**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 (VSK) (Filed May 6, 2010)

COMMENTS OF SIERRA CLUB CALIFORNIA ON INITIAL RULING ON PROCUREMENT PLANNING STANDARDS.

PAUL R. CORT
WILLIAM B. ROSTOV
Earthjustice
426 17th Street, 5th Floor
Oakland, CA 94612
Tel: (510) 550-6725
Fax: (510) 550-6749
pcort@earthjustice.org
wrostov@earthjustice.org

Attorneys for
SIERRA CLUB CALIFORNIA

Dated: June 21, 2010

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 10-05-006 (VSK) (Filed May 6, 2010)

COMMENTS OF SIERRA CLUB CALIFORNIA ON INITIAL RULING ON PROCUREMENT PLANNING STANDARDS.

Sierra Club California respectfully submits the following comments on the Administrative Law Judge's Initial Ruling on Procurement Planning Standards and its attachments, issued May 28, 2010.

This proceeding provides an important opportunity to insure that California and its Investor-Owned Utilities (IOUs) are set on a path to meet the state's clean energy and climate protection targets. A variety of targets and mandates and policies have been established and promoted by the Governor, the Legislature, this Commission, the Air Resources Board and other agencies. The new structure of the Long Term Procurement Proceeding, especially by folding in the planning for renewables, now bears increasing responsibility for meeting the targets of these state programs. The fact that legislative and other decision processes are happening in parallel with this proceeding also makes it important that the content and scope of the proceeding are capable of incorporating these developments as they occur, so that the resulting decisions in this proceeding remain compliant with state law.

One of the risks to achieving the RPS targets, stated by CPUC staff and representatives from utilities, has been the alleged lack of available transmission. Construction of new transmission is a high cost venture that builds years of delay into the planning process, as well as potential for litigation and rejection of lines by the public, regulatory bodies and the courts. A strategy that relies primarily on construction of new transmission places the renewables program at risk of not meeting targets.

The "risk strategy" of reliance on transmission can be reduced or avoided by including substantial incorporation of distributed generation, and by meeting other demand side resource targets established by the state. Meeting these demand side targets can free up existing transmission capacity, and thus allow renewable projects to use existing lines.

This proceeding also bears special responsibility to substantially reduce the amount of greenhouse gases from the energy sector. This proceeding must ensure that the system resource plans and procurement policies of the PUC align with state law on the reduction of greenhouse gases. The California Global Warming Solutions Act of 2006, AB32, requires statewide reductions of greenhouses gases to 1990 levels or below by 2020. The Air Resources Board ("ARB") has adopted a Scoping Plan to implement this requirement. Relying on energy policies that are part of this proceeding, ARB's Scoping Plan assigns the energy sector at least forty percent of the state's total greenhouse gas reductions exclusive of the cap and trade system.[1] The Scoping Plan relies on both the achievement of the 33% Renewables Portfolio Standards and the incorporation of aggressive energy efficiency and combined heat and power, among other things.[2] The state's energy goals--for uncommitted energy efficiency, renewable energy (which should include a strong commitment to deploying distributed generation), combined heat and power, and demand side management programs--must be front and center in the analysis and included in the base case.

[1] California Energy Commission, "Committee Guidance on Fulfilling California Environmental Quality Act Responsibilities for Greenhouse Gas Impacts in Power Plant Siting Applications," (March, 2009) CEC-700-2009-004, at 23.
[2] California Air Resources Board, "Climate Change Scoping Plan: A Framework for Change," (Dec., 2008).

In order to have a transparent proceeding, it will be necessary to unpack all of the numbers in a manner that allows for direct and transparent analysis by parties in this proceeding. For example, renewable resource availability and cost are to be based on RETI and other sources, but it is unclear what other sources will be providing input into these numbers. (Attachment 2 at 9.) In a December 17, 2009, letter to Karen Douglas, Chair of the California Energy Commission, Sierra Club California addressed the variety of information sources and recommended specific inputs for net short calculations for renewables. Sierra Club California incorporates that letter by reference and attaches it as Exhibit A. In March, 2010, Sierra Club California also addressed similar concerns to the Air Resources Board. Those comments are attached and incorporated as Exhibit B. Line items in the net short calculator are structured to reveal specific mandates of the ARB Scoping Plan, such as incremental uncommitted efficiency and combined heat and power. It is important that these line items also be revealed in the utility plans in a transparent manner that allows direct comparison to the ARB targets.

It will also be important that the basis for each component of the Net Present Value Revenue Requirement ("NPVRR"), which includes generation, transmission, distribution and the other utility costs, be clearly articulated; a specific number input without explanation would be insufficient. This explanation would include breaking out the assumptions for each year to derive the NPVRR, showing the discount rate used, presenting value for each year of the plan related to the updated demand in that year, and especially breaking down the cost by specific program elements in a manner that is quite clean, consistent with program targets, using values that are compatible with other data that is presented. We note that this has not always been the case in previous utility plans.

The inputs for the system resource plans and the bundled plans must incorporate targets that meet state requirements and policy goals, and clearly compare these to the annual amount of each resource in the plan. A general problem with the resource table is that this table does not demonstrate a commitment to meet these goals. The base case for this proceeding should include the ARB Scoping Plan targets.[3] The system and bundled plans should be evaluated from the perspective of whether the necessary energy goals are met, as well as the greenhouse gas reduction goals. Moreover, the system resource plans need to require more than just a qualitative assessment of long-term GHG implications. (Attachment 2 at 5.) The plans should include a quantitative assessment of how the resource plans will contribute to meeting the state's AB32 requirements by source category and by the aggregate plan. Each scenario should demonstrate the amount of carbon reduction achieved by the system resource plan. This quantitative assessment should be used to analyze whether the resource choices place California on a trajectory to meet the greenhouse gas reduction goals for 2020 as well as the long-term goal of 80 percent below 1990 levels by 2050. For example, a commitment to long-term GHG emitting assets such as natural gas power plants will likely extend well beyond 2020, and will have ramifications for the long-term goals.

We would also like to see emissions broken out by type, especially CO2 and High Global Warming Potential gases such as Methane. Methane is generally accounted for by a 21 times Global Warming Potential, but recent science shows that this is an underestimate. For this reason it is particularly important that these gases be accounted for separately.

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[3] Both attachments detail relevant inputs applicable to this proceeding. For example, the December 17, 2009 letter recommends an alternate "AB 32 Net Short" that conforms to ARB's Scoping Plan. However, neither letter specifically addresses the base case for this proceeding. Sierra Club California recommends that the base case should include inputs that conform with ARB's Scoping Plan.

The bundled plans base case is expected to be "consistent with current Commission policy and any preferred resource portfolio or procurement strategy adopted in the system track." (Attachment 3 at 4.) However, the timing of the two tracks does not appear to line up. The system resource plans and bundled plans will both require significant work on parallel tracks in 2011. For example, attachment 2 at page 8 acknowledges that there may be more information about the performance of demand side management programs in first quarter of 2011 and allows for the incorporation of this information into system resource plans. This same type of up-to-date information should be made available for each category of the system resource plan, ensuring that these plans use the most up-to-date information for all categories. Furthermore, a mechanism should be developed to incorporate the system resource plans and any updated information into the bundled plans.

While it makes sense to use the most recent IEPR base case 1-in-2 load forecast for the system resource adequacy, it is inappropriate to use a 1-in-10 load forecast for the local resource adequacy need assessments. (Attachment 2 at 6.) Using this metric will result in over estimation of need and a cumulative over procurement of resources. This local 1-in-10 needs assessment is in addition to the Planning Reserve Margin already built into the system and that is specifically in place to account for further margin of risk. Having both a 1-in-10 year need and the 15 to 17 percent reserve will result in over-procurement which is almost certain to be fossil fuel natural gas resources that emit greenhouse gases. This provides a sunk cost that will induce the use of natural gas for decades into the future. The Planning Reserve Margins in combination with a 1-in-2 load forecast for local resource adequacy should adequately provide energy for the extreme scenario that the proposed 1-in-10 metric apparently addresses. Moreover, there is no justification provided for using this 1-in-10 load forecast, and no explanation for incorporating over procurement and increased cost into any system plan especially here where the plan is carbon constrained. Using the 1-in-10 metric would inevitably lead to an unnecessary increase in fossil fuel procurement and generation.

