWh)	Bill with PG&E (\$)	Bill with Contra Costa County CCE (\$)	Savings (\$)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	125	4	3%
2030	500	189	172	17	9%
2038	500	254	225	29	11%

GHG Emissions

Under Scenario 2, we model the Contra Costa County CCE to at least as much carbon-free generation as PG&E. As in Scenario 1, in years where the assumed renewables would not result in the CCE halving PG&E's GHG emissions, we add large hydroelectric generation to the CCE's resource portfolio to make up the difference, subject to a 5% minimum supply from market purchases. In other years when the CCE's RPS targets are sufficient to provide GHG savings relative to PG&E, we assume that emissions are further reduced by sourcing 50% of the non-RPS supply from large hydro. The result is a portfolio that averages 20% large hydro.

Figure 18 compares the Scenario 2 GHG emissions from 2018-2038 for the Contra Costa County CCE with what PG&E's emissions would be for the same load if no CCE were formed. Because Scenario 2 has a higher renewable generation target (80% by 2030), the hydroelectric generation necessary to achieve the same GHG emissions reduction is lower. As a result of trading off large hydro for RPS-eligible energy, GHG emissions in Scenario 2 are the same as Scenario 1 through 2027, after which the CCE's portfolio will produce less than half the GHG emissions compared to PG&E.

Figure 18. Scenario 2 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) (“Normal” PG&E Hydro Conditions)



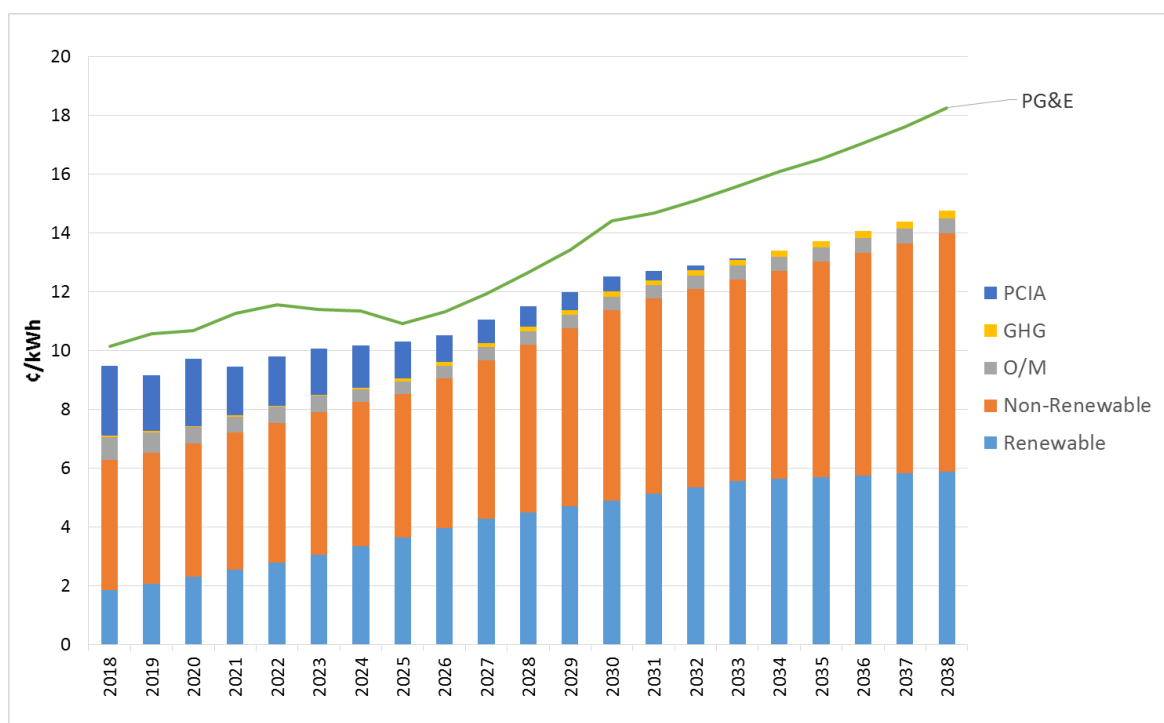
Scenario 3 (Minimum RPS Compliance plus Local Procurement)

Scenario 3 is identical to Scenario 1, save for a greater portion of locally sourced renewables. Under Scenario 3, local renewables increase annually, reaching 50% of the renewable supply by 2027 and continues at 50% through 2038.

CCE Costs

Figure 19 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. As with Scenario 1, the non-renewable cost is the largest component of the CCE's rates, followed by renewable generation costs. The latter are greater than in Scenario 1 due to the higher prices of local generation resources. As with previous scenarios, the PCIA exit fee is the third largest expenditure and it is expected to decrease most years after 2020. As with Scenario 1, the costs associated with GHG allowance purchases are responsible for a marginally larger percentage of the CCE's total costs between 2028 and 2038. This is mostly due to the lower share of GHG-free emissions.

The Scenario 3 differential between PG&E generation rates and Contra Costa County CCE rates falls below the differential in Scenarios 1 and 2. However, the CCE rates are expected to be lower than PG&E's generation rates for the entire forecast period, which will allow the CCE to collect reserve fund contributions annually from 2018 to 2038.

Figure 19. Scenario 3: Forecast Average CCE Cost and PG&E Rates, 2018-2038

Residential Bill Impacts

Table 10 summarizes the average residential bill impacts under Scenario 3. Between 2018 and 2038, the annual bill for a residential customer of the Contra Costa County CCE program will be, on average, 4.5% lower than a corresponding PG&E bill.

Table 10. Scenario 3 Savings for Residential CCE Customers

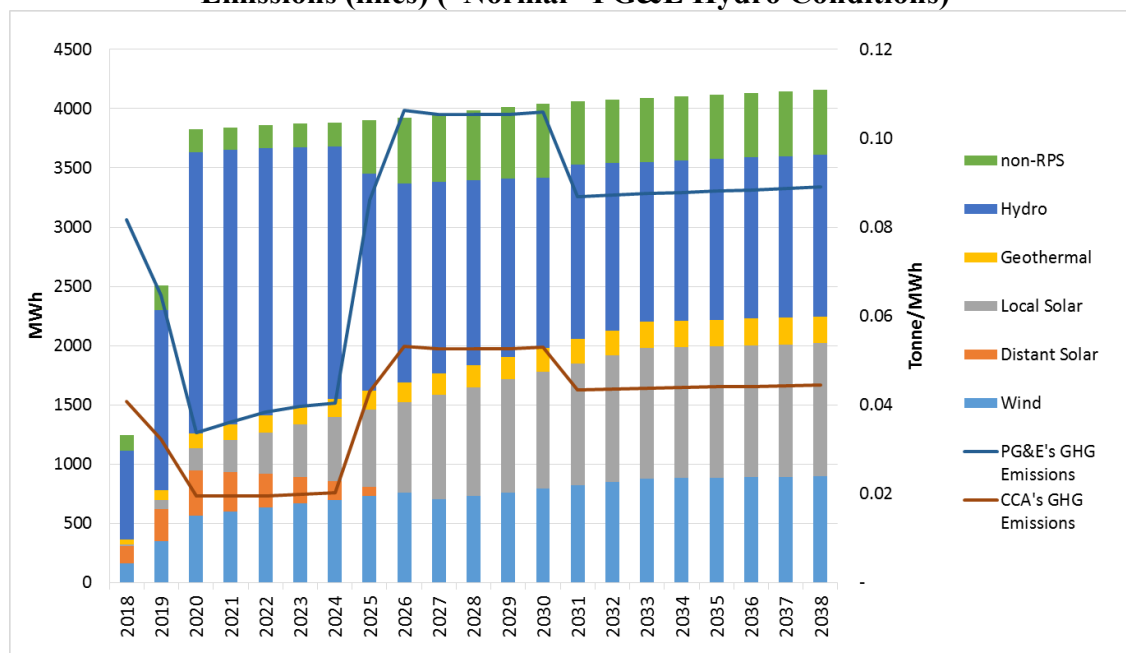
Residential	Monthly Consumption (kWh)	Bill with PG&E (\$)	Bill with Contra Costa County CCA (\$)	Savings (\$)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	126	3	2%
2030	500	189	179	10	5%
2038	500	254	236	18	7%

GHG Emissions

The emissions pattern for Scenario 3 is identical to Scenario 1 due to the equal GHG-free generation proportion. The only difference is that part of this generation is provided by local sources. Figure 20 shows the GHG emissions from 2018-2038 for the Contra Costa County CCE

under Scenario 3. Note that GHG emissions from the Contra Costa CCE supply and PG&E supply are the same as in Scenario 1.

Figure 20. Scenario 3 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) (“Normal” PG&E Hydro Conditions)



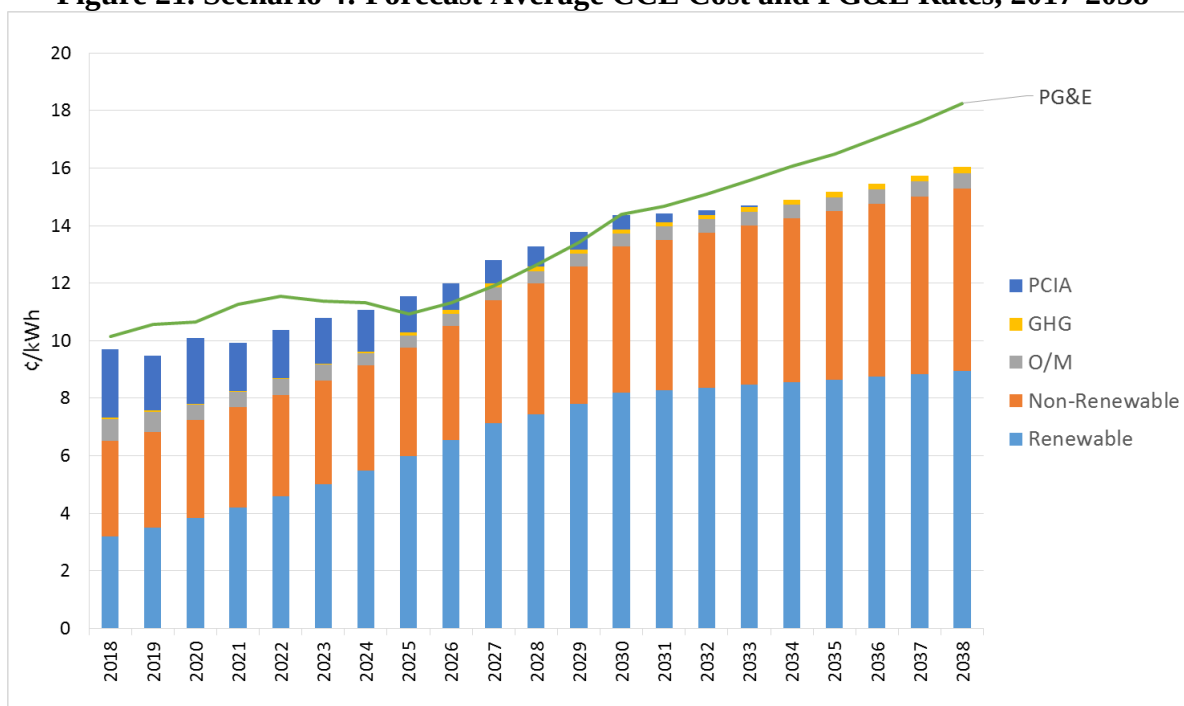
Scenario 4 (Accelerated RPS plus Local Procurement)

Scenario 4 is the same scenario as Scenario 2 but with a more substantial portion of the generation sourced from local renewable sources: increasing annually and achieving 50% of the total RPS supply by 2027 through 2038.

CCE Average Costs

Figure 21 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. Under Scenario 4, the cost for renewables forms the largest component of the CCE's rates and grows steadily to account for nearly 60% of the total CCE rate in 2030. Non-renewable generation is the next largest cost component of the rate, followed by the PCIA exit fee, which is expected to decrease in most years beginning 2020. As with Scenario 2, the costs for GHG allowance purchases in Scenario 4 are a smaller portion of total costs because of more RPS power.

The differential between PG&E generation rates and Contra Costa County CCE customer rates from 2018 to 2038 in Scenario 4 is the lowest of the four scenarios. This is because Scenario 4 has the most expensive supply portfolio, comprised of more locally sourced renewables. Similar to the other scenarios, in Scenario 4 the collection of the reserve fund contributions at the end of 2038 is positive. Contra Costa County CCE rates in Scenario 4 are forecasted to be lower than expected PG&E generation rates for all years from 2018 to 2038, except from 2025 to 2030.

Figure 21. Scenario 4: Forecast Average CCE Cost and PG&E Rates, 2017-2038

Residential Bill Impacts

Table 11 summarizes the average residential bill impacts under Scenario 4. Over the study period, the annual bill for a residential customer of the Contra Costa County CCE program will be, on average, 1% lower than the same bill under PG&E rates under Scenario 4. However, the higher local renewable costs coupled with their assumed high usage cause the CCE's rates to exceed PG&E's in some years. In particular, from 2025 through 2030, the total CCE rates (CCE rate plus PCIA) is projected to be higher than the PG&E generation rate. This implies that very aggressive pursuit of local renewables must be carefully weighed against their additional costs.

However, it should also be noted that the study assumed a conservative \$30/MWh adder on top of the build costs of local solar projects to account for costs of land acquisition/ opportunity costs. If a significant fraction of the local projects does not have these higher soft costs, then this higher level of local renewables can be developed at competitive rates.

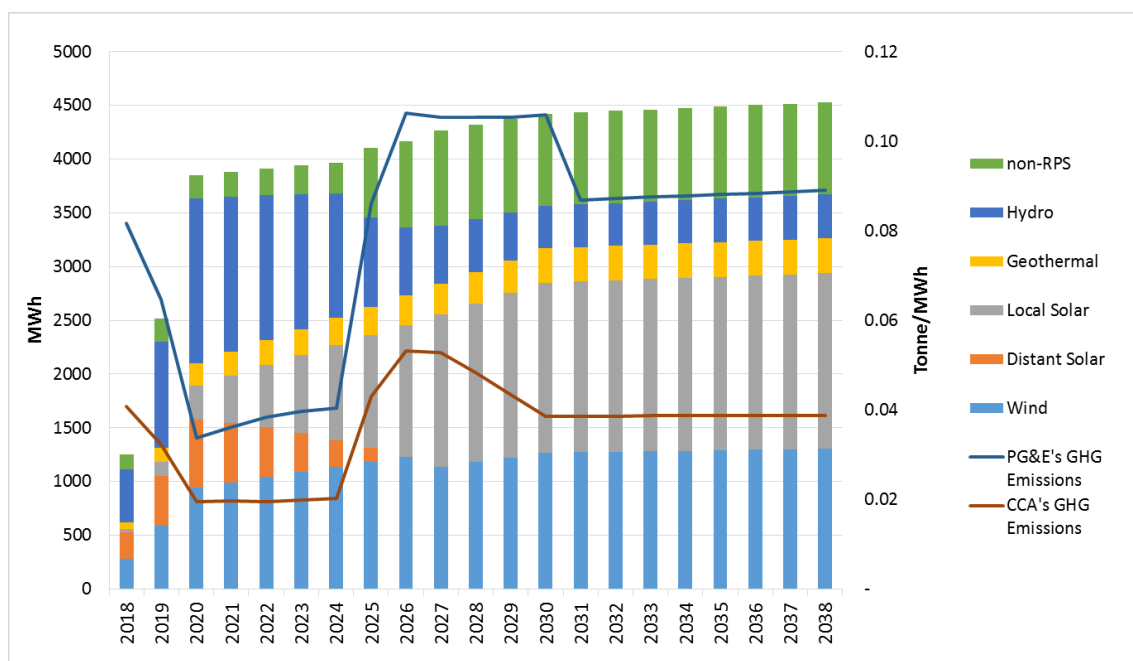
Table 11. Scenario 4 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E (\$)	Bill with Contra Costa County CCA (\$)	Savings (\$)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	128	1	0.7%
2030	500	189	199	-10	-5%
2038	500	254	242	12	5%

GHG Emissions

The GHG emissions pattern for Scenario 4 is the same as Scenario 2 due to the scenarios having the same shares of GHG-free generation; the only difference being that local solar generation is assumed to replace solar supplies from more distant locations. Figure 22 compares the GHG emissions from 2018-2038 for the Contra Costa County CCE under Scenario 4 with what PG&E's emissions would be for the same load were no CCE formed.

Figure 22. Scenario 4 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) (“Normal” PG&E Hydro Conditions)



Chapter 4: Sensitivity of Results to Key Inputs

In addition to the base case forecast described above, MRW has assessed alternative cases to evaluate the sensitivity of the results to possible conditions that would have an impact on Contra Costa County CCE's technical study. The metric considered to compare the alternative sensitivity cases to the base case is the differential between the annual average generation rates for PG&E bundled customers and for Contra Costa County CCE customers over the first ten years (2018-2028).⁴³ The latter 10 years were not included as they are both uncertain and skew the average results due to the widening gap between modeled PG&E's rates and the CCE's average cost.

The base-case analysis (Chapter 3 –Scenario 1) was developed as a reasonable and conservative assessment of the Contra Costa County CCE. In addition to the base case analysis, MRW analyzed alternative cases to address seven risks: (1) low participation, (2) higher local renewable power prices, (3) higher renewable power prices, (4) higher natural gas prices, (5) lower PG&E portfolio costs, (6) higher PCIA charges, and (7) a combination of these six risks (stress scenario).

Lower Participation Sensitivity

This sensitivity case evaluates the impact of lower participation on the CCE program. Lower participation could be due to a higher customer opt-out rates, or if some of the cities included in the study choose not to participate in the CCE program. If fewer customers join, CCE rates will generally be higher because about \$7 million of annual CCE costs are invariant to the amount of CCE load. In the Lower Participation sensitivity, we assume that the load for the Contra Costa County CCE is 70% of the potential load.⁴⁴ Average administration costs in this scenario are 12% higher than in the base case scenario. These higher administration costs do not have a big impact on the CCE rates because administration costs are a small part of the total CCE rate (5% on average). The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.07¢/kWh relative to the base case.

Table 12. Lower Participation Sensitivity Results, 2018-2028

Period 2018-2028	Average Admin costs (¢/kWh)	Average rate differential (¢/kWh)
Base	0.45	1.86
Low participation	0.51	1.79

⁴³The Contra Costa County CCE rate includes the PG&E exit fees (PCIA charges) that will be charged to CCE customers but does not include the rate adjustment for the reserve fund or other possible CCE activities.

⁴⁴ In the base case we considered 85% of the potential load.

Higher Local Renewable Power Prices Sensitivity

This sensitivity case evaluates the impact of higher local renewable power prices on the CCE's financial viability. As discussed in Appendix B, in the base case, the solar local renewable power price starts at \$98/MWh in 2018 and it increases following the price curve. In the Higher Local Renewable Power Prices sensitivity, we assume that local renewable prices would be 20% higher than the base case prices. These higher prices affect only CCE rates for Scenario 3 and Scenario 4 (Scenario 1 and Scenario 2 do not include local generation), reducing the 2018-2028 average rate differential by 0.3¢/kWh relative to the base case.

Table 13. Higher Local Renewable Power Prices Sensitivity Results, 2018-2028⁴⁵

Period 2018-2028	Average local renewable prices (\$/MWh)	Average rate differential (¢/kWh)
Scenario 3	114.30	1.14
High local renewable prices	137.20	0.85

Higher Renewable Power Prices Sensitivity

This sensitivity case evaluates the impact of higher renewable power prices on the CCE's financial viability. As discussed in Appendix B, in the base case, renewable power prices are flat in nominal dollars through 2022, based on the assumption that projected declines in renewable development costs will offset increases associated with the expected expiration of federal renewable tax credits.^{46,47} In the Higher Renewable Power Prices sensitivity, we assume that renewable prices would be flat in nominal dollars through 2022 if it were not for the tax credit expirations and add the impact of the tax credit expirations to the base case prices. Average renewable power prices in this scenario are 0-10% higher than in the base case scenario through 2021, about 20% higher in 2021 and 2022, and 30% higher after 2022 when the solar investment tax credit is reduced to 10%. These higher prices affect both the CCE and PG&E, but they have a greater effect on the CCE because PG&E has significant amounts of renewable resources under long-term contract. The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.35¢/kWh relative to the base case.

⁴⁵ Results for Scenario 3.

⁴⁶ The Investment Tax Credit (ITC) which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain. The federal Production Tax Credit (PTC), which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.

U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). <http://energy.gov/savings/business-energy-investment-tax-credit-itc>; U.S. Department of Energy. Electricity Production Tax Credit (PTC). <http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc>

⁴⁷ The base case forecast would also be consistent with a scenario in which the tax credit expirations are delayed.

Table 14. Higher Renewable Power Prices Sensitivity Results, 2018-2028

	Average RPS prices (\$/MWh)	Resulting average rate differential (¢/kWh)
Base	53.2	1.86
High renewable prices	65.1	1.51

Higher Exit Fee (PCIA) Sensitivity

PG&E's PCIA exit fees are subject to considerable uncertainty. Under the current methodology, PCIA rates can swing dramatically from one year to the next, and this methodology is currently under review and may be adjusted in the coming years. MRW therefore evaluated a stress case in which PCIA rates do not fall after 2018, as anticipated in the base case, but instead remain at 2018 levels through 2028. This increases the 2028 PCIA by more than 300% of its base case value. The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.86¢/kWh relative to the base case.

Table 15. Higher PCIA Exit Fee Sensitivity Results, 2018-2028

	Average PCIA prices (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	1.5	1.86
High PCIA	2.4	1.00

Lower PG&E Portfolio Cost Sensitivity

While changes to natural gas prices and renewable power prices affect both the CCE and PG&E, dampening the impact on the CCE's cost competitiveness, reductions to the costs to operate and maintain PG&E's nuclear and hydroelectric facilities would provide cost savings to PG&E that would not be offset by cost savings to the CCE. MRW considered a case in which PG&E's overall generation rates are 10% below the base case, driven by reductions to PG&E's nuclear and hydroelectric portfolio costs. Under such a scenario, the 2018-2028 average rate differential would be reduced by 1.12¢/kWh relative to the base case scenario.

Table 16. Lower PG&E Portfolio Sensitivity Results, 2018-2038

	Average PG&E Rate (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	11.2	1.86
Low PG&E portfolio costs	10.1	0.74

Higher Natural Gas Prices Sensitivity

Natural gas prices have been low and relatively steady over the last few years, but they have historically been quite volatile and subject to significant swings from local supply disruptions (e.g., Hurricanes Katrina and Rita in 2005). MRW analyzed a gas price sensitivity case using the U.S. Energy Information Administration's High Scenario natural gas prices forecast,⁴⁸ which is on average 50% higher than MRW's base case forecast for the period 2018-2028. Natural gas price increases affect power supply costs for both a Contra Costa County CCE and PG&E; however, the nuclear and hydroelectric capacity in PG&E's resource mix makes PG&E less sensitive than a Contra Costa County CCE to changes in natural gas prices. The net effect of higher natural gas prices is therefore to increase CCE rates relative to PG&E rates⁴⁹ (i.e., reduce the average rate differential). Under the sensitivity conditions considered, the 2018-2038 average rate differential decreases relative to the base case by 1.68¢/kWh.

Table 17. Higher Natural Gas Prices Sensitivity Results, 2018-2028

	Average PG&E Rate (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	11.2	1.86
Low PG&E portfolio costs	10.1	0.18

Stress Case and Sensitivity Comparisons

All rate differentials (i.e., the CCE's competitive positions) are lower in the sensitivity cases than in the base case scenario for all years from 2018 to 2028 (**Table 18**). To evaluate a more extreme scenario, MRW developed a stress case that combines all the sensitivity cases: (1) low

⁴⁸ U.S. Energy Information Administration. "2015 Annual Energy Outlook," Table 13

⁴⁹ For Scenarios 2 and 4 the high gas natural prices case has less negative impact due to the high proportion of renewable generation.

participation, (2) higher local renewable power prices, (3) higher renewable power prices, (4) higher natural gas prices, (5) lower PG&E portfolio costs, and (6) higher PCIA charges. The 2018-2028 average rate differential for this stress case is negative, at -4.08¢/kWh, meaning that CCE customer costs would exceed PG&E customer costs under this scenario.

Table 18. Stress Test Results, 2018-2028

	Resulting average rate differential (¢/kWh)
Base	1.86
Stress Scenario	-2.3

Figure 23. Difference Between PG&E Customer Rates and CCE Customer Rates Under Each Sensitivity Case, 2018-2028⁵⁰

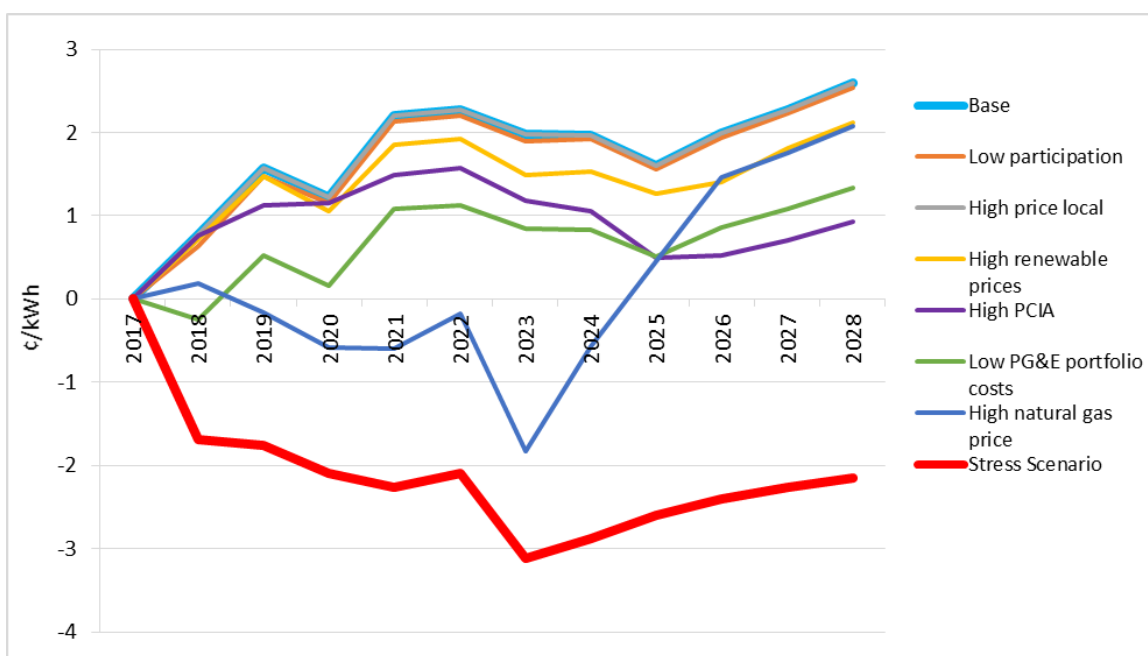


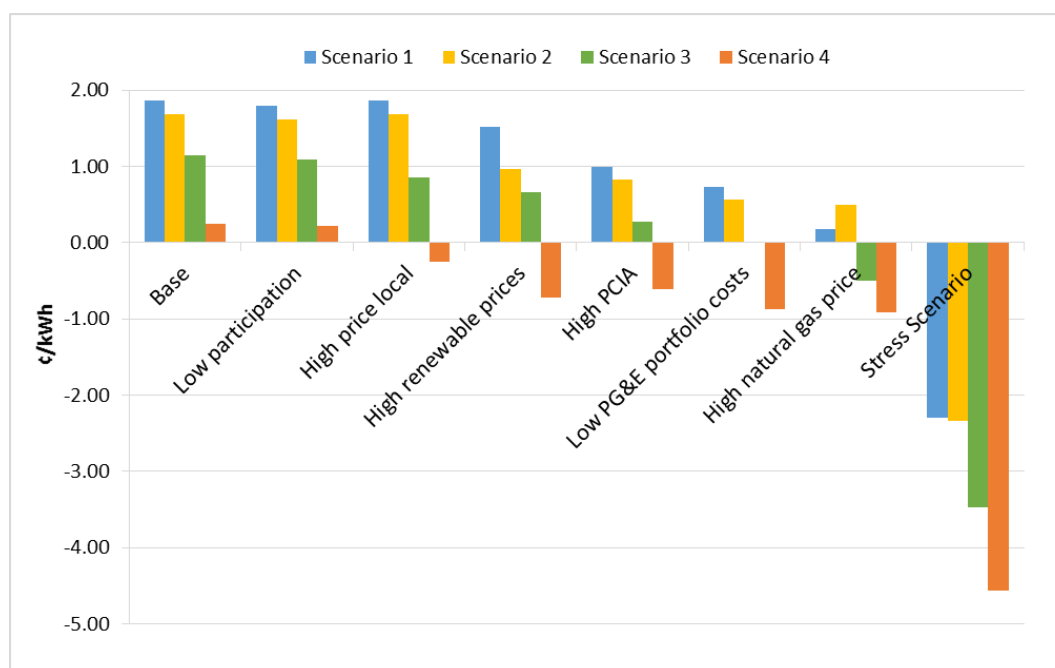
Figure 23 shows the difference between the PG&E customer rates and the Contra Costa County CCE customer rates (including exit fees) in the base case, and in each of the sensitivity scenarios, for each year from 2018 to 2028. As Figure 23 illustrates, CCE customer rates are lower than PG&E customer rates in each of the individual sensitivity cases in each year. For the High Natural Gas Price sensitivity case, in 2023 the rate differential drops due to an increase on the

⁵⁰ The chart plots the sensitivity cases for Scenario 1, therefore it does not reflect the effect of the High Price Local sensitivity (it only applies to Scenario 3 and 4).

PCIA, as the PCIA is highly sensitive to the natural gas prices. Under the Stress Scenario case, the rate differential is negative for each year (i.e., CCE rates are higher than PG&E generation rates).

The results shown above reflect the Minimum RPS Compliance supply scenario (Scenario 1). MRW additionally evaluated each sensitivity scenario under the four alternative supply scenarios: (1) Minimum RPS Compliance, (2) Accelerated RPS, (3) Minimum RPS Compliance plus Local Procurement, and (4) Accelerated RPS plus Local Procurement. Figure 24 depicts the average rate differentials for 2018-2028 for each sensitivity case under the four supply scenarios.

Figure 24. Difference Between PG&E Customer Rates and CCE Customer Rates Under Each Sensitivity Case and Supply Scenario, 2018-2028 Average



Looking at 2018-2028, Scenario 1 (Minimum RPS Compliance) is the least costly scenario for the CCE, and therefore has the best rate differential under most of the sensitivity cases considered.⁵¹ Scenario 2 (Accelerated RPS), though still quite competitive with PG&E, fares slightly worse, with a rate differential approximately 10-20% lower than in Scenario 1 for most of the sensitivity cases considered. The one exception is the High Natural Gas Price sensitivity case, in which Scenario 1 has worse results than Scenario 2. This is due to the higher gas-fired generation content in Scenario 1, which makes the supply portfolio more susceptible to volatility in natural gas prices than Scenario 2. For most of the sensitivity cases, rate differentials for

⁵¹ This is only looking at the period 2018-2028. From 2028-2033 the rates show the same pattern between the four scenarios. If we consider the period 2033-2038, Scenario 2 would be the least costly scenario. After 2033 the prices of renewable generation are expected to be lower than the wholesale electric market, which makes Scenario 2 less costly than Scenario 1 in the period 2033-2038.

Scenario 3 are lower than Scenario 1 and Scenario 2. Scenario 4 is the costliest scenario, with rate differentials much lower than the other three scenarios.

In the stress case, Contra Costa County CCE customer rates exceed PG&E customer rates on average over the 2018-2028 period for all four scenarios, with the negative rate differential being highest in Scenario 4 at -4.5¢/kWh.

Conclusions

Under Scenarios 1, 2 and 3, Contra Costa County CCE customer rates compare favorably to PG&E rates in all years from 2018 to 2038. As modeled, in Scenario 4 Contra Costa County CCE customer rates would be higher than PG&E rates from about 2025 and 2030. Under Scenarios 1 and 2 (simple RPS compliance), Contra Costa County CCE customer rates remain below PG&E rates under all but the most extreme sensitivity case considered. Scenario 3 rates could meet or beat PG&E's under all but the high natural gas and stress cases. Under the stress case, irrespective of the supply scenario considered, CCE rates are higher than PG&E rates. While the stress case may appear extreme given that it involves seven adverse sensitivities simultaneously occurring, cost volatility in the power industry is well established, and the possibility of adverse conditions arising in an isolated year should be understood and planned for in any CCE venture.

Chapter 5: Macroeconomic Impacts

This chapter discusses the job impacts within Contra Costa County for each of the four scenarios. All four scenarios modeled showed positive economic and job impacts. The mix and amount of jobs created would depend upon policy decisions made by the CCE board, primarily trading off the economic stimulus from lower electricity bills versus the direct jobs created by local (higher cost) renewable energy projects sponsored by the CCE.

To understand just how job impacts can come about, and the extent of those changes (positive or negative), a brief description of elements associated with the CCE and how they influence the existing economy is provided.

How a CCE interacts with the Surrounding Economy

The establishment and operation of a CCE creates a new set of spending elements (also referred to as “demands”) as a community changes the type of electricity generation they want to purchase, where the new mix of generation is to be located, adjustments necessary for existing generating assets of the provider utility, and implications on customers’ bills because of retail rate differentials. Some of these new elements have temporary effects, while others have long-term effects. Investment in locally sited solar will result in temporary direct creation of jobs whereas subsequent *maintenance* will support some on-going direct jobs. Regardless of the duration, when a direct job is created in a sector, there will be a multiplier response on “backwardly-linked” jobs with supplier businesses if the supplier is present in the economy. The new elements include:

- **Administration** – direct jobs, long-term effect. County staffing, professional-technical services and I/T-database services
- **Net Rate Savings (or bill savings)** – long-term effect. County households have an increase in their spending ability, County commercial and industrial energy customers experience a reduction in their costs-of-doing business which makes them each more competitive, garnering more business that requires more employees, and municipal energy customers can provide more local services which require more local government staff.
- **New Renewable Capacity Investment within County & Surrounding counties** – direct jobs, short-term, two of the four scenarios.
- **New Renewable Operations within County & Surrounding counties** – direct jobs, long-term, two of the four scenarios.
- **Net Generating Capacity and Operations offsets for PG&E outside of county** – direct jobs, short and long-term, none because we are not focused on the *rest of California* economy.

To frame expectations around how many direct jobs can be created in the County from the above CCE elements, consideration must be given to (a) how much of the spending associated with the CCE scenario is fulfilled by a within-county business or resident workforce, and (b) what do these locally-fulfilled dollars represent in terms of current annual County business activity (e.g., is this a large spending event?).

Job Impacts of Proposed CCE Scenarios

We examine each of the four scenarios for their influence on the County economy and the economy of the four surrounding counties combined (a ring region comprised of Alameda, Sacramento, San Joaquin, and Solano counties). The basis for including the surrounding counties is (i) interdependence of the economies in terms of business-to-business transactions (in part due to proximity) and labor commuting flows (both in and out), as well as (ii) the siting of 50 percent of the proposed CCE funded small-scale solar projects beyond Contra Costa County. The scenario structures assume no electric customer participation from beyond Contra Costa County therefore the proposed *bill savings* are allocated across customer segments solely within Contra Costa County.

The possible sources of *initial* job change in any of the scenarios include:

- CCE Administration *spending* 2018 to 2038 (within Contra Costa County)
- Bill Savings *less* Customer's expense for on-site solar deployed 2018 to 2038 (within Contra Costa County)
- Investment in small-scale Solar 2018 to 2030 (Contra Costa and the 4-county ring region)
- O&M spending on small-scale Solar 2018 to 2038 (Contra Costa and the 4-county ring region)

Only scenarios 3 and 4 include investment for small-solar projects in Contra Costa County and the surrounding region of counties. Once each regional economy experiences its initial change related to any of the above scenario elements, a macroeconomic forecasting tool (the REMI model⁵²) captures impacts from inter-regional transactions (of commuters, of business sales), and impacts from changes in Contra Costa County's relative *cost-of-living* and *cost-of-doing business* resulting from bill savings, and impacts associated with *multiplier effects*.

Overview of Scenario Effects

It is helpful to understand how the various scenarios “stack up” in terms of the four sources that will exert an influence on the local economies. Table 19 presents the cumulative (2018 to 2038) stimuli - bill savings, administrative spending, and where relevant, demands related to investment, O&M. The amounts are a roll-up of nominal values. Scenario 1 poses the greatest amount of Rate Savings for County CCE customers (\$2,390 million), and Scenario 4 poses the largest amount of solar investment *demand* (\$827 million) for in-county installations. Ensuing O&M spending (Scenarios 3 and 4) will increase as the investment *demand* increases. None of the displaced renewable capacity by PG&E (investments under the “business-as-usual” or “without CCE” case) occurs in either Contra Costa or the surrounding 4 counties.

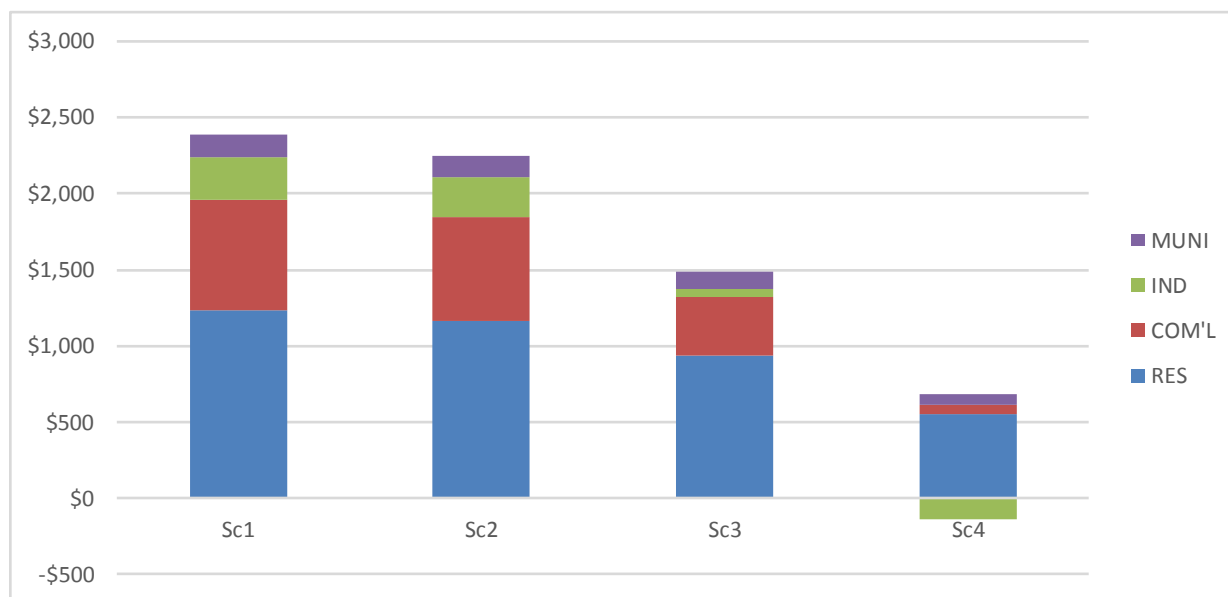
⁵² Regional Economic Models, Inc. of Amherst, MA. www.remi.com

Table 19. CCE Scenario Economic Characteristics (2018-2038, Millions of nominal dollars)⁵³

Scen.	Net Rate savings County customers	CCE Small Solar Investment		CCE Small Solar O&M	
		Contra Costa County	Neighboring Counties	Contra Costa County	Neighboring Counties
1	\$2,390	\$0	\$0	\$0	\$0
2	\$2,251	\$0	\$0	\$0	\$0
3	\$1,485	\$456	\$456	\$234	\$234
4	\$542	\$827	\$827	\$375	\$375

Figure 25 presents the estimated *net* rate savings for various customer-segments in the County by CCE scenario. The rate savings benefit accrues foremost to the residential segment, followed by the commercial segment. The municipal segment has fairly constant rate savings regardless of scenario. In addition to the magnitude of overall net rate savings and local solar-related business opportunities, this segment distribution across customer segments influences part of the job impact response (amidst solar investments). Households spend money saved on electric bills on other consumer basket items, which would include a mix of goods and services, some local, some imported, which all rely on different jobs at different wages. Commercial or industrial electric customers experience a savings as making their operations more cost competitive, which returns some positive (though not equal across all type of activities) market share growth (e.g., more sales which means more jobs and other inputs to their operations). Municipal segment savings allow the state/local government entity to redirect dollars into other forms of public spending.

⁵³ *Net Rate Savings* are net of customer out-of-pocket for on-site solar additions under Scenarios 3 and 4. For the County projects, 25 percent of the investment is paid by *Industrial* customers, 25 percent by *Commercial* customers, with the balance funded by outside investors. Small-solar projects in the surrounding counties are assumed to be funded by outside investors. Under scenarios 1 and 2 *net* is equal to gross rate savings.

Figure 25. Cumulative net Rate Savings in Contra Costa County, Proposed CCE structures

The opportunity for the small-solar investment episode (2018 through 2030), for scenarios 3 and 4, to generate “within region” job requirements is determined by how much of the investment dollars connect with (procure from) ‘within region’ construction labor and businesses that provide project components. The allocations of small-solar investment dollars into these two major types of purchases (with additional breakdown on non-labor expenditures) is done using the National Renewable Energy Laboratory (NREL) Jobs and Economic Development Impact (JEDI) small-solar PV JEDI model⁵⁴ (CA) allocation. As shown in Table 20 for scenarios 3 and 4, no less than 50 percent of the various budgets enlists local workforce, and firms that provide supplies or services.

⁵⁴ The Jobs and Economic Development Impact (JEDI) models are user-friendly screening tools that estimate the economic impacts of constructing and operating power plants, fuel production facilities, and other projects at the local (usually state) level. JEDI results are intended to be estimates, not precise predictions. See: http://www.nrel.gov/analysis/jedi/about_jedi.html

Table 20. Local Fulfillment of CCE Budgets (millions of nominal dollars)

	CCA Admin	Solar Invest	Solar O&M	CCA Admin	Solar Invest	Solar O&M
	Scenario 1			Scenario 3		
Budget	\$316	N/A	N/A	\$316	\$456	\$233
In-County						
<i>locally procured</i>	\$189	N/A	N/A	\$189	\$234	\$146
% capture local	60%	N/A	N/A	60%	51%	63%
Surrounding Counties						
<i>locally procured</i>	N/A	N/A	N/A	N/A	\$234	\$146
% capture local	N/A	N/A	N/A	N/A	51%	63%
	Scenario 2			Scenario 4		
Budget	\$316	N/A	N/A	\$316	\$ 827	\$375
In-County						
<i>locally procured</i>	\$189	N/A	N/A	\$189	\$425	\$235
% capture local	60%	N/A	N/A	60%	51%	63%
Surrounding Counties						
<i>locally procured</i>	N/A	N/A	N/A	N/A	\$450	\$219
% capture local	N/A	N/A	N/A	N/A	51%	63%

Resulting Impacts on Jobs

This section will present several views of the job impacts by scenario. As shown in Table 21, Scenario 1 yields the largest annual job impact for the County over the interval – the result of the maximum rate savings under the CCE program. Job impacts are not limited to the direct job requirements from a CCE but include jobs resulting from *multiplier effects* and *competitiveness effects*. Scenario 4 – with the smallest of *net* rate savings for the County’s electric customers poses the largest investment for small -solar across the 5-county economy. This compensates for the reduced role of the rate savings and thus Scenario 4 yields an annual job gain for the 5-county economy, 886 jobs (compared to Scenario 1 with 731). The largest absolute job gain is in Scenario 3, with a total of 922 annual average jobs. As the amount of small solar investment increases (with subsequent O&M spending to follow), the percent of job impact that occurs within the surrounding multi-county region increases (Scenario 4 has 44%). The County’s annual job increase under Scenario 4 however is moderated when compared to Scenario 1. This is understood by (i) all CCE customers’ realizing smaller rate savings when the CCE attempts to invest in *local* solar, combined with (ii) commercial/industrial businesses in the County picking up 50 percent of the solar investment cost. Also, influencing the “surrounding county region” job impact is the fact that a neighboring economy (the County) is experiencing lower electric bills (regardless of the magnitude) and a solar installation “boom” – namely, economic stimulating events. This can create a positive bounce for the surrounding counties on some of the

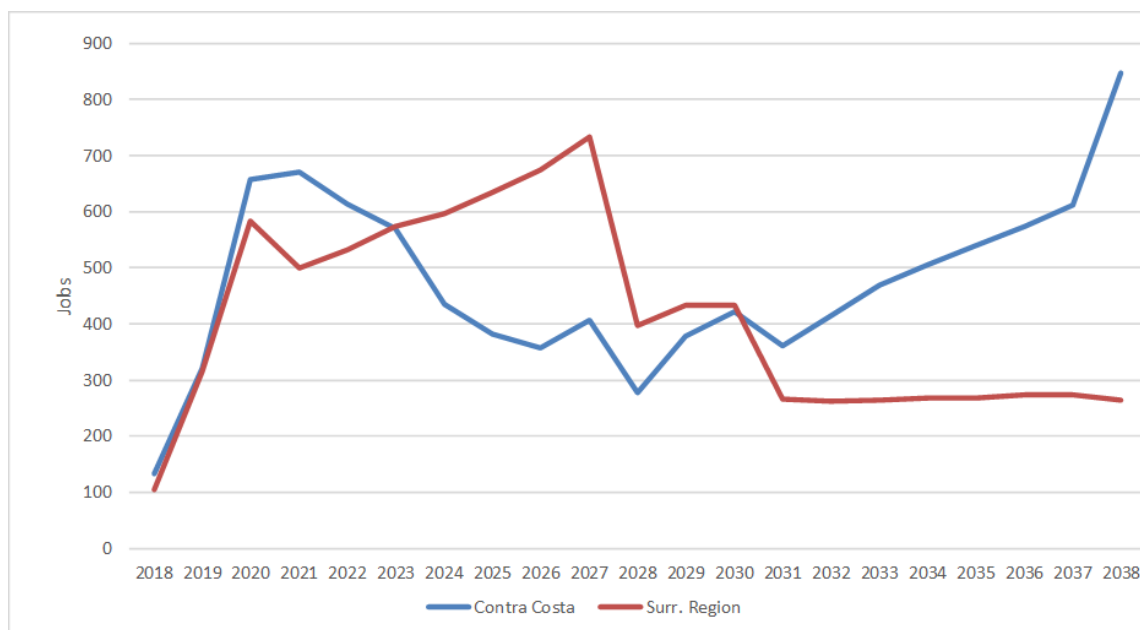
background business (supplier) transactions as well as with working-age households who commute into the County (this point is illustrated in Figure 26). And when the surrounding region is host to its own solar installation boom, this will engage the Contra Costa County economy as well.

Table 21. Average Annual Employment Impacts 2018 through 2038 (Jobs)

Scenario	Contra Costa	Surrounding 4 Counties	All 5 counties	% in Region
1	681	50	731	7%
2	571	48	619	7%
3	654	268	922	29%
4	474	412	886	44%

For Scenario 4 (with the smallest *net* rate savings and the highest local solar-investment/O&M spend) a time-path of the resulting job impacts is shown in Figure 26. To be clear, the results are not depicting *cumulative* job impacts, simply a plot of each year's resulting impact. After 2030, no more solar installations occur in either region.⁵⁵ The surrounding region remains slightly buoyed with job impacts due to some continued O&M spending and feedback from the Contra Costa economy that is still benefitting now from *gross* rate savings (no more project expenses) and some O&M spending.

Figure 26. Scenario 4 – Annual Job Impacts, 2018 to 2038



⁵⁵ This is because the targeted renewable penetration was met and no new generation is needed by the CCE. If the study looked further out, then replacement solar would begin to have an effect and generate jobs.

Figure 27 helps explain ‘the dip’ in the above *blue* series of positive job impacts (*for Contra Costa*) between 2024 and 2030. The estimated forecast of *net* rate savings follows such a trajectory (becoming *negative* between 2023 and 2030, when some customers bear a portion of the investment cost plus CCE rates are slightly higher than PG&E’s) and even the *local* capture on the solar investment comes off a local maximum in 2020 and a global maximum in 2027 (the latter occurs in the surrounding region as well).

Figure 27. Scenario 4 – Contra Costa’s “Local” Benefit

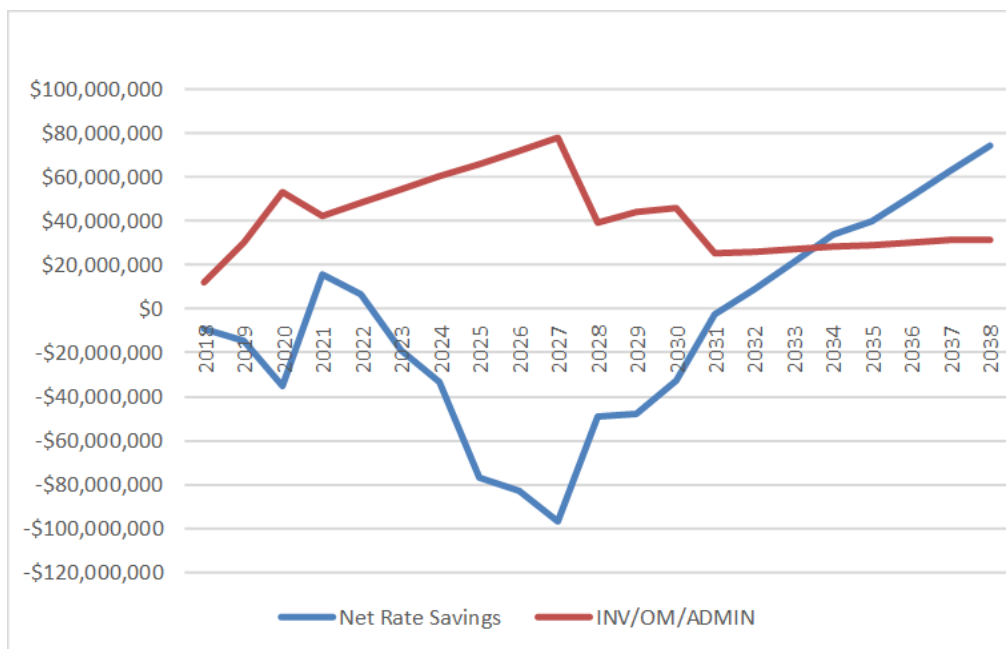
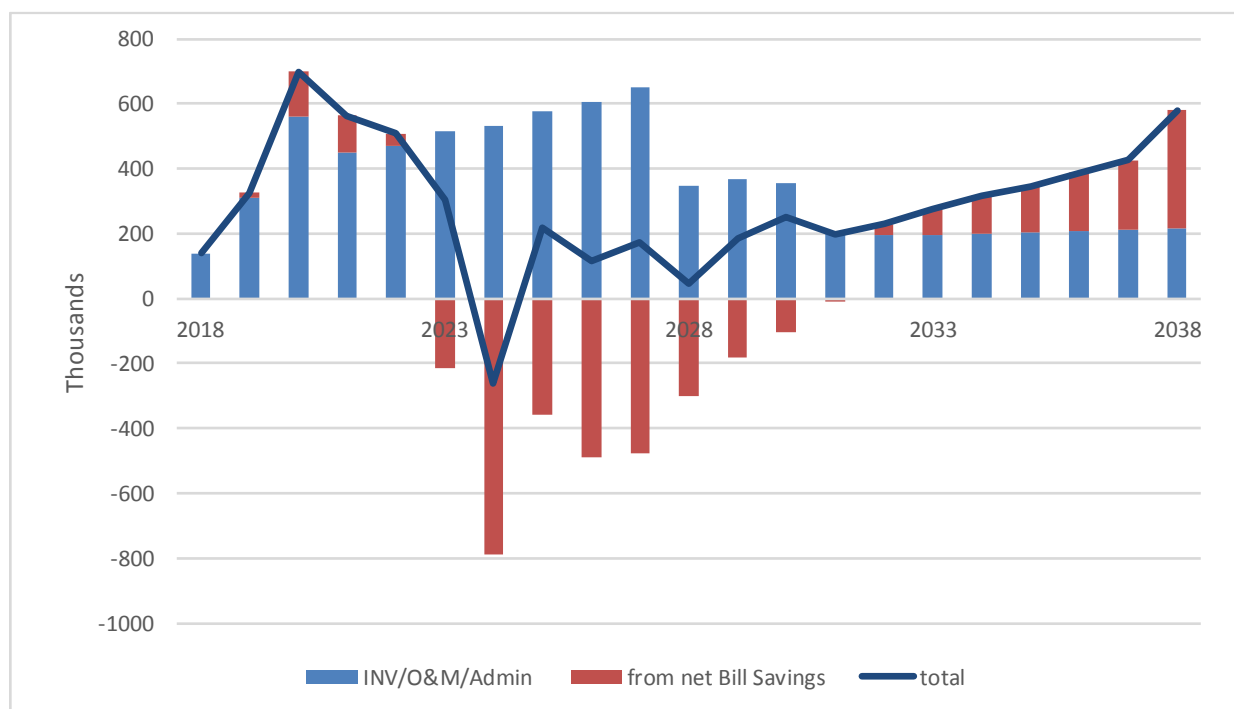
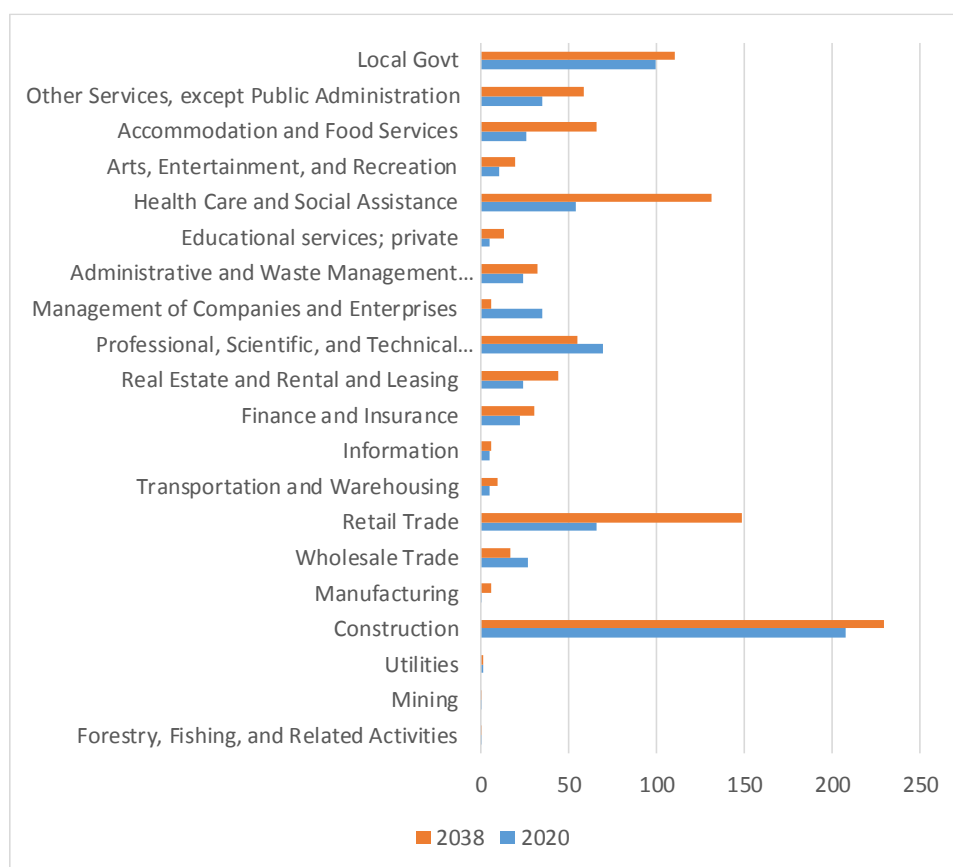


Figure 28 shows what contributes to Contra Costa’s job impact under Scenario 4. The dark blue line is the line from Figure 26. Through 2030, the largest influence on the County’s *positive* job impacts is the stimulus of solar project investment. Afterwards it is the role of *net* Rate Savings exerted through the customers’ roles in the local economy that creates local jobs.

