San Diego Smart Grid Study Final Report

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1.   EXECUTIVE SUMMARY

This San Diego Smart Grid Study is one of the first in the nation to apply the Smart Grid concepts developed by the U. S. Department of Energy's Modern Grid Initiative to a specific region. It provides preliminary analysis to determine the technical feasibility and cost effectiveness of implementing Smart Grid technologies and strategies in the San Diego Region. The objectives of the study are to (1) determine whether the future economic and regulatory climate in the San Diego region could accommodate or necessitate a Smart Grid, (2) determine the portfolio of technologies that could implement a Smart Grid, and (3) conduct a cost-benefit analysis to determine whether implementing a Smart Grid would be cost effective for the region.

Key Findings

1. Economic, technological, and regulatory trends in the San Diego region likely will create a desirable climate for implementation of a Smart Grid.

2. While the existing transmission and distribution grid includes some advanced technologies and SDG&E is planning to implement others, the project team identified 26 technologies that can be implemented to advance the current electric grid toward a smarter, more modern system.

3. Results of a preliminary cost-benefit analysis suggest that implementing Smart Grid technologies and strategies could yield benefits that adequately exceed the initial installed costs and cover the ongoing operation and maintenance costs.

1.1.   Smart Grid Overview

This study is based on the definition of a Smart Grid developed and being pursued by the U.S. Department of Energy's Modern Grid Initiative (MGI).[1] The existing transmission and distribution system in the United States uses technologies and strategies that are many decades old and include limited use of digital communication and control technologies. To address this aging infrastructure and to create a power system that meets the growing and changing needs of customers, the MGI seeks to create a modern – or "smart" – grid that uses advanced sensing, communication, and control technologies to generate and distribute electricity more effectively, economically and securely. The Smart Grid integrates new innovative tools and technologies from generation, transmission and distribution all the way to consumer appliances and equipment. A modernized grid would create a digital energy system that will:

- Detect and address emerging problems on the system before they affect service,
- Respond to local and system-wide inputs and have much more information about broader system problems,
- Incorporate extensive measurements, rapid communications, centralized advanced diagnostics, and feedback control that quickly return the system to a stable state after interruptions or disturbances,

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[1] More details about the Modern Grid Initiative (MGI) and this process can be found at www.moderngrid.org.

- Automatically adapt protective systems to accommodate changing system conditions,
- Re-route power flows, change load patterns, improve voltage profiles, and take other corrective steps within seconds of detecting a problem,
- Enable loads and distributed resources to participate in operations,
- Be inherently designed and operated with reliability and security as key factors, and
- Provide system operators with advanced visualization tools to enhance their ability to oversee the system.

1.2. Study Results

To accomplish the objectives of the San Diego Smart Grid Study, the project team developed a process that included the following six steps: (1) develop a scenario that describes the likely future state of the region's economic, regulatory, and technology climate, (2) assess the current state of the energy infrastructure and climate in the region (as-is state), (3) compare the current state to a future Smart Grid scenario to identify technological, regulatory, and consumer system gaps, (4) identify a core group of Smart Grid technologies that when implemented together would provide the framework for the Smart Grid concept, (5) conduct a cost-benefit analysis to determine if there is a business case for implementing the technologies identified, and (6) recommend an implementation strategy for the identified technologies, including near-term demonstration projects. We present below a summary of the results of this work.

1.2.1. Future San Diego Scenarios

To determine whether a future state of the San Diego region could accommodate and necessitate Smart Grid technologies and strategies, the project team developed a series of future probable scenarios based on spectrums of extreme states of economic, environmental and technology development. The team analyzed the impacts that such factors could have on the operation of the regional electric grid. This analysis demonstrated that under certain scenarios, a favorable climate exists for the implementation of a Smart Grid in the San Diego Region.

Based on our analysis, the most likely scenario to describe the future of the San Diego region includes continued economic growth, more environmentally restrictive regulation, and breakthrough technology in regional businesses, including the electric and gas utility. Given the current trends of regulation, the region likely will see an increasing emphasis on renewable energy, use of alternate fuels, as well as energy efficiency and demand response in all market segments. The region's economy will continue to have a large number of high-tech businesses and a high-tech lifestyle, which could drive a shift in the reliability and power quality requirements of the grid. This probable future environment of the San Diego suggests a desirable climate for the implementation of a Smart Grid.

1.2.2. Current State of the SDG&E Transmission and Distribution System (As-is State)

The project team analyzed the San Diego transmission and distribution infrastructure, communications, distributed energy resources in place in the region, related policy issues, market structure, including, existing technology applied to the grid, and the end-use (consumer-side) technologies available as resources. SDG&E validated the assumptions, provided operational data, and provided subject matter expertise on the existing and planned operations of the regional grid system. This survey is the baseline against which a future Smart Grid scenario will be compared to determine what technology and policy gaps exist.

Significant observations from this review include the following:

- There is an increasing number of customer-owned distributed generation systems installed in the region, including a growing number of photovoltaic systems.
- The existing utility communication infrastructure will not support the requirements of the future Smart Grid scenario.
- The utility is implementing technologies and systems that are necessary for a Smart Grid, including:
  - An Advanced Metering Infrastructure (AMI) initiative that SDG&E has submitted to the California Public Utilities Commission (CPUC). If approved, the project could be completed in 2010.
  - A substation automation program (multi-year) that is already in progress.
  - A field SCADA switch rollout program that is already in progress.
  - A set of broadband over power lines (BPL), advanced transmission conductors, and sensor exploratory demonstration projects are in progress.
- California state law requires the utility to follow a specific "Loading Order" when developing their resource plan. Under this law, utilities should seek new energy resources first from energy efficiency, demand response, renewable energy, and distributed generation before seeking resources from new transmission and fossil-fuel based generation.

1.2.3. Comparing the Current Electric Grid to a Future Smart Grid Scenario (Gap Analysis)

The project team compared the current SDG&E electric grid to a future Smart Grid scenario to determine what technological and regulatory changes would be necessary to modernize the region's grid. The process was modeled after the Modern Grid Initiative for the electric infrastructure of the nation, which focuses on five key technology areas (KTA): advanced grid components, integrated communications, advanced control methods, sensing and measurement, and improved interfaces and decision support.

The project team identified twenty-six (26) technology improvement initiatives that – from a technical standpoint – could move the existing San Diego electric grid to a more modernized, Smart Grid. Through a subsequent screening analysis in the business case, the original 26 initiatives were reduced to thirteen high-value improvement initiatives. Table 1 provides a list of these initiatives.

Table 1 Final Smart Grid Improvement Initiatives

Improvement Initiative No.	Improvement Name
1	GATECH IPIC Dynflo distributed series impedance sensors
2	I-Grid Monitoring System (by Softswitching Technologies)
5	Consumer Portal
7	Ethernet over Fiber
9	4G WiMAX Fixed - Private Wireless
11	Zigbee / WiMedia / WiFi - Wireless
12	Semi-autonomous Agents
14	Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)
17	DER-based Microgrids
19	Advanced Energy Storage Systems
21	Advanced Grid Control Devices
23	Agent and Multi-Agent Systems
25	Distribution (Feeder) Automation

1.2.4. Cost Benefit Analysis (Business Case)

In the cost-benefit – or business case – phase, the project team developed and applied estimates of installed costs and associated benefits (savings) for the thirteen high-value improvement initiatives. The anticipated benefits of implementing a Smart Grid used in the cost-benefit analysis include:

- Reduction in congestion cost,
- Reduced blackout probability,
- Reduction in forced outages/interruptions,
- Reduction in restoration time and reduced operations and maintenance due to predictive analytics and self healing attribute of the grid,
- Reduction in peak demand,
- Other benefits due to self diagnosing and self healing,
- Increased integration of distributed generation resources and higher capacity utilization,
- Increased security and tolerance to attacks/ natural disasters,
- Power quality, reliability, and system availability and capacity improvement due to improved power flow,
- Job creation and increased gross regional product (GRP),
- Increased capital investment efficiency due to tighter design limits and optimized use of grid assets,
- Tax savings for the utility from a depreciation increase, and
- Environmental benefits gained by increased asset utilization.

If all thirteen improvement initiatives were implemented, the initiatives would generate $1.4 billion in utility system benefits and nearly $1.4 billion in societal benefits over 20 years. The total capital cost for all thirteen improvement initiatives would be $490 million. Table 2 presents the overall results of the cost-benefit analysis.

Table 2 Overall Costs and Benefits of Final Smart Grid Improvement Initiatives ($millions)[2]

Total Annual Benefits	**$141M**
System Benefits (20-years)	**$1,433M**
Societal Benefits (20-years)	**$1,396M**
Total Capital Cost	**$490M**
Annual O&M Cost	**$24M**

Figure 1 shows a breakdown of the anticipated benefits of implementing the 13 improvement initiatives to develop a Smart Grid in the region.

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[2] We did not include simple payback in the results because the costs and benefits will be phased in over a period of up to ten years; therefore, simply dividing the total capital cost by the total annual benefits will not be a meaningful measure of cost effectiveness. For example, dividing total cost ($490million) by total annual benefits ($141 million) yields a 3.5 year payback. Because implementation of the 13 improvement initiatives would be phased in over time, expenditures likely will be made over a period of more than 7 years.

Figure 1 Distribution of Benefits for the Final Improvement Initiatives
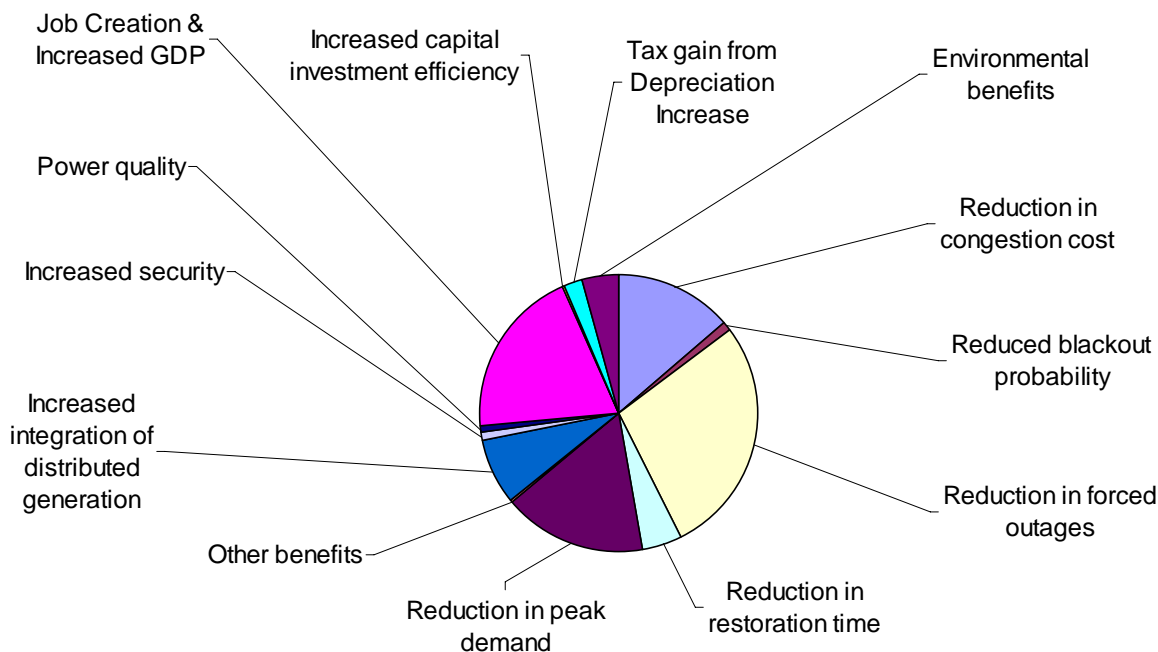
The modeling conducted for the cost-benefit analysis included analyzing the implementation sequence of the thirteen improvement initiatives. Since each initiative has its own level of cost effectiveness and there are interrelated dependencies among the initiatives that dictate when the benefits can be achieved, the timing and staging of initiatives has an impact on the economics of the portfolio. To capture the potential differences that such timing and interdependency might have on the results, the project team modeled the business case using three scenarios for comparison. The scenarios developed were as follows:

- Earliest Positive Cash Flow – This scenario establishes the minimum time for the cumulative cash flow to go positive. Under this scenario the benefits fund future investments as early as possible.

- Maximum Benefits Early – This scenario establishes the earliest time for benefits to be the largest, which usually means the costs are front loaded.

- Optimized Internal Rate of Return (IRR) – This scenario establishes the best mix of realized IRR and net present value (NPV)

The results of the three approaches are presented in the following Table 3.[3]

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[3] Note that the business case analysis assumes that the SDG&E proposal for advanced metering infrastructure (AMI) is implemented as proposed. Based on this assumption, we did not double count the benefits that will be achieved through the AMI project (e.g., demand response savings) with the benefits that will be achieved through the proposed Improvement Initiatives. Also, several Improvement Initiatives identified in this study are predicated on the existence of AMI.

Table 3 Summary of Business Case Results[4]

Scenario	Regional IRR* (%)	NPV ($M)	Point of Positive Cash Flow** (Yrs)	First Year Annual Benefits Top $50M
Earliest Positive Cash Flow	75%	403	3.5	2017
Maximum Benefits Early	26%	508	7.0	2012
Optimized IRR	44%	416	5.5	2014

* Internal Rate of Return normally refers to a single business entity, but here we have treated the San Diego region as a single entity to enable the calculation of a regional benefit, both systems and societal. For this analysis it assumed that all stakeholders will participate in the investment (directly or indirectly through rate recovery) as well as realizing the identified benefits.

** Point of Positive Cash Flow is the collective cash flow analysis from all thirteen (13) improvement initiatives combined as a single overall program. Several improvement initiatives require continued investment for as much as 10 years, well beyond the point of positive cash flow, to achieve full implementation of the Smart Grid. The point of positive cash flow should not be used as a proxy for the simple payback of the scenario.

The business case scenarios represent three points of view. The Earliest Positive Cash Flow scenario represents a managed investment approach that utilizes ongoing savings to finance current and future investments, the Maximum Benefits Early scenario represents a societal-led view, and the optimized IRR scenario represents a compromise view.

The Earliest Positive Cash Flow scenario generates a positive cash flow in a 3.5 year period; however, the sustained large benefits (> $50M/yr) do not occur until 11 years after start. The Maximum Benefits Early scenario generates a positive cash flow in a 6 year period, and the sustained large benefits (> $50M/yr) actually occurs in the final year of the positive cash flow, 5 years earlier than the earliest positive cash flow scenario.

From a regional perspective, the scenario that seems most appropriate is the Maximum Benefits Early because it enables the benefits presented above to be realized by both consumers and the utility earlier than the other two scenarios. This scenario has the quickest entry of sustained system and societal benefits and provides the largest NPV with an attractive internal rate of return for the region.

Based on the preliminary cost-benefit analysis conducted for this study, there appear to be sufficient benefits to the utility system, to the broader region (societal), and in total, to justify a movement of the San Diego regional grid to a Smart Grid architecture. It should be noted however that the capital costs and operations and maintenance costs are substantial. This level of effort will be very challenging to a host utility, especially considering other significant projects in progress and the aggressive proposed implementation schedule.

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[4] The results presented in Table 5 represent the cost effectiveness from the perspective of the San Diego region as a whole. These results demonstrate that both the costs and benefits that can be realized from a Smart Grid are shared with the utility, businesses and residents of the region. That is to say that not all costs and not all benefits are borne by the utility.

1.3.   Recommendations

1.3.1. Recommended Implementation Plan for Improvement Initiatives

Results of the cost-benefit analysis suggest implementing a Smart Grid in the region could be cost effective. Based on this result, the project team developed an implementation plan for the thirteen improvement initiatives. Deployment of the improvement initiatives can be phased in relation to improved reliability with later initiatives building on earlier successes. Table 4 presents a two-phase approach to implementing the improvements.

Table 4 Implementation Plan for Improvement Initiatives

Phase 1 (2007 – 2016)		
Improvement Initiatives	7 – Ethernet over Fiber 9 – 4G WiMAX Fixed - Private Wireless* 25 – Distribution (Feeder) Automation 1 – GATECH IPIC Dynflo distributed series impedance 2 – I-Grid Monitoring System 11 – Zigbee / WiMedia / WiFi - Wireless 21 – Advanced Grid Control Devices 14 – Advanced Visualization Methods 5 – Consumer Portal 19 – Advanced Energy Storage Systems	This grouping of improvement initiatives serves two purposes: (1) establishing the foundation for the complete Smart Grid, and (2) focuses on those initiatives most likely to improve reliability under a changing environment.
Phase 2 (2009 – 2013)		
Improvement Initiatives	9 – 4G WiMAX Fixed - Private Wireless* 12 – Semi-autonomous Agents 23 – Agent and Multi-Agent Systems 17 – DER-based Microgrids	This grouping of improvement initiatives serves two purposes: (1) expand the integration of consumer systems into the Smart Grid, and (2) provide additional options for improved reliability and economic electricity services.

* This Improvement Initiative is implemented as needed across both phases of the deployment.

Table 5 shows the recommended rank order of Smart Grid technologies and an estimated implementation time. The implementation timeline is based on an assumption that the research, development and demonstration (RD&D) projects start in the 2007 to 2008 time frame and are successful and that SDG&E's proposed AMI project is fully implemented by 2010.