Respectfully submitted,

PAUL R. CORT
WILLIAM B. ROSTOV

/s/ WILLIAM B. ROSTOV
By: William B. Rostov

Earthjustice
426 17th Street, 5th Floor
Oakland, CA 94612
Tel: (510) 550-6725
Fax: (510) 550-6749
pcort@earthjustice.org
wrostov@earthjustice.org

Attorneys for
SIERRA CLUB CALIFORNIA

Dated: June 21, 2010

ATTACHMENT A

SIERRA CLUB
CALIFORNIA

December 17, 2009

Karen Douglas, Chair
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Subject: Correcting Net Short Calculations

Dear Commissioner Douglas:

As the state plans for scaling up renewable energy, a key assumption is the amount of renewable generation needed to achieve the 33% Renewable Electricity Standard (RES) targets. The gap between the amount of renewables that we already have, and the amount that we are expected to need by 2020 is called the "Net Short." The estimate for the Net Short directly affects the cost and infrastructure projections for achieving RPS/RES objectives. These forecasts in turn have a wide influence, helping to drive planning and decision processes in RETI, CPUC, CaISO, the utilities, the legislature, the governor's office, environmental groups, ratepayer advocates, and even the general public.

Sierra Club California has noticed over the course of this year that the CEC, CPUC and RETI, and even separate reports within this year's IEPR proceeding, have been using different forecast assumptions, and arrived at a remarkably wide range of results.

Net Short Source	**Agency**	**Date**	**Existing Renewables** (terawatt-hours)	**Net Short** (terawatt-hours)
33% RPS Implementation Analysis	CPUC	Jun. 2009	27	75
Phase 1B Report	RETI	Jan. 2009		67.5
California's Renewable Energy Goals—Assessing the Need	RETI	Feb. 2009	36.8	59.7
Phase 2A Update: Effect of Revised Forecast on RETI Net Short, Discussion Draft.	RETI	Sep. 2009	39.3	51
Impact of AB 32 Scoping Plan	CEC	Jun. 2009	32.4	45

The table above gives a summary of Net Short estimates from five public agency sources. Interestingly, calculations generally use similar data sources, but differ due to which electricity demand forecast was used, how much instate renewable energy exists, and what state polices are assumed. However, none of them shows what happens to the net short if all of the following are accounted for: 1) the most recent amount of existing renewables is assumed (39.3 twh), 2) the most up to date CEC demand forecast is used, and 3) AB 32 Scoping Plan is implemented as required.

801 K Street, Suite 2700, Sacramento, CA 95814 • (916) 557-1100
FAX (916) 557-9669 • www.sierraclubcalifornia.org

Unfortunately, the Net Short numbers that got widest circulation were from the CPUC staff report that used a highly inflated value of an additional **75 terawatt-hours** needed to achieve the 33% RPS, and then attached a "shock and awe" cost of $115 billion.

Table 3. New Renewable Resources Required to Meet a 33% RPS by 2020 in TWh

	20% RPS	33% RPS
2020 retail sales forecast [16]	308	308
Required RPS resources	62	102
RPS resources claimed by utilities in 2007[17]	27	27
Resources needed to reach RPS	*35*	*75*

Source: CPUC staff report, *33% Renewables Portfolio Standard Implementation Analysis Preliminary Result*, June 2009, p 19. The report cites the California Energy Commission as the source for these numbers. Forecast of 2020 retail sales (cited in footnote 16) is from the CEC 2007 forecast, and for the existing RPS resources in 2007 (footnote 17) CPUC staff cites the CEC 2007 Net System Power Report.

The $115 billion figure was echoed all over the state in the press, by the CEO of SoCal Edison in an OpEd in the LA Times titled *Why 33% Renewables by 2020 may be impossible*, and excessive cost was alluded to by the Governor in his veto of RPS bill, SB 14. A prime input for this cost was the Net Short. In other words, the Net Short matters.

Part of the reason the CPUC staff report had such a high Net Short was because they used the CEC 2007 Net System Power Report, which gives only in-state generation. This resulted in their assumption that there is currently 27 terawatt-hours of renewables. However, the CPUC figure was too low, since it leaves out the renewable energy that is imported. Reports this year from the CEC staff and RETI all use higher numbers for existing renewable generation.

RETI performed a Net Short calculation for the Phase 1B Report issued in January 2009, arriving at **67 terawatt-hours**. This was subsequently revised downward by RETI in a short report *California's Renewable Energy Goals—Assessing the Need for Additional Transmission Facilities* released in February/March 2009, to **59 terawatt-hours,** after they recognized that they had left out some key factors. In particular they had not previously accounted correctly for some self-generation which is not under the RPS mandate. The February document corrected this.

In June, CEC staff released a report as part of the 2009 IEPR, *Impact of Assembly Bill 32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation*, that focused on the need for natural gas generation within the framework of AB 32 and ARB's Scoping Plan. The Net Short calculation in this report initially follows the same assumptions as in other reports, but adds elements not contained in other Net Short calculations that are specifically derived from ARB's Scoping Plan to implement AB 32.

The report produced a careful line-item calculation for the net-short, indeed the presentation is a model of clarity in how assumptions are laid out, and came up with **45 terawatt-hours**. Despite the fine work, the staff unfortunately used the 2007 forecasts of load, and not the lower new draft forecast that came out at nearly the same time as part of the same 2009 IEPR. They also used a lower figure for the amount of existing renewables than RETI did.

The new CEC demand forecast reduced the Net Short by 6.8 terawatt-hours, while the newest RETI evaluation shows 39.2 terawatt hours of existing renewables instead of 32.3 assumed by CEC staff. Combined, these two adjustments would lower the Net Short by 13.7 terawatt-hours to only **31.3 terawatt-hours**—if the AB 32 Scoping Plan is fully implemented as required.

Table 5: Impact of AB 32 Complementary Policies on Derivation of Incremental Renewables Needed in 2020 (GWh)

		2020 GWh
1	Statewide Net Energy for Load (Used in Production Cost Modeling)	341,755
2	Statewide Losses	21,387
3	LSE Statewide Retail Sales (line 1 – line 2)	320,368
4	Non-RPS Deliveries (CDWR, WAPA and MWD)	12,299
5	Adjusted Retail Sales for RPS Calculation (line 3 – line 4)	308,069
6	AB 32 EE Beyond Amount in Energy Commission Forecast	34,707
7	AB 32 CHP Beyond Amount in Energy Commission Forecast	32,304
8	AB 32 Rooftop PV Beyond Amount in Energy Commission Forecast	4,845
9	Adjusted Retail Sales for 33% AB 32 RPS Calculation (line 5 – 6,7,8)	236,213
10	Renewable Energy Needed for 33% (33% of Line 9)	77,950
11	Existing Renewable Energy as of 12/31/2008	32,469
12	33% Renewable Net Short (Cases 2 and 3 (line 10- Line11))	45,481

Source: Energy Commission staff, compiled from California Energy Demand 2008–2018 Staff Revised Forecast CEC-200-2007-015SF. Forecast extended to 2020 by Energy Commission staff. The actual rooftop PV, EE and CHP impacts in AB 32 Scoping Plan for 2020 are 4,500, 32,000 and 30,000 GWh, respectively. To these estimates the ARB Scoping Plan adds an amount to account for transmission line losses. Existing renewables based on 2008 production cost model simulation results (29,780 GWh) and eligible renewable generation for regions outside California (2,689 GWh).

Source: *Impact of Assembly Bill 32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation*, California Energy Commission, Staff Report, June 2009, CEC-200-2009-011 (based on 2007 load forecasts).

The CEC staff evaluation of the impact of AB 32 measures shown in the chart above gave a much more comprehensive and explicit calculation than in other reports. For example, they differentiate generation from sales, and properly account for line losses and non-utility electric power sales.

Despite very different results, both the CPUC and CEC staff reports show the same figure for utility retail sales for the purpose of RPS calculation at 308 terawatt-hours (308,000 gigawatt-hours). However, the CEC staff report has three further subtractions that are not present in the CPUC report, all of which are tied to AB 32 implementation—

i) The revised efficiency targets,

ii) Combined heat and power (on-site generation, not subject to RPS), and

iii) Additional DG solar.

