BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	Rulemaking 02-06-001

ADVANCED METERING INFRASTRUCTURE (AMI) BUSINESS CASE SUPPLEMENTAL FILING

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January 12, 2005

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ADVANCED METERING INFRASTRUCTURE (AMI) BUSINESS CASE SUPPLEMENTAL FILING

CHAPTER I.

INTRODUCTION

On October 22, 2004, San Diego Gas & Electric Company (SDG&E) filed its "Preliminary Analysis Regarding Advanced Metering Infrastructure Business Case" (Preliminary Analysis) as required by the "Administrative Law Judge And Assigned Commissioner's Ruling Adopting A Business Case Analysis Framework For Advanced Metering Infrastructure," dated July 21, 2004 (hereinafter, the "July 21 ACR").[1] Because of the Commission's aggressive timetable, SDG&E's Preliminary Analysis was a work in process; the required Base Case and Outsourcing scenarios were incomplete. As discussed on pages 4-6 herein, SDG&E's Preliminary Analysis did not contain a detailed cost recovery proposal, a Two-Part Real-Time Pricing (RTP) structure analysis, or detailed operational cost and/or benefit element estimates.

[1]The Commission initially required IOUs to file their Preliminary Business Case Analysis on October 15, 2004. That deadline was subsequently moved to October 22, 2004.

On November 24, 2004, the Commission issued the "Assigned Commissioner And Administrative Law Judge's Ruling Calling For A Technical Conference To Begin Development Of A Reference Design, Delaying Filing Date Of Utility Advanced Metering Infrastructure Application, And Directing The Filing Of Rate Design Proposals For Large Customers" (hereinafter, the "November 24 ACR"). The November 24 ACR specifically provides:

> "By January 12, 2005, the utilities should complete the analysis that was required by our July 21, 2004 ruling that was not included in their October filings. For example, some utilities did not perform analysis of outsourcing funding and implementation approaches as required, including a description of the functionality of the meter and network systems they analyzed… At a minimum, by January 12, 2005, the utilities should complete, file, and serve the analysis that was required by the July 21, 2004 ruling"(November 24 ACR, at pages 1-3 (emphasis added).[2]

In accordance with the November 24 ACR, SDG&E, in this Advanced Metering (AMI) Business Case Supplemental Filing (Supplemental Filing), provides most of the information missing from SDG&E's Preliminary Analysis. As described below, SDG&E will provide the remaining information/analyses in its March 15, 2005 application.

A. Overview of Supplemental Filing

This Supplemental Filing includes the following Chapters, presenting the remaining information as required by the July 21 ACR:

Chapter I presents an overview of the Supplemental Filing. Chapter II discusses SDG&E's AMI deployment plans and analyses, including the previously-authorized

[2] July 21, 2004 ACR, Attachment A required inclusion of the Base Case scenario (see page 1) and the Outsourcing scenario (see page 4).

deployment of Commercial AMI or Real-Time Electric Meters (RTEM) to its larger Commercial and Industrial (C&I) customers. Chapter III presents SDG&E's proposal to establish a cost recovery mechanism for recovery of the initial planning, design, development and testing expenditures associated with residential and small commercial AMI pre-deployment. Chapter IV contains a detailed discussion of SDG&E's AMI Outsourcing analysis, including such elements as the approach and methodology SDG&E utilized, the meter and network communications acquisition and financing considerations, process and administration issues, and liability and risk issues. Chapter V discusses SDG&E's Real-Time Pricing (RTP) for large C&I customers and 1-in-10 year weather scenario analyses. Chapter VI includes a detailed discussion of the functional requirements of SDG&E's meter and telecommunications systems. Chapter VII presents SDG&E's description and estimates for the AMI Operational Costs and Benefits, as updated and refined from its Preliminary Analysis.

Notably, this Supplemental Filing presents SDG&E's Cost and Operational Benefits data at the specific cost and benefit element level of detail as specified in Appendix A (redacted) of the July 21 ACR. And finally, Chapter VIII presents SDG&E's Base Case discussion.

The Supplemental Filing contains two appendices which contain confidential information: Appendix A presents SDG&E's detailed, updated AMI Operational Costs and Benefits data at the cost element level of detail. Appendix B presents costs associated with SDG&E's AMI Outsourcing Assessment Financial Model. SDG&E is filing both Appendix A and Appendix B pursuant to the provisions of General Order 66-C and California Public Utilities Code Section 583. Appendix A has been redacted from the public versions of this document pursuant to the November 2, 2004 "Administrative

Law Judge's Ruling Granting In Part Pacific Gas And Electric Company And San Diego Gas & Electric Company Leave To File Documents Under Seal." SDG&E has filed concurrently with this Supplemental Analysis a "Motion for Protective Order" to restate the sensitivity of the AMI Operational Costs and Benefits (Appendix A) and to the confidentiality of Appendix B.

B. Items Not Contained in The Supplemental Filing

Although the Supplemental Filing provides the remainder of the preliminary analysis items required by the July 24 ACR (which were not included in the Preliminary Analysis), there are three remaining items not contained herein but which will be included in SDG&E's March 15, 2005 AMI Business Case Application. These items are:

1. SDG&E's final, preferred "full-scale" and preferred "partial" AMI deployment scenario proposals. The final operational costs, operational benefits and demand response benefits presented herein are subject to further refinement and updates for the March 15, 2005 Application. In addition, SDG&E will complete an assessment and recommendation regarding "enabling" technology options as Summer 2004 SPP Track A, CPP-V results become available.
2. Quantification of avoided capacity and avoided transmission and distribution (T&D) benefits based on the analytical results from the summer 2004 Statewide Pricing Pilot (2004 SPP). Charles River Associates is currently preparing the final evaluation report for the summer 2004 SPP.
3. Monte Carlo analysis details regarding the modeling of the price elasticities. SDG&E's Preliminary Analysis provided price elasticity information via three information points, a high estimate, a low estimate and a base value. Further information regarding the Monte Carlo analysis (over and above the three items

mentioned) will be provided in SDG&E's March 15th Application. SDG&E plans to complete a Monte Carlo analysis using the standard errors of the regression parameter estimates contained in the daily elasticity and constant elasticities of substitution demand models.

CHAPTER II.

SDG&E's AMI DEPLOYMENT PLAN

A. Introduction

SDG&E's optimum AMI deployment plan targets all customers in SDG&E's Inland and Desert climate zones, as well as all C&I customers with demands of 100 kW or greater, throughout the service territory. Focusing on customers in SDG&E's warmer climate zones and the large C&I customers is the best way to achieve a positive net present value for AMI and to garner the hoped for demand response benefits. More importantly, by focusing on the largest demand response impacts first, a solid a base is established for the initial phases of AMI deployment, which then can be expanded in the event that full deployment is warranted.

SDG&E's analysis of demand response benefits is described in Chapter VI of Preliminary Analysis filing. It is crucial to note that the demand response benefits identified in the Preliminary Analysis accrue only if dynamic rates are implemented concurrently with the AMI deployment.

Table II.1 reflects SDG&E's updated operational costs and benefits. The demand response benefits are unchanged from SDG&E's October 22nd Preliminary Analysis filing and will be updated with summer 2004 SPP results in the March 15th AMI Application filing.

Table II.1

SDG&E's Revised Preliminary AMI Business Case Possible Range of Financial Impacts (Present Value 2005 - 2021 in Millions of Dollars)							
Deployment Scenario	**Operational Scenario**	**PV Operational**		**PV DR Benefits* Capacity and Energy**		**Overall NPV ** Range**	
		Costs (a)	**Benefits (b)**	**(c)**	**(d)**	**(e)**	**(f)**
Partial	AMI + DR + Reliability	227	40	83	327	(104)	140
Full	AMI + DR + Reliability	439	87	112	412	(240)	60

* Demand response benefits exclude T&D, reliability and emission impacts; unchanged from 10/22/04 filing
** (e) = (b) + (c) - (a), (f) = (b) + (d) - (a)

B. SDG&E's Recommended Optimum Deployment of AMI is to Inland Climate Zones in Conjunction with Demand Response Rates

1. Customers in the Inland Climate Zone

In SDG&E's service territory, the Inland climate zone is generally comprised of the Interstate 15 corridor in the northern section of San Diego County, and the area east of Interstate 805 in the central and southern portions of the county. Higher levels of demand response are possible in this geographical area because of the higher energy consumption due to the warmer climate and the higher penetration and use of air conditioning during peak demand conditions. SDG&E's customer base is shown in Table II.2

Table II.2

SDG&E's Average Customer Base By Climate Zone (Bundled and DA in 2010)			
Customer Class	**Coastal & Mountain (CZ2)**	**Inland & Desert (CZ3 & CZ4)**	**Total**
Residential	739,327	542,073	1,281,400
Small C&I <20 kW	76,445	48,497	124,942
Medium C&I 20kW – 300 kW	13,517	7,183	20,700
Large C&I > 300 kW	1,286	938	2,224
Total	830,575	598,691	1,429,266

Table II.3 illustrates the differences in average usage between residential customers in the inland and coastal zones. Average seasonal monthly usage estimates were derived using SDG&E's 2003 residential load research sample data.

Table II.3

SDG&E's **Residential Customers Average Monthly Use** (kWh/Month)					
Day Type	**Period**	**Summer**		**Winter**	
		Coastal & Mountain	**Inland & Desert**	**Coastal & Mountain**	**Inland & Desert**
CPP Day	**Peak**	10.00	15.78	0.00	0.00
	Off-Peak	30.68	39.95	0.00	0.00
Non-CPP Day	**Peak**	62.70	83.60	73.60	82.41
	Off-Peak	212.42	247.95	235.34	263.02
Weekend	**All Day**	144.56	175.63	151.86	169.17
Total		460.36	562.91	460.8	514.6

The anticipated MW reduction impacts in 2011 are shown in Table II.4 for the AMI full-deployment scenario and SDG&E's preferred deployment scenario. These results (depicted in Table II.4) are unchanged from the October 22, 2004 Preliminary Analysis.

Table II.4

SDG&E's Preliminary AMI Business Case Demand Response Impact Summary (MWs & MWhrs)				
			2011 Results	
Default Tariff	**Optional Tariffs**	**Deployment**	**MW Reduction**	**MWh Increase**
TOU	Current or CPP-F	Partial	84	1,790
TOU	Current or CPP-F	Full	154	2,541
CPP-F (Res) or CPP-V (C&I)	Current or TOU	Partial	171	2,368
CPP-F (Res) or CPP-V (C&I)	**Current or TOU**	**Full**	**346**	**3,694**
Current	CPP-P	Partial	45	410
Current	CPP-P	Full	89	978
Current	CPP-F or CPP-V	Partial	49	725
Current	CPP-F or CPP-V	Full	96	1,163
CPP-F (All)	**Current or TOU**	**Preferred**	**263**	**2,301**

MW Reduction = Expected Capacity benefit.
MWh Increase = Expected annual increase in energy consumption.

2. Operational Benefits Are Smaller for SDG&E's Optimum Deployment Scenario But Costs Are Significantly Less

Table II.1 shows that operational benefits for SDG&E's optimum AMI deployment plans are less than one-half of the operational benefits that could be achieved from a full deployment. Table II.2 shows that about 40% of the customers reside in the Inland climate zone. In SDG&E's optimum deployment strategy, only these residential and small commercial customers will have their meters read (electric and gas) via AMI. Inland climate zone residential customers and the C&I customers 100 kW and greater, however, will provide demand response of almost 76% (263MW/346 MW) of the full-deployment scenario under the default CPP rate assumption. Therefore, approximately 40% of the customer base provides 76% of the full-deployment demand response benefits (See Table II.4). SDG&E's optimum AMI plan includes default dynamic rates and targeting of enabling technology options for automated demand response and reliability. The cost of SDG&E's optimum deployment is approximately one-half the cost of full AMI deployment.

C. SDG&E's Preferred Optimum Scenario Can be Leveraged for Full Deployment

SDG&E's optimum partial/targeted AMI deployment plan can be increased to full-deployment at any time - - even while the partial deployment is in progress. Because the optimum scenario includes SDG&E's commercial customers with demands of 100 kW or greater on the AMI platform, the AMI communications gateways established for these commercial customers could be extended to the remaining residential customers in the Coastal climate zone and elsewhere where appropriate.

By 2010, SDG&E's optimum deployment plan calls installing approximately 600,000 electric meters and approximately 400,000 gas meters over a four-year period (one year beta phase followed by a three year production roll out period). SDG&E is currently reviewing this planned schedule in preparation of its March 15, 2005 Application. In the partial deployments scenario, SDG&E will have gained considerable experience in large scale installation of advanced meters and will have refined the information tracking systems, optimized the installation process, established the meter data collection processes, and worked with customers and communities to maximize the efficiency of the deployment process and the resource requirements. As cost and/or demand response benefit data are refined, full deployment may very well become cost effective. SDG&E plans to make every effort to reduce the price points (or cost per AMI installation) such that a full deployment may be justified on an economic basis.

SDG&E proposes a plan that is balanced and prudent while aggressively moving forward. SDG&E's plan is expandable in terms of both size and scope and allows the Commission considerable flexibility to expand AMI during the early phases of a partial deployment.

