**Witness**: Kenneth Sahm White

**Proceeding**: A.12-01-008 and A.12-04-020

**Judge:** Richard W. Clark

**CLEAN COALITION REBUTTAL TESTIMONY REGARDING**

**PACIFIC GAS AND ELECTRIC COMPANY'S AND**

**SAN DIEGO GAS AND ELECTRIC COMPANY'S**

**APPLICATIONS TO ESTABLISH**

**GREEN TARIFF SHARED RENEWABLES PROGRAMS**

**January 10, 2014**

Prepared by Stephanie Wang

Policy Director & Attorney

Clean Coalition

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## I. Introduction

Pursuant to Assigned Commissioner and Administrative Law Judge's Scoping Ruling, dated October 25th, 2013, the Clean Coalition respectfully submits the following testimony of Kenneth Sahm White, Economics and Policy Analysis Director of the Clean Coalition, into the record.

The Clean Coalition is a California-based nonprofit organization whose mission is to accelerate the transition to local energy systems through innovative policies and programs that deliver cost-effective renewable energy, strengthen local economies, foster environmental sustainability, and enhance energy security. To achieve this mission, the Clean Coalition promotes proven best practices, including the vigorous expansion of Wholesale Distributed Generation (WDG) connected to the distribution grid and serving local load. The Clean Coalition drives policy innovation to remove major barriers to the procurement, interconnection, and financing of WDG projects and supports complementary Intelligent Grid (IG) market solutions such as demand response, energy storage, forecasting, and communications. The Clean Coalition is active in numerous proceedings before the California Energy Commission, the California Public Utilities Commission and other state and federal agencies throughout the United States, and works on the design and implementation of WDG and IG programs for local utilities and governments.

The Clean Coalition recommends that utility methodology for both procurement and maintaining nonparticipating ratepayer indifference include locational value, avoided new generation costs, reasonable proximity to enrolled participants, and to the extent that renewables integration charge is included, avoided conventional integration costs.

The Clean Coalition agrees with the California Environmental Justice Alliance that the Commission should define compliance with the requirement to reserve 100 megawatts for projects located in the most impacted and disadvantaged communities (Environmental Justice Projects) as an ongoing procurement requirement, rather than merely a requirement to reserve the last 100 MW of program capacity for these projects. We recommend that the Commission require utilities to use a procurement method suited for projects with a capacity of one megawatt or smaller, tailored to allow Environmental Justice Projects to compete only against other such projects and to reflect the interconnection needs specific to such projects.

## II. <u>Locational Value</u>

Locational value should be a component of the methodology for calculating the costs and value of participating projects for the purpose of maintaining cost indifference for nonparticipating ratepayers.[1] Utility methodologies for selecting projects should also include locational value, which will help utilities maintain the balance between their requirements to procure energy from projects located near enrolled participants and in disadvantaged communities with their need to keep program portfolio costs at levels low enough to attract high customer participation.

Distributed generation has significant locational value to ratepayers, including avoided transmission costs, avoided line losses, and avoided transmission and distribution upgrade costs. Such value especially applies to any portion of the generation that is deemed "deliverable" and does not exceed 100% of the coincident load at the substation, as all such generation avoids use of transmission system and associated access charges when delivering energy to load. This local generating capacity may also avoid, reduce, or defer the need for additional new transmission capacity. For example, the Long Island Power Authority (LIPA) has recently proposed offering a 7¢/kWh premium to 40 MW of appropriately sited solar DG facilities to encourage locational capacity sufficient to avoid $84,000,000 in new transmission costs that would otherwise be incurred, resulting in a net savings of $60,000,000.[2]

In collaboration with Pacific Gas & Electric, the Clean Coalition is currently performing a detailed analysis of the economic and environmental impacts of a high distributed generation and intelligent grid project for the underserved Bayview-Hunters Point area of San Francisco. The Hunters Point Project, named after the substation that serves both the Bayview and Hunters Point areas, will demonstrate the feasibility and practicality of providing up to 25% of total electric energy consumption though local renewable generation, effectively meeting the bulk of current RPS requires through a combination of wholesale DG and DG on the customer side of the meter. As part of the Hunters Point Project Analysis,[3] the Clean Coalition found that over the course of 20 years, each additional 10 MW of local distributed generation will avoid