Table 5 Timeline for Final Improvement Initiatives

Priority	II No.	Improvement Name	Timing*
1	7	Ethernet over Fiber	2007 – 2009
2	9	4G WiMAX Fixed - Private Wireless	2007 – 2009
3	25	Distribution (Feeder) Automation	2007 – 2011
4	14	Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)	2007 – 2009
5	1	GATECH IPIC Dynflo distributed series impedance sensors	2009 – 2013
6	2	I-Grid Monitoring System (by Softswitching Technologies)	2012 – 2016
7	11	Zigbee / WiMedia / WiFi - Wireless	2007 – 2010
8	21	Advanced Grid Control Devices	2007 – 2011
9	5	Consumer Portal	2008 – 2012
10	19	Advanced Energy Storage Systems	2008 – 2014*
11	17	DER-based Microgrids	2009 – 2013*
12	12	Semi-autonomous Agents	2009 – 2011*
13	23	Agent and Multi-Agent Systems	2009 – 2013*

* Moved the improvement initiative out one or two years to accommodate probable resource limitations based on the number of project starts and the maturity of the technology.

1.3.2. Recommended RD&D Projects

To aid in the risk management and assurance of cost-effective deployment, the project team recommends that the region conduct several RD&D projects. Table 7 presents four RD&D projects, their timing, and the specific improvement initiative that should lead the sequence.

Table 6 Research and Development Project Recommendations

RD&D Project	Timing	Leading Initiative
WiMAX Pilot	2007 – 2008	Midhaul Communications (II-9)
Adv. Energy Storage Pilot	2007 – 2008	AES Integration (II-19)
DER-based Microgrid	2008 – 2009	DER-based Microgrids (II-17)
Agents Pilot	2008 – 2009	Semi-Autonomous Agents (II-12) Agent & Multi-agent Systems (II23)

II = Improvement Initiative

1.3.3. Recommended Policy and Regulatory Changes

In addition to the technological gaps identified above, the study also identified policy and regulatory changes needed to realize the future Smart Grid scenario. The following list includes the key policy and regulatory changes identified.

- A consistent, long-term policy to provide clear and low-cost market signals (real-time pricing, critical peak pricing, etc.) to consumers and third parties interested in participating energy markets through local distribution-level programs.

- Incentives to allow the use of advanced technologies that increase capacity, improve efficiency or reliability of resources per the EPACT 2005.

- CEC support for an in-depth evaluation of the economic benefits of commercially available voltage stabilizing technologies (SVC, D-VAR, DSTATCOM, STATCOM, SuperVAR, etc) to identify and endorse the optimum solutions.

- Policies that encourage open data access, interoperability, reliability standards, and capability to operate micro-grids in intelligent islanding modes. Open communication architecture needs to be standardized.

- New rate designs (e.g., real time pricing, premium power quality) and incentives are needed to encourage consumers and SDG&E to invest in promising advanced technologies. Regulators and policymakers should determine if any existing law or policies would inhibit the development of new rate designs (e.g., residential rate caps in AB 1X).

- Policies that consider the societal benefits of infrastructure investments when determining cost effectiveness.

2.   INTRODUCTION

This San Diego Smart Grid Study is one of the first in the nation to apply the Smart Grid concepts developed the U. S. Department of Energy's Modern Grid Initiative to a specific region. This Study provides a preliminary analysis to determine the technical feasibility and cost effectiveness of implementing Smart Grid technologies and strategies in the San Diego Region. The objectives of the study are to (1) determine whether the future economic and regulatory climate in the San Diego region could accommodate and necessitate a Smart Grid, (2) determine the collection of Smart Grid technologies that could be implemented in order to develop a Smart Grid, and (3) conduct a cost-benefit analysis to determine whether implementing a Smart Grid would be cost effective for the region.

To accomplish the objectives of the San Diego Smart Grid Study, the project team developed a process that included the following six major components: (1) develop a scenario that describes the likely future state of the region's economic, regulatory, and technology climate, (2) assess the current state of the energy infrastructure and climate in the region (as-is state), (3) compare the current state to a future Smart Grid scenario to identify technological and regulatory gaps, (4) identify a core group of Smart Grid technologies that when implemented together would provide the framework for the Smart Grid concept, (5) conduct a cost-benefit analysis to determine if there is a business case for implementing the technologies identified, and (6) recommend an implementation strategy for the identified technologies, including near-term demonstration projects.

 Figure 2 provides a detailed schematic of the entire study process.

Figure 2 San Diego Smart Grid Summit Project Process
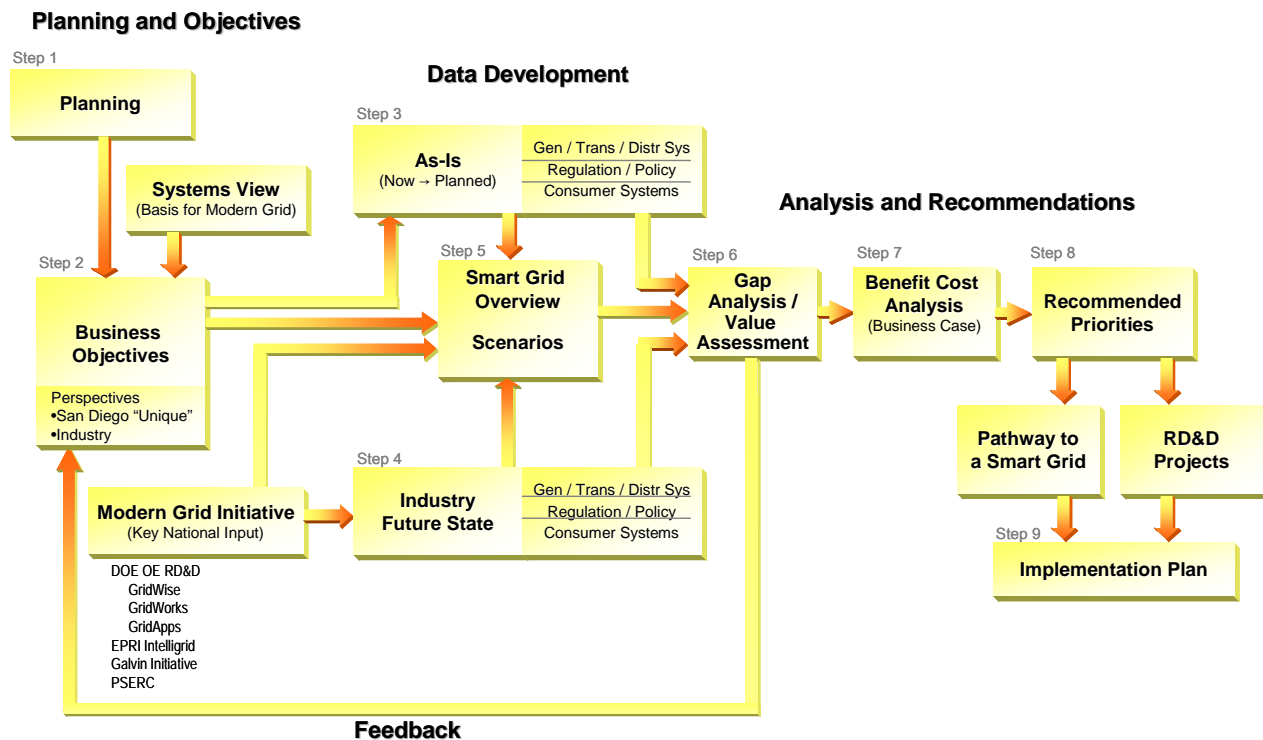
2.1. Interpreting the Results

To provide context for and to help interpret the results, we provide the following:

- This is a conceptual first look at modernizing the grid through a portfolio of technologies with estimates for the cost of implementation and anticipated resulting benefits. Any conclusions of the report should be studied in more detail before being pursued.

- The concept of the Smart Grid does not rely on a single technology or "silver bullet" that will achieve all of the desired results. Rather it requires the integration and interdependence of many technologies that in concert can optimize operations of the grid.

- The portfolio of technologies presented must be considered as an entire package. Additions or subtractions of technologies will yield different results.

- From a technology point of view, the Smart Grid is vendor-neutral. The focus is on technology functionality, interoperability and expansion capabilities.

- This study looks at the Smart Grid from a regional perspective. Even though one utility serves the region's electricity and natural gas needs, this study does not solely address the utility. Instead, this study encompasses the entire regional energy system, which includes the utility but also includes self-generation, photovoltaic systems, and individual customers altering consumption patterns and leveraging investments in new technology.

2.1.1. Key Assumptions and Initial Conditions

The following are assumptions and initial conditions used in the analysis and conclusions of the report:

- Key Assumptions

  - SDG&E's proposed Advanced Metering Infrastructure (AMI) initiative is implemented and complete in the 2010 timeframe.

  - All demand response benefits in the region are assumed to be derived from the AMI initiative to avoid double counting and thus not counted as a benefit in the Smart Grid analysis. However, it is anticipated that the integration of AMI with the Smart Grid portfolio of technologies, will result in an enhanced demand response capability in the region. The enhanced attributes have not been identified or quantified in the benefits of the Smart Grid.

  - Real time communications are not necessarily available to the consumer through the AMI initiative.

  - The communications solution in this study assumes a Zigbee chip (or equivalent home area network capability) is embedded in the AMI meter. A decision on the zigbee chip has not currently been made but SDG&E is committed to having a standard home area network capability as part of their vision.

  - SDG&E's proposed AMI project currently does not include the remote connect/disconnect function but the system will have the capability to add that function in the future.

  - As the San Diego Smart Grid study is focused on the local electric delivery network, we conducted this study independent of the proposed Sunrise Power Link project.

- o Some elements of the study depend on the rate of deployment of distributed energy resources, which may differ from those included in SDG&E's Long Term Resource Plan.

- o Funding for the RD&D Projects identified in this study is available and the projects are successful.

- o Investments and corresponding benefits are to be evaluated on a regional perspective and not from the perspective on any individual entity

- o The California Independent System Operator (CAISO) Market Redesign and Technology Upgrade (MRTU), which includes locational marginal pricing (LMP), will be implemented.

- o Regulatory changes will be required to achieve overall benefits

- • Initial Conditions

  - o A multi-year SDG&E substation automation program is already in progress.

  - o An SDG&E field SCADA switch rollout program is already in progress.

  - o A set of broadband over power lines (BPL), advanced transmission conductors, and sensor exploratory demonstration projects are in progress.

2.2. Sections of this Report

The report includes the following sections:

- • Section 3 provides an overview of the Smart Grid concept and describes the Modern Grid Initiative.

- • In Section 4 of the report, we discuss the future probable state of the San Diego region and whether that sate could support implementation of the Smart Grid.

- • Section 5 describes the results of the gap analysis that compares the current transmission and distribution system with a future Smart Grid scenario.

- • Section 6 presents a cost-benefit analysis – or the business case – for implementing a Smart Grid in the region.

- • In Section 7, the project team proposes an implementation plan, including near-term research, development, and demonstration projects.

- • Appendix A includes a list of acronyms used in the report.

- • Appendix B presents detailed information on interpreting the results of the cost-benefit analysis provided in Section 6.8.

- • We provide a summary of the current status of the region's transmission and distribution system in Appendix C.

- • Appendix D describes the process used to determine the future San Diego scenarios.

- • Appendix E provides detailed information on the method for calculating the Smart Grid benefits used in the cost-benefit analysis.

- • We include biographical information about the SAIC project team in Appendix F.

3. OVERVIEW OF THE SMART GRID

3.1. Background

The idea of the Smart Grid applied to this study is based on the concepts developed and being pursued by the Modern Grid Initiative.[5] This initiative works in cooperation with the U.S. Department of Energy's (DOE) Office of Electricity Delivery and Energy Reliability to align its efforts with existing programs such as Transmission Reliability, Electricity Distribution, GridWise Distributed Generation, GridWorks, etc. It builds on recent documents that were produced by DOE to outline a national technology strategy such as "Grid 2030" and the "National Electric Delivery Technologies Roadmap." This initiative is also closely coupled to recent industry efforts led by the GridWise Alliance, Intelligrid, the Galvin Electricity Initiative and others that focus on raising national awareness on the need to improve grid performance, reliability, and security.

The basic concept of the MGI is to create a modern grid where electricity is generated and distributed more effectively, economically and securely. According to the MGI, a modern grid must include the total impact and benefit of integrating a myriad of new innovative tools and technologies from generation, transmission and distribution all the way to consumer appliances and equipment.

3.2. The Concept of a Smart Grid

The debate over what constitutes a Smart Grid is still emerging. Utility and technology experts are now discussing the need for substantial changes in how we design, build, and operate the power generation and delivery system. The Smart Grid is the integration of technologies that allow us to rethink electric grid design and operations. As starting point for the study, the project team assumed that a Smart Grid would:

- Detect and address emerging problems before they impact service.
- Make protective relaying will be the last line of defense, not the only defense as it often is today.
- Respond to local and system-wide inputs and know much more about broader system problems.
- Incorporate extensive measurements, rapid communications, centralized advanced diagnostics, and feedback control that quickly return the system to a stable state after interruptions or disturbances.
- Automatically adapt protective systems to accommodate changing system conditions.
- Re-route power flows, change load patterns, improve voltage profiles, and take other corrective steps within seconds of detecting a problem.
- Enable loads and distributed resources to participate in operations.
- Be inherently designed and operated with reliability and security as key factors
- Provide system operators with advanced visualization tools to enable them to provide the essential human oversight.

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[5] More details about the Modern Grid Initiative (MGI) and this process can be found at www.moderngrid.org.

A Smart Grid could provide the following benefits:

- Cost savings due to automated operation, predictive maintenance, self-healing, reduced outages, and increased asset utilization.
- Fewer blackouts and local power disruptions.
- Faster recovery when disruptions to occur.
- Greater security from self-healing technologies.
- Better real-time monitoring and response.
- High-quality power on which today's businesses depend for sensitive electronics and computer applications.
- New options for consumers to manage their electricity use and costs.
- The "plug and play" integration of control systems, power electronics, and distributed resources.

3.3.   A Systems View of the Smart Grid

Because the Smart Grid concept is complex and contains many interdependent technologies and strategies, it is difficult to think of the Smart Grid as individual component technologies; rather, the Smart Grid should be viewed as an entire system with the whole greater than the sum of its parts. This complexity requires analysis of the Smart Grid to be done using a systems view. The systems view takes a holistic and objective approach to a subject. This view recognizes the Smart Grid as a single system comprised of interdependent components. From this vantage, we can determine root issues and structure solutions to serve the whole through its component parts. Such a model takes into account the full range of costs and benefits to society associated with the creation of a Smart Grid. Figure 3 illustrates the Modern Grid Initiative's systems view of the Smart Grid.

Figure 3 Modern Grid Initiative Smart Grid Systems View

Key Success Factors

Reliability
Security
Economics
Power quality
Efficiency and
environmental quality
Safety

Performance

Emergency
Restoration
Routine Operations
Optimization
Systems
Planning

Principle Characteristics

Self-healing
Empowers and incorporates the consumer
Tolerates security attack
Provides 21st century power quality
Accommodates a wide variety of generation options
Fully enables electricity markets
Optimizes asset use; minimizes O&M expenses

Key Technologies

Integrated communications
Advanced control methodologies
Sensing, metering, and measurement
Advanced grid components
Decision support and human interfaces

Metrics

Congestion costs
Blackout probability
SAIFI
Restoration time
CAIDI
Peak-to-average load ratio
Capacity utilization

Using this approach, we can determine what the grid (system) must deliver (performance) and therefore identify its key ingredients (principal characteristics). This engenders solutions (key technologies) that will change the grid in a way that is measurable (metrics) and delivers the goals (key success factors) previously determined.

The stakeholders of the grid are the beneficiaries of this approach. For the purposes of this study, the stakeholders comprise the San Diego region's policy makers, California State regulators and legislators, California Independent System Operator, the local utility (SDG&E), non-utility power plant owners, and industrial, commercial, government and residential customers. A Smart Grid vision shows a substantial link between proposed improvements and

expected benefits across all the stakeholders of the region. Consumers experience enhanced performance on every level. And the vendor community gains a new vision for its product research and development.

3.3.1. Key Success Factors

The key success factors are the system "values" that everyone holds to be true, from operator to engineer to consumer to regulator. Such universal values establish a basis for desired performance and a compass for measuring progress and achieved benefits. The following are key success factors to assess the success of a Smart Grid.

Reliability—A reliable grid operates as required by its users, tolerates disturbances without failing, and provides ample warning about growing problems such that corrective action can take place before damage and negative impacts are felt.

Security—A secure grid tolerates physical and cyber attacks without massive blackouts or significant recovery investments.

Economics—An economic grid operates under the basic laws of supply and demand, resulting in the fairest of prices in an open energy market.

Power Quality— Power quality means the electric power will be delivered in a form that meets individual consumer needs, especially in the growing digital environment of the United States.

Efficiency and Environmental Quality—Efficiency means taking advantage of investments that control costs, reduce energy losses, and a lower total cost of ownership. Environmental quality means progressively fewer environmental impacts and reducing the cost of recovery from environmental consequences.

Safety—A safe grid does no harm to the public or to grid workers during operations and maintenance.

3.3.2. Performance

Performance of the Smart Grid will support the grid's key success factors and take many forms. Near-term actions would include engineering, operations, maintenance, and emergency response. Long-term term actions would include system planning and the resulting system capacity additions, new technology applications, and other activities with extended development cycles. For example, the Smart Grid could accommodate new breakthrough technologies such as a hydrogen economy or other advanced fuels in the future. The following are performance characteristics of a Smart Grid.

Emergency—Grid operators take responsive action in the face of grid emergencies to minimize loss, protect major equipment from destruction, and initiate the first wave of restoration. Most actions mitigate naturally occurring events since today's grid systems provide little predictive insight into emerging problems. In the future, this will change as advanced analytical technologies will provide predictive capabilities.