D. Support Enabling Technologies

In order for an AMI network to provide demand response as well as reliability benefits, certain enabling technologies on the customer side of the meter may be a necessary part of the infrastructure. SDG&E would target the highest usage customers with central air conditioning for installing "smart thermostats" that allow the utility to raise the thermostat setting during periods of higher energy prices or energy and/or capacity shortages by a given amount (typically four degrees, but with the capability of sending signals for higher or lower set-backs). Additionally, this technology could include an element of utility-controlled response during reliability events (e.g., ISO Stage 2 and Stage 3 alerts) that could prevent a customer from overriding a "smart thermostat" set point increase. SDG&E's Preliminary Analysis suggested that some form of customer inducements for “smart thermostat” installations would be warranted as a way of “jump-starting” the rollout of advanced demand response technology on the customer side of the meter. SDG&E updated costs assume free enabling technology equipment and installation as an inducement for the demand response portion of this program. In addition, SDG&E’s preliminary costs also include a $50 annual incentive payment for the “reliability” option. SDG&E is conducting further analysis and will provide a more definitive recommendation regarding “enabling” technologies and the size of corresponding customer incentives in the March 15 Application.[3]

E. Beta Test Phase/Need for a Timely CPUC Decision

As discussed in the October 22nd Preliminary Analysis, each of SDG&E’s AMI deployment scenarios includes an initial test, or “beta” phase, beginning January 2006. SDG&E notes specifically that commencement of the beta phase is conditioned on the Commission issuing an authorizing Commission decision by early 2005, enabling SDG&E to begin the ramp-up work necessary to initiate beta phase deployment six months later. In addition, several activities in the planning and design phase must begin on an expedited basis for SDG&E to begin mass deployment by January 2007. Issuance of a Commission decision authorizing deployment beyond mid-year 2005 will necessarily delay commencement of the beta phase, and would similarly delay the broader deployment slated to begin in 2007 for either the partial/targeted or full deployment scenario. As addressed in Chapter III (Establish Memorandum Account and Balancing Account for Recovery of Design, Development and Testing of Residential AMI Design

[3] Charles River Associates (CRA) will complete an analysis of demand reduction impacts for the Track A, CPP-V Enabling Technology treatment cells for residential customers by month-end January. Depending on these results, SDG&E will design an “enabling technology” program that is economically justified from the incremental reductions attributed from such technologies.

and Start-up Costs), SDG&E is requesting that the Commission provide, at a minimum, sufficient funding for AMI planning, start up, design activities and IT systems evaluation and selective other activities as early as possible.[4] Should the Commission not approve such funding by March 2005, SDG&E's proposed schedule would be delayed from that presented herein.

The beta phase of each deployment scenario consists of installing of 10,000 AMI meters (roughly 8,000 single-phase electric meters and 2,000 poly-phase electric meters) during the six-month period of January through June 2006 and, as mentioned above, and would also include the associated gas AMI installations (approximately 10,000 gas AMI installations would occur - - ideally a mix between some older gas meter change-outs, and the more simple gas index retrofit approach). Completion of the beta phase will give SDG&E the opportunity to review its installation process and test installation support systems, and permit execution of any necessary changes or technology or process improvements in preparation for the launch of the "production" installation phase (either preferred partial or preferred full scale) beginning in January 2007.

[4] Of the 10,000 premises chosen for the beta phase, SDG&E envisions that the majority would include both gas and electric AMI installations. SDG&E would strive to include as many of the situations that would be encountered in the production roll-out as possible, such as some number of electric-only installations, gas meter index/module change-outs and gas meter change-outs.

Figure III.1

SDG&E AMI Potential Deployment Timelines

CHAPTER III.

INTERIM COST RECOVERY PROPOSAL

A. Establish a Memorandum and Balancing Account for Recovery of Design, Development and Testing of AMI Pre-Deployment Costs

SDG&E requests immediate Commission authorization to file an Advice Letter to establish a new memorandum account to be named the Advanced Metering Infrastructure Memorandum Account (AMIMA) to record capital and O&M expenses incurred in 2005 to maintain the AMI deployment schedule. These include start-up, design, development and testing costs associated with AMI pre-deployment, and are not expected to exceed $15 million. Since costs will be recovered from SDG&E gas and electric customers, two identical memorandum accounts would be created to separately record the gas and electric expenditures.

Upon approval of a specific AMI deployment plan, SDG&E requests further Commission authorization to file an Advice Letter to request note recovery in January 1, 2006 of the forecasted AMI revenue requirement for 2006, along with the projected year-end balance in the AMIMA for 2005. Beginning January 1, 2006, the memorandum account would be converted to a new balancing account to be named the Advanced Metering Infrastructure Balancing Account (AMIBA) and would record actual capital and O&M costs and rate revenues for annual true-up and recovery. Since costs will be recovered from SDG&E gas and electric customers, two identical balancing accounts would be created to separately record the gas and electric rate revenues and costs.

On an annual basis thereafter, the projected year-end balance in the AMIBA would be combined with the forecasted AMI revenue requirement to produce the total revenue requirement to be recovered in gas and electric distribution rates. SDG&E

would file an annual Advice Letter with the Commission each October to recover this revenue requirement in the following year's gas and electric distribution rates

In the event a final Commission decision approving SDG&E's AMI deployment plan is not available by January 1, 2006, SDG&E request Commission authorization to file an Advice Letter to extend the memorandum account treatment for AMI pre-deployment costs incurred in 2006, until such time as a decision is finalized.

CHAPTER IV

OUTSOURCING OF AMI

As required by the July 21 ACR, SDG&E has completed an analysis of a 'fully outsourced' approach for deploying an AMI system in SDG&E's entire service territory.[5] As detailed below, SDG&E believes that outsourcing of specific activities and functions involved in AMI are justified.

In preparing this analysis, SDG&E retained the services of an external consultant experienced in evaluating outsourcing options. SDG&E provided the results of the numerous RFIs and RFPs to the consultant sent over the past few months as well as other cost estimates and information. The consultant's final report is found in Appendix B (redacted).

In this summary, SDG&E describes the benefits and costs of outsourcing certain components of the AMI project, as well as how the traditional benefits of outsourcing apply to subset of AMI project activities and functions. SDG&E has identified three areas of particular interest to potentially outsource: certain aspects of the IT work necessary to support AMI, 'systems integration' or IT project management, and electric and gas meter/gas module and network communication component deployment and installation.

[5] Due to various factors, analysis associated with a partial deployment utilizing a fully outsourced approach were not developed because a partial AMI deployment necessarily includes simultaneous new AMI processes and systems that must be maintained with existing legacy systems (i.e., metering reading and AMI). In almost all cases, the scale of the outsourced opportunity would not be sufficient for economic outsourcing.

A. Activities and Functions for Outsourcing

Due to the large scope of IT work necessary to support AMI deployment and maintenance of an AMI system, SDG&E analyzed outsourcing specific aspects of the IT activities necessary to support AMI as well as project management for IT systems development. An RFI was sent to nineteen system integrators. From the eleven responses received, SDG&E noted numerous potential benefits, such as the experience of 'systems integrators' who had managed similar projects, the potential for shared labor, technical expertise and existing vendor relationships. Additionally, these system integrators bring with them existing relationships with different sources of IT expertise that could facilitate the process of incorporating and integrating the systems developments completed by other parties.

A systems integrator would allow SDG&E the flexibility to utilize specific technical skills sets without greatly increasing core staffing and could reduce the risk of not meeting required implementation schedules. The integrator's expertise with specific technology and their experience in managing similar projects, combined with their refined systems development methodology should greatly increase SDG&E's ability to deliver AMI systems.

SDG&E also sees advantages to having contractors install AMI-compatible electric meter, and retrofit gas meters with AMI gas modules during the deployment. The various installation vendors will provide vehicles and portable field devices necessary for deployment support. In a like manner, SDG&E also see advantages of having contractors install the AMI communications network components.

B. Other Potential Outsourced Activities and Functions

The scope of this outsourced analysis includes the vast majority of the metering and meter reading functions associated with operating and maintaining an AMI communications network (as well as managing the network) and collection of meter data. However, the scope does not include the billing and customer service functions. Billing and customer service have been excluded from scope based on SDG&E's interpretation of the July 21 ACR, and because current capabilities, cost effectiveness, currently integrated IT systems, sunk investment, and customer relations would be difficult to replace within the short period envisioned for AMI systems development However, even without the billing and customer service functions included, the scope of this analysis includes a major portion of revenue cycle services.

SDG&E engaged a third-party consultant to analyze this 'fully outsourced' approach. The consultant concluded after working with several full-service, integrated solution service providers that the savings opportunities associated with traditional outsourcing initiatives did not exist for the outsourcing of AMI. The total cost to SDGE for 'fully' outsourcing would be higher than the optimum mix for contracting and internal resources approach otherwise analyzed. This conclusion was based on the information gathered over a relatively short period, and therefore, SDG&E recognizes that further analysis is necessary. However, at this point in time, the fully outsourced scenario is not advisable based on costs developed to date. Although the financial analysis was only performed for the full deployment scenario, the partial deployment scenario appears even less viable. Although the total costs would be lower than under the full deployment scenario, the partial scenario would not present the opportunity to consolidate the labor force, leverage existing services or offer the operational efficiency that is present in a full-scale scenario. A partial-deployment scenario will most likely introduce redundant services and systems into the solution and potentially increase the overall cost. To summarize the results of the analysis, the following table is provided:

Table IV.1.

Outsourcing Cost Summary table for Chapter IV – Outsourcing

SDG&E's Revised Preliminary AMI Business Case
Possible Range of Financial Impacts
Fully Outsourced vs Focused Outsourced/Insourced Approach
(Present Value 2005 - 2021 in Millions of Dollars)

Deployment Scenario	Operational Scenario	Operational Costs (a)	Operational Benefits (b)	NPV* (c)*
Full Deployment, Fully Outsourced Approach	AMI Only	(1,217)	125	(1,092)
Full Deployment, Optimum Outsourcing / Insourcing Approach	AMI Only	(445)	77	(368)

** (c) = (a) - (b)

C. Methodology Used for Outsourcing Analysis

In reaching these conclusions, a market survey with five full-service, integrated, solution service providers and well as a meter manufacturer was conducted. These companies were chosen based on their long-term financial viability, size, experience, cultural fit with SDG&E, and low risk profile. Three of the five integrated solution service providers supplied enough information to complete the financial analysis. The remaining two solution providers and the meter manufacturer did not provide sufficient information to complete the financial analysis or were not interested in bidding on the total outsourcing opportunity. All providers indicated that they would partner with multiple organizations to deliver the complete solution (e.g., meter providers, software providers, communications providers, etc.).

For the sake of expediency, the financial data collected from the service providers was normalized to include similar components. This normalization was done through a series of discussions with each of the service providers. Since each service provider's data was presented in a somewhat different fashion it was necessary to make model (price) changes for each. This process also identified functions SDG&E would be required to retain in order to complement the service provider's offerings.

The consultant's analysis indicated that SDG&E's cost of capital or financing rate is well under the financing requirements of third party vendors. Therefore, the utility could likely finance the meters for lower overall cost. Another financial consideration is that an outsourcing solution creates the opportunity to "pay as you go," although not necessarily at a lower cost. This "pay as you go" construct means that resources are paid for only as they are consumed them (can be both infrastructure resources and labor resources). It also presents the ability to amortize certain up-front costs and pay for them over time without the utility having the up-front cash requirements for such capital assets. Two additional concerns about outsourcing AMI should also be noted. The outsourcing providers have all acknowledged that delivering a total solution requires establishing multiple vendor partnerships. These partnerships will bring their own unique set of challenges. The greater and more diverse the number of partnerships, the greater the challenge. Additionally, an outsourcing scenario of this type and magnitude has not been implemented anywhere in the United States.

In conclusion, some targeted outsourcing is required and is recommended for a successful implementation of AMI. However, at this time a ‘fully outsourced’ scenario is not justified.

CHAPTER V

RTP DISCUSSION/1 IN 10 WEATHER DISCUSSION

A. The Likely Impact of Real-Time Pricing on SDG&E customers > 300 kW

The July 21 ACR calls for utilities to estimate the impact of real-time pricing (RTP) for large C&I customers above 200 kW in demand. In the case of SDG&E, the relevant size constraint is 300 kW and not 200 kW.[6] The July 21 ACR specifies three scenarios in which a two-part RTP is made the default tariff for such customers with the option of switching back to their currently applicable tariff (which for all large commercial and industrial customers is a standard time-of-use (TOU) tariff). A two-part RTP tariff is defined as one in which the first part consists of a charge for a previously agreed upon level of use (called the customer base load) and a second part that is based on increments or decrements from that level.

The first part retains the average price paid by the customer under their standard rates and is designed to ensure bill stability for the customer and revenue stability for the utility. It can be interpreted as a forward contract that hedges both the customer and the utility against price volatility. The second part involves the sale of electricity at its marginal cost, which may be based on a day-ahead or an hour-ahead forecast of hourly prices. For this reason, a two-part RTP tariff is generally offered within the context of a functioning wholesale spot market for power. However, an RTP tariff can also be based on estimates of system marginal costs, as demonstrated by the Georgia Power Company.

