STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

F I L E D
03-08-07
01:05 PM

March 8, 2007

Agenda ID #6456
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 05-03-015

This is the proposed decision of Administrative Law Judge (ALJ) Gamson. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's **Rules of Practice and Procedure** (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed either electronically pursuant to Resolution ALJ-188 or with the Commission's Docket Office. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic copies of comments should be sent to ALJ Gamson at dmg@cpuc.ca.gov. All parties must serve hard copies on the ALJ and the Assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail, or other expeditious method of service. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:hl2
Attachment

Decision (**PROPOSED DECISION OF ALJ GAMSON** **(Mailed 3/8/2007)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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 (Filed March 15, 2005)

(See Appendix B for a list of appearances.)

OPINION APPROVING SETTLEMENT ON SAN DIEGO GAS AND ELECTRIC COMPANY'S ADVANCED METERING INFRASTRUCTURE PROJECT

TABLE OF CONTENTS

Title	Page
OPINION APPROVING SETTLEMENT ON SAN DIEGO GAS AND ELECTRIC COMPANY'S ADVANCED METERING INFRASTRUCTURE PROJECT	2
1. Summary	2
2. Background	3
2.1 Commission Guidance	3
2.2 Procedural History	6
3. Litigation Positions of Parties	9
3.1 SDG&E	9
3.2 DRA's Position	11
3.3 UCAN's Position	12
4. Settlement Agreement	13
5. Burden of Proof	16
6. Functionality and Implementability	17
6.1 Functionality	17
6.1.1 SDG&E's Application	17
6.1.2 Functionality and the Settlement	20
6.2 Implementability	21
7. Cost Effectiveness – SDG&E's Application	22
7.1 Comparison Exhibit	23
7.2 Financial Modeling Methodology	26
7.2.1 Discount Rate and Present Value Method	26
7.2.2 Timeframe of Analysis: 17 Years	27
7.3 Project Costs	32
7.3.1 RFP Specifications	33
7.3.2 Meter and Communications Systems	36
7.3.3 Risk Sharing	38
7.3.4 Adopted Cost Estimate	39
7.4 Operational Benefits	39
7.4.1 Meter Reading Benefits	40
7.4.2 Other Operational Benefits	42
7.5 DR Impacts and Benefits	44
7.5.1 Residential Customers	45
7.5.2 Small and Medium Commercial and Industrial Customers	54

7.5.3 Large Commercial and Industrial Customers 56
7.6 Avoided Capacity Cost 58
7.7 Benefits from Avoided DR Program Costs 64
7.8 Information Feedback Systems Benefits 70
7.9 Non-Quantifiable and Newly Quantifiable Benefits 70
7.9.1 Implementation of Time Differentiated Rates 71
7.9.2 Improved Public Safety 72
7.9.3 Environmental 72
7.9.4 Enabling Technologies Advancements/Deployments 73
7.9.5 Smart Grid 74
8. SDG&E's AMI Application is Not Cost-Effective 74
9. Alternative AMI Program Options 75
9.1 December 15, 2006 ALJ Ruling and Comments 76
9.2 SDG&E AMI Alternative Proposal 78
9.3 UCAN Alternative 79
9.4 Technological Improvements 81
10. Analysis of the Settlement Agreement 83
10.1 Cost-Effectiveness of the Settlement Agreement 83
10.2 Reasonableness of the Settlement Agreement 85
10.2.1 Does the Settlement Agreement Include Sufficient Information to Determine its Overall Reasonableness? 86
10.2.2 Is the Settlement Agreement Reasonable in Light of the Whole Record? 87
10.2.3 Is the Settlement Agreement Consistent With the Law? 87
10.2.4 Is the Settlement Agreement in the Public Interest? 88
11. Comments on Proposed Decision 88
12. Assignment of Proceeding 89
Findings of Fact 89
Conclusions of Law 92
ORDER 94

APPENDIX A – Settlement Agreement
APPENDIX B – List of Appearances

OPINION APPROVING SETTLEMENT ON SAN DIEGO GAS AND ELECTRIC COMPANY'S ADVANCED METERING INFRASTRUCTURE PROJECT

1. Summary

This decision approves a settlement among San Diego Gas and Electric Company (SDG&E), the Division of Ratepayer Advocates (DRA) and Utility Consumer's Action Network (UCAN) to allow $572 million for SDG&E's proposed Advanced Metering Infrastructure (AMI) Project from 2007 through 2011.

In this decision, we analyze the Settlement Agreement in light of the litigation positions of the parties in order to consider its reasonableness. We find the Settlement Agreement to be reasonable in light of the whole record, consistent with the law, and in the public interest.

This decision is part of our effort to transform California's investor-owned utility distribution network into an intelligent, integrated network enabled by modern information and control system technologies. SDG&E's deployment is scheduled to begin in mid-2008. From 2008 through 2010, SDG&E will install approximately 1.4 million new, AMI-enabled, solid state electric meters and 900,000 AMI enabled gas modules that can, among other things, measure energy usage on a time-differentiated basis. The deployment will improve customer service by providing customer premise endpoint information, assist in gas leak and electric systems outage detection, transform the meter reading process and provide real near-term usage information to customers. AMI will also support such technological advances as in-house messaging displays and smart thermostat controls.

2. Background

2.1 Commission Guidance

For the last several years, this Commission has encouraged California's investor-owned energy utilities to increase DR (DR) as a means of reducing energy demand during peak periods. In order to implement dynamic pricing, utilities must deploy advanced meters that can measure energy usage on a time-differentiated basis. In Decision (D.) 01-05-032, the Commission adopted a proposal for implementing real-time energy meters for SDG&E's large customers with peak demand of 100 kilowatts (kW) or more. The Commission stated, "real-time energy meters will provide accurate and meaningful price signals" as opposed to the current system where customers pay an average of all customers in its rate group. As the decision acknowledges, average pricing—the type of pricing most utility customers are billed under—masks the market conditions that exist on an hourly basis:

> Any attempt at demand responsiveness is dampened because customers have a significant lag time before they receive their monthly bill, which is usually well after the high hourly prices and peak usage periods occur. Hourly market prices reflect current market conditions. By implementing real time energy meters, customers can optimize their use of electricity during different hours of the day. (D.01-05-032, p. 7)

In June 2002, the Commission initiated Rulemaking (R.) 02-06-001, with the goal of increasing the level of DR "as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment."[1] The Rulemaking clarified that the "Commission anticipates

[1] D.02-06-001, p. 1.

that full scale implementation of AMI will provide all customers in all rate classes with the option to choose between dynamic and static rate structures." AMI consists of metering and communications infrastructure as well as the related computerized systems and software. SDG&E's filed its AMI application in response to the directives of this rulemaking.

The first Energy Action Plan (EAP 1), adopted by the Commission, the California Energy Commission (CEC) and the California Power Authority, articulated various action items to promote DR, including implementing a voluntary dynamic pricing system to reduce peak demand by as much as 1,500 to 2,000 megawatts (MW) by 2007.[2] In October 2005, the Commission and the CEC jointly issued EAP II. EAP II, states that a first important step for achieving DR is to "issue decisions on the proposal for statewide installation of AMI for small commercial and residential time-of-use (TOU) customers by mid-2006 and expedite adoption of concomitant tariffs for any approved meter deployment."

On July 21, 2004, a joint assigned Commissioner and Administrative Law Judge (ALJ) Ruling was issued in R.02-06-001 that established a business case analysis framework for AMI. The ruling specified that the following parameters should be used consistently for each required scenario analyzed:

1. 2006 to 2021 analysis period.
2. Benefits and costs calculated relative to the Base Case.
3. Costs and benefits presented as 2004 present value dollars, with annualized nominal values in work papers.

---

[2] EAP 1, section entitled, "Optimize Energy Conservation and Resource Efficiency."

4. An extensive literature search to identify data or methods used by other electric or gas utilities to estimate benefits shall be performed. Some combination of the specific methods for gathering benefit and cost information (use of Requests for Proposals (RFP), benchmarks from other utilities, indirect benchmarks, in-house cost analysis and actual in-house costs) should be used to estimate the benefits for all of the categories above.

5. Potential costs and benefits that cannot be easily quantified or for which no dollar value can be derived because of uncertainty or lack of data should be reflected in the analysis by including a qualitative assessment of that value.

6. Discount rate equals utility cost of capital.

7. DR savings estimates based on weighted average of savings under average and hot weather conditions developed using Monte Carlo or other simulation techniques.

8. Avoided peak demand cost = $85/kW-yr; Avoided energy cost = $63/MWh.

This Ruling provided guidance for SDG&E's Application, as well as for PG&E's March 15, 2005 Application (A.) 05-03-016.

In D.06-07-027, the Commission authorized PG&E to deploy a new AMI, including authorization for PG&E's rate proposal for critical peak pricing tariffs. The Commission concluded it was reasonable for PG&E to deploy its AMI system, finding PG&E's proposal had sufficient probable and quantifiable economic operating and DR benefits, including sufficient flexibility to upgrade for enhanced features, over the expected 20-year useful life.[3] The decision

[3] D.06-07-027, p. 9.

authorized $1.6846 billion of project costs, with associated ratemaking provisions.

2.2 Procedural History

On March 15, 2005, SDG&E filed this application seeking Commission approval of the company's AMI deployment proposal and associated cost recovery and rate design. SDG&E proposes to replace nearly all 1.4 million electric and gas meters in its territory that are not already equipped with automated metering infrastructure (all large commercial and industrial customers already have this capability). SDG&E's application anticipates a substantial new communications infrastructure as well. SDG&E anticipates new rate structures will be adopted in the future to take advantage of AMI technology.

On May 9, 2005, the assigned ALJ issued a ruling (May 9, 2005 Ruling), directing SDG&E to provide supplemental testimony describing its pre-deployment plan along with a month by month description of all required tasks and costs. The ruling stated:

> We have reached the conclusion that there are three primary issues that we must decide before pre-approving any utility's proposed deployment of AMI. First, we must be able to make an affirmative finding that the proposed systems meet the functionality criteria set forth in the Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the AMI Business Case Analysis issued February 19, 2004 in Rulemaking (R.) 02-06-001. Second, we must be able to make an affirmative finding that the proposed investment provides sufficient operational benefits to ratepayers to move forward with implementation. This finding may not require that 100% of the costs of AMI deployment be covered by operational savings, but that some sufficient threshold is met for us to be confident that future DR benefits

> would result in a cost effective investment. Third, we must make an affirmative finding that SDG&E has a serious plan for accomplishing the task of integrating the AMI investment into its operating systems to ensure that the expected benefits in the areas of customer service, billing, outage management, and operations and maintenance accrue. (May 9, 2005 Ruling, p. 3.)

On May 25, 2005, SDG&E served supplemental testimony presenting a revised plan reducing pre-deployment expenditures from $50.3 million to $9.3 million. SDG&E entered into a settlement agreement with other parties regarding the scope of pre-deployment activities. The settlement (approved in D.05-08-028) authorized SDG&E to spend $3.4 million for activities during a pre-deployment period extending from September 2005 through March 2006, and an additional $5.9 million in bridge funding to be spent from March 2006 through the end of that year.[4]

SDG&E issued five RFPs on October 20, 2005 to implement aspects of its AMI project. SDG&E filed a motion on October 20, 2005, requesting an extension of the procedural schedule that would allow SDG&E to submit testimony reflecting the RFP results. The motion was approved by ALJ Cooke on November 18, 2005.

Accordingly, SDG&E served its updated testimony on March 28, 2006. On July 14, 2006, SDG&E served amendments to its testimony. DRA and UCAN served testimony August 14, 2006 and SDG&E served its rebuttal on September 7, 2006.

---

[4] On September 1, 2006, SDG&E filed a Petition to Modify D.05-08-018. The Commission addressed this Petition in D.06-12-016.

Evidentiary hearings were held September 25, 2006 through October 5, 2006. The case was submitted November 14, 2006 with the filing of reply briefs. ALJ Gamson issued a ruling on December 15, 2006 reopening the record to obtain further information. This ruling and subsequent filings are discussed below in Section 8.

SDG&E convened a properly noticed Settlement Conference on February 1, 2007. Representatives from all parties sponsoring testimony attended, either in person or by telephone. Following that Settlement Conference, the parties reached an agreement in principle to settle all outstanding issues. On February 9, 2007, in accordance with Rule 12.1(a) of the Commission's Rules of Practice and Procedure (Rules), SDG&E, DRA and UCAN (Settling Parties) filed a Joint Motion for Adoption of Settlement. As required by Rule 12.1(d), the Settling Parties contend that the Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest. The Settling Parties seek Commission approval of the Settlement Agreement as presented and without revision. The Settlement is an uncontested, or "all active party," settlement. All parties who sponsored prepared testimony are signatories to the Settlement Agreement. Silicon Valley Leadership Group and eMeter Corporation jointly filed comments supporting the Settlement Agreement.

On February 16, 2007, ALJ Gamson issued a Ruling seeking further information about, and setting an evidentiary hearing on the Settlement Agreement. The Settling Parties provided their response to the ruling on February 23, 2007. The evidentiary hearing was held February 27, 2007, and the case was re-submitted that day.

The record is composed of all documents that were filed and served on parties. It also includes all testimony and exhibits received at hearing. Also, the ALJ sealed as confidential various exhibits and filings. We affirm all assigned Commissioner and ALJ rulings in this proceeding. All Motions not heretofore ruled upon are denied.

3. Litigation Positions of Parties

This section provides an overview of the litigation positions of the three active parties in this proceeding. Subsequent sections develop the parties' litigation positions in detail. The Settlement Agreement is discussed in Section 4.

3.1 SDG&E

SDG&E's states its application seeks to transform SDG&E's electric utility distribution network into an intelligent, integrated network enabled by modern information and control system technologies. SDG&E claims the AMI system will provide SDG&E's customers with the significant benefits that AMI offers today, and lays the foundation for future expansion that will enable greater operational efficiencies, reliability and customer service. SDG&E contends its application is cost-effective.

SDG&E's deployment is scheduled to begin in mid-2008. From 2008 through 2010, SDG&E seeks to deploy approximately 1.4 million new, AMI-enabled, solid state electric meters and 900,000 AMI enabled gas modules that can, among other things, measure energy usage on a time-differentiated basis.[5] In advance of deployment, SDG&E intends to perform approximately

[5] Direct Access customers will continue with their current meters. See Exhibit 22, pp. EF-25-26.

18 months of information technology (IT) related work beginning in early 2007. The IT work will enable the meter deployment and put in place systems suitable to manage and store the data the advanced meters will produce.

SDG&E contends deploying AMI will improve customer service in several ways. First, it will transform the meter reading process by improving the accuracy and timeliness of utility bills. Second, it will provide near real time energy usage information empowering customers to make informed choices about their energy usage. Third, by providing customer premise endpoint information, SDG&E will be able to monitor its system continuously, speeding detection of gas leaks and electric system outages. Fourth, AMI will improve safety and provide greater service reliability through superior outage response and service restoration.[6]

SDG&E's asserts its AMI proposal is an important first step towards developing a "smart grid" in the San Diego region. In addition to collecting data at the farthest endpoint of the distribution system, SDG&E's AMI solution will be capable of providing two-way communication to a customer's premise, which will improve both outage detection and restoration capabilities. AMI will permit transmission and distribution operators to sense, monitor and analyze information from many data sources, enabling system planners to optimize assets. SDG&E says AMI will support such technology advances as in-home messaging displays and smart thermostat controls.

---

[6] SDG&E has identified other benefits which it states are difficult or impossible to quantify. These are discussed in Section 6.

SDG&E proposes that electric distribution rates be adjusted annually during years 2007 through 2011 based on the annual net changes in distribution revenue requirements. Net distribution costs and benefits associated with AMI full deployment would be recovered from all customer classes in which AMI will be installed, and accounted for by means of a balancing account mechanism. Distribution rates would never increases as a result of the AMI balance but rates may decrease. SDG&E proposes that AMI deployment operation and maintenance (O&M) and capital-related costs and benefits should be recorded monthly in a new AMI balancing account. SDG&E proposes to record actual O&M and capital-related costs and make annual adjustments for the variation from the Commission-approved annual AMI revenue requirement. Benefits would be tied to the annual average number of meters actually installed as compared to the annual average number of installed meters supporting SDG&E's revenue requirement calculation.[7]

3.2 DRA's Position

DRA's primary litigation position is that the Commission should deny SDG&E's application as not being cost-effective, and invite SDG&E to submit an amended or new proposal once SDG&E designs a cost-effective business case.

DRA supports the idea of integrating an AMI into California's electricity system, but only if ratepayers receive benefits equal to or greater than the amount of money they will be compelled to spend on that system. DRA claims SDG&E's AMI application presents a business case that will cost its ratepayers

[7] Exhibit 34, pp. RWH-5 through RWH-7.

$98 million more than the benefits they will receive in return for their investment.[8]

Should the Commission approve SDG&E's application, DRA recommends that SDG&E be required to:

1. Accept risk-sharing mechanism on cost overruns.

2. Support open programmable communicating thermostat (PCT) standards expected under the expected Title 24 update and advertise the PCT benefits to ratepayers when PCTs are available.

3. Obtain license agreements from AMI communications manufacturers that allow in-home real-time information feedback device manufacturers free, or low-cost, access to electricity in real-time and gas hourly, or daily.

3.3 UCAN's Position

UCAN's litigation position in that the AMI proposal as presented is not cost-effective. UCAN claims that SDG&E did not comply with the specific guidelines established by the Commission for an advanced meter deployment. UCAN contends SDG&E proposed a plan focused on a narrowband communications platform and off-the-shelf real-time meters, rather than building a platform that could take advantage of emerging communications and "smart chip" technologies. UCAN contends SDG&E chose to deploy universally with little regard for customer usage or acceptance, rather than to deploy the meters incrementally and focus upon those customers who could most readily harness the functionalities of the new meters.

