Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

ERRATA TO

CHAPTER 22

Prepared Rebuttal Testimony

of

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SAN DIEGO GAS & ELECTRIC COMPANY

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

SEPTEMBER 7, 2006

Revised: SEPTEMBER 19, 2006

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I.   Introduction

The purpose of my rebuttal testimony is to refute the erroneous conclusions of DRA and UCAN as they pertain to the derivation of the value of AMI enabled demand response and avoided generation capacity. DRA and UCAN address the net capacity value of a gas combustion turbine (CT) in their AMI capacity valuations. The net capacity value of a CT is generally accepted as the annual fixed costs of a CT minus the market energy benefits the CT could earn. My review of UCAN and DRA net CT value leads to the following conclusions:

- UCAN's net CT values are much larger once UCAN's energy benefits of a CT are corrected to a real 2006 value and adjusted for Southern California market conditions.

- DRA inflates the net market energy benefits for CTs based on a faulty assessment of SDG&E's methodology and inappropriately escalates SDG&E's value using an unjustified price ratio.

This traditional capacity valuation fails to address the Additional Value of AMI Enabled Demand Response.

An important element of SDG&E's capacity valuation is the Additional Value of AMI Enabled Demand Response. Just as the market energy benefit of a CT must be considered, the additional value of AMI enabled demand response must also be considered. This additional value is above and beyond the traditional net capacity value of a CT. The Additional Value of AMI Enabled Demand Response includes:

- Reduced Demand Volatility and Planning Reserves;

- Increase Rate Design Flexibility;

- Additional Reliability Value; and

- Other unique benefits of AMI.

1 These benefits are fully discussed in my July 14 testimony. Both DRA and UCAN

2 identify additional AMI benefits in their August 14 testimony. DRA describes the value

3 of Information Feedback Systems.[1] UCAN lists several benefits including a Consumer

4 Portal.[2]

5

6 My review of UCAN and DRA testimony leads to the following conclusions:

7

8 • All parties agree that the fixed capacity cost of a CT is at least $85/kW-year in

9   levelized nominal dollars.

10 • UCAN does not address or dispute the additional values proposed by

11   SDG&E; and

12 • DRA discounts SDG&E's additional values based on faulty logic and without

13   fully considering the potential benefits.

14

15 Once the issues regarding the additional value of AMI enabled demand response

16 and net CT value are considered, SDG&E's valuation is appropriate.

17 //

18 //

19 //

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[1] DRA, Analysis of SDG&E's AMI Business Case, 8/14/06, Ted Geilan, Chapter 10.
[2] UCAN, Summary of UCAN Testimony and Selected Issues Relating to Expenditures for SDG&E's 2006
AMI application, 8/14/06, pages 8 to 13.

1   Table JCM-1 below summarizes the position of SDG&E, DRA, and UCAN based

2 on direct testimony to date. SDG&E recommends a real 2006 value of $60/kW-Year

3 (equitant to a nominal levelized $85/kW-Year). DRA recommends a $52/kW-Year

4 value. UCAN proposes a real 2006 value range of $52/kW-Year or $20/kW-Year.

5   **Table JCM-1**

Capacity Value of SDG&E's AMI Enabled Demand Response
Comparison of Parties Values
(Summarized from Direct Testimony of Parties)

| | ($/kW-Year) | | |
	SDG&E	**DRA**	**UCAN**
Capacity Components:			
1. Avoided Fixed Generation Capacity	60.00	85.00	82 to 71
2. Gas CT Market Energy	-22.89	-35.37	-64 to -42
Net CT Cost	37.11	49.63	52 to 7
Additional Value of AMI enabled Demand Response:			
3. Resource Availability		-14.89	
4. Reduced Demd. Vol. & Planning Reserves	1.51	0.00	
5. Increased Rate Design Flexibility	13.79	7.50	
6. Additional Reliability Value (range)	0.021 to 0.53	0.021 to 0.53	
Calculated Sum	52.94	42.29 to 42.61	
7. Additional Unique Benefits	7.06	8.39 to 9.07	
Recommended Value	60	52	52 to 20