[6] AB29X interval metering applies to SDG&E’s customers > 300 kW.

SDG&E has quantified RTP impacts by updating an assessment that was made in the year 2001, based on conditions in 2000.[7] This evaluation is summarized below, followed by an update for the current analysis.

i. The Year 2001 Assessment

In 2001, an evaluation was done that considered the impact of placing roughly 5,000 customers with usage above 100 kW on a bundled, two-part RTP rate. Load shape information on these customers was derived from dynamic load profile data on medium and large C&I customers. The analysis used interval load and hourly pricing data from the summers of 1999 and 2000. The analysis for the summer of 2000 covered the one-year time period from October 1999 through September 2000. The 1999 analysis included data for calendar 1999. Hourly price information was obtained from the California Power Exchange (PX) and the California Independent System Operator (CAISO).

Elasticities of substitution drawn from a survey of results from around the country were applied to SDG&E's mix of businesses and industries. This yielded an elasticity of substitution of –0.048 for medium customers and – 0.070 for large customers during the peak period, which was defined as 1 pm to 6 pm. It was assumed that the elasticities would fall to 90 percent of these values during the mid-peak period (7 am to 12 noon and 7 pm to 10 pm) and to 20 percent of these values during the off-peak period (all other hours).

A demand model was constructed to simulate the effect of a two-part RTP on the load shape of medium and large C&I customers on a typical high-price day. The results

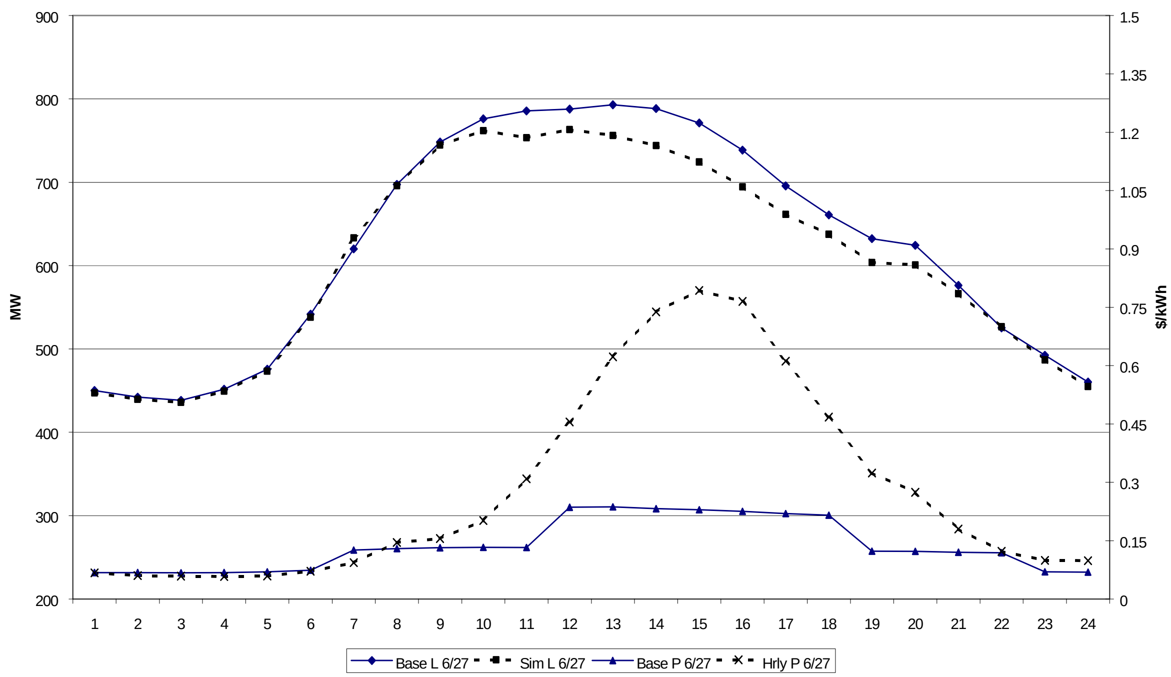
[7] Christensen Associates, "Documentation of Customer Demand Modeling in the Evaluation of RTEM and Hourly Pricing at SDG&E," January 23, 2001.

are shown in Figure V.1 below. The top two lines in the figure show the aggregate hourly load for the target population on June 27, 2000, one of the highest price summer weekdays in SDG&E's history, along with the simulated load under hourly pricing. The bottom two lines in the figure show the baseline TOU and RTP hourly prices.

Maximum demand for customer class on this day was nearly 800 MW. Estimated load response in the highest price hour was approximately 47 MW, representing a drop of 5.88 percent in peak load. During this hour, prices rose from 20 cents/kWh to 75 cents/kWh, or by 275 percent. This yields an own-price elasticity of –0.021.

Figure V.1

RTP Baseline and Simulated Loads – Medium and Large C&I
(June 27, 2000)



ii. Projecting Impacts for the year 2011

Since there is no functioning real-time spot market in California, it is difficult to assess what future prices would look like on an hourly basis. For purposes of developing demand response impacts, SDG&E assumed that the profile of prices would resemble the profile of prices in the year 2000. In addition, SDG&E assumed that the mix of customers and their baseline load shapes prior to being placed on an RTP rate would be the same in the year 2011 as they were in 2000. However, two other factors must be accounted for.

First, we must account for the fact that the 47 MW estimate of demand reduction applied to all customers with demand of 100 kW or greater, whereas the current analysis requires an impact analysis of customers above 300 kW. Thus, we must exclude that portion of the impact due to customers in the 100-300 kW size range. Our estimate of this fraction is 41.5 %. Applying this fraction yields an estimate of 27.5 MW in the year 2000 for customers in the 300 kW and above size range, which is excluded (subtracted) from the final two-part RTP analysis. Second, we must account for growth in base usage. A 2.27 percent annual growth rate is assumed for the greater than 300kW customer load. Thus, the impact of 27.5 MW in the year 2000 would rise to a value of 35.2 MW in 2011.

In Table V.1, we compare the impact of the RTP rate with the impact of the CPP-F rate in the October 22, 2004 Preliminary Analysis. The table also includes estimates of the TRC benefits of the two rates. The estimate for the RTP rate was derived by pro-rating the CPP-F rate estimate downwards by the corresponding share of MW impacts between the two rates.

Table V.1
Comparison of RTP and CPP-F Rate Impacts
Commercial & Industrial Customers >300 kW

Deployment	Avoided Capacity in 2011 (MW)		PV TRC Benefits ($ million)	
	RTP	CPP-F	RTP	CPP-F
Full	35	88	23	58

B. 1-in-10 Year Weather Analysis

The 1-in-10 year weather analysis is summarized in Table V.2, where it is compared with the 1-in-2 year results that were presented in the October 22, 2004 Preliminary Analysis. The capacity savings and TRC benefits are both larger when based on the 1-in-10 year weather compared with the 1-in-2 year weather, but the incremental impact is relatively modest. In the utility preferred scenario, the estimate of avoided capacity savings (at the end-use level) is about 4 percent greater based on the 1-in-10 year weather and the TRC benefits are also about 4 percent greater. In the July 21 ACR Scenario 10, which is similar to the preferred scenario but involves full AMI deployment rather than just partial deployment in the Inland zone for residential customers, the incremental avoided capacity savings is about 9.5 percent in 2011 and the incremental TRC benefits are roughly 11 percent. It is important to note that TRC benefits are reported here as a 16 year NPV, and that for simplification of the analysis, every year was assumed to be a 1-in-10 year. In reality, we would only expect there to be 1 or 2 years that exhibit these conditions over the 16 year analysis period. Therefore, the overall contribution to impacts over the entire 16 year analysis period would be considerably less but the relative differences between a 1-in-2 year and a 1-in-10 year would remain.

TableV.2 Comparison of 1-in-2 and 1-in-10 Year Weather Analysis									
SDG&E Scenario Code	**ACR Scenario Code**	**Default Tariff**	**Other Tariffs**	**Deployment**	**Technology**	**Avoided MWs (2011)**		**PV TRC Benefits ($ millions)**	
						1 in 2	**1 in 10**	**1 in 2**	**1 in 10**
1	**6**	Current	CPP-F	Partial	N	84	87	49	52
	7	Current	CPP-F	Full	N	154	171	92	105
2	**8**	CPP-F	Current	Partial	N	171	178	104	109
	9	CPP-F	Current	Full	N	346	379	212	235
	10	CPP-F	Current	Full	Y	346	379	212	235
3	**11**	Current	CPP-P	Partial	N	45	48	27	29
	12	Current	CPP-P-T	Partial	Y	45	48	27	29
	13	Current	CPP-P	Full	N	88	98	53	60
	14	Current	CPP-P-T	Full	Y	88	98	53	60
4	**15**	Current	CPP-F or CPP-V	Partial	N	49	52	30	32
	16	Current	CPP-F or CPP-V	Partial	Y	49	52	30	32
	17	Current	CPP-F or CPP-V	Full	N	96	106	59	66
Utility Preferred	**18**	CPP-F	Current	Partial/Full	Y	263	273	164	171

The 1-in-10 year analysis differs from the 1-in-2 year analysis in two important ways. First, the starting kWh values for all customer segments in the summer season were adjusted to reflect higher use in the absence of demand response. Second, for residential customers, the elasticity of substitution and the daily price elasticities were modified to reflect differences in weather between the 1-in-2 year and 1-in-10 year conditions. As discussed in Appendix B of SDG&E's October 22, 2004 Preliminary Analysis, the residential elasticities vary with differences in weather. Specifically, the elasticity of substitution is a function of the difference in cooling degree hours in the peak and off-peak periods and the daily elasticity is a function of daily cooling degree hours.

SDG&E selected 1992 as representative of a 1-in-10 weather year based on the following analysis. The selection of the 1-in-10 warm weather year utilized 25 years of historical daily weather temperature data from the Miramar weather station. The total summer Cooling Degree Days (CDD)[8] for both dry bulb and apparent temperatures were calculated and ranked from highest to lowest (warmer to cooler). A probability distribution was calculated for the data series. Two years initially qualified for the 1-in-10 weather year: 1983 and 1992. The weather for 1992 was selected because its probability of occurring on average was the closest to a 1-in-10 probability.

Table V.3 summarizes the change in starting values for summer energy use by rate period and customer segment between the 1-in-2 and 1-in-10 year scenarios. These ratios were multiplied by the 1-in-2 year summer starting values documented in Tables A.1 through V.5 in the October 22, 2004 Preliminary Analysis.

SDG&E developed the estimated changes in energy use underlying the ratios in Table V.3 for the 1-in-10 year scenario based on daily summer time of use periods with positive average cooling degrees. The cooling degrees are computed from hourly apparent temperatures at Lindbergh Field for the coastal zone and Miramar for the inland zone. The cooling degrees are computed with a base temperature of 72 degrees Fahrenheit.[9]

The analysis of the change in energy use from the 1-in-2 to the 1-in-10 year scenario is organized into ten categories based on the following combinations of customer type, time of use (TOU) period, and climate zone:

[8] A 72 degree base was used to calculate the cooling degree days. CDD = [(daily high + daily low) / 72].
[9] An hourly temperature of 72 degrees or less translates into a cooling degree value of zero.

Residential On-Peak Coastal	Residential On-Peak Inland
Residential Off-Peak Coastal	Residential Off-Peak Inland
Commercial/Industrial On-Peak Coastal	Commercial/Industrial On-Peak Inland
Commercial/Industrial Semi-Peak Coastal	Commercial/Industrial Semi-Peak Inland
Commercial/Industrial Off-Peak Coastal	Commercial/Industrial Off-Peak Inland

For each category, average energy use per hour and average cooling degrees per hour are computed. An approximate relationship between average energy use per hour and positive average cooling degrees per hour is estimated using ordinary least squares regression based on 2003 daily data.[10] A binary variable is included in the estimated relationships for the on-peak period categories to estimate higher average energy use per hour on CPP days relative to non-CPP days.[11]

For the 1-in-10 scenario, daily average energy use per hour for each category is calculated with the estimated 2003 relationship using positive average cooling degree hours based on 1992 weather data. Daily energy use for each category is the product of the average energy use per hour and the number of hours in the TOU period for the category. For summer days with positive average cooling degree hours based on 1992 weather data,[12] the increase in energy use from the 1-in-2 to the 1-in-10 scenario for each

[10] In general, the average cooling degree hours used in the estimated relationship is a weighted average of the daily average cooling degree hours for the current and two previous days, where the weights are 0.625 for the current day, 0.25 for the day before, and 0.125 for the day before the day before. An estimated relationship may also include a binary variable for a month, holiday or weekday (i.e., non weekend day). In addition, the estimated relationships for the residential off-peak coastal and inland categories include daily minimum temperature.
[11] The CPP binary variable is set equal to a value one of critical peak pricing (CPP) days and a value of zero on non-CPP days.
[12] Each category has some summer days in which the average cooling degrees are zero, since not all summer days have positive cooling degrees.

category is the difference between estimated energy use based on 1992 weather data and 2003 actual energy use. The energy use ratio for each category in Table V.3 reflects the estimated percentage increase in energy use from the 1-in-2 to the 1-in-10 scenario relative to actual energy use in summer 2003.