---

[8] See Ex. 101, p. 1-1, Table 1-1.

UCAN also contends that the application represents a missed opportunity, because those same monies will no longer be available to leverage the emerging Smart Grid functionalities or to justify investment in other more economic peak shaving programs. UCAN recommends that the Commission first direct SDG&E to conduct a Smart Grid pilot in defined areas that could serve to test and experiment with the emerging technologies identified in the University of San Diego Smart Grid report.[9]

4. Settlement Agreement

Appendix A is the Settlement Agreement, in redacted form. In summary, the Settlement recommends:

- SDG&E's proposal for full AMI deployment and cost recovery as described in its application and testimony should be adopted, with certain specified modifications.
- The total project costs are $572 million through 2011.
- The total project costs of $572 million include the additional functionality and extended warranty provisions as described in the settlement. Additional functionality requirements are:
    - A Home Area Network (HAN) communications system, based on an open standard capability for residential and commercial and industrial customers, which should be compatible with the HAN choice of other major California utilities
    - Remote connect/disconnect functionalities

[9] Ex. 202, p. 6-13.

- The Settling Parties agree that it is prudent for SDG&E to obtain pricing for an extended warranty for the AMI equipment.
- SDG&E will issue an addendum to its RFP in order to:
  - Ascertain the current status and viability of advancements in AMI technology and may, at its discretion, accept bids from technologies excluded from the original RFP;
  - Determine whether project costs are significantly increased by certain functional requirements;
  - Seek proposals to install additional functionality; and.
  - Seek proposals for an extended warranty of the AMI equipment.
- The Settling Parties agree to the risk contingency and symmetrical risk and reward-sharing proposal as described in the Settlement, including:
  - Expenditures up to $572 million are deemed reasonable and will be recovered in rates without any after-the-fact reasonableness review
  - 90% of up to the first $50 million in Project costs exceeding $572 million will be recovered in rates without any after-the-fact reasonableness review, and 10% will be borne by SDG&E shareholders
  - Project costs above $622 million may be recoverable in rates following a reasonableness review by the Commission.
  - 10% of the first $50 million in Project costs below $572 will be awarded to SDG&E shareholders.
  - Any shareholder rewards or costs will be recorded and recovered through SDG&E's Reward and Penalties Balancing Account

  - Total Project costs may be adjusted downward as a result of revisions to SDG&E's RFPs. If total Project costs are reduced, the risk sharing mechanism would apply to the revised total Project cost.
- The Settling Parties agree that 100% of the AMI revenue requirement will be allocated among customers utilizing the SDG&E distribution allocation in place when AMI costs are recovered in rates.
- The Settling Parties agree that the Peak Time Rebate (PTR), Critical Peak Pricing (CPP) and AMI related dynamic rates should be determined in SDG&E's January 31, 2007, General Rate Case Phase 2 proceeding (A.07-01-047).
- SDG&E will establish an AMI Technology Advisory Panel (TAP) and will invite staff from the CEC, the Commission's Energy Division, UCAN, DRA, and other technical experts to serve on this panel.[10]
  - The TAP will work with SDG&E so that SDG&E's AMI design and deployment considers the "best available practices" and "best available technologies" and encourages customer acceptance of the new services enabled by AMI deployment
  - The TAP will provide written feedback and recommendations in the form of an annual report to SDG&E on SDG&E's progress in deploying AMI and the industry status of AMI-related technologies. This report will be submitted to the Commission's Energy Division.

[10] The TAP responsibilities are detailed in Attachment A of the settlement agreement.

  - TAP meetings will be open to the public.
- The Settling Parties agree that SDG&E may recover in rates costs that exceed the $572 million due to events beyond SDG&E's control, including:
  - *Force majeure* events that materially affect SDG&E's ability to implement the Project as planned, such as acts of nature, transportation accidents, civil disturbances or changes in law;
  - Material changes in the scope or functionality of the Project due to governmental or regulatory actions;
  - Material changes in the costs of the AMI Project causes by a delay in Commission approval of the Project beyond April 12, 2007,[11] and
  - Significant delays before or during Project deployment caused by regulatory of governmental action or inaction, including delays caused by cities and local governments or permit delays.

The Settlement provides that its provisions are to be effective on the date the Commission issues its final decision, or as soon after approval as is reasonably feasible. The Settlement Agreement provides a resolution of all issues raised in conjunction with the Application.

5. Burden of Proof

No party disputes that SDG&E bears the burden of proof in this proceeding. SDG&E's burden in this application is to establish that its proposal

[11] The Settlement Agreement used the date of April 5, 2007. This date was modified at the February 27, 2007 Evidentiary Hearing to account for a change in the Commission's meeting schedule. 8 RT 947-8.

is cost-effective, and meet the Commission's functionality and implementability criteria.

6. Functionality and Implementability

6.1 Functionality

6.1.1 SDG&E's Application

As noted above, the May 9, 2005 Ruling in this proceeding stated:

> First, we must be able to make an affirmative finding that the proposed systems meet the functionality criteria set forth in the Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the AMI Business Case Analysis issued February 19, 2004 in R.02-06-001.

The cited February 19, 2004 Ruling (pp. 3-4) stated that the proposed systems must support the following six functions:

- Implementation of the following price responsive tariffs for:
  - Residential and small commercial customers (200 kW) on an opt out basis:
    - Two or three period TOU rates with ability to change TOU period length;
    - Critical peak pricing with fixed (day-ahead) notification;
    - Critical peak pricing with variable or hourly notification; and
    - Flat/inverted tier rates.
  - Large customers (200 kW to 1 MW) on an opt out basis:
    - Critical peak pricing with fixed or variable notification;
    - Time-of-use; and
    - Two part hourly real-time pricing.
  - Very large customers (over 1 MW) on an opt out basis:
    - Two part hourly real-time pricing;

  - Critical peak pricing with fixed or variable notification; and
  - Time-of-use pricing.
- Collection of usage data at a level of detail (interval data) that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.
- Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.
- Compatible with applications that utilize collected data to provide customer education and energy management information, customized billing, and support improved complaint resolution.
- Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.
- Capable of interfacing with load control communication technology.

SDG&E's claims its AMI technology solution will at a minimum:

- Be a technology independent, next generation solution supporting:
  - Open architecture;
  - Fully upgradeable;
  - Scalability;
  - Flexibility; and
  - A complete end-to-end solution.
- Be fully integrated with existing operational infrastructures.
- Be able to support additional functionality at a later date without the need for significant additional systems hardware.

SDG&E states that it pursued a benefits-driven approach to AMI to ensure fulfillment of the six policy goals, realization of DR and operational benefits, while providing the lowest total cost of ownership. DRA agrees with this benefits-driven approach. UCAN asserts that SDG&E did not comply with the specific guidelines established by the Commission for an advanced meter deployment.

SDG&E maintains that the AMI technology in its proposal is ready and available today, supports the Smart Grid, supports open architecture to the extent possible, and is fully upgradeable and scalable. SDG&E claims that, in developing its AMI proposal, SDG&E rigorously assessed the AMI marketplace, seeking systems capable of fulfilling the six Commission policy goals (or functional requirements) required by the February 19, 2004 Ruling.

While listing its expectations for how the Project will develop, SDG&E did not specifically discuss within this record how the proposed technology in its AMI Project would accomplish meeting the Commission's functionality goals, because SDG&E had not (and has not yet to date) selected a technology. SDG&E asserts that the technologies it evaluated based on RFP responses could meet the functionality goals. SDG&E also states that technology is available from the marketplace that can deliver the functional criteria set forth by the Commission Ruling. However, SDG&E witness Pruschki said he could not discuss specific technologies because SDG&E was field testing multiple technologies.[12]

In SDG&E's application and supporting testimony, SDG&E provides no particulars as to how its Project currently meets the Commission's functionality

[12] Exhibit 31, p. PP-2-3.

criteria. Nor can it do so. Unlike PG&E in its AMI application, SDG&E has not selected technologies, has not selected vendors, and has not signed contracts with vendors. Based on the specifications in SDG&E's RFP, it is likely that SDG&E's proposal can, over time, meet the functionality criteria in the February 19, 2004 Ruling.[13] However, we cannot conclude that SDG&E's proposal is capable of meeting the detailed functionality criteria required to be met at this time. In order to come that conclusion, we would need to review specific signed vendor contracts to ensure that SDG&E's RFP specifications would in fact be implemented.

6.1.2 Functionality and the Settlement

The Settlement provides no new information to ensure that the functionality criteria will be met. However, the Settlement does require SDG&E to revise its RFPs to require that all vendor bids include a HAN communication system and seek proposals to install the HAN and remote connect/disconnect capabilities. According to the May 9, 2005 Ruling, we could reject the Settlement because, like SDG&E's proposal, it does not meet the functionality criteria at this time. However, we will not reject the Settlement simply due to temporary functionality concerns. This is because SDG&E has shown that, while definitive evidence of compliance is missing at this time, SDG&E's RFPs contain both a clear objective and detailed requirements which would likely lead to meeting the functionality criteria when vendor contracts are signed. Further, the additional functionality requirements in the Settlement, as well as the Settlement's

---

[13] For example, Section 2.1.2 of Appendix D of SDG&E's RFP for Functional and Technical Requirements, regarding AMI technology, cites as an objective: "To adhere to the CEC 6 Policy Goals." (This refers to the functionality criteria outlined above.)

formation of the TAP to review functionality implementation, increase our confidence that our functionality criteria ultimately will be met.

In order to ensure our functionality criteria are met, we must review SDG&E's RFP contracts. DRA and UCAN agree to support expedited review and approval by the Commission of SDG&E's AMI Contract Advice Letter filings consistent with the provisions of the Settlement.[14] Testimony of the Settling Parties confirms that such Advice Letter filings are consistent with the Settlement.[15] Therefore, our approval is conditioned upon SDG&E filing its technology contracts stemming from its RFPs as Advice Letters, and subsequent Commission certification that the contracts met the functionality criteria.

6.2 Implementability

As noted above, the May 9, 2005 Ruling in this proceeding stated:

> Third, we must make an affirmative finding that SDG&E has a serious plan for accomplishing the task of integrating the AMI investment into its operating systems to ensure that the expected benefits in the areas of customer service, billing, outage management, and operations and maintenance accrue.

SDG&E did not specifically address this criterion. However, as we have discussed above in Section 3.1, SDG&E does have a clear plan for implementing its AMI Project. The plan involves identifying vendors based on its RFPs, negotiating contracts with selected vendors, and performing the needed work between 2007 and 2010. No party questions SDG&E's ability or plan to

---

[14] Ex. 63 (Settlement Agreement), Attachment A, p. 2.

[15] 8 RT 927-930

implement its proposal. We find that SDG&E's proposal contains the implementability criterion in the May 9, 2005 Ruling.

The Settlement is consistent with SDG&E's application with regard to implementability, and expands upon the application through the formation of the TAP to ensure appropriate technological advancement. We find the Settlement meets the Commission's implementability criterion.

7. Cost Effectiveness – SDG&E's Application

As noted above, the May 9, 2005 Ruling in this proceeding stated:

> Second, we must be able to make an affirmative finding that the proposed investment provides sufficient operational benefits to ratepayers to move forward with implementation. This finding may not require that 100% of the costs of AMI deployment be covered by operational savings, but that some sufficient threshold is met for us to be confident that future DR benefits would result in a cost effective investment.

In the following sections, we will analyze the component parts of SDG&E's AMI application to determine cost-effectiveness. An analysis of SDG&E's application is useful for comparison purposes to determine the reasonableness of the settlement. We note that D.06-07-027 found that in PG&E's AMI project business case analysis, approximately 90% of the project costs would be covered through operational savings, on a net present value (NPV) basis, with the additional 10% expected to be covered by DR benefits from the CPP tariff. In SDG&E's application, by contrast, approximately 60% of the Project's costs would be covered through operational benefits. The remaining benefits would mostly come from DR. This makes SDG&E's business case much more dependent upon DR benefits than PG&E's.

The Settlement Agreement is based on SDG&E's business case, with certain modifications. After considering the cost-effectiveness of SDG&E's initial application, as well as the alternatives offered in the underlying application, we will turn to the Settlement Agreement.

7.1 Comparison Exhibit

SDG&E, DRA and UCAN prepared Exhibit 301 as a comparison exhibit of their business case cost-effectiveness recommendations. In Exhibit 301, SDG&E's business case analysis shows benefits outweigh costs on a present value basis by approximately $60 million from the ratepayer perspective.[16]

SDG&E contends the Commission must consider the 'hard to quantify' benefits as well.[17] These include environmental and increased overall electric reliability benefits as well as customer satisfaction and various utility operational process benefits.[18] SDG&E believes these additional benefits make the positive economic evaluation even more compelling. We will address non-quantifiable benefits in Section 7.9 of this decision.

---

[16] This figure is from the ratepayer perspective. See Ex. 33, Ch. 13, p. SK-14 (entire page), Kyle, SDG&E. SDG&E also claims net benefits of $110 million from the societal perspective, which uses a discounted cash flow methodology. See Ex. 33, Ch. 13, p. SK-11. The main difference between the ratepayer perspective and the societal perspective is that the societal perspective ignores all tax implications, as well as cash flows based on capital depreciation rather than actual expenditures. Also, only costs and benefit items that impact the Commission jurisdictional revenue requirement are included in the ratepayer perspective. By including the ratepayer perspective figures in the comparison exhibit, SDG&E recommends use of this perspective.

[17] Tr. p. 129, lines 19-28, Fong, SDG&E.

[18] Ex. 22, Ch. 2, p. EF-12, lines 13-27 and p. EF-13, lines 1-14, Fong, SDG&E.

In Exhibit 301, DRA's business case analysis shows SDG&E's AMI Project not cost-effective by $98 million over a 17-year analytical period.[19] Table 1 below summarizes DRA's analysis of the net benefits of SDG&E's AMI Project over both a 17 year and a 34 year timeframe. Based on either time horizon, DRA calculates that this project will end up costing each gas and each electric customer $40 to $45 more than the benefits they will receive over the life of the project. For a household with both gas and electric service from SDG&E, this means a bill increase of $80 to $90 over the life of the project.

[19] Parties used both 32 and 34 years for the longer analytical period at various times. As explained in SDG&E witness Kyle's prepared direct testimony, the period of analysis is actually 32 years from 2007-2038, but the present value calculations are discounted to 2006 and 2039. See Ex. 40, Ch 19, p. SK-5 – SK-9. We will consistently refer to a 34-year analytical period in reference to SDG&E's proposal in this decision.

Table 1
SDG&E's AMI Project Cost Effectiveness over 17 or 34 Years
Net Present Value of Benefits
Total Revenue Requirements
(2006 $, Million)

	17 Year Analysis	34 Year Analysis
DRA	- $98 M (Recommended)	-$84 M
SDG&E	- $ 6 M	$60 M (As filed)

Table 2 below shows the specific modifications recommended by DRA to SDG&E's estimates of benefits (in this Table, SDG&E's costs are not modified).

Table 2
DRA Calculation of Net Present Value of Benefits
Revenue Requirements
(2006$, Million)

	17-Year Analysis[20]	**34-Year Analysis**
SDG&E Proposed Total AMI Costs	$607 M	$741 M
SDG&E Proposed Total AMI Benefits	$629 M	$801 M
DRA Adjustments to Benefits:		
DR Participation	-$ 68 M	-$ 71 M
DR Capacity Value	-$ 38 M	-$ 64 M
Avoided DR Program Costs	-$ 33 M	-$ 44 M

[20] See Table 1-1 on p. 1-1 of DRA Exhibit 102-E/C.

	17-Year Analysis[20]	34-Year Analysis
Information Feedback **Subtotal DRA Adjustments**	$ 19 M -$120 M	$ 35M -$144 M
DRA Adjusted AMI Benefits	$509 M	$657 M
DRA Net AMI Benefits	**$ - 98 M**	**-$ 84 M**

In Exhibit 301, UCAN contends that SDG&E's AMI business plan has total benefits of between $314 million and $320.5 million. UCAN contends SDG&E's proposal is not cost-effective by a range of $420.5 million to $427 million over a 15-year analytical period. We note that UCAN's analysis removes the benefits claimed by SDG&E beyond 15 years, but does not remove the costs (UCAN does not propose specific cost estimates, but uses SDG&E's 34 year cost estimates). According to Exhibit 301, DRA believes SDG&E's costs would be lower by $134 million if SDG&E used a 17-year analytical period. If UCAN's 15-year analysis backed out DRA's estimate of cost in years 18-34, UCAN's negative net benefit calculation would be reduced to $286.5 to $293 million. In addition, UCAN shows (using all of SDG&E's numbers) the project does not break even on a NPV basis until 2031, 25 years from the program commencement and 20 years after initial deployment is complete.

7.2 Financial Modeling Methodology

7.2.1 Discount Rate and Present Value Method

SDG&E has used its pre-tax authorized rate of return, 8.23%, to calculate the present value of costs and benefits. DRA agrees that SDG&E has used the appropriate discount rate, and UCAN has no comments on this point. This

discount rate is consistent with the July 2004 Ruling leading up to this proceeding. SDG&E's discount rate is reasonable.

7.2.2 Timeframe of Analysis: 17 Years

The question of the timeframe (or analytical period) is critical in evaluating the cost-effectiveness of SDG&E's AMI Project. While SDG&E believes the business case should be considered on a 34-year analytical period, DRA believes a 17-year timeframe is appropriate. UCAN recommends a 15-year timeframe. DRA and UCAN claim that, everything else being equal, this one change renders the Project not cost-effective.

The July 2004 Ruling in the underlying Rulemaking that led to this Application directed SDG&E to use a 15-year timeframe, at the time anticipating an analysis period of 2006-2021. With the passage of time, this would correspond to an analysis period of 2008-2023 for SDG&E's Project.

