**BEFORE THE PUBLIC UTILITIES COMMISSION**

**OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans | Rulemaking 13-12-010<br>(Filed December 19, 2013) |

# WORKSHOP COMMENTS OF THE PROTECT OUR COMMUNITIES FOUNDATION

David A. Peffer, Esq.
PROTECT OUR COMMUNITIES FOUNDATION
4452 Park Boulevard, Suite 209
San Diego, CA 92116
david.a.peffer@gmail.com

January 8, 2014

**BEFORE THE PUBLIC UTILITIES COMMISSION**

**OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans | Rulemaking 13-12-010 (Filed December 19, 2013) |

**WORKSHOP COMMENTS OF THE PROTECT OUR COMMUNITIES FOUNDATION**

## I. INTRODUCTION

Pursuant to Rule 1.4 of the Commission's Rules of Practice and Procedure, the Protect Our Communities Foundation ("POC") submits the following Comments on the *Planning Assumptions and Scenarios* document and related documents in the 2014 LTPP proceeding, R.13-12-010.

As established below, the Commission must: (1) clarify the evidentiary effect of adopting contested material issues of fact as "assumptions"; (2) reject or remedy the proposed scenario's flawed assumptions regarding demand, energy efficiency, photovoltaics, demand response, combined heat and power, and energy storage; (3) reject the scenarios' unreasonable overestimation of plant retirements, and (4) require that all scenarios account for the existence and growth of CCA.

## II. THE EVIDENTIARY EFFECT OF 'ASSUMPTIONS' MUST BE CLARIFIED

The Commission must clearly specify the evidentiary significance of treating a material issue of fact as an "assumption."

Normally, material issues of fact are subject to the Commission's full evidentiary process, under which parties are given the opportunity to conduct discovery, cross-examine witnesses, and receive notice of *ex parte* contact; and each applicant utility bears the full burden of proof for each element of its case. The LTPP process provides for the adoption of "assumptions" based only on a workshop and public comment process, without any of the normal procedural protections.

It is unclear from the *Planning Assumptions and Scenarios* document and related materials whether the treatment of a factual matter as an "assumption" precludes parties from raising issues of fact relating to that matter in the evidentiary phase of this proceeding. In order to protect the public interest, ensure just and reasonable rates, and preserve the substantive and procedural rights of the parties, the Commission must not adopt any material issue of fact as an "assumption" if doing so in any way limits the parties' ability to argue the issue, conduct relevant discovery, or cross-examine witnesses; or if doing so in any way reduces or shifts the utilities' burden of proof.

Each issue discussed in Sections III, IV, and V below is a material issue of fact contested by POC and as such must be subject to the Commission's full evidentiary process with the burden of proof on the utilities.

## III. THE PROPOSED SCENARIOS RELY ON UNREASONABLE ASSUMPTIONS

The scenarios and assumptions presented in the *Planning Assumptions and Scenarios* document and associated *2014 LTPP Scenario Matrix* spreadsheet are not sufficient to cover the current policy issues facing the CPUC; and do not provide a full, reasonable, or factually accurate representation of the most likely scenarios.

Each of the issues raised below is a material issue of fact contested by POC that POC intends to address fully in the evidentiary phase of this proceeding.

A. Demand Forecast – Baseline Load Assumption

The proposed Trajectory Scenario's use of the CEC's Mid load projection is unreasonable.

The actual 1-hour peak load in the CAISO control area has followed a pattern of steady decline from 2006 (50,270 MW) through 2013 (45,097 MW).[1] The peak one-hour demand in the CAISO control area in 2013 of 45,097 MW was actually lower than the peak one-hour demand in 1999 of 45,884 MW,[2] despite a statewide population increase of approximately 15 percent over the same period.[3] Peak one-hour demand has followed a declining pattern since 2006 in PG&E and SCE service territories, while the one-hour peak load in SDG&E territory has fluctuated +/- 150 MW above and below 4,500 MW with no pattern of increase or decrease.[4] The CAISO peak one-hour load would have to increase at about 1 percent per year over the entire 2014-2024 timeframe to rise from the 2013 one-hour peak of 45,097 MW back to the 2006 one-hour peak of 50,270 MW.

Despite this reality, the CEC's *California Energy Demand 2014 – 2024 Final Forecast* projects substantial 1-in-10 year one-hour peak load increases over historic high one-hour actual peak loads in all three IOU service territories by 2024, even in "CED Final Low" forecasts.