6
7 The following discussion points out various issues regarding each party's values.
8   1. Avoided Fixed Generation Capacity:
9   o SDG&E's $85/kW-Year nominal levelized value is equivalent to a
10               $60/kW-Year real escalating value as presented in table JCM-1.
11   o DRA accepts SDG&E's nominal $85/kW-Year value but includes real
12   escalating Additional Values in their analysis. DRA should not mix real
13   and nominal values.
14   o UCAN calculates real escalating values for fixed (gross) generation
15   capacity, but subtracts nominal levelized Market energy benefits. UCAN
16   should not mix real and nominal values.
17   2. Gas CT Market Energy:
18   o SDG&E calculates a $22.89/kW-year real escalating value based on data
19   used for SDG&E's 2004 Long Term Resource Plan filing.
20   o DRA adjusts SDG&E's real value to $35.37 based on a flawed
21   interpretation of SDG&E's methodology. Furthermore the adjustment
22   ratio used by DRA is also flawed.

JCM-3

    o

    o UCAN presents a range of nominal CT market energy benefits which are subtracted from their real capacity costs, resulting in a mismatch of real and nominal values.

3. Resource Availability:
   - SDG&E does not adjust AMI enabled demand Response for resource availability.
   - DRA reduces the resource availability based on faulty assumptions regarding CT reliability run hours and LOLP allocations assuming restricted operational parameters for Demand Response.
   - UCAN does not include a value but makes similar arguments as DRA using assumptions of restricted operations of Demand Response.

4. Reduced Demand Volatility & Planning Reserves:
   - SDG&E calculates a real $1.51/kW-year based on the ability of AMI enabled demand response to reduce the level of planning reserves by 1%.
   - DRA does not recognize this benefit.
   - UCAN does not address SDG&E's proposed values.

5. Increased Rate Design Flexibility:
   - SDG&E calculates a real $13.79/kW-Year value based on the additional value Real-Time pricing could provide above and beyond SDG&E's AMI proposal of CPP and PTR.
   - DRA recommends a real $7.50/kW-Year value by discounting SDG&E's value based on incorrect assumed market conditions, and the current long term generation contracts.
   - UCAN does not address SDG&E's proposed values.

6. Additional Reliability Value:
   - SDG&E proposes a range of value based on the ability of Programmable Communicating Thermostats (PCT)s avoiding un-planned outages.
   - DRA does not contest SDG&E's value.
   - UCAN does not address SDG&E's proposed values.

7. Additional Unique Benefits:
   - SDG&E does not quantify the additional unique benefits of AMI such as peak fuel diversity, reduction on market power of generators, smart home integration, and other demand side management innovations. The real 2006 value of $7.06 in Table 1 is calculated based on the difference in benefits proposed by SDG&E and SDG&E recommended real 2006 value of $60/kW-Year.
   - DRA does not quantify the additional unique benefits of AMI. The value in Table 1 is but based on the difference in benefits proposed by DRA and DRA recommended value of $52/kW-Year.
   - UCAN does not address SDG&E's unique benefits, but introduces several values from their Smart Grid proposals, such as a Consumer Portal.

1
2
3 **II.   SDG&E's Capacity Valuation of Demand Response Captures the Benefits**
4 **Unique to AMI and is the Best Methodology for Purposes of Analyzing AMI**
5 **Business Case**
6
7
8 **A. UCAN fails to the "do careful analysis that does not mix real and nominal**
9 **dollars"[3] they recommend the Commission must do.**

10 UCAN fails to perform its own careful analysis and mixes real and nominal

11 dollars, exactly what they caution against in Table 13 of their August 14, 2006