As seen in Table V.3, the largest difference between summer energy use in the two weather years is found for residential households in the coastal weather zone, where peak use on CPP days is estimated to be roughly 17 percent higher based on 1-in-10 year conditions compared with 1-in-2 year conditions. In the Inland zone, CPP-day peak energy use is estimated to be almost 10 percent higher. For the C&I market segment, however, the difference is only about 3%.

Table V.3
Ratio of Summer Energy Use by Rate Period
1-in-10 vs. 1-in-2 Weather Years

	Residential		C&I	
Rate Period	**Coastal**	**Inland**	**Coastal**	**Inland**
CPP Peak	1.171	1.096	1.033	1.034
Non-CPP Peak	1.056	1.083	1.038	1.059
CPP Partial Peak	Na	Na	1.027	1.006
Non-CPP Partial	Na	Na	1.027	1.006
CPP Off Peak	1.037	1.037	1.015	1.020
Non-CPP Off Peak	1.037	1.037	1.015	1.020
Weekend	1.037	1.037	1.015	1.020

The incremental impacts from demand response may not be proportional to the change in peak period energy use on CPP days accounted for by this 1-in-10 analysis. As documented in the October 22, 2004 Preliminary Analysis, the estimated impacts are complex functions of the elasticity of substitution and the daily price elasticity. The elasticity of substitution relates the change in the ratio of peak and off-peak energy use to changes in the price ratio. The difference in the starting value for this usage ratio between 1-in-10 and 1-in-2 year conditions is less than the difference in the peak-period energy use alone. In other words, the difference in the ratio of peak and off-peak energy use drives the differential percent impacts under 1-in-10 year conditions by altering the daily load shapes whereas the impact magnitude can be driven by both a change in load shape and usage level.

For example, in the Coastal Climate zone, the ratio of peak-to-off peak energy use only increases by roughly 13% (17% increase in peak period usage divided by 4% increase in off-peak period usage), not the 17% increase in peak period energy use that is shown in Table V.3 (see Residential/Coastal column, CPP Peak Row – ratio shown as 1.171). Furthermore, because the impact estimation is non-linear, an 11% increase in the usage ratio does not necessarily translate into an 11% increase in the impacts.

Table V.4 summarizes the weather variable values that underlie the residential elasticity estimates for the 1-in-2 and 1-in-10 year weather scenarios. The weather values for the 1-in-2 year were based on a population-weighted average of weather data for 10 weather stations. Unfortunately, data for the 10 stations was not available for the 1-in-10 weather year. Data for Lindbergh Field and Miramar was available for both years. The weather values for the 1-in-10 year contained in the last two rows of Table V.4 were developed by applying the ratio of the 1-in-10 and 1-in-2 year values for the two weather stations to the 1-in-2 year values based on the 10 weather stations. Note that the resulting weather term for CPP days in the Inland Climate zone actually decreases rather than increases in the 1-in-10 weather year. This results in a drop in the elasticity of substitution in that scenario compared with the 1-in-2 year scenario for this zone, which is another factor contributing to the relatively modest increase in impacts in that zone. Daily cooling degree hours, on the other hand, increase in both zones, which increases the impacts in the 1-in-10 year scenario.

Table V.4 Weather Data Underlying Residential Elasticity Estimates							
Year Type	**# Weather Stations**	**Location**	**CPP Days**		**Non-CPP Days**		**Weekends**
			CDH/hr Peak-Off	**Daily CDH**	**CDH/hr Peak-Off**	**Daily CDH**	**Daily CDH**
1-in-2	**2**	**Coastal**	2.9	2.1	0.4	0.2	0.6
		Inland	6.4	5.4	1.6	1.1	1.8
1-in-10	**2**	**Coastal**	4.3	4.2	0.8	0.6	0.9
		Inland	5.5	6.6	1.6	1.7	2.1
1-in-2	**10**	**Coastal**	3.4	2.8	0.8	0.1	1.4
		Inland	7.7	6.9	3.4	2.7	4.2
1-in-10	**10**	**Coastal**	5.0	5.6	1.6	0.3	2.1
		Inland	6.6	8.4	3.4	4.2	4.9

Table V.5 summarizes the elasticities that underlie the residential sector analysis for the two weather-year scenarios.

Table V.5 Elasticity Estimates							
Rate Type	**Year Type**	**Location**	**CPP Days**		**Non-CPP Days**		**Weekends**
			Elasticity of Substitution	**Daily Price Elasticity**	**Elasticity of Substitution**	**Daily Price Elasticity**	**Daily Price Elasticity**
CPP-F	**1-in-2**	**Coastal**	-0.04698	-0.03206	-0.03300	-0.02358	-0.04342
		Inland	-0.07747	-0.02966	-0.05452	-0.01680	-0.08216
	1-in-10	**Coastal**	-0.05607	-0.04062	-0.03803	-0.02402	-0.04030
		Inland	-0.07170	-0.03419	-0.05408	-0.02147	-0.07922
CPP-V	**1-in-2**	**Coastal**	-0.16320	0.01530	0.04000	-0.09693	-0.02122
		Inland	-0.26132	0.00267	-0.01476	0.01553	-0.19737
	1-in-10	**Coastal**	-0.20204	-0.04062	0.02353	-0.02402	-0.20904
		Inland	-0.23661	-0.03419	-0.01286	-0.02147	-0.19444

While the 1-in-10 analysis is useful to show that demand response impacts are robust under warmer weather conditions, the results from this analysis suggest that the variations due to weather are well within the range of possible benefits outlined previously in the October 22, 2004 Preliminary Analysis. The incremental avoided capacity savings in 2011 are roughly 9.5% more than under 1-in-2 weather conditions. Furthermore, though the incremental TRC benefits are about 10% over the entire 16 year analysis period, when the likelihood of occurrence during this period is taken into account, the expected value will be considerably less.

CHAPTER VI.

FUNCTIONAL REQUIREMENTS

AMI system costs and benefits are dependent on the assumptions regarding AMI system architecture and rate structure that enables those benefits. SDG&E addresses this issue by detailing the most capable system architecture and advantageous rate structure (which enables the most significant benefits).

SDG&E's "most capable" AMI infrastructure assumes:

- the system would be capable of measuring, storing and handling 15 minute interval data for all C&I customers and hourly data for all residential customers.
- the system would be capable of gathering reads from every electric meter, every day.
- the system would have the capability to gather consumption reads for gas and water meters on a daily basis (all meters 'polled' daily; read data gathered monthly).
- the network put in place for communications would be fully bidirectional (two-way communications).
- the utility billing systems would be able to handle the volume of data and deal with the interval data detailed above.

These assumptions of the most capable system architecture would enable hourly pricing with a variable CPP component and demand. A less capable architecture would lead to less flexibility and therefore constrain the possible dynamic rate structure and demand response benefits.

Table VI.1, lists functional requirements and associated benefits that would be derived from the most capable AMI system.

A. Detailed Meter and Telecommunication Requirements Background

When one approaches the issue of the AMI business case, it is natural to jump to the point of listing benefits and costs. This, however, assumes a given AMI system architecture and rate structure that enables those benefits. In order to address the issue in a more complete manner, the functional requirements assumptions are explicitly identified. In practice, the most capable system architecture and advantageous rate structure are designed, and then incrementally constrained as technical, financial, business process and time to implement conditions are incorporated in the design phase.

Another way to describe the system architecture requirements is to assume a specific rate structure (e.g., hourly pricing or CPP). That is, the above description of the most capable system architecture would enable hourly pricing with a variable CPP component and demand. A less capable architecture would enable a somewhat less complex rate structure (e.g. a simple two period time-of-use rate). One can then continue to move to less complex rate structures which also require a less capable system architecture, enables fewer benefits (and potentially has lower costs).

This incremental or decremental capabilities approach provides a method to estimate AMI systems design costs.

The tables below, depict the benefits with each functional requirement.

Table VI.1 – Detailed Table of Meter Requirements

Functional Requirement	Functional Benefit	Explanation
METER DATA		
Meter capable of gathering energy consumption information on a programable interval basis (15 min data from C&I, hourly data from residential) along with other meter related information	Enables the widest variety of rate options (two part, real time pricing in the case of C&I and variable CPP in the case of residential.	Interval data stored in the meter for up to 35 days, and also read by the network / system daily. Gas / water meters also 'polled' on a daily basis with consumption reads gathered monthly.
Electric Meter capable of communicating with gas and water meters for communicating consumption reads as required	Allows automated reading of all meters (resulting in operational benefits). Allows leak detection	Polling ensures 'health' of the network / system, which will then ensure the likelihood of receiving the monthly consumption read.
Provides metering information through an on-site display	Provides customers access to TOU metering information on-site	Customers would have access to TOU and consumption information at their meter for verification purposes
Provides kWhr Consumption information options depending upon technology deployed	May provide for Received, Delivered, Net, and/or bi-directional Metering,	As customers deploy distributed generation, various tariffs and metering functions will have to be performed in order to accommodate the sale of electricity back to the utility, or qualify for specific performance rate structures.
Provides programable interval data recording	Can modify interval length for greater resolution to suit load research data requirements or for implementing new tariff changes	Can modify interval length for greater resolution to suit load research data requirements or for implementing new tariff changes
Provides programable TOU data on-site	Provides an alternate method for billing customers who are not a part of the communication network or choose not to participate in the real-time price tariff options	Allows for display of flexible TOU information on site.
Provides Real Time Pricing TOU period which can be activated and defined through communications network	Provides a way to capture customer consumption on-site for Real Time pricing periods	Provides a way to implement the Critical Peak Pricing rates

Table VI.1 – Detailed Table of Meter Requirements, continued

Functional Requirement	Functional Benefit	Explanation
STANDARDIZATION		
Data provided in ANSI C12.19 table structure or similar within meter	Allows for easier interface firmware if standard tables contain information from multiple vendors equipment	Standardization of meter data tables allows for meter upgrades and open communication standards to be used to develop interfaces
Provides Holiday, Daylight Savings Time and calendar functions associated with tariff structure to support TOU metering	Allows for standardization of TOU data structure and remote updates for calendar changes	Communication network will allow remote updates to calendar when changes are made to holidays or other special dates not originally programmed into the metering device
Remote Disconnect is not included in the design of the basic meter	Reduce cost of basic meter design this function is not built into every meter	It was thought that where remote disconnect functionality was required an external contact closure or radio signal would optionally drive a disconnect device mounted in a separate adapter between the meter and service panel
Solid State Meter accuracy meets ANSI C12.20 - .5% Accuracy Class	Improved accuracy from +/-2% electromenchanical to +/-.5% solid state	Should result in more accurate metering of customer consumption

B. Detailed Telecommunications Requirements

SDG&E's telecommunications architecture will allow the back-haul or wide area network to change and evolve over time. Emergence of other telecommunications media and protocols (e.g., WiMax, BPL) require that SDG&E implement an AMI telecommunications system that can leverage different (but at this point unknown) communications protocols and media.

SDG&E requires an architecture that can use multiple back-haul or wide area network (WAN) communications. For example, SDG&E is currently estimating costs based on the use of a public wireless carrier for data transmission back to SDG&E's enterprise servers from the several thousand meter data collection devices mounted on utility poles or street lights. SDG&E envisions, however, that other WAN alternatives could also be utilized if proven to be cost effective (e.g., SDG&E's private radio network, development of WiMax, standard RBOC landline, SDG&E fiber, etc.).

SDG&E's AMI network architecture has been designed to expand and enable future capabilities. This is inherent in a two-way communication network. Future capabilities may include, but are not necessarily limited to, the following:

- Demand Response/Load Control.
- Remote service disconnect/connect.
- Wireless communication with gas and water meters.
- Energy usage data presentation - in home or web display.

Table VI.2 – Detailed Telecommunications Requirements

Functional Requirement	Functional Benefit	Explanation
Network capable of gathering interval data from every electric meter, every day (15 min data from C&I, hourly from residential)	Enables the widest variety of rate options (two part, real time pricing in the case of C&I and variable CPP in the case of residential.	Interval data stored in the meter for up to <<35 days>> (rolling <<35 days of data stored>>, and also read by the network / system daily. Gas / water meters also 'polled' on a daily basis with consumption reads gathered monthly.
Network / system capable of 'polling' gas and water meters daily and gathering consumption reads on a monthly basis (emergency signals as needed as well)	Allows automated reading of all meters (resulting in operational benefits). Allows leak detection	Polling ensures 'health' of the network / system, which will then ensure the likelihood of receiving the monthly consumption read.
Scalable, High Speed	Read every electric meter every day	To read ~1.3 million electric meters every day, the communications system must have high throughput of data, and must be scalable to allow for a phased rollout.
Capable of enabling future services to customer	Value added services for customer	Data presentation - in home or web display, Fire/Carbon Monoxide detection, Home Security services
Communications system must be reliable	Data quality/accuracy	Communications system must be reliable

Table VI.2 – Detailed Telecommunications Requirements, continued

Functional Requirement	Functional Benefit	Explanation
Redundant Communications Path	Data availability	For disaster recovery purposes. This requires redundant data centers to collect and store data. This requires redundant backhaul (T-1's, Fiber, etc.) paths.
Two Way Communications	Demand response	A signal needs to be sent to the customer, and then acknowledgement sent back that the desired demand response occurred.
Two Way Communications	On demand reads	Eliminates field visits for mid month account changes and aids with bill explanation issues.
Two Way Communications	Load control	A signal needs to be sent to the customer's load control device, and then acknowledgement sent back that the load control device operated successfully.
Two Way Communications	Remote service disconnect/connect capability	A signal can be sent to a customer's electric meter equipped with a switch and service can be disconnected or connected.
Multiple options for WAN service; Supports Electric, Gas and Water meters	Maximum flexibility	Multiple options for WAN service; Supports Electric, Gas and Water meters
Multiple options for WAN service	Leverage existing resources (public and/or private WAN’s)	Multiple options for WAN service
Multiple meters per communication device	Costs reduce as installations increase	Multiple meters per communication device
Data Security	Data Security	Customer data must be secure throughout the communications path.
No monthly recurring LAN costs	Reduces operating expenditures	The LAN must use unlicensed spectrum that does not have costs related to the use of the spectrum.
Minimize the number of poletop mounted devices	Reduces capital expenditures	Minimize the number of poletop mounted devices
Meter communication device is built into meter	Eases installation, reduces vandalism	Meter communication device is built into meter
Wireless gas and water meters	Eases installation, reduces cost of installation	Will not require trenching, etc. to run power cables to device.

