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|---|---|
| Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. | Rulemaking No.: 12-03-014<br>Exhibit No.: ____________<br>Witness: Eric Gimon<br>Judge: David M. Gamson |

# TRACK 1
# PREPARED REPLY TESTIMONY OF ERIC GIMON ON BEHALF OF THE VOTE SOLAR INITIATIVE

**BEFORE THE PUBLIC UTILITIES COMMISISON OF THE STATE OF CALIFORNIA**

**July 23, 2012**

**Q. What is your name and who do you represent?**

**A.** My name is Eric Gimon and I represent The Vote Solar Initiative (Vote Solar), a non-profit organization based in San Francisco which works at the state, federal and local level to implement programs and policies that allow strong solar markets to grow — and pave the way for a transition to a renewable energy economy.

**Q. What is your educational and professional background?**

**A.** I am a Technical Consultant for Vote Solar, advising them on technical and policy issues. Before that I was an AAAS Fellow acting as a scientific advisor with the Office of Electricity Delivery and Energy Reliability (OE) at the US Department of Energy (DOE). In that capacity, I advised staff at OE as they developed and implemented a Recovery Act effort to enhance interconnection-wide planning in WECC, the Eastern Interconnection and Texas (ERCOT). I interacted with ISO's and monitored other stakeholder groups. Relevant to California, I monitored and reported on multiple meetings of WECC-wide groups such as the Transmission Expansion Planning Policy Committee (TEPPC), the Scenario Planning Steering Group (SPSG) and the Committee on Regional Electric Power Cooperation (CREPC). I was an active observer and referee on a DOE financed study to model very high penetrations of renewables (40-90%) in the continental US by 2050, with results just recently published by the National Renewable Energy Laboratory (NREL) in their Renewable Energy Futures report this June. My other function at the DOE was to act as an advisor to the Under-Secretary for Energy on R&D investments for the national grid. I hold a double B.S. with honors in Mathematics and Physics along with an M.S. in Mathematics from Stanford University. I also hold a Ph.D. in physics from the University of California at Santa Barbara and spent more than ten years as a professional research physicist with 25 published papers and over 1,600 citations.

**Q. What is the purpose of this testimony?**

**A**. The purpose of my testimony is to reply to the prepared direct testimony served on June 25, 2012, by other parties in this proceeding.

**Q. Do you have a response to the July 13, 2012 Assigned Commissioner's Ruling (ACR) issued in this proceeding?**

**A.** Yes, I have reviewed the ACR and will respond to Questions 1 and 3, particularly as they relate to my reply to the direct testimony submitted on behalf of The Utility Reform Network (TURN). I disagree with TURN's conclusion that requests for offers (RFOs) "should also solicit non-fossil alternatives…"[1] Specifically, I am referring to a subset of "non-fossil alternatives," namely Renewable Distributed Generation (DG), Combined Heat and Power (CHP), Demand Response (DR) and Energy Efficiency (EE).

This is not to say that such resources should be specifically excluded from conventional generation RFOs *per se*, but instead that under the current circumstances and as I will discuss below, I think there are other options that are, at this juncture, more efficient and effective. Thus, to answer Question 1 of the ACR, I recommend that to "the extent that the Commission determines that Southern California Edison Company (SCE) and/or other Load-Serving Entities in the Los Angeles basin and the Big Creek/Ventura local area must procure capacity to meet long-term local capacity needs," the needs should be met consistent with the Commission's Preferred Loading Order. However, contrary to the inquiry in Question 3 of the ACR and, in part contrary to the conclusion of TURN, for the time being I believe that an all source RFO cannot reasonably embody the directives of the Preferred Loading Order, and therefore an alternative approach must be adopted.

**Q. Why do you believe that an all source RFO cannot reasonably embody the directives of the Preferred Loading Order?**

**A.** The resources at the top of the Preferred Loading Order – DG, CHP, DR and EE (collectively "Preferred Resources") – are endowed with advantages that are difficult to monetize or otherwise reflect or capture in an all source RFO. These advantages include, but are not limited to:

1. Preferred Resources are "modular" and therefore can be deployed in smaller MW increments and over shorter periods of time than conventional fossil resources (CFR). This modularity greatly reduces or even completely eliminates risk to rate payers of over or under procurement, and leaves "space" to procure resources that benefit from future

[1] *Prepared Testimony of Kevin Woodruff on Behalf of The Utility Reform Network Regarding Track 1 – Local Reliability* at p. 3 of 24, lines 11-12.

advances in technology, such as storage. Similarly, utility debt equivalence is potentially greatly reduced or eliminated due to the underlying structure of the procurement agreements. For example, behind the meter DG, because it does not involve a power purchase contract, should not have any impact on debt equivalence. Also, because the capital costs for the same installations are paid for by the owner, they present zero stranded cost risk to the utility and the utility ratepayers.

