Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application 11-10-002
Exhibit No.: (SDG&E-205)

PREPARED REBUTTAL TESTIMONY OF

DAVID T. BARKER

CHAPTER 5

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

JULY 17, 2012

SDG&E #269287

TABLE OF CONTENTS

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(CHAPTER 5)

I. OVERVIEW

The purpose of my testimony is to reply to the opening testimony of the Division of Ratepayer Advocates (DRA), the California Farm Bureau Federation (Farm Bureau), the Solar Energy Industries Association (SEIA), and the San Diego Solar Coalition (SDSC) regarding marginal commodity costs, specifically: generation capacity costs (MGCC) and marginal energy costs (MEC). For all of the reasons discussed below, the Commission should adopt SDG&E's marginal commodity cost proposals in my prepared direct testimony.

My testimony reaches the following conclusions with regard to DRA's position that SDG&E's proposed marginal generation capacity costs are <u>overestimated</u>:

- SDG&E generally agrees with DRA's theoretical position that MGCC should be reduced for current excess system capacity;
- DRA misstates the Commission position on the issue by ignoring avoided cost decisions;
- Adopting DRA's theoretical position would diverge from Commission guidance on demand response impacting demand response (DR) programs considered in this proceeding;
- DRA's position does not account for the current regulatory and practical conditions in which SDG&E operates, where SDG&E must add capacity to meet the State's Greenhouse Gas (GHG) policies;
- For all of these reasons, the Commission should reject DRA's proposed modifications.

In addition, my testimony reaches the following conclusions with regard to SEIA's position that SDG&E's proposed marginal generation capacity costs are <u>underestimated</u>:

- Statewide California Energy Commission (CEC) costs of generation overestimate the marginal generation capacity costs for purposes of this proceeding, by averaging in high-cost plants built elsewhere in the state (outside of San Diego) and by calculating costs on a levelized nominal basis,[1] not a real economic carrying charge (RECC)[2] basis;
- The SEIA adjustment for dry cooling is already incorporated into SDG&E's proposed marginal generation capacity costs and thus should not be included a second time;

[1] Levelized nominal costs are flat over the entire life of the project and thus are high in early years and lower in later years compared to costs of other goods and services that change with inflation.
[2] RECC costs are the same project costs spread over the life of the project except they account for inflation, escalating over time.

- Therefore, the Commission should reject SEIA's proposed modification.

Finally, my testimony continues to support SDG&E's proposed marginal energy costs and reaches the following conclusions with regard to DRA, the Farm Bureau, and SEIA's positions that MEC should have a different hourly shape:

- The proposed alternate proposals all have features that are desirable;
- Therefore, it is a Commission decision regarding how much weight to give to geographic and utility specificity and whether at this time to consider future changes in marginal energy costs due to GHG and renewable portfolio standard (RPS) policies.

II. MARGINAL GENERATION CAPACITY COSTS

For certain long-term purposes, SDG&E generally agrees with DRA that "marginal generation capacity costs should signal the amount of surplus capacity and timing of new additions" (DRA/Levin at 2-6), a position also supported by the Farm Bureau (Farm Bureau/Illingworth at 3-4). For example, in analyzing the cost effectiveness of long-lived assets such as energy efficiency measures or distributed generation, the Commission rightly considers near-term surplus in its calculations of avoided generation capacity costs.[3] However, the Commission has chosen not to consider short-term conditions for short-term programs like demand response (DR) programs, as described below. For DR, a program lasting only three years (2012-14), the Commission chose a long-term approach that ignored short-term surplus of capacity.[4] The GRC Phase 2 likewise considers only 2012-2014 and uses MGCC directly in calculating the price to be paid for critical peak pricing demand response. The Commission should therefore adopt a similar approach here to maintain consistency in the pricing of DR programs across proceedings.