CHAPTER VII.

AMI OPERATIONAL COSTS AND BENEFITS

A. Expected Range of Costs & Benefits

As described in the October 22, 2004 Preliminary Analysis, SDG&E's AMI operational benefit and cost estimates are predicated on a variety of assumptions, reflecting such factors as customer growth rates, energy use per customer estimates, appliance use and saturation, customer energy use price elasticities, and various cost estimates associated with AMI infrastructure elements and supporting systems. SDG&E has recently conducted a round of RFPs and RFIs to evaluate and refine the estimates of the major cost items included in the analysis, such as advanced meter purchase costs, meter installation costs and information systems development costs. These major activities have large elements that are anticipated to be 'outsourced' - - that is, costs included in the business case reflect SDG&E's current intent to contract with vendors to carry out the majority of this work. This approach is reflected in each of the scenarios SDG&E examined as part of the business case analysis. Additionally, SDG&E analyzed a 'fully outsourced' approach in which the full scope of AMI activities and equipment is outsourced. The discussion of the fully outsourced approach is contained in Chapter IV of this filing.

Table VII.1 (duplicated from Chapter II for ease of reference) below indicates that the expected net present value (present value of all benefits minus present value of all costs) for SDG&E's full deployment scenarios with demand response default rates will not generate a positive net benefit for society within the 2006 – 2021 AMI planning horizon. The expected net present value for full deployment is in the range of negative

$240 million to positive $60 million. SDG&E's partial deployment plan, which focuses on the Inland climate zone customers, would result in AMI installation by year-end 2009, and the present value of costs[13] for the 16 year planning horizon through year 2021 is anticipated to be approximately $227 million. The present value of operational and DR benefits for the partial roll out scenario is between $83 and $327 million. The net present value range is negative $104 million to positive $140 million. Table VII.1 also demonstrates that operational benefits alone do not justify AMI deployment.

SDG&E's Revised Preliminary AMI Business Case
Possible Range of Financial Impacts
(Present Value 2005 - 2021 in Millions of Dollars)

Deployment Scenario	Operational Scenario	PV Operational		PV DR Benefits* Capacity and Energy		Overall NPV ** Range	
		Costs (a)	Benefits (b)	(c)	(d)	(e)	(f)
Partial	AMI + DR + Reliability	227	40	83	327	(104)	140
Full	AMI + DR + Reliability	439	87	112	412	(240)	60

* Demand response benefits exclude T&D, reliability and emission impacts; unchanged from 10/22/04 filing
** (e) = (b) + (c) - (a), (f) = (b) + (d) - (a)

B. Overview of Costs and Benefits

The following narrative provides a brief description of SDG&E's AMI system assumptions, activities and other cost drivers, as well as a discussion of the drivers of the estimates of benefits. Many of the cost and benefit assumptions were discussed in SDG&E's October 22, 2004 Preliminary Analysis and the fundamental conclusions have not materially changed. SDG&E has included an update to operational costs and benefits

[13] Note that for all SDG&E cost scenarios (for both full and partial AMI deployment), the gas meter is integrated with the AMI system. Automated gas meter reads will typically occur on a monthly cycle (except for closing and/or opening customer accounts).

at the “element” level in Appendix A (redacted). The narrative is organized into the categories referenced in Appendix A of the July 21 ACR. Those categories are:

Costs:

Start-up and Design Costs
1. Communications system
2. Information Technology and Application
3. Management and other Costs

Installation / Operations and Maintenance Costs
1. Meter System and Installation
2. Communication System
3. Information Technology and Application
4. Customer Services
5. Management and Other Costs
6. Gas Service Impacts

Benefits:

1. Systems Operations Benefits
2. Customer Service Benefits
3. Management and Other Benefits

This narrative is intended to provide an overview of many processes and issues considered within each of the cost categories. Cost and benefit detail (at the cost element level (from Appendix A of the July 21 ACR - e.g.: C-1, SB-1, etc.) for each of the scenarios evaluated is presented in the attached Appendix A (redacted).

C. Background

SDG&E’s implementation costs for the AMI-Only scenario[14] and AMI plus Demand Response scenarios (in either the partial deployment or the full deployment scenario) are based upon planning for the full AMI functional capabilities as defined in the March 15, 2004 Working Group #3 Report and incorporated into the April 14, 2004

[14] AMI-Only is reflective of the “Operational Scenario” required by the July 21 ACR (see July 21 ACR, Attachment A, Section 2.2.1).

Draft Report issued by the California Energy Commission (CEC) and CPUC staff.[15] Specifically, SDG&E has designed its AMI network and developed its cost estimates based upon AMI functional capabilities, as distinguished from working functionality. For example, SDG&E included the capability for signaling load control devices (e.g., smart thermostats) in the AMI plus Demand Response Scenario. The two-way AMI communications network envisioned would support the installation of such devices, however the costs included in this preliminary analysis assume a penetration to approximately 3% of the residential customers. The capability resides in the network to field a much higher percentage, but the functionality/penetration was assumed to be at what SDG&E believes to be a reasonable and conservative level. Another example of this difference is the capability to process, bill and store interval data. In the AMI-only scenario the current rate structure is assumed to remain in place and the capability to process, bill and store interval data is not translated into functionality (and therefore increased costs).

SDG&E's cost estimates have been or will be prepared based on the results of several on-going processes, the most notable of which is SDG&E's recent series of RFI / RFPs . In many cases, such as a new single-phase AMI-compatible advanced meter meeting the requirements of the ACR Functionality Ruling,[16] the equipment or system(s) do not currently exist in sufficient quantities and at a low enough cost to justify wide

[15] The April 14, 2004 staff report, as noted in the July 21 ACR, was filed with the CPUC Docket Office on April 20, 2004, and has been incorporated into the Business Case Analysis Framework as adopted by the ACR.

[16] "Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance For the Advanced Metering Infrastructure Business Case Analysis," issued on February 19, 2004, herein after referred to as the "Functionality Ruling."

scale deployment. Therefore, cost estimates must be based on the results of the RFI and/or RFP process that specifically requests that meter technology vendors assume that significant quantities of solid state interval meters will be ordered and installed as a result of this proceeding. In other cases, such as the costs of meter and communications infrastructure installation and communications components, costs can be estimated based on the initial progress of SDG&E's commercial AMI network.

D. Start-Up and Design Costs

1. Communication System

The AMI communications network envisioned by SDG&E is a wireless system between meters, relays and nodes (called gateways) that communicates back to the utility's enterprise servers. The wireless network in the vicinity of the nodes operates in the 900 MHz Federal Communications Commission Industrial Scientific and Medical (ISM) unlicensed band, with each of the electric meters acting as a relay (along with other dedicated relays) with a power output peaking in the one watt range. Gas meter AMI modules communicate with either an electric meter (acting as a relay), a dedicated relay, or directly with a gateway utilizing a battery (with power output in the one tenth of a watt range) as a power source.

Start-up and design cost estimates for the communications system are driven by engineering labor costs associated with the performance and review of site surveys to determine placement of network equipment as well as labor associated with the mapping of network equipment on company facility diagrams and maps.

2. Information Technology and Application

Start up and design cost estimates for the information technology and application elements are driven by labor associated with communication network planning and engineering for such things as coverage studies, technology selection and field testing.

3. Management and Other Costs

Start up and design cost estimates for management and other cost elements are driven by labor costs associated with such things as managing the various meter and other RFP processes as well as contract negotiation and administration.

4. Electric Meter Acquisition Issues

A major consideration in the overall AMI deployment plan and sequence is the AMI-enabled electric meter acquisition process. As the preliminary business case analysis has progressed, SDG&E issued a single-phase electric meter Request for Proposals (RFP) and factored the responses into its on-going analysis. SDG&E reissued an RFP for both single and three phase electric meter acquisition that included a provision that SDG&E's AMI communications technology or protocol be incorporated into the AMI meter design.

i. *Single / three phase electric meter RFP process description*

SDG&E issued an RFP for both single-phase and poly-phase electric meters on November 5, 2004, to six meter vendors and one power line carrier (PLC) technology provider. Five vendors responded. SDG&E has analyzed the RFP responses to determine the feasibility of and costs associated with their meter offering, but has not identified a 'short list' of vendors or established a contract negotiation process to date. During the process of issuing this RFP, SDG&E engaged in numerous discussions with meter manufacturers about electric single phase (and poly phase) meter requirements and development time schedules.

As required by the RFP, vendors provided pricing information for AMI-compatible electric meters. Pricing included ‘under the glass’ communications capability utilizing the communication vendor’s product that is currently assumed to be SDG&E’s vendor of choice as preliminary business case analysis costing estimates were assembled.

ii. *RTEM Impact / Other Considerations*

It is important to note that due to SDG&E’s Commercial AMI deployment -- also known as RTEM (a poly phase meter with AMI capability for customers whose peak load exceeds 100 kW) - - SDG&E has established meter manufacturer and AMI communication vendor relationships that will aid in the single-phase AMI development effort and beta phase roll out. SDG&E anticipates contracting with multiple meter vendors to provide both single and poly phase metering solutions in preparation for the anticipated AMI deployment (beyond the beta phase deployment) currently anticipated for 2007. Delays in contracting with alternate vendors in 2005 may result in single source supplies for metering products in the short term.

5. Installation / Operation and Maintenance Costs

i. Electric Meter and Installation Costs:

SDG&E has assumed that advanced meter costs will decline over time for these reasons:

- Mass production of solid-state interval AMI-compatible meters will take place as a market for these products develops over the early portion of the planning and deployment horizon.

- A sufficiently large number of advanced meters will be purchased by utilities resulting in manufacturers changing their processes to include integration of communications components at the meter manufacturing facility at time of assembly.
- Meter manufacturers are more likely to eliminate duplication of component hardware (such as power supplies and memory) to reduce the overall cost of the product once volume commitments have been made by the utility to ensure profitability.

The dilemma for estimating a per-unit AMI meter cost is very much a "chicken or the egg" scenario. Meter vendors will likely not provide a formal quote of an ANSI standard solid-state interval meter at a low cost unless sufficiently large quantities are ordered. On the other hand, utilities cannot justify wide scale deployment until a low cost AMI meter is available that satisfies the functional requirements as defined in the April 15, 2004 Working Group 3 Functional Requirements report and the Functionality Ruling. SDG&E is assuming that an advanced single phase solid state interval meter with a communications board (either integrated into the meter board design or deployed as a separate board) will be available at a competitive price if the Commission orders a large deployment of AMI meters.

SDG&E envisions that the installation of AMI electric meters (both single phase and poly phase) will be performed by a combination of internal labor and contractor workforce. These deployment costs are included in SDG&E's estimates and are expected to be refined over time as the RFI/RFP contracting process progresses. Costs included in the AMI meter system and installation category consider installation, a reasonable number of revisits, necessary vehicle costs, associated tools and training, and other tasks. Additionally, no salvage value was assumed in the full deployment scenario for the old meters that would be removed as a result of AMI because the costs and logistics associated with such an endeavor (i.e., sorting, cleaning, etc.) would more than offset any resale value (see item MS-9 in Appendix A (redacted) for further details).

Labor resources are included to train, certify and oversee the contractor installation work force, as well as to train other internal employees who will operate, troubleshoot and maintain the new system.

A low percentage of electric panel rebuilds as well as A-base conversions are included in the cost estimates. Revisits, or situations when the initial installation attempt is unsuccessful, are assumed to be included in the overall installation cost.