12 AMI analysis (page 116). Table 13 calculates a range of net CT costs two

13 different ways; as a nominal levelized cost, and as a real economic carrying

14 charge which escalates for inflation. Unfortunately, UCAN uses the same

15 nominal CT Market Earnings values to calculate both values. By doing so,

16 UCAN creates a fundamental mismatch with the energy costs.

17 The market energy values provided by UCAN are from a PG&E's filing,[4] and

18 from a UCAN CT dispatch analysis. The PG&E value is a nominal levelized cost

19 for 2008 through 2013.[5] The UCAN value is a nominal 2011 value using data

20 from their E3 avoided cost model. UCAN subtracts these nominal values from

21 their real CT fixed costs to incorrectly represent their real net CT costs. In other

22 words, UCAN has mismatched real escalating values (fixed CT costs) with

23 nominal levelized values (CT energy profits).

24
25 **B. UCAN over-estimates the real 2006 CT market earnings, by using**
26 **nominal values, thus UCAN under-estimates the real net CT cost.**

27 Three nominal estimates of CT market energy sales are provided by UCAN in

28 their Figure 8 (page 113). Figure 8 shows nominal values ranging from a low of

29 $51.90/kW-year, sourced from PG&E, to a high of $63.96/kW-year using 2011

30 nominal results from their E3 model modified for seasonal gas pricing.   These

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[3] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 109.
[4] UCAN, Analysis of SDG&E's AMI Application 8/14/06 (Attachment V: Attachment 4A - PG&E Phase 2 Testimony, Table 2-4, page 2-8).
[5] UCAN's attachment V page 2-7 and PG&E's Table 2-4, page 2-8.

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1   nominal values overestimate the real 2006 value. A real 2006 value is the

2   most appropriate comparison.

3   UCAN overestimated the real 2006 PG&E market energy benefits of a CT by

4    $5.24/kW-year.   I convert the nominal PG&E value of $51.90/kW-year to a real

5   2006 value of $46.66/kW-year using the NPV method illustrated in Table JCM-2.

6   The PG&E nominal value is a levelized six year value from 2008 through 2013.

7   My real 2006 $46.66/kW-year value escalating at 2.5% per year yields the same

8   six year NPV (2008 through 2013) as PG&E's nominal value over the same six

9   years. (51.90 – 46.66 = 5.24).

10   //

11   //

12   //

Table JCM-2

		CT Gross Profit ($/kW-Yr)	
Line No.	Year	PG&E's Nominal Levelized Cost*	Calculated Real Escalating Cost**
1	2006		**46.66**
2	2007		47.83
3	2008	51.90	49.03
4	2009	51.90	50.25
5	2010	51.90	51.51
6	2011	51.90	52.80
7	2012	51.90	54.12
8	2013	51.90	55.47
9	2008 NPV***	238.26	238.26

Comparison of PG&E's CT Gross Profit — Nominal vs. Real Values

* Source:UCAN, Analysis of SDG&E's AMI Application 8/14/06 (Attachment V: Attachment 4A - PG&E Phase 2 Testimony, Table 2-4, page 2-2) and (Figure 8: PG&E 2007 TY GRC Phase 2 Market Model, page 113).

** Annual escalation rate is 2.5%

*** Net Present Value in 2008 dollars for cost from 2008 to 2013, discounting at 8.23%.

Likewise UCAN overestimated the real 2006 E3 value of a CT by $15.10/kW-year. Using an E3 model similar to UCAN's model, I calculate the nominal 2011 UCAN value of $63.96 is equivalent to a real 2006 value of $51.70/kW-year. I expand the model to include all of E3's data from 2006 through 2030. Both UCAN's and my models produce similar nominal results for 2011. UCAN reports their E3 model results as $63.96/kW-year of CT profits in 2011 from running 1,600.[6] My E3 model results in a $66.80/kW-year of CT profits in 2011 from running 1,601 hours, or a real 2006 value of $51.70 when considering the more complete E3 data set.[7] My real 2006 value escalated at 2.5% annually, yields the same 2006 NPV as the nominal annual E3 results over the same time period (2006 through 2030). The lower real 2006 market energy benefits result in higher net CT costs.