Even if the Commission were to adopt an approach to MGCC that considered short-term and long-term considerations, DRA's approach has less support than the methods used in EE and DG cost effectiveness. Unlike in the 1990s Commission cases DRA cites, SDG&E does not own all generation to serve its customer load. Rather, SDG&E acquires capacity and energy from the market; every year SDG&E must acquire local and system capacity on behalf of its customers. A better approach would be based on market conditions and develop a weighted average of expected

[3]As described below, avoided generation capacity costs in those applications is the same as marginal generation capacity costs in this proceeding. *See* Commission staff presentation at demand-side cost effectiveness workshop, June 28, 2012, slides 11-14, for a discussion of short-term and long-term considerations present in current cost effectiveness calculations across proceedings. The approach for DG was adopted in D.09-08-026 and for EE in D.12-05-015.
[4] D.10-12-024 at 14.

costs of acquiring capacity in a surplus market and would not simply discount the cost of new capacity from some point in the future.

A. DRA's Approach Is Not Consistent with Current Commission Policy on Avoided Cost.

DRA states at page 2-2, line 13, that "SDG&E neglects to consider the key fact that the Commission has a long history of adjusting the CT deferral value downward, reflecting a reduced … [MGCC] when surplus capacity exists." However, there is no such "long history." DRA's citations simply reflect Commission decisions from a long time in the past. The record of Commission decisions cited by DRA are mostly two decades old, with the most "recent" being a 16-year-old decision.

DRA states it cannot cite to more recent Commission guidance because of "a hiatus during electric industry restructuring" and the fact that all recent General Rate Case Phase 2 (GRC Phase 2) proceedings have been decided by settlements.[5] However, DRA has taken a limited view of where the Commission has addressed the issue, reviewing only GRC Phase 2 and Rate Design Window proceedings. A more expansive approach to marginal costs would also look to what the Commission has decided in avoided cost proceedings, recognizing the close relationship between marginal costs and avoided costs. Economist Alfred Kahn[6] described this relationship as follows:

> As almost any student of elementary economics will recall, marginal cost is the cost of producing one more unit; it can equally be envisaged as the cost that would be saved by producing one less unit. Looked at the first way, it may be termed incremental cost - the added cost of (a small amount of) incremental output. Observed in the second way, it is synonymous with avoidable cost - the cost that would be saved by (slightly) reducing output.[7]

The Commission recognized this relationship first in its definition of marginal costs in 1981[8] and more recently in Southern California Edison's GRC Phase 2 Decision, 06-06-027, stating:

> The Settlement Agreement does use generation marginal capacity cost based on the deferral values of a gas-fired combustion turbine (CT), and installation cost based on annualized Real Economic Carrying Charge methodology. Although we are adopting the Settlement Agreement without change, we note that in Rulemaking (R.) 04-04-025 <u>we are reviewing the various methodologies for determining avoided costs</u> including the use of a CT proxy. Therefore, our adoption of this methodology as used in the Settlement Agreement for this

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[5] DRA, p. 2-2.
[6] DRA relies extensively on Kahn as an economic authority citing his work at 1-10, 1-11, 2-10, and 2-11.
[7] Kahn, pp. 85-86. SDG&E recognizes there can be differences in terms of sunk costs, but that does not apply to the Commission determinations cited herein.
[8] Cited by DRA at page 1-7, lines 8-12.

> proceeding should not be considered precedent, as further review and analysis may indicate a change is warranted. [Emphasis added.]

In the above-referenced avoided cost proceeding, R. 04-04-025, Phase 2, SDG&E proposed an Energy Reliability Index similar to that described by DRA to adjust for the existence of near-term surplus capacity.[9] However, the Commission rejected the proposal. In D.09-07-040 at page 91, the Commission determined the avoided cost should be based solely on the net cost of capacity:

> Payments for as-available capacity will be based on the fixed cost of a Combustion Turbine (CT) as proposed by The Utility Reform Network (TURN), less the estimated value of Ancillary Services (A/S), as proposed by San Diego Gas & Electric Company (SDG&E) and capacity value that is recovered in market energy prices, as proposed by TURN and SDG&E.

The avoided cost of capacity was determined to be the annual cost of a combustion turbine calculated using a real economic carrying charge (RECC), adjusted for energy and ancillary service value - - with no adjustment for surplus capacity.

