



Western Riverside Council of Governments Technical Advisory Committee AGENDA

**Thursday, January 19, 2017
9:30 a.m.**

**County of Riverside
Administrative Center
4080 Lemon Street
5th Floor, Conference Room C
Riverside, CA 92501**

In compliance with the Americans with Disabilities Act and Government Code Section 54954.2, if special assistance is needed to participate in the Technical Advisory Committee meeting, please contact WRCOG at (951) 955-8320. Notification of at least 48 hours prior to meeting time will assist staff in assuring that reasonable arrangements can be made to provide accessibility at the meeting. In compliance with Government Code Section 54957.5, agenda materials distributed within 72 hours prior to the meeting which are public records relating to an open session agenda item will be available for inspection by members of the public prior to the meeting at 4080 Lemon Street, 3rd Floor, Riverside, CA, 92501.

The Technical Advisory Committee may take any action on any item listed on the agenda, regardless of the Requested Action.

- 1. CALL TO ORDER (Brian Nestande, 2nd Vice-Chair)**
- 2. ROLL CALL**
- 3. PLEDGE OF ALLEGIANCE**
- 4. PUBLIC COMMENTS**

At this time members of the public can address the Technical Advisory Committee regarding any items with the subject matter jurisdiction of the Committee that are not separately listed on this agenda. Members of the public will have an opportunity to speak on agenda items at the time the item is called for discussion. No action may be taken on items not listed on the agenda unless authorized by law. Whenever possible, lengthy testimony should be presented to the Committee in writing and only pertinent points presented orally.

5. CONSENT CALENDAR

All items listed under the Consent Calendar are considered to be routine and may be enacted by one motion. Prior to the motion to consider any action by the Committee, any public comments on any of the Consent Items will be heard. There will be no separate action unless members of the Committee request specific items be removed from the Consent Calendar.

- A. Summary Minutes from the October 20, 2016, Technical Advisory Committee meeting are available for consideration. P. 1
Requested Action: 1. Approve Summary Minutes from the October 20, 2016, Technical Advisory Committee meeting.
- B. Finance Department Activities Update Ernie Reyna P. 7
Requested Action: 1. Receive and file.
- C. Financial Report Summary through November 2016 Ernie Reyna P. 9
Requested Action: 1. Receive and file.
- D. Regional Streetlight Program Activities Update Tyler Masters P. 15
Requested Action: 1. Receive and file.
- E. Western Riverside Energy Leader Partnership Update Tyler Masters P. 19
Requested Action: 1. Receive and file.
- F. Environmental Department Activities Update Dolores Sanchez Badillo P. 21
Requested Action: 1. Receive and file.
- G. Clean Cities Coalition Activities Update Christopher Gray P. 27
Requested Action: 1. Receive and file.
- H. Analysis of Fees and Their Potential Impact on Economic Development in Western Riverside County Christopher Gray P. 29
Requested Action: 1. Receive and file.
- I. International City / County Management Association Activities Update AJ Wilson, California Senior Advisor P. 89
Requested Action: 1. Receive and file.
- J. Distribution of Round II BEYOND Allocations to Member Jurisdictions Andrea Howard P. 95
Requested Action: 1. Receive and file.
- K. Single Signature Authority Report Ernie Reyna P. 101
Requested Action: 1. Receive and file.
- L. 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017 P. 107
Requested Action: 1. Recommend that the Executive Committee approve the 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017.

M. Technical Advisory Committee 2017 Meeting Schedule Janis Leonard P. 127
Requested Action: 1. Approve the Schedule of Technical Advisory Committee meetings for 2017.

N. PACE Program Activities Update Barbara Spoonhour P. 133
Requested Action: 1. Receive and file.

O. Regional Homelessness Dialogue Jennifer Ward P. 141
Requested Action: 1. Receive and file.

P. Report from the League of California Cities Erin Sasse, League of CA Cities P. 165
Requested Action: 1. Receive and file.

6. REPORTS/DISCUSSION

A. California Mandatory Conservation Framework Discussion and California WaterFix Update Paul Jones, EMWD, and John Rossi, WMWD P. 177
Requested Action: 1. Receive and file.

B. Santa Ana Municipal Separate Storm Sewer System (MS4) Permit Compliance Program Update David Garcia, Riverside County Flood Control and Water Conservation District P. 179
Requested Action: 1. Receive and file.

C. Transportation Uniform Mitigation Fee (TUMF) Program Activities Update Christopher Gray, WRCOG P. 189
Requested Action: 1. Receive and file.

D. Community Choice Aggregation Program Activities Update Barbara Spoonhour, WRCOG P. 193
Requested Action: 1. Recommend that the Executive Committee receive the final draft Inland Choice Power Community Choice Aggregation Business Plan.

E. Public Service Fellowship Program Jennifer Ward, WRCOG P. 311
Requested Action: 1. Receive and file.

7. REPORT FROM THE EXECUTIVE DIRECTOR Rick Bishop

8. ITEMS FOR FUTURE AGENDAS

Members

Members are invited to suggest additional items to be brought forward for discussion at future Technical Advisory Committee meetings.

9. GENERAL ANNOUNCEMENTS

Members

Members are invited to announce items/activities which may be of general interest to the Technical Advisory Committee.

10. CONFERENCE WITH LEGAL COUNSEL – EXISTING LITIGATION PURSUANT TO SECTION 54956.9(d)(1):

- **Case Number 30-2010-00357976**

11. NEXT MEETING: The next Technical Advisory Committee meeting is scheduled for Thursday, February 16, 2017, at 9:30 a.m., in the County of Riverside Administrative Center, 5th Floor, Conference Room C.

12. ADJOURNMENT

1. CALL TO ORDER

The meeting of the WRCOG Technical Advisory Committee was called to order at 9:35 a.m. by Chairman Gary Nordquist at the County of Riverside Administrative Center, 3rd Floor, Conference Room A.

2. ROLL CALL

Members present:

Michael Rock, City of Banning
Bonnie Johnson, City of Calimesa
Alex Meyerhoff, City of Hemet
Gary Thompson, City of Jurupa Valley
Grant Yates, City of Lake Elsinore
Robert Johnson, City of Menifee
Andy Okoro, City of Norco
John Russo, City of Riverside (9:43 a.m. arrival)
Sharon Paisley, City of San Jacinto
Aaron Adams, City of Temecula
Gary Nordquist, City of Wildomar (Chairman)
Brian Nestande, County of Riverside (10:40 a.m. departure)
Danielle Coats, Eastern Municipal Water District (10:24 a.m. departure)
Danielle Wheeler, March Joint Powers Agency

Staff present:

Steve DeBaun, Legal Counsel
Rick Bishop, Executive Director
Ernie Reyna, Chief Financial Officer
Jennifer Ward, Director of Government Relations
Christopher Gray, Director of Transportation
Christopher Tzeng, Program Manager
Michael Wasgatt, Program Manager
Lupe Lotman, Executive Assistant
Janis Leonard, Executive Assistant

Guests present:

AJ Wilson, International City / County Management Association
Erin Sasse, League of California Cities
Araceli Ruiz, Riverside County District 1
Darcy Kuenzi, Riverside County Flood and Water Conservation District
David Garcia, Riverside County Flood and Water Conservation District
Clint Lorimore, Building Industry Association

3. PLEDGE OF ALLEGIANCE

Jennifer Ward, WRCOG, led the members and guests in the Pledge of Allegiance.

4. PUBLIC COMMENTS

There were no public comments.

5. CONSENT CALENDAR (Meyerhoff/Thompson) 14 yes; 0 no; 0 abstention. Items 5.A – 5.Q were approved by a unanimous vote of those members present. The Cities of Canyon Lake, Corona, Eastvale, Moreno Valley, Murrieta, Perris, Western Municipal Water District, and the Morongo Band of Mission Indians not present. Item Numbers 5.O and 5.Q were pulled for discussion.

A. Summary Minutes from the September 15, 2016, WRCOG Technical Advisory Committee meeting.

Action: 1. *Approved Summary Minutes from the September 15, 2016, WRCOG Technical Advisory Committee meeting.*

B. WRCOG Environmental Department Activities Update

Action: 1. *Received and filed.*

C. WRCOG Finance Department Activities Update

Action: 1. *Received and filed.*

D. WRCOG Financial Report Summary through August 2016

Action: 1. *Received and filed.*

E. WRCOG PACE Program Activities Update

Action: 1. *Received and filed.*

F. Western Riverside Energy Leader Partnership Update

Action: 1. *Received and filed.*

G. WRCOG Clean Cities Coalition Activities Update

Action: 1. *Received and filed.*

H. International City / County Management Association Activities Update

Action: 1. *Received and filed.*

I. Single Signature Authority Report

Action: 1. *Received and filed.*

J. SEI Form 700 eFiling with WRCOG

Action: 1. *Received and filed.*

K. Revised WRCOG Policies and Procedures

Action: 1. *Recommended that the WRCOG Executive Committee approve the revised WRCOG Policies and Procedures.*

L. WRCOG 1st Quarter Draft Budget Amendment for Fiscal Year 2016/2017

Action: 1. *Recommended that the WRCOG Executive Committee approve the WRCOG 1st Quarter Draft Budget Amendment for Fiscal Year 2016/2017.*

M. Preliminary Examinations of Riverside County as a Metropolitan Planning Organization

Action: 1. Received and filed.

N. Committee Members Taxation Status

Action: 1. Received and filed.

O. Distribution of Round II BEYOND Allocations to Member Jurisdictions

Committee member Rob Johnson asked for clarification on the allocation of \$250,000 towards a comprehensive, regional economic development initiative for Western Riverside County. Southwest Riverside cities have a similar initiative and do not want to create a duplication of efforts.

Jennifer Ward responded that the Ad Hoc Committee directed some funds from the Agency carryover revenues be allocated to a regional economic development initiative. The Ad Hoc Committee will meet again to set more specifics to that proposal.

Mr. Johnson indicated that there are four cities utilizing BEYOND funding for “city branding.” There is also an effort to brand Southwest Riverside County. Now there is this initiative to brand the WRCOG subregion. Perhaps the branding initiative can be combined.

Ms. Ward responded that staff is researching how the jurisdictions are approaching branding, and funding for that will most likely not be used until a decision by the Committee is provided.

Action: 1. Received and filed.

(Johnson/Meyerhoff) 14 yes; 0 no; 0 abstention. Item 5.O was approved by a unanimous vote of those members present. The Cities of Canyon Lake, Corona, Eastvale, Moreno Valley, Murrieta, Perris, Western Municipal Water District, and the Morongo Band of Mission Indians not present.

P. Regional Streetlight Program Activities Update

Action: 1. Received and filed.

Q. Community Choice Aggregation Program Activities Update

Committee member Brian Nestande indicted that the Staff Report indicates that the County’s model is more expensive than the in-house model, and that the cost is not allowed to be tax-free bonding to build facilities.

The County does not anticipate bonding for projects in an outsourced model. The County would buy power from the open market. Therefore, the statement in the draft CCA report that the differential mentioned will cost more money because private bonds will have to be used is not applicable to what the County is looking to do, or what has been done with other CCA’s which use the outsource model.

Rick Bishop responded that a revised draft report was being developed. All of the CCA studies are showing savings to the residents no matter which model (in-house versus out-sourced) is chosen. Various governance options need to be researched in more detail, and staff’s desire is to bring the most cost-effective option(s) forward for consideration.

Action: 1. Received and filed.

(Nestande/Yates) 14 yes; 0 no; 0 abstention. Item 5.Q was approved by a unanimous vote of those members present. The Cities of Canyon Lake, Corona, Eastvale, Moreno Valley, Murrieta, Perris, Western Municipal Water District, and the Morongo Band of Mission Indians not present.

6. REPORTS/DISCUSSION

A. Water Quality Mitigation Framework

Christopher Gray reported that within the past several years, new regulations have required Regional Boards to update their MS4 permits to require additional stormwater treatment measures when new development occurs. These additional treatment measures can be significantly more costly than current requirements are for certain types of development. There may also be instances in which treatment measures are infeasible based on the size of the development parcel and other considerations. The regulations imposed by the Regional Boards are a greater burden on cities and private developers.

WRCOG is working with the Riverside County Flood Control and Water Conservation District to design a voluntary program. WRCOG's role could potentially include administration of such program, the issuance and tracking of credits, and/or credit trading. WRCOG would not override local land use decisions, assume responsibility for permits, construct facilities, nor operate nor maintain facilities. Member jurisdictions would have the ability to opt out of this program, partially or entirely; the program would be entirely voluntary.

Darcy Kuenzi indicated that due to these new regulations, agencies are taking a new approach to permits.

Committee member Robert Johnson asked if this presentation has been provided to the Public Works Committee.

Mr. Gray responded that it had.

Grant Yates asked how this program would transition into other programs local agencies may have.

Mr. Gray responded that this program could compliment other programs.

Mrs. Kuenzi indicated that the intent of this program is to ensure that these new permit requirements do not block growth.

Gary Thompson indicated that it is key to have both Regional and State Boards on the same page.

Action: 1. *Received and filed.*

B. Transportation Uniform Mitigation Fee (TUMF) Program Activities

Christopher Gray reported that an Ad Hoc Committee has been formed to address the 2016 TUMF Nexus Study update. Executive Committee representatives include Rusty Bailey, City of Riverside; Jeff Giba, City of Moreno Valley; and Jeff Hewitt, City of Calimesa. Assistance will be provided by the following Technical Advisory Committee members: Rob Johnson, City of Menifee; Grant Yates, City of Lake Elsinore; and Gary Thompson, City of Jurupa Valley. Assistance will also be provided by the following Public Works Committee members: Art Vela, City of Banning; Craig Bradshaw, City of Eastvale; and Patricia Romo, County of Riverside.

A revised growth forecast has been prepared, as well as unit cost assumptions. The 2012 RIVTAM Existing and 2040 No-Build model runs have been examined in order to determine

vehicle miles traveled of a variety of trip types. Updated data sets have been included which covers the number of employees per square foot. Lastly, the TUMF Network has been reviewed for removal of any completed projects.

The Ad Hoc Committee discussed various fee phase-in scenarios, a potential fee schedule, proposed facilities to add to the Network, potential change in fee burden, and the effect of the proposed logistics fee on industrial uses. The removal of facilities from the Network will result in a reduction of \$300 million in Network costs.

The Ad Hoc Committee directed staff to develop phase-in scenarios combined with the Network reduction.

Staff will begin a comprehensive review of the TUMF Program after the Nexus Study is updated, and will work with member jurisdictions on any suggested changes to the Program.

Committee member John Russo asked for how long the Nexus Study is legally good.

Mr. Gray responded that it is good for four years.

Committee member Michael Rock asked if the numbers include the City of Beaumont, and what the next steps are with the lawsuit.

Rick Bishop responded that that information can be discussed in Closed Session.

Committee member Aaron Adams asked which projects are being removed from the Network that total \$300 million.

Mr. Gray responded that he would forward that list to Committee members.

Action: 1. *Received and filed.*

C. WRCOG Public Service Fellowship Update

Jennifer Ward reported that Fellows are currently in their third month of the Program, and 17 Fellows have been placed in WRCOG's member jurisdictions. The Fellows have attended three Academic Sessions to date, and have received presentations from the Cities of Riverside and Menifee, as well as from the City of Riverside Museum and Western Municipal Water District.

Fellows are working on a wide array of projects, ranging from outreach and city events, to legislative matters. WRCOG has received positive feedback from the Fellows, who are all pleased to be part of the Program.

WRCOG is currently partnering with the University of California, Riverside, and California Baptist University, and is looking to expand to other universities.

Action: 1. *Received and filed.*

D. Report from the League of California Cities

Jennifer Ward indicated that Erin Sasse was unable to attend the meeting, and reported that the League is holding a legislative webinar on November 7, 2016; interested individuals can sign-up online. The League will be presenting its Public Servant Award at an upcoming Policy Committee meeting.

Action: 1. *Received and filed.*

7. REPORT FROM THE EXECUTIVE DIRECTOR

Rick Bishop reported that there are four upcoming tours for the Streetlights Demonstration area – November, 10, 14, 29, and December 7, 2016.

8. ITEMS FOR FUTURE AGENDAS

There were no items for future agendas.

9. GENERAL ANNOUNCEMENTS

There were no general announcements.

10. NEXT MEETING

The next Technical Advisory Committee meeting is scheduled for Thursday, November 17, 2016, at 9:30 a.m., in the County of Riverside Administrative Center, 5th Floor, Conference Room C.

11. ADJOURNMENT

The meeting of the Technical Advisory Committee adjourned at 10:51 a.m.



Western Riverside Council of Governments

Technical Advisory Committee

Staff Report

Subject: Finance Department Activities Update

Contact: Ernie Reyna, Chief Financial Officer, reyna@wrcog.coq.ca.us, (951) 955-8432

Date: January 19, 2017

The purpose of this item is to provide an update on the interim WRCOG audit of Fiscal Year 2015/2016, which should result in a final Comprehensive Annual Financial Report issued in January 2017. This report also provides an update on agency budget amendments, and an update on the annual TUMF Audit for 2015/2016.

Requested Action:

1. Receive and file.

Financial Audit

Financial auditors from Vavrinek, Trine, Day, & Co., conducted their interim audit work for Fiscal Year (FY) 2015/2016 at the end of July 2016. The auditors worked with WRCOG staff to begin the process of reviewing the financial ledgers, and returned during the week of September 26, 2016, to conduct final fieldwork. The process of creating the year end financials has begun, and it is anticipated that the audit will conclude in January 2017, with the final Comprehensive Annual Financial Report being issued shortly thereafter. It is anticipated that the Finance Directors Committee will receive a report on the audit and financial statements at its January 26, 2017, meeting.

Budget Amendment

December 31, 2016, marked the end of the second quarter of FY 2016/2017, and the Administration & Finance Committee was presented with a budget amendment at its January 11, 2017, meeting. The Technical Advisory Committee will also consider the amendment report at its January 19, 2017, meeting. The Executive Committee will consider the amendment report at its February 6, 2017, meeting.

Annual TUMF Audit for FY 2015/2016

Staff has completed the TUMF audits of each jurisdiction and the final reports will be issued in January or February of 2017. The TUMF audits allow staff to ensure that member agencies are correctly calculating and remitting TUMF funds in compliance with the TUMF Program.

Prior WRCOG Actions:

January 11, 2017: The Administration & Finance Committee received report.
January 9, 2017: The Executive Committee received report.

WRCOG Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachment:

None.



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Financial Report Summary through November 2016

Contact: Ernie Reyna, Chief Financial Officer, reyna@wrcog.cog.ca.us, (951) 955-8432

Date: January 19, 2017

The purpose of this item is to provide a monthly summary of WRCOG's financial statements in the form of combined Agency revenues and costs.

Requested Action:

1. Receive and file.
-

Attached for Committee review is the Financial Report Summary through November 2016.

Prior WRCOG Action:

January 11, 2017: The Administration & Finance Committee received report.

WRCOG Fiscal Impact:

This item is informational only; therefore there is no fiscal impact.

Attachment:

1. Financial Report Summary – November 2016.

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Item 5.C

Financial Report Summary through
November 2016

Attachment 1

Financial Report
Summary – November 2016

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Western Riverside Council of Governments
Monthly Budget to Actuals
For the Month Ending November 30, 2016

		Approved 6/30/2017 Budget	Thru 11/30/2016 Actual	Remaining 6/30/2017 Budget
Revenues				
40001	Member Dues	309,410	306,410	3,000
42001	Other Revenue	-	15	(15)
42004	General Assembly	300,000	5,000	295,000
40601	WRCOG HERO	1,963,735	565,983	1,397,752
40602	SCE Phase II	57,000	-	57,000
40604	CA HERO	7,615,461	2,766,363	4,849,098
40605	The Gas Company Partnership	62,000	16,944	45,056
40606	SCE WRELP	-	4,692	(4,692)
40607	WRCOG HERO Commercial	27,500	11,384	16,116
40609	SCE Phase III	-	10,634	(10,634)
40611	WRCOG HERO Recording Revenue	335,555	132,125	203,430
40612	CA HERO Recording Revenue	1,301,300	590,290	711,010
40614	Active Transportation	200,000	50,254	149,746
41201	Solid Waste	107,915	93,415	14,500
41401	Used Oil Opportunity Grants	250,000	264,320	(14,320)
41402	Air Quality-Clean Cities	139,500	128,000	11,500
41701	LTF	692,000	701,250	(9,250)
43001	Commercial/Service - Admin (4%)	37,074	30,846	6,229
43002	Retail - Admin (4%)	142,224	51,431	90,793
43003	Industrial - Admin (4%)	128,446	47,587	80,860
43004	Residential/Multi/Single - Admin (4%)	1,067,271	334,459	732,813
43005	Multi-Family - Admin (4%)	224,983	21,185	203,798
43001	Commercial/Service	889,786	740,581	149,205
43002	Retail	3,413,375	1,234,334	2,179,040
43003	Industrial	3,082,710	1,142,077	1,940,632
43004	Residential/Multi/Single	25,614,514	8,026,729	17,587,785
43005	Multi-Family	5,399,595	508,450	4,891,146
	Total Revenues	61,125,676	17,784,757	43,340,919
Expenditures				
Wages and Benefits				
60001	Wages & Salaries	1,981,159	885,417	1,095,742
61000	Fringe Benefits	579,477	300,166	279,311
	Total Wages and Benefits	2,620,636	1,185,583	1,435,053
General Operations				
63000	Overhead Allocation	1,518,136	632,557	885,579
65101	General Legal Services	410,673	324,715	85,958
65401	Audit Fees	25,000	10,300	14,700
65505	Bank Fees	25,500	7,904	17,596
65507	Commissioners Per Diem	46,500	21,150	25,350
73001	Office Lease	145,000	56,514	88,486
73003	WRCOG Auto Fuels Expense	178	299	(121)
73004	WRCOG Auto Maint Expense	16	33	(17)
73102	Parking Validations	3,650	2,835	815
73104	Staff Recognition	1,200	632	568
73107	Event Support	181,888	30,377	151,511
73108	General Supplies	20,833	6,866	13,967
73109	Computer Supplies	7,925	3,336	4,589
73110	Computer Software	13,705	10,638	3,067
73111	Rent/Lease Equipment	25,000	15,525	9,475
73113	Membership Dues	40,600	7,815	32,785
73114	Subscriptions/Publications	8,283	5,102	3,181
73115	Meeting Support/Services	14,098	3,650	10,448
73116	Postage	5,653	1,400	4,253
73117	Other Household Expenditures	2,354	2,630	(276)
73118	COG Partnership Agreement	40,000	10,254	29,746
73122	Computer Hardware	4,000	337	3,663
73201	Communications-Regular	2,000	350	1,650
73203	Communications-Long Distance	1,200	95	1,105
73204	Communications-Cellular	11,186	4,476	6,710
73206	Communications-Comp Sv	17,000	30,414	(13,414)
73209	Communications-Web Site	15,600	407	15,193
73301	Equipment Maintenance - General	7,070	2,724	4,346
73302	Equipment Maintenance - Computers	3,267	11,418	(8,151)
73405	Insurance - General/Business Liason	63,520	73,020	(9,500)
73407	WRCOG Auto Insurance	345	345	-
73502	County RCIT	2,500	545	1,955
73506	CA HERO Recording Fee	1,636,855	474,368	1,162,487
73601	Seminars/Conferences	25,013	6,692	18,322
73605	General Assembly	300,000	1,723	298,277
73611	Travel - Mileage Reimbursement	21,252	6,038	15,214
73612	Travel - Ground Transportation	8,779	1,684	7,095
73613	Travel - Airfare	22,000	6,192	15,808
73620	Lodging	19,550	5,347	14,203
73630	Meals	10,091	4,130	5,961
73640	Other Incidentals	14,164	4,786	9,378
73650	Training	14,200	40	14,160
73703	Supplies/Materials	45,700	300	45,400
73706	Radio & TV Ads	44,853	25,750	19,103
XXXXX	TUMF Projects	38,399,980	15,297,485	23,102,495
85101	Consulting Labor	3,528,328	819,826	2,708,502
85102	Consulting Expenses	245,000	2,889	242,111
85180	BEYOND Expenditures	2,023,000	128,321	1,894,679
90101	Computer Equipment/Software	31,500	9,437	22,063
	Total General Operations	49,225,890	17,441,113	31,152,220
Total Expenditures		51,846,526	18,626,696	32,587,273

Ernie Reyna

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Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Regional Streetlight Program Activities Update

Contact: Tyler Masters, Program Manager, masters@wrcog.cog.ca.us, (951) 955-8378

Date: January 19, 2017

The purpose of this item is to provide the Committee with an update on the Streetlight City Council Presentations and to provide an update on the next steps that member jurisdictions are taking in the Program. Along with information, WRCOG staff is working with the City of Hemet and the Riverside Transit Agency (RTA) to provide an additional tour in January 2017.

Requested Action:

1. Receive and file.
-

WRCOG's Regional Streetlight Program will assist member jurisdictions with the acquisition and retrofit of their Southern California Edison (SCE)-owned and operated streetlights. The Program has three phases, which include: 1) streetlight inventory; 2) procurement and retrofitting of streetlights; and 3) ongoing operations and maintenance. The overall goal of the Program is to provide significant cost savings to the member jurisdictions.

Background

At the direction of the Executive Committee, WRCOG is developing a Regional Streetlight Program that will allow jurisdictions (and Community Service Districts) to purchase the streetlights within their boundaries that are currently owned / operated by SCE. Once the streetlights are owned by the member jurisdiction, the lamps will then be retrofitted to Light Emitting Diode (LED) technology to provide more economical operations (i.e., lower maintenance costs, reduced energy use, and improvements in public safety). Local control of its streetlight system allows jurisdictions opportunities to enable future revenue generating opportunities such as digital-ready networks, and telecommunications and IT strategies.

The goal of the Program is to provide cost-efficiencies for local jurisdictions through the purchase, retrofit, and maintain the streetlights within jurisdictional boundaries, without the need of additional jurisdictional resources. As a regional Program, WRCOG is working with jurisdictions to move through the acquisition process, develop financing recommendations, develop / update regional and community-specific streetlight standards, and manage the regional operations and maintenance agreement that will increase the level of service currently being provided by SCE.

City Council Presentations

To support the education of the Regional Streetlight Program staff has provided the following nine City Council Study Session, Council Members briefings, and City Commission presentations, in addition to over 25 WRCOG Committee update presentations and City-specific cash flow meetings:

July 12, 2016: Hemet City Council Presentation
 July 13, 2016: Eastvale City Council Presentation
 October 18, 2016: Murrieta City Council Study Session Presentation
 November 9, 2016: Wildomar City Council Presentation
 November 16, 2016: Lake Elsinore Public Safety / Traffic Advisory Commission Presentation
 December 7 & 15, 2016: Lake Elsinore Council Member briefings
 December 13, 2016: Temecula City Council Presentation
 January 4, 2017: Menifee City Council Presentation

Next Steps: WRCOG staff has been working with both participating member jurisdictions and SCE to assess the feasibility of, and support jurisdictions through the acquisition processes to transition current SCE-owned streetlights to jurisdictional ownership. After assessing feasibility of acquiring its streetlights from SCE, one of the next major steps in order to complete the acquisition process is for each interested jurisdiction and SCE to mutually agree on a Purchase and Sales Agreement. The Sales Agreement would then need to be taken to City Council for approval. Several WRCOG cities have scheduled City Council meetings to request the approval of their Sales Agreement:

January 24, 2017: City of Lake Elsinore - Anticipated City Council decision
 February 1, 2017: City of Menifee - Anticipated City Council decision
 February 7, 2017: City of San Jacinto - City Council presentation and potential decision
 February 14, 2017: City of Hemet - Council Study Session followed by potential February decision
 February 2017: City of Murrieta - Anticipated City Council decision
 February 2017: City of Temecula - Anticipated City Council decision
 February 2017: City of Wildomar - Anticipated City Council decision

Upon jurisdiction approval of the Sales Agreement, SCE will then submit the Sales Agreement to the California Public Utilities Commission (CPUC) for final approval before the transfer of streetlights can occur. Dependent upon the monetary size indicated in the Sales Agreement, the CPUC could take anywhere between two to six months to approve.

Below is an example of a timeline showing the next steps that will be taken by a WRCOG member jurisdiction during 2017:

Jurisdiction	Received SCE evaluation	Participating in regional program	Reviewed SCE Sales Contract	Council Action on SCE Sales Contract	Selecting financing options	Anticipated CPUC application	Anticipated CPUC approval	Anticipated Retrofit
Calimesa	12/15/15	Yes	In Process	TBD	TBD	TBD	TBD	TBD
Corona	No	No	The City already owns most of the streetlights in their City Boundaries					
Eastvale	12/15/15	Yes	In Process	TBD	TBD	TBD	TBD	TBD
Hemet	1/20/16	Yes	Yes	Feb. 2017	TBD	May 2017	Aug. 2017	Sept. 2017
Jurupa Valley	2/26/16	Yes	In Process	In Process	TBD	TBD	TBD	TBD
Lake Elsinore	9/28/15	Yes	Yes	1/24/17	TBD	April 2017	July 2017	Aug. 2017

Menifee	1/8/16	Yes	Yes	2/1/17	TBD	May 2017	Aug. 2017	Sept. 2017
Murrieta	10/23/15	Yes	In Process	Feb. 2017	TBD	May 2017	Nov. 2017	Dec. 2017
Norco	3/14/16	Yes	In Process	In Process	TBD	TBD	TBD	TBD
Perris	1/19/16	Yes	In Process	In Process	TBD	TBD	TBD	TBD
San Jacinto	1/21/16	Yes	In Process	2/7/17	TBD	May 2017	Aug. 2017	Sept. 2017
Temecula	9/28/16	Yes	Yes	Feb. 2017	TBD	May 2017	Nov. 2017	Dec. 2017
Wildomar	1/19/16	Yes	In Process	Feb. 2017	TBD	May 2017	Aug. 2017	Sept. 2017
County of Riverside	3/16/16	Yes	In Process	In Process	TBD	TBD	TBD	TBD
JCSD	12/15/16	Yes	In Process	Assessing	TBD	TBD	TBD	TBD
RCSD	2/26/16	No	RCSD will support the City of Jurupa Valley if they choose to participate in the Regional Program					

WRCOG staff continues to schedule meetings with the remaining member cities to work with SCE on the finalization of the Sales Agreement and assist WRCOG member cities at City Council meetings for decision on the Sales Agreement. If interested in discussing where your jurisdiction is in the process or and what the next steps are, please contact Tyler Masters, Program Manager, at (951) 955-8378 or masters@wrcog.cog.ca.us.

Demonstration Area Tour Update: In Partnership with the City of Hemet, WRCOG has installed a variety of LED streetlights from different vendors in five Demonstration Areas in the City. These five Demonstration Areas represent different street and land use types, from school, residential, and commercial areas, to low, medium, and high traffic street areas. 12 outdoor lighting manufacturers are participating in these Demonstration Areas.

Input from local government officials, public safety staff, health experts, residents, business owners, and other community stakeholders is important before moving forward with a plan to upgrade streetlights in the subregion. With support from RTA, WRCOG was able to provide guided educational bus tours of the five Demonstration Areas for participants:

- November 10, 2016, at 5:30 p.m.
- November 14, 2016, at 5:30 p.m.
- November 29, 2016, at 5:30 p.m.
- December 7, 2016, at 5:30 p.m.

Additionally, WRCOG is coordinating with the City of Hemet and RTA to host a 5th Regional Streetlight Demonstration Area Tour on January 19, 2017. This additional tour will be provided to interested attendees who were unable to attend the previous four tours or for any interested individuals that would like to participate on the tour for a second time. The tour will run from 5:30 p.m. – 8:00 p.m. and the start of the tour will commence at West Valley High School (3401 Mustang Way, Hemet, CA 92545). If interested in participating in the upcoming tour on January 19, 2017, please RSVP to Anthony Segura, Staff Analyst, at segura@wrcog.cog.ca.us or (951) 955-8389.

Prior WRCOG Actions:

January 12, 2017: The Public Works Committee received report.

January 9, 2017: The Executive Committee received report.

WRCOG Fiscal Impact:

Activities for the Regional Streetlight Program are included in the Agency's adopted Fiscal Year 2016/2017 Budget. The additional costs associated with this contract amendment in the amount of \$70,779 will be reflected in an upcoming Agency Budget Amendment.

Attachment:

None.



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Western Riverside Energy Leader Partnership Update

Contact: Tyler Masters, Program Manager, masters@wrcog.cog.ca.us, (951) 955-8378

Date: January 19, 2017

The purpose of this item is to provide the Committee with an update on the addition of the Cities of Corona and Moreno Valley into the Western Riverside Energy Leader Partnership and the results from the 3rd Annual Holiday LED Lighting Exchange & Energy Efficiency Kit Give-away.

Requested Action:

1. Receive and file.

The Western Riverside Energy Leader Partnership (WRELPL) responds to Executive Committee direction for WRCOG, Southern California Edison (SCE), and the Southern California Gas Company (SoCal Gas) to seek ways to improve marketing and outreach to the WRCOG subregion regarding energy efficiency. WRELPL is designed to assist local governments to set an example for their communities to increase energy efficiency, reduce greenhouse gas (GHG) emissions, increase renewable energy usage, and improve air quality.

Cities of Corona and Moreno Valley to Join WRELPL

The Cities of Corona and Moreno Valley joined the Western Riverside Energy Leader Partnership (WRELPL) in January 2017. Both Cities have been members of the Community Energy Partnership (CEP), which supports energy efficiency projects at municipal facilities and engages within the community to promote the idea of energy efficiency. The City of Corona joined the CEP in 2004 and the City of Moreno Valley joined the CEP in 2002, before WRELPL was developed.

The reason for the transition for both Cities from the CEP to WRELPL is that the California Public Utilities Commission (CPUC) has requested that Local Government Partnerships take on a more regional structure with the purpose of connecting cities with similar climate zones and needs, as well as to promote cost effectiveness. As such, the Cities of Corona and Moreno Valley will be transitioning from the CEP to the WRELPL, implemented by the Western Riverside Council of Governments (WRCOG).

The Cities of Corona and Moreno Valley are leaders in the field of energy efficiency. Through their participation in the CEP, between 2006 and 2016, both Cities have exhibited a combined 8,942,900 kWh in energy savings. WRELPL is excited to work with both Cities to help meet their goals and continue their leadership in the field of energy efficiency.

2016 Holiday LED Light Exchange & Energy Efficiency Kit Give-away

This past holiday season, WRELPL hosted its 3rd Annual Holiday LED Light Exchange & Energy Efficiency Kit Give-away in December 2016 which allowed residents within the Western Riverside County to exchange their old inefficient holiday lights for energy efficient LED holiday lights to support the community in saving money and energy. WRCOG staff participated in the following five holiday-themed community events:

	Event
12/3/16	City of Hemet: Christmas in the Park
12/3/16	City of Murrieta: Festival of Trees and Tree Lighting Ceremony
12/4/16	City of Canyon Lake: Tree Lighting Ceremony
12/10/16	City of Wildomar: Breakfast with Santa
12/10/16	City of Norco: Parade of Lights and Christmas Festival

At these events, residents were able to participate in the Exchange and Give-away by presenting a recent copy of their SCE and SoCal Gas bill, a picture ID, and provide their old inefficient incandescent holiday lights. In addition to the LED holiday lights, participants had the opportunity to receive an energy efficiency starter kit that included a low-flow showerhead and three sink faucet aerators. The energy efficiency kit was provided on behalf of SoCal Gas. The 2016 Holiday LED Light Exchange and Energy Efficiency Kit give-away was provided at no cost to the participating cities or its residents.

Highlights from these events include:

- Over 480 LED Holiday lights distributed to the community
- Over 240 households participated
- Over 70 Energy-Efficiency “starter-kits” distributed on behalf of SoCal Gas
- Educated the community on how to save energy during the holiday season



Resident exchanging old incandescent lights for new, energy efficient LED lights.

Prior WRCOG Action:

January 9, 2017: The Executive Committee received report.

WRCOG Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachment:

None.



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Environmental Department Activities Update

Contact: Dolores Sanchez Badillo, Staff Analyst, badillo@wrcog.cog.ca.us, (951) 955-8306

Date: January 19, 2017

The purpose of this item is to provide an update on the Used Oil and Filter Exchange events and the progress of WRCOG's Pilot Litter Program being conducted in the City of Lake Elsinore.

Requested Action:

1. Receive and file.
-

WRCOG assists its member jurisdictions with addressing state mandates, specifically the Integrated Waste Management Act (AB 939, Chapter 1095, Statutes of 1989), which required 25% and 50% diversion of waste from landfills by 1995 and 2000, respectively. While certain aspects of AB 939 have been modified over the years with legislation defining what materials counted towards diversion and how to calculate the diversion rate for jurisdictions, the intent of the bill remains. Each year, a jurisdiction must file an Electronic Annual Report (EAR) with CalRecycle on the jurisdictions' achievements in meeting and maintaining the diversion requirements. The Environmental Program also has a Regional Used Oil component which is designed to assist member jurisdictions in educating and promoting proper recycling and disposal of used oil, oil filters, and household hazardous waste (HHW) to the community.

Recycling Program Activities Update

In December and January WRCOG hosted three used oil events in Western Riverside County cities, along with a community event in the City of Eastvale.

Used oil events: WRCOG's Used Oil and Oil Filter Exchange events help educate and facilitate the proper recycling of used motor oil and used oil filters in various WRCOG jurisdictions. The primary objective of hosting the events is to educate "Do It Yourself" (DIY) individuals who change their own oil, the DIYer, promoting the recycling of used oil and oil filters; therefore, an auto parts store is a great venue for educating the DIYer. In addition to promoting used oil / oil filter recycling, staff informs the DIYer about the County-wide HHW Collection Program in which residents can drop-off other automotive and household hazardous products for free.

WRCOG's first December Used Oil event was held in the City of Perris. The Saturday morning team consisted of two staff members who were joined by representatives from radio station KQIE. The group engaged with Perris residents by discussing developing environmental issues such as taking the last step in oil changes that are done at home. Staff engaged with over 80 attendees on the importance of regular oil changes and disposal of used oil materials. This included information on disposal of oil and oil filters which still contain 10% of oil from oil changes. The team informed customers on where to take HHW products such as paint, aerosol cans, and even electronics. Those in attendance voiced appreciation of the event and asked for continued education for those who might not know the risks of **not** recycling. Many attendees explained how "back in the day" they illegally disposed of motor oil, but now that the awareness is spreading they know how toxic used

motor oil is to the environment, and will continue to practice recycling their oil. This well attended event was held at the O'Reilly's store on Nuevo Road.



WRCOG staff members Ichelle Acosta and Cherish Latchman (middle) pose with KQIE Radio employees.

In December, Santa Claus, aka, past Eastvale Mayor Ike Bootsma, donated his time to work with WRCOG staff at the final Used Oil event of 2016. The team spent the morning spreading awareness of oil changes that are done at home and the importance of proper disposal. There were discussions regarding further recycling such as oil and oil filters which still contain 10% of oil from oil changes. In order to participate in the Used Oil event, all the public had to do was bring the used oil right back where they purchased it, such as this Auto Zone store at 14228 Schleisman Road in Eastvale. Over 65 people attended the event and 42 completed a Used Oil Survey. On this busy morning, 130 filters were distributed to attendees by Auto Zone staff. The team also spoke to residents about where to take household hazardous wastes such as paint, aerosol cans, and electronic e-waste.



Past Eastvale Mayor Ike Bootsma and WRCOG Intern Kyle Rodriguez (left) take a break to pose for a Used Oil photo. Used Oil materials and information on display and available to all attendees (right).

The community was very appreciative of the event and asked for continued education for those who might not know the risks of not recycling. The City of Eastvale did a very good job promoting this event to its residents via social media. Many attendees explained how they heard of this event through the City's webpage.

The first WRCOG Used Oil event of the year was held in the City of Murrieta on January 7, 2017. Staff coordinated with AutoZone management in advance to market the event to residents. Flyers, radio spots, and Facebook notices helped get the word out. KGCI Radio commercials were broadcasted a week prior to the event and their employees were on hand for a remote broadcast that morning. Free DIY oil materials were distributed to 75 people, 72 used oil containers were handed out, and 21 used oil filters were exchanged that morning. Residents were happy with the valuable materials and HHW information provided.



WRCOG and KGGI Radio staff display actual Used Oil at the Used Oil event in Murrieta.

Community Outreach

Over 1,000 people attended the Winter Fest event on December 3, 2016, in the City of Eastvale. WRCOG's environmental team was there to spread valuable information regarding HHW, the recycling of used motor oil, and the importance of not littering. While at the event, WRCOG promoted the oil filter exchange event that was scheduled in the City for the following weekend. Numerous individuals informed staff that they heard of the future event through the City's website and its social media accounts. A lot of useful materials such as tire gauges, buckets, oil sponges, and shop towels were distributed. Flyers regarding safe medication disposal and flyers detailing proper HHW disposal sites were highly regarded at this event. For the children, coloring books about recycling, soccer balls made from recycled material, and plushy lights bulbs were provided, as well. The community was extremely thankful for the event and for all the vendors who helped make the event successful. The City even hauled in real snow for Santa and the kids! Overall, it was a great event!



WRCOG Intern Jorge Nieto works alongside the City of Eastvale at the 2016 Winter Fest.

Upcoming Used Oil Events

The following is a list of Used Oil and Oil Filter Exchange events that are presently scheduled. To request an event for your jurisdiction please contact Jorge Nieto, WRCOG Intern, at (951) 955-8328 or nieto@wrcog.cog.ca.us.

Date	Event	Location	Time
1/21/17	City of Jurupa Valley Used Oil Event	O'Reillys, 5691 Mission Blvd.	9 a.m. – 12 p.m.
1/28/17	City of Lake Elsinore Used Oil Event	AutoZone, 322231 Mission Trail	9 a.m. – 12 p.m.
2/4/17	City of Norco Used Oil Event	AutoZone, 1404 Hamner Ave.	9 a.m. – 12 p.m.

2/18/17	City of Riverside Used Oil Event	AutoZone, 7315 Indiana Ave.	9 a.m. – 1 p.m.
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CalRecycle Grant Opportunities

The following is a list of current grant opportunities offered by CalRecycle to assist public and private entities in the safe and effective management of the waste stream. WRCOG provides grant assistance to member jurisdictions seeking to pursue funding opportunities. To request grant assistance for the grants listed below, please contact Dolores Sanchez Badillo, Staff Analyst, at (951) 955-8306, or at badillo@wrcog.cog.ca.us

Organics Grant Program (Fiscal Year 2016-2017): The Department of Resources Recycling and Recovery (CalRecycle) administers the Organics Grant Program pursuant to Public Resources Code section 42999. The purpose of this competitive grant Program is to lower overall greenhouse gas emissions by expanding existing capacity or establishing new facilities in California to reduce the amount of California-generated green materials, food materials, or alternative daily cover being sent to landfills.

Funding: \$24,000,000 is available for Fiscal Year 2016-2017, to be distributed as follows:

- Compost Projects: \$12,000,000 allocation for compost projects with a maximum grant award of \$3,000,000 per application. This includes \$2,400,000 in requested infrastructure costs and \$600,000 in performance payments.
- Rural Programs: \$3,000,000 from the compost projects allocation is available for Rural Program applications. The maximum grant award is \$3,000,000 per application. This includes \$2,400,000 in requested infrastructure costs and \$600,000 in performance payments.

There is a \$12,000,000 allocation for a digestion project, with a maximum award of \$4,000,000 per application. This includes \$3,200,000 in requested infrastructure costs and \$800,000 in performance payments. If you are interested you can find the information at:

<http://www.calrecycle.ca.gov/Climate/GrantsLoans/Organics/FY201617/default.htm>

Application due date: March 9, 2017

WRCOG Pilot and Regional Litter Initiative



Lake Elsinore Pilot Litter Program Graphic
Designs for Educational Outreach



A partnership comprised of the City of Lake Elsinore, WRCOG, and Riverside Flood Control and Water Conservation District is working hard to move the Lake Elsinore Litter Pilot program to the next level. April 22, 2017, is both Earth Day and the day of the Annual Lake Elsinore Clean Extreme event. All parties are working together to merge the Litter Pilot Program into the successful community event. This year, over 700 city residents are expected to clean lots, pick up highway trash, and paint a large mural on a wall located directly

across the highway from the Lake Elsinore Outlets. The Lake Elsinore Litter Program will donate materials, conduct contests, bring along a remote radio station opportunity, and provide “Love Where You Live” information for all attendees. Once again, WRCOG would like to thank Lowe’s Home Improvement and CR&R Environmental Services for their contributions. Look for more information on the April 22, 2017, Clean Extreme Event on the City of Lake Elsinore’s and WRCOG websites.



Lake Elsinore
Litter Program
Business Window Sticker

Prior WRCOG Action:

January 9, 2017: The Executive Committee received report.

WRCOG Fiscal Impact:

Solid Waste and Used Oil Program activities are included in the current adopted Agency budget. Costs identified in association with the Pilot Litter Initiative will come from WRCOG carryover funds within the Environment Department and reflected in an upcoming Agency Budget for Fiscal Year 2016/2017, as a quarterly budget amendment, if needed.

Attachment:

None.

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Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Clean Cities Coalition Activities Update

Contact: Christopher Gray, Director of Transportation, gray@wrcog.coq.ca.us, (951) 955-8304

Date: January 19, 2017

The purpose of this item is to provide an on-going briefing for the Clean Cities Coalition, an on-going Program to encourage the purchase and use of alternative fueled vehicles within the WRCOG subregion.

Requested Action:

1. Receive and file.
-

2017 Clean Cities Activities

WRCOG seeks to streamline a few deliverables and reports to the Clean Cities Coalition members, so they are better informed of opportunities on a consistent basis. A few deliverables / reports are highlighted below.

- Establish a list of private Electric Vehicle (EV) charging stations that is updated and disseminated on a monthly basis. The list will also include public stations, which is already available.
- Establish monthly newsletters for Coalition members to provide information on potential grant opportunities related to Clean Cities, such as clean fleet vehicle purchase, EV charging stations, etc.
- Establish a Scope of Work to Coalition members that includes:
 - o AB 2766 reports on behalf of cities
 - o Quarterly meetings
 - o Event(s), as appropriate, to promote Clean Cities opportunities and requirements
- Establish a grant writing assistance program specifically for Clean Cities Coalition members. This Program will offer assistance to members for grant applications that apply precisely to Clean Cities. Grant applications can include but are not limited to Clean Vehicles, EV Charging Stations, Clean Technology, and event support. WRCOG is proposing to assist Coalition members with up to 20 hours per year to provide grant writing assistance for Clean Cities-related grants.

Prior WRCOG Action:

January 9, 2017: The Executive Committee received report.

WRCOG Fiscal Impact:

This item is informational only; therefore there is no fiscal impact.

Attachment:

None.

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Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Analysis of Fees and Their Potential Impact on Economic Development in Western Riverside County

Contact: Christopher Gray, Director of Transportation, gray@wrcog.coq.ca.us, (951) 955-8304

Date: January 19, 2017

The purpose of this item is to provide a final report to Committee members on the Fee Comparison Analysis and provide the overall findings from the analysis.

Requested Action:

1. Receive and file.
-

As part of the efforts being undertaken to update the TUMF Program Nexus Study, WRCOG has received comments from public and private stakeholders regarding the impact of TUMF on the regional economy and the fees' effect on development in the subregion. WRCOG has conducted a study to analyze fees / exactions required and collected by jurisdictions / agencies in, and immediately adjacent to the WRCOG subregion.

Updates to Final Draft Report

WRCOG staff have worked with the project team to prepare the Final Draft Report for the Fee Comparison Analysis. Since the December 2016 Executive Committee meeting, the project team has incorporated input received from the various updates WRCOG staff provided to the various WRCOG Committees and stakeholder workshops with developers.

One major item added to the Final Draft Report is an economic impact analysis of the Cantu Galliano interchange. This interchange was the first major project the TUMF Program funded, so the economic impact analysis was conducted to look into the impact the interchange had on the surrounding area. The analysis found that vacant land with high infrastructure costs do not move forward without funding – planning and constructing the interchange opened the development market in the surrounding area, and, specifically, the land northeast of the interchange was likely influenced by the interchange attaining necessary funding and construction moving forward. The analysis also found that new development generates new fees and results in additional TUMF improvements. In the case of this project area, Hamner Avenue is undergoing roadway widening and additional improvements.

A short conclusion was added to stress that the fees analyzed in this report are subject to change, and that this fee comparison analysis should be conducted on a regular occurrence. Revisions also include that the fees and estimates utilized in the report were not meant to determine a project's feasibility.

Key Findings:

1. TUMF represents about 20 percent of total development impact fees for new single-family and multi-family residential development in Western Riverside County.
 - Single-family and multi-family development impact fees show a similar relationship among WRCOG

jurisdictions though the fees do vary by jurisdiction. The average development impact fees for the 20 WRCOG jurisdictions / areas studied are approximately \$44,900 per single-family unit and approximately \$28,300 per multi-family unit (about 60 percent of single-family fees). Per unit single-family fees range from \$32,900 per unit to \$59,400 per unit, and per unit multi-family fees from \$19,300 to \$40,600 per unit among the WRCOG jurisdictions / areas studied.

2. Total development impact fees and TUMF as a proportion of the total development impact fees show substantial variation among non-residential land uses.
 - Development impact fees on retail development are substantially higher than the fees on office development, primarily due to the difference in the TUMF. Fees on industrial development are lower for all categories.
3. For residential development, average WRCOG fees are modestly below those in San Bernardino County, but above those in Coachella Valley.
 - Average residential development impact fees for WRCOG jurisdictions are lower than the average of selected San Bernardino County cities, higher than the average of selected Coachella Valley cities, and varied relative to the City of Beaumont.
4. For non-residential development, average WRCOG fees are modestly below those in San Bernardino County with the exception of retail development, but above those in Coachella Valley.
 - Average retail development impact fees are approximately twice as high as the relatively similar average fee levels for San Bernardino County, Coachella Valley, and the City of Beaumont.
 - For office and industrial development, the WRCOG average falls in the range defined by the three other areas of study.
5. TUMF fees were estimated to represent between 1.3 percent and 3.5 percent of total development costs / returns for the prototype feasible projects.
 - Total development impact fees represent between 4.1 percent and 9.3 percent of total development costs / returns for the prototype feasible projects.
 - TUMF represents between 1.3 percent and 3.5 percent of total development costs / returns for the prototype feasible projects.
6. Between 2002 and the present, overall construction costs have increased more than the overall increases in the TUMF for all land use categories.
 - Overall construction costs increased by over 40 percent in nominal dollar terms between 2002 and 2014.
 - When considered relative to the Consumer Price Index (a reasonable estimate of inflation), the Residential and Retail TUMF have increased consistently with inflation, while the Service and Industrial TUMF have declined in inflation-adjusted (real) terms.
7. Through its funding of key regional transportation infrastructure projects identified by WRCOG member jurisdictions, TUMF supports substantial output, wages, and jobs in Western Riverside County.
 - TUMF revenues will support a total investment of \$3.13 billion in infrastructure development activity over the next 30 years resulting in an overall regional impact of \$4.56 billion in County economic output, \$1.3 billion in labor income, and 28,900 job-years.
 - When considered in conjunction with the complementary funding, including other regional / local funding, such as Measure A, and the attracted state / federal funding, the overall economic impacts are even greater.

Fee Analysis Background

In July 2015, WRCOG distributed the draft 2015 TUMF Nexus Study for review and comment. During the comment period, WRCOG received various comments from public and private stakeholders regarding the impact of TUMF on the regional economy and the fees' effect on development in the subregion. In response to the comments received on the draft Nexus Study, WRCOG released a Request for Proposal (RFP) to solicit firms interested in performing an analysis of fees / exactions required and collected by jurisdictions / agencies

in and immediately adjacent to the WRCOG subregion. In March 2016, the Executive Committee authorized a Professional Services Agreement with Economic & Planning Systems (EPS), in association with Rodriguez Consulting Group (RCG), to conduct the fee analysis.

The Fee Comparison Analysis is near completion and staff are currently reviewing a draft final report. The Study has provided WRCOG jurisdictions with comprehensive fee comparisons. It also discusses the effect of other development costs, such as the cost of land and interest rates, within the overall development framework. Lastly, the Study analyzes and documents the economic benefits of transportation investment.

Jurisdictions for Fee Comparison: In addition to the jurisdictions within the WRCOG subregion, the Study analyzed jurisdictions within the Coachella Valley and San Bernardino County. The inclusion of additional neighboring / peer communities will allow for consideration of relative fee levels between the WRCOG subregion and jurisdictions in surrounding areas that may compete for new development. At its April 14, 2016, meeting, the Planning Directors' Committee provided input on the additional jurisdictions to be studied – an additional 11 jurisdictions surrounding the WRCOG subregion were selected for comparison.

Land Uses and Development Prototypes: Fee comparisons were conducted for five key land use categories, "development prototypes," including single-family residential, multi-family residential, office, retail, and industrial developments. Since every development project is different, and because fee structures are often complex and derived based on different development characteristics, it was helpful to create "development prototypes" for each of the land uses studied. The use of consistent development prototypes increased the extent to which the fee comparison was an "apples-to-apples comparison."

Development prototypes were selected based on recent trends in new development in Western Riverside County. For single-family development, the selected prototype represents the median home and lot size characteristics of homes built and sold in Western Riverside County since 2014. Development prototypes for the multi-family residential, office, retail, and industrial buildings represent the average building sizes for similar buildings developed since 2010 in Western Riverside County. The prototypical projects analyzed were as follows:

- **Single-Family Residential Development:** 50 unit residential subdivision with 2,700 square foot homes and 7,200 square foot lots
- **Multi-Family Residential Development:** 200 unit market-rate, multi-family residential development in 260,000 gross square foot of building space
- **Retail Development:** 10,000 square foot retail building
- **Office Development:** 20,000 square foot, Class A or Class B office building
- **Industrial Development:** 265,000 square foot "high cube" industrial building

Fee Categories: The primary focus of the Study was on the array of fees charged on new development to pay for a range of infrastructure / capital facilities. The major categories of fees include 1) school development impact fees; 2) water / sewer connection / capacity fees; 3) City capital facilities fees; 4) regional transportation fees (TUMF in Western Riverside County), and 5) other capital facilities / infrastructure / mitigation fees charged by other regional / subregional agencies. As noted in prior fee comparisons, these fees typically represent 90 to 95 percent of the overall development fees on new development. Additional processing, permitting, and entitlement fees are not included in this analysis. Based on the consultant team's review of fees, they concluded that the scale of planning / processing fees versus development impact fees was different in that most jurisdictions charge moderate levels of planning / processing fees as compared to development impact fees – meaning the development impact fees are much higher than the planning / processing fees. The analysis focused on development impact fees, as they are much larger than planning / processing fees for comparison purposes.

Service Providers and Development Prototypes: The system of infrastructure and capital facilities fees in most California jurisdictions is complicated by multiple service providers and, often, differential fees in different parts of individual cities. Multiple entities charge infrastructure / capital facilities fees, e.g., City, Water Districts, School Districts, and Regional Agencies. Additionally, individual jurisdictions are often served by different service providers (e.g., more than one Water District or School District) with different subareas within a

jurisdiction, sometimes paying different fees for water facilities and school facilities. Additionally, some City fees, such as storm drain fees, are sometimes differentiated by jurisdictional subareas.

For the purposes of the Study, an individual service provider was selected where multiple service providers were present, and an individual subarea was selected where different fees were charged by subarea. An effort was made to select service providers that cover a substantive portion of the jurisdiction, as well as to include service providers that serve multiple jurisdictions (e.g., Eastern Municipal Water District).

Fee Analysis: After identification of the cities for fee evaluation and development of prototypes by land use, the Study efforts collected fee schedules and applied them to the development prototypes. The research effort involved 1) reviewing available development impact fee schedules online; 2) reaching out to service providers (Jurisdiction, Water Districts, School Districts) where fee levels or fee calculations were difficult to discern; 3) conducting necessary fee calculations; and 4) presenting initial fee estimates for all WRCOG jurisdictions.

Staff sent initial fee estimates for each jurisdiction to each jurisdiction's representative on the Planning Directors' Committee and Public Works Committee for review and comment in June 2016. Staff presented an update of the Study to these same Committees on July 14, 2016. The update included a summary of jurisdictions that have provided confirmation and feedback on their initial fee analysis, and those whose comments were pending. Staff followed up with those jurisdictions whose comments still had yet to be addressed and those that had not provided any comments.

Fee Analysis Comparisons: A fee comparison of WRCOG and neighboring jurisdictions was conducted, and, overall, total fees by development type were generally found to be uniform throughout the region for that development type, with one exception. For example, average total fees for single-family residential are similar throughout the WRCOG and neighboring San Bernardino County jurisdictions – there are differences in the types of fees charged, such as water fees, which fluctuate between water districts. Fees collected in San Bernardino County may invest in different categories and fee categories may be defined differently than those in WRCOG jurisdictions. It should also be noted that many fees on new development are outside the direct control of jurisdictions, such as MSHCP, School, TUMF, Water, etc.

The one exception in which fees are uniformly higher in the WRCOG subregion than in any other region is retail fees. Retail fees are shown to be higher in the WRCOG subregion because of TUMF, Water, and City fees.

Prior WRCOG Action:

January 9, 2017: The Executive Committee received report.

WRCOG Fiscal Impact:

The fee analysis study is included in the Agency's adopted Fiscal Year 2016/2017 Budget under the Transportation Department.

Attachment:

1. Analysis of Development Impact Fees in Western Riverside County – Final Draft.

Item 5.H

Analysis of Fees and Their Potential
Impact on Economic Development in
Western Riverside County

Attachment 1

Analysis of Development Impact
Fees in Western Riverside County –
Final Draft

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The Economics of Land Use



Draft Final Report

Analysis of Development Impact Fees in Western Riverside County

Prepared for:

Western Riverside Council of Governments (WRCOG)

Prepared by:

Economic & Planning Systems, Inc. (EPS)

In association with:

Rodriguez Consulting Group (RCG)

December 20, 2016

EPS #151155

*Economic & Planning Systems, Inc.
One Kaiser Plaza, Suite 1410
Oakland, CA 94612
510 841 9190 tel
510 740 2080 fax*

*Oakland
Sacramento
Denver
Los Angeles*

www.epsys.com

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1. INTRODUCTION AND FINDINGS

The Western Riverside Council of Governments (WRCOG) commissioned this Report to provide increased regional understanding of development impact fees on new development in Western Riverside County. More specifically, the purpose of this Report is to: (1) indicate the types and relative scale of the development impact fees placed on different land uses; and, (2) indicate the scale of fees relative to overall development costs and their relative degree of change through time. The Report is also intended to provide helpful background information to the current Transportation Uniform Mitigation Fee (TUMF) updating process by placing TUMF in the context of the broader development impact fee structure, overall development costs, and other regional dynamics.

This Report recognizes that there are substantive and ongoing debates about the appropriate levels of development impact fees in regions throughout California and elsewhere in the U.S. On the one hand, development impact fees provide revenue to support the construction of critical infrastructure and capital facilities (or in-kind capital facility development) that can generate development value, economic development, and quality of life benefits. On the other hand, development impact fees act as an additional development cost that can influence development feasibility and potentially the pace of new development. **In reality, each fee-adopting jurisdiction needs to weigh the costs and benefits of potential new / increased fee levels in the context of their goals, capital improvement needs, and economic and development dynamics.**

This Report considers development impact fees defined as one-time fees collected for the purposes of funding infrastructure and capital facilities.¹ Because of the broad variation in land use and development projects in Western Riverside County, prototype development projects for single family, multifamily, retail, Class A/B office and large industrial developments were all developed to support comparisons of fees in different jurisdictions. Key findings are provided below.

A summary of overall findings is provided below, followed by a description of the organization of this Report.

¹ As used in this report and discussed further below, the phrase “development impact fee” includes all fees adopted pursuant to the Mitigation Fee Act and other monetary exactions due at the time of development.

Summary of Findings

FINDING #1: New development in Western Riverside County pays a wide range of one-time infrastructure/capital facilities associated fees with a number of different public agencies.

New development in Western Riverside County is required to pay development impact fees to help fund:

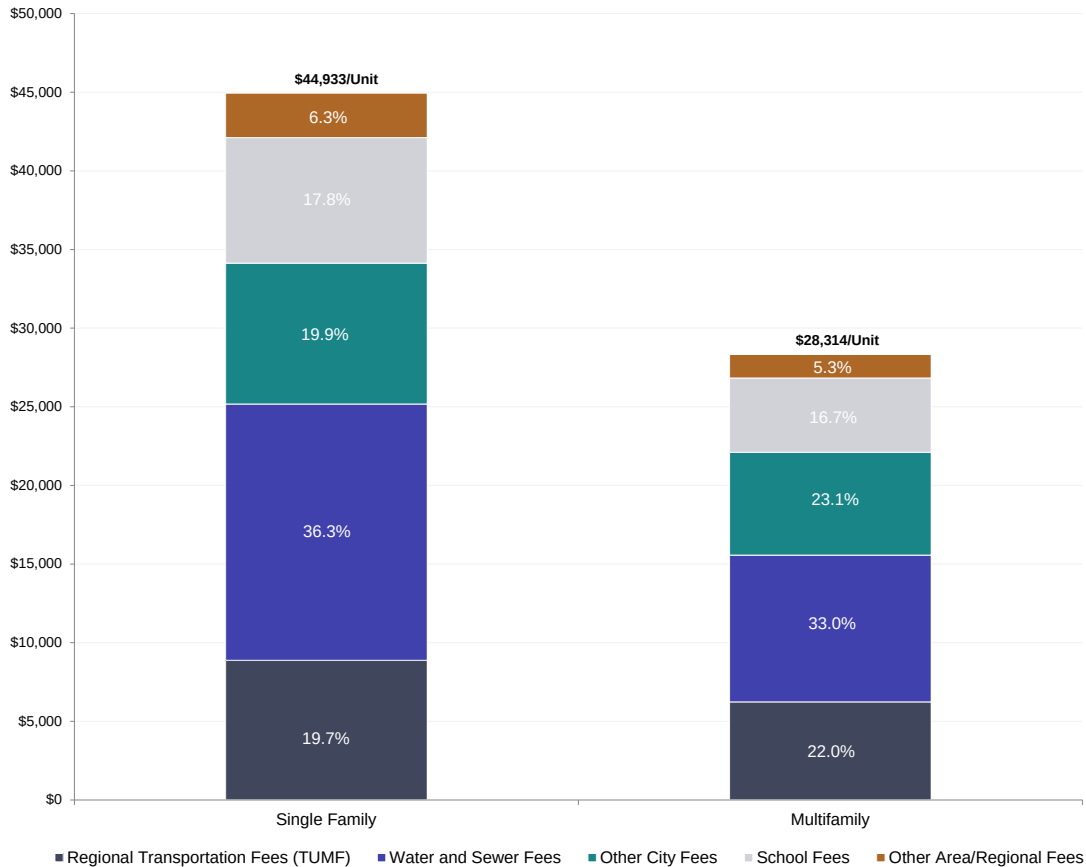
- Water and Sewer facilities
- School Facilities
- Regional Transportation Infrastructure
- Additional Local Infrastructure/Capital Facilities (local transportation, parks and recreation, public facility, community/civic facilities, and storm drain infrastructure).
- Subregional/Area Fees (habitat mitigation fees, Road and Bridge Benefit Assessment Districts, and other area-specific infrastructure/capital facilities fees).

These fees are set/administered by a combination of water districts, school districts, individual cities, the County, the Western Riverside Council of Governments, the Western Riverside County Resource Conservation Authority, and other special districts.

FINDING #2: With the exception of retail development, TUMF represents a modest proportion of total development impact fees in Western Riverside County.

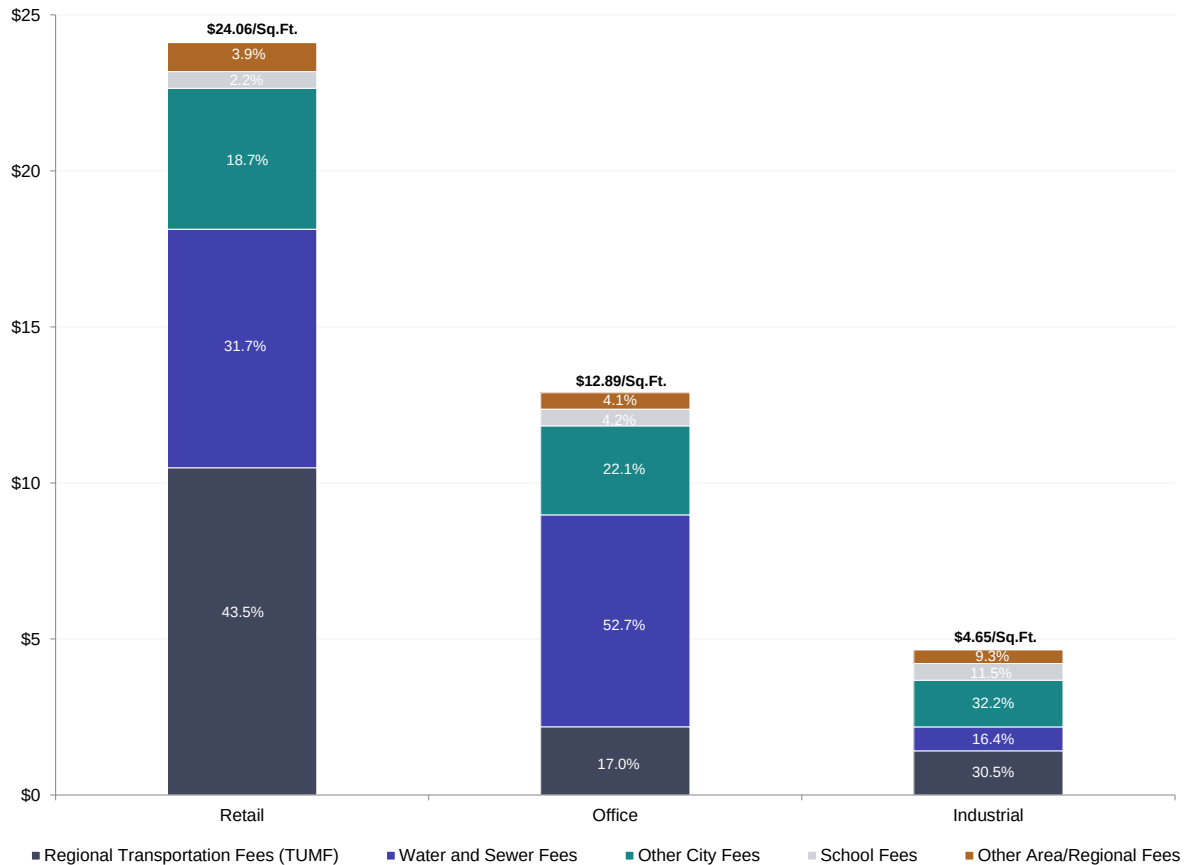
- **On average, TUMF on residential development represents about 20 percent of total development impact fees for both single family and multifamily development.** Water and sewer fees together represent the greatest proportion of residential development impact fees (33.0 percent/36.3 percent), followed by similar proportions from other City fees (19.9 percent/23.1 percent), TUMF (19.7 percent/22.0 percent), and school fees (17.8 percent/16.7 percent). A smaller proportion is associated with other subregional/area fees (6.3 percent/5.3 percent).

Average WRCOG Residential Development Impact Fees by Fee Category



- Average TUMF fees as a proportion of total fees show more variation for Nonresidential land uses, ranging from 43.6 percent for retail development to 17.0 percent for Class A/B office development.** Retail development impact fees are more dominated by the TUMF (43.5 percent) with an additional one-third associated with water and sewer fees. While the overall fees are lower, industrial development impact fees are dominated on a proportionate basis by other City fees (32.2 percent) and TUMF (30.5 percent) (for industrial buildings that are non-intensive water users). Office development impact fees show a different pattern with substantial water and sewer fees (52.7 percent) and lower TUMF (17.0 percent).

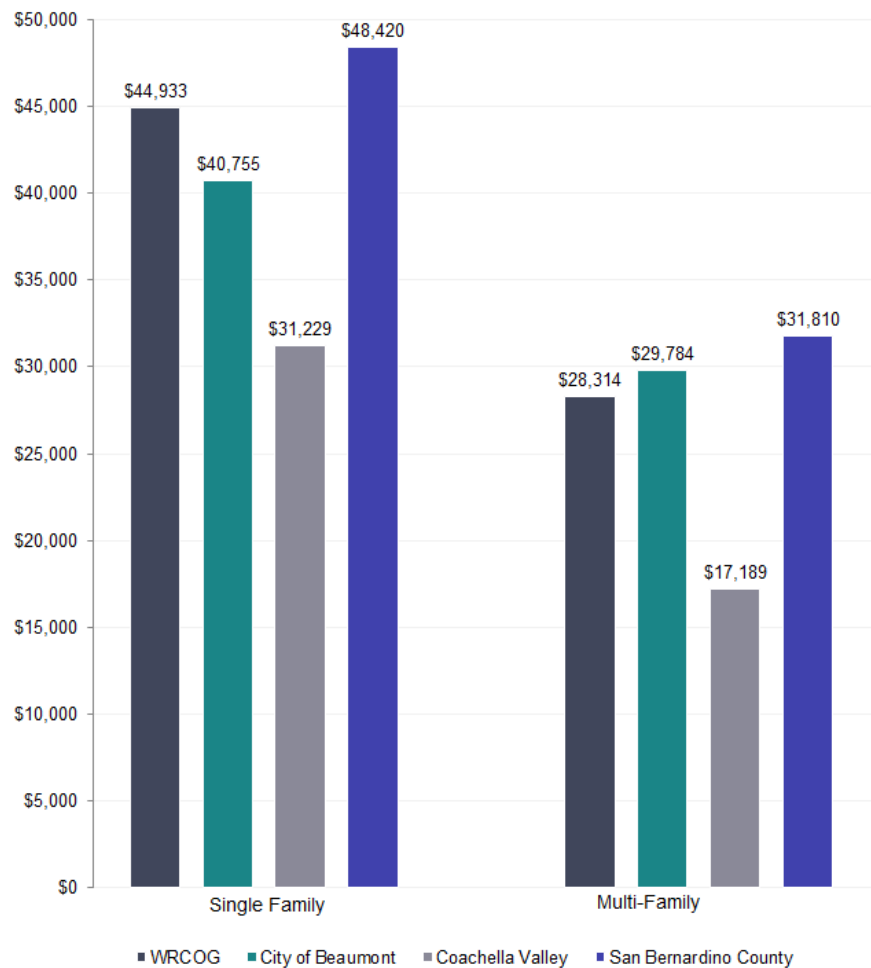
Average WRCOG Nonresidential Development Impact Fees



FINDING #3: Average development impact fees in WRCOG member jurisdictions are within the Inland Empire range.

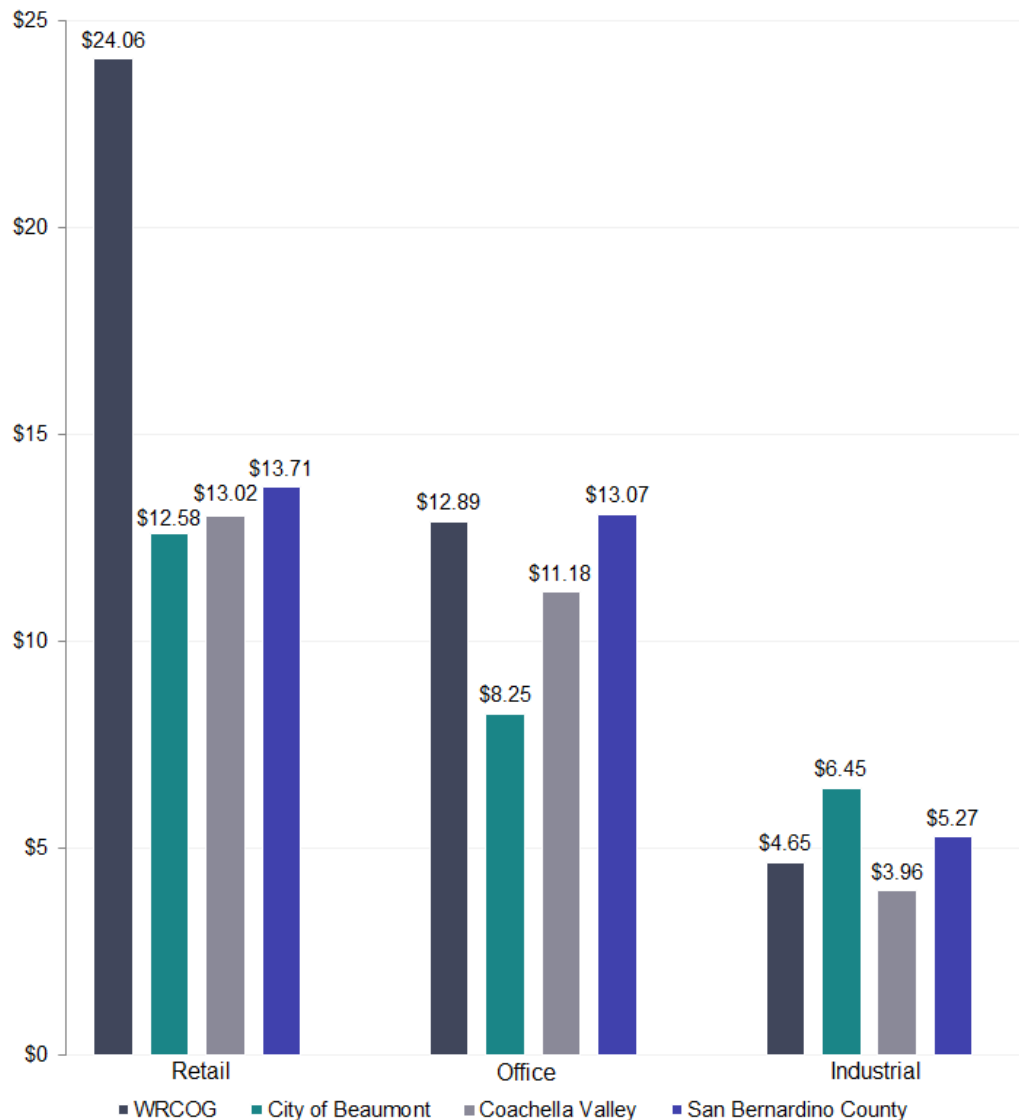
- Average residential development impact fees for WRCOG jurisdictions are lower than the average of selected San Bernardino County cities and higher than the average of selected Coachella Valley cities.** When compared with the average of selected San Bernardino County cities (Fontana, Yucaipa, San Bernardino, Ontario, Chino, and Rialto), the WRCOG average is modestly lower for both single family and multifamily development. The average for selected Coachella Valley cities (Indio, Palm Desert, and Palm Springs) is substantially lower for single family and multifamily development. The City of Beaumont has lower single family fees but higher multifamily fees.

Average Residential Development Impact Fees in Neighboring Jurisdictions



- Average retail development impact fees are about twice as high as the relatively similar average fee levels for San Bernardino County, Coachella Valley, and City of Beaumont.** At \$24.06 per square foot of retail space, the WRCOG average total fee is substantially higher than the equivalent fees in the other areas of study that ranged from \$12.58 to \$13.71 per square foot. This is predominantly due to the substantial TUMF fee, though the water/sewer fee average is also somewhat higher. For office and industrial development, the WRCOG average is below the average of the San Bernardino County cities evaluated and above the average for the Coachella Valley cities evaluated. The City of Beaumont has the highest industrial fee relative to the three other areas, but the lowest office fees.

Average Nonresidential Development Impact Fees in Neighboring Jurisdictions



FINDING #4: Average development impact fees among WRCOG member jurisdictions represent between 4.1 percent and 9.5 percent of total development costs/returns, with TUMF as a lower fraction of these proportions.

- **Total development impact fees represent between 4.1 percent and 9.3 percent of total development costs/returns for the prototype feasible projects.** Total development impact fees represent 9.2 percent and 9.3 percent of total development costs/returns respectively for the prototype single family and multifamily developments evaluated. As is common, Nonresidential development impact fees are lower as a percent of total development cost/return at 4.1 percent for industrial development and 4.7 percent for office development. For retail development, the fee level percentage is 8.0 percent, closer to the residential fee proportion than the other Nonresidential land uses.

