Bill Powers, P.E., Response to December 2007 "Long-Term Electricity Planning in the SDG&E Service Area" by David Rohy, Ph.D.

David Rohy, Ph.D. prepared an analysis of "*San Diego Smart Energy 2020 – The 21st Century Solution*" (October 2007) titled "*Long-Term Electricity Planning in the SDG&E Service Area.*" The analysis was distributed on December 14, 2007. The purpose of this document is to respond to the assertions in "*Long-Term Electricity Planning in the SDG&E Service Area.*" A question and answer format is used to make this document more readable.

There does appear to be a fundamental misunderstanding regarding the amount of solar photovoltaic (PV) energy proposed in *San Diego Smart Energy 2020 (Smart Energy 2020)*. The Rohy critique asserts that *Smart Energy 2020* calls for almost all regional electric energy demand to be met by residential rooftop PV systems funded by homeowners. This is not the case.

Two scenarios of PV development are described in *Smart Energy 2020*.

In the first scenario, only 28 percent of the San Diego region's total annual energy requirement would be met by rooftop PV systems. Most (85 percent) of this PV resource will be added to the regional grid in the 2015-2017 timeframe.

In the second scenario, only 14 percent of the San Diego region's total energy requirement would be met by rooftop PV systems. The majority of this PV energy in both scenarios would be generated by large (greater than 100 kW) PV installations on local commercial structures under third party long-term power purchase agreements.

There would be no upfront costs to the building owners or the purchasers of this commercial PV energy. This is the same successful contracting format used by the City of San Diego and San Diego City Schools for large PV arrays. Both the City of San Diego and San Diego City Schools are paying the third-party provider less for this PV energy than they would pay SDG&E for the same energy.

Summary

The goals of *Smart Energy 2020* can be achieved within the existing investor-owned utility context if:

- Maximum cost-effective energy efficiency is achieved as result of the recent (September 2007) CPUC decision that authorizes the same utility profit for aggressive energy efficiency measures as for "steel-in-the-ground" transmission and generation projects;
- AB 1969 "standard offer contract" for local renewable energy is expanded to include PV and there is no cap on MW output from these standard offer contracts per CEC recommendation;
- Feed-in "must take" renewable energy tariff is established per CEC recommendation;
- Distributed generation (DG) portfolio standard is established, modeled on the renewable energy portfolio, to ensure DG gets built per CEC recommendation. The CEC has developed a roadmap to achieve 25 percent of peak demand from DG by 2020.

The goals of *Smart Energy 2020* could also be achieved within the Community Choice Aggregation (CCA) structure if insufficient forward progress is made working with the existing investor-owned utility framework. The rationale for forming a CCA is straightforward – local control and greater focus on local objectives, especially regarding renewable energy. As described in the 2006 CCA fact sheet prepared by the Local Government Commission: "*Many communities want to increase the amount of non-polluting, renewable energy they use, and are looking at CCAs as a mechanism for doing so. Under CCA, decisions about rates, generating resources and public benefit programs will be made locally and be accountable to local customers.*"

Within the CCA model, the CCA is responsible for generation while the investor-owned utility continues to be responsible for transmission and distribution. The tax free, low-cost municipal bonds available to CCAs to finance renewable energy projects is one reason CCAs may be able to offer competitive retail electricity rates while achieving considerably higher renewable energy targets than their investor-owned utility counterparts. For example, the San Francisco CCA has established a target of 51 percent renewable energy by 2017. California's investor-owned utilities are currently subject only to a requirement to reach 20 percent renewable energy (as a percentage of retail sales) by 2010.

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<u>Assertion #1</u>: All power will come from rooftop solar under San Diego Smart Energy 2020. "*But a third group (the Powers' proposal) sees no reason to celebrate. They will not celebrate unless essentially all of our electricity comes from rooftop photovoltaic cells in the next few years. (Photovoltaics are the rooftop solar panels that produce electricity when the sun is shining.)*" (Rohy, p. 1)

<u>Response to Assertion #1</u>: The assertion that *Smart Energy 2020* calls for all energy demand to be addressed by rooftop solar in a few years is incorrect. *Smart Energy 2020* presents two scenarios as outlined in Tables 1-1 and 1-2 of the report. In the first scenario, only 28 percent of the San Diego region's total annual energy requirement would be met by rooftop PV. The bulk of this PV will be added in the 2015-2017 timeframe. In the second scenario, only 14 percent of the San Diego region's total energy requirement would be met by rooftop PV. The majority of this PV energy would be generated by large (greater than 100 kW) commercial PV installations under third party long-term power purchase agreements. There would be no upfront costs to the purchasers of this PV energy. This is the same successful contracting format used by the City of San Diego and San Diego City Schools for large PV arrays. Both the City of San Diego and San Diego City Schools are paying the third-party provider less for this PV energy than they would pay SDG&E for the same energy. The PV systems under *Smart Energy 2020* will be equipped with sufficient battery storage to allow a shifting of the PV system output to match the afternoon peak demand profile.

<u>Assertion #2</u>: Smart Energy 2020 does not include large new transmission lines or generation resources in the region. "*This small group of people proposes that we have no new transmission facilities for transporting electricity into the region, and no new large generation facilities in the region.*" (Rohy, p. 1)

<u>Response to Assertion #2</u>: A basic premise of *Smart Energy 2020* is that local distributed generation resources, generally defined as resources under 20 MW, are just as effective at meeting grid capacity and reliability requirements as large new generation. Another tenet of *Smart Energy 2020* is the modernization of the aging regional distribution system to create a local "smart grid" must be the first transmission/distribution priority in order to fully realize the benefits of expanded distributed generation and of SDG&E's advanced ("smart meter") metering initiative.

The CEC reinforces this tenet in the 2007 IEPR, stating: "*About 90% of all customer interruptions and outages in California and the U.S. are caused by distribution problems or events*" (p. 196) and "*utilities spend about approximately three-quarters of their total capital budgets on distribution assets*" (p. 199).

The CEC goes on to state: "*Business as usual, where customers passively receive energy from the utilities, must change*" (p. 200) and "*As the goals of the state law are met over the next decade, the distribution system will be called on to integrate and efficiently use all the distributed energy resources that will be installed in California customers' homes and businesses. As California moves toward that, utility investment should be channeled into appropriate technologies and equipment that will lead to the development of a modern and smart network.*" (p. 200).

SDG&E is petitioning the CPUC for authorization to modernize its distribution system. *Smart Energy 2020* also advocates reinforcing the two major existing transmission pathways into San Diego to increase capacity by 550 MW at a fraction of the cost of constructing the Sunrise Powerlink. *Smart Energy 2020* assumes that two local 550 MW combined-cycle plants, Palomar Energy and Otay Mesa, will be in operation and providing power at night and during periods of inclement or cloudy weather when PV is not available. These elements are identified in Tables 1-1 and 1-2 of *Smart Energy 2020*.