More recently, in D.10-12-024, the Commission addressed the issue of the use of short-term considerations in avoided costs in the cost effectiveness of Demand Response programs. The Commission specifically rejected the DRA theoretical position, instead considering only long-term considerations:

> In comments on the proposed decision, DRA and TURN expressed concern that the long-term costs reflected through this method are higher than short-term prices in the bilateral Resource Adequacy market. Both DRA and TURN argue that short-term prices can be much lower when available capacity resources substantially exceed forecasted peak loads; these parties support the use of short term prices in the cost effectiveness analysis as either the primary avoided cost input or as part of the sensitivity analysis. <u>We believe that use of long-term avoided costs are consistent with Commission energy policy for Demand Response activities</u>,…" [D.10-12-024 at 12-13, emphasis added]

The Commission thus explicitly rejected the well-reasoned theoretical arguments of DRA, the same arguments offered here, that short-term avoided costs that reflect surplus conditions should be considered in determining avoided costs for short-term programs such as DR. Since marginal

[9] See DRA, pages 1-8, line 24 through 1-9, line 32 for a detailed description of the Energy Reliability Index.

costs are the flip side of avoided costs in this particular instance, and the application of the MGCC in this proceeding is similar to avoided cost in the DR proceeding, DRA's contention that Commission policy takes short-run surplus capacity into account is incorrect.[10]

B. DRA's Theoretical Approach Is Not Consistent with the Commission's Policy on Demand Response.

D.10-12-024 is also important because SDG&E's GRC Phase 2 proposals implement critical peak pricing (CPP) programs. Here, the MGCC flows through to the determination of the size of the critical peak price, the price charged for usage on-peak on high-demand days. If the DRA proposal were adopted, the critical peak price would be reduced proportionally.[11] This would create a situation where DR programs approved in D.12-04-045 receive a value consistent with long-term avoided costs, while programs approved in this proceeding would receive a lesser value. This approach would make DR programs based on price response the poor sister of DR based on load reduction in response to a utility or California Independent System Operator (CAISO) request. It would not be consistent with the Commission's DR policies to adopt DRA's position.[12]

C. Joint Production of Low Carbon Energy and Capacity

DRA's analysis is based on a world where capacity is only acquired when needed. But this is not the world in which SDG&E operates. DRA bases their calculation of MGCC on a current surplus of capacity, but SDG&E is now required to sign purchase power agreements <u>regardless of the level of generation surplus</u> due to the State's GHG policies.[13] Both the 33 percent RPS and the QF Settlement adopted to implement AB 32 require SDG&E to obtain energy that has low carbon content.[14] In the process, SDG&E is also acquiring capacity since capacity and energy are jointly produced in variable renewable generation and must-take combined heat and power (CHP) generation. The amount of capacity produced in relationship to energy produced varies with each of the different technologies. Under DRA's theoretical approach, the cost of the capacity acquired

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[10] It should be noted that avoided costs and marginal costs can differ in other instances where cost drivers are not the same. For example, the marginal costs of distribution may be different than avoided costs where a significant cost driver in new business. Marginal costs will include the cost of poles and wires to connect new customers, while avoided costs associated with energy efficiency will not avoid the poles and wires.

[11] This statement does not consider the short-term impact of the SONGS outage since a decision in this proceeding would not take effect until 2013.

[12] It would also create a conundrum - where capacity surplus would be reduced since there would be less DR than forecasted, moving capacity additions forward in time, closer to the present.

[13] This view is supported by SEIA testimony at pp. 41-43. The statement regarding generation "surplus" is based on average year conditions in California and does not consider local issues nor the impact of a prolonged SONGS outage.