Electric meters, installation and maintenance costs are a large component of overall costs and are included in this section. These costs are broken down into the following categories:

- Metering equipment
- Meter engineering
- Meter failures
- Battery replacement

ii. Metering Equipment:

SDG&E anticipates being able to deploy metering successfully with 95% coverage from the assumed AMI technology utilizing a communication infrastructure integrated with a solid-state residential and commercial meter. Overall, the mix of SDG&E's single-phase to poly-phase meter population is roughly 80% / 20%. Of the 20% poly phase meters, roughly 14% are Form 12 'network' meters, and roughly 6% are the remaining poly phase form meters. In the case of the single-phase meters, costs assume a 'best price' for the meter with the communications module for the majority of the meters purchased (those purchased during the final three years of deployment). For the poly phase network meters with communication modules, the costs included in this category assume a 'best price' for the majority of the meters deployed (those purchased after 2008). In the case of the three phase meters with communications modules, the costs included in this category assume a 'best price' for the majority of the meters purchased (for deployment in 2008 and later).

iii. Metering Engineer:

Other incremental labor costs in this category are associated with the engineering staff required to access and manage equipment failures, technical development activities with vendors, associated failure analysis to resolve field issues, and to deal with product enhancements associated with the large deployment of AMI equipment over the time horizon. In addition, Meter Engineering is required to follow up with meter manufacturers on product enhancements, maintenance and deployment issues as well as to support the eventual analysis of product changes and alternate technologies.

iv. Meter Failures:

Additional labor and meter hardware are also included in the costs in this category. Solid state meters are expected to have a higher failure rate than their electromechanical counterparts due to the more sensitive nature of electronic components. Meter replacement costs are excluded from the total for meter failures during the first year of operation that are covered under product warranties. Meter failures in subsequent years 2-12 are anticipated to reach their lowest level of annual failure and failure rates during years 13–15 will be at slightly increased values as these meters reach the end of their engineering life cycle. The assumed life cycle of the new AMI meters is 15 years.

v. Battery Replacement:

These costs include the costs to replace batteries contained in the poly phase meters, with an assumed battery life of approximately 10 years and assumed a reasonable annual failure rate. A battery change-out program for these poly phase electric meters will start in the 11th year after installation.

vi. Gas Index Module Installation:

SDG&E anticipates moving through an RFI / RFP process resulting in the selection of a gas AMI module installation contractor (which may very well be the same entity as the electric meter installation contractor). In addition to costs associated with the contractor workforce, company labor resources are required to manage the installation work force. Additionally, the costs associated with the exception case meter data gathering process (alternative solution for the 5% of customers assumed not covered by the fixed communications network) is included in this category.

This category of costs also includes the cost of training the work force involved in gas AMI installation and maintenance (existing SDG&E employees are envisioned to be responsible for routine maintenance but training is necessary). Additional training assumptions include multiple positions (Instrument Technicians, Regulator Technicians, and Patrollers) being trained together. No additional tools will be required for existing field forces (over and above those already used by SDG&E's Customer Service Field group).

vii. Miscellaneous Meter Installation Assumptions:

Meter installation costs also include costs for communication system engineering labor and test equipment and training for supporting new technology associated with the new AMI communications network. These costs include the incremental labor and associated non-labor expenses for customer contact management during deployment and the coordination and resolution of various field deployment problems. These activities include project management and supervision of all deployment related customer contact and problem resolution (correspondence, call center support and field problem resolution management) activities.

Additional costs are included for supply chain management, including establishing various staging facilities for meter deployment and installation. The facilities include a central hub and satellite locations to receive and distribute electric meters, gas modules/meters, and LAN/WAN network communication devices. The facilities costs assume leased space for all the material and installation personnel.

E. Communications System

Cost estimates are based on gateway coverage and the associated relays that are required for each gateway. Gateways are telecommunications servers that collect interval meter data from several hundred meters and then transfer such data back to enterprise servers. The majority of gateways are anticipated to be installed on non-company owned/or third-party owned streetlights, and cost estimates include monthly lease charges for this purpose. Additionally, some devices will be installed on the SDG&E owned overhead distribution network and costs for these installations are also included (i.e., differing equipment/material requirements, wiring requirements, etc.). Network component life is expected to be in the 15-year range, and costs are also included for the relatively small number of gateways and relays that are expected to require a new dedicated pole installation. Back-haul costs from the gateways to the utility's back office are estimated based on the costs of a public digital cellular pocket data network. Estimated costs for installation include anticipated contractor labor costs as well as the labor costs associated with a small number of SDG&E resources for management and quality assurance of the network installation contractor workforce.

Other costs identified in this category include labor to conduct evaluation and testing of new technology and system design activities for network communications. In addition, system design work is required for database management systems and integration with existing and new customer information and billing systems. Additional costs include the value of the power consumed by the network components and the value of additional energy used by the RF communications device within the electric meter (approximately 1 watt power output per device/meter).

SDG&E's multi-vendor and multi-telecommunications architecture will allow the back-haul or wide area network to change and evolve over time. Emergence of other telecommunications media and protocol (e.g., WiMax, BPL) requires that SDG&E implement an AMI telecommunications system that can leverage different (but at this point unknown) communications protocols and media.

SDG&E has been a proponent of adopting ANSI C12.19 standards for meter data storage since 2000. Specifically, SDG&E believes that if all advanced meters adopt a standard data storage format in the meter, then various telecommunications technology vendors can build standard interfaces to capture and transport the data via alternative communications media with less effort. Moreover, SDG&E requires an architecture that can use multiple back-haul or wide area network (WAN) communications. For example, SDG&E is currently estimating costs based the use of a public wireless carrier for data transmission back to SDG&E enterprise servers from the several thousand meter data collection devices mounted on street lights or utility poles. However, SDG&E envisions that other WAN alternatives could also be utilized if proven to be cost effective (e.g., SDG&E private radio network, development of WiMax, standard RBOC landline, SDG&E fiber, etc.).

F. Information Technology and Application

SDG&E assumes, that at a minimum, interval data for customers on dynamic rates (e.g., CPP) will be retrieved nightly from the customer's meter and processed so that customers will be able to access this data the next day. Specifically, SDG&E envisions the development of several new systems and software applications to collect, process, sort, store and retrieve data to allow customers access to their energy usage data as well as provide an accurate customer bill. SDG&E assumes that the following functions, activities and business processes require development of business application software, data management tools and supporting hardware: Meter Data Management Administration (MDMA), on-line data presentment, data warehousing/meter data management, load control programs support and management and systems integration. SDG&E has issued Requests for Information (RFI) for various IT related work associated with these functions. This filing includes updated IT systems development costs as a result of responses of these RFIs.

SDG&E assumes that new software applications, hardware and IT infrastructure are necessary to support the deployment of AMI meters and communications equipment data retrieval and aggregation, customer billings from aggregated interval data, and web-enabled customer access for energy management purposes. In addition, several modifications and interfaces must be developed into existing customer care and dispatching applications. The variable costs between partial and full deployment scenarios are generally related to hardware servers and storage costs, since software applications are assumed to be robust enough to handle either a partial or full deployment. In addition, the difference in incremental cost for systems development associated with demand response and dynamic rates is minimal between a partial or full deployment of AMI technology. SDG&E intends to issue RFPs for software development services and applications. The following sections describe applications and technology projects SDG&E believes are required to support an automated meter reading infrastructure and associated billing and energy management activities:

G. Specific Information Technology (IT) Application Requirements: Base IT Assumptions

IT cost estimates are based on an eighteen-month schedule to implement the majority of the systems projects. This schedule necessitates a higher percentage of contract labor versus internal employees for staffing IT projects. SDG&E plans to outsource much of the IT project work to contractors and software vendors given the aggressive AMI schedule. SDG&E estimates a 50-75% contractor to internal labor mix on most projects. SDG&E will most likely evaluate and select available vendor software packages over custom-built solutions to expedite the AMI development process.

SDG&E assumed three rounds of IT server replacements for the period through 2021. A 20% reduction in cost versus the initial purchase was also assumed for the server replacements. Although it is difficult to predict specific innovations in technology, history (such as Moore's Law)[17] has demonstrated that technology becomes cheaper over time. A 20% reduction may not adequately forecast the innovations coming in the next sixteen years; however, it is a conservative assumption.

SDG&E does not envision contacting individual customers to notify them of critical peak pricing events. The estimates assume that customers will be notified via mass media communications and electronic alerts. Contacting individual customers for critical peak events has significant cost as well as technological implications. Contacting

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[17] Moore' Law is based on Intel co-founder Gordon Moore's predictions that computing processing power doubles every 18-24 months

a large subset of our customers the day before a pricing event, even with an impressive automated notification system, may not be technically possible given the sheer number of customers being contacted over a standard telecommunications infrastructure. Even if it were possible, the recurring monthly cost of maintaining the telecommunications trunking and infrastructure would be significant, and may have little benefit over mass media communications.

SDG&E does not envision the requirement for meter route developments software. The meter routes for the majority of SDG&E's service territory are managed manually today. This type of software requires extensive engineering surveys of the service territory and heavy customization. SDG&E does not anticipate that the surveys and customization could be completed in time to benefit the AMI project. The following are specific IT software applications that require development to support AMI.

1. Meter Information Tracking

AMI requires management of many new data elements such as the firmware version of a meter, the network path (parenting) that a meter most recently used to communicate with the back office, and the number of megabytes a particular gateway used for communication last month. Also, the rollout and maintenance of the metering infrastructure requires new IT support services for order scheduling, telecommunications accounting, issue tracking, interfaces to contractor systems, and project reporting. SDG&E proposes to augment the meter management functions available in current systems with this new system. SDG&E assumes this system will be fully integrated with existing order and dispatch systems to leverage customer service work order efficiencies and customer service operational support.

2. Meter Data Management

SDG&E's current MV-90 system processes approximately 8,000 interval meters every month. In addition to calling meters and retrieving their data, this system validates the data and allows editing and estimation for missing or erroneous intervals. A full deployment of AMI will require a system to validate and process in excess of 18 billion intervals per year. SDG&E's current system would be capable of processing at most 32,768 interval meters. A new system would be required to handle the volume of meter data anticipated for either the partial or the full deployment scenarios. SDG&E anticipates that the bulk of the cost for this system will derive from the hardware and communications infrastructure required to store and process this volume of data.

3. AMI Network Vendor

Before the meter data can be processed, it must be collected from the meters. SDG&E anticipates installing, customizing, and interfacing to an AMI network vendor's software package. This application will be responsible for communication to the meters through the appropriate AMI devices. It is anticipated that this system will also contain the diagnostic functions to remotely determine meter hardware and communication failures. Additionally, this system may provide outage restoration data and information or may work with other outage management applications to support restoration efforts.

SDG&E is currently working with an AMI vendor to develop the Commercial AMI or RTEM project. Further work with the vendor will be required to develop the application to SDG&E's specification to support a larger rollout of advanced meters for residential and small commercial customers.

4. Meter Data Presentment

This customer information application displays load shapes based upon a customer's electricity consumption from the previous day. This web accessed, browserbased application would be provided to all customers free of charge, but SDG&E would require customer enrollment for access privileges. SDG&E estimates that at most 15% of residential customers will be interested in this service; however, no more than 2% of our customers would use the application concurrently. SDG&E plans to store thirteen months of interval data for active participants.

This functionality is currently available to SDG&E customers participating in the AB 29X metering and/or demand response programs, including the Statewide Pricing Pilot. However, this utilizes the existing vendor-hosted product, whose current pricing structure is not cost-effective for mass deployment. Given the anticipated volume of customers using this application, SDG&E must evaluate whether to renegotiate the contract, choose another vendor, or to develop an alternative application. SDG&E has issued an RFI to nine vendors and has received six responses. SDG&E intends to issue an RFP as a next step.

5. AMI Data Warehouse

Managing AMI requires tracking and managing new equipment types, new attributes for existing equipment, and new work order types and elements. This new reporting warehouse will provide meter history information, gateway and relay inventory, interval data, and other data elements. In addition, reports generated from the warehouse will provide key performance information for the deployment activities.

SDG&E envisions the need to integrate information from several different systems, new and legacy, into a single data repository. Data sets and reports will be generated from this repository using various warehousing tools and/or cube technology. These tools will support customer service, metering, project management, and load research activities without impacting production operational systems.

6. AMI Inventory

In 2005, SDG&E will enhance its supply chain management business processes and systems independent of AMI. Specifically, SDG&E will begin to utilize bar code scanning to track assets entering and leaving inventory. AMI, however, will necessitate tracking additional component and equipment types and attributes in SDG&E's asset management systems. SDG&E anticipates the need to build new interfaces between systems, add attributes and equipment types to existing systems, and implement new business processes, etc.

RFID is the next logical step after a bar code system is implemented. A bar code system with all of the related business process improvements provides a better foundation for asset management than SDG&E's current methods. RFID builds on that foundation, but provides no value without first implementing the business process improvements as a first step. SDG&E has not included RFID in scope for AMI. Implementing RFID during the deployment of AMI would divert resources from the same business groups responsible for AMI without providing enough asset-management value to offset the risk of impacting the AMI schedule.

7. AMI Deployment

During the first three years of the deployment, SDG&E will be building, customizing, and integrating systems to support AMI. However, some of the systems will not be available on day one of meter deployment because there are several critical path dependencies involved in system developments. SDG&E anticipates the need for 4-6 FTEs during the first two years. These FTEs would be responsible for building and supporting the "bridging applications" and ad-hoc reporting envisioned during the first two years of the deployment period (e.g., beta test phase and first year of mass deployment). These FTEs will also be responsible for handling data exchange issues with external vendors (such as the contract meter installers) to assure that the terms, conditions and schedule are met.