In D.06-07-027 regarding PG&E's AMI Project, the Commission accepted the use of a 20-year timeframe as proposed by PG&E. No party contested the use of 20 years in that proceeding. D.06-07-027 stated:

> …we find that the cost effectiveness study period should match the useful life of 20 years. Using 20 years will balance the cost-benefit study's results with the likely useful life of the AMI system selected by PG&E.[21]

In this proceeding, UCAN recommends a 15-year timeframe based on the Commission's direction. DRA recommends the use of a 17-year analytical timeframe, based on the longest useful life of the components of the Project. DRA's recommendation is consistent with the analytical approach we used for

[21] D.06-07-027, p. 27.

PG&E in D.06-07-027. SDG&E's proposal for a 34-year timeframe is not based on the useful life of the Project, and is not consistent with the Commission's direction or D.06-07-027.

UCAN contends SDG&E chose a 34-year evaluation period to dilute the effect the assumed terminal value would have on its NPV calculation. By definition, by extending the evaluation period large dollar values are significantly discounted. UCAN notes that SDG&E did not offer a separate 15-year assessment. UCAN claims that running SDG&E's business case analysis (using all of SDG&E's numbers) shows negative net benefits of $83 million over 15 years, and negative net benefits of $26 million over 20 years. Using the same numbers, the program does not break even until 25 years pass. Only using a full 34-year period yields SDG&E's calculation of $60 million in positive net benefits.[22]

SDG&E's argument for a 34-year analytical timeframe rests on its assertion of the terminal value of the Project. SDG&E states that terminal value represents the value to ratepayers of the ongoing benefits generated by the AMI system beyond the useful life of the assets, calculated in the same way an outside investor would look at it, based on expected discounted future incremental cash flows. SDG&E contends that its financial modeling methodology represents standard academic and industry practice for proper financial valuation and analysis, resulting in a conservative estimate of the net benefits that AMI will provide.[23] SDG&E claims a 15-year (or similar) analysis period without a

---

[22] Ex. 201, p. 31.

[23] Ex. 40, Ch. 19, p. SK-1, lines 21-23, Kyle, SDG&E.

suitable terminal value would significantly understate benefits to ratepayers because approximately 500,000 customer meters (or 29.5% of the overall system in place at that time) will have significant depreciable and useful life remaining after year 2023.[24]

Additionally, SDG&E contends the record shows that the AMI investment is like other long-term utility system capital investments (e.g., power plants or transmission lines that require replacement of components during the lifetime of the system), and therefore should be evaluated over at least a 30-year life.[25] Like other long-term utility system capital investments, individual components of the AMI system will be replaced at various intervals over time due to system growth and replacement of failed components. Therefore, SDG&E believes the value of the new components incorporated into the on-going system must be included for a sound financial analysis.

The key question is how to treat terminal value. PG&E did not suggest using a terminal value calculation in its AMI application, and D.06-07-027 did not consider terminal value when calculating the net benefits of PG&E's AMI proposal. DRA points out that SDG&E justifies the use of two project terms by

---

[24] Ex. 40, Ch. 19, p. SK-3, lines 1-7, including footnote 5; p. SK-4 lines 1-9; p. SK 4&5, lines 26-9; p. SK-8, lines 6-13; p. SK-11, line 13 to SK-12, line 31; Attachment E, p. 7, lines 14-15, p. 8, lines 9-11 and p. 10, lines 1-4; TR 340 & 341, lines 28-10, Kyle, SDG&E; Ex. 40, Ch. 19, p. SK-4, lines 19-25. Kyle, SDG&E;Tr. p. 331, line 24 , p. 332, line 4, Kyle, SDG&E.

[25] Ibid, p. SK-3, footnote 6; p. SK-10, lines 3-5; Attachment B, p. 3, lines 7-10 & 15-19; and Attachment E, p. 9, lines 22-26; Tr. p. 335 & 336 lines 9-4, Tr. p. 343 lines 13-28, Tr. p. 45, lines 7-13, Tr. p. 353, lines 5-13, Tr. p. 357, line 1, Tr. p. 362 line 28 to Tr. p. 363 lines 1-11, Kyle, SDG&E.

analogizing a project to a company.[26] SDG&E's AMI project is, by definition, not a company but a project. Projects have a clear start date and, if well run, a clear end date; the SDG&E AMI system will be substantially (if not wholly) replaced after 17 years. Companies, on the other hand, are ongoing ventures.

In the financial literature cited in the record, the financial analysis used for valuing projects is distinct from the financial analysis used for valuing companies. SDG&E's financial modeling witness for the business case, Mr. Kyle, offered rebuttal testimony containing six footnotes that refer to allegedly authoritative texts.[27] But the texts cited in these footnotes clearly refer to company valuation, not project valuation.[28] For example, Footnote 2, from the source "Choosing the Right Valuation Approach:"

> Although straightforward, (the adjusted book value approach) is not very useful for valuing a typical operating business because the value of the typical operating business is . . . typical operating business has something called "going-concern value."[29]

When applied to a Project, terminal value translates into "scrap value" or "resale value" or "remaining book value." When applied to companies, terminal value translates into "going concern value." Whereas an old technology gets scrapped or resold, a full-fledged company (specifically because it can fund new projects) has "going concern" value. DRA contends that if SDG&E were buying

---

[26] Ex. 40, Ch. 19, p. 3.

[27] Ex. 40, Ch. 19, p. 1-5, Footnotes 1, 2, 3, 5, 7, and 8.

[28] SDG&E's witness did not cite any case in the Commission's history where a project was analyzed over a period longer than the asset life of the principle asset.

[29] Ex. 40, Ch. 19, p. 2, Footnote 2.

a company, the final year would include a going concern value. The AMI project is not a company, so DRA claims standard financial analysis protocol dictates that the period of analysis can only be reasonably taken as long as the life of the longest living asset (in this case 17 years). We agree.

In one way, it is appropriate to look to long-term utility system capital investments such as power plants or transmission lines, as SDG&E suggests; the analysis of the AMI Project should be based on the useful life of the Project, as we do with other long-term utility system capital investment. However, SDG&E's analogy is misplaced in attempting to compare a 30-year useful life of a power plant to a 34-year going concern analysis of the AMI Project, when the AMI Project has only a 17-year useful life.

SDG&E believes it has gone beyond the Commission's requirement for a 15-year analysis period to show explicit cash flows (both costs and benefits) through 2038. However, these cash flows stemming from a future replacement to the proposed AMI system are not relevant to our analysis. In D.06-07-027 regarding PG&E's AMI project, we noted:

> "The AMI system's useful life does not depend on when the first component fails or how long the last meter-module can be coaxed to function. Its life depends on the system as a whole operating correctly and reliably."[30]

SDG&E would likely install a second generation of AMI starting after 17 years. By 2026 (the last year of the expected system lifetime of the current project), the AMI system as a whole would likely be overtaken by a faster,

---

[30] D.06-07-027, p. 24.

cheaper and higher functioning AMI system that uses a different communications system. A reasonable analogy would be to consider of a new power plant installed in 2026. The benefits of that power plant cannot be ascribed to a (hypothetical) power plant with a 17-year life installed in 2009. Similar logic can be used for a new billing system, a new human resources system or any other new system: the benefits from the new system should be calculated based on the useful life of the system, and should not include projected benefits from the next system installed far into the future.

SDG&E contends the financial analysis or cost effectiveness evaluation will have substantially identical results for a 15- or 34-year analysis time horizon if the terminal value calculation is performed properly and correctly included. However, SDG&E did not perform the terminal value calculation properly and correctly. By including a going concern value consisting of cash flows (as well as replacement costs) from a second generation of meter installations, SDG&E creates a net value beyond what is appropriate for our analysis. Conversely, DRA does include a reasonable terminal value calculation. DRA calculates $27.4 million as a terminal value net benefit arising from the remaining net book value of the AMI meters.

Use of a 17-year analytical timeframe is reasonable.

7.3 Project Costs

Since we adopt a 17-year analytical period, we need only consider costs over a 17-year timeframe. SDG&E estimates costs of $741 million over 34 years, but did not specifically identify a 17-year cost estimate. DRA estimates SDG&E's costs will be $607 million over 17 years, as noted in the comparison exhibit, Exhibit 301. UCAN did not prepare its own cost estimates. We will adopt DRA's

17-year cost estimate, with modifications as discussed below bringing the final cost estimate to $583.5 million.

7.3.1 RFP Specifications

SDG&E requests $238,119,000[31] in total costs over 34 years to upgrade its IT systems. Other than the timeframe, DRA found SDG&E's IT proposal to be generally reasonable.

SDG&E has not selected and executed contracts with vendors for its proposed AMI Project. SDG&E obtained bids from its RFPs, and estimated costs based on those bids. SDG&E intends to make its AMI technology choice in mid-2007. This approach will allow field tests which will provide further analysis of updated product offerings over as long a period as possible while still planning to complete deployment by year-end 2010. SDG&E says it will file executed AMI contracts for Commission review. We will evaluate SDG&E's operational costs based on SDG&E's estimates, even though final costs are not yet known.

DRA believes SDG&E's benefits-driven approach to specifying the functional requirements for the AMI system is a sound approach. However, DRA asserts SDG&E's RFP included certain demanding technical requirements not needed to provide the benefits identified in the business case, and that the RFP did not clearly identify and communicate to vendors which functional capabilities are required and which are not. As a result, DRA believes other AMI vendor may be able to provide the same benefits that SDG&E has included in its

---

[31] SDG&E-Exhibit 30, p. RC-11, table 10-1.

business case at a lower cost and risk than the vendors whose technologies SDG&E will be testing.

The two specific technological requirements questioned by DRA are: (1) two-channel metering, and (2) the requirement that the AMI system must provide 99.5% of all consumption data for 99.5% of the segment by 8:00 a.m. of the next day.[32] In DRA witness Hadden's opinion, "[i]t is entirely possible that direct costs for AMI Technology could be reduced by 15% by relaxing these two requirements, while having no effect on the ability of AMI to support the functions required to provide the projected benefits."[33]

Two-channel metering capability (also known as bi-directional metering capability) can make it possible to offer dual time-variable rates to customers with solar roofs or other distributed generation facilities one time-variable tariff for the energy they consume, and another time-variable tariff for the excess energy they produce and sell back to the utility.[34] SDG&E maintains that requiring meters to have two data channels incurs no significant cost over meters with a single data channel.[35] DRA contends that two-channel metering requires a certain level of processing and memory in the meters because recording and reporting two channels from the meters would increase the amount of data to be communicated back to the utility, compared with single-channel metering, and

---

[32] Ex. 101, pp. 8-4 through 8-16.

[33] *Id.*, p. 8-16, lines 3-6.

[34] Pruschki/5 RT 671/7-16.

[35] Ex. 39, p. TMR-4, lines 8-15; 24-25; Pruschki/5 RT 665/6-16.

thus could increase requirements and costs for the meters and/or for the communications (data transfer capability) component of the AMI system.

The 99% completeness requirement affects how dense and robust the communication network must be. For this reason, it could impact the cost of the communications network. SDG&E claimed that specifying less than the 99% requirement would result in a deterioration of customer service because SDG&E would have to estimate more bills and would receive more customer complaints.[36] DRA contends that SDG&E can maintain its average performance of billing 99.5% of customers with actual meter readings by specifying AMI meter data recovery completeness of less than 99.5%.

SDG&E disagrees with DRA's assertion that the 99% daily requirement is an over-specification. SDG&E states that, in an AMI and DR system, consumers must be provided with sufficient, transparent consumption information and related cost impacts in order to be able to make informed decisions on how much power to consume and when. Customers reasonably expect that such information must match the completeness, accuracy, and reliability of their current bill, independent of the amount of information it takes to calculate this bill.

DRA has presented speculative evidence that suggests SDG&E's proposed system is over-specified and thus more costly than necessary. In reviewing the record, SDG&E has presented convincing evidence that bi-directional metering

---

[36] Ex. 39 (Prepared Rebuttal Testimony of Ted M. Reguly) p. TMR-4, lines 11– 13. "A reduction in the 99% meter read reliability requirement would lower SDG&E's current level of customer service and would increase costs due to more bill estimations, field service calls, and customer complaints."

does not increase costs and the 99.5% accuracy requirement is not an over-specification. SDG&E's specifications are reasonable.

7.3.2 Meter and Communications Systems

DRA contends SDG&E's procurement process did not identify the lowest possible cost AMI system that will provide the benefits projected because SDG&E's RFP did not give clear guidance to bidders about what AMI system features and functions were actually required.

In the AMI RFP, SDG&E identified economic benefits and other AMI benefits for which it did not estimate an economic value. These non-economic (or policy) benefits were not included quantitatively in SDG&E's business case, but the capabilities to support them were included as requirements in the RFP. DRA is concerned that the requirements supporting the policy benefits incur unnecessary extra costs. DRA believes SDG&E's RFP did not give clear guidance to bidders about what AMI system features and functions were actually required.

The functional requirements for SDG&E's AMI system were stated in Appendix D of SDG&E's AMI RFP.[37] Unknown to the bidders, some features and functions marked as "required" and functions were critical to SDG&E.[38] Others were desirable but not essential. According to SDG&E witness Steklac's testimony, the RFP stated 278 requirements, but 227 of them are "not critical."[39]

---

[37] A portion of Appendix D is entered into evidence as Exhibit 116.

[38] Ex. 41, p. IS-2, lines 23 and 24.

[39] 5 RT 704/3-9.

Thus, SDG&E listed as "requirements" features and functions SDG&E considered "superfluous," or desirable but not essential.[40]

During evidentiary hearings, SDG&E witness Reguly acknowledged that SDG&E did not tell the bidders which requirements were critical and which were not.[41] DRA claims this means the bidders had no basis for knowing the minimum requirements with any clarity, and therefore had no basis for proposing an AMI system to meet them. As a result of the alleged over-specification and lack of clarity in the RFP, DRA believes SDG&E cannot know if there is a lower-cost system that could meet its requirements.

DRA recommends SDG&E restate some of its technical requirements and receive revised vendor quotes to more accurately understand the cost-effectiveness of available AMI systems in providing the benefits SDG&E has included in its business case. DRA believes that revising the system specifications may result in a material reduction in both the cost and risk of the SDG&E AMI program.

SDG&E responds that DRA provides no evidence to support its assertions that costs could have been lower. SDG&E states that its analysis demonstrates 8% lower total SDG&E meter and communications costs on a per-meter basis than PG&E while having less than 25% of PG&E's total meter population. SDG&E points out that DRA has not suggested that costs provided via the data request responses are higher than industry expectations, nor demonstrated that

---

[40] 5 RT 673, lines 3 through 5); 5 RT 708/20 through 709/5.

[41] 4 RT 540, lines 3 through 6.

SDG&E's analysis of meter and communications costs on a per meter basis are in any way flawed.

We agree with DRA that it is possible that SDG&E could have been more clear in its RFP about what specifications were required or critical (and which were not). It is possible that SDG&E could have received lower cost proposals had SDG&E been more clear in its RFP, but there is no specific evidence that this is the case. At the same time, we have no reason to believe SDG&E attempted to increase the costs of its AMI Project. SDG&E's application shows a proposal which is weakly cost-effective using all of SDG&E's figures, and which is not cost-effective according to DRA and UCAN. Thus, inclusion of higher cost than necessary would have harmed SDG&E's business case. If approving the application absent the settlement, we would not require SDG&E to restate its technical requirements or reissue its RFP.

7.3.3 Risk Sharing

DRA proposes that a risk sharing mechanism be applied to risk contingency costs included in A.05-03-015.[42] SDG&E agrees with DRA's proposal that $33.8 million (or approximately 7.4% of the total deployment costs) be included as risk contingency prior to a sharing band.[43] SDG&E points out that given this approach to contingency costs, when considering the cost effectiveness

---

[42] DRA opening brief, pp. 67-69.

[43] SDG&E opening brief, p. 72-74.

of the case, a reduction of $23.5 million in costs must be included. This is based on the precedent set in D.06-07-027 approving PG&E's deployment of AMI.[44]

For the purposes of considering cost-effectiveness, it is reasonable to assume DRA's risk-sharing approach and reduce SDG&E's costs by $23.5 million.

7.3.4 Adopted Cost Estimate

Based on the discussion above, it is reasonable to accept SDG&E's cost recommendation of $607 million (as adjusted by DRA for the adopted 17-year timeframe), minus $23.5 million for risk-sharing adjustment, for purposes of considering the cost-effectiveness of SDG&E's proposal. This results in a cost estimate of $583.5 million.

7.4 Operational Benefits

This section concerns the operational benefits associated with SDG&E's AMI Project. Over 50% of the potential operational benefits SDG&E projects for the AMI project relate to meter reading. SDG&E's total meter reading costs are about 40% less, on a per meter read basis, than those of PG&E.[45] SDG&E claims $69.4 million in benefits associated with reduced energy theft (both electric and gas), improved meter accuracy, and reduced billing exceptions.

If SDG&E's Project is approved, once AMI is deployed SDG&E will no longer read meters manually because meter data will be collected remotely by

---

[44] See SDG&E opening brief, p. 73, footnote 306 for details. In summary, in PG&E's cost effectiveness evaluation, the only contingency costs included in the evaluation were those prior to reaching the sharing band ($128.8 million in PG&E's case; $33.8 million in SDG&E's case).

[45] See Table 7-2 and the discussion on page 7-11 in DRA-Exhibit 101.

the AMI system. This means that meter readers will no longer visit customer premises, and SDG&E's customer service field staff will be reduced by approximately 25%.[46] Staff reductions will occur through natural attrition. No meter reader will be laid off as a result of AMI deployment as SDG&E proposes to offer any displaced employee retraining and reassignment.