2. Preferred Resources have far less impact on our environment and surrounding communities than CFR.
3. Preferred Resources can be sited on many "mini-sites." The resources needed to fulfill Local Capacity Requirements (LCR) must be located in the designated SCE Local Reliability Areas (LRAs). These areas are densely populated and located on and near the coast, where real estate is expensive and scarce. Realistically, under these circumstances, large CFR will be limited to siting on existing Once Through Cooling (OTC) sites. The footprint needed by large scale renewable energy projects is beyond what is cost effective or even feasible in the LRAs. Preferred Resources are the only resources that can leverage siting opportunities throughout the LRAs.
4. DG, EE and DR have capacity and energy values in excess of CFR due to avoided CFR capacity losses in hot weather, avoided risk of planned and unplanned generator outages which require back-up contingency resources, avoided risk of loss of transmission or distribution line capacity, and avoided transmission & distribution line losses.

**Q. Are there other reasons that you do not support an all source RFO?**

A. Yes, I have the following additional reasons:

1) The underlying market that an all source RFO would address gives rise to market power mitigation issues while the CAISO has provided the Commission with very coarse LCR need outputs. Specifically, the CAISO has provided a range of generation necessary to meet LCR needs in Big Creek/Ventura, LA Basin and San Diego local areas and sub-areas, along with a list of generation effectiveness factors at very specific sites. This output offers the Commission no granularity as to the likelihood, frequency and duration of contingency events, or, with the exception of RPS and load sensitivities, how a

different mix of resources with different generation and load-mitigation profiles could effectively fill actual LCR needs. This lack of granularity improperly favors CFR due to its broader generation profile. Moreover, the CAISO is already identifying the locations of incumbent OTC CFR as "preferred."[2] Accordingly, the shortcomings in CAISO modeling coupled with assumptions regarding locational preference in OTC sites result in a significant and unmerited market power advantage for CFR.

2) An all-source RFO requires commitment to the specific time frame of the 7-10 years necessary to build (or re-build) large CFR projects in a timely manner. Such sweeping and irreversible time and resource commitments should be limited to the absolutely necessary procurement of CFR. Casting this onerous time frame net over Preferred Resources obviates much of the modularity value.

3) Each class of Preferred Resources has distinct and different characteristics and procurement needs. Considerable resources have been expended to create unique programs establishing procurement procedures and protocols for each of the Preferred Resources. An all source RFO would need to conform all of these different elements. This would be a highly cumbersome and time and resource intensive undertaking. Rather than seek to reinvent the wheel, it would be far more efficient to build off existing Commission programs.

4) Contrary to the assertions of Mr. Rothleder in his prepared direct testimony,[3] and consistent with the prepared direct testimony of Mr. Beach,[4] at least in large part, LCRs do not need to be filled with the "flexible" resources described by Mr. Rothleder. On its face, this is not a problem with an all source RFO, but this is a problem if the all source RFO improperly values CFR offering "flexibility" characteristics over Preferred Resources.

**Q. In the absence of an all source RFO at this juncture, what mechanism would you propose?**

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[2] For example, in Table 3.3-17 on page 233 of the CAISO *2011-12 Transmission Plan* (March 23, 2012), the CAISO lists effectiveness factors for incumbent CFRs only that would mitigate LCR needs in the Western LA Basin sub-area. The excerpt is found at Attachment B.

[3] *Testimony of Mark Rothleder on Behalf of the California Independent System Operator Corporation*, at pp.7-9 of 9, lines 4-9.

[4] *Testimony of R. Thomas Beach on Behalf of The California Cogeneration Council*, at pp.11-2, lines 24-13.

**A.** I propose a Preferred Resources LCR Mechanism (PRLM, or pronounced "*pree-lim*"). The PRLM fairly and transparently captures the value of the Preferred Resources, ensures that CFR are not over or under procured, addresses CFR market power, utilizes existing Commission programs and CAISO modeling, and can be implemented quickly and efficiently.