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[1] In addition to the specific requirements of SB 43 with respect to bill credits and debits to achieve nonparticipant ratepayer indifference, the statute also provides, "A participating customer's rates shall be debited or credited with any other commission-approved costs or values applicable to the eligible renewable energy resources contained in a participating utility's green tariff shared renewables program's portfolio." California Public Utilities Code Chapter 7.6, Section 2831(m)

[2] Proposal Concerning Modifications to LIPA's Tariff for Electric Service, available at http://www.lipower.org/pdfs/company/tariff/proposals-FIT070113.pdf. LIPA's guidance states: "The rate will be a fixed price expressed in $/kWh to the nearest $0.0000 for 20 years applicable to all projects as determined by the bidding process defined below, plus a premium of $0.070 per kWh paid to projects connected to substations east of the Canal Substation on the South Fork of Long Island."

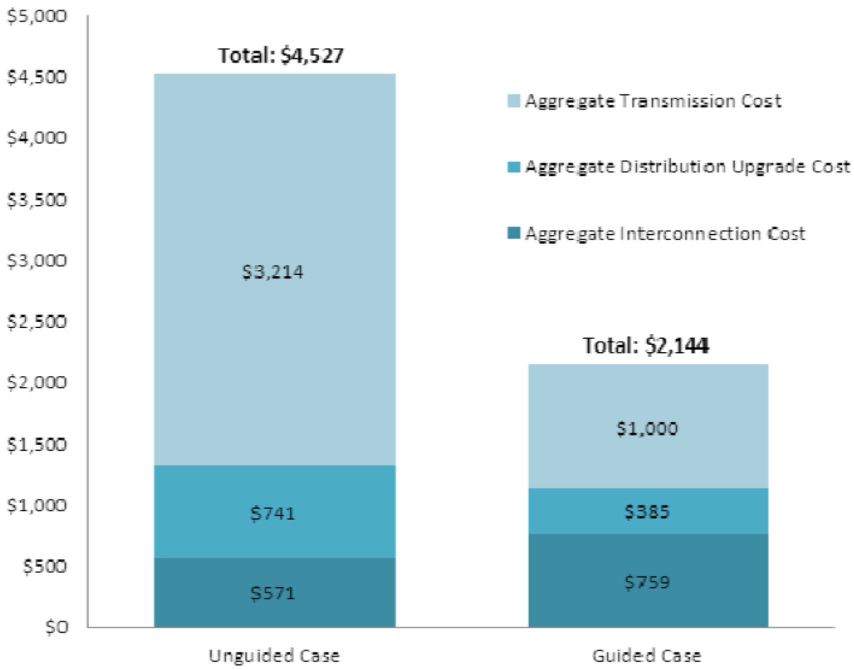
[3] The Clean Coalition's Hunters Point Project Benefits Analysis is available at http://www.clean-coalition.org/site/wp-content/uploads/2013/12/HPP-Benefits-Analysis-19_jb-20-Dec-2013.pdf.

$7,580,000 in Transmission Access Charges, $2,367,000 in line losses, and an average of $6,100,000 in new transmission capacity costs.

Similarly, a May 2012 study by Southern California Edison found that transmission upgrade costs for their share of the Governor's goal of 12,000 MW of distributed generation could be reduced by over $2 billion from the trajectory scenario. The lower costs were associated with the "guided case" where 70 percent of projects would be located in urban areas, and the higher costs were associated with the "unguided case" where 70 percent of projects would be located in rural areas.[4]

[4] The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, SCE, May 2012

*Figure 1: Integration Costs for Distributed Generation*




*Source: Southern California Edison*[5]

Before the Commission has approved a methodology for evaluating locational value for individual or categories of distributed generation in connection with the implementation of Assembly Bill 327,[6] the utilities should use the following simple rules for determining the locational value to be associated with certain eligible distributed generation projects for avoided Transmission Access Charges (TAC), avoided future TAC rate increases on all transmission dependent energy, local capacity value, avoided transmission system impact costs and avoided line losses.

