Response to Dr. Severin Borenstein's January 2008 Paper on the Economics of Photovoltaics in California

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SUMMARY

This brief white paper provides our initial response to Dr. Severin Borenstein's recent paper on the economics of photovoltaics (PV) in California – "The Market Value and Cost of Solar Photovoltaic Electricity Production" (Center for the Study of Energy Markets, January 2008). Dr. Borenstein's paper concludes that the market value of PV production in California today is about one-third of its cost (with a range from 13% to 56%, depending on assumed inflation and discount rates). He concludes that PV today is so uneconomic that an effort to value the environmental and energy security benefits of PV will not close the gap. Dr. Borenstein also finds little value in California's current PV incentive program as a means to drive innovation and cost reductions in solar technologies.

Our review focuses solely on the technical aspects of Dr. Borenstein's paper. There are a number of fundamental problems with Dr. Borenstein's analysis. First, he evaluates small residential PV systems as a source of wholesale power, when in reality they serve electric loads at the retail level, at the point where electricity is consumed. Thus, he largely ignores or dismisses the ability of PV to reduce the costs for the transmission and distribution (T&D) of electricity. Second, he uses one data series of wholesale prices from 2000 - 2003 that is distorted and out-of-date and, by his own admission in another paper, may be unrepresentative of the current market. Third, his second set of wholesale prices is based on a 2005 simulation of the California wholesale market that substantially understates today's much higher costs for fuel and generating capacity.

Dr. Borenstein does find that the value of PV is as much as 30% to 50% higher than the average market price, because most PV generation is produced when the demand for, and the value of, generation is the highest. This result is consistent with our own analyses. If this result were applied to a reasonable measure of current generation costs (such as the California Public Utilities Commission's [CPUC] market price referent for renewable generation), and if one added widely-used measures of the marginal T&D costs that PV can avoid, the value of PV production is almost twice what Dr. Borenstein estimates. This is close enough to the cost of PV that a serious effort must be made to value the external benefits of PV generation. Finally, the cost-effectiveness of an emerging technology like PV should be assessed from a longer-term perspective, for example, over the full ten years of the California's initiative to transform the PV market. The analysis should consider reasonably expected reductions in PV costs as the technology is improved and deployed on a greater scale, as well as anticipated increases over the next decade in the value of renewable generation that serves peak electric demands.

DETAILED RESPONSE

We discuss below the technical issues we have identified with Dr. Borenstein's recent paper on the economics of photovoltaics (PV) in California,[1] which we refer to below as his "PV Paper," to distinguish it from other papers that he has authored that we also cite.

A. PV Systems Serve Retail, not Wholesale, Loads.

Dr. Borenstein's paper examines the wholesale market value of electricity produced by photovoltaic (PV) systems. Distributed PV systems, particularly the small 10 kW systems considered in his paper, serve on-site loads at the retail level. The California's PV incentive program and net metering structure limit a PV system's output to no more than the on-site, retail load served. Fundamentally, PV systems in California today provide retail electricity.

Widely distributed small PV systems that supply retail demand at the point of use should be evaluated using the same framework as energy efficiency programs that reduce retail demand at the point of use. The only retail delivery costs that Dr. Borenstein includes in his valuation are line losses. The paper repeats the typical short-run perspective of utility managers that small changes in end-use demand do not allow the utility to avoid the costs of distribution infrastructure *[17]*. In this view, a PV system does not reduce the costs of distribution, nor does an EnergyStar appliance. This perspective does not makes sense in the long-run, particularly in a state with such impressive long-term results from its energy efficiency programs. In the long-term, there will be a million roofs with PV and tens of millions of EnergyStar appliances, and their impacts on the distribution system will be significant.

It is well-known that electric use per capita has not increased in California over the past 30 years, while per capita electric use in the rest of the U.S. has increased by 50%.[2] It is inconceivable that California's energy efficiency accomplishments have not allowed the state's utilities to avoid capital investments in transmission and distribution. The CPUC has long recognized this fact in its cost-effectiveness evaluations of energy efficiency programs: avoided investment-related T&D costs are included in the CPUC's adopted E3 model for the avoided costs associated with energy efficiency programs.[3] Generally, these avoided T&D costs are based on the utilities' marginal T&D costs. The calculation of marginal, investment-related T&D costs

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[1] "The Market Value and Cost of Solar Photovoltaic Electricity Production" (Center for the Study of Energy Markets, January 2008). All page numbers cited in brackets in the text or footnotes refer to this paper.