Assertion #3: SDG&E's balanced plan is best for the environment, the consumer, and local businesses. "*The purpose of this paper is to rebut those arguments, showing that a balanced approach to utility planning is the best for the environment, best for the consumer and best for local businesses.*" (Rohy, p. 1)

Response to Assertion #3: *Smart Energy 2020* proposes a balanced mix of resources to achieve a two-thirds reduction in greenhouse gases by 2020 relative to SDG&E's current long-term procurement plan, while maintaining the retail cost of electricity at or below SDG&E rates. Aggressive and cost-effective energy efficiency measures will be used to reduce current annual energy demand by 20 percent and current peak demand by 25 percent.

Under *Smart Energy 2020*, annual energy demand in 2020 will be met by:

- Remote and local non-PV renewable energy per the AB 107 "20 percent renewables by 2010" mandate (equals 22 percent in 2020);
- Local combined heat and power (47 percent);
- Local PV (28 percent);
- Utility-scale natural gas-fired sources (3 percent).

In reality the combined-cycle plants will operate at about the same capacity that California combined-cycle plants currently average, 50 to 60 percent, serving the nighttime and cloudy/inclement weather loads in SDG&E service territory alone. During portions of the year the combined daytime output of the PV and CHP systems will exceed the local power demand and will be exported to neighboring grids. The net impact of this diurnal power flow into and out of the San Diego region, from a greenhouse gas emissions calculation standpoint, will be a relatively small amount of GHG emissions attributable to utility-scale natural gas-fired power generation (see *Smart Energy 2020*, Tables 1-1 and 1-2). The existing fleet of local gas-fired simple cycle turbines would continue to be available for reliability support.

Smart Energy 2020 would add over 3,000 MW of new local generation resources to meet peak demand, both PV and CHP, in addition to approximately 1,600 MW to 1,800 MW of existing utility-scale natural gas-fired combined-cycle and simple cycle resources. This would be more than sufficient local generation to meet the region's electric power needs, even if wildfires knocked-out transmission import corridors and electrically isolate the San Diego area at a time of peak electrical demand.

<u>Assertion #4</u>: SDG&E must add 100 MW per year in new generation capacity. "*SDG&E must add 100 MW per year in new generation capacity*." (Rohy, p. 2)

<u>Response to Assertion #4</u>: 100 MW is an incorrect figure. SDG&E identifies a peak demand growth rate of 61 MW per year in its December 11, 2007 2007-2016 Long-Term Procurement Plan (LTPP) submitted to the CPUC.

This peak demand growth rate assumes an average population growth rate in the San Diego region over the 10-year planning interval of 1.1 percent, five times the 2004-2006 population growth rate of 0.2 percent per year (LTPP Vol. III, p. 193). Regional population growth rate has been slowed by the high cost of housing. It is unlikely the high cost housing problem is going to be rectified so quickly that the population growth rate over the next 10 years will average five times greater than the growth rate over the preceding 3 years.

The SDG&E forecast growth rate described in the LTPP also assumes that per capita consumption of electricity will <u>increase</u> over the 10-year planning cycle, despite the growing California and worldwide focus on global warming - and the need to reduce greenhouse gas emissions - as the "issue of our time." This assumption is in direct conflict with CPUC decision D0709043 (September 25, 2007) – *Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency* – where the CPUC states (regarding the decision) that "*It also reinforces our commitment to ensuring that overall per capita electricity consumption in California holds steady, and declines in the future for the investor-owned utilities we regulate*."

The 61 MW per year figure forecast by SDG&E in its LTPP also assumes a business-as-usual approach to energy efficiency. SDG&E achieved only 41 percent of its modest energy efficiency target in 2006 (SDUT, Feb. 14, 2007). The CPUC is aware of investor-owned utility bias against energy efficiency measures, stating in decision D0709043 that "*There is an inherent utility bias towards supply-side procurement under cost-of-service regulation, namely, that investor-owned utilities can generate earnings for shareholders when they invest in "steel-in-the-ground" supply-side resources, but not when the utilities are successful in procuring cost-effective energy efficiency*." The point of D0709043 is to make the achievement of aggressive energy efficiency reduction as profitable for the investor-owned utilities as "steel-in-the-ground" projects like the Sunrise Powerlink (SPL).

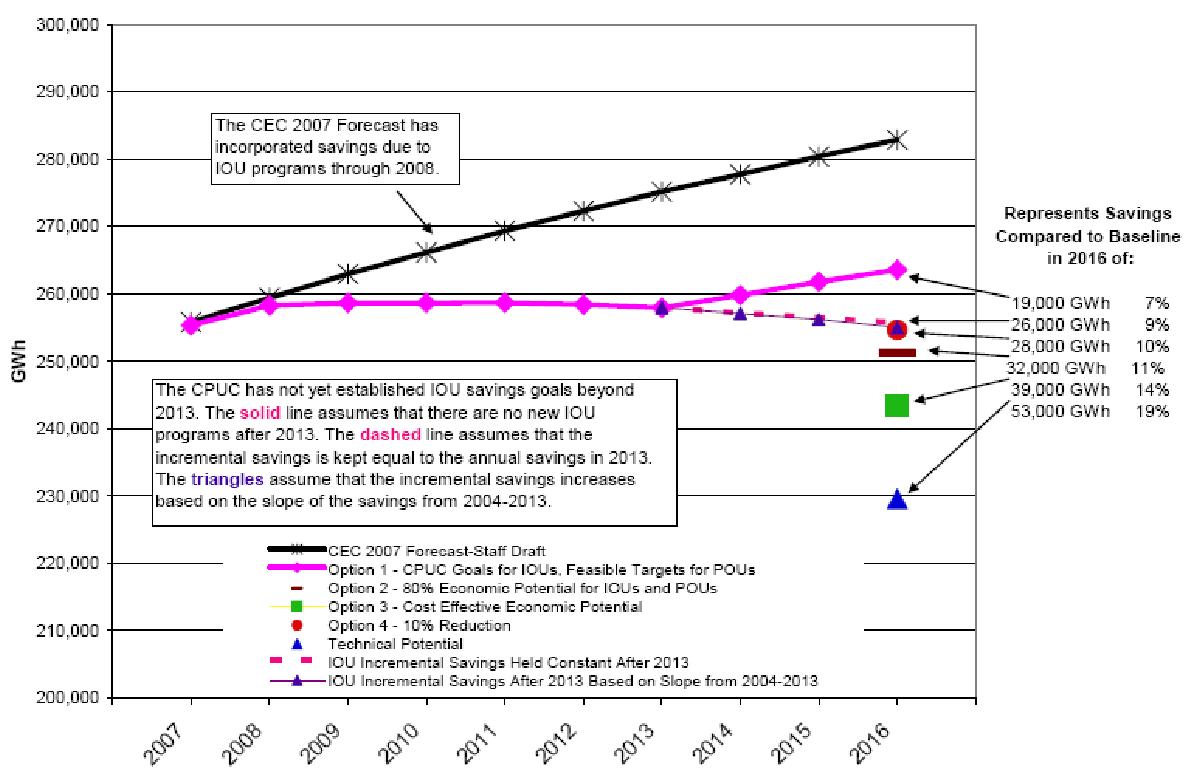
The forecast relies heavily on paper reductions from very high forecast consumption baselines to assert that the 61 MW per year figure represents the best SDG&E can do (Smart Energy 2020, p. 31).