[5] The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, SCE, May 2012

[6] AB 327 requires utilities to "evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation." California Public Utilities Code, Section 769, as amended by AB 327 (2013)

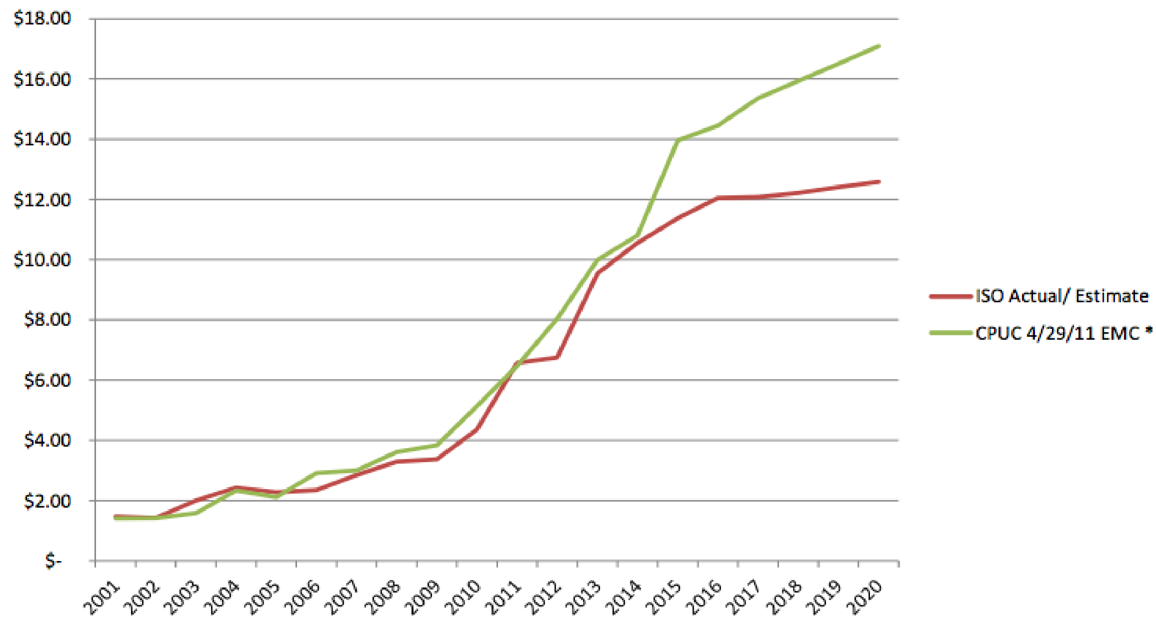
*a. Avoided Transmission Access Charges*

Transmission related costs of delivering energy from remote generation are often combined into costs that are charged by the transmission operators. In California, these costs are called Transmission Access Charges (TACs). This is a flat "postage stamp" fee for every kWh delivered to the distribution system from the transmission grid. TACs are avoided by energy that is delivered directly to the distribution system to serve loads on the same substation.

The High Voltage TAC is currently charged at $8.86/MWh and is consistent throughout the CAISO system. The Low Voltage TAC applies to the CAISO operated portion of systems within each individual utility service territory. For PG&E, the use rate charged is currently $6.057/MWh, resulting in a total 2013 charge of $14.92/MWh (1.492¢/kWh). While the threshold definition of sub-transmission voltage and ISO operation varies between utilities, comparable cost allocation occurs either through ISO charges or internal utility accounting.

TAC rates have increased at an annualized rate exceeding 15% since 2005 as new transmission dependent generation has been approved, and new transmission capacity is far more costly than maintaining existing capacity. CAISO mid value estimates for the rate of increase in TAC charges will be substantially less than the recent trend and prior CPUC estimates, as illustrated below. Utilizing CAISO's current projected average future estimate of 7% nominal escalation (5% real) over the next 20 years, the levelized current value of avoidable TAC charges applicable to a 20 year distributed generation power purchase agreement is 2.4¢/kWh.