- **TUMF represents between 0.8 percent and 3.5 percent of total development costs/returns for the prototype feasible projects. While changes in the TUMF can add or subtract from total development costs, it would take a substantial change to increase/decrease overall development costs/returns by more than 1 percent.**
TUMF represents between 17.0 percent and 43.6 percent of total development impact fees with the highest ratios for retail and industrial development and lowest for office development. As a proportion of overall development costs, TUMF represents 2.0 percent or below for all development prototypes except for retail development where TUMF represents 3.5 percent of total development costs/return.

Development Impact Fees as % of Total Developments Costs /Returns

Development Impact Fees	Single Family	Multifamily	Industrial	Retail	Office
TUMF	1.8%	2.0%	1.3%	3.5%	0.8%
Other Development Impact Fees	<u>7.4%</u>	<u>7.3%</u>	<u>2.8%</u>	<u>4.5%</u>	<u>3.9%</u>
Total Development Fees	9.2%	9.3%	4.1%	8.0%	4.7%

FINDING #5: Through its funding of key regional transportation infrastructure projects identified by WRCOG member jurisdictions, the TUMF supports substantial output, wages, and jobs in Western Riverside County.

- **TUMF revenues will support a total investment of \$3.13 billion in infrastructure development activity over the next 30 years resulting in an overall regional impact of \$4.56 billion in County economic output, \$1.3 billion in labor income, and 28,900 job-years.** TUMF revenues are estimated to generate about \$3.1 billion in revenues for investment in regional transportation infrastructure over the next thirty years. On an annual basis, taking into account “multiplier” effects, this will result in an annual economic output of \$152.1 million, annual labor income of \$43.2 million, and 970 annual jobs.
- **The total regional transportation infrastructure investment in TUMF-supported projects is estimated to be about \$17.7 billion over the next thirty years. When considered in conjunction with the complementary funding, including other regional/local funding, such as Measure A, and the attracted State/federal funding, the overall economic impacts are even greater.** On an annual basis, taking into account “multiplier” effects, this will result in an annual economic output of \$860 million, annual labor income of \$244 million, and 5,400 annual jobs. Even when looking solely at funding flowing from outside of the County (State and federal funding), the annual economic impacts are about \$505 million in economic output, \$143 million in labor income, and 3,100 annual jobs.

Gross Economic Impacts of TUMF-related Transportation Investments

Category	Investment	Output	Labor Income	Employment (Job-Years)
TUMF Investment				
Total	\$3,128,800,000	\$4,562,700,000	\$1,295,300,000	28,900
Annual	\$104,293,000	\$152,090,000	\$43,176,000	970
State and Federal Investment				
Total	\$10,382,700,000	\$15,141,000,000	\$4,298,400,000	95,900
Annual	\$15,141,000,000	\$504,700,000	\$143,200,000	3,100
Total Investment				
Total	\$17,681,300,000	\$25,784,500,000	\$7,319,900,000	163,300
Annual	\$589,400,000	\$859,500,000	\$244,000,000	5,400

Organization of Report

After this initial chapter, this Report is divided into four other chapters and several appendices. **Chapter 2** describes the definitions, methodology, and results of the fee review and comparison for WRCOG and non-WRCOG jurisdictions. **Chapter 3** describes the overall development cost estimates for land uses/development prototypes evaluated and considers total development impact fees and the TUMF relative to all development costs. It also reviews available data on TUMF changes through time relative to other metrics, such as the construction cost index and inflation. **Chapter 4** describes the economic impact analysis of TUMF-funded transportation investments in Riverside County and provides metrics indicating the relative importance and scale of the goods movement industry in Riverside County. Finally, **Chapter 5** provides a brief conclusion on the purposes and goals of this and other development impact fee comparison studies.

The appendices provide a substantial amount of additional supporting detail and information, including:

- **APPENDIX A** provides detailed information on the Development Prototypes.
- **APPENDIX B** provides detailed development cost assumptions for all development prototypes.
- **APPENDIX C** provides a set of estimates of correlation coefficients between TUMF revenues and TUMF fee levels
- **APPENDIX D** provides average fee estimations for each non-WRCOG jurisdiction/area and each land use category.

APPENDIX E provides fee comparison summaries and detailed fee estimation information for each WRCOG jurisdiction/area and each land use category.

2. DEVELOPMENT IMPACT FEE REVIEW AND COMPARISONS

This chapter describes the detailed development impact fee research conducted for WRCOG jurisdictions as well as for selected neighboring jurisdictions in Coachella Valley and San Bernardino County. The purpose of this research is to explore the typical composition of development impact fees in WRCOG member jurisdictions, to understand the scale of TUMF relative to other development impact fees, and to consider the development impact fees among WRCOG member jurisdictions relative to neighboring jurisdictions.

While every effort was made to provide an accurate comparison through the use of defined development prototypes and the latest jurisdictional fee schedules, the frequent adjustments to fee programs and the complex, project-specific calculations required for some fees mean that the numbers presented are planning-level approximations. All the development impact fee estimates shown are based on available fee schedules at the time the research was conducted (Spring/Summer 2016) and as applied to the particular land uses/development prototypes developed. The actual fees due from any particular project will depend on the specifications of the individual project and the fee schedule at the pertinent time.

The first section below provides some key definitions. The subsequent section provides a detailed description of the fee research methodology. The final section provides findings concerning development impacts fees in WRCOG member jurisdictions and relative to the other jurisdictions studied.

Study Definitions

Development impact fees have become an increasingly used mechanism among California jurisdictions to require new development to fund the demands it places on local and regional infrastructure and capital facilities. This Report defines development impact fees as one-time fees collected for the purposes of funding infrastructure and capital facilities.² This includes fees for the funding of a broad range of capital improvements, including water, sewer, storm drain, transportation, parks and recreation, public safety, and numerous other types of civic/community facilities. The majority of these fees are adopted under or consistent with the Mitigation Fee Act, though the analysis also includes other one-time capital facilities fees, such as parkland in-lieu fees under the Quimby Act and one-time charges through Community Facilities Districts or Benefit Assessment Districts among others.

There are a number of smaller permitting, planning, and processing fees that are charged on new development, but that do not fund capital facilities/infrastructure. Due to the large number of more modest charges typically associated with such fees and their relative modesty compared to development impact fees (most studies find them to be in the 5 to 15 percent range of development impact fees, between 1 and 2 percent of total development costs), these smaller fees were not tracked as part of this study.

² As used in this report and discussed further below, the phrase “development impact fee” includes all fees adopted pursuant to the Mitigation Fee Act and other monetary exactions due at the time of development. The term “fee,” as used in this report, means “development impact fee.”

Methodology

In order to provide a fee comparison that was as close as possible to an “apples-to-apples” comparison, WRCOG staff and the Consulting Team identified the following parameters to guide the study:

- Jurisdictions to be studied.
- Land uses to be evaluated and associated development prototypes.
- Selection of service providers where there are multiple service providers in same jurisdiction.
- Organization of development impact fee data.

This section describes these study parameters as well as the process of review with the jurisdictions/relevant service providers.

Selection of Jurisdictions

Jurisdictions selected for this analysis include all seventeen (17) WRCOG member cities. WRCOG staff and the Consulting Team also identified three additional member areas to study, including the March JPA and two unincorporated areas in the County. The selected unincorporated areas included Temescal Valley and Winchester, two areas where substantial growth is occurring/planned.

For the comparison of WRCOG jurisdictions to neighboring/peer areas, the jurisdictions selected included: (1) the City of Beaumont, the non-WRCOG member city in Western Riverside County, (2) selected Coachella Valley communities in eastern Riverside County, and (3) selected San Bernardino County communities. These jurisdictions were selected by WRCOG staff and the Consulting Team and refined based on feedback from the WRCOG Planning Directors’ Committee and WRCOG Public Works Committee. The San Bernardino County communities selected were those likely to compete for development with neighboring WRCOG jurisdictions.

Figure 1 shows the cities/communities evaluated, including the twenty (20) WRCOG cities/communities and the ten (10) non-WRCOG comparison communities.

Figure 1 Jurisdictions included in Fee Study

WRCOG Jurisdictions		Coachella Valley	San Bernardino County	Other
Banning	Murrieta	Indio	Fontana	Beaumont
Canyon Lake	Norco	Palm Desert	Yucaipa	
Calimesa	Perris	Palm Springs	San Bernardino	
Corona	Riverside		Ontario	
Eastvale	San Jacinto		Chino	
Hemet	Temecula		Rialto	
Jurupa Valley	Wildomar			
Lake Elsinore	Temescal Valley			
Menifee	Winchester			
Moreno Valley	March JPA			

Land Uses and Development Prototypes

Land Uses

The TUMF is levied on a variety of residential and Nonresidential land uses with variations for certain product types built into the fee program. TUMF includes fees on the following land uses:

- **Single-Family Residential Development** – Per unit basis.
- **Multifamily Residential Development** – Per unit basis.
- **Retail Development** – Per gross building square foot basis.
- **Industrial Development** – Per gross building square foot basis. The industrial fee includes a base fee on square footage up to 200,000 square feet and then, where the building meets the definition of a “high cube” building, an effective discount of 73 percent in the base fee for all additional development above 200,000 square feet.³ “High Cube” is defined as warehouses/distribution centers with a minimum gross floor area of 200,000 square feet, a minimum ceiling height of 24 feet and a minimum dock-high door loading ratio of 1 door per 10,000 square feet.
- **Service (including Office) Development** – Per gross building square foot basis. There is a per-building square foot fee for Service Development. Office development is a sub-category within Service Development. Class A and B office development was provided a \$2.00 TUMF discount relative to other Service Development, a reduction of almost 50 percent.

For the purposes of this study, five (5) land use types were selected, including the single family residential, multifamily residential, and retail development categories in addition to a large “high-cube” industrial building, and a Class A/B office building. The large industrial building land use was selected based on current industrial development trends in Western Riverside County, while the Class A/B office building was selected due to its reduced fee level.

Development Prototype Selection

Within each of the five (5) general land uses types selected, it is necessary to select specific development prototypes. Because development impact fees vary based on a number of development characteristics, the definition of development prototype improves the extent to which the fee comparison will be “apples-to-apples”.

In order to identify appropriate development prototypes for the five land uses, the Consulting Team reviewed data on the general characteristics of new single family, multifamily, office, retail, and industrial development among Western Riverside County communities in recent years.

Information on multifamily, retail, office, and industrial developments developed since 2010 were reviewed as was information on single family developments since 2014. A smaller time period was used for single family developments as there are substantially more single family developments. The characteristics of the median development for each of the land use types

³ The square footage above 200,000 square feet is multiplied by 0.27 and then the base fee is applied resulting in an effective increment fee of about \$0.47 per square foot.

was identified and used as the selected development prototype. For single-family development, the median home and lot size characteristics were identified, while for multifamily residential, office, retail, and industrial buildings the average building sizes were identified.

Based on this analysis, the following development prototypes were developed for each of the selected land uses and reviewed with the WRCOG Planning Directors' Committee, Public Works Committee, and Technical Advisory Committee (images represent examples of projects that matched the development prototypes):

Single-Family Residential Development

50-unit residential subdivision; 2,700 square foot homes and 7,200 square foot lots



Example Prototype Single-Family Home, City of Riverside

Multifamily Residential Development

200-unit market-rate, 260,000 gross square foot apartment building



Example Prototype Multi-Family Development, City of Temecula

Retail Development

10,000-gross square foot retail building



Office Development

20,000-gross square foot, Class A or Class B office building



Industrial Development

265,000 gross square foot “high cube” industrial building⁴



Example Prototype Industrial Development, City of Perris

In addition to development scale, there are a number of other development characteristics that can affect development impact fees. For example, many water facilities fees are tied to the number and size of meters associated with a new development. Other fees are tied to the gross site area or other characteristics that will vary for each development. The Consulting Team developed a set of additional development prototypes assumptions to use in the fee estimates (see **Appendix A**). These assumptions were based on a review of the equivalent assumptions used in other regional fee studies (e.g., in the San Joaquin Valley and the Sacramento Valley) and were refined based on feedback, when provided, from Western Riverside County service providers. In some cases, the formula for fee calculation required even more assumptions. In these cases, service providers typically conducted their own fee estimates and provided the results to WRCOG Staff/the Consulting Team.

Service Provider / Subarea Selection

In some cities, there were multiple service providers providing the same type of facilities in different parts of the city. For example, some cities were served by two or more distinct School Districts, while many cities were served by two or more Water Districts. For the purposes of the fee comparison one set of service providers was assumed based on the following approach:

- Suggestions from the City.
- Commonality of service provider between multiple cities; for example, Eastern Municipal Water District serves many cities.

⁴ “High Cube” is defined as warehouses/distribution Centers with a minimum gross floor area of 200,000 square feet, a minimum ceiling height of 24 feet and a minimum dock-high door loading ratio of 1 door per 10,000 square feet.

- Scale/nature of service areas was also considered; for example, in some cases the majority of a City was served by one service provider and/or the majority of the growth areas were served by a particular service provider.
- In some cases, there was one service provider – e.g., the City – with different fees by City subarea (e.g., storm drain). In these cases, an effort was made to select the area expected to see the most growth based on discussions with City and WRCOG staff.
- In other cases, area-specific one-time fees/assessments/special taxes were in place to cover the costs of capital facilities in a new growth area. Where substantial in scale, these areas and the associated area fees were used in the fee comparison.

Organization of Fee Information/Categories

The primary focus of the fee research is to develop estimates of existing development impact fees charged on new development in the selected jurisdictions. While there is some conformance in fee categories (e.g., School District fees), there is also variation in the naming and facilities included in water and sewer facilities fees and substantial variation in the capital facilities fees that different cities charge. The fee review sought to obtain all the development impact fees charged from all the jurisdictions studied and then compiled them into a normalized set of categories to allow for comparisons. The key fee categories are as follows:

- **Regional Transportation Fees.** This category includes the respective TUMFs in Western Riverside County and Coachella Valley. It also included regional transportation impact fees in other subregions/jurisdictions where they were clearly called out. The lines between regional transportation fees and local transportation fees are harder to discern in San Bernardino County where cities are required to contribute towards regional transportation funding, but do not necessarily separate out those fees from the other, local transportation fees.
- **Water/Sewer Connection and Capacity Fees.** All jurisdictions charged some form of water and sewer development impact fee and these were combined together into one aggregate water/sewer category. In several cases, the County, city, or water district provided their own calculations due to the complexity of fee calculation.
- **City/County Capital Facilities Fees.** Beyond any water/sewer fees that in some cases might be charged by individual jurisdictions (cities/County), these jurisdictions frequently adopt a large number of additional citywide fees. Such fees often include local transportation fees, parks and recreation facilities fees, Quimby Act requirements in-lieu parkland fees, storm drain fees, public safety facilities fees, other civic/community facilities fees, and, on occasion, affordable housing fees. This category captures all of these local development impact fees.
- **School Development Impact Fees.** School facilities fees are governed by State law and therefore show more similarity between jurisdictions than most fees. Under State law, School Districts can charge specified Level 1 development impact fees. If School Districts go through the process of identifying and estimating required capital improvement costs, higher Level 2 fees can be charged to fund up to 50 percent of the School District's capital

improvement costs. At present, about eight of the fourteen School Districts studied (that serve WRCOG member jurisdictions) appear to charge Level 2 fees.⁵

- **Other Area/Regional Fees.** A final category was developed to capture other fees not included in the above categories, typically other sub-regional fees as well as area-specific fees. For example, this category includes the Western Riverside County MSHCP mitigation fee, relevant Road and Bridge Benefit Districts (RBBD) fees, as well as other one-time CFD charges/impact fees for infrastructure/capital facilities applied in particular growth areas.

Data Compilation and Review Process

For WRCOG member jurisdictions, the following data collection and review process was followed:

- Identify set of service providers and development impact fees charged in jurisdiction.
- Obtain development impact fee schedules from City, County, and other service provider online sources.
- Review available mitigation fee nexus studies, Ordinances, and Resolutions.
- Where sufficient data was not available, contact City, County, or other service provider to obtain appropriate fee schedules.
- Develop initial estimates of development impact fees for each jurisdiction for each development prototype.
- Share PowerPoint document noting development prototypes specifications and initial fee estimates with each jurisdiction and selected other service providers (e.g., Eastern Municipal Water District).
- Receive feedback, corrections, and refinements (and in some cases actual fee calculations).
- Refine fee estimates based on feedback.
- Share revised fee estimates with jurisdictions.

For other non-WRCOG jurisdictions, fee information was obtained either on-line or by contacting cities directly. Fee information was then compiled in a similar structure to the WRCOG jurisdictions.

⁵ At the time of writing this Report, there has been uncertainty over the potential for jurisdictions to begin charging Level 3 fees (typically double Level 2 fees) The State Allocation Board recently indicated that State funds are not currently available setting in motion a process whereby jurisdictions may be able to charge Level 3 fees. However, the recent passage of Proposition 51 by State voters has provided new funding for school construction and is expected to remove the possibility of Level 3 school impact fees for the time being.

Findings from WRCOG Member Jurisdiction Fee Review

General findings from fee research concerning WRCOG member jurisdictions are summarized below and in **Figures 2 to 4**. **Appendix E** provides more detailed summary tables for the WRCOG jurisdictions studied along with detailed information for each jurisdiction.

On average, WRCOG TUMF residential fees represent about 20 percent of total development impact fees for both single family and multifamily development. Single family TUMF and multifamily TUMF both represent about 20 percent of the respective total development impact fees of about \$44,900 per unit and \$28,300 per unit. Due to the variation in overall development impact fees – from \$32,900 per unit to \$59,400 per unit for single family development and from \$19,200 per unit to \$40,600 per unit for multifamily development – and the fixed nature of the TUMF across jurisdictions, TUMF as a percent of total development impact fees ranges from 14.9 percent to 26.9 percent for single family development and 15.4 percent to 32.3 percent for multifamily development (see **Figures 2 and 3**).

Figure 2 TUMF as a Proportion of Total Fees

Item	Average	Range	
		Low	High
Single Family			
Total Fees per Unit	\$44,933	\$32,935	\$59,366
TUMF as a % of Total Fees	19.7%	26.9%	14.9%
Multifamily			
Total Fees per Unit	\$28,314	\$19,262	\$40,573
TUMF as a % of Total Fees	22.0%	32.3%	15.4%
Retail			
Total Fees per Sq.Ft.	\$24.06	\$14.88	\$33.20
TUMF as a % of Total Fees	43.6%	70.5%	31.6%
Industrial			
Total Fees per Sq.Ft.	\$4.65	\$3.05	\$9.60
TUMF as a % of Total Fees	30.5%	54.9%	14.8%
Office			
Total Fees per Sq.Ft.	\$12.89	\$6.53	\$19.07
TUMF as a % of Total Fees	17.0%	33.6%	11.5%

* Average and ranges as shown encompass 20 jurisdictions, including 17 cities, the unincorporated cities of Temescal Valley and Winchester, and March JPA

On average, WRCOG Nonresidential TUMF show more variation in level and in proportion of overall development impact fees (between 17 percent and 44 percent) than for the residential fee categories. Average retail development impact fees are about \$24 per square foot and represents 43.6 percent of the average total fees on new retail development. Due to the variation in the total development impact fees on retail development among jurisdictions from \$14.90 to \$33.20 per square foot, the TUMF as a percent of the total fees ranges from 31.6 percent to 70 percent. Average industrial development impact fees are substantially lower at \$4.65 per square foot with a range from \$3.05 per square foot to \$9.60 per square foot. TUMF still represents about 30.5 percent of the average total industrial fees, with a range from 14.8 percent to 54.9 percent. Total development impact fees on office development fall in between the retail and industrial fees at an average of \$12.90 per square foot and a range from \$6.50 to \$19.10 per square foot. The discounted TUMF means that TUMF represents a relatively low 17.0 percent of average overall fees on office development with a range from 11.5 percent to 33.6 percent (see **Figure 2** to **Figure 4**).

Water and sewer fees together represent the greater proportion of residential development impact fees followed by similar proportions from other City fees, TUMF, and school fees. Single family and multifamily development both show that about 34 percent of their development impact fees are associated with water and sewer fees, about 22 percent with other City capital facilities fees, about 21 percent with regional transportation fees, about 17 percent with school facilities fees, and the remaining 5 percent associated with other regional fees or area-specific fees (see **Figure 3** and **Figure 4**).

Nonresidential development impact fees show more variation in terms of the distribution between fee categories. Retail development impact fees are more dominated by the regional transportation fee (43.6 percent) with an additional one-third associated with water and sewer fees. While the overall fees are lower, industrial development impact fees are more dominated on a proportionate basis by other City fees (32 percent) and TUMF (31 percent), for non-intensive water using industrial buildings. Office development impact fees show a different pattern with substantial water and sewer fees at 52.7 percent (see **Figure 3** and **Figure 4**).

Estimated statistical correlations between the level of development impact fees and a range of metrics for development activity and development value showed no significant correlation. A range of statistical correlation coefficients (r) between the development impact fee levels in the seventeen (17) WRCOG cities and proxies for new development activity (TUMF revenues collected) and development value (average home prices) were estimated. When comparing TUMF revenues and total fees per unit/square feet, all correlation coefficients fell between -0.16 and 0.28 (on a range of -1 to 1) indicating no or very weak correlation with the exception of retail (see **Appendix B** for correlation estimates).⁶ Retail indicated a modest positive correlation between TUMF revenues and total fees per square feet with a correlation coefficient of 0.44. Correlation between total fees per unit and average home sale prices reflect a modest positive relationship. When looking at the 20 jurisdictions/areas evaluated, one differential stood out – fees in the unincorporated areas evaluated (Temescal

⁶ A value of $r = -1$ or 1 is a perfect linear relationship, while a value of $r = 0$ indicates that there is no correlation between two variables. A value of $r = -0.5$ to -0.3 and 0.3 to 0.5 reflect modest correlation. A value of $r = -0.3$ to 0.3 indicates weak correlation.

Valley and Winchester) and in the March JPA were, on average, consistently lower than the overall average for all 20 jurisdictions/areas. As shown in **Figure 5**, the average for these three areas ranged from 66.5 percent to 82.8 percent of the average of all 20 jurisdictions/areas for the five (5) land uses evaluated.

Figure 3 Average Development Impact Fee Costs by Category in WRCOG Jurisdictions

Fee	Single Family (per Unit)	Multi-Family (per Unit)	Industrial (per Sq.Ft.)	Retail (per Sq.Ft.)	Office (per Sq.Ft.)
Regional Transportation Fees (TUMF)	\$8,873	\$6,231	\$1.42	\$10.49	\$2.19
Water and Sewer Fees	\$16,292	\$9,331	\$0.76	\$7.65	\$6.79
Other City Fees	\$8,955	\$6,540	\$1.50	\$4.51	\$2.85
School Fees	\$7,985	\$4,718	\$0.54	\$0.54	\$0.54
Other Area/Regional Fees	<u>\$2,829</u>	<u>\$1,493</u>	<u>\$0.43</u>	<u>\$0.93</u>	<u>\$0.53</u>
Total	\$44,933	\$28,314	\$4.65	\$24.11	\$12.89

Figure 4 Average Development Impact Fee Costs in WRCOG Jurisdictions



Figure 5 Unincorporated Jurisdictions/March JPA and Total Jurisdictions Comparison

Item	Single Family	Multifamily	Retail	Industrial	Office
Unincorporated Jurisdictions and March JPA	\$34,069	\$23,434	\$19.77	\$3.09	\$9.19
Total Jurisdictions	\$44,933	\$28,314	\$24.06	\$4.65	\$12.89
Unincorporated Jurisdictions and March JPA/ Total Jurisdictions	75.8%	82.8%	82.2%	66.5%	71.3%

Findings from Fee Comparison with Non-WRCOG Jurisdictions

Figures 6 through 10 compare the average overall WRCOG development impact fees (and their proportionate distributions between the five major fee categories) with other cities/group of cities for all five land uses/development prototypes studied. The comparative cities/subregions include selected jurisdictions in the Coachella Valley, in San Bernardino County, and the City of Beaumont. Appendix D includes specific information on the average fees for all the non-WRCOG jurisdictions/groups evaluated.

Average development impact fees for WRCOG jurisdictions are modestly lower than the average of selected San Bernardino County cities, with the exception of the retail development impact fees. When compared with the average of selected San Bernardino County cities (Fontana, Yucaipa, San Bernardino, Ontario, Chino, and Rialto), the WRCOG average is modestly lower for all land uses with the exception of retail development where it is substantially higher. New development in San Bernardino County cities is required to make payments towards regional transportation infrastructure, though the distinction between the regional and local transportation fees is often unclear. Overall, the combination of regional transportation fees, other City fees, and area/other regional fees is higher in San Bernardino County than in Riverside County for single-Family and multifamily development.

The average development impact fees for selected Coachella Valley cities is below that of the WRCOG average for single family, multifamily, and retail land uses. The average for selected Coachella Valley cities (Indio, Palm Desert, and Palm Springs) is substantially lower for single family, multi family, and retail development, and modestly lower for office and industrial development. For residential development, there are substantial differences in regional transportation fees, water and sewer fees, and other City fees. Regional transportation fees are set at an equal rate for both office and retail in Coachella Valley resulting in higher regional transportation fees for office development in Coachella Valley but lower fees for retail development.

The City of Beaumont has lower fees than the average for WRCOG for single family residential development, substantially lower fees for office and retail development, but higher fees for multifamily development and industrial development. On average for the City of Beaumont, new residential development pays approximately \$40,800 per single family dwelling unit in development impact fees, lower than the WRCOG average of \$44,900 per unit. Fees on office and retail development are between 60 and 100 percent higher on average for WRCOG than in the City of Beaumont. While the City of Beaumont does not participate in the TUMF program, with the exception of retail development, this is not the reason for the lower fee levels for single family residential and office development (difference is driven by lower other City fees and/or water/sewer fees). The City of Beaumont shifted substantial transportation impact fees to its local fee program, placing transportation fees on single family and multifamily development at a similar level to WRCOG jurisdictions. The exception is for fees on retail development, where the City of Beaumont's fees are substantially lower.

Figure 6 Average Single-Family Development Impact Fee Costs and Proportions in Neighboring Jurisdictions

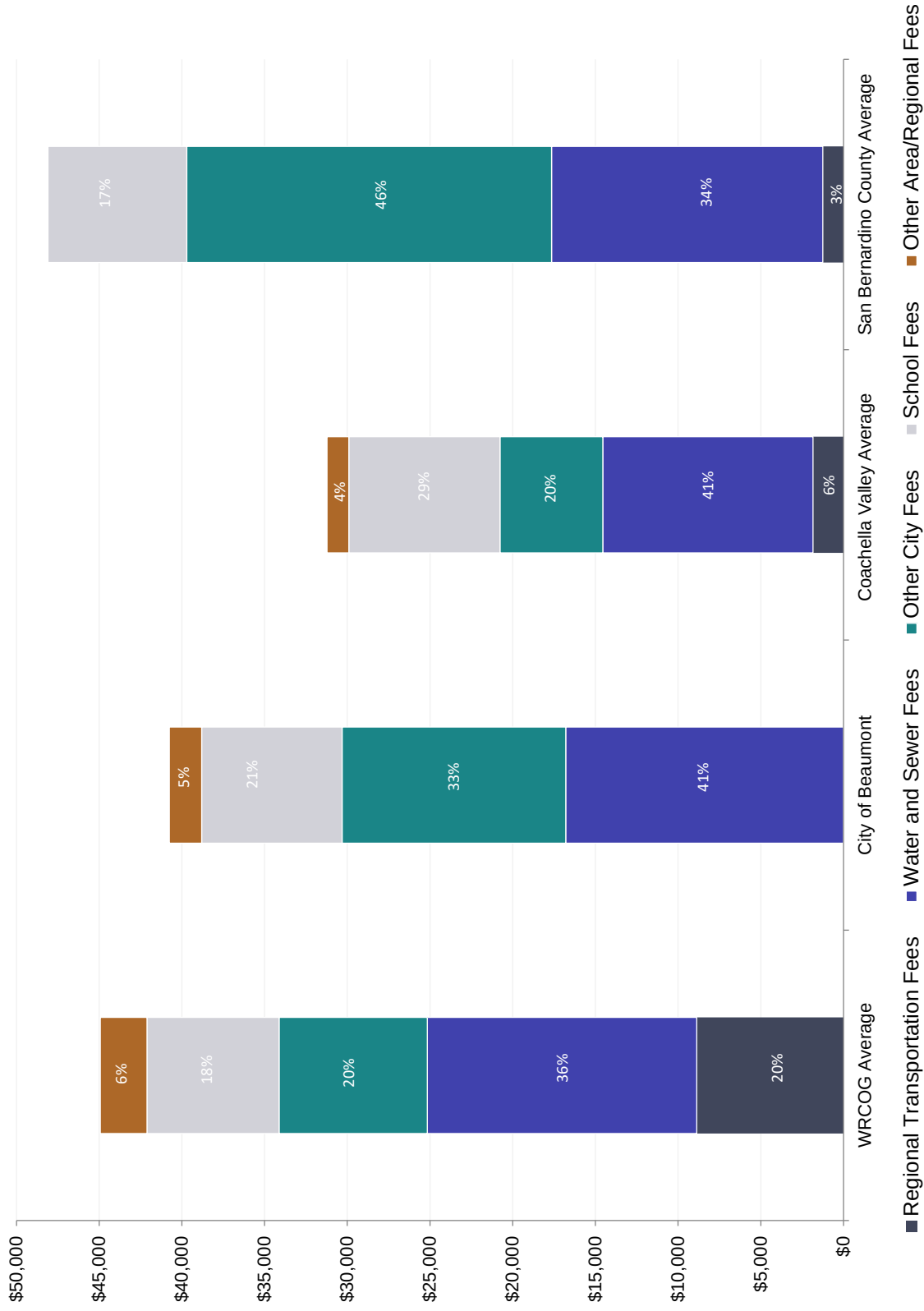


Figure 7 Average Multifamily Development Impact Fee Costs and Proportions in Neighboring Jurisdictions

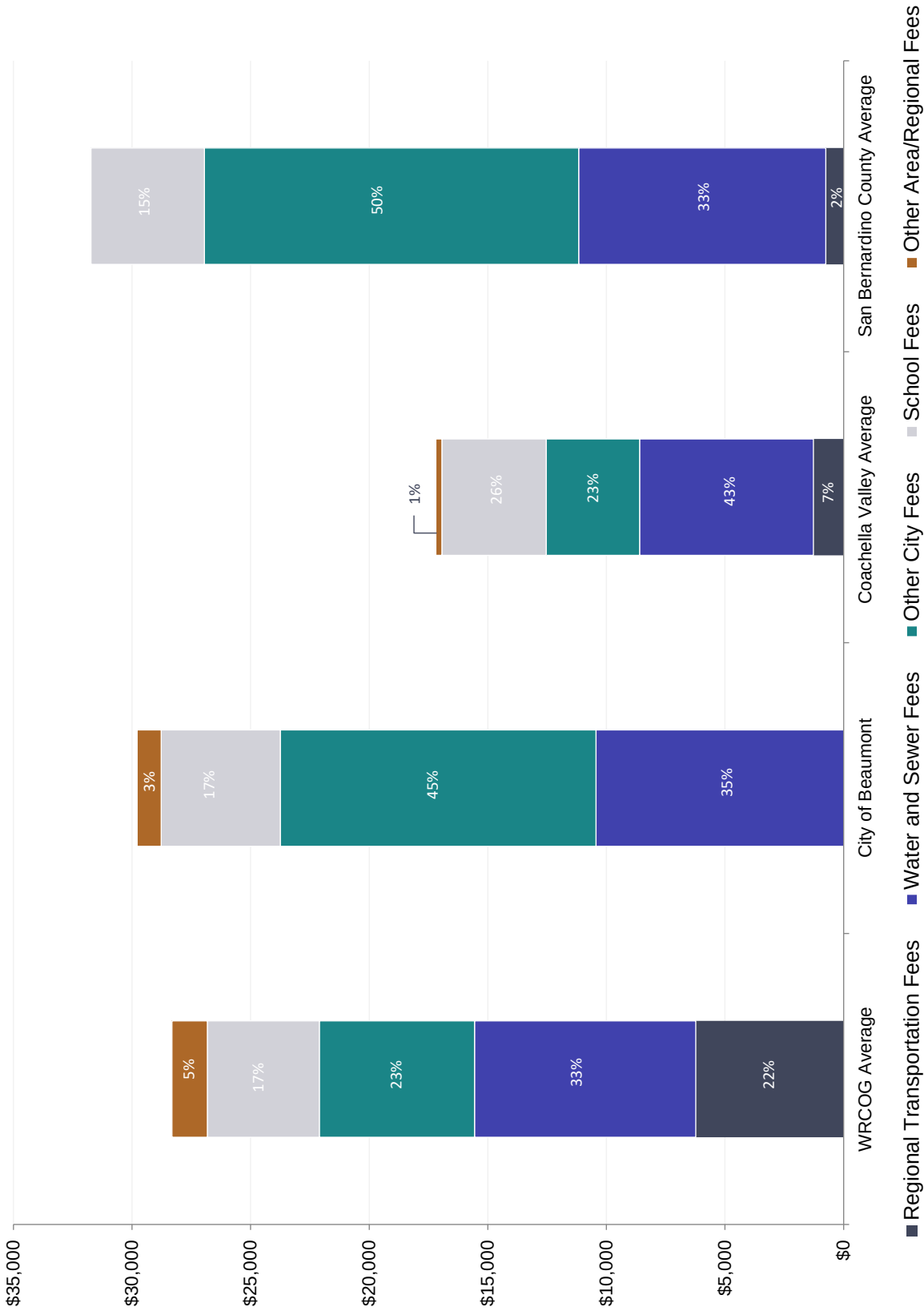


Figure 8 Average Retail Development Impact Fee Costs and Proportions in Neighboring Jurisdictions

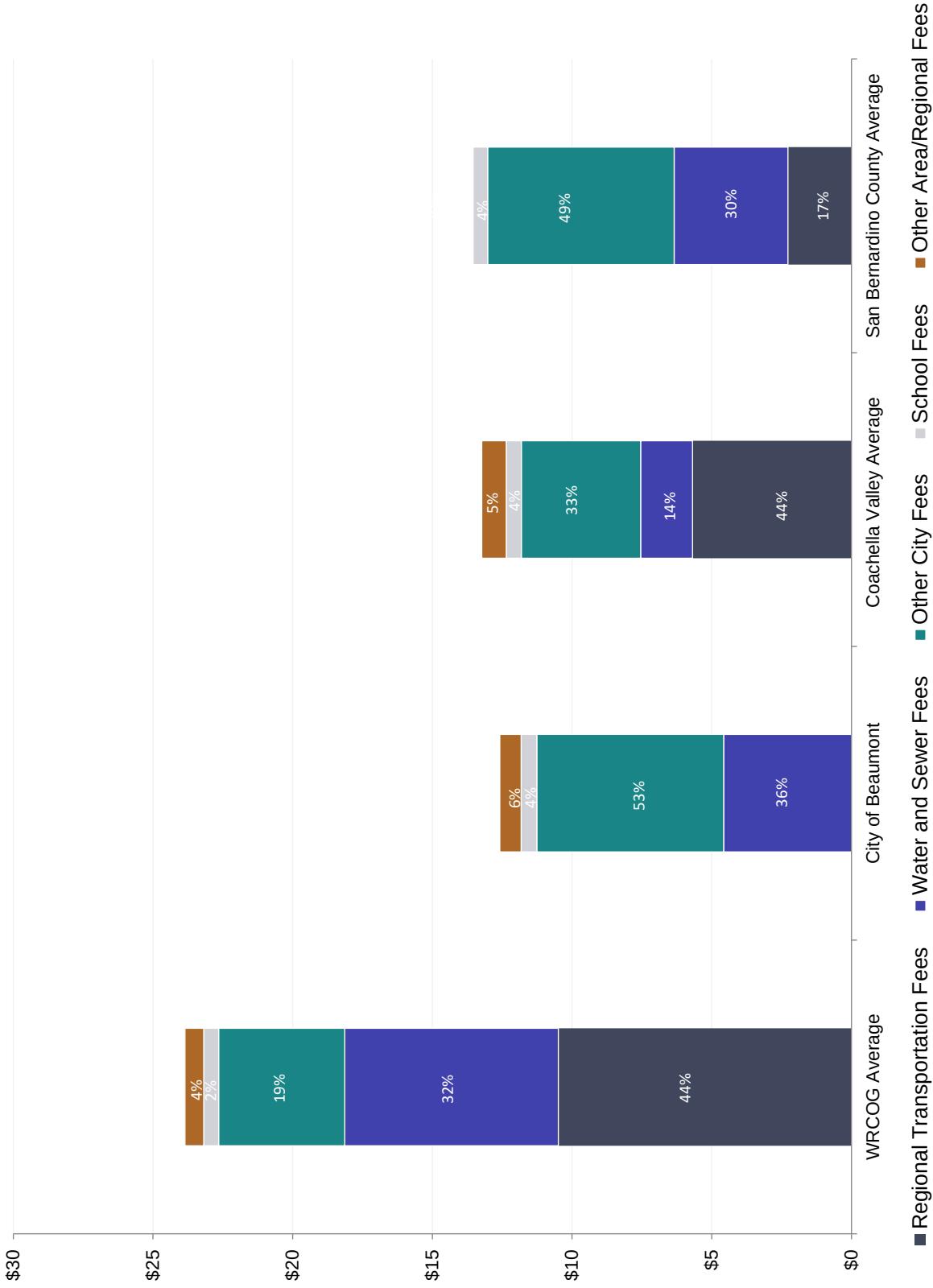


Figure 9 Average Industrial Development Impact Fee Costs and Proportions in Neighboring Jurisdictions

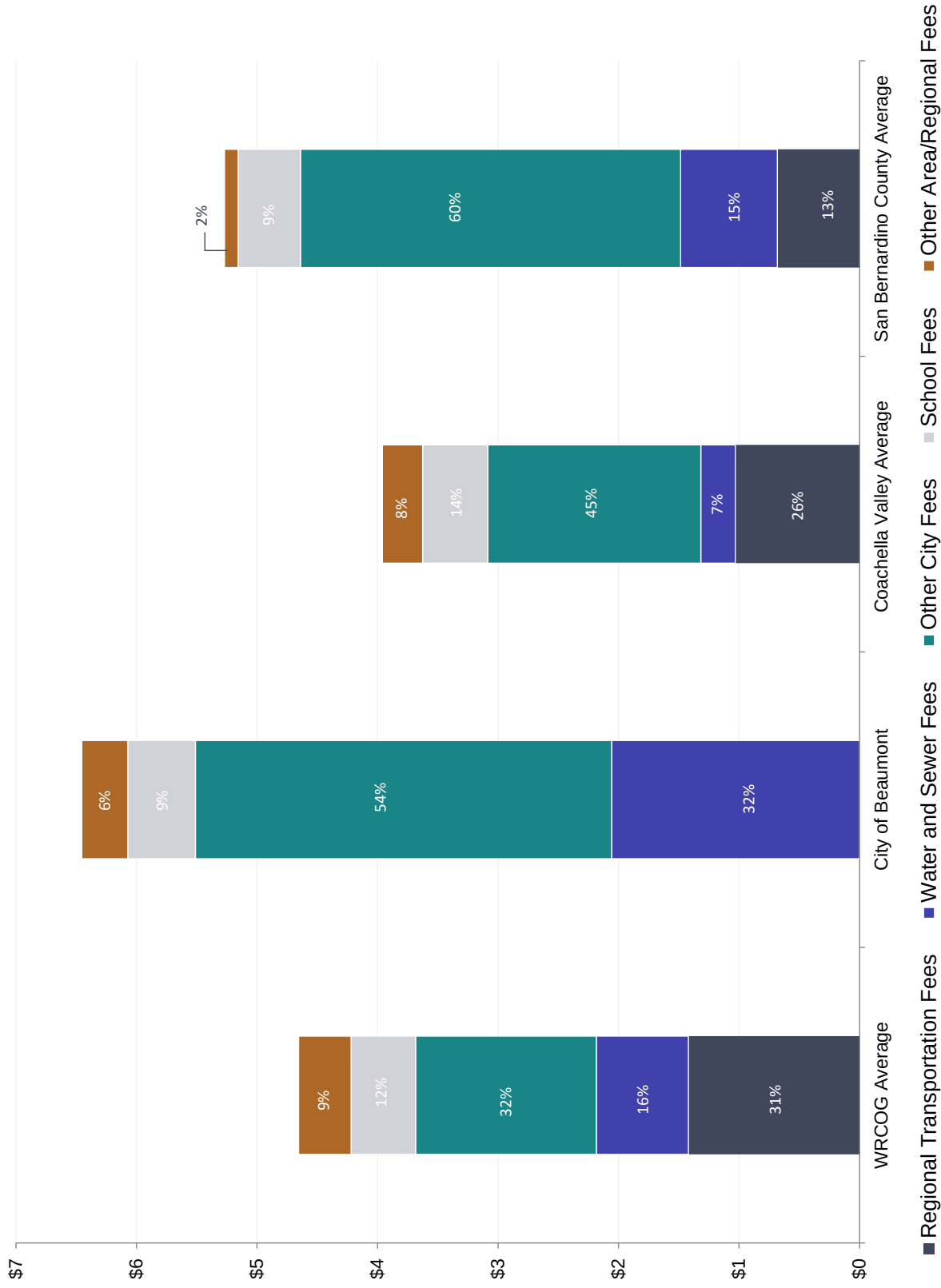
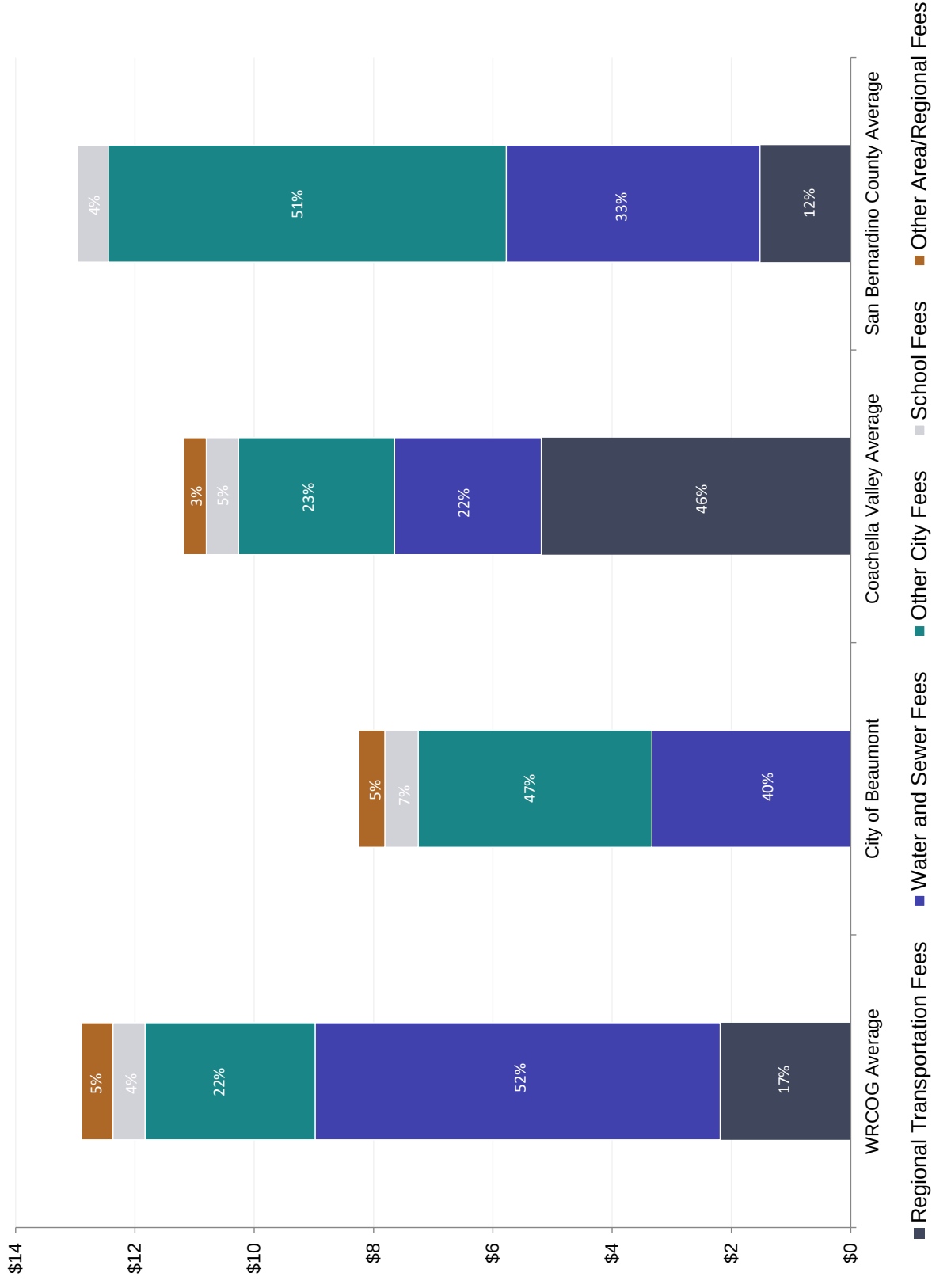


Figure 10 Average Office Development Impact Fee Costs and Proportions in Neighboring Jurisdictions



3. DEVELOPMENT IMPACT FEES AND DEVELOPMENT COSTS

This chapter evaluates development impact fees, including the TUMF, in Western Riverside County in the context of overall development costs. The first section below provides an overview of the complex factors that influence decisions to develop, one of which is development cost. The subsequent section describes the methodology used to estimate development costs for different land use types. The next section provides conclusions concerning the level of development impact fees and TUMF in the context of overall costs. And, the final section looks at changes in the TUMF over time relative to measures of changes in other costs.

It is critical to note that this analysis uses generalized development prototypes and development cost and return estimates to draw overall conclusions about development impact fees relative to development costs. This analysis does not represent a project-specific analysis as the development program, development costs, and returns associated with any individual project can vary widely. No conclusions concerning the feasibility of any specific project should be drawn from this analysis.

Economics of Development

Key Factors in New Development

The drivers of growth and development are complex and multifaceted. Broader global, national, and regional economic conditions are key drivers. As witnessed by the recent Great Recession, there are no regional and local policy options available to fully counterbalance a strong economic downturn. Under more moderate or strong market conditions, the regional demand for housing and workspaces translate into the potential for cities and subregions to capture new residential and economic/workforce development.

Developers (whether looking to do speculative development or to provide build-to-suit developments for larger users) will review a number of conditions before determining whether to move forward with site acquisition/optioning and pre-development activities. Factors will include: (1) the availability of appropriate sites, (2) the availability of/proximity to/quality of infrastructure/facilities (e.g., proximity to transportation corridors, schools, and other amenities), (3) local market strength (achievable sales prices/lease rates) in the context of competitive supply, (4) expected development costs (including land acquisition costs, construction materials and labor costs, the availability and costs of financing, and development impact fees, among others), and, (5) where sites are unentitled, the entitlement risk.

For some subregions, cities, and/or areas, market conditions for particular uses may be too weak to have a realistic chance of attracting certain types of development. For example, to the extent the market-supported lease rates for new office development in a particular area of a City do not support Class A office development construction costs, the attraction of this type of space will not be realistic in the short term. Similarly, some users, like major retailers, will only be interested in sites along major transportation corridors. In other cases, there may be a nominal or potential demand, but the willingness of home-buyers/businesses to pay may still not be sufficient to cover the development costs. This willingness to pay will be constrained by competitive supply and prices, whether the price points/lease rates among existing homes/workspaces in the same community or by the price points/lease rates offered in

neighboring communities with different characteristics (proximity to jobs centers, local infrastructure/amenities, school district quality, among other factors).

In other cases, the strength of market demand for new residential and Nonresidential development will spur more detailed review and evaluation of sites by developers. Even in cases where market factors look strong, there is a complex balance between development revenues, development costs, land costs, and required developer returns that must be achieved to catalyze new development. Modest fluctuations in development revenues (i.e., market prices), development costs (materials, labor costs, etc.), and landowner expectations (perceived value of land) can all affect development decisions as can assessments of entitlement risk and complexity, where entitlements are still required. And many of these factors, such as the price of steel, the complexities of CEQA, and landowner's land value preferences, to name a few, are outside of the control of developers and local public agencies.

WRCOG Growth and TUMF Revenues

There has been substantial variation in the development of different land uses in recent years in Western Riverside County. Single family development has long been a key development sector in Western Riverside County and has shown overall improvements since the Great Recession severely reduced the pace of new development. At the same time, however, there are significant disparities in the levels of development by cities within the region. Western Riverside County has also seen multifamily development in recent years, though developments tend to be clustered in a subset of the Western Riverside County cities/communities. Industrial development, in particular large industrial developments, have been the fastest growing sector in recent years with substantial new development in recent years and substantial new development under construction and in the planning stages. Class A/Class B office development has been limited, while retail development has occurred with a preponderance of smaller scale developments spread throughout Western Riverside County in recent years.

The TUMF revenue collections shown in **Figure 11** and associated indications of new development paying the TUMF in **Figure 12** provide one source of information on the relative distribution of new development among WRCOG jurisdictions.

Figure 11 Average Annual TUMF Revenue Collections (2013 / 14 to 2015 / 16)

Jurisdiction	Retail	Industrial	Single Family	Multifamily
Banning	\$39,963	\$542	\$5,915	\$0
Calimesa	\$7,775	\$33,438	\$2,958	\$103,850
Canyon Lake	\$16,269	\$0	\$28,101	\$0
Corona	\$159,030	\$526,195	\$303,459	\$2,359,295
Eastvale	\$122,883	\$29,604	\$2,880,768	\$189,007
Hemet	\$199,915	\$0	\$940,538	\$0
Jurupa Valley	\$57,213	\$438,803	\$2,484,439	\$0
Lake Elsinore	\$45,949	\$5,496	\$1,691,102	\$0
March JPA	\$0	\$330,690	\$0	\$0
Menifee	\$112,503	\$0	\$2,346,827	\$294,934
Moreno Valley	\$388,777	\$2,086,369	\$848,850	\$0
Murrieta	\$425,785	\$21,132	\$428,862	\$1,061,347
Norco	\$48,964	\$0	\$5,915	\$0
Perris	\$834,140	\$1,967	\$1,679,630	\$2,077
Riverside	\$494,574	\$310,003	\$1,377,026	\$533,037
San Jacinto	\$252,484	\$0	\$579,703	\$0
Temecula	\$150,502	\$94,972	\$460,099	\$669,608
Wildomar	\$56,831	\$108,521	\$354,920	\$0
Unincorporated County	<u>\$183,897</u>	<u>\$161,414</u>	<u>\$4,573,258</u>	<u>\$3,406</u>
Total	\$3,597,454	\$4,149,146	\$20,992,370	\$5,216,562

Source: WRCOG

Figure 12 Average Annual New Development Associated with TUMF Revenue (2013 / 14 to 2015 / 16)

Jurisdiction	Retail (Sq.Ft.)	Industrial (Sq.Ft.)	Single Family (Unit)	Multifamily (Unit)
Banning	3,810	382	1	0
Calimesa	741	23,544	0	17
Canyon Lake	1,551	0	3	0
Corona	15,160	370,499	34	379
Eastvale	11,714	20,845	325	30
Hemet	19,058	0	106	0
Jurupa Valley	5,454	308,966	280	0
Lake Elsinore	4,380	3,870	191	0
March JPA	0	232,842	0	0
Menifee	10,725	0	264	47
Moreno Valley	37,062	1,469,034	96	0
Murrieta	40,590	14,879	48	170
Norco	4,668	0	1	0
Perris	79,518	1,385	189	0
Riverside	47,147	218,276	155	86
San Jacinto	24,069	0	65	0
Temecula	14,347	66,871	52	107
Wildomar	5,418	76,411	40	0
Unincorporated County	<u>17,531</u>	<u>113,653</u>	<u>515</u>	<u>1</u>
Total	342,941	2,921,457	2,366	837

Source: WRCOG and EPS

Methodology

Every development project is different and will have different development costs. For the purposes of this analysis, EPS considered the same set of land use prototypes as for the fee review and comparison and developed an illustrative estimate of the full set of development costs. The steps taken in developing the development cost estimates are described in the subsections below.

Land Uses Evaluated

The development cost evaluation considered the following land uses/development prototypes, consistent with those used in **Chapter 2**:

- Residential Single Family Development – Single Family Units in a 50-unit subdivision
- Residential Multi Family Development – Multi Family Units in a 200-unit apartment building.
- Industrial Development – Industrial Space in a 265,000 square foot “high cube” development.
- Office Development – Office Space in a 20,000 square foot office building.
- Retail Development- Retail Space in a 10,000 square foot retail building.

Development Cost Estimates

An illustrative static pro forma structure was developed. The pro forma incorporated different categories of development costs (see below). It also considered potential land values/acquisition costs based on a residual land value approach that considered potential development values, subtracted direct and indirect development costs and developer return requirements, and indicated a potential residual land value. The development values were refined based on available market data ranges and the need to generate a land value of an appropriate level to support land acquisition and new development. Available information on land transactions was also reviewed. As noted above, this analysis is designed to provide overall insights on general economic relationships and does not draw conclusions concerning the feasibility of individual projects.

It is also important to note that the pro formas developed were specifically configured to represent a potentially feasible set of relationships, in terms of revenues, costs, and returns. This allows for consideration of development impact fees in the context of illustrative projects that would make sense to undertake. To the extent, development costs/ returns are higher than those indicated – a reality which could certainly be true for many projects – development values would need to be higher or feasibility is not likely to be attained. To the extent, this is true, development impact fees as a proportion of development costs/ returns would be lower than those shown.

The key development cost categories estimated for all land uses and associated sources included:

- **Direct Construction Costs** – Site Work/Improvements and Vertical Construction Costs. Estimates were taken from RS Means (a construction cost data provider) estimates, available pro formas, and feedback from developers where provided.

- **Indirect Costs** – Architecture and Engineering Costs, Sales and Marketing, Financing, Development Impact Fee, and other soft costs. Estimates were taken from RS Means, the WRCOG Fee Comparison, available pro formas, and feedback from developers where provided.
- **Developer Return Requirements** – Developer return requirements were set to be equal to 10 percent of development value for all land uses, except where alternative information was provided. This represented between 12 and 15 percent of direct and indirect construction costs consistent with typical developer hurdle returns.
- **Land Costs** – Land costs were based on the estimated residual land values when costs and returns were subtracted from estimates of development value and/or information on actual land transactions. Development values in all cases were adjusted to ensure land values reached between 9.5 and 20 percent of development value, unless other information was available to justify a different percentage. This was used as a general metric of potential feasibility; i.e., if the residual land value fell below this level, developers would have a hard time finding willing sellers of land and so the project as a whole may not be feasible.⁷

It is also important to note that the following additional assumptions were used in this analysis:

- **Development Impact Fees.** The development cost estimates include the average development impact fees for WRCOG jurisdictions identified in **Chapter 2**. In reality, the fees, like other development costs factors, vary by jurisdiction.
- **Land Values.** Land values will vary by area and by development prospects as well as by the level of entitlement and improvement of the land. The land value estimates provided represent illustrative estimates for the purposes of this analysis.
- **Direct Construction Costs.** The direct construction costs shown, whether provided by developers or through RS Means, assume non-union construction costs per square foot. The actual construction cost per square foot would be higher if union-labor is required. Depending on the specific union roles required, direct construction would be expected to increase by 10 percent or more.

Detailed development cost assumptions for each development prototype are provided in **Appendix C**.

Results

As context for the description of the results of this analysis, it is worth repeating that there will be considerable variation throughout Western Riverside County in terms of different development cost components and overall development costs. On an average/illustrative basis, overall development costs included in this analysis may be conservative as they do not include union labor costs and may be conservative with regard to entitlement costs. Given that the focus of

⁷ A similar evaluation was not conducted for retail development as the location decisions of major retailers are typically more tied to location/site characteristics than to modest variations in development costs.

this analysis is on the relationship between development impact fees and total development costs, an underestimate in total development costs would mean that the proportionate significance of development impact fees has been overestimated.

It is again important to note that the analysis shown here is not an evaluation of development feasibility. Such an analysis would require a more-location specific analysis and is highly dependent on site characteristics, local market conditions, and site land values, among other factors.

Figure 13 summarizes the estimated development costs/returns on a per residential unit and per Nonresidential building square foot basis. **Figure 14** converts the cost estimates into percent allocations out of the total development/return. It should be noted that the total cost/return (equivalent to the 100 percent) equals the sum of direct and indirect costs, estimated land costs, and required development return. This total cost/return is equivalent to the sales prices/capitalized building value a developer would need to command to cover all costs/return requirements. To the extent, actual costs are higher (e.g., higher land costs or construction costs), the achievable sales prices/capitalized lease rates would also need to be higher.

Figure 13 Proportionate Development Costs/Return for Development Prototypes

Development Costs, Land Values, and Return	Single Family Per Unit	Multifamily Per Unit	Industrial Per Bldg Sq. Ft.	Retail Per Bldg Sq. Ft.	Office Per Bldg Sq. Ft.
<u>DIRECT</u>					
Basic Site Work/ Lot Improvements	\$30,000	\$9,257	\$11.50	\$25.00	\$14.29
Direct Construction Cost	<u>\$216,000</u>	<u>\$166,402</u>	<u>\$36.00</u>	<u>\$132.58</u>	<u>\$141.93</u>
Hard Cost Total	\$246,000	\$175,659	\$47.50	\$157.58	\$156.21
<u>INDIRECT</u>					
TUMF	\$8,873	\$6,231	\$1.42	\$10.49	\$2.19
Other Development Impact Fees	\$36,060	\$22,083	\$3.23	\$13.62	\$10.70
Other Soft Costs	<u>\$53,460</u>	<u>\$40,579</u>	<u>\$19.20</u>	<u>\$29.62</u>	<u>\$31.22</u>
Soft Cost Total	\$98,393	\$68,893	\$23.85	\$53.73	\$44.12
Total Direct and Indirect Costs	\$344,393	\$244,552	\$71.35	\$211.31	\$200.33
Developer Return Requirement	\$48,600	\$30,447	\$9.20	\$30.01	\$27.45
Land Value	\$93,007	\$29,470	\$32.94	\$59.80	\$47.49
TOTAL COST/RETURN	\$486,000	\$304,468	\$113.49	\$301.12	\$275.27

* Assumes generally feasible market conditions (i.e. ability to generate developer return and positive land value).

Figure 14 Average Development Costs/Return for Development Prototypes

Development Costs, Land Values, and Return	Single Family	Multifamily	Industrial	Retail	Office
<u>DIRECT</u>					
Basic Site Work/ Lot Improvements	6.2%	3.0%	10.1%	8.3%	5.2%
Direct Construction Cost	<u>44.4%</u>	<u>54.7%</u>	<u>31.7%</u>	<u>44.0%</u>	<u>51.6%</u>
Hard Cost Total	50.6%	57.7%	41.9%	52.3%	56.7%
<u>INDIRECT</u>					
TUMF	1.8%	2.0%	1.3%	3.5%	0.8%
Other Development Impact Fees	7.4%	7.3%	2.8%	4.5%	3.9%
Other Soft Costs	<u>11.0%</u>	<u>13.3%</u>	<u>16.9%</u>	<u>9.8%</u>	<u>11.3%</u>
Soft Cost Total	20.2%	22.6%	21.0%	17.8%	16.0%
Total Direct and Indirect Costs	70.9%	80.3%	62.9%	70.2%	72.8%
Developer Return Requirement	10.0%	10.0%	8.1%	10.0%	10.0%
Land Value	19.1%	9.7%	29.0%	19.9%	17.3%
TOTAL COST/RETURN	100.0%	100.0%	100.0%	100.0%	100.0%

* Assumes generally feasible market conditions (i.e. ability to generate developer return and positive land value).

Key findings include:

- Direct construction costs represent the largest proportion of total development costs/returns, typically followed by other land costs, other soft costs (collectively), developer returns, and development impact fees.** Unsurprisingly, direct construction costs are the largest cost, representing between 31.7 percent and 54.7 percent of total costs/returns for the prototypes evaluated. Land costs are likely to be most variable, depending on circumstance, range from 9.7 percent to 29.0 percent for the prototypes. Other soft costs collectively are the next highest component, though their individual components, such as sales and marketing, architecture and engineering, financing costs, are smaller. The expected hurdle developer return at 8 percent to 10 percent is the next highest factor. The range for total development impact fees is below all these other ranges, though when indirect costs are considered individually development impact fees represent the largest component.
- Total development impact fees represent between 4.1 percent and 9.3 percent of total development costs/returns for the prototype feasible projects.** Total development impact fees represent 9.2 percent and 9.3 percent of total development costs/returns respectively for single family and multifamily developments. As discussed in Chapter 2, these capital facilities fees included water and sewer fees, school district fees, other local jurisdiction fees, TUMF, and other agency/subarea fees. As is common, Nonresidential development impact fees are lower as a percent though show a significant range from 4.1 percent for industrial development, 4.7 percent for office development, and 8.0 percent for retail development.
- TUMF represent between 1.3 percent and 3.5 percent of total development costs/returns for the prototype feasible projects.** TUMF represent between 17.0 percent and 43.6 percent of total development impact fees as indicated in the Fee

Comparison with the highest ratios for retail and industrial development and lowest for office development. As a proportion of overall development costs, TUMF represent 2.0 percent or below for all development prototypes except for retail development where the TUMF represents 3.5 percent of total development costs/return. Transportation fees on retail development are often higher due to their relatively high trip generation rates.

Fees and Costs through Time

Another way to consider TUMF in the context of overall development costs and other economic metrics is to compare the relative changes in these factors over time. Methodologically, this is complicated by data availability and the limitations on obtaining accurate historical information. However, there are a number of indices that provide indications of historical changes through time, including changes in construction costs (the Construction Cost Index), changes in overall consumer prices (Consumer Price Index), and changes in other metrics, such as median home sales prices.

Figures 15 through 19 shows the TUMF changes since 2002 relative to changes in other metrics. Key observations include:

- **Overall construction costs increased by over 40 percent in nominal dollar terms between 2002 and 2014, above the equivalent Residential TUMF increase of about 30 percent.** Increases in the TUMF over time were below the pace of increase in the construction cost index between 2002 and 2006, rose substantially above it between 2007 and 2009, and then reduced down to a consistent level as of 2010. Since 2010, the TUMF has remained flat while the construction cost index has continued to increase.
- **When considered relative to the Consumer Price Index (a reasonable estimate of inflation), the residential TUMF has increased consistently with inflation over the period 2002 to 2014.** Stated in another way, the real, inflated-adjusted value of the residential TUMF was consistent in 2002 and 2014; i.e., showing no increase above inflation. The fact that the residential TUMF was consistent with inflation but below overall construction costs indicates that overall construction costs have increased by more than the rate of inflation over this period.
- **Between 2002 and 2014, the single family home price index has increased marginally more than residential TUMF.** Residential TUMF increases fell well behind the increases in home prices between 2002 and 2006, and then saw increases that pushed them above the now-declining home prices as of about 2008. From 2012 to 2014 (and beyond), median single family home prices have improved, pushing the overall home price increase since 2002 slightly above the overall change in residential TUMF.
- **Overall construction costs increased by over 40 percent in nominal dollar terms between 2002 and 2014, above the increases in all the Nonresidential TUMFs.** The construction cost index between 2002 and 2014 increased substantially more than the Service TUMF that declined over the period. As of 2008, the Industrial TUMF and the Retail TUMF had increased similarly to the construction cost index. Thereafter, the Industrial TUMF declined while the Retail TUMF increased, but by less than overall construction costs.

- **When considered relative to the Consumer Price Index (a reasonable estimate of inflation), the Retail TUMF has increased consistently with inflation, while the Service and Industrial TUMF have declined in inflation-adjusted (real) terms.** The Retail TUMF has increased by about 30 percent over the period 2002 to 2014, consistent with the aggregate level of inflation over this period. The Service TUMF has, however, decreased in nominal dollars and even more so in real, inflation-adjusted terms. The Industrial TUMF has increased in nominal terms though at a pace lower than inflation, indicating a decline in the Industrial TUMF in real (inflation-adjusted) terms.

Figure 15 TUMF and Construction Cost Index Comparison (Residential)



Figure 16 TUMF and Construction Cost Index Comparison (Nonresidential)



Figure 17 TUMF and Consumer Price Index (CPI) Comparison (Residential)

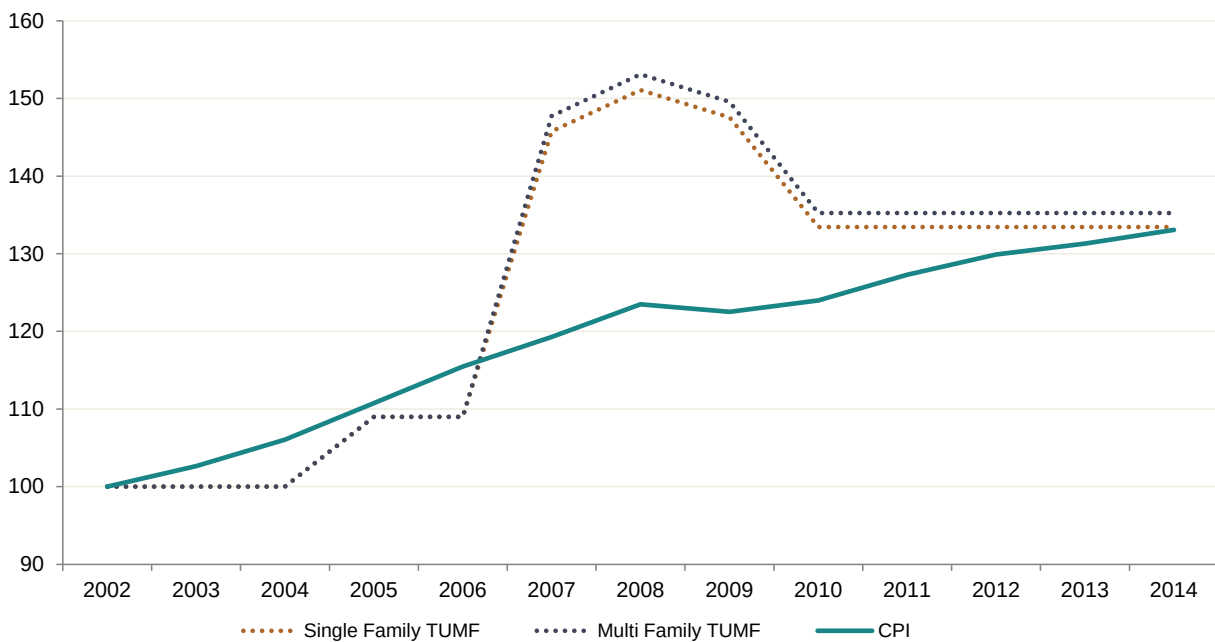


Figure 18 TUMF and Consumer Price Index (CPI) Comparison (Nonresidential)

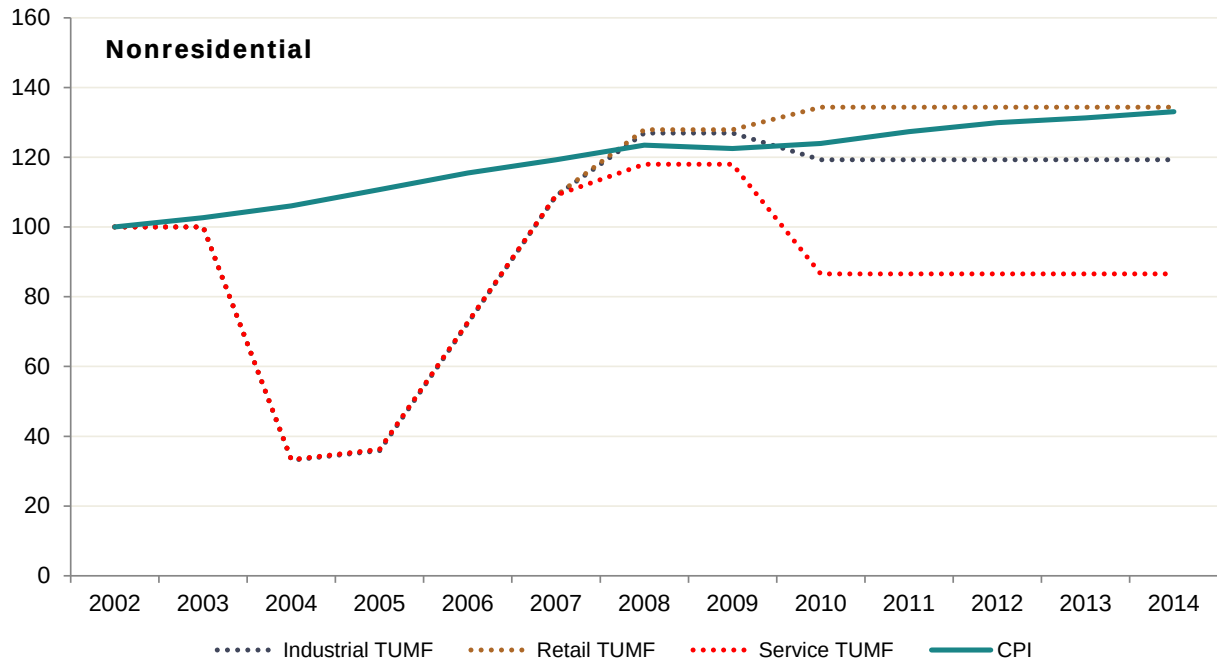
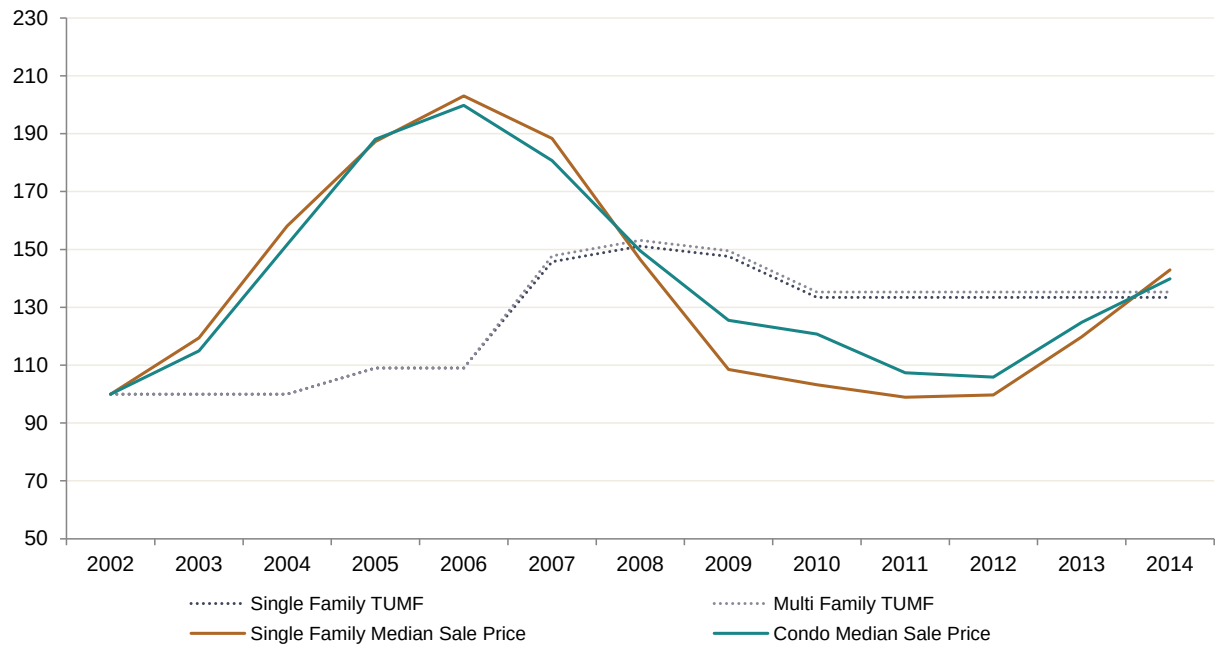


Figure 19 TUMF and SF/Condo Median Sale Price Comparison (Residential)



4. *BROADER ECONOMIC IMPACTS*

Global, national, and regional transportation infrastructure provides the necessary network for the movements of good and people that support the functioning of modern economies. These transportation networks connect people to jobs and services as well as the production, trade, and consumption of goods and services. A strong regional transportation infrastructure enhances regional economic opportunities and supports greater levels of new development than a weak or deteriorated set of infrastructure.

A precise estimation of the additional development value and growth associated with transportation investments is complex and beyond the scope of this analysis. This Chapter does, however, provide insights into the regional economic impacts of the TUMF program, using an economic multiplier model, and into the significance of regional transportation infrastructure through consideration of the scale of the goods movement industry and related sectors to the Western Riverside County economy.

Economic Impacts of TUMF Program

The TUMF Program includes the levying of regional development impact fees on new development in Western Riverside County to support the funding of regional transportation improvement projects. In addition to the TUMF, regional transportation improvement projects are funded by local funding (predominantly Measure A sales tax funds), State and federal sources.

Economic Impact Analysis

Input/Output (I/O) analysis is premised on the concept that industries in a geographic region are interdependent and thus the total contribution of any one establishment's activity is larger than its individual (direct) output and/or employment. Consequently, an establishment's economic activity has a "multiplier" effect that generates successive rounds of spending and output in other economic sectors within a particular region. The County purchases goods from producers, who in turn purchase raw materials from suppliers. Thus, an increase/decrease in the demand for project-related services will stimulate an increase/decrease in output and employment in the interdependent secondary industries.

Input/Output models consider investments and the resulting job-generation, economic output, and economic value-added. They are premised on the concept that industries in a geographic region are interdependent and thus the total contribution of any one activity is larger than its individual (direct) output and/or employment. Consequently, an economic activity has a "multiplier" effect that generates successive rounds of spending and output in other economic sectors within a particular region. The Input/Output analyses provide estimates of the gross economic impacts, including the direct effects and the multiplier effects (indirect and induced effects), for a given investment/activity. The indirect multiplier effects refer to the economic effects associated with the purchases of raw materials from County suppliers as required to support the primary economic investment/activity. The induced multiplier effects refer to the economic effects associated with spending of household income generated by incomes from the primary project. Thus, an increase/decrease in the demand for project-related services will

stimulate an increase/decrease in output and employment in the interdependent secondary industries.

Regional Transportation Spending and Analytical Scenarios

The TUMF program is currently estimated to include a total investment of about \$3.129 billion over thirty years. The 2015 Draft Nexus Study (WRCOG/Parsons Brinckerhoff) estimated the total TUMF revenue investments to include approximately \$3.05 billion in eligible arterial highway and street related improvements and \$77.8 million in eligible transit related improvements. These estimates depend on the achievement of the development forecasts and the associated generation of TUMF revenues.

Most regional transportation investments, however, require multiple funding sources. TUMF revenues along with other local/regional revenues (e.g. Measure A sales tax dollars) act to attract substantial State and federal transportation funding to Western Riverside County. A review of five recent projects provides an indication of the range and distribution of funds used to fully fund regional transportation investments. Estimates for funding sources other than TUMF are based on five recent project funding profiles provided by WRCOG. Projects include Sunset Avenue, Perris Boulevard, Auto Center Drive, Newport Road, and Ramona Expressway.

Figure 20 Collective Funding Sources for Five Regional Transportation Projects*

Source of Funding	Contribution	Percentage
TUMF	\$22,000,000	17.7%
Local	\$29,400,000	23.6%
State/Federal	<u>\$73,100,000</u>	<u>58.7%</u>
Total	\$124,500,000	100.0%

*Based on five recent project funding profiles provided by Western Riverside Council of Governments. Projects include Sunset Avenue, Perris Boulevard, Auto Center Drive, Newport Road, and Ramona Expressway.

