BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	)))))	Rulemaking 11-05-005 (Filed May 5, 2011)

SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) COMMENTS TO SEC. 399.20 RULING DATED JUNE 27, 2011

AIMEE M. SMITH
101 Ash Street, HQ-12
San Diego, California 92101
Telephone: (619) 699-5042
Facsimile: (619) 699-5027
amsmith@semprautilities.com

Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY

July 21, 2011

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E)
COMMENTS TO SEC. 399.20 RULING DATED JUNE 27, 2011

I.
INTRODUCTION AND BACKGROUND

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission (the "Commission" or "CPUC"), the *Administrative Law Judge's Ruling Setting Forth Implementation Proposal for SB 32 and SB 2 1X Amendments to Section 399.20* dated June 27, 2011 (the "ALJ Ruling"), San Diego Gas & Electric Company ("SDG&E") hereby submits these comments in response to areas of inquiry set forth in the ALJ Ruling regarding amendment of the § 399.20 feed-in tariff ("FIT").

Assembly Bill ("AB") 1969, approved in September, 2006, added § 399.20 to the Public Utilities Code.[1/] The measure required electrical corporations to make available to public water and wastewater agencies that are retail customers of the electrical corporation a tariff and/or standard contract for purchase of renewable energy output produced by such electric generation facilities. In order to be eligible to participate in the tariff, such facilities were required, *inter alia*, to (i) have an effective capacity of not more than 1.5 MW; (ii) be located on or adjacent to a water or wastewater facility owned and operated by the public water or wastewater agency; (iii) be interconnected and operate in parallel with the electric transmission and distribution grid; (iv)

[1/] Assembly Bill (AB) 1969 (Stats. 2006, Ch. 731). All statutory references herein are to the Public Utilities Code unless otherwise noted.

be sized to offset part or all of the electricity demand of the public water or wastewater agency; (v) be strategically located and interconnected to the electric transmission system in a manner that optimizes the deliverability of electricity generated at the facility to load centers; and (vi) be eligible renewable energy resources, as defined in § 399.12. The measure required electrical corporations to make this tariff, which included an administratively-set rate tied to the § 399.15 market price referent ("MPR"), available to water and wastewater customer on a first-come, first-served basis until the electric corporation met its proportionate share of a 250 MW statewide procurement limit.

Senate Bill ("SB") 380, approved in September, 2008, amended § 399.20 to broaden the eligibility criteria set forth in the statute to include all retail customers meeting certain requirements set forth in the statute and to increase the statewide procurement limit to 500 MW.[2/] Subsequent legislation, SB 32, which was approved in October, 2009, further amended § 399.20 by, *inter alia* (i) revising the eligibility criteria to remove the "retail customer" requirement (while retaining the requirement that the facility be located in the electric corporation's service territory); (ii) broadening eligibility criteria to include projects up to 3 MW; (iii) modifying the procedure used to establish tariff pricing; (iv) increasing the statewide procurement limit to 750 MW; (iv) requiring the Commission to establish performance standards for any electric generation facility that has a capacity greater than 1 MW; and (v) addressing past or present participation in any net metering program.[3/]

SB x1 2 ("SB 2") was signed by the Governor in April, 2011, and will become effective 90 days after the conclusion of the Legislature's 2011-2012 First Extraordinary Session.[4/] SB 2

2/ SB 380 (Stats. 2008, Ch. 544).
3/ SB 32 (Stats. 2009, Ch. 328).
4/ SB x1 2 (Stats. 2011, Ch. 1).

amended § 399.20 by removing the reference to § 399.15 for determination of price and including specific pricing guidelines in § 399.20.

The ALJ Ruling solicits comments regarding implementation of amendments to § 399.20 required by SB 32 and SB 2. It sets forth several areas of inquiry, requesting that parties identify those aspects of SB 32 and SB 2 that must be addressed before the end of 2011 and those that could be considered in 2012. SDG&E addresses these issues below.

II.
DISCUSSION

A. The Commission has Limited Jurisdiction to Set § 399.20 FIT Pricing

As a starting point for its analysis of pricing options for the § 399.20 FIT, the Commission must consider its jurisdiction to administratively set the pricing for the FIT. The Commission must observe the limitations upon its authority imposed under federal law and must avoid adopting FIT pricing provisions that exceed its jurisdiction.

Section 201(b)(1) the Federal Power Act ("FPA") establishes the Federal Energy Regulatory Commission's ("FERC's") exclusive jurisdiction over "the sale of electric energy at wholesale in interstate commerce."[5/] The FPA governs wholesale sales by public utilities[6/] and defines wholesale sales as a "sale of electric energy to any person for resale."[7/] Where the wholesale sale involves generation that flows on a multi-state interconnected grid, it is deemed to be a "sale in interstate commerce."[8/]

5/ 16 U.S.C. § 824(b)(1).