[2] See the joint CEC/CPUC document "Energy Efficiency: California's Highest Priority Resource" (August 2006), at Figure 1. Available at http://www.cpuc.ca.gov/PUC/energy/electric/Energy+Efficiency/EE+General+Info/.

[3] In D. 05-04-024, the CPUC adopted the use of the E3 model for cost-effectiveness calculations for energy efficiency programs. The model was updated in D. 06-06-063. It is available at http://www.ethree.com/cpuc_avoidedcosts.html, including the report (the E3 Report) from E3 describing the development of and key assumptions used in its model – "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs" (October 25, 2004), prepared for the CPUC's Energy Division.

has been a fundamental element of electric rate design in California since the 1980s; marginal T&D costs are updated in each utility general rate case before the CPUC. A significant portion of T&D costs are driven by customers' peak demands, and thus are avoided by PV production during peak periods.[4] In our view, the use of a retail-level model such as E3's avoided cost model would be a far better means to evaluate the cost-effectiveness of PV than the wholesale market approach that Dr. Borenstein has used.[5]

B. Distorted Wholesale Price Data from 2000 - 2003

The PV Paper uses two sets of data on wholesale market prices. The first is a series of actual real-time market prices from the California Independent System Operator (CAISO) over four years from 2000-2003 *[9-10]*. This data is not just out-of-date; even in 2000 - 2003, these prices were distorted by extraordinary events. Prices in the winter of 2000-2001 were distorted (too high) by the California electricity crisis. Wholesale electric prices in the summer and fall of 2001 and in 2002 - 2003 were much lower than such prices today due to much lower natural gas prices[6] and to reduced demand and excess generating capacity. Dr. Borenstein himself, in another paper, has concisely summarized the problems with this data:

> The value of this whole exercise depends on the plausibility of the distribution of wholesale prices assumed. One could use the actual California prices from the same time period as the customer-level

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4 Although Dr. Borenstein does not believe that PV can reduce the costs of distribution infrastructure (except for line losses), he does concede that widely distributed PV could reduce the costs of the transmission system, by reducing end-use demand during peak periods *[17]*. In this regard, he does agree that PV systems can be viewed as a reduction in the effective demand at the point of use.

5 The E3 Report, at page 2, emphasizes that its work is most appropriate for evaluating resources with the following qualities:

- **Reduce load or produce energy for hundreds of hours per year in a predictable pattern.** The predictable pattern reduces issues related to uncertainty over the timing and reliability of the effective behind-the-meter reductions in load.
- **Are relatively small (such that they can be installed behind the customer meter).** If the resource is small so that the utility can plan its T&D capacity additions based on the expected net load of customers, then those resources can be credited with generation and T&D capacity savings.
- **Are expected to be installed in large numbers.** The more resources that are installed, the more diversity one has, and the more one can rely upon the expected level of reductions on the utility grid. Also, the more resources that are installed, the more likely that the resources will provide sufficient load reductions to defer local T&D projects.

PV systems meet all of these criteria.

6 Natural gas prices from the summer of 2001 through the end of 2003 were $2 - $5 per MMBtu, compared to today's post-Katrina gas prices of $7 - $9 per MMBtu.

> data [2000 - 2003]. While these prices have some credibility, there is a real issue of how representative they are of likely prices in the future. In particular the 2000 to 2003 period includes both the California electricity crisis — which ran roughly from June 2000 through May 2001 — and the subsequent over-capacity and prices that were widely viewed as having been below long-run equilibrium levels. The 2000-01 crisis resulted in prices that were higher, and possibly more volatile, than normal levels, while the subsequent glut of capacity almost certainly damped peak prices more than off-peak prices, leading to reduced price volatility that would tend to understate the wealth transfer effect that introduction of RTP [real time prices] would have.[7]