---

[1] CAISO, *Peak Load History 1998 through 2013*, January 2014: http://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf.

[2] Ibid.

[3] California population July 1, 1999 33,145,121 (http://www.census.gov/population/estimates/state/st-99-3.txt); California population July 1, 2012 38,041,430 (http://quickfacts.census.gov/qfd/states/06000.html). California population growth 2012-1999 = 38,041,430/33,145,121 = 1.15 (15 percent increase).

[4] CEC, *California Energy Demand 2014-2024 Final Forecast, Volume 1*, December 2013, p. 10 (PG&E p. 72 (SDG&E).



SB_GT&S_0334131

California IOUs are experiencing relatively modest peak one-hour loads even during verifiable 1-in-10 year weather events. For example, the Commission has identified September 14, 2012 as a 1-in-10 year weather event in Southern California, affecting the service territories of SCE and SDG&E.[5] There was no spike in one-hour peak load, relative to the prior six years in either SCE or SDG&E during the 1-in-10 year weather condition. The assertion by the CEC that "While 2012 was a warm year on average, the SDG&E planning area experienced a below average peak temperature"[6] is incorrect and contradicts Commission data regarding the same weather event.

The one-hour peak load history of CAISO and individual IOUs, even at 1-in-10 weather year peaks loads, do not support the peak load growth projections in "CED 2013 Final Low" CED 2013 Final Mid" and "CED 2013 Final High" scenarios. As shown below, the one exception is the CED 2024 "Draft Low" and "Final Low" forecasts for SCE territory, which reflects no net peak load growth between the 2007 highest actual peak load and the 2024 "Final Low" peak demand forecast. The 2024 "Final Low" peak load forecasts for PG&E and SDG&E should reflect this same trend – no net peak load growth between the highest actual one-hour peak load and the 2024 peak load forecast.

**Figure 1. Comparison of IOU Highest Actual One-Hour Peak Loads and 2024 "Low" Peak Demand Forecasts in CED May 2013 Draft and December 2013 Final Reports**

| Utility | Highest 1-hour peak recorded (MW) | CED 2013 Draft Low 2024 Peak Load (MW) | CED 2013 Final Low 2024 Peak Load (MW) |
|---|---|---|---|
| PG&E | 22,650 (2006) | 24,390 | 25,207 |
| SCE | 23,831 (2007) | 23,499 | 23,906 |
| SDG&E | 4,643 (2010) | 5,032 | 5,009 |

[5] CPUC, *Lessons Learned From Summer 2012 Southern California Investor Owned* … *Programs* Commission Staff Report, May 1, 2013, Appendix … p. A-3 … Highlight … of 2012 Summer … Load Conditions. See: www.cpuc.ca.gov/NR/rdonlyres/523B9D94-ABC4-4AF6-AA09-DD9ED8C81AAD/0/StaffReport_2012DRLessonsLearned.pdf.

[6] Id. at p. 71

In light of the CEC figures' significant divergence from the current, real-world trends, it is unreasonable for the Commission to select any of the CEC load forecasts in their current form. However, if the only option open to parties is selection of one of these load growth scenarios as the base case trajectory assumption in the 2014-2015 LTPP proceeding, it must be the least exaggerated scenario available to choose from, the "CED 2013 Final Low" peak demand growth scenario.

B. Additional Achievable Energy Efficiency

For the Additional Achievable Energy Efficiency ("AAEE") input, Scenarios 1-5 use the Mid-Low forecast set forth in the CEC's CED 2013 Final Forecast. Scenario 6 uses the high AAEE forecast from the CED 2013 Final Forecast. The high AAEE forecast should be used in all scenarios. The California Energy Efficiency Strategic Plan (2008, 2011) is Commission regulatory policy. The Commission cannot accept or utilize AAEE forecasts substantially below the EE targets described in the California Energy Efficiency Strategic Plan. As such, the Commission must use the AAEE targets rather than the lower values imbedded in the CED 2014-2024 demand forecasts.

In the alternative, the AAEE forecast that most closely reflects California Energy Efficiency Strategic Plan targets is the "High" AAEE forecast. The "High" AAEE forecasts for each IOU are about two-and-a-half times greater than the "Mid-Low" AAEE forecasts proposed as the base case trajectory assumption. The "High" AAEE should be incorporated as the base case trajectory EE scenario and not a sensitivity scenario.

C. Photovoltaics

The use of the CEC's IEPR figures for the photovoltaics input is unreasonable, as they unreasonably project that PV growth will effectively end in 2017.