Figure 28. Scenario 4 – Contra Costa Job Impact by Source

A look at two points in the policy interval illustrates the types of jobs that comprise the impact results. In 2020 there are about 700 additional jobs (when solar investment is at a maximum with little of the *net rate savings* realized) and in 2038, about 600 additional jobs in the County (after the investment hang-over is past and only a small influence is exerted through O&M and administrative spending, and the County economy is still experiencing a ramp up of rate savings).

Figure 29 shows a pattern and an order of magnitude for each of the *snapshot* years that is indicative of the major CCE influence on the County's industry base. In 2020, County job additions are explained foremost by the predominant effect emanating from the CCE scenario – namely solar project investment and program administration (net rate savings are *negative* at this point as a result of C/I customers paying for part of the solar investment cost). So, jobs occur in *Construction*, in *State/Local Government*, in *Professional Technical Services*, and with *Wholesale suppliers*. Project developer overhead payments (part of the investment cost) is why job additions are showing for *Management of Companies and Enterprises*. But not all of the job additions in these sectors are directly related to solar installations. Some of these – as well as jobs gains in other non-investment sectors like health care, and food establishments, and retail – are the result of the initial labor income gains (construction paychecks) which drives added household spending (the *induced* stage of economic multiplier effects), and some are the result of increases in “within county” business-to-business transactions and elevated business needs from the adjacent region (the *indirect* stage of multiplier effects.)

Figure 29. Scenario 4 - Jobs added Among Contra Costa Sectors, 2020 and 2038

In 2038, (the orange series) the predominant ‘economy’ effect from the CCE is the *net* rate savings with a majority benefitting the *residential segment*. Households will redirect these savings into additional household spending (e.g., health care, retail, food establishments). But the municipal segment receives savings as well which drives additional public spending and requires some growth in staff in addition to the local government staff to administer the CCE (an average of 23 *administrative* staff). Commercial and industrial sectors also experience some job increases as their bill savings improve their bottom lines and grow their respective market shares for business. The pronounced gain in local government jobs is more than the (averaged) 23 staff mentioned above. By 2038 the County will have retained a significant number of its working-age residents that would otherwise have out-migrated (under the business-as-usual case) due to a combination of *relative* employment opportunities and inflation adjusted wages. The CCE activity creates job opportunity, mitigates in-county inflation (vis a vis bill savings) so there is real wage appreciation, and helps stem the tide of out-migration of key working-age cohorts. This further bolsters the positive population growth the County was forecast to have (under the BAU case), and local government spending (and staffing) increase on a *per capita* basis. In addition, the S/L government activity increases as the productive capacity of the County grows (in terms of dollars of gross regional product). The *Construction* sector posts strong job increases but now it is more the response to growth in the County (due to CCE influences) and this sector is key during investment (for both residential and non-residential structures) responses to close the gap between actual and optimal capital requirements in a growing economy.

Allocation of Earned Income Gains

A majority but not all jobs added in Contra Costa County will be held by the County's working-age resident households. The same is true for jobs added in the 4-county surrounding region. Which means the household spending effects from the take-home pay on the above impacted jobs occur where the worker *resides*. The above job impacts are measured by *place-of-work*. The commuter from another county registers the induced effects of their earned income on a *place-of-residence* basis.

Again, we focus on Scenario 4 in the year 2020 (year of maximum investment activity that is split 50:50 across both regions). Before we even allocate the impacts across the County boundary, it is helpful to reveal the broad commuting propensity (this is not industry-specific but rather across all activities within an economy) for these two interconnected regions. These relationships are captured in County data on personal (earned) income flows and the journey-to-work data – both federally collected. Table 22 shows the extent of *linkage* on earned income generated in one region and where its workers reside.

Table 22. Earnings-Commuter Reliance between Contra Costa County and the Surrounding region

		Earnings Place-of-Work	
		Contra Costa	Surrounding region
Worker resides	Contra Costa	79%	8.5%
	Surrounding Counties	15%	73%
	Elsewhere	6%	18%
		100%	100%

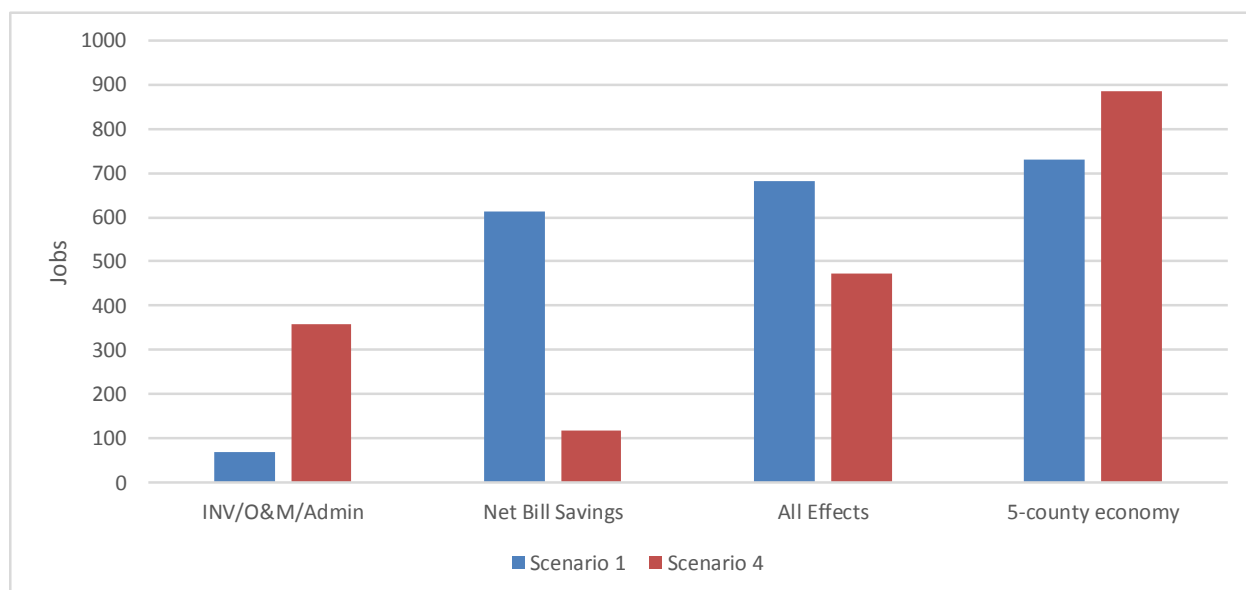
Based on each of the model region's reliance on jobs situated beyond their border there will be "earned income" imported for both Contra Costa and the surrounding region since both economies experience job increases under the CCE activity. For workplace earnings generated in Contra Costa County, 15 percent is earned by residents of the surrounding counties (we ignore the *elsewhere* because it is not part of our macroeconomic consideration). Likewise, of workplace earnings generated in the surrounding counties region, 8.5 percent is by commuters from Contra Costa County. Table 23 shows for 2020 the extent of extra jobs and earnings that will be held by a worker who resides in the other region. Of the 700 jobs added in Contra Costa County in 2020, 83 of these jobs (and \$7 million of earnings) belong to commuters from the adjacent region. Of the 584 jobs added in the surrounding region in 2020, 41 of these jobs (and \$4 million of earnings) belong to commuters from Contra Costa County.

Table 23. Scenario 4 - Earnings Impact by Place-of-Residence, 2020⁵⁶

Scenario 4, Year 2020	Place-of-Work	
	Contra Costa County	Surrounding region
Job impact	700	580
Earnings impact	\$48 million	\$42 million
Earnings per Job	\$86,000	\$87,500
% Commuter earnings (Surrounding counties)	15%	na
% Commuter earnings (Contra Costa)	Na	8.5%
Impact Commuter earnings for Surrounding counties	\$7 million	na
Impact Commuter earnings for Contra Costa	Na	\$4 million
<i>Equiv. # of Surrounding County Commuters</i>	83	na
<i>Equiv. # of Contra Costa Commuters</i>	Na	41

Last, a high-level decomposition of the job impact result in the County is shown in Figure 30 for Scenario 1 (the highest customer savings, no investment in local solar capacity) and Scenario 4. Under Scenario 1 the County realizes most job creation through the effects of rate savings on the County's economy. This response is 5-fold of what Scenario 4 would show as a job impact from rate savings. On the other hand, Scenario 4 exhibits a 5-fold job creation impact from the combined *investment/O&M/administration* effects. Including job creation impacts in the adjacent region of the four surrounding counties, Scenario 4 produces over 100 more jobs (average annual) than Scenario 1. This is predominantly explained by the surrounding region being the location for 50 percent of the small-solar investment that the CCE might choose to fund.

⁵⁶ Earnings per job are weighted estimates.

Figure 30. Average Annual Job Impact in Contra Costa County by Source

Conclusion

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 700 new jobs in the County plus additional jobs in neighboring counties. For Scenarios 1 and 2, the main driver behind the job growth is the general economic stimulus from injecting more dollars into the local economy via reduced electric rates. When costlier, locally-built renewable projects are emphasized, like in Scenarios 3 and 4, the general economic stimulus driver is replaced by the direct jobs and stimulus created by locally-sited and sourced renewable projects.

Because Contra Costa County's economy is not isolated, CCE formation can have positive effects in neighboring counties, too. This is particularly for the Scenarios emphasizing locally-built renewables, where workers would commute to jobsites in Contra Costa County.

Chapter 6: Other Risks

Aside from the risks identified above, the CCE or the political jurisdictions that are part of the CCE could be at risk for several other reasons. This section addresses some of those risks, which are summarized in Table 24.⁵⁷

Table 24. Summary of CCE Risks

Risk	Magnitude	Mitigation
Financial Risks to CCE Members	Low	Keep CCE JPA's financial obligations separate from jurisdiction's
Procurement-Related Risks (i.e., can't meet rate or GHG targets)	Medium-low	Enter into balanced portfolio of power contracts
Legislative and Regulatory Risks	High	Monitor and advocate at Legislature and CPUC
PCIA Uncertainty	High	Establish rate-stabilization fund to account for volatile PCIA
PCIA Policy Uncertainty	High	Monitor and advocate at Legislature and CPUC
Availability/price of low-carbon resources	Medium	Enter into balanced portfolio of power contracts
Bonding Risk	Low	Monitor and advocate at CPUC

Financial Risks to CCE Members

A CCE is effectively an association of various political subdivisions. The formation documents for the CCE define the rights and responsibilities of each member of the CCE. Given the large number of political subdivisions that might participate in a Contra Costa County CCE, MRW assumes that the Contra Costa County CCE would be formed under a Joint Powers Authority, in much the same way as MCE and Sonoma Clean Power.

The CCE will ultimately take on various financial obligations. These include obtaining start-up financing, establishing lines of credit, and entering into contracts with suppliers. Because a CCE will take on such financial obligations, it is likely very important to the prospective member political subdivisions that the financial obligations of the CCE cannot be assigned to the members.

⁵⁷ Note that this section does not provide legal opinion regarding specific risks, especially those related to the formation or the structure of the Joint Powers Authority under which MRW assumes the CCE will be established.

Thus, it is critical that the Joint Powers Authority and any other structuring documents are carefully drafted to ensure that the member agencies are not jointly obligated on behalf of the CCE (unless a member agency chooses to bear such obligations). The CCE should obtain competent legal assistance when developing the formation documents.⁵⁸

Nonetheless, starting up a CCE often requires a credit-worthy entity to backstop its initial financing. Some, such as CleanPowerSF, use the balance sheet from its existing power enterprise to backstop initial financing. Others have relied upon their host county as a backstop to initial financing. For example, MCE's initial bank loans for working capital were guaranteed by Marin County and the Town of Fairfax. After approximately six years, the CCE had demonstrated its creditworthiness and the guarantees were lifted. Still, the JPA cannot place any financial obligations or risks onto any of its members without that member's approval.

Procurement-Related Risks

Because a CCE is responsible for procurement of supply for its customers, the CCE must develop a portfolio of supply that meets the resource preferences of its customers (e.g., ratio of renewable versus non-renewable supply) while controlling risks (e.g., ratio of short-term versus long-term purchase agreements) and meeting regulatory mandates (e.g., resource adequacy and RPS requirements). Thus, it is tempting to assume that customers would prefer a fully hedged supply portfolio. However, such insurance comes at a cost and a CCE must be mindful of the potential competition from PG&E. Thus, the CCE's portfolio must be flexible while meeting the needs of its customers.

The CCE will likely need to negotiate a flexible supply arrangement with its initial set of suppliers. Such an arrangement is important because the CCE's loads are highly uncertain during CCE ramp-up. Without such an arrangement, the CCE faces the risk of either under- or over-procuring renewable or non-renewable supplies. Excessive mismatches between supply and demand of these different products could expose the CCE's customers to significant purchases or sales in the spot markets. These spot purchases could have a large impact on the CCE's financials.

The CCE will by necessity have to procure a certain amount of short-term supplies. These short-term supplies bring with them price volatility for that element of the supply portfolio. While this volatility is not unexpected, the CCE must be mindful that such volatility could increase the need for reserve funds to help buffer rate volatility for the CCE's customers. Funding such reserve funds could be challenging in this time of low gas prices (resulting in high PCIA charges).

The CCE will be entering the renewable market at an interesting time. While all LSEs must meet the expanded RPS targets by 2030, at least the IOUs are currently over-procured relative to their 2020 RPS targets. Whether the IOUs will attempt to sell off some of their near-term renewable supplies is unknown. However, if the IOUs believe that this is a good time to acquire additional

⁵⁸ Cities such as El Cerrito and Benicia conducted legal analyses when they were considering joining MCE, which should also be consulted.

renewables, the CCE could face stiff competition for renewable supplies, meaning that the green portfolio costs for the CCE might be higher than expected.

Finally, it should be noted that as greater levels of renewables are developed to meet the State's very aggressive RPS goals, it is possible that the traditional peak period will change. Adding significant amounts of solar could depress prices during the middle of the day. This could result in the need to try to sell power to out-of-state market participants during the middle of the day, possibly even at a loss. It could also result in the curtailment of renewable resources (even resources owned or controlled by the CCE). This could force the CCE to acquire greater levels of renewable supplies, thereby increasing costs.

Legislative and Regulatory Risks

As noted above, the CCE must meet various procurement requirements established by the State and implemented by the CPUC or other agencies. These include procuring sufficient resource adequacy capacity of the proper type and meeting RPS requirements that are evolving.⁵⁹ Additional rules and requirements might be established. These could affect the bottom line of the CCE.

PCIA Uncertainty

Assembly Bill 117, which established the CCE program in California, included a provision that states that customers that remain with the utility should be "indifferent" to the departure of customers from utility service to CCE service. This has been broadly interpreted by the CPUC to mean that the departure of customers to CCE service cannot cause the rates of the remaining utility "bundled" customers to go up. To maintain bundled customer rates, the CPUC has instituted an exit fee, known as the "Power Charge Indifference Adjustment" or "PCIA" that is charged to all CCE customers. The PCIA is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCE service are not shifted to remaining PG&E bundled service customers.

Even though there is an explicit formula for calculating the PCIA, forecasting the PCIA is difficult, because many of the key inputs to the calculation are not publicly available, and the results are very sensitive to these key assumptions. For PG&E, the PCIA has varied widely; for example, at one time the PCIA was negative.

Current CCEs have chosen to have customers bear the financial risk associated with the level of exit fees they will pay to PG&E. Thus, for a customer taking CCE service to be economically better off (i.e., pay less for electricity), the sum of the CCE charges plus the PCIA must be lower than PG&E's generation rate.

This risk can be mitigated in two ways. First, as discussed in more detail elsewhere, a rate stabilization fund can be created. Second, the CCE can actively monitor and vigorously participate in CPUC proceedings that impact cost recovery and the PCIA.

⁵⁹ Rules to establish RPS requirements under the new 50% RPS mandate are currently being debated at the CPUC.

Impact of High CCE Penetration on the PCIA

Currently, the PCIA calculation is based on the cost and value of a utility's portfolio, without regard to how much of that portfolio is to be paid for by bundled customers and how much by Direct Access (DA) and CCE customers. As such, the PCIA is not affected by the number of DA/CCE customers.

Currently, for bundled customers the rate impacts associated with fluctuating PCIA's are relatively small, but this will change as the number of DA/CCE customers grows. At some point, bundled customers' rates may experience marked volatility as the impacts of the annual PCIA rate swings reverberate to bundled rates. This may be unacceptable to ratepayer advocates and the Commission.

The PCIA rate volatility in part reflects changes to the utilities' generation costs, which are appropriately reflected in bundled customers' rates. But, often to a large degree, it reflects changes to the market price benchmark, which should not be relevant to bundled customer rates. For example, for a utility with flat RPS costs, a reduction to the market price benchmark for renewable power would increase the RPS-related PCIA, which would reduce bundled rates, even though there was no change in RPS costs. This could also happen in the reverse direction, increasing bundled rates when there is no increase in underlying generation costs.

Once DA/CCE load gets large enough that there are real stranded contracts, we suspect that the Commission is going to look much more closely at the value of these stranded contracts (and how to get the most value for them).

Impact of High CCE Penetration on Low-Carbon (Hydro) Resources

Virtually all the CCEs forming in California include carbon reduction as a goal. As the analysis has shown, CCEs will likely need to purchase both RPS-eligible power and other carbon-free power to meet their goals, namely large hydropower. This has been the approach used by MCE, Peninsula Clean Power, and Silicon Valley Clean Power, who all beat PG&E's GHG emissions rate through contracts for hydropower. This increased demand for carbon-free hydropower can change the "supply-demand" balance and in theory increase the cost of these resources. However, to put this in perspective, the amount of hydropower assumed in the technical study is very modest compared to its availability. For example, in the Pacific Northwest, hydroelectric facilities generated approximately 128,000 GWh of electricity, and over the past 5 (drought) years, California hydroelectric resources generated 25,000 GWhs of electricity. In contrast, the technical study assumed only 0.4-1.5 GWh/year of hydropower—well under one percent of the available resource. Furthermore, the assumed hydro premium, \$10/MWh over standard market power, is much higher than the current \$1.50-\$2.50/MWh premiums being seen. Thus, a certain amount of market tightening is already built into the study.

Nonetheless, to address this risk, the Contra Costa County CCE should consider locking in longer-term contracts for non-RPS eligible resources early in the process so as to guarantee their availability at a reasonable price in the longer term when there could be greater demand for them.

Bonding Risk

Pursuant to CPUC Decision 05-12-041, a new CCE must include in its registration packet evidence of insurance or bond that will cover such costs as potential re-entry fees, specifically, the cost to PG&E if the CCE were to suddenly fail and be forced to return all its customers back to PG&E bundled service. Currently, a bond amount for CCEs is set at \$100,000.

This \$100,000 is an interim amount. In 2009, a Settlement was reached in CPUC Docket 03-10-003 between the three major California electric utilities (including PG&E), two potential CCEs (San Joaquin Valley Power Authority and the City of Victorville), and The Utility Reform Network (TURN) concerning how a bonding amount would be calculated. The settlement was vigorously opposed by MCE and San Francisco and never adopted.

Since then, the issue of CCE bond requirements has not been revisited by the CPUC.⁶⁰ If it is, the bonding requirement will likely follow that set for Energy Service Providers (ESPs) serving direct access customers. This ESP bond amount covers PG&E's administrative cost to reintegrate a failed ESP's customers back into bundled service, plus any positive difference between market-based costs for PG&E to serve the unexpected load and PG&E's retail generation rates. Because the ESP bonding requirement has been in place, retail rates have always exceeded wholesale market prices, and thus the ESP's bond requirement has been simply equal to a modest administrative cost.

If the ESP bond protocol is adopted for CCEs, during normal conditions, the CCE Bond amount will not be a concern. However, during a wholesale market price spike, the bond amount could potentially increase to millions of dollars. But the high bond amount would likely be only short term, until more stable market conditions prevailed. Also, it is important to note that high power prices (that would cause a high bond requirement) would also depress PG&E's exit fee and would also raise PG&E rates, which would in turn likely provide the CCE sufficient headroom to handle the higher bonding requirement and keep its customers' overall costs competitive with what they would have paid had they remained with PG&E. As discussed above, JPA member entities would not be individually liable for any increase in the bond amount.

⁶⁰ On January 30, 2017 the CPUC set a pre-hearing Conference to begin a process to address CCE bonding requirements.

Chapter 7: Comparative Analysis of CCE Options

Having the County and cities within the County form their own JPA and CCE Program is not the only possibility for CCE participation. First, the Counties and/or its cities may join Marin Clean Energy (MCE). In fact, 5 cities in the County—El Cerrito, Lafayette, Richmond, San Pablo, Walnut Creek—are already members of MCE. These cities joined between 2013 and 2016, and have full standing on MCE’s Board of Directors. Second, the County and/or its cities could join the East Bay Community Energy (Alameda County) CCE. While this CCE has just been formed, with its JPA board having been seated in January 2017, it aims to begin power delivery in late 2017. Furthermore, the County and each city need not join one or the other CCE *en masse*, but instead can join one or the other CCEs individually (or neither).

This chapter presents the benefits and drawbacks of joining either MCE or EBCE, forming a new CCE with the County and the cities not currently in MCE (which has been the focus of most of the analysis in this report), or remaining with PG&E. To the extent possible, this chapter considers the rate-competitiveness, GHG reduction, local economic development, local control and governance, cost risks, and CCE formation timing of each option. Some of the benefits may depend upon how much of the County chooses which path. Each community chooses for itself; thus, it is possible to have some join MCE, some join EBCE, and others remain on PG&E service. To the extent that it matters, this will be highlighted in the sections that follow.

Note that MRW & Associates are not attorneys, and that the MCE and EBCE JPA agreements are legal documents. Therefore, nothing herein should be interpreted as a legal opinion – only an informed lay-reading of the documents. MRW would strongly recommend that Contra Costa County and any city considering becoming a member of MCE or EBCE have its counsel conduct a thorough review of the respective JPA and related documents prior to committing to a CCE.

Table 25 below summarizes our results. While it is desirable to quantify some (or all) of the criteria, to do so would be an exercise in false precision. First and foremost, two of the potential CCE options are with entities which, while potentially viable, do not exist. Without power contracts, portfolios, or procurement guidelines and policies, it would be unwise to claim that EBCE or a potential Contra Costa-only CCE would have rates or greenhouse gas emissions higher or lower than the other. Comparisons against MCE can be somewhat more reasonably asserted; however, its stated goals—greater renewable energy content, lower greenhouse gas emissions, local generation, and comparable rates—are nearly identical to those stated by EBCE, so as to make long-range rate and emissions distinctions immaterial. This contrasts with PG&E, whose power portfolios, procurement plans, and costs are readily available through various filings and applications it has made before the CPUC. Thus, the qualitative comparisons provided in the table do not provide sharp distinctions between the CCE options. All these options are expected to provide similar rates and GHG emissions, with differences arising from variations in the priorities and procurement decisions of the individual governance boards. What truly distinguishes these options are primarily governance options (i.e., in-county only versus shared with other entities) and the amount of risk assumed (i.e., developing or signing on with a new CCE versus joining one with a record of satisfactory performance).

Each of the lines on the table are discussed in greater detail in the sections that follow.

Table 25. Comparison of Contra Costa CCE Options

Criterion	Form CCCo JPA	Join MCE	Join EBCE	Stay with PG&E
Rates	Likely lower	Likely Lower	Likely Lower	Base
GHG Reduction Potential Over Forecast Period	Some	Some	Some	Base
Local Control/Governance	Most	Some	Some	None
Local Economic Benefit Potential	Greatest	Some	Some	Minimal
Start Up Costs/Cost to Join	Low, but greater risk ⁶¹	None ⁶²	None ⁶²	None
Level of Effort	Greatest	Minimal	Greater	None
Program Risks	Greatest	Minimal	Some	Base
Timing (earliest)	Late-2018	Late-2017	Mid-2018	N/A

Rates

In general, any of the three CCE options can result, in the long run, with rates that are at or slightly below those of PG&E. This is not to say that in some years PG&E's rates may be lower, or that one CCE option would consistently have rates that are lower than the others. Rather, given that a CCE's rates are a function of its communities' values—amount of local renewable generation, promotion of energy efficiency or distributed generation, overall rate minimization—and that two of the three CCEs being compared do not yet exist, let alone have rate or procurement policies, MRW cannot assert that one CCE option will have lower rates than the other two. Both MCE and EBCE have commitments to higher-cost local renewable development, which suggests that they are willing to trade off somewhat lower rates for other benefits. A

⁶¹ Start-up costs provided by the County or others are likely to be reimbursed by the JPA.

⁶² Costs already spent for consulting/technical study will likely not be reimbursed.

Contra Costa CCE that focuses more on rate reduction could in principle offer marginally lower rates than the other two.

GHG Reduction

For climate action planning and reporting purposes, the amount of GHG reduction that can be attributed to a CCE formation is a function of the difference between the average GHG emissions from PG&E and that of the CCE. PG&E’s power portfolio is already relatively “clean,” with large fractions coming from not only qualifying renewables but also nuclear power (through 2024) and large hydroelectric generators. As Table 26 shows, 59% of PG&E’s 2015 power came from GHG-free resources. This number would be closer to 67% GHG-free but for the poor hydroelectric generation due to the ongoing drought.⁶³ Therefore, for any CCE to have a reduced average carbon footprint requires not only the same or greater amount of qualifying renewable generation, but additional sources of GHG-free generation.

Table 26. PG&E and MCE Power Content (2015)

	PG&E 2015	MCE 2015
Eligible renewable	30%	56%
Large Hydro	6%	12%
Nuclear	23%	0%
GHG-Free subtotal	59%	68%
Unspecified/Market	17%	25%
Natural Gas	25%	12%
Fossil subtotal	41%	32%

An approach taken by some of the currently operating Northern California CCEs is to (a) use more qualifying renewable generation than PG&E, and (b) contract with and use power from large hydroelectric resources. This is shown in MCE’s power content mix, and to the extent possible, what was modeled here for Contra Costa County and for MRW’s study of an Alameda County CCE.

Given that both MCE and EBCE have made GHG reductions a very high priority, one can reasonably assume that either will have some GHG-emissions benefit relative to PG&E, but there is no concrete rationale to assume that either MCE or EBCE will have a significantly-lower GHG emissions rate than the other.

Local Economic Benefits

As noted earlier in the report, the amount of local economic benefits is a function of rate reduction and local construction and CCE staffing. The number of local renewable energy projects will be a function of at least two factors. The first is any cost competitiveness advantage of renewable resources in the County; i.e., others will want to build renewable generation in the County because of cost advantages (including interconnection ease). Second, local generation

⁶³ However given climate change, one can sensibly argue that the lower-than-historic-average hydroelectric output in California seen over the past few years may be more predictive than the historical average.

development will be fostered by a preference for local generation by the CCE serving Contra Costa County. While all three CCE options have expressed a preference for “local” renewables, the extent to which these three programs might develop local renewable generation facilities within the County remains uncertain. MCE has already invested in Contra Costa County, with a new utility-scale solar project in Richmond and numerous individuals taking advantage of its rooftop solar program. Nonetheless, in the long run MRW would expect that a Contra Costa CCE would have the greatest interest in developing in-county renewables and thus could potentially have the greatest positive economic impact. Teaming with either of the other CCEs would dilute the interest, as the CCE would have to consider economic development in its non-Contra Costa communities as well. Given the particularly strong interest of the EBCE group in local renewables, the notion that “local” might encompass the whole “East Bay,” and the fact that Contra Costa cities might have greater say in the formation of generation polities with a new group like EBCE than a more established one like MCE all suggest that EBCE might be more responsive in developing in-county renewables than MCE. On the other hand, MCE has a commanding head start, having already developed renewable projects in the County.

Contra Costa County makes up but a small fraction of PG&E’s service area. While PG&E’s local community engagement is admirable, it cannot focus on the County in a way that a smaller CCE can. As such, any of the three CCE scenarios will likely result in greater local economic benefits than remaining with PG&E.

CCE Governance: Voting

How each community is represented on a CCE’s governing board (generally a board of directors) is laid out in its JPA agreement. Per its current JPA agreement, EBCE will have a two-stage vote: under most circumstances, each board member (each representing a single entity) would have one vote, regardless of his or her entity’s size. That is, both Oakland and Piedmont would have an equal vote. In the event of a non-unanimous affirmative vote, three cities can call for a weighted vote. In that case, each Representative Board Member’s vote would be weighted according to the size (in kilowatt-hours) of the entity being represented. These two voting shares are shown in Table 27.

As noted in Table 28 if EBCE consisted of Alameda County alone, the combination of the three largest entities (Oakland, Fremont, plus Hayward or Berkeley) could carry the weighted vote. If all of Contra Costa County joined EBCE, then it would take the five largest entities (Oakland, Fremont, Hayward, Unincorporated Contra Costa County plus Berkeley or Concord) to carry the vote.

Table 27. EBCE Voting Shares, With and Without Contra Costa⁶⁴

	Simple Voting		Load-Weighted Voting*	
	Alameda Only	Alameda + Contra Costa	Alameda Only	Alameda + Contra Costa
Oakland	8.3%	3.7%	24.8%	17.5%
Fremont	8.3%	3.7%	16.2%	11.4%
Hayward	8.3%	3.7%	10.1%	7.1%
Berkeley	8.3%	3.7%	8.5%	6.0%
San Leandro	8.3%	3.7%	6.4%	4.5%
Livermore	8.3%	3.7%	6.2%	4.4%
Unincorporated Ala.	8.3%	3.7%	6.4%	4.5%
Other Alameda Cities	41.7%	18.5%	14.9%	8.3%
Alameda Total	100.0%	44.4%	100.0%	63.6%
Unincorporated C.C.		3.7%		9.0%
Concord		3.7%		5.1%
Pittsburg		3.7%		4.6%
Antioch		3.7%		3.7%
San Ramon		3.7%		3.2%
Brentwood		3.7%		2.1%
Danville		3.7%		1.7%
Martinez		3.7%		1.4%
Pleasant Hill		3.7%		1.4%
Oakley		3.7%		1.1%
Orinda		3.7%		1.0%
Hercules		3.7%		0.7%
Pinole		3.7%		0.6%
Moraga		3.7%		0.5%
Clayton		3.7%		0.3%
Contra Costa Total	N/A	55.6%	N/A	36.4%
<i>*Only in cases where called upon by 3 Board Members</i>				

Table 28. EBCE Minimum Cities Needed to Carry Weighted Vote

Alameda Only		3 cities	Oakland, Fremont + Hayward or Berkeley
Alameda + Costa	Contra	5 cities	Oakland, Fremont, Hayward, Unincorporated Contra Costa Co. + Berkeley or Concord

⁶⁴ It should be noted that two cities in Alameda County opted to not join the CCE at this time. Should they join, that could change the voting shares. Similarly, if not all Contra Costa jurisdictions join either MCE or EBCE, the voting shares will be different.

MCE's voting structure differs from EBCE's in two important ways. First, each board member's vote is a weighted. Half of each board member's weighting is equal to his or her entity's share of MCE's total load. The other half is an equal share for each entity. Thus, if a community is one of 26 members representing 18% of MCE's load, the board member's vote would be 10.9% ($(18\% \times (1/2)) + ((1/26) \times (1/2)) = 9\% + 1.9\% = 10.9\%$). Second, multiple entities have the option to be represented by a single board member. For example, Napa County and all the towns/cities within the County are represented by a single board member. This consolidated seat allows for potentially less administrative burden on the represented entities and "streamlines communication and policy setting." On the other hand, it effectively requires the communities with a joint board member to vote as a bloc, and while the bloc maintains the same voting share, it can reduce the "voice" of the communities: one person to speak on their behalf rather than, say, five, or six (or more).

Table 29 shows what the voting shares might be if all the Contra Costa communities joined MCE and each claimed its own board member. Together, the Contra Costa communities (including those already in MCE) would represent 71% of MCE's load and have a total 62% of the voting share.

Table 29. MCE Voting Shares With Each Contra Costa Community Having Its Own Board Member

VOTING SHARES	Entity Share	Load Share	Voting Share
Antioch	1.3%	2.8%	4.1%
Brentwood	1.3%	1.6%	2.9%
Clayton	1.3%	0.3%	1.5%
Concord	1.3%	3.9%	5.2%
Danville	1.3%	1.3%	2.6%
Hercules	1.3%	0.6%	1.8%
Martinez	1.3%	1.1%	2.4%
Moraga	1.3%	0.4%	1.6%
Oakley	1.3%	0.8%	2.1%
Orinda	1.3%	0.8%	2.0%
Pinole	1.3%	0.5%	1.7%
Pittsburg	1.3%	3.5%	4.7%
Pleasant Hill	1.3%	1.0%	2.3%
San Ramon	1.3%	2.4%	3.7%
Unincorporated Contra Costa County	1.3%	6.8%	8.1%
New Contra Costa Members	19.2%	27.6%	46.8%
Existing MCE Contra Costa Members	6.4%	8.0%	14.4%
TOTAL CONTRA COSTA COUNTY	25.6%	35.6%	61.2%
Rest of MCE	24.4%	14.4%	38.8%

CCE Governance: Other

The proposed EBCE JPA Agreement also calls for a formal Community Advisory Committee (Section 4.9). The relevant section states that the purpose of the Committee:

“shall be to advise the Board of Directors on all subjects related to the operation of the CCA Program ... with the exception of personnel and litigation decisions. The Community Advisory Committee is advisory only, and shall not have decision-making authority... The Board shall appoint members of the Community Advisory Committee from those individuals expressing interest in serving, and who represent a diverse cross-section of interests, skill sets and geographic regions.”

The Chair of the Community Advisory Committee will serve as a non-voting *ex officio* member of the EBCE Board of Directors.

MCE has no analogous official community advisory committee originating from its JPA agreement. Nonetheless, there is a “Community Power Coalition” that provides input to MCE (see, <https://www.mcecleanenergy.org/community-power-coalition/>). The Coalition works “on a variety of issues ranging from local renewable energy project development – like MCE Solar One in Richmond – to outreach for MCE’s Spanish-speaking constituents, to environmental justice and consumer protection issues affecting MCE’s low-income customers.”

The recitals to EBCE’s JPA agreement lay out what can be described as its envisioned values. Besides offering competitive rates and lowering greenhouse gasses, this includes (Recitals, Section 6):

- Establishing an energy portfolio that prioritizes the use and development of local renewable resources and minimizes the use of unbundled renewable energy credits;
- Promoting an energy portfolio that incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals;
- Demonstrating quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);
- Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California. The Authority, as a leader in the shift to a clean energy, commits to ensuring it will take steps to minimize any adverse impacts to these workers to ensure a “just transition” to the new clean energy economy;
- Delivering clean energy programs and projects using a stable, skilled workforce through such mechanisms as project labor agreements, or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;
- Promoting personal and community ownership of renewable resources, spurring equitable economic development and increased resilience, especially in low income communities;
- Provide and manage lower cost energy supplies in a manner that provides cost savings to low-income households and promotes public health in areas impacted by energy production; and

- Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize, and providing appropriate wages and benefits.

Contra Costa communities considering joining EBCE should consider these enunciated values prior to committing to membership.

Timing and Process to Join/Form

The timing required to serve Contra Costa businesses and residents vary markedly among the CCE options. The quickest path the CCE service would be to join with MCE. The first step for a community to join MCE is for its governing body or representative (e.g., city manager) to provide MCE a non-binding letter of interest. The entity's governing body would then need to adopt a resolution requesting MCE membership; have a first reading of an ordinance to join MCE; execute a memorandum of understanding between the entity and MCE to address preliminary data and communication issues; and provide a signed request for PG&E to provide MCE its load data. These steps would need to occur during MCE's "inclusion period" which currently runs from December 1, 2016 through May 31, 2017. Only communities in Contra Costa County are eligible to request MCE membership during this period.

MCE would then evaluate the impact of the new load on its system. If the net result of adding the new community is that MCE's rates would increase, then that community's membership would be tabled until a future date. If the MCE analysis shows that adding the community is favorable, then the MCE Board would vote to accept (or not) the community into MCE. At that point, the local ordinance for MCE membership would receive a second reading and adoption. MCE would then modify its official Implementation Plan to reflect the new community, and submit the updated plan to the California Public Utilities Commission. Once approved (none have been rejected), the phase-in of the community into MCE can occur.

Based on MCE's currently Inclusion Period, Contra Costa County and the jurisdictions not already served by MCE could begin MCE service as early as late 2017.

Although it has just recently formed, the EBCE board has extended an offer to interested Contra Costa communities to join EBCE. In a letter from Chris Bazar, Director, Alameda County Community Development Agency, EBCE would welcome Contra Costa members into its Phase 2 or Phase 3 rollout.⁶⁵

The current EBCE JPA documents states in Section 3.1, Addition of Parties:

Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or county requesting that the incorporated municipality or county, as the case may be, become a member of the

⁶⁵ The letter suggests that Phase 2 would commence in the summer of 2018 and Phase 3 in Fall 2018 or Spring 2019.

Authority, (b) the adoption by an affirmative vote of a majority of all Directors of the entire Board satisfying the requirements described in Section 4.12, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(12) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership fee, if any, and (e) satisfaction of any conditions established by the Board..

Thus, a Contra Costa community would need to adopt a resolution requesting membership in the EBCE, the board of Directors of EBCE would have to vote to authorize the applying community's membership, followed by the applying entity passing an ordinance to join. To be part of the Phase 2 rollout, a City would have need to have an ordinance passed by June 30, 2017.

Implementing a Contra Costa County only CCE would likely have a time line similar to joining EBCE. If the County and its cities were committed to this path, it could potentially begin service as early as 2018. This is consistent with Peninsula Clean Energy, which went from putting out an RFP for a technical study to Phase 1 implementation in 18 months (April 2, 2015 to October 1, 2016). A more measured timeline would suggest that a new Contra Costa CCE would spend much of 2017, planning and generating local support, with implementation beginning in late 2018 or 2019.

Costs to Join the CCE

This section discusses direct, non-reimbursable costs to cities for joining either EBCE or MCE. So far, cities joining MCE have not had to pay for any of the costs incurred by MCE to plan for or integrate their load. They have often spent on the order of \$10,000 to \$15,000 for consultants to evaluate the risks to the city and its residents and businesses that could come from joining MCE. Both MCE and EBCE have extended a no-cost opportunity to join to the Contra Costa jurisdictions who are not already members of MCE.

The start-up costs for a new Contra Costa CCE would be significant—Alameda County has committed \$3.4 million to its effort. However, consistent with other CCEs, these costs would be initially reimbursed to the County and funding cities by a loan taken out by the CCE's JPA, which would in turn be paid down via CCE rates over the initial few years. As such, the only "cost to join" a Contra Costa CCE felt by any individual city would be indirect at best (i.e., asked to backstop any CCE loads with the entities' credit).

Exiting the CCE

MCE's JPA Section 7.0 lays out the process and ramifications of a MEC member withdrawing from the JPA. First, an entity may withdraw from the JPA within 30 days of its notification of joining the JPA, assuming that MCE has not entered into any wholesale power agreements to serve the entity. (Section 7.1.1.1) After MCE has entered into wholesale power agreements to serve the entity, the entity may withdraw from MCE, effective the beginning of the JPA's fiscal

year by giving at least 6 months' written notice of its intent to withdraw. The withdrawing entity may be subject to "certain continuing liabilities" as laid out in Section 7.3:

7.3 Continuing Liability; Refund. Upon a withdrawal or involuntary termination of a Party, the Party shall remain responsible for any claims, demands, damages, or liabilities arising from the Party's membership in the Authority through the date of its withdrawal or involuntary termination, it being agreed that the Party shall not be responsible for any claims, demands, damages, or liabilities arising after the date of the Party's withdrawal or involuntary termination. In addition, such Party also shall be responsible for any costs or obligations associated with the Party's participation in any program in accordance with the provisions of any agreements relating to such program provided such costs or obligations were incurred prior to the withdrawal of the Party. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's liability for the costs described above. Any amount of the Party's funds held on deposit with the Authority above that which is required to pay any liabilities or obligations shall be returned to the Party.

Neither the precise calculation of the liabilities nor how it would be collected is specified.

The proposed EBCE JPA Agreement contains no language concerning a community's exit from EBCE or the JPA.

Remaining With PG&E

Although this study suggests CCE program options would likely produce both environmental and economic benefits for the jurisdictions included in the study, continuing service with PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service (i.e., each individual account maintains its right to opt-out of CCE service). There are benefits of remaining with PG&E, even at a community level. First, remaining with PG&E takes no city action. Thus, a city's leadership and staff can concentrate their limited resources on matters that may be more pressing. Second, PG&E is regulated by the State via the California Public Utilities Commission (CPUC), which oversees its power procurement and approves its rates. While CCEs are partially regulated by the CPUC (e.g., ensuring that the CCE complies with any applicable laws), they are not subject to rate regulation. Some may see State oversight as a benefit, with an official "watchdog" overseeing power supply and procurement, while others might see the local CCE board accountability as a benefit. Third, PG&E is much larger than any of the CCE options that Contra Costa communities might pursue, which (as discussed) might reduce community input and value but also provide some economies of scale. For example, one poor power contract entered might have significant rate or operational ramifications for a CCE. For PG&E, given its size, the impact of that same poor contract would be diluted. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a high PCIA rate.

Summary

The following lays out the principal benefits and risks of each of the options considered.

Potential Benefits of Forming Contra Costa CCE (relative to joining MCE or EBCE)

- More local control (voting shares not diluted)
- Can form JPA and policies to fully reflect County interests and values
- Greatest potential for local economic development (due largely to more local control)
- Even if formed, individuals may still select PG&E as their power provider

Potential Risks/Downsides of Forming Contra Costa CCE (relative to joining MCE or EBCE)

- Commitment of County and city resources to establish a new CCE agency
- Higher risks due lack of experience, fewer partners
- Would need to establish programs, contractors, credit, etc.
- Longest time line to begin enrolling customers
- Given MCE's presence in five Contra Costa communities, potential customer confusion with multiple CCEs in the same county

Potential Benefits of joining MCE (relative to joining EBCE)

- Five other Contra Costa County communities have already joined
- Established, successful program
- Credit capacity and programs in place
- Likely easier transition/implementation
- Able to enroll customers sooner than EBCE
- Programs that create jobs and economic benefits could be implemented more quickly

Potential Risks/Downsides of joining MCE (relative to joining EBCE)

- May have less Board representation (if all of Contra Costa County and its jurisdictions are represented by a shared seat)
- May be less of a "fit" compared to East Bay identification and sensibilities (or, for some cities, this may be a benefit)
- Programs are already in place; less/minimal input into their formation
- Joining a large board serving a very diverse customer base and geography

Potential Benefits of joining EBCE (relative to joining MCE)

- Coming in closer to the "ground floor" — opportunity to influence policy direction and program development
- May be more mission or cultural alignment (East Bay vs. Marin) (or perhaps for some communities, not)

- Board will more likely be one seat per member jurisdiction (not a shared seat)
- Weighted voting process is a little clearer
- EBCE working on a local development business plan with emphasis on local power production in the East Bay

Potential Risks/Downsides of joining EBCE (relative to joining MCE)

- Take longer to enroll County communities
- Take longer for job-creating programs to get up and running
- May be a small fish among some very large fish (Oakland, Hayward)
- Union focused policies may be difficult for some (or preferable)
- Given MCE's presence in five Contra Costa communities, potential customer confusion with multiple CCEs in the same county

Potential Benefits of Remaining with PG&E (relative to joining or forming a CCE)

- Experienced provider
- State regulatory protection
- Continuity- same firm provides all services
- No action needed by City/County—status quo
- May be able to join a CCE at a later date (but perhaps at some cost)

Potential Risks/Downsides Benefits of Remaining with PG&E (relative to joining or forming a CCE)

- Higher GHG emissions
- Less local renewable generation
- Higher electricity rates than CCE rates under most scenarios
- Less local control
- Less local input into policies and offerings
- Less local economic development

Chapter 8: Other Issues Investigated

Synergies on the Northern Waterfront

Contra Costa County has an ongoing initiative to economically develop its Northern Waterfront. The Northern Waterfront stretches from the City of Hercules at San Pablo Bay, along the southern shore of the Carquinez Straight and Suisun Bay, and out to the San Joaquin Delta region of Oakley. The County's Northern Waterfront Economic Development Initiative is a regional cluster-based economic development strategy with a goal of creating 18,000 new jobs by 2035. The Initiative leverages existing competitive advantages and assets by focusing on advanced manufacturing sub-sectors in five targeted clusters (advanced transportation fuels, bio-tech/bio medical, diverse manufacturing, food processing, and clean tech).

To assess the potential positive impacts a CCE might have on this Area, the study looked at the Northern Waterfront to assess local generation potential within the area. Of the potential 3,350 MW of solar resources in the County, approximately 40% lies within the Northern Waterfront. As shown in Table 30, there are over 700 potential solar sites in the area, which could theoretically generate over 2,000 GWhs. Of these sites, over 800 MW have the highest potential ranking, meaning that they are the most appropriate for actual development. In fact, all the local solar capacity specified in Scenarios 3 or 4 could be met at sites in the Northern Waterfront alone.

Table 30 Solar Potential in the Northern Waterfront

Location	Solar Sites	PV Potential (MW)	PV Production (GWh)	Build Cost (\$ Thousands)
Antioch	189	327	524	\$747,130
Concord	108	191	306	\$442,015
Crockett	21	58	93	\$125,187
Hercules	52	90	144	\$200,512
Martinez	139	300	480	\$629,130
Oakley	43	76	121	\$178,390
Pinole	17	24	39	\$57,208
Pittsburg	153	298	477	\$679,851
Rodeo	14	35	57	\$85,875
Grand Total	736	1,400	2,241	\$3,145,298

How much solar could actually be sited in the Northern Waterfront would depend upon (a) the degree to which there is competition for sites for perhaps higher-value projects and (b) the CCE's policies toward fostering local projects.

In addition to this renewable potential, the Northern Waterfront also hosts six major power plants (Table 31). In addition to these, the refineries in the area also generate much of their own power.

A Contra Costa CCE could contract with one of more of these facilities to provide the CCE's Resource Adequacy Requirements or a portion of its energy needs. Alone, a Contra Costa CCE would not be able to use all—or even most—of the power produced by any of these or other major power plant of this magnitude (e.g., the cancelled Oakley power plant).

Table 31. Natural Gas Power Plants in the Northern Waterfront

Plant	Location	Capacity (MW)	Year in Service	Owner	Type
Crockett Cogen	Crocket	275	1995		Steam-Cogen
Los Medanos	Pittsburg	555	2001	Calpine	Combined cycle -Cogen
Delta Energy Facility	Pittsburg	887	2002	Calpine	Combined cycle
Gateway	Antioch	530	2009	PG&E	Combined cycle
March Landing	Antioch	760	2013	NRG	Combined cycle
Pittsburg	Pittsburg	1,029	1970s	NRG	Steam, combined cycle

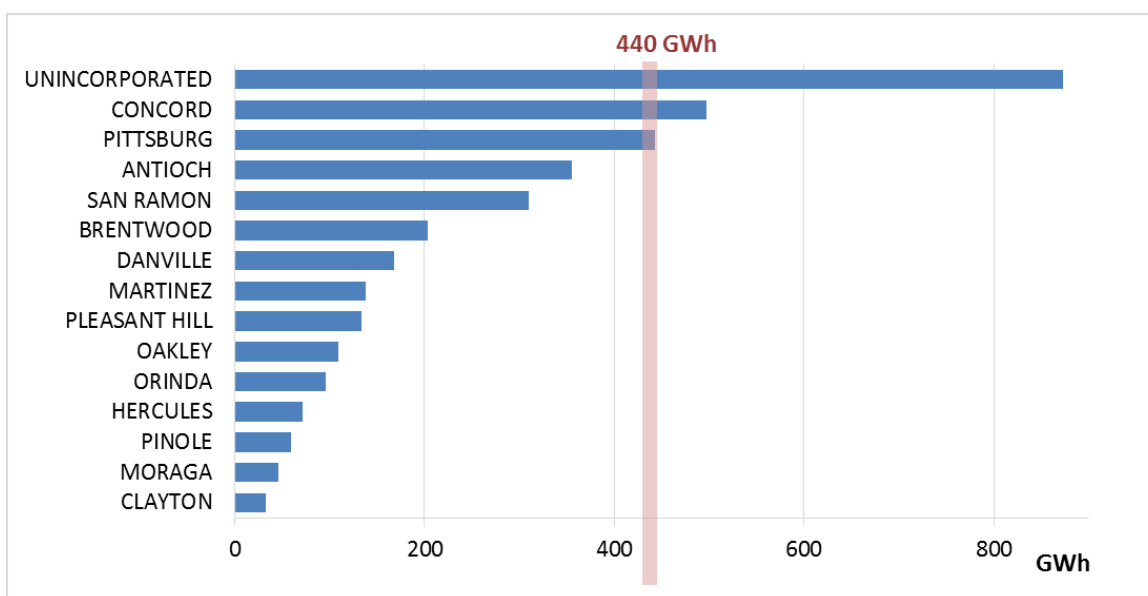
“Minimum” CCE Size?

MRW's analysis above assumed that all eligible Contra Costa County cities join the Contra Costa County CCE program with a participation rate of 85% from each city, resulting in an anticipated CCE load of about 3.6 million MWh per year.⁶⁶ If fewer customers join, CCE rates will generally be higher because about \$7 million of annual CCE costs are invariant to the amount of CCE load. Along with the number of customers, the customer make-up is also important. For example, a higher share of residential customers would improve the competitiveness of the CCE, while a higher share of commercial customers or industrial customers would weaken the competitiveness of the CCE. Because cities vary in their distribution of customers by rate class, a city opting out of the CCE could affect the competitiveness of the CCE due to both the reduction in CCE load and the shift in customer make-up.

To identify the “minimum” load needed for CCE customer rates to be no higher than PG&E customer rates, we will analyze only the period between 2018 and 2030. The “minimum” load for this period is approximately 440,000 MWh per year, assuming the average customer portfolio for Contra Costa County and Supply Scenario 1. This value was estimated by assuming that the fixed costs remained the same (i.e., did not scale with sales) and then lowering the sales until the hypothetical reduced CCE's rates were equal to PG&E's. As shown in Figure 31, this is roughly the load from the big cities (Concord and Pittsburg) and is much smaller than the load from the unincorporated area. As long as two medium-sized cities or one larger city joins the CCE, this “minimum” load will be met. It is not a true minimum, however, because the true minimum depends on the make-up of the customer portfolio; for example, for the stand-alone city of Pittsburg,⁶⁷ due to its load with more industrial proportion, the CCE program would not be cost-competitive.

⁶⁶ In the alternate supply scenarios, the “minimum” annual load assuming the average customer portfolio for Contra Costa County and the base case is 550,000 MWh (Scenario 2).

⁶⁷ See Figure 2. Pittsburg is the only city with this highly industrial profile.

Figure 31. Potential load (85% participation) per city

Individuals and Communities Self-Selecting 100% Renewables

The existing CCEs all offer customers an option to choose to receive 100% of their power from renewable resources in exchange for a rate premium. However, each CCE's program is different. MCE Clean Energy has offered its "Deep Green" at a rate premium of 1¢/kWh because its inception. Sonoma Clean Power offers its "Evergreen" option at approximately the same price as PG&E's "Solar Choice" rate. Lancaster Choice Energy offers its Smart Choice as a fixed monthly premium rather than a variable rate. In all cases, only a very modest number of CCE customers—on the order of a few percent—have selected the 100% green rate option.

Table 32. CCE 100% Green Rate Premiums

CCE	Rate Option	Increment Above Default Rate
Marin Clean Energy	Deep Green	1¢/kWh
Sonoma Clean Power	EverGreen	3.5¢/kWh
Lancaster Choice Energy	Smart Choice	\$10/month
Peninsula Clean Energy	ECO100	1¢/kWh
CleanPowerSF	SuperGreen	2¢/kWh
Potential Contra Costa Co. CCE	TBD	~1.5¢/kWh

Any full renewable pricing option offered by the Contra Costa County CCE would have to be set by the CCE's management. The value shown in Table 32, ~1.5¢/kWh, is the average incremental cost of green power used in the CCE supply assessment (Scenario 2) over the study period. (Initially, it would have to be ~1.9¢/kWh.) The number of customers selecting the rate would not impact the economics of the CCE customer who remain on the standard rate.