As shown in **Figure 20**, a total of \$124.5 million, about \$25 million per project, was spent on five recently funded transportation projects in Western Riverside County that relied, in part, on TUMF funding. On average, a little under one-fifth of the funding was provided through TUMF (17.7 percent), a little under one-quarter was provided by other local funding (predominantly Measure A sales tax funds), and almost 60 percent (58.7 percent) was funded through State and federal sources.

For the purposes of this economic impact analysis, three different sets of economic impact estimates were developed, including:

- **Economic Impacts from TUMF Revenues: Investment of \$3.1 billion.** This scenario considers the economic impacts of TUMF revenue expenditures exclusively.

- **Economic Impacts of Total Spending on Regional Transportation Projects: Investment of \$17.7 billion.** This scenario considers the economic impacts of estimated total spending on regional transportation projects that are partially funded by TUMF revenues. In order to estimate the level of overall expenditures, it was assumed that these TUMF revenues continue to represent 17.7 percent of the total project expenditures.
- **Economic Impacts of State and Federal Spending on Regional Transportation Projects: Investment of \$10.4 billion.** This scenario considers the economic impacts of the State and federal funding that supports regional transportation investments that are also partially supported by TUMF revenues. The level of investment is based on the proportions from the five project studies. This estimate offers a metric of the economic impact associated with regional transportation investments where funding comes completely from outside of the County.

Economic Impact Results

- **Gross Economic Impacts of TUMF Investments.** The \$3.13 billion in TUMF investments in regional transportation infrastructure projects over the next thirty years is estimated to result in \$4.56 billion in economic output in Riverside County. This represents about \$1.9 billion in value-added production and \$1.3 billion in labor income. On annual basis (in 2016 constant dollar terms), this represents \$152.1 million in economic output, \$43.2 million in labor income, and an average of 970 jobs each year for thirty years (28,900 job-years) (see **Figure 21**).
- **Gross Economic Impacts of Regional Transportation Investment.** The \$17.68 billion in investments in regional transportation infrastructure projects over the next thirty years is estimated to result in \$25.78 billion in economic output in Riverside County. This represents about \$10.9 billion in value-added production and \$7.3 billion in labor income. On annual basis (in 2016 constant dollar terms), this represents \$860 million in economic output, \$244 million in labor income, and an average of 5,400 jobs each year for thirty years (163,300 job-years) (see **Figure 22**).
- **Economic Impacts of attracted State and Federal Transportation Funding.** State and federal funding could contribute about \$10.38 billion to the overall regional transportation investments considered. This funding flows in from outside of the County and provides an overall County output of \$15.14 billion, a subset of the total noted above. This represents about \$6.4 billion in value-added production and \$4.3 billion in labor income. On annual basis (in 2016 constant dollar terms), this represents \$505 million in economic output, \$143 million in labor income, and an average of 3,100 jobs each year for thirty years (95,900 job-years) (see **Figure 23**).

Figure 21 Gross Economic Impacts of TUMF Spending on Western Riverside County Transportation Infrastructure

Impact Type	Employment	Labor Income	Value Added	Output (1)
TOTAL				
Direct Effect	17,700	\$848,200,000	\$1,124,100,000	\$3,128,800,000
Indirect Effect	5,900	\$248,100,000	\$421,400,000	\$776,900,000
Induced Effect	<u>5,300</u>	<u>\$199,000,000</u>	<u>\$376,400,000</u>	<u>\$657,000,000</u>
Total Effect	28,900	\$1,295,300,000	\$1,921,900,000	\$4,562,700,000
ANNUAL				
Direct Effect	590	\$28,273,000	\$37,470,000	\$104,293,000
Indirect Effect	200	\$8,270,000	\$14,047,000	\$25,897,000
Induced Effect	<u>180</u>	<u>\$6,633,000</u>	<u>\$12,547,000</u>	<u>\$21,900,000</u>
Total Effect	970	\$43,176,000	\$64,064,000	\$152,090,000

* Does not account for additional non-TUMF supplemental infrastructure spending.

(1) Analysis is driven by \$3.1 billion in TUMF spending (approximately \$104.3 million/year over the next 30 years).

Source: IMPLAN; WRCOG TUMF Nexus Study, 2015; and Economic and Planning Systems, Inc.

Figure 22 Gross Economic Impacts of Total Spending on Western Riverside County Transportation Infrastructure (Partially TUMF Funded)

Impact Type	Employment	Labor Income	Value Added	Output (1)
TOTAL				
Direct Effect	100,000	\$4,793,300,000	\$6,352,400,000	\$17,681,300,000
Indirect Effect	33,300	\$1,402,000,000	\$2,381,400,000	\$4,390,400,000
Induced Effect	<u>30,000</u>	<u>\$1,124,600,000</u>	<u>\$2,127,100,000</u>	<u>\$3,712,800,000</u>
Total Effect	163,300	\$7,319,900,000	\$10,860,900,000	\$25,784,500,000
ANNUAL				
Direct Effect	3,300	\$159,800,000	\$211,700,000	\$589,400,000
Indirect Effect	1,100	\$46,700,000	\$79,400,000	\$146,300,000
Induced Effect	<u>1,000</u>	<u>\$37,500,000</u>	<u>\$70,900,000</u>	<u>\$123,800,000</u>
Total Effect	5,400	\$244,000,000	\$362,000,000	\$859,500,000

* Proportion of total funding including, TUMF, Local, State and Federal based on recent projects.

(1) Analysis is driven by \$3.1 billion in TUMF spending (approximately \$104.3 million/year over the next 30 years).

Source: IMPLAN; WRCOG TUMF Nexus Study, 2015; and Economic and Planning Systems, Inc.

Figure 23 Gross Economic Impacts of Federal and State Spending on Western Riverside County Transportation Projects (Partially TUMF Funded)

Impact Type	Employment	Labor Income	Value Added	Output (1)
TOTAL				
Direct Effect	58,700	\$2,814,700,000	\$3,730,200,000	\$10,382,700,000
Indirect Effect	19,600	\$823,300,000	\$1,398,400,000	\$2,578,100,000
Induced Effect	<u>17,600</u>	<u>\$660,400,000</u>	<u>\$1,249,100,000</u>	<u>\$2,180,200,000</u>
Total Effect	95,900	\$4,298,400,000	\$6,377,700,000	\$15,141,000,000
ANNUAL				
Direct Effect	1,900	\$93,800,000	\$124,300,000	\$346,100,000
Indirect Effect	600	\$27,400,000	\$46,600,000	\$85,900,000
Induced Effect	<u>600</u>	<u>\$22,000,000</u>	<u>\$41,600,000</u>	<u>\$72,700,000</u>
Total Effect	3,100	\$143,200,000	\$212,500,000	\$504,700,000

* Proportion of Federal and State funding based on recent projects.

(1) Analysis is driven by \$3.1 billion in TUMF spending (approximately \$104.3 million/year over the next 30 years).

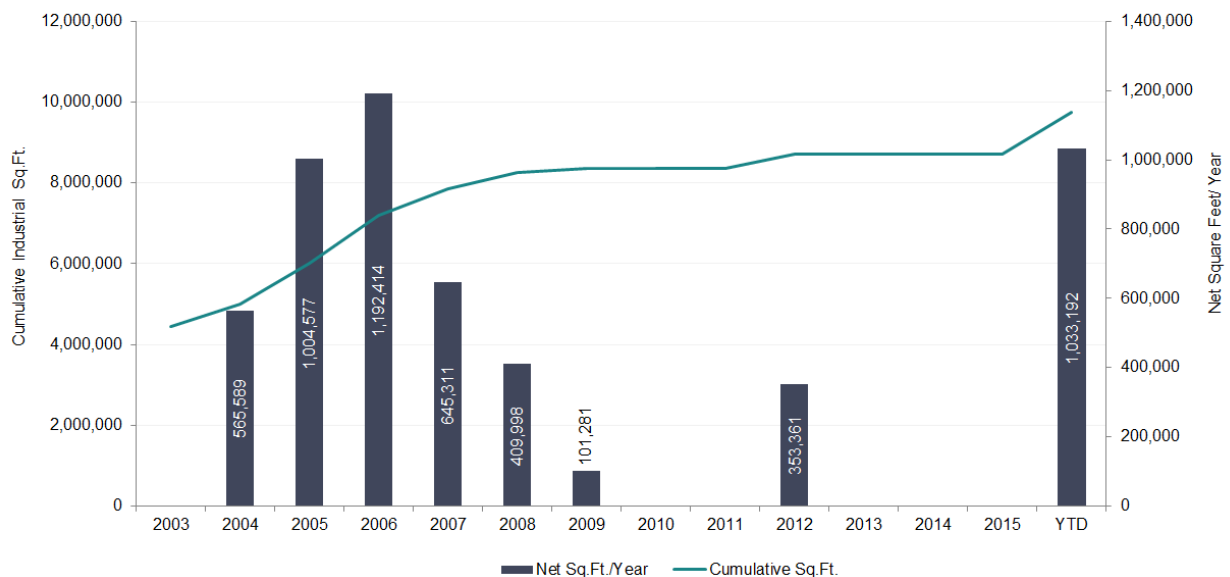
Source: IMPLAN; WRCOG TUMF Nexus Study, 2015; and Economic and Planning Systems, Inc.

Case Study of TUMF-related Development Impacts

In 1997, the County initiated the planning process of the Cantu-Galleano Road and the Interstate 15 interchange project (the Project). The plan consisted of a 6-lane connector, auxiliary lanes, on and off ramps to the I-15, and a 423-foot overcrossing extending Cantu-Galleano Ranch Road from Wineville Road west to Hamner Avenue. By 2004, the Project still lacked funding to cover total construction costs. When the TUMF Program was implemented, the Northwest Zone Technical Advisory Committee (TAC) programmed \$15.5 million in TUMF revenues for construction for this Project as one of the first project-ready line items. The TUMF funding provided a critical component of the overall project cost of about \$40.0 million. With funding secured, construction began in early 2006.



In addition to alleviating big rig truck traffic and providing local access to freeways, the Interchange Project also spurred new industrial development in the area. From 2004 to December 2016, over 5.3 million square feet of industrial space was constructed, more than doubling the existing space in 2003. Some of this development occurred prior, but in anticipation of Project construction. The Great Recession constrained development in the 2009 to 2015 period, but as shown by the substantial development in 2016 and the aerial photos, the substantial future industrial development is expected in this area.



Goods Movement Impacts

The goods movement industry is characterized by a network of warehouse and distribution facilities and shippers that receive, store, and ultimately ship goods to intermediate or end users. The section examines employment, Gross Regional Product (GRP), and building space associated with the goods movement sectors in Riverside County.

Goods Movement Jobs and GRP

Figure 24 summarizes the distribution of jobs and GRP to goods movement related services. As shown, the County had an estimated 61,000 jobs and \$5.8 billion in GRP in these sectors in 2013, representing nearly 7 percent of the total economy. Of this amount, the largest proportion

represents jobs and related output in “Wholesale trade and distribution services” and “truck transportation services”. Other goods movement sectors that are typically significant in larger economies, such as air, rail and pipeline services are relatively small in Riverside County. Based on economic input-output analysis of Riverside County about 30 percent of the jobs and the Gross Regional Product (GRP) can be attributed to goods movement related or dependent sectors.

Figure 24 Distribution of County Jobs and Gross Regional Product

Item	Jobs		GRP	
Goods Movement Industry (1)	61,000	7%	\$5,800,000,000	8%
Goods Movement Dependent Industries (2)	<u>210,000</u>	<u>23%</u>	<u>\$14,700,000,000</u>	<u>22%</u>
Total Goods Movement-Related	271,000	30%	\$20,500,000,000	30%
Non-Goods Movement Related Industries (2)	<u>627,000</u>	<u>70%</u>	<u>\$47,800,000,000</u>	<u>70%</u>
Total Riverside County	898,000	100%	\$68,300,000,000	100%

* IMPLAN divides County economy into 536 industry sectors and tracks data for each sector.

Gross Regional Product (GRP) represents the value-added production of Riverside County businesses/entities which equals the total value of goods and services minus the intermediate goods/ services purchased from outside of the County.

(1) Includes 10 of the 536 industry sectors tracked by IMPLAN for the Riverside County economy identified as providing the bulk of Goods Movement Services. The large majority of the jobs and GRP fall in one of three industry sectors: Wholesale Trade Distribution Services (28,200 jobs), Warehousing and Storage Services (12,700 jobs), and Truck Transportation Services (10,230 jobs).

(2) The distinction between Goods Movement Dependent Industries and Non-Goods Movement Related Industries is imprecise as most industries are somewhat dependent on goods movement. For this analysis, Goods Movement Dependent Industries include industries that involve the purchase or sale of physical commodities while Non-Goods Movement Related Industries are those focused on services.

Sources: IMPLAN; EPS

Warehouse and Distribution Space

In addition to detailed goods movement jobs and GRP data for Riverside County, the location of warehouse distribution space in the County can provide a good proxy for the geographic concentrations of this sector within Western Riverside County. In Riverside County this logistics network is primarily clustered in Western Riverside County due to the existence of major thoroughfares and the majority of urban centers. As shown in **Figure 25**, of the 135.6 million square feet of total warehouse, distribution and truck terminal facilities located in Riverside County, 95 percent are located in Western Riverside County. This indicates the concentration of commercial activity in the western portion of Riverside County.

The significance of logistics networks in Western Riverside County is also emphasized by the proportion of logistics square footage to total commercial and industrial real estate square footage. About 46 percent of all commercial and industrial real estate in Western Riverside County is captured by logistics space (broadly defined, while the State-wide average is 32 percent).

Figure 25 Concentration of Logistics Workspace

Item	Building Sq. Ft.
Western Riverside County	
Logistics (1)	128,379,602
Total Commercial/ Industrial Real Estate (2)	278,940,810
Logistics as % of Total	46%
All Riverside County	
Logistics (1)	135,592,131
Total Commercial/ Industrial Real Estate (2)	328,232,252
Logistics as % of Total	41%
State (California)	
Logistics (1)	2,020,791,489
Total Commercial/ Industrial Real Estate (2)	6,363,711,397
Logistics as % of Total	32%

(1) Includes space identified as industrial and flex that is used for distribution, light distribution, truck terminals, and warehouses.

(2) Includes space identified as retail, office, industrial, and flex.

Sources: CoStar, 2016; Economic and Planning Systems, Inc.

5. CONCLUSIONS

The Western Riverside Council of Governments (WRCOG) commissioned this Report to provide increased regional understanding of development impact fees on new development in Western Riverside County. As noted in **Chapter 1**, the purpose of this Report is to: (1) indicate the types and relative scale of the development impact fees placed on different land uses; and, (2) indicate the scale of fees relative to overall development costs and their relative degree of change through time. This Report is intended to provide helpful background information to the current Transportation Uniform Mitigation Fee (TUMF) updating process by placing TUMF in the context of the broader development impact fee structure, overall development costs, and other regional dynamics.

At this point in time, it is common practice for new and updated Development Impact Fee Nexus Studies to be accompanied by some consideration of development impact fees in neighboring and peer communities and, less frequently, by consideration of development impact fees in the context of overall development costs and economics. This is true where individual jurisdictions are introducing/ updating a single development impact fee category (e.g. transportation or parks) as well as when jurisdictions undertake more comprehensive updates to a larger number of different fee categories.

Similarly, there have been a number of efforts to provide a regional/ subregional review of development impact fee practices and levels to inform regional conversations about the appropriate use and level of development impact fees. All of these regional studies require definitions of development impact fees included and land use and development prototypes utilized to ensure as close of an “apples-to-apples comparison” as possible. Examples of such studies include:

- **Residential Development Impact Fees in California Cities and Counties.** This August 2001 publication by the State of California Division of Housing was entitled: “Pay to Play: Residential Development Fees in California Cities and Counties, 1999” and was prepared by John Landis, Michael Larice, Deva Lawson, and Lan Deng at the Institute of Urban and Regional Development, University of California, Berkeley. This study considered 89 cities and counties spread throughout California.
- **Regional Development Fee Comparative Analysis for San Joaquin County.** This 2013 publication by San Joaquin Partnership represented a fourth publication prepared for the Partnership’s public and private sector investors. The regional development fee comparison compared a snapshot of development fees in 21 jurisdictions, including eight (8) in San Joaquin County and thirteen (13) in comparative/ neighboring California counties.
- **Ongoing Development Impact Fee Databases.** In addition to these regional efforts, there are a number of consulting companies that keep ongoing databases of development impact fees in regions, such as the Sacramento Valley, to inform their work for public and private sector clients. In these cases, development impact fee schedules are typically updated every year or two due to the dynamic nature of the development impact fees and the numerous different agencies that charge development fees.

In this context, it is recommended that this Report/ Study be updated periodically to ensure the regional understanding of development impact fees in Western Riverside County remains current in the context of: (1) frequent adjustments to fee levels by individual jurisdictions, (2) changing development cost and economic conditions, and, (3) less frequent, but highly significant changes in State law that affect the use and availability of other public financing tools. Rather than becoming “out-of-date” soon after publication, the Western Riverside Council of Governments could make this Study a “living document” with periodic updates.



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: International City / County Management Association Activities Update

Contact: AJ Wilson, California Senior Advisor, ajwcm@aol.com, (760) 723-8623

Date: January 19, 2017

The purpose of this item is to provide the Committee of International City / County Management Association (ICMA) activities.

Requested Action:

1. Receive and file.

ICMA

ICMA Coaching Program: A full program of webinars for training purposes has been planned for 2017. These events are free of charge and can be used for training events in your organization. A copy of the program is attached to this report

West Coast Summit

Every year a special west coast event is planned to allow for an abbreviated opportunity for training and networking. This year the Summit will be held in Burlingame on March 23 and 24, 2017. In addition, there is a special session for Emerging Leaders the day before. Registration information can be found on the ICMA website under Events.

[2017 Emerging Professionals Leadership Institute - West Coast Region](#)

March 22, 2017
Seminar / Workshop
Burlingame, CA 94010

[2017 ICMA West Coast Regional Summit](#)

March 23, 2017
10:00 a.m. - 12:00 p.m.
Burlingame, CA 94010

League of CA Cities

League of CA Cities City Manager's Department:

The annual conference of the City Manager's Department will be held in Monterey February 8 - 10, 2017. Unfortunately the registrations are full; however, there is a possibility to be placed on a waiting list. If you wish to do so please contact Mr. Wilson at ajwcm@aol.com.

Senior Advisor Support

As your Senior Advisor, Mr. Wilson is available for personal discussions, resource identification, and general briefings for your employees who may be ICMA members or MMASC members. Please contact Mr. Wilson at (714) 323-9116 or ajwcm@aol.com.

Prior WRCOG Action:

October 20, 2016: The WRCOG Technical Advisory Committee received report.

WRCOG Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachment:

1. Listing of 2017 ICMA Coaching Program webinars.

Item 5.I

International City / County
Management Association Activities
Update

Attachment 1

Listing of 2017 ICMA Coaching
Program webinars

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2017 Coaching Webinars

- [Attracting and Retaining a Dynamic Workforce](#) 10-11:30 a.m. PT / 1-2:30pm ET; Wednesday, March 29
- [Being a Great Coach and a Winning Player in Your Organization](#) 11 a.m. – 12:30 p.m. PT / 2-3:30pm ET; Wednesday, April 19
- [Best Practices in Citizen/Customer Service](#) 10-11:30 a.m. PT / 1-2:30pm ET; Thursday, May 11
- [Effective Communication of Complex Issues to the Public](#) 9:00 – 10:30 a.m. PT, / 12-1:30pm ET; Thursday, September 7
- [Strategies for Having Difficult Conversations](#) 10-11:30 a.m. PT / 1-2:30pm ET; Wednesday, October 11
- [Tools to Resolve Tough Issues in Your Community](#) 10-11:30 a.m. PT / 1-2:30pm ET; Thursday, November 9

Missed a webinar? Watch it full screen 24/7. High quality, full screen video recordings are available for these and other webinars. Click [here](#) for the [Agendas & Archives](#). The Agendas include a PDF of the presentation materials which you can download or print with your browser controls. The videos are now in mp4 format, and you can click on full screen for personal or group viewing and discussion.

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NOTES ABOUT THE WEBINARS

- a) Serving broad audiences: Each webinar offers value for up and comers, mid-managers, and senior managers.
- b) Welcoming your suggestions for outstanding presenters: We invite your suggestions for presenters. Typically, each webinar includes engaging presentations from three leaders in the field sharing a diversity of perspectives, best practices, and concrete resources.

- c) Supporting individual and organizational success: We encourage organizations to form groups to attend the webinars (live or recorded). The agenda for each webinar includes suggested post-webinar discussion questions.
- d) Providing detailed Agendas for each webinar (including specific topics and presenters): These are available two weeks in advance of each webinar. You'll find them at the [Agendas & Archives page](#).
- e) Registering in advance for each webinar: Each webinar requires its own advance registration. Notices with agenda information and registration details become available two weeks in advance of each webinar. The easiest way to receive notices automatically is through the complimentary email list. [Sign up here](#).



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Distribution of Round II BEYOND Allocations to Member Jurisdictions

Contact: Andrea Howard, Staff Analyst, howard@wrcog.cog.ca.us, (951) 955-8515

Date: January 19, 2017

The purpose of this item is to provide the BEYOND Round II allocation formula and final distribution amount for each of the BEYOND funding categories.

Requested Action:

1. Receive and file.

Background

The funding for BEYOND comes from WRCOG's Fiscal Year 2015/2016 Agency Carryover Funds, which are summarized below:

Agency Carryover Funds FY 16-17	
Contribution to WRCOG Agency Reserves	\$ 1,047,083.00
BEYOND Framework Fund - Round II	\$ 2,052,917.00
BEYOND - Regional Collaboration Set Aside	\$ 175,000.00
BEYOND - Healthy Communities Set Aside	\$ 75,000.00
Funding for WRCOG Agency Activities	\$ 700,000.00
Funding for Regional Economic Development Initiative	\$ 250,000.00
Total Funds Available	\$ 4,300,000.00

Updated Allocation Formula – Round II

The Round I formula (approved in June 2015) was intended to provide a set amount of funding for each jurisdiction and recognize that while more populated jurisdictions have higher funding needs, the distribution of funds should not result in only a few jurisdictions receiving the majority of funding. While the formula achieved these goals, it has since been recognized that this method created inequities in how the funding was distributed across the WRCOG member agencies.

With direction from the Administration & Finance Committee, staff developed several alternative formulas for consideration, one of which the Committee ultimately forwarded to the Executive Committee for approval, which was confirmed at the January 9, 2017, Executive Committee meeting.

The approved Round II formula applies a per-capita allocation that incrementally descends over six population tiers – meaning that the per capita allocation is greater for the first resident than for the last – resulting in a balanced distribution across jurisdictions. Under the Round II formula, as with the formula used in Round I, each member agency is guaranteed a specified amount of funding that can be used for a project(s) which demonstrate consistency with one or more of the WRCOG Economic Development and Sustainability

Framework goal areas.

While this new formula will achieve a more equitable distribution of BEYOND funding, the reallocation will result in some jurisdictions receiving lesser amounts in Round II than in Round I. In an effort to ease the transition from Round I to Round II, the Executive Committee approved an increase of Round II BEYOND funding and established a \$35,000 minimum allocation for all member agencies, bringing the total funding to \$2,052,917. With the increased total, only three jurisdictions will receive a lesser amount in Round II, with the greatest decrease being \$13,621 for the City of Temecula. Under the new formula, only the City of Calimesa would fall under the minimum allocation amount and will therefore receive \$35,000.

The increase of \$252,917 has been derived from three sources:

1. \$25,000 has been redirected from the competitive regional collaboration set aside component of BEYOND, previously totaled at \$200,000, resulting in \$175,000 available for BEYOND – Round II applicants;
2. \$25,000 has been redirected from the competitive healthy communities set aside component of BEYOND, previously totaled at \$100,000, resulting in \$75,000 available for BEYOND – Round II applicants; and
3. \$202,917 has been redirected from Fiscal Year 2015/2016 Agency carryover funds allocated toward reserves, which previously totaled \$1,250,000, resulting in \$1,047,083 of Fiscal Year 2015/2016 carryover funds that will be placed in reserves.

Attachment 1 shows the BEYOND Round II allocation formula and the allocation amount for each member agency.

Next Steps

WRCOG staff are working to finalize the Round II Program Guidelines and application materials. Staff anticipates releasing the Call for Concept Proposals in the coming weeks and providing approximately three weeks for proposal submissions. The brief Concept Proposal allows staff to confirm that the proposed project meets BEYOND Program requirements to align with one or more of the WRCOG Sustainability Framework. If a Concept Proposal does not meet requirements, WRCOG staff will work with the project managers to make any necessary revisions. Upon approval of Concept Proposals, jurisdictions will be invited to submit a full application which will include a detailed scope of work, budget, and timeline.

Staff have tentatively planned to hold an informational webinar regarding the BEYOND Round II program to cover all three of the funding opportunities (the fixed, non-competitive agency allocations; the health set aside; and the regional collaboration set aside). As soon as more information is available, WRCOG staff will send notifications to members of this Committee as well as Round I BEYOND Project Managers.

Prior WRCOG Actions:

<u>January 9, 2017:</u>	The Executive Committee 1) approved the tiered allocation formula to allocate BEYOND funding for Round II; and 2) increased the BEYOND Round II allocation by \$252,917.00 from \$1.8 million to \$2.05 million.
<u>December 14, 2016:</u>	The Administration & Finance Committee 1) recommended Option 2, the tiered allocation formula, be used for BEYOND – Round II and subsequent funding rounds; and 2) recommended the total allocation for BEYOND – Round II be increased from \$1.8 million to \$2.05 million.

WRCOG Fiscal Impact:

Funding for Round II of the BEYOND Framework Fund, has been programmed accordingly under the Fiscal Year 2016/2017 Agency Budget, in the General Fund.

Attachment:

1. BEYOND Round II Funding Allocation.

Item 5.J

Distribution of Round II BEYOND
Allocations to Member Jurisdictions

Attachment 1

BEYOND Round II Funding
Allocation

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BEYOND Allocation - Round II

Allocation Per Resident		Tier 1		Tier 2		Tier 3		Tier 4		Tier 5		Allocation - Min \$35K		Round I Allocation		Net Difference	
Population In Tier		Population		0-9,999		10,000-49,999		50,000-99,999		100,000-149,999		150,000+					
1/1/16		Tier 1		Tier 2		Tier 3		Tier 4		Tier 5							
Riverside County		8,289		8,289													
Calimesa																	
Canyon Lake	10,681	10,000			681												
Norco	26,896	10,000			16,896												
Banning	30,834	10,000			20,834												
Wildomar	35,168	10,000			25,168												
San Jacinto	47,656	10,000			37,656												
Lake Elsinore	61,006	10,000			39,999			11,007									
Eastvale	63,162	10,000			39,999			13,163									
Perris	73,722	10,000			39,999			23,723									
Hemet	80,070	10,000			39,999			30,071									
Menifee	89,004	10,000			39,999			39,005									
Jurupa Valley	98,177	10,000			39,999			48,178									
Temecula	109,064	10,000			39,999			49,999		9,066							
Murrieta	113,795	10,000			39,999			49,999		13,797							
Corona	164,659	10,000			39,999			49,999		49,999		14,662					
Moreno Valley	205,383	10,000			39,999			49,999		49,999		55,386					
*W. Unincorporated Coun	270,203	10,000			39,999			49,999		49,999		120,206					
Riverside	324,696	10,000			39,999			49,999		49,999		174,689					
Sum	178,289				581,223			465,141		222,859		364,953					
Total Per Capita Allocation												1,912,917.31				1,659,119.93	\$253,797.39
EMWD																35,000.00	\$0.00
WMWD																35,000.00	\$0.00
Schools																35,000.00	\$0.00
Morengo																35,000.00	\$0.00
Subtotal																140,000.00	\$0.00
Grand Total																1,799,119.93	\$253,797.39

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Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Single Signature Authority Report

Contact: Ernie Reyna, Chief Financial Officer, reyna@wrcog.coq.ca.us, (951) 955-8432

Date: January 19, 2017

The purpose of this item is to notify the Committee that no contracts were signed by the Executive Director, exercising single-signature authority in the most recent quarter. For the second quarter of Fiscal Year 2016-2017, there was no activity to report.

Requested Action:

1. Receive and file.
-

The WRCOG Executive Director has single-signature authority for contracts up to \$50,000. For the period of October 1, 2016, through December 31, 2016, there was one contract signed by the Executive Director.

The one contract signed by the Executive Director is for NetFile, Inc. NetFile is an online platform for filing the required Statement of Economic Interest Form 700. This platform will be used both by WRCOG and RCHCA. The total amount of this contract is \$5,200 and will be paid in four quarterly installments of \$1,300.

Prior WRCOG Action:

January 11, 2017: The Administration & Finance Committee received report for the period October 1, 2016, through December 31, 2016.

WRCOG Fiscal Impact:

This item is information only; therefore, there is no fiscal impact.

Attachment:

1. Contracts Activity Spreadsheet.

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Item 5.K

Single Signature Authority Report

Attachment 1

Contracts Activity Spreadsheet

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Western Riverside Council of Governments
 Contracts Activity Report
 For the Period October 1, 2016, through December 31, 2016

Level Of Authority	Date	Consultant	Description of Services	Amount
Executive Director				
	11/29/2016	NetFile, Inc.	Online platform for filing Form 700	\$5,200
Administration & Finance				
None				
Other				
None				
Total Amount for Single Signature				\$ 5,200



Prepared and Approved by

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Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017

Contact: Ernie Reyna, Chief Financial Officer, reyna@wrcog.coq.ca.us, (951) 955-8432

Date: January 19, 2017

The purpose of this item is to share WRCOG's 2nd Quarter Budget Amendments for Fiscal Year (FY) 2016/2017, as identified in the attachment to this staff report, which include no net changes to both the General Fund and Transportation Department, and a net expenditure increase to the Energy Department that will be offset by a reimbursable grant for Electric Vehicle (EV) chargers. A summary of proposed amendments by Department is listed below.

Requested Action:

1. Recommend that the Executive Committee approve the 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017.
-

General Fund: The Administration's single largest line item increase to expenditures is for the addition of criminal insurance of \$9,280, and with all additions in this Program, increases to expenditures will amount to \$20,396, but will be offset by a decrease in the Membership Dues line item in the same amount. For the Government Relations Program, the single largest increase in expenditures is for computer supplies of \$1,012, and with the other increase in various line items, the total amount of increases will be \$2,131, but will be offset by a decrease to fringe benefits in the same amount.

Net Expenditure Increase to the General Fund: **\$0**

Transportation Department: The TUMF Program's largest increase to expenditures is legal which will need to be increased by \$20,519, and with the other increases in expenditures, the grand total increase will be \$21,993. This amount will be offset by decreasing the amount of consulting by the same amount of \$21,993. The Active Transportation Program will be increasing legal fees by \$1,905, but will be offset by a decrease to consulting labor of the same amount. Lastly, the Clean Cities Program will have increases to the Overhead, fringe benefit, and cell phone line items of \$3,849, but this will be offset in reductions to the Supplies-Materials line item of the same amount.

Net Expenditure Increase to Transportation Department: **\$0**

Energy Department: Within the Energy Department, WRCOG purchased six electric vehicle (EV) chargers in three different locations within the subregion to assist Member Agencies. The cost of those chargers was \$49,605, and is reimbursable up to \$30,000 by the Air Quality Management District (AQMD). In addition, the Regional Street Lights Program will increase their expenditures by \$8,872, and coupled with the Energy Department, expenditures will increase by \$60,248, of which, \$30,000 will be reimbursed by the AQMD. The Southern California Edison Program will be increasing its revenue by \$10,643, leaving a net expenditure increase of \$49,605 in the Energy Department, and will reflect the \$30,000 reimbursable when received.

Net Expenditure Increase to Energy Department: **\$49,605**

Prior WRCOG Action:

January 11, 2017: The Administration & Finance Committee recommended that the Executive Committee approve the 2nd Quarter Draft Budget Amendment for Fiscal Year 2016/2017.

WRCOG Fiscal Impact:

General Fund: No Revenue / Expenditure / Increase or Decrease

Transportation: No Revenue / Expenditure / Increase or Decrease

Energy: Net Expenditure Increase of \$49,605

Overall, FY 2016/2017's Budget for the 2nd Quarter will increase expenditures for the Agency by \$49,605, of which, \$30,000 will be reimbursed through an AQMD grant, leaving a balance of \$19,605. This increase in expenditures will be offset by future HERO revenues in the Energy Department.

Attachment:

1. Annual Budget for the Year Ending June 30, 2017, with 2nd Quarter Amendments.

Item 5.L

2nd Quarter Draft Budget
Amendment for Fiscal Year
2016/2017

Attachment 1

Annual Budget for the Year Ending
June 30, 2017, with 2nd Quarter
Amendments

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**Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017**

Department: Total General Fund			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
Wages and Benefits			
61000 Fringe Benefits	49,793	20,747	(2,131)
Total Wages and Benefits	49,793	20,747	(2,131)
General Operations			
65101 General Legal Services	-	88	88
73003 WRCOG Auto Fuels Expense	178	329	500
73004 WRCOG Auto Maintenance Expense	16	33	17
73102 Parking Validations	-	105	105
73107 Event Support	1,241	1,561	320
73108 General Supplies	-	188	188
73109 Computer Supplies	425	1,437	1,012
73113 Membership Dues	35,000	6,620	(20,171)
73114 Subscriptions/Publications	4,783	4,864	81
73115 Meeting Support/Services	1,100	1,608	508
73116 Postage	-	53	53
73204 Communications - Cellular	38	177	139
73206 Communications - Computer Server	17,000	18,271	1,271
73302 Equipment Maintenance - Computers	3,267	8,151	4,884
73405 Insurance - Gen/Business	62,970	72,250	9,280
73407 WRCOG Auto Insurance	345	1,570	1,225
85101 Consulting Labor	20,000	22,630	2,630
Total General Operations	-	139,935	2,130
Total Net Expenditure Increase/(Decrease)			\$ 0

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Administration			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
General Operations			
73003 WRCOG Auto Fuels Expense	178	329	500
73004 WRCOG Auto Maintenance Expense	16	33	17
73113 Membership Dues	34,750	6,145	(20,396)
73114 Subscriptions/Publications	4,783	4,864	81
73115 Meeting Support/Services	1,100	1,608	508
73206 Communications - Computer Srv	17,000	18,271	1,271
73302 Equipment Maintenance - Computers	3,267	8,151	4,884
73405 Insurance - Gen/Business	62,970	72,250	9,280
73407 WRCOG Auto Insurance	345	1,570	1,225
85101 Consulting Labor	20,000	22,630	2,630
Total General Operations	-	135,851	(0)
Total Net Expenditure Increase/(Decrease)			\$ (0)

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Government Relations (70)				
		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures				
Wages and Benefits				
61000	Fringe Benefit	49,793	20,747	(2,131)
	Total Wages and Benefits	49,793	20,747	(2,131)
General Operations				
65101	General Legal Services	-	88	88
73102	Parking Validations	-	105	105
73107	Event Support	1,241	1,561	320
73108	General Supplies	-	188	188
73109	Computer Supplies	425	1,437	1,012
73113	Membership Dues	250	475	225
73116	Postage	-	53	53
73204	Communications Cellular	38	177	139
	Total General Operations	1,954	4,085	2,131
Total Net Revenue Increase/(Decrease)				\$ (0)

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Transportation (Summary)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
Wages and Benefits			
61000 Fringe Benefit	3,406	4,278	872
Total Wages and Benefits	3,406	4,278	872
General Operations			
63000 Overhead Allocation	12,500	10,000	2,500
65101 General Legal Services	200,000	222,423	22,424
73113 Membership Dues	-	670	670
73114 Subscriptions/Publications	-	-	-
73115 Meeting Support/Services	-	-	-
73116 Postage	-	-	-
73117 Other Household Expenditures	112	213	101
73119 Storage	-	-	-
73120 Printing Services	-	-	-
73122 Computer Hardware	-	-	-
73201 Communications-Regular	-	-	-
73203 Communications-Long Distance	-	-	-
73204 Communications-Cellular	285	762	477
73206 Communications-Comp Sv	-	-	-
73209 Communications-Web Site	-	-	-
73301 Equipment Maintenance - General	-	-	-
73405 Insurance - General/Business Liason	-	-	-
73502 County RIFMIS Charges	-	-	-
73601 Seminars/Conferences	1,000	1,123	123
73605 General Assembly Expenditures	-	-	-
73611 Travel - Mileage Reimbursement	-	-	-
73612 Travel - Ground Transportation	-	-	-
73613 Travel - Airfare	-	-	-
73620 Lodging	1,000	1,066	66
73630 Meals	614	1,128	514
73640 Other Incidentals	-	-	-
73650 Training	-	-	-
73703 Supplies/Materials	10,000	-	(3,849)
73704 Newspaper Ads	-	-	-
73705 Billboard Ads	-	-	-
73706 Radio & TV Ads	-	-	-
85100 Direct Costs	-	-	-
85101 Consulting Labor	803,500	212,374	(23,898)
85102 Consulting Expenses	-	-	-
90101 Computer Equipment Purchases	-	-	-
90201 Office Equipment Purchase	-	-	-
97001 Operating Transfer Out	-	-	-
97005 Benefits Transfer Out	-	-	-
Total General Operations	1,029,011	449,760	(872)
Total Net Revenue Increase/(Decrease)			\$ (0)

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Transportation (TUMF - 1148)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
General Operations			
65101 General Legal Services	200,000	220,519	20,519
73113 Membership Dues	-	670	670
73117 Other Household Expenditures	112	213	101
73601 Seminars/Conferences	1,000	1,123	123
73620 Lodging	1,000	1,066	66
73630 Meals	614	1,128	514
85101 Consulting Labor	643,500	207,852	(21,993)
Total General Operations	846,226	432,571	(0)
Total Net Expenditure Increase/(Decrease)			\$ 0

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Transportation (Active Transportation Program - 2030)			
--	--	--	--

		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures				
General Operations				
65101	General Legal Services	-	1,905	1,905
85101	Consulting Labor	160,000	4,522	(1,905)
Total General Operations		160,000	6,427	-
 Total Net Expenditure Increase/(Decrease)				 \$ -

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Environmental (Clean Cities - 1010)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
Wages and Benefits			
61000 Fringe Benefit	3,406	4,278	872
Total Wages and Benefits	3,406	4,278	872
General Operations			
63000 Overhead	12,500	10,000	2,500
73204 Communications-Cellular	285	762	477
73703 Supplies/Materials	10,000	-	(3,849)
Total General Operations	22,785	10,762	(872)
Total Net Expenditure Increase/(Decrease)			\$ 0

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (Summary)				
		Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Revenues				
40609	SCE Phase Three	-	10,643	10,643
	Total Revenues	-	10,643	10,643
General Operations				
65101	General Legal Services	38,173	55,937	17,764
65507	Commissioners Per Diem	1,500	-	450
73107	Event Support	23,000	15,766	3,772
73113	Membership Dues	-	265	265
73114	Subscriptions/Publications	273	585	312
73115	Meeting Support/Services	37	103	66
73116	Postage	-	2	2
73117	Other Household Expenditures	242	310	68
73126	EV Charging Equipment	-	49,605	49,605
73405	Insurance - General/Business Liason	175	595	420
73601	Seminars/Conferences	5,163	299	(2,101)
73611	Travel - Mileage Reimbursement	425	1,093	668
73613	Travel - Airfare	2,100	1,937	837
73620	Lodging	600	-	(600)
73630	Meals	148	176	28
73640	Other Incidentals	1,500	2,224	724
73650	Training	4,000	-	(2,000)
85101	Consulting Labor	619,793	410,044	(10,032)
	Total General Operations	697,129	538,942	60,248
Total Net Expenditure Increase/(Decrease)				\$ 49,605

**Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017**

Department: Energy (WRCOG HERO - 2006)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
General Operations			
65101 General Legal Services	25,000	33,024	8,024
73640 Other Incidentals	1,500	2,224	724
85101 Consulting Labor	469,793	277,959	(9,624)
Total General Operations	496,293	313,207	(876)
Total Net Expenditure Increase/(Decrease)			\$ (876)

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (SCE - 2010)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
General Operations			
65101 General Legal Services	750	4,307	3,557
73107 Event Support	20,000	5,437	(3,557)
Total General Operations	20,750	9,744	0
Total Net Expenditure Increase/(Decrease)			\$ 0

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (Regional Street Lights - 2026)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
General Operations			
65101 General Legal Services	12,423	18,547	6,124
73107 Event Support	3,000	4,972	1,972
73114 Subscriptions/Publications	273	410	137
73611 Travel - Mileage Reimbursement	425	1,035	610
73630 Meals	148	176	28
Total General Operations	16,269	25,141	8,872
Total Net Expenditure Increase/(Decrease)			\$ 8,872

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (Community Choice Aggregation - 2040)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
General Operations			
73113 Membership Dues	-	265	265
73115 Meeting Support/Services	37	103	66
73116 Postage	-	2	2
73601 Seminars/Conferences	663	-	(663)
73613 Travel - Airfare	600	1,937	1,337
73620 Lodging	600	-	(600)
85101 Consulting Labor	150,000	132,085	(408)
Total General Operations	1,300	134,393	(0)
Total Net Expenditure Increase/(Decrease)			\$ (0)

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (SCE Phase III - 2070)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Revenues			
40609 SCE Phase Three	-	10,643	10,643
Total Revenues	-	10,643	10,643
 Total Net Revenue Increase/(Decrease)			 10,643

**Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017**

Department: Base (Energy Dept - 2100)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
General Operations			
65101 General Legal Services	-	59	59
73107 Event Support	-	5,357	5,357
73114 Subscriptions/Publications	-	175	175
73126 EV Charging Equipment	-	49,605	49,605
73601 Seminars/Conferences	1,500	299	(500)
73613 Travel - Airfare	1,500	-	(500)
73650 Training	4,000	-	(2,000)
Total General Operations	7,000	55,494	52,195
Total Net Expenditure Increase/(Decrease)			\$ 52,195

**Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017**

Department: Spruce (2102)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
General Operations			
73611 Travel - Mileage Reimbursement	-	58	58
Total General Operations	-	58	58
 Total Net Expenditure Increase/(Decrease)			 \$ 58

Western Riverside Council of Governments
Annual Budget
For the Year Ending June 30, 2017

Department: Energy (California HERO - 5000)			
	Approved 6/30/2017 Budget	Thru 12/31/2016 Actual	Amendment Needed 12/31/2016
Expenditures			
General Operations			
65507 Commissioners Per Diem	1,500	1,950	450
73117 Other Household Expenditures	242	310	68
73405 Insurance - General/Business Liason	175	595	420
73601 Seminars/Conferences	3,000	-	(938)
Total General Operations	4,917	2,855	(0)
Total Net Expenditure Increase/(Decrease)			\$ (0)



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Technical Advisory Committee 2017 Meeting Schedule

Contact: Janis Leonard, Executive Assistant, leonard@wrcog.cog.ca.us, (951) 955-8320

Date: January 19, 2017

The purpose of this item is to provide and obtain approval of a meeting schedule for 2017.

Requested Action:

1. Approve the Schedule of Technical Advisory Committee meetings for 2017.
-

Attached are the proposed meeting dates for the 2017 Technical Advisory Committee (TAC) meetings. All TAC meeting dates are proposed for the third Thursday of the month, with the exception of being dark during the months of June and December. All TAC meetings are scheduled at 9:30 a.m. in the County of Riverside Administrative Center, 5th Floor, Conference Room C.

Prior WRCOG Action:

None.

WRCOG Fiscal Impact:

None.

Attachment:

1. Schedule of Technical Advisory Committee meetings for 2017.

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Item 5.M

Technical Advisory Committee 2017
Meeting Schedule

Attachment 1

Schedule of Technical Advisory
Committee meetings for 2017

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WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS SCHEDULE OF MEETINGS FOR 2017

WRCOG Standing Committees	Day	Time	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
Technical Advisory Committee	3rd Thurs.	9:30 a.m.	19	16	16	20	18	DARK	20	17	21	19	16	DARK

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Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: PACE Program Activities Update

Contact: Barbara Spoonhour, Director of Energy and Environmental Programs,
spoonhour@wrcog.coq.ca.us, (951) 955-8313

Date: January 19, 2017

The purpose of this item is to provide the Committee with an update on the PACE Programs that WRCOG oversees. This includes the HERO Program, CaliforniaFIRST, and Spruce Finance.

Requested Action:

1. Receive and file.
-

WRCOG's PACE Programs provide financing to property owners to implement a range of energy saving, renewable energy, and water conserving improvements to their homes and businesses. Improvements must be permanently fixed to the property and must meet certain criteria to be eligible for financing. Financing is paid back through a lien placed on the property tax bill. The HERO Program was initiated in December 2011 and has been expanded (an effort called "California HERO") to allow for jurisdictions throughout the state to join WRCOG's Program and allow property owners in these jurisdictions to participate. The CaliforniaFirst and Spruce Programs will launch in 4th Quarter 2016 and 1st Quarter 2017, respectively.

Overall HERO Program Activities Update

Residential: As of January 6, 2017, over 110,000 applications in both the WRCOG and California HERO Programs have been approved to fund more than \$6.6 billion in eligible renewable energy, energy efficiency and water efficiency projects.

WRCOG Subregion: Over 22,100 projects, totaling nearly \$427 million, have been completed (Attachment 1).

Statewide Program: As of this writing, 361 jurisdictions outside the WRCOG and San Bernardino Associated Governments' (now known as San Bernardino Council of Governments) subregions have adopted Resolutions of Participation for the California HERO Program. Over 41,300 projects have been completed, totaling over \$886 million.

The table below provides a summary of the total estimated economic and environmental impacts for projects completed in both the WRCOG and the California HERO Programs to date:

Economic and Environmental Impacts Calculations	
KW Hours Saved – Annually	585 GWh
GHG Reductions – Annually	152,017 Tons
Gallons Saved – Annually	391 Million

\$ Saved – Annually	\$76 Million
Projected Annual Economic Impact	\$2.27 Billion
Projected Annual Job Creation/Retention	11,154 Jobs

The table below provides a summary of the estimated work breakdown of projects completed in both the WRCOG and the California HERO Programs:

Project Data	
HVAC	30.3%
Windows / Doors	19.2%
Solar	19.6%
Roofing	10.2%
Landscape	9.2%

Additional HERO consumer protections update

Currently, Renovate America conducts a confirmed terms call with every homeowner during the HERO application process before generating their financing documents. In most cases, the contractor is still present in the home when these calls are made. During the confirm terms call, the property owner's financing information is provided on a screen for the consumer to review during the call. Immediately after the call, the property owner is either e-mailed or mailed their contract, at which time their 3-day right to cancel period begins.

Even with these calls, some property owners inform the Program that they do not understand how the Program works or believe that the annual amount placed on their property tax bill is much higher than they expected.

WRCOG will begin implementing, in early 2017, a quality assurance call with property owners participating in the Program. WRCOG believes that adding a quality assurance call will provide the homeowner with an additional opportunity to review the financing documents and ask questions and/or receive clarification regarding their improvements, funding amounts, payments, etc. WRCOG believes this additional call will further improve the Program.

During the month of January 2017, WRCOG will be establishing a call center for these outbound quality assurance calls. WRCOG is in the process of hiring up to four Call Center Representatives, reconfiguring an office to house these individuals, purchasing computer and phone equipment, and hiring a consultant to assist WRCOG with training and infrastructure needs. Staff has reached out to the County of Riverside and City of Riverside, which have call centers, to gather information on their phone and information technology needs and to inquire which consultant they have used to assist them with implementation. Quotes received from various consulting companies range from \$35,000 to \$45,000, which are within the Single Signature Authority of the Executive Director. The consultant will assist with the technology development and setup required for the call center, staff training, ongoing support, and ensuring the goals of the call center meet the established criteria for the Program.

Additional PACE Providers

Over the past two months, staff has conducted additional site visits with Spruce and CaliforniaFirst to work through the mechanics of implementing their Programs within the subregion. It is anticipated that CaliforniaFirst and Spruce will begin accepting applications in the first quarter of 2017.

Prior WRCOG Actions:

- January 11, 2017: The Administration & Finance Committee directed the PACE Ad Hoc Committee to meet and make a recommendation to the Executive Committee at its February 2017 meeting regarding interest rates.
- January 9, 2017: The Executive Committee 1) received summary of the Revised California HERO Program Report; 2) conducted a Public Hearing Regarding the Inclusion of the Counties of Colusa, Mendocino, and Siskiyou Unincorporated areas, for purposes of considering the modification of the Program Report for the California HERO Program to increase the Program Area to include such additional jurisdictions and to hear all interested persons that may appear to support or object to, or inquire about the Program; and 3) adopted WRCOG Resolution Number 01-17; A Resolution of the Executive Committee of the Western Riverside Council of Governments Confirming Modification of the California HERO Program Report so as to expand the Program Area within which Contractual Assessments may be offered.
- December 5, 2016: The Executive Committee 1) received summary of the Revised California HERO Program Report; 2) conducted a Public Hearing Regarding the Inclusion of the Town of Hillsborough and the City of Yreka, for purposes of considering the modification of the Program Report for the California HERO Program to increase the Program Area to include such additional jurisdictions and to hear all interested persons that may appear to support or object to, or inquire about the Program; 3) continued the Public Hearing for the County of Colusa Unincorporated Areas until January 9, 2017; 4) adopted WRCOG Resolution Number 39-16; A Resolution of the Executive Committee of the Western Riverside Council of Governments Confirming Modification of the California HERO Program Report so as to expand the Program Area within which Contractual Assessments may be offered; 5) accepted the Counties of Mendocino and Siskiyou unincorporated areas as Associate Members of the Western Riverside Council of Governments; and 6) adopted WRCOG Resolution Number 40-16; A Resolution of the Executive Committee of the Western Riverside Council of Governments Declaring Its Intention to Modify the California HERO Program Report so as to Increase the Program Area within Which Contractual Assessments may be Offered and Setting a Public Hearing Thereon.

WRCOG Fiscal Impact:

HERO revenues and expenditures for the WRCOG and California HERO Programs are allocated in the Fiscal Year 2016/2017 Budget under the Energy Department.

Attachment:

1. WRCOG HERO Snapshot.

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PACE Program Activities Update

Attachment 1

WRCOG HERO Snapshot

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WRCOG - Western Riverside Council of Governments

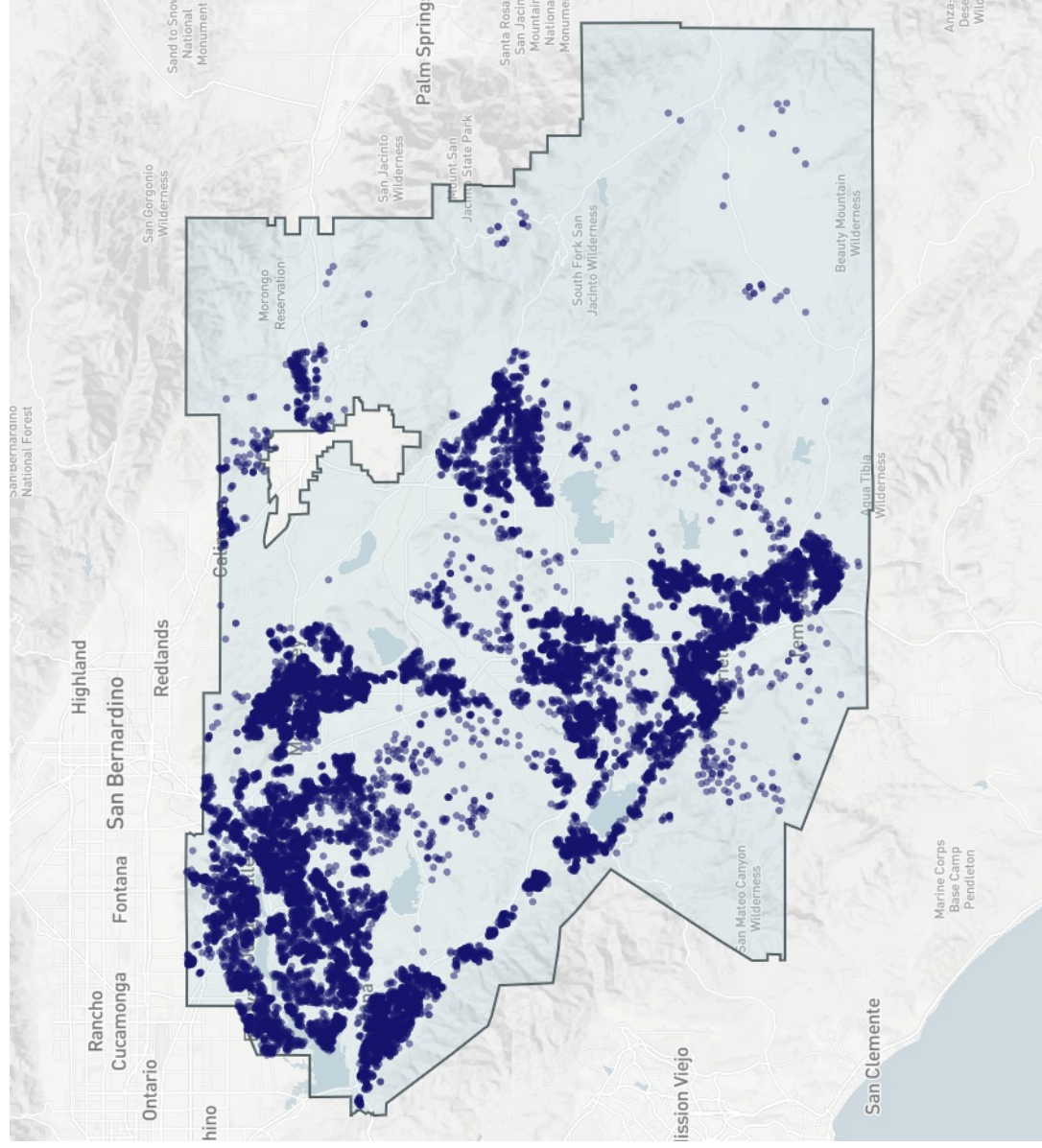
19,005
Homes
Improved

12/14/2011

460,666

HERO Launch Date

Housing Count



Improvements

Type	Total Installed	Bill Savings
Energy	25.3K	\$292M
Solar	12.3K	\$515M
Water	1,691	\$12.4M

Lifetime Impact

Applications Submitted	51.9K
Applications Approved	35.3K
Funded Amount	\$428M
Economic Stimulus	\$740M
Jobs Created	3,630
Energy Saved	3.14B kWh
Emissions Reduced	849K tons
Water Saved	1.34B gal

Learn how these numbers are calculated at <https://www.herogov.com/fac>

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Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Regional Homelessness Dialogue

Contact: Jennifer Ward, Director of Government Relations, ward@wrcoq.cog.ca.us, (951) 955-0186

Date: January 19, 2017

The purpose of this item is to provide Technical Advisory Committee (TAC) members with background information related to ongoing efforts to address homelessness in Riverside County in preparation for a presentation and discussion on a regional approach to addressing homelessness at the February 16, 2017, TAC meeting.

Requested Action:

1. Receive and file.

WRCOG is participating in the ongoing regional dialogue on the challenges facing local jurisdictions related to homelessness in Riverside County and facilitating the sharing of information regarding solutions to this challenge through the Technical Advisory Committee.

Background

WRCOG staff are participating in numerous regional discussions on the topic of homelessness in Riverside County including the Southwest Riverside County Regional Homelessness Alliance, the WRCOG TAC Subcommittee on Homelessness, and ongoing conversations with the County of Riverside, and the Coachella Valley Association of Governments Homelessness Committee.

These regional discussions have been extremely fruitful in terms of providing staff with a greater understanding of the challenge facing jurisdictions in addressing homelessness as well as the existing resources and initiatives dedicated to providing solutions. Staff have also invited numerous speakers to address the TAC regarding homelessness, and will continue to do so on a regular basis.

Proposed Statement of Principles

The TAC Subcommittee on Homelessness, which currently includes the Cities of Hemet, Jurupa Valley, Lake Elsinore, Menifee, Murrieta, Riverside, and Temecula, and the County of Riverside, recently discussed developing a regionally-supported "Statement of Principles," provided as Attachment 1, which would serve as a collective identification of both the challenges associated with serving the homeless population in Riverside County and the strategies that can be employed to address these challenges. Staff requests that the TAC members review the attached "Statement of Principles," as a presentation and discussion item on this topic will be placed on the February 16, 2017, TAC Agenda. After receiving feedback and direction from the TAC, staff would like to present the Statement of Principles to the Executive Committee for consideration by those members as a way to encourage the jurisdictions in WRCOG to collectively support a broad list of observations on homelessness. Any comments or feedback on the Statement of Principles should be emailed to Moises Lopez at mlopez@riversideca.gov.

The Southwest Regional Homelessness Alliance's has also adopted a Homeless Charter, which includes many of the same principles, provided for reference as Attachment 2.

Marketing Materials

Another topic that will be discussed at the February 16, 2017, TAC meeting is a proposal for developing more uniform, widely used, public outreach messages and educational materials on homelessness. Staff is requesting that if a jurisdiction currently uses any messages, flyers, or other marketing materials to raise awareness about resources for the homeless, or about how community members can help, please bring copies of these materials to the February TAC meeting or email them to Jennifer Ward at ward@wrcog.cog.ca.us in advance of the meeting.

Samples of marketing materials related to homelessness provided by the Cities of Riverside and Temecula are provided below:

Riverside:

- Riverside Ending Homelessness website: <http://www.endhomeless.info/>
- Homeless Services & Resources: <http://www.endhomeless.info/pdf/Homeless-Guide.pdf>
- Walk to End Homelessness (April 8, 2017) : <http://www.endhomeless.info/walk.asp>
- Ending Homelessness and Give to Positive Change Posters – Attachment 3

Temecula:

- Door Hangars – Attachment 4
- Resource Guide – Attachment 4
- Responsible Compassion Program Q & A and Talking Points – Attachment 4

Prior WRCOG Action:

None.

WRCOG Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachments:

1. Statement of Principles on Homelessness.
2. Southwest Regional Homeless Charter.
3. Riverside Homeless Resources Marketing Materials.
4. Temecula Homeless Resources Marketing Materials.

Item 5.O

Regional Homelessness Dialogue

Attachment 1

Statement of Principles on
Homelessness

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Riverside County Regional Homelessness Statement of Principles

Introduction:

According to the 2016 homeless Point in time count, the County of Riverside has 1,351 unsheltered homeless individuals living on the streets and 814 living in shelters. The total homeless population of 2,165 reflects a 12% decrease from the 2015 point in time count of 2,470. The reduction is attributed to several factors, including an improving economy, lower unemployment rates and a renewed effort to permanently house homeless veterans and the chronically homeless.

The County of Riverside is not unlike many counties and cities across the nation struggling to address the issue of homelessness. While the number of homeless in the County has continued a gradual but steady decrease, the perception is that the issue has worsened. This perception is a result of the “visible” one-third of the homeless population that continue to decline services. Homelessness is not a crime, it knows no political affiliation and is not concerned with jurisdictional delineations. To better address this challenge, a regional approach is needed. Working collaboratively with the County of Riverside a plan can be developed that ensures each city is doing its part to actively address homelessness.

Regional Commitment:

Each city in the county is committed to the following:

1. Standardize ordinances for panhandling, shopping carts, camping and trespassing
 - Makes it easier to enforce these laws consistently (throughout the region)
2. Engage the local homeless population and provide connections to local resources
 - Utilize multi-disciplinary teams that include service providers, faith-based/non-profit organizations law enforcement, code enforcement, etc. to address local homelessness issues as locally as possible
3. Provide services that meet the needs of the local homeless population to help balance the provision of services across the County
4. Advertise local resources for the local homeless population
 - Identify local available resources and submit information to the 211 Volunteer Center
 - Provide local resource guide handouts
5. Participate in a broad community-focused educational marketing campaign to highlight effective ways to help the local homeless population
 - Use consistent messaging and themes throughout the County
 - Advertise on digital boards and local media

Please email questions, comments, or feedback to Moises Lopez at mlopez@riversideca.gov.

6. Participate in the Riverside County Homeless Point in Time Count
 - Having an accurate count enables our community (and region) to be eligible for federal and state funding for homeless services. The count helps us to better understand the demographics and needs of those experiencing homelessness in our community, and helps to ensure a more equitable distribution of resources to meet the needs of the different populations.
7. Utilize the Coordinated Entry System (CES)
 - Coordinated entry ensures that all people experiencing a housing crisis have fair and equal access, are quickly identified, assessed for, referred, and connected to housing and assistance based on their strengths and needs
 - CES Assessments can be conducted by the following partners in your community: Outreach workers, law enforcement personnel, code enforcement personnel, library and park and recreation center staff, faith based organizations and non-profit organizations
 - CES Assessment Trainings will be provided by the County of Riverside University Health Systems Behavioral Health
8. Identify housing opportunities that are affordable in the local community
 - Identify housing opportunities
 - Identify funding resources
 - Incentivize the development of housing opportunities that are affordable (i.e., amend a development standard or a modification of the Zoning Code)
 - Partner with developers and property owners/landlords
9. Work towards the development and benefit of a permanent and diverse funding stream for homeless services and affordable housing uses throughout the region
10. Encourage faith-based and non-profit organizations to be responsible and compassionate when helping homeless individuals and families without harming them
 - Assist faith-based and non-profit organizations navigate homelessness in your community
 - Encourage faith-based and non-profit organizations to be part of a broad and coordinated regional effort to leverage resources and maximize impact, rather than engage in singular short-term solutions

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Regional Homelessness Dialogue

Attachment 2

Southwest Regional Homeless
Charter

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MISSION STATEMENT:

The mission of the Regional Homeless Alliance is to develop a collaborative partnership that evaluates and addresses the complex issues of homelessness from a regional perspective and provides coordinated homeless outreach services utilizing public, private and non-profit sector resources.

Purpose and Vision:

To increase housing opportunities to individuals, families and veterans experiencing homelessness while maintaining an effective homeless prevention program.

Goals:

#1	Create a nationally recognized regional collaboration based on proven best practices, such as Solutions for Change.	
		• Provide a monthly forum to discuss homeless issues and community needs
		• Present before each City Council in the region ○ Adoption of resolutions that commits to the principles of the Regional Homeless Alliance (RHA). ○ Encourage each city to add a provisions to their legislative platform regarding the RHA.
		• Develop a white paper through research of the causes of homelessness (paying particular attention to prevention and intervention strategies) and identifying regionally appropriate and realistic solutions.
		• Work with 211 Community Connect to develop a countywide resource guide, with regional focus.
		• Perform an initial and on-going needs-assessment through a gap analysis study.

#2	Provide leadership to combat homelessness through advocacy, education and coordination with local communities and create a broad, coordinated system of care.	
		• Increase communication through service providers and government agencies.
		• Establish a collaborative and coordinated system of identifying, collecting and disseminating local resources for public safety personnel, social service program providers and general community distribution.
		• Increase the awareness of resources to the community-at-large.
		• Reduce transportation barriers for homeless and at-risk population.
		• More effectively involve and collaborate with service agencies, school districts, faith-based organizations, transportation agencies, local Chamber of Commerce, and other stakeholders.

#3	Refocus training for public safety and service organizations from ushering homeless away to steering them to resources.	
		• Increase public safety personnel's training to include knowledge of behavioral health issues and community-based resources, including diversion programs, based on the existing success of the County of Riverside and Temecula Sheriff's HOT team efforts.
		• Increase public safety and city's participation in the annual Point-In-Time count.
		• Actively bridge communication between sworn officers, park rangers, code enforcement and county probation officers.
		• Improve communication between public safety organizations and city/county officials regarding encampments and migration of homeless.

#4	Improve community awareness.	
		• Inform and educate the public about homelessness using responsible compassion. ○ Increase communication to the general public through coordinated messages on social media from local governments and service providers. ○ Work with local service providers and faith-based organizations to host community education/outreach events to provide a productive opportunity to address the concerns of NIMBYs.

#5	Develop a fundraising plan.	
		• Create a plan that forecasts the ultimate capital needs and annual operational costs, identifies potential donors/resources and task the appropriate agencies for completing.
		• Seek additional low-income housing opportunities through private, local, state and federal resources.
		• Facilitate community partnerships to identify and secure funding for expanding education and training programs that lead to employment.

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Regional Homelessness Dialogue

Attachment 3

Riverside Homeless Resources
Marketing Materials

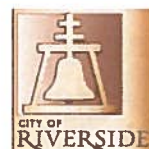
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SAY NO TO PANHANDLERS



GIVE TO POSITIVE CHANGE!

Donate to the
Riverside End Homelessness Fund
EndHomeless.info

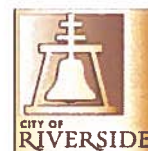


City of Arts & Innovation

**GIVE TO
POSITIVE CHANGE!**

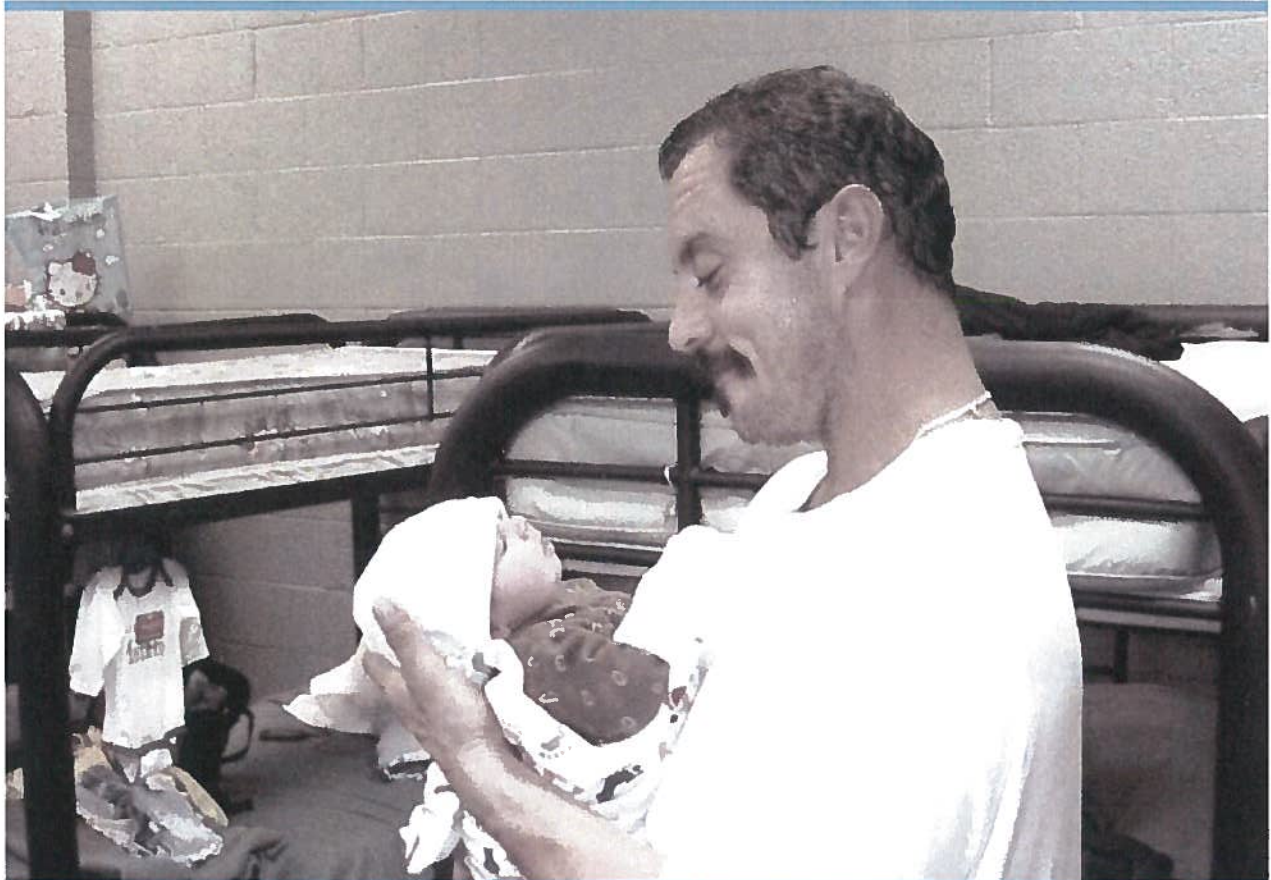


**Donate to the
Riverside End Homelessness Fund
EndHomeless.info**



City of Arts & Innovation

**GIVE TO
POSITIVE CHANGE!**



**Donate to the
Riverside End Homelessness Fund
EndHomeless.info**



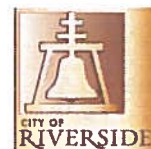
City of Arts & Innovation

SAY NO TO PANHANDLERS



GIVE TO POSITIVE CHANGE!

Donate to the
Riverside End Homelessness Fund
EndHomeless.info



City of Arts & Innovation

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Regional Homelessness Dialogue

Attachment 4

Temecula Homeless Resources
Marketing Materials

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RESPONSIBLE COMPASSION FOR THE HOMELESS



HOW YOU CAN HELP

LET YOUR GENEROSITY BE A PART OF THE SOLUTION

DO'S & DON'TS OF RESPONSIBLE COMPASSION

DO answer requests with a firm NO

DO report illegal activity by calling 911

DO treat homeless with respect

DO offer information where they can
get help, dialing 211

DO volunteer your time with a local
organizations helping homeless

DO make donations to organizations
helping homeless

DON'T encourage panhandling by
giving money, food, etc.

DON'T allow anyone to camp or
loiter on your property

DON'T assume you're making a difference
when you are giving; you may actually be
hurting, not helping.



For more info please visit website.com or call 951.123.4567

We Want To Help You

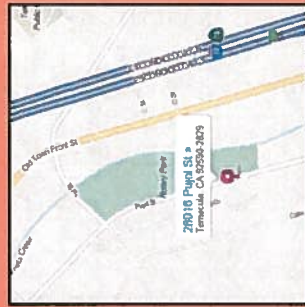
The City of Temecula and the Temecula Police Department believe in educating all citizens in our community. This pamphlet contains locations, telephone numbers and hours of operation for many resources within the County of Riverside. Services offered vary by location, but can include shelter, food, emergency services and cool/warm centers. Our focus is to provide responsible compassion to those in need and walk with them on a path to self-sufficiency. Our goal is that all citizens of Temecula have an excellent quality of life.

WARNING

Below you will find a list of items the Temecula Police Department will administer citations or arrest for:

- Theft of Recyclables
- Possession of a Shopping Cart
- Drinking alcoholic beverages in a park or on public property
- Illegal Camping
- Panhandling/Begging
- Loitering
- Trespassing
- Urinating in Public

Problem Oriented Policing



TEMECULA COMMUNITY PANTRY

28922 Pujol St
Temecula, CA 92590
(951) 676-8022
Monday, Wednesday
and Friday
9:30 am - 12:00 pm
Closed
Tuesday, Thursday,
Saturday and Sunday

The Temecula Pantry is a non-profit organization located in Temecula since 1986. We provide assistance to the homeless, very-low and low-income families in the Temecula Valley, Aguanga and Anza. We welcome all who come to the Pantry regardless of their race, sex, marital status, disability, religion or political affiliation.

For more information regarding your needs you can call

211

Or search the internet at:
www.connectriverside.org

For an emergency or immediate police or Fire response, call

9-1-1

for routine response, call
(951) 776-1099

Riverside County Department of
Public Social Services Homeless
Programs Unit
(951) 358-5637

This brochure is not intended as legal advice nor is the Temecula Police Department engaged in rendering legal advice or services. If legal assistance is required, the services of a competent attorney should be sought.



Public & Private
Social Services

Resource Guide



Temecula

Food:

Community Mission of Hope
27499 Commerce Center Drive,
Temecula, CA 92590
951-444-1404

Temecula Community Pantry
28922 Pujol Street
951-676-8022
(Open: M/W/F 9:30 am-12:00 pm)

Housing:
Project Touch
951-677-9661

Resources:
Department of Social Services
43264 Business Park Drive
Temecula, CA 92590
951-600-6500

Center for Employment Training
27941 Jefferson Ave.
951-296-3010 (cetweb.org)

Habitat for Humanity/Restore
27479 Enterprise Circle West
951-296-3362 (Habitat4inlandvalley.org)

Temecula Mental Health Services
41008 County Center Drive Building B #320
951-600-6355

Temecula Department of Social Services
43264 Business Park Drive Suite 102
951-600-6500

Murrieta

Food:

Community Food Pantry of Murrieta (St. Martha's)
38444 Sky Canyon Drive #170-190 951-677-6347
Hours: (M-Sat 9 am - 2 pm; Thu 8:30 - 10:30 am)

Lighthouse Food Pantry
38345 Innovation Court #101 951-698-7633
Hours: (2nd & 4th Thu 3:00-6:00 pm) Bring ID



Community Care Program
38801 Calistoga Drive 951-600-9112
Hours: (12 am-12 pm)

Resources:
Salvation Army

Lake Elsinore

Food:

HOPE
506 W. Minthorn St.
Lake Elsinore, CA 92530 (951) 245-7510
Hours: Tue, Wed, Thr 9:00 am - 12:00 pm

Hemet

Food:

Community Pantry
521 N. San Jacinto 951-929-1101
Hours: (Mon-Thu 9:30-11:30 am)

Resources:

Our Lady of the Valley Catholic Church
780 South State Street 951-924-9964
Call for appointment: 951-929-6131

Valley Restart Center
200 East Menlo 951-766-7476

Perris/Moreno Valley

Food:

St. Christopher Church
25075 Cottonwood Ave 951-924-1968
Hours: (Mon 1-3 pm)

Resources:

Perris Valley Family Resource Center
2055 N. Perris Blvd Suite C-1 951-443-1158
Hours (Tue & Thu 9:30 am-1 pm)

Lutheran Social Services
24310 Myers Ave. 951-656-6020
Hours: 9:00 am- 4:00 pm

PW Enhancement Center
24490 Sunnymead Blvd. Suite 107 951-616-1628
Hours: (Mon & Wed. 12:00-3:00 pm)

God's Helping Hand
13958 Old Highway 215 951-653-2529
Catholic Charities - Moreno Valley Regional Office
23623 Sunnymead Blvd. Suite E 951-924-9964
Hours: (Mon-Fri 8:30 am-4:30 pm) Closed: 12-1pm

Riverside

Abandoned Men & Women Ministries
3560/3562 Chestnut Street 951-965-3190
Hours: (Mon-Fri 7 am-7 pm; Sat. 8 am-6 pm)
At Fairmont Park (Thu & Fri 3:30-5pm)

Path of Life Ministries
2840 Hulen Place 951-462-9822
Hours (Mon-Fri 1-5 pm)
Shelter Hours (5:30pm-10:30 am)

Riverside Homeless Outreach Team
951-826-2200

Operation Safehouse
9685 Hayes Street
951-351-4418

Other Areas

***Banning Church of the Nazarene**
500 N. 8th Street 951-849-5618
Hours: (Thu 6:30-11:30 am)

***Coachella Valley Rescue Mission**
47518 Van Buren St, Indio 760-347-3512
Hours (24hrs/day/7 days/week)

***Corona Norco Rescue Mission**
420 W. Harrison Street, Corona 951-278-2215

***Martha's Kitchen & Village**
83791 Date Ave. Indio 760-347-4741
Hours (24hrs/day/7 days/week)

***Desert Horizon Transitional Housing**
400 South Farrell Drive Suite B205
Palm Springs 760-327-4394
Hours (Mon-Fri 8 am- 5 pm)

Veteran Services

VA Loma Linda Healthcare: 1-909-825-7084
Vet 24 Hour Crisis Hotline: 1-800-273-8255 #1

City of Temecula Responsible Compassion Program

Addressing Homelessness in Temecula

Q: What is the City doing about homelessness?

A: The City has a three-part approach to dealing with homelessness that focuses on Collaboration, Coordination, and Communication:

- We *Collaborate* with partner organizations like Community Mission of Hope and Temecula Community Pantry to provide services and a path to self-sufficiency to those who are currently in need.
- We *Coordinate* with law enforcement, City staff, and other agencies to provide a continual, visible, and physical presence to deter illegal activity.
- We *Communicate* with residents and businesses to educate the public about well-intentioned actions which may unintentionally contribute to unwanted or illegal behaviors which negatively impact quality of life in our City.