8. Existing Infrastructure Upgrades

With the extensive volume of data associated with wide scale AMI deployment, SDG&E needs to conduct a comprehensive analysis of existing technical infrastructure to identify capacity issues and bottlenecks. It is anticipated that specific infrastructure projects may be required to expand storage capacity, backup and recovery technology, security, networking, or other areas with limited capacity or throughput. These upgrades will likely include a new region of the mainframe for systems development and testing.

9. Meter Shop Enhancements

SDG&E anticipates the need to make enhancements to its Meter Shop to facilitate and expand meter-testing activities.

10. Customer Information System (CIS)/ Service Order AMI Enhancements

SDG&E's core systems such as CIS, are responsible for most billing and customer service functions. Although SDG&E's existing core systems will be augmented with new systems supporting AMI, the existing systems will need to include identification of new equipment types, attributes, and work order types as well as any interaction with the customer. SDG&E also envisions the need for new self-service tools to assist customers to enroll or opt out of the new rate and load control programs. These new customer tools would be available through sdge.com as well as SDG&E's interactive voice response system.

11. Billing System

To minimize the impact of AMI to day-to-day billing and customer service operations, interval data will continue to be aggregated outside of SDG&E's billing system. SDG&E currently aggregates and processes interval data into billing determinants outside of the billing system, and passes those determinants daily to produce customer bills. Interval Data Systems (IDS) is a custom-developed, in-house system that processes interval data into billing determinants. With the extensive volume of data required by the AMI and Demand Response scenario, modification or replacement of SDG&E's existing IDS is required. RFIs have been issued to fourteen vendors, and eight have responded.

12. Systems Integrator

Due to the significant number and complexity of parallel systems projects required to support AMI, SDG&E recognizes the risk to meet the current schedules. An external Systems Integrator resource would add experience, labor resources, tools, and methodologies that could greatly mitigate many of the AMI IT systems development project's risks. Although SDG&E has extensive experience in managing projects, outsourcing some aspect of the project management would provide SDG&E with specific AMI systems integration experience. SDG&E sent an RFI for AMI Systems Integration to nineteen vendors, and received eleven responses.

A Systems Integrator will be tasked with completing an analysis of the most cost effective mix of internal and outsourced software development resources.

13. Handheld Devices

SDG&E anticipates that the installation and retrofit of the meters supporting AMI will be outsourced. However, SDG&E personnel are assigned the role of troubleshooting broken meters and gathering meter data manually when communications fail. This SDG&E staff will require portable handheld devices that support their field work. New handheld devices and supporting software may need to be developed.

14. Load Control Software

SDG&E has included the cost of load control device software to signal various load control devices, track customer enrollment and participation in the program, generate incentive payments, etc. SDG&E will work with load control vendors willing to integrate their products with the chosen AMI telecommunications solutions.

15. Customer Service

As directed in the July 21 ACR, the AMI Only scenario involves no new rates and therefore no additional costs would be incurred in this scenario to educate customers regarding new rate structures or managing energy use due to dynamic pricing. Nevertheless, customer education, community outreach and customer contact would be needed in the AMI Only scenario to inform customers of installation schedules. Moreover, customers would need to be informed about and prepared for a short outage that would result from the electric meter change-out process, and in the cases where a gas meter change-out is required, and a gas outage is anticipated, appliance re-lights would occur. All of these activities require pro-active customer communications, contact and education costs.

SDG&E plans to communicate with customers regarding planned electric and gas meter change-outs and gas module retrofits and the associated short outages. These communications include mailed informational materials and mass media advertising to inform customers of the meter change outs. The volume and complexity of installing interval data meters leads to greater exceptions processing (i.e., those orders that require some form of special or unique treatment outside of the normal processing of meter installations). Additional exception processing is assumed for new electric and gas meters throughout the meter deployment phases. SDG&E assumes all Customer Service

Representatives will require one hour of training during the meter installation deployment period for electric meters and one hour for gas meters.

The demand response and reliability scenarios also include the need for additional skills and incremental labor costs associated with training employees and processing of the more complex billing. Dynamic pricing adds to the complexity involved in addressing customers' billing concerns and bill-related calls. Customer calls are estimated to increase 120 seconds per call on average. An additional four hours of training is assumed for each Customer Service Representative allowing them to deal effectively with customer questions and concerns related to the new demand responsive rates contained in these scenarios.

Additional costs also include customer education and communications for various rate options and additional training materials for other SDG&E employees. The costs also include additional labor costs for communication representatives overseeing customer contact efforts and web technologists to manage the website providing customer access to their usage data.

Costs for enabling technologies, such as smart thermostats, are also included in this category. The costs include devices, installation and incentive payments. Additional program administrative costs are also required to manage such programs.

16. Management and Other Costs

These costs include the incremental labor and associated non-labor costs to centrally manage the AMI project during the partial or full scale deployment scenario as well as to manage the meter reading reroute issue during AMI deployment. The functional responsibilities included in the central project management group are: AMI project management, project management reporting and quality assurance, and financial management. Implementation of dynamic rates requires additional billing resources.

Moreover, additional training is necessary for customer contact and billing personnel, enabling them to become proficient in understanding dynamic rates and resulting bill calculations. Additionally, incremental costs associated with the recruitment of personnel to support the AMI deployment are included in this category.

17. Gas Service Impacts

The largest gas-related cost component is the purchase of AMI compatible gas meter communication modules that would be retrofitted on approximately 72% of SDG&E's existing gas meters. Approximately 28% of SDG&E's existing gas meters cannot be retrofitted with a gas communication module and would require complete meter change-out. Costs for replacement meters gas communication modules have been included in the estimated costs. In addition, the avoided costs associated with replacing those gas meters at a later time in the absence of AMI have been estimated. Once installed, the gas module is powered by a battery that allows RF communication with a relay, an electric meter acting as a relay, or a gateway. These batteries are assumed to have a life of ten years, and costs have been estimated for a routine change out shortly before anticipated battery expiration. Corrective maintenance costs associated with estimated gas AMI module failures have also been included. Costs include incremental labor required to support necessary operations for gathering gas reads monthly over the communications network and monitoring and troubleshooting any data failures from either the communication network or meter data failures. The costs include all activities in gathering the gas meter data and preparing it for billing.

H. Operational Benefits

1. Meter Reading

The primary system operations benefit is the reduction in meter reading costs. SDG&E assumes that most, but not all, meter readers and their associated costs would be eliminated by a full AMI deployment. The meter reading cost reductions include meter readers, support personnel, associated benefits, fleet vehicles, expenses, and meter reading related claims.

2. Customer Service Field

SDG&E assumes that with an AMI fixed communication network for both electric and gas meters, 95% of reads obtained off-cycle on behalf of customer inquiries, billing exceptions and change of account orders will no longer be performed by dispatching customer service field personnel. These benefits reflect labor savings associated with an average of 10 minutes driving and 5 minutes spent on a customer premise per work order. These benefit dollars are adjusted based on the assumed deployment schedules of either a partial deployment (Inland climate zone) or full deployment scenario.

3. On-Schedule Cycle Billing

Balancing meter reading workload over the course of 21 meter reading cycles is an ongoing process and in the absence of AMI, meter reads are not always available for all customers in a given cycle on the scheduled billing date. SDG&E assumes the deployment of AMI technology will allow customer billings to be generated on their regularly scheduled cycle billing date. Other benefits come from SDG&E's experience that shows when customer billings are accelerated by one day that customer payments are received, on average, one day earlier as well. Specifically, this reflects the cash flow benefits associated with the elimination of the late reads. Most non-solid-state (electromechanical) electric meters slow gradually as they age (and average life for these meters is in the 40 year range). Replacement of older meters with interval data meters that are calibrated to within 0.5% for the life of the meter provides benefit dollars. As the AMI deployment progresses and meter reading is converted from manual meter reads to daily transfer of interval data via the telecommunications network, the usage for the final manual meter read (and resultant revenue) would be recorded up to the time that the read was recorded. Under AMI, however, the normal read is only up to the prior day at midnight. The result is lost revenue associated with the 8-16 hour long in one month, made up the following month. The result in revenue shift from one month to the following is lost. This one-time, one day delay for one month is represented as a reduction to the benefit.

4. Meter Revenue Protection

Electric utilities estimate approximately 1 – 2% of their revenue is lost due to energy theft. The most common method of stealing energy is turning the meter upside-down, allowing the meter to run backwards. When usage is recorded in hourly intervals, this method of energy theft will no longer be possible. A solid state meter that is programmed to record energy in the forward direction regardless of how it is placed in the meter socket would eliminate this issue, In addition, there is a tamper alarm in the NCC card. These features would aid in early detection of energy theft. Conversely, meter readers have historically detected approximately 42% of SDG&E’s electric meter diversion. Without the benefit of monthly site visits by meter readers, other methods of diverting energy are likely to go undetected. SDG&E estimates that each energy diversion results in approximately 50% average electric revenue loss for that meter.

Further, SDG&E estimates that AMI technology enabled meters will detect approximately 40% of future energy diversion as customers derive more sophisticated ways of stealing energy. The energy theft revenue benefits are offset by modest increases in labor costs to investigate suspected energy diversion. The benefit calculations reflect the net of these benefits and costs.

5. Other Miscellaneous Systems Operations Benefits

The two way AMI network SDG&E envisions would have some capabilities associated with gathering data previously gathered manually during testing. The AMI network will communicate voltage, current and phase angle information for sites, potentially identifying related problems without having to send company personnel to the field. Remote service connect/disconnect costs are not included in this analysis since the incremental costs of such devices does not justify widescale deployment. SDG&E would consider such functionality on a case-by-case basis to determine if the operational turn-on and turn-off labor costs reductions would justify this additional technological expense. Other benefits identified are labor savings estimated from a reduction in customer calls over disputed bills. SDG&E assumes a lower meter change out rate (fewer Electric Meter Tester orders for certain types of orders) on the order of 20% for some categories of meter change out work, during deployment and following installation of the envisioned AMI system.

I. Meter Reading Errors

SDG&E assumes there will no longer be errors associated with manually reading meters as a result of the AMI technology. These benefit dollars represent the labor savings associated with processing approximately 4,000 electric and approximately 2,800 gas meter read exceptions monthly due to meter reading errors.

J. Net Present Value "NPV" and Revenue Requirements Calculations

1. Purpose and Methodology

SDG&E's cost evaluation of AMI is a cost analysis from 2005 through 2021 from a ratepayer perspective. Because benefits and costs occur over many years, SDG&E used net present value analysis to bring all of the annual costs to the base year of 2005. Measuring benefits and costs from a ratepayer perspective means that SDG&E valued all benefits and costs using the revenue requirement that ratepayers would incur.

2. Overhead Costs

Standard SDG&E overheads were examined on a one-by-one basis to determine which were incremental as required by the analysis. Standard items such as Public Liability (1%), Worker's Compensation (3.5%), Payroll taxes (7.8%) and other standard overheads were applied as applicable, but in cases where the cost elements specifically related to an item or an area 'normally' handled by the utility through the use of overheads, did NOT apply such overheads (as would be standard practice). For example, 'Warehousing' is normally handled through the application of an overhead (50%), but because cost elements such as MS-10 (supply chain management including development of staging facilities, shipment and handling of new meters) were included in the necessary cost breakout, these types of overheads were not applied.

3. Tax Issues and Depreciation Methods

A Federal tax rate of 35% and a State tax rate of 8.84% is assumed. Depreciable life of assets for Federal tax purposes uses Federal tax life 20 yrs, double declining balance/straight line, 150% and assumes normalized federal taxes. Depreciable life of assets for State tax purposes uses State tax life 30 yrs, double declining balance/straight line, 200% and assumes flow through of taxes. Annual Depreciable Rates of capital equipment for book purposes are 7, 9, 15, 30 years. Project assets are placed in service on a one-year lag starting from 2006 to 2022.

4. Discount Rates, Cost of Capital & Capital Structure

To calculate Net Present Values, SDG&E discounts benefits and costs at its estimated incremental cost of capital. SDG&E's current incremental cost of capital is 8.18%. This rate reflects SDG&E's authorized: cost of equity of 10.37%, cost of debt of 5.90%, and cost of preferred stock of 7.45% and assumes SDG&E's authorized capital structure of 49% equity, 45.25% debt and 5.75% for preferred stock.

5. Revenue Requirements

SDG&E will apply a revenue requirement model in the March 15th AMI Application to convert annual costs into revenue requirements, and will then use this annual revenue requirement to derive the net present value of the entire revenue stream. A utility's cost of service or revenue requirement is all of its operating expenses plus a return on its investment. Therefore, the revenue requirement equals the sum of all costs necessary to meet its ongoing obligation to serve. The following formula expresses this revenue requirement:

Revenue Requirement = Operation and Maintenance (O&M) expense +
Depreciation Expense +
Tax Expense +
Return on Investment

O&M expense is the routine work that SDG&E performs to supply service during the course of a year. O&M expenses include labor, materials, supplies, fuel, and variable administrative and general (A&G) expenses. Depreciation expense is the charge against earnings that SDG&E takes each year to allow for the recovery of an investment over its useful life. Tax expense includes taxes based on income, miscellaneous taxes, and property taxes. Return on Investment is the cost of capital that SDG&E incurs to finance its long-term investments. SDG&E multiplies the rate of return by its incurred long-term investment (or Rate Base) to calculate its return. As discussed previously, SDG&E has calculated the revenue requirements for each cost component and then put them on a consistent basis relative to the timing (used an NPV) of the ratepayers' payments. The difference between the sum of the annual revenue requirements and the NPV of the revenue requirements is due to the timing of the ratepayer's payments. The earlier the ratepayer pays the revenue requirement, the higher the PV.