6/ "Public utilities" is defined broadly to include sellers of electricity other than governmental entities, as defined in § 824(f). *See* 16 U.S.C. § 824(b)(1); *Connecticut Light & Power Company*, 70 FERC ¶ 61,012.

7/ *Id*. at § 824(d).

8/ *See Federal Power Commission v. Florida Power & Light*, 404 U.S. 453 (1972); 16 U.S.C. § 824(c).

The U.S. Supreme Court has made clear that FERC's authority over wholesale sales of electricity is plenary[9/] Congress has, however, carved out specific wholesale transactions from the plenary authority exercised by FERC over wholesale sales by public utilities in interstate commerce. Most notably, the federal Public Utility Regulatory Policies Act of 1978 ("PURPA") establishes a separate jurisdictional framework applicable to certain qualifying facilities ("QFs"), including cogeneration and small power production facilities, and provides a limited role for the States in implementing the statute. Where program participants are non-QF "public utilities" under the broad definition included in the FPA, however, <u>exclusive</u> authority to set the rates remains with the FERC.

Under PURPA, IOUs must purchase electric generation from QFs at rates that are (i) just and reasonable; (ii) in the public interest; (iii) non-discriminatory; and (iv) not in excess of the incremental cost of alternative electric energy, or "avoided cost."[10/] Section 210(f) of PURPA directs FERC to develop rules applicable to QF transactions and delegates to the States the authority to implement such rules. Thus, while state regulatory commissions may exercise jurisdiction over QF rates, their authority is limited to ensuring that the rates charged by QFs do not exceed avoided cost.[11/]

Thus, it is clear that under the jurisdictional framework established by the FPA and PURPA, the Commission has authority to administratively set the price in the FIT program only

---

9/ *Nantahala Power & Light Co. et al. v. Thornburg, Attorney General of North Carolina, et al.,* 476 U.S. 953, 966 (1986).

10/ 16 U.S.C. §§ 824a-3(b) and (d); 18 CFR 292.304.

11/ *See, e.g., Connecticut Light & Power Company*, 70 FERC ¶ 61,012 (1995), 1995 FERC LEXIS 37, 20. The FERC recently confirmed these legal principles in a series of orders related to the Commission's implementation of the AB 1613 feed-in tariff program. There, the FERC held that AB 1613 implementation would *not* be preempted by the FPA, PURPA, or the FERC's regulations *provided that*: (i) the generators under AB 1613 are QFs pursuant to PURPA; and (ii) the rate established by the CPUC does not exceed the purchasing utility's avoided cost. *California Public Utilities Commission,* 132 FERC Paragraph 61,047 (2010) P 67; aff'd, *California Public Utilities Commission,* 133 FERC Par 61,059 (2010) ("*Clarification Order*"); *California Public Utilities Commission,* 134 FERC Par 61,044(2011) ("*Order Denying Rehearing*").

to the extent program participants are QFs, and the administratively set FIT pricing is set at avoided cost.[12/] Presently, however, FIT participants are not required to be QFs and the Commission has not undertaken the avoided cost analysis required by FERC. Thus, the Commission may not *require* SDG&E to pay the administratively set rate contemplated in § 399.20. As discussed in SDG&E's earlier briefs and below, however, SDG&E may voluntarily agree to pay an MPR-based administratively-set FIT rate. Given the relatively small size of the contemplated FIT program, SDG&E is willing to do so, on the condition that FIT program participants be required to interconnect using Wholesale Distribution Access Tariff ("WDAT") interconnection procedures.[13/]

B. SDG&E's Responses to the Questions in the ALJ Ruling

1. Define market price of electricity as used in § 399.20. Is there one market price of electricity relevant to all types of electricity procurement or are there different market prices depending on the type of electricity that is being procured? For example, is there a unique market price of electricity for the market segment targeted in § 399.20? Does the market price of electricity include all types of electricity contracts and technologies that a utility procures or a subset of contracts and technologies? If you propose a subset, please define the subset.

RESPONSE: As discussed above, the Commission lack jurisdiction to mandate adherence to § 399.20 pricing for the FIT program as it is currently contemplated. To the extent SDG&E voluntarily agrees to accept § 399.20 pricing, it notes that the modification to the § 399.20 pricing mechanism included in SB 2 was intended to preserve the MPR methodology as the means of setting the price for the FIT.

Prior to adoption of SB 2, § 399.20 required FIT pricing to be set in accordance with "the market price determined by the commission pursuant to Section 399.15" – *i.e.*, the provision

[12/] Sales under the FIT program constitute sales for resale, and would therefore satisfy the "wholesale" sale requirement of FPA *See* 16 U.S.C. § 824(d).