Figure 3-5 from the California Energy Commission's (CEC) November 2007 Integrated Energy Policy Report (IEPR) shows that even the CEC acknowledges that California's utilities could readily reduce annual electric energy usage year-to-year by employing all cost-effective energy efficiency techniques available now. The energy efficiency study conducted by the CEC is limited and does not examine the further reductions in electricity usage or peak demand by aggressive deployment of economical off-the-shelf, state-of-the-art air conditioning systems that require ½ the electric power that typical existing units require.

The lack of analysis in the 2007 IEPR, or in the 2006 Itron study cited by SDG&E in its LTPP (Vol. I, p. 183) as the basis for its energy efficiency projections, of the energy efficiency and demand reduction implications of the widespread deployment of state-of-the-art air conditioning systems is an important omission.

As stated in the 2007 IEPR (p. 85): *Today, close to 95 percent of single-family homes in the Sacramento area and many other parts of the Central Valley and the Inland Empire have central air conditioning. Forecasts suggest that most housing growth in California will continue to be in these hotter areas. More temperate climates in California are also becoming increasingly dependent on air conditioning. The area around San Francisco, from Santa Rosa to San Jose, now has a central air conditioning saturation of nearly 50 percent – double previous estimates. More than 75 percent of new single-family homes in the area are projected to have central air conditioning. These trends foretell a continuing reduction in the state's load factor and continuing concern about meeting peak energy needs.*

Figure 3-5: Investor-Owned Utility and Publicly Owned Utility Electric Energy Consumption 2007–2016



Source: California Energy Commission. From *Statewide Energy Efficiency Potential Estimates and Targets for California Utilities,* pp. 66-68. CEC-200-2007-019-SD, August 2007.

The CPUC is also now requiring net zero energy consumption in new residential construction by 2020 and all new commercial structures by 2030.

This requirement would effectively limit growth in peak electricity demand as population increases. This is also a tenet of *Smart Energy 2020*. As stated in the 2007 IEPR (p. 107): *The CPUC decision of October 18, 2007, directs the investor-owned utilities to prepare a "single comprehensive statewide long-term energy efficiency plan." Three programmatic initiatives form the centerpiece of an expanded "next generation" efficiency effort:*

- *All new residential construction in California will be zero net energy by 2020.*
- *All new commercial construction in California will be zero net energy by 2030.*
- *Heating, ventilation, and air conditioning will be reshaped to ensure optimal equipment performance.*

<u>**Assertion #5**</u>**: A thorough and public examination of San Diego Smart Energy 2020 must be made before passing judgment on the plan. "***As citizens, we have to look at all of the costs of the Powers' proposal, as well as the plan's viability, and it's impact on system reliability. All of these elements associated with PV must become part of the public record and be transparent so that a reasoned assessment is possible.*" (Rohy, p. 3)

<u>**Response to Assertion #5**</u>**:** Agreed. The same degree of thoroughness must also be applied to SDG&E's long-term resource plan.

SDG&E is currently proposing to build the SPL transmission line at a cost of $6.96 billion in 2010 dollars. The stated purpose of the 1,000 MW line is to access up to 900 MW of solar power in Imperial County by 2016 (SDG&E Aug. 4, 2006 CPCN application, p. III-11).

The type of solar power SDG&E proposes to access is identified by SDG&E et al in the 2005 report "*Potential for Renewable Energy in the San Diego Region*" as pre-commercial technology. Pre-commercial by definition means not yet sufficiently reliable or proven for widespread commercial deployment.

Another stated purpose of SPL is to assure reliability during periods of peak demand. It is not clear how SDG&E intends to fulfill the reliability objective of the SPL by filling the line with a pre-commercial form of solar power.

The *Smart Energy 2020* plan eliminates the $6.96 billion expense of SPL to access remote solar power by locating the solar power locally, at its point of use. *Smart Energy 2020* also relies on PV, a demonstrably commercial form of solar energy. The local PV program described in *Smart Energy 2020* will require an incentive budget to be realized, between $700 million and $1.5 billion, to provide either 900 or 2,000 MW of installed PV capacity with sufficient battery storage to match the afternoon peak demand load profile.

The purpose of the incentive budget is to ensure the cost of PV power is less than the retail cost charged by SDG&E. The PV incentive budget is a fraction of the cost of the SPL. All of this is addressed in greater detail in the *Smart Energy 2020* plan.

Regarding transparency, SDG&E has yet to explain the apparent contradiction between filling the SPL with pre-commercial solar technology of suspect reliability while at the same time ensuring grid reliability during periods of peak demand.

Assertion #6: The true costs of solar energy are not transparent. "*The true costs of solar energy are not transparent*." (Rohy, p. 3)

Response to Assertion #6: The true costs of solar energy, in the broadest sense that includes the benefits, are described well by the CEC in the 2007 IEPR (p. 186): *Currently, Californians with a photovoltaic system that generates electricity in excess of their own consumption, provide it to the utilities for free. Recent experience with California's electrical system underscores a real need for reliable, zero emission electricity especially at peak usage times within the state's load centers. The Energy Commission believes that excess solar generation delivered to the grid should be compensated through a feed-in tariff. The price paid for each kWh delivered to the grid should be based on the RPS market price referent that includes a time-of-delivery adjustment. The Energy Commission and the California Public Utilities Commission should work together to establish an appropriate feed-in tariff for excess solar electricity. . . . For example, solar generation would be paid a higher average price per kilowatt-hour because deliveries generally coincide with peak times of delivery. SCE's tariff pays 3.28 times the base MPR (market price referent) for deliveries during the summer peak time of delivery period.*

Assertion #7: Many homeowners do not have the financial resources to make large up-front investments in PV systems. "*Many people live in housing units unsuitable for solar cells. Yet others may not have the financial resources available to make a large, discretionary investment in a PV system.*" (Rohy, p. 3)

Response to Assertion #7: Agreed. The PV program described in *Smart Energy 2020* is directed at commercial-scale PV systems installed by third-party providers on commercial properties under long-term power purchase agreements. Approximately 90 percent of the PV energy generated under the program would be produced by commercial PV installations, not residences. There would be no upfront cost to the PV customer. This is a successful and proven PV contracting mechanism used by the City of San Diego and San Diego City Schools to finance large-scale PV arrays. As noted, the purpose of the PV incentive budget described in *Smart Energy 2020* is to ensure the cost of PV power is less than the retail cost charged by SDG&E.