VIII.

SDG&E's BASE CASE ("BUSINESS AS USUAL") ANALYSIS

A. Introduction

As required by the July 21 ACR,[18] this Chapter presents SDG&E's Base Case, or "Business As Usual" scenario, which assumes that there is no future deployment of AMI. The specific requirements for the base case scenario, as set forth in the July 21 ACR, are as follows:

> "This scenario includes the expected capital and maintenance costs associated with maintaining current metering and communication systems for all customer classes, including planned upgrades to metering and billing systems for the 2006 to 2021 period. Costs should be estimated on an annualized basis for the analysis wherever possible.
>
> Cost estimates to support the current information technology system used for processing current meter reads and converting them into bills for each cost category should be specified for the Base Case to ensure a fair comparison between the business as usual, partial, and full scale deployment of AMI."

[18] July 21 ACR, Attachment A, Section 2.1, page 1.

According to the July 21 ACR, the Base Case analysis "will establish the baseline for evaluating cost effectiveness of the other scenarios."[19] Elsewhere, the July 21 ACR notes that: "Because installing an advanced metering infrastructure requires substantial utility investment and impacts all aspects of utility operations, the decision of whether, and if so, how, to proceed *requires a detailed cost/benefit analysis*." (emphasis added).

[19] July 21 ACR, Attachment A, Section 2, page 1.

In accordance with the directives of the July 21 ACR, SDG&E's AMI Business Case analysis has been prepared on an Incremental Cost and Benefit basis, identifying the anticipated costs incremental to SDG&E's Base Case that are attributable to an AMI deployment, as well as estimating the benefits that may accrue from an AMI deployment, similarly incremental to SDG&E's Base Case operations. The AMI Incremental Costs and Benefits are discussed in detail in Chapter VII, and Appendix A (redacted).

B. Short-Term Nature of Cost-of-Service and Business Planning

SDG&E's Cost-of-Service and Business Planning cycles typically involve preparation of forecasts of operating expenses, capital projects and other business costs that span a forecast horizon much shorter than the 16 year window (2005 – 2021)[20] required for the AMI Business Case analysis. In preparing Cost of Service and Business Planning forecasts, SDG&E identifies and incorporates activities and expenditures that it envisions in the normal course of business, and also includes those activities and expenditures that are less routine or more specialized in nature. As such, these forecasts truly represent a Business as Usual forecasting approach, which typically does not exceed a 5-year forecasting horizon.

SDG&E interprets the July 21 ACR's Base Case requirement to mean the identification of the costs that SDG&E would incur related to its metering, billing and related systems and operations in the absence of an AMI deployment. As such, SDG&E's Base Case costs would represent the costs assumed for these activities and functions under SDG&E's current operations, and would not incorporate any *incremental* future expenditures that might occur to obtain the operational or other benefits that would be attributable to an AMI deployment. Of greatest importance is that all expenditures

[20] July 21 ACR, Attachment A, Section 2.1, page 1 states a window (2006-2021) but in reality, utilities will be incurring costs in 2005 for AMI design, development and supporting information systems development.

underlying any of the possible AMI deployment scenarios would be incremental to SDG&E's Base Case.

C. Current FERC Classification of Accounts

As established by the Federal Energy Regulatory Commission (FERC), and employed by utilities nationwide, SDG&E maintains its current accounting systems to report its accounting results by standard FERC-designated accounts. SDG&E has attempted to dissaggregate its Cost of Service forecast of expenditures in the near term into the specific cost elements as set forth in Appendix A of the July 21 ACR. Unfortunately, there is not a direct one-for-one correspondence between FERC accounts and the July 21 ACR's cost elements. In fact, many of the costs as recorded (or forecasted) by FERC account actually map to a number of July 21 ACR cost elements, or vice-versa, making a reporting of Base Case costs by July 21 ACR cost elements a substantial and difficult undertaking. In recognition of the fact that SDG&E's AMI Business Case anticipated expenditures are indeed incremental to SDG&E's Base Case expenditures, SDG&E has described in further detail in Section D. below those key functions and activities currently included within its Base Case.

D. Key Functions and Activities of SDG&E's Base Case

1. Customer Growth

SDG&E incorporated meter growth forecasts in the Base Case operational or functional activities that are consistent with the meter growth forecast assumed in the demand response impact analysis described in Chapter VI of the Preliminary Analysis.

Table VII.1. Total Meter Counts, by Selected Years

Total Meter Counts, by selected years

Partial Deployment (residential and small commercial customers in the inland climate zone and all medium and large commercial (> 20kW)

	2005	2006	2009	2010	2011	2015	2021
Total Electric Meters	564,245	573,204	600,979	610,545	620,269	660,799	726,810
Total Gas Meters	371,230	377,168	395,563	401,894	408,327	435,116	478,662

Full Deployment (All residential, small, medium and large commercial)

	2005	2006	2009	2010	2011	2015	2021
Total Electric Meters	1,323,579	1,342,383	1,400,481	1,420,423	1,440,662	1,524,662	1,660,334
Total Gas Meters	823,127	836,293	877,081	891,118	905,382	964,781	1,061,336

2. Functional Activities and Expenditures

SDG&E identified key functional activities that are impacted in terms of incremental expenditures, including expenditures for AMI design, deployment/installation and on-going costs. In addition, AMI related cost saving or cost avoidance are identified in several functional activities. The cost savings result from elimination or reduction of business as usual on-going activities (primarily resulting from automation). Cost avoidance generally occurs when capital projects can be deferred or avoided as a result of AMI investments.

3. Meter Reading Activities

SDG&E assumes that Meter Reading costs would continue to increase at rates consistent with the increasing number of annual meter reads and therefore adding an increasing number of meter reading routes and meter readers. Correspondingly, the number of meter reading handheld computers will increase accordingly for each additional meter reader. SDG&E plans for a replacement cycle of the meter reading handheld computers once every seven years. SDG&E will need to replace the current generation of handheld meter reading computers in 2007 and therefore expects another replacement cycle to occur in 2014 through 2015. In addition, SDG&E is planning to purchase and install new meter reading route development software beginning in 2006 with implementation in 2007.

The cost savings from reduction of manual (walking routes) meter reading is reflected in operational saving in the partial and full deployment scenarios.

The reduction in associated nonlabor costs (e.g., equipment, uniforms, etc.) is reflected in operational benefits with a decrease in initial capital purchases for handheld computers in 2006 and 2007. The reduction in handheld computers is reflected throughout the annual cost savings that are associated with reduction in meter reading activity resulting from partial or full AMI deployment.

A reduction in capital expenditures for meter reading route development software is reflected in cost avoidance in 2006.

4. Customer Services Field Activities

Customer Services Field (CSF) activity levels are driven by customer (or meter) growth, general migration in and out of SDG&E's service territory, service requests, and customer movement within the service territory. In the business as usual case, SDG&E applied the meter growth rate assumption to the customer services field service orders that are impacted by customer growth. Using 2004 as the base year, CSF activities are assumed to increase proportionately with meter growth. The migration and intra-service territory movement is assumed to be constant. Customer growth and service offering changes lead to an increasing number of CSF service orders and therefore additional CSF personnel and associated equipment, such as mobile data terminals (computers in service trucks).

AMI related CSF cost savings result from eliminating or reducing CSF activities involving onsite meter reads required for closing or final bills, new accounts and revert to owner (renters who move) transactions or service orders. In addition, CSF also performs meter reads to verify customer inquiries regarding billed amounts of consumption. Many of these transactions will be eliminated as result of AMI. Cost savings related to AMI incorporate the business as usual base case growth in customer orders.

Because AMI eliminates many of the CSF transactions described above, CSF requires fewer personnel and associated equipment. As a result, SDG&E's capital cost avoidance includes reductions in mobile data terminal and modem replacements (portable computers in CSF personnel vehicles).

5. Customer Contact and Call Center Activities

Call center customer inbound calls are driven, in part, by the growing customer base. Call center activities incorporate business as usual customer or meter growth. The business as usual case assumes current levels of average handle time with the customer. The "business as usual" case also assumes that the proportion of calls handled via self-service options in the forecast years will remain constant.

Customer transactions related to customer inquiries concerning billing or meter accuracy are expected to be reduced with the deployment of AMI. However, average handle times related to new customer accounts (turn-on calls) are anticipated to see an increase of 30 seconds because customer service representatives will need to explain the default dynamic rate structure and other rate options. In addition, average handle time for initial billing inquiries are assumed to increase 120 seconds because of the dynamic rate structure, and return to near current levels once customers become accustomed to the new rate structure.

6. Billing and Other Revenue Cycle Activities

Billing and bill payment processing costs are based on the number of bills and billing accuracy. Customer or meter growth increases the number of customers billed and therefore the number of bill payments processed. The business as usual case assumes that Electronic Bill Presentation and Payment (EBPP) will continue to proceed as currently planned. Increased penetration or use of EBPP services by SDG&E's customers is planned in the business as usual case.

In the business as usual case, costs are also included for reviewing bills with unusual (high-low) usage patterns, adjusting meter readings prior to billing and re-mailing customer bills when meter reading errors are detected after the original bill has been mailed. Additionally, due to meter access problems, a number of bills are estimated. Because of operational conditions, a few meters are not read on the scheduled meter read date and will be read the next working day.

With the deployment of AMI, the number of meter reading errors is expected to be virtually nonexistent, substantially reducing the review of usage and volume of billing adjustments. SDG&E assumes that 100% of the cycle meter reads and customer bills will be completed on the scheduled date and customers will pay their bills on average approximately one day earlier, reducing working cash requirements. Estimated bills due to meter access problems will be eliminated, although a smaller number of bills will still require estimates due to meter communication problems.

7. Information Technology and Software Replacement Life Cycle

Most business systems software applications require replacement or major upgrades because of technological obsolescence or major business process changes that cannot be accommodated with minor modifications to the legacy or incumbent systems. SDG&E assumes that the current life cycle of business software applications is unchanged for systems not impacted by AMI. In most cases, the useful life for small and medium size software applications is 5-10 years. In terms of large enterprise software applications (e.g., Customer Information Systems [CIS], Accounting systems), useful lives can often stretch to 7-20 years. SDG&E assumes that new software applications will be purchased or developed to support the new AMI environment.

Modifications to the current CIS because of new dynamic pricing structures are already underway since several large customer demand response and interruptible programs require such billing methods. Changes to the Major Markets Billing System are included in the business as usual base case and are therefore not incremental due to AMI.

SDG&E identified one system that was planned for replacement in 2006, but will be not be necessary as a result of AMI. SDG&E had planned to replace the current software application that collects and processes interval data (MV90) in 2007. AMI will require that a major upgrade or replacement of the MV90 system will need to start in 2005 and completed prior to 2007 meter deployment.

Projected AMI Costs and Benefits are Incremental to Base Case

As required by the July 21 ACR, and described above, SDG&E's AMI Business Case analysis has identified those activities and costs associated with AMI deployment (Start-Up and Design, Installation, and Operations & Maintenance)[21] on an incremental basis for those activities necessary to deploy AMI. Similarly, the potential benefits that would result from AMI deployment are evaluated on an incremental basis (Systems Operations Benefits, Customer Service Benefits, Demand Response Benefits and Maintenance & Other Benefits.[22] The incremental AMI costs and benefits are described in Chapter VII and Appendix A (redacted).

By identifying those activities and related expenditures associated with an AMI deployment, with specific focus on the three phases of deployment as set forth in the July 21 ACR, SDG&E has, by definition, isolated those expenditures which indeed are incremental to its Business as Usual Base Case. Were it not for the deployment of an AMI network, the activities and expenditures that have been identified would not be incurred. The most obvious examples of incremental costs associated with AMI deployment are the costs of physical assets (meters, and communications network components) necessary to deploy an AMI network. Similarly, in identifying and quantifying the potential benefits accruing from an AMI deployment, SDG&E has focused on efficiencies and improvements resulting from the enhanced functionalities of AMI, as well as the incremental benefits (i.e., decremental costs) resulting from AMI deployment. The most obvious example of a decremental cost or benefit is the reduced labor cost of meter reading.

[21] July 21 ACR, Appendix A, pages 1 – 5. Cost categories are identified with three specific Phases noted.
[22] July 21 ACR, Appendix A, pages 5 – 7. Benefit categories are defined utilizing the categorizations noted.

APPENDIX A

UPDATED OPERATIONAL COSTS AND BENEFITS

REDACTED

APPENDIX B

AMI OUTSOURCING ASSESSMENT FINANCIAL MODEL

REDACTED