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[6] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 112 and 113.
[7] Using the same operating parameters as detailed in footnote 100 on page 112 of UCAN Analysis of SDG&E's AMI Application 8/14/06. SDG&E uses city gate monthly varying gas prices, while UCAN uses Henry Hub TX based monthly varying gas prices.

1   **C. The E3 data shows that the CT market energy benefits are at least 5%**
2   **less in Southern California than Northern California.**

3   UCAN incorrectly argues that the similarity of its results and PG&E's option

4   model results makes a nominal $52/kW-year CT profit a "more robust" and

5   "independently confirmed" result.[8] On the contrary, the E3 data illustrates that

6   market differences exist between Northern and Southern California. UCAN's E3

7   model used Southern California data; where as, the PG&E option model uses

8   Northern California (NP15) data.[9] The similarity of UCAN and PG&E results

9   illustrate the random convergence of two different methodologies using different

10 data from different regions.

11   My calculations using the E3 Southern California market data shows 5%

12 lower CT market profits than the same model using market data from Northern

13 California. Table JCM-3 shows results from my E3 Northern and Southern

14 California models. The Northern CT runs more hours and produces more energy

15 benefits than the Southern CT. These results from the E3 model indicate that a

16 Southern California CT would earn about 5% less than a Northern California CT.

17 Results with SCE data indicate that the Southern California market benefits may

18 be even lower.[10]

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[8] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 113, including footnote 101.
[9] UCAN, Analysis of SDG&E's AMI Application 8/14/06 (Attachment V: Attachment 4A - PG&E Phase 2 Testimony, Table 2-4, page 2-7).
[10] See $8.76/kW-year CT gross market energy benefits in TURN, Electric Marginal Cost and Revenue Allocation of Southern California Edison Company, 1/20/06, page 34.

1

Table JCM-3

Comparison of CT Market Earnings Southern and Northern California Using E3 Market Data 2006 - 2030*		
	Year 2011 Run Hours	Nominal 2011 ($/kW-yr)	Real 2006 ($/kW-yr)
Southern California	1,601	$66.80	$51.70
Northern California	1,723	$70.30	$54.17
% South less than North	7%	5%	5%
*E3's March 20, 2006 update, and 6/01/06 gas update for monthly gas factors.		

2

3   **D. The Commission should view the high values for market energy benefits**
4   **developed by UCAN from the E3 model with a healthy skepticism.**

5   The calculation of market energy benefits depends on a number of

6   assumptions including the southern California load profile, the resulting hourly

7   price profile over the year, and the marginal costs of operating a CT. The analysis

8   by Mr. Marcus in the Edison General Rate Case, Phase 2, was based on the hourly

9   price profile developed by SCE in a similar manner to the SDG&E hourly price

10   profile, based on its resource plan and expected future southern California market

11   conditions. In that proceeding, Mr. Marcus calculated a value for market energy

12   benefits of $8.76 per kW-year based on that data for the Southern California

13   market.[11] Based on SDG&E's resource plan data specific to future southern

14   California conditions, I have calculated a value of $22.89 per kW-year. In

15   contrast, the E3 data on hourly price profiles is based on data from the now

16   defunct PX market in 1998-2000 and may not adequately reflect long-term future

17   conditions.

18   But even estimates based on the E3 hourly price data have produced much

19   lower values. SDG&E has used modified versions of the E3 data for transparency

20   purposes in short-term avoided cost applications both in its Rate Design Window

21   (A.05-02-019) and Phase 2 of the Avoided Cost Proceeding, R.04-04-025. In the

22   Rate Design Window, UCAN estimated market energy benefits based on that data

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[11] See $8.76/kW-year CT gross market energy benefits in TURN, Electric Marginal Cost and Revenue
Allocation of Southern California Edison Company, 1/20/06, page 34.

