BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions standards into Procurement Policies	Rulemaking 06-04-009 (Filed April 13, 2006)

BEFORE THE CALIFORNIA ENERGY COMMISSION

Order Instituting Informational Proceeding on a Greenhouse Gas Emissions Cap	Docket 07-OIIP-01

COMMENTS OF FUELCELL ENERGY, INC. REGARDING TREATMENT OF COMBINED HEAT AND POWER

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("CPUC") and May 20, 2008 Administrative Law Judges' Ruling in the above-captioned proceeding, FuelCell Energy Inc. ("FCE") submits the following comments in CPUC Docket R.06-04-009 and California Energy Commission ("CEC") Docket 07-OIIP-01.

FCE supports the efforts of the CPUC and CEC (hereafter "Commissions") and those of the California Air Resources Board ("ARB") to implement Assembly Bill 32 ("AB 32") in an effective and efficient manner, and in particular the Commissions' effort to specifically address issues related to greenhouse gas ("GHG") emissions and emission reductions associated with combined heat and power ("CHP") facilities.

The comments below are organized consistent with the Commissions' suggested outline, and address only issues related to CHP.

I. Summary

FCE manufactures and markets stationary fuel cells for commercial, industrial, municipal and utility customers. FCE is headquartered in Danbury, Connecticut, and has operations in California and other states, Canada, Europe, Japan, and Korea. FCE's fuel cells electrochemically produce electricity from hydrocarbon fuels, such as natural gas and biomass. FuelCell Energy is also developing hybrid products and planar solid oxide fuel cell technology products. FCE products serve a wide variety of customers, including wastewater treatment plants, hotels, manufacturing facilities, universities, hospitals, telecommunications/data centers, and government facilities. Fuel cells are optimally deployed as on-site CHP facilities and are effectively used on both customer and utility-owned applications.

FCE's comments address the questions in Section V regarding the integration of CHP into the overall plan for implementing AB 32. As discussed in greater detail below, FCE does not at this point take a specific position on most of the more general questions regarding how to structure GHG regulation statewide. Rather FCE addresses the critical need for the regulatory construct to accurately and fully account for the value of GHG emissions avoided by installation of on-site CHP, including in particular fuel cell technologies that do not present the same GHG emission issues as combustion-based CHP systems. As a non-combustion CHP technology, fuel cells not only avoid GHG emissions, but also emissions of criteria pollutants. Recognizing that fuel cell technologies are, relatively speaking, newer and perhaps less familiar to regulators than combustion-based CHP applications, FCE will make every effort to assist the Commissions in understanding and correctly reflecting the benefits that fuel cells provide into the modeling and discussion of GHG impacts. FCE looks forward to participating further in these proceedings.

V. Treatment of CHP

A. Detailed proposal

Q1. Taking into account and synthesizing your answers to other questions in this paper, explain in detail your proposal for how GHG emissions from CHP facilities should be regulated under AB 32.

At this point FCE does not offer a specific proposal for how GHG emissions from CHP facilities should be regulated. FCE supports in concept the multi-sector cap–and-trade approach currently under consideration by the Commissions, provided that 1) it is structured in a manner that accurately and completely captures the value of combustion-based emissions avoided by the installation of fuel cell CHP facilities in all relevant commercial and industrial applications, and 2) it provides a means for a customer or developer investing in fuel cells to market and obtain compensation for the value of offset emissions; and 3) it streamlines regulatory requirements to avoid imposing costs that would serve as a disincentive to deployment of CHP.

The most important aspect of regulating and accounting for GHG emissions from CHP facilities is ensuring that CHP receives full emissions reduction credit for its thermal output. To ensure that avoided emissions for CHP are correctly valued, the modeling and analysis underlying the E3 GHG calculator being developed as part of this proceeding should include and account for both combustion-based CHP technologies such as traditional cogeneration *and* non-combustion-based CHP technologies such as fuel cells. Likewise, compliance, measurement and registry mechanisms developed through this proceeding must be designed taking both combustion and non-combustion CHP technologies into account.

B. Regulation of CHP GHG emissions

Q2. Should GHG emissions from CHP systems be regulated in one sector? If so, which one? How?

Regardless of whether GHG emissions from CHP systems are regulated in one sector or in multiple sectors, CHP must receive full emissions reduction credit for its thermal output. FCE conceptually supports the Energy Producers Coalition and Cogeneration Association of California's ("EPUC/CAC") proposed double-benchmarking concept as a reasonable methodology for accounting for GHG emissions of CHP electrical and thermal output compared to the equivalent generation of the same electrical and thermal output using two separate processes.[1] Because the double-benchmarking concept benchmarks CHP output against equivalent output from standard (and separate) processes, it can be applied in a similar manner for any CHP technology.

Q3. For in-state CHP systems, should all of the GHG emissions (i.e., all of the emissions attributed to the electricity generation and to the thermal uses) be regulated as part of the electricity sector? If so, for the electricity that is delivered to the California grid, should the deliverer as defined in D.08-03-018 be the point of regulation? And, what entity(ies) should be the point(s) of regulation for thermal usage and electricity that is not delivered to the California grid if those uses are included in the electricity sector for GHG regulation purposes?

CHP units are deployed in a wide variety of applications and configurations. It is important that the regulation of GHG emissions be designed in a way that accurately and consistently reflects all CHP-related GHG emissions and avoided emissions, regardless of technology and regardless of whether electricity is primarily used on-site or exported to the grid. If the CHP unit is developed for 100 percent on-site use of both the electricity and thermal output, there is no deliverer. Therefore it is important for the Commissions to consider how to

---

[1] *See* "Comments of the Energy Producers and Users Coalition and the Cogeneration Association of California on Allowance Allocation Issues," filed 10/31/07 in joint CPUC/CEC dockets R.06-04-009 and 07-OIIP-01.

integrate on-site CHP into a multi-sector cap-and-trade program or any alternative regulatory approach. Regardless of the regulatory construct, it is critical that the chosen methodology reflect the full value of CHP, including all thermal benefits of *both* combustion-based and non-combustion-based technologies.

Q4. For out-of-state CHP systems, how should GHG emissions attributed to the electricity delivered to the California grid be regulated? If part of the electricity sector, should the deliverer of the CHP-generated electricity delivered to the California grid be the point regulation? (These questions are based on our view that, for out-of-state CHP systems, only emissions attributed to electricity delivered to California, and not attributed to other electricity or the thermal output, are subject to AB 32.)

FCE expresses no view on this issue at this time.

Q5. Should CHP units be placed in different sectors based on CHP unit capacity size?

Probably not. With respect to recognition of GHG emissions reductions, sector placement of CHP is secondary to ensuring that the full value of both the electrical and the thermal output of CHP is recognized.

To this end, it is crucial that the regulatory approach chosen correctly reflects the additional emissions reductions provided by the non-combustion-based fuel cell technologies, including those fuel cell CHP units operated on renewable fuels or waste gases. Whereas these renewable fuel sources (primarily wastewater digester gas, landfill gas, and biomass) have historically been disposed of by combustion in flares or other combustion systems, fuel cells using these gases achieve significant GHG emissions reductions. Through electrochemical conversion of renewable gases to electricity and clean heat, fuel cells reduce GHG emissions by eliminating the venting and combustion of raw feedstocks.

Q6. Should any of the options for assigning the emissions of a CHP unit to one or more sectors be rejected because it might violate the dormant Commerce Clause?

FCE expresses no view on this issue at this time.

Q7. Should the type of GHG regulation (i.e., cap and trade or direct regulation) be different for a topping-cycle CHP unit versus a bottoming-cycle unit?

Fuel cells are a topping-cycle CHP technology, meaning that a fuel cell first generates electricity and then generates a thermal product using waste heat from the electricity generation process. FCE does not see any justification for regulating topping and bottoming-cycle units differently. What is more important is that full emissions reduction credit is provided for both the electrical and the thermal output of a CHP unit, regardless of design and application. To the extent that a "direct regulation" approach is used for CHP units developed for 100 percent on-site use of both the electricity and thermal output, the owner of the CHP facility or its output (whether a regulated entity or not) must be afforded a means of marketing and receiving payment for the full value of offset emissions. Failure to do so would be a market design flaw that could undermine the broader societal benefits of increased efficiencies associated with CHP generally, and fuel cell-based CHP in particular.

Q8. Should the sectors used for GHG regulation be different for topping cycle and bottoming cycle CHP units?

FCE expresses no view on this issue at this time.

Q9. Should CHP be part of a cap-and-trade program or not? If so, should the entire unit or certain CHP outputs be part of the cap and trade program?

If a cap-and-trade program is adopted, it seems that all CHP outputs should be eligible for inclusion in the program. This is important for consistency and to ensure that investors in CHP technology, regardless of their regulatory status, are afforded a means of receiving full compensation for GHG emissions offset by both electrical and thermal outputs. In all cases, it is of utmost importance that full value of both the electrical and the thermal output of a CHP unit is measured and compensated.

In the case of utility partnership and/or ownership of the CHP unit, the utility would become the deliverer for all electricity and thermal products exported offsite. Similarly, a private third-party owner would become the deliverer in the export scenario. As discussed in more detail below in response to Questions 17 and 22, FCE believes that expanded utility ownership of CHP would optimize the value of CHP to the customer *and* to the system through placement of additional CHP in the most highly constrained parts of the electrical grid, removal of barriers to the more efficient matching of thermal load and associated electricity exports, and increased quantities of avoided emissions from CHP. For background on the historical barriers to utility ownership of distributed generation ("DG"), see the 2007 CEC Integrated Energy Policy Report ("IEPR"), pages 160-164.

Q10. Should electricity delivered to the California grid by a CHP unit be regulated under the deliverer point of regulation established in D.08-03-018? Why or why not?

FCE expresses no view on this issue at this time, except to reiterate that the point of regulation must not affect the ability of CHP (regardless of design or application) to be fairly and fully compensated for the value of avoided GHG.

Q11. Should electricity generated by in-state CHP systems for on-site use be subject to the same regulatory treatment as CHP electricity delivered to the California grid? Why or not?

It depends. As discussed above, from FCE's perspective, the regulatory approach is less important than assuring that the value of emissions offset by deployment of CHP facilities are accurately and fully reflected, that the CHP owner has an opportunity to market and receive compensation for such offset emissions, and that CHP is not burdened by unnecessary regulatory requirements.

Q12. If CHP is regulated in the electricity sector (either as one combined unit or based only on the total electricity output or based only on the electricity delivered to the California grid), do any of the proposed staff allocation options for electricity need to be modified? How?

FCE expresses no view on this issue at this time.

Q13. If CHP is treated separately from the electricity sector, but is still included as part of a cap-and-trade program, how should allowance allocation to CHP units be handled?

FCE expresses no view on this issue at this time.

Q14. If allowances are allocated administratively to CHP units, should the allocations take into account increased efficiency of CHP? If so, how?

It is important to maintain a clear distinction between the electrical efficiency and the overall system efficiency when discussing CHP units. In recognition of this distinction, the E3 calculator for GHG emissions being developed in this proceeding includes the ability to specify the percentage of emissions attributable to electrical output. Electrical efficiency refers to the fuel input required just to generate the electrical output of the CHP unit, and ranges from 35-45 percent (HHV), depending on the CHP technology. The overall system efficiency takes into account the waste heat that is recovered for useful thermal production, and ranges from 60-80 percent (HHV), again depending on the CHP technology and the configuration of its application.

Unlike combustion-based CHP technologies, fuel cells generate electricity using an electrochemical reaction rather than through combustion. As a result, fuel cells have a higher electrical efficiency and a lower emissions profile than combustion-based CHP technologies. Fuel cell CHP units can achieve near 85 percent (HHV) overall system efficiency because of the high temperature waste heat that is recovered for thermal use. While not the subject of this question, FCE notes that providing incentives (financial or otherwise) for the encouragement and deployment of higher-efficiency CHP technologies will yield ancillary benefits in the form of avoided fuel use and (related) avoided emissions.

While the overall efficiency of a CHP system may function as the basis of an administrative allowance allocation mechanism, FCE further believes that the avoided GHG emissions associated with any usage of renewable or waste fuels should be recognized and accounted for. The GHG emissions reductions attributable to the elimination of waste or renewable feedstock sources should be recognized and allocated to the CHP system using these fuels in lieu of or in combination with natural gas, to the extent that waste gases are used for energy production instead of being flaring or disposed of through other means.

Q15. Are there advantages to having all emissions from in-state CHP regulated as part of the electricity sector under cap and trade (and therefore with the need for only a single set of allowances?) How should this be accomplished?

Administrative simplicity would be the main advantage to having all emissions from in-state CHP regulated as part of the electricity sector under cap-and-trade (and therefore having the need for only a single set of allowances and/or offsets). However, as discussed above, the regulatory construct is less important to FCE than ensuring that the full value of both thermal and electrical outputs provided by CHP are calculated and that the CHP owner or investor has an opportunity to obtain fair compensation for avoided GHG emissions. Irrespective of whether CHP emissions are regulated within the electric sector for administrative simplicity, such streamlining efforts should not result in any limitations on the full reflection of the value of the CHP resource in other sectors. Failure to allow such flexibility for CHP applications may undermine efforts to encourage investments in GHG offsetting technologies. This is why FCE supports the multi-sector cap-and-trade approach.

Q17. What is the best approach to regulation of CHP emissions to minimize the potential for disincentivizing new installations of CHP and why is that the best approach?

Starting with the assumption that AB 32's ambitious targets will clearly benefit from expanded CHP deployment statewide, the best approach to regulation is to ensure that: 1) regulation is simple to administer and regulatory obligations are minimized, especially for on-site customers; 2) the regulatory construct accurately accounts for and compensates for all avoided emissions for both CHP electrical and thermal output; 3) regulation is coordinated with improvements in state policies aimed at eliminating current obstacles to CHP development, encouraging and supporting development, demonstration and deployment of new CHP technologies, and providing properly structured financial incentives as necessary to create fully self-sustaining markets for CHP statewide.

In particular, and as discussed elsewhere in these comments, FCE believes that utility ownership of CHP would resolve many of the barriers holding back CHP development today, including: (i) the necessity of sizing to meet electrical rather than thermal load due to regulatory constraints on electricity exports; (ii) interconnection issues; and (iii) natural gas procurement issues. With respect to the first issue, a fuel cell CHP unit has approximately a 2:1 electricity-to-heat ratio, meaning that it produces twice as much electricity as heat. Therefore, it would be far more efficient to size a fuel cell CHP unit to match on-site thermal load if it were possible to export the excess electricity. Creating regulatory policy that encourages utility ownership of the CHP unit would remove the regulatory constraints on electricity exports, while also providing for the commercial benefits of a broader, portfolio-based natural gas procurement strategy. Encouraging the matching of on-site thermal load rather than on-site electrical load would lead to increases in CHP unit size and avoided GHG emissions from CHP while also increasing the amount of baseload electricity supplied to the electrical grid. Due to their internal thermal characteristics, fuel cells are operated at full output on a continuous 24-hour basis, and the ability of a utility owner to distribute and utilize any excess electrical output from a host facility would enable broader deployment of the technology. Current fuel cell CHP projects are limited to host sites with a stable 24-hour electrical demand, whereas utility ownership of these units (or, to a lesser extent simply removing barriers to electricity export by CHP units owned by third-party developers or customers) would enable a more diverse group of end users to act as host sites if their excess electricity could be used at other facilities also served by the utility.

A CHP "portfolio standard" requiring utilities to obtain a specified percentage of their electricity sales from CHP would encourage utility ownership of CHP, increasing efficiently generated electricity supply while also reducing GHG emissions. A CHP portfolio standard could be designed similar to the existing Renewable Portfolio Standard ("RPS") and be technology neutral across the board, or it could include a set-aside for highly efficient and/or low GHG-emitting CHP technologies.

Q24. Would including all of CHP in cap and trade create a disincentive if natural gas is not regulated under cap and trade?

Given the hand-in-glove relationship between the natural gas and electricity sectors in California, any cap-and-trade program must be multi-sector to capture the full value of avoided GHG emissions associated with both the production of electricity and thermal output. See response to Q15. Although fuel cell CHP units use natural gas more efficiently than many other CHP technologies, if there is no specific recognition of the value of this increased efficiency, less efficient CHP technologies might prevail in an electricity-only allowance scheme even if such technologies use relatively more natural gas to produce the same (or less) electricity and thermal products. It would be a serious flaw to pursue a regulatory or market design that permits such a result.

C. CHP as an emission reduction measure

Q16. Should CHP be considered an emission reduction measure under AB 32? Why or why not?

Definitely, to the extent that the emissions reductions attributable to CHP can be demonstrated. It is possible that some CHP units may not be able to demonstrate a net reduction in GHG emissions. But most combustion-based CHP units, and virtually all fuel cells in CHP applications will result in significant and measurable reduction of GHG emissions. FCE supports EPUC/CAC's double-benchmarking concept as a reasonable methodology for accounting for GHG emissions of CHP electrical and thermal output compared to an equivalent generation of the same products using two separate processes. Because the double-benchmarking concept compares the outputs from any CHP unit against equivalent electrical and thermal products produced by separate processes, the concept is technology neutral and can be applied in a similar manner to any CHP technology. Double-benchmarking should also be able to identify those circumstances (if any) where CHP does not result in emission reductions.

Regardless of the chosen regulatory mechanism for acknowledging CHP's GHG emissions reductions, the ability to accurately quantify the actual emissions savings attributable to the CHP system will be a fundamental requirement. Although it is technically possible to install instrumentation to measure all emissions from CHP systems, the proportionate cost of these components is prohibitive for smaller CHP installations. Moreover, the administrative costs associated with the collection and analysis of the emissions data would further impede the growth of small to mid-sized CHP projects as a potential GHG emissions reduction strategy.

In an effort to avoid these economic and administrative disincentives, FCE suggests that real-time metered electrical output from CHP systems could function as a readily available and cost-effective index for allocation of GHG reduction values. As electrical output (measured in kW and kWh) is routinely measured for CHP systems, it can define the operational profile of a CHP system including any variability in performance. This electrical output data can then be related to a table of pre-determined or stipulated GHG emissions values based on the relevant CHP technology and its efficiencies at various performance levels.

As the ARB already offers a suitable certification methodology for some CHP systems in the form of its CARB 07 program, an extrapolation of this process could serve as the cost-effective source for the stipulated CHP emissions data. Manufacturers of CHP systems are currently able to submit detailed monitoring data of emissions in order to secure CARB 07 certification for their products. A similar program could be offered to a wider range of manufacturers that would yield a table of GHG emissions reductions characteristics for all eligible CHP systems. Once established, these values combined with the metered electrical output from operational CHP units could provide a cost-effective and reliable stream of real-time, readily verifiable performance based GHG emissions reduction data.

As previously noted, the questions presented for comments all appear to assume that CHP units uses a combustion-based technology. Because this is not the case, it is appropriate to recognize important distinctions in CHP technologies. Indeed, fuel cell CHP units provide substantial emission reductions because their electrochemical process results in low emissions and high electrical efficiency, while their high temperature waste heat results in very high overall system efficiency in CHP applications. The regulatory construct ultimately developed should recognize these important distinctions.

The National Fuel Cell Research Center recently completed a study entitled Build-Up of Distributed Fuel Cell Value in California: Background and Methodology, on behalf of the California Fuel Cell Manufacturers' Initiative. This study concluded that, among other attributes, avoided emissions resulting from fuel cell deployment in California provide significant value to Californians. The study, provided in Attachment A to these comments, shows that if fuel cells achieved a market penetration of 3200 MW in California by 2020, fuel cells could contribute 4.1 million metric tonnes of avoided CO2 emissions per year toward meeting California's AB32 goals. As an early action item under AB32, increasing the deployment of fuel cells could immediately and significantly contribute to the achievement of AB32's emissions reduction goals. This contribution would expand as fuel cell market penetration increases over time. Moreover, fuel cells operated on renewable fuels deliver significant GHG emissions reductions at a very low cost per ton when compared to other available technologies. Thus, early efforts toward AB32 compliance are both technologically feasible and cost effective via the enhanced deployment of fuel cell-based CHP.

Q18. Should ARB and/or the Commissions consider policies or programs to encourage installation of CHP for GHG reduction purposes? Why or why not?

Yes. FCE believes that double-benchmarking will demonstrate the GHG emissions reduction potential of most CHP units compared to the separate generation of electrical and thermal products. Given the priority of CHP in the Energy Action Plan's loading order, and the demonstrable contribution of CHP in reducing GHG emissions, the Commissions should consider initiating and supporting policies that would allow CHP units to match on-site thermal load by easing restrictions on electricity exports for CHP units. Current restrictions result in CHP units designed to match on-site electric load, unnecessarily limiting the potential amount of recoverable thermal energy. Since many of the GHG emissions reduction benefits associated with the efficiency gains from CHP applications come from the thermal side (i.e., from avoided fuel combustion for separate thermal product generation), policies that encourage maximum thermal production would result in larger CHP units designed to match thermal load, with additional electricity exported to the grid near load centers. Electricity supply would be enhanced while long-distance transmission requirements and associated losses would be reduced.

Measures to facilitate utility ownership could likewise encourage installation of CHP units for GHG reduction purposes. The objectives of AB 32 would be served by encouraging utility ownership of CHP, allowing the utility to claim CHP output as a resource and integrate the net CHP electricity exports, and encouraging installation of additional CHP units at locations most beneficial to the utility in terms of addressing localized supply issues and grid constraints.

Q19. Should CHP have an efficiency threshold in order to qualify as an emission reduction measure? If so, why?

No. The emphasis should be on emission reduction, not necessarily strictly as a function of efficiency. This question appears to presuppose that CHP is provided by a combustion-based technology. Fuel cells provide electricity through an electrochemical process, rather than through fuel combustion. As a result, at any given electrical efficiency, a fuel cell will provide greater emissions reduction than a combustion-based generating technology.

Rather than mandating an efficiency threshold, FCE recommends that the double-benchmarking process be used to demonstrate the emissions reduction attributable to any CHP unit. Any CHP unit resulting in reduced emissions compared to the emissions that would result from equivalent output from separate electrical and thermal processes should be considered an emission reduction measure. CHP units should be encouraged based on their cost per unit of emissions reduction, using the results of the E3 GHG calculator being developed as part of this proceeding *<u>provided the E3 GHG calculator incorporates the cost and emissions profiles needed to make such a comparison</u>*. Cost and performance parameters for all potential CHP technologies should be included in the E3 GHG calculator to ensure proper consideration each technology's respective GHG emissions reduction potential.

Q20. Which of the proposed methods best achieves the objectives of an efficiency threshold and why is it the best? Is there a superior method not proposed by staff and why is it superior?

Because FCE does not believe an efficiency threshold is appropriate, it expresses no view on this issue at this time.

