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.	R. 13-12-010 (Filed December 19th, 2013)

CLEAN COALITION'S COMMENTS IN RESPONSE TO QUESTIONS ON THE DECEMBER 12, 2013 LTPP SCENARIOS WORKSHOP

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January 8th, 2014

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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 provide energy resilience. To achieve this mission, the Clean Coalition promotes proven best practices, including the expansion of Wholesale Distributed Generation (WDG) connected to the distribution grid and serving local load. The Clean Coalition drives policy innovation to remove barriers to the procurement and interconnection of WDG projects, integrated with Intelligent Grid (IG) solutions such as demand response, energy storage, and advanced inverters. The Clean Coalition is active in numerous proceedings before the California Public Utilities Commission, the California Energy Commission, and other state and federal agencies throughout the United States. The Clean Coalition also designs and implements WDG and IG programs for utilities and state and local governments.

The Clean Coalition offers the following comments on the LTPP workshop questions addressing the proposed planning scenarios.

Summary:

- The proposed scenarios do not reflect achievable levels of preferred resources – Energy Efficiency (EE), large scale and distributed renewable resources, Demand Response (DR), and local Energy Storage (ES) – necessary to meet greenhouse gas targets set by AB 32 and executive orders.
- EE and DR are at the top of the Loading Order, and accordingly, the scenarios should reflect appropriate levels of such demand side resources. With respect to EE, we recommend that the Commission heed the recommendations of the NRDC. With respect to DR, we recommend that the Commission develop assumptions based on the potential to use DR as California reevaluates and

redesigns its DR programs, rather than using past performance to set DR assumptions for the scenarios. The baseline scenarios should be adjusted to reflect at least the same pace of renewables adoption as the 2010-2020 period – 40% by 2024 and 50% by 2030 respectively. The High Preferred Resources scenarios should include more ambitious targets.

- The scenarios fail to reflect any significant DG additions after 2017 in the "High DG" scenario despite the conflict with state goals, rapidly declining costs, overwhelming demonstrated commercial interest in interconnection and procurement, net zero energy standards, and opportunities to guide wholesale distributed generation (WDG) toward locations where it constitutes an alternative to costly transmission investment.
- Nor do the proposed scenarios reflect the rapidly decreasing costs of renewables and intelligent grid solutions. Utilizing mid-value assumptions and the CEC Cost of Generation calculator, the Clean Coalition has found that a 500 kW distributed solar project in San Francisco is at cost parity with new combined cycle natural gas facilities beginning operation in 2015.

Q. Is the current range of scenarios sufficient to cover current policy issues facing the CPUC?

No. The proposed scenarios do not reflect achievable levels of preferred resources – Energy Efficiency (EE), large scale and distributed renewable resources, Demand Response (DR), and local Energy Storage (ES) – necessary to meet greenhouse gas targets set by AB 32 and executive orders. Nor do the proposed scenarios reflect the rapidly decreasing costs of renewables and intelligent grid solutions.

While the Commission, CEC and California Independent System Operator (CAISO) demonstrate effective coordination in the planning assumptions related to renewable resource portfolios for meeting California's 33% Renewable Portfolio Standard (RPS) mandate, the proposed LTPP scenarios fail to similarly demonstrate coordination with CARB's 2013 AB 32 Draft Implementation Update, or, in fact, any planning option trajectories aligned with longer term State goals related to renewable energy and GHG emissions reduction, including net zero energy standards in new construction within the LTPP planning periods. In addition to the statutory 2020 emissions target, Executive Order S-3-05 and Executive Order B-16-2012 establish long-term climate goals for California to reduce GHG emissions to 80 percent below 1990 levels by 2050.

If California is to meet its target of 80% below 1990 levels by 2050, we need to continue to increase renewable generation at an average rate of 1.5% per year over the next 40 years. While procurement is already planned, approved and contracted at this rate through 2020, none of the scenarios envision even simply maintaining the current rate of progress through the 2024 planning period or beyond.