Assertion #8: Solar PV generation does not count toward meeting the 20 percent by 2010 renewable energy mandate. "*All investor owned utilities must supply 20 percent of their energy from renewable resources by 2010. These resources must be on their side of the meter. As a general principle, roof top photovoltaics do not count toward this goal.*" (Rohy, p. 5)

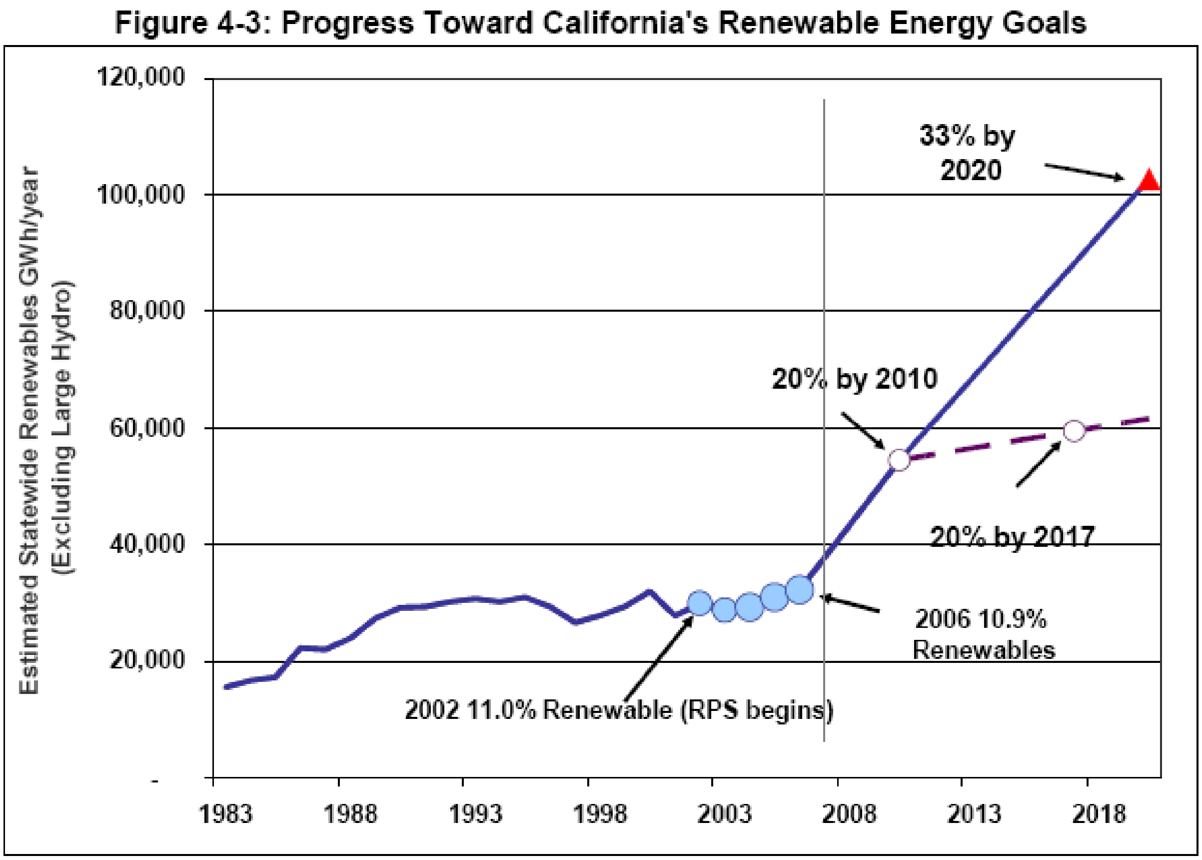
Response to Assertion #8: Expanding RPS-eligible renewable energy sources to include customer rooftop PV is an issue that has already been addressed by the CPUC. The CPUC decision (D. 07-07-027, July 26, 2007) implementing AB 1969 – *Standard Contracts for Water, Wastewater, and Other Customers to Sell Electricity Generated from RPS-Eligible Renewable Resources to Electrical Corporations* - specifically allows locally generated forms of renewable distributed energy to be counted toward the 20 percent renewable energy mandate that applies to investor owned utilities. Though AB 1969 is initially directed at water and wastewater treatment plants, the program is open to other entities as well. As stated in the 2007 IEPR (p. 126): *The purpose of AB 1969 is to bring in additional RPS-eligible energy from facilities that are too small to participate in utility RPS solicitations, either because they fail to meet minimum size requirements or because the process is too complex.* AB 1969 requires that the utilities develop simplified "must take" standard offer contracts for this renewable power.

<u>Assertion #9</u>: The purpose of the loading order is to minimize the societal cost of electricity.
"*The "loading order" uses terms such as "cost effective" energy efficiency. While there are complex rules defining "cost effective", the intent of the policy is to minimize societal cost of providing electricity. In the case of renewable energy, legislation does not mandate utilities to acquire renewable energy priced above a certain level. Thus utilities do not have to buy at any price to meet the renewable energy mandate.*" (Rohy, p. 6)

<u>Response to Assertion #9</u>: The California *Energy Action Plan* does not state that the purpose of the loading order is to minimize the societal cost of providing electricity. It is to fully utilize all cost-effective energy efficiency and demand response first, renewable energy second, CHP third, and only after those resources have been exhausted to pursue new fossil fueled power and related transmission. The CEC defines cost-effective as a simple payback of ten years for energy efficiency projects (San Diego 2020, p. 32).

The utilities have collectively made no forward progress in increasing the amount of renewable energy using the existing renewable energy procurement system. See Figure 4-3 from the 2007 IEPR (p. 158) below. Renewable energy as a percentage of utility retail electricity sales actually dropped from 11.0 percent to 10.9 percent from the time renewable portfolio standard procurement began in 2002 through the end of 2006.

The lack of forward progress on renewable energy procurement has resulted in the CEC now advocating "feed-in" tariffs for renewable energy resources. This approach was used successfully in the 1980s to make California a world leader in renewable energy, and is currently being used successfully in Europe to accelerate renewable energy development there. The 2007 IEPR states (p. 180): *The RPS program structure needs greater transparency, less complexity, and full valuation of the system benefits of renewable energy. The areas most in need of change include the least-cost best-fit evaluation and the use of natural gas prices to calculate the market-price referent. To scale the program toward reaching the 33 percent goal, California must move to a new system, such as the expanded use of feed-in tariffs. Assembly Bill 1969 requires utilities to file tariff/standard contracts for renewable generation operated by a public water or wastewater facility. In July 2007, the CPUC adopted Decision 07-07-027 implementing this requirement. In May 2007, SCE started offering a set of standard contracts priced at the 2006 MPR for biogas and biomass generators as large as 20 MW. Following the example set by CPUC implementation of AB 1969, the contracts offered by SCE should be expanded to other RPS-eligible renewables. Based on SCE's rationale, the size cut-off could be for systems as large as 20 MW, but SCE and the other investor-owned utilities should impose no cap on the total amount to be contracted and renew the offer each year.*



Source: California Energy Commission.[200]

<u>Assertion #10</u>: PV is not cost-effective. "*Many renewable energy resources are not currently cost-effective at this time*." (Rohy, p. 6)

<u>Response to Assertion #10</u>: The CEC has identified commercial-scale flat plate PV as more cost-effective than simple-cycle gas turbines for investor-owned utilities on a $ per MW-hour, levelized-cost basis (Smart Energy 2020, Table 3-2, p. 17).