SDG&E claims employee and customer safety will be enhanced as a result of its AMI project. Since far fewer employees will visit customer premises, typical meter reading injuries and vehicle accidents and usage will be reduced. With the ability to detect electric outages in real time, public safety will be improved through such things as quicker restoration of street and traffic lights, reduction of outage duration for life-support customers, and increasing electric service availability to safety, health, and law enforcement services.

7.4.1 Meter Reading Benefits

7.4.1.1 Meter Accuracy

SDG&E's claims that meter accuracy benefits will amount to $53 million. SDG&E calculated its meter accuracy benefit (the benefit of achieving more accurate readings of meters) as 0.30%. UCAN recommends that SDG&E use an accuracy benefit figure based on recorded and analyzed data for PG&E.[47] SDG&E agrees with UCAN in concept, but believes UCAN used an erroneous figure (0.03%) from an outdated PG&E study. SDG&E shows the correct figure from a current PG&E study is 0.34%.[48] DRA reviewed SDG&E's estimated meter

---

[46] Ex. 23, p. JST-2, lines 22 through 25, Teeter, SDG&E.

[47] Ex. 201, p. 51.

[48] Ex. 50, p. JT-10 line 12 through p. JT-11 line 11.

reading benefits and found them reasonable. We have reviewed the record and find that SDG&E's figure of 0.30% for meter accuracy benefits is reasonable.

7.4.1.2 Energy Theft and Billing Benefits

As SDG&E notes, lost revenues from energy theft and failure to detect meter errors put upward pressure on rates. Ratepayers benefit when energy theft and meter errors are detected sooner and costs are shifted to the customer who actually used the energy.

UCAN recommends the Commission reject attempts to quantify energy theft and billing exceptions. UCAN notes the Commission's decision to authorize PG&E's AMI deployment (D.06-07-027) did not include energy theft benefits. UCAN also notes the Commission's July 21, 2004 Ruling, which provided the comprehensive list of costs and benefits that were to be included in the utilities' final business case analysis, including a category of non-quantifiable benefits that included energy theft benefits. UCAN claims SDG&E's attempt to quantify items previously considered as non-quantifiable should be ignored by the Commission.

SDG&E responds that UCAN does not dispute that reducing energy theft is a benefit, but that UCAN is choosing to subtract this benefit based on a framework developed in 2004 providing guidance to the utilities as they developed their business case analysis. SDG&E argues that it is unreasonable to argue that the energy theft benefit is unquantifiable when reliable studies refute this assertion.

At the time of the July 2004 Ruling, it was not clear whether energy theft benefits would be quantifiable. That Ruling did not rule out future quantification of benefits. SDG&E has in fact quantified these benefits. We have

reviewed SDG&E's calculations of energy theft benefits and find them to be reasonable.

7.4.2 Other Operational Benefits

UCAN claims that SDG&E requests $47 million in other inappropriate operational benefits.[49] UCAN recommends that all of these benefits be excluded from the Commission's consideration.

As an example, UCAN notes the Commission's framework decision included a customer services benefit entitled "load survey" that is classified as an "out of scope" benefit.[50] Instead of treating this benefit as "out of scope," SDG&E quantifies a positive value of $10.6 million.[51] In total, UCAN claims SDG&E inappropriately quantifies approximately $14.5 million in AMI benefits that the Commission has already determined are "out of scope" and not relevant to a final outcome in this proceeding.

In addition, UCAN claims SDG&E quantifies an additional $7.9 million in benefits never considered by the Working Group 3 subcommittee on AMI costs and benefits and therefore never adopted by the Commission.

SDG&E includes approximately $15.6 million in benefits associated with transmission line project deferral and distribution capacity project reductions. UCAN claims the Commission's business case framework decision classifies

---

[49] Ex. 201, p. 52.

[50] As found by the February 19, 2004 ACR (R. 02-06-001), out of scope benefits are defined as an "impact that will not be relevant to the decision of this proceeding." (Page 7.)

[51] Ex. 201, p. 54.

these benefits as DR benefits and not system benefits. UCAN notes those benefits are classified in the July 2004 Ruling as "long term (not yet quantifiable)." Therefore, UCAN says the Commission should exclude this benefit its evaluation of SDG&E's AMI proposal.

SDG&E disagrees with UCAN's assertion that SDG&E's DR impact assumptions should be reduced. SDG&E claims the transmission and distribution (T&D) operational benefits associated with more effective outage management, outage restoration verification and automated T&D system operations are not related to demand and, therefore, should not be reduced.

As with energy theft benefits, we will not reduce SDG&E's benefit calculation simply because SDG&E has quantified a benefit previously considered non-quantifiable or not previously considered. SDG&E's recommendations are reasonable, with one exception. UCAN has identified $14.5 million in out-of-scope benefits. The February 14, 2004 Ruling stated: "'Out of scope' is intended to mean the impact will not be relevant to the decision of this proceeding."[52] UCAN is correct in its interpretation of the Ruling. It is unreasonable for SDG&E to include benefits which are not within the scope of benefits envisioned for this proceeding and therefore operational benefits should be reduced by $14.5 million.

---

[52] Joint Assigned Commissioner and Administrative Law Judge's Ruling providing guidance for the advanced metering infrastructure business case analysis, February 14, 2004, p. 7.

7.5 DR Impacts and Benefits

SDG&E estimates that the present value of DR (DR) benefits equals $262 million, over 34 years.[53] Approximately half (47%) of these benefits are provided by residential consumers. DRA estimates that the value of DR benefits should be calculated as $96 million, over 17 years.[54] DRA contends that SDG&E's proposed and illustrative rate designs and participation rates are unrealistic and based upon highly questionable assumptions. SDG&E argues that a completely accurate evaluation cannot be made because there is no accepted methodology to test its cost-effectiveness, but that it proposes a reasonable methodology.[55] UCAN does not produce a bottom line estimate of DR benefits in its testimony but the values UCAN provided in the comparison table (Exhibit 301) range from $59 to $74 million.

The key drivers of DR benefits are:

1. Average use per customer by time period before being exposed to a new tariff;
2. Price responsiveness (as summarized by price elasticities);
3. The number of customers who choose a tariff or are exposed to the price signal (participation rates);
4. The difference between the new price and the old price by rate period;
5. The value of avoided capacity costs; and
6. The forecast horizon over which benefits are calculated.

---

[53] Ex. 22, p. EF-5, Table EF 2-1.

[54] DRA also adds $18.9 million for information feedback, discussed below.

[55] See SDGE/Gaines, 2 RT 206 and 209.

Differences in assumptions concerning these key drivers underlie the differences in aggregate benefit estimates among the parties. There are no differences among the parties with regard to the first two key drivers. The most significant reasons underlying differences between the parties concern the estimates of participation rates and avoided costs. Any difference in avoided capacity costs leads to a difference in the 4th driver, critical peak prices, so there is a compounding effect if avoided capacity costs differ in that DR is smaller and the value of the savings is also smaller.

7.5.1 Residential Customers

SDG&E requests that the Commission approve its proposed PTR program for residential customers in concept, and has included $123.2 million[56] of PTR related DR benefits in its AMI business case over a 34 year timeframe. SDG&E's business case assumes that the proposed PTR program will be the only dynamic pricing program offered to residential customers for the entire forecast horizon.[57] The PTR program preserves Tiers 1 and 2 rate levels protected by Assembly Bill (AB) 1X, (Statutes 2001, Ch. 4) and ensures that the rates remain revenue neutral between classes.[58]

---

[56] Present value in 2006$ (see Table SSG 6-3 in Ex. 26).

[57] D.06-07-027 adopted a critical peak pricing voluntary supplemental tariff for PG&E, to be offered to its residential and small commercial and industrial (C&I) customers with electric demands below 200 kW. The tariff will be available as an "overlay" in addition to the default rate. The tariff is similar to the rate design used in the Statewide Pricing Pilot (SPP) research project, authorized in D.03-03-036.

[58] A portion of AB 1X is codified as Water Code § 80100. "In no case shall the commission increase the electricity charges in effect on the date that the act that adds this section becomes effective for residential customers for existing baseline quantities or usage by those customers of up to 130% of existing baseline quantities, until such

Footnote continued on next page

Under SDG&E's proposal, all residential customers will remain on a tiered rate structure but be eligible for the PTR program. The PTR program will pay customers for energy reduced during the peak period on critical days when energy usage is very high and supply is tight.[59] SDG&E expects 13 peak events per year, lasting up to seven hours each, for a total of 91 hours per year. While these peak events would likely occur during the summer, SDG&E does not limit peak events to that time of year, nor does it place limits on the actual number of peak events that can be called. Customers would be informed of peak period events through various media messages, including on the internet.

SDG&E proposes a rebate credit of $0.65/kWh for a customer's peak usage below the customer's baseline during a peak event.[60] All residential customers would be automatically enrolled in PTR, and receive a bill credit if their usage falls below a yet-to-be-determined baseline or a reference level during a DR event. Conversely, customers who do not conserve, or who even increase their usage during such periods, would not be penalized in the form of higher rates (although their bills would be higher than if they had reduced usage).

SDG&E estimates the MW of DR that can be expected from residential customers under its PTR program using a set of quantitative relationships and

---

time as the department has recovered the costs of power it has procured for the electrical corporation's retail end use customers as provided in this division."

[59] The tiered rate structure would be similar to that in effect today, but rates would be slightly higher to account for revenue reductions from the PTR rebates.

[60] Ex. 25, p. MFG-15, lines 9-12.

price elasticities developed under the SPP authorized in D.03-03-036[61] and benchmarked to the 2005 Anaheim Pilot.[62] SDG&E's resulting estimate is 105 MW of residential DR expected by 2011 based on participation by 70% of customers.[63] SDG&E projects that the DR would continue and expand in the following years according to assumptions regarding customer growth and average energy use.

We can describe these programs using a "carrot" and "stick" analogy. The Anaheim pilot was a "no lose" program in which where customers were offered 35 cents/kWh to reduce energy on critical days, otherwise remaining on their existing tariff. In the SPP pilot, customers were charged 50-75 cents/kWh on peak on the CPP days (the stick), and lower off-peak prices (the carrot) along with time-of-use rates (higher than their otherwise applicable tariff on weekdays).[64] Customers were offered an appreciation payment of $175 to participate. Under the PTR proposal, customers may benefit from lower bills through adjusting usage (the carrot) but there is no stick if usage is not adjusted. This difference makes comparison to the SPP imperfect. However, while basing its DR projections partially on the SPP pilot, SDG&E did not make any adjustments to its DR calculations to account for the fact that the PTR is not a CPP program.

---

[61] The SPP was a pricing research project designed to estimate the average impact of time-varying rates on energy use by rate period for residential and small commercial and industrial customers.

[62] Ex. 26-E, p. SG-17-SG 22.

[63] *Id.*, at SG-12.

[64] Ex. 201, p. 92.

Unlike the automatic enrollment in SDG&E's proposed PTR program, the SPP and Anaheim pilots were opt-in programs where customers were recruited and gave their consent to participate. For example, in the Anaheim pilot customers received a letter from their utility, followed by a phone call and two subsequent letters, if needed, to enroll the customer. Customers consented to be enrolled by giving their phone number or email address for purposes of notification of events. Again, the difference between "opt-in" and automatic enrollment programs complicates comparisons.

A high proportion of customers who were solicited did not enroll in the SPP and Anaheim pilots. In the SPP, of the customers solicited for one part of the program, 67.8% did not accept the SPP invitation.[65] In the Anaheim pilot, over 70% declined to participate in this "no lose" program.[66] This result occurred even if, as in the case of the SPP, customers were offered $175 to participate or, in the case of Anaheim, customers were assured they had nothing to lose. SDG&E properly noted that there were various reasons why customers did not participate in the SPP (including the requirement to receive a new "smart meter") and in the Anaheim pilot (including "a poor sales job").[67] However, many of these reasons are inapplicable to SDG&E's proposed PTR.

SDG&E's PTR has certain similarities to the statewide 20/20 program. In the 20/20 program, residential customers were given a 20% discount on all summertime usage if they reduced their summertime consumption by 20%

---

[65] Ex. 203, p. 2.

[66] Ex. 201, p. 67.

[67] Ex. 44-E, p. SG-4.

compared to the year before. Both the 20/20 program and the proposed PTR use a baseline methodology, though the definitions of a baseline are different. Both programs have only "carrots" and no "sticks," and thereby are intended to maximize participation without incurring significant recruitment costs. DRA notes that recently published research shows that the 20/20 program was not cost-effective, was expensive, and attracted a much smaller percentage of active participants than policymakers had anticipated.[68] DRA believes SDG&E's PTR program is likely to face the same problems.

SDG&E argues in favor of its PTR program on the basis that it has "carrots" and no "sticks," contending this could maximize participation and DR.[69] SDG&E expects that 70% of the residential customers will be made aware of the PTR program, based on its analysis of elasticities and other factors gleaned from the SPP and Anaheim pilots. Essentially, by "participation" SDG&E means that 70% of customers would be aware of the PTR event when called, and could take action to reduce or shift usage away from the peak period. DRA calculated the participation rate to be 50%. DRA based this lower figure on various differences between the PTR and the pilot programs, including opt-in vs. default enrollment, CPP vs. PTR, and the results of the 20/20 program. DRA calculates a

---

[68] "Evaluation of the California Statewide 20/20 DR Reduction Programs" prepared by Wirtshafter Associates, Inc. on June 6, 2006. This report shows the total cost per kW saved from the statewide 20/20 program is $3,642, 43 times higher than SDG&E's proposed avoided capacity value. The evaluation results indicated "that the program is not cost-effective and should not be continued." (Page xi.)

[69] Ex. 25, p. MFG-15 and MFG-16. SDG&E's Errata revised its June Supplemental Testimony (June Errata), p. 21, lines 10-14. SDG&E PowerPoint presentation on its PTR baseline study at the conference meeting with DRA and CEC on May 5, 2006 (referred as "SDG&E's PTR Presentation" herein).

DR benefit of $38 - $87 million[70] in contrast to SDG&E's estimate of $123.2 million.

UCAN maintains that application of the SPP relationships to SDG&E's residential customers must be adjusted to incorporate reasonable estimates of the willingness of customers to participate in the voluntary program. After such an adjustment UCAN expects 35% participation in the short run, and between 9% and 22% participation in the base and high cases in the longer run. UCAN's objections to SDG&E's assumptions include these assertions:

- DR as predicted by the SPP and Anaheim pilot projects would be substantially lower when applied to the general population on a voluntary basis as proposed in SDG&E's program;
- SDG&E failed to calculate how many customers are willing to act – it equates customer awareness with participation;
- SDG&E ignored that 70% of customers rejected Anaheim's "no lose" pilot; and
- The financial incentives offered to residential customers are too small to sustain meaningful response by customers.

SDG&E's DR estimate appears to assume that all customers are who are aware of the critical day announcements (i.e., 70% of customers) will participate in the PTR program, meaning they may reduce their usage during peak events. SDG&E assumes these customers will replicate the energy savings behavior of customers in the SPP (adjusted for weather and air conditioning saturations in

[70] Present value (2009-20038) and based on SDG&E's avoided capacity value of $85/kW-year. If DRA's avoided capacity value of $52/kW-year and a 17-year AMI life cycle were used, the value is $38 million (see Table 5-2 in Chapter 5 of Ex. 101).

San Diego). SDG&E points out that its numbers are based on average customers. Underlying this average response are customers who chose not to change their usage at all, customers who made modest changes in behavior, and customers who responded quite a lot. This third, relatively small group of high responders, are the ones that provide most of the DR benefits and that will sustain participation over time.[71]

One of the factors that contributes to determining whether customers will provide DR in the long run is whether the incentives are sufficient to compel action. UCAN claims the bill savings available to most customers in SDG&E's PTR program are likely to be too small to sustain continued customer actions to save energy over the long run. For example, residential monthly PTR bill credits for typical customers in the Climate Zone 2 and Climate Zone 3 (inland) are projected to be $1.37 and $2.88, respectively, under SDG&E's assumptions, for four critical events per month during the three inner summer months,[72] amounting to 2-3.5% of the average monthly bills in Climate Zones 2 and 3, respectively.

SDG&E agrees that "these small bill savings might be problematic in sustaining customer interest in reducing demand during the peak period on critical days if every customer (large and small) were to experience these levels of bill savings."[73] SDG&E mentions that 30% of the SPP customers provided 80% of the DR, demonstrating that the distribution of customer price responsiveness

---

[71] SDG&E Opening Brief, pp. 27-28.

[72] Ex. 201, p. 70.

[73] Ex. 44-E, p. SG-10.

was in fact very wide.[74] But UCAN notes that even high responders that save 25% of on-peak energy would save only $2.33 per event on their bill, including both the PTR credit as well as the cost of the energy saved.[75] This constitutes a 3.8% bill savings.

The issue of participation rate is key to our evaluation. We agree with DRA that it is unrealistic to assume that all 70% of those who are aware of the PTR program associated with AMI will, in fact, attempt to reduce their peak energy usage. Based on the record in this case, we agree with DRA and UCAN that a significant number of households would not attempt to lower their peak usage, would not be able to reduce their peak usage or would not reduce their peak usage enough to benefit from the program. These households cannot be considered participants in the sense of being likely to take action in response to the program.

Another problem pertains to the use of a baseline for calculating rate impacts. SDG&E's PTR proposal would incorporate a baseline, so that customer usage would need to decrease below this baseline in order to receive a bill credit. The baseline would compare peak usage in the current period to peak usage in a comparable period (such as the recent few days) to ensure the customer is actually reducing peak usage. However, SDG&E does not specifically define the baseline in its proposal, making analysis very difficult. Considering the baseline concept in theory, customers would have a difficult time understanding the potential for a rebate based on any particular reduction in peak usage, as the

---

[74] SDG&E OB, p. 27.