[13/] SDG&E notes that it has proposed, via pending advice letter 2262-E, that on an interim basis generators who wish to interconnect under the existing and expanded WATER and CRE programs use WDAT rather than the Rule 21 interconnection procedure.

relied upon to set the MPR. SB 2 did not change this requirement. Rather, SB 2 deleted § 399.15 in its entirety, eliminating the existing RPS cost containment provisions that relied on the MPR, and moved the FIT pricing language into § 399.20. In short, SB 2 had no substantive impact on the requirement to base FIT pricing on the MPR.

Analysis provided by the California Assembly Natural Resources Committee on SB 2 makes this point clear. The analysis notes that SB 2 "amends existing 'feed-in tariff' statute for small renewable generators, which relies on the RPS MPR for pricing, to account for this bill's repeal of the MPR, ***by requiring the PUC to set a similar market price specifically for purposes of the feed-in tariff statute***."[14/]

In addition, analysis by the provided by the California Senate Energy, Utilities and Communications Committee refers to the modification as a "technical amendment," and makes it clear the legislative intent was merely to move the MPR language from § 399.15, which was being eliminated, into § 399.20, which would continue to rely on the MPR:

> Rate calculation for feed-in-tariff (FIT). In 2009, the Legislature adopted SB 32 (Negrete-McLeod) which required the CPUC to increase the 1.5 megawatt FIT to three megawatts and also modified the contract payment calculation which was the MPR. This bill deletes the code sections which specify how the MPR is calculated. The author has attempted to incorporate a new definition of the MPR into this bill but in doing so has inadvertently changed the basis of the calculation of the contract payment. ***This bill should be amended to ensure that the payment basis adopted by the Legislature in SB 32 is maintained.***[15/]

Because the language SB 2 adds to § 399.20 is the same language that appeared in § 399.15, it is clear that the Legislature intended that FIT pricing continue to be based on the MPR,

---

14/ Bill analysis prepared for Assembly Committee on Natural Resources hearing dated March 7, Para. 13. http://info.sen.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_cfa_20110304_145825_asm_comm.html

15/ Bill analysis prepared for Senate Energy, Utilities and Communications Committee, "Comments" section, §4(b). http://info.sen.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_cfa_20110214_141136_sen_comm.html with such adjustments that may be required to reflect "environmental compliance costs" and time of delivery, and subject to specific ratepayer protections that those prices must "ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff."

2. **Explain whether the price for electricity purchased under § 399.20(d), as amended by SB 2 1X, must or should be based on the MPR as currently calculated.**

   RESPONSE: Please see response to Question 1.

3. **Explain whether the price for electricity purchased under § 399.20(d) must or should be based on the MPR as currently calculated with the addition of new adders, as suggested by parties in the March 2011 briefs.**

   RESPONSE: Please see response to Question 1.

4. **Explain the benefits and the drawbacks of continuing to use the MPR as the basis of the price for the program under § 399.20 given the statutory changes.**

   RESPONSE: Please see response to Question 1.

5. **Under the current RPS program rules each annual RPS Solicitation triggers an update to the MPR values. Consistent with CPUC decisions, Energy Division staff will calculate a 2011 MPR for the 2011 RPS Solicitation. Due to the statutory changes in SB 2 1X, it is not clear whether the Commission will continue to calculate an MPR to establish an RPS cost limitation. Parties should explain whether a new trigger for an MPR update is necessary and/or a schedule for how the MPR should be updated going forward.**

   RESPONSE: The Commission should update the MPR on an annual basis.

6. **Based on your definition of "market price of electricity," explain whether a technology-specific or product-specific proposal is a viable option for the § 399.20 program as updated by the SB 2 1X amendments.**

   RESPONSE: A technology-specific or product specific proposal is inconsistent with the MPR.

7. **Explain the specific methodology and all calculations and data that would be required to implement the technology or product-specific rate that you propose.**

   RESPONSE: N/A

8. **If applicable, identify what specific subset of proxy plants is appropriate for the calculation. An example of a Commission-adopted methodology for calculating technology-specific costs would be the MPR model, which calculates the proxy costs of building and operating a Combined Cycle Gas Turbine (CCGT) facility.**

   RESPONSE: N/A

9. **In briefs, SCE suggested that price under § 399.20 be determined by competitive auction. Do you support this approach? Please explain. Discuss whether and how this approach is consistent with the provisions in § 399.20(f). Also explain the mechanisms of how a competitive auction would be used to determine the price (e.g., are projects paid as bid, paid the market clearing price, or paid another price point determined through an auction), and how, if at all, the auction would differ from the design of the Renewable Auction Mechanism in D.10-12-048.**

RESPONSE: SDG&E concurs with SCE regarding limitations on the Commission's jurisdiction to administratively set FIT pricing. Further analysis is required, however, to determine whether SCE's proposal would comport with FERC guidelines. Specifically, it is not clear whether the use of a single competitive solicitation would satisfy FERC's requirements if there are restrictions on participation.