At all stages, the City leverages strategic partnerships with established agencies, consistent with our commitment to fiscal responsibility.

Q: Why are there so many homeless people in the City now?

A: The causes of homelessness are many and complex, and include large-scale socioeconomic factors as well as personal risk factors including mental illness, disability, and lack of a family or social network. In our work with other organizations, we have identified four broad categories of at-risk individuals:

1. Those who desire assistance in regaining self-sufficiency
2. Those who suffer from mental illness or other conditions which inhibit reasoning skills
3. Those who refuse help and choose to lawfully live outdoors
4. Those who refuse help and may be engaging in unlawful activity

The City directs its efforts at providing resources to those who are willing to accept help, partnering with regional organizations to address the causes of homelessness, and deterring unwanted behaviors.

Q: If the City is too nice to the homeless, won't we become a "refuge" city?

A: While the City is committed to making resources available those in need who want and will accept help, we are equally committed to maintain the quality of life our residents have come to expect. To that end, we partner with law enforcement and other agencies to simultaneously support a path to self-sufficiency and aggressively deter unwanted and unlawful behaviors.

Q: What should I do when panhandlers approach me?

A: Your first concern is for your safety. If you feel threatened, call 911. The City encourages residents to respond to panhandlers with a respectful but firm "No." All of our partner organizations as well as law enforcement concur that giving money to panhandlers does more harm than good, and may encourage panhandling and support illegal activity including drug use. Responsible options for generosity include volunteering with or donating to any of the local organizations which work to solve homelessness in our community. You may also dial 211 or visit www.connectriverside.org for additional resources for helping those in need, including information about Community Mission of Hope, Temecula Community Pantry, and other front-lines relief organizations.

Q: When can I call the police?

A: You should always call 911 if you need emergency assistance from police or fire, if there is a medical emergency, or an immediate threat to public safety. Additionally, the Temecula Police Department will take action for theft of recyclables, possession of a shopping cart, public consumption of alcohol, illegal camping, panhandling, loitering, trespassing, urinating in public or other disruptive behavior.

Talking Points: City of Temecula Responsible Compassion Program

The City of Temecula has taken the lead on crafting a comprehensive approach to solving the problem of regional homelessness in a way that respects the inherent worth and dignity of every person. The “Responsible Compassion” program is consistent with the City’s *Quality of Life Master Plan* Core Value of Accountable and Responsive City Government and an effective approach to countering the causes and consequences of homelessness within our community.

The City’s efforts include:

1. Partnering with law enforcement, neighboring municipalities, faith-based organizations, and select non-profits to create a cohesive network of resources, proactive outreach, and community education initiatives.
2. Initiating a cooperative agreement to support Community Mission of Hope and Temecula Community Pantry in their missions to help individuals and families chart a path to self-sufficiency by addressing their physical, financial, social, and spiritual needs.
3. Supporting the Problem Oriented Policing (POP) model with a dedicated multi-agency Homelessness Outreach Team (HOT) which works on an individual basis to prevent and respond to unwanted behaviors.
4. Working to educate the community about appropriate avenues for helping homeless individuals without unintentionally exacerbating problem behaviors.
5. Distributing collateral (e.g., *Responsible Compassion* door hanger and tri-fold *Social Services Resource Guide*) to assist in community education.
6. Participating in annual homelessness surveys to support a data-driven approach to policies and initiatives, as well as to gain insight into regional socio-economic factors which impact rates of homelessness in our community.
7. Encouraging continuity among personnel engaged in front-line outreach, because efforts are most effective when staff can engage individuals with an understanding of specific factors which may include mental illness, addiction, disability, willingness to accept help, access to family or other social support, and prior illegal activity.
8. Coordinating with Project T.O.U.C.H. to provide emergency shelter via vouchers during the winter.
9. Sharing best practices with other regional agencies to improve local efforts and create a consistent climate of responsible compassion throughout the region.
10. Utilizing City Park Rangers, other staff, and the Community Action Patrol to act as “eyes and ears” supporting Temecula Police Department in its efforts to deter unlawful behavior and respond quickly to citizen concerns.

The City remains committed to addressing the complex and evolving challenge of homelessness within our community. Future steps include broadening community education to leverage social media, deepening cooperation on the regional level, and reviewing existing initiatives to identify opportunities for improvement.



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Report from the League of California Cities

Contact: Erin Sasse, Regional Public Affairs Manager, League of California Cities,
esasse@cacities.org, (951) 321-0771

Date: January 19, 2017

The purpose of this item is to inform the Committee of activities undertaken by the League of California Cities.

Requested Action:

1. Receive and file.

Ms. Sasse is unable to attend this month's meeting and is providing an update via the attached newsletter.

Prior WRCOG Action:

January 9, 2017: The WRCOG Executive Committee received report.

WRCOG Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachment:

1. Newsletter: CA Cities Advocate Issue #2.

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Item 5.P

Report from the League of California
Cities

Attachment 1

Newsletter: CA Cities Advocate
Issue #2

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Jan. 10, 2017
Issue #2

Governor Unveils Proposed FY 2017-18 Budget with \$1.6 Billion Deficit Projected *Proposal Includes \$4.3 Billion for Transportation but No New Funding for Affordable Housing*

Volatility and prudence were the words of the day during Gov. Jerry Brown's annual January budget release press conference in Sacramento this morning. Similar to recent years, the Governor repeatedly cautioned about the dangers of overspending and the pending recession that will likely follow the last eight years of economic expansion. His words were stronger this year because after four years of balanced budgets with small budget surpluses, this one projects a \$1.6 billion deficit for the fiscal year that starts July 1. The [proposed FY 2017-18 budget](#) he unveiled includes \$122.5 billion General Fund and \$179.5 billion total spending.

State revenues are still growing and projected to grow in FY 2017-18 according to the Governor's budget proposal. However, the trajectory of that growth is declining and the budget lays out some tough choices to rein in spending in the face of the deficit and lower growth.

The proposed budget includes \$3.2 billion in budget solutions. The unappropriated \$400 million in the FY 2016-17 budget — set aside to be exchanged for approval of the by right proposal — is counted as savings. The state will also hold back from transferring \$300 million to modernize state buildings in FY 2017-18. The Proposition 98 constitutional guarantee for K-14 funding will be at its minimum. The Middle Class Scholarship program will not be extended to new students, rate increases for child care will not occur and a number of other spending proposals will not be funded.

California faced a \$27 billion deficit when Governor Brown assumed his third term of office in January 2011. The coming year's deficit is dramatically smaller, however, the Governor is worried that it can quickly grow if it is not immediately addressed. In the midst of the dire warnings, he showed his softer side in calling on the Legislature to "Save some biscuits for a rainy day" in honor of his beloved recently deceased First Dog Sutter Brown. To that end, the Governor stressed the importance of the state's Rainy Day Fund, which is projected to reach \$7.9 billion in FY 2017-18.

Several factors make state budgeting in California challenging. Although the state has the most progressive tax structure in the nation, that in turn results in more volatility because of the reliance on capital gains. Income, sales and corporation taxes comprise the "big three" revenue sources for California.

This year there is more uncertainty resulting from the impacts of unknown changes to be made by the incoming Trump Administration. The Governor's budget did not account for how the new president's policies will impact California, but he did say that his May Revise could be based on very different numbers depending on what happens between now and then. He used this portion of his remarks as another opportunity to remind the Legislature that California must be fiscally prudent and wise this year.

The Governor's proposed budget does reflect several of the League's [2017 strategic goals](#). He reiterated his commitment to transportation funding by including a 10 year, almost \$43 billion transportation infrastructure investment plan. The [Fix Our Roads Coalition](#), of which the League is a member, [issued a statement](#) early Tuesday afternoon commending the Governor for his continued engagement in crafting a sustainable transportation funding package while reinforcing the need for at least \$6 billion annually to stop the deterioration of the system.

California's affordable housing crisis and homelessness were both also addressed. Governor Brown spoke about the need to reduce the per unit affordable housing construction cost, currently averaging \$322,000 per unit. However, the League is disappointed that the Governor chose to emphasize the need to streamline the process and adjust requirements at the local level rather than provide much needed funding. The budget contains no new funding for affordable housing, and principles presented by the Governor for any funding negotiations include "No Impact to the General Fund."

On a positive note, the League-supported [No Place Like Home](#) program will be funded in FY 2017-18 to construct and rehabilitate permanent supportive housing for California's most chronically homeless mentally ill.

The Governor focused on the Cap-and-Trade program and wants to withhold any additional allocations until after the Legislature stabilizes the fund through a two-thirds vote. Early auctions generated significantly more revenues than those held in May and August of last year, which total produced approximately \$18 million. The last auction in November 2016 produced \$364 million.

Details on these and other budget areas of importance to cities are outlined below.

Transportation Funding

While the regular and special session on transportation funding came to a close last year without resolution, the Governor's new transportation funding proposal provides an increase to \$43 billion over the next 10 years.

Of the \$4.3 billion in new funding for transportation in FY 2017-18, \$1.16 billion goes to local streets and roads for maintenance and rehabilitation. Additionally, the Governor's proposal includes the following annual investments in the coming 10 years:

- \$100 million for the Active Transportation Program.
- \$25 million for sustainable (SB 375) transportation grants.
- \$270 million for Corridor Mobility Improvements on congested commute corridors.
- \$25 million for the freeway service patrol program.
- \$400 million for the Transit and Intercity Rail Capital Program.
- \$1.8 billion for highway repairs and maintenance on the state highway system.
- \$250 million for the state's major trade corridors.

These investments will be supported through the following revenue sources:

- \$2.1 billion Road Improvement Charge from \$65 fee on all vehicles, including electric and hybrid.
- \$1.1 billion from eliminating the annual adjustments to the gasoline excise tax and resetting the tax to the FY 2013-14 rate of 21.5 cents, adjusted annually for inflation.
- \$425 million from an 11 cent increase to the diesel excise tax, adjusted annually for inflation.
- \$500 million in additional cap and trade proceeds.
- \$100 million in Caltrans efficiencies.
- \$706 million in loan repayments.

The Governor's budget transportation proposal represents a smaller package than existing legislative proposals in AB 1 (Frazier) and SB 1 (Beall), which generate \$6 billion annually upon full implementation. With a commitment from this Legislature and Administration, the benefits of a comprehensive transportation funding proposal will far exceed the costs for Californians. These modest increases will help ease the costs drivers are already paying, an average of \$762 annually, to fix their vehicles due to poor road conditions.

The Governor's budget proposal assumes adoption of the proposal. Local streets and roads will continue to deteriorate without a new funding package.

Housing

The League was very disappointed to see that the Governor did not include a meaningful funding proposal for affordable housing. The Governor took it a step further in his proposal and clearly stated that the General Fund was completely off the table as a possible source of funding to help spur housing production, including affordable housing. Governor Brown also eliminated the \$400 million set aside in the 2016-17 Budget Act for affordable housing in exchange for approval of the by right proposal. The funds have not been appropriated because the Legislature has not acted on his proposal.

Instead of bringing forward a balanced proposal that comprises significant permanent housing funding and appropriate project streamlining, the Governor unveiled a list of housing policy principles that largely focus on “reforms” at the local level. These “reforms” could dramatically limit plan review, public input, impact fees, and tie housing production to unrelated infrastructure funding, such as much needed transportation dollars.

The Governor’s Housing Policy Principles are as follows:

- **Streamline Housing Construction.** Reduce local barriers to limit delays and duplicative reviews, maximize the impact of all public investments, and temper rents through housing supply increases.
- **Lower Per-Unit Costs.** Reduce permit and construction policies that drive up unit costs.
- **Production Incentives.** Those jurisdictions that meet or exceed housing goals, including affordable housing, should be rewarded with funding and other regulatory benefits. Those jurisdictions that do not build enough to increase production should be encouraged by tying housing construction to other infrastructure-related investments.
- **Accountability and Enforcement.** Compliance with existing laws such as the housing element should be strengthened.
- **No Impact to the General Fund.** No new costs, or cost pressures, can be added to the state’s General Fund, if new funding commitments are to be considered. Any permanent source of funding should be connected to these other reforms.

Curiously, given all of the recent debate in the Capitol about what has led to the rise in home prices, the Governor’s “reform” principles make no mention of CEQA, prevailing wage, high land costs, market conditions, or a number of other factors that put pressure on housing costs.

Homelessness

The only new funding for housing or homelessness comes from the No Place Like Home Program, which allocates \$262 million for permanent supportive housing for persons who are eligible for services under Prop. 63 (2004) and are homeless, chronically homeless, or at risk of chronic homelessness. Grant guidelines are still being developed by the Department of Housing and Community Development, and grant approvals are not expected until 2018.

Workforce Development

The January Budget Proposal includes:

- \$248 million to expand career technical education courses through the Strong Workforce Program at California community colleges.
- \$500 million for the Adult Education Block Grant Program to support programs that assist adult learners with courses to complete high school diplomas, general education equivalent, and English as a Second Language courses.
- \$68 million for apprenticeship programs that offer a clear pathway to obtain classroom instruction and on-the-job training skills leading to gainful employment.
- A policy statement linking the importance of local libraries to workforce development. The state librarian will work with stakeholders to integrate libraries into the state’s workforce strategy.

Cap-and-Trade

Governor Brown proposes legislation authorizing the state Air Resources Board (ARB) to administer Cap-and-Trade auctions beyond 2020. This proposal is meant to address volatility in auction revenues in 2016, which many speculate are the result of legal challenges to the validity

of the program beyond 2020. Governor Brown also announced that any appropriation of Cap-and-Trade funds is contingent on passage of the proposed legislation to extend the Cap-and-Trade authority.

Should this proposal receive the two-thirds it needs in both the Senate and Assembly, the budget proposes the following \$2.2 billion Cap-and-Trade Expenditure Plan:

Continuous Appropriation (60 percent of annual auction proceeds)

- \$375 million for the High-Speed Rail Project.
- \$75 million for Low Carbon Transit Operations.
- \$150 million for the Transit and Intercity Rail Capital Program.
- \$300 million for the Affordable Housing and Sustainable Communities Program.

One-time Appropriation (40 percent of annual auction proceeds)

- \$500 million to the Transportation Agency for Transit and Intercity Rail Capital Program and to Caltrans for Active Transportation (See Transportation Funding section above).
- \$363 million for ARB's Low Carbon Transportation Program to provide incentives for low carbon freight and passenger transportation, including rebates for zero emission cars, vouchers for hybrid trucks and zero-emission trucks and other uses.
- \$142 million for the Strategic Growth Council to administer the Transformational Climate Communities Program as well as to provide technical assistance.
- \$95 million cumulatively to ARB for black carbon woodsmoke, to CalRecycle for waste diversion, and to the Department of Food and Agriculture for dairy digesters.
- \$127.5 million cumulatively to CALFIRE for healthy forests and urban forestry programs, to the Department of Food and Agriculture for Climate Smart Agriculture — Healthy Soils, and to the Natural Resources Agency for urban greening.
- \$27.5 million cumulatively to the Department of Community Services and Development for energy efficiency upgrades and weatherization and to the Department of Food and Agriculture for the State Water Efficiency and Enhancement Program.

Should the Governor's proposal not be approved, programs that receive a continuous appropriation will go forward but with significantly less funding. The programs that received one-time appropriations would not be funded in FY 2017-18.

Beverage Container Recycling Program Reform

In his budget, the Governor highlights the 30-year old Beverage Container Recycling Program as ripe for reform. Depending on the proposed reforms, cities could potentially lose funding that supported recycling programs at the local level. The League will monitor this issue closely as discussions develop.

Environmental Quality

Emergency Drought Response

The Governor's budget proposes an additional \$178.7 million in one-time funding to provide immediate responses to the drought. This budget assumes drought conditions continue, although the administration will continue to monitor drought conditions and make any necessary changes in the May revision to the January budget proposal. Appropriations are proposed in the categories below.

Protecting water supplies and water conservation:

- \$5 million to the Department of Water Resources (DWR) for local assistance to small communities for emergency drinking water.
- \$5.3 million to the State Water Resources Control Board (SWRCB) for water rights management.
- \$7 million to the DWR for drought management and response.
- \$2 million to the DWR for the Save Our Water campaign.

Emergency response for fire protection and tree mortality:

- \$91 million to CALFIRE for enhanced fire protection, including continuation of increase firefighter surge capacity, extended fire season, surge helicopter pilots, California Conservation Corps fire suppression crews, increased vehicle maintenance, and exclusive use of large and very large air tankers.
- \$52.7 million to the Office of Emergency Services (OES) for the California Disaster Assistance Act.
- \$4 million to OES for the State Operations Center.

Protecting Fish and Wildlife:

- \$8.2 million to the Department of Fish and Wildlife (DFW) for emergency fish rescues and monitoring.
- \$3.5 million to the DWR for implementation of the Delta Smelt Resiliency Strategy including aquatic weed control, adaptive food management and distribution, and wetlands flood and drain operations.

California Water Action Plan

The Governor proposes several funding increases to further the goals of the 2014 California Water Action Plan. The proposed allocations below assume drought conditions in the state continue.

- \$248 million (Prop. 1 funding) to DWR for integrated regional water management projects that are regionally driven multi-benefit projects that help meet long-term water needs.
- \$1 million (Waste Discharge Permit Funds) and five new positions for the SWRCB, in coordination with the Department of Food and Agriculture, to address contamination of groundwater basins from agricultural practices.
- \$1.9 million (Prop. 1 funding) increase to DFW for the Water Investment Storage Program for initial outreach and technical review of the ecosystem benefits of the water storage project proposals submitted to the California Water Commission.
- \$2.3 million increase (Water Rights Fund) for five new positions at the SWRCB and \$1.5 million in contract funds to enforce reporting requirements and protect local groundwater resources beginning in July 1, 2017. The proposal targets high or medium-priority groundwater basins that fail to form local governance structures, as required by the Sustainable Groundwater Management Act (SGMA).

Department of Fish and Wildlife

For the Fish and Game Preservation Fund to fully support the commercial fishing program, the budget proposes an increase of \$12.3 million from commercial fish landing fees and redirecting \$10.6 million on a one-time basis from the Lifetime License Account.

Department of Parks and Recreation

In recent years, the Department of Parks and Recreation has undertaken reform and innovation efforts, although the administration notes that the Department has long-term structural shortfalls. The budget proposes a one-time increase of \$12.6 million from the State Parks and Recreation Fund and \$4 million from the Environmental License Plate Fund to maintain existing service levels at state parks.

Local Public Safety

The Governor's Budget Proposal includes:

- \$114.9 million for Community Corrections Performance Incentive Grants: Continued from previous years to fund county efforts to reduce the number of felony probationers going to state prison.
- \$11 million for Post-Release Community Supervision: For county probation departments supervising temporary increase in offenders resulting from Prop. 57 and court-ordered population control measures.
- Policy changes to reduce the number of programs supported by State Penalty Fund due to declining revenues in recent years.

- o The following programs will no longer be supported by the fund: California Gang Reduction, Intervention and Prevention Program (GRIP) with Board of State and Community Corrections; Internet Crimes Against Children Task Forces, OES; Local Public Prosecutors and Public Defenders Training Program, OES; and, Motorcyclist Safety Program, California Highway Patrol (training, education and outreach activities).
- o Funds will continue to be available to the following programs: Driver Training Program; Peace Officer Standards and Training; Standards and Training for Corrections; Victim Witness and Assistance Programs; Restitution Fund; CA Witness Relocation and Protection Program; Traumatic Brain Injury Program; and Fish and Game Prevention Program.
- A repeal of the Drivers License Suspension Program: Eliminates provisions in law providing for suspending a person's drivers license for failure to pay fines/penalties.

Corrections: Proposition 57 Implementation

Prop. 57 (2016) is estimated to reduce average daily adult inmate population by 2,000 in FY 2017-18, and by a total of 9,500 by FY 2020-21. It facilitates removal of all out-of-state inmates in one of the two remaining prison facilities in FY 2017-18. The Governor's proposal promises to provide substance abuse treatment at all state correctional facilities by the end of the year. The proposal anticipates savings of \$22.4 million in FY 2017-18 with a net savings of \$140 million by FY 2020-21.

Specific provisions of the Governor's Budget Proposal include:

Parole Process — Eligibility for Non-Violent Offenders

The budget provides for non-violent second strikers to go before the Board of Parole Hearings, which will evaluate their threat to public safety. An estimated 5,000 inmates will qualify, only eligible after serving 50 percent of the longest possible term for their sentence. In practice, this will affect approximately 500 – 600 inmates. It also increases and standardizes good-time credit earnings.

Inmates who are not eligible include:

- Violent inmates (defined by Penal Code Sec. 667.5).
- Third Strikers.
- Inmates with sentence enhancements violent acts.
- Inmates with in-custody infractions for drugs/gang-related behavior.

Milestones and Mentors

Milestone credits are good-time credits for specified activities. The goal is to award enhanced milestone credits for earned academic and vocational achievements including accredited high school courses, vocational programs certified by the trades, and an AA or BA Degree.

The Offender Mentor Program (approximately 400 programs throughout the program) will require that inmates go through courses and tests to get credits.

While rehabilitation programs are traditionally open only to non-violent inmates, the Governor proposes to open them to all inmates regardless of committed offense in FY 2017-18. This has been shown to be an effective anti-recidivism tool. The California Department of Corrections and Rehabilitation (CDCR) has found that inmates are 31.2 percent less likely to re-offend if they complete an in-prison substance abuse disorder treatment program. Under the proposal, substance abuse program will be available at all prisons by the end of the year.

Funding for Inmate Rehabilitation and Re-Entry

The budget includes \$440 million to division or rehabilitative programs, which represents an increase from \$300 million in FY 2012-13. Support for in-custody rehabilitative programming will include: cognitive behavioral therapy, re-entry/transition programs, Long Term Offender Program,

Offender Mentor Certification Program, and self-help programs. Participation will be incentivized by grants of up to one month off prison sentence for completion of 208 program hours.

Division of Juvenile Justice

There is an anticipated increase of 72 wards due to Prop. 57's shift of authority regarding charging minors as adults from district attorneys to judges. The budget includes \$4.9 million to reactivate two Department of Juvenile Justice living units to accommodate this expected population increase. In addition, juvenile prosecutions in adult court expected to decline and average daily inmate population on the adult side expected to decline by 81 in FY 2017-18. Counties are expected to experience related increased costs as probation departments will provide greater assistance in juvenile court proceedings and County probation departments will pay the state \$24,000 per year per ward for certain juvenile commitments.

Other Programs

The Budget Proposal also includes funding for the following programs:

- Because 80 percent of lifers released on parole need or request transitional housing, CDCR is developing a 300-bed program for six months of transitional housing.
- Continued funding for Drug and Contraband Interdiction.
- Continued funding for Segregated Housing Unit Conversion at Pelican Bay.
- Funding for 647 beds in community re-entry facilities. This is an increase of 187 beds over current levels.
- Funding for the California Leadership Academy, aimed at reducing recidivism among 18 – 25 year old inmates.

Cannabis Regulation

Generally, the Administration has decided on a single regulatory structure for both medical and recreational marijuana. However, it has not yet committed to whether that structure will look more like Prop. 64, or the Medical Marijuana Regulation and Safety Act, which the League supported. Another unknown factor is how the federal government may change enforcement of existing federal law.

For now, the Administration plans to move forward with Prop. 64 implementation and has proposed \$52.2 million in FY 2017-18 for cannabis regulation, processing of licenses, and enforcement. As revenues from the tax included in Prop. 64 will not be collected until 2018, this appropriation is structured as a loan from the General Fund, to be repaid in FY 2018-19.

Specific appropriations in this area include:

- Department of Consumer Affairs (lead agency): \$22.5 million to Bureau of Medical Cannabis Regulation for regulation of transportation, sale, storage and distribution of cannabis.
- Department of Food and Agriculture: \$23.4 million for administrative oversight, promulgation of regulations, issuance of cultivation licenses.
- Department of Public Health: \$1 million for licensing and regulation of manufacturing facilities.
- Board of Equalization: \$5.3 million for educating businesses on new tax requirements and updating information technology systems.
- Department of Health Care Services: \$5 million for public information program specified in Prop. 64.

State Retiree Health and Pension Costs

The budget includes \$5.3 billion dollars (\$2.8 billion General Fund) specifically for state employee contributions. The Department of Finance (DOF) attributes the increased contributions to several factors including a maturing fund and increased life expectancy combined with significantly lower than expected investment returns. These factors, in part, contributed to the recent decision made by the CalPERS board to lower its assumed rate of return (discount rate) [from 7.5 percent down to 7 percent](#) effective immediately for the state — with a one year delay for local agencies. The

immediate action will result in a modest contribution increase of \$172 million (\$105 million General Fund) in FY 2017-18 year. Given the phased-in approach adopted by the CalPERS board, the true impacts of a 7 percent rate will not impact the state's budget until the FY 2023-24, when state contributions are projected to reach \$9.7 Billion (\$5.6 billion General Fund). The Governor called the recent move by the Board "another major step [in reducing costs]".

The Governor did not announce any plans to seek a legislative remedy to further tackle the state's rapidly growing unfunded pension and retiree healthcare liability. However, he did not close the door on seeking a legislative approach this year. "This will continue to be a lively topic this year ... we will continue to take advantage of other opportunities as they come up".

Public Utilities Commission (PUC) Reform

The Governor's budget proposal includes a commitment from the Administration to continue to work on some of the PUC reforms that were enacted last year, including a directive for the Administration to work with the PUC to develop a reorganization plan to transfer regulatory oversight over transportation network companies and charter party carrier vehicles (shuttles, limousines, etc.) to departments within the California Transportation Agency.

Census Address Program

The budget includes \$7 million for the Local Update of Census Address Program. The program will provide grants ranging from \$7,500 to \$125,000 to cities and counties to encourage their voluntary participation in efforts to ensure the accuracy of the Census Bureau's Master List of addresses.

Redevelopment Dissolution

The Governor's proposed budget summary reports that since FY 2011-12 and projected through FY 2017-18, redevelopment dissolution will have returned a total of \$8.6 billion in property taxes to K-14 schools. This consequently allows the state to reduce its General Fund expenditures under Prop. 98 education funding requirements by a similar amount.

The cumulative total received by counties, special districts and cities over this same period is projected to be \$6.32 billion. Cities are anticipated to receive \$733 million over FY 2016-17 and FY 2017-18. The Administration makes no new proposals in this area for FY 2016-17.

Special Needs Housing

While the Governor's budget does not include additional funding for the Community Based Transitional Housing Program, the Department of Finance reminded local governments on a budget conference call that grant applications are currently open. This program was created in the 2016-17 Budget Act, and seeks to encourage local communities to support housing that provides treatment and reentry programming to individuals who will benefit from those services. To date, zero grant applications have been received. More information and grant applications are available on the [DOF's](#) website.

Next Steps

The Department of Finance will begin releasing draft trailer bill language in the next month that will include details of the proposal. The Assembly and Senate Budget committees will also begin hearings to review program-specific details. In May the Governor will release his revised budget proposal for the coming fiscal year that must be passed by June 15 to take effect July 1.



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: California Mandatory Conservation Framework Discussion and California WaterFix Update

Contacts: Paul Jones, General Manager, Eastern Municipal Water District, ionesp@emwd.org, (951) 928-6130
John Rossi, General Manager, Western Municipal Water District, jrossi@wmwd.com, (951) 789-5050

Date: January 19, 2017

The purpose of this item is to inform the Committee of activities undertaken by the two regional water districts to address and inform ratepayers on additional conservation mandates that will be imposed by the State Water Resources Control Board, and to update the Committee on the development of a comprehensive solution to addressing imported water reliability from the Sacramento-San Joaquin Bay Delta.

Requested Action:

1. Receive and file.

This item is reserved for a joint presentation from the general managers of Eastern Municipal Water District and Western Municipal Water District.

Prior WRCOG Action:

None.

WRCOG Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachment:

None.

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Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Santa Ana Municipal Separate Storm Sewer System (MS4) Permit Compliance Program Update

Contact: David Garcia, Engineering Project Manager, Riverside County Flood Control and Water Conservation District, dhgarcia@rcflood.org, (951) 955-1330

Date: January 19, 2017

Requested Action:

1. Receive and file.

The purpose of this item is to provide a presentation from the Watershed Protection Division of the Riverside County Flood Control and Water Conservation District regarding the status of National Pollutant Discharge Elimination System (NPDES) Municipal Separate Storm Sewer System (MS4) Programs within the Santa Ana Region of Riverside County. The Santa Ana NPDES MS4 Permit requires City Managers from Beaumont, Calimesa, Canyon Lake, Corona, Eastvale, Hemet, Jurupa Valley, Lake Elsinore, Menifee, Moreno Valley, Norco, Perris, Riverside and San Jacinto, as well as the County Executive Officer, to meet at least twice annually to discuss Santa Ana NPDES MS4 compliance programs. These meetings are integrated into the WRCOG Technical Advisory Committee meetings for the convenience of the City Managers and Executive Officer. This agenda item will convene the first meeting for Fiscal Year 2016-2017. Each City Manager, or their designated alternate, must attend at least one of two meetings.

Background

The cities and County of Riverside, as well as the Riverside County Flood Control and Water Conservation District (Permittees), are jointly regulated by NPDES MS4 Permits issued by the Santa Ana, Colorado, and San Diego Regional Water Quality Control Boards. These permits, issued pursuant to the federal Clean Water Act, are designed to protect local lakes, rivers and streams from pollution (such as sediment, oils, grease, fertilizers, animal and human waste, trash and dissolved metals) associated with urban land use. The NPDES MS4 Permits specifically regulate discharges of storm water and non-storm water (e.g., irrigation runoff) from the storm drain system owned and operated by the Permittees. The NPDES MS4 Permits require Permittees to take action to regulate business and new developments, as well as residential areas and Permittee facilities (e.g., maintenance yards, parks, etc.) so as to minimize the potential for pollutants to be mobilized by runoff and conveyed through the storm drain system to local lakes, rivers and streams. Enhanced programs are required to address waterbodies that may be impaired by pollutants in urban runoff.

The presentation will address the status of Canyon Lake and the Alum Treatment Successes, and the status of other NPDES MS4 Permit program elements, including the three MS4 Permits in the County.

Prior WRCOG Action:

May 19, 2016: The WRCOG Technical Advisory Committee received report.

WRCOG Fiscal Impact:

This item is informational only; therefore, there is no fiscal impact.

Attachment:

1. Stormwater Permits Program Update PowerPoint.

Item 6.B

Santa Ana Municipal Separate Storm
Sewer System Permit Compliance
Program Update

Attachment 1

Stormwater Permits Program Update
PowerPoint

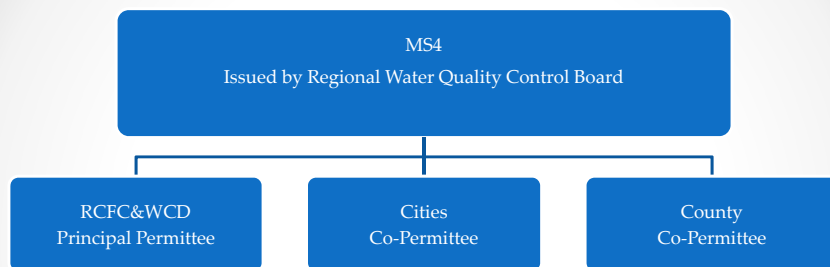
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Stormwater Permits Program Update

January 19, 2017

Riverside County Flood Control
and Water Conservation District

Municipal Separate Storm Sewer System Permit (MS4 Permit)

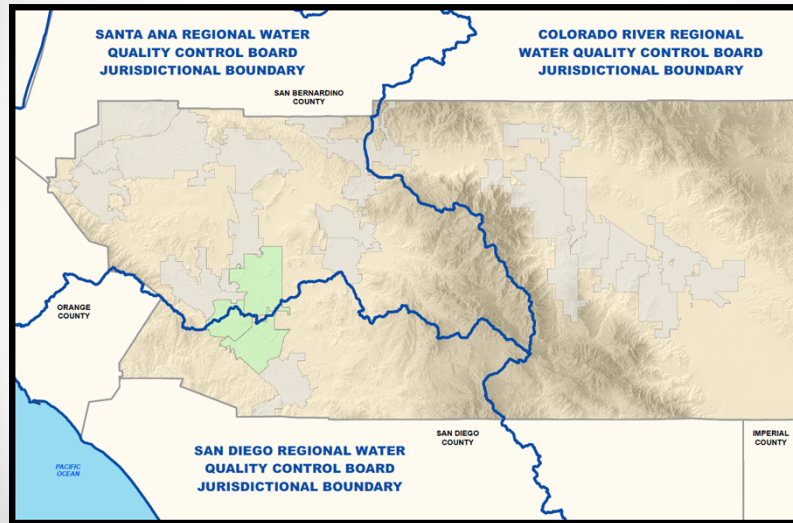


Issued to municipal operators of storm drains (cities and County)

Permit requires:

- Elimination of non-stormwater discharges to storm drains
- Reduce Pollutants to the Maximum Extent Practicable

Regional Board Boundaries in Riverside County



MS4 Compliance Programs – Source Control



Code Enforcement



Public Works Project Controls



New Development Controls



Education/Outreach



Municipal Activities



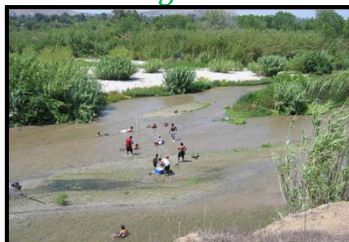
Business Inspection Programs

Water Body Specific Programs

Lake Elsinore/Canyon Lake

Excessive Nutrients

- *Canyon Lake Alum Treatment twice a year*
- *Revising the TMDL*



Santa Ana River

Excessive bacterial indicators
Watershed Monitoring Program



Santa Margarita River/Lagoon

Excessive Algae

Alternative TMDL Workgroup

Canyon Lake Alum Treatment

Update...it's working!

- **Treatment:** Ongoing applications twice a year and it started in Fall of 2013
- **Goal:** Reduce the Phosphorus in the water column and reduce algae blooms in the lake
- **Results:** Dissolved Oxygen(DO) concentrations are increasing, Algae Content reducing, Lake Clarity is increasing
- **Future:** Continue treatments twice a year. Monitoring data is showing improvements to lake water quality



Stormwater Permit Status

- Santa Ana MS4 Permit – Expired January 29, 2015
(Administrative extension)
- Santa Margarita Regional Permit – Expires June 27, 2018
- Whitewater River Permit – Expires June 19, 2018

Permit Fact:

- Issued for five year terms
- Administratively extended upon expiration

New Santa Ana Region Permit on HOLD

- On HOLD due to Unfunded Mandates case in Los Angeles County
- The California Supreme Court concluded that certain provisions in 2001 LA MS4 permit were not mandated by federal law
- The Supreme Court concluded that the State has the burden to show the federal law mandates the provisions
- The state filed a petition for rehearing before the Supreme Court and Supreme Court denied the rehearing
- This means that the lower courts must reexamine the case

SMR Water Quality Improvement Plan

Final must be submitted April 2018

- Clearinghouse is available:
<http://rcflood.org/npdes/WQIP.aspx>
- Priority Water Quality Conditions; January 2017
- Development of goals, strategies, and schedules; June 2017
- Development of a monitoring and assessment program;
- Program must adjust yearly to monitoring and assessment data.

Regional Mitigation

The SMR Permit provides an option for offsite stormwater compliance if certain items are evaluated, submitted and approved by the Regional Board.

The District and WRCOG are evaluating the following:

- GIS Mapping
- Water Quality Equivalency
- Stream Stability Analysis
 - Candidate Projects
 - Fee Credit structure

July 2017 - Program feasibility determination

Questions?



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Transportation Uniform Mitigation Fee (TUMF) Program Activities Update

Contact: Christopher Gray, Director of Transportation, gray@wrcoq.coq.ca.us, (951) 955-8304

Date: January 19, 2017

The purpose of this item is to provide Committee members an update on the progress of the 2017 TUMF Nexus Study Update.

Requested Action:

1. Receive and file.
-

WRCOG's Transportation Uniform Mitigation Fee (TUMF) Program is a regional fee program designed to provide transportation and transit infrastructure that mitigates the impact of new growth in Western Riverside County. Each of WRCOG's member jurisdictions and the March JPA participates in the Program through an adopted ordinance, collects fees from new development, and remits the fees to WRCOG. WRCOG, as administrator of the TUMF Program, allocates TUMF to the Riverside County Transportation Commission (RCTC), groupings of jurisdictions – referred to as TUMF Zones – based on the amounts of fees collected in these groups, and the Riverside Transit Agency (RTA). The TUMF Nexus Study is intended to satisfy the requirements of California Government Code Chapter 5 Section 66000-66008 (also known as the California Mitigation Fee Act) which governs imposing development impact fees in California. The Study establishes a nexus or reasonable relationship between the development impact fee's use and the type of project for which the fee is required. The TUMF Program is a development impact fee and is subject to the California Mitigation Fee Act (AB 1600, Govt. Code § 6600), which mandates that a Nexus Study be prepared to demonstrate a reasonable and rational relationship between the fee and the proposed improvements for which the fee is used. AB 1600 also requires the regular review and update of the Program and Nexus Study to ensure the validity of the Program. The last TUMF Program Update was completed in October 2009.

TUMF Nexus Study Update

Staff, in coordination with TUMF consultant Parsons Brinckerhoff, is preparing the draft 2017 TUMF Nexus Study, which is expected to be released for review and comment in early February. Additionally, staff is available to meet and discuss the Nexus Study at the request of any stakeholder.

Staff will present the key components and address comments received by stakeholders regarding the Nexus study Update to the Committee. Some of items that staff will discuss include the following:

Proposed Fee Levels – With the Executive Committee taking action to delay finalizing the Nexus Study in September 2016, staff and the TUMF consultant have reviewed and updated all components of the technical document. Components of the Nexus Study that have been updated include:

- Growth Forecast – Adopted in April 2016 by the SCAG Regional Council, the updated demographic data show that the subregion will add more than 650,000 people, 250,000 households and 400,000 jobs

- TUMF Network – WRCOG and member jurisdictions undertook a comprehensive review of the facilities included in the TUMF Program to ensure that all facilities warrant inclusion in the Program
- Fee calculation methodology – WRCOG and TUMF consultant used a Vehicle Miles Travel (VMT) approach for fee calculations of residential and non-residential land-use types. This approach has not previously been utilized in past editions of the Nexus Study
- Data sources – In response to the release of the draft Nexus Study in summer 2015, WRCOG received comments regarding the use of outdated studies for the employee to square footage conversion. Staff reviewed requested studies and included more recent data from SCAG and Riverside County.

With the exception of the retail land use fee, there are modest increases to the remaining land use types.

Land Use Type	2017 TUMF Nexus Study – Proposed Fee	% Change From Current Fee	Draft 2015 Nexus Study	% Change From Current Fee
Single-Family Residential	\$9,729	10%	\$9,826	11%
Multi-Family Residential	\$6,336	2%	\$6,399	3%
Industrial	\$1.83	6%	\$2.79	62%
Retail	\$12.71	21%	\$16.24	55%
Service	\$4.71	12%	\$6.63	58%

Phasing Options: WRCOG has convened an Ad Hoc Committee with the goal of ultimately selecting a preferred option to recommend to the WRCOG Committee structure for finalizing the Nexus Study. The Ad Hoc Committee is currently reviewing a set of phase-in options and is expected to meet later this month to make a formal recommendation on a preferred option. The options that are being reviewed by the Ad Hoc Committee include:

- Adopt Fee Schedule Per Updated Nexus Study
- 2-Year Retail Fee Freeze
- 2-Year Retail Fee Freeze plus 2-Year Single-Family Residential Phase-In

The Ad Hoc Committee may recommend other phasing options, which staff will incorporate into the recommendation.

Impact of keeping the 2009 Nexus Study: As the body that presides over the policy decisions of the Program, the Executive Committee has the authority to reject a Nexus Study update and continue operating under the 2009 Nexus Study. The effects of this decision can be widespread throughout the subregion, as many member jurisdictions will lose TUMF funding for facilities added to the TUMF Network during the update. Examples of such facilities include Franklin Street / I-15 Interchange, Cajalco Road / I-15 Interchange, Scott Road / I-215 Interchange, Limonite Avenue, Whitewood Road, and the Adams Street / SR-91 Interchange, among others. Additionally, TUMF has not been increased in over seven years, while construction costs have increased by over thirty percent.

Effect of Any Fee Increase: In spring 2016, WRCOG retained Economic and Planning Systems to conduct a comprehensive fee analysis for the jurisdictions in and around the subregion. A key finding from the study concluded that with the exception of the retail land use, fees assessed on new development in the WRCOG subregion are in line with those assessed on new development in San Bernardino County. The fee analysis determined that with the proposed increase in TUMF, the change in total development costs for all the land uses would be less than one percent.

Benefits of the TUMF Program: Since Program inception in 2003, the TUMF Program has contributed funding to the completion of eighty-seven projects. The contribution of more than \$400 million has been leveraged with various funding sources, which represent more than \$1 billion in transportation improvements. Participation in the TUMF Program by jurisdictions allows those in compliance with the Program to receive funding from Measure A.

TUMF Program Visioning Session: WRCOG is committed to regular review of the policies and procedures of the Program. As part of the visioning session, staff will provide member jurisdictions and stakeholders the opportunity for open dialogue regarding the Program. Staff will ensure to provide member jurisdictions and stakeholders a wide range of perspectives by inviting firms with expertise in fee programs. Staff continues to recommend that any Visioning Session should follow the Nexus Study to allow those recently added projects to proceed in a timely fashion.

The tentative schedule of remaining tasks for the Nexus Study is as follows:

January 2017:	TUMF Nexus Study Ad Hoc Committee begins making a formal recommendation through the WRCOG Committee structure to finalize the Nexus Study
February 2017:	WRCOG releases a draft Nexus Study for review and comment by stakeholders (the draft Nexus Study comment period will be 30 days). Subsequently, the WRCOG Committee structure reviews the draft Nexus Study and recommendation from the Ad Hoc Committee beginning with the Administration & Finance Committee
March 2017:	WRCOG responds to any comment received during the 30-day comment period of the draft Nexus Study. The WRCOG Committee structure reviews the draft Nexus Study and makes a recommendation for action by the Executive Committee
April 2017:	The Executive Committee takes action on the Nexus Study. If approved, member jurisdictions begin the process of approving TUMF Ordinances / Resolutions
July / August 2017:	Any change in fee goes into effect (depending on each member jurisdiction's approval of TUMF Ordinance / Resolutions)

Prior WRCOG Actions:

<u>January 12, 2017:</u>	The Public Works Committee received report.
<u>January 11, 2017:</u>	The Administration & Finance Committee 1) approved staff's recommendation to approve the appeal; and 2) recommended that the Executive Committee approve the appeal consistent with staff's recommendation.
<u>January 9, 2017:</u>	The Executive Committee received report.
<u>December 8, 2016:</u>	The Public Works Committee approved the revised TUMF Network for inclusion in the TUMF Nexus Study.
<u>December 5, 2016:</u>	The Executive Committee 1) authorized the Executive Director to execute a TUMF Reimbursement Agreement Amendment with the City of Moreno Valley for the Nason Street / SR-60 Interchange Project in an amount not to exceed \$11,261,500; 2) approved the TUMF Administrative Plan revision to include an additional process in which developers receive credit against TUMF obligations; 3) approved the Memorandum of Understanding between WRCOG and Riverside Transit Agency (RTA) to set forth a process for WRCOG to allocate RTA's TUMF Share to RTA.

WRCOG Fiscal Impact:

TUMF Nexus Study activities are included in the Agency's adopted Fiscal Year 2016/2017 Budget under the Transportation Department.

Attachment:

None.

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Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Community Choice Aggregation Program Activities Update

Contact: Barbara Spoonhour, Director of Energy and Environmental Programs,
spoonhour@wrcog.coq.ca.us, (951) 955-8313

Date: January 19, 2017

The purpose of this item is to provide the Committee with an update on WRCOG's efforts to examine the feasibility of a Community Choice Aggregation Program for either the subregion, Riverside County, or two Counties (Riverside and San Bernardino).

Requested Action:

1. Recommend that the Executive Committee receive the final draft Inland Choice Power Community Choice Aggregation Business Plan.

Community Choice Aggregation (CCA) allows cities and counties to aggregate their buying power to secure electrical energy supply contracts on a region-wide basis. In California, CCA (Assembly Bill 117) was chaptered in September 2002 and allows for local jurisdictions to form a CCA for this purpose. Several local jurisdictions throughout California are pursuing formation of CCAs as a way to lower energy costs and/or provide "greener" energy supply. WRCOG's Executive Committee has directed staff to pursue the feasibility of Community Choice Aggregation for Western Riverside County. WRCOG, the San Bernardino Associated Governments, now known as San Bernardino Council of Governments (SBCOG) and Coachella Valley Association of Governments (CVAG) have funded a joint, two-county feasibility study in response to the Executive Committee's direction; the study has recently been completed.

CCA Activities Update

In January 2016, staff received direction from the Executive Committee to pursue a Feasibility Study for the potential formation of a CCA Program. To achieve economies of scale and resource efficiencies, San Bernardino Associated Governments, now known as San Bernardino Council of Governments (SBCOG) and the Coachella Valley Association of Governments (CVAG) joined WRCOG's effort to have a multi-county study completed. To complete the Feasibility Study, WRCOG entered into an agreement with BKi.

On October 3, 2016, the Executive Committee directed staff to move forward with the development of a CCA Program and to return with recommendations from the Administration & Finance Committee on governance and operational structures.

On January 11, 2017, the Administration & Finance Committee recommended that the Executive Committee finalize the 4th and final Draft Feasibility Study (Attachment 1) and to authorize staff to release a Request for Proposal (RFP) for CCA services.

The Study outlines the preliminary data and key findings regarding the feasibility of a CCA for the two-county region, including data and findings for the WRCOG, SBCOG and CVAG subregion geographies, as well. The

Study continues to show that the feasibility of developing a CCA is favorable, even in the most conservative, “starting from the ground-up” terms (i.e., hiring staff, leasing office space, buying office equipment, etc.).

The Study concludes that the formation of Inland Choice Power (ICP) in the service areas of CVAG, SBCOG and WRCOG is financially prudent and will yield considerable benefits for ICP's residents and businesses. These benefits include at least a 3.8 percent lower rate for electricity (assuming the 50 percent renewable scenario) than is charged by SCE while receiving nearly twice the amount of renewable energy than is currently provided. With the achievement of Phase 2 level of operations, and all customers in WRCOG, CVAG, and SBCOG deemed eligible to participate, ICP would reduce greenhouse gas emissions by as much as 2.34 million metric tons of CO₂e per year, add over 500 jobs, generate over \$54 million in additional gross domestic product, and give residents and businesses local control over their power supply and energy efficiency programs. Even with these stated rate savings, significant funding is still generated to support new programs, local energy projects, and/or additional rate savings to the CCA's customers.

There are manageable risks associated with development of a CCA. On balance, the formation of a CCA for CVAG, SBCOG, and WRCOG is financially feasible and results in beneficial environmental / economic impacts. A joint CCA with common back office functions and local options for program development is the most economical operational option and is recommended by the consultants; however, staff will continue to examine all the models to determine which is best for this subregion. Also, the consultants recommend a more “hands on” operating model, and staff will continue to examine all cost effective measures.

Some highlights from the report include:

Consumer cost savings: The combined savings (taking into account the generation savings with the SCE distribution cost assumptions) are:

- 4.9% savings with a 33% renewable
- 3.8% savings with a 50% renewable (11.2% lower than SCE's 50% Green Rate)
- 5.7% higher with a 100% renewable (9.4% lower than SCE's 100% Green Rate)

Implementation / start-up costs: The Study examines implementation of a CCA from ground zero and uses very conservative numbers to determine whether or not a CCA is feasible. In looking at the two counties joining together, a number of the implementation / start-up costs would be reduced compared to CCAs operating with smaller geographic bases.

Exhibit 23			
Start-Up Costs Summarized by Phase (ICP)			
	Total 2017 Pre-Start Costs	Phase 1 July – December 2017	Phase 2 CY 2018
Start-Up Costs			
Infrastructure	\$90,000	\$260,000	\$350,000
Consultants (incl. Data Manager)	\$620,000	\$1,471,529	\$15,724,632
Staffing	\$90,000	\$970,000	\$2,488,333
Utility Trans. Fee	\$250,165	\$3,574,050	\$8,197,628
Total Start-Up	\$1,050,165	\$6,275,579	\$26,760,549

However, if 3 CCAs were formed (one for each of the subregions), there would still be savings, due to the fact that a number of the start-up costs would not be needed or would be reduced (i.e., infrastructure and staffing, etc.).

Exhibit 36
Start-Up Costs for Three CCAs Summarized by Phase

	CVAG	CVAG	SANBAG	SANBAG	WRCOG	WRCOG
	2017	2018	2017	2018	2017	2018
Start-Up Costs						
Infrastructure	\$240,000	\$350,000	\$350,000	\$350,000	\$240,000	\$420,000
Consultants	\$1,226,215	\$2,398,639	\$1,792,679	\$9,074,423	\$1,552,634	\$6,331,569
Staffing	\$400,000	\$1,190,000	\$1,060,000	\$2,488,333	\$400,000	\$1,704,167
Utility Trans. Fee	\$453,211	\$918,803	\$2,088,921	\$4,405,258	\$1,297,475	\$2,873,783
Total Start-Up	\$2,319,426	\$4,857,442	\$5,291,600	\$16,318,014	\$3,490,109	\$11,329,519

Economic Development Impacts: The Study outlines enhanced local economic development with the formation of a CCA. The analyses contained in this Study focused primarily on the direct effects of this formation. However, in addition to direct effects, indirect economic effects are also encountered. The indirect effects of creating a CCA include the effects of increased local investments, increased disposable income due to bill savings, and improved environmental and health conditions.

In total, approximately 547 jobs are projected to be created in the TRICOG region. The TRICOG region is also projected to have a labor income impact of over \$24.0 million, a total value added impact of approximately \$37.2 million, and an output impact over \$54.9 million.

SCE Rates and Surcharges: The base case forecast of SCE rates assumes delivery rates increase at 2 percent per year and generation rates increase approximately 2.0 percent based on the projected market prices and renewable resource growth rates. Additionally, SCE's generation cost was modeled in the high and low case by incorporating the expected range of market and renewable resource costs.

The level of the Power Cost Indifference Adjustment (PCIA), or Exit Fee, will impact the cost competitiveness of a CCA. In order to be cost-effective, CCA power supply costs plus PCIA and other surcharges must be lower than SCE's generation rates. Over time, the PCIA will vary, but it is expected that it will decline as market prices increase. The PCIA reflects SCE's own resources and signed contracts. Once the contracts expire, the related PCIA will disappear. Sensitivity to the PCIA has been modeled in the high case by assuming the PCIA would increase to reflect a historic high of 2.5 cents per kWh and remain flat for the 20-year analysis period. For the low case, it was assumed that the PCIA decreases by 50 percent in year one and remains flat for the 20-year analysis period.

Governance structures: One of the next steps in the implementation of a CCA will be to examine and ultimately recommend a governance structure. WRCOG has outlined seven different scenarios and is in the process of further examining and hopes to return to the Committee with a recommendation at its February 2017 meeting.

The following outlines the various governance structures for the creation of a CCA. Once the governance structure has been determined, the development of the operational structure would then be decided. The operational structure will be largely based on the extent to which the Governing Board of a CCA desires to have CCA functions performed in house or are outsourced. Staff is developing a RFP in order to solicit bids from the private sector on the costs of an outsourced model to help inform this analysis.

- **Two County Scenario**

This option will examine **jurisdictions within Riverside and San Bernardino Counties** moving forward with a single, two-county CCA.

A JPA would need to be formed. According to WRCOG's legal counsel's review, a county providing a regional service can do so through a cooperative agreement with city partners and/or through an enterprise fund without establishing a JPA. In the case of CCAs, however, the statutory authority specifically defines

the composition of an aggregator such that a county cannot provide CCA to incorporated area residents absent a JPA. PUC 331.1(a)-(b) and 366.2(c)(12)(A)-(B) define a community choice aggregator and specify CCA program requirements. An entity can elect to implement a CCA program within its jurisdiction, or two or more entities may elect to combine their loads through a joint powers agency.

PUC 331.1 was amended in 2011 by SB 790 (Leno) to add subsection (c), which expanded the entities that are permitted to undertake CCA. PUC 331.1(c) authorizes two non-JPAs, the Kings River Conservation District and Sonoma County Water Agency, and any California public agency possessing statutory authority to generate and deliver electricity at retail within its service territory to combine the loads of cities and counties within, or contiguous to, its jurisdiction that have elected to be served by the CCA.

In other words, a county would either need to have special legislation authorizing it to provide CCA in incorporated areas or it would need to be a public owned electric utility where “city customers” have opted into the program.

Scenario 1: Formation of a new JPA between Riverside and San Bernardino counties that has incorporated jurisdictions participating, and all operations would be performed by the JPA. Decisions on Board representation would be determined through the development of the JPA.

Scenario 2: Formation of a new JPA, where one of the 3 COGs (WRCOG, SBCOG, or CVAG) or perhaps one or more of the jurisdictions takes the lead on the operational functions of the CCA and allows member jurisdictions from both counties to participate. Decisions on Board representation would be determined through the development of the JPA.

- **One County Scenario**

This option examines jurisdictions within Riverside or San Bernardino Counties moving forward with the formation of a separate CCA for each County.

- **A JPA would need to be formed (see discussion above)**

Scenario 3: Formation of a new JPA between jurisdictions within Riverside or San Bernardino counties that has all operations performed by the JPA. Decisions on Board representation would be determined through the development of the JPA.

- **Individual COG Regions Scenario**

This option examines that each of the COG regions would form and operate its own CCA. Scenarios include new JPA utilizing existing COG resources, a new JPA completely separate from the COGs, or amendments to existing JPAs to be made to allow the creation of the CCA.

For WRCOG, this would mean the following:

Scenario 4: WRCOG could amend its existing JPA to form a CCA for participating member jurisdictions. Member jurisdictions that wish to participate would need to take City Council or Board action to be included in the CCA. Those jurisdictions that elect not to participate or already have their own municipal utilities would not have input or representation on CCA activities. This is similar to the Transportation Uniform Mitigation Fee (TUMF) Program, where specific members on WRCOG do not vote on TUMF items.

Scenario 5: WRCOG would form a new JPA, separate from WRCOG but would utilize WRCOG's staffing and resources for the operations. This is similar to the Riverside County Habitat Conservation Authority (RCHCA), which operates under its own JPA but for which WRCOG administers the Program through a separate agreement with the RCHCA. Again, member jurisdictions that wish to participate would need to take City Council action to be included in the CCA.

Scenario 6: Formation of a new JPA, completely separate from WRCOG that would be formed to provide service to the Western Riverside subregion.

- **Individual jurisdiction Scenario**

This option is where a single jurisdiction establishes and administers its own CCA.

Scenario 7: Individual jurisdictions would create a CCA and operate under the jurisdiction.

Operational structures: The operational structures examine hiring new staff, hiring a mix of staff and consultants, or hiring one third party to implement the CCA on behalf of the JPA. The Study uses the fully staffing method in its calculations to show that the implementation is feasible. Any cost savings would be passed onto the consumer.

To adequately address the issues regarding hiring a third party entity or to hire staff with consultants to assist with the administration of the CCA, WRCOG will be releasing a RFP in late January 2017 or early February 2017 in order to gain information from the private sector on the costs of a fully outsourced CCA at the geographies mentioned above

Next Steps: In addition to identifying governance structures, there are other steps that need to be developed in moving forward:

January 2017:	Vet business plan and finalize
March 2017:	Determine governance preference
February 2017:	Release RFP for CCA implementation assistance
April 2017:	Select power supply and data management vendor
May 2017:	Adopt Resolution of Intent and File Implementation Plan with CPUC
May 2017:	File Notice of Intent with SCE
June/July 2017:	Arrange financing of start-up costs
May / November 2017:	SCE data testing
September / October 2017:	Opt-out notice – 1 and 2
November 2017:	Launch phase 1
November 2017:	Opt-out notices – 3 and 4

Prior WRCOG Action:

January 11, 2017: The Administration & Finance Committee 1) recommended that the Executive Committee receive the final draft Inland Choice Power Community Choice Aggregation Business Plan; and 2) directed the Executive Director to issue a Request for Proposals (RFP) for CCA contract services.

WRCOG Fiscal Impact:

WRCOG's portion for Phase 1 is estimated to be \$130,000 to cover the costs of the CCA Feasibility Study, SCE data request, and WRCOG staffing. The costs for this will come from existing carryover funds and will be reflected in an upcoming Quarterly Budget Amendment.

Attachment:

1. Inland Choice Power Community Choice Aggregation Business Plan – Final Draft – December 8, 2016.

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Item 6.D

Community Choice Aggregation Program Activities Update

Attachment 1

Inland Choice Power Community Choice Aggregation Business Plan – Final Draft – December 8, 2016

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FINAL DRAFT

Inland Choice Power Community Choice Aggregation Business Plan

December 8, 2016

Prepared by:



A registered professional engineering and management consulting firm with
offices in Kirkland, WA and Portland, OR

www.eesconsulting.com

570 Kirkland Way, Suite 100
Kirkland, WA 98033
Telephone: (425) 889-2700

In conjunction with

Bevilacqua-Knight, Inc. (BK_i)

www.bki.com

800 West Sixth Street, Suite 1250
Los Angeles, CA 90017
Telephone: (213) 213-1960



December 8, 2016

Ms. Katie Barrows
CVAG
73-710 Fred Waring Drive
Suite 200
Palm Desert, CA 92260

Mr. Duane Baker
SANBAG
1170 W. 3rd Street
2nd Floor
San Bernardino, CA 92410

Ms. Barbara Spoonhour
WRCOG
4080 Lemon Street
3rd Floor, MS 1032
Riverside, CA 92501

SUBJECT: Inland Choice Power Community Choice Aggregation Business Plan

Dear Ladies and Gentleman:

Please find attached EES Consulting, Inc.'s (EES) Final Draft Community Choice Aggregation (CCA) Business Plan (Plan) for Inland Choice Power (ICP). This Plan represents our work product in evaluating the prudence of implementing a CCA organization for Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG) and Western Riverside Council of Governments (WRCOG).

We want to thank you and your staff for your assistance in preparing this Plan. It has been a pleasure working with all of you on this project.

Please contact us directly if you have questions or if we may be of any further assistance. We will finalize this Plan after it has been reviewed and critiqued by all stakeholders, and meets with your final approval.

Very truly yours,

Gary Saleba
President/CEO

570 Kirkland Way, Suite 100
Kirkland, Washington 98033

Telephone: 425 889-2700 Facsimile: 425 889-2725

A registered professional engineering corporation with offices in Kirkland, WA and Portland, OR

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Executive Summary

Background

The California legislature passed AB 117 in 2002 (amended in 2011 by SB 790) allowing all cities, counties, or groups of cities and counties to provide an electric power supply source to customers within their jurisdictions that are currently served by Southern California Edison, Pacific Gas & Electric or San Diego Gas & Electric (collectively the IOUs). Community Choice Aggregation (CCA) or Community Choice Energy (CCE) is a customer opt-out program where the CCA provides power supply and behind the meter services¹, and the incumbent IOUs provide transmission and distribution (wires) service.

This Business Plan (Plan) evaluates the prudence of forming a CCA within three government associations or geographical areas: Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG) and Western Riverside Council of Governments (WRCOG). Collectively, this CCA is referred to in this Plan as Inland Choice Power (ICP). The proposed CCA will provide power supply and behind the meter services, while Southern California Edison (SCE) will continue to provide transmission and distribution services. Customers will be part of the ICP program until they proactively opt-out.

This Plan estimates ICP's power supply costs, administrative costs, electric loads, and future retail rates and compares ICP's rates to the incumbent SCE rates. These forecast rates are compared to determine if a CCA can offer competitive rates, better products and/or superior customer service while also improving the environment and creating local jobs.

Business Plan Goal

The goal of the Business Plan is to use conservative numbers and analysis to show the feasibility of establishing a CCA in the geographical region(s) and to build the framework for the completion of an Implementation Plan that would need to be submitted to the California Public Utilities Commission (CPUC). Conservative assumptions are used throughout this Plan to ensure policymakers make sound policy decisions based on sound financial analysis.

Description of ICP

The Plan and structure of ICP are currently being analyzed by CVAG, SANBAG and WRCOG collectively. CVAG is the regional planning agency coordinating government services in the Coachella Valley, and has 10 cities, Riverside County, the Agua Caliente Band of Cahuilla Indians and the Cabazon Band of Mission Indians as members. SANBAG is the council of governments and transportation planning agency for San Bernardino County. SANBAG's members include 24

¹ For example, energy efficiency programs, net energy metering or other programs that promote the deployment of distributed energy resources.

cities and San Bernardino County. WRCOG's purpose is to unify Western Riverside County so that it can speak with a collective voice on important issues that affect its members and it consists of 17 cities, Riverside County Board of Supervisors, the Eastern and Western Municipal Water Districts, and the Morongo Band of Mission Indians. The geographic area and customer base covered by CVAG, SANBAG and WRCOG are collectively called Inland Choice Power.

Various organizational scenarios are explored in this Plan. For the Plan's "base case," results are provided assuming one organization or agency will operate a CCA for all three entities. This scenario is referred to as the "ICP" scenario and is the basis for the financial analysis throughout the Plan. This base case explores the prudence of full participation of all three COGs as one operating CCA. In addition, results are provided assuming three separate CCA's will be formed. This scenario is referred to in the Plan as the "Three CCA" scenario. The results for the individual COG's CCA option are analyzed starting at page 51 of this Plan and provide insight into CCA operations if not all jurisdictions participate. It is anticipated that the results of this Plan are scalable.

For this Plan, it is assumed that service will be offered to customers in two phases. Phase 1 will include the ICP members' municipal facilities in addition to 5 percent of non-municipal commercial facilities. In Phase 2, all customers located in the service area of ICP will be included in ICP. Exhibit ES-1 summarizes this phased approach to forming ICP, including the number of customers and load attendant with each phase. ICP's total loads will represent roughly 30 percent of SCE's total current electrical loads. The assumed start date is an aggressive estimate but is used throughout the Business Plan to retain consistency in the calculations.

Exhibit ES-1 CCA Load, Customers, and Revenue by Phase in 2017*						
Phase	Assumed Start	Eligibility	Customer Accounts	Peak Load*** (MW)	Average Load*** (aMW)	ICP Annual Revenues (50% RPS)
ICP						
Phase 1**	July, 2017	Municipal + 5% Commercial	69,669	73	49	\$24 million
Phase 2	January 2018	All Customers	961,139	3,951	1,720	\$963 Million
CVAG						
Phase 1**	July, 2017	Municipal + 5% Commercial	10,116	7	6	\$3.2 Million
Phase 2	January 2018	All Customers	108,594	517	209	\$125 Million
SANBAG						
Phase 1**	July, 2017	Municipal + 5% Commercial	41,208	44	29	\$13.8 Million
Phase 2	January 2018	All Customers	517,717	2,126	955	\$535 Million
WRCOG						
Phase 1**	July, 2017	Municipal + 5% Commercial	18,346	22	14	\$7.0 Million
Phase 2	January 2018	All Customers	334,828	1,343	555	\$321 Million

* Estimates assume a 75% participation rate for residential customers, and a 65% participation rate for non-residential customers.

** Phase 1 is assumed to run July – December of 2017. Therefore, load and revenue for this phase is estimated annual.

*** Loads are expressed as wholesale, including losses of 6%.

This phasing strategy enables ICP to manage any start-up and operational issues before full scale operations are undertaken. In addition, this phasing strategy will allow ICP's third party electricity suppliers, scheduling agents and data management entities to ramp up power supply procurement and bill processing over several months.

This Business Plan was started with the assumption that all member cities of the three COGs as well as both counties' unincorporated areas would participate. Consequently, the electric load forecast for the ICP service area includes the load of the unincorporated Counties of Riverside and San Bernardino. During preparation of the Plan, Riverside County opted to move forward with preparation of its own CCA Implementation Plan, separate from the ICP effort. Appendix C provides the results for feasibility of ICP if the County of Riverside unincorporated area loads are not included in this Plan's load projections.

Governance Structure Options

This Business Plan examines two governance structures. The governance structures differ from the operational structures. The governance structure determines what entity would be responsible for policy direction operations of the CCA and ongoing reporting requirements. These governance structure options include:

1. **Single Jurisdiction Model:** A jurisdiction individually establishes and operates a CCA and therefore makes all policy decisions on revenues, power mix, and programs. Any risk and liability associated with the CCA fall solely on this single jurisdiction. In this model, it is recommended that the jurisdiction develop contractual language to minimize risk to the general fund, maintain adequate operating reserves, and proactively track regulatory activities and manage its energy portfolio. Lancaster Choice Energy and CleanPowerSF are examples of single jurisdiction governance models.
2. **Joint Powers Authority (JPA) Model:** The JPA functions as an independent public agency, operating on behalf of its member jurisdictions with shared decision-making authority. This shared structure distributes the risks and liability across multiple jurisdictions, and minimizes risk to its member jurisdictions. Marin Clean Energy, Sonoma Clean Power, and Peninsula Clean Energy are examples of CCAs using the JPA model.

Within each of these governance structure options, there are several scenarios that can be utilized. Given that CVAG, SANBAG, and WRCOG are already each a JPA, it is anticipated that a JPA will be the governing model for the ICP. In the event that ICP forms as three separate CCAs, the existing JPAs of CVAG, SANBAG, and WRCOG may need to be amended to allow for the implementation of a CCA. Alternatively, if ICP elects to launch a single unified CCA, a new JPA could be formed or one of the existing JPAs could be amended to allow other agencies to join for the purposes of implementing the ICP. The governance of a JPA anticipates that a governing board (Board) of elected officials will set policies and procedures for an Executive Director, who will be entrusted to manage the day-to-day operations of the CCA.

Operational Structure Options

Operation of the CCA will involve a range of day-to-day functions including:

- Marketing and outreach
- Power supply contracts and scheduling
- Billing and data transfer with the IOU
- Regulatory compliance with the California Public Utility Commission (CPUC)
- Monitoring regulatory and legislative energy policy relevant to CCA competitiveness

These functions can be fulfilled by internal staff, external consultants, or a mix thereof. The choice of how to allocate these functions between internal and external resources will be at the discretion of the governing Board of the CCA.

For start-up, the Plan assumes that regardless of whether a single jurisdiction or a joint JPA is formed as the CCA's governance structure, an operating team will be employed consisting of an Interim Executive Director, per the example of other CCAs in California plus a few other CCA technical staff. This operating team can either be built by using existing staff or hiring new staff. This team would then be supported by outside consultants to assist with the management of the CCA, until Phase 2 is implemented.

For the longer term and into Phase 2 launch, ICP has three options for staffing after the initial start-up. The first option involves hiring internal staff incrementally to match workloads involved in forming ICP, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario). In option two, the CCA would hire just a few staff internally and contract out the remaining work to consultants (Minimum Staff Scenario). In the third option, ICP would contract with one or more third-parties to complete all the operational aspects of the CCA. Throughout the rest of this Plan, it is assumed that ICP will transition to the Full Staff Scenario. This scenario represents the highest cost scenario so as to maintain a conservative posture for the Plan's financial proformas. Less costly options may be available to the CCA based on subsequent request for proposals to evaluate other staffing options.

It should be noted that the existing California CCAs have opted for an organizational structure that features a significant number of internal staff as opposed to using all consultants to operate their CCA. There are many reasons for this type of operational structure but two primary reasons are:

- The size of the CCA is such that in most cases it is the largest enterprise found among the CCA participants.
- This CCA will have direct contact with most of the governing body's constituents at least once a month through the CCA billing process.

Because of these noteworthy observations, existing CCAs have adopted more of a "hands on" organizational structure, but the preferred operational mode for a new CCA is ultimately dictated by the Board.

Plan Uncertainties/Risks

The results of this Plan are subject to uncertainties. These uncertainties are evaluated in the Plan's sensitivity analysis section. The list below provides a summary discussion of the key uncertainties associated with this Plan.

- **Market Price Forecasts** – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this Plan are based on the best currently available information regarding future natural gas and electricity prices, and have been confirmed by recent wholesale power transactions in southern California. These types of forecasts vary over time. Thus, a range of market price forecasts are evaluated in the Plan's sensitivity analysis.
- **Retail Rate Forecasts** – The Plan forecasts both ICP and SCE retail rates. These forecasts are based on current information regarding inflation and other cost drivers. Unexpected impacts on rates are discussed in more detail in the Plan's sensitivity analysis.
- **Forecasted Load and Customer Growth** – The Plan bases the load forecasts on customer growth assumptions. Each of these forecasts includes a level of uncertainty. To illustrate the impacts of load uncertainty, low, medium, and high load forecasts are analyzed in the Plan's sensitivity analysis.
- **Regulatory Risks** – Unforeseen changes in legislation (California Public Utility Commission, State legislation and Federal legislation) may impact the results of this Plan. Sensitivities on these risks are also provided.

This sensitivity analysis shows that the ICP rates could be greater than SCE rates if:

- The Power Charge Indifference Adjustment (PCIA) becomes much larger. The PCIA is a charge assessed by the IOU to cover generation costs acquired prior to CCA formation, sometimes referred to as stranded costs,
- ICP loads are much less than forecast, and
- Wholesale market prices drop much lower than current rates after ICP enters power contracts, allowing SCE a temporary advantage on generation rates.

Each of these three scenarios has a low probability of actually occurring. For example, wholesale market prices for natural gas and electricity are at all-time lows. The probability of any significantly further lowering of these prices is judged to be very small. The PCIA level should be fairly stable going forward as regulatory remedies are in play to stabilize the CCA and because the CCA community has become very vigilant in this area. Finally, this Plan assumes a relatively low customer participation rate of 75 percent for residential customers and 65 percent for non-residential customers, compared to the roughly 95 percent to 85 percent participation rates seen in California's currently operating CCAs. It is very unlikely ICP loads will not meet or exceed those assumed in the Plan. Thus, the major risks of forming a CCA are manageable and small.

Retail Rate Construct

This Plan evaluates the costs and resulting rates of operating ICP, and compares these rates to a comparable rate forecast for SCE. The analysis begins with a forecast of electrical loads and customers, incorporates several power supply resource portfolio options, and allows for the sensitivity or stress testing of input assumptions. ICP customers will see no obvious changes in electric service other than lower prices and potential increases in renewable resources in their power supply resource mix. Customers will pay the power supply charges set by ICP and no longer pay the costs of SCE power supply.

ICP's power supply rate consists of power supply costs, ICP start-up costs, ICP staffing and operating costs, consulting support, SCE billing and regulatory charges, financing costs, reserves and SCE pass-through charges, such as the Power Cost Indifference Adjustment (PCIA) Charge, franchise charges, and other non-bypassable charges from SCE.

In addition to paying ICP's power supply rate, ICP customers will pay the SCE delivery (wires) rate and all other non-power supply related charges on the SCE bill including the Utility User Taxes.

ICP will establish rates sufficient to recover all costs related to operation of the CCA. It is anticipated that ICP's rate designs initially will mirror the structure of SCE's rates with an appropriate discount so that rates similar to SCE's can be provided to ICP's customers. In setting rates, the Plan's financial analysis assumes the customer phase-in schedule noted above and assumes that the implementation costs are largely financed via a start-up loan.

The information above is used to determine the retail rates for ICP. ICP rates are then compared to the SCE projected rates for ICP service area.

Generation Municipal Surcharge (or Franchise Fee)

The franchise fee is a surcharge that SCE pays cities and counties for the right to use public streets to provide utility services. Under CCA operations, SCE will continue to collect the franchise fees for both generation and distribution services and pay the cities and counties the owed revenue. The franchise fee is not forecast to change during the analysis horizon, and will remain consistent with current franchise fee payments from SCE.

Retail Rate Forecast of SCE versus ICP

The first benefit for forming ICP is the retail rate impact as illustrated on Exhibit ES-2. For this Plan, it has been assumed that the projected rate decrease is applied uniformly across all rate classes. Once established, it will be up to the ICP Board and staff to develop rates for each rate class that reflect cost of service. Exhibit ES-2 compares SCE's current total bundled rates based on the current Renewables Portfolio Standard (RPS), SCE's 50% Green Rate and 100% Green Rate compared to three comparable ICP rate options.

For reference, the column headers noted on ES-2 are summarized below.

- RPS Bundled – ICP rates with the same share (currently 28 percent) of renewables as SCE’s current power supply.
- 50% Green Bundled Rate – ICP rates with 50 percent renewable power.
- 100% Green Bundled Rates – ICP rates with 100 percent renewable power.

A rate schedule comparison of ICP’s rates and SCE’s rates follows.

Exhibit ES-2 Indicative Rate Comparison in ¢/kWh (First Full Year of Service)							
Rate Class	Customer Type	2017 Estimated SCE Bundled Rate*	ICP RPS Bundled Rate	SCE 50% Green Bundled Rate	ICP 50% Green Bundled Rate	SCE 100% Green Bundled Rate	ICP 100% Green Bundled Rate
Residential	Domestic	20.55	19.58	22.30	19.81	24.05	21.79
Residential Care	Domestic	12.22	11.64	13.97	11.78	15.72	12.96
GS-1	Commercial	17.03	16.23	18.78	16.41	20.53	18.06
GS-2	Commercial	16.57	15.79	18.32	15.97	20.07	17.57
GS-3	Industrial	14.71	14.02	16.46	14.18	18.21	15.60
PA-2	Public Authority	13.08	12.46	14.83	12.61	16.58	13.87
PA-3	Public Authority	11.31	10.78	13.06	10.90	14.81	11.99
TOU-8 Secondary	Domestic	13.07	12.45	14.82	12.60	16.57	13.86
TOU-8 Primary	Commercial	11.84	11.28	13.59	11.41	15.34	12.55
TOU-8 Substation	Industrial	7.76	7.39	9.51	7.48	11.26	8.23
Initial Total ICP Rate Savings over Comparable SCE Rates of 50% or 100% Green			4.9%		11.2%		9.4%
Initial Total ICP Rate Savings over SCE’s Standard Bundled Rate			4.9%		3.8%		-5.7%

*SCE bundled average rate based on SCE’s ERRA 2017 Draft Filing

Appendix B contains the proformas to support Exhibit ES-2.

Exhibit ES-2 shows the initial rate savings associated with the formation of a CCA. By referencing Appendix B, these initial savings increase after ICP becomes fully functional. The savings by rate schedule after ICP is fully functional are presented below in Exhibit ES-3.

Exhibit ES-3 CCA Rate Savings at Fully Functional Operations	
Power Supply Scenario	Range of Savings*
ICP 28% Renewable (RPS)	4.9% - 5.7%
ICP 50% Renewable	3.8% - 4.5%
ICP 100% Renewable	(5.7%) – (5.0%)

*Note Appendix B for detail.

The difference between the ICP bundled rate for residential consumers of 19.58¢/kWh and the ICP 50 percent renewable rate forecast of 19.81¢/kWh is close enough that the base case rate for this Plan is the ICP 50 percent renewable rate forecast. The difference in retail rates between the ICP RPS and the 50 percent green rate forecast is de minimis, and there are additional greenhouse gas (GHG) and economic development benefits associated with the 50 percent green power option being the Plan's base case; however, the final decision of the base case rate scenario for ICP will ultimately rest with ICP's Board. The 50 percent green baseline portfolio results initially in a savings over SCE's RPS rate of 3.8 percent.

It should be noted that the rate savings noted in ES-2 still allow the accumulation of significant reserves for ICP. As illustrated in Appendix B, the proformas include a line item called "Contribution to Annual Reserves" that go towards funding the needed cash working capital (approximately \$284M). After the target reserves have been met, additional reserves can be used to further lower CCA retail rates for consumers, invest in local renewable projects, provide additional energy efficiency programs, and/or any other CCA-related activity as directed by the CCA's Board. The projected funds available for this purpose are provided in the line item titled "New Programs" in the proforma. The accumulate reserves and new program accruals present the new CCA with a large amount of funding and numerous opportunities going forward.

Exhibit ES-4 highlights how much financial reserves are generated with the rate reductions noted above.