Q21. What should the minimum efficiency threshold be (in terms of % savings) to qualify as an emissions reduction measure and why is that the appropriate minimum efficiency threshold?

Because FCE does not believe an efficiency threshold is appropriate, it expresses no view on this issue at this time.

Q23. Should the Commissions pursue policy or programmatic measures to overcome some of the barriers to CHP deployment?

Yes. The CPUC and CEC should first identify a set of common goals and recommendations, and then develop specific coordinated actions to accomplish those goals, in a manner similar to the development of the Joint Energy Agency Energy Action Plan. For example, if a barrier such as the lack of a DG portfolio standard is inhibiting utility investment in cost-effective CHP, then the agencies should jointly develop goals, and the CPUC should establish a proceeding to develop the policy needed to accomplish those goals. If the barrier requires passage of legislation, such as addressing extension of the SGIP program or eliminating the 1 MW net metering cap, then the agencies should decide together what action they can take to initiate and support the appropriate legislation. Action items should be prioritized for maximum impact on GHG reduction targets.

D. Legal issues

Q22. Are there other legal and regulatory barriers to CHP implementation in California that should be considered with respect to GHG regulation? If so, please explain in full with citations to specific relevant legal authorities. Also explain if and, if so, how the barriers could be avoided.

There are a number of significant legal and regulatory barriers that impede CHP implementation generally, and fuel cell development particularly. These include:

- Policies that discourage investor-owned utilities from investing in CHP facilities;
- Standby and demand charges that penalize customers for installing CHP facilities;
- Non-bypassable "exit fees" that penalize customers for installing CHP facilities;
- Interconnection rules and charges that inhibit installation of CHP facilities;
- Limited scope and funding of existing incentive programs;
- Lack of coordination and clear direction.

We briefly discuss each of these barriers and potential solutions below.

Utility-owned and procured CHP

The CEC acknowledged in the 2007 IEPR that "[i]nvestor-owned utilities continue to show little interest in accepting energy from customer-owned distributed generation projects or in developing utility-owned distributed generation or combined heat and power projects. As a result, these options continue to struggle with major barriers to market entry."[2] The barriers to utility-owned CHP as documented in the IEPR and in other CEC publications include: 1) a CPUC-administered procurement process that by design favors larger non-CHP generation facilities and that generally discourages development of smaller-scaled IOU-owned generation, 2) the lack of any enforceable (or non-enforceable for that matter) targets for DG procurement by

[2] 2007 IEPR, p. 161.

IOUs, and 3) the lack of policy facilitating natural gas procurement and hedging for on-site natural gas-fueled CHP units.

In order to effectively encourage IOUs to own CHP, the CPUC needs to either change the existing long-term procurement rules or establish new procurement policies specifically designed for CHP. The latter is probably the best course. The current long-term procurement program rules and the RPS process administered by the CPUC have been developed through a lengthy and complex administrative process, and are by design not really intended to facilitate the development of smaller on-site utility-owned CHP. Thus, the best approach to encouraging development of IOU-owned CHP would probably be to establish policies specifically authorizing the IOUs to develop cost-effective on-site CHP and to procure natural gas for such facilities as part of the utility portfolio. There is also significant untapped potential for installation of CHP at state-owned facilities. A program encouraging IOUs to coordinate and partner with state agencies could yield real benefits – for taxpayers, ratepayers and the environment. Likewise, the CPUC's initial efforts to provide incentives for biogas conversion at dairies and other methane-producing sites should be expanded to encompass production of biogas for use as fuel for local CHP.[3] The already-recognized benefits of converting biomass into pipeline-quality biogas are expanded if that gas is used to fuel clean and efficient on-site or locally sited generation rather than being compressed and transported long distances for other less beneficial uses.

[3] The CPUC has recently approved limited measures enabling IOUs to partner with dairies in efforts to convert waste into pipeline quality biogas, which is transported offsite to be combusted or otherwise used as an alternative to natural gas. *See e.g.* CPUC Resolutions E-4076 and E-4083 (approving IOU biogas contracts); *See also* Resolution 3410 (approving PG&E's request to contract for manure management projects for its ClimateSmart program). Notably, the CPUC acknowledges in Resolution G-3410, fn. 16 that biogas from digesters can be used both for on and off-site electricity generation.

In addition to considering barriers to utility ownership of CHP, the CPUC and CEC should likewise address barriers to utility procurement of electricity from CHP units owned by third parties. First, the state needs to eliminate the current limitations prohibiting utilities from paying for net exports by net metered facilities. Second, the CPUC needs to reform the procurement process to set specific targets for procurement from DG. The state's enactment of AB 1613, which will require utilities to purchase excess electricity from CHP units of 20 MW or less, should be helpful.[4] However, the effectiveness of AB 1613 in contributing in the near term toward the reduction of GHG emissions will depend on timely and effective implementation, and continuing program review and improvement.

Standby and demand charges

Standby reservation charges and demand charges are not designed to encourage development of CHP. In 2002, the CEC's Distributed Generation Strategic Plan noted that "…regulatory uncertainty in California continues to be a major concern for those considering the deployment of distributed generation. Utility rate design is confusing at best, including issues surrounding standby charges, interconnection fees, exit fees and grid management charges."[5] In the 2003, 2005 and 2007 Integrated Energy Policy Reports, the CEC similarly acknowledged these obstacles, and in the 2007 IEPR, the CEC specifically recommended that the CPUC "complete a tariff structure to make distributed generation and combined heat and power projects "cost and revenue neutral," while granting owners credit for system benefits such as reduced congestion.[6]

This objective is far from accomplished. Currently, there is an exemption from standby charges that only applies to facilities sized 5 MW or smaller. This statutory exemption has been

---

[4] Link at: http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_1601-1650/ab_1613_bill_20071014_chaptered.pdf.
[5] California Energy Commission, *Distributed Generation Strategic Plan,* June 2002, CEC-700-02-002, p. 16.
[6] 2007 IEPR at p. 163.

extended in six-month increments in accordance with statutory and CPUC requirements.[7] It needs to be made permanent and it needs to be extended to larger installations. Likewise, the future expansion of CHP will require reform of the IOU demand charge rate structure, which serves as a further disincentive to installation of CHP. Currently, demand charge and other DG rate design issues are litigated separately in the IOUs' general rate cases. In order to obtain even small incremental reforms in rate design, DG advocates are forced in intervene and spend scarce resources in multiple, complex proceedings that often run a year or more – resources that would be better expended on developing new and more effective technologies and applications.[8] It is absolutely critical that the CPUC establish a CHP-friendly tariff structure that is specifically designed to encourage and reward customers for installing CHP, that is consistent between the IOUs, and that reflects *all* of the environmental and system benefits provided by investment in CHP.

Non-bypassable Charges

The CPUC has established a very limited exemption from non-bypassable charges for on-site distributed generation.[9] This exemption should be extended to include all non-bypassable charges, without size or other limitations. Starting from a presumption that CHP units (particularly fuel cells) offer significant benefits, including avoided GHG emissions, resource diversity, avoided transmission and distribution costs, etc., it does not make sense to impose exit fees on customers willing to invest in CHP. In the 2007 IEPR, the CEC recommended that:

---

[7] *See* PU Code § 353.13(a), CPUC Decisions 03-04-060 and 01-07-027.

[8] In response to DG advocates' recent request for generic consideration of DG rate design reform in Rulemaking 08-03-008, the CPUC has regrettably ruled that such proposals would not be considered in the DG rulemaking and are rather "more appropriately considered in each utility's rate design proceeding." *See* Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges (May 15, 2008) p. 14.

[9] *See* CPUC Decision 07-05-006.

> The CPUC and Energy Commission should work cooperatively to eliminate all non-bypassable charges for distributed generation and combined heat and power, regardless of size or interconnection voltage…

FCE has first-hand experience with potential fuel cell customers who have been discouraged from installing CHP due to concern about existing and potential future non-bypassable charges. FCE strongly supports the CEC's recommendation and urges the CEC and CPUC to immediately act on the CEC's recommendation.

Interconnection

It is FCE's experience that the DG interconnection process remains unduly complex and confusing for developers and customers. In the 2007 IEPR, the CEC recommends that:

> The CPUC should 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.[10]

FCE agrees with these general recommendations. But it is important to observe that interconnection issues confronting DG vary by size and by technology. It may take different reforms to streamline the interconnection process for 3 MW of fuel cells installed at a water treatment plant than for a 30 kW residential photovoltaic system. As a first step, the CPUC and CEC need to collaboratively understand what the current interconnection issues are, and to establish specific goals and objectives for improving the process in ways that specifically encourage increased deployment of CHP.

Incentives

Currently the SGIP program is scheduled to sunset on January 1, 2012. The program has been successful in initially supporting development of smaller-scaled DG projects, but its scope and impact have been limited by the 1 MW cap on incentives, year-to-year funding and other programmatic limitations. FCE is pleased that the CPUC recently authorized a limited two year

[10] 2007 IEPR, p. 163.

pilot exception to the 1 MW incentive cap, permitting funding for some fuel cell and wind projects to 3 MW.[11] This exception and funding allocation will make incentives available to at least a few larger fuel cell projects. However, in order to truly create a new self-sustaining market for newer CHP technologies, the state needs to expand and fully fund a program that supports all eligible clean and efficient CHP projects, including larger projects, at incentive levels that will help such technologies achieve a scale of production that is commercially viable and cost-effective.

In short, the state needs to "think big" in its approach to building new markets for new clean technologies if the goals of AB 32 are to be achieved. In order to realize significant GHG emissions reduction from CHP at a scale that is achievable, the state needs to make a commensurately ambitious initial commitment of incentive funding. This commitment cannot be cost-justified if the benefits of CHP are not fully accounted for, and it cannot be justified as a regulatory priority unless it is viewed from the perspective of the state's long-term goals under AB 32. However, if the state develops an incentive program that is appropriately scaled and coordinated with long-term GHG emission reduction objectives, California could not only exponentially increase the amount of CHP installed statewide but could simultaneously help create a whole new business sector in the California economy as manufacturers of fuel cells and other emerging new CHP technologies site production facilities close to this new, expanding market.

Coordination

It appears that lack of coordination between agencies and between proceedings contributes to the problems discussed above. This lack of coordination is not intentional, but rather a byproduct of multiple jurisdictions and proceedings addressing similar issues without a

[11] CPUC Decision 08-04-049.

formal means of communicating common goals and intentions. In order to address this in the context of CHP, we recommend that goals and recommendations for increasing CHP be established in this multi-agency effort to implement AB 32 and that those goals and recommendations be implemented consistently and comprehensively by the relevant agencies.

CONCLUSION

FuelCell Energy, Inc. appreciates this opportunity to comment on questions regarding the integration of CHP into GHG regulation under AB 32, and looks forward to further participating in these proceedings.

Dated: June 2, 2008

Respectfully submitted,

By: /s/

William A. Karambelas
Vice President, Western Region
FuelCell Energy, Inc.
27068 La Paz Road #470
Aliso Viejo, CA 92656
Telephone: 949-305-4595
Karambelas@fce.com

Lynn M. Haug
Andrew B. Brown
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H Street
Sacramento, CA 95811
Telephone: 916-447-2166
lmh@eslawfirm.com

Attorneys for FuelCell Energy, Inc.

ATTACHMENT A

Build-Up of Distributed Fuel Cell Value In California: Background and Methodology

NATIONAL FUEL CELL RESEARCH CENTER

UNIVERSITY of CALIFORNIA · IRVINE

May 2008

TABLE OF CONTENTS

FIGURES

ATTACHMENTS

Build-Up of Distributed Fuel Cell Value
In California:
Background and Methodology

I. EXECUTIVE SUMMARY

This paper presents the findings of a study by the California Fuel Cell Manufacturers Initiative ("CAFCMI") that examines the value to California residents of a broad introduction of stationary fuel cells into the state of California. This study examines only stationary fuel cells to be used in distributed generation markets, ranging in size from several hundred kilowatts ("kW") to tens of megawatts ("MW"). This study does not address the application of fuel cells in other stationary applications (*e.g.*, residential, central station), nor does it address the application of fuel cells in portable or transportation applications.

Figure 1, entitled "Build-Up of Fuel Cell Value in California," illustrates the results of the study's step-by-step analysis of the value in cents/kWh of the ***avoided costs*** of central station electricity generation attributable to fuel cells ***today***. This "waterfall" chart shows that distributed fuel cells currently provide 6.6-20.5 cents/kWh of value to California electricity consumers. With only 18 MW of fuel cell capacity in California out of a total annual peak load of over 50,000 MW, fuel cells currently provide less than 0.01% of California's electricity use. With the increased penetration of distributed fuel cells over time, both the amount of electricity provided by fuel cells and the cents/kWh value will increase, together dramatically increasing the total value of distributed fuel cells to California.

The categories of avoided costs in the "Build-Up of Distributed Fuel Cell Value in California" illustrated in Figure 1 depict a number of so-called "distributed value elements" that represent distributed generation technology attributes vis-à-vis a central electricity generating plant. The actual values shown in Figure 1 reflect fuel cell-specific calculations for each distributed value element included in this study, some of which would be similar to values for other distributed generation technologies and some of which have higher values due to the technology-specific characteristics of fuel cells. Technology-specific characteristics contributing to higher relative fuel cell value include:

- Electricity generation through electrochemical reaction rather than by combustion
    - Higher electrical efficiency, resulting in more efficient fuel use and reduced carbon signature
    - Greater reliability, partially due to fewer moving parts
    - Improved power quality
    - Avoided emissions
- Low acoustic signature
- Virtually zero emissions signature
- Low vibration.

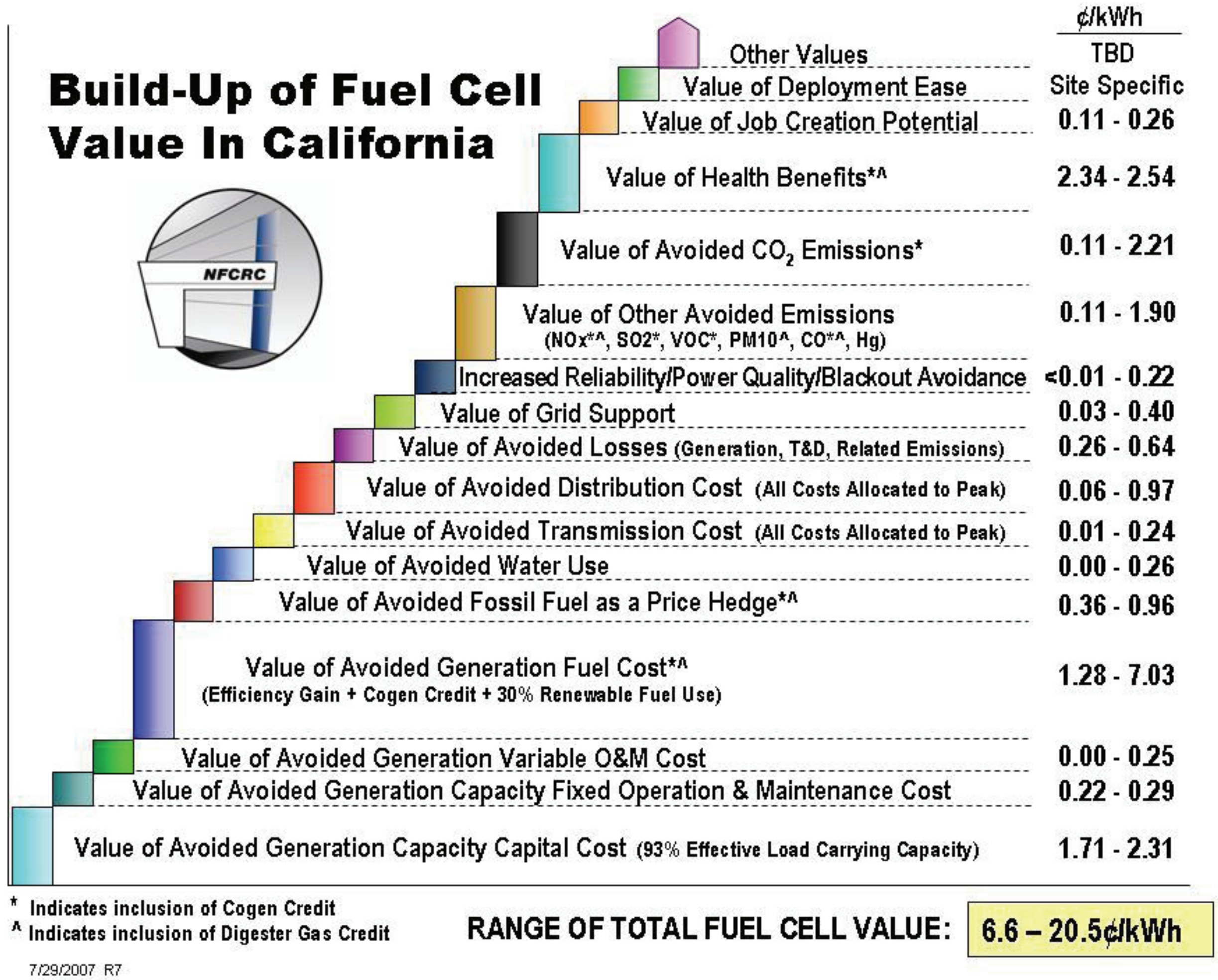


Figure 1. Build-Up of Fuel Cell Value in California

Features that are shared with some but not all distributed generation technologies include:

- Cogeneration potential, resulting in even higher overall system efficiency
- 24/7 baseload operations
- Fuel flexibility
- Well-suited for renewable fuels.

The distributed value elements quantified in this study specifically for fuel cells fall into the following four general categories: (i) Generation-related (avoided fixed and variable costs, including fuel costs); (ii) grid-related (increased reliability, avoided transmission and distribution costs); (iii) avoided emissions and related health benefits; and, (iv) job creation potential.

Each distributed value element quantified for fuel cells in Figure 1 is discussed in some detail in this paper to enable the reader to understand the derivation of its value. Some of the avoided costs illustrated in Figure 1 are quantified based on observable market prices of equipment, services, and other relevant factors, and some are quantified based on values that are derived from a broad-based literature search. Some attributes would also apply to other distributed generation technologies, though the specific value of any given attribute may be technology-dependent (*e.g.*, value of avoided emissions). Therefore, additional data on fuel cell technologies, economics, and underlying assumptions was obtained from the participating organizations.

The results of the avoided cost analysis illustrated in Figure 1 were incorporated into a full benefit-cost analysis of stationary fuel cells in California. Three of the major benefit-cost tests specified by the California Public Utilities Commission ("CPUC") in its Standard Practices Manual were performed as part of this study, including:

- The Participant Test
- The Ratepayer Impact Measure Test
- The Societal Test.

The full benefit-cost analysis was based on detailed fuel cell cost and performance data provided by the participating organizations. Figure 2, entitled "Benefit:Cost Ratios for Fuel Cell Baseload Electricity Generation in California, with SGIP Funding" illustrates the capacity weighted-average results, based on benefit-cost ratios calculated for nine separate fuel cell products. Figure 2 clearly demonstrates that: (i) fuel cells provide significant societal benefits to California for each of the four fuel and operating mode combinations analyzed, and (ii) ratepayer funding provided through the CPUC's Self-Generation Incentive Program ("SGIP") has moved stationary fuel cells that generate baseload electricity to the point of near cost-effectiveness from the participant's (*i.e.*, investor's) perspective, even without federal and state tax credits. Additional details related to the benefit-cost analyses are provided in Section III of this report.

The fuel cells considered in the study operate as a baseload distributed generation technology. Therefore, valuing the avoided costs associated with the deployment of these fuel cells must be based on a comparison with the avoided baseload central station electricity generation technology serving California customers. These avoided baseload central station generation technologies include in-state natural gas-fired generators and out-of-state coal-fired generators from which California imports power. Although coal-fired imports into California will be limited in the future under long-term contracts, it is anticipated that significant volumes of short-tem coal-fired electricity imports will continue to make their way into California for the foreseeable future.

Fuel cells generate electricity using an electrochemical process rather than through combustion, and even though most fuel cells use natural gas, fuel cells on average require less natural gas per kWh generated than most central station natural gas-fired generators. As a result, fuel cells have lower carbon dioxide (*i.e.*, greenhouse gas) emissions than the avoided generator, as described in detail in this paper. In addition, the 30% of California's fuel cells that operate on renewable digester gas from landfills and wastewater treatment plants further reduce emissions by preventing flaring of that digester gas. Emissions are further mitigated by the 60% of all fuel cells that capture waste heat to produce steam or hot water, thereby avoiding fuel input to natural gas boilers to produce those products. Each of these factors contributes to ever more avoided (*i.e.*, reduced) emissions attributable to fuel cells. Another key advantage that fuel cells have over conventional power generation technologies is that fuel cells emit only small quantities of nitrogen oxides ("NO_x") and sulfur oxides ("SO_x") (*i.e.*, acid rain pollutants), in part because their fuel input has to be desulfurized and in part because fuel cells do not employ combustion technology to produce electricity.