- Separate CCE opt-out notifications would be needed. A key feature of the opt-out notification is the price comparisons against PG&E. As the default rate would be different for these communities, a different notice would have to be sent. This would simply increase the start-up cost for the CCE, the increment could be paid for by the city electing a different default rate.
- Having a higher default rate might increase the number of opt-outs in the community.
- PG&E's billing system would have to be able to handle city- or zip code-specific default options. That is, as new residential or businesses move to a self-selected green community, the billing system would need to know to default them on a different rate schedule than a customer in a different CCE community. This may or may not be an issue.

Competition with a PG&E Solar Choice Program

PG&E has been offering a solar choice program known as Green Tariff Shared Renewable Program since February 2015.⁶⁸ The program was established under Senate Bill 43, and pursuant to Decision 15-01-051 from the CPUC, to extend access to renewable energy to ratepayers that are currently unable to install onsite generation.⁶⁹ It offers homes and businesses the option to purchase 50% or 100% of their energy use from solar resources. The program provides those with homes or apartments or businesses that cannot support rooftop solar the opportunity to meet their electricity requirements through renewable energy and support the growth of renewable energy resources.

PG&E's current Solar Choice program costs residential customers an additional 3.58¢/kWh. Given that MRW projects that the CCE can offer 100% green power at ~1.5¢/kWh over its own Scenario 1 or Scenario 2 rate (which is projected to be less than PG&E's), we do not believe PG&E's Community Solar Program will be price competitive with similar CCE product options.

The program is open for enrollment until subscriptions reach 272 MW or January 1, 2019, whichever comes first.⁷⁰ While this does limit the ability for PG&E to provide a 100% renewable

⁶⁸ PG&E website

http://www.pge.com/en/b2b/energysupply/wholesaleelectricssuppliersolicitation/RFO/CommunitySolarChoice.page?WT.mc_id=Vanity_communitysolarchoice. Accessed 5/16/2016

⁶⁹ California Public Utilities Commission, Decision 15-01-051, p.3

⁷⁰ Solar Choice Program FAQs website,

<https://www.pge.com/en/myhome/saveenergymoney/solar/choice/faq/index.page> Accessed, 5/16/2016

option in the long-run, at the start of the CCE this program it provides an opportunity for customers who desire 100% renewable power to remain with PG&E.

Differences Between the Analyses for Contra Costa and Alameda Counties

In the first half of 2016, MRW prepared a similar CCE analysis for Alameda County.⁷¹ Although the fundamental approach and results of study and this one are the same, there are several differing assumptions resulting in differing results. If we compare the results of the present study with the results obtained in the Alameda CCE study, we observe that the savings for CCE customers are very similar in both studies, though PG&E rates and CCE rates are both approximately 1¢/kWh higher in the current study than in the prior study (**Table 33**).

Table 33. Average prices for 2018-2030 Scenario 1 for Contra Costa and Alameda County CCE programs

Average Period 2018-2030	Contra Costa County	Alameda County
Price natural gas (\$/MMBtu)	5.70	4.90
Wholesale (\$/MWh)	51.30	44.80
PG&E Capacity (\$/MWh)	74	39
CCE Capacity (\$/MWh)	52	39
Wind (\$/MWh)	56	57
Solar Distant (\$/MWh)	51	51
Solar Local (\$/MWh)	98	74
% Local Solar by 2030	25%	10%
PG&E rate (¢/kWh)	11.7	10.4
PCIA rate (¢/kWh)	1.4	1.4
CCE rate (¢/kWh)	9.4	8.3
Difference CCE-PGE (¢/kWh)	2.3	2.1

The results of the present study for Contra Costa County differ from the prior results for Alameda County because we updated our forecast to reflect new PG&E rate filings and other public forecasts. The main changes between the models are as follows:

- **Bundled Load Forecast:** As a result of increased interest in CCE, PG&E's most recent bundled load forecasts are 3% below the previously available forecasts for 2017 and an average of 25% below the previously available forecasts over the 2018-2030 period (see Figure 32).⁷² Less load reduces PG&E's procurement costs, increases the share of fixed costs

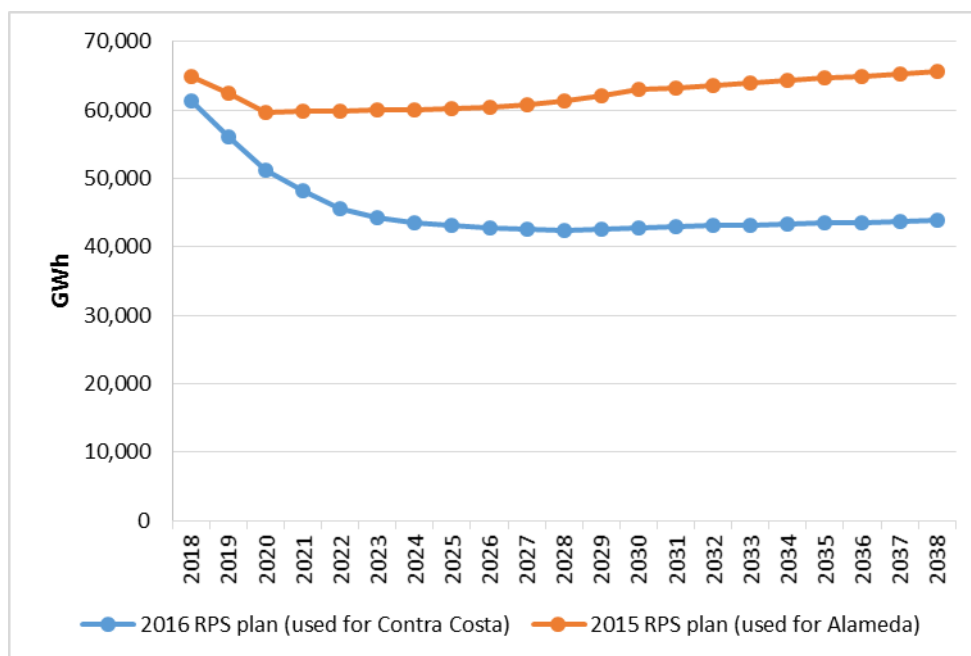
⁷¹ The final version of the Alameda CCE technical study was published on July 1, 2016.

<https://www.acgov.org/cda/planning/cca/documents/Feas-TechAnalysisDRAFT5312016.pdf>

⁷² The sources for the 2017 bundled load forecasts are PG&E's 2017 preliminary and final ERRAs forecasts. (The June 2016 preliminary forecast was used in the Alameda County CCE study, and the November 2016 final forecast

paid by remaining bundled customers, and increases the revenue provided to bundled customers from CCE exit fees. These effects mostly offset each other, resulting in little net change to bundled rates.⁷³

Figure 32: Bundled Load Forecasts used in the Alameda and Contra Costa County Analyses



- **Natural gas prices:** Projections for natural gas prices are about \$0.80/MMBtu higher than they were in the spring when the Alameda County report was developed. The higher natural gas prices increase wholesale market prices by \$7/MWh (14%).
- **Diablo Canyon Retirement application:** In July 2016, PG&E, together with other entities, submitted a proposal to retire the two units of Diablo Canyon when their licenses expire in November 2024 and August 2025. Per the proposal, PG&E would replace Diablo Canyon production with energy efficiency and greenhouse gas-free generation resources. These resources would include the following: (1) 2,000 GWh of load reduction from additional energy efficiency to be installed by January 2025, (2) 2,000 GWh of load reduction or generation from GHG-free generation resources to be on-line between 2025 and 2030, and (3) a voluntary commitment from PG&E to meet a 55% RPS for 2031-2045 (instead of the 50% requirement currently in effect). The joint proposal estimated that the retirement of Diablo Canyon would result in a need for new generation capacity (“load-resource balance”) around 2030, which is about five years earlier than previously anticipated.

was used in the present study.) The sources for the 2018-2030 bundled load forecasts are PG&E’s RPS plans for 2015 (filed in January 2016, used for Alameda County) and for 2016 (draft filed in August 2016, used for Contra Costa).

⁷³ CCE exit fees are designed so that bundled customers’ rates are not affected by CCE departures. In practice, some impact is likely in one direction or the other, and the magnitude and direction of this impact may each vary year by year.

The new energy efficiency resources together with other costs of the nuclear plant retirement would be recovered through non-generation rates (mostly Public Purpose Program and Nuclear Decommissioning charges), and the new RPS resources would be recovered through a new “Clean Energy Charge” applied to all PG&E retail customers. For those load serving entities that are willing to commit to procuring the equivalent new RPS resources, PG&E has proposed a “self-provision” option that would exempt existing DA and CCE loads from the Clean Energy Charge. In the analysis for Contra Costa County, MRW assumed that Contra Costa CCE would choose the “self-provision” option.

MRW assumed for this study that the Diablo Canyon retirement proposal would be adopted, though the proposal is under evaluation by the Commission and is subject to modification. Based on this proposal, we modified the PG&E and Contra Costa County CCE power supply forecasts as follows:⁷⁴

- 1) PG&E’s RPS requirements were increased for 2030-2038 from 50% to 55%,⁷⁵
- 2) Contra Costa County CCE’s RPS requirements were increased for 2030-2038 to 55% (vs. the 50% that was used in the Alameda County CCE study), and
- 3) We began increasing the price of capacity five years earlier than we had in the Alameda County CCE study, reflecting the earlier load-resource balance date due to the retirement of Diablo Canyon. For both Alameda and Contra Costa counties, MRW assumed that the CCEs would build their own power plants (alone or in combination with other public entities) in place of purchasing market capacity when market prices rise above the cost of a new self-build.

On February 27, 2017, PG&E withdrew portions of its Diablo Canyon retirement proposal. In particular, PG&E states it will still pursue GHG-free replacement resources, but will do so in a different CPUC proceeding. MRW does not believe that this change has a material impact on this analysis.

⁷⁴ We also accounted for the changes in the Public Purpose Program and Nuclear Decommissioning fees in our calculation of the Residential bills.

⁷⁵ The generation share of the 2025-2030 commitment for 2,000 GWh of load reduction or GHG-free generation was assumed to be subsumed by procurement needed to meet a 50% RPS by 2030 and therefore did not result in incremental renewable generation in our model.

Chapter 9: Conclusions

Overall, a CCE in Contra Costa County appears feasible. Given current and expected market and regulatory conditions, a Contra Costa County CCE should be able to offer its residents and business electric rates that are less than that available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of local renewable energy are assumed in the CCE portfolio (Scenario 4), combined with other negative factors, do PG&E's rates become consistently more favorable than the CCE's.

A Contra Costa County CCE would also be well positioned to help facilitate the installation of greater amounts renewable generation in the County. Because the CCE would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would actually occur with a CCE in the County than without it.

The CCE can also reduce the amount greenhouse gases emitted by the County, but only under certain circumstances. Because PG&E's supply portfolio has significant carbon-free generation (large hydroelectric and nuclear generators), the CCE must contract for significant amounts of carbon-free power above and beyond the required qualifying renewables in order to actually reduce the County's electric carbon footprint. Therefore, if carbon reductions are a high priority for the CCE, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed.

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 700 new jobs in the County, plus an additional 200 jobs in the neighboring counties if local renewable development is prioritized.

While the analytical focus of this report has been on a stand-alone Contra Costa County CCE for those communities not already in MCE that is not the only, nor necessarily best, choice for these communities. Overall, there is insufficient data to suggest that a stand-alone Contra Costa CCE would offer lower rates or greater GHG savings than joining MCE or EBCE. Either forming or joining a CCE would likely offer modestly lower rates and more local economic development than remaining with PG&E. Joining MCE would likely result in the quickest and least risky path to CCE implementation, however with diminished local input into CCE policy formation. Because it has yet to be formed, joining with EBCE would take longer and involve more uncertainty than joining the already-established MCE, but would offer greater input into the CCE's policies and formation.

Although this study suggests CCE program options would likely produce both environmental and economic benefits for the jurisdictions included in the study, continuing service with PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service. PG&E is an experienced power provider and is regulated by the state. Furthermore, remaining with PG&E takes no city action. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a high PCIA rate.

Technical Study for Community Choice Energy Program in Contra Costa County

Appendices

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Appendix A. Loads and Forecast

Appendix B. Power Supply Cost

Appendix C. Forecast of PG&E's Generation Rates

Appendix D. Detailed CCA Rates

Appendix E. Greenhouse Gas Emissions and Costs

Appendix F. About the REMI Policy Insight Model

Appendix G. Proforma Tables

Appendix H. MCE's Joint Powers Agreements

Appendix I. MCE's approval for inclusion of Contra Costa

Appendix J. EBCE's Joint Powers Agreement

Appendix K. EBCE's offer for inclusion of Contra Costa

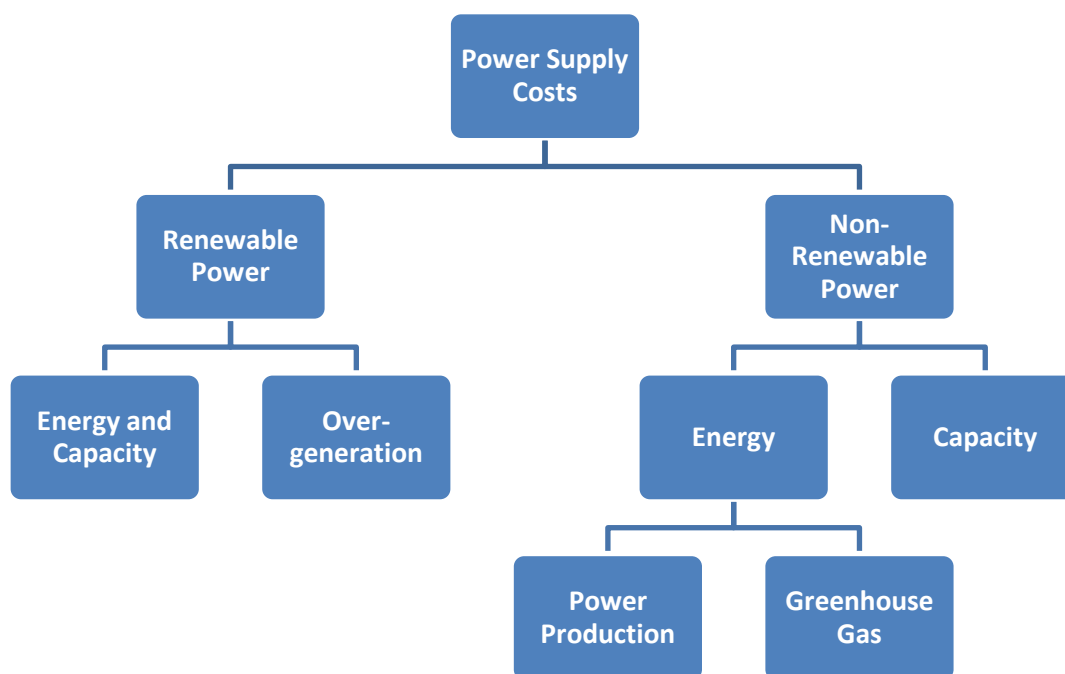
Appendix A. Loads and Forecast

2014 Load (MWh)	Residential	Commercial	Industrial	Public	Street lights + Pumping
UNINCORPORATED	454,716	252,156	237,085	63,574	19,925
CONCORD	269,024	242,584	53,969	18,228	885
PITTSBURG	145,304	134,197	225,362	14,807	1,635
ANTIOCH	270,761	109,487	18,340	18,694	1,077
SAN RAMON	172,364	140,696	32,012	14,458	4,461
BRENTWOOD	150,827	66,635	0	16,407	4,970
DANVILLE	133,085	51,478	0	11,944	1,394
MARTINEZ	86,638	61,730	6,372	6,121	1,140
PLEASANT HILL	82,411	67,087	0	5,905	1,270
OAKLEY	96,389	18,236	0	12,431	901
ORINDA	58,779	14,719	0	39,747	215
HERCULES	48,162	32,749	0	2,751	700
PINOLE	36,629	26,028	0	5,877	963
MORAGA	40,593	8,818	0	3,701	456
CLAYTON	31,795	4,759	0	1,808	661
TOTAL	2,077,476	1,231,360	573,139	236,454	40,652

Appendix B. Power Supply Cost

MRW has developed a bottoms-up calculation of Contra Costa County CCA's power supply costs, separately forecasting the cost of each power supply element. These elements are renewable energy, non-renewable energy (including power production costs and greenhouse gas costs), resource adequacy (RA) capacity (both renewable and non-renewable supplies) and related costs (e.g., CAISO expenses and broker fees).¹ Figure 1 illustrates the components of Contra Costa County CCA's expected supply costs.

Figure 1: Power Supply Cost Forecast



Renewable Power Cost Forecast

MRW developed a forecast of renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and Community Choice Aggregation (CCA) entities in 2015 and early 2016, finding an average price of \$52 per MWh for these contracts.²

¹ MRW included a 5.5% adder in the power supply cost for CAISO costs (ancillary services, etc.), and a 5% premium for contracted supplies to reflect broker fees and similar expenses.

² MRW relied exclusively on prices from municipal utilities and CCAs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in California Energy Markets, an

To forecast the future price of renewable purchases, MRW considered a number of factors:

- Researchers from the National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL) developed a set of forecasts of utility-scale solar costs based on market data and preliminary data from other research efforts.³ Their base case forecast predicts a 3.8% annual decline in utility-scale solar capital costs on a nominal basis, from \$1,932/kW-DC in 2016 to \$1,652/kW-DC in 2020, with costs then remaining roughly constant in nominal dollars through 2030.⁴ Additional scenarios predict even steeper price declines, with the most aggressive scenario predicting an 11% annual nominal decline through 2020, with increases at the rate of inflation after that.
- The federal Investment Tax Credit (ITC), which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain.⁵ The federal Production Tax Credit, which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.⁶ The loss of these credits would put upward pressure on prices.
- NREL and LBNL researchers predicted in 2015 that the cost increase associated with an ITC reduction would be roughly offset by other solar cost reductions even if the full reduction to 10% were to be implemented by 2018, rather than spread out through 2022 as is currently planned.⁷
- Lawrence Berkeley National Laboratory researchers conducted a study anticipating a reduction of the wind costs of 24% by 2030 and 35% by 2050.⁸

independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

³ National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 16. <http://www.nrel.gov/docs/fy16osti/65014.pdf>

⁴ Ibid. Costs converted to nominal dollars using the inflation forecast used throughout the rate forecast model (U.S. EIA's forecast of the Gross Domestic Product Implicit Price Deflator).

⁵ U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). <http://energy.gov/savings/business-energy-investment-tax-credit-itc>

⁶ U.S. Department of Energy. Electricity Production Tax Credit (PTC). <http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc>

⁷ National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 28.

⁸ Lawrence Berkeley National Laboratory . Expert elicitation survey on future wind and energy costs. Nature Energy, September 12th, 2016.

- The production tax credit has been extended six times from 2000-2014,⁹ and the solar ITC has been extended three times since 2007.¹⁰ Further tax credit extensions are therefore plausible.
- The major California investor-owned utilities have significantly slowed their renewable procurement because lower-than-expected customer sales and higher-than-expected contracting success rates have led to procurement in excess of the RPS requirements through 2020. When the utilities start ramping their procurement back up to meet the 50%-by-2030 RPS requirement, the supply-demand balance in the market may shift, resulting in higher-than-expected prices unless an increase in suppliers and development opportunities matches the increase in demand.

Given the potential upward price pressures from tax credits that are currently expected to expire and from higher demand for renewable power to meet the 50%-by-2030 requirement and the potential downward price pressures from falling renewable development costs, the possibility for lower cost procurement through the use of RECs, and the possibility that the expiry of the tax credits will be further delayed, it is unclear whether renewable prices will continue to fall (as NREL, LBNL, and others are predicting) or will start to stabilize and rise.

MRW has addressed this uncertainty by considering two scenarios for this sensitivity case:

- In the solar base renewable cost forecast, MRW used the \$48.5 per MWh average price of recent municipal utility and CCA solar contracts as the price through 2022 (in nominal dollars), which will increase with inflation in subsequent years. This results in a solar price of \$57 per MWh in 2030, and of \$67 per MWh in 2038. In the wind base renewable cost forecast, MRW used the \$55.0 per MWh average price of recent municipal utility and CCA solar contracts as starting point, and extended it applying an annual decrease of 2% through 2030 and 1% through 2038, offset by inflation. This results in a wind price of \$57 per MWh in 2030, and of \$62 per MWh in 2038.
- In the high renewable cost scenario, MRW increased both wind and solar base case prices to account for the expected expiration of the tax credits, resulting in average a price of \$75 per MWh in 2030 and \$86 per MWh in 2038. These scenarios provide a reasonable window of renewable price projections based on current market conditions and analysts' expectations.

MRW used these same renewable prices to calculate PG&E's renewable power costs. However, as described in Appendix B in the PG&E forecast, these renewable energy prices are used only

⁹ Union of Concerned Scientists. Production Tax Credit for Renewable Energy. http://www.ucsusa.org/clean_energy/smart-energy-solutions/increase-renewables/production-tax-credit-for.html

¹⁰ Solar Energy Industries Association. Solar Investment Tax Credit. <http://www.seia.org/policy/finance-tax/solar-investment-tax-credit>; and U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). <http://energy.gov/savings/business-energy-investment-tax-credit-itc>

for incremental power that is needed above PG&E's existing RPS contracts. For Contra Costa County CCA, these prices are used as the basis for its entire RPS-eligible portfolio.

MRW additionally included a premium for the portion of Contra Costa County CCA's RPS portfolio assumed in each scenario to be located in Contra Costa County. While solar energy is anticipated to provide the largest share of incremental supply located in-county, the solar resource in Contra Costa County is not as strong as in the areas being developed to supply the contracts discussed above. As a result, the cost of solar generation in Contra Costa County is expected to be higher than the assumed contract prices for non- Contra Costa County supplies. Based on information provided in the CPUC's current RPS calculator, combined with SAGE inputs (performance assumptions and capital cost of the projects¹¹), the current cost for solar generation in Contra Costa County is expected to be approximately \$98 per MWh. In addition, it is assumed the local solar generation cost will scale with installed capacity.

Non-Renewable Energy Cost Forecast

MRW separated the costs of non-renewable energy generation into two components: power production costs and greenhouse gas costs. The forecast methodologies for these cost elements, described below, are consistent with the forecast methodologies used for these cost elements in the PG&E rate forecast.

Since natural gas generation is typically on the margin in the California wholesale power market, power production costs for market power are driven by the price for natural gas. MRW forecasted natural gas prices based on current NYMEX market futures prices for natural gas, projected long-term natural gas prices in the EIA's *2016 Annual Energy Outlook*,¹² and PG&E's tariffed natural gas transportation rates.¹³ MRW used a standard methodology of multiplying the natural gas price by the expected heat rate for a gas-fired unit and adding in variable operations and maintenance costs to calculate total power production costs.

In addition to power production costs, the cost of energy generated in or delivered to California also includes the cost of greenhouse gas allowances that, per the state's cap-and-trade program, must be procured to cover the greenhouse gases emitted by the energy generation. MRW estimated the price of GHG allowances to equal the auction floor price stipulated by the ARB's cap-and-trade regulation, consistent with recent auction outcomes.¹⁴ MRW estimated the

¹¹ Capital cost for local solar projects in Contra Costa County, according to SAGE price curve, is \$1,350 per kW installed for the first 400MW solar installed in the county. MRW calculated the average price for the cumulative developed capacity forecast for each year (counting only 50% of the capacity of each developed project towards the cumulative total). The total \$1,350for kW installed doesn't include the soft and land acquisition/opportunity costs.

¹² U.S. Energy Information Administration. "2016 Annual Energy Outlook," Table 13.

¹³ Pacific Gas & Electric, Burnertip Transporation Charges. Tariff G-EG, Advice Letter 3664-G, January 2016 and Tariff G-SUR, Advice Letter 3699-G, April 2016.

¹⁴ California Code of Regulations, Title 17, Article 5, Section 95911.

emissions rate of Contra Costa County CCA non-renewable power supply based on an estimated heat rate for market power multiplied by the emissions factor for natural gas combustion.¹⁵

Capacity Cost Forecast for Non-Renewable Power

To estimate Contra Costa County CCA's capacity requirements, MRW developed a forecast of Contra Costa County CCA's peak demand in each year and subtracted the net qualifying capacity credits provided by Contra Costa County CCA's renewable power purchases. This is appropriate because the renewable energy prices used in this analysis reflect prices for contracts that supply both energy and capacity. If Contra Costa County CCA purchases renewable energy via energy-only contracts, Contra Costa County CCA's need for capacity will be greater than forecasted here, but these higher costs will be fully offset by the lower costs for the renewable energy.

MRW estimated current peak demand for Contra Costa County CCA's load using the 2015 monthly bills for all the current PG&E clients in Contra Costa County¹⁶ and PG&E's class-average load profiles. We forecasted changes to this peak demand based on the Contra Costa load forecast.¹⁷ We calculated capacity requirements as 115% of the expected peak demand in order to include sufficient capacity to fulfill resource adequacy requirements. We applied a consistent methodology to obtain the peak demand growth rates and capacity requirements for PG&E.

To estimate the cost of Contra Costa County CCA's capacity needs, MRW priced capacity purchases at the median price of recent Resource Adequacy purchases, escalated with inflation.¹⁸

To estimate the cost of Contra Costa County CCA's capacity needs, MRW considered two time periods: the period before system load-resource balance when there is excess capacity on the system, and the period following system-load resource balance when additional supply must be developed. MRW assumed a system load-resource balance year of 2030.¹⁹ Through 2025, MRW priced capacity at the median price of recent resource adequacy purchases, escalated with inflation. MRW increased the capacity price incrementally starting in 2026 to reflect an increase in the market price for capacity during the transition from the lower near-term prices to the higher post-load-resource balance prices. MRW assumed that Contra Costa County CCA would

¹⁵ U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3.
https://www.eia.gov/electricity/annual/html/epa_a_03.html

¹⁶ Monthly bills corresponding to 2015 for all the clients in Contra Costa County provided by PG&E.

¹⁷ California Energy Commission. Demand Forecast. PG&E Forecast Zone Results Mid Demand Case, Sales Forecast, Central Valley Region. December 14, 2015.

¹⁸ CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

¹⁹ According to the assumption adopted by the CPUC in December 2015 for long-term forecasting purposes, the load resource balance year was 2035. MRW opted to advance this to 2030 due to the retirement of the Diablo Canyon nuclear facility.

build its own power plant (alone or in combination with other public entities) in place of purchasing market capacity when market prices rise above the cost of a new self-build. In MRW's model, this occurs in 2030. From this point on, MRW assumed that the market price for Contra Costa County CCA's capacity would be equal to the levelized fixed cost of a new advanced combustion turbine developed by a publicly owned utility, minus levelized gross margins from energy sales. A similar methodology was used to forecast the cost of capacity for PG&E; however, PG&E's post-load-resource balance price forecast is based on the price of a combustion turbine developed by a merchant developer (see Appendix C).

Appendix C. Forecast of PG&E's Generation Rates

MRW developed a forecast of PG&E's generation rates for comparison with the rates that Contra Costa County CCA will need to charge to cover its costs of service. MRW developed the forecast for the years 2018-2038 using publicly available inputs, including cost and procurement data from PG&E, market price data, and data from California state regulatory agencies and the U.S. Energy Information Administration. The structure of the rate forecast model and the basic assumptions and inputs used are described below.

Generation Charges

PG&E's generation costs fall into four broad categories: (1) renewable generation costs, (2) fixed costs of non-renewable utility-owned generation, (3) fuel and purchased power costs for non-renewable generation, and (4) capacity costs. Each of these categories is evaluated separately in the rate forecast model, and underlying these forecasts is a forecast of PG&E's generation sales.

Sales Forecast

PG&E's generation cost forecast is driven in large part by the amount of generation that PG&E will need to obtain to meet customer demand. To forecast PG&E's electricity sales, MRW started with the 2016-2030 sales forecast that PG&E provided in its August 2016 Renewable Energy Procurement Plan ("RPS Plan") filing with the CPUC.²⁰ This forecast predicts an 8% annual sales reduction through 2020, a 2% reduction per year from 2021-2028, and a rather anemic sales growth of 0.2% per year from 2029-2030.²¹ MRW extended the sales forecast through 2038, maintaining this 0.2% increase per year.

Renewable Generation

The starting point for MRW's analysis is PG&E's "RPS Plan," in which PG&E discusses its plan for meeting California's Renewable Portfolio Standard (RPS) targets and provides the annual amount and cost of renewable generation currently under contract through 2030. PG&E's RPS Plan shows that PG&E's current renewable procurement is in excess of the RPS requirement in each year through 2026. After 2022, PG&E's renewable generation from current contracts falls below the RPS requirements, but PG&E is projected to have enough banked Renewable Energy Credits (RECs) from excess renewable procurement in prior years to meet the RPS requirements until 2034.

²⁰ Pacific Gas & Electric. *Renewables Portfolio Standard 2016 Renewable Energy Procurement Plan (Draft Version)*. August 8, 2016. Appendix D.

²¹ The near-term decline in sales in PG&E's forecast is likely attributable to the growth in CCA, in which a municipality procures electric power on behalf of its constituents instead of having them purchase their power from PG&E. While customers in the jurisdictions of these municipalities have the option to opt-out of CCA and to continue to procure power from PG&E, so far, most CCA-eligible customers have not elected for this option. CCA customers continue to procure electricity delivery services from PG&E; it is only generation services that they obtain through the CCA.

MRW adopted PG&E's RPS Plan forecast of the amount and cost of renewable generation that is currently under contract. For the period starting in 2034 when PG&E's RPS Plan shows a need for incremental renewable procurement to meet RPS requirements, MRW added in the necessary renewable generation to meet current statutory requirements (i.e., 33% of procurement in 2020, increasing to 50% of procurement in 2030, and to 55% of procurement in 2031).²² To project PG&E's cost of this incremental renewable generation, MRW used the same renewable prices used for Contra Costa County CCA's renewable power cost forecast (see Appendix B).

Fixed Cost of Non-Renewable Utility-Owned Generation

PG&E's rates include payment for the fixed costs of the PG&E-owned non-renewable generation facilities, which are primarily natural gas, nuclear, and hydroelectric power plants. Because these costs are not tied to the volume of electricity that PG&E sells, their annual escalation is not driven by the price of fuel and other variable inputs. Instead, they escalate at a rate that stems from a combination of cost increases and depreciation reductions. These escalation rates are determined in General Rate Case (GRC) proceedings, which occur roughly every three years.

As a starting point for the forecast, MRW used the proposed 2017 fixed costs for these facilities.²³ For the period between 2018 and 2020, MRW increased the fixed cost based on PG&E's 2017 GRC settlements.²⁴ For subsequent years, MRW estimated in the base case that PG&E's generation fixed costs would increase by the 6.2% annual average growth rate approved and implemented for these cost over the last ten years.²⁵ These escalation rates are in nominal dollars (i.e., some of the escalation is accounted for by inflation).

²² MRW additionally allowed for the purchase of additional renewable generation when renewable prices are below market prices, subject to some purchase limits, including a 50% cap on renewable generation relative to the entire generation portfolio. This leads to additional renewable purchases from 2027-2029 in the Low Renewable Price scenario. Starting in 2030, the RPS requirement is 50%, and no additional renewable purchases are allowed, per the rules of the model, in order to maintain grid reliability.

²³ Pacific Gas & Electric. Annual Electric True-Ups for 2017. Advice Letter 4902 E-A. September 13, 2016. Table 2 and Pacific Gas & Electric 2017 GRC Settlements, A.15-09-001, Appendix A and B.

²⁴ Pacific Gas & Electric 2017 GRC Settlements, A.15-09-001, Appendix A and B

²⁵ Historic growth rates calculated from Pacific Gas & Electric Advice Letters 2706-E-A, AL 3773-E, 4459-E, 4647-E, and 4755-E. New power plant costs were excluded from these calculations since costs of new plants are offset, at least in part, by a reduction in fuel and purchased power costs.

Table 1: PG&E's Generation Fixed Costs, 2011-2016²⁶
(Nominal \$ Million)

	2011	2012	2013	2014	2015	2016
Generation Fixed Costs	1,400	1,530	1,550	1,710	1,860	1,840
Annual Cost Increase		9%	1%	10%	9%	-1%

MRW made adjustments to this GRC forecast to account for the retirement of the Diablo Canyon nuclear units at the end of the units' current licenses in 2024 and 2025.

Fuel and Purchased Power Costs for Non-Renewable Generation

Each spring, PG&E files a forecast with the CPUC of its fuel and purchased power costs for the upcoming year in its "ERRA" filing, which PG&E updates and finalizes in November. MRW relied on PG&E's November 2017 ERRA testimony,²⁷ adjusted to remove renewable generation costs, as the starting point for the forecast of fuel and purchased power costs for PG&E's non-renewable generation.

To escalate these costs through the forecast period, MRW forecasted changes to natural gas prices and greenhouse gas cap-and-trade program compliance costs, which are the major drivers of change to these costs. The natural gas price forecast is based on current NYMEX market futures prices for natural gas, forecasted natural gas prices in the U.S. EIA's 2016 *Annual Energy Outlook*, and PG&E's tariffed natural gas transportation rates. This forecast is the same forecast used in the forecast of Contra Costa County CCA's wholesale power costs (see Appendix B).

Cap-and-trade program compliance costs are estimated based on (1) PG&E's forecast of carbon dioxide emissions in 2017;²⁸ (2) a forecast of PG&E's fossil generation supply, developed by subtracting expected renewable, hydroelectric, and nuclear generation from PG&E's projected wholesale power requirement; and (3) a forecast of greenhouse gas allowance prices. The greenhouse gas allowance price forecast is the same as used in the forecast of Contra Costa County CCA wholesale power costs and is based on the auction floor price stipulated by the ARB's cap-and-trade regulation (see Appendix B).

²⁶ 2011-2013: CPUC Decision 11-05-018, pages 2 and 15; and 2014-2016: CPUC Decision 14-08-032, Appendix C, Table 1 and Appendix D, Table 1.

²⁷ PG&E Update To Prepared 2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.16-06-003 on Nov 2, 2016, Table 11-3.

²⁸ PG&E Update To Prepared 2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.16-06-003 on Nov 2, 2016, Table 12-2.

The MRW rate model calculates total fuel and purchased power costs by escalating natural gas prices based on the natural gas price forecast described above, escalating nuclear fuel prices based on the EIA forecast of fuel costs for nuclear plants, escalating water costs for hydroelectric projects and the capacity costs of power purchase contracts with inflation, and pricing market power at the same market power price used for Contra Costa County CCA's purchases. The model then sums the cost for each of these resources and adds in projected cap-and-trade compliance costs to this total cost.

Capacity Costs

PG&E must procure capacity to meet 115% of its anticipated peak demand in order to fulfill its resource adequacy requirement. PG&E's own power plants can be used to meet this requirement, as can power plants with which PG&E has contracts.

To estimate PG&E's capacity requirements, MRW started with the Capacity Supply Plan that PG&E submitted to the California Energy Commission in 2015,²⁹ which forecasts PG&E's peak demand and existing capacity resources for each of the years 2013-2024. With limited exception,³⁰ MRW used PG&E's data where publicly available and extended the forecasts to 2038. In extending these forecasts, we used assumptions that are consistent with those used in our assessments of energy sales and costs, including load growth escalation and the projected retirement of PG&E's nuclear plant. We also added in anticipated capacity from new renewable procurement and from new energy storage and adjusted the calculation to account for the portion of Resource Adequacy credits that is allocated to non-bundled customers.

As with the Contra Costa County CCA's capacity cost forecast, MRW priced capacity at the median price of recent Resource Adequacy capacity sales, escalated with inflation.³¹

Rate Development

Following the methodologies described above, MRW developed a forecast of PG&E's generation revenue requirement and divided these expenses by the expected PG&E sales in order to obtain a forecast of the system-average generation rate. We calculated annual escalators based on these system-average rates and applied them to the generation rates that are currently in effect for each customer class.³²

²⁹ California Energy Commission, Energy Almanac, Utility Capacity Supply Plans from 2015. September 4, 2015

³⁰ The two main exceptions are that 1) MRW increased energy efficiency and demand response growth to comply with SB 350 requirements to double energy efficiency by 2030 and the anticipated continuation of CPUC demand response initiatives, and 2) MRW accounted for the energy efficiency and renewable capacity expected to be installed because of the Diablo Canyon retirement application.

³¹ CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

³² PG&E Advice Letter AL-4805-E, effective March 24, 2016.

Appendix D. Detailed CCA Rates

Case-Legend	
Base	BASE
Low participation	LP
High price local	LOC
High renewable prices	RPS
High natural gas price	GAS
Low PG&E portfolio costs	LPGE
High PCIA	PCIA
Stress Scenario	STRS

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	BASE	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	BASE	CCA Res Fund	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	LP	CCA gen	7.1	7.2	7.2	7.5	7.7	7.9	8.0	8.1	8.5	8.9	9.4	9.9	10.5	10.8	11.1	11.4	11.8	12.1	12.4	12.8	13.2
1	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	LP	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	LOC	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	LOC	CCA Res Fund	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	RPS	CCA gen	7.1	7.2	7.3	7.8	8.1	8.5	8.6	8.8	9.2	9.7	10.2	10.8	11.4	11.8	12.2	12.5	12.9	13.2	13.6	14.0	14.4
1	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
1	RPS	CCA Res Fund	0.7	0.7	0.4	0.1	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
1	GAS	CCA gen	8.1	8.5	8.8	9.2	9.5	9.4	9.4	9.6	10.0	10.4	10.8	11.3	11.9	12.3	12.6	12.9	13.3	13.7	14.2	14.6	15.0
1	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
1	GAS	CCA Res Fund	0.2	-0.1	0.0	0.0	0.0	0.0	0.0	1.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
1	LPGE	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	LPGE	CCA Res Fund	0.0	1.1	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
1	PCIA	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

1	PCIA	CCA Res Fund	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	STRS	CCA gen	8.2	8.7	9.1	9.6	9.9	10.1	10.2	10.3	10.8	11.2	11.7	12.3	12.9	13.3	13.7	14.1	14.6	15.0	15.4	15.9	16.4
1	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
1	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
2	BASE	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	BASE	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	LP	CCA gen	7.3	7.4	7.4	7.6	7.8	8.1	8.1	8.3	8.7	9.1	9.6	10.1	10.6	10.9	11.1	11.4	11.7	11.9	12.2	12.5	12.8
2	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	LP	CCA Res Fund	0.5	0.9	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	LOC	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	LOC	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	RPS	CCA gen	7.3	7.5	7.6	8.2	8.5	9.1	9.2	9.5	10.0	10.5	11.0	11.6	12.3	12.5	12.8	13.1	13.4	13.7	14.0	14.4	14.7
2	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
2	RPS	CCA Res Fund	0.5	0.9	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
2	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
2	GAS	CCA gen	8.0	8.3	8.7	9.0	9.3	8.9	9.0	9.2	9.6	9.9	10.3	10.8	11.3	11.6	11.9	12.2	12.5	12.8	13.1	13.4	13.8
2	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
2	GAS	CCA Res Fund	0.3	0.0	-0.1	0.0	1.4	-1.4	0.0	1.4	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
2	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
2	LPGE	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	LPGE	CCA Res Fund	0.0	1.1	0.0	0.4	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
2	PCIA	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

2	PCIA	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	STRS	CCA gen	8.2	8.6	9.0	9.7	9.9	10.1	10.2	10.5	10.9	11.4	11.9	12.4	13.0	13.4	13.7	14.0	14.4	14.7	15.1	15.4	15.8
2	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
2	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
3	BASE	CCA gen	7.1	7.2	7.4	7.8	8.1	8.5	8.7	9.0	9.6	10.3	10.8	11.4	12.0	12.4	12.7	13.1	13.4	13.7	14.1	14.4	14.8
3	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	BASE	CCA Res Fund	0.7	0.7	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	LP	CCA gen	7.2	7.4	7.5	7.9	8.2	8.6	8.8	9.1	9.6	10.3	10.8	11.4	12.0	12.4	12.7	13.1	13.4	13.7	14.1	14.4	14.8
3	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	LP	CCA Res Fund	0.6	0.8	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	LOC	CCA gen	7.1	7.3	7.5	7.9	8.3	8.8	9.1	9.4	10.1	10.8	11.4	12.0	12.6	13.0	13.4	13.8	14.1	14.5	14.8	15.1	15.5
3	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	LOC	CCA Res Fund	0.7	0.8	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	RPS	CCA gen	7.1	7.4	7.6	8.2	8.6	9.3	9.6	10.0	10.6	11.4	12.0	12.6	13.4	13.8	14.2	14.7	15.0	15.4	15.8	16.1	16.5
3	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
3	RPS	CCA Res Fund	0.6	0.8	0.4	0.1	0.1	0.1	0.0	0.1	0.0	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
3	GAS	CCA gen	8.1	8.6	9.0	9.5	9.8	10.1	10.3	10.6	11.2	11.8	12.3	12.9	13.5	13.9	14.3	14.7	15.1	15.5	15.9	16.3	16.7
3	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
3	GAS	CCA Res Fund	0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
3	LPGE	CCA gen	7.1	7.2	7.4	7.8	8.1	8.5	8.7	9.0	9.6	10.3	10.8	11.4	12.0	12.4	12.7	13.1	13.4	13.7	14.1	14.4	14.8
3	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	LPGE	CCA Res Fund	0.0	1.1	-0.1	0.6	0.1	0.1	0.0	-0.5	-0.3	-0.3	-0.1	1.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
3	PCIA	CCA gen	7.1	7.2	7.4	7.8	8.1	8.5	8.7	9.0	9.6	10.3	10.8	11.4	12.0	12.4	12.7	13.1	13.4	13.7	14.1	14.4	14.8
3	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

3	PCIA	CCA Res Fund	0.7	0.7	0.4	0.1	0.1	0.1	0.0	-0.5	-0.7	-0.2	0.0	0.0	1.8	-0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
3	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	STRS	CCA gen	8.3	8.9	9.4	10.1	10.5	11.2	11.6	12.0	12.8	13.6	14.2	14.9	15.6	16.2	16.7	17.2	17.6	18.1	18.5	19.0	19.5
3	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
3	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
4	BASE	CCA gen	7.3	7.6	7.8	8.3	8.7	9.2	9.6	10.3	11.1	12.0	12.6	13.2	13.9	14.1	14.4	14.6	14.9	15.2	15.5	15.7	16.1
4	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	BASE	CCA Res Fund	0.4	0.9	0.4	0.1	0.1	0.1	0.1	-0.6	-0.7	-0.1	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
4	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	LP	CCA gen	7.5	7.7	7.9	8.3	8.8	9.3	9.6	10.3	11.0	11.9	12.5	13.1	13.7	14.0	14.2	14.5	14.8	15.0	15.3	15.6	15.9
4	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	LP	CCA Res Fund	0.3	1.0	0.4	0.1	0.1	0.1	0.1	-0.6	-0.6	-0.2	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
4	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	LOC	CCA gen	7.4	7.7	8.0	8.5	9.1	9.7	10.2	11.0	11.9	12.9	13.6	14.2	15.0	15.2	15.5	15.8	16.1	16.3	16.6	16.9	17.2
4	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	LOC	CCA Res Fund	0.4	1.0	0.4	0.1	0.1	0.1	-0.3	-1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	0.1	0.1	0.1	0.1
4	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	RPS	CCA gen	7.4	7.8	8.1	8.9	9.6	10.6	11.1	11.9	12.9	14.0	14.7	15.4	16.3	16.6	16.9	17.2	17.5	17.9	18.2	18.5	18.9
4	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
4	RPS	CCA Res Fund	0.4	1.0	0.5	0.1	0.1	-0.6	-0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.1	0.1
4	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
4	GAS	CCA gen	8.1	8.6	9.0	9.6	9.9	10.2	10.6	11.3	12.1	13.0	13.5	14.1	14.7	15.0	15.3	15.7	16.0	16.3	16.6	17.0	17.3
4	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
4	GAS	CCA Res Fund	0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
4	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
4	LPGE	CCA gen	7.3	7.6	7.8	8.3	8.7	9.2	9.6	10.3	11.1	12.0	12.6	13.2	13.9	14.1	14.4	14.6	14.9	15.2	15.5	15.7	16.1
4	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	LPGE	CCA Res Fund	0.0	1.1	-0.5	1.0	0.1	-0.5	-0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	0.1
4	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
4	PCIA	CCA gen	7.3	7.6	7.8	8.3	8.7	9.2	9.6	10.3	11.1	12.0	12.6	13.2	13.9	14.1	14.4	14.6	14.9	15.2	15.5	15.7	16.1
4	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

4	PCIA	CCA Res Fund	0.4	0.9	0.4	0.1	0.1	-0.2	-0.6	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	STRS	CCA gen	8.4	9.0	9.6	10.5	11.2	12.1	12.7	13.7	14.8	16.1	16.8	17.5	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4
4	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
4	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Appendix E. Greenhouse Gas Emissions and Costs

In Chapter 3 of the report, MRW provided an estimate of Contra Costa County CCA's annual Greenhouse Gas (GHG) emissions and compared these with the emissions for the same load under the PG&E supply portfolio. The methodology used to calculate both figures is included in this appendix, along with an estimate of Contra Costa County CCA's cost of emissions from purchased power ("indirect emissions").

Methodology for calculating Contra Costa County CCA's indirect GHG emissions

GHG emissions for Contra Costa County CCA will be indirect since the CCA does not plan to generate its own power (*i.e.*, the emissions are embedded in fossil-fuel power that the CCA purchases). These emissions are estimated based on (1) a forecast of the emissions rate for Contra Costa County CCA's fossil generation supply and (2) a forecast of the amount of Contra Costa County CCA's fossil generation supply, developed by subtracting expected renewable and hydroelectric generation from the projected wholesale power requirement to serve the CCA's load.³³

MRW calculated the emissions rate for Contra Costa County CCA's fossil generation supply by estimating the amount of natural gas that will need to be burned to generate the CCA's fossil generation and the GHG emissions rate for natural gas combustion.³⁴ The amount of natural gas needed was estimated based on the average heat rate for the marginal generation plants on the CAISO system. MRW used public data from CAISO's OASIS platform and Platt's Gas Daily reports to calculate this average heat rate for 2015.³⁵ MRW extended the forecast to 2030 using the expected changes to the average heat rate in California from the EIA's 2016 *Annual Energy Outlook*.³⁶

MRW estimated the total annual GHG emissions for the Contra Costa County CCA program as a product of the total energy purchased at wholesale electric market (kWh) and the rate of GHG emissions (tonnes CO₂-equivalent/kWh).

³³ MRW assumed no GHG emissions for the renewable and hydroelectric supply.

³⁴ The GHG emissions rate for natural gas combustion is obtained from U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html

³⁵ MRW calculated the average heat rate of the marginal generation plants in 2015 by dividing the monthly average wholesale electric market price, net of operations and maintenance costs and GHG emissions costs, by the monthly average natural gas price. For the electricity prices, we used the average of the 2015 hourly locational marginal price for node TH_NP15_GEN-APND; for the natural gas prices, we used the average of burnertip natural gas price for PG&E.

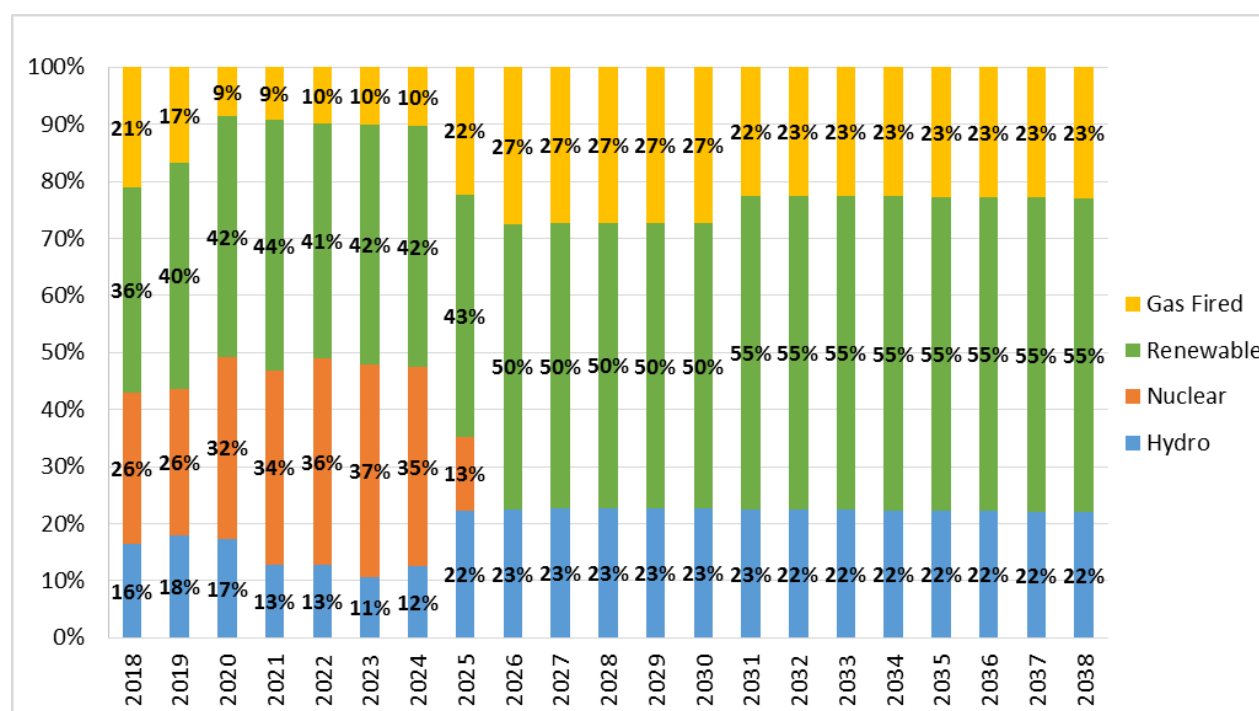
³⁶ U.S. Energy Information Administration. "2016 Annual Energy Outlook," Table 55.20, Western Electricity Coordinating Council. (Note that EIA does not provide a forecast of the marginal heat rate.)

Methodology for calculating GHG emissions under PG&E's supply portfolio

MRW calculated the GHG emissions for the Contra Costa County CCA load under the PG&E supply portfolio by summing the emissions from all resources in PG&E's portfolio. MRW assumed no GHG emissions from renewable power, hydroelectric power, or nuclear generation. In order to maintain a consistent comparison, MRW used the same emissions rate to calculate the emissions from PG&E's fossil-fuel power as used for the Contra Costa County CCA wholesale market purchases.

In order to support the analysis on Chapter 3 of the report, Figure 2 shows the PG&E portfolio. Before the closure of the Diablo Canyon, MRW estimated 80%-90% of PG&E's generation portfolio based on non-fuel-fired resources. After 2025, the non-fuel-fired resources share falls to 70% according MRW estimates.

Figure 2 PG&E's generation portfolio³⁷



³⁷ Before 2025 the hydroelectric generation is below its potential because MRW estimated that PG&E sells the over-procurement in hydroelectric power. MRW has assumed a minimum of fuel-fired generation to facilitate the RPS integration according to PG&E's Diablo Canyon retirement application, A.16-08-006. Table 2-3. In addition, after 2026 MRW estimated the price of the wholesale electric market below PG&E's new RPS prices. In those conditions, according to MRW assumptions, PG&E would procure up to 50% of its portfolio from renewable resources.

GHG allowance prices and GHG indirect costs

MRW developed a forecast of the prices for GHG allowances based on the auction floor price stipulated by the ARB's cap-and-trade regulation, consistent with recent auction outcomes.³⁸

Table 2 GHG Allowances price, \$ per allowance³⁹

	2017	2018	2019	2025	2030	2035	2038
\$/tonne	13.2	14.7	15.9	24.4	34.7	49.8	61.8

MRW used these GHG allowances prices to calculate both PG&E's GHG allowances costs (direct and indirect), which are included in the PG&E rate forecast, and Contra Costa County CCA's indirect GHG costs. The indirect GHG costs for Contra Costa County CCA will be included in the cost of the wholesale market energy purchases. MRW estimated that these costs will be, on average, \$12 per MWh delivered over the 2018-2038 period.