Most dramatically, the adjusted utility retail sales are reduced from 308 terawatt-hours to only 236 terawatt-hours, and 33% of this amount is 77 terawatt-hours, much less than the

102 gigawatt-hours cited by CPUC. And every report used a different value for the amount of existing renewables.

RETI Phase 1B, the CPUC report, and the 2009 CEC staff report, all used the 2007 CEC growth/load forecast, which is now superseded by the 2009 forecast. Based on this new forecast, RETI produced a revised Net Short of **51 terawatt-hours**, and was advised to adopt this by December 5th, or reply to the CEC by that date if they had objections (*Letter from David Olson to Stakeholder Steering Committee, 11/24/2009*). RETI is currently considering whether to adopt this revised Net Short. In the following table, RETI compared the new Net Short calculation with the earlier one this year:

RETI Net Short Update November 2009 (GWh)		
Parameter	Current Update	Feb 09 Update
Total Consumption	312,982	334,169
Wholesale Sales	12,299	12,299
Private Supply	19,303	19,896
Retail Sales	281,380	301,974
33% RPS Renewable Generation	92,855	99,651
Existing Renewable Generation	39,324	36,807
Miscellaneous Other Renewable	2,670	3,134
Net Short	50,862	59,710
Renewable Energy Added	53,532	62,844

Table 1 – Comparison of Net Short Factors from Previous Update

The recent discussion draft, *RETI Phase 2A Final Report Update, Effect of Revised Demand Forecast on RETI Net Short*, also makes clear that a further downward revision will be necessary once new energy efficiency program funding after 2012 is taken into account, the so-called “uncommitted efficiency”.

All of these figures floating around create a cloud of confusion and methodological discord that needs to be corrected. We believe that it is important for all agencies and utilities to be working from the same numbers, and that producing and communicating these numbers is the job of the Energy Commission.

In summary, we recommend that the commission develop, maintain and publish a Net Short that includes all the following:

- The most recent CEC growth forecast
- Net Short forecasts should fully list and clearly state all inputs on a line-item basis, *with uniform descriptive terms and method adopted by all agencies*
- A reasonable Net Short forecast range that accounts for low, baseline and high growth.
- The correct value for existing renewables, that includes in-state and out-of-state resources
- A line item entry and explanation regarding uncommitted efficiency savings, that should be estimated now and accurately added as soon as available

- An alternate “AB 32 Net Short” that conforms to ARB’s Scoping Plan
- AB 32 measures should be incorporated into the Net Short as they are implemented

We recommend that updated and uniform figures, validated by the Energy Commission, be used in all IEPR and CEC staff reports, and that the staff report on AB 32 measures be revised accordingly.

We also recommend that the updated Net Short be delivered to all agencies, especially CPUC and CaISO, for planning renewable resources and transmission lines, and that all these agencies and entities (including utilities) be urged to adopt the forecast as the commission recently did with RETI. We further recommend that the commission follow up with RETI to insure that RETI stays on track to adopt this forecast and future revisions as well. Negotiating and adopting an interagency protocol or perhaps a memorandum of understanding might be necessary.

We respectfully request that the commission accomplish this as soon as possible so that it may inform CARB, the Governor, and the Legislature as they evaluate the RPS/RES program. We hope that the commission’s work will help revive RPS legislation that the Governor can sign, and that a corrected Net Short will make it clear that achieving the 33% renewable target is affordable. A truthful finding that the 33% RPS/RES program will cost far less than what was projected would be important for policymakers, utilities and the general public.

Sierra Club California appreciates the work and leadership provided by you and the commission, and we appreciate the opportunity to offer our comments.

Sincerely,

Jim Metropulos

Jim Metropulos
Senior Advocate
Sierra Club California

cc: Governor Schwarzenegger
Senator Steinberg
Senator Simitian
CEC Commissioners
Mr. Gary Collord, California Air Resources Board

ATTACHMENT B

SIERRA CLUB
CALIFORNIA

March 12, 2010

Gary Collord
Energy Section
Air Resources Board
gcollord@arb.ca.gov

Subject: Comments on Presentation Documents from 2/2/2010 RES Workshop

Dear Mr. Collord,

Sierra Club California would like to comment on the presentations and associated documents provided at the February 2, 2010 CARB Renewable Electricity Standard (RES) workshop. We believe that there are a number of points that need to be incorporated going forward.

One of our largest concerns is that agencies such as the CEC, RETI, CAISO, and CARB use consistent assumptions and values. Sierra Club strongly supports RETI's request for guidance from agencies, such as CARB, for the expected results of certain programs that currently are either indeterminate or zero in the calculation of new renewables needed to meet the RES/RPS 33% target in 2020.

A few of these values directly concern the authority of CARB under AB 32. The CARB-adopted Scoping Plan contains 3 measures that have not been adequately incorporated into planning documents—additional Combined Heat and Power (CHP) beyond current forecasts, energy savings from future programs that is referred to as "uncommitted" Energy Efficiency (EE), and rooftop PV additional to the California Energy Commission forecast. The California Energy Commission produced a staff report on the implications of AB 32 measures, which contains a table that quantified these measures as follows:[1]

AB 32 EE Beyond Amount in Energy Commission Forecast	34,707 GWh
AB 32 CHP Beyond Amount in Energy Commission Forecast	32,304 GWh
AB 32 Rooftop PV Beyond Amount in Energy Commission Forecast	4,845 GWh

It is important to note that the current Energy Commission forecast does not incorporate more than a small fraction of the combined AB 32 measures listed above, under any planning scenario. RETI's new Net Short calculation is more complicated. They have

[1] Impact of Assembly Bill 32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation, California Energy Commission Staff Report, June 2009, CEC-200-2009-011, pp. 11 & 14.

bravely varied from the Energy Commission by incorporating a value close to the figure above for rooftop PV in the baseline Net Short—4,140 Gigawatt-hours (GWh). In addition, RETI has developed a "Low Load Scenario" which incorporates additional CHP and Energy Efficiency beyond the Energy Commission's forecast. However, the values used by RETI in their baseline case for incremental CHP and EE (beyond the staff CEC forecast) are both zero. In other words, this baseline case effectively assumes policy failure for 3 critical AB 32 Scoping Plan measures. While the RETI Low Load Scenario does incorporate significant additional efficiency and CHP, the AB 32 Scoping Plan targets are not cited in these assumptions, and RETI uses values that are much lower than what would be necessary to meet the Scoping Plan targets:

CARB Scoping Plan-- AB 32 Measure	**AB 32: CEC Report, Jun. 2009**	**RETI, Net Short, Feb. 2010**	**RETI Low Load**
	Gigawatt-hours (GWh)	Gigawatt-hours (GWh)	Gigawatt-hours (GWh)
Incremental Efficiency	34,707	0	16,267
Incremental CHP	32,304	0	13,629
Incremental PV	4,845	4,140	4,140
Total AB 32 Measures	71,856	4,140	34,036

The CEC staff report itself uses figures that, while close to CARB's, do vary from the Scoping Plan. We recommend that CARB staff communicate with CEC staff to determine the reasons for this variation and establish published assumed values for baseline, medium and low load scenarios that can be used by CARB and other agencies in planning.

Sierra Club believes that implementation of these measures are vitally important to California's climate protection efforts, as they are responsible for 21.9 million metric tonnes of CO2 equivalent, a slightly larger contribution than the 21.3 million metric tonnes expected from the 33% RPS itself. [2]

Table 7: Energy Efficiency Recommendation - Electricity
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
E-1	Energy Efficiency (32,000 GWh of Reduced Demand) • Increased Utility Energy Efficiency Programs • More Stringent Building & Appliance Standards • Additional Efficiency and Conservation Programs	15.2
E-2	Increase Combined Heat and Power Use by 30,000 GWh	6.7
	Total	**21.9**

The Energy Efficiency and Combined Heat and Power measures under CARB's Scoping Plan are shown representing a total of 62,000 GWh of energy. The CEC estimates that achieving these two AB 32 targets requires an additional 7,000 GWh. Despite these variations, the AB 32 measures above should subtract 33% of approximately 60,000 to

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[2] Climate Change Scoping Plan, *a framework for change*, December 2008, California Air Resources Board, pp. 44-46.