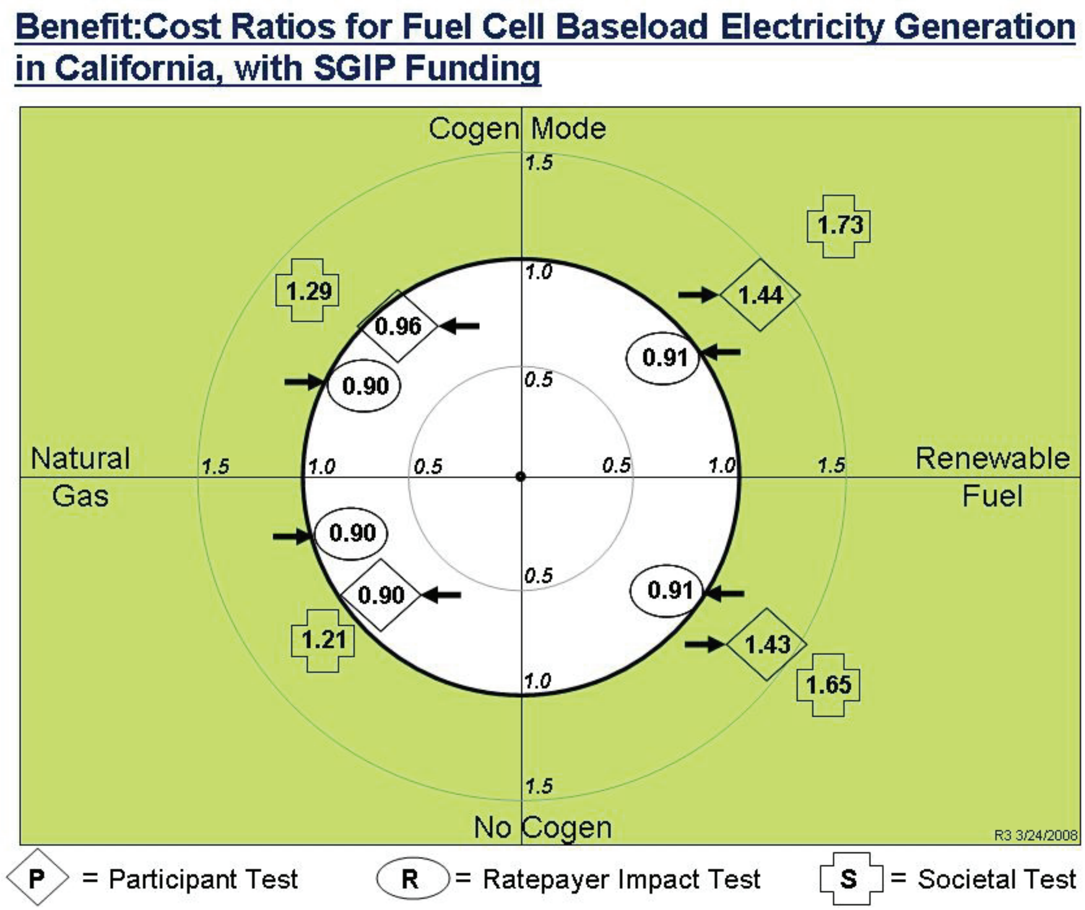


Figure 2. Weighted-Average Benefit-Cost Ratios with SGIP Funding

Fuel cells provide significant value to California's ratepayers today. As fuel cell installed capacity and penetration rates increase throughout the state, the value provided to California's ratepayers through cogeneration, digester gas use, avoided central station generation, and the associated avoided emissions will grow significantly. Per MW of installed capacity, fuel cells result in more *avoided* emissions per year than either solar photovoltaics or wind energy; combining the unique operating characteristics of these diverse technologies would further enhance the benefits of fuel cells to the state.

Fuel cells and their resultant lower emissions have the potential to make a significant contribution to achieving the reduced greenhouse gases ("GHG") emissions goals under the California Global Warming Solutions Act of 2006 ("AB32"). Industry input, supported by California Energy Commission analysis, indicates that stationary fuel cell penetration in California could reach 3200 MW by 2020. This penetration level would reduce carbon dioxide emissions by over 4 million metric tonnes per year and save enough natural gas to generate nearly 15 million MWh of electricity – equivalent to the electricity consumption of 2 million California residences.

II. FUEL CELLS: TECHNOLOGY AND GENERAL ATTRIBUTES

For the reader unfamiliar with fuel cells, Attachment A provides a four-page introduction to fuel cell technology. Attachment A describes the basic operation of a fuel cell, the fundamental differences between the five major fuel cell types, and a number of the general attributes of fuel cells used in stationary applications.

III. DESCRIPTION OF BENEFIT-COST ANALYSIS METHODOLOGY

A. BENEFIT-COST TESTS

Each of the three benefit-cost tests performed as part of this study has its own purpose, and each evaluates the benefits and costs of a project or program from a different perspective. The Participant Test measures the benefits and costs from the perspective of the individual participant, that typically being the individual or company owning the project or participating in the program. The Ratepayer Impact Measure ("RIM") Test measures the benefits and costs of a project or program from the perspective of utility ratepayers. The Societal Test is the broadest of the three benefit-cost tests, measuring the benefits and costs of a project or program from a societal perspective.

While all three tests measure benefits and costs over the life of a project, the Societal Test uses a lower (societal) discount rate than the discount rate used from the Participant Test and the RIM Test. The lower societal discount rate is intended to reflect the fact that society usually takes a longer term perspective than do individual investors or ratepayers. Because all benefits and costs are discounted before the benefit-cost ratio is calculated for each test, there is no relative advantage or disadvantage for fuel cell products that are commercially available today versus products that are still under development. A more detailed discussion of each benefit-cost test will be provided below.

B. DATA USED IN BENEFIT-COST ANALYSIS

The participating fuel cell manufacturers provided detailed cost and performance data for commercially available products and projected cost and performance data for products that are currently under development. A total of nine separate fuel cell products were included in the benefit-cost analysis; four of the fuel cell products are commercially available today and all are projected to be commercially available within the next three-to-ten years. Data provided by the fuel cell manufacturers was supplemented with benefit and cost data obtained from a broad-based literature review. A separate benefit-cost ratio was calculated for each product for each investor-owned utility "(IOU") franchise area in California for each of the three benefit-cost tests identified above.

CPUC-approved natural gas and electricity tariff rates in effect as of the end of February, 2008, were used in the benefit-cost analysis for each test for each of the IOUs included in the study, *i.e.*, PG&E, SDG&E, SCE, and SoCal Gas. Natural gas and electricity tariff rates through 2030 were escalated using the average annual rate of change in costs projected for each IOU in a major study and supporting analysis done for the CPUC by Energy and Environmental Economics, Inc. (*See* E3 Avoided Cost Study and Updated E3 Electric Avoided Costs Workbook.) Because the E3 Avoided Cost Study includes cost projections only through the year 2030, tariff rates for the period from 2031-2042 were assumed in this study to escalate at 2% per year. The E3 Avoided Cost Study also includes calculated marginal costs for transmission and distribution, for electricity generation, and for natural gas supplies for each of the IOUs through 2030. As was the case with IOU natural gas and electricity tariff rates, IOU marginal costs beyond 2030 were assumed to escalate at 2% per year.

Most large stationary fuel cells operating as baseload electricity generators are fueled with natural gas and collect the waste heat to cogenerate steam or hot water. However, such fuel cells may also operate on renewable fuel and there may be cases where there is no on-site use for the waste heat. Therefore, this study assessed four possible combinations of fuel and operating mode for each of the nine fuel cell products included in the analysis in order to create a "spanning scenario" for each of the three benefit-cost tests. The four combinations of fuel and operating mode are as follows:

- Natural Gas + No Cogeneration
- Natural Gas + Cogeneration Mode
- Renewable Fuel + No Cogeneration
- Renewable Fuel + Cogeneration Mode.

The renewable fuel considered in this study is anaerobic digester gas, typically derived from wastewater treatment plants, landfills, and manure collection ponds. Use of such digester gas requires removal of impurities and compression before the gas can be used in a fuel cell. The need for an up-front clean-up skid adds capital costs ranging from $250-1000/kW of installed fuel cell capacity for fuel cells operating on renewable fuel. Additional annual O&M costs associated with the up-front clean-up skid are assumed to be 2% of the additional capital costs. An electrical efficiency loss of 2% is included to reflect the larger volume of (lower Btu) digester gas that must pass through any fuel cell operating on renewable fuel.[1]

[1] This efficiency loss does not apply to molten carbonate fuel cells because the carbon dioxide in the digester gas actually enhances the carbonate-based electrochemistry and offsets any efficiency loss.

Another item that must be considered in the benefit-cost analysis with respect to renewable fuel is the cost of the digester gas as compared to the cost of the natural gas that would otherwise be used by the fuel cell. The results presented in Figure 2 (above) and in Figure 3 (below) assume that digester gas is valued at 10% of the utility's tariff cost of natural gas. This assumption recognizes that there may be some competition for renewable fuel, and is more conservative than simply assuming that digester gas is a cost-free fuel that would otherwise be flared. In addition, because digester gas production depends on a number of uncontrollable factors such as ambient temperature and waste composition, a fuel cell project may need to maintain a portion of its natural gas supply and delivery under contract in the event that there is insufficient digester gas available at any given time to maintain fuel cell operations. The results presented in Figures 2 and 3 assume that natural gas is available to replace up to 15% of the project's annual renewable fuel requirements.

Almost all stationary fuel cells generating baseload electricity operate in cogeneration mode because the capture and re-use of waste heat significantly improves a project's economics. Thus, cogeneration mode is considered to be the base case in the benefit-cost tests performed in this study. Fuel cells not operating in cogeneration mode are assumed to have $70-170/kW less in up-front capital costs and reduced annual O&M costs equal to 2% of the reduced up-front capital costs.

Once the discounted benefit-cost ratios for each fuel cell product, each IOU, and each fuel and operating mode combination were calculated, a capacity weighted-average benefit-cost ratio for all products across all utility franchise areas was calculated for each test and for each fuel and operating mode combination. The ultimate calculation of a capacity weighted-average benefit-cost ratio was deemed necessary in order to maintain the confidentiality of each manufacturer's data.

C. RESULTS OF BENEFIT-COST ANALYSIS

Capacity weighted-average benefit-cost ratios were calculated both with and without the benefit of SGIP funding. Figure 3 (below) shows the weighted-average benefit-cost ratios assuming no SGIP funding, whereas the previously presented Figure 2 showed the weighted-average benefit-cost ratios with SGIP funding included. In each case, the spanning scenarios are reflected in a similar manner:

- The lower left quadrant of Figures 2 and 3 represents the results of each weighted-average benefit-cost test for the "Natural Gas + No Cogeneration" fuel and operating mode combination; the upper left quadrant represents the results for the "Natural Gas + Cogeneration Mode" combination.
- Similarly, the lower right quadrant of Figures 2 and 3 represents the results of each weighted-average benefit-cost test for the "Renewable Fuel + No Cogeneration" combination, and the upper right quadrant represents the results for the "Renewable Fuel + Cogeneration Mode" combination.

- Actual capacity weighted-average benefit-cost ratios for each fuel and operating mode combination are associated with a specific shape for ease of interpretation:
    - Participant Test benefit-cost ratios are shown within a diamond
    - RIM Test benefit-cost ratios are shown within an oval
    - Societal Test benefit-cost ratios are shown within a cross.
- Concentric circles provide a quick reference of the relative value for each of the weighted-average benefit-cost ratios, as indicated along the axis of each quadrant.
    - A benefit-cost ratio less than 1.0 would be located within the white portion of the quadrant for any given fuel and operating mode combination.
    - A benefit-cost ratio greater than 1.0 would be located in the green portion of each quadrant for any given fuel and operating mode combination.

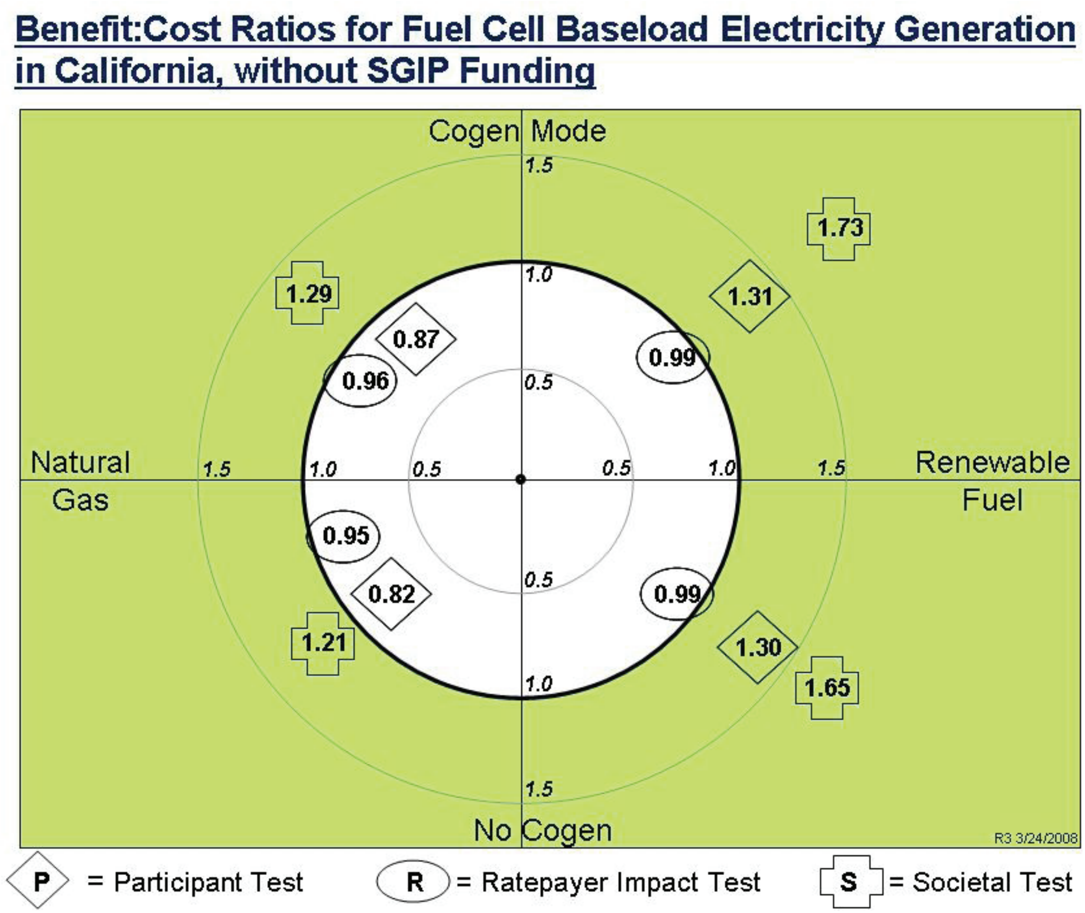


Figure 3. Weighted-Average Benefit-Cost Ratios without SGIP Funding

The results in Figure 3 clearly show that stationary fuel cells in California have the greatest weighted-average benefit-cost ratio when they are operating in cogeneration mode using renewable fuel. Fuel cells operating on natural gas in cogeneration mode have a weighted-average benefit-cost ratio of 0.87 for the Participant Test and 1.29 for the Societal Test, assuming no SGIP ratepayer-funded incentives. Fuel cells operating on natural gas without cogeneration have more limited benefits, as shown in the associated benefit-cost ratios. Typical benefit-cost ratios for the RIM Test ranged from 0.95-0.99, again assuming no SGIP incentives.

Figure 2 (presented earlier) shows how each of the weighted-average benefit-cost ratio changes when SGIP funding for fuel cell projects is included in the analysis. Of note:

- For each fuel and operating mode combination, the benefit-cost ratio for the Participant Test increases as SGIP funding is provided to the participant.
  - Note that the SGIP funding almost brings the benefit-cost ratio for the Participant Test to 1.0, as intended. Including the benefits of the federal Investment Tax Credit would move that benefit-cost ratio into the green area in most cases.
- Conversely, the benefit-cost ratio for the RIM Test decreases since the SGIP funding is provided by the utility ratepayers.
- No changes result under the Societal Test, since the SGIP funding is seen as an intra-societal transfer that has no net impact from a societal perspective.

The sections below explain the results of each of the weighted-average benefit-cost ratios in greater detail, to provide the reader with an intuitive understanding of the calculated outcomes.

D. PARTICIPANT TEST

The participant (*i.e.*, investor) in a fuel cell project will avoid having to pay electric utility energy and demand rates to the extent that onsite electricity is generated by the fuel cell. With respect to the natural gas utility:

- To the extent that the fuel cell operates on natural gas, the participant's payments to the natural gas utility will increase for the natural gas required to run the fuel cell.
- If the fuel cell operates on renewable fuel, the participant's payments to the natural gas utility will increase only to the extent that natural gas is required to supplement the renewable fuel. The (opportunity) cost of the renewable fuel can range from cost-free to 100% of the cost of utility-supplied natural gas.
- If the fuel cell operates in cogeneration mode (regardless of fuel), the amount of natural gas required by on-site boilers will be reduced in proportion to the amount of useful waste heat.

In the Participant Test, the annual difference between reduced payments to the electric utility and increased payments to the natural gas utility is compared to all of the costs and financial offsets associated with the fuel cell over the project's life, including up-front capital cost, annual O&M costs, and investment incentives and tax credits. The benefit-cost ratio is calculated as the ratio of the net present value of each year's benefits and costs over the life of the project, using a nominal discount rate of 8.5%.[2]

E. RIM TEST

The RIM Test reflects the (discounted) aggregate net change in revenues and marginal costs *from the perspective of the electric and/or natural gas utility* affected by the fuel cell project.

The RIM Test reflects the electric utility's lower revenues due to the onsite electricity generated by the fuel cell. Whereas the electric utility's revenues are lower, so too are its marginal costs of transmission and distribution and of electricity generation. Note that the reduction in the electric utility's revenues is independent of whether the fuel cell operates on natural gas or renewable fuel, since electricity is generated by the fuel cell in either case.

Conversely, the natural gas utility benefits from higher revenues only (i) if the fuel cell operates on natural gas or (ii) to the extent that natural gas is required to supplement the fuel cell's renewable fuel use. However, the natural gas utility also faces higher marginal costs to procure and transport whatever additional natural gas is required by the fuel cell. The greater the extent to which the fuel cell operates solely on renewable fuel, the lesser the increase in the natural gas utility's revenues and associated marginal costs. Similarly, the natural gas utility's revenues and associated marginal costs will be reduced in proportion to the amount of useful waste heat that is captured if the fuel cell operates in cogeneration mode on any fuel.[3]

Changes (up or down) in utility revenues and utility marginal costs are captured in the RIM Test; ratepayer-funded incentives and program administration costs are also included as utility costs. It is primarily the difference between each of the affected utility's (average cost) regulated tariff rates and marginal costs, as adjusted by the "net-to-gross" percentage, that determines the value of the RIM Test benefit-cost ratio for any given project in any given utility franchise area.[4] The benefit-cost ratio is calculated as the net present value of each year's benefits and costs over the life of the project using an 8.5% annual discount rate.

---

[2] For the nine fuel cell projects included in this benefit-cost analysis, project life ranged from 15 to 25 years.

[3] This assumes that the useful waste heat that is captured is being used to displace heat from a natural gas-fired boiler, rather than from an electrical chiller.

[4] The "net-to-gross" percentage is a measure of how the utility's electric or natural gas load would have changed even in the absence of an incentive program. If no other empirical data are available, the standard net-to-gross percentage used in California is 85%. The implication is that 15% of the load shift (up or down) would have occurred even without a ratepayer-funded incentive program. Therefore, the utility's revenue impact (positive or negative) due to the incentive program is not 100% of the revenue impact of the load shift, but is rather only the 85% of the load shift that can be attributed to the incentive program.

F. SOCIETAL TEST

The Societal Test in effect combines the benefits and costs from the Participant Test and the RIM Test, but excludes investment incentives and tax credits because these items are a wash (*i.e.*, zero out) from a societal perspective. In addition, the value of externalities–considered in neither the Participant Test nor the RIM Test–is explicitly included in the Societal Test. The analysis underlying the waterfall chart in Figure 1 is used to determine the value of those externalities (*i.e.*, project attributes) to be included in the Societal Test for each individual fuel cell product and for each fuel and operating mode combination.[5] Quantified values for the following externalities were included in the Societal Test benefit-cost ratio calculations:

- Value of Avoided Emissions
- Value of Related Health Benefits
- Value of Avoided Fossil Fuel as a Price Hedge
- Value of Grid Support
- Value of Increased Reliability, Blackout Avoidance and Improved Power Quality
- Value of Job Creation Potential.

As was the case in the RIM Test, actual increases or decreases in the participant's payments to the natural gas or electric utility by the investor are fully included in the Societal Test. However, the actual impact of those revenue changes on the natural gas and/or electric utility is reduced by applying the "net-to-gross" percentage to all utility revenues and marginal costs to reflect the fact that a certain percentage of the load shift attributable to fuel cells would have occurred even in the absence of a ratepayer-funded incentive program. The benefit-cost ratio for the Societal Test is calculated as the ratio of the net present value of each year's benefits and costs over the life of the project, using a societal discount rate of 5.0%.

G. COST OF AVOIDED EMISSIONS

The first step in calculating the Value of Avoided Emissions for inclusion in the Societal Test was to determine the annual physical units of avoided emissions for each fuel cell product as compared to the average California natural gas-fired fleet of electricity generators.[6] Calculation of physical units of avoided emissions was performed for several types of emissions, including carbon dioxide ("CO_2"), NO_x, SO_x, carbon monoxide ("CO"), particulate matter, and volatile organic compounds ("VOC").

---

[5] Note that the value of many of the distributed value elements included in Figure 1's waterfall chart (e.g., avoided generation capital and O&M costs) is captured in the utility tariffs and marginal costs underlying the Participant Test and the RIM Test. To avoid double counting, only the value of those distributed value elements not already captured in the Participant Test and the RIM Test is included in the Societal Test.

[6] Additional detail on the calculation of the Value of Avoided Emissions is provided below in Section IV F.

To calculate the cost per unit of avoided emissions, the annual avoided physical emissions for each fuel cell product were multiplied by the project life and then divided by the net present value ("NPV") of the project's total costs, including initial capital cost, stack change out costs, and lifetime O&M costs.[7]

Similar to the benefit-cost ratio calculations, the cost of avoided emissions for each of the nine fuel cell products was aggregated into a capacity weighted-average cost measure to maintain the confidentiality of product-specific data.[8] The following results were calculated assuming that 50% of the NPV of the project's total costs was assigned to avoided CO_2 emissions and 50% to cumulative avoided NO_x, SO_x, CO, VOC and particulate matter emissions.

- The weighted-average NPV cost of avoided CO_2 emissions was $192/metric tonne for "natural gas + cogeneration mode" and $737/metric tonne for "natural gas + no cogeneration."
- For renewable fuel, the weighted-average NPV cost of avoided CO_2 emissions was $130/metric tonne with cogeneration and $479/metric tonne without cogeneration.
- The weighted-average NPV cost of avoided NO_x, SO_x, CO, VOC and particulate matter emissions was $20/pound for "natural gas + cogeneration mode" and $25/pound for "natural gas + no cogeneration."
- For renewable fuel, the weighted-average NPV cost of avoided NO_x, SO_x, CO, VOC and particulate matter emissions was $13/pound with cogeneration and $15/pound without cogeneration.

As noted, these results are based on a comparison of emissions from fuel cells generating baseload electricity in California and average emissions from the existing in-state natural gas-fired generating fleet. Additional efforts are underway to calculate the costs per unit of avoided emissions for fuel cells when compared to new, technology-specific projects.

H. BENEFIT-COST CONCLUSIONS

The societal benefits of stationary fuel cells generating baseload electricity outweigh the societal costs for each of the four spanning scenarios (*i.e.*, fuel and operating modes) examined in this benefit-cost analysis. As illustrated in Figures 2 and 3, this holds true with or without SGIP funding. However, the SGIP funding remains important from an investor's viewpoint, as seen in the shift of the benefit-cost ratio for the Participant Test

---

[7] The NPV was calculated using the nominal discount rate of 8.5% that was also used to calculate the benefit-cost ratios for the Participant Test and the RIM Test.

