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Washington DC • Boston MA

**BY E**

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**RE: SUPPLEMENTARY COMMENTS – "Next solar incentive program" SEA Report ("Developing a post-1600 MW solar incentive program"), as-released 10-11-16**

Dear Mike:

This presents supplementary comments of CFS and Kearsarge Solar LLC on the Report and its implications. The Report was released two weeks after the agency's Straw Proposal for a feed-in tariff (FIT) approach succeeding DOER's 'marketable SREC' incentive programs, to provide conceptual and analytical support for the FIT approach chosen and the proposed incentive payments in the Straw.

We incorporate by reference our joint comments on the Straw dated October 5. There we urged (among other things) that:

3. **The data and math supporting tariff "base rates" and adders must be provided for comment.** As far as we know, no detailed analytic support has yet been provided for either the "adders" or for "base rates" that sharply diminish by more than 50% from 35₵/kWh (low-income projects less than 25 kW-ac) to 15₵/kWh ("large" projects over 1 MW-ac).

   We understand the overall rationale is to assure projects in each category or sub-category a "reasonable" rate of return sufficient for them to get financed and built (i.e., assure that they will 'pencil out').

   *However,* **as to the base tariff rates**, neither what that IRR is nor the inputs which determined it have been made available for comment. **As to the**

**adders,** how these proposed additional unit values were calculated remains equally unclear.

The extent to which reasoned analysis from real-world data transparently supports such figures will be critical to build investor confidence, avoid possible train-wrecks, minimize potentially disruptive mid-course corrections, and help assure program success.[1]

We **urge DOER promptly to make its underlying data and analyses available for comment,** either well before the current comment period closes October 28 or in a separate comment period.

We appreciate the Report's prompt release.

Unfortunately, neither the Report nor its worksheets appear to meet appropriate standards of transparency or accountability. **It is impossible to tell from these documents how the proposed Tariff incentive levels were derived or what specific information supports them.** The dots simply are not connected enough for affected parties to trace the underlying process or test the robustness of its outputs. There also appear to be substantial gaps and misplaced assumptions in the inputs used to reach the Straw's numeric conclusions.

Most generally, **the actual "modified" CREST (and related) models that SEA used to reach its worksheet results are not disclosed. Nor are the inputs to these models disclosed. Nor are whatever additional analysis or modeling that DOER used to set the Straw's proposed incentive-payment levels disclosed.**

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[1] By way of example, the "reasonable return" issues raised by this approach include: What IRR is DOER using as the yardstick? Does it reflect current financial-market hurdle rates? To what extent does it assume that projects have been 'de-risked" at the point when they typically seek financing? How does it reflect inputs such as current (average, geographical, or utility-specific) site lease, wetlands delineation, local property tax, labor, and interconnection costs?

**DOER should promptly disclose this information** – particularly (though not exclusively) the **IRR it used to identify "reasonably financeable" net project revenue streams.**

DOER also should **promptly disclose all the material data inputs** -- including, for example, permitting, labor preliminary engineering and other soft costs as well as the annual costs of such items as site leases, property taxes, or O&M; and such income items as unit tax-equity, energy or NMC returns -- **that pertinently were modeled to estimate these net revenues.**

We see no meaningful bar to such disclosure. The CREST model was developed by NREL for open public use and is non-proprietary. To the extent SEA's CREST modifications or ancillary models may be proprietary (rather than public information by virtue of SEA's selection under DOER's RFP), such models may be "locked" in xls or presented in PDF for public review. Should these or similar routes be objectionable for some reason, a list of modeled cost and revenue assumptions at least could make meaningful public review possible, though the underlying models could not be run to assess their formulas, their potential biases, their sensitivities, or their outcomes.

We are particularly concerned with the resulting inability to assess the underlying data and modeling support for the proposed incentive payments for 'large' third-party PV projects. Affected parties developing other types of projects likely will have similar concerns.

We note below some examples illustrating our concerns. These examples also suggest how the proposed Straw incentive payments may have been artificially depressed.

• The Report's 7.5% IRR is only what stakeholder survey results apparently yielded, not necessarily what SEA used for its CREST model or what DOER used. What IRR was assumed to determine 'financeable net revenues' for purposes of setting the proposed Straw incentives does not seem to be identified anywhere in the Report or worksheets.

• Also not identified are what adjustments to this critical IRR figure may have been used to reflect -- or at least approximate – fluid real-world financing constraints.

For example: A 7.5% unlevered cumulative annual-average 25-year IRR may be financeable today in the tail of the 2008/9 Great Recession, but may be un-financeable a year from now. That IRR may be acceptable for certain debt financing (assuming it translates to a sufficient debt-service coverage ratio), but not acceptable to limited tax-equity providers who remain free to choose among renewable-energy projects showing higher IRRs – a result that in turn may preclude feasible debt placement.

More generally, what IRR is "acceptable" for third-party financing mainly is a function of project timing, scale and risk. "Earlier-stage" projects typically must show higher IRRs even to be considered for such financing, and often are "parked" until development risks like interconnection costs have been fully defined. "Large" projects or large-scale portfolios of projects may be financed at relatively lower IRRs because potential absolute returns offset some risk or overall risks are diversified, while small projects may not be financeable on a third-party basis (absent "bundling" by a deep-pockets installer) due to financier size thresholds or transactions costs, regardless of their projected IRRs.

- The Report appears substantially to overstate the availability of 50% bonus depreciation, by assuming all eligible projects efficiently utilize such depreciation until it's phased out for projects completed after 2019 (pp. 32-33). However, most projects cannot use such depreciation efficiently because tax-equity providers generally will not monetize this tax benefit. Instead, to preserve their remaining tax appetite for additional deals, such providers typically limit transactions to include only conventional 5-year PV depreciation, leaving developers to carry forward potential deductions whose value (if ever claimed) will be eroded over time.

- The Report appears substantially to overstate the availability and understate the cost of tax equity, apparently concluding that "tax motivation and increasing competition that characterize the third-party-owned market" exert *downward pressure* on tax-equity required returns because tax-equity in general is freely available (p. 36). This is the exact opposite of the real-world situation, at least where rooftop facilities bundled by large installers who can claim tax credits internally (i.e., without monetizing them through transactions with tax-credit-hungry third-parties) are not involved. It is patently untrue for 'large' ground-mounted projects pursued by independent developers.

In the real world, 'large' ground-mounted projects (over 1 MW-ac) face a limited universe of less than two dozen nationwide tax-equity providers, some of whom have suspended further activity because they already are "filled up." Even large national bundlers of residential installs now are constrained on the tax-equity side as their profits and tax-appetites shrink.

Perhaps as important, the Report seems to assume that tax equity is virtually costless. Nothing could be farther from the truth where third-party monetization of tax benefits is concerned. The costs of such deals to project developers typically include extensive additional due diligence; substantial extra documentation and legal fees (including legal fees of the tax-equity provider); and opportunity costs in the form of lengthy delays before tax-equity transactions can close – in addition to "haircuts" that often mean at least a 20% reduction in the nominal "face value" of tax benefits.

● The Report correctly recognizes that utility-side interconnection costs can be project killers. For this reason it seeks to identify such costs separately from direct project-related component costs. Despite admitted wild variations in ISA and other available interconnect cost data, it apparently assumes average non-BTM costs in 2016 of ~ $158/kW-dc capacity for large ground-mounted projects (pp. 38-40). This translates to ~ $884K ($158 X 5600 kW-dc capacity) for a 5.6 MW-dc project on a statewide basis.

However, statewide averages do not reflect wide geographic variations in such interconnect costs (including opportunity costs resulting from different periods of impact-study delay) among serving utilities. Nor do they reflect location-based factors that soon may make apparent high-cost "outliers" the norm. For example, interconnect costs of a ground-mounted project in congested areas within (say) SEMA may far exceed statewide averages. That also may be true in "uncongested" rural areas, where such projects are at the end of a circuit or face other voltage or frequency constraints.[2]

[2] CFS is personally aware of one 400 kW-dc project in a rural area of Western MA that recently received an initial impact study cost estimate of nearly $700,000 (± 25%). As a result the developer has abandoned this project.

In addition, it is not clear whether or how SEA or DOER may have inflated or discounted such costs over their apparent 5- year time horizon. Nor is it clear how such costs are reflected in the Straw's proposed tariffs. The installed cost trajectories at Report pp. 40-42 apparently track only project components, and do not include interconnection costs.

• The Report apparently assumes a 5% discount rate for project revenues. This is far below the financier-acceptable discount rates that we – or, we believe, other industry participants – have seen. In our experience, an 8% discount rate is the most favorable potential scenario for modeled PV projects. Moreover, it generally is available only where projects have stable investment-grade off-take by rated government entities or the like. A discount rate of 10% to 12% is far more common.

• What values SEA input for project property tax costs are barely described. The Report notes in passing that there is a "higher required incentive for third-party-owned systems" which are not BTM. (p. 46). However, this observation appears to relate solely or mostly to *income taxes on net excess generation* – revenues that fall outside conventional state tax-exemptions for residential or commercial PV property installed BTM. Real and personal property taxes for non-BTM projects are not addressed in any quantitative detail.

This is a significant omission. Comprehensive data on current property-tax burdens for ground-mounted projects are difficult to obtain due to their localized nature. Nevertheless, our experience (based in part on CFS/Kearsarge projects completed or pending completion since 2013) strongly suggests that current annual *personal property-tax burdens alone* of $13,000 to $15,000 per MW-dc of capacity -- $65,000 to $75,000 per year for the life of a 5 MW-dc project, or about $1.4 million over 20 years – are close to the norm. Moreover, such assessments appear to be increasing not decreasing over time.

• SEA apparently did not discount expected NMC revenues from the nominal gross value of a Net Metering Credit (Report, p. 58 n. 34). By implication, neither did DOER.

As DOER is aware, such gross values vary substantially by utility service-territory – from current levels of about 20₵/kWh in SEMA to only about half of that in Eversource-WMECO. They also are adjusted periodically. Many observers expect them generally to trend down over time. Whatever their 2016 "start rate," how the underlying models reflected such changes and how those values were translated to the Straw's proposed incentive levels remains unclear.

More immediately, gross NMC values *always are discounted significantly in sales of such excess generation to third-party contract "off-takers."* Absent such discounts, those off-takers would have no economic reason to acquire NMCs – they would continue to secure energy at retail rates, leaving potential VNM providers without counterparties. For this reason, gross NMV values typically are discounted by VNM projects to their "customers" by 15% to 20%. The extent (if any) to which such discounts were taken into account in determining "financeable" project NMC revenues remains unclear.

• The Report also does not seem to reflect the recent 40% volume reduction and associated reduced "energy" revenues for "market net metering credits." Under H.B. 4173 (Acts of 2016, Chap. 75), new VNM projects apparently will receive no revenue whatever for 40% of their production. How SEA's modeling reflected this looming reduction in conventional project revenues, and what adjustments DOER may have made to compensate for that reduction in the Straw's proposed incentive levels, similarly are unclear.

• Finally, the Report appears to overstate the value of project revenues from the Class I REC "tail" after FIT-based incentive payments would cease. We noted in our previous comments that "REC traders currently are characterizing the MA REC market as "unstable" and are projecting Class I values not much higher than 3₵/kWh within the next five to seven years." The distorting inflationary effect on "financeable returns" of assuming higher Class I values is magnified by the Report's apparent 25-year time horizon and the relatively short 10- to 15-year incentive tenors assumed by the Straw.

The cumulative effect of the points above apparently is to:

→ presumptively understate the tariff-based incentive levels required for "reasonable returns" that will be sufficient to make ground-mounted projects financeable;

→ substantially understate such incentive payments *even for projects under 650 kW and other project categories that conservatively would have received predictable SREC revenues* under DOER's previous incentive programs; and

→ make it impossible for affected parties to determine how the Straw's proposed incentive payments were determined, let alone identify or address any shortfalls in that process.

We accordingly urge DOER to remedy this situation by **making the pertinent models and/or their input assumptions promptly available for comment.** Without such disclosure, meaningful comment will be limited at best.

We would be pleased to discuss any aspect of the points above.

Thanks as always,

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for

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C (e): Interested parties