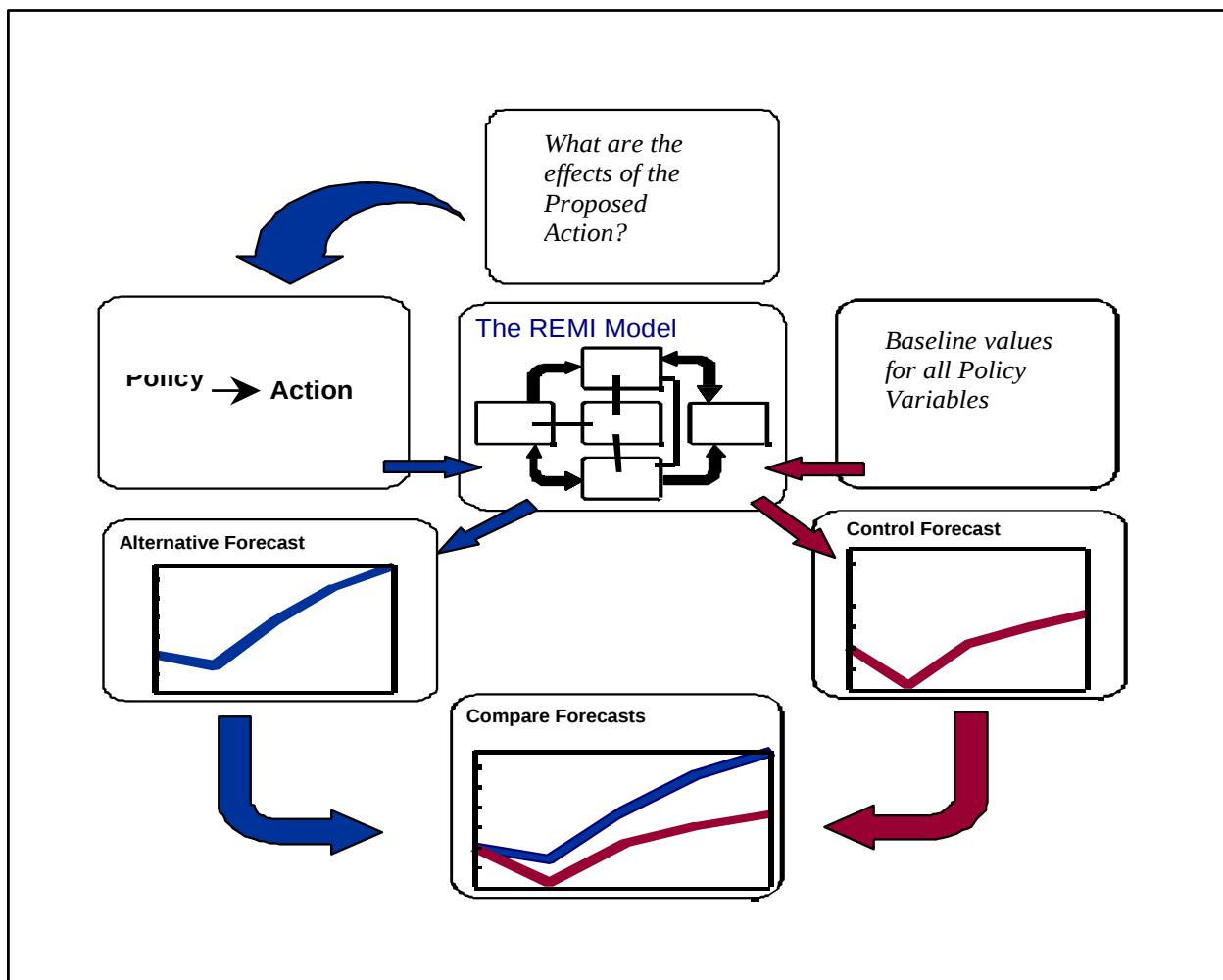
³⁸ California Code of Regulations, Title 17, Article 5, Section 95911.

³⁹ For 2017, the amount listed corresponds to the GHG allowance price for PG&E according to the most recent ERRR 2017 update. Pacific Gas & Electric ERRR 2017, A.16-06-003, Testimony November 2, 2016, Table 12-1.

Appendix F. About the REMI Policy Insight Model

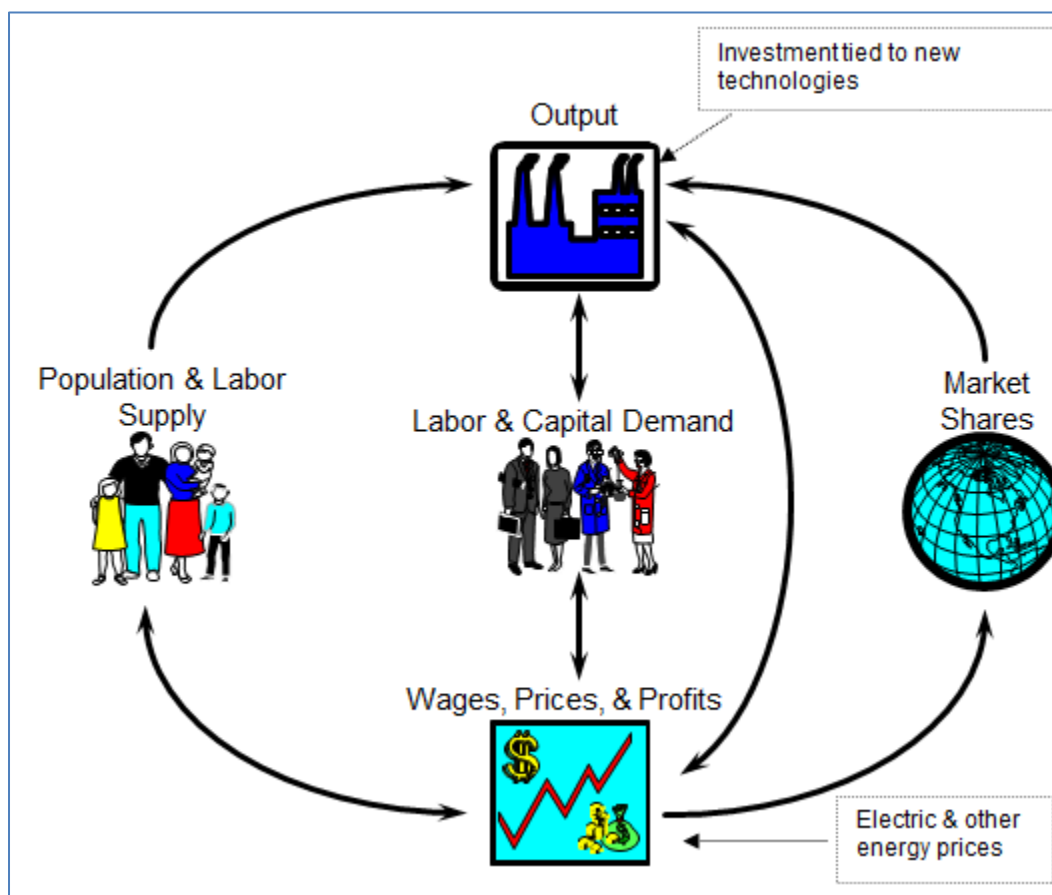
A software analysis forecasting model developed by Regional Economic Models, Inc. (REMI) of Amherst Massachusetts in the mid 1980's. It has a broad national customer base among public agencies, academic institutions, and the private-sector. It is also used in Canada (NRCan), and among other international clients. The model configuration used for this study consisted of 18 aggregate private-sector industries, plus a farm sector, a combined state/local government sector and two federal government sectors.

Economic Impacts Identified with the REMI Model



In the above figure, the central box “The REMI model” is the engine for predicting the economic and demographic dimensions of a *region-of-impact* (here Contra Costa County) under *no-action* (or Control forecast) and with a proposed CCA (alternative forecast). The engine is a combination structural econometric model, part input-output transactions, all with general equilibrium features – meaning *an economy can encounter a disruption (positive or negative), and over time (typically 1-3 years depending on the scale of the region and the size of the shock) re-adjust back to an equilibrium*. The diagram below depicts the organization of the REMI regional model in terms of the major blocks functioning in an economy and the arrows denote the feedback accounted for. Keep in mind this portrayal is at a very high-level, sparing the industry-specific details. Scenario specific changes are inserted through policy variable *levers* into the appropriate block of the model. There is another important dimension of economic response for the key region-of-impact that effectively layers on top of the below diagram – interactions with another regional economy. That additional region - *rest of California* - was explicitly modeled at the same time. The REMI model captures the flows of monetized goods and services, and commuter labor between regions when one (or both) is *shocked* by introduction of a CCA.

Core Logic of the REMI Model



Appendix G. Proforma Tables

Scenario 1

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																						
Cost of Power (including losses)		\$73,495,453	\$151,069,291	\$238,312,375	\$248,611,457	\$257,237,071	\$265,886,720	\$274,183,543	\$279,728,463	\$294,209,869	\$310,824,883	\$329,903,546	\$350,515,984	\$373,621,644	\$386,946,608	\$399,254,590	\$411,812,091	\$425,651,977	\$439,658,506	\$454,135,582	\$468,721,683	\$484,831,280
O&M&G Costs		\$9,081,989	\$11,047,477	\$14,037,456	\$14,312,982	\$14,596,957	\$14,871,929	\$15,146,845	\$15,425,482	\$15,722,408	\$16,025,074	\$16,333,641	\$16,648,197	\$16,968,859	\$17,295,746	\$17,628,978	\$17,968,678	\$18,314,999	\$18,668,042	\$19,027,938	\$19,394,819	\$19,768,820
Energy Efficiency Programming Costs																						
Total Expenses		\$82,577,443	\$162,116,767	\$252,349,831	\$262,924,440	\$271,834,028	\$280,758,650	\$289,330,388	\$295,153,945	\$309,932,277	\$326,849,957	\$346,237,187	\$367,164,181	\$390,590,503	\$404,242,354	\$416,883,567	\$429,780,769	\$443,966,976	\$458,326,548	\$473,163,520	\$488,116,502	\$504,600,100
Debt Service		\$0	\$5,489,006	\$5,489,006	\$5,489,006	\$5,489,006	\$5,489,006	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Revenue Requirement		\$82,577,443	\$167,605,774	\$257,838,838	\$268,413,446	\$277,323,035	\$286,247,656	\$289,330,388	\$295,153,945	\$309,932,277	\$326,849,957	\$346,237,187	\$367,164,181	\$390,590,503	\$404,242,354	\$416,883,567	\$429,780,769	\$443,966,976	\$458,326,548	\$473,163,520	\$488,116,502	\$504,600,100
Total Load, MWh		1,177,121	2,366,944	3,607,181	3,623,598	3,641,698	3,652,169	3,659,921	3,666,956	3,680,582	3,694,258	3,707,985	3,721,763	3,735,593	3,749,473	3,763,406	3,777,390	3,791,426	3,805,514	3,819,655	3,833,848	3,848,093
Contra Costa CCA Customer Charges, \$/MWh (before Reserve Fund Adjustment)																						
Average Contra Costa CCA generation		\$70.2	\$70.8	\$71.5	\$74.1	\$76.2	\$78.4	\$79.1	\$80.5	\$84.2	\$88.5	\$93.4	\$98.7	\$104.6	\$107.8	\$110.8	\$113.8	\$117.1	\$120.4	\$123.9	\$127.3	\$131.1
PG&E average exit fees for CCA load		\$23.7	\$19.1	\$22.9	\$16.6	\$16.6	\$15.7	\$14.6	\$12.6	\$9.1	\$8.0	\$7.0	\$6.0	\$5.1	\$3.1	\$1.7	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total CCA customer rate		\$93.8	\$89.9	\$94.3	\$90.6	\$92.7	\$94.1	\$93.6	\$93.1	\$93.3	\$96.4	\$100.4	\$104.6	\$109.7	\$110.9	\$112.4	\$114.4	\$117.1	\$120.4	\$123.9	\$127.3	\$131.1
PG&E average gen rate for CCA load, \$/MWh		\$101.5	\$105.7	\$106.6	\$112.7	\$115.5	\$113.8	\$113.3	\$109.2	\$113.2	\$119.2	\$126.3	\$134.2	\$144.0	\$146.7	\$151.0	\$155.7	\$160.8	\$165.0	\$170.5	\$176.0	\$182.5
Reserve Fund Adjustment																						
Target		\$12,386,616	\$25,140,866	\$38,675,826	\$40,262,017	\$41,598,455	\$42,937,148	\$43,399,558	\$44,273,092	\$46,489,842	\$49,027,494	\$51,935,578	\$55,074,627	\$58,588,575	\$60,636,353	\$62,532,535	\$64,467,115	\$66,595,046	\$68,748,982	\$70,974,528	\$73,217,475	\$75,690,015
Reserve Fund Adjustment																						
Potential Reserve potential		\$9,037,817	\$37,373,117	\$44,318,310	\$79,873,437	\$82,994,739	\$72,190,684	\$72,076,358	\$58,860,584	\$73,135,250	\$84,142,452	\$96,221,651	\$110,201,860	\$128,194,145	\$134,215,487	\$145,270,805	\$156,288,619	\$165,801,447	\$169,687,264	\$178,229,235	\$186,523,044	\$197,789,460
Potential Reserve additions		\$9,037,817	\$16,103,049	\$13,534,960	\$1,586,191	\$1,336,438	\$1,338,693	\$462,410	\$873,533	\$2,216,750	\$2,537,652	\$2,908,084	\$3,139,049	\$3,513,948	\$2,047,778	\$1,896,182	\$1,934,580	\$2,127,931	\$2,153,936	\$2,225,546	\$2,242,947	\$2,472,540
Subtractions from reserve fund		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Reserve fund total		\$9,037,817	\$25,140,866	\$38,675,826	\$40,262,017	\$41,598,455	\$42,937,148	\$43,399,558	\$44,273,092	\$46,489,842	\$49,027,494	\$51,935,578	\$55,074,627	\$58,588,575	\$60,636,353	\$62,532,535	\$64,467,115	\$66,595,046	\$68,748,982	\$70,974,528	\$73,217,475	\$75,690,015
Contra Costa CCA Customer Charges, \$/MWh (with Reserve Fund Adjustment)																						
Rate adjustment from Reserve Fund		\$7.7	\$6.8	\$3.8	\$0.4	\$0.4	\$0.4	\$0.1	\$0.2	\$0.6	\$0.7	\$0.8	\$0.8	\$0.9	\$0.5	\$0.5	\$0.5	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6
Average Contra Costa CCA rate		\$77.8	\$77.6	\$75.2	\$74.5	\$76.5	\$78.7	\$79.2	\$80.7	\$84.8	\$89.2	\$94.2	\$99.5	\$105.5	\$108.4	\$111.3	\$114.3	\$117.7	\$121.0	\$124.5	\$127.9	\$131.8
PG&E average exit fees for CCA load		\$23.7	\$19.1	\$22.9	\$16.6	\$16.6	\$15.7	\$14.6	\$12.6	\$9.1	\$8.0	\$7.0	\$6.0	\$5.1	\$3.1	\$1.7	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total CCA customer rate		\$101.5	\$96.7	\$98.1	\$91.1	\$93.1	\$94.4	\$93.8	\$93.4	\$93.9	\$97.1	\$101.2	\$105.5	\$110.6	\$111.5	\$112.9	\$114.9	\$117.7	\$121.0	\$124.5	\$127.9	\$131.8
<i>Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.</i>																						
Contra Costa CCA CO2 emissions																						
Emissions (Tonnes/MWh)		0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)		48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	195,332	196,074	197,642	162,803	163,997	165,333	166,460	167,595	168,634	170,197	171,328

Scenario 2

			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																							
Cost of Power (including losses)			\$75,667,208	\$155,562,573	\$244,603,605	\$253,936,224	\$262,178,133	\$270,821,465	\$279,147,605	\$288,420,808	\$302,569,437	\$318,621,199	\$336,840,252	\$356,586,893	\$378,456,407	\$388,844,347	\$399,378,659	\$410,314,502	\$421,560,027	\$432,993,327	\$444,699,721	\$456,541,793	\$469,291,025
O&M/A&G Costs			\$9,081,989	\$11,047,477	\$14,037,456	\$14,312,982	\$14,596,957	\$14,871,929	\$15,146,845	\$15,425,482	\$15,722,408	\$16,025,074	\$16,333,641	\$16,648,197	\$16,968,859	\$17,295,746	\$17,628,978	\$17,968,678	\$18,314,999	\$18,668,042	\$19,027,938	\$19,394,819	\$19,768,820
Energy Efficiency Programming Costs																							
Total Expenses			\$84,749,197	\$166,610,049	\$258,641,061	\$268,249,207	\$276,775,090	\$285,693,394	\$294,294,450	\$303,846,289	\$318,291,846	\$334,646,273	\$353,173,892	\$373,235,090	\$395,425,266	\$406,140,093	\$417,007,637	\$428,283,180	\$439,875,026	\$451,661,369	\$463,727,659	\$475,936,612	\$489,059,845
Debt Service			\$0	\$5,489,006	\$5,489,006	\$5,489,006	\$5,489,006	\$5,489,006	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Revenue Requirement			\$84,749,197	\$172,099,056	\$264,130,067	\$273,738,213	\$282,264,096	\$291,182,400	\$294,294,450	\$303,846,289	\$318,291,846	\$334,646,273	\$353,173,892	\$373,235,090	\$395,425,266	\$406,140,093	\$417,007,637	\$428,283,180	\$439,875,026	\$451,661,369	\$463,727,659	\$475,936,612	\$489,059,845
Total Load, MWh			1,177,121	2,366,944	3,607,181	3,623,598	3,641,698	3,652,169	3,659,921	3,666,956	3,680,582	3,694,258	3,707,985	3,721,763	3,735,593	3,749,473	3,763,406	3,777,390	3,791,426	3,805,514	3,819,655	3,833,848	3,848,093
Contra Costa CCA Customer Charges, \$/MWh (before Reserve Fund Adjustment)																							
Average Contra Costa CCA generation			\$72.0	\$72.7	\$73.2	\$75.5	\$77.5	\$79.7	\$80.4	\$82.9	\$86.5	\$90.6	\$95.2	\$100.3	\$105.9	\$108.3	\$110.8	\$113.4	\$116.0	\$118.7	\$121.4	\$124.1	\$127.1
PG&E average exit fees for CCA load			\$23.7	\$19.1	\$22.9	\$16.6	\$16.6	\$15.7	\$14.6	\$12.6	\$9.1	\$8.0	\$7.0	\$6.0	\$5.1	\$3.1	\$1.7	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total CCA customer rate			\$95.7	\$91.8	\$96.1	\$92.1	\$94.1	\$95.4	\$95.0	\$95.5	\$95.6	\$98.5	\$102.2	\$106.2	\$111.0	\$111.4	\$112.5	\$114.0	\$116.0	\$118.7	\$121.4	\$124.1	\$127.1
PG&E average gen rate for CCA load, \$/MWh			\$101.5	\$105.7	\$106.6	\$112.7	\$115.5	\$113.8	\$113.3	\$109.2	\$113.2	\$119.2	\$126.3	\$134.2	\$144.0	\$146.7	\$151.0	\$155.7	\$160.8	\$165.0	\$170.5	\$176.0	\$182.5
Reserve Fund Adjustment																							
Target			\$12,712,380	\$25,814,858	\$39,619,510	\$41,060,732	\$42,339,614	\$43,677,360	\$44,144,167	\$45,576,943	\$47,743,777	\$50,196,941	\$52,976,084	\$55,985,264	\$59,313,790	\$60,921,014	\$62,551,146	\$64,242,477	\$65,981,254	\$67,749,205	\$69,559,149	\$71,390,492	\$73,358,977
Reserve Fund Adjustment																							
Potential Reserve potential			\$6,866,063	\$32,879,835	\$38,027,080	\$74,548,670	\$78,053,677	\$67,255,940	\$67,112,296	\$50,168,239	\$64,775,682	\$76,346,136	\$89,284,946	\$104,130,951	\$123,359,382	\$132,317,748	\$145,146,736	\$157,786,207	\$169,893,397	\$176,352,443	\$187,665,096	\$198,702,934	\$213,329,715
Potential Reserve additions			\$6,866,063	\$18,948,796	\$13,804,652	\$1,441,222	\$1,278,883	\$1,337,746	\$466,807	\$1,432,776	\$2,166,833	\$2,453,164	\$2,779,143	\$3,009,180	\$3,328,526	\$1,607,224	\$1,630,132	\$1,691,331	\$1,738,777	\$1,767,951	\$1,809,944	\$1,831,343	\$1,968,485
Subtractions from reserve fund			\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Reserve fund total			\$6,866,063	\$25,814,858	\$39,619,510	\$41,060,732	\$42,339,614	\$43,677,360	\$44,144,167	\$45,576,943	\$47,743,777	\$50,196,941	\$52,976,084	\$55,985,264	\$59,313,790	\$60,921,014	\$62,551,146	\$64,242,477	\$65,981,254	\$67,749,205	\$69,559,149	\$71,390,492	\$73,358,977
Contra Costa CCA Customer Charges, \$/MWh (with Reserve Fund Adjustment)																							
Rate adjustment from Reserve Fund			\$5.8	\$8.0	\$3.8	\$0.4	\$0.4	\$0.4	\$0.1	\$0.4	\$0.6	\$0.7	\$0.7	\$0.8	\$0.9	\$0.4	\$0.4	\$0.4	\$0.5	\$0.5	\$0.5	\$0.5	\$0.5
Average Contra Costa CCA rate			\$77.8	\$80.7	\$77.1	\$75.9	\$77.9	\$80.1	\$80.5	\$83.3	\$87.1	\$91.2	\$96.0	\$101.1	\$106.7	\$108.7	\$111.2	\$113.8	\$116.5	\$119.2	\$121.9	\$124.6	\$127.6
PG&E average exit fees for CCA load			\$23.7	\$19.1	\$22.9	\$16.6	\$16.6	\$15.7	\$14.6	\$12.6	\$9.1	\$8.0	\$7.0	\$6.0	\$5.1	\$3.1	\$1.7	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total CCA customer rate			\$101.5	\$99.8	\$99.9	\$92.5	\$94.4	\$95.8	\$95.1	\$95.9	\$96.1	\$99.2	\$103.0	\$107.1	\$111.9	\$111.9	\$112.9	\$114.4	\$116.5	\$119.2	\$121.9	\$124.6	\$127.6
<i>Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.</i>																							
Contra Costa CCA CO2 emissions																							
Emissions (Tonnes/MWh)			0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)			48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	179,036	161,586	144,182	144,830	145,465	146,223	146,793	147,369	147,857	148,803	149,369

Scenario 3

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																						
Cost of Power (including losses)		\$74,421,602	\$155,059,529	\$248,051,939	\$262,405,554	\$275,771,462	\$289,759,015	\$303,955,349	\$316,069,786	\$337,813,788	\$362,649,650	\$383,978,224	\$406,604,081	\$431,423,912	\$446,808,176	\$461,156,092	\$475,748,288	\$489,543,148	\$503,482,983	\$517,889,434	\$532,382,737	\$548,417,000
O&M&G Costs		\$9,081,989	\$11,047,477	\$14,037,456	\$14,312,982	\$14,596,957	\$14,871,929	\$15,146,845	\$15,425,482	\$15,722,408	\$16,025,074	\$16,333,641	\$16,648,197	\$16,968,859	\$17,295,746	\$17,628,978	\$17,968,678	\$18,314,999	\$18,668,042	\$19,027,938	\$19,394,819	\$19,768,820
Energy Efficiency Programming Costs																						
Total Expenses		\$83,503,591	\$166,107,006	\$262,089,395	\$276,718,537	\$290,368,419	\$304,630,945	\$319,102,194	\$331,495,267	\$353,536,197	\$378,674,724	\$400,311,865	\$423,252,278	\$448,392,771	\$464,103,921	\$478,785,070	\$493,716,965	\$507,858,147	\$522,151,025	\$536,917,372	\$551,777,556	\$568,185,821
Debt Service		\$0	\$5,489,006	\$5,489,006	\$5,489,006	\$5,489,006	\$5,489,006	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Revenue Requirement		\$83,503,591	\$171,596,012	\$267,578,402	\$282,207,543	\$295,857,426	\$310,119,951	\$319,102,194	\$331,495,267	\$353,536,197	\$378,674,724	\$400,311,865	\$423,252,278	\$448,392,771	\$464,103,921	\$478,785,070	\$493,716,965	\$507,858,147	\$522,151,025	\$536,917,372	\$551,777,556	\$568,185,821
Total Load, MWh		1,177,121	2,366,944	3,607,181	3,623,598	3,641,698	3,652,169	3,659,921	3,666,956	3,680,582	3,694,258	3,707,985	3,721,763	3,735,593	3,749,473	3,763,406	3,777,390	3,791,426	3,805,514	3,819,655	3,833,848	3,848,093
Alameda CCA Customer Charges, \$/MWh (before Reserve Fund Adjustment)																						
Average Alameda CCA generation		\$70.9	\$72.5	\$74.2	\$77.9	\$81.2	\$84.9	\$87.2	\$90.4	\$96.1	\$102.5	\$108.0	\$113.7	\$120.0	\$123.8	\$127.2	\$130.7	\$133.9	\$137.2	\$140.6	\$143.9	\$147.7
PG&E average exit fees for CCA load		\$23.7	\$19.1	\$22.9	\$16.6	\$16.6	\$15.7	\$14.6	\$12.6	\$9.1	\$8.0	\$7.0	\$6.0	\$5.1	\$3.1	\$1.7	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total CCA customer rate		\$94.6	\$91.6	\$97.0	\$94.4	\$97.8	\$100.6	\$101.8	\$103.0	\$105.1	\$110.5	\$115.0	\$119.7	\$125.1	\$126.9	\$128.9	\$131.3	\$133.9	\$137.2	\$140.6	\$143.9	\$147.7
PG&E average gen rate for CCA load, \$/MWh		\$101.5	\$105.7	\$106.6	\$112.7	\$115.5	\$113.8	\$113.3	\$109.2	\$113.2	\$119.2	\$126.3	\$134.2	\$144.0	\$146.7	\$151.0	\$155.7	\$160.8	\$165.0	\$170.5	\$176.0	\$182.5
Reserve Fund Adjustment																						
Target		\$12,525,539	\$25,739,402	\$40,136,760	\$42,331,131	\$44,378,614	\$46,517,993	\$47,865,329	\$49,724,290	\$53,030,429	\$56,801,209	\$60,046,780	\$63,487,842	\$67,258,916	\$69,615,588	\$71,817,760	\$74,057,545	\$76,178,722	\$78,322,654	\$80,537,606	\$82,766,633	\$85,227,873
Reserve Fund Adjustment																						
Potential Reserve potential		\$8,111,669	\$33,382,879	\$34,578,745	\$66,079,340	\$64,460,347	\$48,318,389	\$42,304,552	\$22,519,261	\$29,531,331	\$32,317,684	\$42,146,974	\$54,113,763	\$70,391,877	\$74,353,919	\$83,369,303	\$92,352,422	\$101,910,276	\$105,862,787	\$114,475,383	\$122,861,990	\$134,203,739
Potential Reserve additions		\$8,111,669	\$17,627,733	\$14,397,358	\$2,194,371	\$2,047,482	\$2,139,379	\$1,347,336	\$1,858,961	\$3,306,139	\$3,770,779	\$3,245,571	\$3,441,062	\$3,771,074	\$2,356,673	\$2,202,172	\$2,239,784	\$2,121,177	\$2,143,932	\$2,214,952	\$2,229,028	\$2,461,240
Subtractions from reserve fund		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Reserve fund total		\$8,111,669	\$25,739,402	\$40,136,760	\$42,331,131	\$44,378,614	\$46,517,993	\$47,865,329	\$49,724,290	\$53,030,429	\$56,801,209	\$60,046,780	\$63,487,842	\$67,258,916	\$69,615,588	\$71,817,760	\$74,057,545	\$76,178,722	\$78,322,654	\$80,537,606	\$82,766,633	\$85,227,873
Alameda CCA Customer Charges, \$/MWh (with Reserve Fund Adjustment)																						
Rate adjustment from Reserve Fund		\$6.9	\$7.4	\$4.0	\$0.6	\$0.6	\$0.6	\$0.4	\$0.5	\$0.9	\$1.0	\$0.9	\$0.9	\$1.0	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6
Average Alameda CCA rate		\$77.8	\$79.9	\$78.2	\$78.5	\$81.8	\$85.5	\$87.6	\$90.9	\$97.0	\$103.5	\$108.8	\$114.6	\$121.0	\$124.4	\$127.8	\$131.3	\$134.5	\$137.8	\$141.1	\$144.5	\$148.3
PG&E average exit fees for CCA load		\$23.7	\$19.1	\$22.9	\$16.6	\$16.6	\$15.7	\$14.6	\$12.6	\$9.1	\$8.0	\$7.0	\$6.0	\$5.1	\$3.1	\$1.7	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total CCA customer rate		\$101.5	\$99.0	\$101.0	\$95.0	\$98.4	\$101.2	\$102.1	\$103.5	\$106.0	\$111.5	\$115.8	\$120.6	\$126.2	\$127.5	\$129.5	\$131.9	\$134.5	\$137.8	\$141.1	\$144.5	\$148.3
Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.																						
Alameda CCA CO2 emissions																						
Emissions (Tonnes/MWh)		0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)		48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	195,332	196,074	197,642	162,803	163,997	165,333	166,460	167,595	168,634	170,197	171,328

Scenario 4

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																						
Cost of Power (including losses)		\$77,332,918	\$162,719,907	\$262,070,819	\$279,609,557	\$297,052,506	\$315,993,039	\$336,528,138	\$362,105,625	\$391,911,928	\$427,041,105	\$449,571,955	\$473,571,311	\$500,641,660	\$511,836,324	\$523,149,117	\$534,898,122	\$546,971,922	\$559,212,625	\$571,745,163	\$584,386,818	\$598,049,458
O&M/A&G Costs		\$9,081,989	\$11,047,477	\$14,037,456	\$14,312,982	\$14,596,957	\$14,871,929	\$15,146,845	\$15,425,482	\$15,722,408	\$16,025,074	\$16,333,641	\$16,648,197	\$16,968,859	\$17,295,746	\$17,628,978	\$17,968,678	\$18,314,999	\$18,668,042	\$19,027,938	\$19,394,819	\$19,768,820
Energy Efficiency Programming Costs																						
Total Expenses		\$86,414,907	\$173,767,384	\$276,108,275	\$293,922,540	\$311,649,463	\$330,864,968	\$351,674,983	\$377,531,107	\$407,634,337	\$443,066,180	\$465,905,596	\$490,219,508	\$517,610,519	\$529,132,070	\$540,778,094	\$552,866,799	\$565,286,921	\$577,880,667	\$590,773,101	\$603,781,637	\$617,818,279
Debt Service		\$0	\$5,489,006	\$5,489,006	\$5,489,006	\$5,489,006	\$5,489,006	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total Revenue Requirement		\$86,414,907	\$179,256,390	\$281,597,282	\$299,411,546	\$317,138,469	\$336,353,975	\$351,674,983	\$377,531,107	\$407,634,337	\$443,066,180	\$465,905,596	\$490,219,508	\$517,610,519	\$529,132,070	\$540,778,094	\$552,866,799	\$565,286,921	\$577,880,667	\$590,773,101	\$603,781,637	\$617,818,279
Total Load, MWh		1,177,121	2,366,944	3,607,181	3,623,598	3,641,698	3,652,169	3,659,921	3,666,956	3,680,582	3,694,258	3,707,985	3,721,763	3,735,593	3,749,473	3,763,406	3,777,390	3,791,426	3,805,514	3,819,655	3,833,848	3,848,093
Alameda CCA Customer Charges, \$/MWh (before Reserve Fund Adjustment)																						
Average Alameda CCA generation		\$73.4	\$75.7	\$78.1	\$82.6	\$87.1	\$92.1	\$96.1	\$103.0	\$110.8	\$119.9	\$125.6	\$131.7	\$138.6	\$141.1	\$143.7	\$146.4	\$149.1	\$151.9	\$154.7	\$157.5	\$160.6
PG&E average exit fees for CCA load		\$23.7	\$19.1	\$22.9	\$16.6	\$16.6	\$15.7	\$14.6	\$12.6	\$9.1	\$8.0	\$7.0	\$6.0	\$5.1	\$3.1	\$1.7	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total CCA customer rate		\$97.1	\$94.8	\$100.9	\$99.2	\$103.7	\$107.8	\$110.7	\$115.6	\$119.8	\$127.9	\$132.7	\$137.7	\$143.7	\$144.2	\$145.4	\$147.0	\$149.1	\$151.9	\$154.7	\$157.5	\$160.6
PG&E average gen rate for CCA load, \$/MWh		\$101.5	\$105.7	\$106.6	\$112.7	\$115.5	\$113.8	\$113.3	\$109.2	\$113.2	\$119.2	\$126.3	\$134.2	\$144.0	\$146.7	\$151.0	\$155.7	\$160.8	\$165.0	\$170.5	\$176.0	\$182.5
Reserve Fund Adjustment																						
Target		\$12,962,236	\$26,888,459	\$42,239,592	\$44,911,732	\$47,570,770	\$50,453,096	\$52,751,248	\$56,629,666	\$61,145,150	\$66,459,927	\$69,885,839	\$73,532,926	\$77,641,578	\$79,369,810	\$81,116,714	\$82,930,020	\$84,793,038	\$86,682,100	\$88,615,965	\$90,567,246	\$92,672,742
Reserve Fund Adjustment																						
Potential Reserve potential		\$5,200,352	\$25,722,501	\$20,559,865	\$48,875,337	\$43,179,304	\$22,084,365	\$9,731,762	\$0	\$0	\$0	\$0	\$0	\$1,174,129	\$9,325,771	\$21,376,279	\$33,202,588	\$44,481,502	\$50,133,145	\$60,619,654	\$70,857,909	\$84,571,282
Potential Reserve additions		\$5,200,352	\$21,688,106	\$15,351,134	\$2,672,140	\$2,659,039	\$2,882,326	\$2,298,151	\$0	\$0	\$0	\$0	\$0	\$77,641,578	\$1,728,233	\$1,746,904	\$1,813,306	\$1,863,018	\$1,889,062	\$1,933,865	\$1,951,280	\$2,105,496
Subtractions from reserve fund		\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$23,516,579	\$24,566,809	\$4,667,860	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Reserve fund total		\$5,200,352	\$26,888,459	\$42,239,592	\$44,911,732	\$47,570,770	\$50,453,096	\$52,751,248	\$29,234,669	\$4,667,860	\$0	\$0	\$0	\$77,641,578	\$79,369,810	\$81,116,714	\$82,930,020	\$84,793,038	\$86,682,100	\$88,615,965	\$90,567,246	\$92,672,742
Alameda CCA Customer Charges, \$/MWh (with Reserve Fund Adjustment)																						
Rate adjustment from Reserve Fund		\$4.4	\$9.2	\$4.3	\$0.7	\$0.7	\$0.8	\$0.6	-\$6.4	-\$6.7	-\$1.3	\$0.0	\$0.0	\$20.8	\$0.5	\$0.5	\$0.5	\$0.5	\$0.5	\$0.5	\$0.5	\$0.5
Average Alameda CCA rate		\$77.8	\$84.9	\$82.3	\$83.4	\$87.8	\$92.9	\$96.7	\$96.5	\$104.1	\$118.7	\$125.6	\$131.7	\$159.3	\$141.6	\$144.2	\$146.8	\$149.6	\$152.3	\$155.2	\$158.0	\$161.1
PG&E average exit fees for CCA load		\$23.7	\$19.1	\$22.9	\$16.6	\$16.6	\$15.7	\$14.6	\$12.6	\$9.1	\$8.0	\$7.0	\$6.0	\$5.1	\$3.1	\$1.7	\$0.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Total CCA customer rate		\$101.5	\$104.0	\$105.2	\$99.9	\$104.4	\$108.6	\$111.3	\$109.2	\$113.2	\$126.6	\$132.7	\$137.7	\$164.5	\$144.7	\$145.8	\$147.4	\$149.6	\$152.3	\$155.2	\$158.0	\$161.1
Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.																						
Alameda CCA CO2 emissions																						
Emissions (Tonnes/MWh)		0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)		48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	179,036	161,586	144,182	144,830	145,465	146,223	146,793	147,369	147,857	148,803	149,369

Appendix H. MCE's Joint Powers Agreements

**Marin Energy Authority
- Joint Powers Agreement -**

Effective December 19, 2008

**As amended by Amendment No. 1 dated December 3, 2009
As further amended by Amendment No. 2 dated March 4, 2010
As further amended by Amendment No. 3 dated May 6, 2010
As further amended by Amendment No. 4 dated December 1, 2011
As further amended by Amendment No. 5 dated July 5, 2012
As further amended by Amendment No. 6 dated September 5, 2013
As further amended by Amendment No. 7 dated December 5, 2013
As further amended by Amendment No. 8 dated September 4, 2014
As further amended by Amendment No. 9 dated December 4, 2014
As further amended by Amendment No. 10 dated April 21, 2016**

Among The Following Parties:

**City of American Canyon
City of Belvedere
City of Benicia
City of Calistoga
Town of Corte Madera
City of El Cerrito
Town of Fairfax
City of Lafayette
City of Larkspur
City of Mill Valley
City of Napa
City of Novato
City of Richmond
Town of Ross
Town of San Anselmo
City of San Pablo
City of San Rafael
City of Sausalito
City of St. Helena
Town of Tiburon
City of Walnut Creek
Town of Yountville
County of Marin
County of Napa**

MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT

This **Joint Powers Agreement** (“Agreement”), effective as of December 19, 2008, is made and entered into pursuant to the provisions of Title 1, Division 7, Chapter 5, Article 1 (Section 6500 et seq.) of the California Government Code relating to the joint exercise of powers among the parties set forth in Exhibit B (“Parties”). The term “Parties” shall also include an incorporated municipality or county added to this Agreement in accordance with Section 3.1.

RECITALS

1. The Parties are either incorporated municipalities or counties sharing various powers under California law, including but not limited to the power to purchase, supply, and aggregate electricity for themselves and their inhabitants.
2. In 2006, the State Legislature adopted AB 32, the Global Warming Solutions Act, which mandates a reduction in greenhouse gas emissions in 2020 to 1990 levels. The California Air Resources Board is promulgating regulations to implement AB 32 which will require local government to develop programs to reduce greenhouse emissions.
3. The purposes for the Initial Participants (as such term is defined in Section 2.2 below) entering into this Agreement include addressing climate change by reducing energy related greenhouse gas emissions and securing energy supply and price stability, energy efficiencies and local economic benefits. It is the intent of this Agreement to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including but not limited to solar and wind energy production.
4. The Parties desire to establish a separate public agency, known as the Marin Energy Authority (“Authority”), under the provisions of the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 et seq.) (“Act”) in order to collectively study, promote, develop, conduct, operate, and manage energy programs.
5. The Initial Participants have each adopted an ordinance electing to implement through the Authority Community Choice Aggregation, an electric service enterprise agency available to cities and counties pursuant to California Public Utilities Code Section 366.2 (“CCA Program”). The first priority of the Authority will be the consideration of those actions necessary to implement the CCA Program. Regardless of whether or not Program Agreement 1 is approved and the CCA Program becomes operational, the parties intend for the Authority to continue to study, promote, develop, conduct, operate and manage other energy programs.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises, covenants, and conditions hereinafter set forth, it is agreed by and among the Parties as follows:

ARTICLE 1 CONTRACT DOCUMENTS

1.1 Definitions. Capitalized terms used in the Agreement shall have the meanings specified in Exhibit A, unless the context requires otherwise.

1.2 Documents Included. This Agreement consists of this document and the following exhibits, all of which are hereby incorporated into this Agreement.

Exhibit A:	Definitions
Exhibit B:	List of the Parties
Exhibit C:	Annual Energy Use
Exhibit D:	Voting Shares

1.3 Revision of Exhibits. The Parties agree that Exhibits B, C and D to this Agreement describe certain administrative matters that may be revised upon the approval of the Board, without such revision constituting an amendment to this Agreement, as described in Section 8.4. The Authority shall provide written notice to the Parties of the revision of any such exhibit.

ARTICLE 2 FORMATION OF MARIN ENERGY AUTHORITY

2.1 Effective Date and Term. This Agreement shall become effective and Marin Energy Authority shall exist as a separate public agency on the date this Agreement is executed by at least two Initial Participants after the adoption of the ordinances required by Public Utilities Code Section 366.2(c)(10). The Authority shall provide notice to the Parties of the Effective Date. The Authority shall continue to exist, and this Agreement shall be effective, until this Agreement is terminated in accordance with Section 7.4, subject to the rights of the Parties to withdraw from the Authority.

2.2 Initial Participants. During the first 180 days after the Effective Date, all other Initial Participants may become a Party by executing this Agreement and delivering an executed copy of this Agreement and a copy of the adopted ordinance required by Public Utilities Code Section 366.2(c)(10) to the Authority. Additional conditions, described in Section 3.1, may apply (i) to either an incorporated municipality or county desiring to become a Party and is not an Initial Participant and (ii) to Initial Participants that have not executed and delivered this Agreement within the time period described above.

- 2.3 Formation.** There is formed as of the Effective Date a public agency named the Marin Energy Authority. Pursuant to Sections 6506 and 6507 of the Act, the Authority is a public agency separate from the Parties. The debts, liabilities or obligations of the Authority shall not be debts, liabilities or obligations of the individual Parties unless the governing board of a Party agrees in writing to assume any of the debts, liabilities or obligations of the Authority. A Party who has not agreed to assume an Authority debt, liability or obligation shall not be responsible in any way for such debt, liability or obligation even if a majority of the Parties agree to assume the debt, liability or obligation of the Authority. Notwithstanding Section 8.4 of this Agreement, this Section 2.3 may not be amended unless such amendment is approved by the governing board of each Party.
- 2.4 Purpose.** The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs, and to exercise all other powers necessary and incidental to accomplishing this purpose. Without limiting the generality of the foregoing, the Parties intend for this Agreement to be used as a contractual mechanism by which the Parties are authorized to participate as a group in the CCA Program, as further described in Section 5.1. The Parties intend that subsequent agreements shall define the terms and conditions associated with the actual implementation of the CCA Program and any other energy programs approved by the Authority.
- 2.5 Powers.** The Authority shall have all powers common to the Parties and such additional powers accorded to it by law. The Authority is authorized, in its own name, to exercise all powers and do all acts necessary and proper to carry out the provisions of this Agreement and fulfill its purposes, including, but not limited to, each of the following:
- 2.5.1** make and enter into contracts;
 - 2.5.2** employ agents and employees, including but not limited to an Executive Director;
 - 2.5.3** acquire, contract, manage, maintain, and operate any buildings, works or improvements;
 - 2.5.4** acquire by eminent domain, or otherwise, except as limited under Section 6508 of the Act, and to hold or dispose of any property;
 - 2.5.5** lease any property;
 - 2.5.6** sue and be sued in its own name;
 - 2.5.7** incur debts, liabilities, and obligations, including but not limited to loans from private lending sources pursuant to its temporary borrowing powers such as Government Code Section 53850 et seq. and authority under the Act;
 - 2.5.8** issue revenue bonds and other forms of indebtedness;
 - 2.5.9** apply for, accept, and receive all licenses, permits, grants, loans or other aids from any federal, state or local public agency;

- 2.5.10 submit documentation and notices, register, and comply with orders, tariffs and agreements for the establishment and implementation of the CCA Program and other energy programs;
 - 2.5.11 adopt rules, regulations, policies, bylaws and procedures governing the operation of the Authority (“Operating Rules and Regulations”); and
 - 2.5.12 make and enter into service agreements relating to the provision of services necessary to plan, implement, operate and administer the CCA Program and other energy programs, including the acquisition of electric power supply and the provision of retail and regulatory support services.
- 2.6 **Limitation on Powers.** As required by Government Code Section 6509, the power of the Authority is subject to the restrictions upon the manner of exercising power possessed by the County of Marin.
- 2.7 **Compliance with Local Zoning and Building Laws.** Notwithstanding any other provisions of this Agreement or state law, any facilities, buildings or structures located, constructed or caused to be constructed by the Authority within the territory of the Authority shall comply with the General Plan, zoning and building laws of the local jurisdiction within which the facilities, buildings or structures are constructed.

ARTICLE 3 AUTHORITY PARTICIPATION

- 3.1 **Addition of Parties.** Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or such county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption, by an affirmative vote of the Board satisfying the requirements described in Section 4.9.1, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(10) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership payment, if any, and (e) satisfaction of any conditions established by the Board. Notwithstanding the foregoing, in the event the Authority decides to not implement a CCA Program, the requirement that an additional party adopt the ordinance required by Public Utilities Code Section 366.2(c)(10) shall not apply. Under such circumstance, the Board resolution authorizing membership of an additional incorporated municipality or county shall be adopted in accordance with the voting requirements of Section 4.10.

- 3.2 **Continuing Participation.** The Parties acknowledge that membership in the Authority may change by the addition and/or withdrawal or termination of Parties. The Parties agree to participate with such other Parties as may later be added, as described in Section 3.1. The Parties also agree that the withdrawal or termination of a Party shall not affect this Agreement or the remaining Parties' continuing obligations under this Agreement.

ARTICLE 4

GOVERNANCE AND INTERNAL ORGANIZATION

- 4.1 **Board of Directors.** The governing body of the Authority shall be a Board of Directors ("Board") consisting of one director for each Party appointed in accordance with Section 4.2.
- 4.2 **Appointment and Removal of Directors.** The Directors shall be appointed and may be removed as follows:
- 4.2.1 The governing body of each Party shall appoint and designate in writing one regular Director who shall be authorized to act for and on behalf of the Party on matters within the powers of the Authority. The governing body of each Party also shall appoint and designate in writing one alternate Director who may vote on matters when the regular Director is absent from a Board meeting. The person appointed and designated as the Director or the alternate Director shall be a member of the governing body of the Party.
- 4.2.2 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.11, shall specify the reasons for and process associated with the removal of an individual Director for cause. Notwithstanding the foregoing, no Party shall be deprived of its right to seat a Director on the Board and any such Party for which its Director and/or alternate Director has been removed may appoint a replacement.
- 4.3 **Terms of Office.** Each Director shall serve at the pleasure of the governing body of the Party that the Director represents, and may be removed as Director by such governing body at any time. If at any time a vacancy occurs on the Board, a replacement shall be appointed to fill the position of the previous Director in accordance with the provisions of Section 4.2 within 90 days of the date that such position becomes vacant.
- 4.4 **Quorum.** A majority of the Directors shall constitute a quorum, except that less than a quorum may adjourn from time to time in accordance with law.

- 4.5 **Powers and Function of the Board.** The Board shall conduct or authorize to be conducted all business and activities of the Authority, consistent with this Agreement, the Authority Documents, the Operating Rules and Regulations, and applicable law.
- 4.6 **Executive Committee.** The Board may establish an executive committee consisting of a smaller number of Directors. The Board may delegate to the executive committee such authority as the Board might otherwise exercise, subject to limitations placed on the Board's authority to delegate certain essential functions, as described in the Operating Rules and Regulations. The Board may not delegate to the Executive Committee or any other committee its authority under Section 2.5.11 to adopt and amend the Operating Rules and Regulations.
- 4.7 **Commissions, Boards and Committees.** The Board may establish any advisory commissions, boards and committees as the Board deems appropriate to assist the Board in carrying out its functions and implementing the CCA Program, other energy programs and the provisions of this Agreement.
- 4.8 **Director Compensation.** Compensation for work performed by Directors on behalf of the Authority shall be borne by the Party that appointed the Director. The Board, however, may adopt by resolution a policy relating to the reimbursement of expenses incurred by Directors.
- 4.9 **Board Voting Related to the CCA Program.**
- 4.9.1. To be effective, on all matters specifically related to the CCA Program, a vote of the Board shall consist of the following: (1) a majority of all Directors shall vote in the affirmative or such higher voting percentage expressly set forth in Sections 7.2 and 8.4 (the "percentage vote") and (2) the corresponding voting shares (as described in Section 4.9.2 and Exhibit D) of all such Directors voting in the affirmative shall exceed 50%, or such other higher voting shares percentage expressly set forth in Sections 7.2 and 8.4 (the "percentage voting shares"), provided that, in instances in which such other higher voting share percentage would result in any one Director having a voting share that equals or exceeds that which is necessary to disapprove the matter being voted on by the Board, at least one other Director shall be required to vote in the negative in order to disapprove such matter.
- 4.9.2. Unless otherwise stated herein, voting shares of the Directors shall be determined by combining the following: (1) an equal voting share for each Director determined in accordance with the formula detailed in Section 4.9.2.1, below; and (2) an additional voting share determined in accordance with the formula detailed in Section 4.9.2.2, below.
- 4.9.2.1 **Pro Rata Voting Share.** Each Director shall have an equal voting share as determined by the following formula: (1/total number of

Directors) multiplied by 50, and

4.9.2.2 Annual Energy Use Voting Share. Each Director shall have an additional voting share as determined by the following formula: (Annual Energy Use/Total Annual Energy) multiplied by 50, where (a) “Annual Energy Use” means, (i) with respect to the first 5 years following the Effective Date, the annual electricity usage, expressed in kilowatt hours (“kWhs”), within the Party’s respective jurisdiction and (ii) with respect to the period after the fifth anniversary of the Effective Date, the annual electricity usage, expressed in kWhs, of accounts within a Party’s respective jurisdiction that are served by the Authority and (b) “Total Annual Energy” means the sum of all Parties’ Annual Energy Use. The initial values for Annual Energy use are designated in Exhibit C, and shall be adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 of each year

4.9.2.3 The voting shares are set forth in Exhibit D. Exhibit D may be updated to reflect revised annual energy use amounts and any changes in the parties to the Agreement without amending the Agreement provided that the Board is provided a copy of the updated Exhibit D.

4.10 Board Voting on General Administrative Matters and Programs Not Involving CCA. Except as otherwise provided by this Agreement or the Operating Rules and Regulations, each member shall have one vote on general administrative matters, including but not limited to the adoption and amendment of the Operating Rules and Regulations, and energy programs not involving CCA. Action on these items shall be determined by a majority vote of the quorum present and voting on the item or such higher voting percentage expressly set forth in Sections 7.2 and 8.4.

4.11 Board Voting on CCA Programs Not Involving CCA That Require Financial Contributions. The approval of any program or other activity not involving CCA that requires financial contributions by individual Parties shall be approved only by a majority vote of the full membership of the Board subject to the right of any Party who votes against the program or activity to opt-out of such program or activity pursuant to this section. The Board shall provide at least 45 days prior written notice to each Party before it considers the program or activity for adoption at a Board meeting. Such notice shall be provided to the governing body and the chief administrative officer, city manager or town manager of each Party. The Board also shall provide written notice of such program or activity adoption to the above-described officials of each Party within 5 days after the Board adopts the program or activity. Any Party voting against the approval of a program or other activity of the Authority requiring financial contributions by individual Parties may elect to opt-out of participation in such program or activity by

providing written notice of this election to the Board within 30 days after the program or activity is approved by the Board. Upon timely exercising its opt-out election, a Party shall not have any financial obligation or any liability whatsoever for the conduct or operation of such program or activity.

- 4.12 Meetings and Special Meetings of the Board.** The Board shall hold at least four regular meetings per year, but the Board may provide for the holding of regular meetings at more frequent intervals. The date, hour and place of each regular meeting shall be fixed by resolution or ordinance of the Board. Regular meetings may be adjourned to another meeting time. Special meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956. Directors may participate in meetings telephonically, with full voting rights, only to the extent permitted by law. All meetings of the Board shall be conducted in accordance with the provisions of the Ralph M. Brown Act (California Government Code Section 54950 et seq.).

4.13 Selection of Board Officers.

- 4.13.1 Chair and Vice Chair.** The Directors shall select, from among themselves, a Chair, who shall be the presiding officer of all Board meetings, and a Vice Chair, who shall serve in the absence of the Chair. The term of office of the Chair and Vice Chair shall continue for one year, but there shall be no limit on the number of terms held by either the Chair or Vice Chair. The office of either the Chair or Vice Chair shall be declared vacant and a new selection shall be made if: (a) the person serving dies, resigns, or the Party that the person represents removes the person as its representative on the Board or (b) the Party that he or she represents withdraws from the Authority pursuant to the provisions of this Agreement.
- 4.13.2 Secretary.** The Board shall appoint a Secretary, who need not be a member of the Board, who shall be responsible for keeping the minutes of all meetings of the Board and all other official records of the Authority.
- 4.13.3 Treasurer and Auditor.** The Board shall appoint a qualified person to act as the Treasurer and a qualified person to act as the Auditor, neither of whom needs to be a member of the Board. If the Board so designates, and in accordance with the provisions of applicable law, a qualified person may hold both the office of Treasurer and the office of Auditor of the Authority. Unless otherwise exempted from such requirement, the Authority shall cause an independent audit to be made by a certified public accountant, or public accountant, in compliance with Section 6505 of the Act. The Treasurer shall act as the depository of the Authority and have custody of all the money of the Authority, from whatever source, and as such, shall have all of the duties and responsibilities specified in Section 6505.5 of the Act. The Board may require the Treasurer and/or Auditor to

file with the Authority an official bond in an amount to be fixed by the Board, and if so requested the Authority shall pay the cost of premiums associated with the bond. The Treasurer shall report directly to the Board and shall comply with the requirements of treasurers of incorporated municipalities. The Board may transfer the responsibilities of Treasurer to any person or entity as the law may provide at the time. The duties and obligations of the Treasurer are further specified in Article 6.

- 4.14 Administrative Services Provider.** The Board may appoint one or more administrative services providers to serve as the Authority's agent for planning, implementing, operating and administering the CCA Program, and any other program approved by the Board, in accordance with the provisions of a written agreement between the Authority and the appointed administrative services provider or providers that will be known as an Administrative Services Agreement. The Administrative Services Agreement shall set forth the terms and conditions by which the appointed administrative services provider shall perform or cause to be performed all tasks necessary for planning, implementing, operating and administering the CCA Program and other approved programs. The Administrative Services Agreement shall set forth the term of the Agreement and the circumstances under which the Administrative Services Agreement may be terminated by the Authority. This section shall not in any way be construed to limit the discretion of the Authority to hire its own employees to administer the CCA Program or any other program.

ARTICLE 5

IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 Preliminary Implementation of the CCA Program.

- 5.1.1 Enabling Ordinance.** Except as otherwise provided by Section 3.1, prior to the execution of this Agreement, each Party shall adopt an ordinance in accordance with Public Utilities Code Section 366.2(c)(10) for the purpose of specifying that the Party intends to implement a CCA Program by and through its participation in the Authority.
- 5.1.2 Implementation Plan.** The Authority shall cause to be prepared an Implementation Plan meeting the requirements of Public Utilities Code Section 366.2 and any applicable Public Utilities Commission regulations as soon after the Effective Date as reasonably practicable. The Implementation Plan shall not be filed with the Public Utilities Commission until it is approved by the Board in the manner provided by Section 4.9.

5.1.3 Effect of Vote On Required Implementation Action. In the event that two or more Parties vote to approve Program Agreement 1 or any earlier action required for the implementation of the CCA Program (“Required Implementation Action”), but such vote is insufficient to approve the Required Implementation Action under Section 4.9, the following will occur:

5.1.3.1 The Parties voting against the Required Implementation Action shall no longer be a Party to this Agreement and this Agreement shall be terminated, without further notice, with respect to each of the Parties voting against the Required Implementation Action at the time this vote is final. The Board may take a provisional vote on a Required Implementation Action in order to initially determine the position of the Parties on the Required Implementation Action. A vote, specifically stated in the record of the Board meeting to be a provisional vote, shall not be considered a final vote with the consequences stated above. A Party who is terminated from this Agreement pursuant to this section shall be considered the same as a Party that voluntarily withdrew from the Agreement under Section 7.1.1.1.

5.1.3.2 After the termination of any Parties pursuant to Section 5.1.3.1, the remaining Parties to this Agreement shall be only the Parties who voted in favor of the Required Implementation Action.