The self-generation PV peak reduction assumed by the CEC in 2024, is approximately the self-generation PV peak reduction that will occur by no later than mid-2017 as a result of AB 327 caps. Assuming peak reduction is 50 percent of nameplate PV rating, by 2017 the expected minimum amount of self-generation PV will be: PG&E = 1,205 MW; SCE = 1,120 MW; SDG&E = 304 MW. In contrast, the CEC projects the following self-generation PV peak reduction in 2024: PG&E = 1,000 to 1,314 MW; SCE = 638 and 850 MW; SDG&E = 367 and 435 MW. CEC staff apparently ignored the targets specified in AB327, passed into law in September 2013, as there is little difference in the CEC self-generation PV forecasts in the May 2013 draft CED and the December 2013 final CED.

AB 327 provides these minimum net metering allocations, by no later than mid-2017, for each IOU:[7] SDG&E, 607 MW; SCE, 2,240 MW; and PG&E, 2,409 MW. After the NEM cap is reached, the IOU compensation is supposed to be modified with no further cap on self-generation PV capacity: "There shall be no limitation on the amount of generating capacity or number of new eligible customer-generators entitled to receive service pursuant to the standard contract or tariff after July 1, 2017." It is reasonable to assume that the rate of PV self-generation will continue beyond the July 1, 2017 termination date for the net-metering targets at or above the rates achieved prior to that date. A reasonable conservative assumption would be that the amount of self-generation PV installed between mid-2017 and the end of 2024 will at least replicate the amount of self-generation PV installed by mid-2017. In this case, the appropriate assumption would be that the total minimum self-generation PV capacity allocated to each IOU by mid-2017 equals the reliable peak contribution of self-generation PV in 2024.

[7] http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_0301-0350/ab_327_bill_20131007_chaptered.htm

D. <u>Demand Response</u>

CAISO and CEC are in error to place DR in two separate categories, "Fast Effective DR" and "Other DR." As identified in Table 10 of the 2013 IEPR, only a small subset of total DR is identified as "Fast Effective DR." "Fast Effective DR" refers to the expectation that fast-response DR would be able to respond in sufficiently less time than 30 minutes from the time of CAISO dispatch, to allow CAISO operators enough time to detect a non-response and dispatch an alternative resource if needed to mitigate a contingency. This assumption is incorrect. All DR can be dispatched a day-ahead consistent with the current alert timeline utilized in the CAISO "Flex Alert" program. All "Other DR" should be assumed to be proactively dispatched day-ahead to meet predicted high demand events the following day, supplemented by 30-minutes ahead "Fast Effective DR" as needed. All DR, both "Other DR" and "Fast Effective DR" should count fully for meeting local capacity requirements. IOU customers are already paying for the DR resource and it is not being dispatched to its potential on high demand days.[8] All DR resources should be counted as available and deployed to meet predicted peak demand events, not just "fast response" DR resources. DR resource capacity should be assumed to grow at the same annual rate in 2025-2034 as it does in 2014-2024.

E. <u>Combined Heat and Power</u>

Use of the Base Case scenario as the CHP forecast in almost all scenarios is an inappropriate assumption. The Base Case CHP scenario is a synonym for the Low scenario. The ICF International CHP consultant report referenced in the 2014 LTPP assumptions description shows a range of new CHP additions from approximately 2,000 MW (Base Case) to 6,000 MW

[8] CPUC, *Lessons Learned From Summer 2012 Southern California Investor Owned Programs Commission Staff Report*, May 1, 2013.

(High Case) in 2025 as shown in Figure 2. Almost no CHP growth is projected beyond 2025 by ICF International.

**Figure 2. Cumulative New CHP Market Penetration, MW**[9]

| 2011 Scenarios | Cumulative New CHP Market Penetration, MW | | | | |
|---|---|---|---|---|---|
| | 2011 | 2015 | 2020 | 2025 | 2030 |
| Base Case | 123 | 617 | 1,499 | 1,817 | 1,888 |
| Medium Case | 233 | 1,165 | 3,013 | 3,533 | 3,629 |
| High Case | 340 | 1,700 | 4,865 | 5,894 | 6,108 |
| **2009 Scenarios** | **Cumulative New CHP Market Penetration, MW** | | | | |
| | **2009** | **2014** | **2019** | **2024** | **2029** |
| Base Case | 136 | 680 | 2,096 | 2,816 | 2,998 |
| High Case (All-in) | 442 | 2,209 | 5,338 | 6,306 | 6,519 |

Source: ICF International, Inc.