[14] California Air Resources Board, Climate Change Scoping Plan, adopted December, 2008, adopted a 33% RPS measure and a CHP measure. SB 1X 2 adopted the 33% RPS which is being implemented in R.11-05-005. D.10-12-035 adopted a process to acquire low-emitting CHP to implement the ARB CHP scoping plan measure.

on behalf of customers in the current year would not be taken into consideration. This would provide a "free ride" to customers with low load factors at the expense of other customers. Thus, under DRA's proposal, customers who contribute disproportionately to peak demand would receive all of the benefits of the GHG-related capacity additions without paying a fair share of the costs.

D. Planning Reserve Margin

DRA proposes that the MGCC value include a 15 percent premium to account for the planning reserve margin (PRM) of 15 percent, stating:

> DRA notes that the MGCC value proposed by SDG&E excludes a resource adequacy adder. Such an adder should be included to reflect the fact that each additional kW of customer demand causes the need for 1.15 kW of additional generation capacity. This is a result of a requirement, instituted in the Commission's Resource Adequacy proceeding, that utilities maintain a planning reserve margin of at least 15%. [DRA/Levin at 2--11.]

SDG&E views the MGCC as a measure of the <u>cost</u> of adding generation capacity. The 15 percent planning reserve margin (PRM), on the other hand, is a <u>quantity</u> of generation capacity. The MGCC presented by DRA in SDG&E's last several GRC Phase 2 proceedings did not include a 15 percent PRM adder even though DRA states it has been a requirement since 1996.[15]

But even if MGCC is characterized as "incremental costs incurred to meet an additional kW of customer demand," as DRA argues (p. 2--12), the 15 percent should be applied only if the incremental demand is for system capacity. If the customer incremental demand is causing a need for local capacity and/or flexible capacity, there should be no 15 percent added capacity requirement since it does not trigger additional purchases of capacity for resource adequacy. SDG&E's analysis in other proceedings has shown its near-term demand for capacity is for local capacity.[16] There is also arguably a near-term need for flexible capacity according to the CAISO analysis.[17] The 15 percent adder does not reflect the type of need for capacity in 2017, is not consistent with DRA's position in prior SDG&E GRC Phase 2 proceedings, and should not be adopted by the Commission.

E. MGCC Costs

While DRA does not dispute SDG&E's calculation of the cost of a combustion turbine, SEIA argues that the proposed cost is underestimated. SEIA first cites data from the CAISO that

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[15] DRA/Levin at 2--12.
[16] Prepared Supplemental Testimony of Robert Anderson, A.11-05-023, April 27, 2012.
[17] Presentation by Mark Rothleder, Executive Director Market Analysis and Development, CAISO, at California Energy Commission 2012 IEPR Workshop, June 11, 2012, slide 8.

the cost of capacity is $163.03 based on the levelized cost of a combustion turbine of $211.70 and energy market earnings offset of $48.67.[18] The two problems with the calculation is that the CAISO relies on a CEC Cost of Generation study that overestimates the cost of generation in San Diego and the more serious problem of using a levelized nominal cost instead of a real economic carrying charge (RECC) approach. Footnote 31 of the CAISO Annual Report clearly states the basis of the calculation is the CEC Cost of Generation study. The difference caused by using a levelized nominal cost compared to the calculation based on the RECC can be seen in SEIA's own calculation of the cost based on an RECC approach, $174.21 versus $211.70. If the CAISO had used an RECC approach, the net cost of capacity would have been $125.54 ($174.21 – $48.67), close to the value proposed by SDG&E.[19] The levelized nominal cost averages the cost of the generation over 20 years without considering inflation. This front loading of costs yields an overestimate of the cost of deferring capacity. The RECC approach, on the other hand, escalates the cost of the marginal resource annually with inflation over the life of the resource; the RECC approach reflects the cost from not delaying investment in new generation plant.

The CEC Cost of Generation overestimates the cost of generation in San Diego by including high cost plants in other areas of California. While the instant cost averaged $1,277 in the CEC database of CTs in California, the four combustion turbines in SDG&E territory averaged $916.[20]

SEIA justifies the higher installed cost because it assumed SDG&E did not consider dry cooling,[21] but my direct testimony shows that dry cooling was specifically included:

> Miramar II is representative of the future costs of new capacity in the San Diego area, compared to the CEC estimate that is an average over all of California. … Miramar II is different in two ways from the assumed CT addition – it uses wet cooling and has black start capability. An assumption was made that dry cooling costs would be similar to the costs of providing black start capability, <u>so that Miramar II's costs would be representative of a CT with dry cooling and without black start capability</u>**.** [SDG&E/Barker Direct at DTB-7, fn.6 (emphasis added).]

