Community Choice Energy Program Comparison Matrix

September 2017

		OPERATIONAL									IN DEVELOPMENT		
	Central Coast Power	Apple Valley Choice Energy	CleanPowerSF	Lancaster Choice Energy	Marin Clean Energy	Peninsula Clean Energy	Pico Rivera Innovative Municipal Energy	Redwood Coast Energy Authority	Silicon Valley Clean Energy	Sonoma Clean Power	Inland Choice Power	Los Angeles Community Choice Energy	Monterey Bay Community Power
Milestones	June 2015 - SB County BOS provided direction and funding for feasibility study December 2015 - Advisory Working Group formed Summer 2017 - feasibility study and peer review expected to be completed Fall 2017 - CCE votes expected Spring 2020 - possible launch	2010 - Initial feasibility study 2014-2015 - Updated feasibility study September 2016 - Submitted implementation plan (IP) November 2016 - IP certified by CPUC April 2017 - Launch	May 2004 - SF BOS authorized CCE program June 2007 - Draft implementation plan (IP) approved by SF BOS March 2010 - Revised IP approved by SF BOS and submitted to CPUC May 2010 - CPUC certified IP; SFPUC & PG&E execute CCA Service Agreement (later extended through Dec 2018) June 2013 - CPUC certified revised IP August 2015 - CPUC certified another revised IP May 2016 - Phase 1 launch Nov 2017 - Phase 2 launch Summer 2019 - Full launch	July 2013 - Initial Phase I feasibility study completed Q2 2014 - Phase II feasibility study completed May 2014 - Lancaster City Council authorized CCE program and approved implementation plan (IP) October 2014 - CPUC certified IP March 2015 - CPUC certified revised IP May 2015 - Phase 1 launch Oct 2015 - Remaining residential + commercial accounts launched 2017 - Launched California Choice Energy Authority to provide backend services to other SoCal CCAs	December 2008 - JPA formed May 2010 - Phase 1 launch 2011 - Included other accounts in original member jurisdictions; added new Marin County cities 2012 - Remaining Marin accounts started service; Richmond joined; EE programs launched 2013 - Program launched in Richmond 2015 - Unincorporated Napa County and cities of Benicia, El Cerrito, and San Pablo joined September 2016 - Additional Napa and Contra Costa County cities joined 2018 - Planned addition of unincorporated Contra Costa County + 8 cities	December 2014 - Initial CCE research September 2015 - Feasibility study completed October 2015 - JPA formed February 2016 - Deadline for cities to join JPA April 2016 - Implementation plan submitted October 2016 - Phase 1 launch April 2017 - Phase 2 launch October 2017 - Estimated final phase launch	Mid-2016 - Joined California Choice Energy Authority to develop implementation plan and provide support services December 2016 - Implementation plan submitted September 2017 - Phase 1 (full) launch	June 2015 - RCEA board approved CCE implementation September 2015 - JPA amended for CCE October 2016 - Implementation plan (IP) submitted January 2017 - IP certified May 2017 - Full launch Late 2017 - Ferndale to join (last city in Humboldt County)	2014 - Initial CCE research May 2015 - Initial CCE assessment report November 2015 - Feasibility study March 2016 - Formed JPA April 2016 - Feasibility study completed July 2016 - Submitted implementation plan April 2017 - Phase 1 launch July 2017 - Phase 2 (final) launch	2011 - Steering committee formed to explore CCE; feasibility study completed 2012 - Original implementation plan; JPA formed 2013 - Revised implementation plan submitted and certified; cities sign on May 2014 - Phase 1 launch December 2014 - Phase 2 launch June 2015 - Cloverdale, Petaluma, and Rohnert Park joined June 2017 - Mendocino County, Fort Bragg, Point Arena, and Willits joined	November 2016 - Feasibility study covering tri-COG region completed Spring 2017 - San Bernardino County withdrew its interest due to pressure from anti-CCE group	July 2016 - Feasibility study completed September 2016 - LA County BOS directed staff to proceed and form a JPA with interested cities April 2017 - LA County approved CCE for unincorporated county January 2018 - Estimated Phase 1 launch July 2018 - Estimated Phase 2 launch January 2019 - Estimated Phase 3 launch	2013 - Advisory group formed Mid-2014 - Study funds raised May 2016 - Feasibility study completed February-April 2017 - JPA formed August 2017 - Submitted implementation plan (IP) March 2018 - Estimated Phase 1 launch July 2018 - Estimated Phase 2 launch
Current No. Customers Served	Tri-County: ~600,000 accounts AWG: ~393,000 Unincorporated SB County: ~53,000	~28,000 accounts (July 2017)	~76,000 accounts (July 2017); ~360,000 accounts at full launch	~51,000 accounts (July 2017)	~256,000 accounts (July 2017)	~290,000 accounts (July 2017	~16,000 accounts (implementation plan estimate at full launch)	~61,000 accounts (July 2017)	~210,000 accounts (July 2017)	~600,000 accounts (July 2017)	~1.3M accounts (feasibility study estimate at full launch)	Unincorporated county: ~300,000 accounts (feasibility study estimate) Uninc. + cities: ~1.5M accounts (feasibility study estimate at full launch)	~270,000 accounts (IP estimate at full launch)
Opt-out Rate	Feasibility study assumed 15% (+ all Direct Access customers, which comprise 23.5% of AWG customers)	Unknown	3.3% (July 2017)	6% (October 2016)	16% (Jun 2010, based on initial participants); decreased to 9% at most recent program expansion in Sep 2016	1.8% (July 2017)	Unknown	3% (May 2017)	< 2% (July 2017)	12% (2017)	Unknown	Unknown	IP estimates ~5% (August 2017)