**Q. At what point do you believe an all source RFO would be feasible?**

**A.** I recognize the appeal of developing an all source RFO framework that allows for head-to-head, level playing field competition between all resources. Nevertheless, to attempt to segue to this type of approach ignores the tremendous resources already, and in many cases, recently, invested in existing Commission programs designed specifically for various types of Preferred Resources. Furthermore, attempting to build a robust and sustainable all source RFO policy which addresses the mismatch in development time scales and the load-offset profiles of each source is well beyond the scope of Track 1 of this LTPP. A more appropriate forum would be Track 2 of this or a subsequent LTPP. Indeed, working *within* the LTPP process to realize the goal of collectively comparing all resources is a far more public and transparent approach than, and thus preferable to, a conventional, utility driven RFO.

**Q. Please describe the PRLM?**

**A.** The purpose of the PRLM is to encourage the market to site Preferred Resources in the appropriate SCE LRAs. When this occurs, additional payment is made to those Preferred Resources that reflects the avoided costs that the utility would have spent on procuring CFR to meet LCRs. Ratepayers and the utility should be indifferent to the payment because it would have been made regardless of the existence of the PRLM – the PRLM simply provides a way to redirect procurement, using market encouragement, from CFR to Preferred Resources. With proper accounting in place, the PRLM will prevent acquisition of excess LCR resources by tracking the incremental impact of new Preferred Resources on lowering overall demand, and therefore overall LCR need.

The PRLM is developed using a differential analysis of two Track 1 cases modeled by the CAISO. The first case is based on the 2011-2021 CAISO Transmission Plan, high net-load trajectory assumptions, and forms the basis for CAISO's procurement recommendations for filling OTC LCR needs[5] (Case A) in Track 1 of this proceeding. The second case is based on the "sensitivity analysis" performed by the CAISO using the mid net-load, environmentally constrained case[6] (Case B). The CAISO recommends against using Case B for determining LCR in Track 1 of this proceeding because the CAISO believes that assuming the incremental, "uncommitted" amounts of Preferred Resources embedded in Case B will materialize is too risky, and thus jeopardizes grid reliability.[7]

I utilize the differential between Case A and Case B because of all the scenarios modeled in the CAISO 2011-2012 Transmission Plan, Case B is the most efficient in using Preferred Resources to mitigate LCR generation needs, and because the differential between the two provides a reasonable basis for developing funding targets for encouraging the incremental Case B Preferred Resources to site in the appropriate SCE LRAs. Essentially, under the CAISO's preferred Case A scenario, the CAISO recommends filling the amount of incremental, "uncommitted" Case B Preferred Resources with CFR. I, on the other hand, am proposing, consistent with the Preferred Loading Order, the PRLM, which redirects this CAISO proposed "chunk" of CFR procurement to Preferred Resource procurement.

**Q. By using the Case A and Case B differential as the basis for the PRLM, are you endorsing the CAISO's modeling?**

**A.** No, I am not endorsing the CAISO's modeling. As described in my direct testimony and the direct testimony of many other parties, the CAISO's modeling is problematic in a variety of ways. Nevertheless, presumably due to resource constraints, no other modeling has been presented and/or vetted as thoroughly as the CAISO modeling. Furthermore, I am not aware of

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5 *Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation*, at p. 17 of 17, lines 4-5.

6 *Supplemental Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation*, at p. 2 of 8, lines 12-24.

7 *Ibid.* at pp. 4-7 of 8, lines 1-2.

anything suggesting that the CAISO's modeling will not be utilized, at least in some fashion, in deciding the disposition of Track 1 of this proceeding.

Thus, my use of the CAISO modeling as the building block for the PRLM is driven by practicality and necessity, and should not be construed, whatsoever, as my agreement with the CAISO's Track 1 procurement recommendations. I continue to support everything contained in my direct testimony. The PRLM is not a retraction of that testimony, but is instead a proposal to ensure that if the Commission does authorize procurement in Track 1, that the procurement properly reflects the Preferred Loading Order.