10. **Given that a significant number of RPS solicitations have occurred since this time, using your definition of the market price of electricity, explain whether a rate under § 399.20(d) should be based on RPS power purchase agreement prices. Parties supporting this methodology should identify what subset of power purchase agreements is appropriate for the calculation, whether the price should be the weighted average of PPA prices or some other price point, and provide specific recommendations and calculations, where appropriate and necessary to implement such a methodology. Lastly, parties should articulate if there should be one rate or multiple rates. If parties suggest multiple rates, parties should define what the multiple rates should be and how they should be derived.**

RESPONSE: As discussed above, the voluntary rate for SDG&E's FIT should be based on the MPR, which reflects the long-term ownership, operating, and fixed-price fuel costs for a new 500 MW natural gas fired combined cycle gas turbine ("CCGT").[16/]

[16/] The base load proxy CCGT is adjusted to account for the value of different products by applying the utilities time-of-delivery factors to the Commission adopted MRP value. The MPR Model inputs include installed capital costs, fixed and variable operations and maintenance costs, natural gas fuel costs, cost of capital and environmental permitting and compliance costs.

In the event the Commission elects to proceed under its PURPA authority and develop an avoided cost rate (applicable solely to QFs), SDG&E notes that development of the avoided cost determination must follow FERC guidelines (these guidelines are discussed in SDG&E's March 11 brief). Within this context, it is not clear how past purchase power agreements should be aggregated and adjusted for declining prices over time for different technologies in order to calculate an avoided cost. Determining an avoided cost from this data will prove to be complex and controversial, likely creating a significant further delay to implementation of SB 32.

11. Provide all relevant details for other alternate pricing proposals, if any, consistent with the provisions of SB 2 1X.

RESPONSE: N/A

12. Identify relevant data sources that could be used to implement any proposed methodology and whether the data used to calculate the rate should be derived from public or confidential data. Please comment on the appropriateness of the data sources as identified by parties in opening comments, such as Fuel Cell Energy and CALSEIA.

RESPONSE: N/A

13. Explain how often the price under § 399.20(d) should be calculated given your preferred price calculation approach. The price may be calculated once, at regular intervals, such as annually, or in response to a triggering event. For example, in March 2011 briefs, CALSEIA proposed that the price be modified quarterly and be increased or decreased based on market participation. The California Solar Initiative presented a different model for reducing prices over time in which incentive rates decline over the life of the program in multiple steps triggered by solar capacity additions to facilitate market transformation.

RESPONSE: Please see response to Question 5.

14. Respond to these interpretations of "ratepayer indifference" and explain how the SB 2 1X amendments to § 399.20(d) and any new pricing proposal that you suggest pursuant to these amendments impact these interpretations.

RESPONSE: While SDG&E does not believe the Commission has made an adequate showing that the MPR is the long-term avoided cost of the utility, the Commission itself has stated that it believes the MPR meets the ratepayer indifference requirement. In D.11-04-03, the Commission observed that:

> The MPR is based on the costs of a proxy power plant (gas fired combined-cycle plant) that would be necessary if not for some other form of new generation, in this case CHP. Basing the price paid for excess electricity from a CHP facility on the estimated cost of a marginal generating unit, meets the ratepayer indifference requirement of PUC Section 2841(b)(4).[17/]

The Commission further noted that:

> In D.09-12-042 we found that the MPR-based price, as a reasonable proxy for the generation the utilities would have purchased "but for" the AB 1613 purchase requirements, met the ratepayer indifference standard of AB 1613 . . . To elaborate on the background supporting our decision on this matter, which is not reflected in the text of our prior CHP decisions, the MPR is intended to represent the long term market price of electricity for fixed price contracts. (Pub. Util. Code, § 399.15, subd. (c)(1).)"[18/]

15. With the statutory amendments set forth in SB 2 1X, parties are provided with an opportunity to offer additional comments on the impact of federal law (FERC Order 134 ¶ 61,044 – Order Denying Rehearing) on the implementation of 399.20. It is not necessary to reiterate the positions set forth in the March 11 briefs. Please indicate how those positions have changed, if at all.

RESPONSE: SDG&E's position has not changed from that set forth in its March 11 brief.