Current Annual Load	Tri-County: ~8,500 GWh AWG: ~5,900 GWh Unincorporated SB County: ~1,300 GWh * Includes non-DA customers only	~220 GWh (2017); ~280 GWh (2018 - 1st full year of operations)	535 GWh (July 2017); ~3,600 GWh (full launch) Peak: 93 MW (July 2017)	~600 GWh (July 2017) Peak: 123 MW (July 2017)	~2,800 GWh (July 2017) Peak: 520 MW (July 2017)	~3,600 GWh (July 2017) Peak: 660 MW (July 2017)	~230 GWh (implementation plan estimate at full launch)	~730K GWh (implementation plan estimate at full launch)	~3,500 GWh (July 2017)	~2,300 GWh (2016); ~2600 GWh (June 2017) Peak: 512 MW (July 2017)	~21,000 GWh (feasibility study estimate at full launch)	~3,000 GWh (feasibility study estimate for unincorporated county)	~2,300 GWh (Phase 1 - March 2018; Phase 2: ~3,600 GWh (Phase 2 - July 2018)
Current Financials	For AWG Middle of the Road (50% Renewable) Scenario, 2020 Net: -$44,000 (feasibility study estimate)	Revenues: $13.2M (2017 projection from IP) Costs: $12.2M (2017 projection from IP) Net: $1.0M (2017 projection from IP)	In process of developing monthly financial statements; will also be included in annual CAFRs for SFPUC (July 2017)	Revenues: $23.4M (2016)	Revenues: $44.1M (March 2016) Costs: $14.6M (March 2016) Net: $29.5M (March 2016)	Net position: $18M (FY16-17); projected $33M (FY1718)	Revenues: $12.5M (2018 projection from IP) Costs: $$12.1M (2018 projection from IP) Net: $$460,000 (2018 projection rom IP)	Unknown	Net position: $6.7M (June 2017); $31.1M (2018 projection from IP)	Revenues: $69.6M (June 2017) Costs: $15.9M (June 2017) Net: $53.7M (June 2017)	Unknown	Unknown	Revenues: $173M (2018 projection from IP) Costs: $134M (2018 projection from IP) Net: $39M (2018 projection from IP)
Rollout Strategy	Phase 1: Large commercial accounts Phase 2: Small and medium commercial accounts Phase 3: Residential, outdoor lighting, and traffic control accounts	No phasing - all customers served on Day 1	Phase 1: Sample of residential and commercial accounts	Phase 1: Municipal + sample of residential and commercial accounts Phase 2: Remaining	Phase 1: Municipal + sample of residential and C&I accounts comprising 20% of load Phase 2: Another 20% of residential and C&I accounts Phase 3: Remaining accounts in Marin Couny Phase 4: Richmond accounts Phase 5: Unincorporated Napa County accounts Phase 6: San Pablo, Benicia, and El Cerrito accounts Phase 7: American Canyon, Calistoga, Lafayette, Napa, St. Helena, Walnut Creek, and Yountville accounts	Phase 1: Municipal + small/medium commercial + 20% of residential + early adopters Phase 2: Large C&I + 35% of residential Phase 3: Agricultural + street lighting + remaining residential Phase 4: Remaining (if needed)	No phasing - all customers served on Day 1	No phasing - all customers served on Day 1	Phase 1: Municipal + small/medium commercial + 20% of residential accounts Phase 2: All remaining accounts Note: IP originally called for 3 phases with option for 4th phase; Board voted to collapse into 2 phases	Phase 1: Sample of residential and most commercial accounts Phase 2: Remaining accounts in initial service territory Phase 3: Cloverdale, Petaluma, and Rohner Park accounts Phase 4: Mendocino County, Fort Bragg, Point Arena, and Willits accounts	Phase 1: Municipal accounts + 5% of commercial accounts Phase 2: Remaining	Phase 1: LA County municipal accounts in unincorporated county Phase 2: Non-residential accounts Phase 3: Residential accounts	Phase 1: All C&I and agricultural accounts Phase 2: All residential accounts Phase 3: Remaining (if needed)
Post-Launch Governing Body		Apple Valley Town Council	SFPUC with rate approval by SF BOS	Lancaster City Council, California Choice Energy Authority (CCEA) JPA	JPA	JPA	Pico Rivera City Council, California Choice Energy Authority (CCEA) JPA	JPA (existing)	JPA	JPA	JPA	JPA	JPA
Pre-Launch Coordinating Body	Advisory Working Group comprised of San Luis Obispo, Santa Barbara, and Ventura Counties and the cities of Camarillo, Carpinteria, Moorpark, Ojai, Santa Barbara, Simi Valley, Thousand Oaks, and Ventura	Town of Apple Valley	SFPUC	City of Lancaster	County of Marin, Marin Municipal Water District, North Marin Water District, Berkeley, Emeryville, Oakland, and Pleasant contributed to "CCA Demonstration Project" Later formed Local Government Task Force	County advisory committee of all cities and select stakeholders met for 8 months until JPA was formed and Board was seated	City of Pico Rivera	RCEA Board	CCE Partnership comprised of Santa Clara County, Cupertino, Mountain View, and Sunnyvale later morphed into JPA with all 12 participating jurisdictions	Steering committee of the Sonoma County Water Agency, city council members, city managers and staff, business representatives, activists, and others	Informal coordination among Coachella Valley Association of Governments, San Bernardino Associated Governments, and Western Riverside Council of Governments	Stakeholder advisory group led by LA County	Santa Cruz County hosts the Planning and Development Advisory Committee which is made up of interested cities and some local experts