Exhibit ES-4 Accumulative Fund Balances for Financial Reserves and New Programs Under the 50% Renewable			
Year	Accumulative Financial Reserve Funds (\$ x 1000)	Accumulative New Project Funds (\$ x 1000)	Total Financial Reserves (\$ x 1,000)
2018	\$63,330	\$0	\$63,330
2019	\$130,225	\$0	\$130,225
2020	\$213,504	\$0	\$213,504
2021	\$259,527	\$46,022	\$305,549
2022	\$259,527	\$147,956	\$407,483
2023	\$259,527	\$262,232	\$521,759
2024	\$259,527	\$384,563	\$644,090
2025	\$259,527	\$515,637	\$775,164
2026	\$259,527	\$653,238	\$912,765
2027	\$259,527	\$796,925	\$1,056,452
2028	\$259,527	\$946,175	\$1,205,702
2029	\$259,527	\$1,101,642	\$1,361,169
2030	\$259,527	\$1,254,153	\$1,513,680

These new project and financial reserve fund balances can be used for CCA-related activities as directed by the Board. These fund balances can also be used for rate reductions larger than assumed in the Plan's base case, additional energy efficiency programs, development of load renewable projects and/or special rate programs.

Compliance with SCE and CPUC

ICP will be required to observe certain regulatory and operational obligations with the California Public Utilities Commission (CPUC) and with SCE. During the formation and launch of ICP, these obligations will include submitting an Implementation Plan, submitting a surety bond, and registering as a CCA all with the CPUC. Also during this phase, ICP will establish its credit-worthiness, test electronic data exchange, and negotiate a start-of-service date with SCE. After launching operations, ICP will prepare integrated resource plans (IRPs) and demonstrate compliance with renewable portfolio standards to the CPUC. The CPUC will have no control over the rates charged by the CCA or its various program offerings.

Renewable Energy Impacts

A second benefit of forming ICP is the potential for an increase in the energy supplied by renewable resources. The majority of this renewable energy will be met by renewable energy contracts or newly constructed renewable resources. By 2020, SCE must procure a minimum of 33 percent of its customers' annual electricity usage from renewable resources due to the State's Renewables Portfolio Standard (RPS) mandate and the Energy Action Plan requirements of the California Public Utilities Commission (CPUC). In contrast, ICP customers will procure at least 50 percent renewable power from day one of ICP's operation under the Plan's base case which will come from new and/or local renewable resources, thus significantly increasing the amount of renewable energy used by CCA customers.

Energy Efficiency Programs

A third benefit of the Plan is a potential increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by SCE will not change as a result of forming ICP. ICP customers will continue to pay the Public Goods Charges to SCE which funds energy efficiency programs for all customers, regardless of power supply provider. The energy efficiency programs ultimately planned by ICP will be in addition to the level of energy efficiency investment currently provided by SCE. Thus, ICP has the potential to increase energy savings with an attendant reduction in greenhouse gas (GHG) emissions due to expanded energy efficiency programs.

Economic Development

The fourth benefit of ICP is increased local economic development. So far, the Plan's analysis has focused on the direct impacts of reduced rates associated with forming ICP. However, in addition to these direct effects, indirect economic effects will also be encountered. The indirect effects of creating ICP include increased local investments, in energy efficiency (EE) and distributed energy resources (DER), increased disposable income due to bill savings, and improved environmental and health conditions.

Exhibit ES-5 shows the economic impact resulting from \$100 million in electric bill savings across the ICP service area. The \$100 million rate savings represents an estimated bill savings per year

achievable by ICP once Phase 2 operations are at steady state. It is estimated that these savings will create approximately 547 additional jobs in the ICP region and over \$24.0 million in labor income. It is also projected that the total value added (revenues less cost of inputs) will be approximately \$37.2 million and the total additional revenues and sales in the economy (output) is estimated to be over \$54.9 million.

Exhibit ES-5 \$100 Million Rate Savings Effects on ICP Economy				
Impact Type	Employment	Labor Income	Total Value Added	Output
Direct Effect	388.0	\$18.2 million	\$27.7 million	\$36.5 million
Indirect Effect ²	60.3	\$2.1 million	\$3.5 million	\$6.3 million
Induced Effect ³	98.3	\$3.8 million	\$7.0 million	\$12.1 million
Total Effect	546.6	\$24.1 million	\$37.2 million	\$54.9 million

In addition to increased economic activity due to electric bill savings, potential local projects can also create job and economic growth within the ICP service territory. As an example of the macroeconomic activity caused by local distributed energy resource (DER) deployment, this Plan analyzes the installation of 50 crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. Overall, the building of a 50 MW solar project is projected to create \$87 million in earnings and \$188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing. ICP could examine installing and will likely need to install a number of larger utility scale solar projects such as the one described to meet its RPS requirements.

Greenhouse Gas Impacts

The fifth consequence of forming ICP is environmental benefits. The amount of renewable power in SCE's power supply portfolio is currently 28 percent⁴ and is scheduled to increase to 33 percent by 2020. Assuming ICP achieves a base case 50 percent RPS target at start-up, GHG emissions reductions attributable to ICP operations in 2019 will range from 1.33 to 2.34 million metric tons CO₂ equivalent (CO₂e) per year. ES-6 details these reductions.

² The Indirect effect describes the business-to-business transactions resulting from the direct effect outcomes. For example, the creation of ICP would directly create 388 additional jobs, and indirectly 60 jobs to support those 388 direct employees through increased demand for products and services in the area.

³ The Induced effect measure the effects of the changes in household income. For example, ICP will save all households and businesses in its service area on energy costs. As a result, households will have more money to spend in the local economy.

⁴ http://www.cpuc.ca.gov/RPS_Homepage/

Exhibit ES-6 Baseline Comparison of GHG Reduction by ICP in 2018				
	ICP	CVAG	SANBAG	WRCOG
Forecast Renewables (50% Renewables) ICP (GWH) – Phase 2	7,533	916	4,184	2,433
ICP RPS (GWH) – Phase 2	4,219	513	2,343	1,362
Additional Green Power	3,315	403	1,841	1,070
CO2 reduction – Low (Million Metric tons CO ₂ e)	1.33	0.16	0.74	0.43
CO2 reduction – High (Million Metric tons CO ₂ e)	2.34	0.28	1.30	0.76

The reduction in GHG emissions associated with ICP operations is significant. This amount of reduced emissions represents a reduction in the emissions from the in-State electric generation resources of 2.6 to 4.6 percent.

Summary

This Plan concludes that the formation of ICP in the service areas of CVAG, SANBAG and WRCOG is financially prudent and will yield considerable benefits for ICP's residents and businesses. These benefits include at least a 3.8 percent lower rate for electricity (assuming the 50 percent renewable scenario) than is charged by SCE while receiving nearly twice the amount of renewable energy. Rate savings increase once the ICP is fully operational to 4.5 percent. With the achievement of Phase 2 level of operations, ICP will reduce GHG emissions by as much as 2.34 million metric tons of CO₂e per year, add over 500 jobs, generate over \$54 million in additional GDP, and give residents and businesses local control over their power supply and energy efficiency/distributed energy resource programs. Even with these stated rate savings, significant funds are still generated to support new programs, local DER and/or additional rate savings to the CCA's customers.

There are risks associated with a CCA which are manageable. On balance, the formation of a CCA for CVAG, SANBAG and WRCOG is financially feasible and results in beneficial environmental/economic impacts. A joint CCA with common back office functions and local branding as opposed to three separate CCAs is the most economical operational option and is also recommended. Finally, a more "hands on" organizational structure is recommended.

Introduction

Background

California's legislature passed AB 117 in 2002 (amended in 2011 by SB 790) which allows all Cities, Counties, or groups of Cities and Counties to provide electric service to customers currently served by Investor-Owned Utilities (IOUs). Community Choice Aggregation (CCA) is the legislative organization empowered to provide this service. California CCAs are customer opt-out programs that provide power supply, data management and behind the meter services, while the incumbent IOUs continue to provide transmission and distribution (wires) service. This legislation states that CCAs will enable California to experience more competitive electricity rates, a more renewable power supply mix, and growth in local resources and associated economic activity. Currently, there are five CCAs operating in California and these utilities offer competitive rates for power supply that have a higher percentage of renewable resources. CCAs have also proven to promote local economic activity and their associated benefits. Several other California Cities and Counties are currently evaluating the feasibility of CCA formation within their jurisdictions. This information can be found in Appendix A.

There are several potential benefits of the CCA model in addition to competitive rates. Other benefits include local control over energy resources selection including renewable local projects, energy efficiency, a reduction in greenhouse gases (GHG), and more economic development. In addition, CCAs can minimize power supply rates and maximize renewable energy utilization with the attendant local jobs in the local community.

Business Plan Goal

The goal of the Business Plan (Plan) is to use conservative assumptions and analysis to show the feasibility of establishing a CCA in the geographical region(s) and to build the framework for the completion of an Implementation Plan that would need to be submitted to the CPUC by the governance structure. Conservative assumptions are used throughout the Plan to ensure prudent decisions are made by the affected policymakers.

Objective

This (Plan) evaluates the feasibility of forming a CCA within the SCE service area of Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG) and Western Riverside Council of Governments (WRCOG), collectively named Inland Choice Power (ICP). The proposed CCA will continue to provide power supply, data management and behind the meter services⁵, and Southern California Edison (SCE) will provide transmission and distribution (wires) services. This Plan estimates ICP's power supply costs, administrative costs,

⁵ For example, energy efficiency programs, net energy metering or other programs that promote the deployment of distributed energy resources.

electric loads, and future retail rates for ICP and the incumbent Investor-Owned Utility (IOU), Southern California Edison (SCE). These forecast rates are compared to determine if the proposed CCA can offer competitive rates, better products, and superior customer service. A sound financial and operational foundation for ICP must be achievable before the other desirable attributes of a CCA can be enjoyed.

Regarding the possible membership of ICP, CVAG is the regional planning agency coordinating government services in the Coachella Valley and has 10 Cities, Riverside County, the Agua Caliente Band of Cahuilla Indians and the Cabazon Band of Mission Indians as members. SANBAG is the council of government and transportation planning agency for San Bernardino County. SANBAG's members include 24 cities and San Bernardino County. WRCOG's purpose is to unify Western Riverside County so that it can speak with a collective voice on important issues that affect its members and it consists of 17 Cities, Riverside County Board of Supervisors, the Eastern and Western Municipal Water Districts, and the Morongo Band of Mission Indians. Combined, these three organizations are referred to in this Plan as ICP.

Governance Structures

Two governance scenarios (individual jurisdictional and joint powers authority models) are explored in this Plan. This provides information to each of the three COGs on the benefits and costs of implementing a CCA in their individual service area. It also provides information about the benefit and cost of different sizes of CCA load. For the base case in this Plan, results are provided assuming one organization will provide all back office functions (power supply and data management) for all three entities. This scenario is referred to as the "ICP" scenario. In addition, results will be provided assuming three separate CCA's will be implemented, which would enable greater local branding and program optionality. This scenario is referred to as the "Three CCA" scenario.

ICP Description

In 2015, before opt-outs, CVAG's average annual wholesale load is 288 aMW (average Megawatts) with a peak load of 697 MW. SANBAG's 2015 average annual wholesale load, before opt-outs, is 1,339 aMW with a peak demand of 2,950 MW, while WRCOG's 2015 average wholesale annual load before opt-outs is 765 aMW with a peak demand of 1,819 MW. Energy consumption for the entire ICP area served by SCE is equal to more than 30 percent of SCE's total retail load.

For this Plan, it is assumed that service will be offered to customers in two phases. Phase 1 assumes that municipal facilities within each COG in addition to 5 percent of each COG's commercial accounts will be included into ICP. While Phase 2 assumes all customers within ICP's service area, including unincorporated Riverside County, are included in ICP, Appendix C provides the results for ICP if the unincorporated areas within the County of Riverside are not included in the analysis. Exhibit 1 summarizes this phased approach to starting ICP and the amount of load attendant with each phase.

Exhibit 1
CCA Load, Customers, and Revenue by Phase in 2017*

Phase	Assumed Start	Eligibility	Customer Accounts	Peak Load*** (MW)	Average Load*** (aMW)	ICP Annual Revenues (50% RPS)
ICP						
Phase 1**	July, 2017	Municipal + 5% Commercial	69,669	73	49	\$24 million
Phase 2	January 2018	All Customers	961,139	3,951	1,720	\$963 Million
CVAG						
Phase 1**	July, 2017	Municipal + 5% Commercial	10,116	7	6	\$3.2 Million
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Phase 1**	July, 2017	Municipal + 5% Commercial	18,346	22	14	\$7.0 Million
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*Estimates assume a 75% participation rate for residential customers, and a 65% participation rate for non-residential customers.

**Phase 1 is assumed to run July – December of 2017. Therefore, load and revenue for this phase is estimated annual.

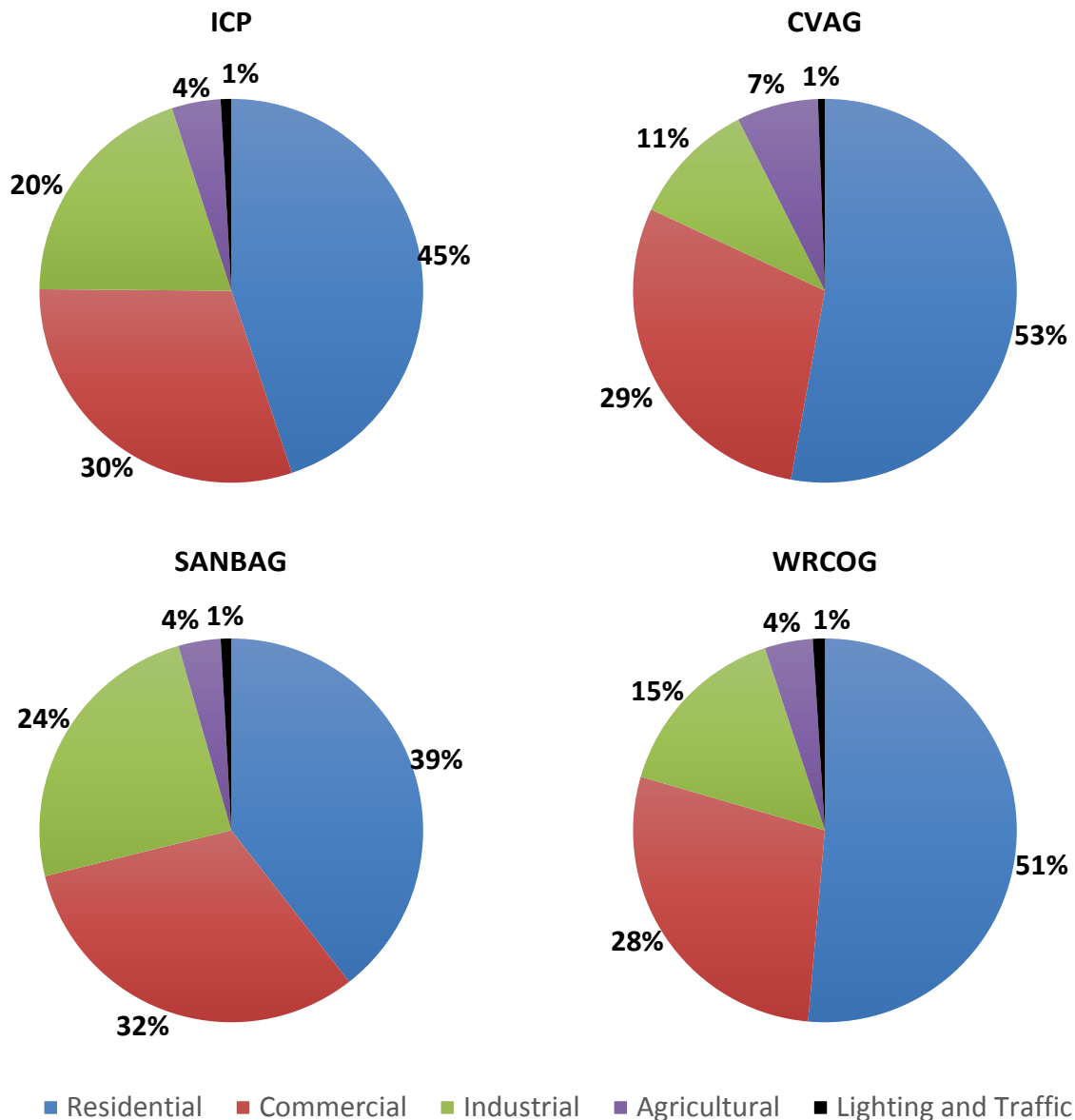
***Loads are expressed as wholesale, including losses of 6%.

Customer Participation Schedule

Because of the number of cities in ICP and the size of their associated loads, a phasing strategy is assumed for this Plan. This phasing strategy enables ICP to address any start-up and operational issues before full scale operations are undertaken. In addition, this strategy will allow ICP's outside party electricity suppliers, scheduling agents and data managers to ramp up their activities.

By 2036, ICP is projected to serve almost 1.16 million retail customers after opt-outs with annual electricity sales potential of over 17,392 GWh. Annual ICP revenues at Phase 2 build-out are projected to be \$1.5 billion. In the same period, CVAG will serve over 132,000 customers with an average annual load of 2,110 GWh and revenues of \$300 million. SANBAG will serve over 633,000 customers, a load of 9,677 GWh, and earn revenues of \$550 million. WRCOG will serve almost 410,000 customers, a load of 5,605 GWh per year, and \$330 million. The breakdown of projected sales in Phase 2 by major customer class is shown in the following Exhibit 2.

Exhibit 2
Retail Energy Share by Rate Class



Summary of ICP's Proposed Governance and Operations Options

ICP will likely be established under the terms of a Joint Powers Authority (JPA) versus an individual jurisdictional model, because of the inclusion of multiple jurisdictions into the CCA, which will promote, develop and conduct electricity-related projects and programs for ICP's residences and businesses. The JPA agreement will dictate the operational provisions of ICP.

ICP activities will be overseen by the new JPA's Board of Directors (Board). This Board will have primary responsibility for managing all aspects of ICP programs and providing policy guidance, which includes determining whether or not the ICP will be operated in-house with staff, minimal

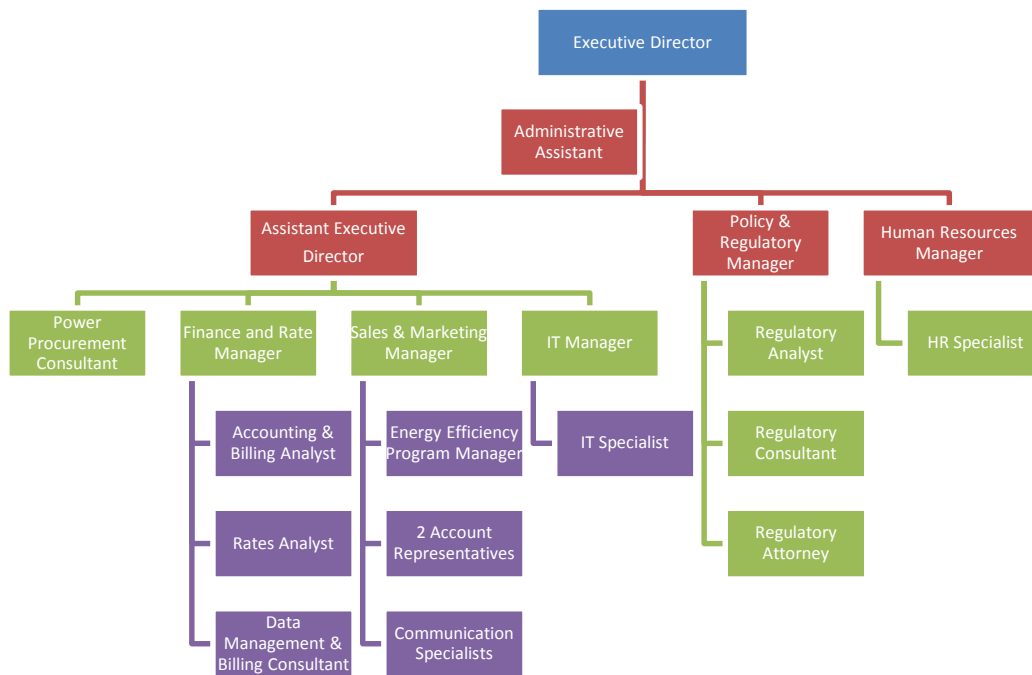
staff with outside consultants assisting, or hiring one third party entity to perform all of the operational mechanics.

CCA operations can be fulfilled by internal staff, external consultants, or a mix thereof. The choice of how to allocate these functions along the continuum between full internal staff and minimal internal staff will be at the discretion of the Board of the CCA. ICP operations will be the responsibility of an Executive Director, appointed by ICP's Board. The Executive Director will manage whatever combination of staff and contractors are deemed most cost-effective in accordance with the general policies established by the Board.

ICP has three options for staffing after the initial start-up:

1. The first option involves hiring internal staff incrementally to match workloads involved in forming ICP, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario). If ICP decides to follow a "Full Staff Scenario", ICP will likely need a full time staff of approximately 15 – 20 employees to perform its responsibilities, primarily related to program and contract management, legal and regulatory, finance and accounting, energy efficiency, marketing and customer service. A sample organizational chart for this scenario is provided in Exhibit 3. Even under the Full Staff Scenario, highly technical functions associated with managing and scheduling power suppliers, retail customer billings, and data management will likely be performed by experienced outside consultants.
2. In option two, the CCA would hire just a few staff internally (i.e., Executive Director and two support staff). All remaining work would be managed through consultants (Minimum Staff Scenario). The costs of a Fully Staffed CCA versus a CCA staffed mostly by consultants are estimated to be roughly equal.
3. In the third option, ICP could contract with one or more third-parties to complete all the operational aspects of the CCA.

**Exhibit 3
Sample Organization Chart**



In order to develop a conservative financial proforma analysis, this Plan estimates operating costs assuming a Full Staff scenario. This is to prove that the CCA is both feasible and viable. The known staffing costs for a CCA are based on staffing the entire organization internally (excluding power supply agents and data management). It is more difficult to estimate the cost of consultants providing all services other than data management and power supply given that all existing CCAs have transitioned to internal staffing fairly quickly. As such, this Plan used the internal staffing option in the cost analysis. However, it is expected that the Board would go out to tender for consulting services and compare the cost-effectiveness of relying on consulting services versus staffing the CCA internally. Any further cost reductions associated with alternative staffing option would serve to make the CCA-related rate savings even larger than portrayed in this Plan.

Plan Outline

This Plan evaluates the cost and resulting rates of operating ICP and compares these rates to a SCE rate forecast. This pro forma 20-year feasibility analysis models the following cost components:

- **Power Supply Costs:**
 - Wholesale purchase
 - Renewable purchases
 - Procurement of resource adequacy capacity
 - Other power supply and charges

- Non-Power Supply Costs:
 - Start-up costs
 - ICP staffing and administration costs
 - Consulting support
 - SCE and regulatory charges
 - Reserves
 - New Program Funding
 - Financing costs (Start-up and Working Capital)
- Pass-Through Charges from SCE:
 - Transmission and distribution charges
 - Power Cost Indifference Adjustment (PCIA) Charge
 - Franchise Fee
 - Other SCE non-bypassable charges

The information above is used to determine the retail rates for ICP. ICP rates are then compared to the SCE projected rates for ICP service area.

Plan Organization

This Plan is organized into the following main sections:

- Load Requirements
- Power Supply Strategy and Costs
- ICP Cost of Service
- Products, Services, Rates Comparison and Environmental/Economic Considerations
- Sensitivity Analysis
- Summary and Recommendations

Each section is discussed in more detail below.

Load Requirements

The viability of ICP depends to various degrees on the number of customers that participate in the CCA and the amount of energy they consume. This section of the Plan provides an overview of these projected values and the methodology used to estimate them.

Historical Consumption

SCE has provided monthly historical data on energy use (kWh), non-coincident peak load (kW), and number of accounts aggregated by rate class for both direct access (DA) and bundled customers for Cities expected to participate in ICP as well as unincorporated areas in the three associations for the 2015 calendar year. These include 7 cities in CVAG, 21 in SANBAG, 16 in WRCOG, as well as both the Riverside and San Bernardino county unincorporated areas. Collectively, CVAG, SANBAG, WRCOG, and the unincorporated counties used almost 20,000 GWh of electricity in 2015. Of this, SANBAG used 56 percent, WRCOG 32 percent, and CVAG 12 percent.

Bundled and Direct Access Customers

Bundled customers (full service) make up over 93 percent of total customer accounts across the three government associations and comprise approximately 85 percent of the total energy use. Direct access customers account for under 7 percent of customers, but use nearly 15 percent of the annual energy. Exhibits 4 and 5 summarize historic energy consumption and number of accounts for bundled and DA customers within the three COGs.

Exhibit 4 Bundled and Direct Access Customer Accounts by COG in 2015				
Government Association	Bundled Accounts	DA Accounts	Bundled Accounts (% of total)	DA Accounts (% of total)
CVAG	142,715	1,299	99%	1%
SANBAG	678,524	38,236	95%	5%
WRCOG	438,019	55,235	89%	11%
Total	1,259,258	89,545	93%	7%

Exhibit 5 Bundled and Direct Access Retail Load by COG in 2015				
Government Association	Bundled Load (MWh)	DA Load (MWh)	Bundled Load (% of total)	DA Load (% of total)
CVAG	2,370,751	79,197	97%	3%
SANBAG	11,085,138	2,043,264	84%	16%
WRCOG	6,312,021	1,285,402	83%	17%
Total	19,767,910	3,407,864	85%	15%

Direct access customers purchase their power supply and other services from an electric service provider (ESP), rather than the incumbent utility. In California, eligibility for DA enrollment is currently limited to retail non-residential customers and enrollment is based on an annual lottery.⁶ Customers classified as taking service under direct access arrangements are not included in this Plan, as it is assumed that these customers will remain with their current ESPs.

City and Unincorporated Loads

Among bundled customers, approximately 79 percent are located within the 44 cities and account for 81 percent of annual energy usage in the three COGs as shown in Exhibit 6. Potential customers and energy consumption are shown in Exhibit 7 aggregated for each COG including the respective unincorporated load. Exhibit 8 illustrates the distribution of load by sector for each jurisdiction.

Exhibit 6 Bundled Load and Accounts by Jurisdiction Type in 2015				
Jurisdiction	Customer Accounts	Customer Accounts (% of total)	Annual Wholesale Load (GWh)	Energy Use (% of total)
Cities	994,814	79%	16,975	81%
Unincorporated Riverside and San Bernardino Counties	264,444	21%	3,982	19%
Total	1,259,258	100%	20,957	100%

It should be noted that the County's unincorporated load has been included in these total usage amounts.

⁶ S.B. 286 (CA, 2015-2016 Reg. Sess.)

Exhibit 7
Bundled Load and Accounts by Sector and COG

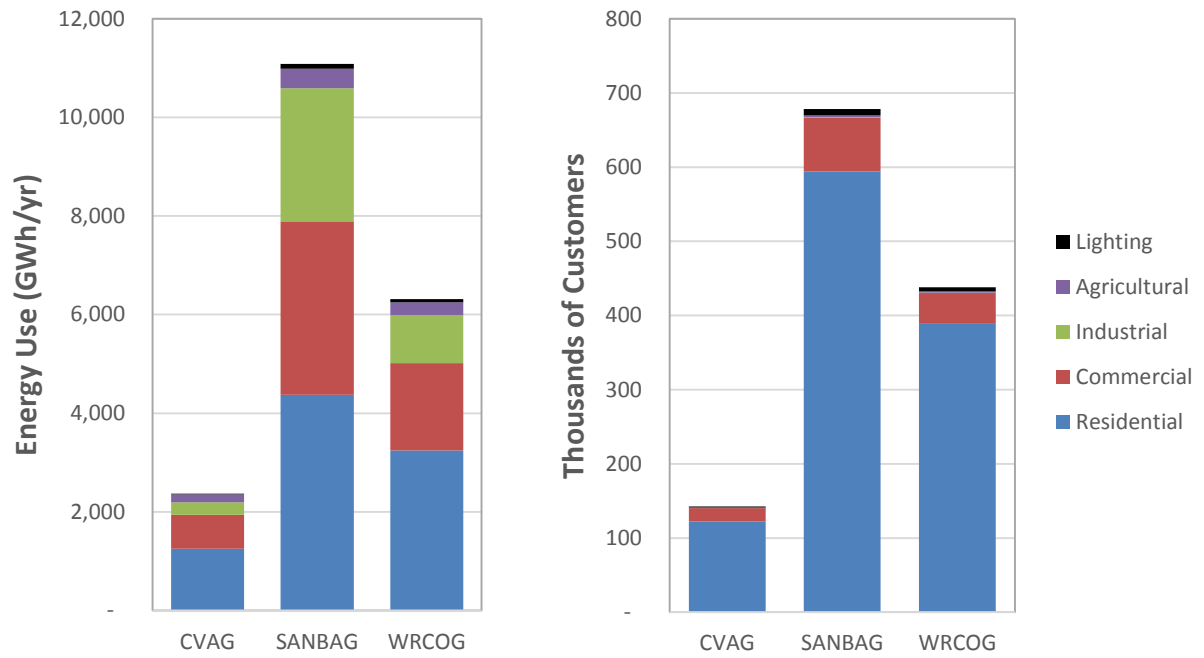
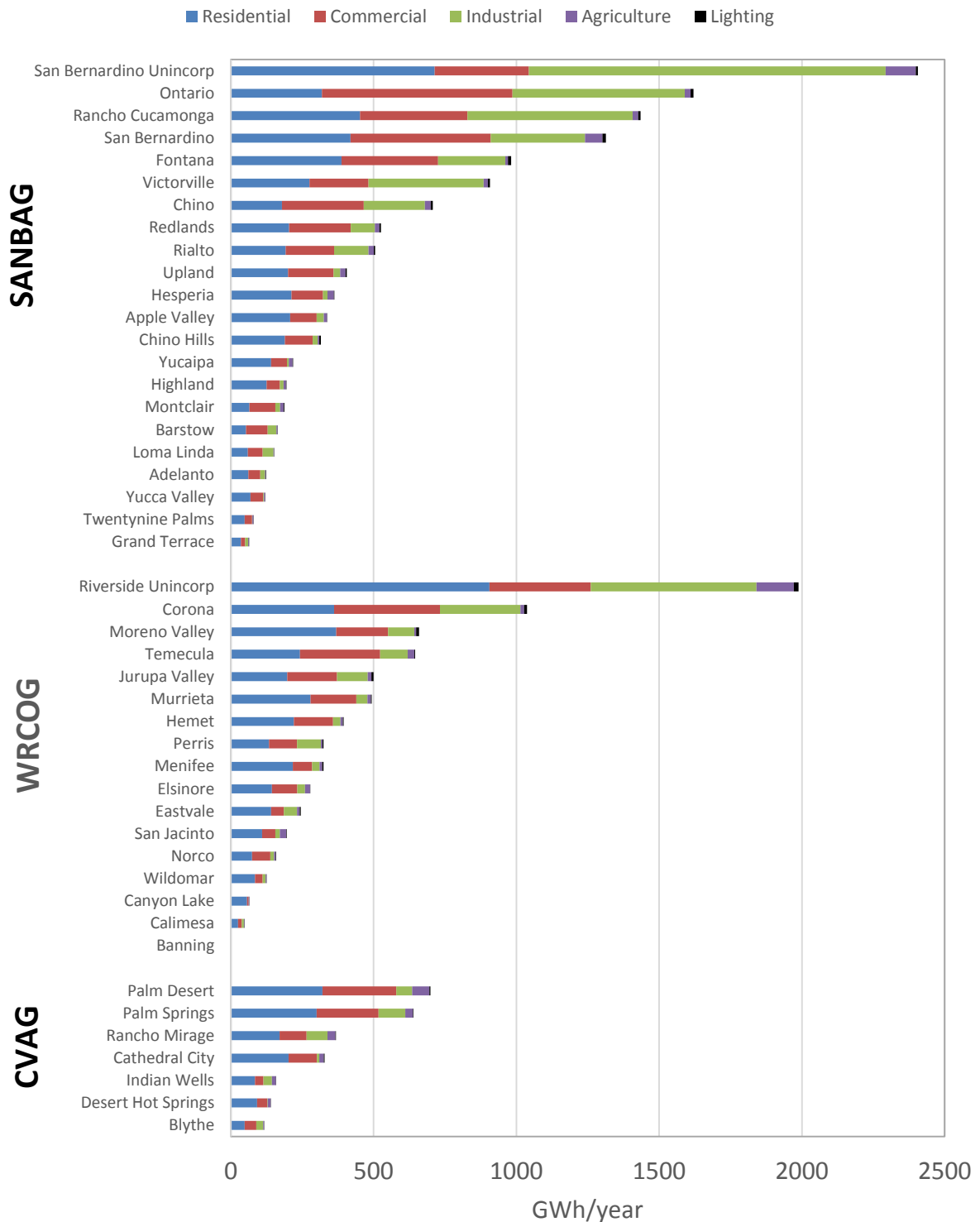


Exhibit 8
Bundled Energy Use by Jurisdiction and Sector



Note: Riverside County unincorporated areas were split up between WRCOG and CVAG for the 3-CCA scenarios, but are represented as a single entity in this figure for comparison.

ICP Launch Phases

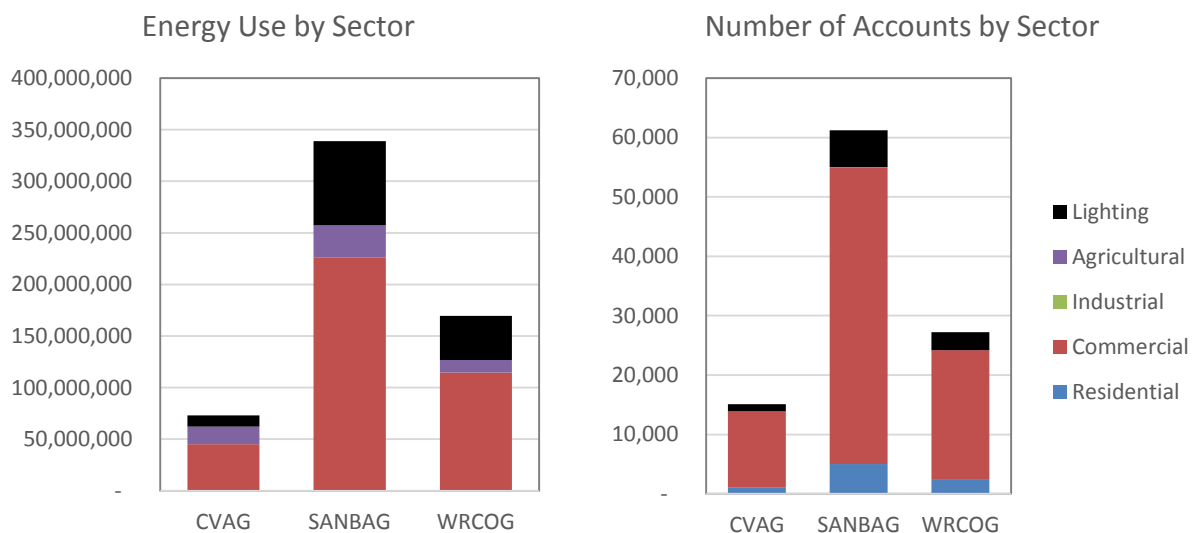
For the purpose of this Plan, it has been assumed that the development of ICP will occur using a two-phase implementation schedule. Phase 1 will include all municipal facilities as well as 5 percent of private commercial accounts within the three COGs. Phase 1 includes the 5 percent non-municipal accounts to balance out the daily load profile of the municipal accounts, which on their own would not be representative of ICP as a whole. These non-municipal accounts will be recruited for participation in Phase 1 during the start-up of ICP. Phase 2 will enroll all remaining customers in the three COGs.

Municipal facility energy use and number of accounts was provided by CVAG, SANBAG, and WRCOG. That data, in combination with 5 percent of non-municipal commercial accounts, is summarized in Exhibit 9. This data provides the basis for Phase 1 of ICP's Implementation Plan. Exhibit 10 shows the total number of eligible municipal facilities in the three COGs and their consumption.

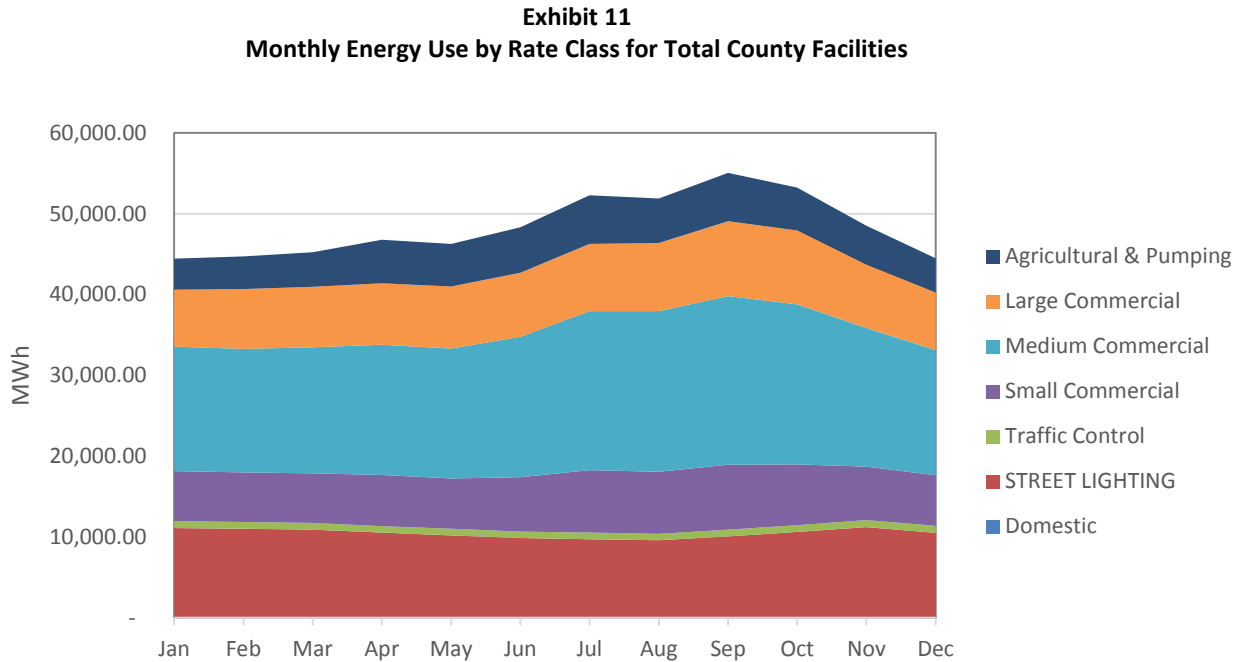
Exhibit 9 Phase 1 Accounts and Load, July 2017				
Location	Customer Accounts	Customer Accounts (% of total)	Annual Wholesale Load (MWh)	Load (% of total)
CVAG	10,121	15%	51,678	13%
SANBAG	41,207	59%	239,845	58%
WRCOG	18,339	26%	119,963	29%
Total	69,667	100%	411,486	100%

Exhibit 10 shows energy consumption and customer distribution by sector for Phase 1 facilities.

Exhibit 10
Phase 1 Load Data by Rate Schedule



The monthly energy distribution of Phase 1 customers is illustrated in Exhibit 11.



ICP Customer Participation Rates

Customers will receive a total of four notices of ICP's service to give them an opportunity to opt-out. The first two notices will be issued before customers are served by ICP at 60 and 30 days before ICP's launch. These notices will provide information needed to understand the terms and conditions of service from ICP and explain how customers can opt-out, if desired. Subsequent to commencement of service, customers will be given two additional opportunities to opt-out and return to SCE at 30 and 60 days after ICP's launch. Customers that opt-out between the initial switchover date and the close of the post enrollment opt-out period will be responsible for ICP usage-related charges for the time they are served by ICP but will not otherwise be subject to any charges for leaving ICP. All customers that do not follow the opt-out process specified in the customer notices will be automatically enrolled into ICP. Customers automatically enrolled will continue to have their electric meters read and billed for electric service by SCE. ICP bills processed by SCE will show separate charges for power supply procured by ICP, all other charges related to delivery of the electricity by SCE and other utility charges that will continue to be assessed.

This Plan anticipates an overall customer participation rate of 100 percent during Phase 1, as service is being offered to municipal facilities and selectively recruited private commercial customers. For Phase 2, it is assumed that approximately 75 percent of residential customers and 65 percent of non-residential customers will remain with ICP. These opt-out assumptions are conservative estimates when compared to participation rates in other CCAs. For operating CCAs in California, at least 85 percent of the potential customers have stayed with the CCA.

Forecast Consumption and Customers

Going forward, projections for customers enrolled in ICP and retail energy consumption have been forecast to increase at 1.13 percent per year. This forecast is based on the mid-case electricity demand forecasts for the SCE planning area, as reported to the California Energy Commission (CEC).⁷ Hourly electric consumption and peak demands have been estimated based on SCE's hourly load profiles for each customer classification.

The forecast of load served by ICP over the next 20 years is shown in Exhibit 12. This exhibit reflects an estimated annual growth of 1.13 percent. The ICP forecast of kWh sales reflects the roll-out and customer enrollment schedule shown above. Annual energy requirements are shown below in Exhibit 13.

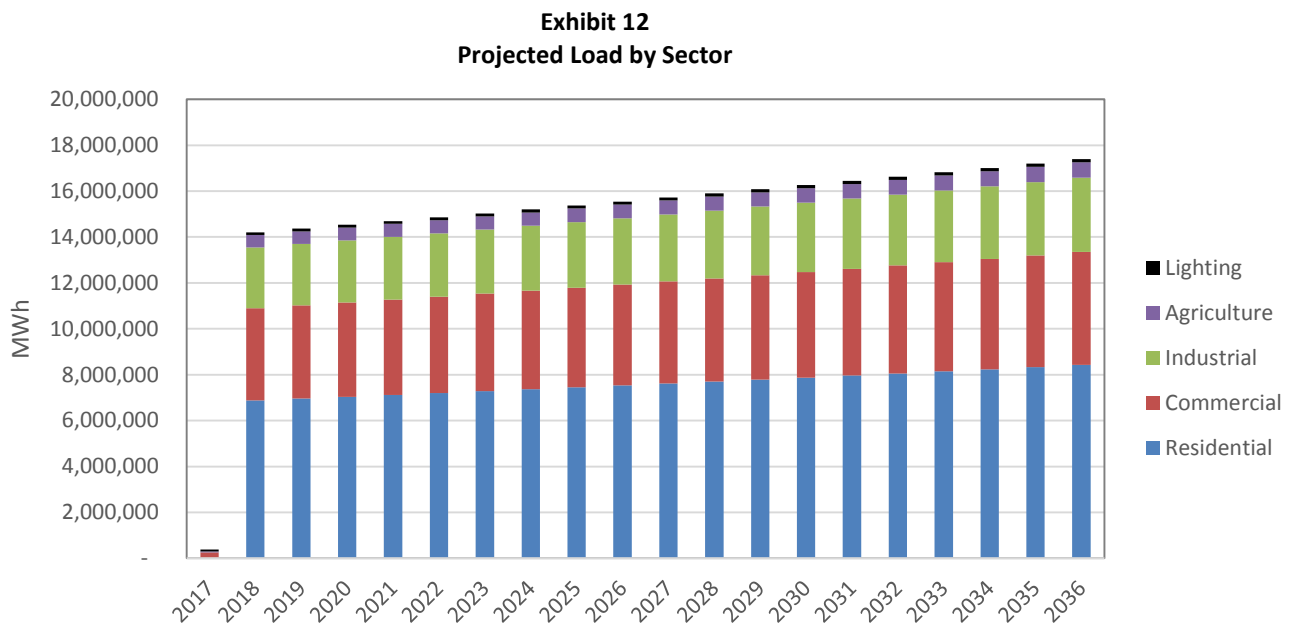


Exhibit 13 ICP Projected Annual Energy Requirements									
	2017	2018	2019	2020	2021	2022	2023	2024	2025
Retail Sales (MWh)	386,383	14,207,376	14,367,920	14,530,277	14,694,469	14,860,517	15,028,441	15,198,262	15,370,003
Losses (MWh)	25,103	858,741	868,445	878,258	888,183	898,219	908,369	918,634	929,014
Total Load Requirements (MWh)	411,486	15,066,118	15,236,365	15,408,536	15,582,652	15,758,736	15,936,810	16,116,896	16,299,017
Max Demand (MW)	434	14,208	14,368	14,531	14,695	14,861	15,029	15,199	15,370

⁷ Southern California Edison. *California Energy Demand Forecast, 2015-2025*. July 2015. Sacramento, CA: California Energy Commission.

Renewable Resource Requirement

In addition to estimating the potential retail loads and customers, current legislation requires that a certain percent of annual retail electric sales be supplied from qualified renewable energy resources.

SBX1 2 passed in April, 2011 established a 33 percent Renewable Portfolio Standard (RPS) requirement by 2020 with certain procurement targets prior to 2020. SBX1 2 also defined three types of renewable categories (or Buckets) that can be used to meet the RPS target.

Bucket 1 – Renewable resources located in California or out-of-state renewable resources that can meet strict scheduling requirement ensuring deliverability into California. According to SBX1 2 there are no limits on Bucket 1 renewable resources.

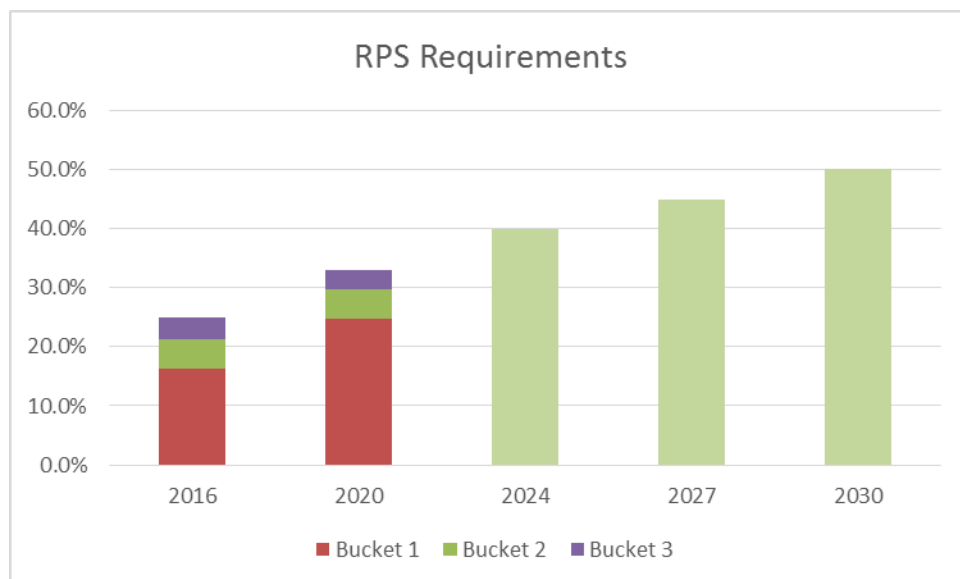
Bucket 2 – Bucket 2 renewable resources are firmed or shaped renewable resources not necessarily delivered to California, but an equivalent amount of energy is delivered from a different non-renewable resource and then bundled with Renewable Energy Certificates (RECs). Bucket 2 resources are limited to annual maximum of 20 percent of total RPS procurement through 2016 and 15 percent through 2020.

Bucket 3 – Bucket 3 consists of unbundled Renewable Energy Certificates which are separated from the actual electric energy. Bucket 3 resources are limited to an annual maximum of 15 percent of total RPS procurement through 2016 and 10 percent through 2020.

In addition, SB350 increased the RPS requirement to 50 percent by 2030. At this time, the amount of REC's that can be used to meet the 50 percent RPS requirement has not been finalized.

Exhibit 14 provides an overview of the RPS requirements until 2030.

Exhibit 14
California RPS Requirements as a Percent of Total Power Supply



ICP's Plan has been developed assuming ICP will meet a 50 percent RPS target as soon as possible through renewable and non-renewable contracts, distributed generation and local resources.

ICP will exceed SCE's renewable energy percentage from the first day of its operations when it meets its 50 percent goal. ICP will therefore significantly exceed the minimum RPS requirements and significantly exceed the renewable power share provided by SCE.

Resource Adequacy Requirements

In addition to determining the renewable resource requirement, ICP will also need to demonstrate and report that it has sufficient physical power supply capacity to meet its projected peak demand plus a 15 percent planning reserve margin. This requirement is in accordance with resource adequacy regulation administered by the CPUC and the California Energy Commission (CEC).

The CPUC's resource adequacy standards applicable to ICP require a demonstration one year in advance that ICP has secured physical capacity for 90 percent of its projected peak demand for each of the five months May through September, plus a minimum 15 percent reserve margin. On a month-ahead basis, ICP must demonstrate 100 percent of the peak load plus a minimum 15 percent reserve margin.

The Plan's load forecast estimates capacity needs, including resource capacity requirements, to be used for the power supply cost forecasting.

Power Supply Strategy and Costs

This section of the Plan provides a discussion of the power supply resource cost forecasts, potential power supply strategies that could be implemented by ICP and provides power supply portfolio pricing based on the loads projected for ICP.

ICP will be charged with developing both short (one and two-year) and long-term (five to twenty years) resource plans. ICP will develop the resource plan under the guidance provided by its Joint Power Authority (JPA), in compliance with California law, and other requirements of California regulatory bodies (CPUC and CEC).

Long-term resource planning includes load forecasting and supply planning. ICP's planners will develop Integrated Resource Plans (IRPs) that meet their supply objectives and balance cost, risk, and environmental considerations. Integrated resource planning considers demand side energy efficiency and demand response programs as well as traditional supply options. ICP will require a planning function even if the day-to-day supply operations are contracted to third parties. This will ensure that local preferences regarding the future composition of supply and demand resources are planned for, developed and implemented.

Resource Strategy

ICP may want to seek to maximize the use of local, cost-effective renewable generation resources in its IRP. The ability to invest capital in power supply and demand-side resources using tax-exempt financing is an important factor in ICP's ability to increase the use of renewable energy while offering rates that are competitive with SCE. Power purchases from renewable and non-renewable resources will supply the remaining majority of the resource mix. ICP's power supply portfolio will be managed by a third party electric supplier, at least during the initial implementation period. Through a power services agreement, the Plan assumes that ICP will obtain full service requirements electricity for its customers, including providing for all electric, ancillary services and the scheduling arrangements necessary to provide delivered electricity.

Resource Costs

For this Plan, individual resource costs are estimated and other energy providers based on current market condition, recent power supply contracts for renewable energy as well as a review of the applicable regulatory requirements.

Market Purchases

Natural gas-fired power plants are typically the marginal power supply resource that sets the electricity market price in southern California and elsewhere in the Western Energy Coordinating Council (WECC) footprint. WECC generally guides power supply resources west of the Rocky Mountains. As the market price of electricity is usually set by the cost of the marginal unit, a wholesale market price forecast has been developed using a forecast of natural gas prices and the projected relationship between gas prices and electricity prices (also defined as market-

implied heat rates or spark spreads). The projected market-implied heat rates reflect the average efficiency of gas-fired power plants in California. Projected heat rates are based on historic market-implied heat rates which are calculated by dividing historic southern California (SP15) wholesale market prices by historic southern California natural gas prices. A natural gas price forecast has been developed based on NYMEX forward gas prices for the Henry Hub trading hub and southern California basis differentials. Projected market heat rates have then been applied to the southern California natural gas price forecast to calculate a wholesale electric market price forecast for southern California.

The following steps have been taken to produce the wholesale electric market price forecast:

1. Forward prices for natural gas at Henry Hub are available through June 2025.
2. The southern California basis differential is used to adjust the Henry Hub forward prices to southern California prices. Southern California forward natural gas prices are equal to NYMEX forward prices (Henry Hub) plus the southern California basis. The southern California basis forward curve is available through December 2020. After December 2020, the monthly southern California basis is assumed to increase at 5 percent.
3. Projected monthly market-implied heat rates are multiplied by forecast southern California natural gas prices to calculate forecast southern California wholesale market prices.
4. Projected heat rates are based on historic heat rates (southern California wholesale electricity prices divided by SoCal natural gas prices).
5. Monthly market-implied heat rates are held constant in all years.
6. Forecast southern California wholesale electric market prices are escalated by a 3.5 percent annual growth rate after June 2025.
7. Forecast southern California wholesale electric market prices are benchmarked against other market price forecasts.

Based on the methodology detailed above, southern California wholesale market prices are projected to escalate annually at an average rate of 3.7 percent over 2017 through 2036.

Exhibit 15 shows the forecast southern California natural gas prices.

Exhibit 15
Forecast SoCal Natural Gas Price (\$/MMBtu)

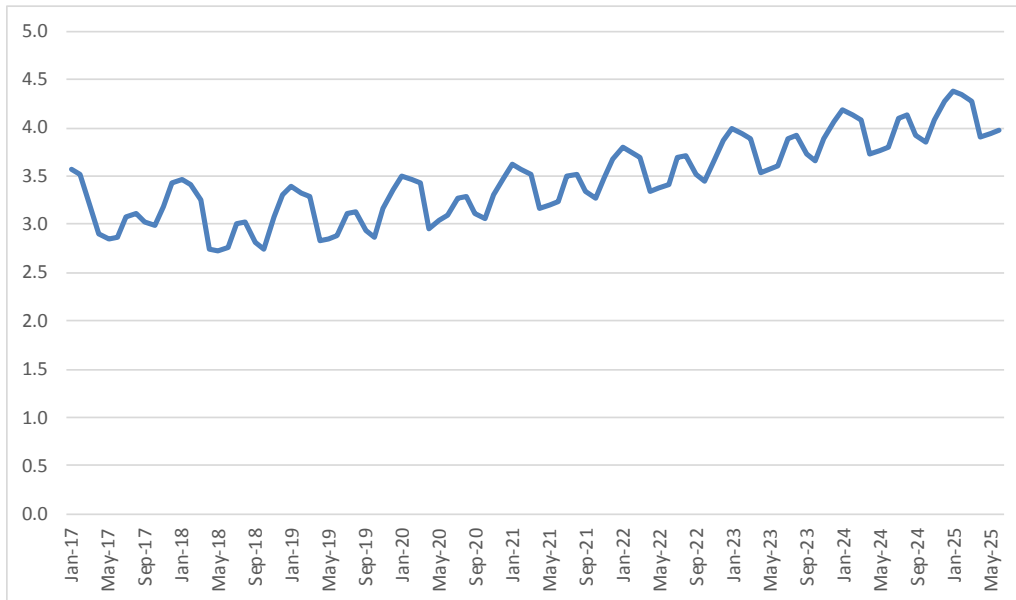
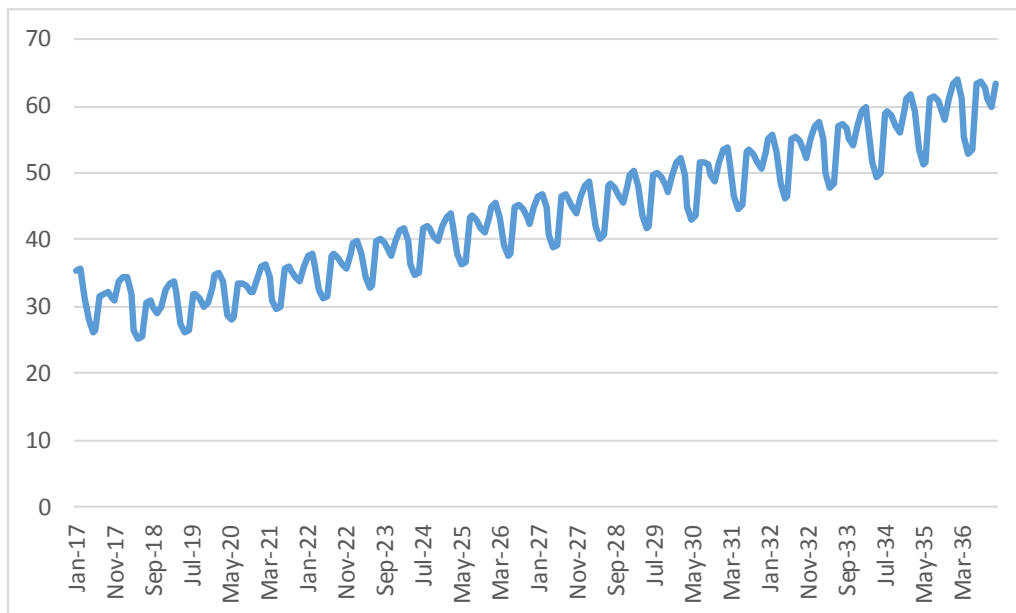


Exhibit 16 shows the resulting monthly southern California wholesale electric market price forecast. The levelized value of market prices over the study period is \$41.6/MWh (2016\$).

Exhibit 16
Forecast Southern California Wholesale Market Prices (\$/MWh)



Wholesale power prices have been used to calculate balancing market purchases and sales. When ICP's loads are greater than its resource capabilities, ICP's scheduling agent will schedule balancing purchases and ICP will incur balancing market purchase costs. When ICP's loads are less than its resource capabilities, ICP's scheduling agent will transact balancing sales and ICP will

receive market sales revenue. Balancing market purchases and sales can be transacted on a monthly, daily and hourly pre-schedule basis.

Renewable Energy

The wholesale market prices shown above are for “non-renewable” power (i.e., this product does not come with any renewable energy credit (REC) attributes). The cost of renewable resources varies greatly. Wind and solar levelized project costs vary from \$35 to \$60/MWh. Geothermal project costs can vary from \$70 to \$100/MWh. The availability of off-shore wind and ocean power in the marketplace is fairly minimal and, as such, these resources were not included in the assessment of renewable energy market prices.

Based on a survey of renewable resources currently in operation and new projects coming on-line, a base case renewable energy market price of \$42/MWh has been determined. Renewable energy prices may increase in the future as the demand for renewable energy increases due to California’s RPS and the possible expiration of the solar investment tax credit. However, renewable prices are being driven down by solar project costs which have declined sharply over the past few years and are expected to continue to decrease over the next 10 to 20 years. Again, the renewable energy prices have been independently confirmed by current market tenders in southern California.

Projected power costs in this Plan are calculated using the base case renewable energy market price of \$42/MWh. The amount of renewable energy purchased will be assumed to be equal to the RPS requirements in the base case. A higher case of 50 and 100 percent renewable energy will also be considered later in this Plan. In the “100 percent renewables” case the renewable energy market price was increased to \$52/MWh. The \$42/MWh price was based on an assumption that renewable purchases would be served almost exclusively with the output from solar projects. In the “100 percent renewables” case a higher price was assumed in recognition that a more diverse, and therefore more expensive, renewable energy portfolio would be needed. As such, the \$52/MWh is a blend of projected solar, geothermal and wind project costs. This is a conservative assumption as current solar contracts have a market value of \$35 - \$40/MWh.

Renewable Energy Credits (RECs)

As noted earlier, California load serving entities must purchase renewable energy or attributes that meet certain eligibility requirements across three categories or buckets. Each of the buckets represents a different type of renewable energy and can be used to meet a specific percent of the total. The shares of each bucket also changes over time. The three buckets and the type of energy included in each bucket can be summarized as follows:

- Bucket 1: In-state renewable generation
- Bucket 2: Firmed and shaped renewable energy products from a generator that has its first point of interconnection with a California Balancing Authority (such as the CAISO)
- Bucket 3: Energy is not included with the RECs (also known as unbundled RECs)

Under the current guidelines, the amount of RECs procured through Buckets 2 and 3 is limited and decreases over time. Historically, the first bucket has been the most expensive type of energy to purchase and load serving entities were only procuring the minimum they need to meet the RPS requirement. However, with the decrease in solar project costs, Bucket 1 has become relatively less expensive (compared to Buckets 2 and 3).

RECs are not generally viewed as good for the development of new local renewable projects. In addition, the REC market is not as liquid as it once was. For the Plan's base case, unbundled REC prices are assumed to increase from \$10/REC in 2017 to \$20 in 2036 (3.7 percent annual escalation). Due to the decline in solar project costs, the cost of unbundled RECs to meet RPS requirements and wholesale market purchases to meet load are negligible. Due to this shift in market dynamics, Bucket 3 RECs are no longer the least expensive option (as they were historically).

The Plan assumes that ICP will not rely on REC purchases to meet RPS requirements. The REC market can, however, be used to balance RPS requirements with renewable energy acquisitions. If ICP is short of RECs in a given compliance year, RECs could be purchased to meet the requirements. If the CCA is long on RECs in a given compliance year, surplus RECs could be sold.

Transmission

ICP will pay the CAISO for transmission congestion and ancillary services. Transmission congestion occurs when there is insufficient capacity to meet the demands of all transmission customers. Congestion refers to a shortage of transmission capacity to supply a waiting market, and is marked by systems running at full capacity and still being unable to serve the needs of all customers. The transmission system is not allowed to run above its rated capacities. Congestion is managed by the CAISO by charging congestion charges in the day-ahead market. Congestion charges can be managed through the use of Congestion Revenue Rights (CRR). CRRs are financial instruments made available through a CRR allocation, a CRR auction, and a secondary registration system. CRR holders manage variability in congestion costs. The CCA's congestion charges will depend on the transmission paths used to bring resources to load. As such, the location of generating resources used to serve ICP load will impact these congestion costs.

The Grid Management Charge (GMC) is the vehicle through which the CAISO recovers its administrative and capital costs from the entities that utilize the CAISO's services. ICP's Grid Management Charges are expected to near \$0.5/MWh.

The CAISO performs annual studies to identify the minimum local resource capacity required in each local area to meet established reliability criteria. Load serving entities receive a proportional allocation of the minimum required local resource capacity by transmission access charge area, and submit resource adequacy plans to show that they have procured the necessary capacity. Depending on these results of the annual studies, there may be costs associated with local capacity requirements for ICP.

Because generation is delivered as it is produced and particularly with respect to renewables can be intermittent, deliveries need to be firmed using ancillary services to meet ICP's load

requirements. Ancillary services will need to be purchased from the CAISO. Regulation and operating reserves are described below.

- *Regulation Service:* Regulation service is necessary to provide for the continuous balancing of resources with load and for maintaining scheduled interconnection frequency at 60 cycles per second (60 Hertz). Regulation and frequency response service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load.
- *Operating Reserves - Spinning Reserve Service:* Spinning reserve service is needed to serve load immediately in the event of a system contingency. Spinning reserve service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service.
- *Operating Reserves – Non-Spinning Reserve Service:* Non-spinning reserve service is available within a short period of time to serve load in the event of a system contingency. Non-spinning reserve service may be provided by generating units that are on-line but not providing power, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service.

Based on a survey of ancillary service costs currently paid by CAISO participants, ICP's ancillary service costs are estimated to be near \$5/MWh. The Plan's base case will assume the CCA's ancillary service costs are \$5/MWh in 2017, escalating by 1.5 percent annually thereafter. Serving a greater percentage of load with renewables will likely result in increased grid congestion and higher ancillary service costs. For this reason, the ancillary service costs have been increased in the 50 percent and 100 percent renewables cases included in this Plan. For the 50 percent renewables case, ancillary service costs are assumed to be \$5.5/MWh in 2017. For the 100 percent renewables case, ancillary service costs are assumed to be \$8/MWh in 2017, escalating by 2.5 percent.

Power Management/Scheduling Agent

Given the likely complexity of ICP's resource portfolio, ICP will want to rely on a reputable scheduling agent to economically manage ICP's power purchases and wholesale market transactions. ICP's resource portfolio will ultimately include market purchases, shares of some relatively large power supply projects, as well as shares of smaller, most likely renewable, resources with intermittent output. Managing a diverse resource portfolio with metered loads that will be heavily influenced by distributed generation will be one of the most important functions of ICP. As such, ICP needs a dependable, established scheduling agent with a proven track record in the industry. ICP's scheduling agent will be one of its most important business partners.

ICP should initially contract with a third party with the necessary experience (and balance sheet) to perform most of ICP's portfolio operation requirements. This will include the procurement of

energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading. Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These activities include the following:

- *Electricity Procurement* – assemble a portfolio of electricity resources to supply the electric needs of ICP customers.
- *Risk Management* – standard industry risk management techniques will be employed to reduce exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices.
- *Load Forecasting* – develop accurate load forecasts, both long term for resource planning, and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.
- *Scheduling Coordination* – scheduling and settling electric supply transactions with the CAISO.

ICP should approve and adopt a set of protocols that will serve as the risk management tools for ICP and any third party involved in ICP portfolio operations. Protocols will define risk management policies and procedures, and a process for ensuring compliance throughout the organization. During the initial start-up period, the chosen full requirements electric suppliers will bear the majority of risks and be responsible for their management. Development of protocols can take place during the first few months of ICP operations to cover electricity procurement activities.

A scheduling agent provides day-ahead and real-time power and transmission scheduling services. Scheduling agents bear the responsibility for accurate and timely load forecasting and resource scheduling including wholesale power purchases and sales required to maintain hourly load/resource balances. A scheduling agent needs to provide the marketing expertise and analytical tools required to optimally dispatch ICP's surplus resources on a monthly, daily and hourly basis.

Inside each hour, the CAISO Energy Imbalance Market (EIM) takes over load/resource balancing duties. The EIM automatically balances loads and resources every fifteen minutes and dispatches least-cost resources every 5-minutes. The EIM allows balancing authorities to share reserves, and more reliably and efficiently integrate renewable resources across a larger geographic region.

Within a given hour, metered energy (i.e. actual usage) may differ from supplied power due to hourly variations in resource output or unexpected load deviations. Deviations between metered energy and supplied power are accounted for by the EIM. The imbalance market is used to resolve imbalances between supply and demand. The EIM deals only with energy, not ancillary services or reserves (which are addressed in the next section).

The EIM optimally dispatches participating resources to maintain load/resource balance in real-time. The EIM uses the CAISO's real-time market which uses Security Constrained Economic Dispatch (SCED). SCED finds the lowest cost generation to serve the load taking into account

operational constraints such as limits on generators or transmission facilities. The five-minute market automatically procures generation needed to meet future imbalances. The purpose of the five-minute market is to meet the very short term load forecast. Dispatch instructions are effectuated through the Automated Dispatch System (ADS).

The CAISO is the market operator, and runs and settles EIM transactions. ICP's scheduling agent will submit ICP's load and resource information to the market operator. EIM processes are running continuously for every fifteen-minute and five-minute intervals, producing dispatch instructions and prices.

Participating resource scheduling coordinators submit energy bids to let the market operator know that they are available to participate in the real-time market to help resolve energy imbalances. Resource schedulers may also submit an energy bid to declare that resources will increase or decrease generation if a certain price is struck. An energy bid is comprised of a megawatt value and a price. For every increase in megawatt level, the settlement price also increases.

The CAISO calculates financial settlements based on the difference between schedules and actual meter data, and bid prices during each hour. Locational Marginal Prices (LMP) are used in settlement calculations. The LMP is the price of a unit of energy at a particular location at a given time. LMPs are influenced by nearby generation, load level, and transmission constraints and losses.

ICP's scheduling agent will need to forecast ICP's hourly loads as well as ICP's hourly resources including shares of any hydro, wind, solar and other resources in which ICP is a participant/purchaser. Forecasting the output of hydro, wind and solar projects involves more variables than forecasting loads. Scheduling agents already have models set up to forecast accurately hourly hydro, wind and solar generation. Accurate load and resource forecasting will be a key element in assuring ICP's power supply costs are minimized.

A scheduling agent also needs to provide monthly checkout and after-the-fact reconciliation services. This requires scheduling agents to agree on the amount of energy purchased and/or sold and the purchase costs and/or sales revenue associated with each counterparty with which ICP transacted in a given month.

Based on conversations with scheduling agents currently working the CAISO footprint, the estimated cost of scheduling services is in the \$1 to \$2/MWh range. For the base case, the Plan has assumed a cost of \$1.5/MWh, escalating at 2.5 percent annually.

Resource Portfolios

In order to develop pricing options for ICP customers and evaluate the impact of varying levels of renewable resources in ICP's portfolios, three resource portfolios were developed: RPS Portfolio, 50 percent renewable portfolio and 100 percent renewable portfolio.

Resource Options

For each of the resource portfolios, a combination of resources has been assumed in order to meet the renewable energy target, resource adequacy targets, and ancillary and balancing requirements.

Exhibit 17 shows the 20-year levelized resource costs included in this Plan.

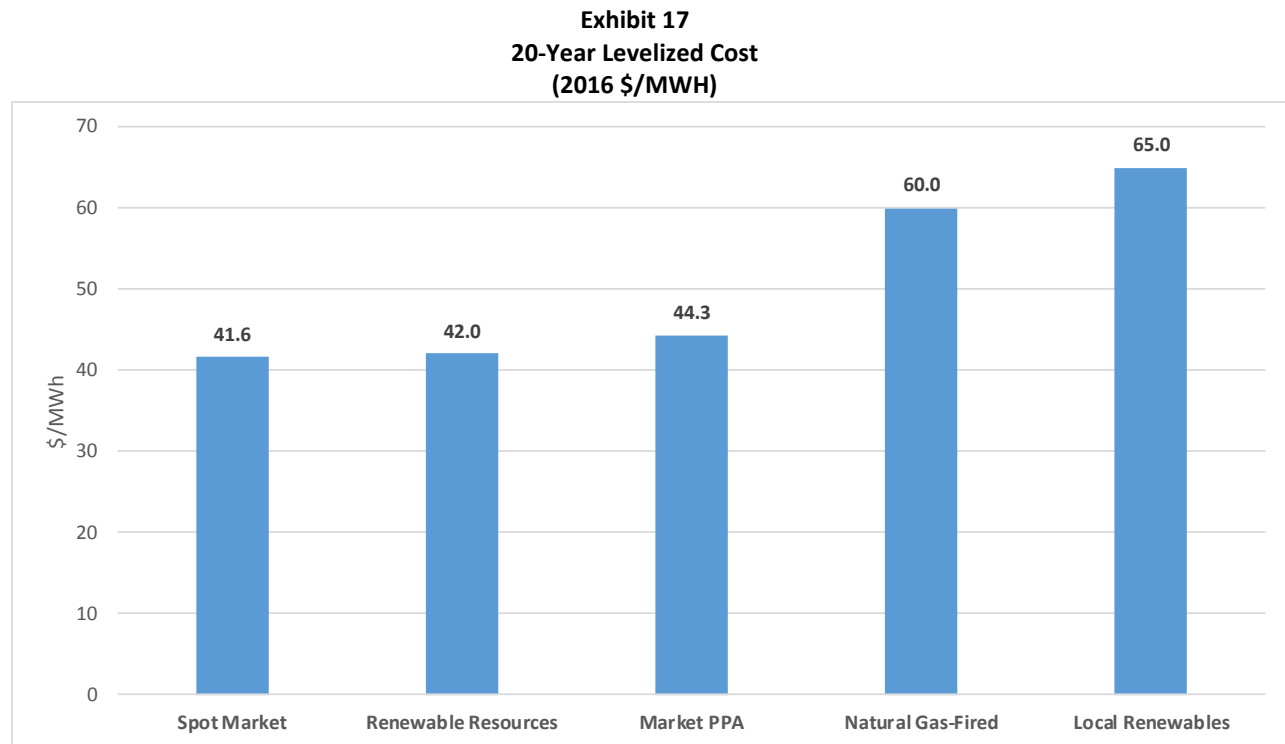


Exhibit 17 above includes both spot market and market PPA costs. It is assumed that these costs are primarily for natural gas resources although the specific resource source cannot be determined from a spot market purchase. Market PPA costs are greater than spot market costs in recognition of the cost of the PPA supplier absorbing the market price risk associated with providing a long-term PPA contract price.

The capacity factor for market PPA purchases is assumed to be 100 percent (flat monthly blocks of power). The average monthly capacity factor for renewable resources and local renewables is assumed to be 33 percent. The capacity factor for non-renewable resources is assumed to be 80 percent. As noted above, the cost of renewable resources was increased from \$42/MWh to \$52/MWh in the 100 percent renewables case in recognition of the need for a more diverse mix of renewable resources. Again, this higher price may be mitigated if large solar projects continue to be pursued in California.

As shown above, the base case 20-year levelized cost of renewable resources is comparable to the 20-year levelized cost of market purchases. The cost of solar projects has declined significantly over the past few years. The \$42/MWh projection is based on the cost of relatively new solar projects that reflect the decreased costs, on a \$/watt basis, of solar projects. The

\$/watt is expected to continue to decrease in future years notwithstanding the possible expiration of the investment tax credit for renewable energy. As such, the cost of the output of solar projects is expected to continue to decrease.

On a \$/watt basis, the cost of smaller scale solar projects is greater than the cost of large scale solar projects. The \$65/MWh cost associated with local renewables reflects this trend. The advantage of local renewable projects is lower transmission costs and less stress on the congested transmission grid.

A more detailed description of each ICP power supply portfolio option follows.

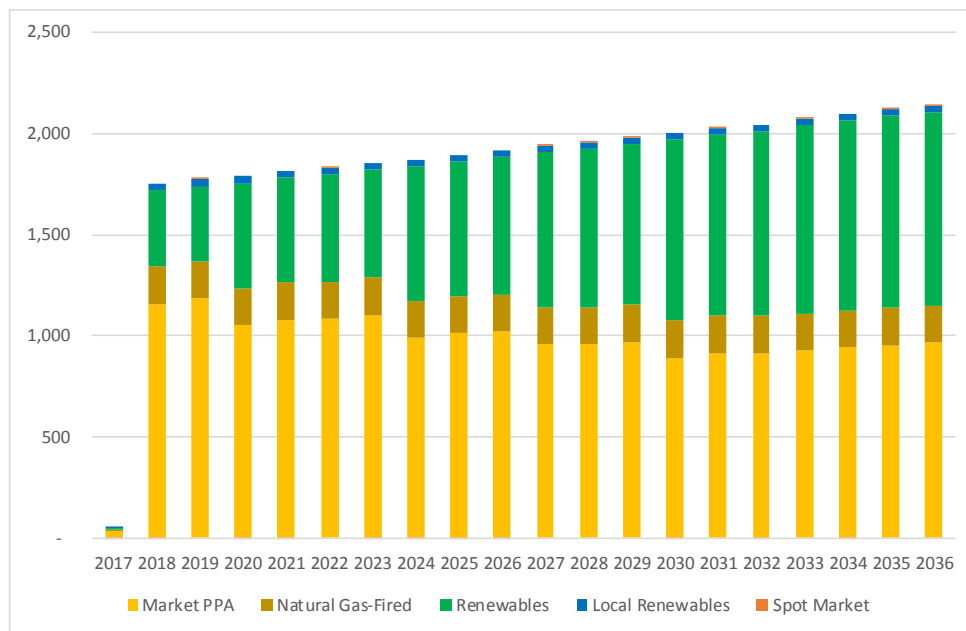
Portfolio 1: Meet Current RPS Requirements (Baseline Portfolio, similar to current SCE resource mix)

In the first portfolio, ICP will meet the State RPS requirements shown below:

- 2017-19: 25 percent
- 2020-23: 33 percent
- 2024-26: 40 percent
- 2027-29: 45 percent
- Post-2030: 50 percent

As shown above, due to the decrease in the cost of solar projects, the projected cost of renewables is comparable to the cost of market power and less than the cost of new gas-fired generation. Exhibit 18 shows the power supply portfolio used to serve load in Portfolio 1.