1   to be $29.72 for 2006, a value much less than used in this proceeding.[12] In the

2   Avoided Cost proceeding, SDG&E calculated market energy benefits produced

3   by a CT based on modified E3 data to be $16.78 per kW-year.[13]

4   The experience of the last several years also raises doubt about the high values

5   for market energy benefits. The CEC has estimated that a new CT can expect to

6   operate a little over 800 hours per year,[14] and it has been reported that some new

7   CTs have been operating at less than 400 hours per year in contrast to UCAN's

8   assumption of 1600 hours per year.[15] Going forward in the long-run, when old

9   and inefficient CTs are replaced by new CTs, not all the new CTs would have

10 high operating hours given the shape of the load profile, some will be relegated to

11 operating substantially less to provide reliability in the top 100 hours.

12

13 **E. SDG&E and UCAN would have similar net CT capacity costs, once**
14   **UCAN's data is corrected to real 2006 values and the minimally adjusted**
15   **for Southern California market conditions.**

16   While SDG&E does not calculate the net CT capacity cost in direct testimony,

17 SDG&E does calculate the required components (fixed CT costs and market

18 energy benefits). Table JCM-5 compares SDG&E's and UCAN's net CT

19 capacity costs after corrections (Comparable to UCAN's Table 13).[16] My

20 comparison shows that the SDG&E's net CT capacity cost is in the same range as

21 the corrected UCAN values.

22 //

23 //

24 //

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26

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[12] UCAN, Electric Marginal Cost, Revenue Allocation, and Rate Design for SDG&E, A. 05-02-019, June 24, 2005, pages 16 and 17.
[13] SDG&E, Prepared Testimony of David T. Barker, August 31, 2005, R.04-04-025, Exhibit 85, page 16.
[14] CEC, Comparative Cost of California Central Station Electric Generation Technologies, Section E-3, Table D-6, August, 2003.
[15] California Cogeneration Council Rebuttal Testimony, October 28, 2005, R.04-04-025, Exhibit 103, page 59.
[16] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 116

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Table JCM-5

Comparison of SDG&E and UCAN Net CT Costs
Real 2006 Values ($/kW-Year)

Case	Gross CT Cost	Market Earnings	Net CT Cost
SDG&E	60.00	22.89	**37.11**
Corrected UCAN*:			
Upper Bound case			52.00
High case	82.12	35.47	46.65
Mid-High case	82.12	44.33	37.79
Recommended case	71.28	44.33	26.95
Low case	71.28	51.70	19.58

* Corrected CT market earnings for real 2006 values and for lower Southern California market earnings.

Table JCM-5 makes the following corrections to UCAN's Table 13:

- SDG&E case subtracts the real 2006 $22.89/kW-year market energy benefit,[17] which UCAN failed to include.

- UCAN High, Mid-High, and Recommended cases corrects PG&E's nominal 2011 CT market earnings, to a real 2006 values (from $51.90 to $46.66), and adjusts the Northern California CT market earnings to reflect that a Southern California CT earns 5% less than a Northern California CT ($46.66 * .95 = 44.33)[18].

- UCAN's Low case is adjusted to convert their E3 nominal 2011 value to a real 2006 value (from $63.96 to $51.70).

      With the correction above, SDG&E and UCAN results are not nearly as far apart as the UCAN testimony would make it appear. The net CT cost for SDG&E is $37.11/kW-Year. On balance both SDG&E and UCAN analyses have similar results except that UCAN ignores the Additional Value of SDG&E's AMI enabled Demand Response.

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[17] SDG&E, AMI Application 7/14/2006, page JCM-13.
[18] UCAN's High case uses 80% of PG&E's energy savings as Market Earnings.

JCM-11

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3

F. DRA incorrectly asserts that SDG&E has calculated its CT market energy benefit by utilizing a "straight average of energy prices across 21 years"[19].