This potential is almost equally split between onsite self-generation CHP and export CHP, as shown in Figure 3.

**Figure 3. Cumulative Market Penetration by Market for Large and Small Systems**[10]

| Scenario | Base | | Medium | | High | |
|---|---|---|---|---|---|---|
| Size | < 20 MW | > 20 MW | < 20 MW | > 20 MW | < 20 MW | > 20 MW |
| On-site | 1,269 | 246 | 1,519 | 263 | 2,901 | 388 |
| Avoided Air Conditioning | 130 | 30 | 155 | 32 | 316 | 45 |
| Export | 91 | 122 | 93 | 1,568 | 295 | 2,162 |
| **Total** | **1,489** | **399** | **1,766** | **1,863** | **3,513** | **2,595** |

Source: ICF International, Inc.

However, The CED 2014-2024 Final Report shows almost no growth of "non-photovoltaic self-generation" in the 2014-2024 timeframe for any of the utilities included in the document. This despite the state's clear commitment to rapid expansion of CHP as underscored in the 2013 IEPR:

[9] ICF International, Inc., *Consultant Report, Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*, June 2012, prepared for California Energy Commission, Table ES-2

[10] Ibid, Table ES-3



SB_GT&S_0334136

> p. 182: "The California Air Resources Board's AB 32 Climate Change Scoping Plan includes a target of 6.7 million metric tons of carbon dioxide equivalent (CO2e) reductions from new and existing CHP resources, and Governor Brown's Clean Energy Jobs Plan sets a goal of 6,500 MW of new CHP capacity by 2030."
>
> p. 183: "In 2011 the Energy Commission contracted with ICF Consulting to identify existing CHP capacity and quantify the long-term market potential for CHP in California and the degree to which CHP can reduce potential GHG emissions over the next 20 years. The resulting Combined Heat and Power: 2011-2030 Market Assessment identified 8,518 MW of installed CHP at the end of 2011 and indicated that cumulative market penetration for new CHP in 2030 varies between 1,888 MW and 6,108 MW"

The 2014 LTPP CHP base case assumption should be the Medium Case identified in the ICF International June 2012 report, both for onsite self-generation CHP and export CHP.

F. Energy Storage

All 1,325 MW of IOU energy storage that will be online in 2024 as a result of CPUC Decision (D.)13-10-040 should be assumed to be available to meet peak demand, not just the 700 MW of transmission-connected energy storage units.

It is incorrect to assume that the 625 MW of distribution and customer-sited energy storage is not used during periods of peak demand. Utility ratepayers will be paying for this energy storage resource and should rightfully expect the Commission to require that these energy storage systems provide maximum benefit for ratepayer dollars invested. One crucial benefit is that these storage systems is that they can be configured to provide power at times of peak demand. The CEC and CAISO assumption that there is no expectation that distribution and customer sited storage will be deployed and operated in a manner that provides capacity value at times of system stress is an erroneous assumption.

## IV. THE PROPOSED SCENARIOS OVERESTIMATE PLANT RETIREMENTS

The proposed scenarios assume an unreasonably high level of plant retirement. Specifically, they unjustifiably assume the retirement of nearly all OTC plants, and without any rational basis for doing so, assume the blanket retirement of all conventional facilities over 40 years old.

A. OTC Retirements

All scenarios presented in the Scenario Matrix adopt the "default assumption" for OTC plants – that all OTC plants "will retire according to the current state Water Resources Control Board (SWRCB) OTC compliance schedule."

At this point, it is unreasonable to assume the retirement of any OTC facility. The SWRCB does not require the retirement of OTC plants. Rather, it merely requires that OTC plants either reduce intake flow and velocity (Track 1 compliance) or reduce impacts to aquatic life comparably by other means (Track 2 compliance).[11] OTC plants are required to submit plans and achieve compliance by 2017 or 2020. Thus, OTC plants should not be assumed to retire by the OTC compliance date unless they have failed to submit a compliance plan to the SWRCB, or their compliance plan has been rejected by the SWRCB.