*Figure 2: Historical and Projected High Voltage Transmission Access Charges ($/MWh)*




*Source: CAISO 2012*[7]

The Clean Coalition recommends the following test for assigning avoided TAC costs to the value of an eligible project. Any portion of the generator's output that is below minimum coincident load (MCL) at the substation level will not utilize the transmission system, and therefore should be credited for avoided TAC costs. Any portion of the generator's output that is above MCL at the substation level will be deemed to backfeed to the transmission system and will not be credited for avoided TAC costs.

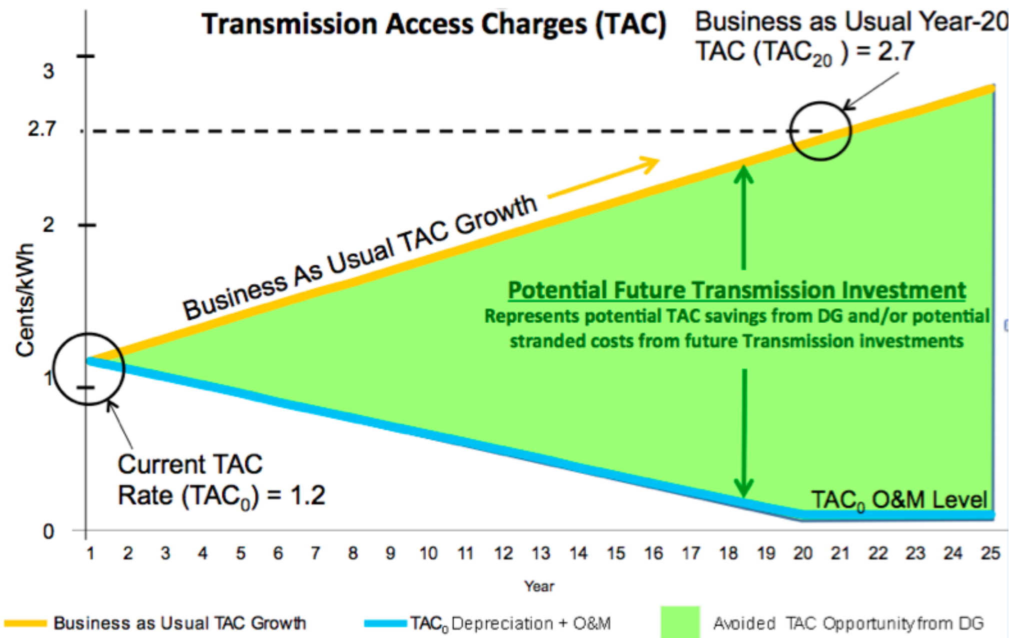
For example, if 90% of the output of a generator falls below MCL, and 10% of the output is above MCL, then the 10% of the output would be presumed to backfeed to the transmission system and would be associated with TAC charges. The project would be associated with the additional value of avoided TAC charges and avoided future TAC rate increases for 90% of its output over the course of its 20-year contract.

[7] http://www.caiso.com/Documents/BriefingLong-TermForecastTransmissionAccessCharge-Memo-Nov2012.pdf

*b. Avoided future TAC Rate increases on all transmission dependent energy*

Deploying distributed generation projects that displace transmission sourced energy during peak demand periods avoids the need to increase transmission capacity, which allows existing transmission investments to depreciate and preempts future investments in transmission – both of which reduce future TAC rates, as reflected in the diagram below.

*Figure 3: Clean Coalition estimate of TAC increases*




*Source: Clean Coalition, 2012*

The orange "Business as Usual" line represents the expected growth in TACs as more investment is made in the transmission system to accommodate additional remote generation. The blue line represents the decrease in TACs that is possible if that net additional remote generation was entirely replaced with distributed resources (the down ramp is based on a 40-year average depreciation schedule for TACs-related assets like transmission lines). Thus, the green wedge represents the potential cost savings achieved with distributed resources and continued operation of existing transmission capacity.