16. Parties are requested to comment on this proposal. ***(ruling identifies the following provisions to be implemented by end of 2011: determine price; eliminate separate tariffs; eliminate retail customer requirement; increase facility size to 3 MW; adjust program cap to 750 MW; the 10-day internet posting requirement for new tariff requests; the exemption for small electric utilities, and coordination with publicly owned utilities)***

RESPONSE: SDG&E generally agrees with the schedule set forth in the ALJ Ruling, but recommends that (i) denial of tariff requests (§399.20(n)); (ii) contract termination provisions (§399.20(1)); and (iii) refunds of other incentives (§399.20(k)) be included as provisions to be

[17/] D.11-04-03, *mimeo*, pp. 21-22.
[18/] *Id*. at p. 23.

implemented by the end of 2011. These are critical contract terms that are inextricably linked to the other provisions of the FIT contract. The public interest clearly will not be served by implementation of the FIT contract on a piecemeal basis. This approach will cause further delay in implementation of SB 32.

17. Explain any further issues to be considered on capacity limitation under this program and next steps necessary to implement the provision. To implement § 399.20(b)(2), tariff language and form contracts may need to be amended. The investor owned utilities should submit tariff changes or revised contract language, if any, to implement this change with comments on July 21, 2011 and July 28, 2011.

SDG&E RESPONSE: As SDG&E explained in its March 11 brief, the Commission has discretion to reduce three MW capacity limit to maintain system reliability. While § 399.20(b) increases the capacity limitation of eligible projects to 3 MW, § 399.20(j)(2) authorizes the Commission to reduce the 3 MW capacity limitation for a particular electric corporation if such reduction "is necessary to maintain system reliability within that electrical corporation's service territory."[19]

Section 399.20(j)(2) makes clear that the FIT program must take into account the realities of electrical corporations' *existing* distribution and transmission systems, and tailor the FIT capacity limitation to match the particular characteristics of an electric corporation's system. The characteristics of each utility's system are unique; the capabilities of one utility's distribution system are not necessarily indicative of the capabilities of another utility's system. Plainly, a larger facility will have a greater impact on utilities with lower voltage systems than it would on a utility with more robust and higher voltage systems. Accordingly, the impacts of a 3 MW facility on resource planning or the distribution system will be more burdensome for SDG&E than they would be for the other California investor-owned utilities ("IOUs")

[19] *See also* § 399.20(n)(2) (providing that an electric corporation may deny a FIT request if it determines that the transmission or distribution grid that would serve as the point of interconnection is inadequate).

SDG&E can sufficiently manage system impacts and reliability risks for projects sized at or below 1.5 MW, due to their smaller scale. As project size increases beyond the 1.5 MW threshold, however, the probability that system upgrades will be required also increases. SDG&E has already observed significant voltage fluctuations on its distribution system with a generator connected under the California Solar Initiative ("CSI") program at the 1 MW level. To achieve the streamlining benefits of the FIT program, a project must be small enough that it is realistic to expect that it will be able to generally avoid the regulatory and market hurdles associated with larger projects. Granting FIT eligibility to projects that are too large to effectively participate will bog down the FIT administration process and will threaten the ongoing viability of the FIT program.

While a project sized at the current 1.5 MW FIT limit may present some challenges, maintaining this limit will ensure that excessive costs and operational constraints are avoided. Projects greater than 1.5 MW will likely be sited in SDG&E's back-country areas, where there is available land. The limitations inherent in SDG&E's distribution system are likely to be particularly evident in these rural areas. SDG&E provides service to its customers located in rural areas through long radial circuits using small conductors sized to accommodate the load. Much of the distribution system in these areas was designed for low peak loads and was radially constructed with smaller substations, relatively longer circuits, and smaller conductors when compared to circuits constructed in urban areas (*i.e.*, 10 MW urban feeder vs. 3-5 MW rural feeder).

This type of distribution system design makes it difficult to interconnect substantial or large quantities of distributed generation that is not located relatively close to a substation, without requiring substation expansions. In the case where the distributed generation is not sited near a substation, conductor upgrades and voltage mitigation measures are likely to be required. A 3 MW photovoltaic generation system located in a rural area, for example, could require replacement of existing conductors and equipment, which could include overhead poles or underground conduit to accommodate the larger conductors. Replacement of overhead conductors and poles could cost up to $1 million per mile, and installation of underground conduit and cables could cost up to $1.4 to $1.7 million per mile (depending on the size conductor required) to replace existing conductors.[20] In addition to issues related to substation and feeder capacity, minimum loading of a substation or feeder is a critical factor in determining how much distributed generation may be allowed to interconnect to the distribution system. In the worst case scenario, if minimum loads at a substation or circuit fall at or below 3 MW, the distributed generation will dominate the substation or circuit voltage, thus affecting the stability of the local distribution system.

For example, as of July 7, 2011 SDG&E has received 30 WDAT Interconnection Request ("IRs"). Fourteen of these IRs are between 1.5 MW and 3.0 MW; one IR is for 1.5 MW. None of the IRs met the WDAT screening requirements to be considered for Fast Track Processing. All 30 IRs are located in rural substation and circuit areas of SDG&E's service territory. Table 1 below shows actual 3 MW and below interconnection request projects sizes, substation area locations, and percent penetration impact of the project on circuits. Thirteen of the fifteen projects exceed 100% penetration.