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Community Advisory Committee		No	Not explicity for CPSF, but SFPUC has an existing Citizens' Advisory Committee that includes a Power Subcommittee	No	No	Yes	Unknown	Yes - existing Community Advisory Committee to also provide feedback on CCE matters	Unknown	Yes - JPA Agreement includes requirement for: - Ratepayer Advisory Committee to be appointed by board and comprised of 3 C&I customers and 4 residential customers (1 of whom must be a tenant) - Business Operations Committee to be appointed by board and comprised of 5 members with expertise in managmeent, administration, finance, public contracts, infrastructure development, renewable power generation, power sale and marketing, and energy conservation	Unknown	Unknown	Yes
Original Jurisdictions		1) Apple Valley	1) City and County of San Francisco	1) Lancaster	1) Marin County 2) Belvedere 3) Fairfax 4) Mill Valley 5) San Anselmo 6) San Rafael 7) Sausalito 8) Tiburon	1) San Mateo County 2) Atherton 3) Belmont 4) Brisbane 5) Burlingame 6) Colma 7) Daly City 8) East Palo Alto 9) Foster City 10) Half Moon Bay 11) Hillsborough 12) Menlo Park 13) Millbrae 14) Pacifica 15) Portola Valley 16) Redwood City 17) San Bruno 18) San Carlos 19) San Mateo 20) South San Francisco 21) Woodside	1) Pico Rivera	1) Humboldt County 2) Arcata 3) Blue Lake 4) Eureka 5) Fortuna 6) Rio Dell 7) Trinidad	1) Santa Clara County 2) Campbell 3) Cupertino 4) Gilroy 5) Los Altos 6) Los Altos Hills 7) Los Gatos 8) Monte Sereno 9) Morgan Hill 10) Mountain View 11) Saratoga 12) Sunnyvale	1) Sonoma County 2) Cotati 3) Santa Rosa 4) Sebastopol 5) Sonoma 6) Windsor	1) Riverside County 2) Banning 3) Blythe 4) Calimesa 5) Canyon Lake 6) Catherdral City 7) Coachella 8) Corona 9) Desert Hot Springs 10) Eastvale 11) Hemet 12) Indian Wells 13) Indio 14) Jurupa Valley 15) La Quinta 16) Lake Elsinore 17) Menifee 18) Moreno Valley 19) Murrieta 20) Norco 21) Palm Desert 22) Palm Springs 23) Perris 24) Rancho Mirage 25) Riverside 26) San Jacinto	1) Los Angeles County	1) Monterey County 2) Carmel-By-The-Sea 3) Del Rey Oaks 4) Gonzales 5) Greenfield 6) King City 7) Marina 8) Monterey 9) Pacific Grove 10) Salinas 11) Sand City 12) Seaside 13) Soledad 14) San Benito County 15) Hollister 16) San Juan Bautista 17) Santa Cruz County (lead agency) 18) Capitola 19) Santa Cruz 20) Scotts Valley 21) Watsonville
Current Jurisdictions		1) Apple Valley	1) City and County of San Francisco	1) Lancaster Note: CCEA jurisdictions listed separately	1) Marin County 2) Belvedere 3) Corte Madera 4) Fairfax 5) Larkspur 6) Mill Valley 7) Novato 8) Ross 9) San Anselmo 10) San Rafael 11) Sausalito 12) Tiburon 13) Napa County 14) American Canyon 15) Calistoga 16) Napa 17) St. Helena 18) Yountville 19) Benicia (Solano County) 20) El Cerrito (Contra Costa County) 21) Richmond (Contra Costa County) 22) San Pablo (Contra Costa County) 23) Walnut Creek (Contra Costa	1) San Mateo County 2) Atherton 3) Belmont 4) Brisbane 5) Burlingame 6) Colma 7) Daly City 8) East Palo Alto 9) Foster City 10) Half Moon Bay 11) Hillsborough 12) Menlo Park 13) Millbrae 14) Pacifica 15) Portola Valley 16) Redwood City 17) San Bruno 18) San Carlos 19) San Mateo 20) South San Francisco 21) Woodside	1) Pico Rivera	1) Humboldt County 2) Arcata 3) Blue Lake 4) Eureka 5) Fortuna 6) Rio Dell 7) Trinidad	1) Santa Clara County 2) Campbell 3) Cupertino 4) Gilroy 5) Los Altos 6) Los Altos Hills 7) Los Gatos 8) Monte Sereno 9) Morgan Hill 10) Mountain View 11) Saratoga 12) Sunnyvale	1) Sonoma County 2) Cloverdale 3) Cotati 4) Petaluma 5) Rohnert Park 6) Santa Rosa 7) Sebastopol 8) Sonoma 9) Windsor 10) Mendocino County 11) Fort Bragg 12) Point Arena 13) Willits	It appears Riverside County, Rancho Mirage, and San Jacinto will pursue their own CCAs independent of what the Tri-COG region chooses. San Bernardino County is not moving forward.	1) Los Angeles County 2) Calabasas 3) Rolling Hills Estates 4) South Pasadena 5) West Hollywood	1) Monterey County 2) Carmel-By-The-Sea 3) Gonzales 4) Greenfield 5) Marina 6) Monterey 7) Pacific Grove 8) Salinas 9) Sand City 10) Seaside 11) Soledad 12) San Benito County 13) Hollister 14) San Juan Bautista 15) Santa Cruz County (lead agency) 16) Capitola 17) Santa Cruz 18) Scotts Valley 19) Watsonville

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JPA Composition		N/A	N/A	Spun off California Choice Energy Authority to provide back-office services to other cities pursuing CCE	24 members - 1 per jurisdiction Nominee and alternate required to be elected official	22 members - 1 per city + 2 for San Mateo County Nominee required to be elected official; alternate can also be staff	Member of California Choice Energy Authority	9 members - 1 per jurisdiction + water district	12 members - 1 member per jurisdiction Nominee required to be elected official; alternate can also be staff or member of public	2 official JPA members (County + Water Agency), but all 9 cities sit on board and have voting privileges, so 11 participants overall - currently 1 per jurisdiction, but allowed to appoint more than 1 with board approval; Santa Rosa permitted to have same number of voting participants as Sonoma County Not required to be elected official	Feasibility study evaluates two JPA options: 1) New tri-COG JPA 2) Separate existing JPAs (1 per COG)	5 members (as of September 2017) - 1 member per jurisdiction Nominee required to be elected official; alternates (up to 2) can also be a member of an advisory body, staff person, or member of public	11 members - weighted based on population as follows: - 1 seat per jurisdiction for populations of 50K+: 1) Monterey County 2) Santa Cruz County 3) Salinas 4) Santa Cruz 5) Watsonville - 1 seat per jurisdiction b/c of large geographic area: 6) San Benito County - 1 seat shared b/t Santa Cruz County's small cities: 7a) Scotts Valley 7b) Capitola - 1 seat shared among Monterey County's small Peninsula Cities: 8a) Carmel 8b) Monterey 8c) Pacific Grove