Reduced demand on transmission will reduce or defer the need for additional investment to expand transmission capacity, slowing the growth in TAC rates that is driven by the need to recoup new investment costs. Reducing the need for new investment in transmission will reduce charges across the board for all energy utilizing the system in a Merit Order Effect.

Transmission costs vary widely between projects, but if an average figure of $1 million is used as the marginal cost per megawatt of new transmission capacity, the savings are seen to accrue rapidly. While existing transmission will still be broadly utilized to supply energy during hours in which local intermittent DG is not available, even intermittent DG can offset its full generation capacity in new transmission capacity required for peak annual transmission loads.

With approximately $20 billion in planned future investments, 1 gigawatt of aggregated avoided new transmission capacity resulting from procurement of DG represents a 5% reduction in the basis for future TAC rates, or 0.005% per fully qualifying MW. Taking a levelized 20-year TAC rate of 2.4¢/kWh, a 0.005% reduction results in a savings of 0.0012¢/kWh. This appears a very small number, but this savings would be realized by virtually all of the 254,000 GWh[8] consumed within CAISO transmission system electricity by 2020 which is subject to TAC charges. These Merit Order cost savings in TAC charges at 0.0012¢/kWh would equal $30,540 in annual CAISO wide ratepayer savings for each MW reduction in required transmission capacity, assuming a 1:1 peak annual capacity reduction. Applied to a DG PV output of 1,500 MWh/MW/yr, this results in an added ratepayer value of 2¢/kWh. While the applicable transmission capacity reduction will depend on CAISO projected relationship between the generation and peak demand profiles, the value of avoided future transmission capacity cost is too large to ignore.

*c. Local Capacity Value*

We recommend that the utility proposals with respect to Resource Adequacy value explicitly include the local capacity value of projects located within a transmission constrained local resource adequacy area. For example, in calculating the avoided cost value of local generation when developing the standard offer price for the Palo Alto CLEAN Program PPA, the City of Palo Alto Utilities estimated the value of avoided local capacity purchase costs at 0.7¢/kWh.

[8] California Energy Demand 2012-2022 Final Forecast Volume 1: Statewide Electricity Demand and Methods, Mid Energy Demand

*d. Avoided transmission system impact costs*

The Renewable Auction Mechanism adjusts the value of projects based on whether transmission upgrades to be reimbursed by ratepayers will be required.[9] The Clean Coalition recommends using the same test for assigning avoided transmission upgrade costs to certain projects as part of the project ratepayer impact comparison methodology.

e. *Avoided line losses*

Where line losses are avoided, these should be recognized in determining the value of a resource. Average transmission losses are tracked by CAISO for each regional transmission zone and average 3% statewide (with the exception of the LA Basin).[10] Losses also occur on the distribution system, averaging 3%, and proportional to the distance between energy supply and load. Where generation is located in closer proximity to load, these losses may also be reduced. System wide losses are substantially higher due to congestion factors during peak demand periods, averaging approximately 10%, and time of delivery differentials should be recognized.[11]

## III. Avoided Conventional Integration Costs

PG&E proposes that program costs will include any renewables integration charge defined by the Long Term Procurement Plan proceeding. If such a charge is included, program participants should receive a credit for the value of avoided integration costs for avoided new conventional generation, including avoided reserves and frequency response.

As illustrated by the chart below, fossil fueled power plants often shut down unexpectedly, and also require shut downs for maintenance, resulting in the need to maintain additional resource adequacy capacity and schedule an average of 4000 MW of additional reserves. Ratepayers foot