[20] These cost estimates are broad conceptual estimates and could vary in each individual case. Development of more precise estimates would require consideration of individual cases.

Table 1
Actual Interconnection Projects 3 MW and Below

Area	Project size, MW	Circuit #	Light load demand, MW	% Penetration, project/light load
Rural	2 MW	C1215	0.59 MW	338%
Rural	2 MW	C211	0.22 MW	909%
Rural	2 MW	C441	0.63 MW	317%
Rural	2 MW	C222	1.8 MW	111%
Rural	2 MW	C220	0.64 MW	313%
Rural	2 MW	C448	1.14 MW	175%
Rural	2 MW	C157	1.39 MW	144%
Rural	2 MW	C449	0.71 MW	282%
Rural	2 MW	C217	1.23 MW	120%
Rural	2.5 MW	C444	0.52 MW	481%
Rural	2 MW	C171	1.66 MW	120%
Rural	1.5 MW	C909	1.08 MW	139%
Rural	2 MW	C909	1.08 MW	139%
Rural	2.5 MW	C249	2.67 MW	94%
Rural	2 MW	C908	3.06 MW	65%

In short, accommodating projects greater than 1.5 MW in many cases will necessitate system upgrades and the associated planning studies, which can be costly.[21/] Given the unique characteristics of SDG&E's system and the likelihood of significant system upgrade costs as project size increases beyond the 1.5 MW threshold, the Commission should exercise its authority to maintain a 1.5 MW project size limitation for SDG&E's FIT. This proposal maintains the benefits of the existing FIT program, while recognizing the realities of SDG&E's distribution system limitations. Limiting the FIT program to 1.5 MW throughout the SDG&E service area would be administratively simpler and would reduce the overlap between the FIT program and other renewable procurement programs, such as the Renewable Auction

[21/] SDG&E notes further that increasing deliveries of PV generation under the FIT may impact SDG&E's ability to integrate additional PV generation under programs such as the California Solar Initiative ("CSI").

Mechanism ("RAM") or the standard Renewables Portfolio Standard ("RPS") Request for Offers ("RFO") process, which set minimum project size at 1 MW and 1.5 MWs respectively.

Should the Commission, nevertheless, elect to require an increase in eligible project size beyond this 1.5 MW threshold, several additional contract terms and conditions will become necessary. For example, contracts for projects sized at 1.5 MW or higher will require provisions that ensure that the generator continues to bear the costs for system upgrades; if a generator finds that its interconnection costs exceed its compensation under the FIT, the additional cost should not be shifted to utility ratepayers. Similarly, project larger than 1.5 MW should be subject to the security requirements included in the standard RPS RFO. With greater size comes greater impact to ratepayers if the project fails; the potential for failure of these projects creates the same need for security as does failure of standard RPS RFO projects. SDG&E identifies below several new contract provisions that will be required in the event the Commission requires SDG&E to increase its eligible project size above the current 1.5 MW:

- Generator to bear the costs for system upgrades
- Security requirements similar to the standard RPS RFO
- Delivery guarantees and damages provisions
- CAISO penalty provisions
- Events of default provision such as that contained in SDG&E's pro forma RPS contract
- Technology-specific terms (*e.g.*, dealing with intermittent renewables versus dispatchable renewables)
- More defined milestone/schedule provisions
- Separate interconnection agreement to allow for more efficient administration of interconnection and purchase power agreement[22/]

18. Explain the drawbacks and benefits to relying on the existing methodology for calculation of proportionate share. Does the statute require a recalculation of proportionate share based on the addition of publicly owned utilities? Would the Commission's calculation of proportionate share for local publicly owned utilities be restricted by any jurisdictional limitations?

[22/] As discussed herein, SDG&E proposes that all interconnection requests be made through the WDAT process rather than the current Rule 21 process.

RESPONSE: The calculation of the proportionate share must take into account the addition of the publicly-owned utilities ("POUs"). Section 387.6, added to the Public Utilities Code by SB 32, extends the FIT requirement to POUs. The provision requires each POU to make its FIT available until the POU has met its proportionate share of the statewide 750 MW cap. Section 399.20(f) requires each electrical corporation to make its FIT available until the electrical corporation has met its proportionate share of the statewide cap of 750 MWs served under § 399.20 and § 387.6.