[75] Ex. 201, p. 76.

baseline information would not be available to the customer at the time when peak reductions are called for.

The baseline issue is problematic in two ways. First, customers' lack of knowledge about what reductions are necessary to receive what level of rebate would likely reduce participation, as price responsiveness is generally dependent on knowledge of prices. Second, some customers would reduce usage, but not obtain a rebate. It is likely that many of these customers would not maintain efforts to reduce usage in response to peak events.

The comparisons to the SPP and the Anaheim pilot are instructive as well. While these programs were not exactly the same as the proposed PTR for SDG&E, analysis of these programs shows that large percentages of households did not participate in them. SDG&E should have considered the limitations of the comparisons. Further, SDG&E should have taken into account the problematic results of the more similar 20/20 program. A reasonable comparison of the PTR proposal with all of these models shows the likelihood of less participation (i.e., customers who are aware of the program and take responsive action) than SDG&E believes.

We note that another problem of SDG&E's illustrative rate design is that a significant proportion of households are so-called "structural benefitors." These are customers who would receive a rebate payment for doing nothing during a peak time event. This occurs randomly due to the nature of a peak event and customer's activities on a peak day. For example, a peak event might occur on the day that a customer starts a vacation.

Based on our review of SPP, the Anaheim pilot, the 20/20 program and SDG&E's proposal, we find that less than 70% of households would both be aware of the program and take action in response to it. We will use DRA's 50%

figure for our analysis. This figure may actually overstate the likely participation level when considering all available information; UCAN's evidence of even lower participation levels may turn out to be more accurate. However, use of a conservative figure is prudent in order to allow for potentially improved results using different rate designs and/or improved communications and technology in the future.

A rate design will not be implemented until 2009. The rate design will be determined in SDG&E's upcoming General Rate Case Phase 2, (A.07-01-047). In that proceeding, we can evaluate the pros and cons of offering a PTR, a voluntary CPP rate design (such as approved for PG&E), or another alternative. It may be possible through use of another rate design to incent a higher percentage of residential customers to reduce peak usage. However, we will base our conclusion on the illustrative rate design in the record.

Using a 50% participation rate, a 17-year timeframe and a $52/MW-year avoided capacity cost (as discussed in Section 7.6), we calculate the expected benefits from SDG&E's DR program for the residential class to be $37 million.

7.5.2 Small and Medium Commercial and Industrial Customers

For small and medium commercial and industrial customers, SDG&E assumes the current TOU rate option remains in effect until 2011. From 2011 and beyond, SDG&E assumes a mandatory CPP rate.

DRA does not dispute SDG&E's participation rate for small commercial customers, or for medium commercial with PCTs. UCAN does not dispute the small commercial participation rate. The key difference between SDG&E's and DRA's estimates of participation for the medium commercial customers is that DRA's participation estimate assumes that commercial customers will continue

to be allowed to opt-out of the default CPP rate back to a TOU rate.[76] SDG&E claims defaulting all customers onto a CPP rate, but allowing them to opt-out to a TOU rate, is unfair because it allows customers to avoid paying the true cost of their energy use. SDG&E believes that customers should have rate options, but that all available options should provide the same economic incentive to provide DR.

DRA disagrees with SDG&E's rate design assumptions for commercial and industrial customers. DRA points out that the Commission has made no determination about whether it will eliminate the current TOU rates and make CPP mandatory. SDG&E's CPP and TOU rates are very different,[77] as are the impacts to individual customers. SDG&E did not perform any bill impact or customer acceptance analysis regarding its illustrative mandatory CPP rate. Therefore, DRA believes there is no justification for assuming 100% participation on a CPP rate for medium commercial and industrial customers beyond 2010. DRA uses a lower participation rate of 69% (the same as its assumption for 2009 and 2010), based on the assumption that customers will continue to have a TOU rate option.

We have not made a determination about rate designs for small and medium commercial and industrial customers. We will do so in SDG&E's upcoming general rate case. It is our intention to design rates which provide clear rate signals to these customers. SDG&E's proposal assumes rate design

---

[76] Ex. 101, p. 5-14, line 24.

[77] Ex. 34, Tables 14-2 and 14-3.

elements which are more consistent with our principles.[78] Although we do not prejudge our future actions here, for the purposes of considering the cost-effectiveness of SDG&E's Project, it is reasonable to use SDG&E's DR estimates for small and medium commercial and industrial customers.

7.5.3 Large Commercial and Industrial Customers

For large commercial and industrial customers, SDG&E assumes their current TOU option will be eliminated in 2009 and replaced with a mandatory CPP rate.

At issue here is whether DR benefits from large commercial and industrial customers should be credited to the AMI deployment. UCAN argues that none of SDG&E's estimated benefits for large commercial and industrial customers should be attributed to the AMI Project. Most of the large commercial and industrial customers already have or will have hourly interval meters prior to AMI deployment. SDG&E acknowledged that it "could implement default dynamic rates (CPP or other dynamic rate structure) with the current technology," SDG&E argues that the communication technology with the current meters must be replaced by 2011, regardless of the AMI deployment. Therefore, SDG&E counted these benefits starting from the 2009 AMI deployment.[79]

---

[78] We also note that there are no legal impediments to adopting CPP or similar rates for commercial and industrial customers, as there are for residential customers due to AB1X.

[79] SDG&E's response to DRA's Data Request No. 28. DRA sent a follow up data request (No. 44) regarding the timing of the required changes to the AB 29X meters. DRA notes that SDG&E's response to Data Request No. 44 is inconsistent with the information in its response to the original question. DRA's analysis relies on SDG&E's response to the original question in Data Request No.28, which seems reasonable.

DRA agrees with SDG&E regarding large customer benefits from AMI starting in 2011, given that the communications technology used to support the already-present AMI meters will apparently be replaced via the AMI project. Prior to 2011, DRA only counts 5% of the benefits from large customers as pertaining to the AMI Project, since only about 5% of large customers will not yet have AMI meters during this period.

While it is true that all large commercial and industrial customers have or will have interval meters, there are benefits that accrue due to the proposed AMI system. The main question is whether benefits for large customers start to accrue before or after 2011. The record shows that by 2009, most if not all large customers will have an AMI meter, whether the SDG&E AMI Project goes forward or not.

It is not appropriate to count large customer DR that would occur without AMI being implemented as AMI benefits. Therefore, it is reasonable to use DRA's calculation of large customer DR benefits, which is $25 million.[80] As SDG&E's figure is $31 million,[81] this results in a decrease of $6 million.

DRA also disagrees with SDG&E's assumption that large customers will have mandatory CPP rates, without a TOU option. As stated above with regard to small and medium C&I customers, we will not prejudge future rates designs, but will assume CPP rates for large customers for analytical purposes.

---

[80] Ex. 101-C, Table 5-2, last column "Recommended."

[81] See SDG&E January 16, 2007 response to ALJ Ruling of December 15, 2006, Scenario 3, "C&I > 200 kW."

7.6 Avoided Capacity Cost

SDG&E proposes to evaluate its DR benefits utilizing a nominal levelized $85/kW-year avoided capacity value, or a $60/kW-year real value. DRA recommends using nominal avoided capacity value of $52/kW-year (or a $36.71/kW-year real value) instead, the same value adopted by the Commission recently D.06-07-027, the decision approving PG&E's AMI business case.[82] However, DRA would also accept a $52/KW-year real value, as was used in D.06-07-027.

When considering this issue, we must first clarify terminology. At various places in the record, parties refer to the avoided capacity value in "nominal" terms and in "real" terms. For example, in Comparison Exhibit 301, avoided capacity value is expressed in real terms, but elsewhere SDG&E's recommendations are expressed in nominal terms. "Nominal" means the use of the actual values in various years, without accounting for the time value of money, while "real" means adjusting to a specific point in time. For the purposes of this cost-effectiveness analysis, it matters not which method we use, but we must use consistent terms to avoid comparing "apples and oranges." For this discussion, we will consider real value because that is how the parties directly compared their proposals, but we will note the nominal value when it is helpful to do so.

Table 3 below summarizes the differing avoided capacity costs per kW-year of SDG&E and DRA's recommendations.

---

[82] PG&E's avoided capacity cost of $52 per kW year was based on the Commission's 2004 Market Price Referent (per Energy Division Revised 2004 Market Price Referent, dated February 10, 2005, adopted in Resolution E-3942).

Table 3

Summary of SDG&E and DRA Capacity Recommendations

[$ per kW-year]

	SDG&E	DRA
A) CT Avoided Cost	60	60
B) CT Market Energy Benefit	-22.89	-35.37
Net CT Avoided Cost	37.11	24.63
C) Resource Availability		-7.39
D) < Planning Reserves	1.51	0
E) Rate Flexibility	13.79	7.5
F) Additional Reliability Value	.021 to 0.53	.021 to .53
Calculated Sum	52.73 to 52.94	24.76 to 25.27
G) Other Benefits	7.06 to 7.27	11.44 to 11.95
Recommended Value (Real)	60	36.71[83]
Nominal	85	52

SDG&E starts its calculations of the levelized fixed annual costs of a combustion turbine (CT) Generator at $85/kW-year (equivalent to a $60/kW-Year real escalating value) based on (1) the Commission's Recommendation in R.02-06-001,[84] (2) the CEC's "Comparative Cost of California Central Station Electricity Generation Technologies"[85] staff report which cites

[83] DRA alternatively recommends a $52/kW-year real value.

[84] R.02-06-001, Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure, Appendix B – Derivation of Capacity and energy values and on and off peak periods, ALJ and ACR filing, July 21, 2004.

[85] Comparative Cost of California Central Station Electricity Generation Technologies. California Energy Commission, Section E-3, Table D-9, August 2003.

average annual fixed costs of $80/kW-year in 2003 dollars as a proxy to the value of avoided energy, and (3) SDG&E's own calculations of a "levelized fixed cost of a CT at $85.84/kW-year."[86] DRA agrees with a real value of $60/kW-Year as an apples-to-apples starting point recommendation.

SDG&E subtracts from the $60/kW-year starting point an annual CT market energy benefit of $22.89/kW-year. This is the price SDG&E estimates that the generator of peak-capacity energy will receive for the incidental energy sold per kW-year. SDG&E calculated this benefit using the price a generator receives from energy sales, less its variable costs, for each hour of the year in 2006 through 2025, using the hourly electricity prices and monthly gas prices from SDG&E's 2004 Long-Term Resource Plan filing.

DRA recommends a CT market energy value of $35.37/kW-year instead. DRA believes that the 91 hours of expected peak hours (13 days times seven hours/day) of potential usage and capacity should be weighed more heavily when considering the potential market energy benefits of an AMI program. SDG&E acknowledges there is considerable variation in estimates of the net energy value benefits. However, SDG&E considers DRA's figures to be arbitrary, asserting that its own methodology accomplishes DRA's objective of producing higher CT profits when energy is more expensive (presumably in the hours when peak events would be called).

Both SDG&E and DRA appear to have the same methodological assumption for CT market energy value. The appropriate value for CT market energy should be the profit a CT can make when operating, and should reflect the fact that the CT is likely to run only when it is profitable. The CT is most

---

[86] Ex. 27, p. JCM-8, line 28 through 29, line 1.

likely to run on days of high energy prices, which should include the projected 13 days (and 91 hours on those days) when peak energy alerts are called. SDG&E's methodology does take into account when the CT is likely to run, producing higher profits in the higher price hours. DRA and UCAN believe SDG&E's method still understates the benefit by allowing the CT to potentially run 1600 hours a year, thereby diluting the peak 91 hours. But CTs will run when it is profitable to do so, and SDG&E's methodology minimizes profit levels in lower energy price hours. Therefore, even if SDG&E uses too many hours in its analysis, the benefit is only slightly understated. SDG&E's figure of $22.89/kW-year for CT market energy is a reasonable approximation.

DRA claims that, whereas a CT is available every hour of the year and tends to operate approximately 822 hours per year,[87] very few DR events can be initiated per year under SDG&E's proposals. SDG&E's analysis is based on the assumption that 13 events would be called each year for a total of 91 hours.[88] Even if SDG&E's critical-peak events were utilized 91 hours per year,[89] this will not replace the need for a CT generator because the CT generator will be needed for the other 731 hours, or 89%[90] of the time each year when they potentially might be dispatched, whether for reliability or economic purposes, as they currently are today. The net result is DRA's recommendation for a real reduction of $7.39/kW-year to SDG&E's estimated avoided capacity value.

---

[87] Comparative Cost of California Central Station Electricity Generation Technologies. California Energy Commission, Section E-3, Table D-5, August 2003.

[88] Ex. 26-E, p. SG-6.

[89] 13 events, 7 hours each = 91 hours of CPP.

SDG&E points out that its PTR may result in more than 13 events and 91 hours per year. But these are the numbers assumed by SDG&E. We agree with DRA that CT generators will still be needed for other hours in the year, and therefore DRA's recommendation for a real reduction of $7.39/kW-year to SDG&E's estimated avoided capacity value is reasonable.

SDG&E claims that, through AMI, it would be able to reduce its planning reserves because a "long term benefit of reduced demand volatility is the possibility of reducing the level of planning reserves (currently 15% to 17% of system peak)."[91] SDG&E claims that "AMI could reduce planning reserves by 1% (e.g., from 15% to 14%)."[92] The latter reduction in planning reserves would result in net additions to the capacity value of $1.51/kW-year.[93] DRA and UCAN disagree with this estimate and do not recommend any reduction in this area. DRA believes Resource Adequacy planning reserves are designed to mitigate generation-related risks, while DR (which is affected by AMI) does not reduce generation risk. UCAN finds this benefit to be speculative and unsupported.

It is the responsibility of this Commission to determine planning reserves. Such decisions are based on many factors, of which the existence of AMI technology may be one. SDG&E's hypothesis is essentially that the Commission will make a specific 1% reduction in planning reserves based solely on the hypothetical possibility of AMI-caused demand changes. This is too speculative

---

[90] 822 – 91 = 731 hours. 731 hours/822 hours = 89%.

[91] JCM-14, line 5, March 28, 2006. Source is D.04-10-035, p. 9.

[92] *Id.*, at lines 7-8., March 28, 2006.

[93] JCM 15, line 12, filed July 14, 2006.

a benefit and too remote from the AMI Project to consider and quantify for these purposes.

SDG&E also calculates a rate design flexibility benefit based on the idea that metering could be used to design different rates than proposed in this proceeding at some time in the future. While DRA agrees that AMI may enable additional rate options in the future, DRA also finds SDG&E's valuation of a $13.79/kW-year capacity value benefit[94] over-valued. Because only a small fraction of SDG&E's energy is actually purchased on the spot market, DRA recommends an incremental valuation of $7.50/kW-year instead. UCAN calls this a speculative benefit based on theoretical economics, arguing that there is no evidence that consumers would make better decisions about consumption that would be worth $13.79/kW to the customers.

There is no doubt that AMI meters could lead to more innovative or flexible rates in the future. For example, because of their capability for hourly pricing, AMI meters can support residential rate designs such as critical peak pricing or real time pricing. As these two types of rate designs may provide more cost-based pricing, SDG&E is correct about potential benefits. DRA offers a different methodology for this portion of the calculation. However, SDG&E's methodology is reasonable for the purposes of cost-effectiveness review of the settlement.

SDG&E adds an additional reliability value of $.021 to $.053/kW-year[95] based programs, "such as Programmable Controllable Thermostats, automated

---

[94] *Id.*, p. JCM – 15, line 2.

[95] Ex. 27, JCM-20, lines 10-11.

energy management systems, and other future technological innovations"[96] which could potentially encourage customers to reduce consumption or demand on short notice with additional technology. DRA does not contest the benefit listed of $0.021/kW-year to $0.53/kW-year.

SDG&E recommends adding about $7/kW-year for additional unique benefits of AMI. These include peak fuel diversity, reduction in market power of generators, smart home integration, and other demand side management innovations. DRA included more additional benefits than SDG&E, but does not agree with the specifics of SDG&E's calculations and recommends an overall lower figure than SDG&E. SDG&E's concept and calculations are reasonable on this point.

By subtracting $7.39/kW-year for continued use of CT generators and $1.51/kW-year for planning reserves from SDG&E's $60/kW-year (in real terms) avoided capacity cost recommendation, we obtain a real figure of $51.10/kW-year for SDG&E's avoided capacity costs. This figure is very close to the $52/kW-year level we adopted in D.06-07-027. Thus, the $52/kW-year figure for SDG&E's avoided capacity cost is reasonable to use for purposes of this application.

7.7 Benefits from Avoided DR Program Costs

In its AMI business case, SDG&E included about $110 million[97] (based on a 34 year timeframe, or about $60 million over a 17-year timeframe) in avoided DR program costs, primarily based on three key assumptions: (1) all of SDG&E's

---

[96] Ex. 27, JCM-19, lines 18-20.

[97] Present value in 2000$ (see Table EF 2-2 on p. EF-13 in SDG&E-Exhibit 22).

day-ahead DR programs will no longer be needed after AMI deployment;[98] (2) a portion of the Technology Assistance and Technology Incentive costs will not be needed due to the success of these programs during the 2005-2008 cycle; and (3) the customer education, awareness, and outreach budget associated with the day-ahead programs will also not be needed.

SDG&E claims that system-wide AMI deployment for customers under 200 kW will avoid the need for DR programs for customers with loads greater than 200 kW. SDG&E claims avoidance of DR programs will reduce non-labor costs (i.e., customer incentives) by $77.45 million and labor reductions (i.e., administrative and general) by $20.18 million. UCAN and DRA contend that the assumed participation rate in the DR programs is overstated, that the Commission did not recognize avoided DR programs as an AMI benefit, and that SDG&E's calculation of avoided costs should be reduced to reflect actual historical expenditures.