The SEIA adjustments of the SDG&E estimate of $120/kW should be ignored as inaccurate.

Although SDSC does not question the MGCC calculation directly, they use a value for MGCC based on the CEC Cost of Generation study and do not include an offset for energy market

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[18] SEIA/Beach at 43-44.

[19] In the procurement context that considers all 20 years, the RECC approach and the levelized nominal yield the same net present value, so use of either RECC or levelized nominal are appropriate.

[20] The $916/kW figure is based on an average of Miramar I, Orange Grove, MMC Escondido, and MMC Chula Vista adjusted to 2009 dollars using the GDP deflator. The costs are based on Table C-24 of the 2009 CEC Cost of Generation Report.

[21] SEIA/Beach at 44, lines 14-19.

earnings.[22] For the reasons cited above regarding the CEC study, plus the general agreement of all other parties to the proceeding that energy market earnings should be deducted, SDSC's calculation of MGCC and the resulting impact on rates should be recognized as significantly overstated.

III. MARGINAL ENERGY COSTS

Marginal Energy Costs (MEC) are composed of two elements – an expected average electricity price and an hourly price profile over the year. The two are multiplied together and aggregated into Time of Use Periods to calculate marginal energy costs. Three parties took issue with SDG&E's proposed hourly price shape (DRA, Farm Bureau, and SEIA), as discussed below.

My direct testimony provided a comparison of different approaches to determining hourly price profile, in Appendix B. There is no one right way to calculate the hourly price profile over 8760 hours in a year. All approaches rely on historical data, but the data can be evaluated for different geographic areas, and the data can adjusted for different factors such as gas price, weather, the amount of variable renewable energy on the grid, and future changes in the amount of variable generation. The level of transparency decreases as more adjustments are made and the complexity of the adjustment process increases. The tables below compare the proposals of the parties. The first table shows the numerical differences, while the second shows the methodology and data differences.

Table 1

			Summer			Winter	
Party	Model	On-peak	Semi-Peak	Off-peak	On-peak	Semi-Peak	Off-peak
SDG&E	SDG&E Internal	1.41	1.11	0.78	1.33	1.14	0.87
DRA	E3 Avoided Cost Calculator	1.33	1.08	0.87	1.27	1.06	0.89
Farm Bureau	SDG&E Production Cost Model	1.39	1.09	0.86	1.25	1.07	0.88
SEIA	SEIA SP-15 modified	1.32	1.01	0.78	1.34	1.16	0.93

[22] SDSC/Powers at 19, lines 13-14.

Table 2

Party	Model	Data Period	Gas Price Adjusted	Weather Adjusted	Geography	Markets Considered	Impact of Renewables Considered	Level of Transparency
SDG&E	SDG&E Internal	2009-2010	Yes	Yes	SDG&E	Day Ahead	No	Medium
DRA	E3 Avoided Cost Calculator	2009-2010	Yes	No	California	DA and RT	No	Medium
Farm Bureau	SDG&E Production Cost Model	2012	Yes	Yes	SDG&E	Day Ahead	Yes	Low
SEIA	SEIA SP-15 modified	2011-2012	Yes	No	Souther California	Day Ahead	No	High

DRA argues that the SDG&E approach is too simplistic in its adjustments for weather, but then chooses a method that does not consider the effects of weather at all.[23] CAISO has documented that the summers of 2009 and 2010 were cooler than normal and the CAISO associated (correlated) that with lower on-peak prices.[24] Approaches that do not make weather adjustments assume that weather going forward will be similar to weather in the year the data was collected.