As noted in CARB's update:

Clearly, a significant gap remains between the ongoing progress and the 2050 GHG target. Progressing toward California's 2050 climate targets will require significant acceleration of GHG reduction rates. Emissions from 2020 to 2050 will have to decline several times faster than the rate needed to reach the 2020 emissions limit. (p. 76)

The Air Resources Board goes on to conclude:

California will be unable to achieve the needed GHG emissions by simply continuing current trends. There is no single party or agency that has complete responsibility for the energy sector. The State needs an overarching energy plan to ensure that long-term climate goals can be achieved.

At the electricity distribution level, the plan should recommend strategies and actions to expedite the development and implementation of small-scale energy storage systems, and micro-grid and "smart-grid" technology deployment to maximize renewable and distributed resource integration. As utilities modernize their aging infrastructure, they need to integrate cutting-edge infrastructure, especially on distribution systems, to enable two-way power flow and increased communication and controls. These technologies will help alleviate the challenges posed when adding more distributed energy onto the grid. At the same time, actions to strengthen and expedite California's policies for achieving ZNE homes and businesses in new and existing construction, and for maximizing energy conservation and demand response participation within the consumer electricity market, should be a priority. (p. 84)

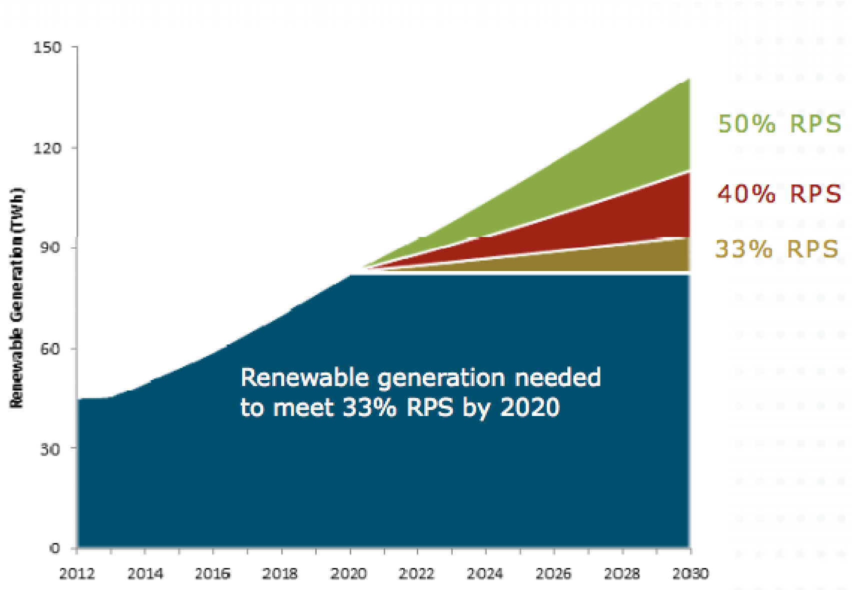
EE and DR are at the top of the Loading Order, and accordingly, the scenarios should reflect appropriate levels of such demand side resources. With respect to EE, we recommend that the Commission heed the recommendations of the NRDC. With respect to DR, we recommend that the Commission develop assumptions based on the potential to use DR as California reevaluates and redesigns its DR programs, rather than using past performance to set DR assumptions for the scenarios. We also urge the Commission to set reasonable but ambitious targets for DR participation to facilitate market transformation, similar to the Commission's recent ES targets, as we have recommended in our comments in the Commission's DR proceeding.

DR programs and tariffs can not only be called upon for emergency reductions of peak demand but can incentivize customers to shift power consumption towards low net demand periods where over-generation may otherwise occur. This is especially applicable with the planned introduction of 1.25 million EVs in California by 2025, and supports use of DG where EVs charging is near or co-located with distributed PV generation at home and work.