JPA Voting Structure		N/A	N/A	N/A	1st Tier: Voting share is split 50/50 as follows: - Simple Majority (1 vote per member) - Load Share (proportional based on load) 2nd Tier: Special Voting - 2/3 majority (based on 50/50 split above) required to amend JPA agreement	1st Tier: Simple Majority (1 vote per member) 2nd Tier: Load Share (proportional based on load) + Simple Majority - 1 vote per member except for County which must share 1 vote among its 2 positions - Can be called by any member on any vote 3rd Tier: Special Voting - 2/3 majority required for involuntary termination of a member or amendment of the JPA agreement - 3/4 majority required for eminent domain and member $ contributions	N/A	1st Tier: Voting share is weighted as follows: - 1/3 Pro Rata Share calculated as follows: [1/Total # CCE Participants] x 1/3 - 2/3 Customer Base Share calculated as follows [# CCE customers in member's jurisdiction/Total # of CCE customers] x 2/3 Only CCE participants may vote on CCE matters (not all existing RCEA JPA members are CCE participants). 2nd Tier (applies to all RCEA members, not just CCE participants): Special Voting - 2/3 majority required for amending the JPA agreement and allowing members to withdraw	1st Tier: Simple Majority (1 vote per member) 2nd Tier: Load Share (proportional based on load) - Requires 2+ members to call for this voting process - Also requires Simply Majority 3rd Tier: Special Voting - 2/3 majority required to add members, incur debt, allow members to withdraw, shorten notification period for members to withdraw, involuntarily terminate a member, or amend the JPA agreement	1st Tier: Load Share (proportional based on load) - If jurisdiction has more than 1 member, jurisdiction gets only 1 weighted vote 2nd Tier: Load Share + Simple Majority (1 vote per member) - Can be called by any member on any vote 3rd Tier: Special Voting - 2/3 majority required for removal of Ratepayer Advisory Committee member, involuntary termination of a party, or amending the JPA agreement; can also require load share vote - 3/4 majority required for eminient domain and member $ contributions; can also require load share vote	Unknown	1st Tier: Simple Majority (1 vote per member) 2nd Tier: Load Share - Can be called by 3+ members on any affirmative 1st Tier vote 3rd Tier: Special Voting - 2/3 majority required for change of Treasurer or Auditor, issuing bonds or other debt, eminent domain, amending the JPA agreement, or involuntary termination of a party	1st Tier: Simple Majority (1 vote per member, per seat assignments above) 2nd Tier: Special Voting - 2/3 majority required for involuntary termination of a party or amending the JPA agreement - 3/4 majority required for eminent domain and member $ contributions
JPA Entry Requirements		N/A	N/A	N/A	"Initial Participants" must execute JPA agreement within 6 months of the 1st two local governments signing and have lower requirements: - Executed JPA agreement - Ordinance To join after 1st 6 months, member agency must submit: - Executed JPA agreement - Resolution - Ordinance - Membership fee (proportional) - MCE currently does not require fee to join - Agreement to any supplemental conditions (established by JPA board) - Receive affirmative vote of JPA board	Takes effect when the County of San Mateo and 2+ municipalities execute agreement. To join, member agency must submit: - Executed JPA agreement - Ordinance	N/A	To join, existing RCEA members must submit: - Ordinance	Takes effect when 3+ initial participants execute agreement To join, member agency must submit: - Executed JPA agreement - Resolution - Ordinance - Membership fee (proportional) - Initial participants share Phase 2 & 3 costs, which must be provided within 30 days of agreement execution date - Agreement to any supplemental conditions (established by JPA board)	To join, member agency must submit: - Executed JPA agreement - Resolution - Ordinance - Membership fee (proportional) - Agreement to any supplemental conditions (established by JPA board) - Receive affirmative vote of JPA board	Unknown	Takes effect when LA County + 1 other entity execute agreement Other "Initial Participants" must execute JPA agreement within 6 months of the 1st two local governments signing and have lower requirements: - Executed JPA agreement - Ordinance To join after 1st 6 months, member agency must submit: - Executed JPA agreement - Ordinance - Membership fee (proportional) - Agreement to any supplemental conditions (established by JPA board) - Receive affirmative vote of JPA board	Takes effect when 3+ jurisdictions execute agreement. To join, member agency must submit: - Executed JPA agreement - Ordinance - Membership fee (start-up costs allocated proportionally based on population for credit guarantee)