While SDG&E does not object to using the hourly profile proposed by DRA, the analysis to get to its choice is flawed. DRA's comparisons with Southern California Edison (SCE) are not relevant and should be ignored. SCE has different definitions of TOU periods compared to SDG&E and DRA's comparisons incorrectly omitted a SEIA forecast because DRA deemed that forecast "too high." Next DRA incorrectly states, "SDG&E's Proposed MECs Have the Wrong Seasonal Profile."[25] It is unclear how DRA correlated season with price to say "it is not a normal or expected result." MEC is affected by two factors: 1) supply and demand conditions in the electricity market

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[23] DRA/Levin at 2--16 – 2--22.

[24] Contrary to DRA's statement, one can "'create' a correlation" without statistical analysis if there is a theory that would support the correlation. In this case, economic theory of competitive markets supports a positive correlation between the level of demand and prices without any statistical analysis of the proposition. If markets are competitive, then changes in demand move one along the supply curve so that exogenous increases in demand are positively correlated with price. SDG&E relied on the CAISO 2010 Market Issues and Performance Annual Report for the fact that markets during this time period were competitive. As stated on page 81, "The day-ahead integrated forward market has continued to be stable and competitive with virtually all loads and supply being scheduled in the day-ahead market." The CAISO Report also found lower loads responsible in part for lower prices. At page 57, "After accounting for higher gas prices, total wholesale energy costs decreased from $38/MWh in 2009 to $35/MWh in 2010, representing a decrease of over 7 percent in gas-normalized prices. A variety of factors contributed to the decrease in gas-normalized total wholesale costs in 2010. As highlighted in Chapter 2, fundamental demand and supply conditions favorable to lower prices in 2010 included: Lower loads, especially during the peak summer hours …." The CAISO 2011 Market Issues and Performance Annual Report found similar results. Again citing lower peak loads as a reason for lower prices, the CAISO states at page 50, "A variety of factors contributed to the decrease in gas-normalized total wholesale costs in 2011. As highlighted in Chapter 1, fundamental demand and supply conditions favorable to lower prices in 2011 included: Increased hydro-electric generation; Increased imports, particularly from the Northwest; and, Lower summer peak loads."

[25] DRA/Levin at 2--19.

and 2) input fuel costs. While demand conditions in the summer would suggest higher electricity prices, gas prices vary by month and are generally higher in the winter due to the increased natural gas demand for heating. The E3 avoided cost calculator has a relatively smaller winter gas price differential than the SDG&E model, but that cannot *a priori* be considered to be "right" and a higher seasonal gas price differential assumed to be "wrong." Indeed, the SEIA hourly price profile, based on 2011-2012 SP-15 prices also results in higher winter MEC value ($41.51) compared to summer value ($37.53). DRA's arguments do not fully account for the relevant factors affecting MEC and should be disregarded.

Finally, DRA rejects the SDG&E proposal because it does not include the impact of increased renewables; SDG&E agrees that its method does not include that impact. SDG&E's approach in this proceeding was to inform stakeholders of the future impacts of increased renewables on MEC as shown in Appendix A of my direct testimony, but not to incorporate those impacts on MEC and TOU periods until the next Rate Design Window or GRC Phase 2. If the Commission does want to consider those impacts, SDG&E agrees with the Farm Bureau that a different model should be chosen. The DRA's choice of the avoided cost calculator hourly profile also does not consider the impacts of renewables since it is based strictly on historical data. The production cost model, on the other hand, does consider the impact in 2012 and has slightly lower on-peak and higher off-peak factors than SDG&E's proposed approach. The E3 avoided cost calculator has a lower on-peak and higher off-peak due to other reasons.[26]

While SDG&E rejects the DRA assessment of the hourly price profile, each of the intervenors' approaches has some merit. Determining the appropriate method depends on the Commission's assessment of the various attributes of the different approaches identified in Table 2 above.

This concludes my prepared rebuttal testimony.

[26] By not considering weather during 2009-2010 and including the real-time market where prices often spike in off-peak hours when surprises happen, a flatter hourly profile occurs, but it is not due to consideration of added variable generation.