Exhibit 18
Portfolio 1: Meet RPS Requirements (aMW)

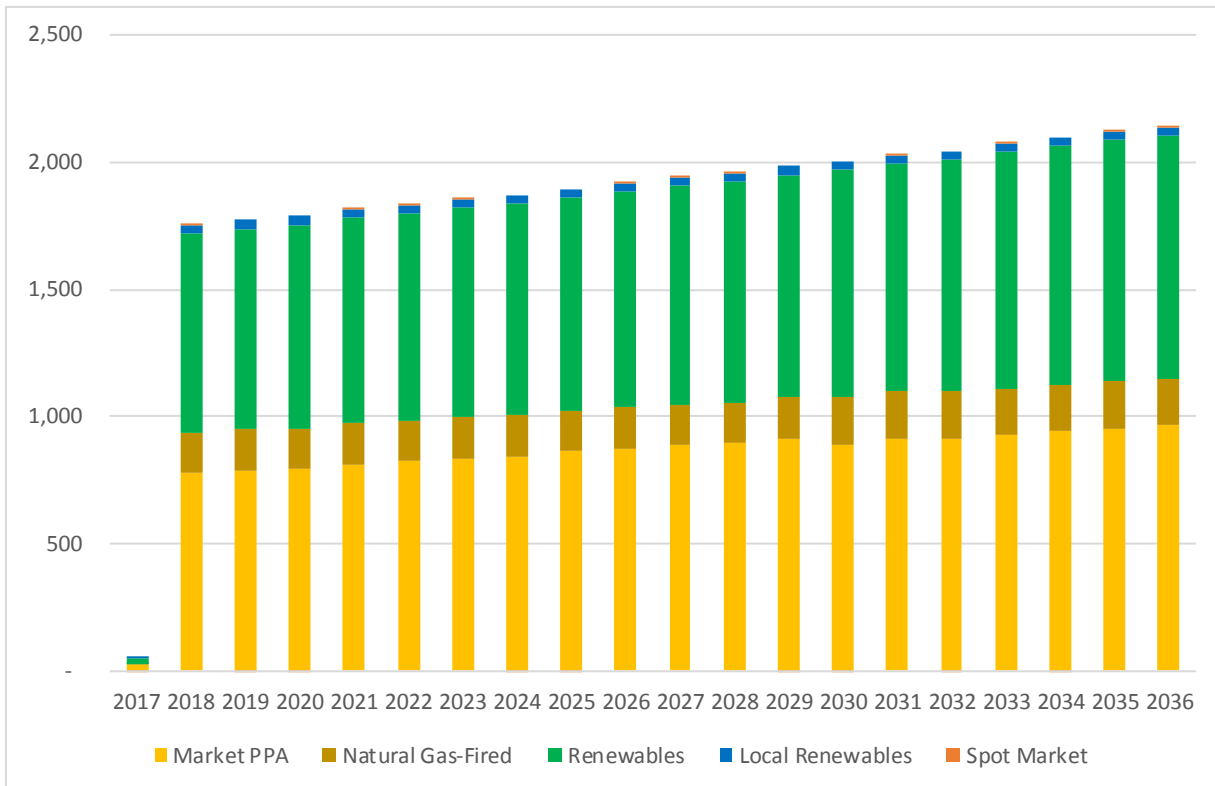


The green bars increase each year along with California’s RPS requirements. The costs associated with this portfolio could be reduced if it was assumed that more power was purchased from market PPAs instead of non-renewable (natural gas-fired) resources. The percent of non-renewable energy purchased via market PPAs, as opposed to natural gas-fired resources, is the same in each of the three portfolios.

Portfolio 2: Serve 50% of Retail Load with Renewables Starting on Day 1

In this portfolio, the 50 percent renewable energy purchase requirement in the RPS is effectively moved up from 2030 to January 1, 2017. Beginning in 2018, the amount of power purchased from the relatively expensive (\$65/MWh 20-year levelized cost) local renewables is held constant at 100 MW with an average monthly capacity factor of 33 percent in each of the three portfolios. As shown below in Exhibit 19 the green bars showing renewable energy purchases in 2017 through 2029 increased compared to those shown above in Exhibit 18.

Exhibit 19
Portfolio 2: Serve 50% of Retail Load with Renewables (aMW)



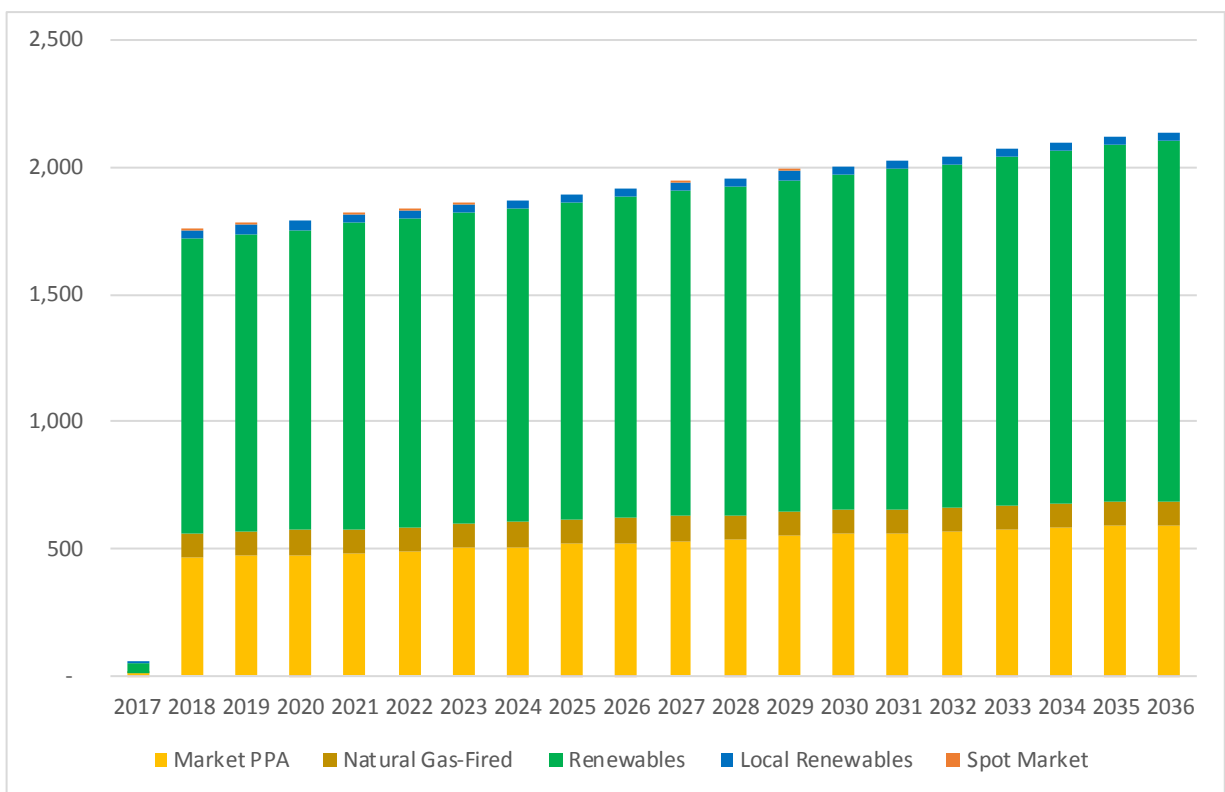
The percentage of non-renewable energy purchased from the more expensive natural gas-fired resources is approximately the same as Portfolio 1. In all three portfolios, approximately 15 percent of non-renewable energy is purchased from new gas-fired generation resources, which has a base case 20-year levelized cost of \$60/MWh. In all three portfolios, 85 percent of non-renewable energy is purchased at the lower \$44.3/MWh levelized cost associated with market PPA purchases.

Portfolio 3: Serve 100% of Retail Load with Renewables Starting on Day 1

In this portfolio retail loads are served entirely with renewable energy purchases. As in Portfolios 1 and 2, it is assumed that 100 MW of capacity from local renewable energy projects is available beginning in 2018. Exhibit 20 below shows the resource mix used to serve load in Portfolio 3.

The renewable energy requirements in the State's RPS are based on retail energy sales. To be consistent, it was assumed that the 100 percent renewable energy target would only apply to retail energy sales. The same concept applies to Portfolios 1 and 2. For example, renewable energy purchases in Portfolio 2 are equal to 50 percent of projected retail energy sales in all years.

Exhibit 20
Portfolio 3: Serve 100% of Retail Load with Renewables (aMW)



There is a significant amount of market PPA and brown resource power included in Portfolio 3 due to the mismatch between seasonal solar generation and seasonal loads. Solar generation is relatively low in winter months and peaks during summer months. Loads are also lower in the winter and higher in the summer. However, beginning in March solar generation ramps up faster than loads. This could put utilities in a position of having to find a market for relatively large amounts of surplus energy during the months of March through June when market prices are typically the lowest. Many utilities and generators will likely be surplus in the spring because of the mismatch between seasonal solar generation and loads in the spring. In addition, utilities and generators located in the Northwest also have surplus energy in the spring due to increased hydroelectric generation (due to melting snow) and wind. Non-renewable resources are included

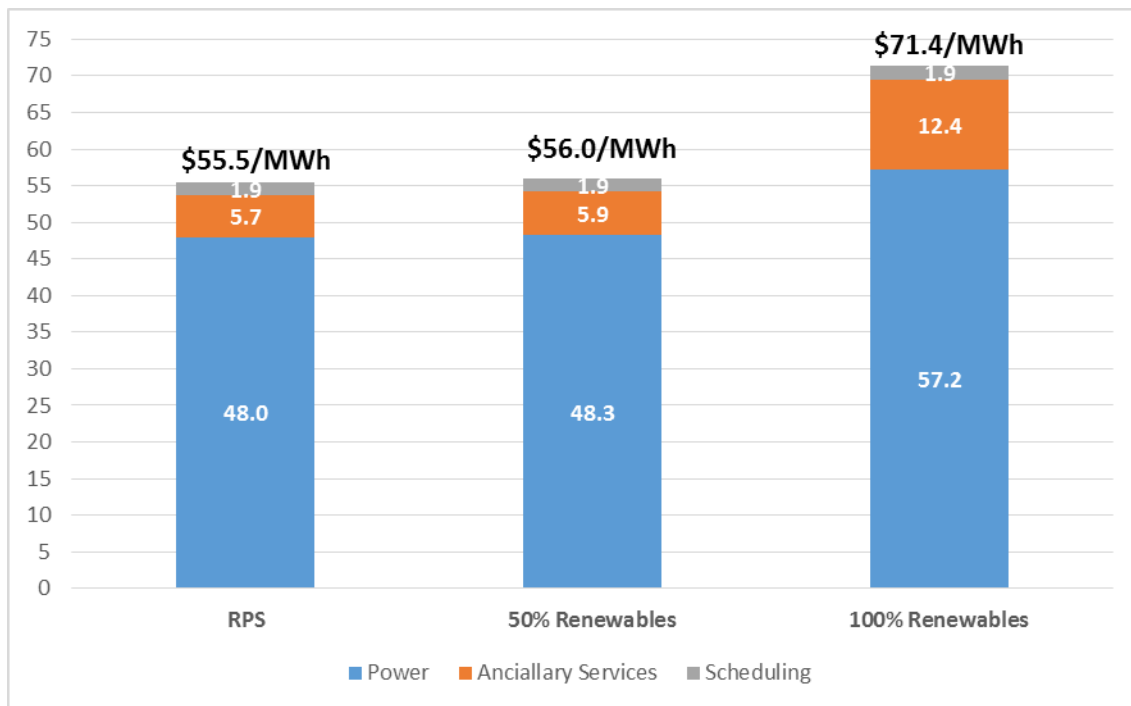
in Portfolio 3 in order to reduce ICP's exposure to low market prices during periods in which there is an abundance of surplus energy available in the region.

Non-renewable resources are needed in Portfolio 3 to serve load during hours when renewable resources are not capable of generating power (e.g., when the wind is not blowing or the sun is not shining). Purchasing large amounts of renewable generation, as in Portfolio 3, will likely result in over-supply in on-peak hours when solar projects are generating power and under-supply in off-peak hours when solar projects are not generating. As such, during some periods, on-peak energy may need to be exchanged for off-peak energy. The cost of exchanging or firming some of the solar generation into off-peak blocks of energy is reflected in higher ancillary service costs in Portfolio 3.

20-Year Levelized Portfolio Costs

The 20-year levelized costs have been calculated based on the base case assumptions detailed above regarding resource costs and resource compositions under the three portfolios. Exhibit 21 shows a breakdown of power, ancillary service and scheduling costs associated with each portfolio.

Exhibit 21
20-year Levelized Base Case Portfolio Costs (\$/MWh)



As shown above Portfolio 1 and 2 power costs are fairly similar. There is not a large variance in power costs in these two portfolios because the majority of power is supplied by market PPA and renewable energy purchases in each portfolio. The projected costs of renewable energy and market PPA purchases are very close. Exhibit 23 shows that the projected 20-year levelized cost of renewables is \$42/MWh while the projected 20-year levelized cost of market PPA purchases is \$44.3/MWh. While the 20-year levelized cost of market PPA purchases is greater than the 20-

year levelized cost of renewables, market PPA purchase prices are assumed to escalate from \$31/MWh in 2017 to \$47/MWh in 2029. Portfolios 1 and 2 are identical beginning in 2030 when the RPS increases to 50 percent. Portfolio 1 has a slightly lower 20-year levelized cost because the cost of PPA market purchases is less than the cost renewables in 2017 through 2029.

Total costs under Portfolio 3 are approximately \$15/MWh greater than Portfolios 1 and 2. The costs of renewables have been assumed to be \$10/MWh greater in Portfolio 3 than in Portfolios 1 and 2 in recognition of the need for a more diverse mix of renewable resources. This translates into greater power costs (the blue bar) for Portfolio 3.

Each portfolio assumes that 15 percent of non-renewable energy is purchased from natural gas-fired resources with a projected 20-year levelized cost of \$60/MWh. However, since more non-renewable energy is purchased in Portfolio 1 it has the highest percentage of natural gas-fired resource purchases. In Portfolio 1, 10 percent of power purchases are natural gas-fired resource purchases, compared to 9 percent in Portfolio 2 and 5 percent in Portfolio 3.

ICP Cost of Service

This section of the Plan describes the financial pro forma analysis and cost of service for ICP. It includes estimates of start-up costs, staffing and administrative costs, consultant costs, power supply costs, and SCE charges. In addition, it provides an estimate of start-up working capital and longer-term financial needs. The analysis and assumptions are first described for the ICP scenario. The financial impacts of three separate COGs are also described.

Cost of Service for ICP Base Case Operations

The first category of the pro forma analysis is the cost of service for ICP operations. To estimate the overall costs associated with ICP operations, the following components have been included:

- Power Supply Costs
- Non-Power Supply Costs
 - Start-up costs
 - ICP staffing and administration costs
 - Consulting Support
 - SCE and regulatory charges
 - Reserves
 - New Program Fund
 - Financing costs
- Pass-Through Charges from SCE
 - Transmission and distribution charges
 - Power Cost Indifference Adjustment (PCIA) Charge
 - Franchise Fee
 - Other non-bypassable charges

Once the costs of ICP operations have been determined, the total costs can be compared to SCE's projected rates.

Power Supply Costs

A key element of the cost of service analysis is the assumption that electricity will be procured under a power purchase arrangement (PPA) for both renewable and non-renewable power until local ICP resources can be developed. Power supply must be obtained by ICP's procurement contractor prior to commencing operations. The products required from the third party procurement are energy, capacity, renewable energy, load forecasting and scheduling coordination.

The calculated starting cost of electric power supply, including the cost of the scheduling coordinator and all regulatory power requirements, is between \$45 and \$65 per MWh. This price

represents the price needed for a full requirements, load following electricity contract. The variation in price is a function of the desired level of renewable resources.

Non-Power Supply Costs

While power supply costs make up the majority of costs associated with operating ICP (roughly 80 percent), there are several additional cost components that must be considered in the pro forma financial analysis. These additional non-power supply costs are noted below.

Start-Up Activities and Costs

Monthly costs associated with ICP start-up and phasing of customer enrollments include expenditures for program staff/contract staff, associated infrastructure, contractor costs and fees payable to SCE by ICP. The estimated startup costs include capital expenditures and one-time expenses as well as ongoing expenses that will be accrued before significant revenues from ICP operations are realized. These cost components are quantified in Exhibit 22 and Exhibit 23 below.

Exhibit 22 Monthly Start-Up Cost Summary (ICP)						
	2017 Pre-Start Costs					
	January	February	March	April	May	June
Start-Up Costs						
Infrastructure	\$0	\$0	\$0	\$0	\$55,000	\$35,000
Consultants	\$70,000	\$100,000	\$100,000	\$100,000	\$125,000	\$125,000
Staffing	\$0	\$0	\$0	\$0	\$38,333	\$51,677
Utility Trans. Fee	\$0	\$0	\$780	\$0	118,636	130,749
Total Start-Up	\$70,000	\$100,000	\$100,780	\$100,000	\$336,969	\$342,416

Exhibit 23 Start-Up Costs Summarized by Phase (ICP)			
		Phase 1	Phase 2
	Total 2017 Pre-Start Costs	July – December 2017	CY 2018
Start-Up Costs			
Infrastructure	\$90,000	\$260,000	\$350,000
Consultants (incl. Data Manager)	\$620,000	\$1,471,529	\$15,724,632
Staffing	\$90,000	\$970,000	\$2,488,333
Utility Trans. Fee	\$250,165	\$3,574,050	\$8,197,628
Total Start-Up	\$1,050,165	\$6,275,579	\$26,760,549

Other costs related to starting up ICP's program will be the responsibility of ICP's consultants and contractors. These include capital requirements paid by others, customer information system costs, electronic data exchange system costs, call center costs, and billing administration/settlements systems costs. The costs payable by ICP are contained in Exhibit 23.

Estimated Staffing Costs

For start-up, it is assumed that an operating team will be employed prior to the Board's selection of an Executive Director, per the example of other CCAs in California. This operating team includes one assistant Executive Director and one manager of policy and regulatory affairs and one administrative assistant. This staff is supported by consultants to manage and operate the CCA.

ICP will have a continuum of options for ongoing staffing. These options range from hiring all internal staff incrementally to match workloads involved in forming ICP, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario) to hiring an entity to run the entire CCA operations. All of these options are discussed below.

Full Staff Scenario

At one end of the continuum, Exhibit 24 provides the estimated staffing budgets for the start-up period through 2018. Staffing budgets include direct salaries and benefits. Exhibit 24 details the anticipated staffing of ICP.

Exhibit 24 Staffing Plan (ICP)			
Number of Staff	Pre Start-Up	2017 (Phase 1)	2018 (Phase 2)
Executive Director	0	1	1
Assistant Executive Director	1	1	1
Policy & Regulatory Manager	1	0	1
Regulatory Analyst	0	1	1
Administrative Assistant	1	1	2
Finance & Rates Manager	0	1	1
Rates Analyst	0	1	1
Accounting & Billing Analyst	0	1	2
Human Resources Manager	0	1	1
HR Specialist	0	1	1
Sales & Marketing Manager	0	1	1
Energy Efficiency Program Manager	0	0	1
Account Representatives	0	2	2
Communication Specialists	0	2	2
IT Manager	0	1	1
IT Specialist	0	0	1
Total Number of Employees	3	15	20
Total Staffing Costs	\$90,000*	\$970,000*	\$2,488,333

*Represents only partial year.

Based on this staffing plan, ICP will initially employ 3 staff members. Once ICP has expanded its service area and operated for one year or so, it is anticipated that staffing will increase to approximately 20 employees. These positions to be hired by ICP over the first two years are described below:

Executive Director

The Executive Director will be responsible for overseeing ICP operation and ensuring that the vision of the JPA Board is followed. The Executive Director will ultimately be responsible for all ICP programs, finances and communication programs plus be accountable to the Board.

Assistant Executive Director

The Assistant Executive Director will oversee the day to day operation of ICP. In particular, this staff position will work closely with outside consultants, and oversee hedging and power procurement, resource portfolio strategy, CAISO settlements and other financial planning and rate setting analysis. Behind the meter ICP programs will also be coordinated through this position.

Policy and Regulatory Manager

The Policy and Regulatory Manager will oversee the legal and regulatory functions of ICP. This position will work closely with the CPUC and State/Federal legislators. ICP will require ongoing regulatory representation to file resource plans, resource adequacy compliance, compliance with California RPS, and overall representation on issues that will impact ICP and its customers. ICP should plan on maintaining an active role at the CPUC, CEC, FERC and the California legislature.

Finance and Rates Manager

The Finance and Rates Manager oversees ICP's budgets and accounting functions. In addition, this person will develop annual budgets, rates and credit policies for approval by the Board. Managing the overall financial aspects of ICP is expected to be a significant work activity.

Sales and Marketing Manager

The Sales and Marketing Manager is responsible for the enrollment and notification of new customers. In addition, this staff person will market ICP, and provide on-going communication with ICP's communities and customers. A significant amount of customer service and key account representation will be necessary in addition to regular marketing services. This position will be the point person for the outsourced data management and customer service consultants.

Administrative Assistant

The staffing plan assumes a full-time administrative assistant will be added during the pilot phase to provide administrative assistance to management.

Future Staff

As additional customers join ICP, duties can be shifted from third-party consultants to in-house staff if internal staffing is more cost effective.

Third-Party Operator Scenario

At the other end of the continuum, ICP’s Board could hire a third-party vendor to operate the CCA. Under this option, the Board would likely issue an RFP for the requested services, evaluate the responses, then decide whether to fully staff internally, hire some internal staff and some consultants, or turn the entire CCA operation over to a third party.

It should be noted that the existing California CCAs have opted for an organizational structure that features a significant number of internal staff as opposed to using all consultants to operate their CCA. There are many reasons for this type of operational structure but two primary reasons are:

- The size of the CCA is such that in most cases it is the largest enterprise found among the CCA participants.
- This CCA will have direct contact with most of the governing body’s constituents at least once a month through the CCA billing process.

Because of these noteworthy observations, existing CCAs have adopted more of a “hands on” organizational structure, but the preferred operational mode for a new CCA is ultimately dictated by the Board.

Estimated Infrastructure Costs

Infrastructure or overhead needed to support the organization includes computers and other equipment, office furnishings, office space and utilities. These expenses are estimated at \$90,000 during program pre-startup. Office space and utilities are ongoing monthly expenses that will begin to accrue before revenues from program operations commence and are therefore assumed to be financed as shown in Exhibit 25 and Exhibit 26

Exhibit 25 Monthly Estimated Infrastructure Costs (ICP)						
	2017 Pre-Start					
	January	February	March	April	May	June
Infrastructure Costs						
Computers	\$0	\$0	\$0	\$0	\$15,000	\$5,000
Furnishings	\$0	\$0	\$0	\$0	\$15,000	\$5,000
Office Space	\$0	\$0	\$0	\$0	\$15,000	\$15,000
Utilities/Other Office Supplies	\$0	\$0	\$0	\$0	\$10,000	\$10,000
Total Start-Up	\$0	\$0	\$0	\$0	\$55,000	\$35,000

Exhibit 26 Estimated Infrastructure Cost by Phase (ICP)			
	2017	Phase 1	Phase 2
	Total Pre-Start Costs	July – December 2017	CY 2018
Infrastructure Costs			
Computers	\$20,000	\$55,000	\$25,000
Furnishings	\$20,000	\$55,000	\$25,000
Office Space	\$30,000	\$90,000	\$180,000
Utilities/Other Office Supplies	\$20,000	\$60,000	\$120,000
Total Infrastructure Costs	\$90,000	\$260,000	\$350,000

It is estimated that the per employee start-up cost is approximately \$10,000. This expense covers computer and furniture needs. An additional annual expense of \$180,000 for office space, and approximately \$120,000 per year in office supplies and utilities costs is expected. In addition, it is assumed that computers will need to be replaced every 5 years and furnishings every 10 years.

Utility Implementation and Transaction Charges

The estimated costs payable to SCE for services related to ICP start-up include costs associated with initiating service with SCE, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees. These distribution utilities fees are explicitly stated in the relevant SCE tariffs.

Customers who establish service with ICP will be automatically enrolled in the program and have sixty days from the date of enrollment to customer opt-out of the program. Such customers will be provided with two opt-out notices within this sixty-day post enrollment period. The first notice will be mailed to customers approximately sixty days prior to the date of automatic enrollment. A second notice will be sent approximately thirty days later. Following automatic enrollment, two additional opt-out notices will be provided within the sixty-day period following customer enrollment. It is estimated that the enrollment charges will be approximately \$3.4 million for 2017 and \$3.5 million for 2018, as shown in Exhibit 27 and Exhibit 28. Enrollment charges are almost as high in 2017 because Phase 2 enrollment starts prior to Phase 2 implementation.

Exhibit 27 Monthly Utility Transaction Fees (ICP)						
	Pre-Start					
	January	February	March	April	May	June
Enrollment Charges	0	0	780	0	\$118,636	\$130,749
Ongoing Charges	0	0	0	0	0	0
Total SCE Transaction Fee	\$0	\$0	\$780	\$0	\$118,636	\$130,749

Exhibit 28 Utility Transaction Fees by Phase (ICP)			
	Total Pre-Start Costs	Phase 1 2017	Phase 2 2018
Enrollment Charges	\$250,165	\$3,402,449	\$3,469,521
Ongoing Charges	0	171,601	\$4,728,107
Total SCE Transaction Fees	\$250,165	\$3,574,050	\$8,197,628

Estimates of Third Party Contractor Costs

Contractor costs include outside assistance for advertising, legal services, resource and financial planning, implementation support, customer enrollment, customer service, and payment processing/accounts receivable and verification. The latter three will be provided by ICP's customer account services provider, and these preliminary estimates will be refined as the services and costs provided by the selected contractor are negotiated. Exhibit 29 and Exhibit 30

show the estimated contractor costs during the startup period assuming full staff scenario is implemented.

Exhibit 29						
Monthly Estimated Consultant Costs (ICP)						
	Pre-Start					
	January	February	March	April	May	June
Legal/Regulatory	\$20,000	\$50,000	\$50,000	\$50,000	\$50,000	\$50,000
Communication	\$0	\$0	\$0	\$0	\$25,000	\$25,000
Data Management	\$0	\$0	\$0	\$0	\$0	\$0
Financial Consulting	\$50,000	\$50,000	\$50,000	\$50,000	\$50,000	\$50,000
Total Consultant Costs	\$70,000	\$100,000	\$100,000	\$100,000	\$125,000	\$125,000

Exhibit 30			
Estimated Consultant Costs by Phase (ICP)			
		Phase 1	Phase 2
	Total Pre-Start Costs	2017	2018
Legal/Regulatory	\$270,000	\$300,000	\$480,000
Communication	\$50,000	\$150,000	\$300,000
Data Management	\$0	\$731,529	\$14,414,632
Financial Consulting	\$300,000	\$290,000	\$530,000
Total Consultant Costs	\$620,000	\$1,471,529	\$15,724,632

The estimate for each of the services is based on costs experienced by other CCAs. Consultant costs are increased by inflation every year.

Estimated Reserves

ICP is assumed to receive capital financing during its startup phase. After a successful launch, ICP should strongly consider building up a reserve fund that is available to address contingencies, cost uncertainties, rate stabilization or other risks faced by ICP. This Plan assumes that ICP will begin building its reserves starting from its launch. It is assumed that the first year's reserve funds can be used to pay off loans. After four years, the assumed savings rate will have accumulated enough reserves for 3 months of expenses. This level of reserves will provide financial stability and assist ICP in obtaining favorable rates if additional financing is needed. After that point, additional savings can begin to fund lower rates, more programs and/or economic development projects (see Programs Section).

Estimated New Programs Fund

Once the reserve fund has reached its target, the revenue requirement includes budget for new customer programs including DER support, additional energy efficiency program offering, further rate discounts, etc. These programs have not been identified at this time as the Board will make the decision of priorities for funding.

Cash Flow Analysis and Working Capital

This cash flow analysis estimates the level of working capital that will be required until full operation of ICP is achieved. For the purposes of this Plan, it is assumed that ICP pre-operations begin in January 2017 and continue through June 2017. In general, the components of the cash flow analysis can be summarized into two distinct categories: (1) Cost of ICP operations, and (2) Revenues from ICP operations. The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with ICP and specifically account for the transition or “Phase-In” of ICP customers. The cash flow analysis assumes the phase-In schedule for ICP as described previously.

The cash flow analysis also provides estimates for revenues generated from ICP operations or from electricity sales to customers. In determining the level of revenues, the cash flow analysis assumes the customer phase-in schedule noted above, and assumes that ICP provides a discount of 3.8 percent from the existing rates for each customer class, where pre-operations run from January 1, 2017 to June 31, 2017. Thereafter, Phase 1 starts in July 2017.

The results of the cash flow analysis provide an estimate of the level of working capital required for ICP to move through the pre-operations period. This estimated level of working capital is determined by examining the monthly cumulative net cash flows (revenues minus cost of operations) based on assumptions for payment of costs by ICP, along with an assumption for when customer payments will be received. The cash flow analysis assumes that customers will make payments within 60 days of the service month, and that ICP will make payments to suppliers within 30 days of the service month. This analysis is somewhat conservative because customer payments begin to come in soon after the bill is issued, and most are received before the due date. At the same time, some customer payments are received well after the due date. The 30-day net lag is a conservative assumption for cash flow purposes.

For purposes of determining working capital requirements related to power purchases, ICP will be responsible for providing the working capital needed to support electricity procurement unless the electricity provider can provide the working capital as part of the contract services. In addition, ICP will be obligated to meet working capital requirements related to program management. For this Plan, it is assumed that this working capital requirement is included in the short term financing associated with start-up funding. Several operating CCAs have been successful in negotiating lines of credit, lockbox arrangements and delayed payment arrangements which reduce the cost of working capital. Any of these arrangements will reduce the cost of working capital and increase the potential savings to customers.

A summary of working capital needs is presented below on Exhibit 31.

Exhibit 31 Working Capital Needs (ICP)		
	2017	2018
Working Capital (ICP)	\$12 Million	\$150 Million

Total Financing Requirements

The start-up of the ICP program will require a significant amount of capital for three major functions: (1) staffing and contractor costs; (2) program initiation; and (3) working capital. Each of these anticipated requirements is discussed below.

Staffing costs for the pre-implementation period (January 2017 through June 2017) are estimated to be approximately \$90,000. Contractor costs for the same time period are estimated to be approximately \$620,000. These costs include: advertising/communications, consulting, legal, and data management.

ICP initiation costs include the infrastructure that ICP will require (office space, utilities, computers) as well as the distribution utility fees for initiating ICP. Infrastructure costs are estimated to be approximately \$90,000 and the distribution utility fees are estimated to be approximately \$250,165.

The Public Utilities Code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to SCE service under certain circumstances. In addition, SCE requires a bond equivalent to two months of transaction fees.

For the ICP scenario, the total financing requirement, including working capital, during the start-up and pilot periods, are estimated to be approximately \$20 million, increasing to approximately \$175 million following full enrollment. The first \$20 million is needed in Spring 2017.

Financing Plan

The initial start-up funding will be provided via short-term financing. ICP will recover the principal and interest costs associated with the start-up funding via subsequent retail rates. It is anticipated that the start-up costs will be fully recovered within the first five years of ICP operations.

Additional financing will be needed at the beginning of Phase 2. Depending on market conditions and payment terms established with the third-party suppliers, the loan may need to be increased to approximately \$175 million for the start of Phase 2. This number will be refined as the ICP program becomes operational, and bids are received from power providers.

Based on recent information regarding financing options for CCA's, the Plan's financial analysis assumes that ICP can obtain a loan for the first \$20 million with a term of 5 years at a rate of 5.5 percent. The second loan for \$175 million is assumed for a 20-year term at 5.5 percent.

The detail of the base case financial analysis is provided in Appendix B.

Cost of Service for Three CCA Operations

There are several options for how to setup and operate a CCA. In addition to forming one CCA as outlined as the base case in the Plan, three CCAs (one for each COG), or individual jurisdictions

is an option. This option would entail each of the three COGs or an individual jurisdiction providing a full service CCA including power procurement, data management and local program development/outreach.

In order to develop this three CCA scenario, each major cost component has been reviewed to determine the appropriate cost structure for each individual CCA based on the size of load. Power procurement, SCE charges and data management costs follow load and number of customers in each CCA. However, the internal costs (staffing, office space, consulting) are about the same for a 100,000-meter utility, and a 1,000,000-meter utility. The results are shown for the 50% Renewable portfolio, but Appendix B provides the results for all three power supply scenarios for each of the three COGs separately.

“Three CCA” Assumptions

It is anticipated that if the three COG’s operate separately, staffing would be fairly similar to the ICP scenario for each of the CCA’s. Exhibit 32 provides the estimated staffing and annual cost under the separate CCA scenario. Again, the Plan is looking at the most conservative numbers to show the feasibility of implementing a CCA, the Plan does not specify that this option hire all in-house staff from the beginning, nor does it specify that a CCA should hire all of the staff listed below. The information below is based on the staffing currently being provided by Marin Clean Energy, Lancaster Choice Energy, and Sonoma Clean Energy.

Exhibit 32 Staffing Plan (Three CCAs)			
Number of Staff	CVAG	SANBAG	WRCOG
Executive Director	1	1	1
Assistant Executive Director	1	1	1
Policy & Regulatory Manager	1	1	1
Regulatory Analyst	0	1	1
Administrative Assistant	2	2	2
Finance & Rates Manager	1	1	1
Rates Analyst	0	1	1
Accounting & Billing Analyst	2	2	2
Human Resources Manager	0	1	1
HR Specialist	0	1	0
Sales & Marketing Manager	0	1	0
Energy Efficiency Program Manager	1	1	1
Account Representatives	0	2	2
Communication Specialists	0	2	0
IT Manager	0	1	1
IT Specialist	0	1	1
Total Number of Employees	9	20	16
Total Staffing Costs	\$1,190,000	\$2,488,333	\$1,704,167

The estimated start-up costs for each of the COGs and the combined “Three CCA” scenario are shown in Exhibit 33.

For the separate scenarios, computers, furnishings and supplies were forecast based on employees in each CCA. In the WRCOG scenario, staff is added slower than in the SANBAG scenario, thus delaying some staffing and infrastructure costs from 2017 to 2018.

Exhibit 33 Estimated Infrastructure Cost by Phase (Three CCAs)			
	Total Pre-Start Costs	Phase 1 2017	Phase 2 2018
Infrastructure Costs			
CVAG	\$90,000	\$150,000	\$350,000
SANBAG	\$90,000	\$260,000	\$350,000
WRCOG	\$90,000	\$150,000	\$420,000
Total Infrastructure Costs	\$270,000	\$560,000	\$1,120,000

The estimated costs payable to SCE for services related to ICP start-up include costs associated with initiating service with SCE, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees. These distribution utilities fees are explicitly stated in the relevant SCE tariffs. The utility transaction fees for each of the COGs separately, are shown in Exhibit 34.

Exhibit 34 Utility Transaction Fees by Phase (Three CCAs)			
	Total Pre-Start Costs	Phase 1 2017	Phase 2 2018
CVAG	\$39,557	\$413,653	\$918,803
SANBAG	\$149,501	\$1,939,421	\$4,405,258
WRCOG	\$68,749	\$1,228,726	\$2,873,783
Total SCE Transaction Fees	\$257,807	\$3,581,800	\$8,197,844

Exhibit 35 shows the estimated contractor costs during the startup period for the “Three CCA” scenario. These are costs assumed for financial and accounting assistance, legal assistance, data management and communication.

Exhibit 35 Estimated Consultant Costs by Phase (Three CCAs)			
	Total Pre-Start Costs	Phase 1 2017	Phase 2 2018
CVAG	\$620,000	\$606,215	\$2,398,639
SANBAG	\$620,000	\$1,172,679	\$9,074,423
WRCOG	\$620,000	\$932,634	\$6,331,569
Total Consultant Costs	\$1,860,000	\$2,711,528	\$17,804,631

Estimated non-power supply costs associated with ICP start-up and phasing of customer enrollments for the “Three CCA” scenarios are provided in Exhibit 36.

Exhibit 36
Start-Up Costs for Three CCAs Summarized by Phase

	CVAG	CVAG	SANBAG	SANBAG	WRCOG	WRCOG
	2017	2018	2017	2018	2017	2018
Start-Up Costs						
Infrastructure	\$240,000	\$350,000	\$350,000	\$350,000	\$240,000	\$420,000
Consultants	\$1,226,215	\$2,398,639	\$1,792,679	\$9,074,423	\$1,552,634	\$6,331,569
Staffing	\$400,000	\$1,190,000	\$1,060,000	\$2,488,333	\$400,000	\$1,704,167
Utility Trans. Fee	\$453,211	\$918,803	\$2,088,921	\$4,405,258	\$1,297,475	\$2,873,783
Total Start-Up	\$2,319,426	\$4,857,442	\$5,291,600	\$16,318,014	\$3,490,109	\$11,329,519

Each CCA will be responsible for providing the working capital needed to support electricity procurement unless the electricity provider can provide the working capital as part of the contract services. In addition, each CCA will be obligated to meet working capital requirements related to program management. It is assumed that this working capital requirement is included in the short term financing associated with start-up funding. A summary of working capital needs for the three CCAs is presented below on Exhibit 37.

Exhibit 37
Working Capital Needs

	2017	2018
Working Capital (CVAG)	\$3 Million	\$35 Million
Working Capital (SANBAG)	\$5 Million	\$75 Million
Working Capital (WRCOG)	\$4 Million	\$50 Million

For the “Three CCA” scenario, the total financing requirements, during the start-up and pilot periods, are estimated to be approximately \$22 million with \$5 from CVAG, \$10 million from SANBAG and \$7 million from WRCOG. Before full enrollment, additional capital in the order of \$190 million will be needed from the three COGs following full enrollment. The first \$22 million is needed in Spring 2017.

The option to form three CCAs within ICP has some initial appeal. If each COG formed a CCA, each would achieve greater local control and avoid potential governance issues. However, the goal of providing the lowest possible rates would not be achieved. As such, forming three CCAs versus one for back office functions would cost the CCA customers an addition \$17 million in the first year of operating (when including the need to build reserves) and an additional \$7 - \$9 million per year in operating costs on an ongoing basis. This is a material amount of economic inefficiency. However, the additional cost is only a small portion of total program costs at 1.7 percent in the first year and roughly 1 percent in the subsequent years. Therefore, it remains a viable option if the separate COGs value local control at that premium. A summary of the comparison between organizational structures is shown in Exhibit 38.

Exhibit 38 Comparison between Organizational Structures			
	Total Start-Up Costs	Operating Costs	Estimated Rate Savings
	2017	2018	2018
CVAG	\$2,319,426	\$124,635,397	2.1%
SANBAG	\$5,291,601	\$535,477,882	3.4%
WRCOG	\$3,490,109	\$320,724,514	3.0%
Three COGs Combined	\$11,101,136	\$980,837,793	
ICP	\$7,325,744	\$963,997,388	3.7%
Savings/Year	\$3,775,392	\$16,840,405	

Products, Services, Rates Comparison and Environmental/Economic Impacts

This section of the Plan provides a comparison of service and rates between SCE and ICP. Rates are evaluated based on total ICP electric total bundled rates as compared to SCE's total bundled rates. Total bundled electric rates include the rates charged by ICP, including non-bypassable charges, plus SCE's delivery charges. This section also includes the environmental impacts based on the reduction in Green House Gases (GHG), and the economic development impact on local jobs and overall economic activity created by ICP programs.

Rates Paid by SCE Bundled Customers

The average customer weighted SCE rates have been calculated based on current rate schedules and ICP's projected customer mix. SCE's current 2016 rates and surcharges have been applied to customer load data aggregated by major rate schedules to form the basis for the SCE rate forecast.

The average SCE delivery rate, which is paid by both SCE bundled customers and ICP customers, has been calculated based on the forecasted customer mix for ICP. For future years, the SCE rate forecast assumes the delivery costs will increase by 2 percent per year, a conservative assumption given the history of SCE rate increases.

Similarly, the current average power supply rate component for SCE bundled customers has been calculated based on the estimated ICP customer mix. The SCE power supply rate component has been forecast to increase based on SCE's most recent filings and incorporating the increased RPS requirement mandated by SB 350. The most recent Energy Resource Recovery Account (ERRA) filing has been used to determine the 2017 SCE generation rates for each rate category. Finally, the SCE power supply rates have been projected to increase based on the renewable and non-renewable market price forecast, regulatory requirement for RPS, storage requirement and resource adequacy objectives.

Rates Paid by ICP Customers

It is anticipated that ICP's rate designs will initially mirror the structure of SCE's rates with the appropriate discounts so that similar rates can be provided to ICP's customers. In determining the level of ICP rates, the financial analysis assumes the customer phase-in schedule noted above and that the implementation phase costs are financed via a start-up loan.

In addition to paying ICP's power supply rate, ICP customers will pay the SCE delivery rate and non-bypassable charges. The calculation of the delivery rate is described earlier. The non-bypassable charges that are payable to SCE by ICP customers include:

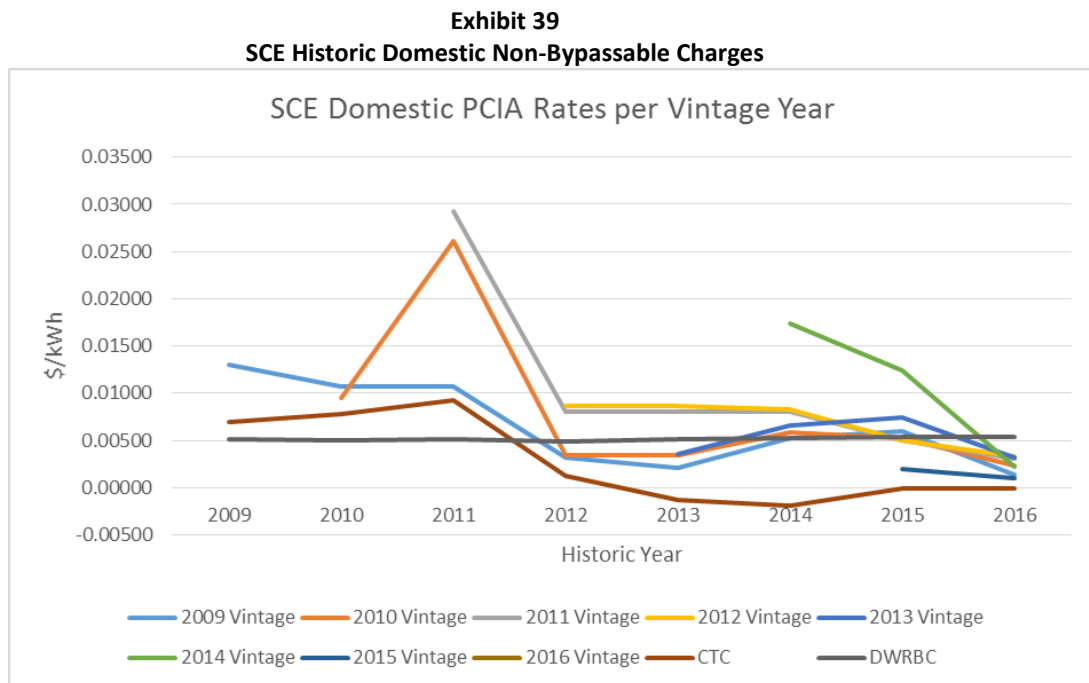
- Power Cost Indifference Adjustment (PCIA)
- Department of Water Resources Bond Charge (DWRBC)
- Competition Transition Charge (CTC)
- Generation Municipal Surcharge (or Franchise Charge)

The DWRBC is the charge to recover the interest and principal of the California Department of Water and Resources (DWR) bonds. This charge is projected to remain at the current level and is scheduled to end in 2023. The CTC is the ongoing charge, which recovers the above market costs of utility generation. This charge is minimal at the moment and is not expected to be a significant cost to ICP customers.

Power Cost Indifference Adjustment (PCIA)

The PCIA is a charge that is designed to keep bundled customers “indifferent” when other customers leave bundled service. The PCIA is calculated annually by subtracting the market price of wholesale power from the incumbent utility’s average cost of power supply based on a methodology determined by the CPUC.⁸

Exhibit 39 provides the historic values of the PCIA, CTC and DWRBC for the residential class. It is important to note that the non-by passable charges differ by the vintage of a CCA. The vintage of the CCA depends on when the CCA provides a binding notice of intent to SCE.



Note that CARE and medical base line customers do not pay the DWRBC or PCIA charges.

⁸ See D.-6-07-030 as modified by D. 11-12-018.

For this Plan, it was assumed in the base case that the PCIA changes based on the differential between SCE's generation cost and market prices. For this Plan, PCIA is forecast to increase initially due to the end of offsetting credits that expire in 2018. Post-2018, the PCIA is expected to grow based on the inverse of the market price growth rate. The PCIA is calculated based on the difference between SCE's surplus resource cost and the market price. Therefore, as market prices increase, SCE's PCIA rate decreases as their surplus resources become more cost effective relative to market prices.

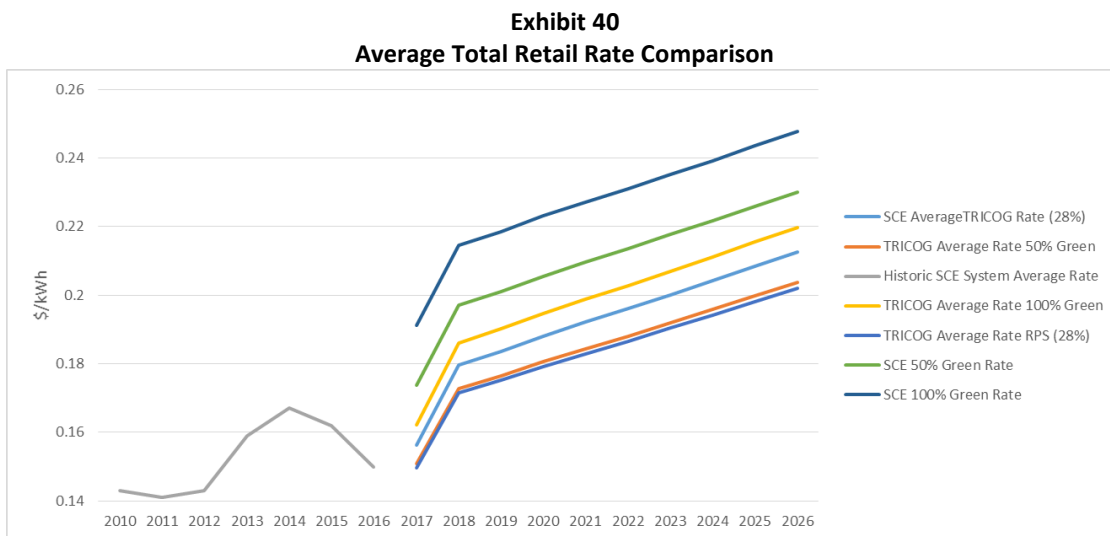
Generation Municipal Surcharge (or Franchise Fee)

The franchise fee is a surcharge that SCE pays cities and counties for the right to use public streets to provide utility services. The franchise fee is a revenue source for municipalities implemented on privately owned utilities. The franchise Fee is a "rental" or "toll for the use of a municipality's streets and poles, as well as for permission to provide service in their jurisdiction. The Franchise Act establishes that a franchise fee of 2 percent of the franchisees gross annual receipts arising from the use, operation, or possession of the franchise within the city limits.⁹"

SCE collects the surcharges and passes them to cities and counties. This tax is part of SCE's current rates and is therefore passed on to the CCA customers as a non-bypassable charge called the Generation Municipal Surcharge. SCE will continue to collect the franchise fees for both generation and distribution services and pay the cities and counties the owed revenue. The franchise fee is not forecast to change during the analysis horizon.

Rate Impacts

Based on ICP's projected power supply costs and operating costs, and SCE's power supply and delivery costs, forecasts of ICP and SCE total rates have been developed. These rates are illustrated below on Exhibit 40.



⁹ The California Municipal Law Handbook. 2002 Edition

For this Plan, it has been assumed that the projected rate decrease is applied uniformly across all rate classes. Once established, it will be up to the ICP Board and staff to develop rates for each rate class that reflects cost of service. Based on these assumed ICP discounts off the comparable SCE rate, Exhibit 41 provides a comparison of the indicative bundled rates for ICP's products with the current SCE rate.

Exhibit 41 Indicative Rate Comparison in ¢/kWh (First Full Year of Service)							
Rate Class	Customer Type	2017 Estimated SCE Bundled Rate*	ICP RPS Bundled Rate	SCE 50% Green Bundled Rate	ICP 50% Green Bundled Rate	SCE 100% Green Bundled Rate	ICP 100% Green Bundled Rate
Residential	Domestic	20.55	19.58	22.30	19.81	24.05	21.79
Residential Care	Domestic	12.22	11.64	13.97	11.78	15.72	12.96
GS-1	Commercial	17.03	16.23	18.78	16.41	20.53	18.06
GS-2	Commercial	16.57	15.79	18.32	15.97	20.07	17.57
GS-3	Industrial	14.71	14.02	16.46	14.18	18.21	15.60
PA-2	Public Authority	13.08	12.46	14.83	12.61	16.58	13.87
PA-3	Public Authority	11.31	10.78	13.06	10.90	14.81	11.99
TOU-8 Secondary	Domestic	13.07	12.45	14.82	12.60	16.57	13.86
TOU-8 Primary	Commercial	11.84	11.28	13.59	11.41	15.34	12.55
TOU-8 Substation	Industrial	7.76	7.39	9.51	7.48	11.26	8.23
Initial Total ICP Rate Savings over Comparable SCE Rates of 50% or 100% Green			4.9%		11.2%		9.4%
Initial Total ICP Rate Savings over SCE's Standard Bundled Rate			4.9%		3.8%		-5.7%

*SCE bundled average rate based on SCE's ERRR 2017 Draft Filing

Exhibit 42 shows the initial rate savings associated with the formation of a CCA. By referencing Appendix B, these initial savings increase after ICP becomes fully functional. The savings by rate schedule after ICP is fully functional are presented below in Exhibit 42.

Exhibit 42 CCA Rate Savings at Fully Functional Operations	
Power Supply Scenario	Range of Savings*
ICP RPS	4.9% - 5.7%
ICP 50% Renewable	3.8% - 4.5%
ICP 100% Renewable	(5.7%) – (5.0%)

*Note Appendix B for detail.

A financial proforma in support of these rates can be referenced in Appendix B.

It should be noted that the rate savings noted in ES-2 still allow the accumulation of significant reserves for the CCA. As illustrated in Appendix B, the proforma include a line item called “Contribution to Annual Reserves” that go towards funding the needed cash working capital (approximately \$250M). After the target reserves have been met, additional reserves can be used to further lower CCA retail rates, invest in local renewable projects, provide additional energy efficiency programs, or any other CCA-related activity as directed by the CCA’s Board. The projected funds available for this purpose are provided in the line item titled “New Programs” in the proforma. It is widely held that Proposition 26 prohibits the use of these reserves for any non-CCA related activity. The accumulate reserves and new program accruals present the new CCA with a large amount of funding and numerous opportunities going forward.

Exhibit 43 below highlights how much financial reserves are generated among the rate reductions noted above.

Exhibit 43 Accumulative Fund Balances for Financial Reserves and New Programs Under the 50% Renewable			
Year	Accumulative Financial Reserve Funds (\$ x 1000)	Accumulative New Project Funds (\$ x 1000)	Total Financial Reserves (\$ x 1,000)
2018	\$63,330	\$0	\$63,330
2019	\$130,225	\$0	\$130,225
2020	\$213,504	\$0	\$213,504
2021	\$259,527	\$46,022	\$305,549
2022	\$259,527	\$147,956	\$407,483
2023	\$259,527	\$262,232	\$521,759
2024	\$259,527	\$384,563	\$644,090
2025	\$259,527	\$515,637	\$775,164
2026	\$259,527	\$653,238	\$912,765
2027	\$259,527	\$796,925	\$1,056,452
2028	\$259,527	\$946,175	\$1,205,702
2029	\$259,527	\$1,101,642	\$1,361,169
2030	\$259,527	\$1,254,153	\$1,513,680

These new project and financial reserve fund balances can be used for CCA-related activities as directed by the Board. These fund balances can also be used for rate reductions larger than calculated in the Plan’s base case.

Local Resources/Behind the Meter ICP Programs

ICP may wish to plan to establish a Net Energy Metering (“NEM”) program for qualified customers in their service territory to encourage DER. In addition, ICP should work with State agencies and SCE to promote deployment of distributed energy resources (DER) within ICP’s service territory, with the goal of maximizing use of the available incentives that are funded through current utility distribution rates and public goods surcharges.

ICP should also consider establishing a program which offers a combination of retail tariffs, rebates, incentives and other bundled offerings intended to increase customer participation in demand-side programs including: renewable distributed energy resources, energy storage,

energy efficiency, demand response, electric vehicle charging, and other clean energy benefits defined as Distributed Energy Resources (DER). ICP can work with State agencies and SCE to promote deployment of DERs in specific and targeted locations throughout SCE's distribution grid in order to help support efficient grid operations and maintenance as part of development of the future "smart grid".

Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

The amount of renewable power in SCE's power supply portfolio is 28 percent¹⁰ and will rise to 33 percent by 2020. Based on power supply strategy described previously, the estimated GHG emission reductions attributable to forming ICP are forecast to range from 1.33 to 2.34 million metric tons CO₂e per year by 2018 assuming a 50 percent RPS target is achieved. The baseline for comparison is the resource mix used by SCE versus the resource mix that will be utilized by ICP. Exhibit 44 details these reductions.

Exhibit 44 Baseline Comparison of GHG Reduction by ICP by 2018				
	ICP	CVAG	SANBAG	WRCOG
Forecast Renewables (50% Renewables) ICP (GWH) – Phase 2	7,533	916	4,184	2,433
ICP RPS (GWH) – Phase 2	4,219	513	2,343	1,362
Additional Green Power	3,315	403	1,841	1,070
CO ₂ reduction – Low (Million Metric tons CO ₂ e)	1.33	0.16	0.74	0.43
CO ₂ reduction – High (Million Metric tons CO ₂ e)	2.34	0.28	1.30	0.76

The reductions in GHG associated with ICP operations are significant. This amount of reduced emissions represents a reduction in the emissions from the in-State generation resources from 2.6 to 4.6 percent.

Economic Development

The analyses contained in this Plan for forming ICP has focused on the direct rate effects of this formation. However, in addition to direct effects, indirect microeconomic effects are also encountered.

The indirect effects of creating ICP include the effects of increased commerce, and improved environmental and health conditions. Within this Plan, an Input/Output (IO) analysis is undertaken to analyze these indirect effects. The IO model turns on the assumption that forming ICP will lead to lower energy rates for their customers. Three types of impacts are analyzed in the IO model. These are described below.

Local Investment - ICP may choose to implement programs to incentivize investments in local

¹⁰ http://www.cpuc.ca.gov/RPS_Homepage/

distributed energy resources (DER). These resources can be behind the meter or community projects where several customers participate in a centrally located project. This demand for local resources will lead to an increase in the manufacturing and installation of DER, and lead to an increase in employment in the manufacturing and construction sectors.

Increased Disposable Income - Establishing ICP will lead to reduced customer rates for energy, more disposable income for individuals and greater revenues for businesses. These cost savings would then lead to more investment by individuals and businesses for personal or business purposes. This increase in spending will then lead to increased employment for multiple sectors such as retail, construction, and manufacturing.

Environmental and Health Impacts - With the creation of ICP, other non-commerce indirect effects will occur. These may be largely environmental such as improved air quality or improved human health due to ICP adopting mainly renewable energy sources versus continuing use of traditional energy sources. This resource strategy significantly reduces GHG emissions compared with SCE's current resource mix. While the change in GHG emissions is not modeled directly in economic development models used in this Plan, the reduction of these GHGs may be captured in indirect effects projected by the models.

Input-Output Modeling (IO Modeling)

IO modeling is a quantitative analysis representing relationships (dependence) between industries in an economy. IO models are based on the implicit assumption that each basic sector has a multiplier, or ripple effect, on the wider economy because each sector purchases goods and services to support that sector. IO modeling estimates the inter-industry transactions and uses those transactions to estimate the economic impacts of any change to the economy.

The IO model used in the Plan, IMPLAN, displays the economic impacts of changes in rates into four categories: employment, labor income, value added, and output. Employment is the number of jobs gained or lost. Labor income involves the increase in salaries and wages for current and newly gained or lost employees. Value added, similar to Gross Domestic Product (GDP), is the payment to labor and capital used in production of a particular industry.

IO models are made up of matrices of multipliers between each industry present in an economy. Each column shows how an industry is dependent on other industries for both its inputs to production and outputs. The tables of multipliers can be used to estimate the effects in changes in spending for various industries, household consumption, or labor income. Both positive and negative impacts can be measured using IO modeling. IO modeling produces results broken down into several categories. Each of these is described below:

- **Direct Effects** – Increased purchases of inputs used to produce final goods and services purchased by residents. Direct effects are the input values in an IO model, or first round effects.
- **Indirect Effects** – Value of inputs used by firms affected by direct effects (inputs). Economic activity that supports direct effects.

- **Induced Effects** – Results of Direct and Indirect effects (calculated using multipliers). Represents economic activity from household spending.
- **Total Effects** – Sum of Direct, Indirect, and Induced effects.
- **Total Output** – Value of all goods and services produced by industries.
- **Value Added** – Total Output less value of inputs, or the Net Benefit/Impact to an economy.
- **Employment** – Number of additional/reduced full time employment resulting from direct effects.

This Plan uses value added and employment figures to represent the total additional economic impact for each Project Alternative. IMPLAN has been used in this Plan to gauge the impacts on the ICP region of retail rate reductions associated with forming ICP. These impacts are discussed in detail below.

Increase in Disposal Income Associated with Rate Reduction Impacts

Exhibit 43 shows the effects \$100 million in rate savings will have on the ICP economy. The \$100 million rate savings represents the minimum bill savings per year achievable by ICP once in full operation. Direct effects from reduced rates are expected to add 388 jobs. Indirect effects are expected to add about 60 jobs. The induced effects of the project create approximately 98 jobs. In total, approximately 547 jobs are expected to be created in the ICP region. The ICP region is also projected to have a labor income impact of over \$24.0 million, a total value added impact of approximately \$37.2 million, and an output impact over \$54.9 million. Exhibit 45 details the macroeconomics on the ICP region of the anticipated ICP customer bill reductions.

Exhibit 45 \$100 Million Rate Savings Effects on ICP Economy				
Impact Type	Employment	Labor Income	Total Value Added	Output
Direct Effect	388.0	\$18.2 million	\$27.7 million	\$36.5 million
Indirect Effect	60.3	\$2.1 million	\$3.5 million	\$6.3 million
Induced Effect	98.3	\$3.8 million	\$7.0 million	\$12.1 million
Total Effect	546.6	\$24.1 million	\$37.2 million	\$54.9 million

These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand.

DER Development Impacts

The economic impacts of DER development are estimated using the Jobs and Economic Development Impact (JEDI) model. JEDI estimates the effects of DER development on construction industries and the local economy. JEDI was initially developed by the National Renewable Energy Laboratory to demonstrate the economic benefits associated with constructing and operating wind and photovoltaic systems in the United States. JEDI has since

been expanded to analyze similar economic impacts for various energy sources such as biofuels, coal, concentrating solar power, geothermal, marine and hydrokinetic power, and natural gas. A primary goal of JEDI is that it is being used as a tool for system developers, renewable energy advocates, government officials, decision makers, and others to easily identify the local economic impacts associated with constructing and operating these systems on the economy as a whole, whether through direct and indirect effects.

Users input general information about a particular energy project, such as the project location, the type of system being installed, nameplate capacity, annual operations and maintenance costs, and others. JEDI has default but modifiable data regarding various aspects of each energy system type, such as equipment costs, tax parameters, and labor costs. JEDI then uses the input general information and the data, default or modified, to run calculations on the types of economic effects produced by the proposed project. This model can output projected direct job creation by industry, indirect job and business increases due to the project, projected operation costs, and more.

In order for JEDI to provide information, it must be populated with detailed data for the assumed DER project. Projected system data, type of solar cell, nameplate capacity (kW), and the number of systems. As an example of the macroeconomic activity caused by local DER deployment, this Plan explores the impact of ICP installing of a 50 crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. ICP could install a number of larger local solar projects such as the one described above. Exhibit 46 describes the macroeconomic impacts of constructing only one of these local solar projects.

Exhibit 46 Projected Solar Systems Impacts on ICP's Economy			
Description	Jobs	Earnings, \$000	Output (GDP), \$000
During Construction and Installation Period			
*Project Development and Onsite Labor Impacts			
Construction and Installation Labor	342.5	\$22,182	
Construction and Installation Related Services	374.3	\$20,007	
Subtotal	716.8	\$42,189	\$67,620
*Module and Supply Chain Impacts			
Manufacturing Impacts	0.0	\$0	\$0
Trade (Wholesale and Retail)	79.4	\$4,425	\$12,887
Finance, Insurance and Real Estate	0.0	\$0	\$0
Professional Services	53.9	\$2,326	\$6,908
Other Services	141.4	\$15,048	\$42,364
Other Sectors	317.1	\$10,656	\$19,428
Subtotal	591.7	\$32,455	\$81,587
Induced Impacts	326.7	\$13,067	\$39,092
Total Impacts	1,635.3	\$87,710	\$188,298
During Operating Years			
*Onsite Labor Impacts			
PV Project Labor Only	9.2	\$555	\$555
*Local Revenue and Supply Chain Impacts	2.7	\$145	\$458
*Induced Impacts	1.9	\$74	\$221
Total Impacts	13.8	\$774	\$1,235

Exhibit 46 shows the construction and ongoing effects of building a 50 MW solar power project. It is projected that roughly 1,635 jobs will be created during construction and installation. Of this total, about 719 jobs will be directly involved in construction and installation while roughly 592 jobs will be indirectly involved with the building of the project. Induced impacts of the construction and installation will create approximately 327 jobs. These induced effects may include anything from increased employment in restaurants, retail, education, and others. Overall, the building of this sample 50 MW solar project is projected to create \$87 million in earnings and \$188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing.

Sensitivity Analysis

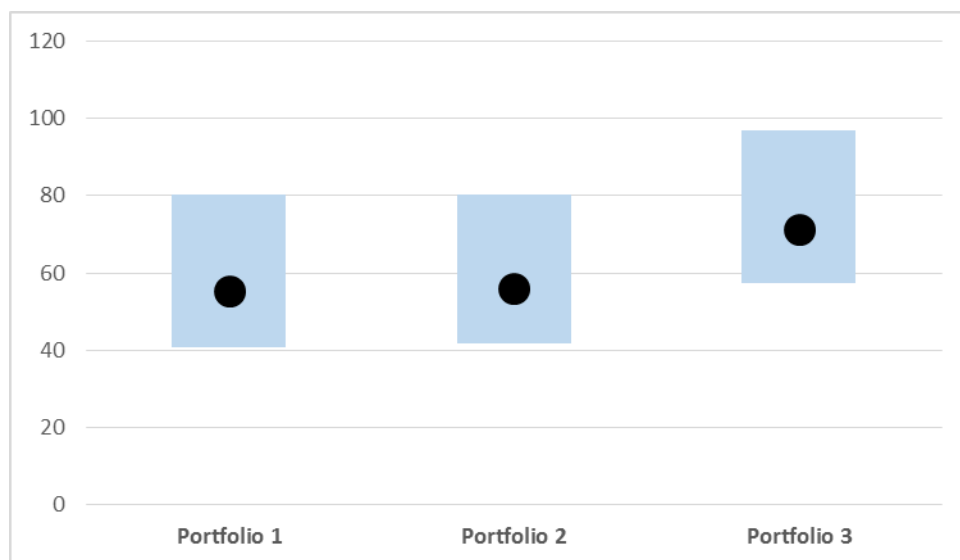
The aforementioned economic analysis provides the base case analysis of forming ICP. This base case is predicated on numerous assumptions and estimates that influence the overall results. This section of the Plan will provide the range of impacts that could result from changes in the most significant variables for the ICP scenario. In addition, this section will address risks that cannot be quantified, but should be addressed and mitigated to the maximum amount possible. Each key assumption is discussed, a band of uncertainty is established and ICP's rate impacts associated with factoring in this uncertainty is developed for each key variable.

Since resource costs are based on forecast natural gas, wholesale market and renewable market prices, it is prudent to look at the sensitivity of the 20-year levelized cost calculation to fluctuations in these projections. Exhibit 47 below shows a summary of low, base, and high resource costs.

Exhibit 47 Low, Base and High 20-year Levelized Resource Costs (\$/MWh)					
Case	Market PPA	Portfolio 1 and 2 Renewables	Portfolio 3 Renewables	Natural gas- fired Resources	Local Renewables
Low Case	26.3	32	40	45	45
Base Case	44.3	42	52	60	65
High Case	73.3	62	76	80	85

The 20-year levelized costs of each portfolio has been calculated using the range of resource costs shown above. The base case costs are depicted by the black dots in Exhibit 48.

Exhibit 48
Sensitivity of Portfolio 20-year Levelized Costs



Portfolio 3, which relies on renewable energy purchases to serve all retail loads, has the highest projected costs that range from a low of \$57/MWh to a high of \$97/MWh. The low case for Portfolio 3 (\$57/MWh) is greater than the base case for both Portfolios 1 and 2. The likelihood of solar costs increasing to the point that 20-year levelized costs are near \$62/MWh seems unlikely. All signs point to decreases in solar equipment costs on a \$/watt basis. There have been significant decreases in solar costs over the past few years. Given the financial incentives targeted at the solar industry as well as the continuing advances in technology, it seems very unlikely that solar costs will increase over the next 10 to 20 years. The study assumes that Production Tax Credits (PTCs) will continue based on the number of times it has been renewed and expanded since 1992.

The potential for market PPA prices to increase to the high case of \$73/MWh has a much higher likelihood. Wholesale market prices are dependent on many factors the most notable of which are natural gas prices. Natural gas prices are at historic lows and wholesale market prices have followed. However, natural gas prices are subject to variety of local, national and international forces that could drastically alter the current market place. For one, increased regulation of the natural gas industry with respect to the deployment of fracking technology could cause decreases in natural gas supplies and commensurate increases in natural gas prices. If natural gas prices increased, it is highly likely that electric wholesale market prices would also increase.

When evaluating risks, it is important to note that power supply costs are approximately 81 percent of the total CCA costs, SCE non-bypassable charges account for 13 percent and CCA operating costs account for 6 percent of total CCA revenue requirement.

Loads and Customer Participation Rates

The Plan bases the 20-year load forecasts on expected load growth, load profiles and participation rates. In order to evaluate the potential impact of varying loads, low, medium, and high load forecasts have been developed for the sensitivity analysis. SCE made available load shape profiles by customer class for the entire SCE service area. These load profiles were applied to all customer loads despite the varying climate zones within the County.

Another assumption that can impact the costs of ICP is the overall ICP customer participation rates. This Plan uses a conservative participation rate of 75 percent for residential customers and 65 percent for non-residential customers as its base case. A higher participation rate, such as has been experienced by all of California's operating CCAs to date, will increase energy sales relative to the base case and decrease the fixed costs paid by each customer. On the other hand, a reduced participation rate will increase the fixed costs to ICP participants. Sensitivity to changes in projected loads has been tested for the high and low load forecast scenarios. For the sensitivity analysis, the high case assumes an additional 10 percent participation rate, while the low case assumes the participation rate is reduced by 50 percent. This low participation scenario is intended to explore the case where only some Cities elect to join. The low case assumes a 0 percent growth in energy and customers after 2017, while the high scenario assumes a 5 percent growth in energy and customers.

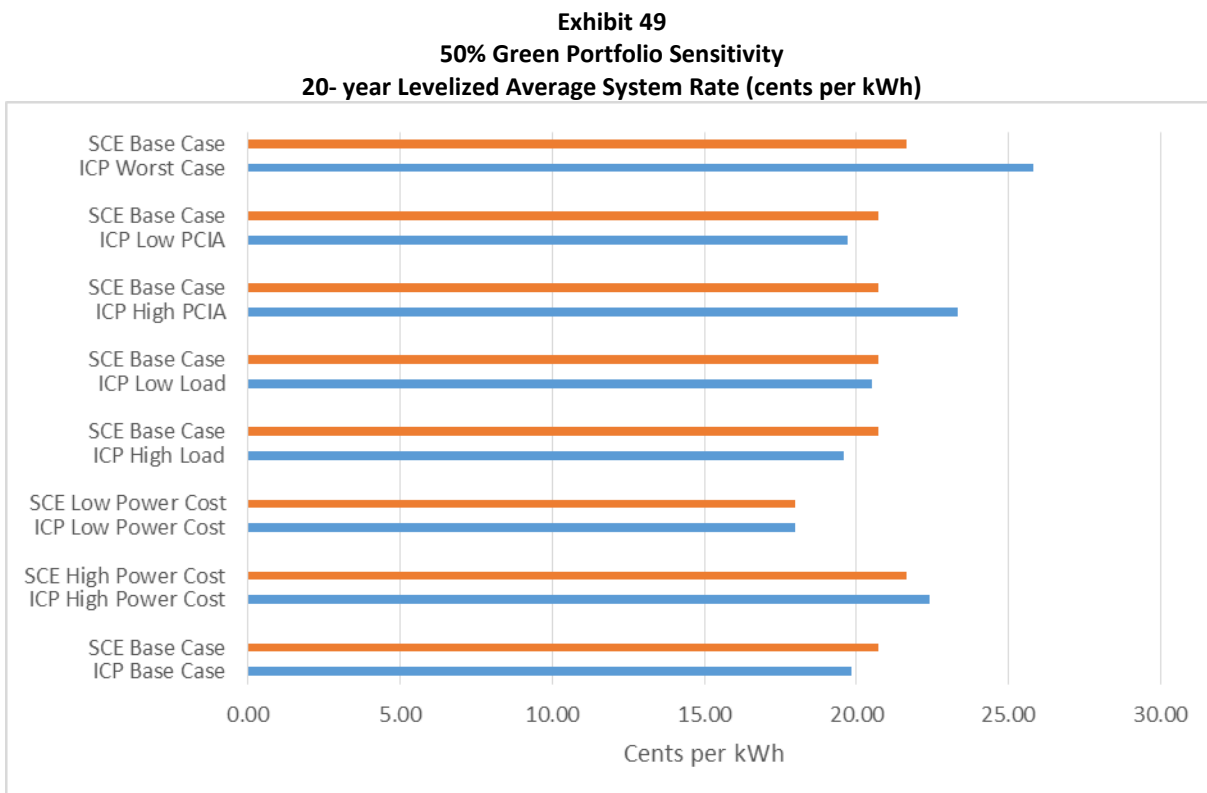
SCE Rates and Surcharges

The base case forecast of SCE rates assumes delivery rates increase at 2 percent per year and generation rates increase approximately 2 percent based on the projected market prices and renewable resource growth rates. In addition, SCE's generation cost was modeled in the high and low case by incorporating the expected range of market and renewable resource costs into SCE's portfolio.

The level of the PCIA will impact the cost competitiveness of ICP. In order to be cost-effective, ICP power supply costs plus PCIA and other surcharges must be lower than SCE's generation rates. Over time, the PCIA will vary, but it is expected that it will decline as market prices increase. The PCIA reflects SCE's own resources and signed contracts. Once the contracts expire, the related PCIA will disappear. Sensitivity to the PCIA has been modeled in the high case by assuming the PCIA would increase to reflect a historic high of 2.5 cents per kWh and remain flat for the 20-year analysis period. For the low case, it was assumed that the PCIA decreases by 50 percent in year 1 and remains flat for the 20-year analysis period.

Sensitivity Results

Exhibit 49 provides the results of the sensitivity analysis for the 50% Green ICP scenario, which is the most likely portfolio for ICP to pursue. This sensitivity shows that the biggest risk to ICP is if the PCIA increases to historic levels, ICP does not achieve sufficient customer participation or if market prices fall significantly below their current historical low level.



This sensitivity analysis shows that ICP rate could be greater than SCE rates if:

- The PCIA becomes much larger
- ICP loads are much less than forecast
- Wholesale market prices are much less than current experience

Each of these three scenarios has a low risk of actually occurring. For example, wholesale market prices for natural gas/electricity are at all-time lows. The probability of any significant further lowering of these prices is judged to be very small. The PCIA level should be fairly stable going forward as regulatory remedies are in play to stabilize the PCIA and the CCA vigilance in this area has increased markedly. Finally, this Plan assumes a relatively high customer opt-out percentage (25 percent for residential customers and 35 percent for non-residential customers) compared to the more modest opt-out rates experienced by California's actively operating CCAs, which is closer to 5 percent – 15 percent. It is very unlikely ICP loads will not meet or exceed those assumed in this Plan.

Risks

Regulatory Risks

There are numerous factors that could impact SCE's rates in addition to the market price impacts described above. Regulatory changes, plant or technology retirements or additions, and the long-term impact of the Aliso Canyon leak all can impact SCE rates in the future. However, the impact of these factors is difficult to assess and model quantitatively.

Regulatory issues continue to arise that may impact the competitiveness of ICP. However, California's operating CCAs have worked hard to address any potentially detrimental changes through effective lobbying and technical support.

New legislation can also impact ICP. For example, new legislation that recently affected CCAs are SB 350 and AB 1110. In addition, there are several changes that impact CCAs regarding power supply procurement and contracting. The CCA-specific changes reflected in SB 350 are generally positive, providing for ongoing autonomy with regard to resource planning and procurement. CCAs must be aware, however, of the long term contracting requirement associated with renewable energy procurement.

Regulatory risks also include the potential for utility generation costs to be shifted to non-bypassable and delivery charges. ICP will need to continually monitor and lobby at the Federal, State and local levels to ensure fair and equitable treatment related to non-bypassable charges.

Summary and Recommendations

Rate Impacts and Comparisons

The first impact associated with forming ICP will be lower electricity bills for ICP customers. ICP customers should see no obvious changes in electric service other than the lower price and increased procurement of renewable power. Customers will pay the power supply charges set by ICP and no longer pay the higher costs of SCE power supply.

Given this Plan's findings, ICP's rate setting can establish a goal of providing rates that are lower than the equivalent rates offered by SCE even under the 50 percent renewable portfolio. Under the 100 percent renewable portfolio, ICP customers will pay 11 percent less for their power compared to the comparable product offered by SCE. The projected ICP and SCE rates are illustrated in Exhibit 50. For this study, it has been assumed that the projected rate decrease is applied uniformly across all rate classes. Once established, it will be up to the ICP Board and staff to develop rates for each rate class that reflects cost of service.

Exhibit 50 Indicative Rate Comparison in ¢/kWh (First Full Year of Service)							
Rate Class	Customer Type	2017 Estimated SCE Bundled Rate*	ICP RPS Bundled Rate	SCE 50% Green Bundled Rate	ICP 50% Green Bundled Rate	SCE 100% Green Bundled Rate	ICP 100% Green Bundled Rate
Residential	Domestic	20.55	19.58	22.30	19.81	24.05	21.79
Residential Care	Domestic	12.22	11.64	13.97	11.78	15.72	12.96
GS-1	Commercial	17.03	16.23	18.78	16.41	20.53	18.06
GS-2	Commercial	16.57	15.79	18.32	15.97	20.07	17.57
GS-3	Industrial	14.71	14.02	16.46	14.18	18.21	15.60
PA-2	Public Authority	13.08	12.46	14.83	12.61	16.58	13.87
PA-3	Public Authority	11.31	10.78	13.06	10.90	14.81	11.99
TOU-8 Secondary	Domestic	13.07	12.45	14.82	12.60	16.57	13.86
TOU-8 Primary	Commercial	11.84	11.28	13.59	11.41	15.34	12.55
TOU-8 Substation	Industrial	7.76	7.39	9.51	7.48	11.26	8.23
Initial Total ICP Rate Savings over Comparable SCE Rates of 50% or 100% Green			4.9%		11.2%		9.4%
Initial Total ICP Rate Savings over SCE's Standard Bundled Rate			4.9%		3.8%		-5.7%

*SCE bundled average rate based on SCE's ERRA 2017 Draft Filing

Exhibit 48 shows the initial rate savings associated with the formation of a CCA. By referencing Appendix B, these initial savings increase after ICP becomes fully functional. The savings by rate schedule after ICP is fully functional are presented below in Exhibit 51.

Exhibit 51 CCA Rate Savings at Fully Functional Operations	
Power Supply Scenario	Range of Savings*
ICP RPS	4.9% - 5.7%
ICP 50% Renewable	3.8% - 4.5%
ICP 100% Renewable	(5.7%) – (5.0%)

*Note Appendix B for detail.