JPA Exit Requirements		N/A	N/A	N/A	Minimum 30-day notice prior to initial program agreement Subsequent to initial program agreement, minimum 6-month notice required with withdrawal to take effect at beginning of next FY Liable for applicable costs through termination date	Minimum 15-day notice prior to program launch if, after receiving bids from power suppliers, bids do not result in: 1) rates equal to or less than PG&E, 2) GHG emission rates lower than PG&E, OR 3) renewable energy content higher than PG&E Subsequent to program launch, minimum 6-month notice required with withdrawal to take effect at beginning of next FY 30-day notice required if member seeks to withdraw after an amendment to the JPA agreement that the member voted against Except for the pre-program launch withdrawal option, liable for applicable costs through termination date	N/A	No specific exit requirements for CCE participants; any member may withdraw upon receiving 2/3 vote	Minimum 15-day notice prior to program launch if, after receiving bids from power suppliers, bids do not result in: 1) rates equal to or less than PG&E, 2) GHG emission rates lower than PG&E, OR 3) renewable energy content higher than PG&E Subsequent to program launch, minimum 6-month notice required with withdrawal to take effect at beginning of next FY Pre-vote notice required if member seeks to withdraw after an amendment to the JPA agreement that the member plans to vote against Liable for applicable costs through termination date, even if withdraw prior to program launch	Minimum 6-month notice required with withdrawal to take effect at beginning of next FY 30-day notice required if member seeks to withdraw after an amendment to the JPA agreement that the member voted against Liable for applicable costs through termination date	Unknown	Minimum 6-month notice and affirmative vote of local government's governing body required Liable for applicable costs through termination date	Minimum 15-day notice prior to program launch if, after receiving bids from power suppliers, bids do not result in: 1) rates equal to or less than PG&E, 2) GHG emission rates lower than PG&E, OR 3) renewable energy content higher than PG&E Minimum 6-month notice required with withdrawal to take effect at beginning of next FY 30-day notice required if member seeks to withdraw after an amendment to the JPA agreement that the member voted against Liable for applicable costs through termination date (for pre-program launch withdrawal option, only liable for proportionate credit guarantee contribution)

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JPA Compensation		N/A	N/A	N/A	No - but reimbursement policy may be adopted	No - but reimbursement policy may be adopted	N/A	No - but will reimburse for documented expenses related to Board duties	No - but reimbursement policy may be adopted	No - but reimbursement policy may be adopted	Unknown	Unknown	No - but reimbursement policy may be adopted
Implementation model (at launch)		In-house 1) Finance 2) Outreach/marketing 3) Key account management 4) Resource planning 5) Legal/regulatory (with outside counsel as needed) Outsourced 1) Customer service/call center 2) Data management/billing coordination/enrollment 3) Power scheduling 4) Power procurement 5) Legal/regulatory	In-house 1) Resource planning 2) Power procurement 3) Finance 4) Key account management 5) Legal/regulatory 6) Outreach/marketing Outsourced 1) Power scheduling 2) Customer service/call center (with expectation to bring in-house) 3) Data management/billing coordination/enrollment (with expectation to bring in-house) 4) DSM program development and implementation (via SFE and possibly others)	In-house 1) Finance 2) Outreach/marketing Outsourced 1) Resource planning 2) Power procurement 3) Power sheduling 4) Customer service/call center 5) Data management/billing coordination/enrollment 6) Legal/regulatory 7) DSM program development and implementation	In-house 1) Finance 2) Outreach/marketing 3) Key account management 4) Legal/regulatory Outsourced 1) Resource planning 2) Power procurement 3) Power scheduling 4) Customer service/call center 5) Data management/billing coordination/enrollment	In-house 1) Finance 2) Outreach/marketing 3) Key account management 4) Legal/regulatory 5) Resource planning Outsourced 1) Power procurement 2) Power scheduling 3) Customer service/call center 4) Data management/billing coordination/enrollment	In-house 1) Finance 2) Outreach/marketing 3) Key account management 4) Legal/regulatory (with outside counsel as needed) Outsourced 1) Resource planning 2) Power procurement 3) Power scheduling 4) Customer service/call center 5) Data management/billing coordination/enrollment	In-house 1) Finance 2) Key account management 3) Resource planning (in coordination with TEA) 4) Outreach/marketing (in coordination with LEAN) Outsourced 1) Power procurement 2) Power scheduling 3) Customer service/call center 4) Data management/billing coordination/enrollment 5) Outreach/marketing 6) Legal/regulatory	In-house 1) Finance 2) Outreach/marketing 3) Key account management 4) Resource planning 5) Legal/regulatory (with outside counsel as needed) Outsourced 1) Customer service/call center 2) Data management/billing coordination/enrollment 3) Power scheduling 4) Power procurement 5) Legal/regulatory	In-house 1) Finance 2) Outreach/marketing 3) Key account management 4) Legal/regulatory Outsourced 1) Resource planning (later brought in house 2) Power procurement (later brought in house) 3) Power scheduling 4) Customer service/call center (some brought in house) 5) Data management/billing coordination/enrollment	Unknown	Unknown	In-house 1) Finance 2) Outreach/marketing 3) Key account management 4) Legal/regulatory (with outside counsel as needed) 5) Resource planning Outsourced 1) Power procurement 2) Power scheduling 3) Customer service/call center 4) Data management/billing coordination/enrollment 5) Legal/regulatory