<u>The assumptions for both large scale and distributed renewable resources are too low.</u>

The 40% Renewable Portfolio Standard (RPS) scenario proposed for 2030 would be best considered to represent a <u>low</u> renewables scenario, since this projects only half the rate of renewable additions procured for 2010-2020 - in conflict with state goals and the increasing cost-competitiveness of renewables. The value of a scenario projecting such low growth in renewables is unclear unless seen as the outcome of greatly reduced demand, which is an unlikely outcome even with aggressive EE considering the need to increasingly electrify transportation.

Figure 1: California Renewable Generation Trends Under Alternate 2030 RPS Scenarios



Source: E3 calculation[1] of statewide renewable generation needs under various RPS scenarios

The baseline scenarios should be adjusted to reflect at least the same pace of renewables adoption as the 2010-2020 period – 40% by 2024 and 50% by 2030 respectively. The High Preferred Resources scenarios should include more ambitious targets. While concerns have been raised regarding the need to address the impact of increasing levels of intermittent generation on ISO scheduling and flexible capacity, the Clean Coalition has illustrated the capacity of conservative application of multiple adaptation measures to offer mitigation without procurement of additional fossil fuel resources in prior comments.[2]

We also recommend that the Commission consider setting EV capacity and DR or grid services participation targets for EVs in relation to both 2020 and longer term renewable energy scenarios, such as 50% by 2030, or high DG scenarios, that have been modeled in the LTPP already. EV capabilities should be fully recognized along with other load

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[1] https://www.ethree.com/documents/Olson_NWPCC_2013-09-04_AM-RPS.pdf

[2] Clean Coalition AFV OIR comments, 13 Dec 2013, R. 13-11-007; see also the Clean Coalition's recommendations on Flattening the Duck, available at http://www.clean-coalition.org/resources/integrating-high-penetrations-of-renewables/.

shifting and responsive demand opportunities in meeting Resource Adequacy standards including those for Flexible Capacity. As shown below, simply coordinating load and supply can effectively address the challenges of integrating inflexible resources.

While such adjustments to the rate of renewable adoption would address the most basic planning needs, substantial shortcomings would remain. These include such factors as the failure to reflect any significant DG additions after 2017 in the "High DG" scenario despite the conflict with state goals, rapidly declining costs, overwhelming demonstrated commercial interest in interconnection and procurement, net zero energy standards, and opportunities to guide wholesale distributed generation (WDG) toward locations where it constitutes an alternative to costly transmission investment, as discussed further below.

Regardless of policy goals or planning, the rapidly declining costs of renewables are already driving the shift towards large-scale and distributed renewable generation. The costs of mature technologies associated with fossil fuels and large-scale electric infrastructure are all expected to gradually increase over time, along with the costs of emission compliance, while the costs of developing technologies used in renewable generation will continue to decline. Retail markets are already reflect this as we see customers shift both to solar panels on homes and businesses and to Community Choice Aggregation (CCA) and some municipal utilities with higher renewable portfolios than required by State policy. While such cases reflect current rate design and may not accurately be generalized to the state as a whole, the Commission must recognize that the levelized cost of energy from new renewable generation is already reaching or exceeding parity with new conventional facilities, and this trend will continue. For Long Term Planning and Procurement scenarios to not reflect these trends is simply unrealistic. Planning should reflect the most likely future scenarios, and include consideration of both reasonable deviation from this trajectory and the impact of relevant policy alternatives.

LTPP scenarios should not only all reflect the impact of anticipated demand, projected capacities, contracted procurement and cost forecasts adopted by State agencies, but at least some should also reflect the impact of efforts undertaken by the CPUC in active proceedings that are liable to significantly impact the policy options and procurement outcomes available to the State.

The application of coordinated distributed energy resources and advanced grid functionality is called for by the CEC in the Integrated Energy Policy Report, is deemed essential in the CARB Scoping Plan discussions, and is central to the efforts of the CPUC across a range of proceedings. The proposed scenarios fall short on this measure. For example, as detailed below, the Clean Coalition has found that distributed renewable generation has already reached cost parity with new fossil fueled generation in California.