Once ICP gives notice to SCE that it will commence service, ICP customers will not be responsible for costs associated with SCE's future electricity procurement contracts or power plant investments.¹¹ This is a distinct advantage to ICP customers as they will now have local control of power supply costs through ICP.

Renewable Energy Impacts

A second consequence of forming ICP will be an increase in the proportion of energy generated and supplied by renewable resources. The Plan includes procurement of renewable energy sufficient to meet 50 percent or more of ICP's electricity needs. The majority of this renewable energy will be met by new renewable resources. By 2020, SCE must procure a minimum of 33 percent of its customers' annual electricity usage from renewable resources due to the State Renewable Portfolio Standard and the Energy Action Plan requirements of the CPUC. In contrast, ICP will target 50 percent renewable by 2018 and these resources will likely be new renewable resources.

Energy Efficiency Programs

A third consequence of forming ICP could be an increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by SCE are not expected to change as a result of forming ICP. ICP customers will continue to pay the public goods charges to SCE which funds energy efficiency programs for all customers, regardless of supplier. The energy efficiency programs ultimately planned for ICP will be in addition to the level of investment that would continue in the absence of ICP. Thus, ICP has the potential for increased energy investment and savings with an attendant further reduction in emissions due to expanded energy efficiency programs.

¹¹ CCAs may be liable for a share of unbundled stranded costs from new generation, but would then receive associated Resource Adequacy credits.

Economic Development Impacts

The fourth consequence of forming ICP will be enhanced local economic development. The analyses contained in this Plan has focused primarily on the direct effects of this formation. However, in addition to direct effects, indirect economic effects are also encountered. The indirect effects of creating ICP include the effects of increased local investments, increased disposable income due to bill savings and improved environmental and health conditions.

Exhibit 49 shows the effects \$100 million in rate savings will have on the ICP economy. The \$100 million rate savings represents the minimum bill savings per year achievable by ICP once in full operation. Direct effects from reduced rates are expected to add 388 jobs. Indirect effects are expected to add about 60 jobs. The induced effects of the project create approximately 98 jobs. In total, approximately 547 jobs are expected to be created in the ICP region. The ICP region is also projected to have a labor income impact of over \$24.0 million, a total value added impact of approximately \$37.2 million, and an output impact over \$54.9 million. Exhibit 52 details the macroeconomics on the ICP region of the anticipated ICP customer bill reductions.

Exhibit 52 \$100 Million Rate Savings Effects on ICP Economy				
Impact Type	Employment	Labor Income	Total Value Added	Output
Direct Effect	388.0	\$18.2 million	\$27.7 million	\$36.5 million
Indirect Effect	60.3	\$2.1 million	\$3.5 million	\$6.3 million
Induced Effect	98.3	\$3.8 million	\$7.0 million	\$12.1 million
Total Effect	546.6	\$24.1 million	\$37.2 million	\$54.9 million

These savings are based on the economic construct that households will spend some share of the increased disposable income on more goods and services. This increased spending on goods and services will then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn will give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand.

In addition to increased economic activity due to electric bill savings, potential local projects can also create job and economic growth in the local economy. As an example of the macroeconomic activity caused by local DER deployment, this Plan assumes the installation of fifty crystalline silicon, fixed mount solar systems with nameplate capacities of 1 MW each for a total capacity of 50 MW. Overall, the building of this one solar project is projected to create \$87 million in earnings and \$188 million in output (GDP) in the local economy along with 1,636 jobs during construction and 14 full-time jobs ongoing. It is anticipated that ICP will ultimately install a number of larger local solar projects such as the one described.

Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

The last consequence of forming ICP would be environmental benefits. The share of renewable power in SCE's power supply portfolio is currently 28 percent¹² and is scheduled to shift to 33 percent by 2020. Assuming ICP adopts a base case 50 percent RPS target at start-up, GHG emissions reductions attributable to ICP operations in 2019 will range from 1.33 to 2.34 million metric tons CO₂ equivalent (CO₂e) per year relative to SCE's projected resource mix over the same period. Exhibit 53 details these reductions.

Exhibit 53 Baseline Comparison of GHG Reduction by ICP by 2018				
	ICP	CVAG	SANBAG	WRCOG
Forecast Renewables (50% Renewables) ICP (MWH) – Phase 2	7,533	916	4,184	2,433
ICP RPS (MWH) – Phase 2	4,219	513	2,343	1,362
Additional Green Power	3,315	403	1,841	1,070
CO ₂ reduction – Low (Metric Tons of CO ₂ e)	1.33	0.16	0.74	0.43
CO ₂ reduction – High (Metric tons of CO ₂ e)	2.34	0.28	1.30	0.76

The reduction in GHG emissions associated with ICP operations is significant. This amount of reduced emissions represents a reduction in the emissions from the in-State generation resources of 2.6 to 4.6 percent.

Summary

This Plan concludes that the formation of ICP in the service areas of CVAG, SANBAG and WRCOG is financially prudent and will yield considerable benefits for ICP's residents and businesses. These benefits include at least a 3.8 percent lower rate for electricity (assuming the 50 percent renewable scenario) than is charged by SCE while receiving nearly twice the amount of renewable energy. With the achievement of Phase 2 level of operations, ICP will reduce GHG emissions by as much as 2.34 million metric tons of CO₂e per year, add over 500 jobs, generate over \$54 million in additional GDP, and give residents and businesses local control over their power supply and energy efficiency programs. Even with these stated rate savings, significant funding is still generated to support new programs, local DER and/or additional rate savings to the CCA's customers.

There are risks associated with a CCA which are manageable. On balance, the formation of a CCA for CVAG, SANBAG and WRCOG is financially feasible and results in beneficial environmental/economic impacts. A joint CCA with common back office functions and local

¹² http://www.cpuc.ca.gov/RPS_Homepage/

options for program development is the most economical operational option and is recommended. A more “hands on” operating model is also recommended.

Appendix A – Cities/Counties Evaluating CCA Feasibility

	CCA Name	Service Area	Start Date	IOU
Operational				
	Marin Clean Energy	Marin County, Napa County, part of Contra Costa and Solano Counties	May 2010	PG&E
	Sonoma Clean Power	Sonoma County	May 2014	PG&E
	Lancaster Choice Energy	City of Lancaster	May 2015	SCE
	Clean Power San Francisco	City of San Francisco	May 2016	PG&E
	Peninsula Clean Energy	San Mateo County	October 2016	PG&E
Exploring/In Process				
	Redwood Coast Energy Authority	Humboldt County	May 2017	PG&E
	East Bay Community Energy	Alameda County		PG&E
	TBD	Butte County		PG&E
	TBD	City of San Jose		PG&E
	TBD	Contra Costa County		PG&E
	TBD	Humboldt County		PG&E
	LA Community Choice Energy	LA County		SCE
	TBD	Mendocino County		PG&E
	TBD	Monterey County		PG&E
	TBD	Placer County		PG&E
	TBD	Riverside County		SCE
	TBD	San Benito County		PG&E
	TBD	San Bernardino County		SCE
	TBD	San Diego County		SDG&E
	TBD	San Luis Obispo County		PG&E
	TBD	Santa Barbara County		SCE/PG&E
	Silicon Valley Clean Energy	Santa Clara County	April 2017	PG&E
	TBD	Santa Cruz County		PG&E

Appendix B – Financial Proforma Analyses

ICP Community Choice Aggregation
Financial Proforma
Portfolio RPS

Load Data		2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts													
	Domestic	0	6,563	857,965	867,660	877,464	887,379	897,407	907,548	917,803	928,174	938,662	949,269
	Commercial	0	56,243	88,543	89,543	90,555	91,578	92,613	93,660	94,718	95,788	96,871	97,965
	Industrial	0	0	457	462	467	472	478	483	488	494	500	505
	Lighting & Traffic Control	0	6,801	11,029	11,154	11,280	11,407	11,536	11,666	11,798	11,931	12,066	12,203
	Agricultural	0	63	3,146	3,182	3,218	3,254	3,291	3,328	3,366	3,404	3,442	3,481
	Total Customers	0	69,669	961,139	972,000	982,983	994,091	1,005,324	1,016,685	1,028,173	1,039,791	1,051,541	1,063,423
Energy Sales (MWh)													
	Domestic	0	95	6,882,813	6,960,589	7,039,244	7,118,787	7,199,230	7,280,381	7,362,851	7,446,052	7,530,192	7,615,283
	Commercial	0	136,839	4,018,999	4,064,414	4,110,342	4,156,789	4,203,760	4,251,263	4,299,307	4,347,884	4,397,015	4,446,702
	Industrial	0	0	2,640,375	2,670,212	2,700,385	2,730,899	2,761,759	2,792,966	2,824,527	2,856,444	2,888,772	2,921,365
	Lighting & Traffic Control	0	44,238	118,280	119,616	120,968	122,335	123,717	125,115	126,529	127,959	129,405	130,867
	Agricultural	0	21,702	546,909	553,089	559,339	565,659	572,051	578,515	585,052	591,663	598,349	605,111
	Total Energy Sales (MWh)	0	202,873	14,207,376	14,367,920	14,530,277	14,694,469	14,860,517	15,028,441	15,198,262	15,370,003	15,543,684	15,719,327
CCE Operating Costs													
	Power Supply	\$0	\$99,735,995	\$707,645,195	\$733,748,921	\$765,882,666	\$792,385,834	\$818,332,855	\$846,659,904	\$874,361,323	\$903,459,966	\$931,873,882	\$961,012,268
	Billing & Data Management	\$0	\$731,529	\$14,414,632	\$14,577,517	\$14,742,243	\$14,908,830	\$15,077,330	\$15,247,674	\$15,419,972	\$15,594,218	\$15,770,433	\$15,948,639
	SCE Fees	\$250,165	\$373,050	\$8,197,628	\$4,891,534	\$4,895,564	\$4,890,204	\$5,005,462	\$5,001,345	\$5,057,859	\$5,115,012	\$5,172,810	\$5,231,261
	Technical Services	\$620,000	\$740,000	\$1,331,000	\$1,356,600	\$1,383,732	\$1,411,407	\$1,439,633	\$1,468,427	\$1,497,796	\$1,527,752	\$1,558,307	\$1,589,473
	Staffing	\$900,000	\$770,000	\$2,482,333	\$2,632,212	\$2,684,856	\$2,738,553	\$2,793,324	\$2,849,191	\$2,906,175	\$2,964,298	\$3,023,584	\$3,084,056
	General & Administrative expenses	\$900,000	\$260,000	\$350,000	\$306,000	\$312,120	\$318,362	\$324,730	\$331,224	\$337,849	\$344,606	\$351,498	\$358,528
	Debt Service (CCE Bonds & Start up Costs)	\$0	\$2,341,764	\$19,327,411	\$19,327,411	\$19,327,411	\$19,327,411	\$16,985,647	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883
	Contribution to Annual Reserves	\$0	\$0	\$0	\$62,327,327	\$66,632,200	\$35,097,145	\$0	\$0	\$0	\$0	\$0	\$0
	New Programs	\$0	\$0	\$0	\$0	\$0	\$35,097,145	\$75,906,074	\$82,489,758	\$86,198,044	\$90,078,875	\$93,855,938	\$97,882,406
	Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$4,794,622	\$4,919,582	\$4,649,509	\$4,790,060	\$4,937,722	\$5,082,168	\$5,231,049
	Uncollectibles	\$5,251	\$101,566	\$4,370,491	\$4,889,833	\$4,654,354	\$4,794,622	\$4,919,582	\$4,649,509	\$4,790,060	\$4,937,722	\$5,082,168	\$5,231,049
	Total Operating Costs	\$1,055,416	\$8,627,503	\$813,547,104	\$843,557,356	\$880,155,147	\$910,969,515	\$940,799,610	\$973,365,914	\$1,005,212,961	\$1,038,666,330	\$1,071,332,502	\$1,10

ICP Community Choice Aggregation
Financial Proforma
Portfolio RPS

Lead Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	959,996	970,844	981,814	992,909	1,004,129	1,015,475	1,026,950	1,038,555	1,050,291
Commercial	99,072	100,192	101,324	102,469	103,627	104,798	105,982	107,180	108,391
Industrial	511	517	523	528	534	540	547	553	0
Lighting & Traffic Control	12,341	12,480	12,621	12,764	12,904	13,054	13,201	13,350	0
Agricultural	3,520	3,560	3,601	3,641	3,682	3,724	3,766	3,809	0
Total Customers	1,075,640	1,087,593	1,099,882	1,112,311	1,124,880	1,137,591	1,150,446	1,163,446	1,158,681
Energy Sales (MWh)									
Domestic	7,701,336	7,788,361	7,876,369	7,965,372	8,055,381	8,146,407	8,238,461	8,331,556	8,425,703
Commercial	4,496,949	4,547,765	4,599,155	4,651,125	4,703,683	4,756,834	4,810,587	4,864,946	4,919,920
Industrial	2,954,376	2,987,760	3,021,522	3,055,665	3,090,194	3,125,114	3,160,427	3,196,140	3,232,257
Lighting & Traffic Control	132,346	133,842	135,354	136,884	138,430	139,995	141,576	143,176	144,794
Agricultural	611,948	618,863	625,857	632,929	640,081	647,314	654,628	662,026	669,507
Total Energy Sales (MWh)	15,896,956	16,076,591	16,258,257	16,441,975	16,627,769	16,815,663	17,005,680	17,197,844	17,392,180
CCE Operating Costs									
Power Supply	\$990,057,690	\$1,021,103,132	\$1,046,331,881	\$1,082,093,730	\$1,114,321,376	\$1,149,294,280	\$1,187,432,515	\$1,226,128,522	\$1,267,265,121
Billing & Data Management	\$16,128,858	\$16,311,114	\$16,495,430	\$16,681,828	\$16,870,333	\$17,060,968	\$17,253,757	\$17,448,724	\$17,645,895
SCE Fees	\$5,290,374	\$5,350,154	\$5,410,609	\$5,471,748	\$5,533,577	\$5,596,105	\$5,659,340	\$5,723,290	\$5,787,961
Technical Services	\$1,621,263	\$1,653,688	\$1,686,762	\$1,720,497	\$1,754,907	\$1,790,005	\$1,825,805	\$1,862,321	\$1,899,568
Staffing	\$3,145,737	\$3,208,652	\$3,272,825	\$3,338,281	\$3,405,047	\$3,473,148	\$3,542,611	\$3,613,463	\$3,685,732
General & Administrative expenses	\$415,698	\$373,012	\$380,473	\$388,082	\$470,844	\$428,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883
Contribution to Annual Reserves	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
New Programs	\$101,541,893	\$105,735,775	\$109,032,602	\$113,848,978	\$118,073,390	\$122,815,616	\$127,985,610	\$133,205,901	\$138,774,019
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$5,378,352	\$5,535,854	\$5,665,131	\$5,846,319	\$6,010,631	\$6,187,959	\$6,381,142	\$6,577,340	\$6,785,717
Total Operating Costs	\$1,138,223,748	\$1,173,915,263	\$1,202,919,595	\$1,244,033,346	\$1,281,083,987	\$1,321,290,724	\$1,365,136,498	\$1,409,623,515	\$1,456,916,370
Other Revenues									
Total CCE Revenue Requirement	\$1,138,223,748	\$1,173,915,263	\$1,202,919,595	\$1,244,033,346	\$1,281,083,987	\$1,321,290,724	\$1,365,136,498	\$1,409,623,515	\$1,456,916,370
Average CCE Rate (\$/kWh)	\$0.0716	\$0.0730	\$0.0740	\$0.0757	\$0.0770	\$0.0786	\$0.0803	\$0.0820	\$0.0838
Average SCE Generation Rate (\$/kWh)	\$0.0863	\$0.0880	\$0.0891	\$0.0912	\$0.0928	\$0.0947	\$0.0967	\$0.0988	\$0.1009
Total CCE Charges									
SCE Non-bypassable Charges	\$44,366,859	\$44,577,161	\$44,804,342	\$44,925,839	\$45,126,238	\$45,304,664	\$45,458,584	\$45,627,682	\$45,786,716
SCE Revenue Requirement	\$1,138,223,748	\$1,173,915,263	\$1,202,919,595	\$1,244,033,346	\$1,281,083,987	\$1,321,290,724	\$1,365,136,498	\$1,409,623,515	\$1,456,916,370
Total CCE Generation Revenue Requirement	\$1,182,590,606	\$1,218,442,424	\$1,247,723,937	\$1,288,959,185	\$1,326,210,225	\$1,366,595,388	\$1,410,595,082	\$1,455,251,198	\$1,502,703,086
Bundled SCE Revenues	\$3,493,543,297	\$3,541,557,705	\$3,643,564,853	\$3,762,275,864	\$3,878,272,416	\$4,000,321,101	\$4,129,074,697	\$4,260,994,562	\$4,398,764,102
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$3,244,779,991	\$3,345,644,391	\$3,441,988,073	\$3,552,399,692	\$3,661,007,958	\$3,774,999,954	\$3,894,927,011	\$4,017,904,175	\$4,146,146,261
Savings	\$188,763,307	\$195,913,314	\$201,576,780	\$209,876,172	\$217,264,458	\$225,321,147	\$234,147,686	\$243,090,387	\$252,617,842
Percent Savings	5.5%	5.5%	5.5%	5.6%	5.6%	5.6%	5.7%	5.7%	5.7%
Cumulative Reserves	\$892,195,217	\$997,930,992	\$1,106,963,594	\$1,220,812,571	\$1,338,885,961	\$1,461,701,577	\$1,589,687,187	\$1,722,893,088	\$1,861,667,107
Reserve Target									

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	2017	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Data	Jan - June	July - Dec										
Customer Accounts												
Domestic	0	6,563	857,965	867,660	877,464	887,379	897,407	907,548	917,803	938,174	938,662	949,269
Commercial	0	56,243	88,543	90,555	91,578	91,578	92,613	93,660	94,718	95,788	96,871	97,965
Industrial	0	0	457	462	467	472	478	483	488	494	500	505
Lighting & Traffic Control	0	6,801	11,029	11,154	11,280	11,407	11,536	11,666	11,798	11,931	12,066	12,203
Agricultural	0	63	3,146	3,182	3,218	3,254	3,291	3,328	3,366	3,404	3,442	3,481
Total Customers	0	69,669	961,139	972,000	982,983	994,091	1,005,324	1,016,685	1,028,173	1,039,791	1,051,541	1,063,423
Energy Sales (MWh)												
Domestic	0	95	6,882,813	6,960,589	7,039,244	7,118,787	7,199,230	7,280,581	7,362,851	7,446,052	7,530,192	7,615,283
Commercial	0	136,839	4,018,999	4,064,414	4,110,342	4,156,789	4,203,760	4,251,263	4,299,302	4,347,884	4,396,702	4,446,702
Industrial	0	0	2,640,375	2,670,212	2,700,385	2,730,899	2,761,759	2,793,966	2,824,527	2,856,444	2,888,722	2,921,365
Lighting & Traffic Control	0	44,238	118,280	119,616	120,968	122,335	123,717	125,115	126,529	127,959	129,405	130,867
Agricultural	0	21,702	546,909	553,089	559,339	565,659	572,051	578,515	585,052	591,663	598,349	605,111
Total Energy Sales (MWh)	0	202,873	14,367,920	14,530,277	14,530,277	14,694,469	14,860,517	15,028,441	15,198,262	15,370,003	15,543,684	15,719,327
CCE Operating Costs												
Power Supply	\$0	\$10,381,996	\$738,881,822	\$759,553,192	\$780,672,276	\$803,006,868	\$826,270,323	\$850,038,727	\$874,560,745	\$900,033,370	\$926,876,984	\$954,872,057
Billing & Data Management	\$0	\$731,529	\$14,414,632	\$14,577,517	\$14,742,243	\$14,906,830	\$15,077,300	\$15,247,674	\$15,419,972	\$15,594,218	\$15,770,433	\$15,948,639
SCE Fees	\$250,165	\$3,574,050	\$8,197,628	\$4,781,534	\$4,835,564	\$5,049,462	\$5,001,345	\$5,045,462	\$5,057,859	\$5,115,012	\$5,172,810	\$5,231,261
Technical Services	\$620,000	\$740,000	\$1,310,000	\$1,356,600	\$1,383,732	\$1,411,407	\$1,439,635	\$1,468,427	\$1,497,796	\$1,527,752	\$1,558,307	\$1,589,473
Staffing	\$90,000	\$970,000	\$2,632,212	\$2,488,333	\$2,684,856	\$2,738,553	\$2,793,324	\$2,849,191	\$2,906,175	\$2,964,298	\$3,023,584	\$3,084,056
General & Administrative expenses	\$90,000	\$260,000	\$350,000	\$306,000	\$312,120	\$318,362	\$399,730	\$356,244	\$337,849	\$344,606	\$351,498	\$358,528
Debt Service (CCE Bonds & Start-up Costs)	\$0	\$2,341,764	\$19,327,411	\$19,327,411	\$19,327,411	\$19,327,411	\$16,985,647	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883
Contribution to Annual Reserves	\$0	\$9,874,541	\$53,455,920	\$66,894,060	\$83,279,978	\$46,022,380	\$0	\$0	\$0	\$0	\$0	\$0
New Programs	\$0	\$0	\$0	\$0	\$0	\$46,022,380	\$101,933,723	\$114,275,941	\$122,330,624	\$131,074,810	\$137,600,681	\$143,686,990
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$5,251	\$103,608	\$4,526,674	\$4,618,854	\$4,729,802	\$4,849,727	\$4,959,270	\$4,666,403	\$4,791,058	\$4,920,539	\$5,057,184	\$5,200,438
Total Operating Costs	\$1,055,416	\$8,977,488	\$842,952,421	\$874,047,381	\$911,967,983	\$943,896,124	\$974,804,415	\$1,008,547,815	\$1,041,545,960	\$1,076,208,487	\$1,110,055,364	\$1,144,765,235
Other Revenues												
Total CCE Revenue Requirement	\$1,055,416	\$8,977,488	\$842,952,421	\$874,047,381	\$911,967,983	\$943,896,124	\$974,804,415	\$1,008,547,815	\$1,041,545,960	\$1,076,208,487	\$1,110,055,364	\$1,144,765,235
Average CCE Rate (\$/kWh)	\$0.0495	\$0.0495	\$0.0693	\$0.0608	\$0.0628	\$0.0642	\$0.0656	\$0.0671	\$0.0685	\$0.0700	\$0.0714	\$0.0728
Average SCE Generation Rate (\$/kWh)	\$0.0575	\$0.0575	\$0.0690	\$0.0707	\$0.0730	\$0.0747	\$0.0763	\$0.0780	\$0.0797	\$0.0814	\$0.0830	\$0.0847
Total CCE Charges												
SCE Non-bypassable Charges	\$1,722,191	\$1,722,191	\$120,365,021	\$121,236,384	\$122,002,252	\$123,943,738	\$123,942,523	\$123,942,523	\$123,942,523	\$123,942,523	\$123,942,523	\$123,942,523
SCE Revenue Requirement	\$1,055,416	\$8,977,488	\$842,952,421	\$874,047,381	\$911,967,983	\$943,896,124	\$974,804,415	\$1,008,547,815	\$1,041,545,960	\$1,076,208,487	\$1,110,055,364	\$1,144,765,235
Total CCE Generation Revenue Requirement	\$1,055,416	\$10,699,679	\$963,317,442	\$995,283,765	\$1,033,970,236	\$1,066,839,862	\$1,098,746,938	\$1,052,222,916	\$1,085,333,197	\$1,120,103,090	\$1,154,094,592	\$1,188,956,969
Bundled SCE Revenues	\$0	\$32,500,966	\$2,492,090,079	\$2,575,911,573	\$2,669,172,535	\$2,757,015,564	\$2,845,271,634	\$2,938,473,662	\$3,032,510,433	\$3,130,237,483	\$3,228,826,383	\$3,330,286,114
Start-Up Costs	\$0	\$31,493,045	\$2,398,421,430	\$2,477,184,377	\$2,564,160,338	\$2,646,859,581	\$2,730,185,158	\$2,817,966,561	\$2,906,743,676	\$2,998,935,356	\$3,092,158,924	\$3,188,120,717
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$1,007,921	\$93,668,649	\$98,727,196	\$105,012,197	\$110,155,982	\$115,086,476	\$120,507,101	\$125,766,577	\$131,302,128	\$136,667,459	\$142,165,397
Savings												
Percent Savings	3.1%	3.1%	3.8%	3.8%	3.9%	4.0%	4.0%	4.1%	4.1%	4.2%	4.2%	4.3%
Cumulative Reserves												
Reserve Target	\$9,874,541	\$9,874,541	\$63,330,461	\$130,224,521	\$213,504,499	\$305,549,260	\$407,482,983	\$521,758,924	\$644,089,548	\$775,164,358	\$912,765,040	\$1,056,452,029

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Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	959,996	970,844	981,814	992,909	1,004,129	1,015,475	1,026,950	1,038,555	1,050,291
Commercial	99,072	100,192	101,324	102,469	103,627	104,798	105,982	107,180	108,391
Industrial	511	517	523	528	534	540	547	553	0
Lighting & Traffic Control	12,341	12,480	12,621	12,764	12,908	13,054	13,201	13,350	0
Agricultural	3,520	3,560	3,601	3,641	3,682	3,724	3,766	3,809	0
Total Customers	1,075,640	1,087,993	1,099,882	1,112,311	1,124,880	1,137,591	1,150,446	1,163,446	1,158,681
Energy Sales (MWh)									
Domestic	7,701,336	7,788,361	7,876,369	7,965,372	8,055,381	8,146,407	8,238,461	8,331,556	8,425,703
Commercial	4,496,949	4,547,765	4,599,155	4,651,125	4,703,683	4,756,834	4,810,587	4,864,946	4,919,920
Industrial	2,954,376	2,987,760	3,021,522	3,055,665	3,090,194	3,125,114	3,160,427	3,196,140	3,232,257
Lighting & Traffic Control	132,346	133,842	135,354	136,884	138,430	139,995	141,576	143,176	144,794
Agricultural	611,948	618,863	625,857	632,929	640,081	647,314	654,628	662,026	669,507
Total Energy Sales (MWh)	15,896,956	16,076,991	16,258,257	16,441,975	16,627,769	16,815,663	17,005,680	17,197,844	17,392,180
CCE Operating Costs									
Power Supply	\$983,522,942	\$1,013,839,299	\$1,046,331,881	\$1,082,093,730	\$1,114,321,376	\$1,149,294,280	\$1,187,432,515	\$1,226,128,522	\$1,267,265,121
Billing & Data Management	\$16,128,858	\$16,311,114	\$16,495,430	\$16,681,828	\$16,870,333	\$17,060,968	\$17,253,757	\$17,448,724	\$17,645,895
SCE Fees	\$5,290,374	\$5,350,154	\$5,410,609	\$5,471,748	\$5,533,577	\$5,596,105	\$5,659,340	\$5,723,290	\$5,787,961
Technical Services	\$1,621,263	\$1,653,688	\$1,686,762	\$1,720,497	\$1,754,907	\$1,790,005	\$1,825,805	\$1,862,321	\$1,899,568
Staffing	\$3,145,737	\$3,208,652	\$3,272,825	\$3,338,281	\$3,405,047	\$3,473,148	\$3,542,611	\$3,613,463	\$3,685,732
General & Administrative expenses	\$415,698	\$373,012	\$380,473	\$388,082	\$400,844	\$428,761	\$441,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883
Contribution to Annual Reserves	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
New Programs	\$149,249,933	\$155,466,999	\$152,511,623	\$158,814,038	\$164,377,630	\$170,573,112	\$177,327,893	\$184,156,148	\$191,433,647
Start-up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$5,345,678	\$5,499,535	\$5,665,131	\$5,846,319	\$6,010,631	\$6,187,959	\$6,381,142	\$6,577,340	\$6,785,717
Total Operating Costs	\$1,179,364,365	\$1,216,345,935	\$1,246,398,616	\$1,288,998,407	\$1,327,388,228	\$1,369,048,220	\$1,414,478,781	\$1,460,573,763	\$1,509,575,998
Other Revenues									
Total CCE Revenue Requirement	\$1,179,364,365	\$1,216,345,935	\$1,246,398,616	\$1,288,998,407	\$1,327,388,228	\$1,369,048,220	\$1,414,478,781	\$1,460,573,763	\$1,509,575,998
Average CCE Rate (\$/kWh)	\$0.0742	\$0.0757	\$0.0767	\$0.0784	\$0.0798	\$0.0814	\$0.0832	\$0.0849	\$0.0868
Average SCE Generation Rate (\$/kWh)	\$0.0863	\$0.0880	\$0.0891	\$0.0912	\$0.0928	\$0.0947	\$0.0967	\$0.0988	\$0.1009
Total CCE Charges									
SCE Non-bypassable Charges	\$44,366,859	\$44,577,161	\$44,804,342	\$44,925,839	\$45,126,238	\$45,304,664	\$45,458,584	\$45,627,682	\$45,786,716
CCE Revenue Requirement	\$1,179,364,365	\$1,216,345,935	\$1,246,398,616	\$1,288,998,407	\$1,327,388,228	\$1,369,048,220	\$1,414,478,781	\$1,460,573,763	\$1,509,575,998
Total CCE Generation Revenue Requirement	\$1,223,731,224	\$1,260,873,096	\$1,291,202,959	\$1,333,924,246	\$1,372,514,466	\$1,414,352,884	\$1,459,937,365	\$1,506,201,445	\$1,555,362,714
Bundled SCE Revenues	\$3,493,543,297	\$3,541,557,705	\$3,643,564,853	\$3,762,275,864	\$3,878,272,416	\$4,000,321,101	\$4,129,074,697	\$4,260,994,562	\$4,398,764,102
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$3,285,920,608	\$3,388,075,063	\$3,485,467,095	\$3,597,364,753	\$3,707,312,199	\$3,822,757,450	\$3,944,269,294	\$4,068,854,422	\$4,198,805,888
Savings	\$147,622,689	\$153,482,642	\$158,097,758	\$164,911,111	\$170,960,217	\$177,563,651	\$184,805,403	\$192,140,140	\$199,958,214
Percent Savings	4.3%	4.3%	4.3%	4.4%	4.4%	4.4%	4.5%	4.5%	4.5%
Cumulative Reserves	\$1,205,701,962	\$1,361,168,561	\$1,513,680,184	\$1,672,494,222	\$1,836,871,852	\$2,007,444,965	\$2,184,772,858	\$2,368,929,006	\$2,560,362,653
Reserve Target									

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Load Data		2017 Jan - June	2017 July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts													
Domestic	0	6,563	857,965	867,660	877,464	887,379	897,407	907,548	917,803	928,174	938,662	949,269	960,000
Commercial	0	56,243	88,543	90,555	91,578	92,613	93,650	94,693	95,742	96,796	97,854	98,915	100,000
Industrial	0	0	457	462	467	472	478	483	488	493	498	503	508
Lighting & Traffic Control	0	6,801	11,029	11,154	11,280	11,407	11,534	11,661	11,789	11,917	12,045	12,173	12,301
Agricultural	0	63	3,146	3,182	3,218	3,254	3,291	3,328	3,365	3,402	3,439	3,476	3,513
Total Customers	0	69,669	961,139	972,000	982,983	994,091	1,005,324	1,016,685	1,028,173	1,039,791	1,051,541	1,063,423	1,075,305
Energy Sales (MWh)													
Domestic	0	95	6,882,813	6,960,589	7,039,244	7,118,787	7,199,230	7,280,581	7,362,851	7,446,052	7,530,192	7,615,283	7,701,424
Commercial	0	136,839	4,018,999	4,064,414	4,110,342	4,156,789	4,203,760	4,251,674	4,299,302	4,347,884	4,396,715	4,445,797	4,495,130
Industrial	0	0	2,640,375	2,670,212	2,700,385	2,730,899	2,761,759	2,792,966	2,824,527	2,856,444	2,888,702	2,921,365	2,954,428
Lighting & Traffic Control	0	44,238	118,280	119,616	120,968	122,335	123,717	125,115	126,529	127,959	129,405	130,867	132,344
Agricultural	0	21,702	546,909	553,089	559,339	565,659	572,051	578,515	585,052	591,663	598,349	605,111	611,927
Total Energy Sales (MWh)	0	202,873	14,367,920	14,530,277	14,694,469	14,860,517	15,028,441	15,198,262	15,370,003	15,543,684	15,719,327	15,896,881	16,075,336
CCE Operating Costs													
Power Supply	\$0	\$13,812,233	\$965,273,392	\$988,855,853	\$1,013,033,065	\$1,038,816,390	\$1,064,978,225	\$1,092,187,159	\$1,120,292,984	\$1,149,278,806	\$1,179,609,155	\$1,211,057,134	\$1,243,699,639
Billing & Data Management	\$0	\$731,529	\$14,414,632	\$14,507,517	\$14,742,243	\$14,908,830	\$15,077,330	\$15,249,674	\$15,419,972	\$15,594,218	\$15,770,433	\$15,948,639	\$16,129,845
SCE Fees	\$250,165	\$3,574,050	\$8,197,628	\$4,581,534	\$4,835,564	\$5,090,620	\$5,345,662	\$5,600,704	\$5,855,746	\$6,110,788	\$6,365,830	\$6,620,872	\$6,875,914
Technical Services	\$620,000	\$740,000	\$1,310,000	\$1,356,600	\$1,383,732	\$1,411,407	\$1,439,635	\$1,468,427	\$1,497,796	\$1,527,752	\$1,558,307	\$1,589,473	\$1,620,250
Staffing	\$90,000	\$970,000	\$2,488,333	\$2,632,212	\$2,684,856	\$2,738,553	\$2,793,324	\$2,849,175	\$2,906,175	\$2,964,298	\$3,023,584	\$3,084,056	\$3,144,712
General & Administrative expenses	\$90,000	\$260,000	\$350,000	\$306,000	\$312,120	\$318,362	\$324,604	\$330,846	\$337,089	\$343,332	\$349,575	\$355,818	\$362,061
Demand Service (CCE Bonds & Start up Costs)	\$0	\$2,341,764	\$19,327,411	\$19,327,411	\$19,327,411	\$19,327,411	\$16,985,647	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883
Contribution to Annual Reserves	\$0	\$9,227,034	\$61,174,927	\$80,365,085	\$104,260,078	\$59,435,532	\$0	\$0	\$0	\$0	\$0	\$0	\$0
New Programs	\$0	\$0	\$0	\$0	\$0	\$59,435,532	\$134,070,724	\$152,371,971	\$166,033,712	\$180,910,349	\$193,387,742	\$205,690,356	\$218,002,970
Start-Up Capital	\$0	(\$20,000,000)	\$0	\$0	\$0	\$59,435,532	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$5,251	\$120,759	\$5,658,632	\$5,765,368	\$5,891,606	\$6,026,774	\$6,162,857	\$5,871,019	\$5,871,019	\$6,162,857	\$6,338,256	\$6,481,274	\$6,629,292

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Portfolio -100% Renewable

Lead Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	959,996	970,844	981,814	992,909	1,004,129	1,015,475	1,026,950	1,038,555	1,050,291
Commercial	99,072	100,192	101,324	102,469	103,627	104,798	105,982	107,180	108,391
Industrial	511	517	523	528	534	540	547	553	0
Lighting & Traffic Control	12,341	12,480	12,621	12,764	12,908	13,054	13,201	13,350	0
Agricultural	3,520	3,560	3,601	3,641	3,682	3,724	3,766	3,809	0
Total Customers	1,075,640	1,087,593	1,099,882	1,112,311	1,124,880	1,137,591	1,150,446	1,163,446	1,158,681
Energy Sales (MWh)									
Domestic	7,701,336	7,788,361	7,876,369	7,965,372	8,055,381	8,146,407	8,238,461	8,331,556	8,425,703
Commercial	4,496,949	4,547,765	4,599,155	4,651,125	4,703,683	4,756,834	4,810,587	4,864,946	4,919,920
Industrial	2,954,376	2,987,760	3,021,522	3,055,665	3,090,194	3,125,114	3,160,427	3,196,140	3,232,257
Lighting & Traffic Control	132,346	133,942	135,354	136,884	138,430	139,995	141,576	143,176	144,794
Agricultural	611,948	618,863	625,857	632,929	640,081	647,314	654,628	662,026	669,507
Total Energy Sales (MWh)	15,896,956	16,076,591	16,258,257	16,441,975	16,627,769	16,815,663	17,005,680	17,197,844	17,392,180
CCE Operating Costs									
Power Supply	\$1,243,478,415	\$1,277,923,815	\$1,313,160,531	\$1,349,217,248	\$1,386,279,882	\$1,425,852,830	\$1,466,789,205	\$1,508,492,221	\$1,551,453,949
Billing & Data Management	\$16,128,858	\$16,311,114	\$16,495,430	\$16,681,828	\$16,870,333	\$17,060,968	\$17,253,757	\$17,448,724	\$17,645,895
SCE Fees	\$5,290,374	\$5,350,154	\$5,410,609	\$5,471,748	\$5,533,577	\$5,596,105	\$5,659,340	\$5,723,290	\$5,787,961
Technical Services	\$1,621,263	\$1,653,688	\$1,686,762	\$1,720,497	\$1,754,907	\$1,790,005	\$1,825,805	\$1,862,321	\$1,899,568
Staffing	\$3,145,737	\$3,208,652	\$3,272,825	\$3,338,281	\$3,405,047	\$3,473,148	\$3,542,611	\$3,613,463	\$3,685,732
General & Administrative expenses	\$415,698	\$373,012	\$380,473	\$388,082	\$470,844	\$428,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883	\$14,643,883
Contribution to Annual Reserves	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
New Programs	\$217,119,621	\$229,507,037	\$332,181,003	\$250,075,388	\$261,493,256	\$274,691,737	\$291,312,684	\$307,982,611	\$327,100,898
Start-up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$6,645,455	\$6,819,957	\$6,999,274	\$7,181,937	\$7,370,424	\$7,570,752	\$7,777,925	\$7,989,158	\$8,206,661
Total Operating Costs	\$1,508,489,304	\$1,555,791,312	\$1,594,230,788	\$1,648,718,892	\$1,697,822,152	\$1,751,108,188	\$1,809,217,045	\$1,868,175,743	\$1,930,853,020
Other Revenues									
Total CCE Revenue Requirement	\$1,508,489,304	\$1,555,791,312	\$1,594,230,788	\$1,648,718,892	\$1,697,822,152	\$1,751,108,188	\$1,809,217,045	\$1,868,175,743	\$1,930,853,020
Average CCE Rate (\$/kWh)	\$0.0949	\$0.0968	\$0.0981	\$0.1003	\$0.1021	\$0.1041	\$0.1064	\$0.1086	\$0.1110
Average SCE Generation Rate (\$/kWh)	\$0.0863	\$0.0880	\$0.0891	\$0.0912	\$0.0928	\$0.0947	\$0.0967	\$0.0988	\$0.1009
Total CCE Charges									
SCE Non-bypassable Charges	\$44,366,859	\$44,577,161	\$44,804,342	\$44,925,839	\$45,126,238	\$45,304,664	\$45,458,584	\$45,627,682	\$45,786,716
CCE Revenue Requirement	\$1,508,489,304	\$1,555,791,312	\$1,594,230,788	\$1,648,718,892	\$1,697,822,152	\$1,751,108,188	\$1,809,217,045	\$1,868,175,743	\$1,930,853,020
Total CCE Generation Revenue Requirement	\$1,552,856,163	\$1,600,318,473	\$1,639,035,131	\$1,693,644,731	\$1,742,948,390	\$1,796,412,852	\$1,854,675,629	\$1,913,803,426	\$1,976,639,736
Bundled SCE Revenues	\$3,493,543,297	\$3,541,557,705	\$3,643,564,853	\$3,762,275,864	\$3,878,272,416	\$4,000,321,101	\$4,129,074,697	\$4,260,994,562	\$4,398,764,102
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$3,615,045,547	\$3,727,520,440	\$3,833,299,267	\$3,957,085,239	\$4,077,746,123	\$4,204,817,418	\$4,339,007,558	\$4,476,456,403	\$4,620,082,911
Savings	(\$181,502,250)	(\$185,962,735)	(\$189,734,414)	(\$194,809,375)	(\$199,473,707)	(\$204,496,317)	(\$209,932,861)	(\$215,461,841)	(\$221,318,809)
Percent Savings	-5.3%	-5.3%	-5.2%	-5.2%	-5.1%	-5.1%	-5.1%	-5.1%	-5.0%
Cumulative Reserves	\$1,623,482,661	\$1,852,989,698	\$2,085,170,701	\$2,335,246,090	\$2,596,739,346	\$2,871,431,083	\$3,162,743,767	\$3,470,726,377	\$3,797,827,275
Reserve Target									

**CVAG Community Choice Aggregation
Financial Proforma
Portfolio RPS**

	2017		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Jan - June	July - Dec										
Load Data												
Customer Accounts												
Domestic	0	780	94,731	95,801	96,884	97,979	99,086	100,205	101,338	102,483	103,641	104,812
Commercial	0	8,577	12,246	12,385	12,525	12,666	12,809	12,954	13,100	13,248	13,398	13,550
Industrial	0	0	33	34	34	34	35	35	35	36	36	37
Lighting & Traffic Control	0	750	1,152	1,165	1,178	1,191	1,205	1,218	1,232	1,246	1,260	1,274
Agricultural	0	9	432	437	442	447	452	457	462	467	473	478
Total Customers	0	10,116	108,594	109,821	111,062	112,317	113,586	114,870	116,168	117,481	118,808	120,151
Energy Sales (MWh)												
Domestic	0	15	971,817	982,799	993,904	1,005,135	1,016,493	1,027,980	1,039,596	1,051,343	1,063,224	1,075,238
Commercial	0	16,251	464,157	469,402	474,707	480,071	485,496	490,982	496,530	502,141	507,815	513,553
Industrial	0	0	168,487	170,391	172,317	174,264	176,233	178,224	180,238	182,275	184,335	186,418
Lighting & Traffic Control	0	3,451	9,302	9,408	9,514	9,621	9,730	9,840	9,951	10,064	10,177	10,292
Agricultural	0	5,957	109,632	110,870	112,123	113,390	114,672	115,967	117,278	118,603	119,943	121,299
Total Energy Sales (MWh)	0	25,675	1,742,870	1,762,565	1,782,482	1,802,624	1,822,993	1,843,593	1,864,426	1,885,494	1,906,800	1,928,151
Total Operating Costs												
Power Supply	\$0	\$1,257,583	\$86,127,816	\$89,335,669	\$93,319,633	\$96,590,120	\$99,841,575	\$103,246,018	\$106,729,471	\$110,096,494	\$113,705,277	\$116,946,487
Billing & Data Management	\$0	\$1,066,215	\$1,628,639	\$1,647,043	\$1,665,654	\$1,684,476	\$1,703,511	\$1,722,761	\$1,742,228	\$1,761,915	\$1,781,825	\$1,801,959
SCE Fees	\$39,557	\$413,653	\$918,803	\$540,338	\$546,443	\$552,616	\$558,860	\$565,173	\$571,559	\$578,016	\$584,546	\$591,151
Technical Services	\$620,000	\$500,000	\$770,000	\$867,000	\$884,340	\$902,027	\$920,067	\$938,469	\$957,238	\$976,383	\$995,910	\$1,015,829
Staffing	\$90,000	\$310,000	\$1,190,000	\$1,238,076	\$1,262,838	\$1,288,094	\$1,314,856	\$1,340,133	\$1,366,936	\$1,394,275	\$1,422,160	\$1,450,603
General & Administrative expenses	\$90,000	\$150,000	\$350,000	\$306,000	\$312,120	\$318,362	\$324,730	\$331,224	\$337,849	\$344,606	\$351,498	\$358,528
Debt Service (CCE Bonds & Start-up Costs)	\$0	\$585,441	\$4,518,055	\$4,518,055	\$4,518,055	\$4,518,055	\$3,932,614	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173
Contribution to Annual Reserves	\$0	\$2,108,273	\$6,373,420	\$7,223,951	\$7,883,898	\$0	\$0	\$0	\$0	\$0	\$0	\$0
New Programs	\$0	\$0	\$0	\$0	\$0	\$8,411,118	\$9,501,817	\$10,683,769	\$11,271,997	\$11,812,299	\$12,395,778	\$12,869,931
Start-Up Capital	\$0	(\$5,000,000)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$4,198	\$17,768	\$551,968	\$567,554	\$588,689	\$606,273	\$620,951	\$637,041	\$650,057	\$662,625	\$674,414	\$685,575
Total Operating Costs	\$843,755	\$448,934	\$102,428,702	\$106,243,686	\$110,981,670	\$114,871,143	\$118,737,981	\$122,786,762	\$126,929,507	\$130,933,785	\$135,225,581	\$139,080,235
Other Revenues	\$843,755	\$448,934	\$102,428,702	\$106,243,686	\$110,981,670	\$114,871,143	\$118,737,981	\$122,786,762	\$126,929,507	\$130,933,785	\$135,225,581	\$139,080,235
Total CCE Revenue Requirement	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Average CCE Rate (\$/kWh)	\$0.0503	\$0.0594	\$0.0594	\$0.0610	\$0.0630	\$0.0644	\$0.0659	\$0.0674	\$0.0688	\$0.0702	\$0.0717	\$0.0729
Average SCE Generation Rate (\$/kWh)	\$0.0599	\$0.0708	\$0.0708	\$0.0726	\$0.0750	\$0.0767	\$0.0784	\$0.0802	\$0.0820	\$0.0836	\$0.0854	\$0.0868
Total CCE Charges												
SCE Non-bypassable Charges	\$230,758	\$14,890,359	\$15,058,620	\$15,228,783	\$15,400,868	\$15,574,898	\$5,892,314	\$5,958,897	\$6,026,232	\$6,094,329	\$6,163,195	\$6,232,071
CCE Revenue Requirement	\$843,755	\$448,934	\$102,428,702	\$106,243,686	\$110,981,670	\$114,871,143	\$118,737,981	\$122,786,762	\$126,929,507	\$130,933,785	\$135,225,581	\$139,080,235
Total CCE Generation Revenue Requirement	\$843,755	\$679,692	\$117,319,061	\$121,302,307	\$126,210,453	\$130,272,010	\$134,312,879	\$138,679,075	\$143,288,404	\$148,196,018	\$153,419,910	\$158,362,306
Bundled SCE Revenues												
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$3,832,608	\$316,552,316	\$327,229,345	\$339,198,608	\$350,357,259	\$361,694,778	\$373,461,195	\$385,558,469	\$397,716,797	\$410,450,428	\$422,904,017
Savings	\$0	\$3,678,273	\$302,612,480	\$312,625,791	\$323,756,237	\$334,904,494	\$346,094,954	\$357,340,317	\$378,803,261	\$390,787,503	\$402,575,738	\$414,575,738
Percent Savings	\$0	\$154,335	\$13,939,836	\$14,603,554	\$15,442,371	\$16,118,847	\$16,790,284	\$17,495,641	\$18,218,152	\$18,913,536	\$19,662,925	\$20,328,278
Cumulative Reserves	\$2,108,273	\$8,481,693	\$15,705,644	\$23,589,542	\$32,000,660	\$41,502,478	\$52,186,247	\$63,458,244	\$75,270,543	\$87,666,321	\$100,536,251	\$113,964,251
Reserve Target	\$27,736,410											

**CVAG Community Choice Aggregation
Financial Proforma
Portfolio RPS**

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	105,996	107,194	108,405	109,630	110,869	112,122	113,389	114,670	115,966
Commercial	13,703	13,857	14,014	14,172	14,333	14,495	14,658	14,824	14,991
Industrial	37	37	38	38	39	39	40	40	0
Lighting & Traffic Control	1,289	1,318	1,333	1,333	1,348	1,363	1,379	1,394	0
Agricultural	483	489	494	500	506	511	517	523	0
Total Customers	121,508	122,881	124,270	125,674	127,094	128,530	129,983	131,453	130,958
Energy Sales (MWh)									
Domestic	1,087,388	1,099,676	1,112,102	1,124,669	1,137,378	1,150,230	1,163,227	1,176,372	1,189,665
Commercial	519,356	525,225	531,160	537,162	543,232	549,371	555,578	561,857	568,205
Industrial	188,524	190,654	192,809	194,988	197,191	199,419	201,673	203,952	206,256
Lighting & Traffic Control	10,409	10,526	10,645	10,766	10,887	11,010	11,135	11,261	11,388
Agricultural	122,669	124,055	125,457	126,875	128,309	129,758	131,225	132,708	134,207
Total Energy Sales (MWh)	1,928,347	1,950,137	1,972,173	1,994,459	2,016,996	2,039,788	2,062,838	2,086,148	2,109,722
CCE Operating Costs									
Power Supply	\$120,715,713	\$124,641,715	\$127,608,173	\$131,633,023	\$135,819,990	\$140,182,348	\$144,729,275	\$149,470,270	\$154,412,499
Billing & Data Management	\$1,822,321	\$1,842,913	\$1,863,738	\$1,884,799	\$1,906,097	\$1,927,636	\$1,949,418	\$1,971,446	\$1,993,724
SCE Fees	\$597,829	\$604,584	\$611,414	\$618,322	\$625,308	\$632,373	\$639,517	\$646,742	\$654,049
Technical Services	\$1,036,145	\$1,056,868	\$1,078,006	\$1,099,566	\$1,121,557	\$1,143,988	\$1,166,868	\$1,190,205	\$1,214,009
Staffing	\$1,479,615	\$1,509,208	\$1,539,392	\$1,570,180	\$1,601,583	\$1,633,615	\$1,666,287	\$1,699,613	\$1,733,605
General & Administrative expenses	\$415,698	\$373,012	\$380,473	\$388,082	\$415,844	\$428,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173
Contribution to Annual Reserves									
New Programs	\$13,470,686	\$14,158,610	\$14,618,002	\$15,270,918	\$15,932,080	\$16,639,080	\$17,408,657	\$18,187,257	\$19,001,297
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$677,658	\$697,809	\$713,423	\$734,340	\$756,180	\$778,833	\$802,271	\$826,816	\$852,380
Total Operating Costs	\$143,562,840	\$148,231,892	\$151,759,793	\$156,546,402	\$161,525,811	\$166,713,806	\$172,121,302	\$177,759,596	\$183,637,211
Other Revenues									
Total CCE Revenue Requirement	\$143,562,840	\$148,231,892	\$151,759,793	\$156,546,402	\$161,525,811	\$166,713,806	\$172,121,302	\$177,759,596	\$183,637,211
Average CCE Rate (\$/kWh)	\$0.0744	\$0.0760	\$0.0770	\$0.0785	\$0.0801	\$0.0817	\$0.0834	\$0.0852	\$0.0870
Average SCE Generation Rate (\$/kWh)	\$0.0886	\$0.0905	\$0.0916	\$0.0934	\$0.0953	\$0.0973	\$0.0993	\$0.1014	\$0.1036
Total CCE Charges									
SCE Non-bypassable Charges	\$6,117,154	\$6,186,278	\$6,256,183	\$6,326,877	\$6,398,371	\$6,470,673	\$6,543,791	\$6,617,736	\$6,692,517
CCE Revenue Requirement	\$143,562,840	\$148,231,892	\$151,759,793	\$156,546,402	\$161,525,811	\$166,713,806	\$172,121,302	\$177,759,596	\$183,637,211
Total CCE Generation Revenue Requirement	\$149,679,994	\$154,418,170	\$158,015,976	\$162,873,279	\$167,924,183	\$173,184,479	\$178,665,093	\$184,377,333	\$190,329,728
Bundled SCE Revenues									
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$436,353,110	\$450,279,924	\$463,112,047	\$477,714,771	\$492,827,740	\$508,478,593	\$524,689,456	\$541,483,196	\$558,879,668
Savings	\$21,228,149	\$22,048,369	\$22,650,445	\$23,491,485	\$24,368,450	\$25,284,338	\$26,241,218	\$27,241,235	\$28,286,000
Percent Savings	4.9%	4.9%	4.9%	4.9%	4.9%	5.0%	5.0%	5.0%	5.1%
Cumulative Reserves									
Reserve Target	\$114,006,937	\$128,165,547	\$142,783,549	\$158,054,467	\$173,986,546	\$190,625,626	\$208,034,283	\$226,221,540	\$245,222,837

**CVAG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable**

	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026		2027	
	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec
Load Data																						
Customer Accounts																						
Domestic	0	780	94,731	95,801	96,884	97,979	99,086	100,205	101,338	102,483	103,641	104,812										
Commercial	0	8,577	12,246	12,385	12,525	12,666	12,809	12,954	13,100	13,248	13,398	13,550										
Industrial	0	0	33	33	34	34	35	35	35	36	36	37										
Lighting & Traffic Control	0	750	1,152	1,165	1,178	1,191	1,205	1,218	1,232	1,246	1,260	1,274										
Agricultural	0	9	432	437	442	447	452	457	462	467	473	478										
Total Customers	0	10,116	108,594	109,821	111,062	112,317	113,586	114,870	116,168	117,481	118,808	120,151										
Energy Sales (MWh)																						
Domestic	0	15	971,817	982,799	993,904	1,005,135	1,016,493	1,027,980	1,039,596	1,051,343	1,063,224	1,075,238										
Commercial	0	16,251	464,157	469,402	474,707	480,071	485,496	490,982	496,530	502,141	507,815	513,553										
Industrial	0	0	168,487	170,391	172,317	174,264	176,233	178,224	180,238	182,275	184,335	186,418										
Lighting & Traffic Control	0	3,451	9,302	9,408	9,514	9,621	9,730	9,840	9,951	10,064	10,177	10,292										
Agricultural	0	5,957	109,632	110,870	112,123	113,390	114,672	115,967	117,278	118,603	119,943	121,299										
Total Energy Sales (MWh)	0	25,675	1,723,396	1,742,870	1,762,565	1,782,482	1,802,624	1,822,993	1,843,593	1,864,426	1,885,494	1,906,800										
CCE Operating Costs																						
Power Supply	\$0	\$1,330,076	\$89,872,073	\$92,484,855	\$95,103,582	\$97,924,199	\$100,729,211	\$103,611,908	\$106,609,724	\$109,653,650	\$112,870,312	\$116,216,850										
Billing & Data Management	\$0	\$106,215	\$1,628,639	\$1,647,043	\$1,665,654	\$1,684,676	\$1,703,551	\$1,722,761	\$1,742,221	\$1,761,915	\$1,781,825	\$1,801,959										
CCE Fees	\$39,557	\$413,653	\$918,803	\$540,338	\$546,443	\$552,616	\$558,860	\$565,173	\$571,559	\$578,016	\$584,546	\$591,151										
Technical Services	\$620,000	\$500,000	\$770,000	\$867,000	\$884,340	\$902,027	\$920,067	\$938,469	\$957,238	\$976,383	\$995,910	\$1,015,829										
Staffing	\$90,000	\$310,000	\$1,190,000	\$1,238,076	\$1,262,838	\$1,288,094	\$1,313,856	\$1,340,133	\$1,366,936	\$1,394,275	\$1,422,160	\$1,450,603										
General & Administrative expenses	\$90,000	\$150,000	\$350,000	\$306,000	\$312,120	\$318,362	\$344,730	\$356,224	\$337,849	\$344,606	\$351,498	\$368,528										

**CVAG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable**

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	105,996	107,194	108,405	109,630	110,869	112,122	113,389	114,670	115,966
Commercial	13,703	13,857	14,014	14,172	14,333	14,495	14,658	14,824	14,991
Industrial	37	37	38	38	39	39	40	40	0
Lighting & Traffic Control	1,289	1,318	1,333	1,333	1,348	1,363	1,379	1,394	0
Agricultural	483	489	494	500	506	511	517	523	0
Total Customers	121,508	122,881	124,270	125,674	127,094	128,530	129,983	131,453	130,958
Energy Sales (MWh)									
Domestic	1,087,388	1,099,676	1,112,102	1,124,669	1,137,378	1,150,230	1,163,227	1,176,372	1,189,665
Commercial	519,356	525,225	531,160	537,162	543,232	549,371	555,578	561,857	568,205
Industrial	188,524	190,654	192,809	194,988	197,191	199,419	201,673	203,952	206,256
Lighting & Traffic Control	10,409	10,526	10,645	10,766	10,887	11,010	11,135	11,261	11,388
Agricultural	122,669	124,055	125,457	126,875	128,309	129,758	131,225	132,708	134,207
Total Energy Sales (MWh)	1,928,347	1,950,137	1,972,173	1,994,459	2,016,996	2,039,788	2,062,838	2,086,148	2,109,722
CCE Operating Costs									
Power Supply	\$119,761,096	\$123,386,432	\$127,608,173	\$131,633,023	\$135,819,990	\$140,182,348	\$144,729,275	\$149,470,270	\$154,412,499
Billing & Data Management	\$1,822,321	\$1,842,913	\$1,863,738	\$1,884,799	\$1,906,097	\$1,927,636	\$1,949,418	\$1,971,446	\$1,993,724
SCE Fees	\$597,829	\$604,584	\$611,414	\$618,322	\$625,308	\$632,373	\$639,517	\$646,742	\$654,049
Technical Services	\$1,036,145	\$1,056,868	\$1,078,006	\$1,099,566	\$1,121,557	\$1,143,988	\$1,166,868	\$1,190,205	\$1,214,009
Staffing	\$1,479,615	\$1,509,208	\$1,539,392	\$1,570,180	\$1,601,583	\$1,633,615	\$1,666,287	\$1,699,613	\$1,733,605
General & Administrative expenses	\$415,698	\$373,012	\$380,473	\$386,082	\$415,844	\$428,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173
Contribution to Annual Reserves									
New Programs	\$24,684,565	\$26,008,162	\$25,457,987	\$26,452,804	\$27,469,638	\$28,547,209	\$29,703,036	\$30,884,371	\$32,118,240
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$672,885	\$691,532	\$713,423	\$734,340	\$756,180	\$778,833	\$802,271	\$826,816	\$852,380
Total Operating Costs	\$153,817,329	\$158,819,885	\$162,599,779	\$167,728,288	\$173,063,369	\$178,621,935	\$184,415,680	\$190,456,711	\$196,754,155
Other Revenues									
Total CCE Revenue Requirement	\$153,817,329	\$158,819,885	\$162,599,779	\$167,728,288	\$173,063,369	\$178,621,935	\$184,415,680	\$190,456,711	\$196,754,155
Average CCE Rate (\$/kWh)	\$0.0798	\$0.0814	\$0.0824	\$0.0841	\$0.0858	\$0.0876	\$0.0894	\$0.0913	\$0.0933
Average SCE Generation Rate (\$/kWh)	\$0.0886	\$0.0905	\$0.0916	\$0.0934	\$0.0953	\$0.0973	\$0.0993	\$0.1014	\$0.1036
Total CCE Charges									
SCE Non-bypassable Charges	\$6,117,154	\$6,186,278	\$6,256,183	\$6,326,877	\$6,398,371	\$6,470,673	\$6,543,791	\$6,617,736	\$6,692,517
CCE Revenue Requirement	\$153,817,329	\$158,819,885	\$162,599,779	\$167,728,288	\$173,063,369	\$178,621,935	\$184,415,680	\$190,456,711	\$196,754,155
Total CCE Generation Revenue Requirement	\$159,934,482	\$165,006,162	\$168,855,961	\$174,055,165	\$179,461,741	\$185,092,608	\$190,959,472	\$197,074,447	\$203,446,672
Bundled SCE Revenues									
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$436,353,110	\$450,279,924	\$463,112,047	\$477,714,771	\$492,827,740	\$508,478,593	\$524,689,456	\$541,483,196	\$558,879,668
Savings	\$10,973,660	\$11,460,376	\$11,810,459	\$12,309,599	\$12,830,892	\$13,376,209	\$13,946,840	\$14,544,121	\$15,169,056
Percent Savings	2.5%	2.5%	2.6%	2.6%	2.6%	2.6%	2.7%	2.7%	2.7%
Cumulative Reserves									
Reserve Target	\$202,358,163	\$228,366,325	\$253,824,312	\$280,277,116	\$307,746,754	\$336,293,962	\$365,996,998	\$396,881,369	\$428,999,609

**CVAG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable**

Category	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		
	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	
Load Data																							
	Customer Accounts																						
	Domestic	0	780	94,731	95,801	96,884	97,979	99,086	100,205	101,338	102,483	103,641	104,812										
	Commercial	0	8,577	12,246	12,385	12,525	12,666	12,809	12,954	13,100	13,248	13,398	13,550										
	Industrial	0	0	33	34	35	36	37	38	39	40	41	42										
Lighting & Traffic Control	Agricultural	0	750	1,152	1,165	1,178	1,191	1,205	1,218	1,232	1,246	1,260	1,274										
	Domestic	0	9	432	437	442	447	452	457	462	467	473	478										
	Total Customers	0	10,116	108,594	109,821	111,062	112,317	113,586	114,870	116,168	117,481	118,808	120,151										
	Energy Sales (MWh)																						
	Domestic	0	15	971,817	982,799	993,904	1,005,135	1,016,493	1,027,980	1,039,596	1,051,343	1,063,224	1,075,238										
Commercial	0	16,251	464,157	469,402	474,707	480,071	485,496	490,982	496,530	502,141	507,815	513,553											
Industrial	0	0	168,487	170,391	172,317	174,264	176,233	178,224	180,238	182,275	184,335	186,418											
Lighting & Traffic Control	0	3,451	9,302	9,408	9,514	9,621	9,730	9,840	9,951	10,064	10,177	10,292											
Agricultural	0	5,957	109,632	110,870	112,123	113,390	114,672	115,967	117,278	118,603	119,943	121,299											
Total Energy Sales (MWh)	0	25,675	1,723,396	1,742,870	1,762,565	1,782,482	1,802,624	1,822,993	1,843,593	1,864,426	1,885,494	1,906,800											
2017																							
CCE Operating Costs																							
Power Supply	\$0	\$1,774,143	\$117,097,797	\$120,159,004	\$123,200,139	\$126,432,728	\$129,674,380	\$133,037,090	\$136,498,693	\$140,045,903	\$143,804,155	\$147,684,617											
Billing & Data Management	\$0	\$106,215	\$1,628,639	\$1,647,043	\$1,665,654	\$1,684,476	\$1,703,511	\$1,722,761	\$1,742,228	\$1,761,915	\$1,781,825	\$1,801,959											
SCE Fees	\$39,557	\$413,653	\$918,803	\$540,338	\$546,443	\$552,616	\$558,860	\$565,173	\$571,559	\$578,016	\$584,546	\$591,151											
Technical Services	\$620,000	\$500,000	\$770,000	\$867,000	\$884,340	\$902,027	\$920,067	\$938,469	\$957,238	\$976,383	\$995,910	\$1,015,829											
Staffing	\$90,000	\$310,000	\$1,190,000	\$1,238,076	\$1,262,838	\$1,288,094	\$1,313,856	\$1,340,133	\$1,366,936	\$1,394,275	\$1,422,160	\$1,450,603											
General & Administrative expenses	\$90,000	\$150,000	\$350,000	\$306,000	\$312,120	\$318,362	\$324,730	\$331,224	\$337,849	\$344,606	\$351,498	\$358,528											
Debt Service (CCE Bonds & Start-up Costs)	\$0	\$585,441	\$4,518,055	\$4,518,055	\$4,518,055	\$4,518,055	\$3,932,614	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173											
Contribution to Annual Reserves	\$0	\$2,004,637	\$8,172,100	\$10,396,256	\$13,526,669	\$0	\$0	\$0	\$0	\$0	\$0	\$0											
New Programs	\$0	\$0	\$0	\$0	\$0	\$15,342,165	\$17,885,628	\$20,210,915	\$22,152,700	\$23,799,002	\$25,611,771	\$26,682,471											
Start-Up Capital	\$0	(\$5,000,000)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0											
Uncollectibles	\$4,198	\$20,351	\$706,818	\$721,671	\$738,092	\$755,486	\$770,115	\$735,997	\$753,903	\$772,373	\$791,908	\$812,265											
Total Operating Costs	\$843,755	\$864,441	\$135,352,214	\$140,393,443	\$146,654,350	\$151,794,010	\$156,903,761	\$162,253,935	\$167,728,278	\$173,019,645	\$178,690,946	\$183,784,596											
Other Revenues																							
Total CCE Revenue Requirement	\$843,755	\$864,441	\$135,352,214	\$140,393,443	\$146,654,350	\$151,794,010	\$156,903,761	\$162,253,935	\$167,728,278	\$173,019,645	\$178,690,946	\$183,784,596											
Average CCE Rate (\$/kWh)																							
Average SCE Generation Rate (\$/kWh)																							
Total CCE Charges																							
SCE Non-bypassable Charges	\$0	\$20,758	\$14,890,359	\$15,058,620	\$15,228,783	\$15,400,868	\$15,574,898	\$5,892,314	\$5,958,897	\$6,026,232	\$6,094,329	\$6,163,195											
CCE Revenue Requirement	\$843,755	\$864,441	\$135,352,214	\$140,393,443	\$146,654,350	\$151,794,010	\$156,903,761	\$162,253,935	\$167,728,278	\$173,019,645	\$178,690,946	\$183,784,596											
Total CCE Generation Revenue Requirement	\$843,755	\$1,095,199	\$150,242,573	\$155,452,063	\$161,883,133	\$167,194,878	\$172,478,658	\$168,146,249	\$173,687,175	\$179,005,877	\$184,785,275	\$189,947,791											
Total CCE Revenues																							
Bundled SCE Revenues	\$0	\$3,832,608	\$316,552,316	\$327,229,345	\$339,198,608	\$350,357,259	\$361,694,778	\$373,461,195	\$385,558,469	\$397,716,797	\$410,450,428	\$422,904,017											
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$4,093,781	\$335,535,991	\$346,775,547	\$359,428,917	\$371,161,280	\$383,070,274	\$395,432,727	\$408,139,087	\$420,889,121	\$434,252,869	\$447,280,099											
Savings	\$0	(\$261,173)	(\$18,983,675)	(\$19,546,202)	(\$20,230,309)	(\$20,804,021)	(\$21,375,496)	(\$21,971,533)	(\$22,580,618)	(\$23,172,323)	(\$23,802,441)	(\$24,376,083)											
Percent Savings																							
Cumulative Reserves	\$2,004,637	\$10,176,737	\$20,572,993	\$34,099,662	\$49,441,827	\$67,127,455	\$87,338,371	\$109,491,071	\$133,290,073	\$158,901,844	\$185,584,315												
Reserve Target	\$35,517,618																						

**CVAG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable**

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	105,996	107,194	108,405	109,630	110,869	112,122	113,389	114,670	115,966
Commercial	13,703	13,857	14,014	14,172	14,333	14,495	14,658	14,824	14,991
Industrial	37	37	38	38	39	39	40	40	0
Lighting & Traffic Control	1,289	1,318	1,333	1,333	1,348	1,363	1,379	1,394	0
Agricultural	483	489	494	500	506	511	517	523	0
Total Customers	121,508	122,881	124,270	125,674	127,094	128,530	129,983	131,453	130,958
Energy Sales (MWh)									
Domestic	1,087,388	1,099,676	1,112,102	1,124,669	1,137,378	1,150,230	1,163,227	1,176,372	1,189,665
Commercial	519,356	525,225	531,160	537,162	543,232	549,371	555,578	561,857	568,205
Industrial	188,524	190,654	192,809	194,988	197,191	199,419	201,673	203,952	206,256
Lighting & Traffic Control	10,409	10,526	10,645	10,766	10,887	11,010	11,135	11,261	11,388
Agricultural	122,669	124,055	125,457	126,875	128,309	129,758	131,225	132,708	134,207
Total Energy Sales (MWh)	1,928,347	1,950,137	1,972,173	1,994,459	2,016,996	2,039,788	2,062,838	2,086,148	2,109,722
CCE Operating Costs									
Power Supply	\$151,626,153	\$155,830,800	\$160,130,352	\$164,644,719	\$169,237,300	\$174,146,086	\$179,228,310	\$184,428,157	\$189,686,298
Billing & Data Management	\$1,822,321	\$1,842,913	\$1,863,738	\$1,884,799	\$1,906,097	\$1,927,636	\$1,949,418	\$1,971,446	\$1,993,724
SCE Fees	\$597,829	\$604,584	\$611,414	\$618,322	\$625,308	\$632,373	\$639,517	\$646,742	\$654,049
Technical Services	\$1,036,145	\$1,056,868	\$1,078,006	\$1,099,566	\$1,121,557	\$1,143,988	\$1,166,868	\$1,190,205	\$1,214,009
Staffing	\$1,479,615	\$1,509,208	\$1,539,392	\$1,570,180	\$1,601,583	\$1,633,615	\$1,666,287	\$1,699,613	\$1,733,605
General & Administrative expenses	\$415,698	\$373,012	\$380,473	\$386,082	\$415,844	\$428,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173	\$3,347,173
Contribution to Annual Reserves									
New Programs	\$28,550,893	\$30,459,545	\$30,713,146	\$32,412,649	\$34,266,695	\$36,092,103	\$38,061,831	\$40,191,595	\$42,577,375
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$832,210	\$853,754	\$876,034	\$899,399	\$923,266	\$948,652	\$974,766	\$1,001,606	\$1,028,749
Total Operating Costs	\$189,708,039	\$195,877,858	\$200,539,727	\$206,864,888	\$213,444,822	\$220,300,386	\$227,446,006	\$234,896,610	\$242,663,458
Other Revenues									
Total CCE Revenue Requirement	\$189,708,039	\$195,877,858	\$200,539,727	\$206,864,888	\$213,444,822	\$220,300,386	\$227,446,006	\$234,896,610	\$242,663,458
Average CCE Rate (\$/kWh)	\$0.0984	\$0.1004	\$0.1017	\$0.1037	\$0.1058	\$0.1080	\$0.1103	\$0.1126	\$0.1150
Average SCE Generation Rate (\$/kWh)	\$0.0886	\$0.0905	\$0.0916	\$0.0934	\$0.0953	\$0.0973	\$0.0993	\$0.1014	\$0.1036
Total CCE Charges									
SCE Non-bypassable Charges	\$6,117,154	\$6,186,278	\$6,256,183	\$6,326,877	\$6,398,371	\$6,470,673	\$6,543,791	\$6,617,736	\$6,692,517
CCE Revenue Requirement	\$189,708,039	\$195,877,858	\$200,539,727	\$206,864,888	\$213,444,822	\$220,300,386	\$227,446,006	\$234,896,610	\$242,663,458
Total CCE Generation Revenue Requirement	\$195,825,192	\$202,064,136	\$206,795,910	\$213,191,765	\$219,843,193	\$226,771,059	\$233,989,797	\$241,514,346	\$249,355,974
Bundled SCE Revenues									
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$436,353,110	\$450,279,924	\$463,112,047	\$477,714,771	\$492,827,740	\$508,478,593	\$524,689,456	\$541,483,196	\$558,879,668
Savings	\$461,270,160	\$475,877,521	\$489,241,535	\$504,541,771	\$520,378,300	\$536,780,836	\$553,772,942	\$571,378,974	\$589,619,915
Percent Savings	-5.7%	-5.7%	-5.6%	-5.6%	-5.6%	-5.6%	-5.5%	-5.5%	-5.5%
Cumulative Reserves Reserve Target	\$214,135,207	\$244,594,752	\$275,307,898	\$307,720,547	\$341,987,242	\$378,079,345	\$416,141,176	\$456,332,771	\$498,910,146

WRCOG Community Choice Aggregation
Financial Proforma
Portfolio RPS

[illegible]

**WRCOG Community Choice Aggregation
Financial Proforma
Portfolio RPS**

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	338,173	341,995	345,859	349,768	353,720	357,717	361,759	365,847	369,981
Commercial	30,758	31,105	31,457	31,812	32,172	32,535	32,903	33,275	33,651
Industrial	162	163	165	167	169	171	173	175	0
Lighting & Traffic Control	4,392	4,441	4,491	4,542	4,593	4,645	4,698	4,751	0
Agricultural	1,163	1,176	1,189	1,203	1,216	1,230	1,244	1,258	0
Total Customers	374,647	378,881	383,162	387,492	391,870	396,298	400,777	405,305	403,632

Energy Sales (MWh)									
Domestic	2,816,101	2,847,922	2,880,104	2,912,649	2,945,562	2,978,847	3,012,508	3,046,549	3,080,975
Commercial	1,334,728	1,349,810	1,365,063	1,380,488	1,396,088	1,411,864	1,427,818	1,443,952	1,460,269
Industrial	732,125	740,398	748,765	757,226	765,782	774,436	783,187	792,037	800,987
Lighting & Traffic Control	48,285	48,831	49,383	49,941	50,505	51,076	51,653	52,237	52,827
Agricultural	192,363	194,537	196,735	198,958	201,207	203,480	205,780	208,105	210,456
Total Energy Sales (MWh)	5,123,602	5,181,499	5,240,050	5,299,262	5,359,144	5,419,702	5,480,945	5,542,880	5,605,514

CCE Operating Costs									
Power Supply	\$321,288,943	\$331,789,420	\$339,780,613	\$350,560,224	\$361,621,599	\$373,280,365	\$385,469,911	\$398,069,919	\$411,358,419
Billing & Data Management	\$5,618,748	\$5,682,239	\$5,746,449	\$5,811,384	\$5,877,052	\$5,943,463	\$6,010,624	\$6,078,544	\$6,147,232
SCE Fees	\$1,843,057	\$1,863,883	\$1,884,943	\$1,906,242	\$1,927,781	\$1,949,564	\$1,971,593	\$1,993,870	\$2,016,400
Technical Services	\$1,621,263	\$1,653,688	\$1,686,762	\$1,720,497	\$1,754,907	\$1,790,005	\$1,825,805	\$1,862,321	\$1,899,568
Staffing	\$2,486,749	\$2,536,484	\$2,587,213	\$2,638,958	\$2,691,737	\$2,745,571	\$2,800,483	\$2,856,492	\$2,913,622
General & Administrative expenses	\$485,698	\$373,012	\$380,473	\$388,082	\$415,844	\$463,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760
Contribution to Annual Reserves	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
New Programs	\$36,657,501	\$38,364,057	\$39,526,302	\$41,153,506	\$42,805,016	\$44,533,731	\$46,449,029	\$48,369,874	\$50,403,157
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$1,770,397	\$1,824,056	\$1,865,793	\$1,921,495	\$1,978,731	\$2,039,079	\$2,101,606	\$2,166,510	\$2,234,883
Total Operating Costs	\$376,793,115	\$389,107,598	\$398,479,307	\$416,121,147	\$424,098,426	\$437,766,298	\$452,061,646	\$466,838,364	\$482,422,514
Other Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total CCE Revenue Requirement	\$376,793,115	\$389,107,598	\$398,479,307	\$416,121,147	\$424,098,426	\$437,766,298	\$452,061,646	\$466,838,364	\$482,422,514
Average CCE Rate (\$/kWh)	\$0.0735	\$0.0751	\$0.0760	\$0.0776	\$0.0791	\$0.0808	\$0.0825	\$0.0842	\$0.0861
Average SCE Generation Rate (\$/kWh)	\$0.0875	\$0.0894	\$0.0905	\$0.0924	\$0.0942	\$0.0962	\$0.0982	\$0.1003	\$0.1025

Total CCE Charges									
SCE Non-bypassable Charges	\$15,714,145	\$15,891,714	\$16,071,291	\$16,252,896	\$16,436,554	\$16,622,287	\$16,810,119	\$17,000,073	\$17,192,174
CCE Revenue Requirement	\$376,793,115	\$389,107,598	\$398,479,307	\$411,121,147	\$424,093,426	\$437,766,298	\$452,061,646	\$466,838,364	\$482,422,514
Total CCE Generation Revenue Requirement	\$392,507,260	\$404,999,313	\$414,550,597	\$427,374,043	\$440,529,980	\$454,388,586	\$468,871,765	\$483,838,437	\$499,614,689