Restoration—In cases of emergency, grid operators take action to recover the damaged or compromised sections of the grid from major events, like cascading outages. Today this is a long, arduous process requiring significant coordination with field resources as damage is cleared, physical systems and equipment are restored or replaced, and circuits are reconfigured. Restoration from major events usually requires days and weeks to affect the necessary repairs, replacements, and reconfigurations to return the damaged grid to full operation. In the Smart Grid model, new data sets and geographical based information could be available to assist operators in the restoration process, improving restoration times.

Routine operations—During the course of a normal day, grid operators manage planned changes to the grid configuration, manage understood transients, and respond to small upset conditions, typically from losses of single components. Activities can include the start-up and shutdown of generators, injections and withdrawals of megawatts (MW) for bulk power movement, and diurnal load changes. With Smart Grid technologies and strategies, the role of the grid operator could change as advanced visualization tools and decision support capabilities are provided to help them better understand system conditions and make decisions on actions to be taken.

Optimization—During the course of a normal day or week, grid operators fine tune the grid, minimizing unnecessary congestion, unnecessary power generation, reducing the total cost of generation, and maximizing overall grid efficiency. The Smart Grid could provide grid operators advanced tools to increase their effectiveness in optimization.

Systems planning—Grid engineers and planners analyze intermediate and long-term issues, newly planned generation, and projected growth in supply and demand to determine courses of action. The Smart Grid could allow planning processes to become more effective as improvements in data collection and modeling provide more accurate historical demands and enable more accurate load forecasts.

3.3.3. Principal Characteristics

Principal characteristics are the attributes of a fully integrated Smart Grid. These describe what the Smart Grid is and what it can enable. Principal characteristics of the Smart Grid include the following.

Self-healing—The grid routinely or automatically detects, analyzes, responds to, and restores grid elements or network sections to maintain reliability, security, affordability, power quality, and an efficient state.

Empowers and incorporates the consumer—The consumer becomes an integral, active part of the electric power system.

Tolerates security attacks—It is critical for the Smart Grid to address security from the outset, making security a requirement and ensuring an integrated and balanced approach across the system.

Provides enhanced power quality—Sensitive loads represent an increasing portion of the total power system load. Future power quality must "smooth" power in generation, delivery, and load, while enabling loads to better tolerate distorted power.

Accommodates a wide variety of generation options—The Smart Grid will accommodate a portfolio of diverse generation types, necessitating a greatly simplified interconnection process analogous to the "plug and play" in today's computer environment, particularly at the distributed energy resources level.

Fully enables electricity markets—The Smart Grid will integrate electricity markets into the fabric of the electric system because operations, planning, pricing, and reliability are dependent on how open-access markets are designed and instituted. For this reason, it will not only support wholesale electric markets, but also retail markets where applicable.

Optimizes asset utilization and minimizes operations and maintenance expenses—Assets will be managed in concert so that, as a system, they will deliver functionality at a minimum cost. For example, advanced sensing and robust communications will allow early problem detection and corrective action.

3.3.4. Key Technologies

With the principal characteristics shaping the development of the Smart Grid, key technologies enable desired performance. A focus on technology and innovation would be encouraged and needed to achieve the functional specifications of the principal characteristics.

Integrated communications across the grid— High-speed, fully-integrated, two way communications technologies could establish the infrastructure needed to enable the Smart Grid to become a dynamic, interactive "mega-infrastructure" for real-time information and power exchange. Its open architecture could create a "Plug and Play" environment that would securely network smart sensors and control devices, control centers, protection systems, and users.

Advanced control methods—Computer-based algorithms that collect data from and monitor all essential grid components, analyze the data to diagnose and provide solutions from both deterministic and probabilistic perspectives, determine and take appropriate actions autonomously, provide information and solutions to human operators and integrate with enterprise-wide processes and technologies. These advanced control methodologies would support such applications as distributed energy resources and demand response dispatch, distribution automation and substation automation, adaptive relaying, energy management, market pricing, grid modeling, operator displays and advanced visualization systems, to name a few. In addition, they would be integrated into asset management processes and technologies to further optimize grid operations and planning.

Sensing, metering, and measurement—New digital technologies using two-way communications, a variety of inputs (pricing signals, time-of-day tariff, regional transmission organization (RTO) curtailments for congestion relief), a variety of outputs (real time consumption data, power quality, electric parameters), the ability to connect and disconnect, and interfaces with generators, grid operators, and customer portals to enhance power measurement, provide outage detection and response, evaluate the health of equipment and the integrity of the grid, eliminate meter estimations, provide energy theft protection, enable consumer choice, and enable demand-side management for congestion relief by the RTO. In addition, new smart sensors would be applied to various grid monitoring functions.

Advanced grid components—These are the next generation of power system devices taking advantage of new materials technologies, nanotechnologies, advanced digital designs, etc., to produce higher power densities, better reliability, and improved real-time diagnostics to greatly improve grid performance. Such technologies include superconducting transmission cable, fault current limiters, composite conductors, FACTS, advanced energy storage, distributed generation, advanced transformers and circuit breakers, and smart loads.

Decision support and human interfaces—With the time horizon for operator decisions having moved to seconds, the Smart Grid requires the wide, seamless, real-time use of applications and tools that transform the grid operator and manager into knowledge workers. This includes the role of artificial intelligence to support the human interface, operator decision support (alerting tools, what-if tools, course-of-action tools, etc.), semi-autonomous agent software, visualization tools and systems, performance dashboards, advanced control room design, and real-time dynamic simulator training.

These Key Technology Areas (KTAs) will be the focus of categorizing potential technologies that the region can implement in order to achieve a Smart Grid.

4.   SCENARIOS: SAN DIEGO FUTURE CONDITIONS

The project team used a scenario-based approach to determine whether future economic, regulatory, technology conditions in the San Diego region would accommodate and necessitate development of a Smart Grid. This is the initial step in the process to determine the feasibility of implementing a Smart Grid in the region.

4.1.   Scenario Development

A scenario is a "picture" or glimpse of the region's future based on current trends that move the region in a certain direction and external influences that can affect that direction. While literally thousands of variables, trends, drivers, and influences can create the future state of the region, several emerge as the primary forces. The project team assembled the external influences and trends that it believes are the primary forces for shaping the region's future and organized them into three main factors: economic, environmental regulation, and level of technology development. Figure 4 shows the continuum of influence for the three main factors shaping the region's future.

Figure 4 Main Factors in Scenario Development

Blue Sky	Economic Influence	Recession
Environmentally Friendly	Environmental Regulation Influence	Constrained Regulation
Breakthrough Development	Level of Technology Development Influence	Minimal Development
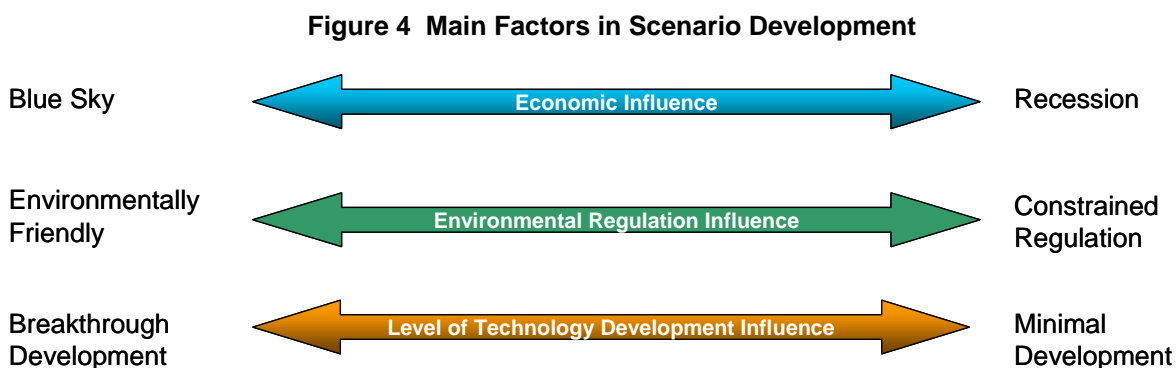
Given external influences and trends, will the San Diego future more closely resemble a powerful (Blue Sky) economy or will it trend toward recession? Will the regulatory trends affecting the region support environmental advances, or will advances in environmental issues be limited? Will the region's technological nature encourage breakthroughs in technologies in the grid, or will the region's technological appetite actually retard innovation?

No one knows the answer to these key questions, however, we can examine key variables to help shape our view of likely future trends and conditions that "point" the region in a particular direction. That is, there is a probable future state of the San Diego region that can be used to shape the study of Smart Grid technologies and strategies that are likely to matter, and address the needs represented by the future scenarios.

4.2.   Scenario Methods

The project team developed a probable future state of the region to determine if a Smart Grid would be beneficial or necessary. If a Smart Grid is beneficial, then a gap analysis and benefits analysis should determine what needs to be done to deliver a Smart Grid strategy for the region. Figure 5 represents this process.

Figure 5 Scenario Development Process
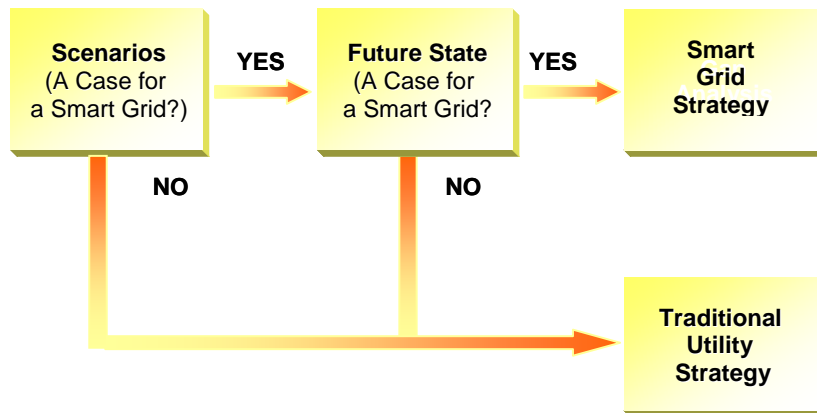
To select the future probable state, the project team developed a range of scenarios and the external influences that would affect future scenarios. The drivers and trends associated with the external influences were identified to estimate their impact on the case for a Smart Grid.   A focus group then scored the level of the impacts for the drivers that encompassed each scenario to evaluate if a scenario substantiated a case for a Smart Grid in the region. The details of the process and the analysis are presented in Appendix D.

4.3.   Summary of Scenario Results

The results of the scenario development suggest that the future state of the San Diego region will be include high economic growth, continued high technology environment, and a probable move toward more environmentally friendly regulations. Figure 6 depicts the results of the scenario analysis. The analysis shows that the Blue Sky and the Breakthrough Technology scenarios make a favorable case for a Smart Grid. The Environmentally Friendly scenario makes no definitive case for a Smart Grid. The other three scenarios do not justify the need for the implementation of a Smart Grid.

Figure 6 Scenario Analysis Scoring Summary
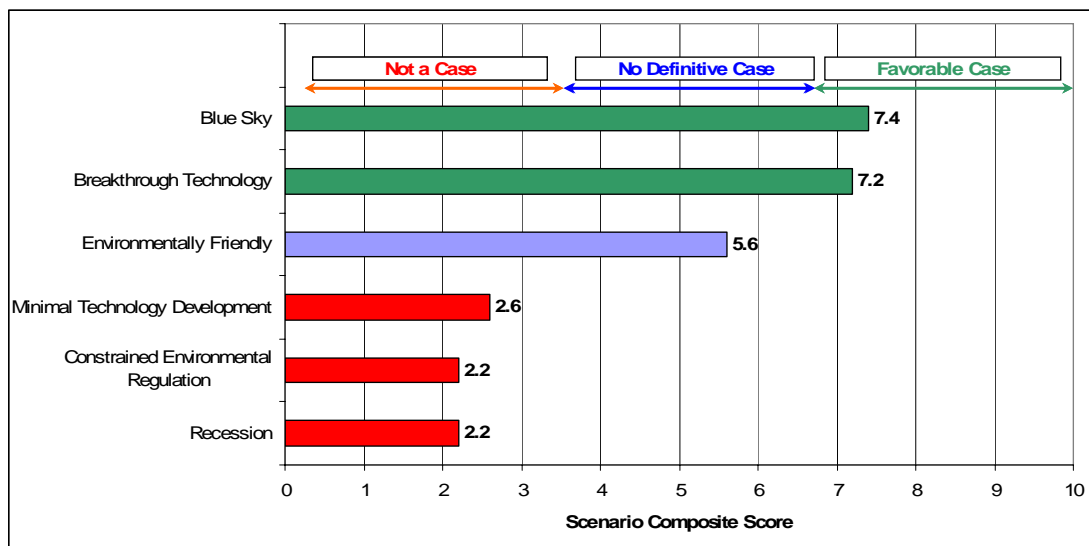
The Blue Sky scenario includes the following trends.
- Market-based change in utility structure
- Increasing number of businesses in the region
- Increasing population in the region
- Increasing awareness and push for economic development
- Increasing need / desire for broadband communications infrastructure
- Increasing time-based rates (tariffs)
- Increasing availability of zero energy homes
- Increasing renewable resources and availability of new fuels

The Breakthrough Technology includes the following trends.
- Increasing distributed generation installations
- Increasing enforcement of grid reliability and performance

The Environmentally Friendly scenario signifies:
- Increasing energy efficiency requirements
- Increasing renewable portfolio standards
- Increasing photovoltaic installations

4.4. San Diego Region Probable Future Scenario

The above scenarios represent a spectrum of potential conditions or environments. The project team evaluated the external influences and associated drivers to project the probable future for the region. Table 7 presents the project team's projection of the probable future scenario.

Table 7 Probable Future State of the San Diego Region

Scenario Category	External Influence	Scenario	Driver	Scenario Trend
Economic	Environment	Blue Sky	New fuels	Increased Availability
	Legislation	Blue Sky	Change in utility structure	Market-based
	Legislation	Blue Sky	Renewable Portfolio Standards	Increased Renewables
	Load	Blue Sky	Business Profile	Increasing Businesses
	Load	Blue Sky	Culture/People Profile	Increasing Population
	Load	Blue Sky	Economic Development	Increase Economy
	Regulation	Blue Sky	Tariffs	Increase Time-based rates
	Technology	Blue Sky	Communication Infrastructure	Increasing Bandwidth
	Technology	Blue Sky	Zero Energy Homes	Increased Availability
	Technology	Blue Sky	Communication Standards	Increasing Standards
	Load	Recession	Manufacturing	Decreased Manufacturing
Envirinmental and Regulatory	Environment	Environmentally Friendly	New Fuels	Increased Availability
	Legislation	Environmentally Friendly	Title 24	Increased EE Requirements
	Legislation	Environmentally Friendly	Renewable Portfolio Standards	Increased Renewables
	Load	Environmentally Friendly	California Solar Initiative (WC)	Increased PV Installations
Technology	Regulation	Minimal Technology Change	Loading Order	Maintain Ranks in Order
	Regulation	Minimal Technology Change	FERC Orders	Status Quo
	Regulation	Minimal Technology Change	Reliability Rules	Status Quo
	Environment	Breakthrough Technology	Firestorms	Proactive Planning
	Load	Breakthrough Technology	LNG terminal	Increased Installations
	Regulation	Breakthrough Technology	ERO Reliability Enforcement	Increasing Enforcement
	Regulation	Breakthrough Technology	Change in ISO (WC)	Reduced Control
	Technology	Breakthrough Technology	Shift from Central to Distributed Generation	Increasing DG Installations

The Probable Future State Scenario has a composite score of 7.1 which falls in the range of the Favorable Case for a Smart Grid as presented in the scenario analysis conclusions. Thus, the Likely Future Case suggests a desirable climate for the implementation of a Smart Grid strategy for the San Diego Region. This "picture" of the probable future state of the San Diego region helped to direct the gap analysis, type of benefits selected for analysis, and the eventual business case for the San Diego Smart Grid.

5.   GAP ANALYSIS

The project team used the Modern Grid Initiative's (MGI) Key Technology areas (KTAs) as the framework for performing the gap analysis for the San Diego region. The team compared the current state of the region's electric transmission and distribution grid to the expected future Smart Grid scenario, which assumed that all the KTAs are implemented. The differences, or "gaps", were evaluated from three perspectives: technology, policy and regulatory, and consumer systems.

This comparison was conducted for each of the following KTAs:

- Advanced Grid Components
- Sensing, Metering and Measurement
- Integrated Communications
- Advanced Control Methods
- Decision Support and Human Interface

The method for analyzing these gaps is presented in Figure 7.