Vendors	Technical: Willdan/EnerNex Other: LEAN Energy US, MRW & Associates (peer review)	Power Supply: Shell Energy North America	Technical: Davis & Associates Communications, MRW & Associates, and Pacific Energy Advisors Power Scheduling: APX Power Supply: Calpine, Constellation, and Iberdrola Data Management/Call Center: Calpine Energy Solutions (formerly Noble Americas) Other: Willdan/EnerNex (job creation impact); SF Department of Environment (DSM)	Technical: Willdan/EnerNex, Pacific Energy Advisors Power Supply & Scheduling: Direct Energy Data Management/Call Center: Calpine Energy Solutions (formerly Noble Americas)	Technical: Navigant Consulting Power Supply: Shell Energy North America, G2Energy, Dominoin, Genpower, Calpine, EDP, Recurrent, Waste Management, East Bay MUD, Avangrid, Portland General Electric, 3 Phases, SunPower, Powerex, City of Santa Clara, First Solar, Nextera, SPower, EDF, Terra Gen, LA County Sanitation District, WAPA, Exelon, Energy America, Morgan Stanley Forecasting: Pacific Energy Advisors Data Management/Call Center: Calpine Energy Solutions (formerly Noble Americas)	Technical: Pacific Energy Advisers Marketing: Circlepoint; Green Ideals Power Scheduling: Energy America, ZGlobal Power Supply: Energy America, Shell Energy North America, Exelon, NRG, Mega Renewables, Wright Solar Park, Silicon Valley Power, Direct Energy, Buena Vista Energy, Energy Development & Construction Corp., Cuyama Solar, LLC, Morgan Stanley Group Data Management/Call Center: Calpine Energy Solutions (formerly Noble Americas) Other: MRW & Associates (peer review); Winston & Strawn (legal); Troutman Sanders (legal); PIN Presort (mailing)	California Choice Energy Authority	Strategy: LEAN Technical: The Energy Authority Marketing: LEAN Power Supply & Scheduling: The Energy Authority Data Management/Call Center: Calpine Energy Solutions (formerly Noble Americas) Other: Braun Blaising McLaughlin & Smith (legal/regulatory), Richards Watson & Gershon (legal/regulatory)	Technical: Pacific Energy Advisers	Technical: Dalessi Management Consulting (now Pacific Energy Advisors) Power Scheduling: Constellation, Shell Energy North America Power Supply: Constellation, NRG, Direct Energy, ConEdison (finalists but not clear if contracts were executed with all) Data Management/Call Center: Calpine Energy Solutions (formerly Noble Americas) Other: MRW & Associates (peer review); Troutman Sanders (legal)	Technical: EES Consulting with Bki	Technical: EES Consulting with BKi Other: Arc Alternatives (peer review)	Strategy: LEAN Technical: Pacific Energy Advisors Marketing: Miller Maxfield Other: MRW & Associates (peer review)
Staffing	Tri-County: 57 FTEs (feasibility study estimate) AWG: 45 FTEs (feasibility study estimate) Unincorporated SB County: 28 FTEs (feasibility study estimate)	3-5 FTEs (May 2017)	10 FTEs (May 2017)	3-5 FTEs (May 2017)	40-45 FTEs (May 2017)	10-15 FTEs (May 2017)	3 FTEs expected to start (September 2017)	3 dedicated FTEs + 4 mostly dedicated FTEs + interns + 2 FTE CCE/EE shared Key Account Managers (May 2017)	12 FTEs (May 2017)	15-20 FTEs (May 2017)	Unknown	Unknown	8 FTEs to launch (Aug 2017)
Funding Sources	Feasibility Study: $220,756 provided by members of AWG Start Up: Feasibility study suggests a bond issuance	Feasibility Study: GF Start Up: ~$2.6M from GF (includes interest, 5-year repayment term starting in 2nd year of operations);	Feasibility Study: General Fund Start Up: ~$12.9M from SF GF ($8.9M for feasibility study, IP, etc. + $4M for 2 months working capital that was subject to internal 0.73% IR)	Feasibility Study: ~$600K (not confirmed) Start Up: Combination of financing ($3M line of credit) and negotiated cash flow agreements with power service providers (begin payback in 3rd year of operations with 3 years to pay in full)	Start UP: ~$3.4M - $110K CEC grant - $75K BAAQMD grant - $140K Marin Municipal Water District contribution - $10K North Marin Water District contribution - $847K Marin County contribution (including interest-free loans) - $750K loan from 3 individuals ($250K each investor @ 5.75% IR, unsecured) - $1.45M in bank loans (secured by Marin County and City of Fairfax, both of whom earned interest) MCE has a $25M line of credit with River City Bank but has not used it as of June 2017	Feasibility Study: San Mateo County provided funding from GF (from residual revenues of a previous project) Start Up: Combination of County and bank financing, including $12 million loan from Barclay and nearly $9M from County including $6M credit guarantee for bank loan; County loans include interest	Feasibility Study: General Fund Start Up: General Fund	Feasibility Study: Included in start up costs fronted by TEA Start Up: ~$8.2M - $120K RCEA GF - $700K Revolving line of credit wtih 5% interest from county economic development fund - Balance vendor financed with 5% interest for power procurement and operational costs	Feasibility Study: ~$680K split evenly between the County, Cupertino, Mountain View, and Sunnyvale Start Up: ~$222.7M, of which $2.0M shared proportionally among initial participants to JPA agreement, with repayment within 3 years (codified in agreement); all debt expected to be repaid by December 2017	Feasibility Study: $60K funded by Water Agency Start Up: $10M funded through 2 separate lines of credit (one for power procurement-related expenses and the other for everything else)	Feasibility Study: Each COG contributed proportionately Start Up: ~$20M (feasibility study estimate)	Feasibility Study: GF, up to $15M of which the JPA agreement specifies will be repaid to LA County Start Up: ~$43M (feasibility study estimate)	Feasibility Study: ~$400K from a combination of grants and private individual and organization contributions Start Up: ~$13M (feasibility study and IP estimate) secured through 2 loans from River City Bank; IP states MBCP expects to recover borrowed costs within 1st year of operations; JPA agreement includes provision for Santa Cruz County to be reimbursed for its early contributions

Community Choice Energy Program Comparison Matrix

September 2017

		OPERATIONAL									IN DEVELOPMENT		
	Central Coast Power	Apple Valley Choice Energy	CleanPowerSF	Lancaster Choice Energy	Marin Clean Energy	Peninsula Clean Energy	Pico Rivera Innovative Municipal Energy	Redwood Coast Energy Authority	Silicon Valley Clean Energy	Sonoma Clean Power	Inland Choice Power	Los Angeles Community Choice Energy	Monterey Bay Community Power
Products & Rates		Base - 35% renewable at 3% discount relative to SCE generation rate (CARE rate 13% lower) Premium - 50% renewable at $2/month premium (residential) or $0.002/kWh premium (non-residential)	Base - 40% renewable (Cat 1), example generation charge slightly lower than PG&E but total bill roughly equivalent Premium - 100% renewable (Cat 1), base rate + $0.02/kWh; rates and total bill lower than PG&E 100% green product Note: overall 2017 portfolio is 53% renewable	Base - 35% renewable, example residential generation charge and overall monthly bill very slightly lower (-$1 for resi and -$2.60 for C&I); designed to be 3% lower than SCE Premium - 100% renewable, flat $10 premium resulting in about $10 higher monthly bill for example residential customer	Base - 50% renewable, example residential generation charge $12 lower than PG&E but total bill slightly higher (+$2) Premium 1 - 100% renewable, example residential generation charge $7 lower than PG&E but total bill higher (+$6); 2.6% of sales in 2016 Premium 2 - 100% local solar, example residential generation charge $20 higher than PG&E and total bill much higher (+$34) Note: IP noted 25% renewable at launch; have 626.5 MW of new generation under contract	Base - 50% renewable and 80% carbon free at 5% discount below PG&E generation rate Premium - 100% renewable and 100% carbon free at $0.01/kWh premium Note: One of PCE's new-build projects is Cuyama (40MW)	Base - 50% renewable at unknown rate delta (estimated 1-5% savings in IP) Premium - 100% renewable at $11 more for residential customers and $0.01/kWh premium for non-residential customers	Base - 40% renewable - designed portfolio to achieve 2.7% rate savings compared to PG&E's standard rate Premium - 100% renewable at $0.01/kWh premium	Base - 50% RPS-eligible renewable & 100% carbon free (other 50% from hydro, as of April 2017) at 1% below PG&E; example residential generation charge ~$15 lower than PG&E and total bill roughly the same Premium - 100% renewable and 100% carbon free at <$0.01/kWh premium; example residential generation charge ~$11 lower than PG&E and total bill ~$3 more	Base - 42% RPS-eligible renewable and 91% carbon free Premium - 100% renewable & local to Sonoma County (geothermal) Note: IP noted 33% RE at launch and has incrementally increased since then	Feasibility study evaluates three renewble content scenarios (savings shown for year 1): 1) RPS-equivalent - estimated 4.9% rate savings compared to SCE standard rate 2) 50% renewable - estimated 3.8% rate savings compared to SCE standard rate; 11.2% rate savings compared to SCE 50% green power product 3) 100% renewable - estimated 5.7% rate increase compared to SCE standard rate; 9.4% rate savings compared to SCE 100% green power product	Feasibility study evaluates three renewable content scenarios (savings shown for year 1): 1) RPS-equivalent - estimated 5.4% rate savings compared to SCE standard rate 2) 50% renewable - estimated 4.1% rate savings compared to SCE standard rate 3) 100% renewable - estimated 6.3% rate increase compared to SCE standard rate	Board is considering 30-35% RPS-eligible renewable energy in base product at launch with the remaining power coming from carbon free resources Board is considering setting rates exactly equal to PG&E by customer class and returning any accumulated revenues above costs to customers in the form of a quarterly or year-end bill credit