4   SDG&E estimated a CT market energy benefit using forecasted hourly prices

5   for 20 years (2006 through 2025), not a "straight average of energy prices across

6   21 years". SDG&E used forecasted hourly energy prices and associated

7   forecasted monthly gas prices to evaluate a gas CT's market energy profitability

8   each hour to arrive at a $22.89/kW-year value. An analysis of the underlying data

9   translates to over 1,600 hours of CT operations that provide at least some profit to

10   the CT operator. The 1,600 hours of operations is a very liberal estimate of

11   annual operating hours, far exceeding the typical annual 800-1,000 hours that are

12   used for CT profitability analysis. DRA ramps up SDG&E's value by using a

13   ratio of "straight average of energy prices across 21 years" and an average energy

14   prices for "CPP-like" times.

15   DRA's ratio arbitrarily doubles SDG&E's estimate of CT market energy

16   benefits and does not produce a reasonable result. Using DRA's logic, if the

17   projected price of energy during CPP-periods was four times higher than the

18   average price, then AMI enabled demand response would have zero value. One

19   would expect the avoided capacity cost of AMI to increase as CPP-period prices

20   increase.

21   Alternatively, by doubling the value of CT energy profits, DRA may be

22   implying that a CT will run almost 3,200 hours a year. That is, on average, DRA

23   may be implying that a CT would operate for over 36% of the total annual hours.

24   This level of long term operation is essentially unprecedented and impractical for

25   a CT unit designed for peaking generation.

26
27
28

G. The AMI valuation must include the additional benefits of AMI enabled demand response (beyond net CT costs).

29   Just as the CT energy benefits must be included in an AMI capacity valuation,

30   so must the additional value attributed of SDG&E's AMI enabled demand

---

[19] DRA, Analysis of SDG&E's AMI Business Case page 6-4.

1   response. UCAN does not dispute these additional benefits, and both UCAN and

2   DRA identify additional benefits of this type.

3
4   **H. UCAN incorrectly characterizes AMI enabled demand response as**
5   **merely "a demand response program with only 100 hours or less of**
6   **operation per year"[20].**

7   SDG&E's AMI enabled demand response is more that a (Critical Peak

8   Pricing) CPP rate with limited dispatch. SDG&E's business case includes rates

9   and programs described in Dr. George's & Mr. Gaines' testimony. These rates

10   and programs include **CPP** with limited dispatch, Peak Time Rebate (**PTR)** with

11   flexible dispatch, Time-Of-Use (**TOU)** rates, and a Programmable, Controllable

12   Thermostat (**PCT**) program. These rates and programs provide a greater capacity

13   benefit than proposed by UCAN.

14   Additional unique benefits are provided by AMI enable demand response that

15   a CT can not provide. These unique benefits are described in my prepared direct

16   testimony and later in this rebuttal. These unique benefits include rate design

17   flexibility which allows for Real Time Pricing (RTP), a variety of dynamic rates,

18   interruptible programs and enhanced energy management tools (per DRA witness

19   Mr.Geilen). These unique benefits make SDG&E's AMI-enabled demand

20   response as valuable as a combustion turbine.

21
22   **I. UCAN acknowledges the planning reserves benefit of AMI enabled**
23   **Demand Response, as well as the Additional Value of AMI Enabled**
24   **Demand Response.**

25   UCAN does not dispute including a 15% reserve margin benefit for demand

26   response. They simply continue to question whether or not demand response is

27   real. UCAN sees the planning reserves "as a contingent benefit" – which will

28   only be received by ratepayers if the demand response program is successful for

29   several years. SDG&E agrees with this assessment. That is why SDG&E's AMI

30   proposal includes demand response programs with wide participation across all

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[20] UCAN, Analysis of SDG&E's AMI Application, 8/14/06, page 109.

1 customer classes, has a PCT program, and includes rate design flexibility to

2 assure the success of long term demand response.