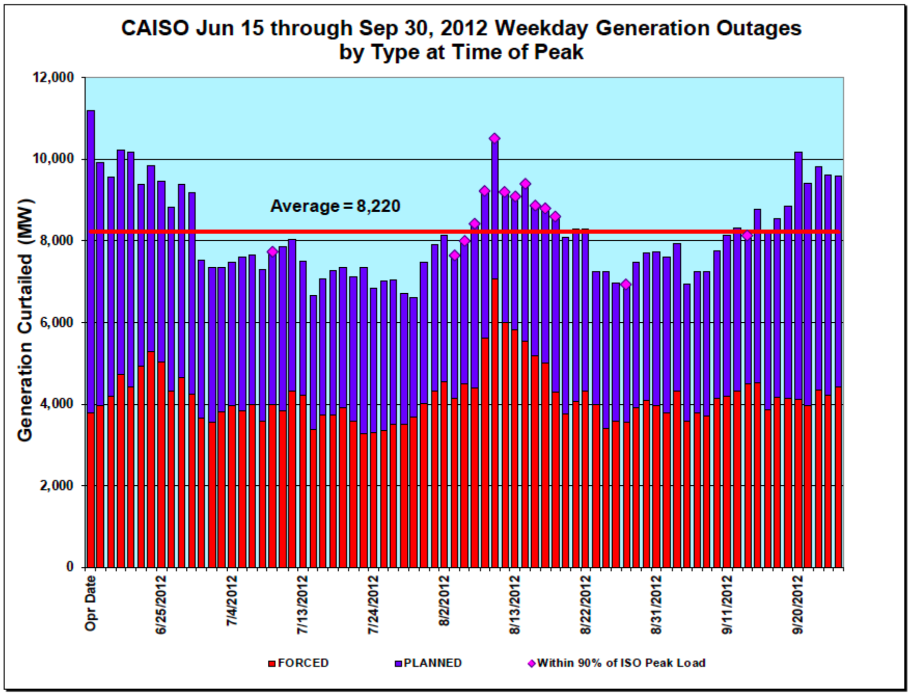
[9] Commission D.10-12-048
[10] CAISO, *2012 Local Capacity Technical Analysis Final Report and Study Results*, April 29, 2011
[11] Table ES-1: Comparison of Loss Factors, *A Review of Transmission Losses in Planning Studies*, August 2011, California Energy Commission, CEC-200-2011-009

the bill for resource adequacy capacity, reserves and frequency response necessary to accommodate these conventional reliability factors.

In contrast, the actual availability of the solar resource in SCE territory during the top 100 demand hours is approximately 96 percent. The high reliability of solar PV, combined the grid reliability benefits of distributing output over many smaller sources instead of a single unit, make rooftop PV an excellent substitute for conventional natural gas-fired peaking units.[12]

[12] Prepared direct testimony of Bill Powers on behalf of the California Environmental Justice Alliance, June 25th, 2012, R.12-03-014

*Figure 4: CAISO Planned and Unplanned Outages of Fossil and Nuclear Generation, Summer 2012*




Source: *CAISO Summer Loads and Resources Assessment (2013)*

To the degree that any resource reduces these costs for ratepayers through improved reliability, these savings should be considered in relation to integration charges.

## IV. <u>Avoided New Generation Costs</u>

To the extent that the Long Term Procurement Plan proceeding finds that new generation is needed to meet system needs or AB 32 obligations, and to the extent that the proceeding finds that SB 43 generation can be used to meet these needs, program participants should receive a credit for the value to nonparticipating ratepayers of offsetting the need to procure new generation. While participants should be responsible for the additional costs of procuring energy from SB 43 projects when (a) the utility otherwise has no need to procure additional generation or (b) the utility would otherwise procure conventional generation, participants should receive a credit for avoided additional costs of procuring new generation when such procurement is used to satisfy system needs and state goals. This value should be calculated as the avoided rate impact over the length of the contract.

For example, if the Commission found that a utility must procure an additional 400 MW of generation of any type to meet local area needs within the program period, and it found that 200 MW of SB 43 generation could be used to meet these needs, then program participants subscribing to the applicable portfolio should receive a credit for the avoided rate impact of new generation over the length of the contract. Failure to credit the value of SB 43 subscriber procurement to non-participating ratepayers would otherwise unfairly transfer the costs of meeting the utility's increasing energy demands to participating ratepayers in violation of the principle of ratepayer indifference.