70,000 GWh, or at least 20,000 GWh, from the amount of renewables needed to meet the 33% RPS under a scenario that assumes these measures are successfully implemented.

RETI, CPUC and other agencies need CARB's leadership and guidance on these AB 32 measures. RETI has specified a list of the values that they will need quantified to make credible planning estimates and decisions:

Factor #	Area	Issues
1	Energy Services	economic and technology changes
2	Efficiency	uncommitted efficiency savings
3	Private Supply	PV and CHP penetration
4	Utility Supply	distributed generation development
5	Renewable Generation	location and quantity of resources developed
6	Other Generation	location and quantity of displaced resources

Table 3 – Major Factors Determining Need for Expanded Transmission Capacity for RPS

Factors 1-4 in Table 3 must be quantified and agreed upon before the net short value can be used for credible transmission planning (see also Table 2.)

Our primary overall recommendations are as follows:

- Use figures that conform to CEC forecasts and the most recent baseline RETI Net Short calculation for the "High Scenario"
- Use a clear and consistent terminology
- Develop at least one Scenario that fully conforms to the CARB Scoping Plan targets
- Develop at least one Scenario that considers the CPUC High DG case in the context of new market data and updated planning forecasts.
- On the policy level, CARB should develop and promote a timely implementation schedule and strong enforcement
- On the policy level, CARB should take a pro-active role to insure the successful implementation of AB 32 Scoping Plan targets for increased CHP and energy efficiency and incorporate these objectives in the RES planning work. Further, it should direct these assumptions to be incorporated in related planning efforts by other agencies, such as the CEC, CPUC, RETI and CAISO

These points are discussed in more detail in the following sections.

Recommendations for Assumptions and Scenarios

The three proposed draft Scenarios recently developed by CARB staff needs to be adjusted to conform to planning assumptions and models already developed by the CEC and RETI. We found a number of values that appear to be at variance with the latest data, especially as reported by RETI in its most recent Net Short report. The most important of these are: the value used for existing renewables appears to be too low, and the scenario calculations do not appear to conform to the results derived if the assumed values are loaded into the RETI Net Short spreadsheet-calculator. We have appended tables at the end of this letter that show the results we obtained from using this tool, and urge CARB to investigate and verify whatever assumptions and calculations are used, as well as to make use of the RETI tool. Here are some observations we have about the quantities used in the Scenarios:

1. **Calculation of Need for Renewable Energy & Transmission** – The Net Short Calculation determines the amount of new renewables and transmission required to meet the 33% target by 2020. As such it directly affects assumptions about cost, feasibility, schedule, and environmental impact of the RPS/RES program. The governor's veto of this past year's RPS legislation, and his initiation of the RES process at CARB is in part due to former calculations of the Net Short and associated RPS program costs. It is our belief that past forecasts have consistently overestimated needed transmission. There are several assumptions that appear to be different than forecasts by RETI and the California Energy Commission. Using new scenarios and new numbers at variance with other agencies is already a significant problem, and we believe that it undermines credibility for the RPS program and creates confusion for policymakers, utilities and the general public. We are urging all agencies to use values that conform to one another, and we urge CARB, as a general rule, to use values that rely on the CEC and RETI, and only use different values when these are necessary for policy reasons, and where the differences are clearly noted and explained.

   a. A key assumption we noticed in the proposed scenarios is that California currently produces about 32 TWh of renewable energy in 2009. We believe this assumption to be in error and that, instead it should be 38.1 TWh. The CPUC draft RPS report last summer contained a similar error, which only considered in-state renewables for the out-of-date baseline year of 2007, and failed to consider out-of-state renewables that were delivered to California utilities. According to the most recent RETI report as of February 2010, renewables produced for the state utilities were 31.2 TWh from the 2008 Net System Power Report (NSP), and projects brought on-line since the 2008 NSP report plus out of state imports add another 6.9 TWh of energy. This brings the total to 38.1 TWh at the beginning of 2010.[3] We recommend utilizing this new value of 38.1 TWh for existing renewables, which is derived from the most up-to-date CEC staff estimates. This brings the baseline forecast need for new renewables to 94.2 – 38.1 TWh = 56.1 TWh.

   b. We were baffled at how adding 27 TWh of Efficiency and CHP in Scenario 2 only reduced the "total load" from 290 TWh to 270 TWh—or 20 TWh. This appears to us to be incorrect; the total load should have been reduced by 27 TWh, adjusted only by the 7.6% loss factor (only 2 TWh). Similarly, the "total load" in Scenario 3 is reduced by 40 TWh—from 290 TWh to 250 TWh—when the added efficiency plus CHP plus DG solar totals 47 TWh. Again the loss factor should

[3] RETI Net Short Draft, February 22, 2010.

only be 7.6% of 47; about 3.5 TWh.

c. Using the updated number from RETI for existing renewables, and using the RETI spreadsheet structure for making calculations, results in significantly lower numbers than are shown in the draft CARB scenarios. 57.3, 49.0 and 40.2 TWh for the high, medium and low scenarios respectively, using the spread of values presently assumed by CARB staff. These calculations are appended in tables at the end of this letter.

d. Scenario 3 specifies that it assumes the CARB Scoping Plan measures are fully implemented. While the value of 30.2 TWh for CHP is very close to the number used in the actual Scoping Plan, the value used for efficiency is only 24 TWh, which is significantly lower than the 32 TWh in the Scoping Plan. And, as noted above, the Scoping Plan numbers are for some reason lower than what the energy commission staff report showed in its report last July. We urge CARB to have at least one Scenario that fully shows AB 32 implementation which for CHP and Energy Efficiency would total 62,000 GWh. If CARB has some reason to believe that lower values for efficiency can achieve the same GHG reductions as the Scoping Plan calls for using this measure, then this needs to be explained and demonstrated.

e. RETI makes a deduction in their net short calculation for future renewables that can be brought on-line, but do not need additional transmission. RETI estimates this to be 3.3 GWh; bringing the "RETI Net Short"—the baseline assumption about the amount of renewables RETI believes might need new transmission—to 52.7 TWh. This explains one important difference between the RETI net short and the net short used here by CARB.

f. We urge CARB to adopt a consistent terminology that conforms to usage by other agencies. At this point RETI and CARB are using the term "Net Short" in two different ways. CARB is using the term to mean the amount of new renewables that must be procured to reach the 33% target in 2020. RETI is using the term "New Renewable Generation" to mean the same thing, and reserves the term "Net Short" for a subset of New Renewable Generation that specifically *requires the construction of new transmission*. We recommend the adoption of two "Net Short" terms: "Generation Net Short" for the amount of new renewable generation needed to meet the 2020 target of 33%, and "Transmission/RETI Net Short" to refer to the portion of new renewables that will require the construction of new transmission. This should help avoid confusion. In addition, the use of the term "net load" does not conform to the usage of other agencies, such as CEC and RETI. CEC uses "net energy for load" to refer to a different concept, while RETI uses the term LSE Retail Sales, to refer to the value CARB has called "net load" We recommend that CARB adopt the RETI terminology.

2. **Distributed Generation Assumption** – The solar DG assumption that was included in the low net short scenario was only 2,030 GWh. It is unclear in

CARB's assumptions of whether this "solar DG" is for net metered / self generation solar ("private PV"), DG solar on the grid side of the meter or both. CARB should clearly indicate its plan assumptions for both categories of DG solar. At any rate, this is significantly lower than the value for incremental PV required to meet AB 32 targets that has been assumed by RETI (4140 GWh), and in the Energy Commission staff report on AB 32 measures (4845 GWh). In fact, both of these seem minimal compared to scenario values considered both by RETI and the CPUC. According to a presentation on 12/10/09 by CPUC on the Long-Term Procurement Proceedings (LTPP), there is potential for 15,000 MW of capacity for DG solar (wholesale distributed generation – WDG) in the High DG case. In a recent Black and Veatch presentation, a recommendation was made to consider a scenario in which they would "Replace central station solar and wind with 15,000 MW of mostly distributed solar PV" [4] This would equal about 30,000 GWh of power –many times greater than the 2,030 GWh included in the Plausible Scenarios. These opportunities were found at the substation level by RETI, which now appear to have the potential to be quite cost-effective as discussed below. These substation DG systems need to be distinguished from the line item AB 32 value for "rooftop solar", which exists behind the meter. The DG rooftop systems are initially installed under the CSI program, but RETI has assumed that additional DG solar will continue to be installed after CSI concludes at the end of 2016, and up to the 2020 date for the 33% RES/RPS._ We recommend including a High DG case—in conformity to RETI and to CPUC— in at least one of the three net short scenarios with a potential of contributing 30,000 GWh of generation towards meeting the net short. This 30,000 GWh DG solar is part of the RPS program and not part of the CSI.