3

4 **J. UCAN neither addresses nor disputes the Additional Value of AMI**
5   **Enabled Demand Response.**

6   Nowhere in their testimony does UCAN dispute the value of Reduced

7 Demand Volatility and Planning Reserves, or dispute the value of Increase Rate

8 Design Flexibility, or dispute the Additional Reliability Value of PCTs. In fact

9 UCAN identifies several Additional Unique Benefits of AMI, including a

10 Consumer Portal.[21]

11

12 **K. DRA unjustifiably argues that the resource availability of AMI Enabled**
13   **Demand Response is less than a CT.**

14   DRA asserts that a CT operates 822 hours a year,[22] presumably for reliability

15 purposes. This is based on the CEC's Comparative Cost study of generation

16 technologies.[23] The CEC's study does not differentiate between reliability and

17 economic operation. If the DRA assertion is to be believed, Solar Photovoltaics

18 provide 2,086 hours a year of reliability, a wind farm provides 5,336 hours a year

19 of reliability, and a Combined Cycle-Baseload plant provides 8,024 hours a year

20 of reliability. The CEC's operating hours should be viewed as a combination of

21 both reliability and economic dispatch. SDG&E includes the CT market energy

22 benefit to reflect the fact that a CT operates many hours for economic purposes.

23

24 **L. DRA use of a LOLP allocation to reduce the capacity value of AMI**
25   **enabled demand response but ignores the rate design flexibility enabled**
26   **by AMI.**

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[21]UCAN, Summary of UCAN Testimony and Selected Issues Relating to Expenditures for SDG&E's 2006
AMI application, 8/14/06, page 8.
[22]DRA, Analysis of SDG&E's AMI Business Case 8/14/20006, page 6-6.
[23]CEC, Comparative Cost of California Central Station Electricity Generation Technologies. (100-03-001),
August 2003. Tables M-6, R-6, & C-6.

1	DRA asserts that "a valuation of demand response should also be lowered due
2	to limitations of the program".[24] DRA's argues that since SDG&E's CPP and
3	PTR is limited to only day-ahead dispatch for on-peak operation during summer
4	months and limited to 91 hours per year, it can not provide capacity that may be
5	needed at other times. SDG&E's PTR proposal does not limit the number of
6	dispatch hours, thereby, allowing for unlimited dispatch in any season, including
7	day-of dispatch if necessary. In addition SDG&E's proposal includes over 50,000
8	PCTs which can provide reliability dispatch comparable to a CT. The rate design
9	flexibility of AMI enabled demand response allows for implementation of
10	additional interruptible and curtailable rates that can provide unlimited dispatch
11	possibilities. AMI enabled demand response provides for real-time pricing which
12	can reduce the overall loss of load probabilities because it can help reduce the
13	short term variations in load due to weather,[25] as well as reduce other demand
14	factors affecting the hourly LOLP probabilities. DRA chooses to ignore these
15	facts when discounting AMI enabled demand response for LOLP periods.
16	
17	**M. DRA discounts the "potential of AMI to allow the Commission to more**
18	**accurately allocate costs and fairly reflect the true cost of service in**
19	**energy rates to all customers."[26]**
20	DRA asserts that RTP "is a rate design and pricing strategy which neither
21	SDG&E nor DRA would propose, especially for all residential customers."[27]
22	DRA has not reflected the Commission's direction as shown in the following
23	passage from the favorable PG&E AMI decision. "In subsequent proceedings,
24	with adequate time and an appropriate record, AMI opens the door to true real-
25	time pricing which accurately reflects the cost of energy." SDG&E includes the
26	RTP functionality in its AMI proposal, not only to comply with prior ALJ
27	rulings,[28] but because of the additional benefits RTP can provide. Mr. Fong and

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[24] DRA, Analysis of SDG&E's AMI Business Case 8/14/20006, page 6-7.
[25] SCE, Phase 2 of 2006 GRC Marginal Cost and Sales Forecast Proposals (A.05-05-023), 9/6/2005, page 29.
[26] CPUC, Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure. (D.06-07-027), 7/24/06, page 11.
[27] DRA, Analysis of SDG&E's AMI Business Case, 8/14/06, page 6-11.
[28] CPUC, ALJ Ruling (02-06-001), 2/19/04, page 3 and Appendix A.