As we have stated elsewhere in this decision, we will not ignore benefits or costs simply because the July 2004 Ruling did not anticipate quantification. Nor shall we preclude these figures simply because they were not considered in the PG&E case. We wish to have the most accurate accounting of costs and benefits from the proposal at hand. Therefore, we will not accept UCAN's recommendation to eliminate all benefits from avoided DR programs.

UCAN notes that SDG&E's monthly report to the Commission for December 2005 concerning SDG&E's 2005 expenditures for DR programs documents that SDG&E spent $11.29 million on DR programs that were

---

[98] See RT 2, SDG&E/Gaines, p. 210, lines 6-25.

budgeted at $20.3 million. Of the $20.3 million budget, $8.814 million (43%) was associated with administrative and general (A&G) expenses and $9.954 million was associated with customer incentives (49%). By year-end 2005, SDG&E recorded A&G expenditures of $5.2 million (59%) of its budgeted $8.8 million and only spent $6.04 million of its budgeted $9.954 million in customer incentives (61%). Out of that $6.04 million, SDG&E spent $5.905 million on incentives for its residential and small commercial 20/20 program and $135,000 in customer incentives for all of SDG&E's other DR programs. After excluding recorded expenditures on its 20/20 program, SDG&E spent less than 1.4% of its entire 2005 DR budget on customer incentives.

UCAN recommends adjusting SDG&E's forecast of labor reductions from avoided DR programs downward to reflect actual recorded expenditures. SDG&E assumes levels of benefits it would experience by avoiding DR programs based upon a level of spending on DR that SDG&E has never achieved, i.e., recorded expenditures show SDG&E has never come close to spending its entire authorized program budgets.[99] A&G expenditures for 2005 programs constituted only 26% of the total authorized 2005 budget. Therefore, UCAN recommends including only 26% of SDG&E's forecast of $20.81 million as a potential benefit, resulting in $5.3 million of NPV benefits over the life of the project.

SDG&E claims that its AMI deployment will allow it to reduce future investments in its DR programs. SDG&E states that its customers are better served pursuing DR programs for larger customers in order to avoid an

[99] Ex.210, p. 35.

uneconomic investment in AMI. SDG&E forecasts that it would achieve more from its DR programs (mainly targeted to customers over 200 kW) by 2008 than its entire AMI deployment will achieve over the next 30 years.

UCAN notes that SDG&E forecasts 2008 DR programs for large customers will achieve over 384 MW of DR, at a cost of between $15.4 and $15.9 million. In contrast, UCAN notes that SDG&E forecasts that its system-wide deployment of AMI will not result this level of DR until 2038 when SDG&E forecasts that it will achieve 377 MWs for a cost of $741 million (NPV).

DRA argues that SDG&E's calculation of avoided costs should be reduced to reflect actual historical expenditures by $33 million[100] if one adopts DRA's 17 year analysis period. DRA notes that, as of June 2006, SDG&E's estimated contractual load reduction associated with these DR programs is 53.4 MW.[101] However, in its July Testimony in this proceeding, SDG&E only reduced the DR reflecting the elimination of the day-ahead programs by 11 MW.

DRA contends that SDG&E's methodology involved a contradiction. On the one hand, SDG&E estimated the cost savings of eliminating these DR events based on the total authorized amount for these programs, ($110 million) rather than their recorded historical expenditures. On the other hand, for purposes of determining the load reduction attributable to these programs, SDG&E used the recorded amount, rather than the estimated amount when the budget was

---

[100] On a revenue requirement basis (=$73 million x 45%). The $73 million is shown in Table EF 2-4 on p. 8 in Exhibit 40, Attachment E.

[101] Calculated based on the numbers shown in SDG&E's June 2006 Report on Interruptible and Outage Programs.

adopted. DRA claims the combination of using these contradictory assumptions was to increase the net benefit of eliminating these DR programs.

In 2005, SDG&E only spent 38% of its authorized budget on the day-ahead and Technology Assistance and Technology Incentive programs, and 62% was unspent. If only the recorded load reduction was used to reduce the total AMI DR benefits estimates, SDG&E's program cost savings were overstated. Therefore, DRA adjusted SDG&E's estimated cost savings for these programs by the 2005[102] unspent percentage (62%). The total avoided costs based on the 2008 budget for the day-ahead and TA/TI programs are about 72% of the total. Therefore, DRA recommends reducing it by 45%[103] to $33 million (this also adjusts for the 17-year timeframe). Alternatively, if the Commission adopts the full $110 million (or about $60 million over a 17-year timeframe), DRA argues we should offset the AMI DR by the full contractual amount of 53.4 MW, or at minimum, by 28 MW, which is the most recent recorded performance of these programs.

SDG&E criticizes DRA's analysis in three ways. First, SDG&E says its 2005 DR programs are not representative of future programs. Second, SDG&E says recent actions by the Commission demonstrate commitments to expansion of DR programs. Third, SDG&E claims 2005 was not a representative year in terms of the number, frequency or duration of DR program events. SDG&E argues that, to the extent that fewer than the maximum number of events occur (or fewer customers enroll and participate in programs), SDG&E's program expenditures

---

[102] The first year of the 2005-2008 budget cycles.

[103] 72% x 62%.

will be less than budgeted. SDG&E points out that the historical number of program events has been less than the program design maximum.[104] SDG&E contends that fact alone should not be the basis for an artificial reduction in expectations of future program events or expenditures.

SDG&E claims implementing AMI and the DR rates/programs it enables will result in tangible reductions to traditional DR program spending. SDG&E believes that, with the deployment of AMI, a certain portion of its then-existing 2008 DR program portfolio will be eliminated, or at least scaled back as other AMI-enabled tariffs and programs are put in place. SDG&E anticipates that with the deployment of AMI beginning in mid 2008 and rate/program roll-out beginning in 2009, the need for certain of its existing and anticipated future DR programs will be reduced.

We do not anticipate eliminating all DR programs in the event SDG&E's AMI program is approved. We also reaffirm our commitment to appropriate DR programs in the future. At the same time, we recognize that there is an interaction between the proposed AMI Project and the need for specific DR programs. Therefore, we agree with SDG&E that AMI will lead to a reduction in duplicative spending on DR programs.

However, DRA and UCAN make a valid argument that SDG&E appears to overstate the benefits of its current DR programs. While there is no way of telling whether SDG&E's recent experience is predictive of future experience in terms of DR events, the record does clearly show that SDG&E significantly underspent its DR budget in recent years. SDG&E offers no compelling

---

[104] Ex. 45, p. MFG-16, Table MFG 19-2.

argument about why these figures should be disregarded. Further, we have not made affirmative decisions to reduce all the DR programs SDG&E assumes will be eliminated. We will therefore use SDG&E's historical figures as a basis to estimate future DR activities.

Both DRA and UCAN present useful methodologies to reduce SDG&E's estimates for benefits from avoided DR program costs. DRA's method appears to be somewhat more rigorous. While we could adopt DRA's suggestion to reduce DR benefits to take this into account, we will instead use DRA's parallel recommendation to reduce the benefits resulting from SDG&E's avoided DR programs by $33 million (based on a 17-year analytical timeframe).

7.8 Information Feedback Systems Benefits

DRA quantified AMI-related benefits attributable to the website presentation of day-late energy use. DRA assigned a $19 million value to this Information Feedback Systems benefit, based on a 17-year analytical period.[105] SDG&E agrees. We will use this figure and add $19 million to the cost-effectiveness calculation.

7.9 Non-Quantifiable and Newly Quantifiable Benefits

SDG&E contends that various non-quantifiable, or difficult to quantify, benefits must be considered by the Commission as they evaluate the merits of SDG&E's AMI application. These non-quantified benefits were not included in SDG&E's main financial analysis.

---

[105] See DRA-Exhibit 101, Table 1-1, p. 1-1, and Ch. 10.

These various benefits (and potentially others) are real, even if not quantified. In its January 16, 2007 comments on ALJ Gamson's December 15, 2006 Ruling (see Section 8.1 below) SDG&E identified and quantified a number of benefits previously considered non-quantifiable (we refer to these as newly-quantified benefits).[106]

We have already stated that we will count benefits (except for out-of-scope benefits) that were previously considered non-quantifiable, to the extent that reasonable quantifications can be made. We examine each category, except for those for which SDG&E calculates insignificant benefits[107] (i.e., no more than $1 million at the high end).[108] As discussed in detail below, we use a total of $32 million to $43 million in additional benefits from newly quantified sources.

7.9.1 Implementation of Time Differentiated Rates

SDG&E proposes $0 to $26 million for this category of benefits. SDG&E proposes to assume that its residential rates will change from PTR rates to CPP rates after 2013. This proposal assumes that AB1X rate caps will end in 2013 and that the Commission will adopt residential CPP rate at that point. As UCAN

---

[106] SDG&E's filing claims between $90 million and $387 million in newly quantifiable benefits. However, SDG&E counts between $19 million and $207 million in benefits for "information feedback." As discussed in Section 6.8, SDG&E has already agreed to DRA's recommendation of a $19 million benefit. Therefore, SDG&E proposes between $71 million and $180 million in newly quantified benefits.

[107] SDG&E lists "improved customer service and satisfaction" and "reading water meters" as benefits, with a collective range of $0.38 million to $0.72 million in benefits.

[108] SDG&E also lists "optimized deployment sequence" as an additional benefit, without providing any quantification for this benefit.

points out, there is significant controversy about when AB1X rate caps can legally be lifted. DRA opposes residential CPP rates and objects to counting this benefit. We do not have a sufficient record to engage this complex legal question here.

SDG&E itself argued in its June 21, 2006 supplemental testimony that a voluntary CPP tariff similar to that adopted for PG&E would not be a good fit in SDG&E's territory; it is hard to see how a more stringent mandatory CPP tariff would be more acceptable. Even assuming that SDG&E is correct on its reading of the AB1X statute, it is highly speculative to assume the Commission will adopt residential CPP rates in the future. Even if this does occur, SDG&E suggests the benefits may be nil. Therefore, we will use a zero figure for benefits in this category.

7.9.2 Improved Public Safety

SDG&E proposes $11 million to $15 million for this category of benefits. SDG&E attributes these benefits to increased security and tolerance to attacks/natural disasters, detecting customer's electrical back-feed into SDG&E's electrical system from unmapped photovoltaic or distributed generation sources, and quicker detection of gas leaks. DRA points out that these purported benefits rely on our rejected 34-year timeframe analysis and implementation of smart grid technologies that are often unrelated to SDG&E's AMI proposal. We agree with DRA's calculation of $5 million for this category of benefits.

7.9.3 Environmental

SDG&E proposes $8 million to $54 million for this category of benefits. SDG&E claims the conservation effect of information feedback can provide an additional $8 million in carbon dioxide (CO2) reductions, and AMI DR can provide $46 million of reduced nitrous oxides (NOx) and sulpher oxides (SOx)

emissions during critical peak periods and from use of distributed generation. DRA agrees with the calculation of $8 million in CO2 benefits. However, DRA disagrees with the SDG&E calculations for NOx and SOx benefits, finding a potential of $3 million in benefits based on greenhouse gas adders adopted in D.04-12-048.[109] DRA's calculations are reasonable, as they are based on established valuations. DRA's calculations result in $11 million for environmental benefits.

7.9.4 Enabling Technologies Advancements/Deployments

SDG&E proposes $24 million to $48 million for this category of benefits. SDG&E calculates this benefit comes from assuming Title 24 energy code requirements for PCTs will be adopted by the CEC. DRA agrees that PCTs can be an effective means to increase DR, but notes that SDG&E has unreasonably attributed all PCT benefits to AMI and has ignored the costs of PCTs. UCAN points to studies showing PCTs are not cost-effective. UCAN also points out that the 2008 Title 24 building standards are only a proposal at this point, and that a utility need not have AMI to implement a PCT program.

We note that SDG&E's Table 1 in its January 16, 2007 filing shows $13 million for the PCT benefit, not the $24 million to $48 million discussed elsewhere in its filing. SDG&E has reasonably shown that there are likely to be net benefits for PCT technology, but has not supported the higher $48 million level. A range of $13 million to $24 million for this category is reasonable.

---

[109] DRA also calculates a high figure of $30 million for environmental benefits if ratepayers are able to access real-time usage information through a wireless network, a feature not included in SDG&E's plan.

7.9.5 Smart Grid

SDG&E proposes $28 million to $36 million for this category, as incremental benefits.[110] These incremental benefits are based on the San Diego Smart Grid Study Final Report, which showed 20-year net benefits from infrastructure improvements, including AMI. DRA points out that the smart grid system includes many systems beyond the scope of SDG&E's AMI system, including WiMAX and Ethernet-over-fiber communications. DRA claims there is no connection between many of these technologies and the AMI system proposed by SDG&E, and recommends a value of zero incremental net benefits. Since our analysis, using SDG&E's own method, has already directly incorporated the most likely smart grid benefits, we cannot add further benefits for potential technologies which may not come to fruition and do not have a clear nexus with the proposed SDG&E AMI system. We will use a zero figure for incremental benefits in this category

8. SDG&E's AMI Application is Not Cost-Effective

The total adopted costs for SDG&E's AMI Project are $583.5 million as adjusted for a 17-year analytical timeframe. The total adopted benefits to ratepayers over 17 years are $502 million,[111] a gap of $81.5 million.

---

[110] SDG&E claims this figure eliminates any double-counting of benefits already incorporated into its analysis.

[111] This figure is substantiated in SDG&E's January 4, 2007 response to the December 15, 2007 ALJ Ruling. Table 1, column 3 in that filing delineates the costs and benefits of the SDG&E AMI Project under the assumptions used in this decision. SDG&E's figure of $508 million is adjusted for $6 million in reduced large customer DR benefits, discussed herein in Section 6.5.3, but not reflected in Table 1.

We must also consider if there could be sufficient additional societal benefits to overcome the lack of cost-effectiveness of SDG&E's AMI proposal from the ratepayer's perspective. Although the additional benefits discussed in Section 6.9 do not necessarily impact ratepayers directly, it is appropriate to consider the societal impacts of SDG&E's proposal as well. We have found reasonable about $32 million to $43 million in newly-quantified societal benefits. Now that SDG&E has quantified virtually every category of benefits previously considered non-quantifiable, there are few, if any, non-quantified benefits which could assist in consideration of the cost-effectiveness of the SDG&E AMI proposal. Thus, even including all the newly quantified benefits, the costs of SDG&E's AMI proposal still exceed the benefits by at least $37.5 million, and up to $48.5 million.

We conclude that SDG&E's Project as discussed in its application is not cost-effective. Combined with our finding that SDG&E has not yet met the Commission's functionality criteria, we could not approve SDG&E's application as originally submitted, absent the settlement.

9. Alternative AMI Program Options

Although we could not approve SDG&E's application as submitted, we remain committed to our belief that the operational and DR benefits of AMI technology should be made available statewide over time. Therefore, we are interested in alternative AMI program options that may deliver many of the benefits identified by SDG&E in a cost-effective way. Prior to the parties' settlement, the Commission solicited alternative AMI program options for SDG&E, as discussed in this section. A brief discussion of these alternatives also informs the reasonableness of the settlement.

9.1 December 15, 2006 ALJ Ruling and Comments

UCAN suggests a gradual roll-out of cheaper time-of-use meters for residential customers.[112] UCAN notes that data shows that large customers had much higher use during summer on-peak periods and much lower load factors than small customers.[113] In addition, most customers use very little energy. UCAN references survey data showing that about 63% of SDG&E's 1997 residential customers used less than 6,000 kWh/year, with an average usage among these customers of 3783 kWh/year.[114]

Therefore, one alternative to the full SDG&E AMI Project would be a targeted roll-out of AMI technology. In order to move toward cost-effectiveness—while still achieving the Commission's overall objectives and gaining the public policy benefits of AMI—SDG&E potentially could significantly reduce the number (and overall cost) of installed meters by limiting installation in the residential sector to those customers most likely to reduce peak usage, and/or to those customers with the greatest potential peak reductions. In the residential class, most of the likely DR would come from a relatively small group of households. A summary of SPP participation provided in shows that

---

[112] UCAN suggests this could occur starting at the end of the AB1X period, with meters required first in new single-family construction and potentially later in customers above a certain size.

[113] Ex. 201, p. 25.

[114] *Id.*

30% of the SPP participants were high responders, providing 80% of the total demand reduction on critical days.[115]

Based on the potential for a cost-effective targeted roll-out, ALJ Gamson issued a Ruling on December 15, 2006 reopening the record and seeking further information about possible alternatives to SDG&E's recommendation. Specifically, the Ruling sought information to allow consideration of an AMI program whereby all commercial and industrial customers would receive AMI technology as proposed by SDG&E, but only residential customers inland would be outfitted at this time. Parties were also given the option to propose other alternatives. SDG&E provided the requested data on January 4, 2007. SDG&E, UCAN and DRA commented on January 16, 2007.

The Ruling suggested targeting the residential customers most likely to reduce peak usage. These will be customers with high usage, as they have the greatest ability to decrease their overall usage and receive a significant enough financial benefit. Customers who lower usage may be able to reduce their usage significantly, but the financial reward would be small. Even for customers with high usage, the greatest impact would probably be from those with discretionary usage that could be reduced at peak times. Residential customers in the warmer Climate Zone 3 are more likely to have higher, and more discretionary, usage.

SDG&E's data shows that a partial roll-out to Climate Zone 3 customers incorporating the parameters of this decision does not significantly improve cost-effectiveness. While costs (based on the Ruling's parameters) decrease significantly from $583 million to $406 million due to installation of fewer

---

[115] Ex 44-E, p. SG-11.

residential meters, benefits decrease significantly as well due to partial retention of meter readers, reduction of other operational benefits, and some reduction of DR benefits. SDG&E shows that the cost-effectiveness of the partial roll-out is nearly the same as full roll-out – that is, neither are cost-effective using the Ruling's parameters. UCAN and DRA also do not believe this option is cost-effective.