3. **Distributed Generation PV should be given high priority** – CARB's responsibility given by the governor is to insure that the utilities are successful in achieving the 33% RPS on schedule in spite of their inability until now to make reasonable progress even towards the 20% RPS. In the past, utilities typically dismissed Photovoltaic (PV) solar because it was believed that it could not make a significant contribution to total renewables, and because it was considered "too expensive". The first assumption has been proven incorrect by the recent estimates of total available capacity in California completed by Black and Veatch through the RETI process and in other countries with more favorable policies, and the second assumption has lost traction as prices have changed dramatically over the past year. By consistently including a High DG case in the policy options, the State will have a much higher likelihood of being successful in its RPS program. The benefits of High DG (with mostly PV) include the following:

    a. **Cost has been rapidly getting lower** – Solar PV panels (polycrystalline and thin film) as well as complete systems have dropped dramatically in price in the past year. According to Black & Veatch, tracking PV has dropped from \$.232 - \$.286 / KWh, to \$.135-\$.214 / KWh. Thin film is

[4] "Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis" on December 9, 2009 as part of the "Re-DEC Working Group Meeting" convened by the CPUC.

now at \$.138 - \$.206 / KWh. The range mostly reflects variation in solar availability. These prices are now lower than solar thermal technology which has gone up in cost over the past few years.

b. **Potential for least environmental effect** - DG Solar PV can be installed on large commercial rooftops with little to no environmental effects – no habitat loss, disruption of land, depletion of water, visual degradation, etc.

c. **Faster installation** - Since little to no new construction of transmission is required (beyond upgrades and what is already under construction), the often 10 year delays required for new transmission lines and corridors are eliminated and the DG generation capacity can be implemented in less time and at less risk. Permitting and building new transmission facilities will be difficult, especially in California. Local communities often object and seek to stop their construction. A forecast increase in construction of transmission facilities to historically high levels, may result in a shortage of engineers, skilled construction workers, building materials, etc. that could further slow their completion.

d. **Higher probability of RPS success** - A High DG case has a much higher likelihood of enabling California to achieve its 33% RPS on schedule, at lower cost and with less environmental destruction for all the reasons cited above.

The high DG case can be promoted in three ways. One is by removing utility caps for DG in net metered programs; the second is to allow load-serving entities to purchase RECs from net metered DG renewable projects; and the third is to promote wholesale DG (WDG) through feed-in tariffs. All of these can be facilitated by policy bodies such as CARB including High DG cases in their analysis, and specifying the reasons for such a case.

Avoiding the Need for Incremental New Transmission

An effective combination of factors would greatly reduce and *even has the potential to eliminate the need* to approve and build new transmission lines, beyond what is already on-line and what is already approved and likely to be built in the next few years. This would avoid further delay, assure the feasibility, and help control the cost of the RES/RPS program.

1. **Available Transmission Capacity** can be secured through lines that already exist, as well as some that have already been approved and/or are under construction. Even excluding the future lines that environmentalists including the Sierra Club have opposed (Sunrise and Green Path North), approximately 9 gigawatts of new transfer capacity should be available by 2013. These lines

should be able to carry at least 30 TWh of renewable energy, assuming a 40% capacity utilization.

Available Transmission Transfer Capacity				
Transmission line(s)	Owner	Year Available	Capacity	CREZ(s)
			MW	
Tehachapi 1-3, and 4-11	SCE	2011 to 2013	4350	Fairmont, Tehachapi, Kramer (N), Inyokern, Owens Valley, C. Nevada
Palo Verde-Devers 2	SCE	2013	1200	Riverside (E), Arizona
Gates Substation	PG&E	existing	1500	Carrizo (N & S), Cuyama, Santa Barbara
Tesla Substation	PG&E		2000	Solano
Transmission Total			**9050**	
source: RETI Phase 2B Report, Table 3-11, p. 3-18				
Sunrise and Green Path are included in the RETI Report, but omitted here due to opposition to these lines.				

2. **The High DG Scenario** can be implemented, resulting in 30 TWh of DG solar that is located on the distribution system side of substations, and thus would not require new transmission lines. This has been explored extensively by RETI.

3. **Implement AB 32 measures,** such as Combined Heat and Power (CHP), future additional Efficiency, and rooftop solar, to reduce the need for new renewables to 50 TWh or less.

4. **Renewable Energy Certificates (RECs)** from renewable generators inside or out of the state can avoid the need for transmission for the quantity of RECs that are purchased. Sierra Club supported a provision in the RPS bill to allow up to 20% of the RPS to be met with RECs. This would equal 20% of 75 TWh to 95 TWh = 15 TWh to 19 TWh.

5. Offloading Conventional Power: California has multiple policies that have the potential to remove conventional power off of existing transmission lines. One of the most important is the state's Emission Performance Standard (SB 1368) which will require retirement of all existing coal contracts. California utilities currently import about 3500 megawatts of capacity from shares of out-of-state coal plants.[5] These plants use up a significant portion of the approximately 17,000 megawatts of import lines entering the state. As coal contracts expire, they may not be renewed under state law and regulation. This should free up the line capacity that could be used by either in-state or out-of-state renewable energy sources. SCE's contract with Four Corners expires in 2016 (786 MW share), and it is our understanding that LADWP's share of Navaho Generating Station expires

[5] A Preliminary Environmental Profile of California's Imported Electricity, Staff Report, California Energy Commission, June 2005, CEC-700-2005-017, pp. 22-25. Table 3-2 lists 4744 MW of out-of-state coal. Subsequent to the report Mohave Generating Station was closed, removing 1244 MW from the list.

in 2019 (510 MW). In addition, increasing renewable energy to 33% should itself displace at least some conventional capacity on existing lines. Since only the coal plant retirements can be known with some certainty, we assume that a total of 1296 MW of import capacity should be freed up by 2020, allowing the state utilities to import at least 2 TWh of renewables.

6. **Proposed Projects That Don't Need Transmission:** RETI identified 3.3 TWh of projects that in their view did not require new transmission capacity. This includes distributed generation as well as smaller utilities near the state border that are excluded from needing transmission for renewables.

Measure	Energy (TWh)
Existing Renewables (as of Jan. 2010)	38
Available Transfer Capacity (existing or online by 2013, excluding Sunrise Powerlink and Green Path North)	30
High DG	30
20% RECs	19
Offloaded Conventional Power	2
Projects That Don't Need Transmission	3
Total Measures	122

The amount of renewable energy needed to supply the entire 33% RES/RPS (not just the net short) in 2020 could be as high as approximately 95 terawatt-hours. This amount can be reduced by lower growth rate, and/or by implementing the AB 32 Scoping Plan measures, to as low as approximately 80 terawatt-hours.

It can be seen that a combination of factors in the table above could actually avoid the need for additional transmission beyond what has been described, and that would be on-line by 2013. This is true even in the case where no AB 32 measures are implemented. An additional margin of assurance of meeting the 33% RES/RPS target is provided if the corrected value from RETI and CEC staff for existing renewables is used.

One of the factors considered in the model used by CARB is that the aging power plants will retire. It should be noted that these plants represent 15 GW of capacity, but they only generate about 12 TWh in total. It is important to realize that at least some of this capacity is expected to be replaced. Retirement of aging plants has been studied using transmission modeling, and the conclusion is that there should be no significant problem for the grid as long as retirement is not sudden. The issue is discussed in a recent report from Pacific Environment: [6]

> In its 2008 report produced for the California Ocean Protection Council, ICF Jones & Stokes conclude that given their low usage, the shuttering of the OTC natural gas plants by 2015 could occur with no need for

[6] Green Opportunity, Pacific Environment, Nov. 2009, p. 9.