5.1.4 Termination of CCA Program. Nothing contained in this Article or this Agreement shall be construed to limit the discretion of the Authority to terminate the implementation or operation of the CCA Program at any time in accordance with any applicable requirements of state law.

5.2 Authority Documents. The Parties acknowledge and agree that the affairs of the Authority will be implemented through various documents duly adopted by the Board through Board resolution, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies defined as the Authority Documents by this Agreement. The Parties agree to abide by and comply with the terms and conditions of all such Authority Documents that may be adopted by the Board, subject to the Parties’ right to withdraw from the Authority as described in Article 7.

ARTICLE 6 FINANCIAL PROVISIONS

6.1 Fiscal Year. The Authority's fiscal year shall be 12 months commencing July 1 and ending June 30. The fiscal year may be changed by Board resolution.

6.2 Depository.

6.2.1 All funds of the Authority shall be held in separate accounts in the name of the Authority and not commingled with funds of any Party or any other person or entity.

6.2.2 All funds of the Authority shall be strictly and separately accounted for, and regular reports shall be rendered of all receipts and disbursements, at least quarterly during the fiscal year. The books and records of the Authority shall be open to inspection by the Parties at all reasonable times. The Board shall contract with a certified public accountant or public accountant to make an annual audit of the accounts and records of the Authority, which shall be conducted in accordance with the requirements of Section 6505 of the Act.

6.2.3 All expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its Operating Rules and Regulations. The Treasurer shall draw checks or warrants or make payments by other means for claims or disbursements not within an applicable budget only upon the prior approval of the Board.

6.3 Budget and Recovery Costs.

6.3.1 Budget. The initial budget shall be approved by the Board. The Board may revise the budget from time to time through an Authority Document as may be reasonably necessary to address contingencies and unexpected expenses. All subsequent budgets of the Authority shall be prepared and approved by the Board in accordance with the Operating Rules and Regulations.

6.3.2 County Funding of Initial Costs. The County of Marin shall fund the Initial Costs of the Authority in implementing the CCA Program in an amount not to exceed \$500,000 unless a larger amount of funding is approved by the Board of Supervisors of the County. This funding shall be paid by the County at the times and in the amounts required by the Authority. In the event that the CCA Program becomes operational, these Initial Costs paid by the County of Marin shall be included in the customer charges for electric services as provided by Section 6.3.4 to the extent permitted by law, and the County of Marin shall be reimbursed from the

payment of such charges by customers of the Authority. The Authority may establish a reasonable time period over which such costs are recovered. In the event that the CCA Program does not become operational, the County of Marin shall not be entitled to any reimbursement of the Initial Costs it has paid from the Authority or any Party.

6.3.3 CCA Program Costs. The Parties desire that, to the extent reasonably practicable, all costs incurred by the Authority that are directly or indirectly attributable to the provision of electric services under the CCA Program, including the establishment and maintenance of various reserve and performance funds, shall be recovered through charges to CCA customers receiving such electric services.

6.3.4 General Costs. Costs that are not directly or indirectly attributable to the provision of electric services under the CCA Program, as determined by the Board, shall be defined as general costs. General costs shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

6.3.5 Other Energy Program Costs. Costs that are directly or indirectly attributable to energy programs approved by the Authority other than the CCA Program shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

ARTICLE 7 WITHDRAWAL AND TERMINATION

7.1 Withdrawal.

7.1.1 General.

7.1.1.1 Prior to the Authority's execution of Program Agreement 1, any Party may withdraw its membership in the Authority by giving no less than 30 days advance written notice of its election to do so, which notice shall be given to the Authority and each Party. To permit consideration by the governing body of each Party, the Authority shall provide a copy of the proposed Program Agreement 1 to each Party at least 90 days prior to the consideration of such agreement by the Board.

7.1.1.2 Subsequent to the Authority's execution of Program Agreement 1, a Party may withdraw its membership in the Authority, effective as of the beginning of the Authority's fiscal year, by giving no less than 6

months advance written notice of its election to do so, which notice shall be given to the Authority and each Party, and upon such other conditions as may be prescribed in Program Agreement 1.

7.1.2 Amendment. Notwithstanding Section 7.1.1, a Party may withdraw its membership in the Authority following an amendment to this Agreement in the manner provided by Section 8.4.

7.1.3 Continuing Liability; Further Assurances. A Party that withdraws its membership in the Authority may be subject to certain continuing liabilities, as described in Section 7.3. The withdrawing Party and the Authority shall execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, as determined by the Board, to effectuate the orderly withdrawal of such Party from membership in the Authority. The Operating Rules and Regulations shall prescribe the rights if any of a withdrawn Party to continue to participate in those Board discussions and decisions affecting customers of the CCA Program that reside or do business within the jurisdiction of the Party.

7.2 Involuntary Termination of a Party. This Agreement may be terminated with respect to a Party for material non-compliance with provisions of this Agreement or the Authority Documents upon an affirmative vote of the Board in which the minimum percentage vote and percentage voting shares, as described in Section 4.9.1, shall be no less than 67%, excluding the vote and voting shares of the Party subject to possible termination. Prior to any vote to terminate this Agreement with respect to a Party, written notice of the proposed termination and the reason(s) for such termination shall be delivered to the Party whose termination is proposed at least 30 days prior to the regular Board meeting at which such matter shall first be discussed as an agenda item. The written notice of proposed termination shall specify the particular provisions of this Agreement or the Authority Documents that the Party has allegedly violated. The Party subject to possible termination shall have the opportunity at the next regular Board meeting to respond to any reasons and allegations that may be cited as a basis for termination prior to a vote regarding termination. A Party that has had its membership in the Authority terminated may be subject to certain continuing liabilities, as described in Section 7.3. In the event that the Authority decides to not implement the CCA Program, the minimum percentage vote of 67% shall be conducted in accordance with Section 4.10 rather than Section 4.9.1.

7.3 Continuing Liability; Refund. Upon a withdrawal or involuntary termination of a Party, the Party shall remain responsible for any claims, demands, damages, or liabilities arising from the Party's membership in the Authority through the date of its withdrawal or involuntary termination, it being agreed that the Party shall not be responsible for any claims, demands, damages, or liabilities arising after the date of the Party's withdrawal or involuntary termination. In addition, such

Party also shall be responsible for any costs or obligations associated with the Party's participation in any program in accordance with the provisions of any agreements relating to such program provided such costs or obligations were incurred prior to the withdrawal of the Party. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's liability for the costs described above. Any amount of the Party's funds held on deposit with the Authority above that which is required to pay any liabilities or obligations shall be returned to the Party.

- 7.4 **Mutual Termination.** This Agreement may be terminated by mutual agreement of all the Parties; provided, however, the foregoing shall not be construed as limiting the rights of a Party to withdraw its membership in the Authority, and thus terminate this Agreement with respect to such withdrawing Party, as described in Section 7.1.
- 7.5 **Disposition of Property upon Termination of Authority.** Upon termination of this Agreement as to all Parties, any surplus money or assets in possession of the Authority for use under this Agreement, after payment of all liabilities, costs, expenses, and charges incurred under this Agreement and under any program documents, shall be returned to the then-existing Parties in proportion to the contributions made by each.

ARTICLE 8 MISCELLANEOUS PROVISIONS

- 8.1 **Dispute Resolution.** The Parties and the Authority shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Should such efforts to settle a dispute, after reasonable efforts, fail, the dispute shall be settled by binding arbitration in accordance with policies and procedures established by the Board.
- 8.2 **Liability of Directors, Officers, and Employees.** The Directors, officers, and employees of the Authority shall use ordinary care and reasonable diligence in the exercise of their powers and in the performance of their duties pursuant to this Agreement. No current or former Director, officer, or employee will be responsible for any act or omission by another Director, officer, or employee. The Authority shall defend, indemnify and hold harmless the individual current and former Directors, officers, and employees for any acts or omissions in the scope of their employment or duties in the manner provided by Government Code Section 995 et seq. Nothing in this section shall be construed to limit the defenses

available under the law, to the Parties, the Authority, or its Directors, officers, or employees.

- 8.3 Indemnification of Parties.** The Authority shall acquire such insurance coverage as is necessary to protect the interests of the Authority, the Parties and the public. The Authority shall defend, indemnify and hold harmless the Parties and each of their respective Board or Council members, officers, agents and employees, from any and all claims, losses, damages, costs, injuries and liabilities of every kind arising directly or indirectly from the conduct, activities, operations, acts, and omissions of the Authority under this Agreement.
- 8.4 Amendment of this Agreement.** This Agreement may be amended by an affirmative vote of the Board in which the minimum percentage vote and percentage voting shares, as described in Section 4.9.1, shall be no less than 67%. The Authority shall provide written notice to all Parties of amendments to this Agreement, including the effective date of such amendments. A Party shall be deemed to have withdrawn its membership in the Authority effective immediately upon the vote of the Board approving an amendment to this Agreement if the Director representing such Party has provided notice to the other Directors immediately preceding the Board's vote of the Party's intention to withdraw its membership in the Authority should the amendment be approved by the Board. As described in Section 7.3, a Party that withdraws its membership in the Authority in accordance with the above-described procedure may be subject to continuing liabilities incurred prior to the Party's withdrawal. In the event that the Authority decides to not implement the CCA Program, the minimum percentage vote of 67% shall be conducted in accordance with Section 4.10 rather than Section 4.9.1.
- 8.5 Assignment.** Except as otherwise expressly provided in this Agreement, the rights and duties of the Parties may not be assigned or delegated without the advance written consent of all of the other Parties, and any attempt to assign or delegate such rights or duties in contravention of this Section 8.5 shall be null and void. This Agreement shall inure to the benefit of, and be binding upon, the successors and assigns of the Parties. This Section 8.5 does not prohibit a Party from entering into an independent agreement with another agency, person, or entity regarding the financing of that Party's contributions to the Authority, or the disposition of proceeds which that Party receives under this Agreement, so long as such independent agreement does not affect, or purport to affect, the rights and duties of the Authority or the Parties under this Agreement.
- 8.6 Severability.** If one or more clauses, sentences, paragraphs or provisions of this Agreement shall be held to be unlawful, invalid or unenforceable, it is hereby agreed by the Parties, that the remainder of the Agreement shall not be affected thereby. Such clauses, sentences, paragraphs or provision shall be deemed reformed so as to be lawful, valid and enforced to the maximum extent possible.

- 8.7 Further Assurances.** Each Party agrees to execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, to effectuate the purposes and intent of this Agreement.
- 8.8 Execution by Counterparts.** This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.
- 8.9 Parties to be Served Notice.** Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 48 hours after the deposit thereof (excluding Saturdays, Sundays and holidays) if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties.

Exhibit A

To the Joint Powers Agreement Marin Energy Authority

-Definitions-

“AB 117” means Assembly Bill 117 (Stat. 2002, ch. 838, codified at Public Utilities Code Section 366.2), which created CCA.

“Act” means the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq.*)

“Administrative Services Agreement” means an agreement or agreements entered into after the Effective Date by the Authority with an entity that will perform tasks necessary for planning, implementing, operating and administering the CCA Program or any other energy programs adopted by the Authority.

“Agreement” means this Joint Powers Agreement.

“Annual Energy Use” has the meaning given in Section 4.9.2.2.

“Authority” means the Marin Energy Authority.

“Authority Document(s)” means document(s) duly adopted by the Board by resolution or motion implementing the powers, functions and activities of the Authority, including but not limited to the Operating Rules and Regulations, the annual budget, and plans and policies.

“Board” means the Board of Directors of the Authority.

“CCA” or “Community Choice Aggregation” means an electric service option available to cities and counties pursuant to Public Utilities Code Section 366.2.

“CCA Program” means the Authority’s program relating to CCA that is principally described in Sections 2.4 and 5.1.

“Director” means a member of the Board of Directors representing a Party.

“Effective Date” means the date on which this Agreement shall become effective and the Marin Energy Authority shall exist as a separate public agency, as further described in Section 2.1.

“Implementation Plan” means the plan generally described in Section 5.1.2 of this Agreement that is required under Public Utilities Code Section 366.2 to be filed with the

California Public Utilities Commission for the purpose of describing a proposed CCA Program.

“Initial Costs” means all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as the hiring of an Executive Director and any administrative staff, any required accounting, administrative, technical and legal services in support of the Authority’s initial activities or in support of the negotiation, preparation and approval of one or more Administrative Services Provider Agreements and Program Agreement 1. Administrative and operational costs incurred after the approval of Program Agreement 1 shall not be considered Initial Costs.

“Initial Participants” means, for the purpose of this Agreement, the signatories to this JPA as of May 5, 2010 including City of Belvedere, Town of Fairfax, City of Mill Valley, Town of San Anselmo, City of San Rafael, City of Sausalito, Town of Tiburon and County of Marin.

“Operating Rules and Regulations” means the rules, regulations, policies, bylaws and procedures governing the operation of the Authority.

“Parties” means, collectively, the signatories to this Agreement that have satisfied the conditions in Sections 2.2 or 3.2 such that it is considered a member of the Authority.

“Party” means, singularly, a signatory to this Agreement that has satisfied the conditions in Sections 2.2 or 3.2 such that it is considered a member of the Authority.

“Program Agreement 1” means the agreement that the Authority will enter into with an energy service provider that will provide the electricity to be distributed to customers participating in the CCA Program.

“Total Annual Energy” has the meaning given in Section 4.9.2.2.

Exhibit B

To the Joint Powers Agreement Marin Energy Authority

-List of the Parties-

City of American Canyon
City of Belvedere
City of Benicia
City of Calistoga
Town of Corte Madera
City of El Cerrito
Town of Fairfax
City of Larkspur
City of Lafayette
City of Mill Valley
City of Napa
City of Novato
City of Richmond
Town of Ross
Town of San Anselmo
City of San Pablo
City of San Rafael
City of Sausalito
City of St. Helena
Town of Tiburon
City of Walnut Creek
Town of Yountville
County of Marin
County of Napa

Appendix I. MCE's approval for inclusion of Contra Costa

Kathrin Sears, Chair
County of Marin

Tom Butt, Vice Chair
City of Richmond

Bob McCaskill
City of Belvedere

Alan Schwartzman
City of Benicia

Sloan C. Bailey
Town of Corte Madera

Greg Lyman
City of El Cerrito

Barbara Coler
Town of Fairfax

Kevin Haroff
City of Larkspur

Brandt Andersson
City of Lafayette

Sashi McEntee
City of Mill Valley

Brad Wagenknecht
County of Napa

Denise Athas
City of Novato

P. Rupert Russell
Town of Ross

Ford Greene
Town of San Anselmo

Genoveva Calloway
City of San Pablo

Andrew McCullough
City of San Rafael

Ray Withy
City of Sausalito

Emmett O'Donnell
Town of Tiburon

Bob Simmons
City of Walnut Creek

1125 Tamalpais Avenue
San Rafael, CA 94901

1 (888) 632-3674
mceCleanEnergy.org

November 8, 2016

John Kopchik, Director of Conservation and Development
Contra Costa County
30 Muir Road
Martinez, CA 94553

Dear Mr. Kopchik:

As you may be aware, MCE is currently serving customers in many jurisdictions of Contra Costa County with clean electricity choices at competitive rates for customers. We have been in touch with staff representatives from the County and we are familiar with the technical study currently underway to consider community choice options in other parts of the county not currently served. As part of this process MCE has been asked to clarify what the cost and process would be for new jurisdictions interested in joining MCE.

To respond to this request the MCE Board recently held a Special Meeting to discuss the inclusion process and costs for new jurisdictions within the borders of Contra Costa County. We are pleased to inform you that our Board has approved a six-month "inclusion period" that would allow no-cost membership consideration if your membership application is completed between December 1, 2016 and May 31, 2017.

Membership application requirements are attached here and include the following:

- Adoption of a resolution requesting membership
- Adoption of the ordinance required by the Public Utilities Code Section 366.2(c) (10)
- Executed Memorandum of Understanding
- Signed request for load data from PG&E
- County assessor data for all building stock in jurisdiction
- Designation of a staff person from your county to serve as a liaison to MCE

If you are interested in submitting a membership application please notify Alex DiGiorgio, MCE's Community Development Manager, and he will assist you with any questions you may have as you complete the checklist. You can reach Alex by email at: adiorgio@mcecleanenergy.org or by phone at: 415-464-6031.

Please note that (1) adoption of your Ordinance to join MCE will be subject to approval by the MCE Board, and (2) MCE will conduct an economic feasibility analysis prior to approving membership. Also, if membership is approved, timing of procurement and customer enrollment would be determined by the MCE Board. We will remain in close contact with your county about the most likely target dates for each process.

To streamline communications and policy setting, participating jurisdictions may consolidate voting representation on the MCE Board. If you choose this option, the selected representative would have a weighted vote based on the combined customer load of all the jurisdictions which voted to consolidate.

We are happy to meet with you or your council to answer questions or provide additional information. We look forward to the opportunity to work with you on your membership application for MCE service. Please let me know if we can be of any further assistance.

Sincerely,

A handwritten signature in dark ink, appearing to read "Dawn Weisz", with a long, sweeping horizontal line extending to the right.

Dawn Weisz
CEO

Appendix J. EBCE's Joint Powers Agreement

East Bay Community Energy Authority

- Joint Powers Agreement –

Effective _____

Among The Following Parties:

EAST BAY COMMUNITY ENERGY AUTHORITY

JOINT POWERS AGREEMENT

This Joint Powers Agreement (“Agreement”), effective as of _____, is made and entered into pursuant to the provisions of Title 1, Division 7, Chapter 5, Article 1 (Section 6500 *et seq.*) of the California Government Code relating to the joint exercise of powers among the parties set forth in Exhibit A (“Parties”). The term “Parties” shall also include an incorporated municipality or county added to this Agreement in accordance with Section 3.1.

RECITALS

1. The Parties are either incorporated municipalities or counties sharing various powers under California law, including but not limited to the power to purchase, supply, and aggregate electricity for themselves and their inhabitants.
2. In 2006, the State Legislature adopted AB 32, the Global Warming Solutions Act, which mandates a reduction in greenhouse gas emissions in 2020 to 1990 levels. The California Air Resources Board is promulgating regulations to implement AB 32 which will require local government to develop programs to reduce greenhouse gas emissions.
3. The purposes for the Initial Participants (as such term is defined in Section 1.1.16 below) entering into this Agreement include securing electrical energy supply for customers in participating jurisdictions, addressing climate change by reducing energy related greenhouse gas emissions, promoting electrical rate price stability, and fostering local economic benefits such as jobs creation, community energy programs and local power development. It is the intent of this Agreement to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including but not limited to State, regional and local solar and wind energy production.
4. The Parties desire to establish a separate public agency, known as the East Bay Community Energy Authority (“Authority”), under the provisions of the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq.*) (“Act”) in order to collectively study, promote, develop, conduct, operate, and manage energy programs.
5. The Initial Participants have each adopted an ordinance electing to implement through the Authority a Community Choice Aggregation program pursuant to California Public Utilities Code Section 366.2 (“CCA Program”). The first priority of the Authority will be the consideration of those actions necessary to implement the CCA Program.
6. By establishing the Authority, the Parties seek to:
 - (a) Provide electricity rates that are lower or competitive with those offered by PG&E for similar products;

- (b) Offer differentiated energy options (e.g. 33% or 50% qualified renewable) for default service, and a 100% renewable content option in which customers may “opt-up” and voluntarily participate;
- (c) Develop an electric supply portfolio with a lower greenhouse gas (GHG) intensity than PG&E, and one that supports the achievement of the parties’ greenhouse gas reduction goals and the comparable goals of all participating jurisdictions;
- (d) Establish an energy portfolio that prioritizes the use and development of local renewable resources and minimizes the use of unbundled renewable energy credits;
- (e) Promote an energy portfolio that incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals;
- (f) Demonstrate quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);
- (g) Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California. The Authority, as a leader in the shift to a clean energy, commits to ensuring it will take steps to minimize any adverse impacts to these workers to ensure a “just transition” to the new clean energy economy;
- (h) Deliver clean energy programs and projects using a stable, skilled workforce through such mechanisms as project labor agreements, or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;
- (i) Promote personal and community ownership of renewable resources, spurring equitable economic development and increased resilience, especially in low income communities;
- (j) Provide and manage lower cost energy supplies in a manner that provides cost savings to low-income households and promotes public health in areas impacted by energy production; and
- (k) Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize, and providing appropriate wages and benefits.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises, covenants, and conditions hereinafter set forth, it is agreed by and among the Parties as follows:

ARTICLE 1 **CONTRACT DOCUMENTS**

1.1 Definitions. Capitalized terms used in the Agreement shall have the meanings specified below, unless the context requires otherwise.

- 1.1.1** “AB 117” means Assembly Bill 117 (Stat. 2002, ch. 838, codified at Public Utilities Code Section 366.2), which created CCA.
- 1.1.2** “Act” means the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq.*)
- 1.1.3** “Agreement” means this Joint Powers Agreement.
- 1.1.4** “Annual Energy Use” has the meaning given in Section 1.1.23.
- 1.1.5** “Authority” means the East Bay Community Energy Authority established pursuant to this Joint Powers Agreement.
- 1.1.6** “Authority Document(s)” means document(s) duly adopted by the Board by resolution or motion implementing the powers, functions and activities of the Authority, including but not limited to the Operating Rules and Regulations, the annual budget, and plans and policies.
- 1.1.7** “Board” means the Board of Directors of the Authority.
- 1.1.8** “Community Choice Aggregation” or “CCA” means an electric service option available to cities and counties pursuant to Public Utilities Code Section 366.2.
- 1.1.9** “CCA Program” means the Authority’s program relating to CCA that is principally described in Sections 2.4 and 5.1.
- 1.1.10** “Days” shall mean calendar days unless otherwise specified by this Agreement.
- 1.1.11** “Director” means a member of the Board of Directors representing a Party, including an alternate Director.
- 1.1.12** “Effective Date” means the date on which this Agreement shall become effective and the East Bay Community Energy Authority shall exist as a separate public agency, as further described in Section 2.1.

- 1.1.13** “Ex Officio Board Member” means a non-voting member of the Board of Directors as described in Section 4.2.2. The Ex Officio Board Member may not serve on the Executive Committee of the Board or participate in closed session meetings of the Board.
- 1.1.14** “Implementation Plan” means the plan generally described in Section 5.1.2 of this Agreement that is required under Public Utilities Code Section 366.2 to be filed with the California Public Utilities Commission for the purpose of describing a proposed CCA Program.
- 1.1.15** “Initial Costs” means all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as the hiring of a Chief Executive Officer and any administrative staff, any required accounting, administrative, technical and legal services in support of the Authority’s initial formation activities or in support of the negotiation, preparation and approval of power purchase agreements. The Board shall determine the termination date for Initial Costs.
- 1.1.16** “Initial Participants” means, for the purpose of this Agreement the County of Alameda, the Cities of Albany, Berkeley, Emeryville, Oakland, Piedmont, San Leandro, Hayward, Union City, Newark, Fremont, Dublin, Pleasanton and Livermore.
- 1.1.17** “Operating Rules and Regulations” means the rules, regulations, policies, bylaws and procedures governing the operation of the Authority.
- 1.1.18** “Parties” means, collectively, the signatories to this Agreement that have satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.
- 1.1.19** “Party” means, singularly, a signatory to this Agreement that has satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.
- 1.1.20** “Percentage Vote” means a vote taken by the Board pursuant to Section 4.12.1 that is based on each Party having one equal vote.
- 1.1.21** “Total Annual Energy” has the meaning given in Section 1.1.23.
- 1.1.22** “Voting Shares Vote” means a vote taken by the Board pursuant to Section 4.12.2 that is based on the voting shares of each Party described in Section 1.1.23 and set forth in Exhibit C to this Agreement. A Voting Shares vote cannot take place on a matter unless the matter first receives an affirmative or tie Percentage Vote in the manner required by Section 4.12.1 and three or more Directors immediately thereafter request such vote.

1.1.23 “Voting Shares Formula” means the weight applied to a Voting Shares Vote and is determined by the following formula:

(Annual Energy Use/Total Annual Energy) multiplied by 100, where (a) “Annual Energy Use” means (i) with respect to the first two years following the Effective Date, the annual electricity usage, expressed in kilowatt hours (“kWh”), within the Party’s respective jurisdiction and (ii) with respect to the period after the second anniversary of the Effective Date, the annual electricity usage, expressed in kWh, of accounts within a Party’s respective jurisdiction that are served by the Authority and (b) “Total Annual Energy” means the sum of all Parties’ Annual Energy Use. The initial values for Annual Energy use are designated in Exhibit B and the initial voting shares are designated in Exhibit C. Both Exhibits B and C shall be adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 of each year subject to the approval of the Board.

1.2 Documents Included. This Agreement consists of this document and the following exhibits, all of which are hereby incorporated into this Agreement.

- Exhibit A: List of the Parties
- Exhibit B: Annual Energy Use
- Exhibit C: Voting Shares

1.3 Revision of Exhibits. The Parties agree that Exhibits A, B and C to this Agreement describe certain administrative matters that may be revised upon the approval of the Board, without such revision constituting an amendment to this Agreement, as described in Section 8.4. The Authority shall provide written notice to the Parties of the revision of any such exhibit.

ARTICLE 2

FORMATION OF EAST BAY COMMUNITY ENERGY AUTHORITY

2.1 Effective Date and Term. This Agreement shall become effective and East Bay Community Energy Authority shall exist as a separate public agency on December 1, 2016, provided that this Agreement is executed on or prior to such date by at least three Initial Participants after the adoption of the ordinances required by Public Utilities Code Section 366.2(c)(12). The Authority shall provide notice to the Parties of the Effective Date. The Authority shall continue to exist, and this Agreement shall be effective, until this Agreement is terminated in accordance with Section 7.3, subject to the rights of the Parties to withdraw from the Authority.

2.2 Initial Participants. Until December 31, 2016, all other Initial Participants may become a Party by executing this Agreement and delivering an executed copy of this Agreement and a copy of the adopted ordinance required by Public Utilities Code Section 366.2(c)(12) to the Authority. Additional conditions, described in Section 3.1, may apply (i) to either an incorporated municipality or county desiring to become a Party that is not an Initial Participant and (ii) to Initial Participants that have not executed and delivered this Agreement within the time period described above.

2.3 Formation. There is formed as of the Effective Date a public agency named the East Bay Community Energy Authority. Pursuant to Sections 6506 and 6507 of the Act, the Authority is a public agency separate from the Parties. The debts, liabilities or obligations of the Authority shall not be debts, liabilities or obligations of the individual Parties unless the governing board of a Party agrees in writing to assume any of the debts, liabilities or obligations of the Authority. A Party who has not agreed to assume an Authority debt, liability or obligation shall not be responsible in any way for such debt, liability or obligation even if a majority of the Parties agree to assume the debt, liability or obligation of the Authority. Notwithstanding Section 8.4 of this Agreement, this Section 2.3 may not be amended unless such amendment is approved by the governing boards of all Parties.

2.4 Purpose. The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party and any other powers granted to the Authority under state law to participate as a group in the CCA Program pursuant to Public Utilities Code Section 366.2(c)(12); to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs; and, to exercise all other powers necessary and incidental to accomplishing this purpose.

2.5 Powers. The Authority shall have all powers common to the Parties and such additional powers accorded to it by law. The Authority is authorized, in its own name, to exercise all powers and do all acts necessary and proper to carry out the provisions of this Agreement and fulfill its purposes, including, but not limited to, each of the following:

- 2.5.1** to make and enter into contracts, including those relating to the purchase or sale of electrical energy or attributes thereof;
- 2.5.2** to employ agents and employees, including but not limited to a Chief Executive Officer and General Counsel;
- 2.5.3** to acquire, contract, manage, maintain, and operate any buildings, works or improvements, including electric generating facilities;
- 2.5.4** to acquire property by eminent domain, or otherwise, except as limited under Section 6508 of the Act, and to hold or dispose of any property;
- 2.5.5** to lease any property;
- 2.5.6** to sue and be sued in its own name;

- 2.5.7 to incur debts, liabilities, and obligations, including but not limited to loans from private lending sources pursuant to its temporary borrowing powers such as Government Code Section 53850 *et seq.* and authority under the Act;
- 2.5.8 to form subsidiary or independent corporations or entities, if appropriate, to carry out energy supply and energy conservation programs at the lowest possible cost consistent with the Authority's CCA Program implementation plan, risk management policies, or to take advantage of legislative or regulatory changes;
- 2.5.9 to issue revenue bonds and other forms of indebtedness;
- 2.5.10 to apply for, accept, and receive all licenses, permits, grants, loans or other assistance from any federal, state or local public agency;
- 2.5.11 to submit documentation and notices, register, and comply with orders, tariffs and agreements for the establishment and implementation of the CCA Program and other energy programs;
- 2.5.12 to adopt rules, regulations, policies, bylaws and procedures governing the operation of the Authority ("Operating Rules and Regulations");
- 2.5.13 to make and enter into service, energy and any other agreements necessary to plan, implement, operate and administer the CCA Program and other energy programs, including the acquisition of electric power supply and the provision of retail and regulatory support services; and
- 2.5.14 to negotiate project labor agreements, community benefits agreements and collective bargaining agreements with the local building trades council and other interested parties.

2.6 Limitation on Powers. As required by Government Code Section 6509, the power of the Authority is subject to the restrictions upon the manner of exercising power possessed by the City of Emeryville and any other restrictions on exercising the powers of the Authority that may be adopted by the Board.

2.7 Compliance with Local Zoning and Building Laws. Notwithstanding any other provisions of this Agreement or state law, any facilities, buildings or structures located, constructed or caused to be constructed by the Authority within the territory of the Authority shall comply with the General Plan, zoning and building laws of the local jurisdiction within which the facilities, buildings or structures are constructed and comply with the California Environmental Quality Act ("CEQA").

2.8 Compliance with the Brown Act. The Authority and its officers and employees shall comply with the provisions of the Ralph M. Brown Act, Government Code Section 54950 *et seq.*

2.9 Compliance with the Political Reform Act and Government Code Section 1090. The Authority and its officers and employees shall comply with the Political Reform Act (Government Code Section 81000 *et seq.*) and Government Code Section 1090 *et seq.*, and shall adopt a Conflict of Interest Code pursuant to Government Code Section 87300. The Board of Directors may adopt additional conflict of interest regulations in the Operating Rules and Regulations.

ARTICLE 3 **AUTHORITY PARTICIPATION**

3.1 Addition of Parties. Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption by an affirmative vote of a majority of all Directors of the entire Board satisfying the requirements described in Section 4.12, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(12) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership fee, if any, and (e) satisfaction of any conditions established by the Board.

3.2 Continuing Participation. The Parties acknowledge that membership in the Authority may change by the addition and/or withdrawal or termination of Parties. The Parties agree to participate with such other Parties as may later be added, as described in Section 3.1. The Parties also agree that the withdrawal or termination of a Party shall not affect this Agreement or the remaining Parties' continuing obligations under this Agreement.

ARTICLE 4 **GOVERNANCE AND INTERNAL ORGANIZATION**

4.1 Board of Directors. The governing body of the Authority shall be a Board of Directors ("Board") consisting of one director for each Party appointed in accordance with Section 4.2.

4.2 Appointment of Directors. The Directors shall be appointed as follows:

4.2.1 The governing body of each Party shall appoint and designate in writing one regular Director who shall be authorized to act for and on behalf of the Party on matters within the powers of the Authority. The governing body of each Party also shall appoint and designate in writing one alternate Director who may vote on matters when the regular Director is absent

from a Board meeting. The person appointed and designated as the regular Director shall be a member of the governing body of the Party. The person appointed and designated as the alternate Director shall also be a member of the governing body of the Party.

- 4.2.2 The Board shall also include one non-voting ex officio member as defined in Section 1.1.13 (“Ex Officio Board Member”). The Chair of the Community Advisory Committee, as described in Section 4.9 below, shall serve as the Ex Officio Board Member. The Vice Chair of the Community Advisory Committee shall serve as an alternate Ex Officio Board Member when the regular Ex Officio Board Member is absent from a Board meeting.
- 4.2.3 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.12 may include rules regarding Directors, such as meeting attendance requirements. No Party shall be deprived of its right to seat a Director on the Board.

4.3 Terms of Office. Each regular and alternate Director shall serve at the pleasure of the governing body of the Party that the Director represents, and may be removed as Director by such governing body at any time. If at any time a vacancy occurs on the Board, a replacement shall be appointed to fill the position of the previous Director in accordance with the provisions of Section 4.2 within 90 days of the date that such position becomes vacant.

4.4 Quorum. A majority of the Directors of the entire Board shall constitute a quorum, except that less than a quorum may adjourn a meeting from time to time in accordance with law.

4.5 Powers and Function of the Board. The Board shall conduct or authorize to be conducted all business and activities of the Authority, consistent with this Agreement, the Authority Documents, the Operating Rules and Regulations, and applicable law. Board approval shall be required for any of the following actions, which are defined as “Essential Functions”:

- 4.5.1 The issuance of bonds or any other financing even if program revenues are expected to pay for such financing.
- 4.5.2 The hiring of a Chief Executive Officer and General Counsel.
- 4.5.3 The appointment or removal of an officer.
- 4.5.4 The adoption of the Annual Budget.
- 4.5.5 The adoption of an ordinance.
- 4.5.6 The initiation of resolution of claims and litigation where the Authority will be the defendant, plaintiff, petitioner, respondent, cross complainant or cross petitioner, or intervenor; provided, however, that the Chief Executive Officer or General Counsel, on behalf of the Authority, may

intervene in, become party to, or file comments with respect to any proceeding pending at the California Public Utilities Commission, the Federal Energy Regulatory Commission, or any other administrative agency, without approval of the Board. The Board shall adopt Operating Rules and Regulations governing the Chief Executive Officer and General Counsel's exercise of authority under this Section 4.5.6.

4.5.7 The setting of rates for power sold by the Authority and the setting of charges for any other category of service provided by the Authority.

4.5.8 Termination of the CCA Program.

4.6 Executive Committee. The Board shall establish an Executive Committee consisting of a smaller number of Directors. The Board may delegate to the Executive Committee such authority as the Board might otherwise exercise, subject to limitations placed on the Board's authority to delegate certain Essential Functions, as described in Section 4.5 and the Operating Rules and Regulations. The Board may not delegate to the Executive Committee or any other committee its authority under Section 2.5.12 to adopt and amend the Operating Rules and Regulations or its Essential Functions listed in Section 4.5. After the Executive Committee meets or otherwise takes action, it shall, as soon as practicable, make a report of its activities at a meeting of the Board.

4.7 Director Compensation. Directors shall receive a stipend of \$100 per meeting, as adjusted to account for inflation, as provided for in the Authority's Operating Rules and Regulations.

4.8 Commissions, Boards and Committees. The Board may establish any advisory commissions, boards and committees as the Board deems appropriate to assist the Board in carrying out its functions and implementing the CCA Program, other energy programs and the provisions of this Agreement. The Board may establish rules, regulations, policies, bylaws or procedures to govern any such commissions, boards, or committees and shall determine whether members shall be compensated or entitled to reimbursement for expenses.

4.9 Community Advisory Committee. The Board shall establish a Community Advisory Committee consisting of nine members, none of whom may be voting members of the Board. The function of the Community Advisory Committee shall be to advise the Board of Directors on all subjects related to the operation of the CCA Program as set forth in a work plan adopted by the Board of Directors from time to time, with the exception of personnel and litigation decisions. The Community Advisory Committee is advisory only, and shall not have decision-making authority, or receive any delegation of authority from the Board of Directors. The Board shall publicize the opportunity to serve on the Community Advisory Committee, and shall appoint members of the Community Advisory Committee from those individuals expressing interest in serving, and who represent a diverse cross-section of interests, skill sets and geographic regions. Members of the Community Advisory Committee shall serve staggered four-year terms (the first term of three of the members shall be two years, and four years

thereafter), which may be renewed. A member of the Community Advisory Committee may be removed by the Board of Directors by majority vote. The Board of Directors shall determine whether the Community Advisory Committee members will receive a stipend and/or be entitled to reimbursement for expenses.

4.10 Chief Executive Officer. The Board of Directors shall appoint a Chief Executive Officer for the Authority, who shall be responsible for the day-to-day operation and management of the Authority and the CCA Program. The Chief Executive Officer may exercise all powers of the Authority, including the power to hire, discipline and terminate employees as well as the power to approve any agreement, if the expenditure is authorized in the Authority's approved budget, except the powers specifically set forth in Section 4.5 or those powers which by law must be exercised by the Board of Directors. The Board of Directors shall provide procedures and guidelines for the Chief Executive Officer exercising the powers of the Authority in the Operating Rules and Regulations.

4.11 General Counsel. The Board of Directors shall appoint a General Counsel for the Authority, who shall be responsible for providing legal advice to the Board of Directors and overseeing all legal work for the Authority.

4.12 Board Voting.

4.12.1 Percentage Vote. Except when a supermajority vote is expressly required by this Agreement or the Operating Rules and Regulations, action of the Board on all matters shall require an affirmative vote of a majority of all Directors on the entire Board (a "Percentage Vote" as defined in Section 1.1.20). A supermajority vote is required by this Agreement for the matters addressed by Section 8.4. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, action of the Board shall require an affirmative Percentage Vote of the specified supermajority of all Directors on the entire Board. No action can be taken by the Board without an affirmative Percentage Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved by an affirmative "Voting Shares Vote," as defined in Section 1.1.22, if three or more Directors immediately request such vote.

4.12.2 Voting Shares Vote. In addition to and immediately after an affirmative percentage vote, three or more Directors may request that, a vote of the voting shares shall be held (a "Voting Shares Vote" as defined in Section 1.1.22). To approve an action by a Voting Shares Vote, the corresponding voting shares (as defined in Section 1.1.23 and Exhibit C) of all Directors voting in the affirmative shall exceed 50% of the voting share of all Directors on the entire Board, or such other higher voting shares percentage expressly required by this Agreement or the Operating Rules

and Regulations. In the event that any one Director has a voting share that equals or exceeds that which is necessary to disapprove the matter being voted on by the Board, at least one other Director shall be required to vote in the negative in order to disapprove such matter. When a voting shares vote is held, action by the Board requires both an affirmative Percentage Vote and an affirmative Voting Shares Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved on an affirmative Voting Shares Vote. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, the supermajority vote is subject to the Voting Share Vote provisions of this Section 4.12.2, and the specified supermajority of all Voting Shares is required for approval of the action, if the provision of this Section 4.12.2 are triggered.

4.13 Meetings and Special Meetings of the Board. The Board shall hold at least four regular meetings per year, but the Board may provide for the holding of regular meetings at more frequent intervals. The date, hour and place of each regular meeting shall be fixed by resolution or ordinance of the Board. Regular meetings may be adjourned to another meeting time. Special and Emergency meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956 and 54956.5. Directors may participate in meetings telephonically, with full voting rights, only to the extent permitted by law.

4.14 Officers.

4.14.1 Chair and Vice Chair. At the first meeting held by the Board in each calendar year, the Directors shall elect, from among themselves, a Chair, who shall be the presiding officer of all Board meetings, and a Vice Chair, who shall serve in the absence of the Chair. The Chair and Vice Chair shall hold office for one year and serve no more than two consecutive terms, however, the total number of terms a Director may serve as Chair or Vice Chair is not limited. The office of either the Chair or Vice Chair shall be declared vacant and the Board shall make a new selection if: (a) the person serving dies, resigns, or ceases to be a member of the governing body of the Party that the person represents; (b) the Party that the person represents removes the person as its representative on the Board, or (c) the Party that he or she represents withdraws from the Authority pursuant to the provisions of this Agreement.

4.14.2 Secretary. The Board shall appoint a Secretary, who need not be a member of the Board, who shall be responsible for keeping the minutes of all meetings of the Board and all other official records of the Authority.

4.14.3 Treasurer and Auditor. The Board shall appoint a qualified person to act as the Treasurer and a qualified person to act as the Auditor, neither of whom needs to be a member of the Board. The same person may not simultaneously hold both the office of Treasurer and the office of the Auditor of the Authority. Unless otherwise exempted from such

requirement, the Authority shall cause an independent audit to be made annually by a certified public accountant, or public accountant, in compliance with Section 6505 of the Act. The Treasurer shall act as the depositary of the Authority and have custody of all the money of the Authority, from whatever source, and as such, shall have all of the duties and responsibilities specified in Section 6505.5 of the Act. The Board may require the Treasurer and/or Auditor to file with the Authority an official bond in an amount to be fixed by the Board, and if so requested, the Authority shall pay the cost of premiums associated with the bond. The Treasurer shall report directly to the Board and shall comply with the requirements of treasurers of incorporated municipalities. The Board may transfer the responsibilities of Treasurer to any person or entity as the law may provide at the time.

4.15 Administrative Services Provider. The Board may appoint one or more administrative services providers to serve as the Authority's agent for planning, implementing, operating and administering the CCA Program, and any other program approved by the Board, in accordance with the provisions of an Administrative Services Agreement. The appointed administrative services provider may be one of the Parties. The Administrative Services Agreement shall set forth the terms and conditions by which the appointed administrative services provider shall perform or cause to be performed all tasks necessary for planning, implementing, operating and administering the CCA Program and other approved programs. The Administrative Services Agreement shall set forth the term of the Agreement and the circumstances under which the Administrative Services Agreement may be terminated by the Authority. This section shall not in any way be construed to limit the discretion of the Authority to hire its own employees to administer the CCA Program or any other program.

4.16 Operational Audit. The Authority shall commission an independent agent to conduct and deliver at a public meeting of the Board an evaluation of the performance of the CCA Program relative to goals for renewable energy and carbon reductions. The Authority shall approve a budget for such evaluation and shall hire a firm or individual that has no other direct or indirect business relationship with the Authority. The evaluation shall be conducted at least once every two years.

ARTICLE 5

IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 Implementation of the CCA Program.

5.1.1 Enabling Ordinance. Prior to the execution of this Agreement, each Party shall adopt an ordinance in accordance with Public Utilities Code Section 366.2(c)(12) for the purpose of specifying that the Party intends to implement a CCA Program by and through its participation in the Authority.

5.1.2 Implementation Plan. The Authority shall cause to be prepared an Implementation Plan meeting the requirements of Public Utilities Code Section 366.2 and any applicable Public Utilities Commission regulations as soon after the Effective Date as reasonably practicable. The Implementation Plan shall not be filed with the Public Utilities Commission until it is approved by the Board in the manner provided by Section 4.12.

5.1.3 Termination of CCA Program. Nothing contained in this Article or this Agreement shall be construed to limit the discretion of the Authority to terminate the implementation or operation of the CCA Program at any time in accordance with any applicable requirements of state law.

5.2 Other Authority Documents. The Parties acknowledge and agree that the operations of the Authority will be implemented through various documents duly adopted by the Board through Board resolution or minute action, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies defined as the Authority Documents by this Agreement. The Parties agree to abide by and comply with the terms and conditions of all such Authority Documents that may be adopted by the Board, subject to the Parties' right to withdraw from the Authority as described in Article 7.

5.3 Integrated Resource Plan. The Authority shall cause to be prepared an Integrated Resource Plan in accordance with CPUC regulations that will ensure the long-term development and administration of a variety of energy programs that promote local renewable resources, conservation, demand response, and energy efficiency, while maintaining compliance with the State Renewable Portfolio standard and customer rate competitiveness. The Authority shall prioritize the development of energy projects in Alameda and adjacent counties. Principal aspects of its planned operations shall be in a Business Plan as outlined in Section 5.4 of this Agreement.

5.4 Business Plan. The Authority shall cause to be prepared a Business Plan, which will include a roadmap for the development, procurement, and integration of local renewable energy resources as outlined in Section 5.3 of this Agreement. The Business Plan shall include a description of how the CCA Program will contribute to fostering local economic benefits, such as job creation and community energy programs. The Business Plan shall identify opportunities for local power development and how the CCA Program can achieve the goals outlined in Recitals 3 and 6 of this Agreement. The Business Plan shall include specific language detailing employment and labor standards that relate to the execution of the CCA Program as referenced in this Agreement. The Business Plan shall identify clear and transparent marketing practices to be followed by the CCA Program, including the identification of the sources of its electricity and explanation of the various types of electricity procured by the Authority. The Business Plan shall cover the first five (5) years of the operation of the CCA Program. The Business Plan shall be completed by the Authority no later than eight (8) months after the seating of the Authority Board of Directors. Progress on the implementation of the Business Plan shall be subject to annual public review.

5.5 Labor Organization Neutrality. The Authority shall remain neutral in the event its employees, and the employees of its subcontractors, if any, wish to unionize.

5.6 Renewable Portfolio Standards. The Authority shall provide its customers energy primarily from Category 1 eligible renewable resources, as defined under the California RPS and consistent with the goals of the CCA Program. The Authority shall not procure energy from Category 3 eligible renewable resources (unbundled Renewable Energy Credits or RECs) exceeding 50% of the State law requirements, to achieve its renewable portfolio goals. However, for Category 3 RECs associated with generation facilities located within its service jurisdiction, the limitation set forth in the preceding sentence shall not apply.

ARTICLE 6

FINANCIAL PROVISIONS

6.1 Fiscal Year. The Authority's fiscal year shall be 12 months commencing July 1 and ending June 30. The fiscal year may be changed by Board resolution.

6.2 Depository.

6.2.1 All funds of the Authority shall be held in separate accounts in the name of the Authority and not commingled with funds of any Party or any other person or entity.

6.2.2 All funds of the Authority shall be strictly and separately accounted for, and regular reports shall be rendered of all receipts and disbursements, at least quarterly during the fiscal year. The books and records of the Authority shall be open to inspection by the Parties at all reasonable times.

6.2.3 All expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its Operating Rules and Regulations. The Treasurer shall draw checks or warrants or make payments by other means for claims or disbursements not within an applicable budget only upon the prior approval of the Board.

6.3 Budget and Recovery Costs.

6.3.1 Budget. The initial budget shall be approved by the Board. The Board may revise the budget from time to time through an Authority Document as may be reasonably necessary to address contingencies and unexpected expenses. All subsequent budgets of the Authority shall be prepared and approved by the Board in accordance with the Operating Rules and Regulations.

6.3.2 Funding of Initial Costs. The County shall fund the Initial Costs of establishing and implementing the CCA Program. In the event that the

CCA Program becomes operational, these Initial Costs paid by the County and any specified interest shall be included in the customer charges for electric services to the extent permitted by law, and the County shall be reimbursed from the payment of such charges by customers of the Authority. The Authority may establish a reasonable time period over which such costs are recovered. In the event that the CCA Program does not become operational, the County shall not be entitled to any reimbursement of the Initial Costs.

- 6.3.4 Additional Contributions and Advances.** Pursuant to Government Code Section 6504, the Parties may in their sole discretion make financial contributions, loans or advances to the Authority for the purposes of the Authority set forth in this Agreement. The repayment of such contributions, loans or advances will be on the written terms agreed to by the Party making the contribution, loan or advance and the Authority.

ARTICLE 7

WITHDRAWAL AND TERMINATION

7.1 Withdrawal.

- 7.1.1 General Right to Withdraw.** A Party may withdraw its membership in the Authority, effective as of the beginning of the Authority's fiscal year, by giving no less than 180 days advance written notice of its election to do so, which notice shall be given to the Authority and each Party. Withdrawal of a Party shall require an affirmative vote of the Party's governing board.
- 7.1.2 Withdrawal Following Amendment.** Notwithstanding Section 7.1.1, a Party may withdraw its membership in the Authority following an amendment to this Agreement provided that the requirements of this Section 7.1.2 are strictly followed. A Party shall be deemed to have withdrawn its membership in the Authority effective 180 days after the Board approves an amendment to this Agreement if the Director representing such Party has provided notice to the other Directors immediately preceding the Board's vote of the Party's intention to withdraw its membership in the Authority should the amendment be approved by the Board.
- 7.1.3 The Right to Withdraw Prior to Program Launch.** After receiving bids from power suppliers for the CCA Program, the Authority must provide to the Parties a report from the electrical utility consultant retained by the Authority comparing the Authority's total estimated electrical rates, the estimated greenhouse gas emissions rate and the amount of estimated renewable energy to be used with that of the incumbent utility. Within 30 days after receiving this report, through its City Manager or a person expressly authorized by the Party, any Party may immediately withdraw

its membership in the Authority by providing written notice of withdrawal to the Authority if the report determines that any one of the following conditions exists: (1) the Authority is unable to provide total electrical rates, as part of its baseline offering to customers, that are equal to or lower than the incumbent utility, (2) the Authority is unable to provide electricity in a manner that has a lower greenhouse gas emissions rate than the incumbent utility, or (3) the Authority will use less qualified renewable energy than the incumbent utility. Any Party who withdraws from the Authority pursuant to this Section 7.1.3 shall not be entitled to any refund of the Initial Costs it has paid to the Authority prior to the date of withdrawal unless the Authority is later terminated pursuant to Section 7.3. In such event, any Initial Costs not expended by the Authority shall be returned to all Parties, including any Party that has withdrawn pursuant to this section, in proportion to the contribution that each made. Notwithstanding anything to the contrary in this Agreement, any Party who withdraws pursuant to this section shall not be responsible for any liabilities or obligations of the Authority after the date of withdrawal, including without limitation any liability arising from power purchase agreements entered into by the Authority.

7.2 Continuing Liability After Withdrawal; Further Assurances; Refund. A Party that withdraws its membership in the Authority under either Section 7.1.1 or 7.1.2 shall be responsible for paying its fair share of costs incurred by the Authority resulting from the Party's withdrawal, including costs from the resale of power contracts by the Authority to serve the Party's load and any similar costs directly attributable to the Party's withdrawal, such costs being limited to those contracts executed while the withdrawing Party was a member, and administrative costs associated thereto. The Parties agree that such costs shall not constitute a debt of the withdrawing Party, accruing interest, or having a maturity date. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's costs described above. Any amount of the Party's funds held by the Authority for the benefit of the Party that are not required to pay the Party's costs described above shall be returned to the Party. The withdrawing party and the Authority shall execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, as determined by the Board, to effectuate the orderly withdrawal of such Party from membership in the Authority. A withdrawing party has the right to continue to participate in Board discussions and decisions affecting customers of the CCA Program that reside or do business within the jurisdiction of the Party until the withdrawal's effective date.

7.3 Mutual Termination. This Agreement may be terminated by mutual agreement of all the Parties; provided, however, the foregoing shall not be construed as limiting the rights of a Party to withdraw its membership in the Authority, and thus terminate this Agreement with respect to such withdrawing Party, as described in Section 7.1.

7.4 Disposition of Property upon Termination of Authority. Upon termination of this Agreement as to all Parties, any surplus money or assets in possession of the Authority for use under this Agreement, after payment of all liabilities, costs, expenses, and charges incurred

under this Agreement and under any Authority Documents, shall be returned to the then-existing Parties in proportion to the contributions made by each.

ARTICLE 8

MISCELLANEOUS PROVISIONS

8.1 Dispute Resolution. The Parties and the Authority shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Before exercising any remedy provided by law, a Party or the Parties and the Authority shall engage in nonbinding mediation in the manner agreed upon by the Party or Parties and the Authority. The Parties agree that each Party may specifically enforce this section 8.1. In the event that nonbinding mediation is not initiated or does not result in the settlement of a dispute within 120 days after the demand for mediation is made, any Party and the Authority may pursue any remedies provided by law.

8.2 Liability of Directors, Officers, and Employees. The Directors, officers, and employees of the Authority shall use ordinary care and reasonable diligence in the exercise of their powers and in the performance of their duties pursuant to this Agreement. No current or former Director, officer, or employee will be responsible for any act or omission by another Director, officer, or employee. The Authority shall defend, indemnify and hold harmless the individual current and former Directors, officers, and employees for any acts or omissions in the scope of their employment or duties in the manner provided by Government Code Section 995 *et seq.* Nothing in this section shall be construed to limit the defenses available under the law, to the Parties, the Authority, or its Directors, officers, or employees.

8.3 Indemnification of Parties. The Authority shall acquire such insurance coverage as the Board deems necessary to protect the interests of the Authority, the Parties and the public. Such insurance coverage shall name the Parties and their respective Board or Council members, officers, agents and employees as additional insureds. The Authority shall defend, indemnify and hold harmless the Parties and each of their respective Board or Council members, officers, agents and employees, from any and all claims, losses, damages, costs, injuries and liabilities of every kind arising directly or indirectly from the conduct, activities, operations, acts, and omissions of the Authority under this Agreement.

8.4 Amendment of this Agreement. This Agreement may be amended in writing by a two-thirds affirmative vote of the entire Board satisfying the requirements described in Section 4.12. Except that, any amendment to the voting provisions in Section 4.12 may only be made by a three-quarters affirmative vote of the entire Board. The Authority shall provide written notice to the Parties at least 30 days in advance of any proposed amendment being considered by the Board. If the proposed amendment is adopted by the Board, the Authority shall provide prompt written notice to all Parties of the effective date of such amendment along with a copy of the amendment.

8.5 Assignment. Except as otherwise expressly provided in this Agreement, the rights and duties of the Parties may not be assigned or delegated without the advance written consent of all of the other Parties, and any attempt to assign or delegate such rights or duties in contravention of this Section 8.5 shall be null and void. This Agreement shall inure to the benefit of, and be binding upon, the successors and assigns of the Parties. This Section 8.5 does not prohibit a Party from entering into an independent agreement with another agency, person, or entity regarding the financing of that Party's contributions to the Authority, or the disposition of proceeds which that Party receives under this Agreement, so long as such independent agreement does not affect, or purport to affect, the rights and duties of the Authority or the Parties under this Agreement.

8.6 Severability. If one or more clauses, sentences, paragraphs or provisions of this Agreement shall be held to be unlawful, invalid or unenforceable, it is hereby agreed by the Parties, that the remainder of the Agreement shall not be affected thereby. Such clauses, sentences, paragraphs or provision shall be deemed reformed so as to be lawful, valid and enforced to the maximum extent possible.

8.7 Further Assurances. Each Party agrees to execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, to effectuate the purposes and intent of this Agreement.