<u>Assertion #11</u>: Natural gas-fired generation is inexpensive. "*Even with today's high price for natural gas, generators using natural gas produce electricity at lower costs than any commercial type of solar energy generator*." (Rohy, p. 6)

<u>Response to Assertion #11</u>: The capital and operating costs of natural gas-fired generators are increasing at a spectacular rate. Four years ago, the typical installed capital cost of a natural gas-fired combined cycle plant like SDG&E's Palomar Energy was approximately $500 per kW (Powers Engineering, *Comments on CEC Decision on Morro Bay Modernization Project*, June 2003). The 2007 CEC estimate for a combined-cycle plant is nearly $900 per kW (CEC, *Comparative Costs of California Generation Technologies*, June 2007, p. 28). The capital cost of simple-cycle turbines rose nearly 18 percent in 2006, roughly ten times the rate of general inflation (The Brattle Group, *Rising Utility Construction Costs*, September 2007, p. 25). The average cost of natural gas in 2002 was $3 per MMBtu (DOE EIA, 2002 yearly wellhead average price). The CEC forecasts a $6.82 per MMBtu natural gas cost in 2008 that will rise 50 percent in real dollars to $10.16 per MMBtu in 2020 (CEC, *Comparative Costs of California Generation Technologies*, June 2007, p. 22). These trends in traditional natural gas-fired power plant capital and fuel costs must be taken into account when comparing proposed generation sources.

<u>Assertion #12</u>: Municipal utilities are not doing their share to address CO_2 reduction. "*Before the state takes draconian actions to change the way utilities produce electricity to reduce CO_2 (to address global warming and AB 32), it must accurately assess the true cost of policy implementation, inform the public of the effects of any regulations on their electric bills, and enforce the new regulations uniformly and fairly on all users of specified fuels. Currently the State of California regulates the investor-owned utilities, but only suggests actions to municipally-owned utilities such as Los Angeles Department of Water and Power. Regulations should not create economic advantages and disadvantages in different parts of the state*." (Rohy, p. 6)

<u>Response to Assertion #12</u>: This assertion implies that municipallyowned utilities are not doing their share to address global warming, and that the burden is falling unfairly on investor-owned utilities like SDG&E. This is incorrect and opposite the reality on the ground. The three biggest publicly-owned utilities in California are LADWP, Sacramento Municipal Utility District (SMUD), and Imperial Irrigation District (IID). These three publicly-owned utilities have committed to the following renewable energy targets: LADWP, 35 percent by 2020; SMUD, 23 percent by 2020; IID, 30 percent by 2020 (2007 IEPR, p. 170; 2007 Status Report on Renewable Energy at SMUD, p. 2). The City of San Francisco has formed its own public power generation entity and has established a renewable energy target of 51 percent by 2017. All of these public utilities are under local political control and are responding to overwhelming public pressure to take action on global warming. In contrast, investor-owned SDG&E/Sempra lobbied successfully to kill legislation in 2007 that would have raised the renewable energy mandate to 33 percent by 2020 for investor-owned utilities. The breakdown by utility type of California electricity consumption is shown in Figure 1-11 from the 2007 IEPR (p. 16) below. In any case, any perceived lack of progress by municipal utilities pursuing their own RPS goals should not be used as an excuse for laxity in our own regional efforts.

Figure 1-11: Investor and Publicly Owned Utility Shares of California's Electricity Consumption - 2006

Source: California Energy Commission

<u>Assertion #13</u>: New technologies must work before being deployed on large scale. "*To preserve the good features (of the existing SDG&E electric grid), we have to determine if new technologies work as promised, before large scale deployment*." (Rohy, p. 7)

<u>Response to Assertion #13</u>: The San Diego area currently has approximately 40 MW of PV and 350 MW of cogeneration and CHP systems. This capacity is around 17 percent of current SDG&E service territory average demand of approximately 2,300 MW. There is no question these technologies work as promised. Over 200 MW of cogeneration "qualifying facilities" in SDG&E service territory have been exporting excess power to the SDG&E grid since the 1980s. Virtually all of the hundreds of individual PV systems in operation in the San Diego area export to the grid with no known problems. *Smart Energy 2020* calls for increasing the excess power from this kind of generation supplied to the SDG&E grid, with customers and third parties being paid a reasonable price by SDG&E for the excess power.

<u>Assertion #14</u>: Power from renewable resources must be available when needed. "*The grid of the future must have the technology to allow thousands of small generators such as PVs to export to the grid when the grid needs the power, not when the generators have the power to sell. In addition, the grid must have low-cost and effective electricity storage technologies.*" (Rohy, p. 7)

<u>Response to Assertion #14</u>: As noted in the response to Assertion #6, the 2007 IEPR states: *Recent experience with California's electrical system underscores a real need for reliable, zero emission electricity especially at peak usage times within the state's load centers. The Energy Commission believes that excess solar generation delivered to the grid should be compensated through a feed-in tariff. Solar generation would be paid a higher average price per kilowatt-hour because deliveries generally coincide with peak times of delivery.* The CEC already has a demonstration project under way in SCE territory where PV systems with battery storage are controlled by SCE to match PV system output to the afternoon demand peak profile. See *Smart Energy 2020* (p. 57) for a brief discussion of this demonstration project. Development and refinement of the technology needed to integrate more customer distributed generation surplus power into a local smart grid should be one of our top priorities. The CPUC should adopt shareholder penalties and rewards for SDG&E and other IOUs for supporting this effort, similar to the those it has adopted in its energy efficiency proceedings.

<u>Assertion #15</u>: Back-up power must be available when renewable solar and wind resources are not generating. "*Is the sun doesn't shine or the wind doesn't blow, what facilities must be in place to provide continuous electricity service?*" (Rohy, p. 7)

<u>Response to Assertion #15</u>: Implementation of *Smart Energy 2020* will reduce peak load in the San Diego area from 4,600 MW to 3,500 MW in 2020. A total in-region natural gas-fired generation base of approximately 2,800 MW will be available to meet this load in 2020 (combined-cycle, 1,100 MW; simple cycle, 700 MW; CHP, 1,000 MW). Non-PV renewable energy, primarily from sources outside the region, will also be under contract to meet the SB 107 "20 percent by 2010" mandate.

If the sun isn't shining, it is unlikely the load will approach the projected 2020 peak of 3,500 MW.

However, the region will have: 1) up to 6,000 MW-hr of stored electric energy in the new storage systems associated with the 2,000 MW of installed PV (equivalent to three hours of battery storage for each system), and 2) over 4,000 MW of existing import capacity available along the Southwest Powerlink and the Path 44 "South of San Onofre Nuclear Generating Station" transmission corridors. Should a load of over 2,800 MW be experienced when the San Diego region is completely overcast in 2020, either stored in-region solar power or imported renewable or conventional generation will be available to meet the need.

Assertion #16: Electricity demand from plug-in vehicles must be accounted for. "*The introduction of a plug-in car could dramatically change the pattern of electricity use and create a larger demand during nighttime hours*." (Rohy, p. 8)

Response to Assertion #16: The estimated electricity consumption for a typical plug-in is 0.36 kW-hour per mile (NREL, *Costs and Emissions of Plug-In Vehicle Charging*, May 2007, p. 7). Assuming 100,000 plug-in hybrids are on the roads in the San Diego area by 2020 and each of these vehicles averages 50 miles per day, the total additional electric load would be 1,800 MW-hour per day.

Assuming these vehicles are recharged over a 6-hour period during the evening, the average additional nighttime load will be 300 MW during the charging period. The current nighttime load can drop to approximately 2,000 MW in SDG&E service territory. The nighttime load will be lower in 2020 if *Smart Energy 2020* is implemented. At least 2,100 MW of in-region high efficiency gas-fired generation, both combined-cycle and CHP, will be available to meet this load.