Bundled SCE Revenues	\$1,147,726,447	\$1,184,428,365	\$1,218,321,871	\$1,256,825,188	\$1,296,461,281	\$1,337,694,117	\$1,380,454,747	\$1,424,599,990	\$1,470,543,601
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$1,091,670,474	\$1,126,204,347	\$1,158,492,341	\$1,194,769,294	\$1,232,118,134	\$1,270,932,348	\$1,311,157,886	\$1,352,678,470	\$1,395,845,773
Savings	\$56,055,972	\$58,224,018	\$59,829,529	\$62,055,893	\$64,343,146	\$66,761,770	\$69,296,861	\$71,921,520	\$74,697,828
Percent Savings	4.9%	4.9%	4.9%	4.9%	5.0%	5.0%	5.0%	5.0%	5.1%

Cumulative Reserves	\$320,779,395	\$359,143,452	\$398,669,754	\$439,823,260	\$482,628,276	\$527,162,007	\$573,611,036	\$621,980,910	\$672,384,067
Reserve Target									

WRCOG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable

	2017		Load Data									
	Jan - June	July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Accounts												
Domestic	0	1,919	302,231	305,647	309,100	312,593	316,125	319,698	323,310	326,964	330,658	334,395
Commercial	0	14,460	27,789	27,799	28,113	28,431	28,752	29,077	29,406	29,738	30,074	30,414
Industrial	0	144	0	146	148	149	151	153	154	156	158	160
Lighting & Traffic Control	0	1,955	3,925	3,969	4,014	4,059	4,105	4,152	4,199	4,246	4,294	4,342
Agricultural	0	11	1,039	1,063	1,051	1,075	1,087	1,099	1,112	1,124	1,137	1,150
Total Customers	0	18,346	334,828	338,612	342,438	346,308	350,221	354,179	358,181	362,228	366,321	370,461

Energy Sales (MWh)									
0	31	2,516,796	2,545,236	2,573,997	2,603,084	2,662,246	2,692,329	2,722,752	2,784,634
0	40,038	1,192,869	1,206,348	1,219,980	1,233,766	1,261,806	1,276,065	1,305,067	1,310,814
0	0	654,313	661,706	669,184	676,745	684,392	699,947	715,856	723,945
0	13,960	43,153	44,134	44,633	45,137	45,247	46,163	46,685	47,212
0	4,688	171,918	173,861	175,826	177,812	178,854	179,887	180,989	182,014
0	58,716	4,579,049	4,630,793	4,683,121	4,736,040	4,843,679	4,898,413	4,953,765	5,066,332
Total Energy Sales (MWh)									
Total Energy Sales (MWh)									

2017	2018		2019		2020		2021		2022		2023		2024		2025		2026		2027	
	Jan - June	July - Dec	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027								
CCE Operating Costs																				
	\$0	\$3,042,266	\$239,817,771	\$746,529,453	\$253,410,401	\$760,765,453	\$768,435,822	\$275,831,414	\$283,833,176	\$291,963,329	\$700,514,540	\$309,463,503								
Power Supply	\$0	\$132,654	\$5,022,156	\$5,078,313	\$5,135,698	\$5,193,731	\$5,254,420	\$5,311,773	\$5,371,796	\$5,432,497	\$5,493,884	\$5,555,965								
Billing & Data Management		\$12,288,726	\$2,873,783	\$1,665,795	\$1,742,969	\$1,731,652	\$1,722,902	\$1,761,957	\$1,762,961	\$1,772,967	\$1,802,102	\$1,822,465								
SCE Fees	\$68,749	\$740,000	\$740,000	\$1,356,600	\$1,383,742	\$1,411,407	\$1,439,635	\$1,468,427	\$1,497,796	\$1,527,732	\$1,558,307	\$1,589,473								
Technical Services	\$620,000	\$1,310,000	\$1,310,000	\$2,080,800	\$2,122,416	\$2,164,864	\$2,208,162	\$2,252,325	\$2,343,319	\$2,390,185	\$2,437,989	\$2,486,000								
Staffing	\$900,000	\$1,700,000	\$1,700,000	\$3,060,000	\$3,122,120	\$3,184,362	\$3,244,730	\$3,301,224	\$3,371,849	\$3,446,006	\$3,514,498	\$3,588,528								
General & Administrative expenses	\$900,000	\$150,000	\$150,000	\$306,000	\$312,120	\$320,362	\$334,730	\$341,224	\$351,224	\$364,006	\$376,498	\$388,528								
Debt Service (CCE Bonds & Start-up Costs)		\$819,618	\$6,659,995	\$6,659,995	\$6,659,995	\$6,659,995	\$6,659,995	\$6,659,995	\$6,659,995	\$6,659,995	\$6,659,995	\$6,659,995								
Contribution to Annual Reserves		\$1,557,868	\$22,392,737	\$26,688,660	\$32,441,122	\$35,400,664	\$39,265,431	\$43,326,392	\$46,482,220	\$49,207,777	\$52,224,244	\$55,020,760								
New Programs	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0								
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0								
Uncollectibles	\$4,344	\$34,873	\$1,484,238	\$1,515,792	\$1,553,183	\$1,592,981	\$1,628,945	\$1,635,625	\$1,576,991	\$1,619,321	\$1,663,779	\$1,710,449								
Total Operating Costs	\$873,093	\$2,075,985	\$281,684,259	\$291,881,407	\$304,703,283	\$315,211,110	\$325,948,424	\$336,880,310	\$343,180,015	\$359,241,327	\$371,019,300	\$381,649,391								
Total Revenues																				
Other CCE Revenue Requirement	\$873,093	\$2,075,985	\$281,684,259	\$291,881,407	\$304,703,283	\$315,211,110	\$325,948,424	\$336,880,310	\$343,180,015	\$359,241,327	\$371,019,300	\$381,649,391								
Average CCE Rate (\$/kWh)		\$0.0502	\$0.0615	\$0.0630	\$0.0651	\$0.0666	\$0.0680	\$0.0711	\$0.0741	\$0.0775	\$0.0826	\$0.0858								
Average SCE Generation Rate (\$/kWh)		\$0.0572	\$0.0701	\$0.0718	\$0.0741	\$0.0758	\$0.0775	\$0.0792	\$0.0810	\$0.0826	\$0.0844	\$0.0858								

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**WRCOG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable**

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	338,173	341,995	345,859	349,768	353,720	357,717	361,759	365,847	369,981
Commercial	30,758	31,105	31,457	31,812	32,172	32,535	32,903	33,275	33,651
Industrial	162	163	165	167	169	171	173	175	0
Lighting & Traffic Control	4,392	4,441	4,491	4,542	4,593	4,645	4,698	4,751	0
Agricultural	1,163	1,176	1,189	1,203	1,216	1,230	1,244	1,258	0
Total Customers	374,647	378,881	383,162	387,492	391,870	396,298	400,777	405,305	403,632
Energy Sales (MWh)									
Domestic	2,816,101	2,847,922	2,880,104	2,912,649	2,945,562	2,978,847	3,012,508	3,046,549	3,080,975
Commercial	1,334,728	1,349,810	1,365,063	1,380,488	1,396,088	1,411,864	1,427,818	1,443,952	1,460,269
Industrial	732,125	740,398	748,765	757,226	765,782	774,436	783,187	792,037	800,987
Lighting & Traffic Control	48,285	48,831	49,383	49,941	50,505	51,076	51,653	52,237	52,827
Agricultural	192,363	194,537	196,735	198,958	201,207	203,480	205,780	208,105	210,456
Total Energy Sales (MWh)	5,123,602	5,181,499	5,240,050	5,299,262	5,359,144	5,419,702	5,480,945	5,542,880	5,605,514
CCE Operating Costs									
Power Supply	\$318,781,912	\$328,536,021	\$339,780,613	\$350,560,224	\$361,821,599	\$373,280,365	\$385,469,911	\$398,069,919	\$411,358,419
Billing & Data Management	\$5,618,748	\$5,682,239	\$5,746,449	\$5,811,384	\$5,877,052	\$5,943,463	\$6,010,624	\$6,078,544	\$6,147,232
SCE Fees	\$1,843,057	\$1,863,688	\$1,884,943	\$1,906,242	\$1,927,781	\$1,949,564	\$1,971,593	\$1,993,870	\$2,016,400
Technical Services	\$1,621,263	\$1,653,688	\$1,686,762	\$1,720,497	\$1,754,907	\$1,790,005	\$1,825,805	\$1,862,321	\$1,899,568
Staffing	\$2,486,749	\$2,536,484	\$2,587,213	\$2,638,958	\$2,691,737	\$2,745,571	\$2,800,483	\$2,856,492	\$2,913,622
General & Administrative expenses	\$485,698	\$373,012	\$380,473	\$388,082	\$415,844	\$463,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760
Contribution to Annual Reserves	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
New Programs	\$56,222,470	\$59,236,209	\$57,552,747	\$59,751,843	\$61,990,194	\$64,337,445	\$66,899,437	\$69,488,753	\$72,227,033
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$1,757,862	\$1,807,789	\$1,865,793	\$1,921,495	\$1,978,731	\$2,039,079	\$2,101,606	\$2,166,510	\$2,234,883
Total Operating Costs	\$393,838,518	\$406,710,085	\$416,505,751	\$428,719,484	\$443,278,605	\$457,570,012	\$472,512,054	\$487,957,242	\$504,246,390
Other Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total CCE Revenue Requirement	\$393,838,518	\$406,710,085	\$416,505,751	\$428,719,484	\$443,278,605	\$457,570,012	\$472,512,054	\$487,957,242	\$504,246,390
Average CCE Rate (\$/kWh)	\$0.0769	\$0.0785	\$0.0795	\$0.0811	\$0.0827	\$0.0844	\$0.0862	\$0.0880	\$0.0900
Average SCE Generation Rate (\$/kWh)	\$0.0875	\$0.0894	\$0.0905	\$0.0924	\$0.0942	\$0.0962	\$0.0982	\$0.1003	\$0.1025
Total CCE Charges									
SCE Non-bypassable Charges	\$15,714,145	\$15,891,714	\$16,071,291	\$16,252,896	\$16,436,554	\$16,622,287	\$16,810,119	\$17,000,073	\$17,192,174
CCE Revenue Requirement	\$393,838,518	\$406,710,085	\$416,505,751	\$428,719,484	\$443,278,605	\$457,570,012	\$472,512,054	\$487,957,242	\$504,246,390
Total CCE Generation Revenue Requirement	\$409,552,663	\$422,601,799	\$432,577,042	\$445,972,381	\$459,715,159	\$474,192,299	\$489,322,173	\$504,957,316	\$521,438,564
Bundled SCE Revenues	\$1,147,726,447	\$1,184,428,365	\$1,218,321,871	\$1,256,825,188	\$1,296,461,281	\$1,337,694,117	\$1,380,454,747	\$1,424,599,990	\$1,470,543,601
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$1,108,715,877	\$1,143,806,833	\$1,176,518,786	\$1,213,367,632	\$1,251,303,313	\$1,290,736,061	\$1,331,008,293	\$1,373,797,349	\$1,417,669,648
Savings	\$39,010,570	\$40,621,532	\$41,803,085	\$43,457,556	\$45,157,967	\$46,958,056	\$48,846,453	\$50,802,641	\$52,873,953
Percent Savings	3.4%	3.4%	3.4%	3.5%	3.5%	3.5%	3.5%	3.6%	3.6%
Cumulative Reserves	\$458,859,754	\$518,095,962	\$575,648,710	\$635,400,553	\$697,390,747	\$761,728,192	\$828,627,629	\$898,116,381	\$970,343,414
Reserve Target									

**WRCOG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable**

	2017	2017	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Data	Jan - June	July - Dec											
Customer Accounts	Domestic	0	1,919	302,231	305,647	309,100	312,593	316,125	319,698	323,310	326,964	330,658	334,395
	Commercial	0	14,460	27,489	27,799	28,113	28,431	28,752	29,077	29,406	29,738	30,074	30,414
	Industrial	0	0	144	146	148	149	151	153	154	156	158	160
	Lighting & Traffic Control	0	1,955	3,925	3,969	4,014	4,059	4,105	4,152	4,199	4,246	4,294	4,342
	Agricultural	0	11	1,039	1,051	1,063	1,075	1,087	1,099	1,112	1,124	1,137	1,150
	Total Customers	0	18,346	334,828	338,612	342,438	346,308	350,221	354,179	358,181	362,228	366,321	370,461
Energy Sales (MWh)	Domestic	0	31	2,516,796	2,545,236	2,573,997	2,603,084	2,632,498	2,662,246	2,692,329	2,722,752	2,753,519	2,784,634
	Commercial	0	40,038	1,192,869	1,206,348	1,219,980	1,233,766	1,247,707	1,261,806	1,276,065	1,290,484	1,305,067	1,319,814
	Industrial	0	0	654,313	661,706	669,184	676,745	684,393	692,126	699,947	707,857	715,856	723,945
	Lighting & Traffic Control	0	13,960	43,153	43,641	44,134	44,633	45,137	45,647	46,163	46,685	47,212	47,746
	Agricultural	0	4,688	171,918	175,826	177,872	177,872	179,826	181,854	183,909	185,987	188,089	190,214
	Total Energy Sales (MWh)	0	58,716	4,579,049	4,630,793	4,683,121	4,736,040	4,789,557	4,843,679	4,898,413	4,953,765	5,009,742	5,066,352
CCE Operating Costs	Jan - June	July - Dec	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Power Supply	\$0	\$4,037,959	\$313,511,321	\$320,806,679	\$328,299,543	\$336,307,961	\$344,453,480	\$352,877,874	\$361,535,487	\$370,482,012	\$379,738,967	\$389,410,496
	Billing & Data Management	\$0	\$192,634	\$5,021,569	\$5,078,313	\$5,135,698	\$5,193,731	\$5,252,420	\$5,311,773	\$5,371,796	\$5,432,497	\$5,493,884	\$5,555,985
	CCE Fees	\$68,749	\$1,228,726	\$2,873,783	\$1,665,795	\$1,684,617	\$1,703,652	\$1,722,902	\$1,742,369	\$1,762,057	\$1,781,967	\$1,802,102	\$1,822,465
	Technical Services	\$620,000	\$740,000	\$1,310,000	\$1,356,600	\$1,383,732	\$1,411,407	\$1,439,635	\$1,468,427	\$1,497,796	\$1,527,752	\$1,558,473	\$1,589,473
	Staffing	\$90,000	\$310,000	\$1,704,167	\$2,080,800	\$2,122,416	\$2,164,864	\$2,208,162	\$2,252,325	\$2,297,371	\$2,343,319	\$2,390,185	\$2,437,989
	General & Administrative expenses	\$90,000	\$420,000	\$150,000	\$306,000	\$312,120	\$318,362	\$324,730	\$331,224	\$337,849	\$344,606	\$351,498	\$358,528
	Debt Service (CCE Bonds & Start-up Costs)	\$0	\$819,618	\$6,659,995	\$6,659,995	\$6,659,995	\$6,659,995	\$5,840,377	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760
	Contribution to Annual Reserves	\$0	\$1,185,303	\$8,324,975	\$14,206,134	\$22,074,475	\$26,615,384	\$0	\$0	\$0	\$0	\$0	\$0
	New Programs	\$0	\$0	\$0	\$0	\$0	\$0	\$31,976,753	\$37,644,834	\$42,548,188	\$46,809,175	\$51,624,890	\$54,588,766
Other Revenues	Start-Up Capital	\$0	\$6,000,000	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
	Uncollectibles	\$4,344	\$39,852	\$1,852,705	\$1,887,178	\$1,927,628	\$1,970,694	\$2,010,484	\$1,920,857	\$1,965,502	\$2,011,914	\$2,059,901	\$2,110,184
Total Operating Costs	\$873,093	\$2,704,092	\$341,678,515	\$354,047,493	\$369,600,223	\$382,346,050	\$395,248,942	\$408,630,444	\$422,336,806	\$435,754,002	\$450,040,494	\$462,934,625	
Other Revenues	Total CCE Revenue Requirement	\$873,093	\$2,704,092	\$341,678,515	\$354,047,493	\$369,600,223	\$382,346,050	\$395,248,942	\$408,630,444	\$422,336,806	\$435,754,002	\$450,040,494	\$462,934,625
	Average CCE Rate (\$/kWh)	\$0.0609	\$0.0746	\$0.0765	\$0.0789	\$0.0807	\$0.0825	\$0.0844	\$0.0862	\$0.0880	\$0.0898	\$0.0914	\$0.0931
Total CCE Charges	Average SCE Generation Rate (\$/kWh)	\$0.0572	\$0.0701	\$0.0718	\$0.0741	\$0.0758	\$0.0775	\$0.0792	\$0.0810	\$0.0826	\$0.0844	\$0.0861	\$0.0878
	Total CCE Revenue Requirement	\$0	\$4091,389	\$39,040,255	\$39,481,410	\$39,927,550	\$40,378,731	\$40,835,011	\$41,291,291	\$41,747,571	\$42,203,851	\$42,659,131	\$43,115,411
SCE Non-bypassable Charges	Total CCE Revenue Requirement	\$873,093	\$2,704,092	\$341,678,515	\$354,047,493	\$369,600,223	\$382,346,050	\$395,248,942	\$408,630,444	\$422,336,806	\$435,754,002	\$450,040,494	\$462,934,625
	Total CCE Generation Requirement	\$873,093	\$2,704,092	\$341,678,515	\$354,047,493	\$369,600,223	\$382,346,050	\$395,248,942	\$408,630,444	\$422,336,806	\$435,754,002	\$450,040,494	\$462,934,625
Bundled SCE Revenues	Total CCE Generation Requirement	\$873,093	\$2,704,092	\$341,678,515	\$354,047,493	\$369,600,223	\$382,346,050	\$395,248,942	\$408,630,444	\$422,336,806	\$435,754,002	\$450,040,494	\$462,934,625
	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
Total CCE Customer Bill Revenues (Power Supply and Delivery)	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
Savings	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
Percent Savings	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
Cumulative Reserves	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
Reserve Target	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447
	Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$9,149,294	\$833,422,747	\$861,196,970	\$892,470,098	\$921,633,162	\$951,485,800	\$982,347,021	\$1,014,090,088	\$1,046,156,636	\$1,079,653,180	\$1,112,475,447

**WRCOG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable**

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	338,173	341,995	345,859	349,768	353,720	357,717	361,759	365,847	369,981
Commercial	30,758	31,105	31,457	31,812	32,172	32,535	32,903	33,275	33,651
Industrial	162	163	165	167	169	171	173	175	0
Lighting & Traffic Control	4,392	4,441	4,491	4,542	4,593	4,645	4,698	4,751	0
Agricultural	1,163	1,176	1,189	1,203	1,216	1,230	1,244	1,258	0
Total Customers	374,647	378,881	383,162	387,492	391,870	396,298	400,777	405,305	403,632
Energy Sales (MWh)									
Domestic	2,816,101	2,847,922	2,880,104	2,912,649	2,945,562	2,978,847	3,012,508	3,046,549	3,080,975
Commercial	1,334,728	1,349,810	1,365,063	1,380,488	1,396,088	1,411,864	1,427,818	1,443,952	1,460,269
Industrial	732,125	740,398	748,765	757,226	765,782	774,436	783,187	792,037	800,987
Lighting & Traffic Control	48,285	48,831	49,383	49,941	50,505	51,076	51,653	52,237	52,827
Agricultural	192,363	194,537	196,735	198,958	201,207	203,480	205,780	208,105	210,456
Total Energy Sales (MWh)	5,123,602	5,181,499	5,240,050	5,299,262	5,359,144	5,419,702	5,480,945	5,542,880	5,605,514
CCE Operating Costs									
Power Supply	\$399,260,495	\$409,838,077	\$420,638,303	\$431,859,515	\$443,204,440	\$455,241,222	\$467,405,096	\$480,393,649	\$493,957,968
Billing & Data Management	\$5,618,748	\$5,682,239	\$5,746,449	\$5,811,384	\$5,877,052	\$5,943,463	\$6,010,624	\$6,078,544	\$6,147,232
SCE Fees	\$1,843,057	\$1,863,883	\$1,884,943	\$1,906,242	\$1,927,781	\$1,949,564	\$1,971,593	\$1,993,870	\$2,016,400
Technical Services	\$1,621,263	\$1,653,688	\$1,686,762	\$1,720,497	\$1,754,907	\$1,790,005	\$1,825,805	\$1,862,321	\$1,899,568
Staffing	\$2,486,749	\$2,536,484	\$2,587,213	\$2,638,958	\$2,691,737	\$2,745,571	\$2,800,483	\$2,856,492	\$2,913,622
General & Administrative expenses	\$485,698	\$373,012	\$380,473	\$388,082	\$415,844	\$463,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760	\$5,020,760
Contribution to Annual Reserves	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
New Programs	\$59,222,818	\$64,150,406	\$64,999,852	\$69,569,454	\$74,410,714	\$79,421,900	\$85,192,109	\$90,680,516	\$96,610,926
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$2,160,255	\$2,214,299	\$2,270,081	\$2,327,992	\$2,386,645	\$2,448,883	\$2,511,282	\$2,578,129	\$2,647,881
Total Operating Costs	\$477,719,842	\$493,332,848	\$505,218,835	\$521,242,882	\$537,689,880	\$555,025,128	\$573,149,587	\$591,884,354	\$611,642,831
Other Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total CCE Revenue Requirement	\$477,719,842	\$493,332,848	\$505,218,835	\$521,242,882	\$537,689,880	\$555,025,128	\$573,149,587	\$591,884,354	\$611,642,831
Average CCE Rate (\$/kWh)	\$0.0932	\$0.0952	\$0.0964	\$0.0984	\$0.1003	\$0.1024	\$0.1046	\$0.1068	\$0.1091
Average SCE Generation Rate (\$/kWh)	\$0.0875	\$0.0894	\$0.0905	\$0.0924	\$0.0942	\$0.0962	\$0.0982	\$0.1003	\$0.1025
Total CCE Charges									
SCE Non-bypassable Charges	\$15,714,145	\$15,891,714	\$16,071,291	\$16,252,896	\$16,436,554	\$16,622,287	\$16,810,119	\$17,000,073	\$17,192,174
CCE Revenue Requirement	\$477,719,842	\$493,332,848	\$505,218,835	\$521,242,882	\$537,689,880	\$555,025,128	\$573,149,587	\$591,884,354	\$611,642,831
Total CCE Generation Revenue Requirement	\$493,433,987	\$509,224,562	\$521,286,126	\$537,495,779	\$554,126,434	\$571,647,416	\$589,959,706	\$608,884,428	\$628,835,005
Bundled SCE Revenues	\$1,147,726,447	\$1,184,428,365	\$1,218,321,871	\$1,256,825,188	\$1,296,461,281	\$1,337,694,117	\$1,380,454,747	\$1,424,599,990	\$1,470,543,601
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$1,192,597,201	\$1,230,429,596	\$1,265,227,870	\$1,304,891,030	\$1,345,714,588	\$1,388,191,178	\$1,432,245,827	\$1,477,774,461	\$1,525,066,089
Savings	(\$44,870,755)	(\$46,001,231)	(\$46,905,999)	(\$48,065,842)	(\$49,253,307)	(\$50,497,060)	(\$51,791,080)	(\$53,124,471)	(\$54,522,488)
Percent Savings	-3.9%	-3.9%	-3.9%	-3.8%	-3.8%	-3.8%	-3.8%	-3.7%	-3.7%
Cumulative Reserves	\$396,821,695	\$460,972,100	\$525,971,952	\$595,541,406	\$669,952,120	\$749,374,021	\$834,566,129	\$925,246,645	\$1,021,857,571
Reserve Target									

**SANBAG Community Choice Aggregation
Financial Proforma
Portfolio RPS**

Load Data		2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017
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**SANBAG Community Choice Aggregation
Financial Proforma
Portfolio RPS**

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	515,826	521,655	527,550	533,511	539,540	545,636	551,802	558,037	564,343
Commercial	54,612	55,229	55,853	56,484	57,122	57,768	58,421	59,081	59,749
Industrial	312	316	319	323	327	330	334	338	0
Lighting & Traffic Control	6,660	6,735	6,812	6,889	6,966	7,045	7,125	7,205	0
Agricultural	1,874	1,896	1,917	1,939	1,960	1,983	2,005	2,028	0
Total Customers	579,285	585,831	592,451	599,145	605,916	612,763	619,687	626,689	624,092
Energy Sales (MWh)									
Domestic	3,797,847	3,840,763	3,884,163	3,928,054	3,972,442	4,017,330	4,062,726	4,108,635	4,155,062
Commercial	2,642,865	2,672,730	2,702,932	2,733,475	2,764,363	2,795,600	2,827,191	2,859,138	2,891,446
Industrial	2,033,727	2,056,708	2,079,949	2,103,452	2,127,221	2,151,259	2,175,568	2,200,152	2,225,013
Lighting & Traffic Control	73,652	74,484	75,326	76,177	77,038	77,909	78,789	79,679	80,580
Agricultural	296,916	300,271	303,664	307,095	310,566	314,075	317,624	321,213	324,843
Total Energy Sales (MWh)	8,845,007	8,944,955	9,046,033	9,148,254	9,251,629	9,356,172	9,461,897	9,568,817	9,676,944
CCE Operating Costs									
Power Supply	\$548,658,172	\$566,362,265	\$580,875,978	\$599,067,291	\$617,551,808	\$637,671,875	\$658,180,175	\$679,537,499	\$701,816,578
Billing & Data Management	\$8,687,789	\$8,785,961	\$8,885,243	\$8,985,646	\$9,087,184	\$9,189,869	\$9,293,715	\$9,398,734	\$9,504,939
SCE Fees	\$2,849,703	\$2,881,903	\$2,914,468	\$2,947,400	\$2,980,704	\$3,014,385	\$3,048,446	\$3,082,893	\$3,117,728
Technical Services	\$3,076,034	\$3,688,515	\$4,523,600	\$5,678,260	\$7,298,639	\$9,608,019	\$12,952,350	\$17,875,422	\$25,244,683
Staffing	\$3,145,737	\$3,208,652	\$3,272,825	\$3,338,281	\$3,405,047	\$3,473,148	\$3,542,611	\$3,613,463	\$3,685,732
General & Administrative expenses	\$415,698	\$373,012	\$380,473	\$388,082	\$470,844	\$428,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140
Contribution to Annual Reserves									
New Programs	\$54,606,116	\$56,437,696	\$57,523,867	\$58,825,997	\$59,624,763	\$60,093,856	\$59,551,620	\$57,519,167	\$53,160,470
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$3,006,230	\$3,100,085	\$3,179,383	\$3,278,698	\$3,382,215	\$3,496,763	\$3,618,585	\$3,752,704	\$3,903,698
Total Operating Costs	\$631,976,619	\$652,369,231	\$669,086,976	\$690,040,794	\$711,332,344	\$734,507,815	\$758,130,477	\$782,731,094	\$808,393,442
Other Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total CCE Revenue Requirement	\$631,976,619	\$652,369,231	\$669,086,976	\$690,040,794	\$711,332,344	\$734,507,815	\$758,130,477	\$782,731,094	\$808,393,442
Average CCE Rate (\$/kWh)	\$0.0715	\$0.0729	\$0.0740	\$0.0754	\$0.0769	\$0.0785	\$0.0801	\$0.0818	\$0.0835
Average SCE Generation Rate (\$/kWh)	\$0.0851	\$0.0868	\$0.0881	\$0.0898	\$0.0915	\$0.0935	\$0.0954	\$0.0974	\$0.0995
Total CCE Charges									
SCE Non-bypassable Charges	\$26,881,816	\$27,185,580	\$27,492,777	\$27,803,446	\$28,117,624	\$28,435,354	\$28,756,673	\$29,081,624	\$29,410,246
CCE Revenue Requirement	\$631,976,619	\$652,369,231	\$669,086,976	\$690,040,794	\$711,332,344	\$734,507,815	\$758,130,477	\$782,731,094	\$808,393,442
Total CCE Generation Revenue Requirement	\$658,858,435	\$679,554,811	\$696,579,753	\$717,844,240	\$739,449,969	\$762,943,169	\$786,887,151	\$811,812,718	\$837,803,688
Bundled SCE Revenues	\$1,861,813,136	\$1,921,066,891	\$1,977,048,485	\$2,039,210,466	\$2,102,947,810	\$2,170,138,209	\$2,239,109,425	\$2,310,532,679	\$2,384,548,303
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$1,768,318,453	\$1,823,991,665	\$1,877,096,124	\$1,935,577,570	\$1,995,573,559	\$2,058,667,312	\$2,123,460,293	\$2,190,522,665	\$2,259,978,845
Savings	\$93,494,683	\$97,075,226	\$99,952,361	\$103,632,896	\$107,374,251	\$111,470,897	\$115,649,132	\$120,010,013	\$124,569,457
Percent Savings	5.0%	5.1%	5.1%	5.1%	5.1%	5.1%	5.2%	5.2%	5.2%
Cumulative Reserves	\$487,560,592	\$543,998,289	\$601,522,155	\$660,348,152	\$719,972,916	\$780,066,772	\$839,618,392	\$897,137,559	\$950,298,029
Reserve Target									

**SANBAG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable**

Load Data	2017		2017	2017		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Jan - June	July - Dec		Jan - June	July - Dec										
Customer Accounts															
Domestic	0	3,864	461,002	466,212	471,480	476,808	482,196	487,644	493,155	498,727	504,363	510,062	515,761	521,460	527,159
Commercial	0	33,205	48,808	49,359	49,917	50,481	51,051	51,628	52,212	52,802	53,398	54,002	54,613	55,229	55,850
Industrial	0	279	0	282	285	289	292	295	299	303	307	311	315	319	323
Lighting & Traffic Control	0	4,096	5,952	6,020	6,088	6,156	6,226	6,296	6,367	6,439	6,512	6,586	6,661	6,736	6,811
Agricultural	0	43	1,675	1,694	1,713	1,733	1,752	1,772	1,792	1,812	1,833	1,853	1,874	1,894	1,915
Total Customers	0	41,208	517,717	523,567	529,483	535,466	541,517	547,636	553,824	560,083	566,412	572,812	579,281	585,810	592,399
Energy Sales (MWh)															
Domestic	0	48	3,394,200	3,432,554	3,471,342	3,510,568	3,550,238	3,590,355	3,630,926	3,671,956	3,713,449	3,755,411	3,797,847	3,840,778	3,884,204
Commercial	0	80,550	2,361,973	2,388,663	2,415,655	2,442,952	2,470,558	2,498,475	2,526,708	2,555,259	2,584,134	2,613,335	2,642,864	2,672,721	2,702,914
Industrial	0	0	1,817,576	1,838,114	1,858,885	1,879,890	1,901,133	1,922,616	1,944,341	1,966,313	1,988,532	2,011,002	2,033,821	2,056,989	2,080,506
Lighting & Traffic Control	0	26,827	65,824	66,568	67,320	68,081	68,850	69,628	70,415	71,211	72,015	72,829	73,650	74,478	75,313
Agricultural	0	11,057	265,359	268,357	271,390	274,456	277,558	280,694	283,866	287,074	290,318	293,598	296,914	300,266	303,654
Total Energy Sales (MWh)	0	118,482	7,904,931	7,994,257	8,084,592	8,175,948	8,268,336	8,361,769	8,456,256	8,551,812	8,648,448	8,746,175	8,844,994	8,944,913	9,045,932
CCE Operating Costs															
Power Supply	\$0	\$6,032,329	\$409,940,751	\$421,359,492	\$433,117,927	\$445,534,854	\$458,291,916	\$471,270,295	\$484,786,278	\$498,634,313	\$513,387,229	\$528,761,063	\$544,488,806	\$560,580,459	\$577,147,021
Billing & Data Management	\$0	\$432,679	\$7,764,423	\$7,852,161	\$7,940,891	\$8,030,623	\$8,121,369	\$8,213,140	\$8,305,949	\$8,400,806	\$8,497,824	\$8,596,914	\$8,698,096	\$8,801,379	\$8,906,763
SCE Fees	\$149,501	\$1,939,421	\$4,405,258	\$2,575,617	\$2,604,720	\$2,634,152	\$2,663,917	\$2,694,018	\$2,724,459	\$2,755,244	\$2,786,377	\$2,817,862	\$2,849,706	\$2,881,909	\$2,914,471
Technical Services	\$620,000	\$740,000	\$1,310,000	\$1,356,600	\$1,401,003	\$1,455,319	\$1,552,981	\$1,669,111	\$1,821,084	\$2,019,393	\$2,278,936	\$2,620,965	\$3,084,056	\$3,674,191	\$4,404,606
Staffing	\$90,000	\$970,000	\$2,488,333	\$2,632,212	\$2,684,856	\$2,738,553	\$2,793,324	\$2,849,191	\$2,906,175	\$2,964,298	\$3,023,584	\$3,084,056	\$3,144,828	\$3,205,999	\$3,267,569
General & Administrative expenses	\$90,000	\$260,000	\$350,000	\$306,000	\$312,120	\$318,362	\$324,604	\$330,846	\$337,088	\$343,330	\$349,572	\$355,814	\$362,056	\$368,298	\$374,540
Debt Service (CCE Bonds & Start-up Costs)	\$0	\$1,170,882	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904
Contribution to Annual Reserves	\$0	\$3,326,217	\$29,715,629	\$36,950,700	\$45,960,681	\$50,735,321	\$55,821,177	\$62,584,959	\$67,362,454	\$72,326,198	\$76,289,957	\$80,253,716	\$84,217,475	\$88,181,234	\$92,145,000
New Programs	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Start-Up Capital	\$0	(\$10,000,000)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$4,748	\$62,727	\$2,516,230	\$2,569,139	\$2,632,871	\$2,700,051	\$2,763,625	\$2,831,884	\$2,900,846	\$2,970,509	\$3,040,872	\$3,111,934	\$3,183,695	\$3,256,056	\$3,329,017
Total Operating Costs	\$954,248	\$4,934,254	\$468,363,529	\$485,474,825	\$506,527,972	\$524,030,140	\$541,110,061	\$559,769,962	\$578,447,878	\$597,720,141	\$616,966,102	\$634,872,994	\$653,389,885	\$672,504,776	\$692,229,667
Other Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total CCE Revenue Requirement	\$954,248	\$4,934,254	\$468,363,529	\$485,474,825	\$506,527,972	\$524,030,140	\$541,110,061	\$559,769,962	\$578,447,878	\$597,720,141	\$616,966,102	\$634,872,994	\$653,389,885	\$672,504,776	\$692,229,667
Average CCE Rate (\$/kWh)	\$0.0497	\$0.0592	\$0.0607	\$0.0627	\$0.0641	\$0.0654	\$0.0669	\$0.0684	\$0.0699	\$0.0713	\$0.0728	\$0.0743	\$0.0758	\$0.0773	\$0.0788
Average SCE Generation Rate (\$/kWh)	\$0.0571	\$0.0681	\$0.0698	\$0.0720	\$0.0737	\$0.0752	\$0.0769	\$0.0786	\$0.0803	\$0.0820	\$0.0837	\$0.0854	\$0.0871	\$0.0888	\$0.0905
Total CCE Charges															
SCE Non-bypassable Charges	\$0	\$1,000,043	\$67,114,353	\$67,872,745	\$68,639,707	\$69,415,336	\$70,199,729	\$71,000,122	\$71,811,515	\$72,633,908	\$73,467,301	\$74,312,194	\$75,168,587	\$76,036,480	\$76,915,873
CCE Revenue Requirement	\$954,248	\$4,934,254	\$468,363,529	\$485,474,825	\$506,527,972	\$524,030,140	\$541,110,061	\$559,769,962	\$578,447,878	\$597,720,141	\$616,966,102	\$634,872,994	\$653,389,885	\$672,504,776	\$692,229,667
Total CCE Generation Revenue Requirement	\$954,248	\$5,934,297	\$535,477,882	\$553,347,570	\$575,167,680	\$593,445,476	\$611,309,791	\$635,563,579	\$660,532,963	\$687,209,988	\$714,697,913	\$743,106,838	\$772,446,763	\$802,726,688	\$833,956,613
Bundled SCE Revenues	\$0	\$18,296,669	\$1,351,759,556	\$1,397,071,297	\$1,447,722,341	\$1,495,125,726	\$1,542,903,988	\$1,593,385,654	\$1,644,803,337	\$1,697,848,344	\$1,751,837,051	\$1,805,291,234	\$1,859,200,000	\$1,913,658,757	\$1,968,677,514
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$17,776,245	\$1,306,158,609	\$1,349,189,033	\$1,396,972,863	\$1,442,042,787	\$1,487,553,868	\$1,535,535,483	\$1,584,453,681	\$1,634,913,687	\$1,686,324,653	\$1,737,404,554	\$1,789,064,480	\$1,841,275,406	\$1,894,036,332
Savings	\$0	\$520,424	\$45,600,949	\$47,882,263	\$50,749,479	\$53,082,939	\$55,350,120	\$57,580,170	\$60,349,655	\$62,934,657	\$65,512,398	\$67,886,680	\$70,064,962	\$72,147,244	\$74,133,526
Percent Savings		2.8%	3.4%	3.6%	3.5%	3.6%	3.6%	3.6%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
Cumulative Reserves		\$3,326,217	\$33,041,846	\$69,992,545	\$115,953,226	\$166,688,548	\$222,509,725	\$285,094,683	\$352,457,137	\$424,783,336	\$501,073,293	\$579,127,489	\$656,954,916	\$735,562,400	\$814,944,884
Reserve Target		\$126,440,563													

**SANBAG Community Choice Aggregation
Financial Proforma
Portfolio -50% Renewable**

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	515,826	521,655	527,550	533,511	539,540	545,636	551,802	558,037	564,343
Commercial	54,612	55,229	55,853	56,484	57,122	57,768	58,421	59,081	59,749
Industrial	312	316	319	323	327	330	334	338	0
Lighting & Traffic Control	6,660	6,735	6,812	6,889	6,966	7,045	7,125	7,205	0
Agricultural	1,874	1,896	1,917	1,939	1,960	1,983	2,005	2,028	0
Total Customers	579,285	585,831	592,451	599,145	605,916	612,763	619,687	626,689	624,092
Energy Sales (MWh)									
Domestic	3,797,847	3,840,763	3,884,163	3,928,054	3,972,442	4,017,330	4,062,726	4,108,635	4,155,062
Commercial	2,642,865	2,672,730	2,702,932	2,733,475	2,764,363	2,795,600	2,827,191	2,859,138	2,891,446
Industrial	2,033,727	2,056,708	2,079,949	2,103,452	2,127,221	2,151,259	2,175,568	2,200,152	2,225,013
Lighting & Traffic Control	73,652	74,484	75,326	76,177	77,038	77,909	78,789	79,679	80,580
Agricultural	296,916	300,271	303,664	307,095	310,566	314,075	317,624	321,213	324,843
Total Energy Sales (MWh)	8,845,007	8,944,955	9,046,033	9,148,254	9,251,629	9,356,172	9,461,897	9,568,817	9,676,944
CCE Operating Costs									
Power Supply	\$544,480,927	\$561,496,738	\$580,875,978	\$599,067,291	\$617,551,808	\$637,671,875	\$658,180,175	\$679,537,499	\$701,816,578
Billing & Data Management	\$8,687,789	\$8,785,961	\$8,885,243	\$8,985,646	\$9,087,184	\$9,189,869	\$9,293,715	\$9,398,734	\$9,504,939
SCE Fees	\$2,849,703	\$2,881,903	\$2,914,468	\$2,947,400	\$2,980,704	\$3,014,385	\$3,048,446	\$3,082,893	\$3,117,728
Technical Services	\$3,076,034	\$3,688,515	\$4,523,600	\$5,678,260	\$7,298,639	\$9,608,019	\$12,952,350	\$17,875,422	\$25,244,683
Staffing	\$3,145,737	\$3,208,652	\$3,272,825	\$3,338,281	\$3,405,047	\$3,473,148	\$3,542,611	\$3,613,463	\$3,685,732
General & Administrative expenses	\$415,698	\$373,012	\$380,473	\$388,082	\$470,844	\$428,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140
Contribution to Annual Reserves									
New Programs	\$81,374,841	\$84,626,453	\$81,419,830	\$83,470,311	\$85,029,490	\$86,326,278	\$86,627,708	\$85,473,849	\$82,031,664
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$2,985,344	\$3,075,758	\$3,179,383	\$3,278,698	\$3,382,215	\$3,496,763	\$3,618,585	\$3,752,704	\$3,903,698
Total Operating Costs	\$654,547,213	\$675,668,132	\$692,982,939	\$714,685,109	\$736,737,071	\$760,740,237	\$785,206,566	\$810,685,776	\$837,264,636
Other Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total CCE Revenue Requirement	\$654,547,213	\$675,668,132	\$692,982,939	\$714,685,109	\$736,737,071	\$760,740,237	\$785,206,566	\$810,685,776	\$837,264,636
Average CCE Rate (\$/kWh)	\$0.0740	\$0.0755	\$0.0766	\$0.0781	\$0.0796	\$0.0813	\$0.0830	\$0.0847	\$0.0865
Average SCE Generation Rate (\$/kWh)	\$0.0851	\$0.0868	\$0.0881	\$0.0898	\$0.0915	\$0.0935	\$0.0954	\$0.0974	\$0.0995
Total CCE Charges									
SCE Non-bypassable Charges	\$26,881,816	\$27,185,580	\$27,492,777	\$27,803,446	\$28,117,624	\$28,435,354	\$28,756,673	\$29,081,624	\$29,410,246
CCE Revenue Requirement	\$654,547,213	\$675,668,132	\$692,982,939	\$714,685,109	\$736,737,071	\$760,740,237	\$785,206,566	\$810,685,776	\$837,264,636
Total CCE Generation Revenue Requirement	\$681,429,028	\$702,853,712	\$720,475,716	\$742,488,554	\$764,854,695	\$789,175,591	\$813,963,239	\$839,767,400	\$866,674,882
Bundled SCE Revenues	\$1,861,813,136	\$1,921,066,891	\$1,977,048,485	\$2,039,210,466	\$2,102,947,810	\$2,170,138,209	\$2,239,109,425	\$2,310,532,679	\$2,384,548,303
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$1,790,889,047	\$1,847,290,566	\$1,900,992,087	\$1,960,221,884	\$2,020,978,286	\$2,084,899,734	\$2,150,536,382	\$2,218,477,347	\$2,288,850,040
Savings	\$70,924,090	\$73,776,325	\$76,056,398	\$78,988,582	\$81,969,524	\$85,238,475	\$88,573,044	\$92,055,332	\$95,698,263
Percent Savings	3.8%	3.8%	3.8%	3.9%	3.9%	3.9%	4.0%	4.0%	4.0%
Cumulative Reserves	\$660,502,330	\$745,128,783	\$826,548,613	\$910,018,924	\$995,048,414	\$1,081,374,693	\$1,168,002,401	\$1,253,476,250	\$1,335,507,915
Reserve Target									

**SANBAG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable**

Load Data	2017		2017		2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		
	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	Jan - June	July - Dec	
Customer Accounts																									
Domestic	0	3,864	461,002	466,212	471,480	476,808	482,196	487,644	493,155	498,727	504,363	510,062													
Commercial	0	33,205	48,808	49,359	49,917	50,481	51,051	51,628	52,212	52,802	53,398	54,002													
Industrial	0	0	279	282	285	292	295	299	302	305	309	313													
Lighting & Traffic Control	0	4,096	5,952	6,020	6,088	6,156	6,226	6,296	6,367	6,439	6,512	6,586													
Agricultural	0	43	1,675	1,694	1,713	1,733	1,752	1,772	1,792	1,812	1,833	1,853													
Total Customers	0	41,208	517,717	523,567	529,483	535,466	541,517	547,636	553,824	560,083	566,412	572,812													
Energy Sales (MWh)																									
Domestic	0	48	3,394,200	3,432,554	3,471,342	3,510,568	3,550,238	3,590,355	3,630,926	3,671,956	3,713,449	3,755,411													
Commercial	0	80,550	2,361,973	2,388,663	2,415,655	2,442,952	2,470,558	2,498,475	2,526,708	2,555,259	2,584,134	2,613,335													
Industrial	0	0	1,817,576	1,838,114	1,858,885	1,879,890	1,901,133	1,922,616	1,944,341	1,966,313	1,988,532	2,011,002													
Lighting & Traffic Control	0	26,827	65,824	66,568	67,320	68,081	68,850	69,628	70,415	71,211	72,015	72,829													
Agricultural	0	11,057	265,359	268,357	271,390	274,456	277,558	280,694	283,866	287,074	290,318	293,598													
Total Energy Sales (MWh)	0	118,482	7,904,931	7,994,257	8,084,592	8,175,948	8,268,336	8,361,769	8,456,256	8,551,812	8,648,448	8,746,175													
CCE Operating Costs																									
Power Supply	\$0	\$8,054,913	\$536,576,640	\$549,138,715	\$562,272,029	\$576,365,622	\$590,588,068	\$605,302,786	\$620,418,253	\$636,081,141	\$652,426,823	\$669,500,366													
Billing & Data Management	\$0	\$432,679	\$7,764,423	\$7,852,161	\$7,940,891	\$8,030,623	\$8,121,369	\$8,213,140	\$8,305,949	\$8,399,806	\$8,494,724	\$8,590,714													
SCE Fees	\$149,501	\$1,939,421	\$4,405,258	\$2,575,617	\$2,604,720	\$2,634,152	\$2,663,917	\$2,694,018	\$2,724,459	\$2,755,244	\$2,786,377	\$2,817,862													
Technical Services	\$620,000	\$740,000	\$1,310,000	\$1,356,600	\$1,401,003	\$1,465,319	\$1,552,981	\$1,669,111	\$1,821,084	\$2,019,393	\$2,278,936	\$2,620,965													
Staffing	\$90,000	\$970,000	\$2,488,333	\$2,632,212	\$2,684,856	\$2,738,553	\$2,793,324	\$2,849,191	\$2,906,175	\$2,964,298	\$3,023,584	\$3,084,056													
General & Administrative expenses	\$90,000	\$260,000	\$350,000	\$306,000	\$312,120	\$318,362	\$324,604	\$330,846	\$337,088	\$343,330	\$349,572	\$355,814													
Debt Service (CCE Bonds & Start-up Costs)	\$0	\$1,170,882	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904	\$9,872,904													
Contribution to Annual Reserves	\$0	\$2,850,249	\$26,266,804	\$36,876,500	\$50,070,502	\$57,787,103	\$65,915,629	\$75,867,468	\$83,975,321	\$92,210,104	\$99,661,146	\$104,451,184													
New Programs	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0													
Start-Up Capital	\$0	(\$10,000,000)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0													
Uncollectibles	\$4,748	\$72,840	\$3,149,410	\$3,208,035	\$3,278,641	\$3,354,204	\$3,425,106	\$3,500,650	\$3,576,194	\$3,651,738	\$3,727,282	\$3,802,826													
Total Operating Costs	\$954,248	\$6,490,984	\$592,183,773	\$613,818,744	\$640,437,666	\$662,566,843	\$684,162,147	\$707,755,124	\$731,370,880	\$755,738,110	\$780,072,083	\$802,712,980													
Other Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0													
Total CCE Revenue Requirement	\$954,248	\$6,490,984	\$592,183,773	\$613,818,744	\$640,437,666	\$662,566,843	\$684,162,147	\$707,755,124	\$731,370,880	\$755,738,110	\$780,072,083	\$802,712,980													
Average CCE Rate (\$/kWh)	\$0.0628	\$0.0749	\$0.0768	\$0.0768	\$0.0792	\$0.0810	\$0.0827	\$0.0846	\$0.0865	\$0.0884	\$0.0902	\$0.0918													
Average SCE Generation Rate (\$/kWh)	\$0.0571	\$0.0681	\$0.0698	\$0.0698	\$0.0720	\$0.0737	\$0.0752	\$0.0769	\$0.0786	\$0.0803	\$0.0820	\$0.0834													
Total CCE Charges																									
SCE Non-bypassable Charges	\$0	\$1,000,043	\$67,114,353	\$67,872,745	\$68,639,707	\$69,415,336	\$70,199,729	\$70,984,179	\$71,768,629	\$72,553,079	\$73,337,529	\$74,121,979													
CCE Revenue Requirement	\$954,248	\$6,490,984	\$592,183,773	\$613,818,744	\$640,437,666	\$662,566,843	\$684,162,147	\$707,755,124	\$731,370,880	\$755,738,110	\$780,072,083	\$802,712,980													
Total CCE Generation Revenue Requirement	\$954,248	\$7,491,027	\$659,298,126	\$681,691,489	\$709,077,373	\$731,982,179	\$754,361,876	\$773,548,742	\$792,735,618	\$811,922,494	\$831,109,370	\$850,296,246													
Bundled SCE Revenues	\$0	\$18,296,669	\$1,351,759,556	\$1,397,071,297	\$1,447,722,341	\$1,495,125,726	\$1,542,903,988	\$1,593,385,654	\$1,644,803,337	\$1,697,848,344	\$1,751,837,051	\$1,805,291,234													
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$0	\$19,332,976	\$1,429,978,853	\$1,477,532,952	\$1,530,882,557	\$1,580,579,491	\$1,630,605,953	\$1,683,520,646	\$1,737,376,684	\$1,792,931,655	\$1,849,430,634	\$1,905,244,541													
Savings	\$0	(\$1,036,307)	(\$78,219,296)	(\$80,461,656)	(\$83,160,215)	(\$85,453,765)	(\$87,701,965)	(\$90,134,992)	(\$92,573,347)	(\$95,083,311)	(\$97,593,583)	(\$99,953,307)													
Percent Savings		-5.7%	-5.8%	-5.8%	-5.7%	-5.7%	-5.7%	-5.7%	-5.6%	-5.6%	-5.6%	-5.5%													
Cumulative Reserves	\$2,850,249	\$29,117,053	\$65,993,553	\$116,064,055	\$173,851,157	\$239,766,786	\$315,634,254	\$399,609,575	\$491,819,679	\$591,480,825	\$695,932,009	\$743,884,143													
Reserve Target	\$158,257,831																								

**SANBAG Community Choice Aggregation
Financial Proforma
Portfolio -100% Renewable**

Load Data	2028	2029	2030	2031	2032	2033	2034	2035	2036
Customer Accounts									
Domestic	515,826	521,655	527,550	533,511	539,540	545,636	551,802	558,037	564,343
Commercial	54,612	55,229	55,853	56,484	57,122	57,768	58,421	59,081	59,749
Industrial	312	316	319	323	327	330	334	338	0
Lighting & Traffic Control	6,660	6,735	6,812	6,889	6,966	7,045	7,125	7,205	0
Agricultural	1,874	1,896	1,917	1,939	1,960	1,983	2,005	2,028	0
Total Customers	579,285	585,831	592,451	599,145	605,916	612,763	619,687	626,689	624,092
Energy Sales (MWh)									
Domestic	3,797,847	3,840,763	3,884,163	3,928,054	3,972,442	4,017,330	4,062,726	4,108,635	4,155,062
Commercial	2,642,865	2,672,730	2,702,932	2,733,475	2,764,363	2,795,600	2,827,191	2,859,138	2,891,446
Industrial	2,033,727	2,056,708	2,079,949	2,103,452	2,127,221	2,151,259	2,175,568	2,200,152	2,225,013
Lighting & Traffic Control	73,652	74,484	75,326	76,177	77,038	77,909	78,789	79,679	80,580
Agricultural	296,916	300,271	303,664	307,095	310,566	314,075	317,624	321,213	324,843
Total Energy Sales (MWh)	8,845,007	8,944,955	9,046,033	9,148,254	9,251,629	9,356,172	9,461,897	9,568,817	9,676,944
CCE Operating Costs									
Power Supply	\$686,649,590	\$705,191,857	\$724,371,278	\$744,095,507	\$764,079,831	\$784,837,086	\$806,863,453	\$829,354,073	\$852,432,239
Billing & Data Management	\$8,687,789	\$8,785,961	\$8,885,243	\$8,985,646	\$9,087,184	\$9,189,869	\$9,293,715	\$9,398,734	\$9,504,939
SCE Fees	\$2,849,703	\$2,881,903	\$2,914,468	\$2,947,400	\$2,980,704	\$3,014,385	\$3,048,446	\$3,082,893	\$3,117,728
Technical Services	\$3,076,034	\$3,688,515	\$4,523,600	\$5,678,260	\$7,298,639	\$9,608,019	\$12,952,350	\$17,875,422	\$25,244,683
Staffing	\$3,145,737	\$3,208,652	\$3,272,825	\$3,338,281	\$3,405,047	\$3,473,148	\$3,542,611	\$3,613,463	\$3,685,732
General & Administrative expenses	\$415,698	\$373,012	\$380,473	\$388,082	\$470,844	\$428,761	\$411,836	\$420,072	\$428,474
Debt Service (CCE Bonds & Start-up Costs)	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140	\$7,531,140
Contribution to Annual Reserves									
New Programs	\$111,536,551	\$118,837,766	\$120,409,440	\$126,656,695	\$132,538,397	\$139,540,476	\$144,784,360	\$149,227,421	\$152,008,749
Start-Up Capital	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Uncollectibles	\$3,696,188	\$3,794,233	\$3,896,859	\$4,003,839	\$4,114,855	\$4,232,589	\$4,362,001	\$4,501,787	\$4,656,776
Total Operating Costs	\$827,588,430	\$854,293,040	\$876,185,325	\$903,624,850	\$931,506,641	\$961,855,473	\$992,789,911	\$1,025,005,004	\$1,058,610,460
Other Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Total CCE Revenue Requirement	\$827,588,430	\$854,293,040	\$876,185,325	\$903,624,850	\$931,506,641	\$961,855,473	\$992,789,911	\$1,025,005,004	\$1,058,610,460
Average CCE Rate (\$/kWh)	\$0.0936	\$0.0955	\$0.0969	\$0.0988	\$0.1007	\$0.1028	\$0.1049	\$0.1071	\$0.1094
Average SCE Generation Rate (\$/kWh)	\$0.0851	\$0.0868	\$0.0881	\$0.0898	\$0.0915	\$0.0935	\$0.0954	\$0.0974	\$0.0995
Total CCE Charges									
SCE Non-bypassable Charges	\$26,881,816	\$27,185,580	\$27,492,777	\$27,803,446	\$28,117,624	\$28,435,354	\$28,756,673	\$29,081,624	\$29,410,246
CCE Revenue Requirement	\$827,588,430	\$854,293,040	\$876,185,325	\$903,624,850	\$931,506,641	\$961,855,473	\$992,789,911	\$1,025,005,004	\$1,058,610,460
Total CCE Generation Revenue Requirement	\$854,470,246	\$881,478,620	\$903,678,102	\$931,428,295	\$959,624,265	\$990,250,826	\$1,021,546,584	\$1,054,086,628	\$1,088,020,706
Bundled SCE Revenues									
Total CCE Customer Bill Revenues (Power Supply and Delivery)	\$1,861,813,136	\$1,921,066,891	\$1,977,048,485	\$2,039,210,466	\$2,102,947,810	\$2,170,138,209	\$2,239,109,425	\$2,310,532,679	\$2,384,548,303
Savings	(\$102,117,127)	(\$104,848,584)	(\$107,145,989)	(\$109,951,159)	(\$112,800,046)	(\$115,876,760)	(\$119,010,301)	(\$122,263,897)	(\$125,647,560)
Percent Savings	-5.5%	-5.5%	-5.4%	-5.4%	-5.4%	-5.3%	-5.3%	-5.3%	-5.3%
Cumulative Reserves									
Reserve Target	\$807,468,561	\$926,306,327	\$1,046,715,766	\$1,173,372,462	\$1,305,910,858	\$1,445,451,335	\$1,590,235,694	\$1,739,463,115	\$1,891,471,864

Appendix C – ICP Excluding Riverside County

Introduction

Riverside County (County) has already been exploring developing a Community Choice Aggregation Program for the unincorporated Riverside County separate from ICP. The County is interested in hiring a third party to operate the CCA on behalf of the County, rather than joining a Joint Power Agreement with other public entities.

This Appendix provides the estimated cost impact of Riverside County not joining the ICP CCA given the 50% Renewable Scenario.

Analysis

Based on the data received by SCE, Riverside County load makes up approximately 9 percent of the total ICP load. This scenario was therefore modeled assuming the ICP load and the number of customers would be reduced by 9 percent.

Power supply, data management, billing, SCE charges and non-bypassable charges were reduced to reflect the lower load and number of customers. It was assumed that ICP without the County would still need the same number of staff, operating and administrative costs, and consultant services as the 9 percent reduction in load would not significantly reduce the level of effort required in these areas.

Results

Based on the analysis, the overall savings to ICP customers are reduced from 3.7 percent to 3.2 percent. Savings are reduced largely because the fixed costs needed to operate the CCA remain nearly unchanged while the generation revenues decrease with the load. Table C-1 provides a summary of the projected cost impacts and savings for 2018, while the following pages provide the proforma for the ICP without County analysis for all three power supply scenarios.

Table C-1
Savings Comparison Under the 50% Renewable Scenario

	ICP	ICP without Riverside County
Power Supply Expenses	\$738.9 million	\$643.2 million
Non-Power Supply Expenses	\$104.1 million	\$103.1 million
SCE Non-bypassable Charges	\$120.3 million	\$105.4 million
Total	\$963.3 million	\$851.7 million
Bundled SCE Rate	\$2,492.1 million	\$2,173.2 million
CCA Total Bill	\$2,384.4 million	\$2,104.1 million
Savings	\$93.7 million	\$69.0 million
	3.8%	3.2%

Appendix D – Glossary

aMW: Average annual Megawatt. A unit of energy output over a year that is equal to the energy produced by the continuous operation of one megawatt of capacity over a period of time (8,760 megawatt-hours).

Basis Difference (Natural Gas): The difference between the price of natural gas at the Henry Hub natural gas distribution point in Erath, Louisiana, which serves as a central pricing point for natural gas futures, and the natural gas price at another hub location (such as for Southern California).

Buckets: Buckets 1-3 refer to different types of renewable energy contracts according to the Renewable Portfolio Standards requirements. Bucket 1 are traditional contracts for delivery of electricity directly from a generator within or immediately connected to California. These are the most valuable and make up the majority of the RECS that are required for LSEs to be RPS compliant. Buckets 2 and 3 have different levels of intermediation between the generation and delivery of the energy from the generating resources.

Bundled Customers: Electricity customers who receive all their services (transmission, distribution and supply) from the Investor-Owned Utility.

CAISO: The California Independent System Operator. The organization responsible for managing the electricity grid and system reliability within the former service territories of the three California IOUs.

California Clean Power (CCP): A private company providing wholesale supply and other services to CCAs.

California Energy Commission (CEC): The state regulatory agency with primary responsibility for enforcing the Renewable Portfolio Standards law as well as a number of other, electric-industry related rules and policies.

California Public Utilities Commission (CPUC): The state agency with primary responsibility for regulating IOUs, as well as Direct Access (ESP) and CCA entities.

Capacity Factor: the ratio of an electricity generating resource's actual output over a period of time to its potential output if it were possible to operate at full nameplate capacity continuously over the same period. Intermittent renewable resources, like wind and solar, typically have lower capacity factors than traditional fossil fuel plants because the wind and sun do not blow or shine consistently.

CCEAC: Community Choice Energy Advisory Committee - a committee formed to advise the City of Davis on the best options for pursuing a CCA.

Climate Zone: A geographic area with distinct climate patterns necessitating varied energy demands for heating and cooling.

Coachella Valley Association of Governments (CVAG): CVAG is the regional planning agency coordinating government services in the Coachella Valley. It includes 10 Cities, Riverside County, the Agua Caliente Band of Cahuilla Indians and the Cabazon Band of Mission Indians as members.

Coincident Peak: Demand for electricity among a group of customers that coincides with peak total demand on the system.

Community Choice Aggregation: Method available through California law to allow Cities and Counties to aggregate their citizens and become their electric generation provider.

Community Choice Energy: A City, County or Joint Powers Agency procuring wholesale power to supply to retail customers.

Community Choice Partners: A private company providing services to CCAs in California.

Congestion Revenue Rights (CRRs): Financial rights that are allocated to Load Serving Entities to offset differences between the prices where their generation is located and the price that they pay to serve their load. These rights may also be bought and sold through an auction process. CRRs are part of the CAISO market design.

Demand Response (DR): Electric customers who have a contract to modify their electricity usage in response to requests from a utility or other electric entity. Typically, will be used to lower demand during peak energy periods, but may be used to raise demand during periods of excess supply.

Direct Access: Large power consumers which have opted to procure their wholesale supply independently of the IOUs through an Electricity Service Provider.

EI (Edison Electric Institute) Agreement: A commonly used enabling agreement for transacting in wholesale power markets.

Electric Service Providers (ESP): An alternative to traditional utilities. They provide electric services to retail customers in electricity markets that have opened their retail electricity markets to competition. In California the Direct Access program allows large electricity customers to opt-out of utility-supplied power in favor of ESP-provided power. However, there is a cap on the amount of Direct Access load permitted in the state.

Electric Tariffs: The rates and terms applied to customers by electric utilities. Typically have different tariffs for different classes of customers and possibly for different supply mixes.

Enterprise Model: When a City or County establish a CCA by themselves as an enterprise within the municipal government.

Federal Tax Incentives: There are two Federal tax incentive programs. The Investment Tax Credit (ITC) provides payments to solar generators. The Production Tax Credit (PTC) provides payments to wind generators.

Feed-in Tariff: A tariff that specifies what generators who are connected to the distribution system are paid.

Forward Prices: Prices for contracts that specify a future delivery date for a commodity or other security. There are active, liquid forward markets for electricity to be delivered at a number of Western electricity trading hubs, including NP15 which corresponds closely to the price location which the City of Davis will pay to supply its load.

Implied Heat Rate: A calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the ‘break-even natural gas market heat rate,’ because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices.

Inland Choice Power (ICP): The name of the proposed CCA that would serve the ICP areas of CVAG, SANBAG, and WRCOG.

Integrated Resource Plan: A utility's plan for future generation supply needs.

Investor-Owned Utility: For profit regulated utilities. Within California there are three IOUs - Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric.

ISDA (International Swaps and Derivatives Association): Popular form of bilateral contract to facilitate wholesale electricity trading.

Joint Powers Agency (JPA): A legal entity comprising two or more public entities. The JPA provides a separation of financial and legal responsibility from its member entities.

Lancaster Choice Energy (LCE): The most recent California CCA to go-live, exclusively serving the City of Lancaster in Southern California.

LEAN Energy (Local Energy Aggregation Network): A not-for-profit organization dedicated to expanding Community Choice Aggregation nationwide.

Load Forecast: A forecast of expected load over some future time horizon. Short-term load forecasts are used to determine what supply sources are needed. Longer-term load forecasts are used for budgeting and long-term resource planning.

Marginal Unit: An additional unit of power generation to what is currently being produced. At and electric power plant, the cost to produce a marginal unit is used to determine the cost of increasing power generation at that source.

MCE: Formerly Marin Clean Energy - the first CCA in California serving Cities within and the Counties of Marin and Napa.

MRTU: CAISO's Market Redesign and Technology Upgrade. The redesigned, nodal (as opposed to zonal) market that went live in April of 2009.

Net Energy Metering: The program and rates that pertain to electricity customers who also generate electricity, typically from rooftop solar panels.

Non-Coincident Peak: Energy demand by a customer during periods that do not coincide with maximum total system load.

Non-Renewable Power: Electricity generated from non-renewable sources or that does not come with a Renewable Energy Credit (REC).

NP15: Refers to a wholesale electricity pricing hub - North of Path 15 - which roughly corresponds to PG&E's service territory. Forward and Day-Ahead power contracts for Northern California typically provide for delivery at NP15. It is not a single location, but an aggregate based on the locations of all the generators in the region.

On-Bill Repayment (OBR): Allows electric customers to pay for financed improvements such as energy efficiency measures through monthly payments on their electricity bills.

Operate on the Margin: Operation of a business or resource at the limit of where it is profitable.

Opt-Out: Community Choice Aggregation is, by law, an opt-out program. Customers within the borders of a CCA are automatically enrolled within the CCA unless they proactively opt-out of the program.

Power Cost Indifference Adjustment (PCIA): A charge applied to customers who leave IOU service to become Direct Access or CCA customers. The charge is meant to compensate the IOU for costs that it has previously incurred to serve those customers.

PPA (Power Purchase Agreement): The standard term for bilateral supply contracts in the electricity industry.

Renewable Energy Credits (RECs): The renewable attributes from RPS-qualified resources which must be registered and retired to comply with RPS standards.

Resource Adequacy (RA): The requirement that a Load-Serving Entity own or procure sufficient generating capacity to meet its peak load plus a contingency amount (15 percent in California) for each month.

RPS (Renewable Portfolio Standards): The state-based requirement to procure a certain percentage of load from RPS-certified renewable resources.

San Bernardino Associated Governments (SANBAG): SANBAG is the council of government and transportation planning agency for San Bernardino County. SANBAG’s members include 24 cities and San Bernardino County.

Scheduling Coordinator: An entity that is approved to interact directly with CAISO to schedule load and generation. All CAISO participants must be or have an SC.

Scheduling Agent: A person or service that forecasts and monitors short term system load requirements and meets these demands by scheduling power resource to meet that demand.

Sonoma Clean Power (SCP): A CCA serving Sonoma County and Sonoma County Cities.

Spark Spread: The theoretical grow margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity. All other costs (capital, operation and maintenance, etc.) must be covered from the spark spread.

Supply Stack: Refers to the generators within a region, stacked up according to their marginal cost to supply energy. Renewables are on the bottom of the stack and peaking gas generators on the top. Used to provide insights into how the price of electricity is likely to change as the load changes.

ICP: Refers collectively to the three councils of governments: Coachella Valley Association of Governments (CVAG), San Bernardino Associated Governments (SANBAG), and Western Riverside Council of Governments (WRCOG).

Weather Adjusted: Normalizing energy use data based on differences in the weather during the time of use. For instance, energy use is expected to be higher on extremely hot days when air conditioning is in higher demand than on days with comfortable temperature. Weather adjustment normalizes for this variation.

Western Electric Coordinating Council (WECC): The organization responsible for coordinating planning and operation on the Western electric grid.

Western Riverside Council of Governments (WRCOG): WRCOG is the council of governments in Western Riverside County consisting of 17 Cities, Riverside County, and the Morongo Band of Mission Indians.

Wholesale Power: Large amounts of electricity that are bought and sold by utilities and other electric companies in bulk at specific trading hubs. Quantities are measured in MWs, and a standard wholesale contract is for 25 MW for a month during heavy-load or peak hours (7am to 10 pm, Mon-Sat), or light-load or off-peak hours (all the other hours).

WSPP (Western States Power Pool) Agreement: Common, standardized enabling agreement to transact in the wholesale power markets.

Appendix E – Inland Choice Power Launch Schedule

		COG or JPA Action			CCA Team Process					Non-negotiable External Timeline						
		2017													2018	
		January	February	March	April	May	June	July	August	September	October	November	December	January	February	
ICP Formation & Staffing	CVAG, WRCOG, SANBAG form and join Inland Choice Power (ICP)				◆											
	Setup ICP Governance Board															
	Hire Executive Director and key staff for pre-operations															
	Hire Staff															
CPUC Implementation Plan & Registration	Develop Implementation Plan															
	ICP approves & files Implementation Plan				◆											
	CPUC certifies implementation plan ¹							◆								
	Submit Surety Bond to CPUC and copy to SCE ²							◆								
Power Supply and Data Management	JPA submits registration package to CPUC ³							◆								
	Develop RFP for Power Supply & Data Management															
	Issue power supply and data mgmt RFP and receive responses					◆										
	Review, select, negotiate power supply and data management providers							◆								
Financing	ICP executes Power Supply & Data Management Contracts							◆								
	ICP finalizes initial rates							◆								
	Prepare financing plan															
	Negotiate Financing & Line of Credit															
SCE Process	ICP Approves Financing Agreement					◆										
	Transaction testing															
	ICP negotiates notice of start date with SCE							◆								
	Establish credit worthiness with IOU															
SCE Process	SCE Forms ⁴															
	Negotiate opt-out notification & processing responsibility (CCA or SCE)															
	Determine Annual Joint Rate Comparison (JRC) lead (CCA or SCE)															
	ICP executes service agreement with IOU							◆								
SCE Process	SCE starts six month preparation for CCA launch															
	Test Electronic Data Exchange with SCE															
	Create and validate mass enrollment account list									◆						
	Update SCE on opt-out list															
Customer Communication	Customer outreach															
	Opt Out notice 1															
	Opt Out Notice 2										◆					
	Automatic enrollment of customers that have not opted out												◆		◆	
Customer Communication	Opt Out notice 3															
	Customers switched to CCA service at scheduled meter read															
	Opt Out Notice 4															
																◆

¹Represents maximum possible duration for CPUC review of implementation plan, ²Contingent on completing financing agreement, ³Contingent on completion of service agreement with SCE

⁴SCE forms include: "Participant Information Form", "Credit Application & Security Form", "EDI Trading Partner Agreement", "EDI Partner Profiles form", "MFT Server Form", scheduling coordinator letter, non-disclosure agreement, and a declaration by JPA board.

¹Represents maximum possible duration for CPUC review of implementation plan, ²Contingent on completion of financing agreement, ³Contingent on completion of service agreement with SCE

⁴SCE forms include: "Participant Information Form", "Credit Application & Security Form", "EDI Trading Partner Agreement", "EDI Partner Profiles form", "MFT Server Form", scheduling coordinator letter, non-disclosure agreement, and a declaration by JPA board.



Western Riverside Council of Governments Technical Advisory Committee

Staff Report

Subject: Public Service Fellowship Program

Contact: Jennifer Ward, Director of Government Relations, ward@wrcog.cog.ca.us, (951) 955-0186

Date: January 19, 2017

The purpose of this item is to make the Technical Advisory Committee members aware of the second round of WRCOG's Public Service Fellowship, conducted in partnership with University of California, Riverside and California Baptist University.

Requested Action:

1. Receive and file.
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In partnership with higher education institutions, WRCOG launched a Public Service Fellowship Program that provides local university graduates with career opportunities with local governments and agencies in a way that is mutually beneficial to both the Fellow and Agency.

Fellowship Program Overview

In early 2016, WRCOG launched a Public Service Fellowship Program in Western Riverside County, administered by WRCOG in partnership with University of California, Riverside (UCR) and California Baptist University (CBU). The goal of this pilot program is to retain local students in Western Riverside County to fulfill the subregion's needs for a robust public sector workforce and to combat the often-mentioned "brain drain" that Riverside County experiences when local students graduate but then leave the region to seek full-time employment elsewhere. The Fellowship Program targets students graduating from UCR and CBU and engages them in career opportunities with local governments and agencies in a way that is mutually beneficial to both the fellow and agency. The first round of Fellows began working within WRCOG's member agencies in July 2016 and will conclude their Fellowships in February or March 2017.

Fellowship Program Second Round

Based on the success of the Fellowship thus far as indicated by feedback from both the Fellows, university partners, and participating jurisdictions, WRCOG is proceeding with a second round of the Fellowship. The academic institutions will continue to provide high-caliber students that can contribute valuable assistance to agencies and ensure these students are prepared with the necessary skills, understanding, and education to succeed in the public sector. WRCOG's member agencies will again be able to draw from a "pre-screened" pool of qualified candidates that are likely to want to pursue a career in local government in Western Riverside County. WRCOG, UCR, and CBU will conduct a first round of interviews with the students who apply to the Fellowship to determine eligibility, and then the member agencies will have an opportunity to also interview potential candidates for their particular jurisdiction.

In order to facilitate the most successful fellow placements, staff is requesting feedback from the Technical Advisory Committee through an Agency Interest Form, provided as Attachment 1. WRCOG is requesting these forms be returned to Crystal Adams at adams@wrcog.cog.ca.us by January 19, 2017. The information

included in the Agency Interest Form will provide valuable input to WRCOG, UCR, and CBU, which will inform the process of recommending fellows for placement at the agencies.

Program Structure

WRCOG will continue operating the Fellowship by hiring the Fellows as temporary employees of WRCOG and overseeing the human resources and payroll aspects of the Program. Under this structure, Fellows can work up to 30 hours per week at their host Agency for a total of up to 960 hours per fiscal year. WRCOG staff are working with UCR and CBU to adhere to the following schedule for the second round of the Fellowship.

Timeline:

- January 2017: Collect feedback from WRCOG member agencies and finalize pilot program structure.
- February 2017: Notify students at UCR and CBU about the Fellowship and solicit interested applicants.
- March 2017: WRCOG, UCR, and CBU review applications, interview top candidates, and recommend agency placements.
- April 2017: Agencies interview and confirm Fellow placements. Fellows participate in Program orientation.
- May – July 2017: Fellowships begin.

Program Funding: WRCOG has allocated \$300,000 in its Fiscal Year 2015/2016 Budget to initiate this Program. For this pilot year, a small portion of funds will be allocated toward administration / operational costs, and the majority of funds will be allocated for compensation for the Fellows.

Prior WRCOG Action:

None.

WRCOG Fiscal Impact:

A total of \$400,000 was allocated under the Agency Fiscal Year 2015/2016 Budget for the Public Service Fellowship Program.

Attachment:

1. Member Agency Interest Form.

Item 6.E

Public Service Fellowship Program

Attachment 1

Member Agency Interest Form

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WRCOG Public Service Fellowship Program Agency Interest Form

Please submit completed forms to adams@wrcog.cog.ca.us by January 19, 2017.

I. Program Overview

In February 2016, WRCOG launched a Public Service Fellowship Program in partnership with the University of California, Riverside (UCR) and California Baptist University (CBU). The goal of this Program is to retain local students to fulfill the subregion's needs for a robust public sector workforce and to combat the often-mentioned "brain drain" that Riverside County experiences when local students graduate but then leave the region to seek full-time employment elsewhere. The Fellowship Program is currently geared towards students graduating from UCR and CBU—but is anticipated to be expanded to additional universities in future rounds—to engage them in career opportunities with local governments and agencies in a way that is mutually beneficial to both the Fellows and the agency.

WRCOG is responsible for general Program operation and oversight, administering employment of the Fellows, soliciting interest from local government agencies, serving as the liaison between member agencies and the universities, providing Program funding, and coordinating payment of Fellowship stipends. UCR and CBU are responsible for soliciting interest from students, reviewing applications and conducting interviews, and recommending local government and agency placements. WRCOG, UCR, and CBU also provide ongoing training to Fellows on career readiness and other theoretical topics during regular Academic Sessions to support their hands-on work experience. A representative from each university serves as an "advisor" to answer questions from the Fellows or host agencies, monitor the Fellows' performance, handle HR-related issues or complaints in collaboration with WRCOG, and provide needed support to ensure that the Fellowship placement is successful.

II. Jurisdiction/Agency Information

Agency Name: _____
Contact Name: _____
Title: _____
Phone Number: _____
Email Address: _____
Address: _____

Are you able and willing to provide direct oversight of the Fellow in 2017/2018?

Yes: ____
No: ____

If no, who will be responsible for supervising the Fellow?

Name: _____
Title: _____
Email: _____
Phone: _____

III. Fellow Information

A. Select the preferred area of study/education background(s) you would like the Fellow to have (please check all that apply):

Public Policy: _____
Public Health: _____
Economics: _____
Engineering: _____
Urban Planning: _____
Environmental Science: _____
Other: _____

B. Preferred level of educational attainment of Fellow (please check one):

Bachelor's degree in process: _____
Bachelors' degree: _____
Master's degree in process: _____
Master's degree: _____

C. How many hours per week would the Fellow be needed?

Up to 15 hours/week: _____
Up to 30 hours/week: _____

D. Please list goals and activities your agency would like the Fellow to work on in 2017/2018:

1. _____
2. _____
3. _____
4. _____
5. _____

- E.** Do you want to participate in the Fellow interview process or do you want the Fellowship Program Administrators to make a placement selection on your behalf? (please check one)

Participate in interview process: ____

Receive fellow placement: ____

Unsure at this time: ____

IV. Other Comments

Please leave any other comments or feedback on the Public Service Fellowship you would like WRCOG staff to be aware of prior to placing the Round II Fellows.

V. Interest Form Submission and Program Contact Information

Please submit interest forms to Crystal Adams at adams@wrcog.cog.ca.us by Thursday, January 19, 2017.

For questions please contact:

Jennifer Ward
Government Relations Director
WRCOG
(951) 955-0186
ward@wrcog.cog.ca.us

Crystal Adams
Staff Analyst
WRCOG
(951) 955-8312
adams@wrcog.cog.ca.us

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