[8] Note that the cost of avoided CO_2 emissions is expressed in $/metric tonne. A metric tonne (or, more formally, a "megagram") is 1000 kilograms. At the equivalent of 2205 pounds, a metric tonne is 10.25% heavier than the 2000 pound ton commonly used in the U.S. Therefore, to obtain the cost of avoided CO_2 emissions in $/ton, simply divide the cost in $/metric tonne by 1.1025,

from less than 1.0 in Figure 3 to nearly 1.0 in Figure 2 for the most common "natural gas + cogeneration mode" scenario (upper left-hand quadrant). As explained above, the federal ITC has provided the final push towards cost-effectiveness from the participant's perspective.

The RIM Test benefit-cost ratio moves counter to the Participant Test benefit-cost ratio since the SGIP funding is provided by the ratepayers to the fuel cell project investors. The RIM Test reflects the ratepayers' perspective, based solely on changes in utility revenues and marginal costs. To the extent that the ratepayers and the society are one and the same, the results of the RIM Test must be considered in conjunction with the results of the Societal Test. In California, IOU ratepayers represent over two-thirds of the state's total electricity use[9] and over three-fourths of the state's total natural gas use.[10] Therefore, the substantial benefits reflected in the Societal Test accrue predominantly to those ratepayers providing SGIP funding and spill over the consumers of the state's remaining electricity and natural gas deliveries.

In terms of the cost of avoided emissions, fuel cells reduce CO_2 emissions at a weighted-average NPV cost of $130-737/metric tonne and cumulative NO_x, SO_x, CO, VOC and particulate matter emissions at a weighted-average NPV cost of $13-25/pound, depending on the underlying fuel and operating mode combination.

IV. INTRODUCTION TO AVOIDED COST VALUATION METHODOLOGY

This section will describe the details and assumptions behind the cents per kWh ("cents/kWh") avoided cost values derived in the "Build-Up of Distributed Fuel Cell Value in California" waterfall chart, as illustrated above in Figure 1. Some of the avoided costs are quantified based on observable market prices equipment, service, and other relevant factors, and some are quantified based values that are derived from a broad-based literature search. For the benefit of the reader, descriptions of the underlying assumptions are provided below for each calculated cents/kWh value range, starting at the bottom of the waterfall, continuing up through each value range toward the top of the waterfall.

The ***categories*** of avoided costs quantified in Figure 1 relate to a number of so-called "distributed value elements," which represent attributes of distributed generation technology vis-à-vis a central generating plant; the ***values*** derived in this study are specific to distributed fuel cells. Distributed value elements are categorized as being Political, Locational, Environmental, Antidotal, Security-related, or Efficiency-related.[11] Taking the first letter of each category, the "PLEASE" matrix is developed to summarize the potential distributed value elements in each category, as shown in Attachment B. The

9 *See* CPUC, "Annual Report 2007," p. 17.

10 *See* California Gas Utilities, "2006 California Gas Report," p. 19.

11 The PLEASE Matrix was first presented on April 13, 2005, in testimony before the CPUC on behalf of the Americans for Solar Power by Lori Smith Schell, Ph.D. in proceeding R.04-03-107.

quantified values in Figure 1 are not all-inclusive, and do not include many of the distributed value elements identified in the PLEASE matrix. Those distributed value elements that are featured in the "Build-Up of Fuel Cell Value in California" waterfall chart are marked with an asterisk (*) on the PLEASE matrix in Attachment B.

The fuel cells being considered in this analysis operate as a baseload distributed generation technology, generating electricity through an electrochemical process rather than through combustion. The resultant lower CO_2 emissions have the potential to make a significant contribution to achieving reduced GHG emissions goals under AB32. Fuel cells are also essentially free of particulates and unburned hydrocarbons, and have very low NO_x and SO_x emissions (both of which are acid rain pollutants that contribute to secondary particulate formation).

As a baseload technology, valuing the avoided costs associated with the deployment of fuel cells must be based on a comparison with the avoided baseload central station electricity generation technology serving California customers.

- For baseload central stations located in California, many of the avoided costs are derived from the natural gas combined cycle parameters that the CPUC defined as the 2006 Market Price Referent ("MPR") proxy plant in its Resolution E-4049. Additional avoided costs specific to California are taken from the E3 Avoided Cost Study.
- For baseload central stations located outside of California serving California markets, avoided costs are based on repowering existing coal-fired generators, based on the assumption that California's resource planning and AB32 requirements will result in no new coal-fired generators being built to serve California's electricity demand. Despite California's pending reduced reliance on coal-fired electricity imports purchased under long-term contracts, it is anticipated that a significant portion of California's imported electricity will continue to be from coal-fired generation, albeit purchased under short-tem or spot market contracts.

Avoided costs related to these two baseload generation technologies establish the range of values for each of the distributed value elements included in the "Build-Up of Distributed Fuel Cell Value in California." The cumulative range of value is calculated to be 6.6-20.5 cents/kWh for fuel cells currently installed in California, with the value expected to increase significantly over time as the penetration of fuel cells throughout the state increases.

A. AVOIDED GENERATION COSTS

The avoided generation costs include separate estimates for avoided capacity costs and avoided energy/generation costs.

***Capacity**:* Fuel cells achieve their highest electrical efficiency when operated as a baseload electricity generating technology. Fuel cells currently operating in California have an estimated annual capacity factor of 91%, and also have high availability during periods of peak electric demand. (*See* Itron, SGIP Fourth Year Impact Report, pp. 8-15.)

Value of Avoided Generation Capacity Capital Cost – The range of the Value of Avoided Generation Capacity Capital Cost is calculated here based on the annualized capacity value of a repowered subcritical pulverized coal generator (low end of range) and a combined cycle natural gas-fired generator (high end of range). The avoided capacity capital cost is calculated as the annual capacity charge rate (15% from Duke, *et al*., p. 9) times the capital cost for the technology ($770 per kW-yr for repowering a baseload coal plant,[12] and $980 per kW-yr for a combined cycle gas generator for the CPUC 2006 MPR proxy plant).

Value of Avoided Generation Capacity Fixed Operation & Maintenance ("O&M") Cost – This is an additional avoided capacity cost, with an unadjusted range of $13.94/kW-yr for a combined-cycle gas turbine and $19.60/kW-yr for a repowered baseload coal generator, derived from the same sources as above.

However, electrical grid peak loads are predominantly driven by air conditioning demand on sunny days. The capacity credit (avoided cost) for any distributed generation technology should be set based on the effective load carrying capacity ("ELCC") of that technology at a certain area within the system. The ELCC is the capacity of any electricity generator, whether distributed or conventional, to contribute effectively to a utility's capacity to meet its peak load. (*See* Herig, p. 2.)

Based on the performance of fuel cells participating in the SGIP, the average ELCC for fuel cells in California is 93%. (*See* Itron, SGIP Fourth Year Impact Report, pp. 8-15.) Although the fuel cells in this study operate as a baseload technology, their on-peak performance effectively reduces peak load due to their distributed nature. Therefore, a 93% ELCC is used to adjust both the Avoided Generation Capacity Capital Cost and the Avoided Generation Capacity Fixed O&M Cost. ***Note that for any given fuel cell project, the capacity-related avoided costs should reflect the localized system average ELCC.***

To recognize the dispersion value of distributed fuel cells, the generation-related avoided capacity costs have been multiplied by 1.14, the California electric generation reserve margin that is not applied to distributed generation projects.

To convert $/kW-yr capacity values to cents/kWh, it is necessary to divide the $/kW-yr capacity value by the number of hours per year during which a fuel cell project is expected to generate electricity; this number is derived from the annual capacity factor

---

12 The repowering-related capital and O&M costs used in this analysis are derived from repowering costs used by the U.S. Environmental Protection Agency ("EPA") in its Base Case 2004 Integrated Planning Model (Exhibit 4-21). EPA's repowering costs are inflated to 2007$ and escalated by the ratio of applicable costs from: (i) U.S. Department of Energy, Energy Information Administration ("EIA"), Assumptions to the Annual Energy Outlook 2007 ("AEO 2007") (p. 77), and (ii) EPA (Exhibit 4-9) for a new conventional pulverized coal plant. Application of such a ratio is necessary because EIA does not include cost estimates for repowering in its Assumptions to the AEO 2007.

for fuel cells. With 91% being the average annual capacity factor for fuel cells in California, there are 7,972 hours of expected fuel cell generation per year (*i.e.*, 8760 hours/year x 0.91). The resultant Value of Avoided Generation Capacity Capital Cost is 0.171-0.231 cents/kWh.

***Energy/Generation**:* Energy should be valued at the avoided real-time cost on at least an hourly basis. Avoided energy/generation costs include the avoided cost of central generating station fuel and the central station avoided variable O&M costs.

Value of Avoided Generation Variable O&M Cost - The Value of Avoided Generation Variable O&M Cost range of 0-0.25 cents/kWh is determined by the 2006 MPR proxy plant on the low side and by the adjusted EPA repowering costs on the high side, with the Value of Avoided Water Use subtracted out as a separate variable that sets an upper limit on the avoided variable O&M costs, as discussed below.

Value of Avoided Generation Fuel Cost – Although most fuel cells use natural gas to fuel the chemical reaction through which the fuel cell generates electricity, fuel cells have a higher electrical efficiency than the average California natural gas-fired generator. Thus, the Value of Avoided Generation Fuel Cost in this analysis reflects this efficiency gain for fuel cells that rely on natural gas. In addition, fuel cells may also be fueled with waste hydrogen from industrial processes, digester gas from landfills, waste water treatment plants, or other "renewable" sources. Electricity generated by these fuel cells contributes to the Value of Avoided Generation Fuel Cost in proportion to the renewable share of total installed fuel cell capacity in California, as described below. Similarly, the proportion of fuel cells that capture waste heat that is used to displace steam or hot water production from a natural gas-fired boiler also contributes to the Value of Avoided Generation Fuel Cost, as described below.

The Avoided Generation Capacity Cost parameters described above serve as a starting point for calculating the Avoided Generation Fuel Cost for fuel cells. The range of the avoided costs of central station generating fuel is set by the avoided baseload coal generation plant on the low side and by the average California avoided natural gas-fired plant on the high side.[13]

The range of avoided natural gas prices is based on the range of daily settlement prices for prompt-month natural gas futures contract prices on the New York Mercantile Exchange ("NYMEX").[14] Since the beginning of calendar year 2004, this range has been

---

[13] With respect to the avoided natural gas plant, the natural gas-fired 2006 MPR proxy plant is used as a point of comparison only for avoided capital capacity costs and avoided O&M costs; the average California avoided natural gas-fired plant is used as a point of comparison for all other calculations.

[14] The term "prompt month" refers to the earliest month for which futures contracts are trading. Trading of futures contracts for any given delivery month ends prior to the end of immediately previous month. Therefore, "the prompt month" in mid-April would be May, but by the end of April, after trading for the May futures contract closes, the prompt month becomes June.

$4.20-15.40/MMBtu, for natural gas located at the Henry Hub, onshore Louisiana.[15] The NYMEX natural gas price is converted to cents per kWh by multiplying it times the range of heat rates assumed for (i) the average California avoided natural gas-fired plant (*i.e.*, 8,087-9,100 Btu/kWh)[16] and (ii) the average fuel cell (*i.e.*, 8,060-8,343 Btu/kWh).

The range of avoided coal prices is based on the monthly national average cost of coal delivered to electric utilities, as reported on FERC Form 423. Since the beginning of 2004, this monthly average coal price has ranged from $1.27-1.71/MMBtu. (*See* EIA, November 19, 2006, Table 4.2.) The coal price is converted to cents per kWh by multiplying it times the range of heat rates assumed for the baseload coal generation plant (*i.e.*, 8,844-10,875 Btu/kWh).

The Avoided Generation Fuel Cost values calculated using the above methodology yields a range of 1.12-1.86 cents/kWh for coal and 3.40-14.01 cents/kWh for natural gas (but only if the avoided natural gas-fired generation was 100% avoided). However, since only 30% of all installed fuel cell capacity in California is assumed to use "renewable" digester gas instead of natural gas, the Avoided Generation Fuel Cost attributed to fuel cells in this analysis is only 30% of the absolute range of values, *i.e.*, 0.34-4.20 cents/kWh.[17] The higher efficiency of fuel cells contributes an additional 0.01-0.82 cents/kWh to the Avoided Generation Fuel Cost for those 70% of California fuel cells assumed to be operating on natural gas. The avoided coal price of 0.34 cents/kWh sets the lower end of the range, and the combined avoided natural gas price of 5.02 cents/kWh sets the upper end of the range for the electric-only Avoided Generation Fuel Cost, *i.e.*, prior to recognition of the Cogen(eration) Credit. As explained below, the Cogen(eration) Credit adds another 0.94-2.01 cents/kWh of Value of Avoided Generation Fuel Cost, making the total Value of Avoided Generation Fuel Cost 1.28-7.03 cents/kWh.

Value of Avoided Fossil Fuel as a Price Hedge – Fossil fuel price volatility can wreak havoc with personal and corporate budgets. Fossil fuel input that is avoided by fuel cells using renewable fuel and/or using captured waste heat, therefore, provides a type of price hedging mechanism that protects electricity consumers from unpredictable fossil fuel price volatility.

The range of estimates for the Value of Avoided Fossil Fuel as a Price Hedge is based on applying the heat rate end-points of 8,087 Btu/kWh and 10,875 Btu/kWh (discussed above) to the estimates derived by Bolinger, *et al.* (January 2004, p. 8). As was the case for the Avoided Generation Fuel Cost, the attributed Value of Avoided Fossil Fuel as a

---

15 No cost adjustment has been made to reflect the value of transportation from the Henry Hub to California, since this transportation value (known as the "basis") is highly volatile, varies seasonally, and may be either positive or negative.

16 The average California avoided natural gas-fired plant had a five-year weighted-average heat rate for 2001-2005 that was approximately 21% less efficient than that of the 2006 proxy plant, based on state-specific electricity generation and fuel consumption values as reported by EIA (June 2007; March 2007c).

17 It is assumed that all power generated fuel cells using such renewable fuel will continue to be used on-site, as is currently the case.

Price Hedge reflects in part the 30% of total California fuel cell capacity that is assumed to operate using renewable digester gas rather than natural gas. The electric-only hedge value range of 0.02-0.36 cents/kWh attributed to these renewable fuel-based fuel cells reflects the fact that their generated electricity requires no fossil fuel input, thereby avoiding the financial impact of fossil fuel price volatility (*e.g.*, budget uncertainty, uneconomic projects). Similarly, an additional Value of Avoided Fossil Fuel as a Price Hedge of 0.34-0.60 cents/kWh is attributed to the 60% of total California fuel cell capacity that captures waste heat for cogeneration and combined cooling, heating, and power ("CCHP") applications, thereby avoiding natural gas input to the avoided boiler. Combined, these two components have a total hedge value range of 0.36-0.96 cents/kWh.

B. AVOIDED WATER USE

Value of Avoided Water Use – Some fuel cells consume water for the electrochemical reaction than generates electricity and for the water purification required to meet fuel cell input requirements.[18] Other fuel cells either produce a net output of water or use no water during normal operations, and only a nominal amount during startup and shutdown.

The Value of Avoided Water Use that electricity generated by fuel cells provides is calculated based on avoided water consumption relative to a central station generating station. The combined cycle, natural gas-fired 2006 MPR proxy plant uses dry cooling; CEC data for a similar plant indicates that only 0.02 gallons of raw water are required per kWh of generation (CEC, April 2006, p. 36).[19] The existing fleet of baseload coal generators serving California is assumed to use closed recirculating cooling, which requires 1.12 gallons of raw water per kWh of generation (National Energy Technology Laboratory ("NETL"), August 2005, p. 68).[20] These values compare to an estimated range of raw water use per kWh for fuel cells of 0-0.17 gallons. These values indicate that even the minimal water use by the dry-cooled proxy plant may be avoided by fuel cells, and that the avoided water use compared to the baseload coal plant is significant at 0.95 gallons per kWh. The range of water costs applied to the avoided coal-fired central station water use is $0.557-$3.636 per hundred cubic feet of metered water, based on tariff rates as of March 2007 for Class A water companies located throughout California.

The calculated (unadjusted) range of Value of Avoided Water Use is 0.001-0.461 cents/kWh. However, since the cost of water usage is typically included in the Value of Avoided Generation Variable O&M Cost,[21] the (adjusted) Value of Avoided Water Use

---

[18] This water, as well as other water generated by some fuel cells, may be recovered and used for non-potable purposes such as irrigation.

[19] All water usage quantities have been adjusted by a scaling factor such that the underlying plant size is 500 MW, which is the size of the 2006 proxy plant.

[20] The CEC dry-cooled water usage for a natural gas combined cycle plant represents a 95% reduction from the NETL recirculating cooling water usage for a similar plant. This is in line with the 90% reduction discussed in the March-April 2002 University of Arizona publication *Arizona Water Resource*.

[21] *See* CEC, online "California Distributed Energy Resource Guide."

cannot exceed the Value of the Avoided Generation Variable O&M Cost. In our study, the (adjusted) Value of Avoided Water Use of 0.00-0.26 cents/kWh has been subtracted from the values derived in the Value of Avoided Generation Variable O&M Cost category to avoid double counting.

Note that the Value of Avoided Water Use varies significantly depending on location. In addition, commercial prices for water will underestimate the Value of Avoided Water Use to the extent that those prices do not fully reflect the societal cost of the water used.

C. AVOIDED TRANSMISSION & DISTRIBUTION COSTS

Because fuel cells are distributed energy resources that are typically located close to the point of use, fuel cells require much less transmission and distribution ("T&D") infrastructure than does conventional central station generation. The value of avoided T&D is very much dependent on location and on the adequacy of T&D infrastructure relative to load growth in that location. Fuel cell installations in "load pockets" where transmission capacity is constrained will provide maximum value. The same applies to areas located within a constrained distribution grid, or in a new housing development where marginal investment can be directly avoided.

Avoided transmission costs are separate and distinct from avoided distribution costs; both are taken from the E3 Avoided Cost Study, and have been (i) adjusted to reflect the assumed 93% California average ELCC of fuel cells in California and (ii) converted to cents/kWh using the assumed 91% annual fuel cell capacity factor. The ELCC is applied here (as it was earlier) on the assumption that the on-peak performance of baseload fuel cells effectively reduces peak load due to the distributed nature of those fuel cells.

Value of Avoided Transmission Cost – The (adjusted) Value of Avoided Transmission Cost ranges from a low of 0.01 cents/kWh into the service territory of Pacific Gas & Electric ("PG&E") to a high of 0.24 cents/kWh into the service territory of Southern California Edison ("SCE").

Value of Avoided Distribution Cost – The (adjusted) Value of Avoided Distribution Cost ranges from a low of 0.06 cents/kWh in the Dominguez Hills area within SCE's service territory to a high of 0.97 cents/kWh within the service territory of San Diego Gas & Electric ("SDG&E"). When avoided T&D costs for a specific area are combined, the minimum value of 0.11 cents/kWh occurs in the East Bay region within PG&E's service territory, and the maximum value of 1.10 cents/kWh occurs within SDG&E's service territory.

Value of Avoided Losses – This category of avoided cost accounts for the fact that distributed generation from fuel cells does not have to pass through the electrical grid and thus does not incur the associated T&D line losses. This means that 6% less electricity has to be generated by central generating stations, with an equivalent percentage reduction in generation-related capacity requirements, O&M costs, fuel input, and emissions output.[22]

Value of Grid Support – The estimated Value of Grid Support reflects the avoided ancillary services costs associated with the electricity load displaced by fuel cell generation. The value is based on 2.84% of the range of (unadjusted) Avoided Generation Fuel Cost, since fuel cost is assumed to be a major driver of wholesale electricity prices in California. Note that 2.84% is the same value that the E3 Avoided Cost Study applies to the avoided market price of electricity to estimate avoided ancillary services (pp. 146-147).

Value of Improved Reliability and Blackout Avoidance – Electricity generated by distributed fuel cells reduces the amount of electricity generated at central stations that must pass through the electric grid, thereby relieving potential overloading of many grid components (*e.g.*, transformers). To the extent that reduced overloading reduces the likelihood of load loss, distributed fuel cells have additional value in improved grid reliability and blackout avoidance.

The calculated Value of Improved Reliability and Blackout Avoidance for distributed fuel cells in California is based on the following five factors:

- The percentage of the state's population affected by a blackout.
- The duration of a blackout.
- The penetration of distributed fuel cells.[23]
- California's daily per capita Gross State Product ("GSP"), as a surrogate measure of the direct costs of a blackout.
- An assumption that indirect costs related to a blackout are 60% as large as the direct costs.[24]

The current calculated range of the Value of Improved Reliability and Blackout Avoidance is 0.002-0.192 cents/kWh, using 2005 values for GSP and fuel cell penetration.[25] The lower end of the range is based on a 1-hour blackout that affects 10%

---

[22] This value approximates the 5.52% volume-weighted average for California's three investor-owned utilities as agreed to by Working Group for use in 2007 market price benchmark calculation (CPUC, January 25, 2007, p.7).

[23] The penetration of distributed fuel cells is calculated as the ratio of fuel-cell generated MWh to total California retail electricity sales in MWh. For 2006, this ratio was estimated to be 0.04%.

[24] ICF Consulting, Summer 2003, estimates "Aggregate Indirect Costs" as 63% of "Aggregate Direct Costs" in its modeling of "Economic Costs of a Simulated Attack on the California Electric Grid."

[25] The Value of Increased Reliability/Power Quality/Blackout Avoidance of <0.01-0.24 cents/kWh shown in the "Build-Up of Fuel Cell Value in California" waterfall chart illustrated in Figure 1 combines the Value of Increased Reliability and Blackout Avoidance with the Value of Increased Power Quality (discussed below).

of the state's population; the upper end is based on a 24-hour blackout affecting 50% of the state's population.

Results calculated using the methodology described above were compared to estimated losses derived by others for both California (in whole or in part) and for the Northeastern U.S. August 2003 blackout (as it affected New York City).[26] Although not identical, the results were such that the methodology used here was deemed to be a reasonable means of valuing the improved reliability and blackout avoidance attributable to distributed fuel cells in California.

The calculated range of the Value of Improved Reliability and Blackout Avoidance is anticipated to increase significantly as the penetration of fuel cells throughout the state increases. Assuming the goal of 3200 MW of installed fuel cell capacity is achieved by 2020 (as described below), fuel cell penetration would increase 200-fold from today's level, potentially generating nearly 8% of the total MWh consumed in California, providing up to 45 cents/kWh (in 2007$) in Value of Improved Reliability and Blackout Avoidance.