8.8 Execution by Counterparts. This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

8.9 Parties to be Served Notice. Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 72 hours after the deposit thereof (excluding Saturdays, Sundays and holidays) if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. In addition, a duplicate copy of all notices provided pursuant to this section shall be provided to the Director and alternate Director for each Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties. All notices required hereunder shall be delivered to:

The County of Alameda

Director, Community Development Agency

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to [PARTY No. ____]

Office of the City Clerk

Office of the City Manager/Administrator

Office of the City Attorney

if to [PARTY No.____]

Office of the City Clerk

Office of the City Manager/Administrator

Office of the City Attorney

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: _____

Name: _____

Title: _____

Date: _____

Party: _____

EXHIBIT A

-LIST OF THE PARTIES

(This draft exhibit is based on the assumption that all of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)-

-

DRAFT EXHIBIT B

-ANNUAL ENERGY USE

(This draft exhibit is based on the assumption that all of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)

This Exhibit B is effective as of _____.

Party	kWh ([YEAR]*)
--------------	----------------------

*Data provided by PG&E

DRAFT EXHIBIT C

- VOTING SHARES

(This draft exhibit is based on the assumption that all of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)

This Exhibit C is effective as of _____.

Party	kWh ([YEAR]*)	Voting Share Section 4.11.2
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Total

*Data provided by PG&E

Appendix K. EBCE's offer for inclusion of Contra Costa



February 21, 2017

John Kopchik
Director, Department of Conservation and Development
Contra Costa County
30 Muir Street
Martinez, CA 94553

Dear Mr. Kopchik:

This letter is in response to your request for East Bay Community Energy (EBCE) to indicate its desire to expand beyond Alameda County and its willingness to engage interested Contra Costa County jurisdictions as EBCE members. This letter also outlines the terms of EBCE membership.

As you may know, the EBCE Board of Directors met for the first time on January 30, 2017. During that meeting, the Board had a robust discussion on this topic and was strongly in favor of formally inviting Contra Costa County and its Cities to join EBCE. The general sense was that it would be an exciting and positive development to have a more regionally focused East Bay Community Choice Energy (CCE) program. Some EBCE Board members expressed a willingness to present at your upcoming Board of Supervisors and City Council meetings as Contra Costa County officials deliberate on which CCE option would be in the best interests of their constituents.

With regards to the terms of membership, the EBCE Board discussed each of the points your letter raised, and we can provide you the following feedback:

- **Cost to Join:** The Board agreed that there would be no cost for Contra Costa County jurisdictions to join the JPA. EBCE will absorb all of the initial launch expenses, including load data analysis, communications costs and noticing requirements. The Board believes these one-time costs are offset by the longer-term value of including Contra Costa County communities in order to form a larger, regional program. We do request, however, that new member jurisdictions identify appropriate municipal staff to assist in coordinating the JPA resolution and Agreement, passage of the CCE ordinance and help with local public outreach, such as organizing workshops and having a presence at community events.
- **Required actions and steps in the membership process:** The Board agreed that the steps for joining EBCE would be the same as for the Alameda County jurisdictions, namely that the prospective members must pass the required CCA ordinance, authorize access to their load data, hold at least two duly noticed public hearings, and pass the JPA resolution in order to become a party to the EBCE Joint Powers Agreement. A copy of the CCE ordinance, JPA Agreement and JPA resolution are attached for your reference. For the purposes of completing EBCE's implementation plan, conducting public outreach, and procuring power for customers in new member jurisdictions, we request that interested jurisdictions cast deciding votes by June 30, 2017. It should be noted that there will be additional opportunities to join EBCE in 2018, if that is preferred. See below for more information regarding timing.

Letter to John Kopchik, Director
Department of Conservation and Development
Contra Costa County
February 21, 2017

- **Representation on EBCE Board:** Each Contra Costa County jurisdiction choosing to join EBCE will have a seat on its Board, which is the same manner of representation as other Alameda County members. As you may know, EBCE has a two-tiered voting structure, the first being one-city/one-vote with simple majority to carry the vote. In this case, every jurisdiction will have one equal vote, and it is anticipated that most votes will proceed in this fashion. However, if at least three members call for a weighted vote, then each city's voting share would be determined by its electrical load; weighted votes may only be used to overturn an affirmative vote and may not be used to resurrect or overturn a negative vote. Please see Attachment 4 for a comparison of EBCE and CCCo jurisdictional loads. New Board members can be seated once the JPA resolution has been passed, and the first and second readings of the CCE ordinance are complete.
- **Estimated date of service commencement:** Your letter asked for a date when electric service could begin. As of this writing, it is likely that EBCE will begin serving Phase 1 customers (a subset of the total number of accounts) in Spring of 2018. Phase 2 customers, including additional Contra Costa County accounts, would be enrolled in the Summer or Fall of 2018. Cities that join after the June 30th deadline or in 2018 will be enrolled in Phase 3, likely to be the late Fall of 2018 or Spring of 2019.

The EBCE Board is excited about the prospect of creating a regional East Bay Community Energy program. A member of our Board and Alameda County interim staff will attempt to attend as many of your upcoming presentations as possible, including the Board of Supervisors meeting on March 21. If possible, we would very much like the opportunity to make a more formal presentation at that meeting if the Contra Costa County Board of Supervisors and staff are agreeable.

Finally, for the purposes of planning, it would be helpful to know how many Contra Costa County jurisdictions would be interested in joining EBCE. As noted above, we are requesting that the County and any interested cities complete their decision-making and passage of the required resolution and ordinance by June 30, 2017 if they are interested in a Spring/Summer 2018 enrollment period.

We hope this addresses your questions on behalf of Contra Costa County and interested cities. Please don't hesitate to contact us if you'd like to discuss any of these matters further.

Sincerely Yours,



Chris Bazar
Director, Alameda County Community Development Agency

Cc: EBCE Board of Directors

Attachments:

- 1) EBCE JPA Agreement and sample resolution
- 2) Copy of CCE ordinance
- 3) PG&E Attestation form for load data authorization
- 4) Load size / voting shares comparison by jurisdiction

AGENDA ITEM REQUEST FORM

Department: City Manager's Office

Department Director: David Biggs

Phone: 799-8216

Meeting Date: September 27, 2016

Final Decision Date Deadline: 9/27/2016

SUBJECT:
PG & E Solar Choice Program

INDICATE APPROPRIATE BODY

☒ City
Council

☐ Successor Agency to the
Redevelopment Agency

☐ Public Finance
Authority

☐ Finance
Commission

☐ Planning
Commission

☐ Community/Library
Services Commission

☐ Oversight Board

☐ Other _____

ITEM

☐ Presentation/Introduction

☐ Study Session

☐ Grant Application/Acceptance

☐ Public Hearing

☐ Resolution

☐ Video/PowerPoint

☐ Consent Calendar

☐ Ordinance

☒ Discussion Action

☐ Contract/Agreement

RECOMMENDED ACTION:

Discuss and Provide Direction, if any.

☐ Copy of executed Resolution/Ordinance/Contract/Application required immediately upon approval.

REVIEWED AND APPROVED FOR AGENDA:

City Attorney (if Contract, Ordinance or Resolution)

Patrick Tany 9.22.16.
Signature Date

Finance Department for Fiscal Impact

[Signature] 9/22/16
Signature Date

City Manager

David Bm 9/22/16
Signature Date

AGENDA ITEM NO:

XII.1



STAFF REPORT TO THE CITY COUNCIL

DATE: Regular Meeting of September 27, 2016

TO: Members of the City Council

SUBMITTED BY: David Biggs, City Manager
Mike Roberts, Public Works Director

SUBJECT: PG & E Solar Choice Program

RECOMMENDED ACTION: Discuss and Provide Direction, if any.

COMMISSION/SUBCOMMITTEE ACTION AND RECOMMENDATION: Not Applicable

FISCAL IMPACT OF RECOMMENDATION: No change from prior staff report (Attachment 1).

DISCUSSION: This item was discussed by the City Council on September 13, 2016, at which time the City Council requested additional information.

PG & E has provided additional background information on the Solar Choice Program (Attachment 2). In addition, they have updated their spreadsheet regarding the cost to participate in the program at the two levels offered to add our current rate/tariff information for each account.

Staff also contacted My Clean Energy to get an estimate of what the cost would be to secure renewable energy from this source if they were to become an option in Hercules. MCE was able to provide a high level estimate for one category of accounts, which together with all of the accounts, could be refined on a more detailed analysis of our accounts and usage. For the 10 accounts which lent themselves to easy comparison, the 100% Deep Green option would be \$1,700 more per year than standard PG & E rates, and the 50% Light Green option would result in a small saving of \$27 per year. In comparison, the PG & E Solar Choice option for the same accounts would be \$4,853.49 more at 100% renewable and \$2,426.64 at the 50% level. MCE has also provided some generic comparisons of the PG & E Solar Choice pricing for residential and commercial to MCE current pricing which are attached (Attachment 3)

MCE also advises that in the later part of 2015 they changed the requirements for new community to participate in the program. Communities no longer have to be contiguous to an existing member, but can be within 30 miles of an existing member.

In addition, the Contra Costa County led effort to review options related to community choice aggregation is in the technical study phase with a draft study to be completed by the end of November, followed by a public review process through January, 2017, and a final study in February 2017. Thereafter, there will be a review of options in Spring 2017 by the participating agencies.

ATTACHMENTS:

1. September 13, 2016 Staff Report
2. PG & E Information
3. MCE Comparisons

<i>Financial Impact</i>			
Description:			
Funding Source:			
Budget Recap:			
Total Estimated cost:	\$	New Revenue:	\$
Amount Budgeted:	\$	Lost Revenue:	\$
New funding required:	\$	New Personnel:	\$
Council Policy Change: Yes ☐ No ☐			

AGENDA ITEM REQUEST FORM

Department: City Manager's Office

Department Director: David Biggs

Phone: 799-8216

Meeting Date: September 13, 2016

Final Decision Date Deadline:

SUBJECT:
PG & E Solar Choice Program

INDICATE APPROPRIATE BODY

☒ City
Council

☐ Successor Agency to the
Redevelopment Agency

☐ Public Finance
Authority

☐ Finance
Commission

☐ Planning
Commission

☐ Community/Library
Services Commission

☐ Oversight Board

☐ Other _____

ITEM

☐ Presentation/Introduction

☐ Study Session

☐ Grant Application/Acceptance

☐ Public Hearing

☐ Resolution

☐ Video/PowerPoint

☐ Consent Calendar

☐ Ordinance

☒ Discussion Action

☐ Contract/Agreement

RECOMMENDED ACTION:

Discuss and Provide Direction, if any.

☐ Copy of executed Resolution/Ordinance/Contract/Application required immediately upon approval.

REVIEWED AND APPROVED FOR AGENDA:

City Attorney (if Contract, Ordinance or Resolution)

Signature

Date

9.8.16

Finance Department for Fiscal Impact

Signature

Date

9/8/16

City Manager

Signature

Date

9/8/16

AGENDA ITEM NO:

XII.4

September 27, 2016

Item XII.1: Page 204



STAFF REPORT TO THE CITY COUNCIL

DATE: Regular Meeting of September 13, 2016

TO: Members of the City Council

SUBMITTED BY: David Biggs, City Manager
Mike Roberts, Public Works Director

SUBJECT: PG & E Solar Choice Program

RECOMMENDED ACTION: Discuss and Provide Direction, if any.

COMMISSION/SUBCOMMITTEE ACTION AND RECOMMENDATION: Not Applicable

FISCAL IMPACT OF RECOMMENDATION: For the facilities listed on Attachment 1, and it does not appear to cover any street lighting, it would be between \$14,770.08 and \$29,540.76 per year for the City to go with one of the two solar options. Additional appropriations would be required in most funds to cover this increase in costs. Most funds could accommodate this small increase, though some of the Landscape & Lighting District Zones which operate at a deficit would see the deficit exacerbated.

DISCUSSION: On July 26, 2016, the City Council received a presentation from PG&E on their new Solar Choice Program which would allow the City to elect to utilize either 100% or 50% solar as the source of the electricity used by the City. Attached is a copy of the presentation made by PG&E (Attachment 2). PG&E is encouraging local governments to opt into the program. The City Council expressed a desire to discuss this option at a future meeting.

In addition, the City is exploring with other Cities in the County the possibility of a Community Choice Energy program like My Clean Energy. This program would also provide an option for consumers to elect to use a renewable source for electricity. This joint effort is underway with technical study to be completed within the next three months.

ATTACHMENTS:

1. Average Monthly Costs
2. PG & E Presentation

Financial Impact

Description:

Funding Source:

Budget Recap:

Total Estimated cost:	\$	New Revenue:	\$
Amount Budgeted:	\$	Lost Revenue:	\$
New funding required:	\$	New Personnel:	\$
Council Policy Change:	Yes ☐ No ☐		

Service Address	Description	Avg Monthly kWh	Avg Monthly Electricity Cost	100 % Solar Choice Additional Monthly	50% Solar Choice Additional Monthly
111 CIVIC DR PLNG ENG	Planning and Engineering	920	\$191.45	\$25.84	\$12.92
1375 WILLOW AVE	BART Parking Lot	4,806	\$980.83	\$135.04	\$67.52
111 CIVIC DR CITY HALL		27,987	\$4,890.18	\$800.42	\$400.21
1000 SYCAMORE AVE CORP YARD # A		6,000	\$1,261.87	\$168.59	\$84.30
REFUGIO VALLEY AND SYCAMORE		4,651	\$929.57	\$130.69	\$65.35
REFUGIO VLY RD @ MAIN, SCHOOL ENTRANCE	Traffic Controllers	166	\$38.11	\$4.66	\$2.33
N/W CORNER SYCAMORE &, TURQUOISE	Traffic Light	351	\$70.28	\$9.86	\$4.93
For 1500 SYCAMORE AVE, @ X-FROM-C	Traffic Signal	4,575	\$916.27	\$128.56	\$64.28
800 WILLOW AVE	Sewer Lift Station	3,012	\$699.22	\$84.65	\$42.32
30 TRESTLE COVE		561	\$120.00	\$15.75	\$7.88
SAN PABLO AVE, @ S/W-CRNR-JOHN-MUIR	Signal Lights	274	\$52.56	\$7.71	\$3.85
SAN PABLO& SYCAMORE, S/W CORNER	Traffic Signal	443	\$87.17	\$12.44	\$6.22
2007 REFUGIO VALLEY RD	Teen Center	1,367	\$296.55	\$38.42	\$19.21
BAYBERRY & SYCAMOR	Traffic Signal	468	\$90.66	\$13.14	\$6.57
SAN PABLO AVE @, TRANSIT CENTER	Traffic Signal	191	\$42.42	\$5.36	\$2.68
2482 REFUGIO VALLEY RD, @ HANNA-RANCH-PARK	Park Bathroom Lights	270	\$63.26	\$7.58	\$3.79
HERCULES AVE & SAN PABLO AVE NW CORNER	Traffic Signal	384	\$76.06	\$10.79	\$5.39
PARTRIDGE DR @ REFUGIO, VLY RD	Traffic Controllers	2,891	\$622.95	\$81.24	\$40.62
REFUGIO VALLEY RD, & PHEASANT	Refugio Valley Park	5,164	\$1,123.69	\$145.12	\$72.56
111 CIVIC DR	Senior Citizen Center	1,771	\$386.40	\$49.77	\$24.88
199 FAWCETT		530	\$122.15	\$14.88	\$7.44
1616 PHEASANT DR	Ohlone Child Care	90	\$37.56	\$2.53	\$1.26
PHEASANT DR @ SWALLOW WY	Irrigation	353	\$81.28	\$9.91	\$4.95
4850 SAN PABLO AVENUE		877	\$181.17	\$24.65	\$12.33
LILAC CIR @ FOOT-OF	Communication Tower	136	\$37.89	\$3.82	\$1.91
425 ALFRED NOBEL DR		316	\$84.50	\$8.88	\$4.44
109 CIVIC DR LIBRARY	Library	10,372	\$2,220.53	\$296.65	\$148.32
997 SYCAMORE AVE	Duck Pond Park	185	\$47.22	\$5.19	\$2.59
199 TRESTLE CV	Lift Station	6,750	\$1,401.19	\$193.05	\$96.53
1303 PROMENADE ST LIFT STATION	Lift Station	944	\$203.02	\$26.53	\$13.26

Total **September 27, 2016** **86,804** **\$17,356.01** **\$2,461.73** **\$1,230.84**

Introducing PG&E's Solar Choice Program



Introduction

Growing the solar movement



PG&E's Solar Choice Program

Is a Community Solar Program that provides the option for 100% or 50% solar power to all residential and business electric customers. Customers can purchase their electric power from solar energy sourced in PG&E's service territory.



Benefits of a “Community Solar” Program

• Providing Choice for Customers

- Multiple PG&E studies have consistently shown that customers want more renewable energy options.
- Approximately **half of homes and businesses** lack access to rooftop solar today, due to insufficient roof space or ownership issues.¹



• Drives the Growth of New Solar

• No Cost Shift

- As PG&E's program is designed, all program costs are to be borne by participants in the program.

¹April 2015 NREL Report, “Shared Solar: Current Landscape, Market Potential, and the Impact of Federal Securities Regulation”.

3



Enrollment

First-Come, First-Served

- **PG&E bundled electric customers*** are eligible for the program
 - Certain usage limitations apply for large customers
- 272 MW program cap, of which **45 MW are reserved** for residential customers.
- Enrollment open **until 2019** or until cap is reached, whichever comes first.
 - Once a customer enrolls, he/she may stay on the program beyond this date.
- Customers can leave the program at any time, without penalty.
 - However, once a customer de-enrolls, they may not re-enroll for 1 year.



*100% Standby, non-metered service and Transitional Bundled Service customers are not eligible to participate. NEM customers will not be eligible initially but will be allowed to participate at a later point in time.

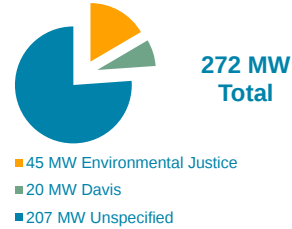
4



Procurement

Incremental, New Solar Projects

- In response to customer enrollment, PG&E will issue competitive solicitations for the power and sign **long-term contracts for new solar resources** within our service area.
- Independent of customer enrollment, **52.75 MW of solar resources** have been procured to meet the 50 MW minimum CPUC advance procurement goal.



Interim Resources

- Prior to new projects coming online, participants to be served by recently developed solar resources of the same type from PG&E's Renewables Portfolio Standard (RPS) program.

Beyond State Mandate

- All program resources are **above and beyond** PG&E's renewables portfolio requirements.

5



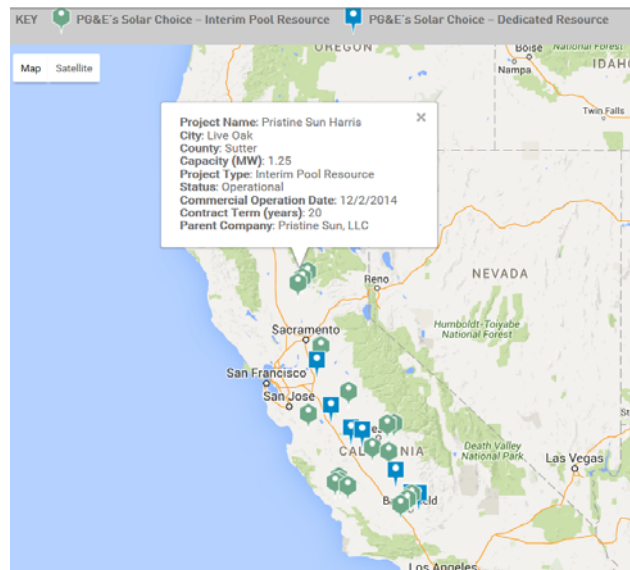
Project Map

Energy Source

Pool of Solar Projects

.5 to 20 MW

PG&E Service Area



6



PG&E's Solar Choice Pricing

Customers may enroll for 50% or 100% of their electric usage and remain on their regular base rate schedule.

In addition to regular charges, customers are assessed the following charges on enrolled kWh every month:

The total customer premium ranges from **2.81 to 4.85 cents/kWh**, depending on the customer class.

The current residential customer premium is **3.58 cents/kWh**.

Details of Electric Charges

01/25/2016 - 02/23/2016 (30 billing days)

Service For:

Service Agreement ID:

Rate Schedule: E6 TB Residential Time-of-Use Service

Enrolled Programs: SmartRate™, PG&E's Solar Choice Plan - 100%

01/25/2016 - 02/23/2016	Your Tier Usage	1	2	3	4
Tier 1 Allowance	255.00 kWh (30 days x 8.5 kWh/day)				
Tier 1 Usage					
Part Peak	37.350000 kWh @ \$0.17017			\$6.36	
Off Peak	217.650000 kWh @ \$0.15334			33.37	
Tier 2 Usage					
Part Peak	11.205000 kWh @ \$0.20413			2.29	
Off Peak	65.295000 kWh @ \$0.18730			12.23	
Tier 3 Usage					
Part Peak	15.531600 kWh @ \$0.26166			4.06	
Off Peak	90.520800 kWh @ \$0.24483			22.16	
PG&E's Solar Choice Plan Details ¹					
Solar Charge	437.552400 kWh @ \$0.09550			41.79	
Program Charge	437.552400 kWh @ \$0.01368			5.99	
PCIA	437.552400 kWh @ \$0.02323			10.16	
Generation Credit	437.552400 kWh @ -\$0.09650			-42.27	
Energy Commission Tax				6.13	

Total Electric Charges

\$96.27

¹ Your total cost of participating in PG&E's Solar Choice Plan this period is **\$15.67**. This is included in the Total Electric Charges amount. If you have any additional questions, please visit our website at pge.com/solarchoice.

2015 Vintaged Power Charge Indifference Adjustment (PCIA)

7



Online Rate Calculator

TYPE OF SERVICE Choose type of service: ☒ Residential ☐ Commercial Usage Level: ☐ 50% ☒ 100%	MONTHLY USAGE 500 kWh <i>Estimated Residential Usage:</i> 500 kWh average, 300 kWh low, 700 kWh high Get Results	COSTS Estimated additional monthly cost: \$17.91 Estimated premium: 3.58 Cents/kWh
Equivalencies that are presented are based on annual values. They are estimates and are not actual values.		

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PG&E's Solar Choice Customer Benefits

It's Easy

Program enrollment is as simple as a phone call



No Contract

Customers can enroll on a month to month basis. There is no termination fee

Enjoy convenience

The program offers a convenient solar option for commercial buildings that aren't well suited for rooftop installation

Get solar immediately

Upon enrollment, businesses will purchase solar energy from existing solar projects

Meet sustainability goals

Participation will lower each business' carbon footprint, support their clean energy goals, and may help them earn LEED points.



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PG&E's Solar Choice Customer Benefits - Continued

Demonstrate environmental leadership

Businesses have the opportunity to show their customers, employees and local community that sustainable business practices are important to them



Get recognized

Businesses will receive a variety of promotional marketing benefits when they sign up, including: window clings, certificate of participation, poster, website badge, sample social media posts, press release draft

Make a difference

Business participation funds the growth of new solar energy in California.

EPA Green Power Partnership

The EPA Green Power Partnership recognizes organizations that have voluntarily purchased renewable energy to meet between 3 and 20 percent of their annual electricity needs.



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Get Recognized

Businesses will receive a variety of promotional marketing benefits when they sign up, including: window clings, certificate of participation, poster, website badge, sample social media posts, press release draft

Business posts

- Lead the solar movement with us through PG&E's Solar Choice program! pge.com/solarchoice
- We claimed our spot in the solar movement by purchasing California solar energy. Claim your spot too! pge.com/solarchoice
- We're proud to support the development of renewable energy in California. You can help too! pge.com/solarchoice
- PG&E's Solar Choice program is helping us meet our sustainability goals. Reach yours too! pge.com/solarchoice

Web tool

Use your website to promote your program participation and let online visitors know about your commitment to sustainability with the provided web-ready artwork.

Email signature

Share a little sunshine every time you click send. Add a Solar Proud badge to your email signature to show you're making a difference every day you're enrolled PG&E's Solar Choice program. Pair the badge with the provided text and link to pge.com/solarchoice so solar energy can be one-click away for everyone.

Press release

Enrolling in PG&E's Solar Choice program is newsworthy! Your participation directly increases the amount of renewable energy in the power system. It makes it possible to construct new solar projects here in Northern and Central California, protecting our environment and helping build the green economy in our region.

Participation announcement

Include employees in the important decision to reduce your business' carbon footprint. Use the provided email messaging and artwork to ensure employees know program participation goes beyond business as usual—and how they'll benefit too.

Top with caption

Keep sustainable business practices top of mind among your employees by adding a Solar Proud badge to pay stubs. Write and promote this artwork in a track and write for your company's. Complete your message by pairing the badge with the provided caption.

Social media posts

Use the provided artwork and text to create social media posts for Facebook, Twitter, LinkedIn, and Instagram. Pair the badge with the provided text and link to pge.com/solarchoice so solar energy can be one-click away for everyone.

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Customers that are a good fit for Solar Choice

- ✓ Green minded
- ✓ Mission driven
- ✓ Energy Efficient
- ✓ Have constraints that don't allow traditional solar options
- ✓ Wants to differentiate themselves as sustainable
- ✓ Have sustainability requirements



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Thank You

www.pge.com/solarchoice



PG&E's Solar Choice Product Information

2016 PRODUCT CONTENT LABEL ¹

The PG&E's Solar Choice Plan matches 50% or 100% of your electricity usage with solar photovoltaic (pv) resources. In 2016, PG&E's Solar Choice Plan will be made up of the following new renewable resources averaged annually.

Green-e Energy Certified New ² Renewables in PG&E's Solar Choice Plan 2016		Generation Location
Solar	100%	California (within PG&E's service territory)
Total Green-e Energy Certified New Renewables	100%	

1. These figures reflect the renewables that we have contracted to provide. Actual figures may vary according to resource availability. We will annually report to you the actual resource mix of the electricity you purchased during the preceding year before August 1 in the form of a Historic Product Content Label.

2. **New Renewables for PG&E's Solar Choice Plan first began commercial operation January 1, 2014 or later.** As customers enroll in the Plan PG&E will procure more, newer solar resources to match customer demand.

For comparison, the current average mix of resources supplying PG&E customers includes: Biomass and Biowaste (5%), Geothermal (5%), Renewable-Eligible Hydro (1%), Solar Electric (9%), Wind (7%), Nuclear (21%), Natural Gas (24%), Large Hydroelectric (8%), and Other (21%). This resource mix was reported to the California Energy Commission as part of PG&E's 2014 Power Source Disclosure Report.

The average residential customer served by PG&E uses 531 kWh per month. Source: [PG&E FERC Form 1, 2014](#)
For specific information about PG&E's Solar Choice Plan, please contact PG&E at 877-743-8429 or visit pge.com/solarchoice.

PG&E's Solar Choice Plan is Green-e Energy certified, and meets the environmental and consumer-protection standards set forth by the nonprofit Center for Resource Solutions. Learn more at www.green-e.org.



2016 PRICE, TERMS AND CONDITIONS



PG&E's Solar Choice Plan is Green-e Energy certified, and meets the environmental and consumer-protection standards set forth by the nonprofit Center for Resource Solutions. Learn more at www.green-e.org.

Company

Pacific Gas and Electric Company (PG&E)

Whom should I contact for more information?

For more information about PG&E's Solar Choice Plan, visit pge.com/solarchoice or call 877-743-8429.

How will I be billed for PG&E's Solar Choice Plan?

You will be billed for PG&E's Solar Choice Plan on your monthly PG&E electricity bill. PG&E's Solar Choice Plan charges and credits will be listed as separate line items and are in addition to your regular electricity charges.

How will my PG&E's Solar Choice bill be calculated?

Your PG&E's Solar Choice Plan bill is calculated with a **Solar Charge**, a **Program Charge**, a **Power Charge Indifference Adjustment** and a **Generation Credit**:

- The **Solar Charge** is the cost of the renewable power.
- The **Program Charge** is set to fund the program's marketing and administration costs as well as cover additional energy-related costs to ensure that non-participating customers do not fund the program. The energy-related costs include: costs associated with integrating the new renewable resources with the grid (Renewables Integration Charge), state-level grid management costs (California Independent System Operator), costs for registering, tracking and retiring Renewable Energy Certificates (RECs) in the Western Renewable Energy Generation Information System (WREGIS), Resource Adequacy costs (RA), and a credit for the positive value that solar provides in delivering energy to the grid during peak hours (Solar Value Adjustment).
- The **Power Charge Indifference Adjustment (PCIA)** is set to ensure stranded generation costs are not shifted to non-participating customers when you switch to PG&E's Solar Choice Plan.
- The **Generation Credit** is a credit equal to the average generation rate for your customer class. This credit is to recognize that your renewable energy purchase displaces the charges for the generation portfolio associated with your base rate.

These charges and credits will be applied on a per kWh basis to either 50% or 100% of your monthly electricity usage, depending on your participation level. Applicable federal, state, and local taxes and charges still apply.

Rates are rounded to two decimal places for presentation purposes. See rate schedule E-GT for complete rates.

Customer Class	Solar Charge	Program Charge	PCIA*	Generation Credit	Total
Residential					
-- 2015 Vintage	9.55¢	1.37¢	2.32¢	-9.66¢	3.58¢
-- 2016 Vintage	9.55¢	1.37¢	2.32¢	-9.66¢	3.58¢

	<table><tr><th>Customer Class</th><th>Solar Charge</th><th>Program Charge</th><th>PCIA*</th><th>Generation Credit</th><th>Total</th></tr><tr><td>Small Business**</td><td></td><td></td><td></td><td></td><td></td></tr><tr><td>-- 2015 Vintage</td><td>9.55¢</td><td>1.15¢</td><td>1.79¢</td><td>-9.68¢</td><td>2.81¢</td></tr><tr><td>-- 2016 Vintage</td><td>9.55¢</td><td>1.15¢</td><td>1.79¢</td><td>-9.68¢</td><td>2.81¢</td></tr><tr><td>Medium Business</td><td></td><td></td><td></td><td></td><td></td></tr><tr><td>-- 2015 Vintage</td><td>9.55¢</td><td>1.32¢</td><td>1.88¢</td><td>-9.90¢</td><td>2.86¢</td></tr><tr><td>-- 2016 Vintage</td><td>9.55¢</td><td>1.32¢</td><td>1.88¢</td><td>-9.90¢</td><td>2.86¢</td></tr><tr><td>Schedule E-19</td><td></td><td></td><td></td><td></td><td></td></tr><tr><td>-- 2015 Vintage</td><td>9.55¢</td><td>1.14¢</td><td>1.59¢</td><td>-9.17¢</td><td>3.11¢</td></tr><tr><td>-- 2016 Vintage</td><td>9.55¢</td><td>1.14¢</td><td>1.59¢</td><td>-9.17¢</td><td>3.11¢</td></tr><tr><td>Schedule LS-3</td><td></td><td></td><td></td><td></td><td></td></tr><tr><td>-- 2015 Vintage</td><td>9.55¢</td><td>1.08¢</td><td>.28¢</td><td>-8.03¢</td><td>2.88¢</td></tr><tr><td>-- 2016 Vintage</td><td>9.55¢</td><td>1.08¢</td><td>.28¢</td><td>-8.03¢</td><td>2.88¢</td></tr><tr><td>Agriculture and Schedule E-37</td><td></td><td></td><td></td><td></td><td></td></tr><tr><td>-- 2015 Vintage</td><td>9.55¢</td><td>1.25¢</td><td>1.89¢</td><td>-7.84¢</td><td>4.85¢</td></tr><tr><td>-- 2016 Vintage</td><td>9.55¢</td><td>1.25¢</td><td>1.89¢</td><td>-7.84¢</td><td>4.85¢</td></tr><tr><td>Schedule E-20 T</td><td></td><td></td><td></td><td></td><td></td></tr><tr><td>-- 2015 Vintage</td><td>9.55¢</td><td>1.17¢</td><td>1.28¢</td><td>-7.75¢</td><td>4.26¢</td></tr><tr><td>-- 2016 Vintage</td><td>9.55¢</td><td>1.17¢</td><td>1.28¢</td><td>-7.75¢</td><td>4.26¢</td></tr><tr><td>Schedule E-20 P</td><td></td><td></td><td></td><td></td><td></td></tr><tr><td>-- 2015 Vintage</td><td>9.55¢</td><td>1.13¢</td><td>1.42¢</td><td>-8.44¢</td><td>3.67¢</td></tr><tr><td>-- 2016 Vintage</td><td>9.55¢</td><td>1.13¢</td><td>1.42¢</td><td>-8.44¢</td><td>3.67¢</td></tr><tr><td>Schedule E-20 S</td><td></td><td></td><td></td><td></td><td></td></tr><tr><td>-- 2015 Vintage</td><td>9.55¢</td><td>1.12¢</td><td>1.49¢</td><td>-8.71¢</td><td>3.45¢</td></tr><tr><td>-- 2016 Vintage</td><td>9.55¢</td><td>1.12¢</td><td>1.49¢</td><td>-8.71¢</td><td>3.45¢</td></tr></table> * PCIA will be applied based on the date that you begin service on PG&E's Solar Choice Plan. If you begin service in the first six months of the calendar year (e.g. 2016), you are assigned the prior year's vintage (i.e. 2015). If you begin service on or after July 1, you are assigned the vintage for the current year (2016 in this example). ** The Small Business class includes Schedules A-1, A-6, A-15 and TC-1.	Customer Class	Solar Charge	Program Charge	PCIA*	Generation Credit	Total	Small Business**						-- 2015 Vintage	9.55¢	1.15¢	1.79¢	-9.68¢	2.81¢	-- 2016 Vintage	9.55¢	1.15¢	1.79¢	-9.68¢	2.81¢	Medium Business						-- 2015 Vintage	9.55¢	1.32¢	1.88¢	-9.90¢	2.86¢	-- 2016 Vintage	9.55¢	1.32¢	1.88¢	-9.90¢	2.86¢	Schedule E-19						-- 2015 Vintage	9.55¢	1.14¢	1.59¢	-9.17¢	3.11¢	-- 2016 Vintage	9.55¢	1.14¢	1.59¢	-9.17¢	3.11¢	Schedule LS-3						-- 2015 Vintage	9.55¢	1.08¢	.28¢	-8.03¢	2.88¢	-- 2016 Vintage	9.55¢	1.08¢	.28¢	-8.03¢	2.88¢	Agriculture and Schedule E-37						-- 2015 Vintage	9.55¢	1.25¢	1.89¢	-7.84¢	4.85¢	-- 2016 Vintage	9.55¢	1.25¢	1.89¢	-7.84¢	4.85¢	Schedule E-20 T						-- 2015 Vintage	9.55¢	1.17¢	1.28¢	-7.75¢	4.26¢	-- 2016 Vintage	9.55¢	1.17¢	1.28¢	-7.75¢	4.26¢	Schedule E-20 P						-- 2015 Vintage	9.55¢	1.13¢	1.42¢	-8.44¢	3.67¢	-- 2016 Vintage	9.55¢	1.13¢	1.42¢	-8.44¢	3.67¢	Schedule E-20 S						-- 2015 Vintage	9.55¢	1.12¢	1.49¢	-8.71¢	3.45¢	-- 2016 Vintage	9.55¢	1.12¢	1.49¢	-8.71¢	3.45¢
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-- 2016 Vintage	9.55¢	1.14¢	1.59¢	-9.17¢	3.11¢																																																																																																																																																		
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-- 2015 Vintage	9.55¢	1.08¢	.28¢	-8.03¢	2.88¢																																																																																																																																																		
-- 2016 Vintage	9.55¢	1.08¢	.28¢	-8.03¢	2.88¢																																																																																																																																																		
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-- 2016 Vintage	9.55¢	1.12¢	1.49¢	-8.71¢	3.45¢																																																																																																																																																		
Will my rate change over time?	PG&E's Solar Choice Plan rates are based on current California Public Utility Commission approved tariffs. Rates are subject to change annually and as approved by the California Public Utilities Commission.																																																																																																																																																						
What other fees might I be charged?	No other fees apply.																																																																																																																																																						
What length of agreement /contract is required?	There is no required length of agreement or contract.																																																																																																																																																						
Can I cancel my participation?	You may cancel your participation in PG&E's Solar Choice Plan at any time and without a fee. The cancellation will become effective as of your last closed bill period. You will then be ineligible to participate in PG&E's Solar Choice Plan for a period of 12 months from the date of the change (certain customers may be excepted).																																																																																																																																																						
Can I change my participation level?	You may elect to change your participation level once in a 12 month period (e.g. changing from 50% to 100% and vice versa). If PG&E's Solar Choice Plan is closed to new customers, existing customers may change their enrollment level down only (from 100% to 50%). Participation level changes will apply on the first day of the next Billing Cycle where the Billing Cycle start date occurs at least five business days after the date of the customer's request. A customer request that is received within five business days of the customer's next Billing Cycle may result in the customer being placed on PG&E's Solar Choice Plan the following Billing Cycle.																																																																																																																																																						
Can I move and continue to participate in PG&E's Solar Choice Plan?	Yes. PG&E's Solar Choice Plan is portable within PG&E's electric service territory. You will be considered as having continuously received service under this schedule for the purposes of determining the PCIA vintage to apply to the new service agreement.																																																																																																																																																						
Can I participate in both Solar Choice programs at the same time?	No. You may only be enrolled in one Solar Choice Plan at a time.																																																																																																																																																						

Service Address	SAID (Account)	Description	Rate	Solar Choice cost per kwh	Avg Monthly kWh	Avg Monthly Electricity Cost	100 % Solar Choice Additional Monthly	50% Solar Choice Additional Monthly
111 CIVIC DR PLNG ENG	316953249	Planning and Engineering	HA1X (A1)	2.8 cents	920	\$191.45	\$25.84	\$12.92
1375 WILLOW AVE	4368976640	BART Parking Lot	HA1X (A1)	2.8 cents	4,806	\$980.83	\$135.04	\$67.52
111 CIVIC DR CITY HALL	4433516600		HA10SX (A10)	2.86 cents	27,987	\$4,890.18	\$800.42	\$400.21
1000 SYCAMORE AVE CORP YARD # A	4470428978		HA1X (A1)	2.8 cents	6,000	\$1,261.87	\$168.59	\$84.30
REFUGIO VALLEY AND SYCAMORE	4777027075		TC1	2.8 cents	4,651	\$929.57	\$130.69	\$65.35
REFUGIO VLY RD @ MAIN, SCHOOL ENTRANCE	5449704055	Traffic Controllers	TC1	2.8 cents	166	\$38.11	\$4.66	\$2.33
N/W CORNER SYCAMORE &, TURQUOISE	5449704075	Traffic Light	TC1	2.8 cents	351	\$70.28	\$9.86	\$4.93
For 1500 SYCAMORE AVE, @ X-FROM-C	5449704080	Traffic Signal	TC1	2.8 cents	4,575	\$916.27	\$128.56	\$64.28
800 WILLOW AVE	5449704105	Sewer Lift Station	A6	2.8 cents	3,012	\$699.22	\$84.65	\$42.32
30 TRESTLE COVE	5449704148		A1	2.8 cents	561	\$120.00	\$15.75	\$7.88
SAN PABLO AVE, @ S/W-CRNR-JOHN-MUIR	5449704170	Signal Lights	TC1	2.8 cents	274	\$52.56	\$7.71	\$3.85
SAN PABLO & SYCAMORE, S/W CORNER	5449704185	Traffic Signal	TC1	2.8 cents	443	\$87.17	\$12.44	\$6.22
2007 REFUGIO VALLEY RD	5449704187	Teen Center	A1	2.8 cents	1,367	\$296.55	\$38.42	\$19.21
BAYBERRY & SYCAMOR	5449704190	Traffic Signal	TC1	2.8 cents	468	\$90.66	\$13.14	\$6.57
SAN PABLO AVE @, TRANSIT CENTER	5449704195	Traffic Signal	TC1	2.8 cents	191	\$42.42	\$5.36	\$2.68
2482 REFUGIO VALLEY RD, @ HANNA-RANCH-PARK	5449704213	Park Bathroom Lights	A1	2.8 cents	270	\$63.26	\$7.58	\$3.79
HERCULES AVE & SAN PABLO AVE NW CORNER	5449704230	Traffic Signal	TC1	2.8 cents	384	\$76.06	\$10.79	\$5.39
PARTRIDGE DR @ REFUGIO, VLY RD	5449704245	Traffic Controllers	TC1	2.8 cents	2,891	\$622.95	\$81.24	\$40.62
REFUGIO VALLEY RD, & PHEASANT	5449704345	Refugio Valley Park	HA6 (A6)	2.8 cents	5,164	\$1,123.69	\$145.12	\$72.56
111 CIVIC DR	5449704431	Senior Citizen Center	HA1X (A1)	2.8 cents	1,771	\$386.40	\$49.77	\$24.88
199 FAWCETT	5449704556		HA6 (A6)	2.8 cents	530	\$122.15	\$14.88	\$7.44
1616 PHEASANT DR	5449704738	Ohlone Child Care	HA1X (A1)	2.8 cents	90	\$37.56	\$2.53	\$1.26
PHEASANT DR @ SWALLOW WY	5449704771	Irrigation	HA1X (A1)	2.8 cents	353	\$81.28	\$9.91	\$4.95
4850 SAN PABLO AVENUE	5449704784		HA1X (A1)	2.8 cents	877	\$181.17	\$24.65	\$12.33
LILAC CIR @ FOOT-OF	5449704949	Communication Tower	HA1X (A1)	2.8 cents	136	\$37.89	\$3.82	\$1.91
425 ALFRED NOBEL DR	6683707340		HA1X (A1)	2.8 cents	316	\$84.50	\$8.88	\$4.44
109 CIVIC DR LIBRARY	7951390663	Library	HA10SX (A10)	2.86 cents	10,372	\$2,220.53	\$296.65	\$148.32
997 SYCAMORE AVE	8221045003	Duck Pond Park	HA1X (A1)	2.8 cents	185	\$47.22	\$5.19	\$2.59
199 TRESTLE CV	8834352392	Lift Station	HA10SX (A10)	2.86 cents	6,750	\$1,401.19	\$193.05	\$96.53
1303 PROMENADE ST LIFT STATION	8888512121	Lift Station	HA1X (A1)	2.8 cents	944	\$203.02	\$26.53	\$13.26
Total					86,804	\$17,356.01	\$2,461.73	\$1,230.84

From: [Gianotti, Kerynn](#)
To: [David Biggs](#)
Cc: [Reid, Treva](#)
Subject: PG&E's Solar Choice program
Date: Thursday, September 22, 2016 10:09:01 AM
Attachments: [image001.png](#)

Hi David,

I wanted to provide you with some information that outlines the additional outreach opportunities for the first city that signs up for the Solar Choice program. Please let me know if you have any questions or need additional information.

First City to sign up for Solar Choice

- Award given to the city at a council meeting
- Banners for the facilities that were signed up
- Large poster explaining the importance of Solar Choice for City Hall and/or facility
- Mention in presentations to Industry Professionals (i.e. League of Cities)
- Promote in testimonials across PG&E territory (may include video)
- Provide a draft message to include in communications from local community organizations
- Hyperlink to our Solar Choice page from the city's website
- Work with city staff on additional promotional opportunities. This could include:
 - Hosting a community meeting
 - Event participation
 - Kick-off event or ribbon cutting

In addition customer will receive

- Business posts
- Web tout
- Email Signature
- Sample press release
- Pay stub caption
- Window Cling
- Poster
- Certificate of participation

Thank you,

Kerynn Gianotti
Pacific Gas and Electric Company
245 Market St, 730B
San Francisco, CA 94105
Wk: 415.973.4476
Cell: 408.799.2057



[PG&E's Solar Choice](#)

Residential Cost Comparison

	PG&E	MCE Light Green	MCE Deep Green	PG&E Solar Choice
Renewable Content	30%	50%	100%	100%
PG&E Electric Delivery	\$47.53	\$47.53	\$47.53	\$47.53
Electric Generation	\$44.84	\$33.34	\$37.97	\$50.67
Added PG&E Fees	—	\$11.04	\$11.04	\$10.76
Average Total Cost	\$92.37	\$91.91	\$96.54	\$108.96

September 27, 2016

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*Based on a typical usage of 463 kWh at current PG&E and MCE rates scheduled to be effective as of September 2016 under the Res-1/E-1 rate schedule. Actual differences may vary depending on usage, rate schedule, and other factors. Estimate provided is an average of seasonal rates.

Commercial Cost Comparison

	PG&E	MCE Light Green	MCE Deep Green	PG&E Solar Choice
Renewable Content	30%	50%	100%	100%
PG&E Electric Delivery	\$154.11	\$154.11	\$154.11	\$154.11
Electric Generation	\$116.42	\$93.78	\$105.88	\$128.74
Added PG&E Fees	—	\$22.43	\$22.43	\$21.62
Average Total Cost	\$270.53	\$270.32	\$282.42	\$304.47

September 27, 2016

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*Based on a typical usage of 463 kWh at current PG&E and MCE rates scheduled to be effective as of September 2016 under the Res-1/E-1 rate schedule. Actual differences may vary depending on usage, rate schedule, and other factors. Estimate provided is an average of seasonal rates.

AGENDA ITEM REQUEST FORM

Department: City Manager's Office

Department Director: David Biggs

Phone: 799-8216

Meeting Date: June 28, 2016

Final Decision Date Deadline:

SUBJECT:

Approve Memorandum of Understanding for Community Choice Energy Technical Study

INDICATE APPROPRIATE BODY

☒ City Council

☐ Successor Agency to the Redevelopment Agency

☐ Public Finance Authority

☐ Finance Commission

☐ Planning Commission

☐ Community/Library Services Commission

☐ Oversight Board

☐ Other _____

ITEM

☐ Presentation/Introduction

☐ Study Session

☐ Grant Application/Acceptance

☐ Public Hearing

☐ Resolution

☐ Video/PowerPoint

☐ Consent Calendar

☐ Ordinance

☒ Discussion Action

☐ Contract/Agreement

RECOMMENDED ACTION:

Authorize the City Manager to sign a Memorandum of Understanding with Contra Costa County and participating cities regarding a technical study to evaluate alternatives for potentially implementing Community Choice Energy within the jurisdictions included in the study

☐ Copy of executed Resolution/Ordinance/Contract/Application required immediately upon approval.

REVIEWED AND APPROVED FOR AGENDA:

City Attorney (if Contract, Ordinance or Resolution)

Signature

Date

Finance Department for Fiscal Impact

Signature

Date

City Manager

Signature

Date

AGENDA ITEM NO:

XII.7

June 28, 2016

Item XII.7: Page 24



STAFF REPORT TO THE CITY COUNCIL

DATE: Regular Meeting of June 28, 2016

TO: Members of the City Council

SUBMITTED BY: David Biggs, City Manager

SUBJECT: Approve Memorandum of Understanding for Community Choice Energy Technical Study

RECOMMENDED ACTION: Authorize the City Manager to sign a Memorandum of Understanding with Contra Costa County and participating cities regarding a technical study to evaluate alternatives for potentially implementing Community Choice Energy within the jurisdictions included in the study

COMMISSION/SUBCOMMITTEE ACTION AND RECOMMENDATION: Not Applicable

FISCAL IMPACT OF RECOMMENDATION: None as a result of this action.

DISCUSSION: Community Choice Energy (CCE) is described in State law as Community Choice Aggregation. CCE involves cities and counties, or a joint powers authority (JPA) comprised of cities and/or counties, pooling ("aggregating") retail electricity customers for the purpose of procuring and selling electricity. Under a CCE program, the CCE entity would become the default electricity provider to all electricity customers within the service area. Customers would have the ability to opt out of service from the CCE and return to service from the incumbent electrical utility. In Contra Costa County, the incumbent electrical utility is Pacific Gas and Electric (PG&E).

Following the successful launch of CCE programs in Marin County in 2010 and Sonoma County in 2014, most other counties in the Bay Area and many counties throughout California are now in the process of implementing or studying the creation of CCE programs. The City and County of San Francisco launched its CCE programs in May 2016. San Mateo County is scheduled to launch its program in October 2016. Alameda County and Santa Clara County are both in the process of establishing JPAs for this purpose and plan to launch programs in 2017.

On March 15, the Contra Costa County Board of Supervisors (Board) directed County staff to work with interested cities within Contra Costa County to conduct a technical study of Community Choice Energy. The Board directed County staff to request that each participating city contribute financially towards the cost of the technical study in an amount proportional to the size of that city's population. A copy of the Board Agenda item is attached (Attachment 1).

Early in the process, the City Manager authorized PG&E to provide data for our community to the County to facilitate the proposed technical study. Since that time, a Memorandum of Understanding has been prepared to provide structure to this joint effort.

The technical study will analyze electrical load data that the County has requested from PG&E for the unincorporated area and the 14 cities in Contra Costa County that are not currently participating in a CCE program (5 cities in Contra Costa County are members of MCE Clean Energy). The study will provide participating jurisdictions information concerning the projected electricity rates that might be charged by a CCE program and the revenues that such a program might generate, the ability of a CCE program to lower greenhouse gas emissions generated from energy use within the County, and the extent to which a CCE program could stimulate economic activity in the County through implementation of local renewable energy generation projects. Similar technical studies have been performed recently in other Bay Area counties that are in the process of implementing Community Choice Energy programs, such as Alameda County, San Mateo County and Santa Clara County.

The technical study will compare 3 different CCE program models that could be implemented by participating jurisdictions in Contra Costa County. These are: forming a new joint powers authority (JPA) of interested jurisdictions within Contra Costa County, forming a similar JPA in partnership with jurisdictions in Alameda County, and joining the CCE program initiated in Marin County known as MCE Clean Energy.

The Memorandum of Understanding (MOU) describes the roles and responsibilities of the County and cities regarding the technical study. Presently, 8 of the 14 cities within Contra Costa County that are not already members of a CCE program have decided to contribute financially towards the technical study, and 6 cities have not decided to contribute financially. Cities that have decided to contribute financially towards the cost of the study are designated in the MOU as “Funding Cities,” and cities that are not contributing financially are designated as “Non-Funding Cities.” The MOU provides Non-Funding cities an opportunity to become Funding Cities by providing a notice to that effect to the other parties by September 1, 2016.

The County has recently issued a Request for Proposals (RFP) to select a consultant to perform the technical study. The County and several of the Funding Cities will screen the proposals submitted in response to the RFP, and the County will enter into a contract with the selected consultant. Upon completion of the technical study, the Funding Cities will each reimburse the County for their proportionate share of cost based on their population size, up to a maximum amount established in the MOU.

The County will provide the Funding Cities with a draft of the technical study report once it is prepared by the selected consultant. The Funding Cities will have an opportunity to comment on the draft study. The Final Report will be provided to the Funding Cities, and the County and its consultants will assist in presenting the Final Report to City Councils. The Final Report will assist all of the jurisdictions covered in the study to decide whether to participate in the implementation of a CCE program.

Approval of the MOU does not commit the City of Hercules to participating in any future CCE program. However, having access to the results of the technical study would facilitate any future City Council consideration of the matter.

ATTACHMENTS:

1. March 15, 2016 Board of Supervisors Item
2. Memorandum of Understanding

1. Financial Impact

Description:

Funding Source:

Budget Recap:

Total Estimated cost:	\$	New Revenue:	\$
Amount Budgeted:	\$	Lost Revenue:	\$
New funding required:	\$	New Personnel:	\$
Council Policy Change:	Yes ☐ No ☐		



**Contra
Costa
County**

To: Board of Supervisors
From: John Kopchik, Director, Conservation & Development Department
Date: March 15, 2016

Subject: Consider options for potential implementation of Community Choice Energy within the unincorporated area of the County.

RECOMMENDATION(S):

Consider the following options regarding potential implementation of Community Choice Energy (CCE) within the unincorporated area of the County:

Option 1: Work with interested cities in Contra Costa County to obtain electrical load data from PG&E and conduct a technical study of the following three CCE alternatives:

- Form a new joint powers authority of the County and interested cities within Contra Costa County for the purpose of implementing Community Choice Energy
- Join Marin Clean Energy (MCE)
- Form a new joint powers authority with Alameda County and the interested group of cities in the two-county region

Option 2: Proceed with the steps necessary to join Marin Clean Energy (MCE).

Option 3: Undertake an abbreviated technical study summarizing technical studies recently completed by other Bay Area cities and counties and including a comparison of tradeoffs between CCE alternatives available to the County.

☒ APPROVE

☐ OTHER

☒ RECOMMENDATION OF CNTY

☐ RECOMMENDATION OF BOARD

ADMINISTRATOR

COMMITTEE

Action of Board On: **03/15/2016** ☐ APPROVED AS RECOMMENDED ☒ OTHER

Clerks Notes: SELECTED OPTION 1

VOTE OF SUPERVISORS

AYE: John Gioia, District I Supervisor

Candace Andersen, District II Supervisor

Mary N. Piepho, District III Supervisor

Karen Mitchoff, District IV Supervisor

Federal D. Glover, District V Supervisor

I hereby certify that this is a true and correct copy of an action taken and entered on the minutes of the Board of Supervisors on the date shown.

ATTESTED: March 15, 2016

David J. Twa, County Administrator and Clerk of the Board of Supervisors

By: June McHuen, Deputy

Contact: 925-674-7722

cc: June 28, 2016

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FISCAL IMPACT:

Option 1: Technical Study

The estimated cost of the activities associated with partnering with cities within the County to conduct a technical study of Community Choice Energy is \$400,000. This includes an estimated \$225,000 in consulting services and \$175,000 in County staff costs to manage the project. Staff recommends that the cities be proposed to share in the cost of the technical study consultant, which would reduce the County's overall cost to \$300,000.

These costs would include an amendment to the County's current consulting services contact with LEAN Energy to increase the contract limit by \$75,000 to assist DCD with obtaining electrical load data from PG&E, refining the scope of the technical study and developing the RFP, evaluating proposals from consultants for conducting the technical study, interpreting the results of the technical study and reporting the findings of the technical study to cities, the IOC and the Board of Supervisors. LEAN Energy would also assist County staff in conducting community outreach activities to provide information and education to the public and to gather public input to assist decision-makers in evaluating the results of the technical study.

The cost of the actions associated with Option 1 also includes an estimated \$50,000 for the County's share of cost for conducting a technical study. The total cost of the technical study is estimated to be up to \$150,000. The balance of the cost not paid by the County is proposed to be paid by participating cities proportionate to their share of the total population of the jurisdictions covered by the study.