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.

The Hunters Point Project Technical Study is modeling the distribution power grid's ability to dynamically support large amounts of clean local energy while maintaining or improving power quality, security, and reliability. This includes the application of the advanced inverter functionality standards[3] and use of local energy storage[4] and

[3] Currently under development in R. 11-09-011 for adoption in 2014
[4] See D.13-10-040 and adopted storage procurement and use case scenarios

automated local demand response (such as associated with grid responsive EV charging[5]) as needed to avoid potential voltage violations.

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.[6]

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

LCOE Cost Comparison[7]		
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**

[5] Scoped for development in R. 13-11-007

[6] 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] 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.

Total Levelized Costs w/o Transmission	**$574.71**	**$124.27**	**$205.69**	**$154.05**
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

The levelized cost of generation over the life of new facilities alone argues for at least some scenarios to incorporate more rapid adoption of renewables and the escalating cost of delivering power through an expanded transmission system supports consideration of higher levels of DG, both wholesale and customer sided. Further systemic savings realized through conservation voltage reduction, reduced customer outages, and avoided transmission capacity addition costs that can be derived from improved distribution grid operation offers additional ratepayer value that should be recognized in scenario alternatives.

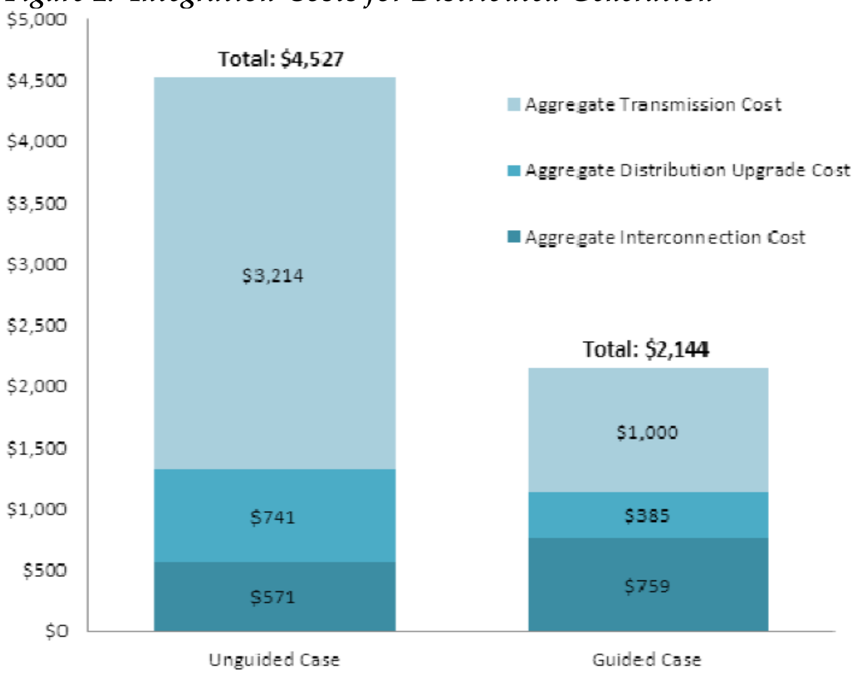
Distributed generation has significant locational value to ratepayers, including avoided transmission costs, avoided line losses, and avoided transmission and distribution upgrade costs. For example, the Long Island Power Authority (LIPA) has recently proposed offering a 7¢/kWh premium to 40 MW of appropriately 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. 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."[8] As part of the Hunters Point Project Analysis,[9] the Clean Coalition found that over the course of 20 years, each additional 10 MW of local distributed generation will avoid $6,100,000 in new transmission capacity costs, $7,580,000 in Transmission Access Charges, and $2,367,000 in line losses.