Also, the regional wind resource is typically strongest at night and in the non-summer months and is a good match for nighttime plug-in vehicle charging.

SDG&E already projects having over 400 MW (TURN, *California Renewable Portfolio Standard Review* - presentation, March 26, 2007, p. 13) of wind power under contract to meet the 20 percent renewables by 2010 mandate. Expanding relatively low-cost wind power generation to meet the additional demand imposed by nighttime plug-in hybrid charging would be one solution to meeting plug-in hybrid electricity demand as the regional plug-in population moves beyond 100,000 vehicles.

Assertion #17: SDG&E relies on a balanced mix of generation, not one technology (PV). "*SDG&E relies on both local generation and distant generation supplied via transmission lines. This balance of resources provides a robustness that cannot be matched in a system based on one technology*." (Rohy, p. 8)

Response to Assertion #17: As explained above, the assertion that all energy will come only from PV under *Smart Energy 2020* is incorrect. At most PV will provide 28 percent of the San Diego area's energy needs in 2020. See the response to Assertion #1 and Table 1-1 of *Smart Energy 2020*.

The San Diego area will rely on a mix of local and imported resources under *Smart Energy 2020*. The San Diego area will be capable of avoiding blackouts even when 1) firestorms shut down our main transmission corridors, or 2) when regional demand for power is so high, as it was during the statewide Stage 1 electrical emergency declared by CAISO on August 29, 2007, that there is little power available to import when it is most needed.

There will be more than sufficient local generation resources under *Smart Energy 2020* to meet demand under all peak demand conditions. There is little robustness in the current SDG&E system to meet unexpected emergency conditions. The firestorms that occurred in late October 2007 temporarily forced both major transmission import corridors off-line at a time when the SDG&E load was in the range of 3,000 MW. SDG&E was forced to import several hundred MW of power from Baja California to avoid partial blackouts at a demand level of 3,000 MW due to insufficient local generation. Yet the peak load reached in 2007 was over 4,600 MW. Had the firestorms occurred in early September instead of late October, large areas of the San Diego area would have been blacked-out for lack of local generation resources. *Smart Energy 2020* rectifies this lack of robustness in the current SDG&E system.

<u>Assertion #18</u>: Many CHP units cannot meet ultra-strict air emissions requirements of the California Air Resources Board. "*Many CHP units cannot meet ultra-strict air emissions requirements of the California Air Resources Board*." (Rohy, p. 8)

<u>Response to Assertion #18</u>: This is an incorrect statement. Many local CHP units already meet those emission requirements. For example the 3.5 MW Solar Centaur CHP plant at San Diego Children's Hospital, which began operation in 2006, is equipped with selective catalytic reduction (SCR) for NO_x control and typically operates between 1 and 2 ppm NO_x. This level is as low or lower than SDG&E Palomar Energy combined-cycle plant NO_x emissions level. Palomar Energy also began operation in 2006.

CHP has a lower greenhouse gas footprint than a combined-cycle plant if it is operated efficiently, 639 lb CO_2/MWh versus 819 lb CO_2/MWh for combined cycle. This higher efficiency is the reason that CHP is ranked higher in the CPUC/CEC loading order than combined-cycle plants. The 1.5 MW of fuel cell CHP plant at the Sheraton San Diego (see *Smart Energy 2020*, Attachment N) has significantly lower NO_x emissions than the CHP plant at Children's Hospital.

<u>Assertion #19</u>: Building owners have no incentive to install CHP. "*Many companies and businesses rent their buildings from investors. The building owners have no incentive to install energy efficiency, CHP or thermal storage*." (Rohy, p. 8)

<u>Response to Assertion #19:</u> This is an incorrect statement. Virtually any company or business, whether renter or owner, would be willing to facilitate the development of CHP if: 1) it means lower rates relative to utility rates and 2) the process for developing CHP and accessing those rates is straightforward. One obstacle to increased customer CHP adoption is SDG&E's current rate structure. One straightforward way to facilitate increased local CHP is to have a third party developer build, own, and operate the plant and charge the building occupant/owner favorable rates under a long-term power purchase agreement.

For example, Duke Energy Generating Services (formerly Cinergy Solutions, Inc.) built and operates the 3.5 MW CHP plant at Children's Hospital. Sempra Energy Services built, owns, and operates the 4.6 MW CHP plant at the Veteran's Administration Hospital in La Jolla. The contract

Sempra Energy Services has with the Veteran's Administration Hospital guarantees that the Veteran's Administration will save at least $1.3 million per year relative to SDG&E charges (2007 Solar Turbines CHP case study - online). The third party power purchase agreement model is a proven model that could readily serve as the platform to add 700 MW of CHP to the San Diego area by 2020.

<u>**Assertion #20**</u>**: Utility ownership may be the solution to increasing CHP capacity.** "*One solution to increased use of CHP and thermal storage may be utility ownership and operation of such facilities*." (Rohy, p. 8)

<u>**Response to Assertion #20**</u>**:** Utility ownership may be one solution, however to date steadfast utility opposition has been the main brake on local CHP development. As the CEC states in the 2007 IEPR (pp. 208-209): "*The Energy Commission found that, despite many years of articulated policy preferences, distributed generation and CHP in California continues to face major barriers to market entry in the context of traditional utility cost-of-service grid management. Investor-owned utilities continue to show little interest in accepting energy from customer-owned distributed generation projects or in developing utility-owned distributed generation or CHP projects. As a result, these options continue to struggle with major barriers to market entry. Large CHP units appear to offer the greatest fuel efficiency of available distributed generation technologies. Because CHP systems are located close to the load, transmission and distribution line losses are minimized, further reducing greenhouse gas impacts. As regulations for AB 32 compliance are finalized, the benefits of distributed generation and CHP for the electricity system will become more quantifiable. This will reinforce the need to make distributed generation and CHP projects a higher priority in utility resource mixes for both IOUs and publicly-owned utilities.*"

The CEC is now recommending a distributed generation portfolio standard, similar to the current 20 percent portfolio standard for renewable energy, to assure CHP systems get built (2007 IEPR, p. 212). Additional CEC recommendations regarding CHP are:

1) A tariff structure to make distributed generation and CHP projects "cost and revenue neutral", while granting owners' credit for system benefits, such as reduced congestion;
2) Elimination of all non-bypassable charges for distributed generation and CHP, regardless of size or interconnection voltage, and standby reservation charges for distributed generation; and
3) Continue the work of the "Rule 21" industry/utility collaborative working group to refine interconnection standards, provide third party resolution of interconnection issues and streamline permitting (p. 212).

SANDAG should work with SDG&E and the CPUC to support these CHP goals.