SONGS was responsible for approximately 90 percent of Southern California power plant OTC water withdrawals prior to its June 2013 retirement.[12] The retirement occurred nearly 10 years prior to SONGS OTC compliance date of December 2022, and has by itself reduced the

[11] http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/

[12] SONGS was a 2,254 MW baseload power plant with a seawater withdrawal rate See TetraTech. California's Coastal Power Plants: Alternative Cooling System Analysis Onofre Nuclear Generating Station, average capacity factor = 83.1%, 1,591,200 water flowrate = 2.29 billion gallons per day at 100% capacity fac flowrate = 2,290 million gallons per day × 0.831 = 1,900 million http://www.opc.ca.gov/webmaster/ftp/project_pages/OTC/engineering%20study/CA_Power_Plant_Analysis_Complete.pdf. In contrast, average 2011 capacity factor of approximately 8,000 boiler capacity Thermal Efficiency of Gas-Fired Generation in California: Update (Mar. 2013), Table 2, p. 5. (2011 coastal steam boiler cap http://www.energy.ca.gov/2013publications/CEC-200-2013-002/CEC-200-2013-002.pdf. [Using Scattergood Generating Station (TetraTech, Feb. 2008, 803 MW capacity and 344,000 gp flowrate as scale, daily OTC flowrate of 8,000 MW of coastal stea MW/803 MW) 0.041 × 344,000 gpm × (60 min/hr) × 24 hr/day] of average daily OTC water withdrawals by SoCal coastal steam boiler 202 mgd)] = 0.90 (90%).]

OTC withdrawals of Southern California OTC power plants by 90 percent.[13] NRG, owner of Encina, has submitted an OTC phase-out compliance plan to allow the plant to continue to operate beyond the 2017 compliance date.[14]

B. Other Retirements

All scenarios presented in the Scenario Matrix assume the mid-case for "other retirements," a category that includes all conventional generation that does not fall into the nuclear, OTC, or renewables/hydro categories. The distinction between a mid-case and a low or high case is that "a "Low" level of retirement assumes "Other" resource types stay online unless there is an announced retirement date. A "Mid" level assumes retirement based on resource age of 40 years or more. A "High" level assumes retirement based on resource age of 25 years or more."

It is unreasonable to assume the retirement of any facility based solely on that facility's COD. A plant's COD, taken alone, provides no information regarding its cost-effectiveness, efficiency, reliability, and environmental impact. A plant's COD further fails to provide any insight into a plant's contract status or whether it makes economic sense for the plant's operator to consider retiring the plant.

Most generation units can operate effectively well beyond 40 years from the date of initial commercial operation if properly maintained. For example, SDG&E has attacked the Cabrillo II combustion turbines as old, dirty, and inefficient to justify replacement of this

[13] Sparks, Robert (CAISO), San Diego Local Capacity Needs, presented at CPUC Wor *Authority to Enter into Purchase Power Tolling Agreements with Escondido and Quail Brush Power* (April 17, 2012), available at: http://www.cpuc.ca.gov/NR/rdonlyres/AEDFD614-B96D-4C26-8DAB-BB23046DB98C/0/April172012cpucworkshopv7.pdf.

[14] Piantka, George. (NRG Energy), Once Through Cooling Policy Implementation Plan Update fo Station, submitted to State Water Resources Control Board (Jan. 30, 20 http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/powerplants/encina/docs/nrg_en_01302012.pdf.



SB_GT&S_0334139

peaking capacity with new units. SDG&E indicated that:[15] "Since these units would be over 60 years old in 2022, it was assumed that they would be retired. SDG&E does not believe that prudent resource planning allows the assumption that very old, inefficient (heat rates of 16,000 btu/kwhr), and highly polluting (no selective catalytic reduction equipment for NOx reduction) generating sources will be available indefinitely." SDG&E subsequently clarified that they were built between 1968 and 1972 (making them 50 to 54 years old in 2022) and had all undergone major "zero hour" overhauls between 1981 and 1992.[16] Thus, while the Cabrillo II *facility* is well over 40 years old, all of its meaningful *components* are significantly newer. In practical terms this means that, from an operational perspective, the Cabrillo II combustion turbines will be the equivalent of 30 to 40 years old in 2022. All of the Cabrillo II combustion turbines have valid air permits. These are fast-start units that can continue to provide reliable low cost peaking capacity throughout the 2014-2024 timeframe.