Figure 7 Method for Gap Analysis
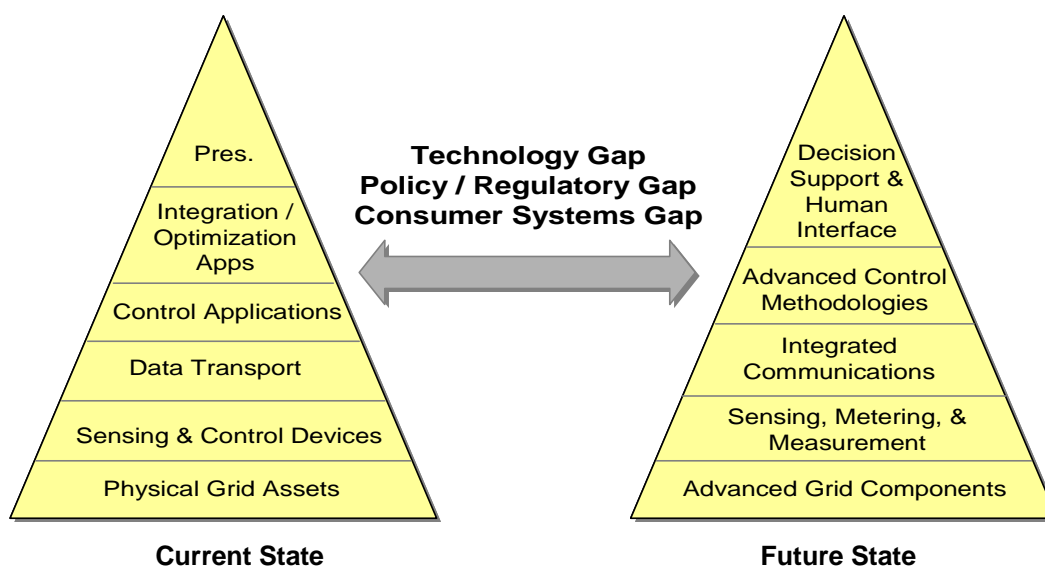
Gaps statements were identified for each of the KTAs from each of the three perspectives. These gap statements were evaluated to determine the suite of technologies most appropriate for filling the gaps in the San Diego region. Figure 8 illustrates this process.

Figure 8 Gap Analysis Process
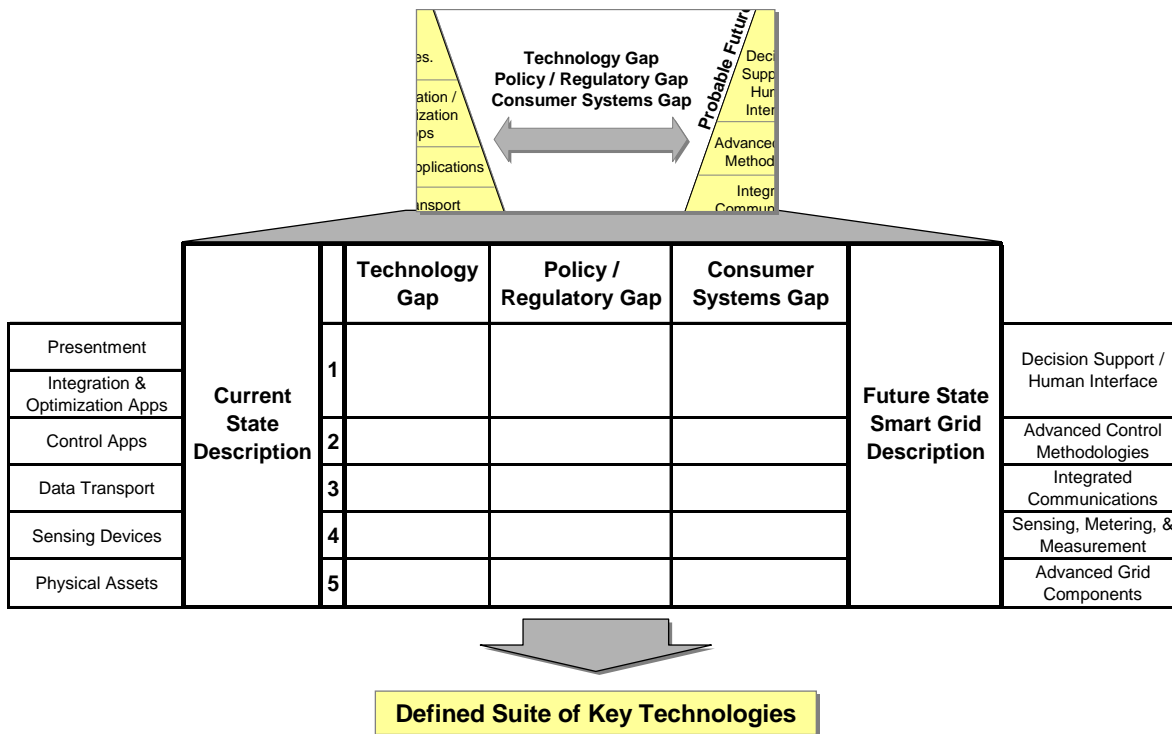
The following sections present a list of the technologies evaluated for each key technology area, a description of the technologies, and a presentation of gaps by each of the three categories (technology, policy and regulatory, and consumer systems). A glossary of terms is presented in Appendix A.

5.1. Advanced Grid Components

Table 8 summarizes the gaps identifies in the area of advanced grid components and the improvement initiatives recommended to address those gaps.

Table 8 Advanced Grid Component Improvement Initiatives

Area of Identified Gap	Specific Improvement Initiative to Address Gap
Micro-grids	DER-based Micro-grids
Consumer Distributed Generation	High-Efficiency & Renewable DG
Energy Storage	Advanced Energy Storage Systems
Demand Response Resources	Electric Loads as a Reliability Resource
Control Devices	Advanced Grid Control Devices
Improved Conductors	Advanced Higher Capacity Conductors

5.1.1. New Technology Overview

DER based Micro-grids

A distributed energy resources (DER)-based micro-grid aggregates loads and resources, including distributed generation and advanced energy storage resources to operate as a single system providing both power and heat. The majority of the DER is power electronics to provide the required flexibility to insure operation as a single aggregated system. DER systems include high frequency AC (micro-turbines) and DC systems (solar, fuel cells, etc.). This control flexibility allows the micro-grid to present itself to the bulk power system as a single "control area" that meets local needs for reliability and security.

High-Efficiency & Renewable Distributed Generation (DG)

Consumer distributed generation includes the deployment of high efficiency and renewable generation sources at residential, commercial and industrial facilities. These technologies include such commercially available technologies as photovoltaics, micro-turbines, reciprocating engines, and combustion turbines. Future technologies will include advanced low cost solid state technologies for photovoltaics, fuel cells, and vehicle-based energy storage. Again, the interface will typically be power conversion systems based on power electronic inverter and/or converter systems. These systems can provide significant reactive power while the consumer distributed generation is energized and operating, independent of the real power generated.

Advanced Energy Storage

- Sodium Sulfur (NaS) batteries are now available that provide up to 8 hours of energy for about $3500/kW. Vanadium Redox flow batteries (VRB) are also available in smaller sizes for $2800/kW. These batteries can be used for load following, peak shaving of loads, voltage and transient stability support and customer ride-through. Peak shaving can avoid the need for new substations or second transformer banks.

- Beacon 25kWh flywheels should be available in a few years for $1000/ kw-15 minutes, and can used for voltage and transient stability support, frequency regulation and short term customer ride-through.

- Superconducting magnetic energy storage (SMES) systems store energy in the magnetic field created by the flow of direct current in a superconducting coil which has been cryogenically cooled to a temperature below its superconducting critical temperature. These systems can provide not only voltage support, but have sufficient real power to dampen system oscillations and mitigate transient instabilities.

- Ultra-Capacitors are high energy, high power density electrochemical devices that are easy to charge and discharge. They have the ability to store energy like a battery for hours, but can quickly discharge the energy like a capacitor. Progress is being made in their development and deployment and could make a significant impact on energy storage capabilities.

Electric Loads as a Reliability Resource

Numerous technologies and approaches to Demand Response are commercially available. Some of the specific resources include:

- Grid-friendly appliances that monitor system parameters such as frequency and voltage and autonomously disconnect all or a part of their load from the grid.

- Integrated load controls using consumer portals that shed load based on dispatch signals from the utility or based on parameters set by the consumer.

- The integration of plug-in hybrid electric vehicles, fuel cells and other forms of DG and advanced energy storage are other options of reducing load on the consumer side of the meter.

Advanced Grid Control Devices

- Wide-band gap semiconductors like Silicon Carbide (SiC), Gallium Nitride (GaN), Gallium Arsenide (GaAs), and chemical vapor depositions of polycrystalline tips in a vacuum field effect transistor are promising materials for fast switching of high voltage, high current and high temperature power electronics such as FACTS, HVDC terminals, distributed series impedance devices, DG and DER power conditioning systems, power electronic transformers, and power electronic circuit breakers.

- Solid state transfer switches are available now that provide consumers uninterruptible power from two independent feeders.

- D-VARs or DSTATCOMs are small, mobile FACTS devices. They use air cooled, insulated gate bipolar transistors (IGBTs) and, operate at high efficiency resulting in low harmonics. They are sited at T&D interfaces or at an industrial interface to provide voltage support, reduce industrial flicker generation, provide improved power quality, mitigate wind generator impact on transmission lines, etc.

- The Dynaflo distributed series impedance device is expected to be low cost ($20 to $40/kVAr). It injects or removes series impedance, controls the flow of power using either wireless or power line carrier, is modular, and is coupled to the line at a transmission or sub-transmission tower. It balances the flow between phases and

optimizes the use of T&D assets. It is expected to be developed and tested at 161 kV during 2007. It can also monitor line conditions like thermal rating, vibrations, icing, etc

- High temperature superconducting synchronous condensers are now available in 10 MVAR size ranges that are competitive sources of dynamic voltage support at T&D interfaces, for flicker control, etc. These devices immediately respond to changing voltage conditions, and with fast exciter action, they can provide reactive reserves of 2-4 times more output during emergencies for seconds up to minutes. Due to their inherent mechanical inertia these condensers can provide seconds of fault ride through and mitigation of transient instabilities. These devices are cost effective, highly reliable sources of distributed voltage support.

Advanced Higher Capacity Conductors

- Aluminum Conductor Composite Reinforced (ACCR) costs 5-8 times the cost of ACSR conductor but its thermal capacity is 1.5 to 3 times the magnitude. Aluminum Conductor Composite Core (ACCC) configured into a trapezoidal wire is expected to cost 3-5 times the cost of ACSR and provide a greater than 100% capacity increase. This latter technology is anticipated to be commercially available in 1 to 2 years.

- HTS cables for HVAC applications can be used to transmit large quantities of power from medium voltage levels up to 138 kV levels at high currents underground with low loss, low heat release. This capability may support smaller trenching requirements and may be competitive now with underground cables using large quantities of high-priced copper. HTS cables can reduce urban transmission congestion thus enabling more intensive urban development.

- HTS cables can also be used in low voltage, high direct current applications to greatly reduce the costs for DC converter stations or terminals. This also eliminates AC line losses which reduce the cooling requirements even further.

- Fault Current Limiters (FCL) that are thyristor switched tuned capacitors and reactors are ready for deployment now with 110 kA ratings and operate at voltages up to 500 kV. Second generation (2G) wire using YBCO (Yttrium Boron Copper Oxide) as wire for fault current limiters can be developed that have 10 times less AC losses, are instantaneous, limit currents by 3-10 times and have small footprints.

5.1.2. Gaps to Implementation

Technology Gaps

- Low-cost, ubiquitous, secure communications infrastructure which can reach all system nodes with the ability to flexibly adapt to new system configurations and additions of new communication nodes

- Standard interoperability framework which provides machine-to-machine understanding among system nodes.

- Deployment of grid friendly appliances into appliances such as washing machines, dryers, refrigerators, HVAC, etc and their integration into grid operations.

- Commercialization of advanced conductors that are cost competitive.

- General reduction in the total cost of ownership of DG and FACTS devices.

- Discovery of a breakthrough energy storage technology.

Policy/Regulatory Gaps

- A consistent, long-term policy to provide clear and low-cost market signals (real-time pricing, critical peak pricing, etc.) to DERs interested in participating energy markets in coordination with the local distribution-level programs with the CAISO programs.

- Micro-grids should be allowed to buy/sell capacity, energy and other ancillary services to other micro-grids within the region. IEEE 1457 needs to be modified to allow for individual DERs and micro-grids to supply power during contingencies.

- Standard interconnection protocols for micro-grids and other distributed energy resources.

- Measurement and evaluation protocols to allow demand response resources to be recognized by the CAISO. These resources should be valued based on the reliability of the resource and the value of the capacity at the time of use of the resource.

- Open access to meter data is needed to support real-time settlement.

- FERC incentives need to be requested by utilities to allow the use of advanced technologies that increase capacity, improve efficiency or reliability of existing rights of way per the EPACT 2005.

- CEC support is needed for an in-depth evaluation of the economic benefits of commercially available voltage stabilizing technologies (SVC, D-VAR, DSTATCOM, STATCOM, SuperVAR, etc) to identify and endorse the optimum solutions.

- A better understanding of the value that the San Diego area consumers place on premium power quality and the creation of an appropriate rate structure to support investment in technologies that provide the needed level of premium power quality is needed.

Consumer Systems Gaps

- Cyber security gaps will be a major factor in networking large numbers of consumer generation and demand response into the grid, particularly where consumer system nodes will have both communications and control capabilities that are integrated into system operations.

- Consumers lack the necessary information required to understand the market value of DER and therefore do not yet see a compelling value proposition to invest in these technologies. They also lack the needed grid interfacing technologies to support market participation.

5.2. Integrated Communications

Table 9 summarizes the gaps identified in the area of integrated communications and the improvement initiatives recommended to address these gaps.

Table 9 Integrated Communications Improvement Initiatives

Area of Identified Gap	Specific Improvement Initiative to Address Gap
Backhaul	Internet2
Backhaul	Ethernet over Fiber
Mid-haul	Broadband over Powerline (BPL)
Mid-haul	4th Generation (4G) WiMAX
Last Mile	3rd Generation (3G) Wireless Voice and Data
Last Mile	Zigbee / WiMedia / WiFi - Wireless

5.2.1. New Technology Overview

Internet2

Internet2 is the next generation high speed internet backbone and its development is led by more than 200 universities. IPv6 extends the Internet IP address scheme to 6 octets which is desirable for Broadband over Powerline (BPL) based ISP services. With a high performance backbone and Multiprotocol Label Switching (MPLS) Quality of Services (QoS), integration of QoS sensitive applications is directly supported. This technology is currently in the demonstration phase and projected to be commercially available in approximately 3 years.

Ethernet over Fiber

Ethernet over Fiber (IEEE 802.3z) is becoming a common carrier service and an inexpensive interconnection method as multi-gigabit Ethernet switches are being used for fiber terminations. This technology aids in digital convergence when coupled with MPLS, potentially simplifying the need to use costly digital cross-connect systems. Further use of optoelectronic technology allows operators to drive fiber deep into the network more effectively, make better use of existing bandwidth, economically increase bandwidth, target programming to specific areas, and enable the efficient delivery of many revenue-generating interactive services. Utilities can now

cost-effectively overlay video on fiber in the loop (FITL) architectures, efficiently carry analog video on synchronous optical network (SONET) backbones, and solve the power challenge the dense wave division multiplexing (DWDM) deployments impose on optical amplifiers in the long-haul network if needed for substation monitoring and providing new services. This technology is currently in the proof of concept phase and projected to be commercially available in approximately 2 years.

Broadband over Powerline (BPL)

Use of BPL over short distances at 2-50 MHz to achieve data transfers of 20 Mbps to 100 Mbps for consumer portals and even video surveillance for O&M and detection of terrorist attacks is achievable. Standards for BPL are now in development and will be needed for broader market acceptance. HomePlug allows Ethernet-like network plug and play using home power plugs and house wiring to communicate via broadband.   Communications with smart appliances via HomePlug is feasible as well as user interaction with utility programs. This technology is currently in the proof of concept phase and projected to be commercially available in approximately 3 years.

4th Generation (4G) WiMax

4th Generation (4G) WiMax

WiMax can provide the requisite long distance communications up to 10 miles and in some instances beyond 30 miles at data transfer rates of 75 Mbps. WiMax using IEEE 802.16D-2004 can communicate between fixed sites in point to point and point to multipoint configurations with different vendors. This standard will likely be used for private fixed networks in the USA which will utilize super-cell (high site) based deployments more focused on coverage than capacity. WiMax can communicate out-of sight via IEEE 802.16E-2005 and can communicate with moving trucks or cars. Mobile WiMAX products will enter the market in late 2007 and are expected to be deployed by major carriers such as Sprint and Covad. The availability and capabilities of WiMAX allow it to be the backbone of a T&D communication system that will support WiFi applications for substation or distribution automation. This technology is currently in the research and development phase and projected to be commercially available in approximately 3 years.

3rd Generation (3G) Wireless Voice and Data

Using existing and future 3G commercial carrier cellular data networks may be cost effective by avoiding the substantial capital costs for private wireless networks. Coverage may be less than 100% (some dead zones), and encryption will be needed to achieve security. 3G wireless could serve as a backup broadband connection where high availability is required. Commercial site coverage can be as high as 95% for urban/suburban/rural mixed counties per previous experience. Private voice networks can be consolidated by relying more heavily on commercial cell carriers. Commercial carriers have advanced services including push-to-talk, presence information on buddy list, wireless web, etc. This technology is currently in the early adopter phase and projected to be commercially available in approximately 2 years.

Zigbee / WiMedia / WiFi - Wireless

Zigbee Alliance's Zigbee standard (IEEE 802.15.4) uses frequency hopping spread spectrum (FHSS) radio technology, which offers reliable, low speed, long range performance and immunity against jamming and interference. The 802.15.4 document provides a common standard for networking for sensors and control devices common to modern grid elements. The WiMedia Alliance is championing an Ultra-Wideband standard physical layer to the existing IEEE 802.15.3 standard.   The subcommittee working on it is the 802.15.3a committee. The WiMedia solution will provide higher data rate service and mesh networking capability with similar RF coverage capabilities as Zigbee. WiMedia UWB will expand grid control to include

complex monitoring and content distribution applications. This technology is currently in the research and development phase and projected to be commercially available in approximately 3 years.