**Q. What do you do with the differential between Case A and Case B?**

**A.** As previously stated, the difference between Case A and Case B represents in MW the incremental Preferred Resources included in Case B, but excluded from Case A. I then re-characterize the MW differential between Case A and Case B as avoided costs. A core purpose of the PRLM is to encourage the use of Preferred Resources to fill the LCR need and thereby avoid unnecessary procurement of the CFR. To provide extra insurance that ratepayers are getting the full benefit of the Preferred Resource procurement, I discount the avoided costs by 25%. I chose 25% because it is a robust discount and leaves sufficient funds to encourage Preferred Resources to site in the appropriate SCE LCAs.

After calculating the discounted avoided cost (DAC), to determine the value over time, I then calculate the net present value of the DAC using a 20 year net present value calculation. Because I am recommending that the PRLM be iterated and reviewed on the 2 year LTPP planning cycle, this amount is divided by four to represent the four LTPP cycles between now and the year 2020. I will refer to this final amount as the Per Cycle Funding (PCF).

Consistent with the ratios of Preferred Resources embedded in Case B, I would then allocate the PCF to the various Preferred Resources, such that each class of Preferred Resource would have a separate "bucket" of PRLM funding. The funding would be utilized consistent with existing Commission programs applicable to each Preferred Resource, and to new programs as, or if, they are developed.

**Q. What are the advantages of the PRLM over an all-source RFO?**

**A.** The advantages of the PRLM over an all source RFO include but are not limited to:

1) The PRLM makes use of a sensitivity already modeled by the CAISO, thereby providing a good guide for the initial cycle. At each iteration, the Commission can evaluate whether incremental preferred resources are on track, how conditions on the ground may have changed, and incorporate improvements to the CAISO modeling. Thus, the PRLM makes good use of current CAISO analysis and provides needed nimbleness to adapt to new or improved future analysis. This open-endedness allow for an on-going dialog between the Commission, the CAISO and stakeholders on the best ways to refine future LCR analysis. Furthermore, by requiring a much smaller number of MW coming from CFR, the PRLM opens the way for more competition between types and locations of CFR and mitigates market power issues.
2) The PRLM is inherently modular. By operating on two-year LTPP cycles, the PRLM takes advantage of the shorter development times of Preferred Resources. By adjusting the buckets for each Preferred Resource as needed during LTPP cycles, the PRLM takes advantage of the granularity offered by the smaller increments of Preferred Resources.
3) Management of the Preferred Resource buckets can be informed by existing Commission programs, leveraging work already performed and minimizing incremental resource needs.

**Q. Does the PRLM completely obviate the need for a CFR RFO?**

**A.** Without conceding a need for new or replacement CFR, to the extent that the Commission finds the need to procure CFR, this would need to occur in an effort parallel to the PRLM. Based on my previously discussed analysis of the scarcity of real estate in the SCE LRAs and the related market power issues, such an effort may ultimately be best addressed through a bilateral negotiation between incumbent CFR and the utility.

**Q. Is the PRLM a subsidy to Preferred Resources?**

**A.** No, the PRLM is not a subsidy. As discussed above, funds used to encourage Preferred Resources to site in the appropriate LRAs are funds that would otherwise be spent on CFR. Appropriate PRLM accounting, such as memo accounts or other similar mechanisms, would ensure accurate tracking and would be trued up and reflected in the CAISO modeling during each subsequent LTPP cycle.

**Q. Does the PRLM have a sunset date?**

**A.** Absent changed circumstances, the PRLM should end in 2020. By 2020, all OTC related LCR needs should be addressed in a resource and cost efficient manner, and completely consistent with the Preferred Loading Order. The iterative nature of the PRLM will have enabled the Commission and the CAISO to hone in on the best ways to analyze how LCR needs can be covered by the widest range of Preferred Resources (including new ones like storage) in an integrated fashion. OTC retirements will have been mitigated, and PRLM-learned insights will be incorporated into ongoing reliability assessments.

**Q. Can you calculate the PCF that would be utilized in the first iteration of the PRLM?**

**A.** For the LA Basin, I have calculated approximately $370mm of PCF for the first iteration of the PRLM. My calculations are found at Attachment A to my testimony. I cannot, however, due to lack of transparency in the CAISO modeling and/or lack of resources, provide approximate bucket allocations. For this reason as well as others, I recommend that the Commission hold workshops to set the PCF, allocate the PCF to the various Preferred Resource buckets, and develop any other policy that might be necessary to implement the PRLM. As the owner/operator of the modeling, the CAISO would provide invaluable assistance in the workshops.