19. **Based on the language of § 399.20, it appears reasonable to direct electric corporations to consolidate the two rates schedules. Consolidation of tariffs may decrease transaction costs by simplifying the administration of the program. This ruling proposes to implement this provision by end of 2011. Explain the next steps necessary to implement this request.**

RESPONSE: SDG&E's electric tariff currently includes its WATER tariff schedule, which implements AB 1969, and its CRE tariff schedule, which extended the provisions of the WATER tariff schedule to all SDG&E retail customers in accordance with the Commission direction in D.08-09-033. SDG&E proposes that its WATER tariff schedule be eliminated and its CRE tariff updated to reflect the requirements of SB 32.

20. **399.20 apply to those that are not retail customers of the electrical corporation and also to those that are not owners or operators of the electric generation facility. This ruling proposes that the Commission implement this provision by end of 2011. Explain the next steps necessary to implement this provision, what modification to tariffs are needed to reflect this change, and what changes to the form contract might be required.**

RESPONSE: The FIT should set forth eligible facility requirements that are consistent with SB 32. The eligibility criteria contained in the current FIT should be revised, for example, to:

- Eliminate the retail customer requirement;
- Implement the eligible facility requirements included in § 399.20(b); and

- Implement an eligible facility requirement consistent with § 399.20(f), which requires electrical corporations to make the FIT available "to the owner or operator of an electric generation facility ***within the service territory of the electric corporation***. . ." Thus, the eligible facility requirements listed in the FIT should include the requirement that the facility be located in the electric corporation's service territory.

21. SB 32 added the requirement to § 399.20 that the "owner of the electric generation facility receiving a tariff pursuant to this section shall provide an inspection and maintenance report to the electrical corporation at least once every other year." This requirement was added at subsection (p) of § 399.20. SB 2 1X did not modify this requirement. This ruling proposes that the Commission not implement this provision by end of 2011 and, to instead, address this matter at the beginning of 2012. Parties are asked to comment on this recommendation.

RESPONSE: SDG&E agrees with the proposal to address this matter at the beginning of 2012.

22. 10-day Reporting Requirement of Request for Service under Tariff. This ruling proposes to implement this provision by end of 2011. Parties are asked to comment on this recommendation. This implementation will primarily rely on the reporting format that the Commission already requires, with the specific changes to reflect SB 32. This ruling also anticipates by the end of 2011 clarifying, as requested by PG&E, whether the compliance period is 10 business days or 10 calendar days. PG&E also requested the Commission explain the event which starts the counting of this 10 day compliance period. This too will be addressed within 2011.

RESPONSE: Section 399.20(m) requires electric corporations to post a copy of each FIT request on its Internet website within 10 days of receipt of such request. While this requirement is not objectionable -- provided that it is consistent with confidentiality requirements -- it raises the practical question of what constitutes a "request" triggering a posting requirement.

SDG&E proposes that a "request" be defined as the execution of tariff contract. Category VIII(A) of the Confidentiality Matrix adopted in D.06-06-066, *et seq.*, treats bid data as confidential until contracts are submitted to the Commission. FIT participation requests are akin to bid data where they are not automatically accepted – it is necessary to confirm that eligibility requirements, etc. have been satisfied. Accordingly, the disclosure required under § 399.20(m) should not be triggered until the FIT contract has been executed.

In addition, since SDG&E is proposing that these requests become part of the interconnection queue, SDG&E submits that the utilities should also have the option of charging a bid fee to discourage speculative requests. Speculative and phantom bids clog up the queue and prevent viable developers from interconnecting. Finally, SDG&E recommends the compliance period be 10 business days rather than calendar days.

23. Section 387.6 requires a local publicly owned electric utility to offer a tariff to owners or operators of electric generation facilities within its service territory. It is reasonable to anticipate that certain issues to be resolved in implementing SB 32 and SB 2 1X for investor owned utilities may benefit from coordination with local publicly owned electric utilities. This ruling anticipates addressing these issues by the end of 2011. Identify any issues and explain why coordination would be helpful. Identify any potential matters that the Commission may address relative to § 399.20 that may impact the implementation of § 387.6. One issue already identified in March 2011 briefs is the calculation of proportionate share of the 750 MW program cap.

RESPONSE: SDG&E does not have comments on this issue at this time, but reserves the right to comment at a later date.

24. SB 32 added subsection (n) to § 399.20 to provide an electric corporation the ability to deny a tariff request by an electric generation facility in certain circumstances relating, generally, to compliance with the statute and ensuring the safety of the electric grid. This ruling proposes to not implement this provision by end of 2011. This issue will be addressed at the beginning of 2012. Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to deny tariff requests.

RESPONSE: SDG&E recommends implementing this provision by 2011. It is essential that the IOUs have that ability to deny tariff requests that threaten to interfere with the reliability and safety of the electric grid. Likewise, eligibility is critical components of the FIT contract; the contract cannot be effectively implemented without this essential component.