5.2.2. Gaps to Implementation

Technology Gaps

- Transition to IPv6 to support a BPL internet service rollout is needed.
- Transition to an MPLS based backbone network with Ethernet over Fiber is needed to lower connectivity costs and complexity. Use of DWDM over fiber can be considered as capacity demands grow.
- Need to evaluate existing microwave tower based coverage footprint for application in WiMAX Private (dedicated third party) super-cell deployment scenario.
- Environmentally suitable devices are needed to bring 3G wireless data service to narrowband or off-network locations.
- Need to determine if a Very Small Aperture Terminal (VSAT) package can be used to link off-network sites (remote facilities including substations) in an affordable manner while meeting needed QoS.
- Need to determine if some off-network sites can be affordably connected to microwave or fiber backbone sites via high bandwidth point-to-point short-hop radio technology.

Policy/Regulatory Gaps

- Making connection to Internet2, as long term goal of a Smart Grid, may require regulatory approval in conjunction with peering role to other utilities and with respect to undersubscribed backbone capacity.
- Need to acquire RF spectrum in the Broadband Radio Service (BRS) or Educational Broadband Service (EBS) band(s) to support private WiMAX build-out for BPL, Substations (SCADA, Security, WiFi), and remote Intelligent Electronic Devices.

Consumer Systems Gaps

- Integration of HomePlug based (or equivalent) technologies with consumer products is needed. This will be dependent upon the AMI approach chosen and decisions regarding BPL.
- Deployment timelines for mobile WiMAX consumer grade products supported by commercial carrier services will determine when 4G WiMAX could be used in lieu of 3G wireless services for remote connectivity.
- Further investigation is needed to determine the level of deployment of   consumer products that support load shedding and other consumer applications, based on Zigbee and WiMedia technologies.

5.3.   Advanced Control Methods

Table 10 presents the gaps identified in the advanced control method area and the improvement initiatives recommended to address these gaps.

Table 10 Advanced Control Methods Improvement Initiatives

Area of Identified Gap	Specific Improvement Initiative to Address Gap
Distributed Intelligent Control Systems	Agent and Multi-Agent Systems
Substation Automation	Substation Automation
Distribution Automation	Distribution (Feeder) Automation
Integration with Enterprise Systems	Web Services and Grid Computing

5.3.1. New Technology Overview

Agent and Multi-Agent Systems

These systems integrate utility control operations with mainstream web technologies and through multiple independent computers communicating over a network accomplish a common objective or task. This enables agent and multi-agent systems to become adaptive, self-aware, self-healing and semi-autonomous control systems. This technology is currently in the research and development phase and projected to be commercially available in 1-5 years.

Substation Automation

Substation automation systems provide the local control, remote control, and monitoring functions at the substation level. Intelligent Electronic Devices (IED) utilized for protection and control are normally integrated with a station computer, which provides the human machine interface (HMI) for local control, monitoring, and system configuration. The IED and the local network are linked to various other users and lay the foundation for higher-level remote functions such as advanced power system management and equipment condition monitoring while it is in service.

These systems have the capability to make the substation information, which was traditionally only available at the local level, available for retrieval by substation planners, protection engineers, maintenance personnel, and others as needed. As more power system asset information is stored electronically in Geographical Information Systems (GIS) and AM/FM systems, even more varieties and volumes of data will be maintained and managed. Substation

automation technologies are becoming more "intelligent," both in what power system characteristics they can capture and also in what calculations and algorithms they can execute. Numerous vendors provide modern substation automation technologies today; however, additional advances are expected in the future.

Distribution Automation

Distribution automation control utilizes the integration of IEDs with distribution Supervisory Control and Data Acquisition Systems (SCADA) to provide rapid reconfiguration of discrete devices such as switches, capacitor banks, reactor banks, and tap changing transformers. Distribution automation objectives are to improve reliability and power quality by maintaining bus voltages across the system within specified voltage and power quality limits and responding to disturbances on the distribution system to minimize customer out of service time. This technology is currently available on a limited basis however additional research and development is needed before a significant deployment can be achieved.

Web Services and Grid Computing

Web services and grid computing address the integration of grid operations with other Enterprise-wide processes and technologies such as Outage Management (OMS), Condition Based Maintenance (CBM), System Planning and others. Any enterprise-wide process or technology that can benefit from the information acquired from other KTAs can be integrated with these technologies. Technologies that fall under this category are as follows:

- Grid computing is an emerging computing model that performs higher throughput computing by taking advantage of many networked computers. These networked computers model a virtual computer architecture that is able to distribute process execution across a parallel infrastructure. This technology is currently in the research and development phase and projected to be commercially available in approximately 3 to 5 years.

- The Semantic Web is a project that intends to create a universal medium for information exchange by giving computer-understandable meaning (semantics) to the content of documents on the World Wide Web. This technology is currently in the proof of concept phase and projected to be commercially available in approximately 4 to 10 years.

- Fault Anticipation Integrated with Condition-based Maintenance is a distributed fault analysis linked to OMS and CBM systems. This technology is currently in the research and development phase with some demonstrations and projected to be commercially available in approximately 2 to 5 years.

5.3.2. Gaps to Implementation

Technology Gaps

The advanced control methodology technologies needed to support the future Smart Grid in the San Diego region are highly dependent on having embedded intelligence that is distributed throughout the electrical network system with the underlying capability to provide for seamless interoperability among system nodes. The following gaps in technologies needed to support the deployment of advanced control methods include:

- Low-cost, secure communications infrastructure which can reach all system nodes (meters, gateways, IEDs, DERs, substations, network protectors).

- Ability to flexibly adapt to new system configurations and addition of new communication nodes.

- Interoperability framework which provides the capability to provide device to device understanding among system nodes.

- To implement advanced control methods such as micro-grids and intelligent islanding, intelligent reconfiguration, large-scale demand response, and context-aware and self-healing components, ACM technologies will need to be integrated with autonomous agent software. These agents must coordinate not only the communications, but also provide sense and respond capabilities to implement physical aspects of control within targeted areas within the San Diego grid system. For micro-grids to co-exist with the current grid system, control algorithms need to be developed which can provide adaptive, optimized control of the aggregated micro-grid devices (loads, generation, and storage) in addition to the ability to provide intelligent islanding capability.

Policy/Regulatory Gaps

- Policies that encourage open data access, interoperability, reliability standards, and capability to operate micro-grids in intelligent islanding modes as well as allow for buying and selling of power between entities on the system without complex rules and regulations.

- A consistent, long-term policy to provide clear and low-cost market signals (real-time pricing, critical peak pricing, etc.) to consumers interested in participating in both price-responsive and contingency responsive energy markets. This policy needs to coordinate the local distribution-level programs with the CAISO programs.

Consumer Systems Gaps

On the consumer system side, the major gaps which impact the future state in the San Diego region include:

- Since most consumer systems are connected to the current grid system in a non-uniform way, cyber security gaps will be a major factor in networking large numbers of customers into the grid system. This is especially apparent where consumer system nodes will have both communications and control capabilities that are integrated into system operations.

- Gaps in the current interval metering infrastructure include capability to upgrade the firmware to enable future power electronics functionality, gaps in residential metering infrastructure for large-scale demand response automation, and gaps in integrated applications within the metering infrastructure (e.g., being able to seamlessly integrated the meter data with device control nodes via a two-way interface).

Gaps exist in both connectivity (monitoring and control) capabilities and the information necessary to understand the market value of DERs that are integrated into consumer systems. For example, existing back-up generators (BUG) are not fully utilized due to regulatory limitations and lack of retrofit capabilities to meet air quality restrictions. Other load control capabilities within consumer systems are not being utilized due to lack of information on when and how they could be utilized as well as lack of a low-cost communications system to integrate them into grid operations.

5.4. Sensing, Metering and Measurement

Table 11 summarizes the gaps for the sensing, metering and measurement and the improvement initiatives to address those gaps.

Table 11 Sensing, Metering and Measurement Improvement Initiatives

Area of Identified Gap	Specific Improvement Initiative to Address Gap
Dynamic Ratings	Dynamic Line Thermal Ratings
Low cost wireless sensors	Wireless, Intelligent Sensors for System Information
Advanced instrument transformers	Fiberoptic Potential and Current Transformers
Ad Hoc sensor networks	Wireless, Intelligent Sensors for Condition Information
Consumer Portal	Consumer Portal

5.4.1. New Technology Overview

Dynamic Line Thermal Ratings

Installation of technologies that determine dynamic ratings may enable SDG&E to identify additional capacity (10%-25%) in lines, transformers, etc. These technologies could provide solutions for components that violate planning criteria and enable opportunities for increased revenues (transmission line loading). Dynaflo distributed series impedance devices mounted on each phase of each tower can measure line temperature. Integrated with the low cost wireless Sensornet technology, dynamic line ratings can be calculated. This would enable the establishment of dynamic ratings for all spans which would eliminate the need to identify a critical span and would be independent of the effects of micrometeorological conditions. These technologies are currently being demonstrated and are expected to be commercially available in 2 to 3 years.

Wireless, Intelligent Sensors for System Information

- Low cost wireless nodes that operate as Intelligent Radio Devices (IRD) in a mesh network at 2.4 GHZ and 5.2 GHz with ranges up to 10 miles are currently available and can be added to various substation sensors (T, I2T, P, etc.) and lines (T, strain, stress, etc.). This IRD mesh could also be used with wireless nodes on towers in a mesh network for reliability for broadband communication. These are unlicensed frequencies that provide no protection from the FCC and are subject to signal interference.

- I-Grid now offers a national web-based power disturbance monitoring and reporting system. Approximately 1500 power quality monitors are installed nation-wide. This technology can provide analysis of events in almost any given region.

Fiber Optic Potential Transformers (PT) and Current Transformers (CT)

Fiber optic PT and CT sensors and meters are available from NxtPhase (fiber optic cables) and ABB (silicon crystals) that accurately measure voltage and current to revenue standards at any voltage over the entire range of the device. Other vendors include Mitsubishi Electric and Hitachi/Toshiba.

Wireless, Intelligent Sensors for Condition Information

An ad-hoc (or "spontaneous") network is a local area network or other small network, especially one with wireless or temporary plug-in connections, in which some of the network devices are part of the network only for the duration of a communications session or, in the case of mobile or portable devices, while in some close proximity to the rest of the network. The integration of as-hoc networks with equipment condition sensors enables a near real-time assessment of asset health to be determined. Numerous technologies are available today and include:

- Nortech's hot spot monitoring for small and medium transformers is intended for utilities concerned about safe and reliable operation of their high voltage equipment.

- Sophisticated transformer monitoring tools that measure dissolved gases-in-oil and predict the health of transformers and load tap changers in real-time are now commercially available.

- Circuit breaker real-time monitoring systems are available that measure the number of operations since last maintenance, oil or gas insulation levels, and breaker mechanism signatures.

- Cable monitors are available to help determine changes in buried cable health by trending partial discharges or periodic impulse testing of monitored lines.

Consumer Portal

Based on an open flexible architecture the consumer portal would facilitate the implementation of new services such as demand response, real time pricing, outage detection, remote connect/disconnect, support to distribution operations, PQ monitoring and improved customer information. In addition, consumer portals will support new information-based solutions that improve the efficiency, comfort and safety of businesses, buildings and homes and integrate with power delivery system applications.

Successful use of consumer portals has been demonstrated by Bonneville Power Authority in their non-wires solution program at several hundred customer sites. In this application the portal acts as a gateway from the customer's utility meter to other controllable loads such as pool pumps, water heaters, air conditioners, etc. Consumer portals are available on a limited basis today, however widespread deployment of portals with full functionality is 3-5 years away.

5.4.2. Gaps to Implementation

Technology Gaps

- Sensing and measurement technologies require direct interface with future communication infrastructures to make near real time data available to other key technologies. Low-cost, ubiquitous, secure communication infrastructures which can reach all system nodes (meters, gateways, IEDs, DERs, substations, network

protectors) are required to take full advantage of advanced sensing and measurement technologies.

- Interoperability frameworks and standards need to be finalized to provide device to device understanding among system nodes.

- The cost for advanced SM technologies and their associated communication infrastructures needs to be reduced to provide more compelling business cases for investors.

- SDG&E's plans for AMI deployment will significantly close the technology gap for SM at the consumer level. A long term view is suggested when deciding on the level of integration with other SDG&E technologies and systems. Additionally, the new AMI should be flexible so that it can interface with future improvements in communication infrastructures.

- The collective benefits of customer integration with grid operations system via consumer portal technologies has not yet been adequately evaluated or communicated. Consideration should be given to what the value proposition might be for both consumers and SDG&E as part of the AMI project.

Policy/Regulatory Gaps

- Regulators need to take into account the societal benefits associated with Smart Grid technologies and allow costs to be recovered in rates across customer classes.

- Additionally, acceptance of new Smart Grid technologies such as revenue grade fiber optic instrument transformers should be timely.

- New rate designs (e.g., real time pricing, premium power quality) and incentives are needed to encourage consumers and SDG&E to invest in new Smart Grid technologies.

- Open communication architecture needs to be standardized.

- CAISO should allow dynamic line ratings to be applied in transmission operations to provide additional capacity for increased revenues or reduction in congestion costs.

Consumer Systems Gaps

- The value proposition for a consumer to integrate with system operations via AMI or consumer portals is not yet compelling.   Need to identify a value proposition that would empower and motivate the consumer to invest in consumer portal technologies, (behind the meter services, information, security systems, energy management systems, internet access, etc.). Current net metering tariffs should be a positive motivator for consumer portal technologies.

- Incorporation of the consumer into grid operations through new rate designs and incentives will require extensive consumer education.

5.5.   Decision Support and Human Interface

Table 12 presents the gaps for the decision and human interface areas and the improvement initiatives to address those gaps.

Table 12 Decision Support and Human Interface Improvement Initiatives

Area of Identified Gap	Specific Improvement Initiative to Address Gap
Tools for Asset Management and Performance Optimization	Semi-autonomous Agents
Tools for Asset Management and Performance Optimization	Advanced Pattern Recognition
Tools for Operations and Planning	Advanced Visualization Methods
Tools for Operations and Planning	Numerical Weather Prediction
Tools for Operations and Planning	Geospatial Information Systems

5.5.1. New Technology Overview

Semi-autonomous Agents

Collaborative agent societies with intelligent user interfaces provide a new complementary style of human-computer interaction, where the computer becomes an intelligent, active and personalized collaborator. Interface agents are computer programs that employ Artificial Intelligence (AI) methods to provide active assistance to a user of a particular computer application. Underlying software has characteristics that learn from data and then adjust themselves to better handle those types of data. This technology is currently in R&D at MIT.

Advanced Pattern Recognition and Visualization Methods

- Artificial Intelligence-driven data reduction—Advancement in grid operations today is handicapped by the limitations in the data that is available. Through advancements in sensing and measurement and integrated communications, the modern grid will have access to essentially all needed data. The new challenge will be to reduce this data into a volume and format that can be readily comprehended by the human operator. AI will be utilized in conjunction with advanced control methods to minimize data volume without losing the information needed by the operator and to create a format most effective for operator/user comprehension.

- Color contouring and animation—The use of color contouring and animation to increase not only operator speed of recognition but also speed of diagnosis is currently in research and development.

- Rapid refresh—Advancements in communication and processor speeds will enable rapid refresh and display of real-time conditions so operators can quickly understand rapidly moving trends.

- Voice recognition—Advances in this area will rapidly increase the speed and effectiveness of the human-machine interface.

- Virtual reality environments - Virtual reality techniques will be applied to grid control centers to closely integrate the "thinking" of the operator and the decision support technologies.

- Region of Stability Existence (ROSE) technology using phasor measurement data can be plotted for the operator on-line using Phasor Measurement Unit data in 1D or 2D space and show regions of secure operations limited by voltage constraints, voltage instability, thermal limits, and flow gate constraints. Optimal mitigation measures can be applied on-line to expand the ROSE. ROSE will be available in 1-2 years.

- Physical Operating Margin (POM) performs ultra-fast load flows (40,000 bus system solved in 0.5 seconds) and provides "boundary of operating" visualization tools. It also generates nomograms for operators showing regions of secure operations limited by voltage constraints, voltage instability, thermal limits, and flow gate constraints. Optimal mitigation measures can be applied on-line to expand the "boundary of operating" region. POM is currently available.

- As part of the Intelligrid program. EPRI has undertaken the Transmission Fast Simulation and Modeling (TFSM) project to develop a technical vision that models and simulates system behavior based on real-time modeling of data. TFSM will anticipate changing conditions and provide timely response during system disturbances, including prevention, containment, and support for recovery. A key concept incorporated in TFSM is the recognition of the different time frames associated with the various aspects of the modern grid that need to be controlled. TFSM is expected to also address the decision support and human interface needs of the modern grid. Projects such as TFSM will play a key role in future decision support needs.

Numerical Weather Prediction

- The forecasting of the weather in the 0-6 hour timeframe is often referred to as "now-casting". With "now-casting" the timing of data is not the same for all variables, in particular for the possible predictors. The horizon of prediction is "today" rather than "tomorrow". It is in this range that the human forecaster still has an advantage over computer NWP models. This technology is in the research and development phase and is anticipated to be commercially available in 3 to 5 years.

- Ensemble forecasting uses a number of forecasts to reflect the uncertainty in the initial state of the atmosphere (due to errors in the observations and insufficient sampling). The uncertainty in the forecast can then be assessed by the range of different forecasts produced. This technology has been shown to be better at detecting the possibility of extreme events at long range. This technology is in the research and development phase and is anticipated to be commercially available in 3 to 5 years.

Geospatial Information Systems

- The use of geospatial information systems as a platform for presenting the "where" dimension to support decision support is rapidly emerging as a valuable tool. Various

geospatial technologies have been integrated with system topologies and other enterprise-wide processes and technologies for such applications as outage management, transmission congestion, etc. to enable users to understand the information at a glance. Geospatial technologies are available today.