Value of Improved Power Quality – The Value of Improved Power Quality is calculated as being 15% of the Value of Reliability and Blackout Avoidance.[27] This percentage is based on an analysis done for the New York State Energy Research and Development Authority ("NYSERDA") that provided separate estimates of the total U.S. cost of outages and of power quality problems. As defined in the NYSERDA report:

- "The ability of the electric system to deliver electric power without interruption is termed 100% *reliability*.
- The ability to deliver a clean signal without variations in the nominal voltage or current characteristics is termed high *power quality*." (Emphasis in original.)

(*See* Energy and Environmental Analysis, Inc., and Pace Energy Project, December 2005, pp. ES1 and ES3.)

The calculated range for the current Value of Improved Power Quality is 0.0002-0.0288 cents/kWh. As was the case for the Value of Increased Reliability and Blackout Avoidance, this value is expected to increase significantly as the penetration of fuel cells in California increases.

---

[26] *See*, for instance, Anderson Economic Group, August 19, 2003; Consortium for Electric Infrastructure to Support a Digital Society ("CEIDS"), June 2001; Clean Power Research, LLC, March 17, 2006; Center for Risk and Economic Analysis of Terrorism Events ("CREATE"), May 31, 2005; Electricity Consumers Resource Council ("ELCON"), February 9, 2004; ICF Consulting, August 21, 2003; ICF Consulting, Summer 2003; Rose, *et al*., October 14, 2005.

[27] Because of its relationship with the Value of Increased Reliability a
nd Blackout Avoidance, the Value of Improved Power Quality is added to the Value of Increased Reliability and Blackout Avoidance under the category of Increased Reliability/Power Quality/Blackout Avoidance in Figure 1.

D. DIGESTER GAS CREDIT

Biomethane is considered a renewable fuel source, with technically feasible for use digester gas levels (conservatively) estimated to reach 75 trillion Btu in California by 2020 (CEC, December 2006, p. 12, Figure 1.6). This level of biomethane availability could support nearly 40% of the state's potential 2020 installed fuel cell capacity of 3200 MW. The analysis underlying this valuation assumes that 30% of the state's installed fuel cell capacity operates using digester gas, which is based on an industry estimate.

Digester gas is assumed to be approximately half biogenic CO_2 [28] and half methane (CH_4), [29] with small amounts of N_2, O_2, hydrogen sulfide (H_2S), and PM10; average heat content is about 600 Btu/ft^3 (HHV). Use of digester gas by fuel cells has several benefits. First, such use means that the digester gas will not be flared, thereby avoiding flare-related emissions of NO_x, CO, and PM10. Second, use of digester gas by fuel cells directly displaces natural gas use, resulting in natural gas savings.

The direct benefits of natural gas cost savings and avoided emissions from digester gas use, as well as the indirect health-related benefits of those avoided emissions, contribute a total value ranging from 0.75-1.81 cents/kWh. This range of values is included in the values illustrated in Figure 1 and can be broken down as follows:

- Value of Avoided Natural Gas = 0.34-1.03 cents/kWh.
- Value of Fossil Fuel Price Hedge = 0.02-0.36 cents/kWh.
- Value of Health Benefits of Avoided In-State Emissions = 0.39-0.41 cents/kWh.
- Value of Avoided Emissions = 0.003-0.015 cents/kWh.

E. COGEN(ERATION) CREDIT

Fuel cells typically capture the waste heat from the electrochemical reaction process that produces electricity. The waste heat is then used to cogenerate another useful product such as hot water, steam, process heat, or cooling (*e.g.*, through the use of an absorption chiller). As a result, whatever process would otherwise have been used to provide the cogenerated product(s) is avoided, reducing the amount of input fuel required for that process and the amount of output emissions.

The Value of Cogen Credit is calculated using a format similar to that used by the CPUC in calculating avoided greenhouse gas emissions. (*See* CPUC, December 13, 2006, Attachment 5.) It is assumed that approximately 46% of the fuel cell's captured waste heat is available as useful energy, and that this useful energy replaces the output from an

[28] Biogenic carbon dioxide is considered to be part of the natural carbon cycle, and is not generally included in CO_2 emissions inventories.

[29] Both carbon dioxide and methane are greenhouse gases, though methane is 20 times more damaging as a greenhouse gas than is carbon dioxide according to the U.S. Climate Change Science Program.

in-state natural gas-fired boiler operating at 80% efficiency. The avoided natural gas is priced using the same range of NYMEX futures prices that was used for the Value of Avoided Generation Fuel Cost, averaged over a six-month period to reflect a more conservative (seasonal) fuel procurement practice. The avoided emissions are valued at in-state emissions prices (as discussed below for each relevant type of emissions). All values are adjusted to reflect the 60% of fuel cell capacity that is assumed to operate in a cogeneration or CCHP mode.

Values related to cogeneration and CCHP are calculated over the range of fuel cell heat rates for the avoided natural gas boiler fuel, for the corresponding fossil fuel price hedge, and for avoided emissions of NO_x, SO_2, and CO_2. The cumulative Value of Cogen Credit for fuel cells across all categories is 1.42-3.61 cents/kWh.

The following Value of Cogen Credit values are included in the total range of values for the appropriate category in the "Build-Up of Fuel Cell Value in California" waterfall chart illustrated in Figure 1:

- Value of Avoided Natural Gas = 0.94-2.01 cents/kWh.
- Value of Fossil Fuel Price Hedge = 0.34-0.60 cents/kWh.
- Value of Health Benefits of Avoided In-State Emissions = ~0.02 cents/kWh.[30]
- Value of Avoided Emissions = 0.12-0.98 cents/kWh.[31]

F. AVOIDED EMISSIONS AND RELATED HEALTH BENEFITS

The E3 Avoided Cost Study assumes that the cost of regulated emissions is captured in the market price of electricity. The category of regulated emissions includes only generation-related emissions for which emissions allowances are currently mandated, including NO_x, SO_2, and PM10. However, due to the decision made in this analysis to separate capacity value from a derived energy value, it is necessary to consider separately those values captured in the market value of electricity in California that are neither capacity- nor fuel-related.

Natural gas is typically the marginal fuel source that sets the market price of electricity in California. In this analysis, natural gas prices set the upper bound on the Avoided Generation Fuel Cost, and coal prices (as a component of the electricity import price) set the lower bound. Natural gas as the Avoided Generation Fuel Cost thus acts (in part) as a surrogate for the market price of electricity. However, since NYMEX natural gas futures contract prices do not include the cost of emissions allowances, the value of avoided emissions must be calculated as a separate distributed value element for each of the avoided emissions identified.

---

30 Details regarding the Value of Health Benefits of Avoided In-State Emissions related to cogeneration are provided below in the Value of Health Benefits section.

31 Avoided NOx, SO_2, and CO_2 emissions from the natural gas-fired boiler are calculated using the "CHP Emissions Calculator" developed by EPA's Combined Heat and Power Partnership. Avoided CO and VOC emissions are calculated using results derived by the Scottish Executive (2006).

To calculate the value of avoided emissions related to fuel cells, it is first necessary to identify *for each pollutant* (i) the emissions rate applicable to the avoided baseload technology and (ii) the resultant emissions over the assumed heat rate range for both the average California avoided natural gas-fired plant and the existing fleet of baseload coal generating plants serving California. The resultant emissions rate range for each baseload generating technology is then compared to the emissions rate for fuel cells to identify the quantity (if any) of avoided emissions in lb/MWh. The minimum and maximum avoided emissions are then valued at the end points of a range of emissions allowance prices either observed in the marketplace or derived from the literature.

The underlying assumptions and results for the avoided emissions and related health benefits are summarized in Attachment C. The Value of Avoided CO2 Emissions attributed to distributed fuel cells in California is calculated at 0.11-2.21 cents/kWh; the combined Value of Other Avoided Emissions is 0.11-1.90 cents/kWh. Assuming that the Value of Health Benefits associated with avoided emissions is not reflected in emissions allowance prices, the additional Value of Health Benefits is calculated to be 2.34-2.54 cents/kWh. Specific details for each avoided pollutant and related health benefits are discussed below.

Value of Avoided NOx Emissions – For the average avoided California natural gas-fired plant, the NO_x emissions rate is calculated using the updated E3 Electric Avoided Costs workbook. Using the average natural gas-fired plant's assumed heat rate range of 8,087-9,100 Btu/kWh, the resultant NO_x emissions rate is 0.11-0.14 lb/MWh. For the typical avoided baseload coal generating plant serving California, the assumed NO_x emissions rate is 0.074 lb/MMBtu, as identified by the Center for Energy Efficiency and Renewable Technologies ("CEERT") for a subcritical pulverized coal plant burning bituminous coal without carbon capture (CEERT, p. 31). For the assumed heat rate range of 8,844-10,875 Btu/kWh, the resultant NO_x emissions rate is 0.69-0.85 lb/MWh. The estimated NO_x emissions rate for fuel cells ranges from 0.01-0.06 lb/MWh.

For the average avoided natural gas-fired plant, the value of the avoided NO_x emissions is based on observed prices for Emissions Reduction Credits ("ERCs") bought and sold in California. These NO_x ERCs are bought once for the life of the emissions permit, and are priced in $/lb/day. The range of prices used is this analysis is $25,000-$356,164/lb/day. For the baseload coal plant, which is assumed to be located outside of California, the value of avoided NO_x emissions is based on observed prices for annual NO_x emissions allowances in markets outside of California. The range of prices used in this analysis is $500-$7,500/ton, where the NO_x emissions allowances must be purchased separately for each year.

Combining the calculated range of avoided NO_x emissions and the applicable range of prices for each of the baseload technologies considered in this analysis yields a range of values of avoided NO_x emissions from 0.06-0.99 cents/kWh.[32]

---

[32] All reported values for avoided emissions in this section of the report include (i) the value of avoided emissions (where applicable) for avoided digester gas flaring for that 30% of fuel cells assumed to use

Value of Avoided SO2 Emissions – The Updated E3 Electric Avoided Costs Workbook does not include calculations of SO_2 emissions, and the NETL indicates that target SO_2 emissions from a new natural gas combined cycle plant are negligible. However, the California Environmental Protection Agency ("Cal EPA") in its California Hydrogen Blueprint estimates SO_2 emissions from a natural gas combined cycle plant at 0.0026 lb/MMBtu of natural gas, and it is this value that is used here for the average avoided natural gas-fired plant. For the baseload coal generator, the CEERT-equivalent SO_2 emissions rate of 0.15 lb/MMBtu of coal is used in the valuation of Avoided SO_2 Emissions.

For the assumed heat rate range of 8,087-9,100 Btu/kWh for the average avoided natural gas-fired plant, the resultant SO_2 emissions rate is 0.022-0.025 lb/MWh. For the avoided baseload coal generating plant at the assumed heat rate range of 8,844-10,875 Btu/kWh, the resultant SO_2 emissions rate is 1.41-1.73 lb/MWh. The SO_2 emissions rate for fuel cells is assumed to be 0.001-0.005 lb/MWh.

As was the case for NO_x emissions, the value of the avoided SO_2 emissions for the average avoided natural gas-fired plant is based on observed prices for one-time ERCs bought and sold in California, which are priced in $/lb/day. The range of prices for SO_2 ERCs used is this analysis is $40,000-$163,014/lb/day. For the baseload coal plant, the value of avoided SO_2 emissions is again based on observed prices for annual SO_2 emissions allowances in markets outside of California. The range of prices used in this analysis is $100-$1,650/ton, where SO_2 emissions allowances (like NO_x allowances) must be purchased separately for each year.

Combining the calculated range of avoided SO_2 emissions and the applicable range of prices for each of the baseload technologies yields a range of Value of Avoided SO_2 Emissions of 0.01-0.14 cents/kWh.

Value of Avoided VOC Emissions – The VOC emissions rate for both the average avoided natural gas-fired plant and the baseload coal plant is taken from Abt Associates, and is estimated to be 0.0120 lb/MMBtu for the average avoided natural gas-fired plant and 0.0023 lb/MMBtu for the baseload coal plant. Applying the applicable heat rate range to each baseload technology, the resultant range of VOC emissions is 0.10-0.12 lb/MWh for the average natural gas-fired plant and 0.02-0.03 lb/MWh for the baseload coal plant.

The Value of Avoided VOC Emissions uses observed California VOC ERC prices for the proxy plant emissions, and the Cantor-Fitzgerald VOC ERC index for the Houston-Galveston Area for the outside-of-California baseload coal plant VOC emissions.[33] The range of Value of Avoided VOC Emissions is 0.002-0.345 cents/kWh.

---

digester gas as reported above (in Section D) and (ii) the value of avoided emissions for cogeneration and CCHP as reported above (in Section E).

[33] These were the only VOC emissions allowance prices found for outside-of-California.

Value of Avoided PM10 Emissions – The methodology and data sources for calculating avoided PM10 emissions are the same as those used for valuing avoided NO_x emissions. The PM10 emissions rate for the average avoided natural gas-fired plant of 0.067-0.074 lb/MWh is calculated using the parameters in the updated E3 Electric Avoided Costs workbook and the heat rate range of 8,087-9,100 Btu/kWh. The PM10 emissions rate range for the baseload coal plant of 0.28-0.35 lb/MWh is calculating using the CEERT-equivalent 0.03 lb/MMBtu emissions rate and the heat rate range of 8,844-10,875 Btu/kWh. As a rule, fuel cells have no solid emissions, so the PM10 emissions rate for fuel cells is nil.

The Value of Avoided PM10 Emissions uses observed California PM10 ERC prices for the average natural gas-fired plant emissions, and the Cantor-Fitzgerald VOC ERC index for the Houston-Galveston Area as a surrogate for an outside-of-California PM10 emissions allowance price. The rationale behind the latter assumption is based on (i) a lack of pricing data for PM10 emissions allowances outside of California's ERC markets and (ii) a similarity in the maximum price of California PM10 and VOC ERC prices. The range of Value of Avoided PM10 Emissions is 0.03-0.22 cents/kWh.

Value of Avoided CO Emissions – The CO emissions rate for both the average natural gas-fired plant and the baseload coal plant is taken from Abt Associates, and is estimated to be 0.1095 lb/MMBtu for the average natural gas-fired plant and 0.0192 lb/MMBtu for the baseload coal plant. Applying the applicable heat rate range to each baseload technology, the resultant range of CO emissions is 0.94-1.06 lb/MWh for the average natural gas-fired plant and 0.18-0.22 lb/MWh for the baseload coal plant. These emissions rates are all higher than the CO emissions rate from fuel cells, which is estimated to be 0.10 lb/MWh.

The Value of Avoided CO Emissions is based on observed California CO ERC prices for both the average natural gas-fired plant and the baseload coal plant CO emissions, as no outside-of-California CO emissions allowance prices were found in the literature. The range of observed California CO ERC prices is \$4,214-\$8,337/lb/day of CO emissions. Multiplying the endpoints of these prices times the end-points of the avoided CO emissions results in a Value of Avoided CO Emissions of 0.01-0.10 cents/kWh.

Value of Avoided Mercury Emissions – EPA's Clean Air Mercury Rule ("CAMR") became effective on May 18, 2006. However, compliance with the new regulations is not required until 2008, so observable market pricing is not yet available. As a result, the assumed range of value for mercury emissions allowances is based on estimated technological costs of capturing mercury from flue gas, as found in the literature. These costs range from \$5,000-\$35,000/lb of mercury removed. (*See* Krotz, p. 3.)

Neither fuel cells nor the average natural gas-fired plant have any mercury emissions, which means that the lower end of the Value of Avoided Mercury Emissions is zero. The mercury emissions rate from the baseload coal plant is assumed to be the CEERT-equivalent average value of 2.94 lb/TBtu.[34] At the baseload coal plant's assumed heat

[34] "TBtu" stands for "trillion Btu," which is equal to a million MMBtu.

rate range, the range of mercury emissions is 2.76E-05 lb/MWh to 3.39E-05 lb/MWh; all of these mercury emissions would be avoided by electricity generated by fuel cells.[35]

It is assumed that the maximum price for mercury emissions allowances will be limited by the $35,000/lb technical cost of mercury removal. Multiplying this $35,000/lb maximum value by the 3.39E-05 lb/MWh upper limit on baseload coal generator mercury emissions yields a maximum Value of Avoided Mercury Emissions of 0.12 cents/kWh.

Based on previous findings by the U.S. EPA, Lutter, *et al.*, adopt the position (p. 4) that "mercury controls on utility emissions are likely to have 'little effect' on sulfur dioxide and oxides of nitrogen." This would indicate that there is little to no double-counting of avoided emissions values, at least as it concerns mercury, SO_2, and NO_x.

Value of Avoided CO2 Emissions – Although CO_2 and other GHG emissions are not yet subject to mandatory regulation in the United States, there is increasing pressure for the implementation of some type of carbon tax, particularly on the transportation and electric utility sectors of the economy. The CPUC now requires the investor-owned utilities that it regulates to "penalize" potential new generation resources with an $8/ton CO_2 cost as part of its Integrated Resource Planning process, and CO_2 markets in Europe have traded anywhere from €2-€35/metric tonne since October 2005 (Chicago Climate Exchange, various dates).

For a natural gas-fired plant, the E3 Avoided Cost Study (pp. 74-75) estimates a linear relationship between CO_2 emissions and heat rate between a heat rate floor of 6,240 Btu/kWh and a heat rate ceiling of 14,000 Btu/kWh, with a carbon intensity of natural gas of 117 pounds CO_2 per MMBtu. (*See* Update E3 Electric Avoided Costs Workbook supporting file cpucAvoided26-1_update3-20-06.xls for detailed derivation.) Based on the 8,087-9,100 Btu/kWh heat rate range assumed for the average California avoided natural gas-fired plant in this analysis, the associated CO_2 emissions rate would be 0.50-0.56 ton/MWh. The CO_2 emissions rate for fuel cells is 0.46-0.49 ton/MWh, resulting in a range of avoided CO_2 emissions compared to the average California natural gas-fired plant of 0.04-0.07 ton/MWh; the avoided 0.04 ton/MWh will set the lower end of the range of avoided CO_2 emissions attributable to fuel cells.

The CO_2 emissions rate for the baseload coal generator is estimated to range from 0.97-1.20 ton/MWh, using the CEERT-equivalent average CO_2 emissions rate of 208 lb/MMBtu over the assumed heat rate range of 8,844-10,875 Btu/kWh.[36] Thus, the avoided CO_2 emissions from the baseload coal generator range from 0.51-0.71 ton/MWh, and the 0.71 ton/MWh avoided CO_2 emissions sets the upper end of the range of avoided CO_2 emissions attributable to fuel cells.

---

[35] 1.0E-05 is scientific notation for 0.00001.

[36] This is similar to the range of 0.91-1.12 ton/MWh calculated using the CO_2 emissions rate of 206.7 lb/MMBtu for Southwest mid-sulfur bituminous coal, as reported in EIA's Assumptions to AEO2007 (p. 138).

The CPUC's assumed \$8.00/ton CO_2 is used to establish the minimum Value of Avoided CO_2 Emissions.[37] The maximum price per ton of CO_2 is more difficult to assess, with the European prices mentioned above being the only real source of existing market data. If the maximum European price of €35/metric tonne is converted to \$/ton using a historical range of \$0.85-\$1.35/€, the resultant range of CO_2 emissions allowance prices is \$27.00-\$41.87/ton CO_2.

In terms of carbon, rather than of CO_2, the CPUC's required use of \$8/ton of CO_2 in the IRP process is the equivalent of \$29.33/ton of carbon. This is in contrast to the \$100/ton of carbon assumed in Duke, *et al.*, p. 9, which is the equivalent of \$27.27/ton of CO_2. If a cost of \$100/ton of carbon is applied to range of avoided CO_2 emissions of 0.04-0.71 ton/MWh, the associated Value of Avoided CO_2 Emissions ranges from \$1.09-\$19.36/MWh, equivalent to 0.109-1.936 cents/kWh. Multiplying the \$8/ton CO_2 times the same range of avoided CO_2 emissions results in a range of Value of Avoided CO_2 Emissions from \$0.32-\$5.68/MWh, equivalent to 0.032-0.568 cents/kWh. Combining these results yields a range of electric-only value of 0.032-1.936 cents/kWh. Adding the range of Value of Avoided CO_2 Emissions from fuel cell cogeneration of 0.08-0.27 cents/kWh yields a total Value of Avoided CO_2 Emissions of 0.11-2.21 cents/kWh.

Value of Health Benefits of Avoided In-State Emissions – Lutter, *et al.*, conclude (p. 11) that "[a]vailable data suggest that cutting power plants' mercury emissions may reduce cases of subtle and mostly imperceptible neurological effects among children at a cost on the order of \$150,000 per case avoided. Other health and environmental benefits appear negligible." No attempt is made to estimate a California-specific health benefit from mercury emissions reductions in this analysis for two reasons. First, the estimate made by Lutter, *et al.*, is a national average estimate, with no state-specific breakdown of data provided. Second, the avoided baseload coal generator is assumed to be located outside of California, so any health benefits related to mercury removal would benefit Californians only indirectly.

By far the largest contributor to the Value of Health Benefits of Avoided In-State Emissions is reductions in particulate matter, particularly reductions in particulate matter less than 2.5 microns in diameter ("PM2.5"). PM2.5 emissions are a subset of particulate matter less that 10 microns in diameter ("PM10"), but PM2.5 emissions are more damaging to health because they lodge deeper in the lungs, and cannot readily be coughed out.

PM2.5 emissions are estimated at 90% of PM10 emissions in the electricity generation sector, based on the statewide estimated annual average emissions published by the California Air Resources Board ("CA ARB") for calendar year 2000 for electric generation and cogeneration (*See* CA ARB, 2001). Calendar year 2000 emissions levels were used to correspond to California-specific calculations of the health-related economic value of reducing PM2.5 and PM10 emissions. (*See* Hall, 2006; Cal EPA/CA ARB,

[37] The E3 Avoided Cost Study (p. 79) uses a cost estimate of \$0.004/lb of CO_2, which is the equivalent of the \$8/ton of CO_2 penalty applied in the CPUC's Integrated Resource Planning process.

2002; Cal EPA/CA ARB, 2003; Cal EPA/CA ARB, 2006.) Combining results from these sources, the Value of Health Benefits of Avoided In-State Emissions for PM2.5 ranges from 1.91-2.09 cents/kWh and the additional value for avoided >PM2.5-PM10 emissions is 0.40-0.41 cents/kWh, including the health benefits of avoided digester gas flare emissions.

The health benefits of reduced NO_x and SO_2 power plant emissions on a cents/kWh basis are derived using the results of an extensive study by Abt Associates (Abt Associates, October 2000).[38] The Abt Associates study provides both nationwide and state-specific estimates of health benefits in terms of avoided incidences of mortality, hospitalizations, and various categories of illness. These estimates were used to calculate the value of California-specific benefits based on the proportion of California-specific avoided health-related incidences to nationwide totals. (*See* Abt Associates, Exhibits 6-2 and 6-7.) The California-specific estimates here are derived using a methodology similar to that used to estimate the health benefits of avoided emissions due to distributed solar photovoltaics in New Jersey (Hoff and Margolis, 2003).