Dr. Borenstein's PV Paper does not attempt to resolve the "real issue" of the credibility of using 2000 - 2003 California market prices as the basis for an evaluation of market conditions in California today, although his paper quoted above concluded that a set of simulated market prices would be "more representative" of future conditions.[8] Data is readily available on today's wholesale electric market prices in California, including data on hourly prices in the CAISO's real-time market or on day-ahead bilateral trades (on- and off-peak blocks) reported by Dow Jones, Platts, and others. Although today's wholesale market has its own set of issues (such as the lack of capacity value in the market, no hourly prices in the day-ahead market, and no convergence between real-time and day-ahead prices), current prices are more representative of market conditions today than is data that is four-plus years old. Reasonable measures are also available of the "all-in" (energy and capacity) price for new wholesale generation in California, such as the CPUC's annual calculation of the market price referent (MPR), which is the all-in cost of a new natural gas-fired combined-cycle power plant built in California.[9]

C. Use of a Price Series with Abnormally High Winter Prices

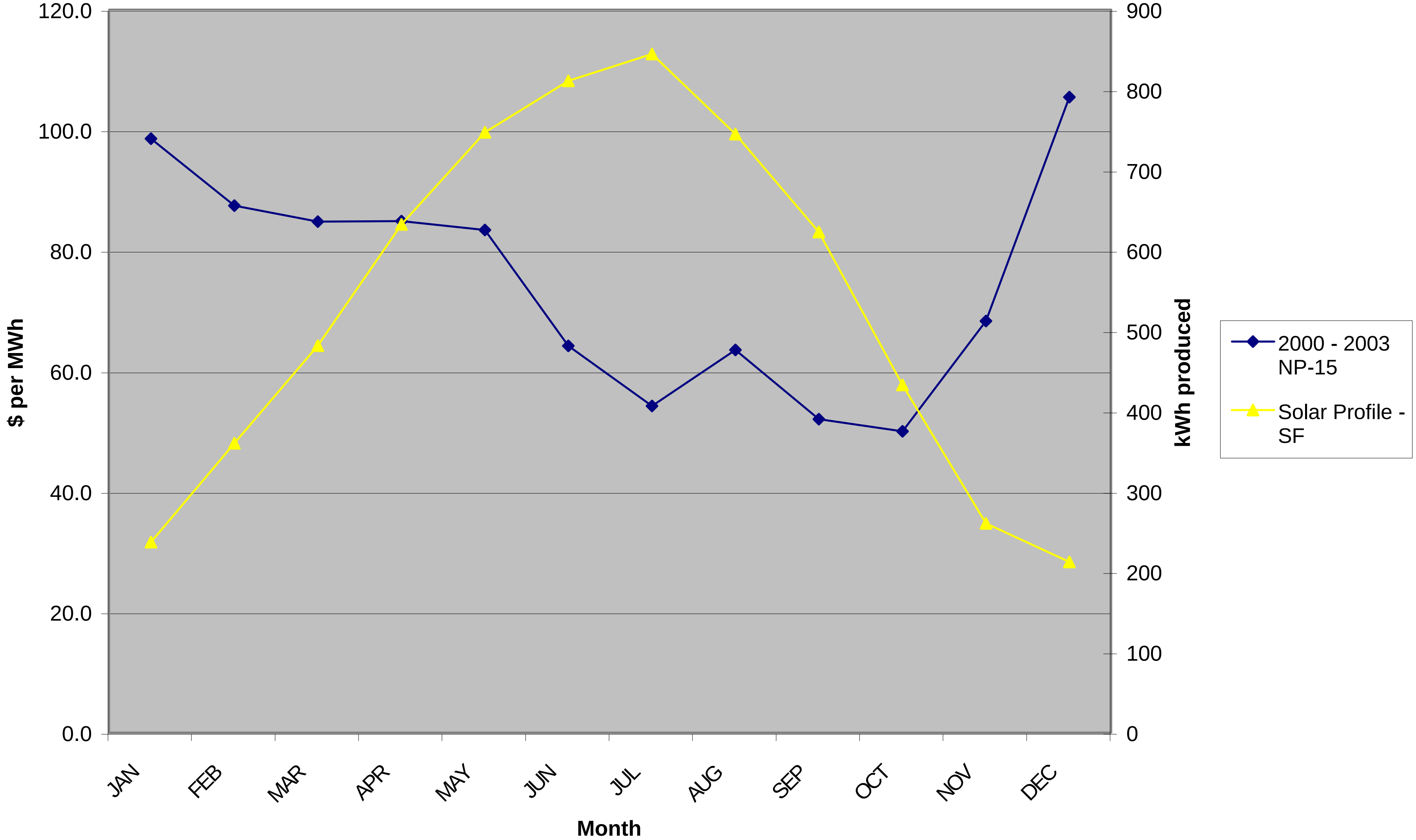
We note that the sustained, very high prices during the California energy crisis occurred mostly during the winter of 2000 - 2001, in months when PV output is low. The attached **Figure 1** shows the monthly average of wholesale, day-ahead market prices reported by the California Power Exchange (to January 2001) and by Dow Jones (after January 2001) in each month of the year for the years 2000 - 2003, compared to the average PV output from a south-facing PV system in San Francisco. The figure shows clearly that 2000 - 2003 wholesale prices featured much lower prices in summer months compared to winter months. The highest wholesale prices were in December and January of those years. Dr. Borenstein's choice of 2000 - 2003 wholesale price data is not representative of California's summer-peaking electric system: wholesale