§399.20(n) expressly confers upon electrical corporations the discretion to deny a FIT request under the following circumstances: 1) The electric generation facility does not meet the requirements of § 399.20; 2) The transmission or distribution grid that would serve as the point of interconnection is inadequate; 3) The electric generation facility does not meet all applicable state and local laws and building standards, and utility interconnection requirements; and/or 4) The aggregate of all electric generating facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system.

In addition, § 399.20(f) makes clear that utilities are required to make the FIT available only "to the owner or operator of an electric generation facility within the service territory of the electric corporation. . ." Thus, an additional ground for denial of an FIT request is location of the electric generation facility outside the utility's service territory.

More generally, in implementing § 399.20(n), the Commission must clarify the obligations of the utility related to each of the enumerated grounds for denial. First, with regard to the second and fourth grounds listed above, the Commission should make clear that the determination regarding (i) the adequacy of the transmission or distribution grid that would serve as the point of interconnection; and (ii) whether the aggregate of all electric generating facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system will be made in all cases by the utility. Second, the ability to deny a FIT request on the first and third grounds should not be interpreted as an affirmative obligation on the part of the utility to "police" sellers in order to ensure compliance with § 399.20, other state and local laws, and/or applicable building standards. While the utility may require sellers to warrant that they are in compliance with all relevant laws and standards, and may cite such compliance as a condition of eligibility for the FIT, the Commission should not require the utility to independently certify compliance by the seller or to monitor compliance on an ongoing basis.

With regard to the existing procedures used by SDG&E to deny FIT tariff requests, SDG&E notes that it would deny a FIT participation request if, for example, if the customer did not meet the eligibility requirements or if SDG&E had exceeded its maximum capacity threshold.

25. SB 32 added subsection (l) to § 399.20 to provide for contract termination before the contract expiration date in certain circumstances. SB 2 1X makes no modifications to this subsection. This ruling proposes to not implement this provision by end of 2011. This issue will be addressed at the beginning of 2012 Parties are asked to comment on this recommendation. Also, explain the existing procedure relied upon by electric utilities to terminate contracts.

RESPONSE: The grounds upon which a FIT contract may be terminated is plainly a critical component of the FIT contract, which should be implemented by the end of 2011. New termination provisions must be part of any new FIT contract. Existing procedures relied upon by SDG&E include an "events of default" provision, such as that contained in SDG&E's *pro forma* RPS contract.

26. SB 32 added subsection (e) to § 399.20 to provide that an electric corporation shall provide expedited interconnection procedures for a facility that is connected on a distribution circuit and generate electricity in a manner to offset peak demand on the electric circuit. This ruling proposes to not implement this provision by end of 2011. This issue will be addressed at the beginning of 2012. Parties are asked to comment on this recommendation.

RESPONSE: SDG&E agrees with the proposal to address this matter at the beginning of 2012.

27. SB 380 amended § 399.20 to add subsection (h), which authorized the Commission to modify or adjust the applicability of § 399.20 for any electric corporation with less than 100,000 service connections, as individual circumstance merit. SB 32 moved this provision to subsection (c) but left the language essentially unchanged. This ruling anticipates addressing these issues by the end of 2011. Parties are asked to comment on this recommendation.

RESPONSE: SDG&E does not have comments on this issue at this time, but reserves the right to comment at a later date.

28. SB 32 added subsection (k) to § 399.20 to require owners of eligible generation facilities to refund any incentives received from the California Solar Initiative or the Small Generator Incentive Program. This ruling proposes not to implement this provision by

end of 2011. This issue will be addressed at the beginning of 2012. Parties are asked to comment on this recommendation.

RESPONSE: SDG&E proposes this provision be implemented by the end of 2011. In order to ensure timely implementation of SB 32, SDG&E recommends that contract provisions be addressed in the first phase – by the end of 2011.

SDG&E possesses the records necessary to identify and verify those customers who have been paid incentives through either the California Solar Initiative ("CSI") or the Self-Generation Incentive Program ("SGIP"), and could determine the proper incentive refund amount in the event these customers were to elect to participate in the FIT program. SDG&E agrees that customers who have participated in CSI or SGIP should refund prior incentives received in order to participate in the FIT. With regard to the relationship between the FIT and the net energy metering ("NEM") program, customers should have the option of participating in either the FIT or NEM program, but should not be permitted to participate in both programs. Consistent with the policy underlying refund of the CSI and SGIP incentives, customers cannot receive the economic benefits of bypassing fixed costs in variable rates (*i.e.*, residential Tiers 3 & 4) through NEM and then also participate in the FIT.

Respectfully submitted this 21st day of July, 2011.

/s/ *Aimee M. Smith*
AIMEE M. SMITH
101 Ash Street, HQ-12
San Diego, California 92101
Telephone: (619) 699-5042
Facsimile: (619) 699-5027
amsmith@semprautilities.com

Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY