Dear Mr. Franz:

Below are responses to selected questions posed in the request for comments.

**What types of process heat applications will you consider installing? Please describe the load and the system configuration, including temperature needs, storage needs, etc.**

California’s solar industry can provide renewable-energy alternatives to fossil-fuel use by commercial and institutional facilities and industrial plants, thereby increasing the state’s fuel diversity and security and reducing emissions of criteria pollutants and greenhouse gases. Each application must be evaluated so that the solar energy system is configured to interface with the commercial or industrial plant. Some configurations will have thermal energy storage, others will not.

Industrial uses of heat can be many tens of millions of Btus per hour. Temperature requirements range from 120°F to 500°F, a range well suited to solar thermal technologies. California’s food processing industry, for example, uses hot water for clean-up and heats water or other heat-transfer fluids for sterilization, pasteurization, cooking, and other processes. It generates steam as a heating medium for applications such as sterilization, pasteurization, cooking, frying, and baking. Food processing facilities may operate 24/7 or only five days per week.

**Do you foresee applications that produce steam in the collector?** If yes, please describe the application.

Industrial plants use steam to transport thermal energy, so steam production is a major solar thermal market. Direct steam generation (DSG) in the collectors is a potential means of reducing the cost of solar-steam production. DSG is still in the developmental stage, but we should expect to see field deployments in the next few years.

**Should [the CPUC] develop installation standards and system design requirements? If so, what should those standards be, or by what process should we develop them?**

The same building codes, ASME pressure vessel codes, plumbing and electrical codes, etc. that apply to conventional heating equipment like boilers also apply to solar thermal
collector systems. Standards specifically for solar thermal technologies, therefore, would be redundant. Existing CSI regulations require sign off by building officials performing the role of inspectors.

**How should [the CPUC] calculate energy displacement for purposes of paying CSI-Thermal incentives? Options include:**

**Up Front:** Program Administrators create a simulation tool to predict system performance, and payment is made in one lump sum based on that estimate.

Up-front payments would be the most advantageous to the solar industry and host facility, because they provide the maximum financial incentive. Providing all the incentive up-front, however, may remove motivation for ensuring the solar energy system operates efficiently throughout its life. Abengoa Solar recommends paying an up-front incentive for small-sized projects only.

Creating a simulation tool is not trivial given all of the industrial applications that can exist for steam, hot water, hot oil, etc. The number of cases, however, is finite. Over time, the necessary tools will be developed.

**70/30 true-up:** A partial payment is made up-front, and the balance paid after 1 year of metering.

A 70/30 incentive structure is a good approach to "jump start" solar-thermal applications in the industrial and commercial sectors, where no applications currently exist. The solar energy system would be monitored and, therefore, would need to perform well over the first year to receive the full payment.

**Performance-Based Incentive:** Pay incentive based on actual metered energy displacement over a number of years. The nominal value of the incentive would be increased to compensate the customer for time-value of money. Metering cost would be borne by the applicant.

Abengoa recommends PBI incentives be instituted after a period of providing 70/30 incentives. PBI incentives would be paid for the heat delivered (that is, no delivery, no incentive payments).

For simplicity, Abengoa recommends that PBI be paid per kW-thermal delivered, at a fixed rate over a fixed term, such as 10 years. Program administrators would need to predict each solar project’s performance and then set-aside funds for future PBI payments. This set aside could be adjusted based on year 1 measured system performance. Actual payments over the term, however, would be based on measured energy delivery, or energy displacement if a fuel-burning efficiency factor were added.
Should project size determine the incentive calculation method?

If the goal is to maximize GHG displacement with the available funds, then no upper limit should be imposed on incentive payments. Otherwise, the program would work against larger systems that can achieve economies of scale and drive down the cost of solar energy. If the goal is also to encourage small systems, such as residential or small commercial, then such systems could be offered larger per-unit incentive payments.

If the incentive payment is based on a modeling simulation, how should [the CPUC] determine building load profiles?

A solar simulation model is only as accurate as the load forecast. Some types of data are always available at a commercial facility, but engineering judgment is required to interpret the data. You put the collector SRCC ratings into the model and the solar field has a potential to deliver X. However, if the load is smaller than X, the modeled amount of solar energy will not be delivered. Under 70/30 or PBI, the system user suffers in terms of incentives if they over-estimate the load. With up-front payments, the user gets the incentives, but will suffer if energy savings are not as predicted. Hence, under 70/30 or PBI, the model is more of an estimation tool to give an idea of the range of incentive payouts, whereas for upfront payments, the model is the payment mechanism.

If there are options for determining load profiles other than those listed below, please provide them.

Options for determining load profiles include:
1) Use data from pre-installation metering for a given period and extrapolate to create a load profile for 8760 hours of the year (Professional Engineer stamp would likely be required).

Thermal load data can be difficult to obtain, especially in complex industrial operations. It must come from plant personnel and recent utility fuel bills. Even with these data inputs, solar system designers must use professional judgment. In an ideal word, solar project developers would install flow meters and temperature sensors and collect data for a year. This data-collection effort, however, is impractical, costly, and intrusive to plant operations and rarely allowed by the host-site’s personnel. If using 70/30 and PBI incentives, the solar-project owners, not the program administrators, bear the risk of inaccurate estimates. Hence, under these conditions, the at-risk system user should make the decision as whether or not to employ a professional engineer to predict energy consumption.
2) Use data from the California Commercial End Use Survey Data (link: http://www.energy.ca.gov/ceus/index.html)
Gross energy use is of little value when evaluating specific load requirements.

References to Abengoa Solar’s Process Heating Applications


Please let me know if I can be of further assistance in this important work.

Best regards,

Ken May
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