5.5.2. Gaps to Implementation

Technology Gaps

- Improvements in real-time visualization and analysis capability of transmission system parameters using phasor data as well as state estimator output from SCADA data is needed.
- Development of applications that integrate advanced visualization and geospatial tools in order to improve speed of comprehension and real-time decision making is needed.
- Advances in computing power are needed to support the processing of complex near real time applications and the presentation of the information to the operators.

Policy/Regulatory Gaps

- Coordination is required between CAISO and the California Energy Commission (CEC) to encourage the development of ROSE and support the use of the growing data base of phasor data that is coming from the new PMUs installed throughout the CAISO and the San Diego region.

Consumer Systems Gaps

- As consumers become engaged in market operations, they too will have a need for more information. Visualization technologies should consider the needs of the consumer. Additionally, consumer based agents and portals need to be equipped with decision support algorithms that are consistent with those used by the grid.

6. BUSINESS CASE

6.1. Business Case (Cost-Benefit Analysis)

Based on the results from the Gap Analysis, the project team developed a list of improvement initiatives that if implemented together would create a Smart Grid in the San Diego region. These initiatives will form the basis for the cost-benefit analysis, implementation plan (project sequencing), and recommended research, development, and demonstration projects.

The 26 improvement initiatives in Table 13 below represent technologies that fall into the five (5) key technology areas of the Modern Grid Initiative. The projects team selected technologies using the systems view approach described above to form an integrated system that must be assessed together. It is important to note that if this "designed" integration framework is broken by selecting improvement initiatives that focus on only one or two of the key technology areas, the benefits become severely reduced. Figure 9 represents the interconnected nature of the key technology areas. Note that integrated communications is a foundational element that links together the other four areas.

Figure 9 Relationship among the Key Technology Areas
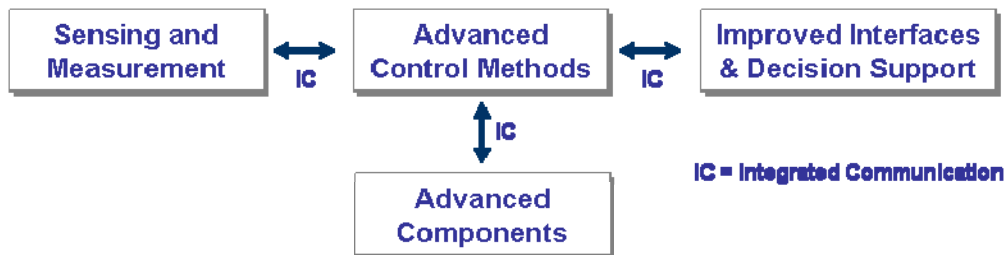
The potential improvement initiatives presented in the following section are mapped to the key technology areas as presented in the Table 13.

Table 13 Improvement Initiatives by Key Technology Area

Key Technology Area	Potential Improvement Initiatives
Sensing and Measurement	1 – 5
Integrated Communications	6 – 11
Improved Interfaces & Decision Support	12 – 16
Advanced Components	17 – 22
Advanced Control Methods	23 – 26

6.2. Improvement Initiatives

The improvement initiatives are described in Table 14, as well as the selection process and types of benefits used in evaluating each improvement initiative.

Table 14 Improvement Initiative Descriptions

	Key Technology Area	Improvement Name	Improvement Description
1	Sensing and Measurement	GATECH IPIC Dynflo distributed series impedance sensors	Dynflo distributed series impedance devices on each phase on each tower can also measure line temperature and thus line sag.
2	Sensing and Measurement	I-Grid Monitoring System (by Softswitching Technologies)	Wireless, intelligent system sensors for operating information (MW, MVAR, Volts, Amps, PF, PQ, etc.). Use at key nodes in the transmission system; and distribution system where load pockets are dynamic.
3	Sensing and Measurement	Fiberoptic PT and CT meters	Fiberoptic PT and CT sensors and meters are available from NxtPhase (fiberoptic cables) and ABB (silicon crystals) that accurately measure voltage and current to revenue standards at any voltage over the entire range of the device
4	Sensing and Measurement	Wireless, intelligent system sensors for condition information	Low cost wireless nodes that operate as intelligent radio devices (IRD) in a mesh network at 2.4 GHZ to 5.2 GHz with ranges up to 10 miles are available and can be added to various substation sensors (T, I2T, P, etc.) and lines (T, strain, stress, etc.). This IRD mesh could also be used with wireless nodes on towers in a mesh network for reliability for broadband communication.
5	Sensing and Measurement	Consumer Portal	Emerging information-based solutions that improve the efficiency, comfort and safety of businesses, buildings and homes and integrate with power delivery system applications (Broadband Energy Networks). Based on an open flexible architecture the portal will facilitate the implementation of new services such as DR and real time pricing, outage detection, remote connect/disconnect, support to distribution operations, PQ monitoring and improved customer information (EPRI Intelligrid).

6	Integrated Communications	Internet2 (IPv4 IPv6)	Internet2 led by more than 200 universities for next-generation high speed internet backbone. IPv6 extends Internet IP address scheme to 6 octets which is desirable for BPL based ISP services. With high performance backbone and MPLS QoS services, integration of QoS sensitive applications is directly supported.
7	Integrated Communications	Ethernet over Fiber	Ethernet over Fiber (IEEE 802.3z) is becoming a common carrier service and in-expensive interconnection method as multi-gigabit ethernet switches are being used for fiber terminations. This technology aids in digital convergence when coupled with MPLS potentially simplifying the need to use costly digital cross-connect systems. Further use of optoelectronic technology allows operators to drive fiber deep into the network more effectively, make better use of existing bandwidth, economically increase bandwidth, target programming to specific areas, and enable the efficient delivery of many revenue-generating interactive services. Utilities can now cost-effectively overlay video on fiber in the loop (FITL) architectures, efficiently carry analog video on synchronous optical network (SONET) backbones, and solve the power challenge the dense wave division multiplexing (DWDM) deployments impose on optical amplifiers in the long-haul network if needed for substation monitoring and providing new services.
8	Integrated Communications	BPL	Proof of Concept looks viable for Midhaul, Last Mile, and HAN application. Use of BPL over short distances at 2-50 MHz to achieve data transfers of 20 Mbps to 100 Mbps for consumer portals and even video surveillance for O&M and detection of terrorist attacks. Standards for BPL are now in development and will be needed for broader market acceptance. HomePlug allows ethernet-like network plug and play using home power plugs and house wiring to communicate via broadband. Communications with smart appliances via HomePlug is feasible as well as user interaction with utility programs.

| 9 | Integrated Communications | 4G WiMAX Fixed - Private Wireless | R&D looks viable for Midhaul, Last Mile, and HAN application. WiMax can provide the requisite long distance communications up to 10 miles and in some instances beyond 30 miles at data transfer rates of 75 Mbps. WiMax using IEEE 802.16D-2004 can communicate between fixed sites in point to point and point to multipoint configurations with different vendors. This standard will likely be used for private fixed networks in the USA which will utilize super-cell (high site) based deployments more focused on coverage than capacity. Imax can communicate our-of sight via IEEE 802.16E-2005 and can communicate with moving trucks or cars. Mobile WiMAX products will enter the market in late 2007 and is expected to be deployed by major carriers such as Sprint and Covad. The availability and capabilities of WiMAX allow it to be the backbone of a T&D communication system that will support WiFi applications for substation or distribution automation. |
| 10 | Integrated Communications | 3G Wireless Voice & Data - 1xEVDV / UTMS | Early Adoption looks viable for Midhaul and Last Mile application. Using an existing and future 3G commercial carrier cellular data networks may be cost effective by avoiding the substantial capital costs for a private wireless networks. Coverage may not be 100% (some dead zones), and encryption will be needed to achieve security. 3G wireless can be a backup broadband connection where high availability is required. Commercial site coverage can be as high as 95% for urban/suburban/rural mixed counties per previous experience. Private voice networks can be consolidated by relying more heavily on commercial cell carriers. Commercial carriers have advanced services including push-to-talk, presence information on buddy list, wireless web, etc. |

11	Integrated Communications	Zigbee / WiMedia / WiFi - Wireless	R&D looks viable for Last Mile and HAN application. Zigbee Alliance's Zigbee standard (IEEE 802.15.4) uses frequency hopping spread spectrum (FHSS) radio technology, which offers reliable, low speed, long range performance and immunity against jamming and interference. The 802.15.4 document provides a common standard for networking for sensors and control devices common to modern grid elements. The WiMedia Alliance is championing an Ultra-Wideband standard physical layer to the existing IEEE 802.15.3 standard. The subcommittee working on it is the 802.15.3a committee. The WiMedia solution will provide higher data rate service and mesh networking capability with similar RF coverage capabilities as Zigbee. WiMedia UWB will expand grid control to include complex monitoring and content distribution applications.
12	Improved Interfaces and Decision Support	Semi-autonomous Agents	Collaborative agent societies with intelligent user interfaces (e.g., MIT's Project Oxygen) using techniques from the field of autonomous agents provides a new complementary style of human-computer interaction, where the computer becomes an intelligent, active and personalized collaborator. Interface agents are computer programs that employ Artificial Intelligence methods to provide active assistance to a user of a particular computer application.
13	Improved Interfaces and Decision Support	Advanced Pattern Recognition	Pattern recognition (include waveform analysis) is also intrinsic to computer vision, network intruder detection, forgery detection, biometrics, next-generation computer interfaces and automatic paraphrasing, translation and language understanding.

14	Improved Interfaces and Decision Support	Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)	Physical Operating Margin (POM) for ultrafast load flows (40,000 bus system solved in 0.5 seconds) with Boundary of Operating Region visualization tools generating nomagrams for operators showing regions of secure operations limited by voltage constraints, voltage instability, thermal limits, and flow gate constraints. Optimal mitigation measures can be applied on-line to expand the boundary of operating region. Region of Stability Existence (ROSE) using phasor measurement data can be plotted for the operator on-line using PMU data in 1D or 2D space and show regions of secure operations limited by voltage constraints, voltage instability, thermal limits, and flow gate constraints. Optimal mitigation measures can be applied on-line to expand the ROSE. POM/TS with FFS can quickly determine areas of the system that can transient instabilities to support system planning and is fast enough to be used for on-line systems. Integrated with OPM can support CAPEX planning for minimal cost mitigation of transient instabilities, or in operations can mitigate potential transient instabilities.
15	Improved Interfaces and Decision Support	AI-based Weather and Load Forecasting Methods (Numerical Weather Prediction)	The forecasting of the weather in the 0-6 hour timeframe is often referred to as nowcasting. With "nowcasting" the time of availability of data is not the same for all variables, in particular for the possible predictors. The horizon of prediction is "today" rather than "tomorrow". It is in this range that the human forecaster still has an advantage over computer NWP models. Ensemble forecasting uses lots of forecasts produced to reflect the uncertainty in the initial state of the atmosphere (due to errors in the observations and insufficient sampling). The uncertainty in the forecast can then be assessed by the range of different forecasts produced. They have been shown to be better at detecting the possibility of extreme events at long range.
16	Improved Interfaces and Decision Support	Geospatial Information Systems	A geographic information system or geographical information system (GIS) is a system for creating and managing spatial data and associated attributes.

17	Advanced Components	DER-based Microgrids	Application of distributed energy (DE) is minigrids, a set of generators and load-reduction technologies that supply the entire electricity demand of a localized group of customers. Power parks (also called "premium power parks") are an alternative to the traditional approach. They may include uninterruptible power supplies such as battery banks, ultracapacitors, or flywheels. They typically include an on-site power source to increase reliability. Pumped storage is used to even out the daily generating load, by pumping water to a high storage reservoir during off-peak hours and weekends, using the excess base-load capacity from coal or nuclear sources. Grid energy storage method is to use off-peak electricity to compress air, which is usually stored in an old mine or some other kind of geological feature. Off-peak electricity can be used to make ice from water, and the ice can be stored until the next day, when it is used to cool either the air in a large building (thereby shifting that demand off-peak) or the intake air of a combustion gas turbine generator (thereby increasing the on-peak generation capacity).
18	Advanced Components	Various High-Efficiency & Renewable DG	Various types of existing DG: Reciprocating diesel, natural gas engine, microturbine, combustion gas turbine, fuel cell, photovoltaic, wind turbine, geothermal, tidal, wave, biomass. Hybrid DER (e.g., Solid oxide fuel cell combined with a gas turbine or microturbine), PHEV Plugin Hybrid Electric Vehicles, Fuel Cells, Integrated Load Control, Grid-friendly Appliances, etc.
19	Advanced Components	Advanced Energy Storage Systems	NaS batteries are now available for up to 8 hours for about $3500/kw for load follow and peak shaving the loads and can be used for voltage and transient stability support and customer ride-through. Shaving the peak can avoid need for new substations or second transformer banks. VRB flow batteries for 8 hours of storage currently in small sizes for $2800/kw for load follow and peak shaving the loads , frequency regulation and can be used for voltage and transient stability support and customer ride-through. Shaving the peak can avoid need for new substations or second transformer banks. (Private communication with Tim Hennessy of VRB). Beacon 25kWh flywheels for frequency regulation for $1000/ kw-15 minutes, and can be used for voltage and transient stability support and customer ride-through.

20	Advanced Components	Electric Loads as a Reliability Resource	Both price and emergency-responsive load technologies. Implementing controllable GFAs could be a low cost solution to mitigate system collapse and blackouts. Grid Friendly Appliances (GFA) sensitive to drop in frequency are ready now, but manufacturers need to be convinced to add them to appliances like washing machines, dryers, fridges, HVACs, etc. Grid Friendly Appliances (GFA) that are sensitive to drop in frequency plus voltage and are dispatchable need to be developed and tested.
21	Advanced Components	Advanced Grid Control Devices	This class of devices includes FACTS, GridAgents, Distr Power Flow Controllers, Fault Current Limiters, High-speed Switches, D-VAR, DSTATCOM, and SuperVAR. Flexible alternating current (AC) transmission systems, or FACTS, incorporate high-current and high-voltage power electronic devices to increase the carrying capacity of individual transmission lines and improve overall system reliability by reacting very quickly to grid disturbances. Infotility's GridAgents Framework has built-in capability for fast-switching microgrid control but is being developed to integrate with Distribution Automation. Solid State Transfer (SSTs) switches are available now to provide customers uninterruptible power from two independent feeders.
22	Advanced Components	ACSS/TW, ACCR, and ACCC	Annealed aluminum steel supported with trapezoid cross section conductor wire (ACSS/TW) is commercially available, can operate at 200C, carry 100% more current, reduces line losses at normal loads, and can be handled as normal ACSR conductor wire. 3M Aluminum Conductor Composite Reinforced costs from 5X to 8X ACSR conductor but increase transmission thermal capacity 150% to 300% and CTC's Aluminum Conductor Composite Core (ACCC) configured also into trapezoidal wire and is expected to cost 3X to 5Xs with a >100% capacity increase.
23	Advanced Control Methods	Agent and Multi-Agent Systems	Adaptive, self-aware, self-healing, and semi-autonomous control systems. Parallel and Distributed Processing. Distributed computing is parallel computing using multiple independent computers communicating over a network to accomplish a common objective.

24	Advanced Control Methods	Substation Automation	Substation automation systems provide the local control, remote control, and monitoring functions at the substation level. Intelligent Electronic Devices (IED) utilized for protection and control are normally integrated with a station computer, which provides the human machine interface (HMI) for local control, monitoring, and system configuration. The IED and the local network are linked to various other users and lay the foundation for higher-level remote functions such as advanced power system management and equipment condition monitoring while it is in service.
25	Advanced Control Methods	Distribution (Feeder) Automation	Control strategy to coordinate the switching of discrete devices such as capacitor banks, reactor banks, and tap changing transformers as well as continuous control of generator high side voltage settings. (objectives include maintaining bus voltages across the network within specified voltage limits; minimize number of switchings, increase voltage control reserves by keeping maximum number of devices offline, mitigating circular reactive power flows, improve voltage security.
26	Advanced Control Methods	Web Services and Grid Computing	A flexible networked communication system that can be modified in real time to adapt to ancillary services such as responsive demand, reactive power, voltage control, etc. Distributed fault analysis linked to OMS and CBM systems. The Semantic Web is a project that intends to create a universal medium for information exchange by giving computer-understandable meaning (semantics) to the content of documents on the World Wide Web. Grid computing is an emerging computing model that provides the ability to perform higher throughput computing by taking advantage of many networked computers to model a virtual computer architecture that is able to distribute process execution across a parallel infrastructure.

Pursuing all 26 improvement initiatives in a multi-year program would be complicated and likely not achievable in a reasonable number of years. In addition, some improvement initiatives compete against one another.   To reduce the number of initiatives to a manageable number, the project team screened each initiative to determine the value of its benefits, how it could be sequenced with the other initiatives and how the implementation could be accomplished.

While all the improvement initiatives have technologies ready for deployment today or over the next 5 years, several of the technology streams are more mature than others. The project team decided to focus on the more mature technologies, unless there was a compelling reason to include a specific technology.

A summary of the reasons for being selected or not selected each technology is presented in the Table 15. Some of the technologies that have been selected will require due diligence by the utility through research, development and demonstration as a precursor to implementation.