The estimated \$175,000 cost of County staff time for management of the activities associated with Option 1 includes DCD staff time until the end of 2016 at a cost of approximately \$150,000 plus the cost of County Counsel staff time, estimated to be \$25,000 during 2016.

If a technical study resulted in the County taking additional steps to implement a CCE program, such steps would involve additional time and expense. The cost of these additional steps would depend on the outcome of the study. The estimated schedule and budget following completion of a technical study is described in more detail in Attachment E to this report. The greatest expense would be associated with a scenario involving the formation of a new joint powers authority of the County and cities within Contra Costa County. The cost of forming such a JPA and launching a program is estimated to be approximately \$2 million. These costs would likely be reimbursed by the JPA to the County from CCE program revenues.

Option 2: Take Steps to Join MCE

The estimated cost of activities associated with studying membership in MCE that would be comparable to a full technical study is minimal. There may be some research required of County staff and consultants to answer questions the Board may have regarding MCE, but the estimated cost of addressing these issues would be no more than \$10,000.

If the Board reaches a decision to join MCE and directs staff to take the actions necessary to do so, there would be additional costs of approximately \$50,000 associated with County staff time in DCD and County Counsel related to preparing an ordinance and resolution for adoption by the Board, assisting MCE with program launch activities, and coordinating with Contra Costa cities regarding MCE membership. These costs could be described as "back-end" costs and are not comparable to the "front-end" costs associated with the costs of a technical study as described in Option 1 above. The back-end costs of \$50,000 are more comparable to the back-end costs associated with JPA formation and program launch activities that might follow a technical study, as described more fully in Attachment E.

Option 3: Abbreviated Technical Study

The cost of this option is estimated to be approximately \$65,000. This would include \$50,000 in consulting services to perform the study and \$15,000 in County staff time for project management. The cost of next steps would depend on the approach selected, similar to Option 1, however a portion of a full technical study could be necessary if the abbreviated technical study prompted selection of the option to form a new JPA.

Summary

Overall, the cost of Option 1 (Technical Study) is by far the greatest, and the cost of Option 2 (Join MCE) is the least. Option 3 (Abbreviated Technical Study) represents a middle ground that would provide some of the benefits of a full technical study at a reduced cost and in a shorter time period.

Reimbursement and Potential Source of County Funds

The County would seek to have its costs associated with this project reimbursed in the future from the revenues of a new CCE program should a new JPA be created for this purpose. If a new JPA is not established, the County's costs are unlikely to be reimbursed.

DCD's costs related to this project in the current fiscal year, including the cost of consulting services, can be offset by the unspent portion of the \$200,000 in General Fund revenues budgeted in DCD for FY 2015-2016 for the newly created position of County Sustainability Coordinator, which has not yet been filled. Depending on the direction chosen by the Board, it is anticipated that most, if not all, costs associated with this project in FY 2015-2016 can be paid for from this funding source.

BACKGROUND:

Community Choice Energy (CCE) is described in State law as Community Choice Aggregation. CCE involves cities and counties, or a joint powers authority (JPA) composed of cities and/or counties, pooling ("aggregating") retail electricity customers for the purpose of procuring and selling electricity. Under a CCE program, the CCE entity would become the default electricity provider to all electricity customers within the

service area. Customers would have the ability to opt out of service from the CCE and return to service from the incumbent electrical utility. In Contra Costa County, the incumbent electrical utility is Pacific Gas and Electric (PG&E).

Following the successful launch of CCE programs in Marin County in 2010 and Sonoma County in 2014, most other counties in the Bay Area and many counties throughout California are now in the process of implementing or studying the creation of CCE programs. The City and County of San Francisco and San Mateo County are planning to launch CCE programs in 2016. Alameda County and Santa Clara County are both in the process of establishing JPAs for this purpose and plan to launch programs in 2017.

On October 13, 2015, the Board of Supervisors (Board) accepted the recommendations of the Internal Operations Committee (IOC) and directed County staff to initiate outreach to cities within Contra Costa County to determine the level of interest cities have in joining with the County to investigate three alternatives for potentially implementing CCE in Contra Costa County. These three alternatives are:

1. Form a new Joint Powers Authority (JPA) of the County and interested cities within Contra Costa County for the purpose of CCE;
2. Form a new JPA in partnership with Alameda County, and interested cities in both counties; and
3. Join the existing CCE program initiated in Marin County known as Marin Clean Energy, or MCE

At its meeting on February 29, 2016, the IOC considered a status report from the Department of Conservation and Development (DCD) concerning CCE and heard from numerous members of the public. The IOC directed DCD to prepare a report to the Board of Supervisors (Board) presenting options for proceeding with potential implementation of CCE in the County's jurisdiction, including continuing work with cities to complete a technical study of the three CCE alternatives mentioned above, or proceeding with steps to join the CCE program known as Marin Clean Energy (MCE). Subsequent to the IOC meeting, staff identified an additional option not discussed at the IOC meeting, which is for the County to conduct an abbreviated technical study summarizing other technical studies that have been recently released by Bay Area cities and counties, and including a comparison of tradeoffs between CCE alternatives.

Results of Outreach to Contra Costa Cities

Between November 2015 and January 2016, County staff conducted a variety of outreach activities to engage cities on the topic of CCE. These activities included meetings with City Managers and other city staff, attendance at the December 3, 2015 Mayors Conference, three public workshops in mid-December held in different regions of the County, and presentations provided by County staff and consultants at five City Council meetings during the month of January.

On November 13, 2015, the County Administrator sent a letter (Attachment A) to all City

Managers in Contra Costa County asking for responses back from cities by January 31, 2016 indicating the level of interest cities have in partnering with the County to study CCE. This letter specifically asked if cities would authorize the County to obtain electrical load data from PG&E for the purpose of potentially conducting a technical study of CCE in Contra Costa County, and if the cities would be willing to contribute financially towards the cost of such a study if one were conducted.

To facilitate greater public understanding of CCE and assist cities in their deliberations on the subject, DCD staff and consultants hosted three public workshops in December 2015: the first on December 10 at Walnut Creek City Hall, the second on December 14 at the Hercules Public Library and the third on December 16 at the Brentwood Community Center. Average attendance at these workshops was approximately 20 people, and several cities sent representatives to attend the workshops.

During the month of January 2016, many City Councils throughout the County placed items on their agendas to discuss their interest in partnering with the County to further study implementation of CCE. County staff and consultants were invited to attend and make presentations at the Concord, Clayton, Pinole, Lafayette and Brentwood City Council meetings.

The workshops and city council meetings held in December and January generated several press articles, which can be viewed at the following links:

- [East Bay Express: \(10/12/15\)](#)
- [Contra Costa Times: \(1/8/16\)](#)
- [The Press: \(10/29/15\)](#)
- [Yodeler \(Sierra Club\): \(1/28/16\)](#)
- [East Bay Express: \(1/29/16\)](#)
- [MarinIJ: \(2/16/16\)](#)
- [The Press: \(2/18/16\)](#)

Responses from Cities

By the end of January, all 16 cities in Contra Costa County not currently enrolled in a CCE program (Richmond, El Cerrito and San Pablo are currently enrolled in Marin Clean Energy) provided written responses to the County (Attachment B) authorizing the County to request electrical load data from PG&E necessary for a technical study of CCE in Contra Costa County. Approximately half of these cities indicated varying degrees of willingness to participate in the cost of a technical study of this data, should such a study proceed. These responses are summarized in Table 1 below.

Table 1. City Responses to County

City	Load Data Authorization	Cost Sharing for Tech Study
Antioch	Yes	No indication

Brentwood	Yes	Yes, not to exceed \$30,000
Clayton	Yes	Yes, pending more details
Concord	Yes	Yes, not to exceed \$25,000
Danville	Yes	Yes, not to exceed \$18,000
Hercules	Yes	No indication
Lafayette	Yes	No indication
Martinez	Yes	No indication
Moraga	Yes	No indication
Oakley	Yes	No indication
Orinda	Yes	Need more information
Pinole	Yes	Need more information
Pittsburg	Yes	Yes, pending more details
Pleasant Hill	Yes	Yes, not to exceed \$15,000
San Ramon	Yes	Maybe, pending more details
Walnut Creek	Yes	Yes, not to exceed \$20,000

Internal Operations Committee Discussion and Direction

At its meeting on February 29, 2016, the Internal Operations Committee directed staff to present the Board with information concerning two options for consideration. One option is to proceed to work with cities in Contra Costa County to conduct a technical study of alternatives for implementing CCE. The other option is to forego such a technical study and proceed immediately to apply for membership in the CCE program called Marin Clean Energy, or MCE. MCE was created in Marin County, and has now expanded to serve jurisdictions in the Counties of Marin, Napa, Solano and Contra Costa, including the cities of Richmond, El Cerrito and San Pablo. Subsequent to the IOC meeting, staff conceived an alternative not discussed at the IOC meeting, which is for the County to conduct an abbreviated technical study summarizing other technical studies that have been recently released by Bay Area cities and counties, and including a comparison of tradeoffs between CCE alternatives.

Each of these three options has advantages and disadvantages, summarized as follows:

Option 1 – Proceed with Technical Study: If the County proceeds to conduct a technical study of CCE with a group of interested Contra Costa cities, the advantages are that County and the cities will receive additional information regarding projected CCE revenues and electricity rates under various renewable energy portfolio scenarios and a comparative analysis of the three CCE alternatives under consideration. The technical study would provide information about revenues that could be generated for new local programs and initiatives to promote energy efficiency and economic development through renewable energy generation projects. The technical study would inform decisions by the Board and city councils to either implement one of the three options studied, or to take no additional action. The disadvantages of conducting a technical study

are the time and expense associated with conducting the study.

The immediate next step in performing a technical study would be for the County to obtain electrical load data from PG&E on behalf of the County and the 16 cities that have authorized the County to do so. This would provide the County with detailed information regarding electrical usage within the covered jurisdictions, and would constitute the raw data necessary to conduct a technical study of potential CCE implementation within the County.

Based on prior Board direction, a technical study of CCE in Contra Costa County would evaluate three options: a program including only interested jurisdictions within Contra Costa County; a program that is a partnership with Alameda County and interested cities in the two-county region; and joining the existing CCE program originated in Marin County known as Marin Clean Energy, or MCE.

Such a technical study would be conducted by a qualified consultant selected through a competitive process. The technical study would evaluate electrical load data to determine the amount of electricity a CCE program would need to procure in order to serve electricity consumers in the participating communities, and would estimate the billing rates that a CCE program would need to charge electricity customers in order to pay for program operations.

The study would analyze how rates might vary under scenarios in which the CCE program offered customers different levels of electricity originating from renewable sources (for example, rates associated with 50% renewable or 100% renewable options). Electricity rates for these scenarios would be compared to products offered by the incumbent utility, PG&E (Attachment C). The technical study would also include a risk analysis of factors that could potentially interfere with successful operation of a CCE program within the County, such as risks associated with price volatility in energy markets and risks stemming from legal or regulatory changes. CCE technical studies performed in other Bay Area counties have included additional components, including analysis of the impact a CCE program might have on local renewable power generation and local job creation.

As stated in Table 1 above, roughly half of the cities in Contra Costa County have indicated some degree of willingness to contribute financially towards the cost of a technical study. Staff recommends that if the Board directs DCD to work with cities to finalize payment arrangement and initiate the technical study, the County and each participating city pay for a portion of the cost of the technical study similar to its proportion of the total population covered under the study.

If the Board directs staff to proceed with a technical study, staff would work with the cities to finalize the scope of the technical study, develop and issue a Request for Proposals (RFP), and select a consultant to perform the technical study. The County would then enter into a contract with the selected consultant. The results of the technical

study would be reported to the cities and the Board of Supervisors, and staff would seek further direction.

Option 2 – Join MCE: The advantages of the County proceeding to take steps now to join MCE are substantially lower start-up costs and a faster time to CCE program launch within the area served. The County would be able to leverage the considerable success MCE has achieved in creating a high-quality CCE program and would not need to go through the time and expense of recreating a similar program. A disadvantage of the County proceeding to join MCE without performing a technical study is that the County will not have access to information about the revenues projected to be generated from CCE electricity sales within the County and the potential to use such revenues to reduce consumer electricity rates, procure greater amounts of renewable energy, incentivize increased local renewable energy generation, or other purposes. If the County joins MCE, the revenues generated from electricity sales in Contra Costa County will be controlled by MCE's Board of Directors, who would represent jurisdictions covering portions or all of four counties, meaning that investments in initiatives such as additional renewable energy production would be spread over a larger area and controlled by a broader group of board members than a Contra Costa JPA. The County would also forego an opportunity to more thoroughly consider the tradeoffs between the three CCE alternatives the Board has previously expressed interest in evaluating through a technical study.

MCE is now comprised of 17 member jurisdictions. These include Marin County, all 11 cities in Marin County, the County of Napa, the City of Benecia, and the cities of Richmond, El Cerrito and San Pablo. MCE is presently accepting applications for new membership from jurisdiction within the four counties currently being served. MCE staff has indicated that all of the cities in Napa County are seeking membership during MCE's current inclusion period, which closes on March 31, 2016. Several additional cities in Contra Costa County are giving consideration to joining MCE as well, including Lafayette, Moraga, Oakley and Walnut Creek. If additional jurisdictions within the Counties of Contra Costa and Solano join MCE, the number of MCE's member jurisdictions could grow to 40 or more. MCE has weighted vote system that is 50% dependent on proportion of electrical load. Were Contra Costa County to join, it would likely have the largest vote of any single member.

If the County directs staff to take steps necessary to join MCE, the technical steps involved would include the County sending a letter of interest to MCE and subsequently adopting an ordinance and entering into a joint powers agreement to join MCE. MCE staff has indicated that the County could submit a letter of interest to MCE after the current MCE inclusion period closes on March 31, 2016, and that cities could join the County in its request for membership. Opening a new inclusion period for the County and Contra Costa cities, and approval of the County's membership in MCE, would be subject to approval by MCE's Board of Directors.

County staff would work with MCE staff to complete other necessary technical and operational steps, and to conduct marketing activities within the unincorporated area as

part of MCE's program launch in the new service area. The Board of Supervisors would need to designate one of its members as the County's representative on the MCE Board of Directors.

Should the Board wish to further contemplate joining MCE in the near term, staff recommends the County consider several uncertainties, the outcome of which will likely have an impact on the County. These include:

- Policy and organizational changes MCE may make as it continues to evolve into a regional agency rather than one originally formed solely to serve Marin County, such as
 - Change of name from MCE to a new name reflecting regional identity
 - Rotate the location of MCE Board meetings and add an office in Contra Costa County
 - Change Board membership and voting structure as MCE membership grows
 - Limits on geography area served and related limits on membership
- Comparison between MCE and PG&E billing rates for Contra Costa customers
- Policies to promote economic development and renewable energy generation in Contra Costa County

MCE is aware that such issues may be of concern to the County and other jurisdictions considering membership in MCE. MCE is evaluating these issues, but decisions have not yet been made (see Attachment D for information from MCE concerning these and other issues).

Option 3: Abbreviated Technical Study: Instead of conducting a full technical study, an alternative the Board may wish to consider is to conduct an abbreviated technical study that would summarize recently released technical studies conducted by other Bay Area cities and counties and would analyze tradeoffs between CCE options; for example, forming a new JPA versus joining an existing CCE program, such as MCE. The advantages of this alternative are that the Board would receive additional information regarding projected electricity rates under varying renewable energy scenarios, risk analysis, and economic development and renewable generation opportunities for jurisdictions that are similar to the County. Another advantage of this alternative is that it could be done at a lower cost and in a shorter amount of time than a full technical study, which would involve obtaining load data from PG&E and performing a detailed analysis of that data. A disadvantage of this alternative is that the analysis would not be specific to the County electricity load data and therefore some of the findings may not be as precise or reliable as a full technical study. Also, if the eventual outcome is to form a new JPA, portions of a full technical study, including analysis of electrical load data specific to Contra Costa County, would need to be subsequently completed. This alternative has been identified by staff following the February 29, 2016 IOC meeting, and was not discussed at the IOC meeting.

Public Involvement

If the Board directs staff to proceed with one of the three CCE options described in this report, staff recommends that the County's activities include a public involvement component. The recommended public involvement activities for each of the three options are as follows:

Option 1: Full Technical Study

- Public workshops to obtain public input
- Focused outreach to key stakeholder groups
- Web-based educational materials
- Presentations at Mayors Conference, city councils and other venues

Option 2: Join MCE

- Coordinate with cities in Contra Costa County to provide information concerning MCE

Option 3: Abbreviated Technical Study

- Public workshop prior to consultant preparing study, and a second public workshop to review a draft of the study
- Additional public involvement actions could be considered upon completion of the abbreviated study

Staff is aware that some members of the public have expressed an interest in creating an Advisory Committee to advise the Board and city councils on this topic. Staff is not recommending the creation of an Advisory Committee due to the added cost and time this would involve, and because staff believes the steps described above will allow for effective public input concerning the development of a CCE program without the significant effort involved in recruiting for and selecting members. However, if a more structured involvement program is desired, staff could suggest approaches for forming and structuring such a committee process.

Project Schedule and Budget

If the Board directs staff to proceed with a technical study of CCE (either a full study or an abbreviated one), this would represent the first phase of activity related to potential implementation of CCE within Contra Costa County. Following a technical study, additional steps would be required to launch a CCE program, should the Board decide to proceed with implementation.

An estimated schedule and budget for fully implementing CCE within the County is attached to this report (Attachment E). The time and expense associated with implementing CCE within the County would depend heavily on the outcome of the technical study and the resulting direction selected by the Board and participating cities.

The CCE option likely to require the greatest commitment of time and resources would be the option to form a new JPA comprised of the County and cities within Contra Costa County. Following the technical study, such an option would involve two additional phases of activity: JPA Formation and Program Launch. The activities associated with these additional project phases and the estimated time and expense to complete these activities are described in greater detail in Attachment D. Staff estimates the total time needed to implement the Contra Costa JPA option and begin providing electricity to customers would be in the range of two to three years and would cost approximately \$2 million. These costs would likely be recovered if a new JPA becomes operational.

If the Board directs staff to proceed with steps necessary to join MCE, either immediately or following a technical study, the cost and time associated with joining MCE are expected to be substantially less than creating a new JPA. The organizational start-up activities and costs associated with creating a new public agency would not be required.

However, a financial tradeoff associated with joining MCE is that jurisdictions in Contra Costa County would not have exclusive control over the revenues generated from a CCE program. If the County and several more cities in Contra Costa County decide to join MCE, Contra Costa jurisdictions would represent the majority of the population served by MCE. Therefore, Contra Costa jurisdictions would have a strong collective voice within MCE. Nevertheless, the majority of seats on the MCE Board of Directors would continue to be held by jurisdictions in Marin, Napa and Solano Counties.

Extrapolating from the experience of the existing CCE programs, CCE revenues generated from the sale of electricity within jurisdictions in Contra Costa County not currently in MCE would likely be in the hundreds of millions of dollars annually. Most of these revenues would be used to pay for energy procurement, with smaller portions used to pay for administrative costs, reserves, and local economic development and energy efficiency programs

CONSEQUENCE OF NEGATIVE ACTION:

If no action is taken, the County will not proceed with implementation of a Community Choice Energy program.

ATTACHMENTS

- Attachment A: CAO Letter to Cities re CCE
- Attachment B: City Responses to CAO Letter re CCE
- Attachment C: PG&E's New Solar Choice Offering
- Attachment D: Marin Clean Energy Documents
- Attachment E: Option 1 Technical Study Schedule and Budget
- PowerPoint Presentation

**MEMORANDUM OF UNDERSTANDING REGARDING
TECHNICAL STUDY OF ELECTRICAL LOAD DATA FOR
COMMUNITY CHOICE ENERGY**

This “Memorandum of Understanding Regarding Technical Study of Electrical Load Data for Community Choice Energy” (“MOU”) is entered as of _____, 2016 (“Effective Date”), by and among Contra Costa County, a political subdivision of the State of California (“County”), the Cities of Brentwood, Clayton, Concord, Martinez, Pittsburg, and Pleasant Hill, and the Towns of Danville and Moraga (collectively the “Funding Cities” and each a “Funding City”), and the Cities of Antioch, Hercules, Oakley, Orinda, Pinole, and San Ramon (collectively the “Non-Funding Cities” and each a “Non-Funding City”). The County, the Funding Cities, and the Non-Funding Cities are referred to herein together as the “Parties,” and each is sometimes referred to herein as a “Party.”

Recitals

- A. The Parties desire to cooperate to study options for participating in Community Choice Energy (“CCE”), pursuant California Public Utilities Code sections 331, 366, and 366.2, and other applicable laws and regulations.
- B. To study options for participating in CCE, the Parties will need to obtain, from Pacific Gas and Electric Company (“PG&E”), electrical load data for all of the Parties’ jurisdictions. The electrical load data for the Parties’ jurisdictions is collectively referred to herein as the “Load Data.” The Load Data is confidential and not subject to public disclosure pursuant to Public Utilities Code section 8380. Each Funding City and each Non-Funding City has authorized PG&E to release to the County the Load Data for electricity use within that city’s jurisdiction. PG&E will require the County to enter into a non-disclosure agreement (“NDA”) before PG&E will release the Load Data to the County.
- C. The Load Data must be analyzed to determine the electricity needs within the Parties’ jurisdictions, and to evaluate options for participating in CCE. The analysis of the Load Data will require the services of a technical consultant.
- D. The Parties enter into this MOU to identify their roles and responsibilities with respect to studying options for participating in CCE, and to establish a procedure for a Non-Funding City to become a Funding City under this MOU.

Agreement

NOW, THEREFORE, the Parties agree as follows:

1. County’s Responsibilities.

- A. Load Data. The County will enter into a NDA with PG&E and will obtain the Load Data from PG&E. The County will maintain and dispose of the Load Data

in accordance with the provisions of the NDA and all applicable laws and regulations.

B. Selection of a Technical Consultant.

1. After the County requests the Load Data from PG&E, the County will prepare and publish a request for proposals (“RFP”) to solicit proposals from qualified technical consultants for the analysis of the Load Data and for the preparation of a technical report. The County will solicit comments on the RFP from the Funding Cities before the County publishes the RFP.
2. An evaluation committee will evaluate responses to the RFP, and will be responsible for either (i) recommending a technical consultant that, in the committee’s opinion, is most qualified to analyze the Load Data, or (ii) recommending that no technical consultant be retained from among the technical consultants that respond to the RFP. The evaluation committee will be comprised of five representatives of the Parties – two representatives from the County, and one representative from each of the Cities of Brentwood and Pittsburg, and the Town of Danville. The County, as the Party responsible for retaining a technical consultant, shall have sole discretion to determine whether to follow the evaluation committee’s recommendation, and to determine whether to enter into a contract with a technical consultant.
3. If the County selects a technical consultant (the “Consultant”) to analyze the Load Data, the County will negotiate and, if negotiations are successful and any required Board of Supervisors approval is obtained, enter into a contract with the Consultant, to require the Consultant to do all of the following: (a) analyze the Load Data to determine the electricity needs within the Parties’ jurisdictions, (b) evaluate the Parties’ options for participating in CCE, (c) prepare a draft technical report documenting the Consultant’s analysis and findings (“Draft Report”), and (d) prepare a final technical report documenting the Consultant’s analysis and findings (“Final Report”), all of which are collectively referred to herein as the “Consultant Services.”

C. Technical Report.

1. After the Consultant prepares the Draft Report, the County will provide each Funding City a copy of that report. The County will provide each Funding City 30 days to comment on the Draft Report, as described in Section 2.A., below, before the County directs the Consultant to prepare the Final Report. The County will review and discuss with the Consultant all comments the County receives from the Funding Cities within that 30-

day period. The County will cooperate with the Funding Cities to resolve any conflicting or inconsistent comments.

2. Within 10 days after the Consultant provides the County the Final Report, the County will provide each Funding City a copy of the Final Report so that the Parties may present the Final Report to their governing bodies in a timely manner. Within 60 days after the Consultant provides the County the Final Report, the County will provide each Funding City: (a) documentation showing the Consultant's total charges to the County for the performance of all Consultant Services, including any reimbursable expenses (the "Total Consultant Charges"), and (b) a request for reimbursement of the Funding City's share of Total Consultant Charges, calculated in accordance with Section 2.C., below.

2. Funding Cities' Responsibilities.

- A. Comments on the RFP and Draft Report. Within 30 days after the County provides a Funding City a copy of the Draft Report, the Funding City will provide the County with that city's written comments related to the Draft Report, if any. The Funding Cities will cooperate with the County to resolve any conflicting or inconsistent comments.
- B. Presentations. The Funding Cities will coordinate with the County to schedule any presentations concerning the Final Report before the cities' governing and advisory bodies.
- C. Reimbursement of County.

1. Calculation of Reimbursement. Except as otherwise specified in Section 2.C.2., below, within 30 days after receipt of a request for reimbursement from the County pursuant to Section 1.C.2., above, each Funding City shall pay the County that city's proportional share of the Total Consultant Charges, calculated as follows:

$$[(\text{Total Consultant Charges})] \times [(\text{Funding City's Population}) \div (\text{Population of unincorporated Contra Costa County} + \text{population of all Funding Cities})] = \text{Amount of Funding City's Reimbursement to County}$$

The request for reimbursement will calculate the amount due from each Funding City based on the total number of Funding Cities, including any city that becomes a Funding City under Section 3.F.

2. Maximum Reimbursement for Specified Funding Cities. Notwithstanding the resultant of the calculation in Section 2.C.1., above, no Funding City shall be required to reimburse the County in excess of the Funding City's approved maximum reimbursement limit, as follows:

<u>Funding City</u>	<u>Maximum Reimbursement</u>
Brentwood	\$30,000
Clayton	\$5,000
Concord	\$25,000
Danville	\$18,000
Martinez	\$15,000
Moraga	\$10,000
Pittsburg	\$15,000
Pleasant Hill	\$15,000

3. **Miscellaneous Provisions.**

- A. Confidentiality of Data. The Parties agree that, notwithstanding anything to the contrary contained herein, nothing in this MOU shall require the County to disclose, disseminate, or dispose of Load Data in any manner that would violate the terms of the NDA, or any state or federal laws or regulations.
- B. No Obligations to Pursue CCE. The purpose of this MOU is to provide for the Parties' roles and responsibilities related to undertaking a technical study to analyze options for the Parties' potential future participation in CCE. Nothing in this MOU obligates any Party to become a community choice aggregator, or to participate with other Parties to establish a community choice aggregator, or to participate in CCE, or to take any other future discretionary actions.
- C. No Joint Powers Agency. Nothing in this MOU creates, nor shall it be construed as creating, a partnership, joint venture, or a joint exercise of powers agency separate and apart from the Parties hereto.
- D. Assignment; No Third-Party Beneficiaries. This MOU may not be assigned unless the assignment is approved in writing by all Parties. Nothing in this MOU, express or implied, is intended to confer on any person, other than the Parties and their successors and assigns, any rights or remedies by reason of this MOU.
- E. Notices. All notices and other correspondence required to be given under this MOU shall be in writing, and shall be delivered in person, by overnight carrier, or by U.S. Mail, to the following person and address designated for each Party. A notice shall be deemed given on the same day if it is personally delivered, on the next day if it is delivered by overnight carrier, or on the fifth (5th) day after the postmark date if it is given by U.S. Mail.

Contra Costa County:
Jason Crapo
Dept. of Conservation and
Development
30 Muir Road
Martinez CA 94553

Antioch:
Julie Haas-Wajdowicz
200 H Street
Antioch CA 94531

Brentwood:
Casey McCann
150 Park Way
Brentwood CA 94513

Concord:
Laura Simpson
1950 Parkside Drive
Concord CA

Clayton:
Gary Napper
6000 Heritage Trail
Clayton CA 94517

Danville:
Nat Rojanasathira
510 La Gonda Way
Danville CA 94526

Hercules:
David Biggs
111 Civic Drive
Hercules CA 94547

Martinez:
Michael Chandler
525 Henrietta Street
Martinez CA 94553

Moraga:
Ellen Clark
329 Rheem Boulevard
Moraga CA 94556

Oakley:
Joshua Mc Murray
3231 Main Street
Oakley CA 94561

Orinda:
Daisy Allen
22 Orinda Way
Orinda CA 94563

Pinole:
Michelle Fitzer
2131 Pear Street
Pinole CA 94564

Pittsburg:
Peter Guadagni
440 Walnut Avenue
Vallejo CA 94592

Pleasant Hill:
Andrew Murray
100 Gregory Lane
Pleasant Hill CA 94523

San Ramon:
Lauren Barr
2401 Crow Canyon Road
San Ramon CA 94583

A Party may change its contact person and address listed above by giving written notice to all other Parties.

- F. Amendment. At any time before September 1, 2016, a Non-Funding City may become a Funding City by providing all Parties written notice that the city will be a Funding City under this MOU. The notice shall specify the city's maximum reimbursement limit under Section 2.C.2., if any. A city giving notice shall have all the rights and obligations of a Funding City under this MOU, effective on the date notice is given. At any time during the term of this MOU, a Funding City may increase, but not decrease, its Maximum Reimbursement limit under Section 2.C.2. by providing all Parties written notice specifying the increased limit. Except as otherwise provided in this Section 3.F., this MOU may be modified only by a written amendment signed by all Parties.

- G. Effective. This MOU shall be effective as to a Party upon the execution of the MOU by that Party.
- H. Construction. If any provision of this MOU is held by a court of competent jurisdiction to be invalid, void, or unenforceable, the remaining provisions will continue in full force.
- I. Governing Law. This MOU shall be governed and construed in accordance with California law.
- J. Counterparts. This MOU may be executed in one or more counterparts, each of which shall be deemed an original.

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CONTRA COSTA COUNTY

By: _____

Jason Crapo

Deputy Director

Approved as to form:

Sharon L. Anderson, County Counsel

By: _____

Deputy County Counsel

SMS

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CITY OF ANTIOCH

By: _____
Forrest Ebbs
Community Development Director

Approved as to form:

By: _____
City Attorney

CITY OF BRENTWOOD

By: _____

Gustavo Vina

City Manager

Approved as to form:

By: _____

City Attorney

CITY OF CONCORD

By: _____

Valerie Barone

City Manager

Approved as to form:

By: _____

City Attorney

CITY OF CLAYTON

By: _____

Gary Napper
City Manager

Approved as to form:

By: _____

City Attorney

TOWN OF DANVILLE

By: _____

Joseph A. Calabrigo

Town Manager

Approved as to form:

By: _____

Town Attorney

CITY OF HERCULES

By: _____

David Biggs

City Manager

Approved as to form:

By: _____

City Attorney

CITY OF MARTINEZ

By: _____

Jim Jakel
Interim City Manager

Approved as to form:

By: _____

City Attorney

TOWN OF MORAGA

By: _____

Bob Priebe

Interim Town Manager

Approved as to form:

By: _____

Town Attorney

CITY OF OAKLEY

By: _____
Bryan H. Montgomery
City Manager

Approved as to form:

By: _____
City Attorney

CITY OF ORINDA

By: _____

Janet Keeter

City Manager

Approved as to form:

By: _____

City Attorney

CITY OF PINOLE

By: _____

Michelle Fitzer

City Manager

Approved as to form:

By: _____

City Attorney

CITY OF PITTSBURG

By: _____

Joseph Sbranti

City Manager

Approved as to form:

By: _____

City Attorney

CITY OF PLEASANT HILL

By: _____

June W. Catalano

City Manager

Approved as to form:

By: _____

City Attorney

CITY OF SAN RAMON

By: _____

Greg Rogers

City Manager

Approved as to form:

By: _____

City Attorney



Legislation Details (With Text)

File #:	17-302	Version:	1	Name:	
Type:	Discussion/Action Item	Status:		Agenda Ready	
File created:	7/20/2017	In control:		City Council	
On agenda:	7/25/2017	Final action:			
Title:	Electing City Council Members as an Approved Employee Group the Ability to Obtain Health Benefits from the City's CalPERS Medical Plan Recommendation: Adopt two (2) CalPERS Resolutions which will add City Council members as an authorized employee group to the City's health and benefit plans through CalPERS.				
Sponsors:					
Indexes:					
Code sections:					
Attachments:	Agenda Item Review and Approval Form Staff Report - CalPERS Resolutions - Council Benefits Resolution - Hercules - 701 NonPERS Council Resolution - Hercules - 005 PERS Council				

Date	Ver.	Action By	Action	Result
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Electing City Council Members as an Approved Employee Group the Ability to Obtain Health Benefits from the City's CalPERS Medical Plan

Recommendation: Adopt two (2) CalPERS Resolutions which will add City Council members as an authorized employee group to the City's health and benefit plans through CalPERS.

AGENDA ITEM REQUEST FORM

Department: Administrative Services

Department Director: Lori Martin

Phone: 799-8215

Meeting Date: July 25, 2017

Final Decision Date Deadline:

SUBJECT:

Approve Resolutions Electing City Council Members as an Approved Employee Group the Ability to Obtain Health Benefits from the City's CalPERS Medical Plan.

INDICATE APPROPRIATE BODY

☒ City Council

☐ Successor Agency to the Redevelopment Agency

☐ Public Finance Authority

☐ Finance Commission

☐ Planning Commission

☐ Community/Library Services Commission

☐ Oversight Board

☐ Other _____

ITEM

☐ Presentation/Introduction

☐ Study Session

☐ Grant Application/Acceptance

☐ Public Hearing

☒ Resolution

☐ Video/PowerPoint

☐ Consent Calendar

☐ Ordinance

☒ Discussion Action

☐ Contract/Agreement

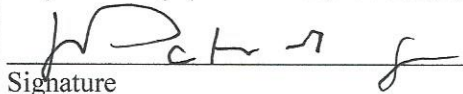
RECOMMENDED ACTION:

Adopt two (2) CalPERS Resolutions which will add City Council Members as an authorized employee group to the City's Health and Benefit Plans through CalPERS.

☐ Copy of executed Resolution/Ordinance/Contract/Application required immediately upon approval.

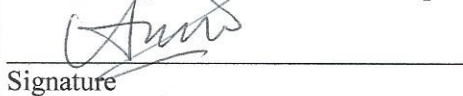
REVIEWED AND APPROVED FOR AGENDA:

City Attorney (if Contract, Ordinance or Resolution)


Signature

7-20-17
Date

Finance Department for Fiscal Impact


Signature

7/20/17
Date

City Manager


Signature

7/20/17
Date

AGENDA ITEM NO:



STAFF REPORT TO THE CITY COUNCIL

DATE: Regular Meeting of July 25, 2017

TO: Members of the City Council

SUBMITTED BY: David Biggs, City Manager
Lori Martin, Administrative Services Director/City Clerk

SUBJECT: Approve Resolutions Electing City Council Members as an Approved Employee Group the Ability to Obtain Health Benefits from the City's CalPERS Medical Plan

RECOMMENDED ACTION:

Adopt two CalPERS Resolutions which will add City Council Members as an authorized employee group to the City's Health and Benefit Plans through CalPERS.

COMMISSION/SUBCOMMITTEE ACTION AND RECOMMENDATION:

There was no commission or subcommittee review on this item.

FISCAL IMPACT OF RECOMMENDATION:

The annual cost is estimated not to exceed approximately \$45,000.

DISCUSSION:

At the July 11, 2017 City Council meeting, Council took action on a 3-2 vote to approve Resolution 17-054 to reinstate limited health care benefits for City Council Members. In order for this to take effect, CalPERS requires by City Council adoption two Resolutions electing that City Council Members which are CalPERS members and non-CalPERS members be entered as an authorized employee group to access the City's CalPERS Health Benefits program.

City Council took action at the July 11, 2017 City Council meeting to allow health insurance coverage to Members of the City Council with the City covering the cost at the Kaiser single level and set the opt-out provision at 50%. In addition the City Council added a provision to allow a Council Member to waive the health insurance benefit and opt-out option.

ATTACHMENTS:

1. Resolution Electing to be Subject to the Public Employees' Medical and Hospital Care Act at an Equal Amount for Employees and Annuitants with Respect to a Recognized Employee Organization – 701 Non-PERS City Council
2. Resolution Electing to be Subject to the Public Employees' Medical and Hospital Care Act at an Equal Amount for Employees and Annuitants with Respect to a Recognized Employee Organization – 005 PERS City Council

RESOLUTION NO. Number
ELECTING TO BE SUBJECT TO THE PUBLIC EMPLOYEES' MEDICAL AND HOSPITAL CARE ACT
AT AN EQUAL AMOUNT FOR EMPLOYEES AND ANNUITANTS
WITH RESPECT TO A RECOGNIZED EMPLOYEE ORGANIZATION
701 NON-PERS CITY COUNCIL

- WHEREAS, (1) A contracting agency meeting the eligibility requirements set forth in Government Code Section 22920, may obtain health benefit plan(s), as defined under Government Code Section 22777, by submitting a resolution to the Board of Administration of the California Public Employees' Retirement System (the "Board"), and upon approval of such resolution by the Board, become subject to the Public Employees' Medical and Hospital Care Act (the "Act"); and
- WHEREAS, (2) **City of Hercules** is a contracting agency eligible to be subject to the Act under Government Code Section 22920; and
- WHEREAS, (3) Government Code Section 22892(a) provides that a contracting agency subject to Act shall fix the amount of the employer contribution by resolution; and
- WHEREAS, (4) Government Code Section 22892(b) provides that the employer contribution shall be an equal amount for both employees and annuitants, but may not be less than the amount prescribed by Section 22892(b) of the Act; and
- WHEREAS, (5) **City of Hercules** desires to obtain for its employees and annuitants who are members of **Non-PERS City Council Members** the benefit of the Act and to accept the liabilities and obligations of an employer under the Act; now, therefore, be it
- RESOLVED, (a) **City of Hercules** elects to be subject to the provisions of the Act; and be it further
- RESOLVED, (b) That the employer contribution for each employee or annuitant shall be the amount necessary to pay the full cost of his/her enrollment, including the enrollment of family members, in a health benefits plan up to a maximum of **the PEMHCA Minimum** per month, plus administrative fees and Contingency Reserve Fund assessments; and be it further
- RESOLVED, (c) **City of Hercules** has fully complied with any and all applicable provisions of Government Code Section 7507 in electing the benefits set forth above; and be it further
- RESOLVED, (d) That the participation of the employees and annuitants of **City of Hercules** shall be subject to determination of its status as an "agency or instrumentality of the state or political subdivision of a State" that is eligible to participate in a governmental plan within the meaning of Section 414(d) of the Internal Revenue Code, upon publication of final Regulations pursuant to such Section. If it is determined that **City of Hercules** would not qualify as an agency or instrumentality of the state or political subdivision of a State under such final Regulations, CalPERS may be obligated, and reserves the right to terminate the health coverage of all participants of the employer.

- RESOLVED, (e) That the executive body appoint and direct, and it does hereby appoint and direct, **David Biggs, City Manager** to file with the Board a verified copy of this resolution, and to perform on behalf of **City of Hercules** all functions required of it under the Act; and be it further
- RESOLVED, (f) That coverage under the Act be effective on **September 1, 2017**.

Adopted at a regular or special meeting of the City of Hercules City Council at 111 Civic Drive, Hercules, CA 94547, this 8th day of August, 2017.

Signed: _____
Myrna de Vera, Mayor

Attest: _____
Chris Kelley, Vice Mayor

INSTRUCTIONS

This resolution form is the approved form designated by the California Public Employees' Retirement System (CalPERS). It should be used by a contracting agency for the purpose of electing to be subject to Public Employees' Medical and Hospital Care Act (PEMHCA) and to fix the monthly employer health contribution for employees and annuitants in accordance with Government Code Section 22892.

If the resolution is filed **on or before the tenth day of any month, it will be effective on the first of the following month** (date stamped as received by CalPERS; See address below).

WHEREAS, (2) should be completed with full name of the contracting agency.

WHEREAS, (5) should be completed with full name of the contracting agency and recognized employee organization.

RESOLVED, (a) should be completed with full name of the contracting agency.

RESOLVED, (b) should be completed to specify medical groups and the amount of the employer contribution toward the cost of enrollment for active employees and annuitants. The amount specified must be an amount equal to or greater than that prescribed by Section 22892(b).

Commencing January 1, 2009, the employer contribution shall be adjusted annually by the Board to reflect any change in the medical component of the Consumer Price Index, and shall be rounded to the nearest dollar.

RESOLVED, (c) should be completed with full name of the contracting agency.

RESOLVED, (d) should be completed with full name of the contracting agency.

RESOLVED, (e) requests the position title of the individual who handles the PEMHCA resolution for the contracting agency.

RESOLVED, (e) should be completed with full name of the contracting agency.

RESOLVED, (f) should be completed with the date the coverage is to become effective.

For resolution processing, deliver to the following:

Overnight Mail Service

California Public Employees' Retirement System
Health Resolution & Compliance Services, HAMD
400 Q Street
Sacramento, CA 95811

Regular Mail

California Public Employees' Retirement System
Health Resolution & Compliance Services, HAMD
PO BOX 942714
Sacramento, CA 94229-2714

The certification shown following the resolution is to be completed by those individuals authorized to sign for the contracting agency in legal actions and is to include the name of the executive body; i.e. Board of Directors, Board of Trustees, etc., the location and the date of signing.

RESOLUTION NO. Number
ELECTING TO BE SUBJECT TO THE PUBLIC EMPLOYEES' MEDICAL AND HOSPITAL CARE ACT
AT AN EQUAL AMOUNT FOR EMPLOYEES AND ANNUITANTS
WITH RESPECT TO A RECOGNIZED EMPLOYEE ORGANIZATION
005 PERS CITY COUNCIL

- WHEREAS, (1) A contracting agency meeting the eligibility requirements set forth in Government Code Section 22920, may obtain health benefit plan(s), as defined under Government Code Section 22777, by submitting a resolution to the Board of Administration of the California Public Employees' Retirement System (the "Board"), and upon approval of such resolution by the Board, become subject to the Public Employees' Medical and Hospital Care Act (the "Act"); and
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- WHEREAS, (4) Government Code Section 22892(b) provides that the employer contribution shall be an equal amount for both employees and annuitants, but may not be less than the amount prescribed by Section 22892(b) of the Act; and
- WHEREAS, (5) **City of Hercules** desires to obtain for its employees and annuitants who are members of **PERS City Council Members** the benefit of the Act and to accept the liabilities and obligations of an employer under the Act; now, therefore, be it
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- RESOLVED, (e) That the executive body appoint and direct, and it does hereby appoint and direct, **David Biggs, City Manager** to file with the Board a verified copy of this resolution, and to perform on behalf of **City of Hercules** all functions required of it under the Act; and be it further
- RESOLVED, (f) That coverage under the Act be effective on **September 1, 2017**.

Adopted at a regular or special meeting of the City of Hercules City Council at 111 Civic Drive, Hercules, CA 94547, this 8th day of August, 2017.

Signed: _____
Myrna de Vera, Mayor

Attest: _____
Chris Kelley, Vice Mayor

INSTRUCTIONS

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RESOLVED, (a) should be completed with full name of the contracting agency.

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The certification shown following the resolution is to be completed by those individuals authorized to sign for the contracting agency in legal actions and is to include the name of the executive body; i.e. Board of Directors, Board of Trustees, etc., the location and the date of signing.



Legislation Details (With Text)

File #: 17-299 **Version:** 1 **Name:**
Type: Discussion/Action Item **Status:** Agenda Ready
File created: 7/18/2017 **In control:** City Council
On agenda: 7/25/2017 **Final action:**
Title: Contract Amendment No. 2 with WSP USA
Recommendation: Approve contract amendment No. 2 with WSP USA for \$25,704 for a total not to exceed contract amount of \$63,154 to conduct a feasibility study for remedial work within Refugio Creek associated with the Path to Transit project and perform site inspections and maintenance prior to the remediation.

Sponsors:

Indexes:

Code sections:

Attachments: [Agenda Item Review and Approval Form](#)
[Staff Report - WSP Amend No 2](#)
[Attachment 1 - Figures 1-5](#)
[Attachment 2 - Resolution](#)
[Attachment 3 - Contract Amendment No.2](#)
[Attachment 4 - Proposal](#)

Date	Ver.	Action By	Action	Result
------	------	-----------	--------	--------

Contract Amendment No. 2 with WSP USA

Recommendation: Approve contract amendment No. 2 with WSP USA for \$25,704 for a total not to exceed contract amount of \$63,154 to conduct a feasibility study for remedial work within Refugio Creek associated with the Path to Transit project and perform site inspections and maintenance prior to the remediation.

AGENDA ITEM REQUEST FORM

Department: Public Works

Department Director: Michael Roberts

Phone: 799-8241

Meeting Date: July 25, 2017

Final Decision Date Deadline:

SUBJECT:

Contract Amendment No.2 with WSP USA for \$25,704, for a Not to Exceed Total Contract Amount of \$63,154, to Conduct a Feasibility Study for Remedial Work within Refugio Creek associated with the Path To Transit Project and

INDICATE APPROPRIATE BODY

☒ City
Council

☐ Successor Agency to the
Redevelopment Agency

☐ Public Finance
Authority

☐ Finance
Commission

☐ Planning
Commission

☐ Community/Library
Services Commission

☐ Oversight Board

☐ Other _____

ITEM

☐ Presentation/Introduction

☐ Study Session

☐ Grant Application/Acceptance

☐ Public Hearing

☒ Resolution

☐ Video/PowerPoint

☐ Consent Calendar

☐ Ordinance

☒ Discussion Action

☒ Contract/Agreement

RECOMMENDED ACTION:

Adopt a resolution authorizing the City Manager to execute Contract Amendment No.2 with WSP USA for \$25,704, for a not to exceed total contract amount of \$63,154, to conduct a feasibility study for remedial work within Refugio Creek associated with the Path To Transit Project and perform site inspections and maintenance prior to the remediation.

☐ Copy of executed Resolution/Ordinance/Contract/Application required immediately upon approval.

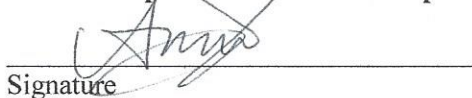
REVIEWED AND APPROVED FOR AGENDA:

City Attorney (if Contract, Ordinance or Resolution)


Signature

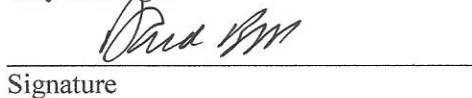
7-20-17
Date

Finance Department for Fiscal Impact


Signature

7/20/17
Date

City Manager


Signature

7/20/17
Date

AGENDA ITEM NO:



STAFF REPORT TO THE CITY COUNCIL

DATE: Regular Meeting of July 25, 2017

TO: The Mayor and Members of the City Council

SUBMITTED BY: Mike Roberts, Public Works Director/City Engineer

SUBJECT: Contract Amendment No.2 with WSP USA for \$25,704, for a Not to Exceed Total Contract Amount of \$63,154, to Conduct a Feasibility Study for Remedial Work within Refugio Creek associated with the Path To Transit Project and Perform Site Inspections and Maintenance Prior to the Remediation

RECOMMENDED ACTION:

Adopt a resolution authorizing the City Manager to execute Contract Amendment No.2 with WSP USA for \$25,704, for a not to exceed total contract amount of \$63,154, to conduct a feasibility study for remedial work within Refugio Creek associated with the Path To Transit Project and perform site inspections and maintenance prior to the remediation.

FISCAL IMPACT OF RECOMMENDATION:

There is sufficient funding in the Measure J Street Fund to cover the \$25,704 cost of Amendment No. 2 in addition to the original agreement and Amendment No.1.

DISCUSSION:

In early December 2016 an oily sheen was observed from the Bayfront Bridge bubbling up to the surface of Refugio Creek before it enters into the San Pablo Bay (Figure 1). The creek had recently been realigned and the bridge was under construction as part of the Path To Transit Phase of the Regional Intermodal Transit Center Project. Staff subsequently notified the appropriate authorities, authorized the City's contract construction manager to utilize his firm's (then named Parsons Brinckerhoff) environmental division to perform emergency surface water sampling and analytical testing, and had an absorbent boom installed to contain the oily sheen. The test results from the water samples taken from the creek detected the presence of petroleum hydrocarbons found in gasoline, diesel, and motor oil.

Given the urgency to determine the extent of the soil contamination, staff then entered into a contract with the same environmental team now called WSP USA, which was in the process of acquiring Parsons Brinckerhoff, on February 1, 2017 for \$15,520 to map any potential metal sources (i.e. which could be leaking contaminants) below the surface of the ground using a magnetometer and obtain and test 11 soil borings in the vicinity of the oil sheen. Buried debris was subsequently located (Figure 2) and the general location of the petroleum hydrocarbon plume was successfully mapped. Staff subsequently entered into Amendment No.1 for \$21,926 to refine the mapping of the lateral extent and vertical thickness of the petroleum hydrocarbon plume to the level needed to develop a remediation plan (Figures 3, 4 & 5). The scope of work included additional borings and analytical testing (The full report for the final testing and analysis can be accessed at www.ci.hercules.ca.us/documents/Projects/Path2Transit/Refugio-Creek-2ndPhase-Investigation.pdf). The work also included a site inspection, boom replacement, and ongoing communication with California Department of Fish & Wildlife.

Now that the extent of the contamination is known, it is recommended City Council approve Amendment No.2 with WSP USA for \$25,704 to complete a feasibility study to evaluate options to remediate the petroleum hydrocarbon contaminants including cost, technical feasibility, regulatory steps required, and estimated duration. Amendment No.2 also includes inspection of the site and maintenance of the absorbent boom for up to a 5 month period. The feasibility study is anticipated to take approximately 1 month to complete, after which time final design, if needed, can be completed and a contractor can be hired to perform the remediation.

The remediation work could include temporarily re-routing Refugio Creek, constructing a coffer dam to isolate the contaminated area, grading including removal of the debris and contaminated soil, and permits from the Corps of Engineers, California Fish & Wildlife, and the San Francisco Bay Conservation and Development Commission.

A representative from WSP USA will be attending the Council meeting and be able to respond to any specific questions.

ATTACHMENTS:

Attachment 1 - Figures 1-5

Attachment 2 – Resolution

Attachment 3 – Contract Amendment No.2

Attachment 4 - Proposal

Description:

Consultant Contract Amendment No.2 to conduct a feasibility study.