**Q. Can you calculate the PCF that would be utilized in the first iteration of the PRLM for the Moorpark sub-area of the Big Creek/Ventura LRA?**

**A.** Unfortunately, Case B covers only the LA Basin LCA, leaving me without data on the Moorpark –Big Creek/Ventura LRA and thus without an ability to calculate the related PCF. However, while all of the RPS sensitivities in the CAISO 2011-12 Transmission Plan describe 430MW of LCR need under high net-load conditions, it is quite possible that under mid net-load (or low net-load) conditions this need no longer exists. Moreover, SCE recommends that the "Commission Should Defer Authorizing LCR Generation in the Ventura/Big Creek Area Until the 2014 LTPP Cycle." [8] We endorse this recommendation, and further recommend that the Commission request an analysis from the CAISO responsive to stakeholder input, and perhaps similar in style to Case B for the 2014 LTPP planning cycle, for all applicable LRAs, for use in calculating the PCF of the PRLM.

**Q. How would the PRLM address issues of flexibility brought up by the CAISO in its testimony?**

A. I continue to affirm that it is premature to address flexibility needs in Track 1 of this proceeding. I will point out that if Preferred Resources are deployed according to the PRLM, transmission capacity will become more available in constrained pockets and thus flexibility needs can be met on a system-wide basis, further eliminating market power distortions that might arise from contracting for such flexibility in a specific set of locations.

**Q. Have you discussed the PRLM proposal with other parties to the LTPP?**

A. Yes, I have. In fact, on behalf of the California Cogeneration Council, I understand that Tom Beach will be co-sponsoring the PRLM proposal. I also understand that the Sierra Club and the Solar Energy Industries Association are generally supportive of the concept.

**Q. Does this conclude your testimony?**

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[8] *Testimony of Southern California Edison Company on Local Capacity Requirements* at p.10, lines 12-13.

**A.** Yes, it does.

# ATTACHMENT A

**TRACK 1**

**PREPARED REPLY TESTIMONY OF**

**ERIC GIMON ON BEHALF OF**

**THE VOTE SOLAR INITIATIVE**

**<u>Calculation of the PCF for the first iteration of the PRLM</u>**

(1) In his original direct testimony Robert Sparks recommends procuring about 2,400MW from a Case A 1,870-2,884MW-estimated range of OTC replacement need for Western LA (225MW of which covers its Ellis sub-area). In his supplemental direct testimony, Mr. Sparks identifies an OTC replacement need in the Case B scenario 1,042 MW (+ SONGS) at the most "effective" sites, with no further need in the Ellis or Moorpark sub-areas. This leads to avoided procurement of 2400MW – 1042M ≈ 1,400MW of conventional generation at the most "effective" sites. The use of an assumed 1,400 MW of avoided generation, and the CAISO's recommended split between combined cycle gas turbines (CCGTs) and combustion turbines (CTs), results in avoiding the construction of one 500MW CCGT and nine 100MW CTs.[1]

(2) The CAISO *2011 Annual Report on Market Issues and Performance* calculates that the cost of a new 500 MW CCGT, less the revenues that can be recovered in the market, is $126.6 per kW-year.[2] The corresponding above-market cost for a new 100 MW CT unit is $153.5 per kW-year.[3] Thus, the annual savings from the reduced local area requirements in Case B are approximately $200 Million

[1] In *Testimony of Mark* Rothleder *on Behalf of the California Independent System Operator Corporation*, at p 3 of 9 lines 27-28, Mark Rothleder indicated that CAISO modeled 2,800 MW of new generation with two 500 MW CCGTs and eighteen CTs. Iused exactly half of these to model 1,400 MW of avoided costs.

[2] Taken from the CAISO *2011 Annual Report on Market Issues & Performance* (April 2012), at pp.45-46, Tables 1.7 and 1.8, and Figure 1.20. I use the CAISO's calculated five-year average for the market revenues for this unit. The excerpt is found at Attachment B.

[3] *Ibid.,* at pp. 47-48, Tables 1.9and 1.10, and Figure 1.21. Again, this assumes the CAISO's calculated five-year average for the market revenues for this unit.

Per Year (an average of $143.9per kW-year), or a 20-year net present value of $2.0 billion ($1,413 per kW) at an 8% discount rate. I then multiply the $2.0 billion by 75% to reflect the discount ($1.5mm), and then divide by 4 to represent the LTPP cycles between now and the year 2020 ($370mm).