1   Mr. Hansen discuss both the direction of the Commission as it pertains to demand
2   response rates and SDGE's rate strategy looking forward over the next several
3   years.

5   **N. DRA inappropriately adjusts SDG&E's Rate Design Flexibility.**

6   DRA reduces SDG&E's benefits which are based on Dr. Borenstein's 2005
7   study titled The Long-Run Efficiency of Real-Time Electricity Pricing. DRA
8   asserts that "the reality of California's generation supply does not reflect the
9   paper's theoretical assumptions."[29] In fact, the current generation mix only
10   increases the benefits described in Dr. Borenstein's paper. The paper evaluates an
11   optimal generation portfolio under flat rates vs. an optimal generation portifolio
12   under RTP rates. The paper shows that RTP results in a lower cost generation
13   portfolio compared to the optimal flat rates portfolio. Today's mix of generation
14   is likely not as "optimal" as modeled by Dr. Borenstein, therefore, moving to an
15   optimal generation mix under RTP will likely result in even greater benefits than
16   stated in the paper, all else being equal.

18   **O. DRA incorrectly argues that long term contracts will prevent SDG&E**
19   **from achieving the benefit of Rate Design Flexibility.**

20   DRA states that the "bulk of SDG&E's power procurement over the next 20
21   years will be tied-up in long-term and nuclear contracts."[30] Therefore, DRA
22   argues that the generation mix can not change to achieve these benefits. Their
23   prospective does not recognize the flexibility of wholesale markets. It is true that
24   SDG&E will have generation tied up in long term contracts, but much of the
25   current DWR allocations (43% in DRA testimony) are eliminated by 2011. Thus,
26   as these contracts expire, new opportunities to optimize SDG&E's supply
27   portfolio will arise. Even with a fixed physical generation portfolio, SDG&E will
28   buy and sell excess capacity in the wholesale market as it does today. Under
29   RTP, there will be less wholesale purchases in high price periods and less

[29]DRA, Analysis of SDG&E's AMI Business Case, 8/14/06, page 6-11.
[30] DRA, Analysis of SDG&E's AMI Business Case, 8/14/06, page 6-12.

1 wholesale sales in low price periods, thus providing the benefits of Rate Design

2 Flexibility. Regardless of SDG&E's current contracts for generation, Rate Design

3 Flexibility creates opportunities to create a lower cost generation portfolio.

4

5 **P. DRA testimony by Ted Geilen on Information Feedback illustrates the**

6 **existence of even more unique benefits of AMI.**

7 Mr. Geilen identifies energy conservation benefits associated with customers

8 increased understanding of the cost of energy use. This benefit valuation has not

9 been evaluated by this witness, however the value appears considerable, at $29.6

10 million, based on Mr. Geilen's testimony.

11 In conclusion, UCAN calculates an equivalent CT value as SDG&E when the

12 market energy benefits are correctly calculated. The Additional Value of AMI

13 enabled demand response is not contested by UCAN. DRA's analysis is highly

14 flawed. DRA uses flawed reasoning to increase CT market energy benefits

15 estimated by SDG&E. DRA also discounts SDG&E's additional values based on

16 faulty logic and without fully considering their potential benefit. The appropriate

17 value of capacity for evaluation of AMI enabled Demand Response should

18 include fixed CT costs, CT market energy benefits, and the additional value of the

19 AMI system.   When all these factors are considered, SDG&E's valuation is

20 appropriate.

21

22 This concludes my prepared rebuttal testimony.