Funding Source:

Measure J Fund	(263-5432-611.90-00)	\$25,704
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Budget Recap:

Total Estimated cost:	\$25,704	New Revenue:	\$
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Amount Budgeted: \$25,704 Lost Revenue: \$

New funding required: \$ New Personnel: \$

Council Policy Change: Yes ☐ No ☒

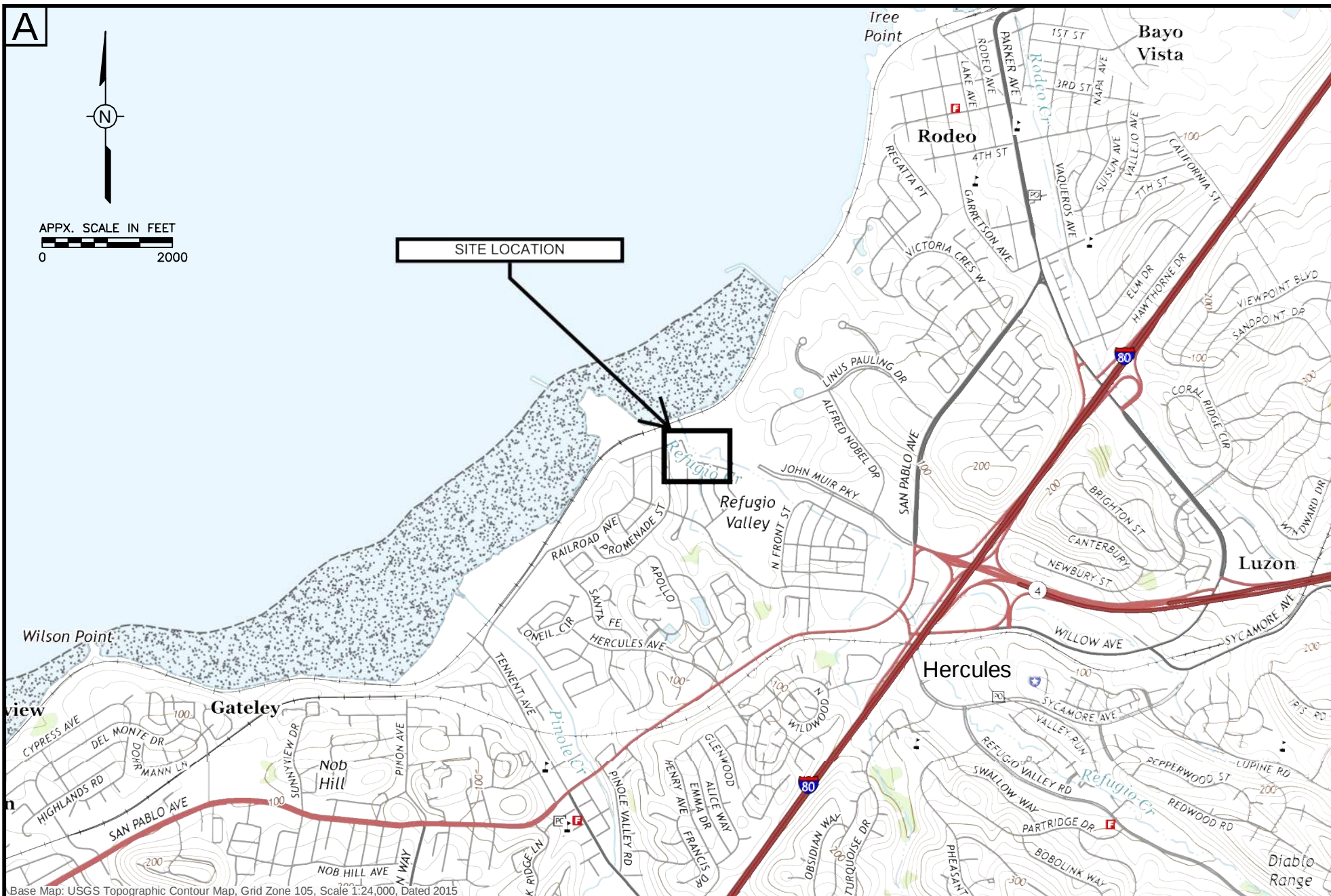


FIGURE 1

SITE LOCATION MAP

FIRST AND SECOND PHASE
SUBSURFACE INVESTIGATION
REFUGIO CREEK
PREPARED FOR
CITY OF HERCULES
111 CIVIC DRIVE, HERCULES, CALIFORNIA

Drawn By: CRB 5/19/2017

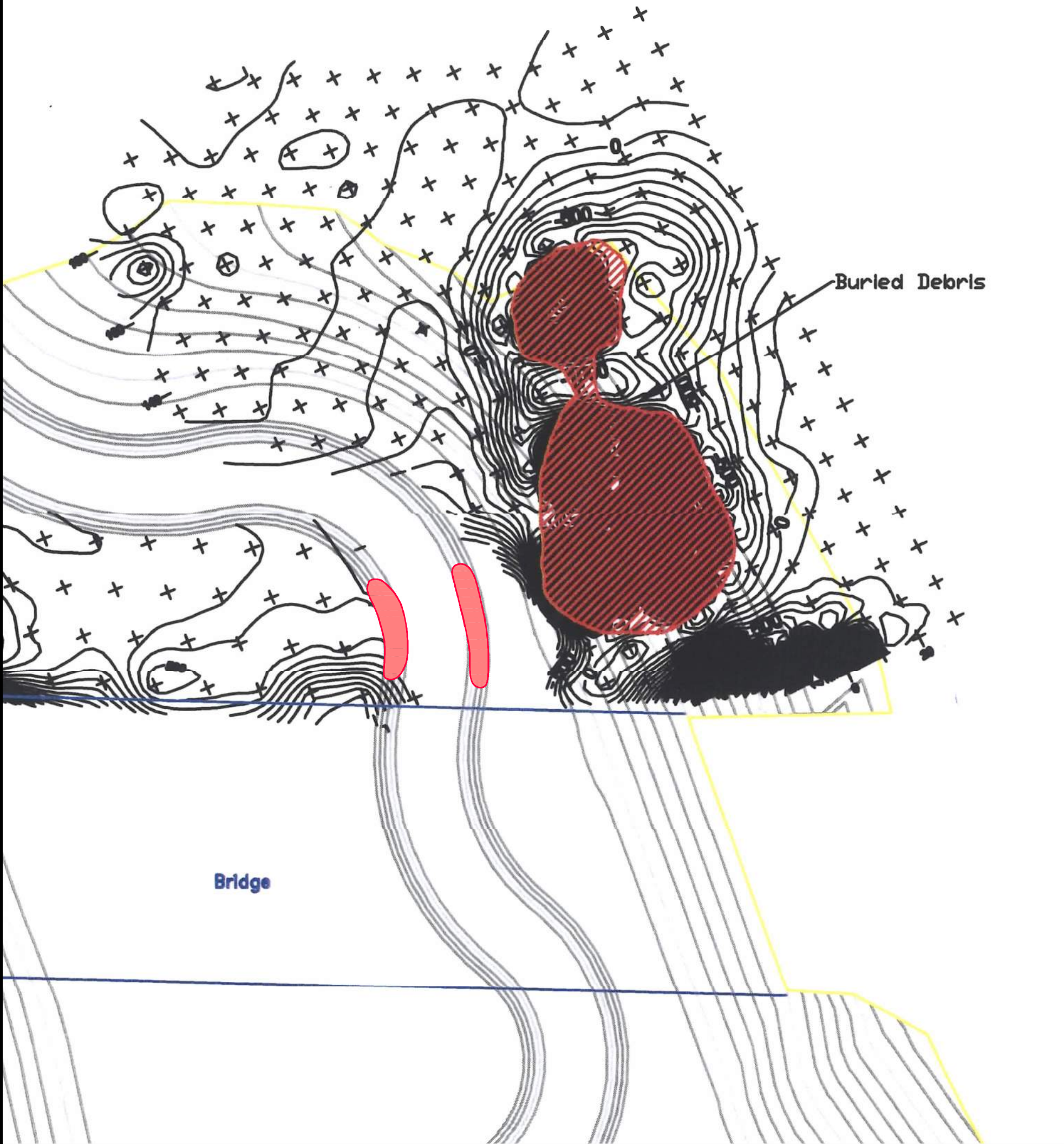
Checked:

Approved:

DWG Name: 31400611.001

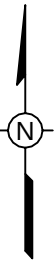


WSP USA Inc.
2025 GATEWAY PLACE
SUITE 348
SAN JOSE, CA 95110
TEL: +1 408.453.6100



LEGEND

 Areas with visible oily plume

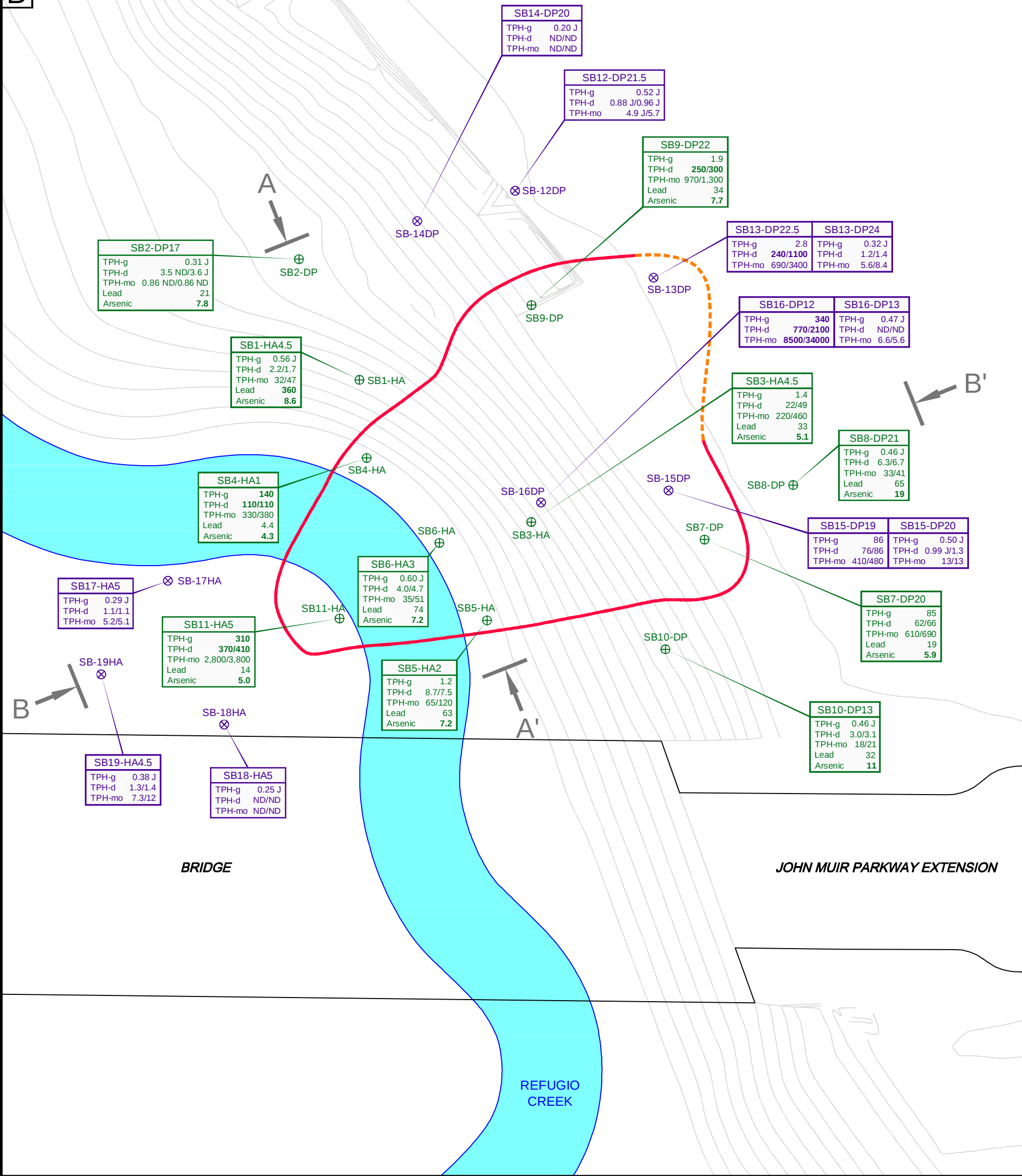


APPX. SCALE IN FEET
0 20

Base map: Magnetic contour map provided by J R Associates
Topographic map produced by WSP/Parsons Brinkerhoff, 2017

 WSP USA Inc. 2025 GATEWAY PLACE SUITE 348 SAN JOSE, CA 95110 TEL: +1 408.453.6100	FIGURE 2	FIRST AND SECOND PHASE SUBSURFACE INVESTIGATION REFUGIO CREEK PREPARED FOR CITY OF HERCULES 111 CIVIC DRIVE, HERCULES, CALIFORNIA	Drawn By: CRB 5/19/2017
	SITE AREA INCLUDING MAGNETIC CONTOUR MAP AND OILY SHEEN LOCATIONS		Checked: Approved: DWG Name: 31400611.002

B



LEGEND

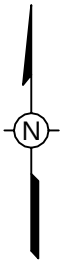
Boring ID
⊕ SB - soil boring, sequential number, HA - hand auger or DP - direct push
⊗ Soil boring location performed March 8, 2017
⊗ Soil boring location performed May 9, 2017

SAMPLE ID	SB - soil boring, sequential number, HA - hand auger or DP - direct push, sample depth
TPH-g	Total Petroleum Hydrocarbons as gasoline (C6-C10) by EPA 8015B
TPH-d	Total Petroleum Hydrocarbons as diesel (C10-C-23) by EPA 8015B
TPH-mo	Total Petroleum Hydrocarbons as motor oil (C18-C36) by EPA 8015B
Lead	Lead by EPA 6020
Arsenic	Arsenic by EPA 6020

85 Soil sample result in mg/kg
310 Sample result exceeds compound specific Environmental Screening Level (ESL)
6.3/6.7 Result with silica gel cleanup/result without silica gel cleanup
ND Analyte not detected at laboratory method detection limit
J Analyte reported at a concentration above the laboratory method detection limit but below the reporting limit. The reported value is an estimate.

Approximate area of TPH-mo impact
Inferred area of TPH-mo impact. Further delineation may be necessary.

A-A' Cross section location



APPX. SCALE IN FEET
0 20

Base map: Topographic map produced by WSP|Parsons Brinckerhoff, 2017

FIGURE 3

SAMPLE LOCATIONS AND PERTINENT
ANALYTICAL DATA SHOWING APPROXIMATE
EXTENT OF AREA OF IMPACT

FIRST AND SECOND PHASE
SUBSURFACE INVESTIGATION
REFUGIO CREEK
PREPARED FOR
CITY OF HERCULES
111 CIVIC DRIVE, HERCULES, CALIFORNIA

Drawn By: CRB 5/23/2017

Checked: CDW 5/23/2017

Approved:

DWG Name: 31400611.003

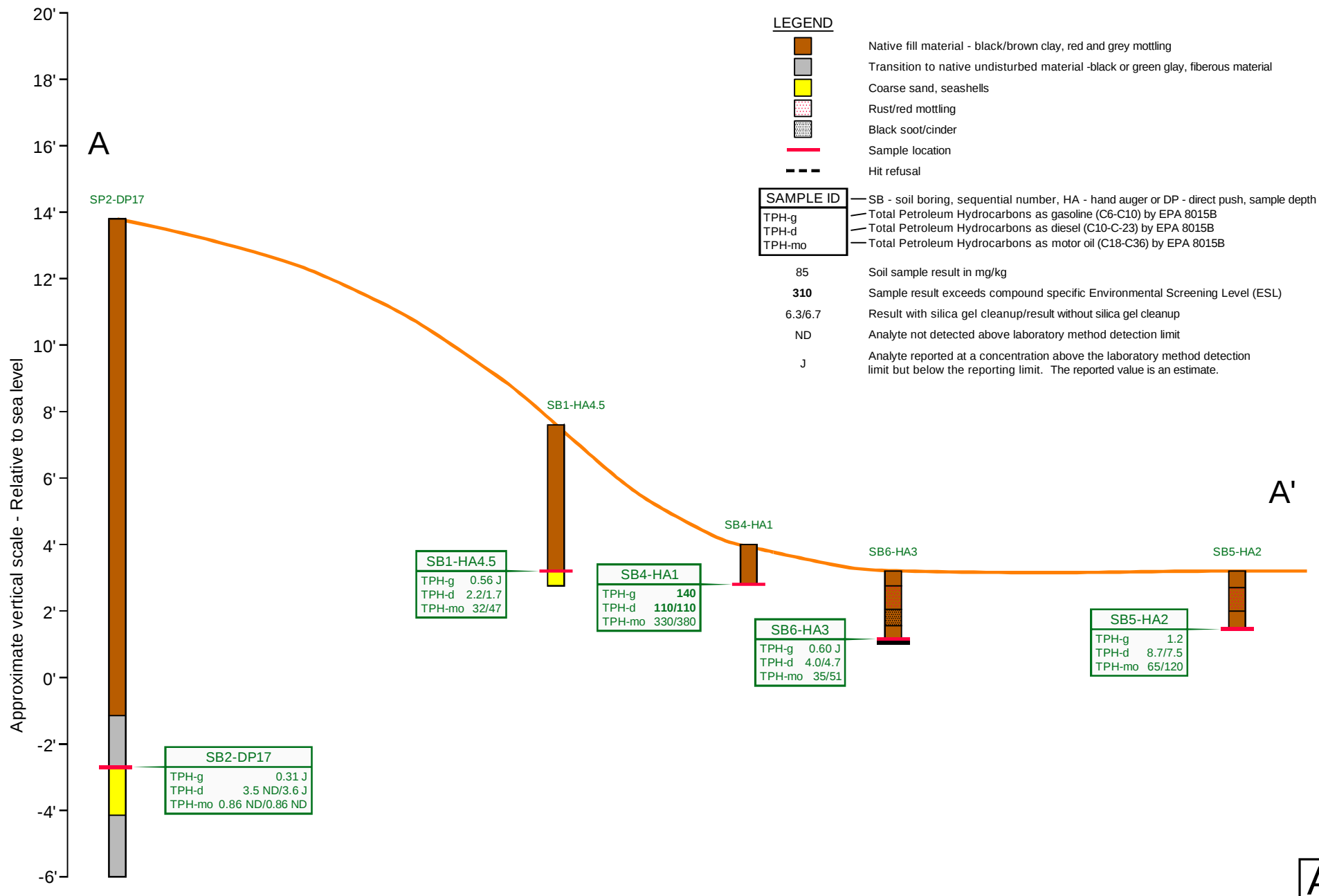


FIGURE 4

CROSS SECTION A-A'
SHOWING PETROLEUM ANALYTICAL DATA

FIRST AND SECOND PHASE
SUBSURFACE INVESTIGATION
REFUGIO CREEK
PREPARED FOR
CITY OF HERCULES
111 CIVIC DRIVE, HERCULES, CALIFORNIA

Drawn By: CRB 5/22/2017
Checked:
Approved:
DWG Name: 31400611.004



WSP USA Inc.
2025 GATEWAY PLACE
SUITE 348
SAN JOSE, CA 95110
TEL: +1 408.453.6100

LEGEND

-  Native fill material - black/brown clay, red and grey mottling
-  Transition to native undisturbed material - black or green clay, fibrous material
-  Coarse sand, seashells
-  Rust/red mottling
-  Black soot/cinder
-  Filamentous metal/rusted metal
-  Sample location
-  Hit refusal
-  Free petroleum observed in soil/sediment core

SAMPLE ID	
TPH-g	Total Petroleum Hydrocarbons as gasoline (C6-C10) by EPA 8015B
TPH-d	Total Petroleum Hydrocarbons as diesel (C10-C-23) by EPA 8015B
TPH-mo	Total Petroleum Hydrocarbons as motor oil (C18-C36) by EPA 8015B

- 85 Soil sample result in mg/kg
- 310 Sample result exceeds compound specific Environmental Screening Level (ESL)
- 6.3/6.7 Result with silica gel cleanup/result without silica gel cleanup
- ND Analyte not detected above laboratory method detection limit
- J Analyte reported at a concentration above the laboratory method detection limit but below the reporting limit. The reported value is an estimate.

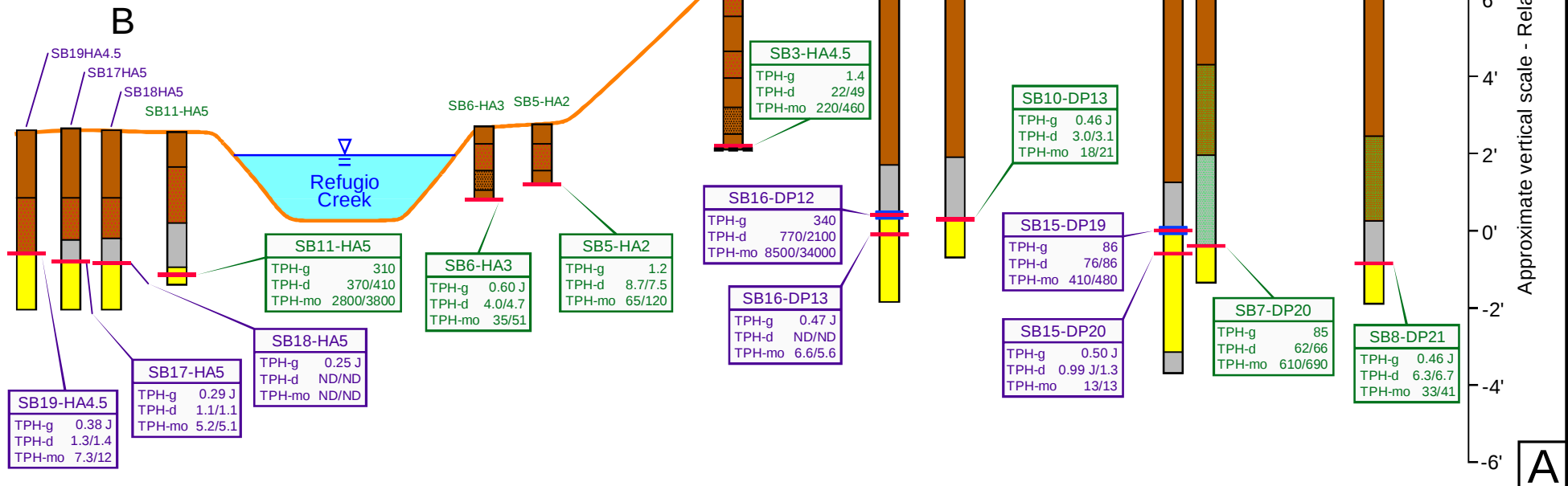


FIGURE 5

CROSS SECTION B-B'
SHOWING PETROLEUM ANALYTICAL RESULTS

FIRST AND SECOND PHASE
SUBSURFACE INVESTIGATION
REFUGIO CREEK
PREPARED FOR
CITY OF HERCULES
111 CIVIC DRIVE, HERCULES, CALIFORNIA

Drawn By: CRB 5/22/2017
Checked:
Approved:
DWG Name: 31400611.005



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RESOLUTION NO. 17-

RESOLUTION AUTHORIZING THE CITY MANAGER TO EXECUTE CONTRACT AMENDMENT NO.2 WITH WSP USA FOR \$25,704, FOR A NOT TO EXCEED TOTAL CONTRACT AMOUNT OF \$63,154, TO CONDUCT A FEASIBILITY STUDY FOR REMEDIAL WORK WITHIN REFUGIO CREEK ASSOCIATED WITH THE PATH TO TRANSIT PROJECT AND PERFORM SITE INSPECTIONS AND MAINTENANCE PRIOR TO THE REMEDIATION.

WHEREAS, contaminated soil near Refugio Creek discovered during the construction of the Path To Transit Phase of the Regional Intermodal Transit Center Project was analyzed and mapped as part of the original contract with WSP USA and Contract Amendment No.1; and

WHEREAS, the soil needs to be remediated; and

WHEREAS, Amendment No.2 with WSP USA will complete a feasibility study for the remedial work and provide for site inspections and maintenance until the remediation begins; and

WHEREAS, there is sufficient Measure J funding in the adopted Fiscal Year 2017-18 Budget to cover the cost of Amendment No.2.

NOW, THEREFORE, BE IT RESOLVED that the City Council of the City of Hercules hereby authorizes the City Manager to execute Contract Amendment No.2 with WSP USA for \$25,704, for a not to exceed total contract amount of \$63,154, to conduct a feasibility study for remedial work within Refugio Creek associated with the Path To Transit Project and perform site inspections and maintenance prior to the remediation.

The foregoing Resolution was duly and regularly adopted at a regular meeting of the City Council of the City of Hercules held on the twenty-fifth day of July, 2017, by the following vote of the Council:

AYES:

NOES:

RECUSED:

Myrna De Vera, Mayor

ATTEST:

Lori Martin
Administrative Services Director/City Clerk

AMENDMENT NO. 2

1. Parties. The parties to this Contract Amendment are the City of Hercules, a public body corporate and the following named Contractor:

WSP USA (formerly WSP | Parsons Brinckerhoff)
2025 Gateway Place, Suite 348
San Jose, CA 95110

The parties to this Contract Amendment do mutually agree and promise as follows:

2. Purpose. This Amendment No. 2 is being entered into to amend an existing contract between the City and Contractor which was approved by the City Manager of the City of Hercules on February 1, 2017. Said contract shall hereinafter be referred to as the "Original Contract" and is incorporated herein by reference.

3. Original Contract Provisions. The parties hereto agree to continue to abide by those terms and conditions of the Original Contract, and any amendments thereto, which are unaffected by this Contract Amendment Agreement.

4. Amendment. This Amendment No. 2 is intended to amend the Original Contract and previously approved amendments (collectively, the "Amended Contract") thereto to provide a feasibility study and maintenance of the remediation site for additional compensation in an amount not to exceed \$25,704, total contract amount \$63,154.

5. Amendment Approval: This Amendment No. 2 is hereby approved by the City Council of the City of Hercules on this 25th day of July, 2017 by Resolution No. _____.

6. Signatures. These signatures attest the parties' agreement hereto:

City of Hercules

Contractor: ____WSP_USA_____

By _____

By

David Biggs



Title: City Manager

Date: _____

Form approved:

Title: Area Manager

Date:

By _____

____7/17/2017_____

Patrick Tang, City Attorney



VIA ELECTRONIC MAIL

July 17, 2017

Mike Roberts, P.E.
Public Works Director/City Engineer
City of Hercules
111 Civic Drive
Hercules, California 94547

RE: Proposal to Conduct a Feasibility Study for Remedial Work within Refugio Creek, Hercules, CA and to Perform Site Inspections/Maintenance Prior to Remedial Efforts

Dear Mr. Roberts,

Pursuant to your request, WSP USA Inc. (WSP) is submitting this proposal to prepare a feasibility study comparing options for mitigating impacts from sub-surface petroleum to surface waters of Refugio Creek in Hercules, CA (the Site).

Additionally, WSP has included in this proposal costs to perform inspection and maintenance of the absorbent boom currently deployed as a stop-gap measure at the Refugio Creek site. WSP will ensure the boom is replaced as needed, and the inspection will remove any accumulated debris and address any maintenance issues.

This scope of work is separated into two phases, considered subsequent to the completed scope of work submitted previously as Phases A through C (proposal dated January 23, 2017) and also subsequent to the scope of work included in Phases D through F (proposal dated June 30, 2017):

G. Feasibility Study

H. Inspection and Maintenance of Absorbent Boom

PHASE G : FEASIBILITY STUDY

Using information collected from the subsurface investigation, WSP will prepare a feasibility study approved by a licensed civil engineer to evaluate options for mitigating the petroleum hydrocarbon impact to Refugio Creek. Each remedial option will be described and evaluated based on cost, technical feasibility, regulatory steps required, and estimated duration. WSP will review the pros and cons of each option with the City of Hercules prior to completing final recommendations, in order to identify the most appropriate option for moving forward.

PHASE H: INSPECTION AND MAINTENANCE OF ABSORBENT BOOM

WSP also proposes the inspection and maintenance/replacement of the absorbent boom within the Refugio Creek petroleum impacted area. This boom will remain in place until the remedial efforts are underway.

Assumptions included in this cost estimate include:

- Monthly site visits for inspection and maintenance over 5 months
- Three boom replacements including the disposal of spent boom



This estimate covers time and materials for five site inspections, and three maintenance and boom replacement events. Additional inspections and boom maintenance/replacements may be needed prior to the completion of remedial activities. The estimate is presented as a total cost following the assumptions outlined above. Work will be billed on an as-completed basis.

If additional inspections are needed, WSP will proceed only with prior written authorization from the City of Hercules.

COST ESTIMATE

The total estimated cost for Phase G is \$17,450. The estimated cost for Phase H is \$8,254. The total estimated cost for this work is therefore \$25,704.

The Phase G cost estimate includes time for consultation with a WSP Professional Civil Engineer and Professional Geologist, both registered in the State of California. Additional time has been allocated for discussions with Regulatory agencies to determine the appropriate path forward for remedial options. All work will be completed on a time and materials basis, not to exceed the total estimated cost of \$17,450.

Table 1 attached presents the tabulated costs for each of these phases, including rates for each level of staff. This work will be completed on a time and materials basis.

We are prepared to implement the scope of work described above immediately upon your approval. If you have any questions or require additional information, please do not hesitate to call.

Sincerely,

Claire Wilkin
Assistant Environmental Engineer
408.878.0663
408.781.4140 (cell)
CW:bm

Betsy Mitton
Area Manager
408.878.0660

Authorized Signature

Date

Table 1
Feasibility Study for Remedial Alternatives to Address Olly Sheen and Continued Site Maintenance
Refugio Creek, Hercules, CA
July, 2017

Phase G: Preparation of Feasibility Study of Remedial Alternatives and Recommendations

Personnel	Task	Rate	Quantity	Unit	Total	Labor	Expenses	Subcontractor
Professional Engineer - Civil	Preliminary Alternatives Design & Project management	\$ 190	24	hr	\$ 4,560	\$ 4,560		
Professional Engineer - Civil	Regulatory Evaluation & Interface	\$ 190	12	hr	\$ 2,280	\$ 2,280		
Professional Geologist/Senior Staff	Data review, Document Review, Meetings/Calls	\$ 170	16	hr	\$ 2,720	\$ 2,720		
Professional/Technical Staff	Report Preparation	\$ 108	70	hr	\$ 7,560	\$ 7,560		
Expenses	Estimated - based on actual expenditures	\$ 300	1	ls	\$ 300		\$ 330	
								Phase G Total: \$ 17,450

Phase H: Inspection and Maintenance of Absorbent Boom

Personnel	Task	Rate	Quantity	Unit	Total	Labor	Expenses	Subcontractor
Professional/Technical Staff	Project Management, meetings/calls - assume 2 hours per month	\$ 108	10	hr	\$ 1,080	\$ 1,080		
Subcontractors	Task							
Boom Inspections - monthly	2 technician inspectors/maintenance (60 hours total)	\$ 115	1	60 hr	\$ 690			\$ 725
Technician H&S Equipment	Protective Equipment/ Tools	\$ 50	5	ea	\$ 250			\$ 263
Technician Vehicle	Field truck - per day	\$ 167	5	day	\$ 835			\$ 835
Boom Replacement	Installation of new boom - 8 bales per replacement	\$ 159	24	bale	\$ 3,816			\$ 3,816
Boom Transportation and Disposal	Cost presented per 55 gallon drum	\$ 172	9	55 gal drum	\$ 1,548			\$ 1,548
								Phase H Total \$ 8,266

	<u>Phase G</u>	<u>Phase H</u>	<u>TOTAL</u>
<u>Total:</u>	\$ 17,450	\$ 8,266	\$ 25,716

Notes:

1. Expenses 10% mark-up, subcontractor 5% mark-up. No mark-up on subcontractor expenses.
2. Assume monthly inspections of containment boom required. Replacement and disposal every 6 weeks. Assume maintenance through December, 2017.



Legislation Details (With Text)

File #: 17-297 **Version:** 1 **Name:**
Type: Discussion/Action Item **Status:** Agenda Ready
File created: 7/17/2017 **In control:** City Council
On agenda: 7/25/2017 **Final action:**
Title: Part-Time Employees Salary Adjustment to Provide a Cost of Living Adjustment and to Address New Minimum Wage as of January 1, 2018 and Approve New Job Classification for Administrative Engineering/Planning Intern
Recommendation: Adopt a Resolution approving a new salary schedule for part-time employees to provide a 3.8% cost of living adjustment and to comply with the new minimum wage as of January 1, 2018 and creating the Administrative Engineering/Planning Intern job classification.

Sponsors:

Indexes:

Code sections:

Attachments: [Agenda Item Review and Approval Form](#)
[Staff Report - Part-Time Employees Salary Adjustment Resolution](#)
[Exhibit A - Part-Time Salary Schedule](#)
[Exhibit B - Administrative Intern Job Description](#)

Date	Ver.	Action By	Action	Result
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Part-Time Employees Salary Adjustment to Provide a Cost of Living Adjustment and to Address New Minimum Wage as of January 1, 2018 and Approve New Job Classification for Administrative Engineering/Planning Intern

Recommendation: Adopt a Resolution approving a new salary schedule for part-time employees to provide a 3.8% cost of living adjustment and to comply with the new minimum wage as of January 1, 2018 and creating the Administrative Engineering/Planning Intern job classification.

AGENDA ITEM REQUEST FORM

Department: City Manager's Office

Department Director: David Biggs

Phone: 799-8216

Meeting Date: July 25, 2017

Final Decision Date Deadline: July 25, 2017

SUBJECT:

Part-Time Salary Adjustment to Provide Cost of living Adjustment and to Address New Minimum Wage as of January 1, 2018

INDICATE APPROPRIATE BODY

☒ City Council

☐ Successor Agency to the Redevelopment Agency

☐ Public Finance Authority

☐ Finance Commission

☐ Planning Commission

☐ Community/Library Services Commission

☐ Oversight Board

☐ Other _____

ITEM

☐ Presentation/Introduction

☐ Study Session

☐ Grant Application/Acceptance

☐ Public Hearing

☒ Resolution

☐ Video/PowerPoint

☐ Consent Calendar

☐ Ordinance

☒ Discussion Action

☐ Contract/Agreement

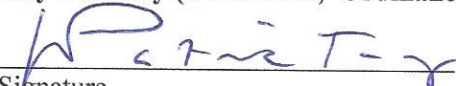
RECOMMENDED ACTION:

Adopt a Resolution Approving a New Salary Schedule for Part-Time Employees to Provide a 3.8% Cost of Living Adjustment and to comply with the New Minimum Wage as of January 1, 2018

☐ Copy of executed Resolution/Ordinance/Contract/Application required immediately upon approval.

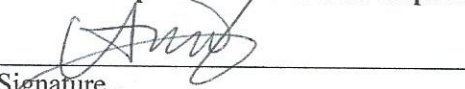
REVIEWED AND APPROVED FOR AGENDA:

City Attorney (if Contract, Ordinance or Resolution)


Signature

7.20.17
Date

Finance Department for Fiscal Impact


Signature

7/20/17
Date

City Manager


Signature

7/20/17
Date

AGENDA ITEM NO:



STAFF REPORT TO THE CITY COUNCIL

DATE: Regular Meeting of July 25, 2017

TO: Members of the City Council

SUBMITTED BY: David Biggs, City Manager

SUBJECT: Part-Time Salary Adjustment to Provide Cost of Living Adjustment and to Address New Minimum Wage as of January 1, 2018 and Approval of Administrative/Engineering/Planning Intern Job Classification

RECOMMENDED ACTION: Adopt a Resolution Approving a New Salary Schedule for Part-Time Employees to Provide a 3.8% Cost of Living Adjustment and to comply with the New Minimum Wage as of January 1, 2018 and creating the Administrative/Engineering/Planning Intern Job Classification

COMMISSION/SUBCOMMITTEE ACTION AND RECOMMENDATION: Not Applicable

FISCAL IMPACT OF RECOMMENDATION: Represented part-time employees received a 3.8% COLA as of July 1, 2017, this has been incorporated into the FY 2017/18 budget. To provide unrepresented part-time employees the same 3.8% COLA will be \$16,474 for the 2017/18 fiscal year. The adopted budget also includes funding for a part-time intern in Planning and Public Works.

DISCUSSION: The State of California has enacted legislation which is raising the State's minimum wage to \$15.00 per hour by 2022. The increase for 2018 will take minimum wage to \$11.00 per hour, and increasing by \$1.00 per hour to \$15.00 per hour in 2022. In November last year, the City modified unrepresented part time salaries to provide the same COLA as was provided to other employees and made other adjustments to ensure compliance with the January 1, 2017, new minimum wage of \$10.50 an hour. These adjustments resulted in some compaction between the grade and steps which were anticipated to be addressed through a comprehensive class and comp study which has not yet been completed.

The City recently completed labor negotiations with represented employees which provided for a 3.8% COLA. It would be equitable to also provide unrepresented part-time employees with the same COLA which is proposed in the attached salary schedule. While this 3.8% increase assists in getting the lowest paid position PT 2 at Step 1 to the new \$11.00 minimum wage as of January 1, 2018, it does not quite do so at \$10.90, as such the proposed new part-time salary schedule notes that the PT 2, Step 1 hourly rate would increase to \$11.00 as of January 1, 2018, unless the upcoming class &

comp study has been completed and other adjustments are proposed at that time. The RFP for the proposed class & comp study will be going out later this month.

A resolution (Attachment 1) has been prepared which would approve a new part-time salary schedule which incorporates the following changes:

- Provides for a 3.8% COLA to all remaining grades for non-represented part-time employees;
- Further increases the PT 2 Grade at step 1 to \$11.00 per hour to meet the new minimum wage requirement (adjusted upwards slightly from \$10.90) as of January 1, 2018.

There will be a slight level of compaction between the PT 2 Grade Step 1 and the next step as a result of the recommended action.

In addition, a job classification for Administrative/Engineering/Planning Intern requires approval in order to allow for the planned positons in Planning and Public Works to be filled. This position is recommended to be added to the part-time salary schedule at the PT 4 Grade and the attached resolution does so in addition to approving this new classification. The addition of interns was approved as Decision Packages 17- 5 & 17-14 in the FY 2016/17 Budget and was part of the base budget approved for FY 2017/18.

ATTACHMENTS:

1. Resolution w/ exhibits
2. Current part time Salary Schedule

<i>Financial Impact</i>			
Description: To provide a 3.8% Cost of Living Adjustment to the non-represented part-time employees and to comply with the New Minimum Wage as of January 1, 2018			
Funding Source: Various			
Budget Recap:			
Total Estimated cost:	\$16,474	New Revenue:	\$
Amount Budgeted:	\$16,474	Lost Revenue:	\$
New funding required:	\$	New Personnel:	\$
Council Policy Change: Yes ☐ No ☐			

RESOLUTION NO. 17-

A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF HERCULES APPROVING A NEW SALARY SCHEDULE FOR PART-TIME EMPLOYEES WITH A 3.8% COST OF LIVING ADJUSTMENT TO COMPLY WITH THE NEW MINIMUM WAGE AS OF JANUARY 1, 2018, AND CREATING THE CLASSIFICATION OF ADMINISTRATIVE/ENGINEERING/PLANNING INTERN

WHEREAS, represented part time employees were provided with a Cost of Living Adjustment (COLA) of 3.8% as of July 1, 2017, as were other employees; and

WHEREAS, the State of California is increasing the minimum wage to \$11.00 an hour effective January 1, 2018; and

WHEREAS, in order to provide non-represented part time employees with the same COLA as represented part time employees and to comply with the new minimum wage requirements, the new part time salary schedule will be effective the pay period commencing July 1, 2017; and,

WHEREAS, the creation of an Administrative/Engineering/Planning Intern classification will allow for the recruitment of qualified undergraduate students to assist in a variety of City operational areas.

NOW, THEREFORE, BE IT RESOLVED by the City Council of the City of Hercules that the City Council hereby approve a Part-Time Salary Schedule as attached hereto as Exhibit A to address the increase in minimum wage and to adjust part-time salaries as necessary and desirable.

BE IT FURTHER RESOLVED that the position of Administrative/Engineering/Planning Intern shall be created and the class specification approved as attached hereto as Exhibit B and added to the Part-Time Salary Schedule at the PT 4 Grade.

The foregoing Resolution was duly and regularly adopted at a regular meeting of the City Council of the City of Hercules held on the 25th day of July, 2017 by the following vote of the Council:

AYES:

NOES:

ABSTAIN:

ABSENT:

ATTEST:

Myrna de Vera, Mayor

Lori Martin
Administrative Services Director/City Clerk

Part-Time Salary Schedule Effective July 1, 2017

GRADE	PT1		GRADE	PT2		GRADE	PT3		GRADE	PT4	
	Annual	Hourly		Annual	Hourly		Annual	Hourly		Annual	Hourly
Step 1	Not in use		Step 1	21,536.42	10.8990	Step 1	22,088.32	11.1783	Step 1	23,855.46	12.0726
Step 2			23,869.49	12.0797	Step 2	23,193.13	11.7374	Step 2	25,048.63	12.6764	
Step 3			25,062.96	12.6837	Step 3	24,352.59	12.3242	Step 3	26,300.66	13.3101	
Step 4			26,316.11	13.3179	Step 4	25,570.02	12.9403	Step 4	27,615.50	13.9755	
Step 5			27,631.92	13.9838	Step 5	26,848.72	13.5874	Step 5	28,996.67	14.6744	
Step 6			29,013.51	14.6830	Step 6	28,191.36	14.2669	Step 6	30,446.70	15.4082	
GRADE	PT5		GRADE	PT6		GRADE	PT7		GRADE	PT8	
	Annual	Hourly		Annual	Hourly		Annual	Hourly		Annual	Hourly
Step 1	25,763.68	13.0383	Step 1	27,825.04	14.0815	Step 1	30,051.01	15.2080	Step 1	32,455.21	16.4247
Step 2	27,052.26	13.6904	Step 2	29,216.30	14.7856	Step 2	31,553.56	15.9684	Step 2	34,078.36	17.2461
Step 3	28,405.07	14.3750	Step 3	30,676.91	15.5248	Step 3	33,131.43	16.7669	Step 3	35,781.89	18.1082
Step 4	29,825.13	15.0937	Step 4	32,210.96	16.3011	Step 4	34,788.01	17.6053	Step 4	37,570.98	19.0137
Step 5	31,316.38	15.8484	Step 5	33,821.70	17.1162	Step 5	36,527.21	18.4854	Step 5	39,449.53	19.9643
Step 6	32,882.20	16.6408	Step 6	35,512.19	17.9718	Step 6	38,353.77	19.4098	Step 6	41,422.01	20.9626
GRADE	PT9		GRADE	PT10		GRADE	PT11		GRADE	PT12	
	Annual	Hourly		Annual	Hourly		Annual	Hourly		Annual	Hourly
Step 1	35,051.67	17.7387	Step 1	37,855.81	19.1578	Step 1	40,884.23	20.6904	Step 1	44,154.91	22.3456
Step 2	36,804.25	18.6256	Step 2	39,748.60	20.1157	Step 2	42,928.24	21.7248	Step 2	46,362.85	23.4630
Step 3	38,644.67	19.5570	Step 3	41,735.84	21.1214	Step 3	45,074.66	22.8111	Step 3	48,680.99	24.6361
Step 4	40,577.10	20.5350	Step 4	43,822.83	22.1775	Step 4	47,328.39	23.9516	Step 4	51,115.04	25.8679
Step 5	42,605.56	21.5615	Step 5	46,013.97	23.2864	Step 5	49,694.81	25.1492	Step 5	53,670.79	27.1613
Step 6	44,736.03	22.6397	Step 6	48,314.47	24.4506	Step 6	52,179.55	26.4067	Step 6	56,354.13	28.5193
GRADE	PT13		GRADE	PT14		GRADE	PT15		GRADE	PT16	
	Annual	Hourly		Annual	Hourly		Annual	Hourly		Annual	Hourly
Step 1	47,687.20	24.1332	Step 1	51,502.27	26.0639	Step 1	55,622.42	28.1490	Step 1	60,072.18	30.4009
Step 2	50,071.76	25.3400	Step 2	54,077.58	27.3672	Step 2	58,403.35	29.5564	Step 2	63,075.79	31.9209
Step 3	52,574.95	26.6068	Step 3	56,781.06	28.7354	Step 3	61,323.51	31.0342	Step 3	66,229.38	33.5169
Step 4	55,204.29	27.9374	Step 4	59,620.51	30.1723	Step 4	64,389.69	32.5859	Step 4	69,541.05	35.1928
Step 5	57,964.11	29.3341	Step 5	62,601.53	31.6809	Step 5	67,609.57	34.2154	Step 5	73,017.90	36.9524
Step 6	60,862.32	30.8008	Step 6	65,731.81	33.2651	Step 6	70,989.85	35.9260	Step 6	76,668.80	38.8000
GRADE	PT17		Part-time Positions:		Grade	Grade		Grade			
	Annual	Hourly									
Step 1	64,878.01	32.8330	Administrative Secretary		PT12	Lifeguard/Swim Instructor I		PT3	Senior Lifeguard		PT6
Step 2	68,122.11	34.4748	Aquatics Pool Manager		PT9	Lifeguard/Swim Instructor II		PT5	Senior Recreation Leader		PT4
Step 3	71,528.21	36.1985	Children's Program Aide		PT2	Office Assistant I		PT3	Sports Coach/Referee		PT2
Step 4	75,104.62	38.0084	Children's Program Leader I		PT5	Office Assistant II		PT5	Swim Coach		PT7
Step 5	78,859.85	39.9088	Children's Program Leader II		PT7	Parking Enforcement Officer		PT11			
Step 6	82,802.85	41.9043	Children's Program Leader III		PT8	Recreation Leader III		PT9			
			Facility Attendant		PT2	Recreation Specialist		PT6			

PT 2 Step 1 to increase to \$11.00 hourly effective December 31, 2017

***Rates based on 1,976 annual hours worked.**

JOB DESCRIPTION

Administrative/Engineering/Planning Intern

Date Prepared: July 18, 2017

SUMMARY: Under close supervision, performs a variety of entry-level administrative tasks and special projects; assists in the coordination of administrative, engineering, or planning activities and analysis of department systems and procedures; and performs related work, as required. May work in any City department or office.

ESSENTIAL FUNCTIONS: -- *Essential functions, as defined under the Americans with Disabilities Act, may include any of the following representative duties, knowledge, and skills. This is not a comprehensive listing of all functions and duties performed by incumbents of this class; employees may be assigned duties which are not listed below; reasonable accommodations will be made as required. The job description does not constitute an employment agreement and is subject to change at any time by the employer. Essential duties and responsibilities may include, but are not limited to the following:*

- Research, compile, tabulate, and analyze data for a variety of administrative and departmental matters.
- Assist department personnel in assigned administrative, planning, organizational, technical, and professional tasks.
- Provide suggestions or recommendations with regard to department specific projects.
- Prepare and present reports; draft policies and procedures; respond to requests for information.
- Perform specific tasks related to the actual department vacancy; and performs related duties, as required.

MINIMUM QUALIFICATIONS:

Education, Training and Experience Guidelines:

Proof of enrollment in a college or university AND work experience paid or volunteer, which demonstrates the ability to successfully perform the duties of the position. Major course of study may be in one of the following areas: Business Administration, Public Administration, Accounting, Architecture, Computer Science, Engineering, Urban Planning, Human Resources, Communications, Recreation Administration, OR a related field of study. Education and experience will be evaluated based on the actual position.

Knowledge of:

- Principles and practices of public administration and organization applicable to a local agency.
- Administrative techniques; statistical practices and methods of graphic presentation.

- Modern office methods, practices, procedures, and equipment, including personal computers and modern software and spreadsheet programs.
- Elements of business writing and proper use of English, vocabulary, spelling, punctuation, and grammar.

Skill in:

- Providing efficient customer service and communicating clearly and objectively both verbally and in writing.
- Organizing with the ability to prioritize work and exercise independent judgment, wisdom, common sense, and initiative.
- Thoroughly carrying out oral and written instructions.
- Gathering and analyzing data; preparing narrative reports and performing numerical analysis.
- Evaluating and recommending changes to policies, programs, and practices.
- Conducting research; proficiently utilizing a personal computer in completing special projects.
- Following written and oral instructions with minimum supervision; effectively presenting information in writing and orally to the general public, outside agencies, and fellow employees.
- Speaking effectively in a public forum on related topics and issues.
- Prioritizing and scheduling workload to ensure completion when faced with deadlines or emergencies.
- Establishing and maintaining effective working relationships with those contacted in the course of work, including City and other government officials, community groups, and the general public; and apply safe work practices.

LICENSE AND CERTIFICATION REQUIREMENTS:

Possession of a valid Class “C” California driver’s license.

PHYSICAL DEMANDS AND WORKING ENVIRONMENT:

Work is performed in an office environment in close proximity to other workers and may require some field work including site visits. Incumbent shall be exposed to those conditions normally encountered in a business office environment. Physical demands require frequent standing, reaching, leaning, twisting, grasping, lifting, and sitting for prolonged periods of time. Must carry moderately heavy boxes up to 50 pounds and/or utilize a dolly. Incumbent must be able to drive safely to various City sites. Incumbent must be able to see and hear in the normal range, with or without correction. Incumbent must have the stamina to work long hours and overtime, if assigned, and be willing to work an irregular schedule, which might include evenings, weekends, holidays, and varying hours.



Legislation Details (With Text)

File #: 17-301 **Version:** 1 **Name:**

Type: Discussion/Action Item **Status:** Agenda Ready

File created: 7/20/2017 **In control:** City Council

On agenda: 7/25/2017 **Final action:**

Title: Temporary Waiver of Business Licenses for Fee Class Contractors and City Professional Services Contractors.
Recommendation: Approve a Resolution establishing a temporary waiver of business licenses for fee class contractors (up to \$20,000 per year in value) and City professional services contractors.

Sponsors:

Indexes:

Code sections:

Attachments: [Agenda Item Review and Approval Form](#)
[Staff Report](#)
[Resolution - Business License Pilot Temp Waiver](#)

Date	Ver.	Action By	Action	Result
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Temporary Waiver of Business Licenses for Fee Class Contractors and City Professional Services Contractors.

Recommendation: Approve a Resolution establishing a temporary waiver of business licenses for fee class contractors (up to \$20,000 per year in value) and City professional services contractors.

AGENDA ITEM REQUEST FORM

Department: Parks & Recreation

Department Director: Christopher Roke

Phone: 788-8228

Meeting Date: July 25, 2017

Final Decision Date Deadline: July 25, 2017

SUBJECT:
Resolution Adopting a Temporary Waiver of Business Licenses for Fee Class Contractors and City Professional Service Contracts

INDICATE APPROPRIATE BODY

- | | | | |
|--|---|---|---|
| ☒ City Council | ☐ Successor Agency to the Redevelopment Agency | ☐ Public Finance Authority | ☐ Finance Commission |
| ☐ Planning Commission | ☐ Community/Library Services Commission | ☐ Oversight Board | ☐ Other _____ |

ITEM

- | | | |
|---|--|---|
| ☐ Presentation/Introduction | ☐ Study Session | ☐ Grant Application/Acceptance |
| ☐ Public Hearing | ☒ Resolution | ☐ Video/PowerPoint |
| ☐ Consent Calendar | ☐ Ordinance | |
| ☒ Discussion Action | ☐ Contract/Agreement | |

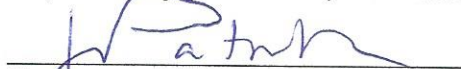
RECOMMENDED ACTION:

Approve a Resolution Establishing a Temporary Waiver of Business Licenses for Fee Class Contractors (up to \$20,000 per year in value) and City Professional Services Contractors

☐ Copy of executed Resolution/Ordinance/Contract/Application required immediately upon approval.

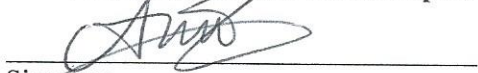
REVIEWED AND APPROVED FOR AGENDA:

City Attorney (if Contract, Ordinance or Resolution)


Signature

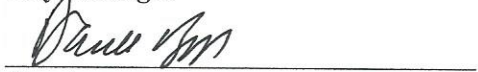
7-20-17
Date

Finance Department for Fiscal Impact


Signature

7/20/17
Date

City Manager


Signature

7/20/17
Date

AGENDA ITEM NO:



STAFF REPORT TO THE CITY COUNCIL

DATE: Regular Meeting of July 25, 2017

TO: Members of the City Council

SUBMITTED BY: Christopher Roke, Parks & Recreation Director
Annie To, Finance Director

SUBJECT: Resolution Adopting a Temporary Waiver of Business Licenses for Fee Class Contractors and City Professional Service Contracts

RECOMMENDED ACTION:

Approve a Resolution Establishing a Temporary Waiver of Business Licenses for Fee Class Contractors (up to \$20,000 per year in value) and City Professional Services Contractors.

COMMISSION/SUBCOMMITTEE ACTION AND RECOMMENDATION:

N/A

FISCAL IMPACT OF RECOMMENDATION:

While the City is able to collect money on the requirement to obtain a Business License for Fee Contract Class Contractors, it is losing money overall due to the paperwork and cost. In addition, some contractors are choosing to no longer do business with the City. Recommended changes to the City's Municipal Code for Business License fees will help the department attract and retain quality Fee Class Contractors which in turn will help generate more revenue and reduce the overall deficit in Parks and Recreation Department.

The City's standard professional services contracts require the vendor to secure a business license. However, the cost of the business license is a reimbursable expense. As such, the current process does not result in additional revenue.

DISCUSSION:

The Parks & Recreation Department has identified that our ability to secure Fee Class Contractors is being impacted by the requirement that the contractors secure a business license. As a result, there are less options available to the community for these types of offerings, as contractors sometimes decline to provide services to the City due to the paperwork and expense required to comply with the business license requirements. This also means that the Parks & Recreation Department is losing out on revenue generating programs. For those contractors that are starting out, or those that are earning a minimal amount of money, it is not worth it to offer classes. Some of the bigger Fee Class Contractors are choosing not to return or have already left because of the costs associated with the requirements to purchase a business license and to provide insurance.

In a recent survey regarding the requirement to obtain a Business License to teach a Fee Class for the community, here is a list of what others are doing.

- Cities that require a business license include Alameda, Fremont, Hayward (HARD), Dublin and Union City.
- Cities that only require a business license under special circumstances include Danville, El Cerrito, Oakley and Richmond.
- Cities that do not require a business license include Concord, Kensington, Martinez, Moraga and San Leandro.

The following is a list of cities that have special circumstances, and what those circumstances are:

- Danville: Fee Class Contractors only pay for a business license if they make over \$10,000 in a fiscal year. If they make less than \$10,000, they complete an exemption form.
- El Cerrito: Fee Class Contractors agree to purchase a City business license if the Contractor's total payment exceeds \$8,500 in a fiscal year (July 1 – June 30).
- Oakley: Fee Class Contractors are required to obtain a business license, but they have a fee exemption for businesses that make under \$20K/year. **All** of their Fee Class Contractors fall in this category.
 - However there is a \$1 state fee that is not waived. So their Fee Class Contractors pay \$1 annually for a business license.
- Richmond: Fee Class Contractors only pay for a business license if they make more than \$5,000 a year.

Most of our Fee Class Contractors here in Hercules do not make more than \$5,000 annually, as such a pilot temporary waiver program is recommended for the Fee Class Contractors and for City Professional Services Contractors.

The City is currently in the process of contracting out the administration and processing of business licenses. Once the vendor for that program is selected, it is anticipated that they will also identify needed or desirable changes and updates to our business license ordinance. The pilot temporary waiver program would be reviewed as part of this effort and if effective and desirable, could then be codified into whatever global changes are recommended.

ATTACHMENTS:

1. Resolution to Establish a Temporary Waiver of Business Licenses

<i>Financial Impact</i>			
Description:			
Funding Source:			
Budget Recap:			
Total Estimated cost:	\$0	New Revenue:	\$0
Amount Budgeted:	\$0	Lost Revenue:	\$0
New funding required:	\$0	New Personnel:	\$0
Council Policy Change: Yes ☒ No ☐			

RESOLUTION NO. 17-__

**A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF HERCULES
AUTHORIZING THE TEMPORARY SUSPENSION AND/OR WAIVER OF BUSINESS
LICENSE TAX REQUIREMENTS FOR ENTITIES PROVIDING FEE CLASS
INSTRUCTION THROUGH THE PARKS AND RECREATION DEPARTMENT AND
CONTRACTORS PROVIDING PROFESSIONAL SERVICES TO THE CITY**

WHEREAS, the City's current Business License Tax requirements, codified in the Hercules Municipal Code at Title 8, Chapter 6, calls for payment of a business license fee on an annual basis; and

WHEREAS, the application of business license requirements creates an unnecessary burden on the City's administrative staff; and

WHEREAS, the business license compliance requirements create a disincentive for small businesses providing instructional and educational services and contractors doing business with the City of Hercules; and

WHEREAS, granting staff the authority to suspend and/or waive on a temporary one year basis the business license requirements for Fee Class Contractors who provide instructional and educational services and that earn less than \$20,000 a year, and contractors doing business with the City of Hercules, is in the best interests of the City as it will reduce the compliance burden on staff and make it easier for contractors and service providers to do business with the City; and

WHEREAS, the City is currently in the process of evaluating the contracting out of the administration and processing of business licenses, and the temporary suspension and/or waiver would be reviewed as part of this effort and could be codified into whatever global changes to the City's Business License Program are recommended.

NOW, THEREFORE, BE IT RESOLVED by the City Council of the City of Hercules that effective immediately upon passage and for a period of one (1) year thereafter, the City Manager is granted the authority to allow staff to grant the suspension and/or waiver of business license requirements for Fee Class Contractors that earn less than \$20,000 and contractors providing professional services to the City.

AYES:

NOES:

ABSENT:

ABSTAIN:

Myrna de Vera, Mayor

ATTEST:

Lori Martin, City Clerk