> replacement generation capacity. The report's modeling indicates that "given sufficient time to react, the electric[8] industry could likely tolerate and compensate for mass OTC retirement at relatively modest costs to the ratepayer…the retirements could be compensated for with as little as $135 million in instate transmission upgrades."
>
> The report goes on to conclude that, "…under all but the most extreme scenarios, more than enough power plants are expected to be operating in 2015 to more than compensate for any OTC plant retirements, with a projected 28 percent reserve margin of supply over demand in the Western half of North America."

The pending retirement of aging plants in California has unfortunately been a source of some confusion, which is implied in RETI's recent draft Net Short report, namely that if the aging power plants retire, then the capacity on lines will not be "freed up" for renewables. However, it should be noted that backup capacity for renewables does not compete with capacity for the renewables themselves—precisely because they are backup capacity. We recommend further investigation and even challenging the experts to respond to this specific point.

Encourage Utilities use of Feed-in Tariffs (FiTs)

California's RPS goals can be met with a combination of utility-scale projects and many smaller projects. Smaller projects – e.g. under 20MW, in aggregate can provide a large contribution to the RES/RPS, as referenced above in the B&V report. In fact, 30 GWh of DG PV could meet between 50% and 75% of the need for new renewables, using the recommended corrected values and calculations, under the 3 CARB Scenarios. This segment of the energy industry has been significantly under-represented in on-line projects due to barriers to entry and insufficient reimbursement. Properly designed Feed-in Tariffs (FiTs), utilizing proven best practices, would include the following key features:

a. Tariffs would be based on cost + reasonable profit and would not be based on a market price referent or complex auction mechanisms.

b. Technology and project size differentiated – e.g. different tariffs for PV solar, thermal solar, wind, etc. and different tariffs according to the size of the project.

c. Long term contracts – typically 20-25 years long

d. Simple, standard must-take contracts that only pay on delivered electricity.

These features would lower investor risk, reduce financing costs, and thus provide renewable energy at lower costs than other policy mechanisms. FiTs would enable smaller developers, such as the owner of a furniture warehouse, manufacturing plant, church, etc. to be able to get such a project on-line because of simplification of the complex, expensive and risky traditional contracting process that utilities use for large scale projects.

FiTs have demonstrated that they can successfully bring renewables on-line quickly, in volume and at the lower cost. By CARB encouraging utilities to implement FiTs with sufficiently high caps on annual capacity, the state can be assured that it will meet its RPS targets.

Compliance and Enforcement

CARB is now recommending the following compliance intervals:

- 20% in calendar year 2013
- 24% in calendar year 2016
- 28% in calendar year 2018
- 33% in calendar year 2020

While we strongly support having interim compliance targets, we are concerned that the proposed targets build in significant risks to meeting the targets. Not meeting the 20% level until 2013 is already placing extra scheduling burden on the program, and gives the utilities a free pass on their failure to meet the 2010 date that was written into law. By starting with 2013 at 20%, considerable pressure is taken off the utilities to meet any of the existing or future deadlines; they are starting 3 years late; they only have 7 years to meet 33%, and they will have to add renewables at an average rate of 2% of total energy supply per year.

The targets will create both the planning assumptions and the framework for issuing penalties. In these capacities they work as both market and enforcement mechanisms. We recommend keeping pressure on utilities to meet targets as mandated by existing law, so that they face consequences if they continue to delay in meeting the state targets by years. Under current mechanisms, utilities have not had to pay one cent in penalties despite years of delay, and likely will face none for delaying meeting the 20% goal by 2013. If the 20% RPS/RES clock is officially reset to 2013, this will have further implications on penalties and pressure on utilities to comply. It also places the 2020 date at great risk.

One of these risks has to do with the allocation between the interim years. Utilities are given 3 years (2013 to 2016) to increase renewables by 4%; the next 2 year interval must be accelerated to 4% in only 2 years. The final 2 years must add 5%. While it is conceivable that utilities might be able to accelerate development of renewables over time, this is at the cost of making steady, sustainable progress.

But, even more important, this schedule makes effective and timely program monitoring and intervention more difficult. The main problem is that enforcement of targets is impaired by the “flexible compliance” mechanisms that allow delay by as much as 3 years. In addition, regulators generally don’t know what amount of renewables utilities have procured until the following year. At that time a penalty proceeding would need to be initiated, which creates even further delay. This means that a feedback loop is set up where a 2013 target date does not actually take effect until 2016, with the possibility of a penalty not occurring until 2017.

If flexible and delayed compliance is combined with targets that are loaded up toward the end of the decade, then regulatory response and penalties may make the program mechanisms unable to enforce the 2020 target—by design:

- 2016— target for 24% target
- 2019—3 year compliance delay
- 2020—first possibility for penalties for failing to meet 24% target
- 2021—first response by utilities to penalty for not meeting 2016 target of 24%

In other words, the compliance problems and delay that already exist in the current program are very likely propagated into the new RES/RPS program unless significant changes are made to the compliance schedule, regulatory response time, enforcement, utility planning, and utility implementation.

This problem might be averted by rational anticipation of future likely compliance, both by utilities and by regulators, but the accelerating and delayed schedule makes such future potential compliance more difficult to track and respond to in a timely way.

We recommend CARB build in some additional pressure into the schedule targets so that the utilities are not given the full slack that arises due to their past delays and failures to meet targets in a timely way. This will also build in a more sustainable pace of development and help assure that the 2020 target of 33% is more likely to be achieved. The 20% target should remain as it has been in law at 2010; as stated above, there is already a 3-year delay built into this system. Thereafter the targets should be:

- 23% in calendar year 2013
- 26% in calendar year 2015
- 29% in calendar year 2017
- 33% in calendar year 2020

A set of interim targets that maintains a continuous and regular pace keeps the pressure on utilities to perform, and allows regulators time to accomplish enforcement, and gives the utilities the ability to respond to this enforcement, within the 2020 timeframe.

In order for CARB to fulfill its mission given under the Executive Order, it will be necessary for it to require enforcement of meaningful financial penalties that are significant, and that will not be dismissed by the utilities as a “cost of doing business”. If they are confident that they will reach these targets, then they should not be concerned if significant penalties are established. Enforcement will encourage utilities to explore strategies that are lower risk and can be brought on board sooner than their current approach, which so far has not been very successful.

Enforcement must also be much timelier than in the past. A 3 to 4 year delay in penalty feedback cycles, created through "flexible compliance" mechanisms, creates a system that is by design incapable of insuring success. We recommend mandated penalties in any year which the utility does not comply for 100% of the shortfall, with very narrow exceptions. Flexibility should be built in through other mechanisms than delay, to make it easier to comply. The flexibility could come through the following mechanisms:

- allowing compliance with purchase of RECs from in-state DG renewable projects
- giving "extra credit" for these in-state, local RECs based on avoided transmission costs and energy losses, as well as value for on-peak; this is similar to what has been done in other states.
- purchasing up to 20% of the 33% RES/RPS with out of state RECs
- banking extra procurement above the targets from previous years
- upgrading the distribution system and developing plans with CPUC, CAISO and the utilities for implementing a High DG Scenario

Lack of transmission, which has been frequently cited in the past as a problem for meeting RPS targets, should not be accepted in the future as a reason for load serving entities' failure to comply. As shown above, the RES targets can be met under a High DG Scenario, with transmission already under construction, and with RECs. In addition, the ability to comply with the RES/RPS, under the planning assumptions discussed above, is directly related to success in implementing efficiency, CHP, and DG solar, all as required under CARB's AB 32 Scoping Plan. Utilities should not be allowed to give the excuse that the need for renewables was "higher than expected" because they failed in other AB 32 measures. In this sense, strong enforcement of the RES/RPS should be designed to support the success of other AB 32 measures.

Thank you for the opportunity of providing our input into this crucially important process.