Rate Setting and Structure		Rates approved by Town Council Customer classes generally match SCE's with option to establish customized tariffs for large C&I customers (e.g., indexed pricing, fixed term pricing)	Rates set through public process overseen by existing Rate Fairness Board and approved by SFPUC Board with veto authority by SF BOS Customer classes match PG&E's at launch with flexibility to modify later	Rates approved by City Council Adopted simplified (not 1:1) rate structure/customer class from beginning	Rates approved by JPA Board Customer classes generally match PG&E's	Rates approved by JPA Board Customer classes generally match PG&E's with flexibility to modify	Rates approved by City Council Customer classes generally match SCE's with option to establish customized tariffs for large C&I customers	Rates approved by JPA Board Customer classes generally match PG&E's	Rates approved by JPA Board Customer classes generally match PG&E's with option to establish customized tariffs for large C&I customers (e.g., indexed pricing, fixed term pricing)	Rates approved by JPA Board Customer classes generally match PG&E's with flexibility to modify (e.g., customerize for C&I customers)	Unknown	Rates to be approved by JPA board	Rates to be approved by JPA board Customer classes generally match PG&E's with flexibility to modify (e.g., customerize for C&I customers)
Reserve Fund	Reserve Fund: 5 months working capital Contingency/Rate Stabilization Fund: 12% of power costs + 10% of non-power costs	Reserve Fund: 3% of annual revenues Contingency/Rate Stabilization Fund: Unknown	Reserve Fund: 90 days operating costs Contingency/Rate Stabilization Fund: 15% of annual revenues to be achieved within 3 years of completing enrollment	Reserve Fund: Unknown Contingency/Rate Stabilization Fund: Unknown	Reserve Fund: 90 days operating costs Contingency/Rate Stabilization Fund: 15 % of annual revenues to be achieved by March 2019 (subject to ability to maintain competitive rates)	Reserve Fund: Unknown Contingency/Rate Stabilization Fund: 5% of annual gross revenues	Unknown	Reserve Fund: $6M within first year of operations Contingency/Rate Stabilization Fund: Unknown	Reserve Fund: 90 days operating costs, excluding power costs Contingency/Rate Stabilization Fund: Unknown	Reserve Fund: Unknown Contingency/Rate Stabilization Fund: Unknown	Unknown	Unknown	Reserve Fund: ~50% of operating expenses
Use of Unbundled RECs	No	Yes - 8% (July 2017)	No - exclusively use Cat 1 (CA bundled) RECs	Yes - 8% (July 2017)	Yes - 2017-2026 IRP commits to ≤ 3% unbundled RECs in line with RPS	No	Unknown	Initially no, but does not appear to be explicit restriction on Cat 3 RECs	Initially no, but amended procurement strategy to include up to 12.5% Cat 3 RECs for 2017-18 due to difficulty securing Category 2 RPS-eligible renewables	Initially yes; sold Cat 3 RECs in 2016 and will only use going forward if required to suport local RE programs or protect the value of CA renewables	Unknown	Unknown	No
Renewable Energy/Environmental Goals	Lower GHG emissions and supports participating local governments' climate action plans Prioritizes local and in-state renewable resources	Unknown	Unknown	City aims to be zero net energy community	Base product to be 80% renewable by 2025; long-term* goal of 100% renewable energy 75% GHG-free portfolio by 2017; 100% GHG-free portfolio by 2025 ("subject to operational practicalities and product availability") 25 MW of local solar by 2021 Long-term* goal of offsetting 2% of annual energy requirements with DER Offset 5% of annual capacity (Resource Adequacy) requirements through DR by 2026 * Long-term not defined	100% GHG-free portfolio by 2021 100% CA RPS eligible renewable energy by 2025 20MW of new local power by 2025	Unknown	5% more renewables than PG&E 5% lower GHG intensity than PG&E	100% carbon free Reduce electricity sales by 0.5% by 2024 through energy efficiency (incremental to existing PG&E EE efforts)	Website states SCP is "on track" to be 50% renewable by 2020	Unknown	Unknown	Maximize carbon-free resources
DSM Programs	Desires to administer/support DSM programs	Plans to apply for independent administration	Plans to apply for independent administration	Withdrew business plan to apply for independent administration	Self administer	Plans to apply for independent administration; may bring existing local DSM programs in house	Plans to apply for independent administration	Does not plan to apply to administer; RCEA to continue to administer PG&E-funded programs with intent to add new programs	Plans to apply for independent administration; may bring existing local DSM programs in house	Plans to apply for independent administration; may bring existing local DSM programs in house	Unknown	Unknown	Do not plan to apply for independent administration within the first few years; TBD after that
Opt-out Notice Mechanism		Mailer	Mailer independent from PG&E bills	Mailer	Mailer	Mailer - possible bill insert with PG&E	Mailer	Mailer	Mailer	Mailer	Unknown	Unknown	Mailer
Opt-out Fee (after 1st 60 days)		Resi- $5; C&I - $25 (proposed)	Resi - $5; C&I - $25	Not clear - no mention of fee on website but IP included an estimated $75 fee for resi and$100 for C&I	Resi - $5; C&I - $5-25	Resi - $5; C&I - $25 (after 1st year of service)	Unknown	No fee	Base product: Resi - $5; C&I - $25 Premium product: Resi - $105; Small C&I - $125; Large C&I - $25 + $0.03/kWh (if no notice) or $25 (6-month notice)	Resi - $5; C&I - $25	Unknown	Unknown	Resi - $5; C&I - $25 (estimate included in IP)