# ATTACHMENT B

**TRACK 1**

**PREPARED REPLY TESTIMONY OF**

**ERIC GIMON ON BEHALF OF**

**THE VOTE SOLAR INITIATIVE**

# CITATIONS

[redacted]

[redacted]

## 1.3 Net market revenues of new gas-fired generation

Every wholesale electric market must have an adequate market and regulatory framework for facilitating investment in needed levels of new capacity. The CPUC's long-term procurement process and resource adequacy program is currently the primary mechanism to ensure investment in new capacity when and where it is needed. Given this regulatory framework, annual fixed costs for existing and new units critical for meeting reliability needs should be recoverable through a combination of long-term bilateral contracts and spot market revenues.

Each year, DMM examines the extent to which revenues from the spot markets would contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents an important market metric tracked by all ISOs. Costs used in the analysis are based on a 2009 (most recent) report by the California Energy Commission.[29]

### Hypothetical combined cycle unit

Key assumptions used in this analysis for a typical new combined cycle unit are shown in Table 1.7. The increase in new generation costs from 2009 are primarily attributable to increases in capital and financing costs and taxes, according to the California Energy Commission report used in this analysis.

Table 1.7 Assumptions for typical new combined cycle unit[30]

| | |
|---|---|
| **Technical Parameters** | |
| Maximum Capacity | 500 MW |
| Minimum Operating Lev el | 150 MW |
| Startup Gas Consumptio n | 1,850 MMBtu/start |
| Heat Rates | |
| Maximum Capacity | 7,100 MBtu/MWh |
| Minimum Operating Le vel | 7,700 MBtu/MWh |
| **Financial Parameters** | |
| Financing Costs | $134.4 /kW-yr |
| Insurance | $7.2 kW-yr |
| Ad Valorem | $9.4 kW-yr |
| Fixed Annual O&M | $10.1 /kW-yr |
| Taxes | $29.6 kW-yr |
| **Total Fixed Cost Revenu e Requirement** | **$190.7/kW-yr** |
| Variable O&M | $3.7/MWh |

Results for a typical new combined cycle unit are shown in Table 1.8 and Figure 1.15. The 2011 net revenue results show a decrease in net revenues compared to 2010. The 2011 net revenue estimates

[29] A more detailed description of the methodology and results of the analysis presented in this section are provided in Appendix A.1 of DMM's 2009 Annual Report on Market Issues & Performance, April 2010, which can be found at http://www.caiso.com/2777/27778a322d0f0.pdf.

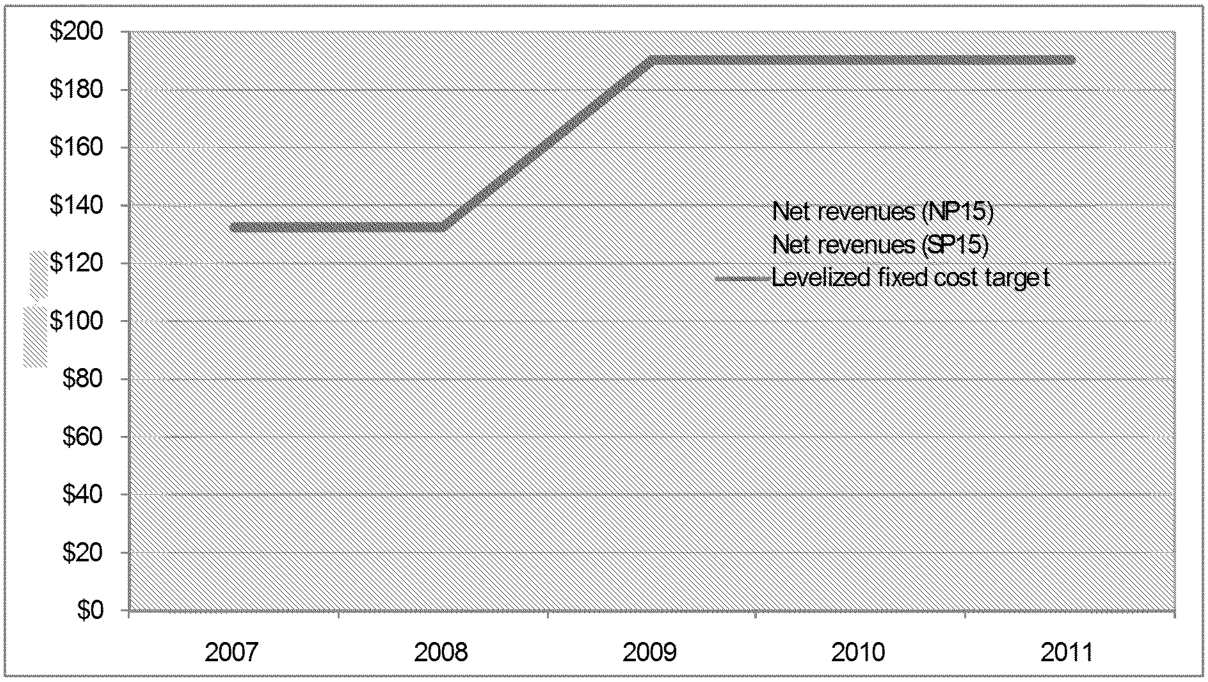
[30] The financing costs, insurance, ad valorem, fixed annual O&M and tax costs for a typical unit in this table were derived directly from the data presented in the CEC's 2009 Comparative Costs of California Central Station Electricity Generation Technologies report which can be found at: http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF.