7 Borenstein, "Wealth Transfers Among Large Customers from Implementing Real-time Electricity Pricing" (July 2006, CSEM Working Paper 156 – also in The Energy Journal, vol. 28, no. 2 [2007]), pp. 4-5.

8 *Ibid.*

9 The 2007 MPR was adopted in CPUC Resolution E-4118 (October 4, 2007).

Figure 1: 2000 - 2003 NP-15 Wholesale Market Prices compared to a PV Output Profile



electric prices in California today typically are high in the summer, and would be even higher if the current market fully valued capacity as well as energy. As a result, Dr. Borenstein's use of 2001 - 2003 data may undervalue the summer output of PV systems.

D. Use of CAISO Real-time Prices

We have a fundamental problem with the paper's use of CAISO real-time prices. The CAISO's real-time market is a small balancing market whose prices often are based more on the balance between scheduled and actual loads than on the fundamental supply/demand conditions in the wholesale market.[10] For the last five years, CAISO real-time prices have not converged with reported day-ahead bilateral market prices, and typically average 10% to 30% below bilateral day-ahead NP-15 and SP-15 prices reported by Dow Jones and Platts. In 2003, for example, CAISO real-time prices were 20% lower than bilateral day-ahead prices reported by Dow Jones. The low real-time prices may result from the requirements that the FERC has imposed since the energy crisis that force generators to bid their generation into the real-time market.

E. Use of Simulated Prices with Based on Outdated Generation Costs

Dr. Borenstein's second series of wholesale prices is a set of simulated market prices constructed assuming market prices are in a long-term equilibrium that allows generators to receive full average cost recovery for a system with baseload coal generation, gas-fired combined-cycle (CCGT) generation for intermediate loads, and gas-fired simple-cycle combustion turbine (CT) peakers *[10-11]*. The generation costs used to produce this data seem to date from 2005 *[10, ftn 15]*. It is unclear when these costs were calculated, but they do not appear to reflect either post-Katrina natural gas prices or the extraordinary 2006 - 2007 increases in power plant construction costs. The PV Paper uses CCGT fixed and variable costs of $94 per kW-year and $50 per MWh, respectively *[10, ftn 15]*. In comparison, in October 2007 the CPUC adopted its 2007 MPR using CCGT fixed costs of $178 per kW-year and variable costs of $69 per MWh.[11] For CTs, Dr. Borenstein uses fixed and variable costs of $72 per kW-year and $75 per MWh *[10, ftn 15]*. Current annual CT fixed costs range from $119[12] to $176[13] per kW-

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[10] For example, real time prices can be low if actual demand is significantly lower than scheduled demand, even if it is a high-demand summer day with high day-ahead prices. The converse can also occur – high real-time prices can occur if actual demand exceeds scheduled demand, even in an off-peak period.

[11] CPUC Resolution E-4118, issued October 4, 2007, approved the 2007 MPR. The 2007 MPR spreadsheet model is attached to the resolution. CCGT fixed and variable costs are for a 20-year contract starting in 2008. The variable CCGT costs are shown in Appendix A to the resolution; see the Cap_Fac tab of the model (cell E4) for CCGT fixed costs in $ per kW-year.