Total California health benefits as derived from the Abt Associates study were divided by 75% of California's total 1997 NO_x and SO_2 power plant reductions to arrive at a value of $1.02/lb (1999$) of reduced emissions.[39] The $1.02/lb (1999$) of reduced emissions was inflated to 2007$ and then converted to cents/kWh using estimated NO_x and SO_2 emissions rates from the Updated E3 Electric Avoided Costs Workbook for the heat rate range of 8,087-9,100 Btu/kWh for the average California natural gas-fired plant. Estimated NO_x and SO_2 emissions rates for the baseload coal-fired generator plant were obtained from the literature, and applied to the heat rate range of 8,844-10,875 Btu/kWh. The Value of Health Benefits of Avoided In-State Emissions for avoided NO_x and SO_2 emissions ranges from 0.034-0.037 cents/kWh, including the health benefits of avoided digester gas flare emissions and avoided boiler emissions in the appropriate proportions.

The Total Value of Health Benefits is 2.34-2.54 cents/kWh, which includes the values for avoided PM2.5, PM10, NO_x and SO_2.

G. JOB CREATION POTENTIAL

Value of Job Creation Potential – Every megawatt of installed fuel cell capacity generates immediate local employment opportunities for the initial installation of the fuel cells and for the ongoing maintenance and service requirements. In addition, because fuel cells are costly to ship, as the market for fuel cells in California grows, at some point

38 A summary of the Abt Associates study can be found in the October 2000 Clean Air Task Force report.

39 A 75% reduction in NO_x and SO_2 was the underlying assumption in the health benefits calculated in the Abt Associates study. A 75% reduction in total 1997 California electricity utility emissions as reported by EIA was used to calculate the $/lb value, based on the total California-specific health benefits derived from the Abt Associates study. (*See* EIA, Electric Power Annual, Table 5.1.)

it will likely become economic for fuel cell manufacturing, assembly, and remanufacturing facilities to be built in California.

The Value of Job Creation Potential related to installation and ongoing maintenance of fuel cells in California is estimated to range from 0.11-0.26 cents/kWh. This range is based on the following set of assumptions:

- California represents 1/3rd of the total U.S. market for fuel cells.
- Labor represents 25% of the total installed cost of fuel cells.
- Installation of a fuel cell requires three full-time workers to work for three weeks, for a total of 360 hours.
- Ongoing maintenance of a fuel cell requires 1/4th as much labor as the initial installation (90 hours per year).
- The average labor cost is $90/hour.

Although more speculative, the additional Value of Job Creation Potential due to fuel cell companies building manufacturing capacity in California could in the longer term add another 1.93 cents/kWh (in 2007$), based on the following assumptions:

- Manufacturing plants with 40 MW per year of manufacturing capacity will be added once the annual volume of fuel cells installed in California reaches twice that size.
- Each MW of manufacturing capacity adds 8 new jobs (direct job creation; no estimate of new jobs created as an indirect result of the new manufacturing capacity has been made).[40]
- The average labor cost for manufacturing production workers is $45/hour.

The value of these economic benefits is purposefully conservative. The Value of Job Creation Potential could be significantly higher, given its dependence on the specific types of jobs created, local wage rates, and the actual growth of the fuel cell market in California.

H. ADDITIONAL VALUES

Value of Deployment Ease and Speed – Fuel cell systems can be sited and installed in a relatively short period of time given available land and equipment. The carrying costs associated with the lead times necessary for siting, permitting and constructing a central generating station are largely avoided. Low emissions (as discussed in detail above) and quiet operation mean that fuel cell systems can be rapidly deployed with minimal to no "greenfield" or unmanageable "NIMBY" impact. The value created through fuel cell modularity is especially dependent on the localized circumstances and difficult to quantify in average terms. In much of California, as is true in much of the United States,

[40] Based on a March 7, 2006 press release by the Ohio Department of Development related to Governor Taft's Third Frontier Fuel Cell Program (TFFCP) indicating the creation of 200 new jobs for a 25 MW fuel cell manufacturing facility.

opposition to new infrastructure usually results in opponents availing themselves of the full suite of administrative remedies to thwart or delay investment. No specific estimate of this value is provided since the Value of Deployment Ease and Speed may vary significantly for each fuel cell project site.

Other Values - The estimated values in the "Build-Up of Fuel Cell Value in California" are not all-inclusive, and do not reflect many of the distributed value elements identified in the PLEASE matrix in Attachment B. Among those distributed value elements not included because they are difficult to quantify are the visibility impact due to reduced emissions, the impact on local control of resources, and the impact on responsiveness to load growth due to their modularity.

V. COMPARISON OF AVOIDED EMISSIONS ACROSS TECHNOLOGIES

The avoided proxy plant emissions for fuel cells (as calculated above) are compared against the avoided emissions for electricity generated using solar photovoltaics ("PV") and wind. PV and wind have no fuel input and, consequently, no emissions; all proxy plant emissions are avoided by these two generating technologies. For the same reason, however, PV and wind receive no emissions-related credit for either digester gas use (*i.e.*, avoided flare emissions) or cogeneration (*i.e.*, avoided boiler fuel).

Wind generation typically occurs in remote locations that require full use of the grid, with all of the related losses. As is the case for fuel cells, PV tends to be a distributed energy resource that avoids the losses related to use of the electrical grid. Thus, the avoided emissions per kWh will be higher for PV than for wind by the percentage of grid-related losses (assumed to be 6% in this analysis).

Attachment D presents two graphical comparisons of *avoided* emissions for fuel cells, PV, and wind. The top graph compares the avoided emissions per MWh of electricity generated by each of the three technologies. As expected, *avoided* emissions are greater for distributed PV than for wind in all cases. However, *avoided* emissions of NO_x and PM10 are greatest for fuel cells because of (i) fuel cell use of digester gas and (ii) cogeneration.

The bottom graph in Attachment D compares the annual avoided emissions for the three technologies per MW of installed capacity. As discussed previously, fuel cells are a baseload technology with an annual capacity factor of 91%. Conversely, PV generates electricity only when the sun is shining and wind, when the wind is blowing. Such intermittent resources have a much lower annual capacity factor than that of fuel cells, averaging 20% for PV[41] and 25% for wind resources[42] in California. *The significant*

[41] The SGIP Fifth-Year Impact Report reported (p. 5-5) that: "Level 1 PV projects had capacity factors that ranged from approximately 12% to slightly over 20%."

[42] The 25% capacity factor is taken from the CEC's "Wind Performance Summary 2002-2003" (Fig. 5-3, p. 21). Monthly capacity factors for wind as reported in the SGIP Fifth-Year Impact Report were less than 25% in all months (Fig. 5-2, p. 5-5.)

difference in capacity factors results in a somewhat counterintuitive outcome: ***Per installed MW of capacity, fuel cells have greater avoided emissions per year across the board than either PV or wind.***

VI. INDUSTRY DATA INPUT

In addition to the detailed cost and performance data, data on projected fuel cell penetration in California for the next 15 years was obtained from four of the five participating organizations actively manufacturing or developing stationary fuel cells for baseload electricity generation. In addition, each company provided information on its anticipated level of participation in each of the following five market segments:

- Distributed Generation with Waste Heat Recovery: Customer-sited, with waste heat recovery for cogeneration or CCHP applications.
- 24/7 Renewable Fuel Power Generation with Waste Heat Recovery: Baseload electricity generation using renewable fuel, with waste heat recovery for cogeneration or CCHP applications.
- Cogeneration of Hydrogen: Sited at or near locations needing hydrogen feedstock (*e.g.*, refineries, chemical facilities, refueling stations), with the ability to change the ratio of electricity and hydrogen generated as dictated by demand.
- Advanced Fuel Cell/Gas Turbine Power Generation: Large-scale "hybrid" generation systems that combine fuel cells and gas turbines to maximize the efficiency of electricity-only generation.
- Utility Procurement: Relatively larger-scale installations, with targeted locations at utility substations.

Projections of future installed MW of fuel cells for each company were aggregated year-by-year and market segment-by-market segment. The five companies in aggregate projected that the total installed MW of stationary fuel cell capacity in California would grow from its current level of 18 MW to over 3200 MW by 2020, assuming that current incentive levels were continued over the long term. This penetration level is in line with estimates provided in the CEC's November 2005 Staff Report entitled "Assessment of California Combined Heat and Power Market and Policy Options of Increased Penetration," as shown in the calculations provided in Attachment E.

VII. MARKET SEGMENT VALUATION DETAIL

The 18 MW of stationary fuel cells currently installed in California serve the first two market segments (described in Section V above) in an approximate 3:1 ratio. Over time, because of the value of their exhaust heat, distributed fuel cells with cogeneration will continue to dominate the market over time, fueled up to 30% with renewable digester gas.

As the Advanced Fuel Cell/Gas Turbine Power Generation hybrid technology approaches commercialization, its focus will be on using the energy in the exhaust heat to generate increased amounts of electricity only, thus achieving even greater electrical efficiencies. These hybrid units will tend to be larger scale, with capacities ranging upward from 1 MW; their 2020 market share is anticipated to exceed 5%. Electric-only fuel cell units of all types will increasingly target utility customers, with the Utility Procurement market segment anticipated to grow to over 15% of the total California market for stationary fuel cells by 2020.

The Cogeneration of Hydrogen market segment will develop in parallel with the other market segments, with its ultimate market share dependent on the speed at which California's "Hydrogen Highway" develops. Refinery and other industrial demand alone would limit the Cogeneration of Hydrogen market share in 2020 to less than 5% of California's total stationary fuel cell market.

Attachment F illustrates what percentage of the total value of fuel cells in California each of the five market segments identified above could contribute by 2020, based on input from fuel cell manufacturers.

VIII. NATURAL GAS SAVINGS

The dominance of the Distributed Generation with Waste Heat Recovery market segment, approximately half of which is fueled using digester gas, creates the added benefit of reducing California's natural gas consumption.

As described above, this analysis assumes that 30% of fuel cells operate using digester gas and that 60% of fuel cells capture waste heat for cogeneration or CCHP applications.[43] Assuming that 3200 MW of installed stationary fuel cell capacity in California is achieved by 2020:

- The total annual natural gas savings for California would be 136,000,000 MMBtu.
    - Enough natural gas to generate 15,000 GWh of electricity.
    - Enough electricity to satisfy 2.3 million homes in California.
    - Equivalent to 23 million barrels of oil.
- Total CO_2 reductions would be 4.1 million metric tonnes.
    - Equivalent to 674,000 acres of forest.

[43] Note that these percentages may overlap and thus are not additive, since fuel cells that operate on digester gas typically also cogenerate heat or steam.

IX. CONCLUSIONS

As demonstrated throughout this paper, fuel cells provide significant value to California's ratepayers today, as measured in terms of both benefit-cost ratios and avoided costs. As fuel cell installed capacity and penetration rates increase throughout the state, the value provided to California's ratepayers through cogeneration, digester gas use, avoided central station generation, and the associated avoided emissions will grow significantly. Fuel cells have the potential to make a significant contribution to meeting the state's AB32 GHG reduction goals while adding ratepayer value in many different respects.

X. ACKNOWLEDGEMENTS

This study was conducted by the National Fuel Cell Research Center ("NFCRC"). Professor Scott Samuelsen served as the Principal Investigator. Lori Schell of Empowered Energy was retained to collaborate in the research and to provide the economics expertise required to meet the goals of the effort. The research study was supported by FuelCell Energy, Inc.; HydroGen LLC; Rolls-Royce Fuel Cell Systems (US) Inc.; Siemens Power Generation, Inc.; and, UTC Power Corporation. Market data were submitted following a standard format and protected by a secure management protocol. Analyses of the data, meetings to discuss assumptions and overall approach, delineation of market segments, and reporting were wholly the responsibility of the NFCRC.

* * * * *

DATA SOURCES

[1] Abt Associates, Inc., October 2000, "The Particulate-Related Health Benefits of Reducing Power Plant Emissions." http://www.abtassociates.com/reports/particulate-related.pdf

[2] Anderson Economic Group, August 19, 2003, "Northeast Blackout Likely to Reduce US Earnings by $6,4 Billion," AEG Working Paper 2003-2. http://www.andersoneconomicgroup.com/modules/Content/dl.php?format=application/pdf&filename=Doc544.pdf

[3] Bolinger, Mark and Ryan Wiser, December 13, 2004, "Comparison of AEO 2005 Natural Gas Forecast to NYMEX Futures Prices."

[4] Bolinger, Mark, Ryan Wiser and William Golove, January 2004, "Accounting for Fuel Price Risk When Comparing Renewable to Gas-Fired Generation: The Role of Forward Natural Gas Prices," LBL-54751. http://eetd.lbl.gov/EA/EMP/reports/54751.pdf

[5] Bolinger, Mark, Ryan Wiser and William Golove, June 2002, "Quantifying the Value that Wind Power Provides as a Hedge against Volatile Natural Gas Prices," Proceedings of WINDPOWER 2002, June 2-5, 2002, Portland, Oregon. http://eetd.lbl.gov/EA/EMP/reports/50484.pdf

[6] Breakthrough Technologies Institute, Inc., 2003, "Fuel Cells at the Crossroads: Attitudes Regarding the Investment Climate for the U.S. Fuel Cell Industry and a Projection of Industry Job Creation Potential," Report ANL/OF-00405/300. http://www.fuelcells.org/info/charts/economicstudy.pdf

[7] California Air Resources Board, 2006, "The California Almanac of Emissions and Air Quality, 2006 Edition." http://www.arb.ca.gov/aqd/almanac/almanac06/almanac2006all.pdf

[8] California Air Resources Board, 2001, "2000 Estimated Annual Average Emissions, Statewide," available online at: http://www.arb.ca.gov/app/emsinv/emssumcat_query.php?F_YR=2000&F_DIV=-4&F_SEASON=A&SP=2006&F_AREA=CA

[9] California Air Resources Board and South Coast Air Quality Management District, April 20, 2001, "Refinement of Selected Fuel-Cycle Emissions Analyses," Final Report FR-00-101 (Volume 1 of 2). http://www.arb.ca.gov/research/apr/past/98-338_1.pdf

[10] California Department of Finance, January 2007, "2006 California Statistical Abstract." http://www.dof.ca.gov/HTML/FS_DATA/STAT-ABS/2006_statisticalabstract.pdf

[11] California Energy Commission, December 2006, "A Preliminary Roadmap for the Development of Biomass in California," PIER Collaborative Report, CEC-500-2006-095-D. http://www.energy.ca.gov/2006publications/CEC-500-2006-095/CEC-500-2006-095-D.PDF

[12] California Energy Commission, June 2006, "Wind Performance Summary 2002-2003," CEC-500-2006-060. http://www.energy.ca.gov/2006publications/CEC-500-2006-060/CEC-500-2006-060.pdf

[13] California Energy Commission, April 2006, "Cost and Value of Water Use at Combined-Cycle Power Plants," CEC-500-2006-034. http://www.energy.ca.gov/2006publications/CEC-500-2006-034/CEC-500-2006-034.PDF

[14] California Energy Commission, "California Distributed Energy Resource Guide." http://www.energy.ca.gov/distgen/economics/operation.html.

[15] California Environmental Protection Agency, May 2005, "California Hydrogen Blueprint Plan, Volume 2." http://www.hydrogenhighway.ca.gov/plan/reports/volume2_050505.pdf

[16] California Environmental Protection Agency and California Air Resources Board, March 21, 2006, "Proposed Emission Reduction Plan for Ports and Goods Movement in California." http://www.arb.ca.gov/planning/gmerp/march21plan/march22_plan.pdf

[17] California Environmental Protection Agency and California Air Resources Board, June 2005, "Characterization of Ambient PM10 and PM2.5 in California – Technical Report." http://www.arb.ca.gov/pm/pmmeasures/pmch05/pmch05.htm

[18] California Environmental Protection Agency and California Air Resources Board, May 31, 2003, "The Economic Value of Respiratory and Cardiovascular Hospitalizations," Final Research Report, Contract Number 99-329. http://www.arb.ca.gov/research/apr/past/99-329.pdf

[19] California Environmental Protection Agency and California Air Resources Board, May 3, 2002, "Staff Report: Public Hearing to Consider Amendments to the Ambient Air Quality Standards for Particulate Matter and Sulfates." http://www.arb.ca.gov/research/aaqs/std-rs/pm-final/pm-final.htm

[20] California Gas Utilities, 2006, "2006 California Gas Report." http;//www.socalgas.com/regulatory/docs/2006_CGR.pdf

[21] California Independent System Operator, Department of Market Monitoring, April 2007, "Annual Report, Market Issues and Performance." http://www.caiso.com/1bb7/1bb776216f9b0.pdf

[22] California Public Utilities Commission, 2008, "Annual Report 2007." http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/78315.PDF

[23] California Public Utilities Commission, January 25, 2007, Decision 07-01-030, "Opinion Granting Joint Petition for Modification of Decision 06-07-0303," Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1x and Decision 01-09-060, R.02-01-011. http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/64048.PDF

[24] California Public Utilities Commission, December 14, 2006, Resolution E-4049. ("2006 MPR Resolution") http://www.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/63132.pdf

[25] California Public Utilities Commission, December 13, 2006, "Proposed Decision of President Peevey and ALJ Gottstein – Interim Opinion on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard," Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies, R.06-04-009. http://www.cpuc.ca.gov/EFILE/PD/62840.htm

[26] California Public Utilities Commission, September 4, 2003, D.03-09-021, "Opinion Authorizing Rate Increases (Attachment G)." http://www.cpuc.ca.gov/Published/Final_Decision/29515.htm

[27] California Public Utilities Commission, October 2001, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects." http://ftp.cpuc.ca.gov/puc/energy/electric/energy+efficiency/em+amd+v/Std+Practice+Manual.doc

[28] Cantor Environmental Brokerage, Historic Electronic Pricing Files and Various Dates, "Monthly Market Price Indices." http://www.emissionstrading.com

[29] Center for Energy Efficiency and Renewable Technologies ("CEERT"), Environmental Defense, and Western Resource Advocates, 2005, "Clearing California's Coal Shadow from the American West." http://www.ceert.org/reports/Coalreport.pdf

[30] Center for Risk and Economic Analysis of Terrorism Events ("CREATE"), May 31, 2005, "DRAFT Electricity Case: Main Report – Risk, Consequences, and Economic Accounting," CREATE Report #05-014 under FEMA Grant EMW-2004-GR-0112, University of Southern California, Los Angeles, California. http://www.usc.edu/dept/create/assets/001/50773.pdf

[31] Chicago Climate Exchange, Historic Electronic Pricing Files and Various Dates, "CCX Market Report." http://www.chicagoclimateexchange.com

[32] Clean Air Task Force, October 2000, “Death, Disease & Dirty Power: Mortality and Health Damage Due to Air Pollution from Power Plants.” http://www.catf.us/publications/reports/Death_Disease_Dirty_Power.pdf

[33] Clean Power Research, LLC, March 17, 2006, “The Value of Distributed Photovoltaics to Austin Energy and the City of Austin,” Prepared for Austin Energy under Solicitation Number: SL04300013. http://www.clean-power.com/research/distributedgeneration/AE_PV_ValueReport.pdf

[34] Consortium for Electric Infrastructure to Support a Digital Society (“CEIDS”), June 2001, “The Cost of Power Disturbances to Industrial & Digital Economy Companies,” EPRI Report #1006274. http://www.epri-intelligrid.com/intelligrid/docs/Cost_of_Power_Disturbances_to_Industrial_and_Digital_Technology_Companies.pdf

[35] Duke, Richard, Robert Williams and Adam Payne, 2004, “Accelerating Residential PV Expansion: Demand Analysis for Competitive Electricity Markets,” *Energy Policy*. http://www.nrel.gov/ncpv/thin_film/pdfs/energy_policy_pv_expansion_residential_demand_issues.pdf

[36] Electricity Consumers Resource Council (“ELCON”), February 9, 2004, “The Economic Impacts of the August 2003 Blackout.” http://www.elcon.org/Documents/EconomicImpactsOfAugust2003Blackout.pdf

[37] Energy and Environmental Analysis, Inc., and Pace Energy Project, December 2005, “The Role of Distributed Generation in Power Quality and Reliability – Final Report,” Prepared for New York State Energy Research and Development Authority (“NYSERDA”). http://www.eea-inc.com/natgas_reports/DGPowerQualityReport-NYSERDA.pdf

[38] Energy and Environmental Economics, Inc., March 20, 2006, “Avoided Cost Calculation Spreadsheets, Updated Electric and Gas Avoided Costs – 2006 Update (5/23/06 Draft Decision): Electric Avoided Costs.” (“Updated E3 Electric Avoided Costs Workbook”) http://www.ethree.com/cpuc_avoidedcosts.html

[39] Energy and Environmental Economics, Inc., and Rocky Mountain Institute, October 25, 2004, “Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs,” report prepared for the California Public Utilities Commission. (“E3 Avoided Cost Study”) http://www.ethree.com/cpuc_avoidedcosts.html

[40] Evolution Markets, Inc., Various Dates, “Weekly Market Update.” http://www.evomarkets.com

[41] Hall, Jane V., Victor Brajer, and Frederick W. Lurmann, March 2006, “The Health and Related Economic Benefits of Attaining Healthful Air in the San Joaquin Valley,”

Institute for Economic and Environmental Studies, California State University-Fullerton. http://business.fullerton.edu/Centers/iees/reports/SJVFinalReport.pdf

[42] Herig, Christy, "Using Photovoltaics to Preserve California's Electricity Capacity Reserves," National Renewable Energy Laboratory. NREL/BR-520-31179 September 2001. http://www.nrel.gov/docs/fy01osti/31179.pdf

[43] Hewlett Foundation Energy Series, April 2003, "The Last Straw: Water Use by Power Plants in the Arid West." ("Hewlett Foundation Report") http://www.catf.us/publications/reports/The_Last_Straw.pdf

[44] Hoff, Thomas E., and Robert Margolis, 2003, "Distributed Photovoltaics in New Jersey," under contract to the Department of Energy through the National Renewable Energy Laboratory.