<u>**Assertion #21**</u>**: Air conditioners are not used as often in this area as many imagine.** "*One of the largest users of residential electricity is air conditioning. With more houses being built further from the ocean, more houses have central air conditioning. While these units can consume large amounts of electricity they are not used as often in this area as many imagine. Typical usage per home is in the range of 300 to 500 hours per year*." (Rohy, p. 9)

Response to Assertion #21: Air-conditioning load is responsible for 35 percent of SDG&E's current summertime peak load (San Diego 2020, Attachment G). Yet SDG&E has no incentive program to encourage the purchase of state-of-the-art commercial central air conditioning units, which require one-half the electricity for the same cooling output as the average existing unit (San Diego 2020, Attachment I). The term "typical air conditioning usage" is almost meaningless for San Diego County on a countywide basis, given the distinct micro-climates within the county. Fast-growing inland areas like Escondido, Ramona, Santee, El Cajon, and the eastern edge of Chula Vista have much higher air-conditioning usage rates than coastal communities located west of Interstate 5. A state-of-the-art, commercially-available residential central air conditioning unit is 40 percent more efficient than the federal minimum standard unit and costs only 10 to 20 percent more than the federal minimum standard unit. There is no question that payment of this differential by SDG&E for central air conditioning units in hotter parts of the county would meet the CEC's definition of cost-effective – "simple payback in ten years or less" - as central air conditioning units typically operate at least 800 to 1,000 hours per year in these hotter areas (San Diego 2020, p. 38). SANDAG should work with SDG&E and the CPUC to pursue this kind of new incentive program in the upcoming 2009-2011 program cycle.

Assertion #22: Energy efficiency can only be achieved by individuals taking responsibility for their own energy use. "*Energy efficiency is the first strategy in the California loading order. It can only be achieved when individuals take responsibility for their own energy use. It cannot be done by the utility, or by the legislature, or by energy plans.*" (Rohy, p. 10)

Response to Assertion #22: This is an incorrect statement. While customer behavior change is an important element of solving our energy problems, that behavior is subject to utility customer energy efficiency education, incentive and rebate program efforts, and local building codes and regulations.

For example, SDG&E can pay the difference between the cost of the federal minimum central air conditioning unit and a state-of-the-art unit on an automatic basis in every micro-climate in San Diego County where the energy saved for typical "hours per year" usage meets the CEC definition of a cost-effective energy efficiency measure. The incentive could be pro-rated to meet the CEC defined cost-effectiveness standard in micro-climates where typical usage might not justify an automatic upgrade to the highest efficiency unit. Central air conditioning units have an average lifetime of approximately ten years (San Diego 2020, p. 37).

Municipalities within the county should revise their building standards to require that central air conditioning units on all buildings in the hotter climate zones in the region be upgraded to the maximum cost-effective efficiency level when first installed. Existing units should be replaced or retrofitted within ten years, whichever comes first. This requirement would assure that central air conditioning units on all the buildings in the warmer parts of San Diego County would be at today's state-of-the-art level by 2020.

SDG&E can also greatly expand its existing home weatherization programs, or contract-out that responsibility to a third party like the California Center for Sustainable Energy, to maximize the energy efficiency benefits of retrofitting local homes to achieve the benefits of well-insulated and sealed homes in San Diego County. The California legislature can also require the phase-out of incandescent bulbs to greatly reduce electricity consumption for lighting. Legislation to phase-out incandescent bulbs was introduced in 2007 (San Diego 2020, p. 38).

<u>Assertion #23</u>: PV is expensive and will remain expensive. "*Contrary to predictions and many reports, the price of photovoltaics has been rising for the past three years.*" (Rohy, p. 10)

<u>Response to Assertion #23</u>: What matters is the price of PV when PV is deployed in earnest under the *Smart Energy 2020* plan in the 2015-2017 timeframe.

The CEC forecasts that the price of PV will drop in half by 2020 (2007 IEPR, p. 53).

Smart Energy 2020 assumes that PV costs will drop by 40 percent by 2017 (San Diego 2020, Attachments J and K), comparable to the CEC forecast that the price of PV will drop in half by 2020. The PV industry is undergoing a dramatic acceleration. Total PV manufacturing capacity in 2006 was 2,100 MW. Installed manufacturing capacity is expected to reach 11,200 MW by 2010 (PV News, August 2007, p. 7). This large and rapid increase in manufacturing capacity is the reason the PV industry projects that costs will drop 40 percent by 2010 (San Diego 2020, p. 47).

<u>Assertion #24</u>: Battery technology has not advanced as rapidly as many would like. "*The Powers' proposal selected batteries for electricity storage. While this is technically possible, there are many issues involved with battery based energy storage. Battery technology has not advanced as fast as many would like.*" (Rohy, p. 10)

<u>Response to Assertion #24</u>: This assertion about battery technology is misleading. Battery storage for PV systems is like any well-established commodity product – you get what you pay for. Using existing technologies, a low-cost lead-acid battery will last 3-5 years in PV system usage. A lead-antimony thick-plate battery comes with a 15-year guarantee in PV system usage, and costs three- to four-times the cost of the low-cost, relatively short-lived lead-acid battery alternative (2007 Nova Sun Power, Surrette Series 5000 deep cycle lead-antimony battery brochure - online).

For large PV projects, high temperature sodium-sulfur batteries are an option and are currently in commercial use (San Diego 2020, Attachment L). PV battery storage systems qualify for California Solar Initiative incentives, and would have a rapid payback at the peak rate offered by SCE for PV energy described in the response to Assertion #6.

<u>Assertion #25</u>: If this community were to adopt the Powers' plan, there could be a requirement for most houses to have a solar energy system. "*If this community were to adopt the Powers' plan, there could be a requirement for most houses to have a solar energy system.*" (Rohy, p. 12)

<u>Response to Assertion #25</u>: This is an incorrect statement. Residential PV is a minor component of the PV program described in *Smart Energy 2020*. In no case would the installation of PV systems be required of individual homeowners.

<u>Assertion #26</u>: PV is risky, it is not wise to put all our eggs in one basket. "*Until the (PV) technology advances to provide much lower costs, and all of the back up system issues have been* *resolved, the risks are not acceptable. Putting all of our eggs in one, unproven basket could lead to massive unintended consequences for this community. This is not a risk that I am willing to take.*" (Rohy, p. 12)

<u>Response to Assertion #26</u>: This is an incorrect statement. *Smart Energy 2020* does not propose to depend only on local solar power.

As noted earlier, PV would only provide up to 28 percent of total energy needs by 2020 under the proposed *Smart Energy 2020* plan. PV technology is already fully commercial and operating in San Diego County in large arrays up to 1,000 kW in output. The CEC has identified PV as cost-effective now relative to simple-cycle gas turbines for peaking applications (Smart Energy 2020, p. 17).

This statement also implies that electricity from natural gas is economical and risk-free, and will remain so indefinitely. A major concern of the CEC is ever greater dependence on natural gas for electric power generation, 1) exposing California to risk in the form or higher fuel prices and higher cost of electricity, and 2) geopolitical risk if California becomes dependent on overseas liquefied natural gas (LNG) sources for much of its natural gas supply.

The natural gas demand in SDG&E service territory is currently about 320 million cubic feet per day. This demand is not forecast by SDG&E to grow at all over the next decade (2006 California Gas Report, p. 99). The CEC acknowledges that up to 100 percent of San Diego's supply of natural gas will come from LNG as early as 2008, when SDG&E parent company Sempra Energy begins operation of its Baja California LNG import terminal, stating (2007 IEPR, p. 224): "*About 300 million cubic feet per day will serve electric power plants in Mexico and up to 400 million cubic feet per day will flow to San Diego through the SDG&E lines.*" Much of this LNG supply will come from Indonesia, one of the less stable countries in the Far East (Smart Energy 2020, Attachment C).