As solar costs continue to drop, it is likely SB 43 projects will generally be found to be less expensive than new natural gas plants, and therefore the main generation cost of the program will relate to the costs of procuring new generation (as opposed to relying on existing generators) when new capacity has not been found necessary by the Commission.

As part of the Hunters Point Project Analysis, the Clean Coalition found that the 20-year levelized cost of energy (LCOE) delivered to load from 500 kW commercial scale distributed solar photovoltaic systems (PV) is at parity with the LCOE of new combined cycle natural gas (CCNG) facilities when transmission access charges are included, based upon the adopted California Energy Commission Cost of Generation model for systems commencing delivery to the area in 2015.[13]

[13] The Clean Coalition's Hunters Point Project Benefits Analysis is available at http://www.clean-coalition.org/site/wp-content/uploads/2013/12/HPP-Benefits-Analysis-19_jb-20-Dec-2013.pdf.

*Table 1: Levelized Cost of Energy Comparison of Generators Commencing Delivery in 2015*

| LCOE Cost Comparison[14] | | |
|---|---|---|
| **Levelized Cost of Energy** | **CCNG** | **Photovoltaic** |
| | **$155/MWh** (15.5¢/kWh) | **$154/MWh** (15.4¢/kWh) |

| **Summary of Levelized Cost Components** | | | | |
|---|---|---|---|---|
| **Combined Cycle - 2 CTs With Duct Firing 550 MW** | | | **Photovoltaic** | |
| **Merchant Fossil** | **Mid-Cost Case** | | **Mid-Cost Case** | |
| Start Year = 2015 (2015 Dollars) | $/kW-Yr | $/MWh | $/kW-Yr | $/MWh |
| Capital & Financing - Construction | $121.98 | $26.38 | $274.77 | $205.78 |
| Insurance | $8.20 | $1.77 | $13.17 | $9.86 |
| Ad Valorem Costs | $11.94 | $2.58 | $3.89 | $2.92 |
| Fixed O&M | $45.31 | $9.80 | $37.01 | $27.71 |
| Corporate Taxes (w/Credits) | $40.25 | $8.70 | ($123.16) | ($92.24) |
| **Fixed Costs** | **$227.69** | **$49.23** | **$205.69** | **$154.05** |
| Fuel & GHG Emissions Costs | $343.09 | $74.19 | $0.00 | $0.00 |
| Variable O&M | $3.93 | $0.85 | $0.00 | $0.00 |
| **Variable Costs** | **$347.02** | **$75.04** | **$0.00** | **$0.00** |
| **Total Levelized Costs w/o Transmission** | **$574.71** | **$124.27** | **$205.69** | **$154.05** |

[14] CEC 2013 Cost of Generation Model v.3.91 Reference case (mid price) inputs:

Merchant Plant, CCNG 550 MW (w/duct firing), PG&E gas price forecast, BAAQMD and GHG emissions price included, Bay Area average transmission charges and losses to Substation.

| | | | | |
|---|---|---|---|---|
| Transmission Service Costs | $142.00 | $30.70 | $0.00 | $0.00 |
| **Total Levelized Costs with Transmission** | **$716.71** | **$154.97** | **$205.69** | **$154.05** |

Source: Clean Coalition, 2013

## V. Reasonable Proximity to Enrolled Participants

The statute provides, "To the extent possible, a participating utility shall seek to procure eligible renewable energy resources that are located in reasonable proximity to enrolled participants."[15] The Clean Coalition recommends that the Commission adopt the following framework for compliance with this requirement to ensure that developers will be incentivized to develop projects with meaningful physical and electrical proximity to subscribers.

A utility shall be required to procure at least 60% of energy from projects located in reasonable proximity to enrolled participants. Projects will be found to be in reasonable proximity to such enrolled participants if at least 40% of the project output will serve unmet enrolled participant demand at the related transmission node.