[45] ICF Consulting, August 21, 2003, "The Economic Cost of the Blackout – An issue paper on the Northeastern Blackout, August 14, 2003." http://www.icfi.com/Markets/Energy/doc_files/blackout-economic-costs.pdf

[46] ICF Consulting, Summer 2003, "Measuring the Economic Costs of Terrorist Attacks," in *ICF Perspectives*. http://www.icfi.com/Markets/Homeland-Security/doc_files/costs_terrorist.pdf

[47] Itron, Inc., March 1, 2007, "CPUC Self-Generation Incentive Program Fifth Year Impact Evaluation: Final Report," Submitted to PG&E and The Self-Generation Incentive Program Working Group. ("SGIP Fifth Year Impact Report")

[48] Itron, Inc., April 15, 2005, "CPUC Self-Generation Incentive Program Fourth-Year Impact Report: Final Report," Submitted to Southern California Edison and The Self-Generation Incentive Program Working Group. ("SGIP Fourth Year Impact Report") http://www.cpuc.ca.gov/static/energy/electric/050415_sceitron+sgip2004+impacts+final+report.pdf

[49] Krotz, Dan, October 26, 2006, "Clamping Down on Mercury Emissions," Science@Berkeley Lab online article. http://www.lbl.gov/Science-Articles/Archive/sabl/2006/Oct/2.html

[50] Lutter, Randall, Elizabeth Mader, and Nathan Knuffman, March 2001, "Regulating Mercury Emissions: What Do We Know About Costs and Benefits?" Report for AEI-Brookings Joint Center for Regulatory Studies. http://www.aei-brookings.org/admin/authorpdfs/page.php?id=143&PHPSESSID=d42102724eb433734d11631791ada144

[51] National Energy Technology Laboratory ("NTEL"), February 5, 2007, "2006 Cost and Performance Baseline for Fossil Energy Plants: Updated Technical Performance," U.S. Department of Energy. http://www.netl.doe.gov/energy-analyses/pubs/Sept-06%20Pitt%20Coal%20Conf_Update_Jan07.pdf

[52] National Energy Technology Laboratory, August 2005, "Power Plant Water Usage and Loss Study," U.S. Department of Energy. http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/WaterReport_IGCC_Final_August2005.pdf

[53] Ohio Department of Development, March 7, 2006, "Taft Announces Fuel Cell Research Projects to Receive Third Frontier Grants," press release found online at http://www.odod.state.oh.us/newsroom/2006pr/releases/1424.asp.

[54] Pew Center on Global Climate Change, 2005, "The European Union Emissions Trading Scheme (EU-ETS) Insights and Opportunities." http://www.pewclimate.org/docUploads/EU-ETS%20White%20Paper.pdf

[55] PriceWaterhouseCoopers, June 2002, "Fuel Cells: The Opportunity for Canada," Report for Fuel Cells Canada. http://www.pwc.com/extweb/pwcpublications.nsf/docid/1CD4C1A4CD21E707852570CA001790BC

[56] Rose, Adam, Gbadebo Oladosu, and Shu-Yi Liao, October 14, 2005, "Business Interruption Impacts of a Terrorist Attack on the Electric Power System of Los Angeles: Customer Resilience to a Total Blackout," Working Draft; Not for Quotation, Presented at Carnegie Mellon Electricity Industry Center, November 8, 2005. http://wpweb2.tepper.cmu.edu/ceic/SeminarPDFs/R_O_L_Bus_Int10_14.pdf

[57] Scottish Executive, 2006, "Review of Greenhouse Gas Life Cycle Emissions, Air Pollution Impacts and Economics of Biomass Production and Consumption in Scotland," Table 5.4: Indicative Comparison of Emissions from Biomass and Fossil Fuels in Small Boilers. http://www.scotland.gov.uk/Publications/2006/09/22094104/6

[58] University of Arizona, "'Dry' Power Plants Produce Energy Using Less Water," in *Arizona Water Resource*, Volume 10, Number 4, March-April 2002.

[59] U.S. Climate Change Science Program, "Methane as a Greenhouse Gas," online at www.climatescience.gov/infosheets/highlight1/CCSP-H1-methane18jan2006.pdf.

[60] U.S. Department of Energy, Energy Information Administration, June 2007, "Natural Gas Consumption by End Use: California, Monthly, Series History." http://tonto.eia.doe.gov/dnav/ng/xls/ng_cons_sum_dcu_SCA_m.xls

[61] U.S. Department of Energy, Energy Information Administration, March 2007a, "Annual Energy Outlook 2007, With Projections to 2030," U.S Department of Energy, DOE/EIA-0363(2007). http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2007).pdf

[62] U.S. Department of Energy, Energy Information Administration, March 2007b, "Assumptions to the Annual Energy Outlook 2007, With Projections to 2030," U.S

Department of Energy, DOE/EIA-0554(2007).
http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2007).pdf

[63] U.S. Department of Energy, Energy Information Administration, March 2007c, "California Electricity Profile, 2005 Edition, Table 5: Electric Power Industry Generation by Primary Energy Source, 1990-2005," DOE/EIA-0348.
http://www.eia.doe.gov/cneaf/electricity/st_profiles/california.html

[64] U.S. Department of Energy, Energy Information Administration, November 19, 2006, "Electric Power Annual with Data for 2005 (Revised)," Table 4.2. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 1992 through November 2006. Microsoft Excel file epmxlfile4_2.xls at:
http://www.eia.doe.gov/cneaf/electricity/epa/epat4p5.html.

[65] U.S. Department of Energy, Energy Information Administration, October 7, 2006, "Electric Power Annual with Data for 2005," Table 5.1. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, 1994 through 2005. Microsoft Excel file emission_state.xls at:
http://www.eia.doe.gov/cneaf/electricity/epa/epat5p1.html.

[66] U.S. Environmental Protection Agency, Combined Heat and Power Partnership, "CHP Emissions Calculator." http://www.epa.gov/chp/project_resources/calculator.htm.

[67] U.S. Environmental Protection Agency, October 2004, "Documentation Summary for EPA Base Case 2004 (V.2.1.9) Using the Integrated Planning Model," EPA430/R-04-008. http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/basecase2004.pdf

[68] Western Resource Advocates, 2004, "A Balanced Energy Plan for the Interior West." In Collaboration with Synapse Energy Economics, Inc. and the Tellus Institute.
http://www.westernresourceadvocates.org/energy/BEP/WEB_pdfs/BEP_West_lwres.pdf

Attachment A

FUEL CELLS: TECHNOLOGY AND GENERAL ATTRIBUTES

INTRODUCTION

Fuel cells can be made to suit a wide variety of applications or market sectors, including stationary, transportation and portable applications. This study addresses fuel cells for stationary applications. Stationary applications include baseload power for the needs of utilities, commercial buildings, government and military complexes, large institutional, medical and industrial centers and a host of others. To serve these applications, systems ranging in capacity from several hundred kilowatts to multi-megawatts are now available and larger systems are being developed.

In its most basic form a fuel cell is an electrochemical device in which a fuel and an oxidant are combined to produce electricity and heat. With two electrodes separated by an electrolyte, a fuel cell is similar to a battery, except that it will not run down as long as fuel and air are supplied. To generate useful quantities of electricity, individual cells must be connected together in series to build voltage, and the size and number of cells in a cell stack or module will determine its electric generating capacity. Because the conversion of the fuel to electrical energy takes place electrochemically, without combustion, the process is highly efficient, clean and quiet. Perhaps confusingly, the term "fuel cell" can refer to an individual cell itself, to a cell stack, to a module consisting of a number of cells, or to the entire electrical system.

While the basic principles of all fuel cells are the same, the electrolytes, conducting ions and operating temperatures differ greatly between fuel cell types. Five major types of fuel cells have been (or are being) developed, generally identified according to the type of electrolyte used. In ascending order of operating temperature, the five major types of fuel cells are: (1) Alkaline ("AFC," ~70^{o}C); (2) Proton Exchange Membrane ("PEMFC," ~80^{o}C); (3) Phosphoric Acid ("PAFC," ~200^{o}C); (4) Molten Carbonate ("MCFC," ~650^{o}C); and, (5) Solid Oxide ("SOFC," 800-1000^{o}C). With some exceptions, higher temperature fuel cells (*i.e.*, PAFC, MCFC, and SOFC) tend to be better suited to larger applications, while lower temperature systems (*i.e.*, AFC and PEMFC) are considered better suited to smaller applications.

FUEL FLEXIBILITY

While the ideal fuel for a fuel cell is a simple molecule such as hydrogen, hydrogen is not widely available, especially in amounts suitable for power generation. Consequently, natural gas is the most widely used fuel for fuel cells, given its wide availability and the fact that hydrogen can be extracted from it with relative ease. Renewable fuels such as digester gas from wastewater treatment plants, landfill gas, and biofuels in general are also attractive fuels for fuel cells, as is propane; these fuels extend the range of fuel cells to areas where natural gas is not available. Fuel cells having higher operating temperatures thrive on these less hydrogen-rich fuels and thus have an advantage with respect to fuel flexibility over fuel cells that require very pure hydrogen.

HOW A FUEL CELL OPERATES

Typically hydrogen, or in the case of some fuel cells, a mixture of hydrogen and carbon monoxide (“CO”), is fed into the anode of the fuel cell. Air carrying the oxygen enters the fuel cell at the cathode. In a high temperature fuel cell, the oxygen easily splits into two streams: oxygen ions and electrons. (Low-temperature fuel cells usually require a platinum-based catalyst to encourage formation of the oxygen ions.) The oxygen ion stream passes through the electrolyte and seeks a hydrogen molecule to form water (“H_2O”), or a CO molecule to form carbon dioxide (“CO_2”). The electron stream is the useful stream, and is created once an external circuit is provided, forming an electric current. This electric current can be utilized before the electrons return to the cathode to keep the fuel cell’s electrochemical process going. An overview of the entire electrochemical process is illustrated below in Figure A-1.

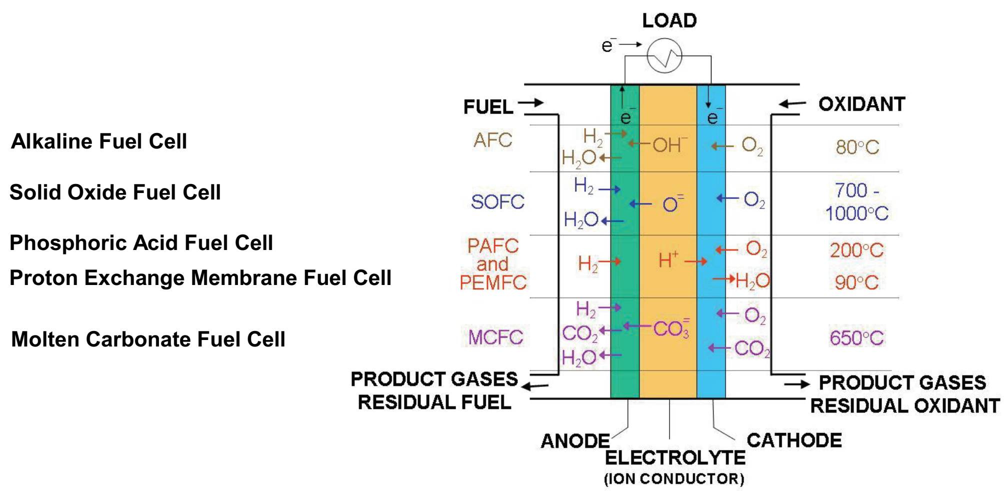


Figure A-1. Types of Fuel Cells

EFFICIENCY

The efficiency of stationary fuel cells encompasses both the generation of electrical power and the cogeneration of a thermal product. The thermal product can be used for either heating or cooling. This attribute is referred to as “Combined Cooling, Heating, and Power” or “CCHP.”

Electrical Efficiency – Electrical efficiency is a measure of how well fuel input is converted to electrical power. The higher the electrical efficiency, the lower the amount of fuel input required per kilowatt-hour (“kWh”) of electricity generated. High electrical efficiency is an important benefit of fuel cells from the viewpoints of both the cost of operation and environmental impact.

Fuel cells have demonstrated lower heating value ("LHV") electrical efficiencies as high as 48% when operating as simple cycle systems, and as high as 55% (LHV) when operated as hybrids in combination with other systems such as gas turbines.[1] Now in the early stages of development, fuel cell hybrids have the potential to achieve an electrical efficiency in excess of 70% (LHV), a level that is impossible to achieve by conventional electricity generating technologies. Since the amount of CO_2 generated ***per kWh of electricity produced*** is inversely proportional to the electrical efficiency, fuel cells with their higher electrical efficiency emit less CO_2 (a greenhouse gas) than other electricity generating technologies using the same fuel. Further, with the ability of fuel cells to achieve such a high electrical efficiency, the ability to further reduce CO_2 emissions from electricity generation is inevitably tied to the development of fuel cell hybrids.

CCHP Efficiency – In addition to generating electrical power, the stationary fuel cell can cogenerate a thermal product. The strategy is to capture and utilize the heat produced by the fuel cell for the provision of heat, hot water, steam, or cooling (using, for example, an absorption chiller). This will result in the fuel cell's overall efficiency (electrical power generation and use of the captured thermal energy) reaching and exceeding 80% (LHV). This attribute displaces the fuel and emissions that would be associated with boilers (in the case of using the thermal energy as heat), and the displacement of electricity to drive chillers (in the case of using the thermal energy for cooling). The resultant effect is to dramatically reduce CO_2 emissions, criteria pollutant emissions, and the demand on fuel resources.

ENVIRONMENTAL IMPACT

A second major benefit of fuel cells is their low environmental signature. This is due in part to the reaction chemistry. Fuel cells are driven by electrochemistry versus high-temperature combustion chemistry. As a result, fuel cells emit only trace amounts of NO_x. Because fuel cells are intolerant of sulfur, the fuels used have to be desulfurized, and thus fuel cells emit essentially no SOx. Thus fuel cells produce essentially no acid rain pollutants, a key advantage over conventional power generation technologies. Additionally, because fuel cells use gaseous fuels, they emit no particulates, and because they completely oxidize the fuel, there are no unburned hydrocarbons. If the fuel input is hydrogen, then only water vapor is generated in the exhaust. On the other hand, if the fuel is natural gas or another hydrocarbon fuel, then carbon dioxide is also generated. As explained above, because of the high electrical efficiency of fuel cells, the amount of CO_2 emitted per kWh of electricity generated is lower than from conventional power

[1] Electrical efficiency can reported relative to either the LHV or higher heating value ("HHV") of the fuel. LHV is standard for natural gas-fueled systems and represents the typical case where the water in the effluent is exhausted in the gaseous state. In contrast, HHV corresponds to the case where the water in the exhaust is condensed and the latent heat of vaporization is retained in the cycle. As a result, a fuel's heat content expressed in HHV units exceeds its heat content expressed in LHV units. Conversely, for any given fossil fuel, efficiency expressed in LHV units exceeds efficiency expressed in HHV units. For natural gas, efficiency expressed in LHV units is approximately 10% greater than electrical efficiency expressed in HHV units.

generation technologies of comparable size. In addition to electric power generation, the ability of fuel cells to capture and use the thermal energy further reduces the amount of CO_2 emitted.

FUEL CELLS FOR STATIONARY APPLICATIONS

Within the stationary power market, different types of fuel cells are better suited to serve different market segments, based on size and customer needs (especially for heat and/or cooling), fuel availability, *etc.*

PAFCs, MCFCs, and SOFCs are well suited for continuous, baseload generation of electricity and heat for the following reasons:

- Highest electrical efficiency of any comparable-sized system
- Lowest environmental impact of any power generation system using similar fuels
- Amenable to operation on natural gas, industrial waste hydrogen, digester gas and other biofuels fuels; do not need pure hydrogen
- High quality power produced
- Ease of siting at or near the point of use
- Unattended operation, low maintenance, high availability
- Minimal licensing, permitting and installation time
- Some are air-cooled, most need limited water during normal operation
- Cogeneration (with options for chilled water, steam) or electric-only options.

PEMFCs are well suited for backup power and intermittent power demand (*e.g.*, peak load shaving) for the following reasons:

- Lowest environmental impact of any power generation system using similar fuels
- High quality power produced
- Ease of siting at or near the point of use
- Unattended operation, low maintenance, high availability
- Readily turned on and off as required on demand
- Minimal licensing, permitting and installation time.

The heat available from fuel cells for cogeneration or CCHP applications is an important aspect of fuel cell economic viability, and most stationary fuel cells will have a cogeneration or CCHP application.[2]

[2] The study assumes that 60% of installed fuel cell capacity in California captures waste heat for cogeneration (*e.g.*, CCHP use).

Attachment B

"PLEASE" MATRIX OF DISTRIBUTED VALUE ELEMENTS

(* Indicates inclusion in "Build-Up of Fuel Cell Value in California")

POLITICAL	LOCATIONAL	ENVIRONMENTAL	ANTIDOTAL Hedge against:	SECURITY	EFFICIENCY (Market, Technical)
Impact on local control of resources	Impact on local tax base	"Renewable energy credits" and "green certificates" impact	Fossil fuel price volatility*	Impact on likelihood of system outages*	Impact due to combined cooling, heating & power (CCHP) configuration*
Impact on "political capital"	Land use impact (*e.g.*, T&D line rights of way)	Impact on NO_x and SO_x emissions levels*	Future electricity price volatility	Impact on supply diversity	Impacts on competition & market power mitigation
Impact on achieving RPS goals	Impact on local property values	Impact on PM10 emissions level*	Utility power outages*	Impact on power quality*	Impact on project carrying cost
	Noise level impact	Impact on CO_2 emissions level	Utility load forecast uncertainty	Impact on utility grid VAR support*	Impact on decision making time required
	Impact on NIMBY-BANANA-NOPE-attitudes	Impact on other emissions levels (*e.g.*, VOCs, mercury)*	Uncertain reserve % requirements	Impact on likelihood & severity of terrorist attacks	Impact on project installation time (due to modularity)
	Impact on local economic activity (*e.g.*, job creation)*	Impact on material input (*e.g.*, solar panels replace some roofing)	Wheeling costs	Impact on domestic fossil fuel use*	Impact on # of available supply options (as DG markets & technologies mature)
	Ability to impact urban load pockets	Healthcare cost impact related to emissions level changes*	Future changes in environmental regulations	Impact on fossil fuel import reliance	Impact on responsiveness to load growth (due to modularity)
	Ability to impact suburban load pockets	Visibility impact due to emissions impact	Site remedia-tion costs (current and future)		Impact on permitting time and cost
	Ability to impact rural or remote loads	Impact on urban "heat islands" (*e.g.*, shading ability)			Impact on operating life of grid components
	Impact of DG fuel delivery system	Impact on consumptive water use*			Impact on resale or salvage value of equipment
	Visual impact	Impact on water & soil pollution levels			

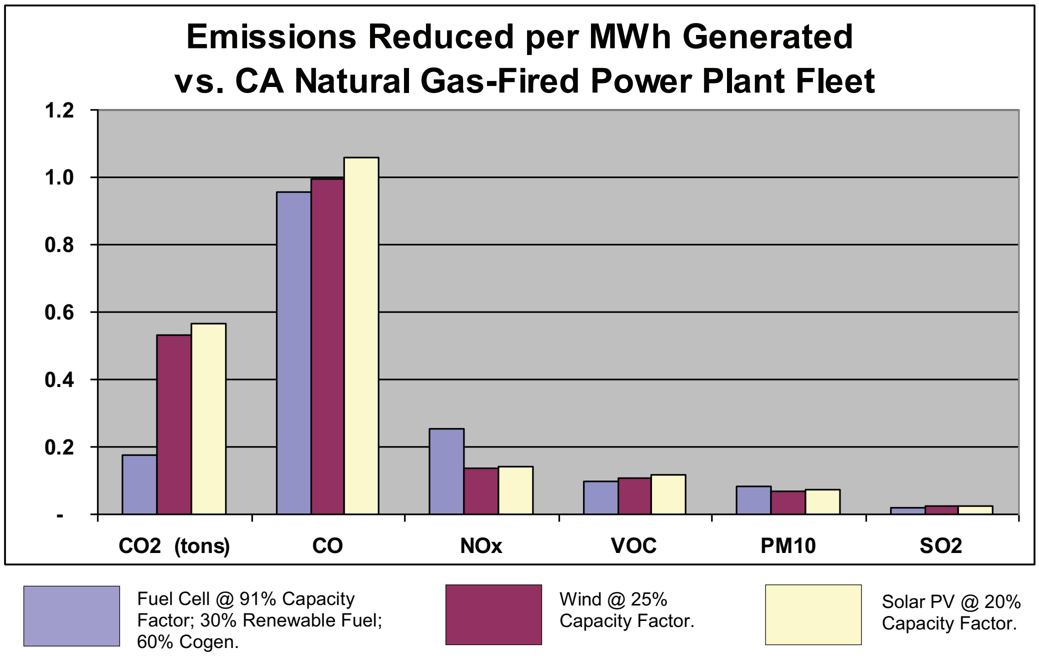
Attachment C

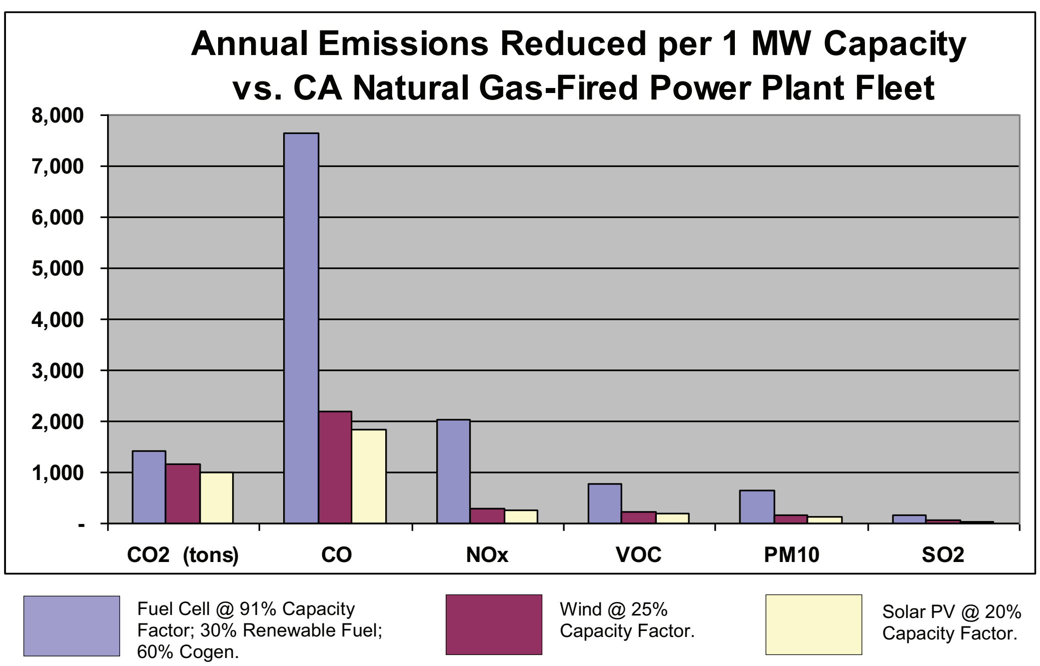
ASSUMPTIONS AND RESULTS FOR AVOIDED EMISSIONS AND RELATED VALUE OF HEALTH BENEFITS