Table 15 Evaluation of Improvement Initiatives for Inclusion

	Improvement Name	Business Case Selection
1	GATECH IPIC Dynflo distributed series impedance sensors	Selected; Provides the ability to sense and respond to voltage support issues; improves reliability.
2	I-Grid Monitoring System (by Softswitching Technologies)	Selected; Provides the ability to sense multiple parameters on the distribution network and support general distributed intelligence.
3	Fiberoptic PT and CT meters	Not selected; Good system cost savings, but smaller incremental benefits than other improvement initiatives.
4	Wireless, intelligent system sensors for condition information	Not selected; Shares the same benefits picture as I-Grid Monitoring System and not as mature.
5	Consumer Portal	Selected: Necessary companion technology to AMI to fully take advantage of the benefits of shared information across the consumer / utility interface.
6	Internet2 (IPv4 IPv6)	Not selected; A single Backhaul solution is necessary and Ethernet over Fiber is ready today. Internet2 needs a few years to mature.
7	Ethernet over Fiber	Selected; Preferred and most cost effective Backhaul solution available today.
8	BPL	Not selected; A single Midhaul solution is needed and the BPL maturity cycle is still in question because the investment forces are utilities.

		Selected;
9	4G WiMAX Fixed - Private Wireless	Telecommunications industry investment in WiMAX is rich with drivers other than utility communications. Thus, the maturity cycle will be quick, and the investment burden not carried by utilities, making this the preferred Midhaul solution.
		Not selected;
10	3G Wireless Voice & Data - 1xEVDV / UTMS	However, this is the backup strategy for the Last Mile solution. Its use would be in areas where, for other reasons, 3G Wireless is more available or cost effective than the Zigbee/WiFi solution.
		Selected;
11	Zigbee / WiMedia / WiFi - Wireless	The primary Last Mile solution because of its flexibility, low cost, and drivers (other than utilities) to expand the communications base.
		Selected;
12	Semi-autonomous Agents	While the maturity cycle in a couple years away, there are huge reliability, economics, and grid flexibility afforded by agents operating in communities on the grid. This solution is low cost.
		Not Selected;
13	Advanced Pattern Recognition	While the cost is low and benefits high, this technology requires most of the technologies being selected in advance to become valuable. Suggest revisiting once agents and advanced visualization methods are in place.
		Selected;
14	Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)	Low cost, high benefits in reliable operations, and immediately available.
		Not selected;
15	AI-based Weather and Load Forecasting Methods (Numerical Weather Prediction)	The CAISO is working to improve forecasting methods for the state, including the potential for micro-forecasting. It is likely that San Diego can benefit from this work later.
		Not selected;
16	Geospatial Information Systems	SDG&E has a decision process for upgrading already in place that will drive this improvement.
		Selected:
17	DER-based Microgrids	As the region's growth continues East, the peak to average MW capacity profile will continue to increase. This will increase reliability issues, making DER-based Microgrids a necessary part of the grid design process where cost-effective reliability is the priority. Thus, while the costs are high, so are the benefits.
		Not selected;
18	Various High-Efficiency & Renewable DG	While the cost is high, so are the benefits. Yet, the industry drivers for this solution will have to be vendors, so the maturity cycle is later than most of the selected solutions.

19	Advanced Energy Storage Systems	Selected;
		Based on San Diego's load profile, moving the peak is very important to the region over the next 20 years. While costly, today, energy storage is the most stable method to achieve this needed improvement.
20	Electric Loads as a Reliability Resource	Not selected;
		While the smart loads solution looks to be promising, its maturity cycle is longer than most of the selected solutions, and the industry drivers for this are not completely aligned so far.
21	Advanced Grid Control Devices	Selected;
		Along with adequate communications, this technology deployment is a foundational element to the Smart Grid.
22	ACSS/TW, ACCR, and ACCC	Not selected;
		SDG&E has a decision process for upgrading already in place that will drive this improvement.
23	Agent and Multi-Agent Systems	Selected;
		While the maturity cycle in a couple years away, there are huge reliability, economics, and grid flexibility afforded by agents operating in communities on the grid and within consumer groups. This solution is low cost.
24	Substation Automation	Not selected;
		SDG&E has a decision process for upgrading already in place that will drive this improvement.
25	Distribution (Feeder) Automation	Selected;
		Along with adequate communications, this technology deployment is a foundational element to the Smart Grid.
26	Web Services and Grid Computing	Not selected;
		SDG&E has a decision process for upgrading already in place that will drive this improvement as part of a long-term overall corporate computing strategy.

6.3. Calculation of Benefits

The next phase of the business case analysis is to determine the anticipated costs and benefits of the final list of thirteen improvement initiatives. The following list of benefit types was quantified and used in the business case.

- Reduced congestion cost
- Reduced blackout probability
- Reduced number of forced outages and interruptions
- Reduced restoration time and reduced operations and maintenance due to predictive analytics and self healing attribute of the grid
- Reduced peak demand
- Other benefits due to self diagnosing and self healing
- Increased integration of distributed generation resources and higher capacity utilization
- Increased security and tolerance to attacks/ natural disasters
- Improved power quality, reliability, system availability and capacity due to improved power flow
- Increased job creation and gross regional product (GRP)
- Increased capital investment efficiency due to tighter design limits and optimized use of grid assets
- Tax savings to the utility from increase in depreciation
- Environmental benefits gained by increased asset utilization

To quantify the benefits, the project team identified more than 300 variables required to make the appropriate calculations for all the improvement initiatives. A majority of the values for the variables have been obtained through the investigation of the current infrastructure. In some cases, the values for the variables are based on the results of published studies by others including, the San Diego Association of Government, Modern Grid Initiative, Electric Power Research Institute (EPRI) Midwest Independent System Operator (MISO), Ontario Hydro, and vendor case studies. The areas where these values have been applied are as follows:

- Percent decrease in interruption hours post project
- Percent increase in Transmission Line capacity addition due to better sensing
- Percent increase in avoided Interruptions post-project
- Percent reduction in restoration costs post project
- Percentage of distributed generation made dispatchable by consumer portal
- Percent of Transformer Units identified for life extension by identification of through faults
- Percent of Lightning recognition events identified and tied to component failure and upgrade
- Transformer Life extension due to less fault current
- Percent Reduction of Distribution Losses post-project
- Substation Automation Improvement Potential
- Percent reduction in Complaints

- Percent of C&I Customers sensitive to PQ
- Present MW Deviation of forecast to actual in MW
- Micro-Grid energy output/year in MWh
- Micro-grid capacity MW
- Customer-owned dispatchable renewable and DER MWs
- MWH on congested T nodes
- LMP during peak hours - DG/DER operating cost
- Cost of DER energy as $/MWh
- Maximum MW support to system instability from AGC Devices
- pre-project restoration costs in $/year
- Cost per complaint
- Percent decrease in sustained Interruptions
- Percent PQ problems avoided post project
- Business Revenue per job

With these assumptions and the information from the San Diego As-Is assessment (Appendix C), the project team estimated the value of each benefit. It evaluated each of the selected thirteen improvement initiatives for its anticipated impact on the identified benefits listed above. It is possible and common for multiple improvement initiatives to contribute to several different benefit types. For example, to fully realize the benefits of reduced outages, improvements in sensing, communications, and control methods are required. Since their integration enables the full benefit, it is important that the collective benefits be weighed against the collective cost, rather than looking at each improvement individually. To avoid double-counting benefits, the benefits sharing process assigns percentages of the total benefits by type to each contributing improvement initiative. As stated earlier, the evaluation assumes that the proposed AMI project will be implemented and does not include potential benefits associated with the AMI project, such as demand response.

The contribution of a benefit attributed to each improvement initiative is assigned to capture the impact on a per improvement initiative basis. A detailed description of the calculations used to estimate the benefits of each improvement initiative is presented in Appendix E.

6.4. Selected Improvement Initiatives

Table 16 summarizes the improvement initiatives selected by the project team.

Table 16 Improvement Initiatives Selected by Project Team

Number	Improvement Name
1	GATECH IPIC Dynflo distributed series impedance sensors
2	I-Grid Monitoring System (by Softswitching Technologies)
5	Consumer Portal
7	Ethernet over Fiber
9	4G WiMAX Fixed - Private Wireless
11	Zigbee / WiMedia / WiFi - Wireless
12	Semi-autonomous Agents
14	Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)
17	DER-based Microgrids
19	Advanced Energy Storage Systems
21	Advanced Grid Control Devices
23	Agent and Multi-Agent Systems
25	Distribution (Feeder) Automation

6.5. Summarizing the Results

The project team analyzed the thirteen high-value improvement initiatives in the business case phase to estimate the installed cost and resulting benefits. Table 17 presents a summary of the costs and benefits that are expected for the region when all thirteen improvement initiatives are implemented.

Table 17 Summary of Cost-Benefit Analysis Results

Total Annual Benefits	**$141M**
System Benefits (20-years)	**$1,433M**
Societal (Consumer-side) Benefits (20-years)	**$1,396M**
Total Capital Cost	**$490M**
Annual O&M Cost	**$24M**

The estimated annual savings for each of the benefit categories are presented in the Table 18. These values represent the annual savings that are anticipated once all the initiatives are fully implemented.

Table 18 Summary of Annual Benefits

Benefit Type	Societal $$	System $$
Reduction in congestion cost		$13.1M
Reduced blackout probability	$1.5M	
Reduction in forced outages/interruptions	$38.6M	
Reduction in restoration time and reduced operations and management due to predictive analytics and self healing attribute of the grid		$11.3M
Reduction in peak demand		$25.6M
Other benefits due to self diagnosing and self healing attribute of the grid		$0.2M
Increased integration of distributed generation resources and higher capacity utilization		$14.7M
Increased security and tolerance to attacks/ natural disasters		$1.2M
Power quality, reliability, and system availability and capacity improvement due to improved power flow	$1.3M	
Regional job creation and increased GDP	$28.3M	
Increased capital investment efficiency due to tighter design limits and optimized use of grid assets		$0.2M
Tax benefits from asset depreciation, tax credits, and other		$3.1M
Environmental benefits gained by increased asset utilization		$2.4M
Subtotals	**$69.7M**	**$71.8M**
Total	**$141.5M**	

Note that societal benefits are those benefits that accrue to non-utility stakeholders (i.e. the region at large) and represent such things as fewer outages resulting in avoidance of lost revenue to local businesses, job growth, and an increase in high-tech businesses that require and value high power reliability (e.g., biotech, pharmaceutical and research and development) and the resultant economic development attributes. System benefits are those benefits that can be achieved through the operations of the grid system.[6]

Figure 10 shows the breakdown of the estimated Smart Grid benefits. It shows the areas and relative contributions of the improvement initiatives implemented together to form a Smart Grid in the San Diego region. The benefits are divided roughly evenly between system benefits and societal benefits.

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[6] The classification of the system benefits differs from the utility's requirement for the demonstration of revenue requirements for rate recovery. That is, the calculations used in regulatory proceedings may not match up completely with those used in this analysis.

Figure 10 Breakdown of Smart Grid Benefits
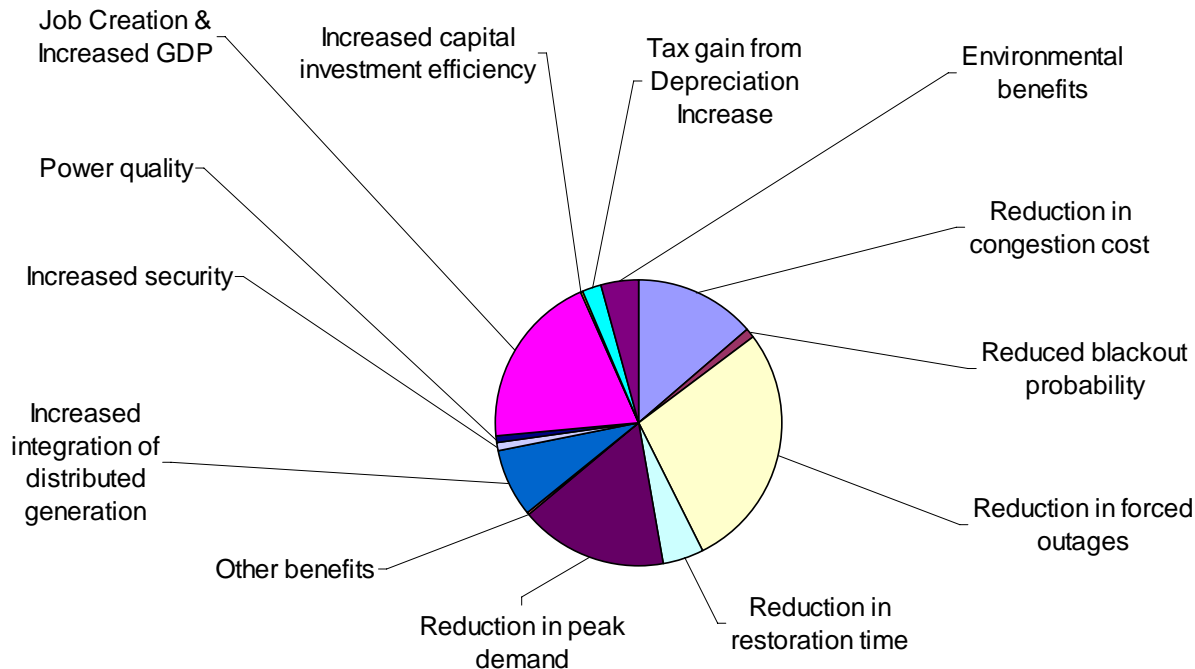
6.6.   Implementation Cost Estimates

The project team estimated the cost of implementing each of the improvement initiatives. These costs include the initial installed capital costs and the associated annual operation and maintenance (O&M) costs. Costs to implement the Initiatives are based on the following inputs:

- Assumptions previously specified in Section 2.1.1
- Existing and planned regional assets
- Estimated percentage of eligible assets to be affected
- Regional construction cost factors
- Projected installed cost estimates from vendors
- National rule of thumb numbers
- Values obtained through the Modern Grid Initiative
- Experiential values from project team members

The cost estimates for each initiative are presented in the Table 19.

Table 19 Cost summary for Improvement Initiatives

	Improvement Name	Capital Cost ($000)	Annual O&M Cost ($000)
1	GATECH IPIC Dynflo distributed series impedance sensors	$20,070	$602
2	I-Grid Monitoring System (by Softswitching Technologies)	$10,136	$1,824
5	Consumer Portal	$9,899	$1,782
7	Ethernet over Fiber	$1,228	$98
9	4G WiMAX Fixed - Private Wireless	$8,200	$656
11	Zigbee / WiMedia / WiFi - Wireless	$26,000	$2,080
12	Semi-autonomous Agents	$10,000	$632
14	Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)	$2,820	$102
17	DER-based Microgrids	$101,700	$3,051
19	Advanced Energy Storage Systems	$150,500	$4,515
21	Advanced Grid Control Devices	$30,399	$912
23	Agent and Multi-Agent Systems	$20,083	$3,615
25	Distribution (Feeder) Automation	$98,996	$3,960
	Totals	**$490,032**	**$23,829**

6.7. Business Case Scenarios

The business case represents the costs (capital and O&M) and benefits (system and societal) based on the phasing of when the costs occur and when the benefits begin to be realized. The modeling included analyzing the timing of the implementation of the thirteen improvement initiatives. Since each initiative has its own cost effectiveness and there are interrelated dependencies among the initiatives that dictate when the benefits can be achieved, the timing and staging of initiatives has an impact on the cost effectiveness of the portfolio. The project team assessed results for the following three scenarios:

- Earliest Positive Cash Flow
  - Minimum time for Cumulative Cash Flow to go positive
  - Means having benefits fund future investments as early as possible
- Maximum Benefits Early
  - Earliest time for Benefits to be the largest
  - Usually means costs are front loaded
- Optimized Internal Rate of Return (IRR)
  - Best mix of achievable IRR and Net Present Value (NPV)

The business case scenarios (earliest positive cash flow, maximum benefits early, and optimized IRR) represent three points of view. The earliest positive cash flow scenario represents a traditional utility view, the maximum benefits early scenario represents a societal view, and the optimized IRR scenario represents a compromise view

The results of the three approaches are presented in the Table 20.

Table 20 Comparison of Business Case Scenario Results

Scenario	Regional IRR* (%)	NPV ($M)	Point of Positive Cash Flow** (Yrs)	First Year Annual Benefits Top $50M
Earliest Positive Cash Flow	75%	403	3.5	2017
Maximum Benefits Early	26%	508	7.0	2012
Optimized IRR	44%	416	5.5	2014

* Internal Rate of Return normally refers to a single business entity, but here we have treated the San Diego region as a single entity to enable the calculation of a regional benefit, both systems and societal.

** Point of Positive Cash Flow is the collective cash flow analysis from all thirteen (13) improvement initiatives combined as a single overall program. Several improvement initiatives require continued investment for as much as 10 years, well beyond the point of positive cash flow, to achieve full implementation of the Smart Grid. The point of positive cash flow should not be used as a proxy for the simple payback of the scenario.

Selection of the desired business case scenario provides one of two fundamental inputs to sequencing of the projects (improvement initiatives), which leads to the Implementation Plan. The other fundamental input is the capability of the host organization to assimilate the projects (and sequence) into its overall business goals.

6.8. Supporting Business Case Details

Tables 21 through 23 provide a summary of the cost benefit analysis results for each scenario described above. Figures 11 through 13 provide annual and cumulative cash flows for each scenario. To help the reader understand and interpret the detailed summary tables that follow, the project team developed supporting documentation located in Appendix B.