[12] Based on CT capital costs of $1,000 per kW and fixed O&M costs of $11 per kW-year, as reported by the CEC for 100 MW simple-cycle peakers in its 2007 study of comparative generation costs in California (CEC Generation Cost Study). See Tables 6 and 19 and Figure 11of this report. This study was part of the CEC's *2007 Integrated Energy Policy Report (2007 IEPR)* process, and is available at http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF. We annualize the

year, with CT variable costs of $100 per MWh.[14]

Dr. Borenstein's simulated prices show volume-weighted average prices in the range of $67 - $68 per MWh (see the PsimH and PsimL values in the second column of his Table 1). These simulated prices are somewhat higher than recent (2005 - 2007) wholesale market prices, which have averaged $56 per MWh in NP-15 over the years 2005 - 2007. However, current wholesale market prices clearly are inadequate to support new generation in the state. A better measure of the "all-in" (energy and capacity) price for new wholesale generation in California today is the CPUC's annual calculation of the MPR, based on the all-in costs of a new natural gas-fired combined-cycle power plant built in California. Dr. Borenstein's second price series is about 30% below the CPUC's 2007 MPR, which ranges from $96 to $101 per MWh for CCGTs with 20-year contracts and on-line dates from 2008 - 2012.[15]

F. Congestion Costs

The PV Paper examines the potential transmission benefits of PV only by examining congestion costs. Dr. Borenstein uses a set of 29 zonal prices for the CAISO system that date from 2003-2004, and examines whether PV systems have been located predominantly in areas with higher congestion-related costs *[17-19]*.[16] Dr. Borenstein's analysis shows, essentially, that PV systems are widely distributed, and are roughly as likely to be located in areas with lower congestion-adjusted wholesale prices as they are in areas with higher congestion costs *[19]*. We agree with Dr. Borenstein's conclusion that this result is not surprising, because the purchasers of PV systems are using their systems to offset their <u>retail</u> cost of electricity, and retail electric rates in California have no information about congestion costs.

It is important to note that congestion costs represent the additional energy-related costs necessary to re-dispatch the system to avoid transmission constraints. Congestion costs do not

capital costs using a real fixed charge rate of 10.84%, which is the one used by Southern California Edison to annualize CT capital costs in its last general rate case, A. 05-05-023.

[13] Based on the $1,455 per kW that Southern California Edison spent to build four 45 MW peakers in southern California in 2006-2007 and $18 per kW-year in fixed O&M for these smaller peakers. See A. 07-12-029, filed December 31, 2007, at 2-3, and Figure 11 from the CEC Generation Cost Study. We annualize these CT capital costs using the same fixed charge rate of 10.84% described in footnote 10.

[14] The CEC Generation Cost Study reports CT heat rates of 9.266 MMBtu/MWh and variable O&M of $26 per MWh; see Table 20 and Figure 12 from the CEC Generation Cost Study. Assuming natural gas at $8 per MMBtu, CT variable costs are $100 per MWh.

[15] CPUC Resolution E-4118, at 1.

[16] This data set appears to date from the early stages of the CAISO's development of nodal pricing on its system, a process that has taken more than six years. The CAISO's MRTU nodal pricing regime (with 3,000 pricing nodes) is scheduled to "go live" this year, although the planned April 1, 2008 start date has been delayed due to testing problems. It is difficult to draw real-world conclusions from the various MRTU simulations that the CAISO has released during the long development of its nodal pricing scheme.

necessarily represent the full transmission investment costs that may be avoided by PV generation, as transmission can be added for reasons other than avoiding congestion (for example, to serve increased peak demands or to access new supplies). Dr. Borenstein concedes that widely distributed PV could reduce the cost of transmission infrastructure, by reducing end-use demand, particularly at times of peak demand *[17]*, but does not attempt to value such avoided investment-related transmission costs.

G. Overall Value of PV

The CPUC's 2007 market price referent indicates that an average wholesale market price of about $100 per MWh is necessary for full recovery of both capacity- and energy-related generation costs in the California wholesale market today. Accepting Dr. Borenstein's analysis in his PV paper that the value of PV is 30% to 50% higher than the average market price *[16]*, the wholesale market value of PV would appear to be $130 to $150 per MWh. To this we would add $30 to $50 per MW for avoided T&D costs that Dr. Borenstein does not consider, based on recent marginal T&D costs in California utility rate cases.[17] The resulting value for PV of $160 to $200 per MWh is close enough to the cost of PV, such that – contrary to Dr. Borenstein's conclusions – a serious effort to value externalities is necessary before reaching any conclusions about the cost-effectiveness of PV in the California market.