The CEC also states (2007 IEPR, p. 234): "*Given the consequences for California, the Energy Commission will monitor North American natural gas production for signs of decline or production difficulties. . . . Alternatives to North American natural gas are essential, and will likely require increased amounts of the preferred resources of energy efficiency combined with renewables and other natural gas sources such as LNG.*" The riskiest strategy of all may be over-dependence on natural gas-fired sources, whether domestic sources or LNG imports. Greater reliance on PV means greater independence from 1) volatile natural gas prices and 2) from potential ominous geopolitical entanglements associated with securing LNG supply lines. California has also positioned itself as a world leader on greenhouse gas reduction. Greenhouse gas reduction will not be achieved by increasing California's dependence on natural gas-fired power generation.

<u>Assertion #27</u>: Actions taken by the utility are intended to increase the common good. "*The utilities are charged with providing universal service throughout the utilities service area to increase the common good.*" (Rohy, p. 12)

<u>Response to Assertion #27</u>: A local lesson has been that investor-owned SDG&E may not be the best candidate to design and implement a regional energy plan, and may not be interested in serving the common good over its own shareholders interests. Sempra Energy, SDG&E's parent company, settled a class-action lawsuit over natural gas pricing abuses during the 2000-2001 energy "crisis" for overcharging its customers by $580 million in early 2006. Sempra was also fined $70 million in

2006 for breaching the terms of its long-term power supply contract with the state that evolved out the crisis. In the same proceeding, Sempra was admonished to stop artificially congesting San Diego area transmission lines. Not surprisingly, "relief of transmission congestion" has been one of SDG&E's fundamental justifications for the Sunrise Powerlink. Sempra has bet its financial future on remote natural gas-fired power plants, associated transmission infrastructure, and liquefied natural gas imports. It is not realistic to expect that any energy plan developed by SDG&E will challenge the strategic objectives of its parent Sempra.

Assertion #28: Community Choice Aggregators (CCA) are public institutions and have access to tax free, low-cost financing as a result. "*The focus of a CCA is on procuring electricity for its customers. The electricity is transported to the customer over utility facilities. Because the CCA is part of local government it has access to lower cost financing through municipal bonds. Municipal bonds typically have interest rates 2 to 4 points lower than private capital. Because of the large amount of capital required for electrical facilities, some argue that the lower cost of capital will reduce the cost of electricity to the citizens in the CCA service area.*" (Rohy, p. 13)

Response to Assertion #28: The tax free, low-cost municipal bond financing available to CCAs is one reason CCAs may be able to offer competitive retail electricity rates while achieving considerably higher renewable energy targets than their investor-owned utility counterparts. The San Francisco CCA has established a target of 51 percent renewable energy by 2017.

Assertion #29: CCAs resist long-term planning. "*A CCA procures electricity for its customers, but unlike typical utility procurement activities, the procurement plans of a CCA are not reviewed by the CPUC through a public process. CCAs typically resist engaging in long-term planning for new resources and facilities.*" (Rohy, p. 13)

Response to Assertion #29: A more accurate statement would be that SDG&E is strongly resisting the formation of CCAs in its service territory. The CPUC requires any proponent interested in forming a CCA to submit a detailed plan of how the CCA will function, its goal and objectives, and the mix of generation resources it proposes to secure for its customers. The two CCAs the CPUC has approved, City of San Francisco and the San Joaquin Valley Joint Power Authority, both submitted plans that served as the basis for CPUC approval. The rationale for forming a CCA is straightforward – local control and greater focus on local objectives, especially regarding renewable energy (2006 Local Government Commission fact sheet on CCA): "*Many communities want to increase the amount of non-polluting, renewable energy they use, and are looking at Community Choice Aggregation as a mechanism for doing so. Under CCA, decisions about rates, generating resources and public benefit programs will be made locally and be accountable to local customers.*" Many jurisdictions are evaluating CCAs, including Berkeley, Beverly Hills, Emeryville, Los Angeles County, Marin County, Oakland, Pleasanton, Richmond, San Diego County, San Marcos, Vallejo, and West Hollywood.

To date, SDG&E has taken a very hard line against CCAs proposed in its service area. As Navigant notes in its report to the CEC on progress toward the formation of CCAs in California (Navigant, *Report to CPUC on Process to Implement CCA*, December 2005, p. 8): "*SDG&E took the extreme position that all implementation costs, which could be in the millions of dollars, should be paid by the first CCA in SDG&E's service territory. Consistent with its overall posture in this proceeding,* *SDG&E staked out an extreme position that it would not disclose the identities of the CCA's customers, even after the CCA begins serving the customers*."

Assertion #30: CCAs want investor-owned utilities to do their resource planning at no cost. "*To date, representatives of cities considering CCA have resisted being bound to such long-term planning obligations. Those entities have, in essence, argued that the investor owned utility should continue to provide backup for local systems, and do long term planning at no cost.*" (Rohy, p. 13)

Response to Assertion #30: No supporting documentation is provided for this counterintuitive assertion. As noted in the response to Assertion #26, the whole point of forming a CCA is to make decisions about rates, generating resources, and public benefit programs locally and be accountable to local customers. There would be no reason to form a CCA if these core functions were going to continue to be performed by the investor-owned utility.

Assertion #31: A CCA may not be able to pay enough to hire sufficiently capable staff. "*Even when they have the capital, cities do not have the experienced staff to maintain electric generation facilities and create plans for future needs. The salaries for the key people may not fit into municipal salary schedules*." (Rohy, p. 14)

Response to Assertion #31: One-third of the electric energy consumed in California is provided by entities other than investor-owned utilities. See the graphic in the response to Assertion #11 (Figure 1-11 from the 2007 IEPR). The implication that investor-owned utilities are uniquely qualified to provide electric service has no basis in fact. In addition, SDG&E has made clear that it is having difficulty attracting and training competent technical staff, stating (2007 IEPR, p. 198): "*Another issue that was highlighted in the workshop by SDG&E is the aging utility workforce and the inability of utilities to attract both new operational and engineering talent.*"

Assertion #32: Solar energy is too costly to play a dominant role in the near future. "*While solar energy should and will play a significant role in our energy future, it cannot play a dominant role in the near future. Costs are still far too high. Storage technologies are not fully developed and/or may be environmentally damaging. There is no one right answer, but some answers are more dangerous to the public good than others.*" (Rohy, p. 14)

Response to Assertion #32: SDG&E is proposing up to 900 MW of solar energy as the basis for the 1,000 MW Sunrise Powerlink.

Smart Energy 2020 is proposing two solar energy scenarios, either 2,000 MW or 900 MW with sufficient battery storage to match the afternoon peak load profile. Large-scale deployment would begin in 2015, not "the near future". Both the PV and battery technology that would be utilized is fully commercial today. In neither of the two *Smart Energy 2020* scenarios will solar energy be "dominant." In Scenario 1 solar energy represents only 28 percent of total annual energy consumption. In Scenario 2 it represents only 14 percent of total annual energy consumption. It is contradictory to imply that the addition of 900 MW of remote solar energy under the SDG&E plan is balanced, while the addition of 900 MW of local solar energy under the *Smart Energy 2020* plan is "dangerous."