9.2 SDG&E AMI Alternative Proposal

As allowed by the December 15, 2006 Ruling, SDG&E proposed what it characterizes as a new alternative. Essentially, this alternative constitutes SDG&E's recommended AMI Project with a few new assumptions, but little or no change to the proposed project.

First, SDG&E proposed to use a 20-year evaluation timeframe, based on the use of that figure in the PG&E case. Second, SDG&E proposes an assumption that all residential customers would be placed on a critical peak pricing schedule after 2013. Third, SDG&E proposes an assumption of implementation of proposed Title 24 provisions requiring all new construction and remodels to have PCTs central air conditioned buildings. Under SDG&E's alternative scenario, SDG&E estimates costs of $608 million and benefits of $626 million, leading to a positive cost-effectiveness outcome of $18 million.

As discussed herein, we utilize a 17-year analytical timeframe for SDG&E because it corresponds to the useful life of the Project. The PG&E analogy supports this 17-year timeframe, as we used a 20-year timeframe for PG&E to correspond with a 20-year useful life for PG&E's AMI Project. There is no basis in the record for a 20-year timeframe. We have discussed SDG&E's proposal to assume residential critical peak pricing rates after 2013 in Section 6.9.1. We found no need to adjust our cost-effectiveness analysis for this proposal. We

have discussed SDG&E's proposal to assume new CEC Title 24 energy code requirements for PCTs in Section 6.9.4. We use a value of $13 million to $24 million for this benefit.

SDG&E's alternative does not sufficiently improve net benefits compared to our analysis of SDG&E's original AMI Project to make its alternative cost-effective.[116] Further, SDG&E now supports the Settlement Agreement.

9.3 UCAN Alternative

UCAN recommends that, instead of the AMI Project, SDG&E can achieve the Commission's DR objectives by taking the following steps:

- Deploying interval meters to a limited subset of SDG&E customers – those SDG&E customers that are over 20 kW in size.

- Expanding the Comverge program so as to secure cost-effective and immediate peak demand reductions benefits amongst residential customers.

- Aggressively pursue air conditioner efficiency (for all sizes of customers) and combined heat and power producing chilled water to reduce air conditioning demand (for larger customers).

- Re-assess UCAN's 2000 proposal for a gradual roll-out of cheaper time-of-use meters for residential customers – starting at the end of the AB1X period, with meters required first in new single-family construction and potentially later in customers above a certain size.

- Take immediate steps to see that all residential swimming pools are equipped with load control devices that the utility can use at its discretion

[116] After rejecting SDG&E's 20-year analytical timeframe and post-2013 residential CPP rate design, SDG&E's alternative is exactly the same as SDG&E's main AMI Project when newly-quantified benefits are included.

for up to 1000 hours per year through incentive programs and local licensing/code strategies.

UCAN contends that SDG&E proposed deploying AMI meters universally rather than deploy the meters incrementally and focus upon those customers who could most readily harness the functionalities of the new meters. UCAN supports deployment of interval meters to a limited subset of SDG&E customers – those SDG&E customers that are over 20 kW in size and believes pricing programs should be offered to these customers. UCAN notes these customers between 20 kW and 200 kW comprise only 1.25% of SDG&E's projected 2011 customer base but SDG&E expects them to provide 32% of its 2011 MW savings achieved from customers under 200 kW.[117]

UCAN suggests that for customers under 20 kW, the Commission should consider expanding the Comverge Summer AC Saver program.[118] The program directly controls and cycles customer air conditioners, electric water heaters, and pump motors. As of June 2006, SDG&E reports a total enrollment of 8,740 customers for a total of 17.2 MW in dispatchable load reductions. UCAN asserts the program is a more cost effective alternative than SDG&E's PTR for obtaining measurable and dispatchable DR.

UCAN believes that efficiency and combined heat and power solutions must be an integrated part of a peak demand solution. UCAN notes that SDG&E, SCE and PG&E (as part of their 2006-2008 energy efficiency portfolios)

---

[117] Ex. 201, p. 22.

[118] Ex. 201, pp. 57-58.

are launching a statewide HVAC quality installation campaign.[119] UCAN believes a ramp-up of this program, in conjunction with cash rebates to promote higher efficiency equipment, should be at the top of SDG&E's priority list. UCAN claims these steps could be taken immediately.

Further, UCAN suggests SDG&E should aggressively pursue equipping of all new and residential swimming pools are equipped with load control devices that the utility can use at its discretion for up to 1,000 hours per year. UCAN suggests SDG&E could offer a program by which pools without remote load control devices would pay a summer adder, or this could be achieved through a combination of tariffs, local building permit processes, and Title 24 changes.

UCAN's proposals have merit. As a whole, UCAN seeks to attain the benefits of AMI technology where cost-effective (i.e., for large customers) and to attain the desired benefits of DR for other customers through expansion of existing programs. However, we have concerns that UCAN's recommendations do not clearly lead us to a broader implementation of AMI technology, as it becomes more cost-effective and functionality improves. Further, UCAN now supports the Settlement Agreement.

9.4 Technological Improvements

We have found that SDG&E's original AMI proposal currently does not meet the functionality criteria required for this proceeding, as SDG&E is unable to show at this time that its specific requirements would be met. While we are confident that SDG&E ultimately will be able to meet our functionality criteria after contracts are signed with vendors, we now believe this level of functionality

[119] Ex. 201, p. 23.

may not be sufficient for the longer run. Our vision is that all customers, over time, will have more access to more information about their electricity usage, be better able to act upon that information, increasingly be able to interact with the utility to better customize services, and have greater ability to work with their own selected suppliers and technologies to manage their environments. Had we adopted SDG&E's recommendations, we would have acted to continue movement toward enhanced Smart Grid functionalities.

In order to provide the Commission and policymakers with an alternative vision of grid investment possibilities, UCAN initiated a study in early 2006, conducted by the Energy Policy Initiatives Center (EPIC) located at the University of San Diego that examined the deployment of an integrated "smart grid" in the SDG&E service area. SDG&E later agreed to jointly fund the project with UCAN and to participate in the development of this report.

UCAN maintains that SDG&E's AMI proposal has a too-narrow focus upon DR and meter readings and that SDG&E has not adequately applied a system-wide view to its initiative. UCAN believes SDG&E would have benefited from having considered the findings of the EPIC study before unveiling its AMI proposal.

UCAN also took issue with SDG&E's decision not to incorporate a broadband component to its AMI proposal. UCAN noted that broadband communications capabilities, when added to an electric distribution grid, could facilitate the offering of a number of very useful end-user products and services, including:

- Automated monitoring and control of end-use equipment, including DR and load shedding;
- Billing data and energy consumption data;
- Real-time building security monitoring/reporting;

- Automated inventory tracking of various goods such as fuel stocks;
- Dynamic price information;
- Video on demand;
- Streaming audio delivered through a stereo or computer;
- Real-time, interconnected Internet-based games; and
- Transmission of data/telephone/fax without multiple fixed lines;

We believe it is likely that new technologies will increase functionality and/or reduce costs in the near future. We have received promising information from Southern California Edison in its recent AMI filing as well as in the Smart Grid study in San Diego. We hope the fruits of such advancement allow SDG&E's customers (large and small) to continue to garner the advantages of new technologies in the future, as has already been achieved through integration of HAN and remote connect/disconnect in the Settlement Agreement.

We agree with UCAN that there are a wide variety of possible technological advances, new functionalities and potential benefits which may be available to complement a cost-effective AMI program. Some of these functionalities and benefits are a part of the Settlement Agreement, to which UCAN is a party. The formation of the TAP should lead to a robust review of AMI-related technologies by the various stakeholders, thereby improving the overall Project.

10 Analysis of the Settlement Agreement

10.1 Cost-Effectiveness of the Settlement Agreement

As discussed above, the Settlement begins with the SDG&E AMI application, and makes specific modifications. The cost-effectiveness evaluation thus starts with the SDG&E business case. After considering newly-quantified

benefits, we have found that the SDG&E business case is not cost-effective, as it has costs of between $38.5 million to $49.5 million more than its benefits.

The Settlement itself does not specifically discuss how or if its provisions would be cost-effective. However, the Settling Parties February 23, 2007 Response to ALJ Gamson's Ruling (Exhibit 64) and the February 27, 2006 evidentiary hearing provide sufficient record information to evaluate the cost-effectiveness of the Settlement.

The Settlement provides that SDG&E costs for 2007-2011 (inclusive) will be $572 million, subject to specified contingency and sharing proposals. This figure is not directly comparable to SDG&E's proposal AMI cost of $741 million over 34 years, or DRA's proposed cost of $607 million over 17 years. Nor is it directly comparable to our calculated cost of SDG&E's AMI Project, which is $583 million over 17 years. Instead, the $572 million figure is intended to represent SDG&E's expected expenditures, in nominal dollars, for 2007-2011, and is used as a starting point for the risk-sharing mechanism of the Settlement. The Settling Parties state that post-2011 expenses would be reviewed in general rate cases for future years. By contrast, the figures we have used for cost-effectiveness analysis encompass the life of the Project.

In Exhibit 64, the Settling Parties show the cost of the Project, using the assumptions incorporated into this decision, increases from $583 million to $652 million due to the additional functionalities (e.g., HAN and remote connect/disconnect) provided for in the Settlement. Exhibit 64 shows these functionalities increase the benefits of the Project from $508 million to $666 million. Because our analysis differs slightly from the figures used in Exhibit 64, we have found $502 million in benefits from SDG&E's proposal instead of $508 million. Adding in the additional functionalities from the

Settlement, total Project benefits in our analysis are now $660 million. Therefore, we find that SDG&E's proposal, as modified by the Settlement, provides a net benefit of $8 million ($660 million in benefits minus $652 million in costs).

Further, we have found $32 million to $43 million in newly-quantified benefits for SDG&E's proposal, which would also occur with the Settlement but which the Settling Parties testified are not counted in the Exhibit 64.[120] In total, we find between $692 million and $703 million in benefits. Compared to the total cost of $652 million, we find between $40 million and $51 million in net benefits for the Settlement Agreement.[121]

Overall, we find the figures from the Settlement to be reasonable and compatible with the record. Therefore, with the modifications of the Settlement Agreement, we find SDG&E's proposal to be cost- effective.

10.2 Reasonableness of the Settlement Agreement

In approving the Settlement Agreement, Rule 12.1(d) requires the Commission find the Settlement Agreement to be reasonable in light of the whole record, consistent with the law, and in the public interest. In addition, D.92-12-049 (46 CPUC2d 538) (where the Commission originally articulated policy regarding review of settlements), calls for review to determine if the Settlement Agreement includes information sufficient to allow the Commission to determine its overall reasonableness.

---

[120] 8 RT 942-943

[121] The Settling Parties estimate total net benefits of between $14 million and $192 million. See the February 23, 2007 Response to ALJ Gamson's February 16, 2007 Ruling, p. 6, (Response #3).

Here, the Settlement Agreement commands unanimous sponsorship of all active parties, thus conferring a greater sense of deference to the Settling Parties. The Settling Parties are fairly reflective of the affected interests: DRA represents ratepayer interests, especially residential and small commercial/industrial customers; UCAN also represents residential and small commercial ratepayer interests, and since 1984 has been the most active non-governmental ratepayer advocate in SDG&E matters before the Commission. Thus, the parties to the Settlement represent the full panoply of ratepayer interest affected by this application. These are "parties ideally positioned to comment on the operation of the utility and ratepayer perception" as required by D.92-12-019, 46 CPUC 2d.

We will evaluate the Settlement Agreement by the factors set forth in Rule 12.1(d) and D.92-12-019.

10.2.1 Does the Settlement Agreement Include Sufficient Information to Determine its Overall Reasonableness?

The Settlement starts with the SDG&E proposal in its application, and makes specified modifications. The Settling Parties fully developed their positions before settlement and submitted prepared testimony and additional information requested by the ALJ. The Commission held eight days of evidentiary hearings, which assessed the strengths and weaknesses of parties' positions. SDG&E's application contained sufficient detail to evaluate its reasonableness; however, we have found that we cannot approve SDG&E's application. The modifications contained in the Settlement are fairly detailed, and were explained more fully in Exhibit 64 and through responses to ALJ questions at the February 27, 2007 evidentiary hearings. The totality of the information provided is sufficient to allow us to determine the overall

reasonableness of the Settlement and to permit us to discharge our future regulatory obligations with respect to the parties and their intentions.

10.2.2 Is the Settlement Agreement Reasonable in Light of the Whole Record?

The key aspects of the Settlement Agreement are set forth in Section 4 above. Settlement does not bring new issues into the proceeding, nor does it seek to formulate new Commission policy. The record shows that the resolutions of particular issues adopted in the Settlement are within the range of positions taken by parties on such issues. On the central issue of cost-effectiveness, the calculations supporting the Settlement are consistent with the litigation positions taken in the proceeding. Moreover, on discrete issues, the Settlement generally adopts some result that was specifically recommended by one party or another in their testimony. The Settlement generally does not introduce new concepts or mechanisms outside the litigated record. It is also apparent that the Settlement reflects give-and-take. As an example, the allocation of revenue responsibility between customer classes is a central issue in this application. The issue is resolved in the Settlement by adoption of a compromise between DRA and SDG&E's initial recommended allocation proposals.

10.2.3 Is the Settlement Agreement Consistent With the Law?

The Settling Parties represent that no term of the Settlement contravenes statutory provisions or prior Commission decisions.[122] The Settling Parties

[122] In D.00-09-037, the Commission based its finding that the third criteria had been met on representation by the settling parties that they expended considerable effort ensuring that the Settlement Agreement comports with statute and precedents and did

Footnote continued on next page

reached Settlement in accordance with Rule 12.1 of the Rules. We have reviewed the Settlement find it to be consistent with the law.

10.2.4 Is the Settlement Agreement in the Public Interest?

We have found that the Settlement Agreement is consistent with our criteria for implementability and cost-effectiveness. We will ensure that our functionality criteria are met through required Commission review of advice letters.

The Settling Parties contend the Settlement Agreement benefits ratepayers and serves the public interest by resolving issues in a collaborative fashion. For example, the public interest will be further served by the establishment of the TAP. The TAP will serve to advise SDG&E in the implementation of the AMI project and consider emerging AMI technologies such as those identified in the EPIC study, referenced in the UCAN and SDG&E testimony and briefs. Further, the Settling Parties have a long history of taking opposing positions. We find that the Settling Parties have used their collective experience to produce a sound outcome without the need for further commitments of scarce time and resources.

11. Comments on Proposed Decision

The proposed decision of the in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____.

---

not believe that any of its terms or provisions contravenes statute or prior Commission decisions.

12. Assignment of Proceeding

Dian M. Grueneich is the assigned Commissioner and David M. Gamson is the ALJ in this proceeding.

Findings of Fact

1. The May 9, 2005 Assigned Commissioner/Administrative Law Judge Ruling in this proceeding requires that SDG&E must show:

   a. that it meets the functionality criteria set forth in the Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the AMI Business Case Analysis issued February 19, 2004 in Rulemaking (R.) 02-06-001;

   b. that its proposed AMI Project is cost-effective; and

   c. that it has a serious plan for accomplishing the task of integrating the AMI investment into its operating systems to ensure that the expected benefits in the areas of customer service, billing, outage management, and operations and maintenance accrue.

2. SDG&E has not yet chosen an AMI technology, has not selected technology vendors and has not signed contracts with any technology vendors to support its AMI project.

3. SDG&E has a clear plan for implementing its AMI Project. The plan involves identifying vendors based on its RFPs, negotiating contracts with selected vendors, and performing the needed work between 2007 and 2010. This plan also applies to the Settlement Agreement.

4. SDG&E's pre-tax authorized rate of return is 8.23%.

5. SDG&E's AMI Project should be evaluated on a Project basis, not on a company basis.

6. Terminal value in the context of project evaluation means residual value, not going concern value.

7. The analytical timeframe for evaluating the cost-effectiveness of SDG&E's AMI Project is 17 years, because the useful life of the project is 17 years.

8. SDG&E has not selected and executed contracts with vendors for its proposed AMI Project. SDG&E obtained bids from its RFPs, and estimated costs based on those bids. These costs are appropriate for evaluating the cost-effectiveness of SDG&E's AMI Project.

9. SDG&E's RFP specification for bi-directional metering does not increase costs.

10. SDG&E's RFP specification for a 99.5% accuracy requirement is not an over-specification.

11. For the purposes of considering cost-effectiveness, we will assume DRA's risk-sharing approach is adopted and reduce SDG&E's costs by $23.5 million.

12. Over 17 years, SDG&E's estimated costs are $607.5 million, before adjusting for the DRA risk-sharing proposal. The DRA risk-sharing proposal reduces SDG&E's estimated costs by $23.5 million, resulting in a final cost estimate of $583.5 million.

13. There are $14.5 million in operational benefits in SDG&E's proposal which are out-of-scope for this proceeding and should not be counted in evaluating its cost-effectiveness.

14. SDG&E's proposal has operational benefits of $54.9 million.

15. A reasonable estimate of meter accuracy benefits is 0.30%.

16. SDG&E's recommendation for energy theft benefits is reasonable.

17. For analytical purposes, it is reasonable to assume 50% of households would both be aware of SDG&E's proposed Peak Time Rebate program and take action to reduce peak energy usage in response to it.