Sincerely,

Jim Metropulos

Jim Metropulos
Senior Advocate
Sierra Club California

Cc:

Robert Fletcher, Chief, Stationary Source Division
Chair, Renewable Electricity Standard Committee
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
rfletche@arb.ca.gov

Joseph Fischer
Strategy Evaluation Section
joseph.fischer@arb.ca.gov
(916) 445-0071

RETI Net Short Calculator

Modifed with Inputs for CARB High Net Short Scenario (recalculated)

Variable	Name	2020 Value GWh	capacity factor	capacity GW	Description
Electric Energy Services	EnergyServices	343,647			Services provided by electricity and electric efficiency. Calculated as gross generation per 2009 demand forecast , Form 1.2, plus "other" LSE sales, Form 1.1c, not included in Form 1.2
Incremental Efficiency	IncEff	0			Incremental EE savings not included in the 2009 demand forecast.
Gross Generation	GrossGen	343,647			Electric generation required to meet load net of incremental efficiency.
Total Private Supply	TotPrivSupply	14,895			Behind the meter generation, assuming none is sold to LSEs via net metering or other arrangements. Components assumed to be customer-
Private PV	PrivPV	3,218	20%	1.84	PV from CEC Form 1.2, not RPS eligible under current rules.
Incremental Private PV	IncPV	0	20%	0.00	RETI approved increase to CEC value (provides total of 3.7 GW @ 0.2 cf)
Private CHP	PrivCHP	11,677	80%	1.67	Non-PV self-generation from CEC form 1.2
Incremental Private CHP	IncCHP	0	80%	0.00	Potential Increase in non-PV private supply, eg CHP, above CEC value.
Net Losses	Losses	25,644	7.8%		Net Losses = LossFactor*(GrossGen - TotPrivSupply). LossFactor obtained from Form 1.2 data.
Utility Supply	UtilSupply	303,108			Gross Generation less losses and private supply
Water Pumping	PumpLoad	13,556			Total Pumping Load from Form 1.1c
LSE Retail Sales (CARB: "Total Load")	**RetailSales**	**289,552**			Utility Supply less Water Pumping
Non-RPS Generation	NonRPSGen	194,000			67% of LSE retail sales
33% RPS Generation	RPSGen	95,552			33% of LSE retail sales
Existing Renewable Generation	ExistRenew	38,174			RPS eligible generation on line 1/1/2010 (CEC staff data).
CARB New Renewable Generation	**NewRenew**	**57,378**			New RPS eligible renewable generation required to meet 33% goal (RPSGen - ExistRenew)
Misc. Other Generation	MiscRenew	3,355			New RPS eligible renewable generation NOT needing transmission expansion, including RPS elegible renewable distributed generation and 33% of "other" LSE sales, Form 1.1c.
Additional DG PV		0	20%	0.00	DG PV to meet a "high dg scenario" for RPS; the Bill Powers Variable.
Additional Other Renewable DG		0	80%	0.00	RPS DG that is not PV, such as biomass, waste to energy, and in-conduit
RETI Renewable Net Short	**NetShort**	**54,023**			New RPS eligible renewable generation NEEDING transmission expansion.

RETI Net Short Calculator

Modifed with Inputs for CARB Mid Net Short Scenario (recalculated)

Variable	Name	2020 Value GWh	capacity factor	capacity GW	Description
Electric Energy Services	EnergyServices	343,647			Services provided by electricity and electric efficiency. Calculated as gross generation per 2009 demand forecast , Form 1.2, plus "other" LSE sales, Form 1.1c, not included in Form 1.2
Incremental Efficiency	IncEff	12,100			Incremental EE savings not included in the 2009 demand forecast.
Gross Generation	GrossGen	331,547			Electric generation required to meet load net of incremental efficiency.
Total Private Supply	TotPrivSupply	30,080			Behind the meter generation, assuming none is sold to LSEs via net metering or other arrangements. Components assumed to be customer-
Private PV	PrivPV	3,218	20%	1.84	PV from CEC Form 1.2, not RPS eligible under current rules.
Incremental Private PV	IncPV	0	20%	0.00	RETI approved increase to CEC value (provides total of 3.7 GW @ 0.2 cf)
Private CHP	PrivCHP	11,677	80%	1.67	Non-PV self-generation from CEC form 1.2
Incremental Private CHP	IncCHP	15,185	80%	2.17	Potential Increase in non-PV private supply, eg CHP, above CEC value.
Net Losses	Losses	23,516	7.8%		Net Losses = LossFactor*(GrossGen - TotPrivSupply). LossFactor obtained from Form 1.2 data.
Utility Supply	UtilSupply	277,951			Gross Generation less losses and private supply
Water Pumping	PumpLoad	13,556			Total Pumping Load from Form 1.1c
LSE Retail Sales (CARB: "Total Load")	**RetailSales**	**264,395**			Utility Supply less Water Pumping
Non-RPS Generation	NonRPSGen	177,145			67% of LSE retail sales
33% RPS Generation	RPSGen	87,250			33% of LSE retail sales
Existing Renewable Generation	ExistRenew	38,174			RPS eligible generation on line 1/1/2010 (CEC staff data).
CARB New Renewable Generation	**NewRenew**	**49,076**			New RPS eligible renewable generation required to meet 33% goal (RPSGen - ExistRenew)
Misc. Other Generation	MiscRenew	3,355			New RPS eligible renewable generation NOT needing transmission expansion, including RPS elegible renewable distributed generation and 33% of "other" LSE sales, Form 1.1c.
Additional DG PV		0	20%	0.00	DG PV to meet a "high dg scenario" for RPS; the Bill Powers Variable.
Additional Other Renewable DG		0	80%	0.00	RPS DG that is not PV, such as biomass, waste to energy, and in-conduit
RETI Renewable Net Short	**NetShort**	**45,722**			New RPS eligible renewable generation NEEDING transmission expansion.

RETI Net Short Calculator					
Modifed with Inputs for CARB Low Net Short Scenario (recalculated)					
Variable	**Name**	**2020 Value GWh**	**capacity factor**	**capacity GW**	**Description**
Electric Energy Services	EnergyServices	343,647			Services provided by electricity and electric efficiency. Calculated as gross generation per 2009 demand forecast , Form 1.2, plus "other" LSE sales, Form 1.1c, not included in Form 1.2
Incremental Efficiency	IncEff	24,200			Incremental EE savings not included in the 2009 demand forecast.
Gross Generation	GrossGen	319,447			Electric generation required to meet load net of incremental efficiency.
Total Private Supply	TotPrivSupply	47,147			Behind the meter generation, assuming none is sold to LSEs via net metering or other arrangements. Components assumed to be customer-
Private PV	PrivPV	3,218	20%	1.84	PV from CEC Form 1.2, not RPS eligible under current rules.
Incremental Private PV	IncPV	2,030	20%	1.16	RETI approved increase to CEC value (provides total of 3.7 GW @ 0.2
Private CHP	PrivCHP	11,677	80%	1.67	Non-PV self-generation from CEC form 1.2
Incremental Private CHP	IncCHP	30,222	80%	4.31	Potential Increase in non-PV private supply, eg CHP, above CEC value.
Net Losses	Losses	21,241	7.8%		Net Losses = LossFactor*(GrossGen - TotPrivSupply). LossFactor obtained from Form 1.2 data.
Utility Supply	UtilSupply	251,059			Gross Generation less losses and private supply
Water Pumping	PumpLoad	13,556			Total Pumping Load from Form 1.1c
LSE Retail Sales (CARB: "Total Load")	**RetailSales**	**237,503**			Utility Supply less Water Pumping
Non-RPS Generation	NonRPSGen	159,127			67% of LSE retail sales
33% RPS Generation	RPSGen	78,376			33% of LSE retail sales
Existing Renewable Generation	ExistRenew	38,174			RPS eligible generation on line 1/1/2010 (CEC staff data).
CARB New Renewable Generation	**NewRenew**	**40,202**			New RPS eligible renewable generation required to meet 33% goal (RPSGen - ExistRenew)
Misc. Other Generation	MiscRenew	3,355			New RPS eligible renewable generation NOT needing transmission expansion, including RPS elegible renewable distributed generation and 33% of "other" LSE sales, Form 1.1c.
Additional DG PV		0	20%	0.00	DG PV to meet a "high dg scenario" for RPS; the Bill Powers Variable.
Additional Other Renewable DG		0	80%	0.00	RPS DG that is not PV, such as biomass, waste to energy, and in-conduit
RETI Renewable Net Short	**NetShort**	**36,847**			New RPS eligible renewable generation NEEDING transmission expansion.