	Heat Rate Range (Btu/kWh)	Emissions Rate (CO_2 in tons/MWh; all others in lb/MWh)						
		NO_x	SO_2	PM10	CO	VOC	Mercury	CO_2
Fuel Cells	8,343	0.06	0.005	-	0.10	0.02	-	0.49
	8,060	0.01	0.001	-	0.10	0.02	-	0.46
Average CA Natural Gas-Fired Generator	9,100	0.14	0.025	0.074	1.06	0.12	-	0.56
	8,087	0.11	0.022	0.067	0.94	0.10	-	0.50
Pulverized Coal-Fired Generator	10,875	0.85	1.730	0.350	0.22	0.03	3.39E-05	1.20
	8,844	0.69	1.406	0.280	0.18	0.02	2.76E-05	0.97
Emissions Prices		NO_x	SO_2	PM10	CO	VOC	Mercury	CO_2
	In-State:	($/lb/day)	($/lb/day)	($/lb/day)	($/lb/day)	($/lb/day)	($/lb)	($/ton)
	Maximum	$356,164	$163,014	$261,189	$8,337	$295,890	$35,000	$27.27
	Minimum	$ 25,000	$ 40,000	$ 80,000	$4,214	$ 5,000	$ 5,000	$ 8.00
	Out-of-State:	($/ton)	($/ton)	($/ton)	($/ton)	($/ton)	($/lb)	($/ton)
	Maximum	$ 7,500	$ 1,650	$ 2,000	n/a	$ 2,000	$35,000	$27.27
	Minimum	$ 500	$ 100	$ 2,000	n/a	$ 2,000	$ 5,000	$ 8.00
Fuel Cells: Value of Avoided Emissions (cents/kWh)		NO_x	SO_2	PM10	CO	VOC	Mercury	CO_2
	Maximum	0.99	0.14	0.22	0.10	0.345	0.12	2.21
	Minimum	0.06	0.01	0.03	0.01	0.002	-	0.11
Fuel Cells: Value of Health Benefits of Avoided Emissions		NO_x & SO_2		PM10	PM2.5*	* *PM2.5 emissions make up 98% of the PM10 emissions category by weight, per California Air Resources Board 2000 Emissions Inventory.*		
	Maximum	0.037 ¢/kWh		0.41 ¢/kWh	2.09 ¢/kWh			
	Minimum	0.034 ¢/kWh		0.40¢/kWh	1.91 ¢/kWh			

Attachment D

COMPARISON OF AVOIDED EMISSIONS FOR FUEL CELLS, SOLAR PV, AND WIND: PER MWH vs. ANNUAL PER INSTALLED MW





Attachment E

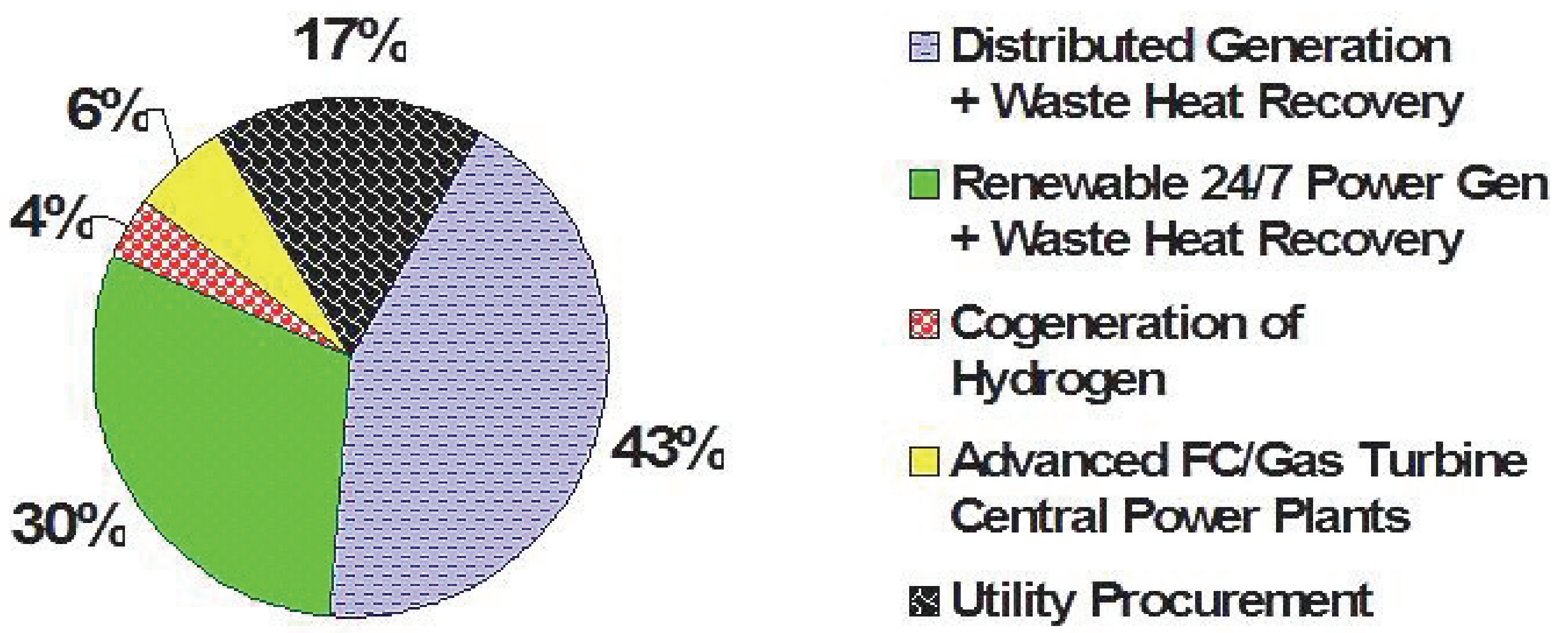
ALTERNATE DERIVATION OF 3200 MW OF INSTALLED FUEL CELL CAPACITY IN CALIFORNIA IN 2020

CEC Aggressive Market Access Scenario, Total On-Site CHP MW:	4,471	MW		
CEC Aggressive Market Access Scenario, Total Export CHP MW:	2,869	MW	64%	= Export as % of On-Site CHP
CEC TOTAL On-Site and Export CHP MW (All Technologies):	7,340	MW		
CEC Aggressive Mkt Access Scenario, Total On-Site CHP MW (Fuel Cells Only):	1,101	MW		
Industry Estimate, Total Export CCHP MW (Fuel Cells Only):	551	MW	50%	= Export as % of On-Site CCHP
TOTAL CEC On-Site and Industry Estimate Export CHP MW (Fuel Cells Only):	1,652	MW		
% CCHP of Total Fuel Cell Installed MW in California (Industry Estimate):	60%			
Grossed Up for All Fuel Cell Installed MW (CCHP and Non-CCHP):	2,753	MW		
# of Projects >5 MW (Industry Estimate; "0" in CEC Report):	98	Projects		
Installed Capacity Assuming 5 MW for Each Project >5 MW:	490	MW		
TOTAL On-Site and Export CCHP and Non-CCHP MW (Fuel Cells Only):	$\boxed{\textbf{3,243}}$	**MW**		

Sources of Data:
(1) Industry Estimates.
(2) California Energy Commission, November 2005, "Staff Report: Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration," PIER Collaborative Report with Electric Power Research Institute, CEC-500-2005-173.

Attachment F

2020: CONTRIBUTION TO FUEL CELL VALUE IN CALIFORNIA, BY MARKET SEGMENT



PROOF OF SERVICE

I declare that:

I am employed in the County of Sacramento, State of California. I am over the age of eighteen years and am not a party to the within action. My business address is ELLISON, SCHNEIDER & HARRIS; 2015 H Street; Sacramento, California 95811-3109; telephone (916) 447-2166.

On June 2, 2008, I served the attached *Comments of FuelCell Energy, Inc. Regarding Treatment of Combined Heat and Power* by electronic mail or, if no e-mail address was provided, by United States mail at Sacramento, California, addressed to each person shown on the attached service list.

I declare under penalty of perjury that the foregoing is true and correct and that this declaration was executed on June 2, 2008, at Sacramento, California.

/s/

Karen A. Mitchell

SERVICE LIST
R. 06-04-009

abb@eslawfirm.com
abonds@thelen.com
achang@nrdc.org
adamb@greenlining.org
aeg@cpuc.ca.gov
agc@cpuc.ca.gov
agrimaldi@mckennalong.com
ahendrickson@commerceenergy.com
ahl@cpuc.ca.gov
aimee.barnes@ecosecurities.com
akbar.jazayeri@sce.com
akelly@climatetrust.org
alan.comnes@nrgenergy.com
alex.kang@itron.com
alho@pge.com
amber@ethree.com
andrew.mcallister@energycenter.org
andy.vanhorn@vhcenergy.com
anita.hart@swgas.com
annabelle.malins@fco.gov.uk
apak@sempraglobal.com
atrial@sempra.com
atrowbridge@daycartermurphy.com
Audra.Hartmann@Dynegy.com
aweller@sel.com
ayk@cpuc.ca.gov
bbaker@summitblue.com
bbc@cpuc.ca.gov
bbeebe@smud.org
bcragg@goodinmacbride.com
bdicapo@caiso.com
bernardo@braunlegal.com
beth@beth411.com
Betty.Seto@kema.com
bill.chen@constellation.com
bill.schrand@swgas.com
bjeider@ci.burbank.ca.us
bjones@mjbradley.com
bkc7@pge.com
blm@cpuc.ca.gov
bmcc@mccarthylaw.com
bmcquown@reliant.com
Bob.lucas@calobby.com
bpotts@foley.com
bpurewal@water.ca.gov
brabe@umich.edu
brbarkovich@earthlink.net
brbc@pge.com
brenda.lemay@horizonwind.com
burtraw@rff.org
bushinskyj@pewclimate.org
bwallerstein@aqmd.gov
bwetstone@hotmail.com
C_Marnay@lbl.gov
californiadockets@pacificorp.com
carla.peterman@gmail.com
carter@ieta.org
case.admin@sce.com
cathy.karlstad@sce.com
cbaskette@enernoc.com
cbreidenich@yahoo.com
cchen@ucsusa.org
cem@newsdata.com
cf1@cpuc.ca.gov
cft@cpuc.ca.gov
charlie.blair@delta-ee.com
chilen@sppc.com
cjw5@pge.com
ckmitchell1@sbcglobal.net
clarence.binninger@doj.ca.gov
clark.bernier@rlw.com
clyde.murley@comcast.net
cmkehrein@ems-ca.com
cpe@cpuc.ca.gov
cpechman@powereconomics.com
cswoollums@midamerican.com
curt.barry@iwpnews.com
curtis.kebler@gs.com
cweddington@commerceenergy.com
Cynthia.A.Fonner@constellation.com
cynthia.schultz@pacificorp.com
daking@sempra.com
Dan.adler@calcef.org
dansvec@hdo.net
dave@ppallc.com
david.reynolds@ncpa.com
david.zonana@doj.ca.gov
david@branchcomb.com
david@nemtzow.com
dbrooks@nevp.com
deborah.slon@doj.ca.gov
dehling@klng.com
derek@climateregistry.org
dhecht@sempratrading.com
dhuard@manatt.com
Diane_Fellman@fpl.com
dietrichlaw2@earthlink.net
dil@cpuc.ca.gov
dkk@eslawfirm.com
dks@cpuc.ca.gov
dmacmull@water.ca.gov
dmetz@energy.state.ca.us
dniehaus@semprautilities.com
douglass@energyattorney.com
dschwyze@energy.state.ca.us
dseperas@calpine.com
dsh@cpuc.ca.gov
dsoyars@sppc.com
dtibbs@aes4u.com

dwood8@cox.net
dws@r-c-s-inc.com
echiang@elementmarkets.com
edm@cpuc.ca.gov
edwardoneill@dwt.com
egw@a-klaw.com
ehadley@reupower.com
ej_wright@oxy.com
ek@a-klaw.com
ekgrubaugh@iid.com
eks@cpuc.ca.gov
ELL5@pge.com
elvine@lbl.gov
emahlon@ecoact.org
emello@sppc.com
epoelsterl@sunpowercorp.com
epoole@adplaw.com
e-recipient@caiso.com
etiedemann@kmtg.com
ewolfe@resero.com
fiji.george@elpaso.com
filings@a-klaw.com
fjs@cpuc.ca.gov
fred.wellington@navigantconsulting.com
fstern@summitblue.com
fwmonier@tid.org
garson_knapp@fpl.com
gbarch@knowledgeinenergy.com
gblue@enxco.com
gcollord@arb.ca.gov
george.hopley@barcap.com
ghinners@reliant.com
GloriaB@anzaelectric.org
glw@eslawfirm.com
gmorris@emf.net
gpickering@navigantconsulting.com
grosenblum@caiso.com
gsmith@adamsbroadwell.com
GXL2@pge.com
harveyederpspc@hotmail.com
hayley@turn.org
hcronin@water.ca.gov
hgolub@nixonpeabody.com
hlouie@energy.state.ca.us
hoerner@redefiningprogress.org
hurlock@water.ca.gov
HYao@SempraUtilities.com
hym@cpuc.ca.gov
info@calseia.org
Jairam.gopal@sce.com
james.keating@bp.com
janill.richards@doj.ca.gov
jarmstrong@goodinmacbride.com
jason.dubchak@niskags.com
jbf@cpuc.ca.gov
jbw@slwplc.com
jchamberlin@strategicenergy.com
jci@cpuc.ca.gov
JDF1@PGE.COM
jdh@eslawfirm.com
jdoll@arb.ca.gov
jeanne.sole@sfgov.org
jeffreyGray@dwt.com
jen@cnt.org
jenine.schenk@apses.com
jennifer.porter@energycenter.org
JerryL@abag.ca.gov
jesus.arredondo@nrgenergy.com
jf2@cpuc.ca.gov
jgreco@terra-genpower.com
jhahn@covantaenergy.com
jholtkamp@hollandhart.com
jimross@r-c-s-inc.com
jj.prucnal@swgas.com
jk1@cpuc.ca.gov
jkarp@winston.com
jkloberdanz@semprautilities.com
jlaun@apogee.net
jleslie@luce.com
jluckhardt@downeybrand.com
jm3@cpuc.ca.gov
jnelson@psrec.coop
jnm@cpuc.ca.gov
jody_london_consulting@earthlink.net
joe.paul@dynegy.com
john.hughes@sce.com
johnrredding@earthlink.net
jol@cpuc.ca.gov
jose@ceert.org
josephhenri@hotmail.com
joyw@mid.org
jsanders@caiso.com
jscancarelli@flk.com
jsqueri@gmssr.com
jst@cpuc.ca.gov
jtp@cpuc.ca.gov
julie.martin@bp.com
jwiedman@goodinmacbride.com
jwmctarnaghan@duanemorris.com
jwmctarnaghan@duanemorris.com
jwoodruff@nextlightrp.com
jxa2@pge.com
jzr@cpuc.ca.gov
karen@klindh.com
karla.dailey@cityofpaloalto.org
Kathryn.Wig@nrgenergy.com
kbowen@winston.com
kcolburn@symbioticstrategies.com
kdusel@navigantconsulting.com
kdw@woodruff-expert-services.com
KEBD@pge.com
keith.mccrea@sablaw.com

kellie.smith@sen.ca.gov
kelly.barr@srpnet.com
ken.alex@doj.ca.gov
ken.alex@doj.ca.gov
kenneth.swain@navigantconsulting.com
kerry.hattevik@nrgenergy.com
kevin.boudreaux@calpine.com
kfox@wsgr.com
kgough@calpine.com
kgrenfell@nrdc.org
kgriffin@energy.state.ca.us
kjinnovation@earthlink.net
kjsimonsen@ems-ca.com
kkhoja@thelenreid.com
klatt@energyattorney.com
kmills@cfbf.com
kmkiener@fox.net
koconnor@winston.com
kowalewskia@calpine.com
krd@cpuc.ca.gov
ksmith@sunpowercorp.com
kyle.l.davis@pacificorp.com
kyle.silon@ecosecurities.com
kyle_boudreaux@fpl.com
lars@resource-solutions.org
Laura.Genao@sce.com
lcottle@winston.com
ldecarlo@energy.state.ca.us
LeeWallach@SolelUS.com
leilani.johnson@ladwp.com
lfletcher@nrdc.org
liddell@energyattorney.com
lisa.c.schwartz@state.or.us
lisa_weinzimer@platts.com
llorenz@semprautilities.com
llund@commerceenergy.com
lmh@eslawfirm.com
lmiles@adamsbroadwell.com
Lorraine.Paskett@ladwp.com
lpark@navigantconsulting.com
lrm@cpuc.ca.gov
lschavrien@semprautilities.com
ltenhope@energy.state.ca.us
ltt@cpuc.ca.gov
marcel@turn.org
marcie.milner@shell.com
mary.lynch@constellation.com
mc3@cpuc.ca.gov
mclaughlin@braunlegal.com
mday@goodinmacbride.com
mdjoseph@adamsbroadwell.com
mdorn@mwe.com
mflorio@turn.org
mgillette@enernoc.com
mhyams@sfwater.org
Mike@alpinenaturalgas.com
mjd@cpuc.ca.gov
mmattes@nossaman.com
mmazur@3phasesRenewables.com
mona@landsiteinc.net
monica.schwebs@bingham.com
mpa@a-klaw.com
mpryor@energy.state.ca.us
mrw@mrwassoc.com
mscheibl@arb.ca.gov
myuffee@mwe.com
nenbar@energy-insights.com
ner@cpuc.ca.gov
nes@a-klaw.com
nlenssen@energy-insights.com
norman.furuta@navy.mil
npedersen@hanmor.com
nrader@calwea.org
nsuetake@turn.org
ntronaas@energy.state.ca.us
nwhang@manatt.com
obartho@smud.org
obystrom@cera.com
pbarthol@energy.state.ca.us
pburmich@arb.ca.gov
pduvair@energy.state.ca.us
pepper@cleanpowermarkets.com
phanschen@mofo.com
Philip.H.Carver@state.or.us
philm@scdenergy.com
pmaxwell@navigantconsulting.com
policy@recurrentenergy.com
pperez@energy.state.ca.us
ppettingill@caiso.com
psp@cpuc.ca.gov
pssed@adelphia.net
pstoner@lgc.org
pthompson@summitblue.com
pvallen@thelen.com
pw1@cpuc.ca.gov
pzs@cpuc.ca.gov
rachel@ceert.org
ralf1241a@cs.com
ram@cpuc.ca.gov
randy.howard@ladwp.com
randy.sable@swgas.com
rapcowart@aol.com
ray.welch@navigantconsulting.com
rhelgeson@scppa.org
rhwiser@lbl.gov
richards@mid.org
rick_noger@praxair.com
rita@ritanortonconsulting.com
rkeen@manatt.com
rkmoore@gswater.com
rmccann@umich.edu
rmiller@energy.state.ca.us

rmm@cpuc.ca.gov
rmorillo@ci.burbank.ca.us
robert.pettinato@ladwp.com
Robert.Rozanski@ladwp.com
roger.montgomery@swgas.com
rogerv@mid.org
ron.deaton@ladwp.com
rprince@semprautilities.com
rreinhard@mofo.com
rrtaylor@srpnet.com
rsa@a-klaw.com
rschmidt@bartlewells.com
rsmutny-jones@caiso.com
rwinthrop@pilotpowergroup.com
ryan.flynn@pacificorp.com
S1L7@pge.com
saeed.farrokhpay@ferc.gov
samuel.r.sadler@state.or.us
sandra.carolina@swgas.com
Sandra.ely@state.nm.us
sas@a-klaw.com
sasteriadis@apx.com
sbeatty@cwclaw.com
sberlin@mccarthylaw.com
sbeserra@sbcglobal.net
scarter@nrdc.org
scohn@smud.org
scott.tomashefsky@ncpa.com
scottanders@sandiego.edu
scr@cpuc.ca.gov
sdhilton@stoel.com
SEHC@pge.com
sellis@fypower.org
sephra.ninow@energycenter.org
sgm@cpuc.ca.gov
slins@ci.glendale.ca.us
sls@a-klaw.com
smichel@westernresources.org
smindel@knowledgeinenergy.com
smk@cpuc.ca.gov
snewsom@semprautilities.com
spauker@wsgr.com
sscb@pge.com
ssmyers@att.net
steve.koerner@elpaso.com
steve@schiller.com
stevek@kromer.com
steven.huhman@morganstanley.com
steven.schleimer@barclayscapital.com
steven@iepa.com
steven@lipmanconsulting.com
steven@moss.net
svn@cpuc.ca.gov
svongdeuane@semprasolutions.com
svs6@pge.com
tam@cpuc.ca.gov
tandy.mcmannes@solar.abengoa.com
tburke@sfwater.org
tcarlson@reliant.com
tcx@cpuc.ca.gov
tdarton@pilotpowergroup.com
tdelfino@earthlink.net
tdillard@sppc.com
THAMILTON5@CHARTER.NET
thunt@cecmail.org
tiffany.rau@bp.com
tim.hemig@nrgenergy.com
todil@mckennalong.com
Tom.Elgie@powerex.com
tomb@crossborderenergy.com
tomk@mid.org
trdill@westernhubs.com
troberts@sempra.com
UHelman@caiso.com
vb@pointcarbon.com
vitaly.lee@aes.com
vjw3@pge.com
vprabhakaran@goodinmacbride.com
vwelch@environmentaldefense.org
wamer@kirkwood.com
wbooth@booth-law.com
westgas@aol.com
wetstone@alamedapt.com
william.tomlinson@elpaso.com
wsm@cpuc.ca.gov
wtasat@arb.ca.gov
wwester@smud.org
wynne@braunlegal.com
ygross@sempraglobal.com
zac@cpuc.ca.gov
zaiontj@bp.com

CINDY ADAMS
COVANTA ENERGY CORPORATION
40 LANE ROAD
FAIRFIELD NJ 7004

STEPHEN E. DOYLE
CLEAN ENERGY SYSTEMS, INC.
3035 PROSPECT PARK DRIVE, STE 150
RANCHO CORDOVA CA 95670-6071

DOWNEY BRAND
DOWNEY BRAND
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO CA 95814-4686

MARY MCDONALD
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR
151 BLUE RAVINE ROAD
FOLSOM CA 95630

MELISSA JONES
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-39
SACRAMENTO CA 95814