for a hypothetical combined cycle unit in NP15 and SP15 both fall substantially below the $191/kW-year estimate of annualized fixed costs provided in the CEC report.

Table 1.8 Financial analysis of new combined cycle unit (2007–2011)

| Components | 2007 | | 2008 | | 2009 | | 2010 | | 2011 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 |
| Capacity Factor | 69% | 76% | 74% | 81% | 57% | 57% | 67% | 74% | 53% | 66% |
| DA Energy Revenue ($/kW - yr) | $369.59 | $389.41 | $489.17 | $505.42 | $172.67 | $169.61 | $137.95 | $142.65 | $101.62 | $94.27 |
| RT Energy Revenue ($/kW - yr) | $36.20 | $41.98 | $47.41 | $51.98 | $21.27 | $15.50 | $34.89 | $37.31 | $28.62 | $30.84 |
| A/S Revenue ($/kW – yr) | $0.37 | $0.42 | $0.41 | $0.42 | $0.76 | $0.85 | $1.01 | $1.25 | $1.71 | $2.29 |
| Operating Cost ($/kW - yr) | $321.86 | $337.82 | $425.16 | $428.39 | $154.57 | $147.48 | $143.25 | $145.69 | $108.65 | $104.41 |
| Net Revenue ($/kW – yr) | $84.30 | $95.23 | $111.82 | $128.25 | $40.14 | $38.48 | $30.60 | $35.52 | $23.30 | $22.99 |
| 5-yr Average ($/kW – yr) | $58.03 | $64.10 | | | | | | | | |

Figure 1.20 Estimated net revenue of hypothetical combined cycle unit



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### Hypothetical combustion turbine unit

Key assumptions used in this analysis for a typical new combustion turbine are shown in Table 1.9. Table 1.10 and Figure 1.16 show estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the real-time energy and non-spinning reserve markets. These results show a decrease in the net revenues in 2011. Estimated net revenues for a hypothetical combustion turbine also fell well short of the $212/kW-year estimate of annualized fixed costs in the CEC report.

These findings continue to underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment. Local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC resource adequacy and long-term procurement framework. Under California's current market design, these programs can provide additional revenue for new generation and cover the gap between annualized capital cost and the simulated net spot market revenues provided in the previous section.

Table 1.9 Assumptions for typical new combustion turbine[31]