RETI Net Short Calculator					
Modified with Inputs for Sierra Club Proposed Low Net Short, High DG Scenario					
Variable	**Name**	**2020 Value GWh**	**capacity factor**	**capacity GW**	**Description**
Electric Energy Services	EnergyServices	343,647			Services provided by electricity and electric efficiency. Calculated as gross generation per 2009 demand forecast , Form 1.2, plus "other" LSE sales, Form 1.1c, not included in Form 1.2
Incremental Efficiency (CARB Scoping Plan value)	IncEff	32,000			Incremental EE savings not included in the 2009 demand forecast.
Gross Generation	GrossGen	311,647			Electric generation required to meet load net of incremental efficiency.
Total Private Supply	TotPrivSupply	49,035			Behind the meter generation, assuming none is sold to LSEs via net metering or other arrangements. Components assumed to be customer-owned PV and CHP
Private PV	PrivPV	3,218	20%	1.84	PV from CEC Form 1.2, not RPS eligible under current rules.
Incremental Private PV	IncPV	4,140	20%	2.36	RETI approved increase to CEC value (provides total of 3.7 GW @ 0.2 cf)
Private CHP	PrivCHP	11,677	80%	1.67	Non-PV self-generation from CEC form 1.2
Incremental Private CHP (CARB Scoping Plan)	IncCHP	30,000	80%	4.28	Potential Increase in non-PV private supply, eg CHP, above CEC value.
Net Losses	Losses	20,485	7.8%		Net Losses = LossFactor*(GrossGen - TotPrivSupply). LossFactor obtained from Form 1.2 data.
Utility Supply	UtilSupply	242,127			Gross Generation less losses and private supply
Water Pumping	PumpLoad	13,556			Total Pumping Load from Form 1.1c
LSE Retail Sales (CARB: "Total Load")	**RetailSales**	**228,571**			Utility Supply less Water Pumping
Non-RPS Generation	NonRPSGen	153,143			67% of LSE retail sales
33% RPS Generation	RPSGen	75,428			33% of LSE retail sales
Existing Renewable Generation	ExistRenew	38,174			RPS eligible generation on line 1/1/2010 (CEC staff data).
CARB New Renewable Generation	**NewRenew**	**37,254**			New RPS eligible renewable generation required to meet 33% goal (RPSGen - ExistRenew)
Misc. Other Generation	MiscRenew	3,355			New RPS eligible renewable generation NOT needing transmission expansion, including RPS elegible renewable distributed generation and 33% of "other" LSE sales, Form 1.1c.
Additional High DG PV		26,000	20%	14.84	DG PV to meet a "high dg scenario" for RPS; the Bill Powers Variable.
Additional Other Renewable DG		1,000	80%	0.14	RPS DG that is not PV, such as biomass, waste to energy, and in-conduit hydro
RETI Renewable Net Short	**NetShort**	**6,900**	40%	1.97	New RPS eligible renewable generation NEEDING transmission expansion.

CERTIFICATE OF SERVICE BY ELECTRONIC MAIL

I, the undersigned, state that I am a citizen of the United States and am employed in the City of Oakland, County of Alameda; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is Earthjustice, 426 17th Street, 5th Floor, Oakland, CA 94612.

On the 21st day of June 2010, I caused to be served a true copy of:

COMMENTS OF SIERRA CLUB CALIFORNIA ON INITIAL RULING ON PROCUREMENT PLANNING STANDARDS

[X] By Electronic Mail – serving the enclosed via e-mail transmission to each of the parties listed on the official service list for R 10-05-006.

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on this 21st day of June, 2010 at Oakland, California.

/s/ JESSIE BAIRD
Jessie Baird

abe.silerman@nrgenergy.com
mpieniazek@drenergyconsulting.com
mdorn@mwe.com
jarmenta@calpine.com
b.buchynsky@dgc-us.com
jbloom@winston.com
Don.Vawter@AES.com
douglass@energyattorney.com
deana.ng@sce.com
mary@solutionsforutilities.com
AMSmith@SempraUtilities.com
liddell@energyattorney.com
mtierney-lloyd@enernoc.com
mdjoseph@adamsbroadwell.com
chh@cpuc.ca.gov
nao@cpuc.ca.gov
josh@brightlinedefense.org
mflorio@turn.org
smartinez@nrdc.org
nes@a-klaw.com
tjl@a-klaw.com
dbehles@ggu.edu
bcragg@goodinmacbride.com
jeffreygray@dwt.com
lcottle@winston.com
crmd@pge.com
ssmyers@att.net
JChamberlin@LSPower.com
wbooth@booth-law.com
pcort@earthjustice.org
wrostov@earthjustice.org
kfox@keyesandfox.com
gmorris@emf.net
jansar@ucsusa.org
lwisland@ucsusa.org
agerterlinda@gmail.com
tomb@crossborderenergy.com
kristin@consciousventuresgroup.com
janreid@coastecon.com
michaelboyd@sbcglobal.net
martinhomec@gmail.com
cmkehrein@ems-ca.com
abb@eslawfirm.com
deb@a-klaw.com
achang@efficiencycouncil.org
mrw@mrwassoc.com
steven.huhman@morganstanley.com
vlauterbach@mwe.com
myuffee@mwe.com
dgilligan@naesco.org
cynthia.brady@constellation.com
kjsimonsen@ems-ca.com
ckmitchell1@sbcglobal.net
amber.wyatt@sce.com
case.admin@sce.com
GBass@SempraSolutions.com
JPacheco@SempraUtilities.com
WKeilani@SempraUtilities.com
ek@a-klaw.com
sue.mara@rtoadvisors.com
rcox@pacificenvironment.org
marcel@turn.org
mang@turn.org
matthew@turn.org
nlong@nrdc.org
AxL3@pge.com
AGL9@pge.com
GxZ5@pge.com
filings@a-klaw.com
lwilliams@ggu.edu
MWZ1@pge.com
mpa@a-klaw.com
CPUCCases@pge.com
will.mitchell@cpv.com
devin.mcdonell@bingham.com
jfilippi@nextlight.com
rafi.hassan@sig.com
robertgex@dwt.com
todd.edmister@bingham.com
vidhyaprabhakaran@dwt.com
Diane.Fellman@nrgenergy.com
cem@newsdata.com
arthur@resource-solutions.org
RegRelCPUCCases@pge.com
wetstone@alamedamp.com
Sean.Beatty@mirant.com
kowalewskia@calpine.com
barmackm@calpine.com
cpucdockets@keyesandfox.com
dmarcus2@sbcglobal.net
rschmidt@bartlewells.com
patrickm@crossborderenergy.com

philm@scdenergy.com
bperlste@pacbell.net
wem@igc.org
dwang@nrdc.org
bmcc@mccarthylaw.com
mnelson@mccarthylaw.com
brbarkovich@earthlink.net
bill@jbsenergy.com
brian.theaker@dynergy.com
mary.lynch@constellation.com
Danielle@ceert.org
ddavie@wellhead.com
kdw@woodruff-expert-services.com
blaising@braunlegal.com
steven@iepa.com
eddyconsulting@gmail.com
atrowbridge@daycartermurphy.com
dsanchez@daycartermurphy.com
sas@a-klaw.com
aeg@cpuc.ca.gov
clu@cpuc.ca.gov
dbp@cpuc.ca.gov
jp6@cpuc.ca.gov
kpp@cpuc.ca.gov
kkm@cpuc.ca.gov
kd1@cpuc.ca.gov
cho@cpuc.ca.gov
nws@cpuc.ca.gov
nlr@cpuc.ca.gov
rmm@cpuc.ca.gov
wtr@cpuc.ca.gov
rls@cpuc.ca.gov
rb2@cpuc.ca.gov
svn@cpuc.ca.gov
vsk@cpuc.ca.gov
ys2@cpuc.ca.gov
claufenb@energy.state.ca.us
jwoodward@energy.state.ca.us
ldecarlo@energy.state.ca.us
mjaske@energy.state.ca.us
irhyne@energy.state.ca.us
aeg@cpuc.ca.gov
sas@a-klaw.com
brian.theaker@dynergy.com
dgilligan@naesco.org
irhyne@energy.state.ca.us
jfilippi@nextlight.com
rafi.hassan@sig.com
rb2@cpuc.ca.gov