Further, the goal of the California Solar Initiative is to achieve a market transformation over a ten-year period, such that at the end of the program PV technologies can compete on a stand-alone basis. Thus, the cost-effectiveness of an emerging technology like PV should be assessed from the longer-run perspective of the full ten years of the California's initiative to transform the PV market. The analysis should consider reasonably expected reductions in PV costs over time, as well as anticipated increases in the value of renewable generation that serves peak electric demands. In the spring of 2005, one of us (Tom Beach) presented an initial effort to do such an analysis using the CPUC's adopted E3 model, in testimony in the CPUC's proceeding on distributed generation.[18] That analysis showed that the societal benefits of a program to provide incentives for a million PV installations over a ten-year period would exceed the costs. We anticipate that updating such an analysis today would show even greater benefits, due to the significant increases in fossil fuel and power plant construction costs that have occurred since 2005.

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[17] For example, SDG&E's filed marginal distribution costs (A. 07-01-047) total $63 per kW-year. Assuming that a PV system operating in peak hours avoids these costs, and the PV system has an overall capacity factor of 18%, the avoided distribution costs amount to $40 per MWh.

[18] "Prepared Direct Testimony of R. Thomas Beach on behalf of the California Solar Energy Industries Association," served April 28, 2005 in R. 04-03-017.

H. Externalities

Dr. Borenstein mentions greenhouse gases (GHGs) and the security benefits of distributed generation as external benefits of PV systems *[25]*. The benefits of reducing emissions of criteria and GHG pollutants can be quantified in California; these values are included in the E3 model.[19] There are other external, but quantifiable, market benefits of PVs that Dr. Borenstein does not mention:

- The E3 model includes the price elasticity benefits of reducing demand on the grid – lower demands reduce the market-clearing price for all power bought at the prevailing market price.[20]

- Similarly, renewable generation displaces natural gas use, thus reducing the demand for gas, and its market price. The work of Wiser *et al.* has quantified this benefit in the California market – about $5 per MWh.[21]

- The reduced reliance on natural gas also removes ratepayers from exposure to volatility in natural gas prices. The CEC's *2007 Integrated Energy Policy Report* includes an analysis quantifying this "fuel price risk" benefit as adding 10% to 15% to the CPUC's market price referent.[22]

- Resources that increase economic activity in California may be preferred to resources where most of the money spent benefits out-of-state economies. For example, the largest cost component for natural gas-fired generation is the fuel itself. California imports about 85% of its natural gas supplies,[23] so much of the economic activity stimulated by gas-fired generation benefits the other states and provinces where most of California's natural gas is produced. In contrast, investments by consumers and the state in solar generation

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[19] We recognize that the valuation of reductions in GHG emissions may undergo significant change in the near future, as California and the rest of the U.S. and the world develop more comprehensive control strategies for GHG emissions. The GHG emission values of about $10 per short ton of CO_2 now used in the E3 model are likely to be at the low end of future values; the large European cap & trade market is now trading at up to $30 per short ton of CO_2.

[20] See Section 2.7 of the E3 Report. avoided cost report.

[21] R. Wiser, M. Bolinger, M. St. Clair, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (LBNL-56756, January 2005), available at http://eetd.lbl.gov/EA/EMP.

[22] CEC *2007 IEPR*, at 181 - 184, esp. Table 4-10. The *2007 IEPR* is available at http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF.

[23] The *2004 California Gas Report*, at page 9, indicates that, in 2004, only 660 MMcf/d (12%) of the state's 5,338 MMcf/d of total gas demand will be served from California production. California production also provides a small amount of additional gas that is consumed by private parties at or near the production fields and is not included in the *CGR* data.

> will produce greater benefits for the California economy than will investments in the gas-fired plants that they replace. More broadly, Dr. Borenstein's colleague Professor Daniel Kammen of U.C. Berkeley has studied the incremental economic benefits associated with renewable energy, and has estimated that 1.6 to 2.2 additional jobs are created per MW of PV installed, over the life of a facility, compared to conventional electric generation.[24]

All of these benefits would add appreciably to the calculated value of PV generation in California.

[24] Daniel M. Kammen, Kamal Kapadia, and Matthias Fripp (2004), "Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate?" (RAEL Report, University of California Berkeley, Energy & Resources Group, April 13, 2004).