NRG pointed-out in Track 4 testimony that existing generation can meet some of the identified local area needs through 2024 if provided with a reliable means to recover the costs of required maintenance (Theaker, p. 11).[17] This statement was made in the context of SCE's Track 4 modeling assumption that NRG's Etiwanda units 3 and 4 (640 MW) and Coolwater Units 3 and 4 (490 MW) would continue to operate indefinitely. NRG noted that, without additional capacity revenues, it is more reasonable to assume that older gas fired generating stations such as Etiwanda and Coolwater will be retired. However NRG also stated that, if reliable and sufficient multi-year forward capacity revenues are available to make such major maintenance economic

---

[15] DRA/CEJA/Sierra Club DATA REQUEST DR-01 SDG&E TRACK 4 R.12-03-014 SDG&E RESPONSE DATE RECEIVED: SEPTEMBER 4, 2013, DATE RESPONDED: SEPTEM

[16] DRA DATA REQUEST DR-02 SDG&E TRACK 4 R.12-03-014 SDG&E RESPONSE, DATE RECEIVED: SEPTEMBER 25, 2013, DATE RESPONDED: OCTOBER 7, 2013

[17] Rulemaking 12-03-014, Track 4 Testimony of Brian Theaker on Behalf of p. 11.

(e.g., as potentially available under five-year forward Resource Adequacy (RA) solicitations), the life of these resources may well be extended.

C. Older Plants Offer Cost and Performance Benefits to Ratepayers

From an economic perspective, the capacity cost of existing OTC and older peaker turbine resources is a small fraction of the capacity cost of new gas turbines. For example, the capacity cost of 300 MW Pio Pico, consisting of three 100 MW LMS100 gas turbines, is $218/kW-yr.[18] The maximum capacity cost of existing generation is $38/kW-yr.[19] Existing gas-fired resources can and should be kept online until "high in loading order" alternatives displace the need for existing gas-fired capacity. The very cost-effective option of keeping available older coastal OTC units and older peaker plants must be examined in the 2014-2015 LTPP proceeding.

OTC steam boiler units can be dispatched a day ahead to provide predictable ramping capacity as more solar resources come online statewide. There is no need for fast ramp peaking units to meet a load change that is predictable 24 hours in advance.

## V. ALL SCENARIOS MUST ACCOUNT FOR CCA

Any factually accurate scenario must account for the existence and growth of Community Choice Aggregation (CCA) in California. CCA's have now been established in Marin, the San Joaquin Valley, and Sonoma. Every indication points to CCA development being an

[18] SDG&E PPA over 25 years for 300 MW Pio Pico is $1.634 [illegible] ($1.634 billion [illegible] 0,000 kW)/25 yr = $217.87/kW

[19] The Brattle Group, *Resource Adequacy in California: Options for Improving Efficiency [illegible] Effectiveness*, October 2012, p. 1. "Price discrepancies among different types [illegible] Currently, different types of capacity are paid very different prices for providin[g] [illegible] product, with existing resources earning $38/kW-year [illegible] under the RAR while IOUs are paying $300/kW-year equivalent capacity payments for co[illegible] with new resources under LTPP. This large price discrepancy indicates t[illegible] substantially overpaying for new generation [illegible] retain existing resources. Many existing resources [illegible] are compensated at these [illegible] though they could be retained for less than the cost of building [illegible]



SB_GT&S_0334141

accelerating trend, and CCA's have been investigated planned, or proposed in many more California communities.

As CCA's grow, their share of retail energy load will increase, reducing IOU procurement needs. The need to account for this has previously been recognized by Pacific Gas and Electric, which, in its 2006 LTPP, modeled a scenario where CCA would increase to account for 10% of retail load. PG&E noted:

> Several entities have expressed desire to take advantage of the CCA to receive commodity service outside of the utility bundled service… if and when it happens, CCA will reduce PG&E's procurement needs.[20]

In order to be factually accurate, any scenario considered in this proceeding must account for the existence and accelerating growth of CCA's by reducing retail load accordingly. Given the upward trend in CCA adoption, the 10% figure used by PG&E in 2006 is appropriate for all scenarios in this proceeding.

/ / /

/ / /

/ / /

/ / /

/ / /

/ / /

/ / /

/ / /

/ / /

/ / /

---

[20] PG&E 2006 Long Term Procurement Plan Volume 1, at p. IV-32



SB_GT&S_0334142

## VI. CONCLUSION

As established above, many of the assumptions used in the Proposed Scenarios are flawed, factually inaccurate, or otherwise unreasonable. As contested material issues of fact, these issues must be subject to the Commission's full evidentiary process with discovery and the burden of proof on the utilities.

To the extent that the Commission approves the adoption of assumptions as a starting point, the above-identified errors must be remedied.

Respectfully Submitted,

Dated: January 8, 2014

______/S/____________

David A. Peffer, Esq.
Protect Our Communities Foundation
4452 Park Boulevard, Suite 209
San Diego, CA 92116
david.a.peffer@gmail.com