## VI. Most Impacted and Disadvantaged Communities

The Clean Coalition agrees with the California Environmental Justice Alliance that the Commission should define compliance with the requirement to reserve 100 megawatts for projects located in the most impacted and disadvantaged communities (Environmental Justice Projects) as an ongoing procurement requirement, rather than merely a requirement to reserve the last 100 MW of program capacity for these projects. SB 43 provides that utilities have an obligation to "actively market the utility's green tariff shared renewables program to low-income and minority communities and customers."[16] Further, the statute provides, "To the extent possible, a participating utility shall seek to procure eligible renewable energy resources

[15] California Public Utilities Code Chapter 7.6, Section 2883(e)
[16] California Public Utilities Code Chapter 7.6, Section 2883(j)

that are located in reasonable proximity to enrolled participants."[17] The foregoing provisions show legislative intent for the utilities to be responsible for ensuring that low-income and minority communities will participate in the program throughout the program period, and that the program will procure Environmental Justice Projects in reasonable proximity to such participants throughout the program period. Failure of a utility to meet its obligations to successfully market the program to these communities should not excuse its obligation to procure projects in these communities.

We recommend that the Commission require utilities to use a procurement method such as ReMAT that is suited for projects with a capacity of one megawatt or smaller, tailored to allow Environmental Justice Projects to compete only against other such projects, to recognize the locational value of certain Environmental Justice Projects, and to reflect the interconnection needs specific to such projects.

For example, a utility may be authorized to use the SB 32 ReMAT method to procure Environmental Justice Projects with the following adjustments to the process. First, the utility would offer a separate bi-monthly allocation for Environmental Justice Projects, calculated as one sixth of the total amount that the utility plans to procure during such year, divided by six to reflect the fact that annual procurement through the ReMAT would be split among six bi-monthly allocations. Next, eligible Environmental Justice Projects would be assigned queue positions for such separate allocation. Then the utility would offer a contract price to Environmental Justice Projects at the top of such queue, and the future contract price would be adjusted based on the response of such Environmental Justice Projects. The contract price for each project would be adjusted based on existing ReMAT payment allocation factors (time-of-delivery and deliverability) and any additional payment allocation factors specific to this program (including locational value and reasonable proximity to enrolled participants).

Due to the special need for GTSR subscribers to create demand before certain projects can meet the "reasonable proximity" criteria, qualifying for "reasonable proximity" should allow an applicant to avoid applying for interconnection before entering the queue. Instead, such applicants should be required to complete Fast Track, System Impact Study, or Phase 1 Study within 6 months of accepting a PPA offer. Otherwise, they will be required to apply for interconnection before they know whether their projects will be eligible to meet the "reasonable proximity" requirement. Removing this barrier will increase applicant participation and result in lower prices.

[17] California Public Utilities Code Chapter 7.6, Section 2883(e)

## SUMMARY OF QUALIFICATIONS FOR KENNETH SAHM WHITE

Q1: What is your name and business address?

A1: My name is Kenneth Sahm White and my business address is as follows:

16 **Palm Ct**. **Menlo Park**, **CA** 94025.

Q2: What is your job title?

A2: Director, Economics and Policy Analysis, Clean Coalition.

Q3: Please describe your educational background and professional experience.

A3: I am currently the Economics and Policy Analysis Director for the Clean Coalition and have held this position for the past 3 years. Prior to joining the Clean Coalition, I spent 15 years working on economic and environmental policy as a Senior Research Consultant to the Center for Ecoliteracy, Technical and Policy Analyst in the development of the Ecological Footprint, and Associate Director of Progressive Secretary, a leading web source of legislative constituent engagement, and Policy Associate at the Ann Arbor Ecology Center. In addition to my graduate work in the social studies of science and technology at the Massachusetts Institute of Technology, I will also receive an MS Environmental Studies from San Jose State University upon completion of a thesis on economic optimization of local greenhouse gas reduction strategies.

Q4: Have you been involved in other related proceedings before this Commission?

A4: Yes, I have submitted comments on several related major proceedings before this Commission. These include SB 32, SB 1122, RAM, LTPP and Rule 21 proceedings.

Q5: Are you willing to be cross-examined in evidentiary hearings?

A5: Yes.

Q6: Is this the end of your testimony?

A6: Yes.