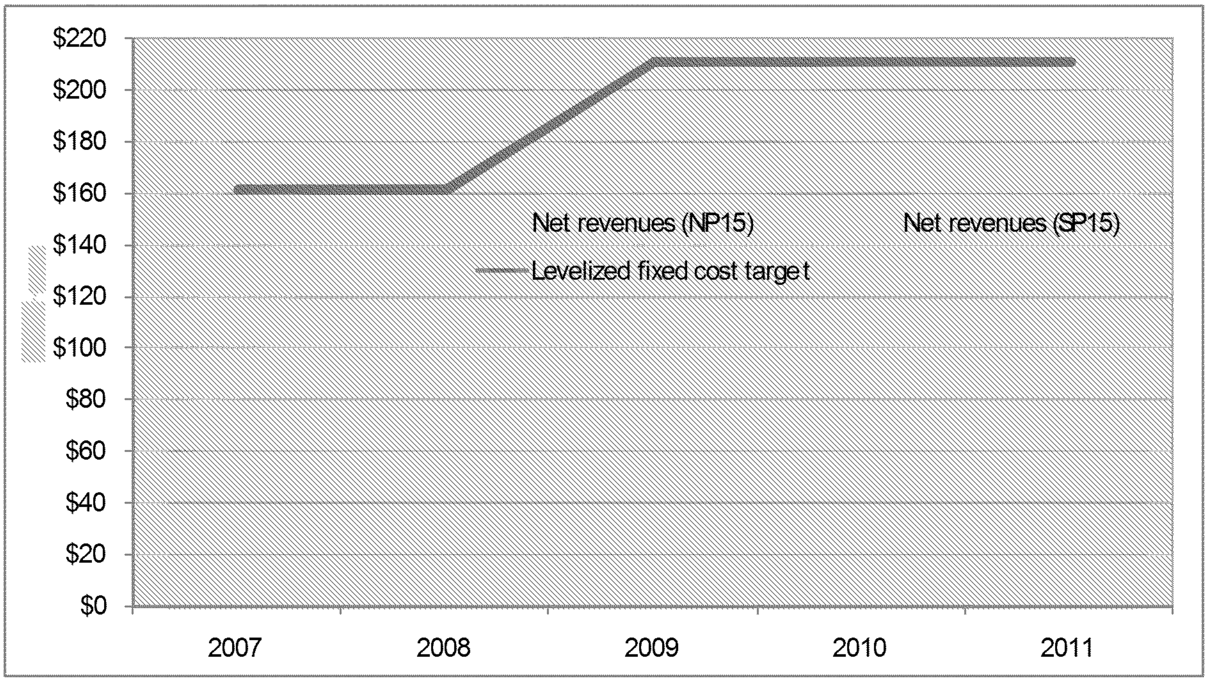
| Technical Parameters | |
|---|---|
| Maximum Capacity | 100 MW |
| Minimum Operating Lev el | 40 MW |
| Startup Gas Consumptio n | 180 MMBtu/start |
| Heat Rates | |
| Maximum Capacity | 9,300 MBtu/MWh |
| Minimum Operating Le vel | 9,700 MBtu/MWh |
| **Financial Parameters** | |
| Financing Costs | $146.6 /kW-yr |
| Insurance | $7.9 kW-yr |
| Ad Valorem | $10.4 kW-yr |
| Fixed Annual O&M | $20.3 /kW-yr |
| Taxes | $26.5 kW-yr |
| Total Fixed Cost Revenu e Requirement | $211.7/kW-yr |
| Variable O&M | $5.1/MWh |

[31] The financing costs, insurance, ad valorem, fixed annual O&M and tax costs for a typical unit in this table were derived directly from the data presented in the CEC's 2009 Comparative Costs of California Central Station Electricity Generation Technologies report which can be found at: http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF.

Table 1.10 Financial analysis of new combustion turbine (2007-2011)

| Components | 2007 | | 2008 | | 2009 | | 2010 | | 2011 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 |
| Capacity Factor | 8% | 9% | 11% | 12% | 6% | 6% | 7% | 10% | 6% | 7% |
| Energy Revenue ($/kW - yr) | $97.54 | $104.99 | $155.58 | $158.98 | $70.50 | $84.62 | $64.97 | $95.94 | $57.60 | $69.57 |
| A/S Revenue ($/kW - yr) | $13.30 | $12.83 | $5.50 | $5.53 | $8.64 | $8.37 | $3.36 | $2.97 | $6.06 | $5.98 |
| Operating Cost ($/kW - yr) | $59.18 | $64.63 | $100.12 | $104.09 | $25.85 | $27.70 | $24.80 | $35.60 | $23.23 | $26.88 |
| Net Revenue ($/kW - yr) | $51.66 | $53.19 | $60.96 | $60.43 | $53.29 | $65.29 | $43.54 | $63.32 | $40.43 | $48.67 |
| 5-yr Average ($/kW - yr) | $49.98 | $58.18 | | | | | | | | |

Figure 1.21 Estimated net revenues of new combustion turbine



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