[8] Proposal Concerning Modifications to LIPA's Tariff for Electric Service, available at http://www.lipower.org/pdfs/company/tariff/proposals-FIT070113.pdf

[9] The Clean Coalition's Hunters Point Project Benefits Analysis

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.[10].

Figure 2: Integration Costs for Distributed Generation



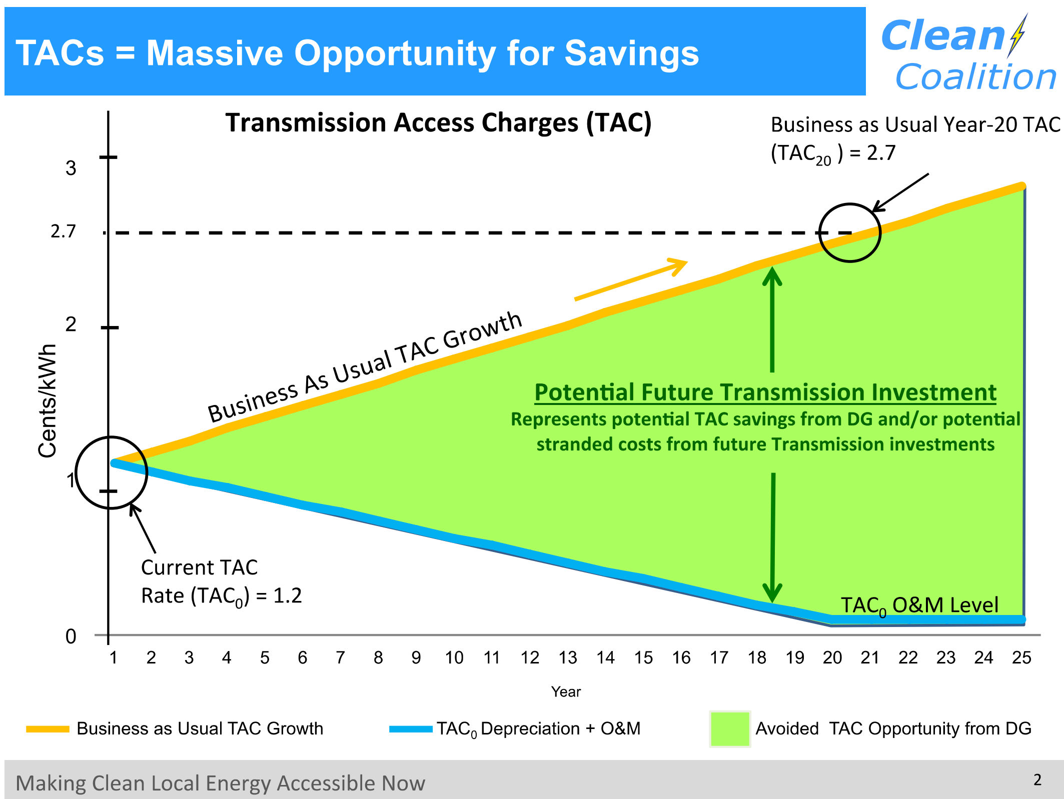
Source: Southern California Edison, 2012

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 when energy is delivered directly to the distribution system to serve loads on the same substation.

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

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. Deploying a distributed generation project avoids needs to increase transmission capacity, which allows existing transmission investments to depreciate and preempts future investments in transmission – both of which reduce TACs, as reflected in the below diagram.

Figure 2: Clean Coalition estimate of TACs



The orange "Business as Usual" line represents the expected growth in TACs as more investment is made in the transmission system to accommodate the 2012 LTPP Trajectory Scenario generation. The blue line represents the decrease in TACs that is possible if new added transmission capacity were avoided through increased reliance on distributed resources and energy efficiency (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 avoidable investment that can support a balance of reduced ratepayer costs and improved progress toward sustainable and resilient locally sourced low emission energy supply.

Respectfully submitted,

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Dated: January 8th, 2014