18. Large customer DR that would occur without AMI being implemented should not be counted as AMI benefits.

19. SDG&E's $85/kW-Year nominal levelized value is equivalent to a $60/kW-Year real escalating value.

20. SDG&E methodology for CT market energy value results in a reasonable approximation of this value at $22.89/kW-year.

21. CT generators will be needed for other hours in the year aside from the estimated 91 hours when peak events are called. DRA's recommendation for a real reduction of $7.39/kW-year to SDG&E's estimated avoided capacity value is reasonable.

22. SDG&E's hypothesis that the Commission will make a specific 1% reduction in planning reserves based solely on the hypothetical possibility of AMI-caused demand changes is too speculative a benefit and too remote from the AMI Project to consider and quantify for these purposes of considering the cost-effectiveness of SDG&E's AMI project.

23. SDG&E's rate design flexibility benefit of a $13.79/kW-year capacity value is reasonable.

24. The $52/kW-year figure for SDG&E's avoided capacity cost is reasonable to use for purposes of this application.

25. SDG&E's historical figures are a reasonable basis to estimate future DR activities. Based on historical data, the benefits resulting from SDG&E's avoided DR programs should be reduced by $33 million (based on a 17-year analytical timeframe).

26. The projected benefits of SDG&E's AMI Project are $502 million, not counting newly-quantified benefits.

27. There are a variety of benefits associated with SDG&E's AMI Project previously considered non-quantifiable which have now been quantified, based on filings received January 16, 2007. The value of these benefits is $32 million to $43 million.

28. The total benefits of SDG&E's proposal are $534 million to $547 million.

29. The total cost of SDG&E's proposal is $38.5 million to $49.5 million greater than the total benefits.

30. SDG&E's alternative proposal in its January 16, 2007 comments does not significantly improve net benefits compared to our analysis of SDG&E's original AMI Project.

31. UCAN's alternative proposal has merit. However, UCAN's recommendations do not clearly lead to a broader implementation of AMI technology, as it becomes more cost-effective and functionality improves.

32. The Settlement Agreement among SDG&E, DRA and UCAN has unanimous support of all active parties, representing different viewpoints.

33. The Settlement Agreement encompasses SDG&E's application and testimony, with specified modifications.

34. The Settlement Agreement leads to a total cost of $652 million, and total benefits between $692 million and $703 million (including newly-quantified benefits).

35. There are between $40 million and $51 million in net benefits for the Settlement Agreement. Without the newly-quantified benefits, the Settlement Agreement has $8 million in net benefits.

Conclusions of Law

1. Neither SDG&E's AMI proposal nor the proposal in the Settlement Agreement at this time meet the functionality criteria set forth in the Joint

Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the AMI Business Case Analysis issued February 19, 2004 in Rulemaking (R.) 02-06-001. However, both proposals would be likely to meet these criteria once SDG&E executes signed contracts with vendors in response to RFPs for the project.

2. SDG&E's proposal and the proposal in the Settlement Agreement meet the implementability criterion in the May 9, 2005 Ruling.

3. SDG&E has not demonstrated that its proposed AMI Project, as proposed in this application, is cost-effective. The projected costs of SDG&E's AMI Project so outweigh the projected benefits that any reasonable consideration of non-quantifiable benefits cannot make the Project cost-effective.

4. SDG&E's AMI Project should not be adopted as proposed in his application.

5. SDG&E's January 16, 2007 alternative AMI Project is not cost-effective and should not be adopted.

6. UCAN's alternative recommendations should not be adopted at this time.

7. The proposal in the Settlement Agreement is cost-effective.

8. The totality of the information provided is sufficient to allow a determination of the overall reasonableness of the Settlement Agreement and to permit the Commission to discharge future regulatory obligations with respect to the parties and their intentions.

9. The Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest.

O R D E R

IT IS ORDERED that:

1. The February 9, 2007 Settlement Agreement Regarding San Diego Gas & Electric Company's (SDG&E) Advanced Metering Infrastructure (AMI) Application (A.), A.05-03-015 (Appendix A herein), among SDG&E, the Division of Ratepayer Advocates and Utility Consumer Action Network is adopted, subject to Commission review of contracts executed with vendors, as set forth in Ordering Paragraph #2.

2. SDG&E shall file one or more Advice Letters with the executed contracts with vendors for its AMI Project, as adopted herein. These contracts are contingent upon Commission approval that they meet the functionality criteria set forth in the Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the AMI Business Case Analysis issued February 19, 2004 in Rulemaking 02-06-001.

3. A.05-03-015 is closed.

This order is effective today.

Dated _____, at San Francisco, California.

APPENDIX B
APPEARANCES

********** **APPEARANCES** **********

Marc D. Joseph
Attorney At Law
ADAMS, BROADWELL, JOSEPH & CARDOZO
601 GATEWAY BLVD., STE. 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
mdjoseph@adamsbroadwell.com
For: Coalition of California Utility Employees

Paul Angelopulo
Legal Division, RM. 5031
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-4742
pfa@cpuc.ca.gov
For: ORA

Frederick M. Ortlieb
Office Of City Attorney
CITY OF SAN DIEGO
1200 THIRD AVENUE, 11TH FLOOR
SAN DIEGO CA 92101
(619) 533-5800
fortlieb@sandiego.gov

Chris King
EMETER STRATEGIC CONSULTING
1 TWIN DOLPHIN DRIVE
REDWOOD CITY CA 94065
(650) 631-7230
chris@emeter.com
For: California Consumer Empowerment Alliance

Renee H. Guild, CEO
GLOBAL ENERGY MARKETS
2481 PORTERFIELD COURT
MOUNTAIN VIEW CA 94040
(650) 279-7692
renee@gem-corp.com

Chris King
Chair,Svlg DR Subcommitte
224 AIRPORT PARKWAY, SUITE 620
SAN JOSE CA 95110
(408) 501-7864
chris@emeter.com

Karen P. Paull
Legal Division, RM. 4300
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2630
kpp@cpuc.ca.gov

Kelly M. Morton
Attorney At Law
SAN DIEGO GAS & ELECTRIC
101 ASH STREET
SAN DIEGO CA 92123
(619) 699-1500
kmorton@sempra.com
For: San Diego Gas & Electric

Vicki L. Thompson
Attorney At Law
SEMPRA ENERGY
101 ASH STREET, HQ-13D
SAN DIEGO CA 92101-3017
(619) 699-5130
vthompson@sempra.com
For: San Diego Gas & Electric

Justin Bradley
Director Energy Programs
SILCON VALLEY LEADERSHIP GROUP
224 AIRPORT PARKWAY, SUITE 620
SAN JOSE CA 95110
(408) 501-7864
jbradley@svlg.net

Scott H. Debroff
SMIGEL, ANDERSON & SACKS
RIVER CHASE OFFICE CENTER
4431 NORTH FRONT STREET
HARRISBURG PA 17110
(717) 234-2401
sdebroff@sasllp.com
For: Hunt Technologies, Inc,& Cellnet Technology, Inc.

Nina Suetake
Attorney At Law
THE UTILITY REFORM NETWORK
711 VAN NESS AVE., STE 350
SAN FRANCISCO CA 94102
(415) 929-8876
nsuetake@turn.org
For: TURN

Michael Shames
Attorney At Law
UCAN
3100 FIFTH AVE., STE. B
SAN DIEGO CA 92103
(619) 696-6966
mshames@ucan.org
For: UCAN

(END OF APPENDIX B)

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a copy of the Notice of Availability to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the copy of the Notice of Availability is current as of today's date.

Dated March 8, 2007, at San Francisco, California.

/s/ ELIZABETH LEWIS
Elizabeth Lewis

********** SERVICE LIST **********
Last Update on 02-FEB-2007 by: SMJ
A0503015 LIST

********** **APPEARANCES** **********

Marc D. Joseph
Attorney At Law
ADAMS, BROADWELL, JOSEPH & CARDOZO
601 GATEWAY BLVD., STE. 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
mdjoseph@adamsbroadwell.com
For: Coalition of California Utility Employees

Paul Angelopulo
Legal Division
RM. 5031
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-4742
pfa@cpuc.ca.gov
For: ORA

Frederick M. Ortlieb
Office Of City Attorney
CITY OF SAN DIEGO
1200 THIRD AVENUE, 11TH FLOOR
SAN DIEGO CA 92101
(619) 533-5800
fortlieb@sandiego.gov

Chris King
EMETER STRATEGIC CONSULTING
1 TWIN DOLPHIN DRIVE
REDWOOD CITY CA 94065
(650) 631-7230
chris@emeter.com
For: California Consumer Empowerment Alliance (CCEA)

Renee H. Guild
Ceo
GLOBAL ENERGY MARKETS
2481 PORTERFIELD COURT
MOUNTAIN VIEW CA 94040
(650) 279-7692
renee@gem-corp.com

Chris King
Chair,Svlg DR Subcommitte
224 AIRPORT PARKWAY, SUITE 620
SAN JOSE CA 95110
(408) 501-7864
chris@emeter.com

Karen P. Paull
Legal Division
RM. 4300
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2630
kpp@cpuc.ca.gov

Kelly M. Morton
Attorney At Law
SAN DIEGO GAS & ELECTRIC
101 ASH STREET
SAN DIEGO CA 92123
(619) 699-1500
kmorton@sempra.com
For: San Diego Gas & Electric

Vicki L. Thompson
Attorney At Law
SEMPRA ENERGY
101 ASH STREET, HQ-13D
SAN DIEGO CA 92101-3017
(619) 699-5130
vthompson@sempra.com
For: San Diego Gas & Electric

Justin Bradley
Director Energy Programs
SILCON VALLEY LEADERSHIP GROUP
224 AIRPORT PARKWAY, SUITE 620
SAN JOSE CA 95110
(408) 501-7864
jbradley@svlg.net

Scott H. Debroff
SMIGEL, ANDERSON & SACKS
RIVER CHASE OFFICE CENTER
4431 NORTH FRONT STREET
HARRISBURG PA 17110
(717) 234-2401
sdebroff@sasllp.com
For: Hunt Technologies, Inc,& Cellnet Technology, Inc.

Nina Suetake
Attorney At Law
THE UTILITY REFORM NETWORK
711 VAN NESS AVE., STE 350
SAN FRANCISCO CA 94102
(415) 929-8876
nsuetake@turn.org
For: TURN

********** SERVICE LIST **********
Last Update on 02-FEB-2007 by: SMJ
A0503015 LIST

Michael Shames
Attorney At Law
UCAN
3100 FIFTH AVE., STE. B
SAN DIEGO CA 92103
(619) 696-6966
mshames@ucan.org
For: UCAN

********** **STATE EMPLOYEE** **********

Joseph A. Abhulimen
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1552
jaa@cpuc.ca.gov

Nilgun Atamturk
Executive Division
RM. 5303
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-4953
nil@cpuc.ca.gov

Christopher J. Blunt
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1779
cjb@cpuc.ca.gov

David Hungerford
CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, MS-22
SACRAMENTO CA 95814
(916) 654-4906
dhungerf@energy.state.ca.us

Karen Herter
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-35
SACRAMENTO CA 95814
(916) 654-4328
kherter@energy.state.ca.us

Mike Messenger
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-28
SACRAMENTO CA 95814
(916) 654-4774
mmesseng@energy.state.ca.us

Andrew Campbell
Executive Division
RM. 5304
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2501
agc@cpuc.ca.gov

Moises Chavez
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1851
mcv@cpuc.ca.gov

Marshal B. Enderby
Division of Ratepayer Advocates
RM. 4205
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2769
mbe@cpuc.ca.gov

Julie A. Fitch
Division of Strategic Planning
RM. 5203
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 355-5552
jf2@cpuc.ca.gov

Damon A. Franz
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2165
df1@cpuc.ca.gov

David M. Gamson
Administrative Law Judge Division
RM. 5019
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1232
dmg@cpuc.ca.gov

Louis M. Irwin
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1225
lmi@cpuc.ca.gov

********** SERVICE LIST **********
Last Update on 02-FEB-2007 by: SMJ
A0503015 LIST

Bruce Kaneshiro
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1187
bsk@cpuc.ca.gov

Robert Kinosian
Division of Ratepayer Advocates
RM. 4205
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1500
gig@cpuc.ca.gov

Scarlett Liang-Uejio
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2043
scl@cpuc.ca.gov

Ralph E. Abbott
PLEXUS RESEARCH, INC.
629 MASSACHUSETTS AVE
BOXBOROUGH MA 01719-1528
(978) 263-6080
rabbott@plexusresearch.com
For: PLEXUS RESEARCH, INC.

Edgar A. Quiroz
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2376
eaq@cpuc.ca.gov

Thomas M. Renaghan
Division of Ratepayer Advocates
RM. 4205
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2107
tmr@cpuc.ca.gov

Michael Rosauer
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2579
fly@cpuc.ca.gov
For: Energy Division

******** **INFORMATION ONLY** *********

Tanya Gulesserian
ADAMS BROADWELL JOSEPH & CARDOZO
601 GATEWAY BLVD. STE 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
tgulesserian@adamsbroadwell.com
For: Coalition of California Utility Employees

Kevin Golden
Attorney At Law
ADAMS, BROADWELL, JOSEPH & CARDOZO
601 GATEWAY BLVD., SUITE 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
kgolden@adamsbroadwell.com

Greg Chang
BLOOMBERG NEWS
345 CALIFORNIA ST., STE 3500
SAN FRANCISCO CA 94104
(415) 743-3526
gchang1@bloomberg.net
For: BLOOMBERG NEWS

CALIFORNIA ENERGY MARKETS
517-B POTRERO AVE.
SAN FRANCISCO CA 94110
(415) 552-1764
cem@newsdata.com

Chris Hickman
CELLNET TECHNOLOGIES, INC.
4085 SUDBURY ROAD
COLORADO SPRINGS CO 80908
(719) 337-9862

Ben Boyd
DISTRIBUTION CONTROL SYSTEMS, INC.
5430 HICKORY VILLAGE DRIVE
KINGWOOD TX 77345
(314) 482-2854
bboyd@twacs.com

Donald C. Liddell
Attorney At Law
DOUGLASS & LIDDELL
2928 2ND AVENUE
SAN DIEGO CA 92103
(619) 993-9096
liddell@energyattorney.com

********** SERVICE LIST **********
Last Update on 02-FEB-2007 by: SMJ
A0503015 LIST

mrw@mrwassoc.com

Epic Intern
EPIC/USD SCHOOL OF LAW
5998 ALCALA PARK
SAN DIEGO CA 92110
(619) 260-4806
usdepic@gmail.com

Jeff Francetic, P.E.
Landis + Gyr
14891 LAGO DRIVE
RANCHO MURIETA CA 95683
(916) 354-8400
jeff.francetic@us.landisgyr.com

Joseph F. Wiedman
Attorney At Law
GOODIN MACBRIDE SQUERI RITCHIE & DAY,LLP
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
jwiedman@gmssr.com

Jeff Nahigian
JBS ENERGY, INC.
311 D STREET
WEST SACRAMENTO CA 95605
(916) 372-0534
jeff@jbsenergy.com

Jody S. London
JODY LONDON CONSULTING
PO BOX 3629
OAKLAND CA 94609
(510) 459-0667
jody_london_consulting@earthlink.net

Roger Levy
LEVY AND ASSOCIATES
2805 HUNTINGTON ROAD
SACRAMENTO CA 95864
(916) 487-0227
rogerl47@aol.com

David Marcus
PO BOX 1287
BERKELEY CA 94701
(510) 528-0728
dmarcus2@sbcglobal.net

MRW & ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND CA 94612
(510) 834-1999

Devra Wang
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER STREET, 20TH FLOOR
SAN FRANCISCO CA 94104
(415) 875-6100
dwang@nrdc.org

Bonnie W. Tam
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, B8R
SAN FRANCISCO CA 94105
(415) 972-5509
bwt4@pge.com

David Rochefort
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET MC B29R
SAN FRANCISCO CA 94105
(415) 973-9215
DJRo@pge.com

Julianna Gassman
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST., MC B8R
SAN FRANCISCO CA 94105
JxGb@pge.com

June Ruckman
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B8R
SAN FRANCISCO CA 94105
(415) 972-5266
jcr4@pge.com

Karen Moglia
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, B10A
SAN FRANCISCO CA 94105
(415) 973-2623
klm3@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

Larry Nixon
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B10A
SAN FRANCISCO CA 94105
(415) 973-5450
lrn3@pge.com

Law Department File Room
PACIFIC GAS AND ELECTRIC COMPANY

********** SERVICE LIST **********
Last Update on 02-FEB-2007 by: SMJ
A0503015 LIST

PO BOX 7442
SAN FRANCISCO CA 94120-7442
cpuccases@pge.com
Kathleen H. Cordova
SAN DIEGO GAS & ELECTRIC
8306 CENTURY PARK COURT
SAN DIEGO CA 92123-1530
(858) 650-4186
KCordova@semprautilities.com

Patrick Charles
SAN DIEGO GAS & ELECTRIC
8330 CENTURY PARK CT.
SAN DIEGO CA 92123
(858) 636-7909
pcharles@semprautilities.com

Wendy Keilani
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK CT. CP32D
SAN DIEGO CA 92123
(858) 654-1185
wkeilani@semprautilities.com
For: San Diego Gas & Electric Company

Central Files
SAN DIEGO GAS AND ELECTRIC COMPANY
8330 CENTURY PARK COURT, CP31E
SAN DIEGO CA 92123
(858) 654-1240
centralfiles@semprautilities.com
For: SEMPRA ENERGY UTILITIES

Andrew Shirley
11755 WILSHIRE BLVD. STE 1350
LOS ANGELES CA 90025-1540
(310) 899-7317
ashirley@ivorycapital.com

Bruce Foster
SOUTHERN CALIFORNIA EDISON
601 VAN NESS AVENUE, STE. 2040
SAN FRANCISCO CA 94102
(415) 775-1856
bruce.foster@sce.com

Case Administration
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-3003
case.admin@sce.com

Janet Combs
Attorney At Law
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770