Table 21 Summary of the Annual Benefits and Construction Costs for Earliest Positive Cash Flow Scenario

Benefit Types->	Congest	Black out	Outage	Restore Time	Peak Demand	Other Benefit	DG Utilization	Security	Power Quality	Jobs	Capital Invest	Tax Benefit	Enviro	Totals	Total CapEx	Annual OpEx	Total Cost / Annual Benefit
Total CapEx->	$82,383	$5,400	$156,672	$37,835	$91,311	$719	$51,468	$4,480	$4,788	$27,232	$472	$15,241	$12,028	$490,032	$490,032		
Annual Op Ex->	$2,510	$304	$7,333	$2,187	$3,417	$35	$3,419	$270	$360	$2,971	$14	$609	$399	$23,829			
Improvement Initiatives																	
1- Dynamic Ratings	$1,920											$125		$2,045	$20,070	$602	9.8
2 - I-Grid		$93	$2,151					$182				$63		$2,489	$10,136	$1,824	4.1
5 - Portal	$0	$93	$398	$1,250	$0		$57		$74	$8,324	$0	$62	$139	$10,397	$9,899	$1,782	1.0
7 - Ethernet	$228		$398	$625	$1,772		$23		$44	$3,330		$8	$46	$6,474	$1,228	$98	0.2
9 - WIMAX	$228		$398	$625	$5,315		$57		$44	$8,324		$51	$46	$15,089	$8,200	$656	0.5
11 - Wireless	$228		$398	$625	$5,315		$57		$44	$8,324		$163	$139	$15,293	$26,000	$2,080	1.7
12-SemiAuto Agents				$1,250			$4,352	$291				$63	$24	$5,980	$10,000	$632	1.7
14 - AVM	$0	$393						$291				$18	$52	$754	$2,822	$102	3.7
17 - DER Microgrids	$1,410		$11,955	$1,250				$291	$148			$636	$1,956	$17,646	$101,700	$3,051	5.8
19 - Energy Storage	$8,828		$2,151	$625	$11,917			$36	$222			$941	$0	$24,720	$150,500	$4,515	6.1
21- AGC Devices		$409	$12,488					$36	$177		$210	$190		$13,511	$30,399	$912	2.2
23 - Multi Agents		$93	$2,088	$1,250	$0	$15	$2,901		$443			$126	$3	$6,918	$20,083	$3,615	2.9
25 - DA	$228	$463	$6,199	$3,750	$1,324	$138	$7,253	$36	$148			$619	$22	$20,180	$98,996	$3,960	4.9
Total Benefits/Year	**$13,068**	**$1,544**	**$38,626**	**$11,250**	**$25,643**	**$153**	**$14,700**	**$1,165**	**$1,344**	**$28,303**	**$210**	**$3,063**	**$2,428**	**$141,497**	**$490,032**	**$23,829**	3.5
Total Cost / Annual Benefit	6.3	3.5	4.1	3.4	3.6	4.7	3.5	3.8	3.6	1.0	2.2	5.0	5.0	3.5			
	Sys	Soc	Soc	Sys	Sys	Sys	Sys	Sys	Soc	Soc	Sys	Sys	Sys				

(Dollars in 000's)

Internal Rate of Return = 75% (Includes societal benefits)   20-year Total Societal Benefits $1,396,325
Net Present Value @ 8% = $403 Million Dollars   20-year Total System Benefits $1,433,611

Figure 11 Cash Flow for Earliest Positive Cash Flow Scenario

Table 22 Summary of the Annual Benefits and Construction Costs for Maximum Benefits Early Scenario

Benefit Types->	Congest	Black out	Outage	Restore Time	Peak Demand	Other Benefit	DG Utilization	Security	Power Quality	Jobs	Capital Invest	Tax Benefit	Enviro	Totals	Total CapEx	Annual OpEx	Total Cost / Annual Benefit
Total CapEx->	$82,383	$5,400	$156,672	$37,835	$91,311	$719	$51,468	$4,480	$4,788	$27,232	$472	$15,241	$12,028	$490,032	$490,032		
Annual Op Ex->	$2,510	$304	$7,333	$2,187	$3,417	$35	$3,419	$270	$360	$2,971	$14	$609	$399	$23,829			
Improvement Initiatives																	
1- Dynamic Ratings	$1,920											$125		$2,045	$20,070	$602	9.8
2 - I-Grid		$93	$2,151					$182				$63		$2,489	$10,136	$1,824	4.1
5 - Portal	$0	$93	$398	$1,250	$0		$57		$74	$8,324	$0	$62	$139	$10,397	$9,899	$1,782	1.0
7 - Ethernet	$228		$398	$625	$1,772		$23		$44	$3,330		$8	$46	$6,474	$1,228	$98	0.2
9 - WIMAX	$228		$398	$625	$5,315		$57		$44	$8,324		$51	$46	$15,089	$8,200	$656	0.5
11 - Wireless	$228		$398	$625	$5,315		$57		$44	$8,324		$163	$139	$15,293	$26,000	$2,080	1.7
12-SemiAuto Agents				$1,250			$4,352	$291				$63	$24	$5,980	$10,000	$632	1.7
14 - AVM	$0	$393						$291				$18	$52	$754	$2,822	$102	3.7
17 - DER Microgrids	$1,410		$11,955	$1,250				$291	$148			$636	$1,956	$17,646	$101,700	$3,051	5.8
19 - Energy Storage	$8,828		$2,151	$625	$11,917				$36	$222		$941	$0	$24,720	$150,500	$4,515	6.1
21- AGC Devices		$409	$12,488						$36	$177	$210	$190		$13,511	$30,399	$912	2.2
23 - Multi Agents		$93	$2,088	$1,250	$0	$15	$2,901			$443		$126	$3	$6,918	$20,083	$3,615	2.9
25 - DA	$228	$463	$6,199	$3,750	$1,324	$138	$7,253		$36	$148		$619	$22	$20,180	$98,996	$3,960	4.9
Total Benefits/Year	**$13,068**	**$1,544**	**$38,626**	**$11,250**	**$25,643**	**$153**	**$14,700**	**$1,165**	**$1,344**	**$28,303**	**$210**	**$3,063**	**$2,428**	**$141,497**	**$490,032**	**$23,829**	**3.5**
Total Cost / Annual Benefit	6.3	3.5	4.1	3.4	3.6	4.7	3.5	3.8	3.6	1.0	2.2	5.0	5.0	3.5			
	Sys	Soc	Soc	Sys	Sys	Sys	Sys	Sys	Soc	Soc	Sys	Sys	Sys				

(Dollars in 000's)

Internal Rate of Return = 26% (Includes societal benefits)

Net Present Value @ 8% = $508 Million Dollars

20-year Total Societal Benefits $1,396,325

20-year Total System Benefits $1,433,611

The Total Cost / Annual Benefit ratio is a rough approximation of a payback period from the start of an improvement initiative. System Benefits are defined as those that may manifest themselves through the utility system to the rate payers. However, this is not equivalent to the traditional Revenue Requirements treatment. Societal Benefits are defined as those that manifest themselves through general community value, such as better business performance, jobs, quality of life, environmental quality, etc.

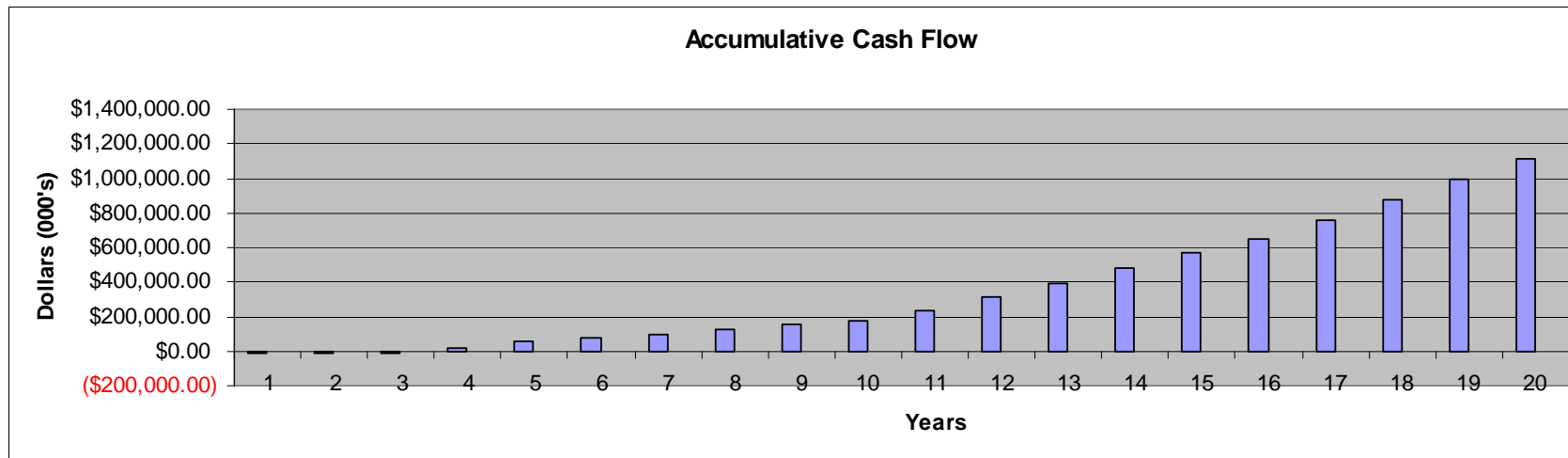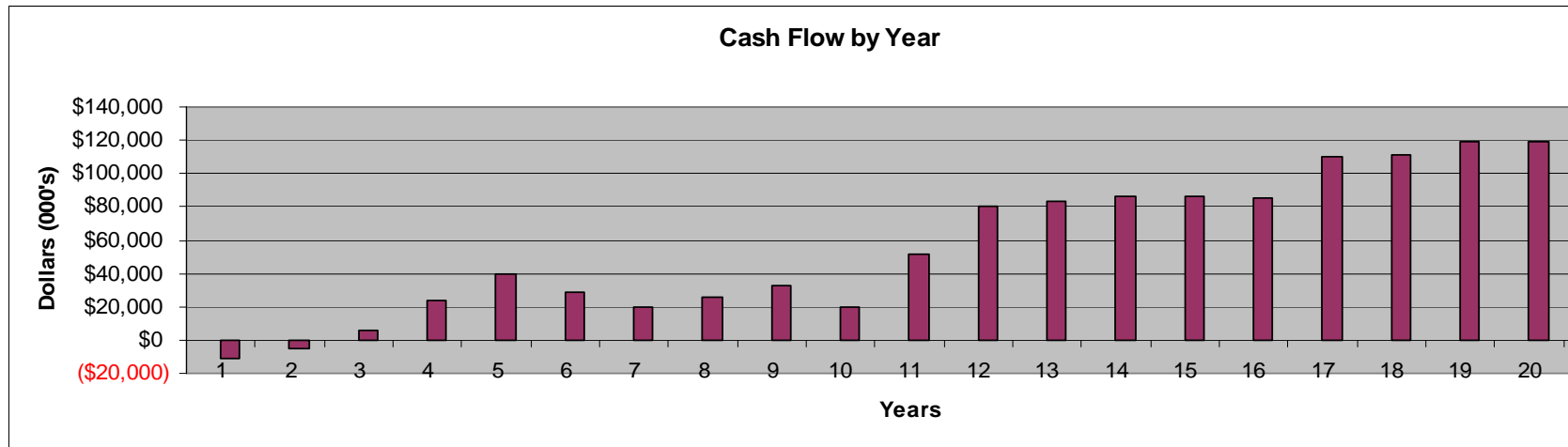**Figure 12 Cash Flow for Maximum Benefits Early Scenario**
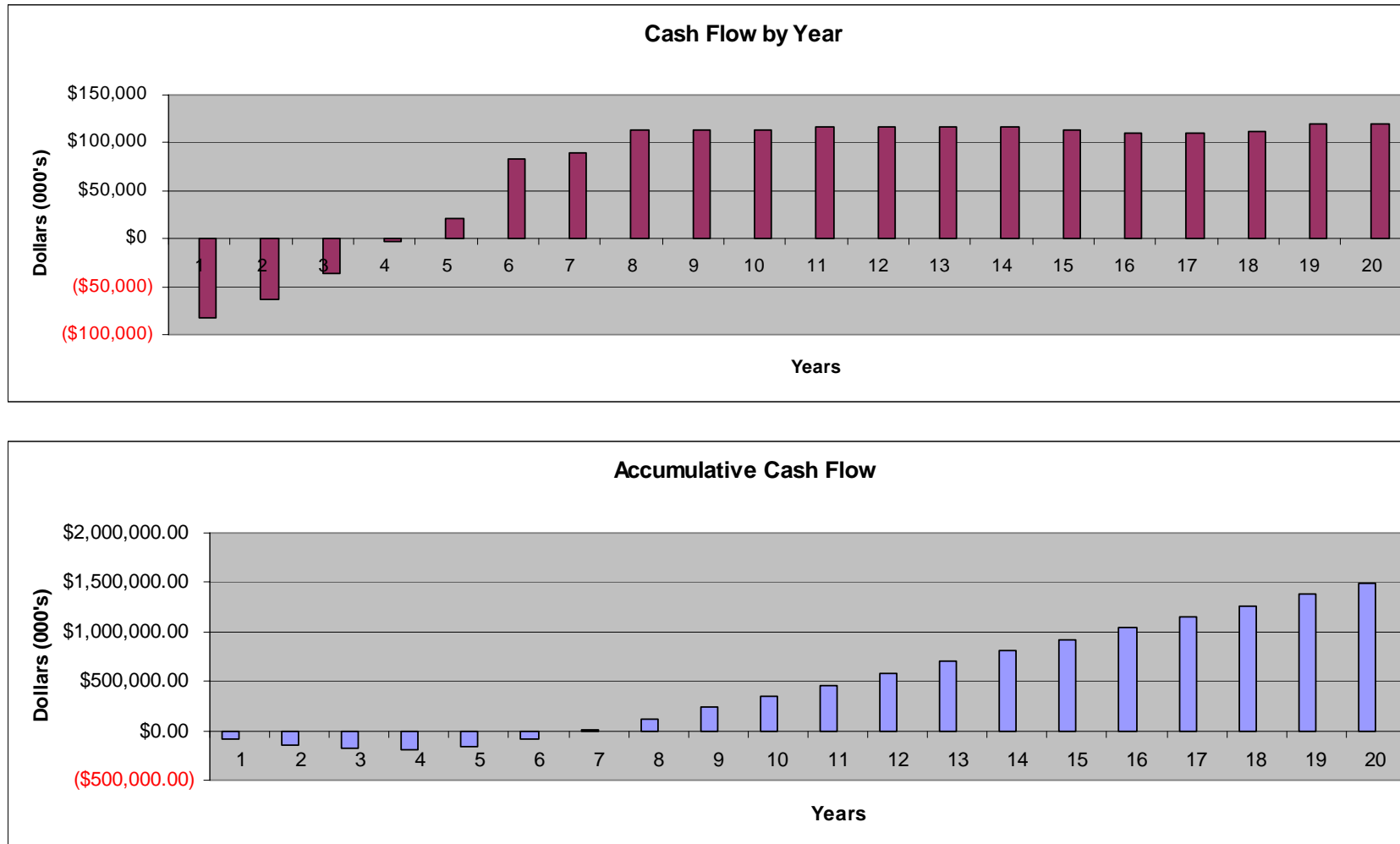
Table 23 Summary of the Annual Benefits and Construction Costs for Optimized IRR Scenario

Benefit Types->	Congest	Black out	Outage	Restore Time	Peak Demand	Other Benefit	DG Utilization	Security	Power Quality	Jobs	Capital Invest	Tax Benefit	Enviro	Totals	Total CapEx	Annual OpEx	Total Cost / Annual Benefit
Total CapEx->	$82,383	$5,400	$156,672	$37,835	$91,311	$719	$51,468	$4,480	$4,788	$27,232	$472	$15,241	$12,028	$490,032	$490,032		
Annual Op Ex->	$2,510	$304	$7,333	$2,187	$3,417	$35	$3,419	$270	$360	$2,971	$14	$609	$399	$23,829			
Improvement Initiatives																	
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2 - I-Grid		$93	$2,151					$182				$63		$2,489	$10,136	$1,824	4.1
5 - Portal	$0	$93	$398	$1,250	$0		$57		$74	$8,324	$0	$62	$139	$10,397	$9,899	$1,782	1.0
7 - Ethernet	$228		$398	$625	$1,772		$23		$44	$3,330		$8	$46	$6,474	$1,228	$98	0.2
9 - WIMAX	$228		$398	$625	$5,315		$57		$44	$8,324		$51	$46	$15,089	$8,200	$656	0.5
11 - Wireless	$228		$398	$625	$5,315		$57		$44	$8,324		$163	$139	$15,293	$26,000	$2,080	1.7
12-SemiAuto Agents				$1,250			$4,352	$291				$63	$24	$5,980	$10,000	$632	1.7
14 - AVM	$0	$393						$291				$18	$52	$754	$2,822	$102	3.7
17 - DER Microgrids	$1,410		$11,955	$1,250				$291	$148			$636	$1,956	$17,646	$101,700	$3,051	5.8
19 - Energy Storage	$8,828		$2,151	$625	$11,917			$36	$222			$941	$0	$24,720	$150,500	$4,515	6.1
21- AGC Devices		$409	$12,488					$36	$177		$210	$190		$13,511	$30,399	$912	2.2
23 - Multi Agents		$93	$2,088	$1,250	$0	$15	$2,901		$443			$126	$3	$6,918	$20,083	$3,615	2.9
25 - DA	$228	$463	$6,199	$3,750	$1,324	$138	$7,253	$36	$148			$619	$22	$20,180	$98,996	$3,960	4.9
Total Benefits/Year	**$13,068**	**$1,544**	**$38,626**	**$11,250**	**$25,643**	**$153**	**$14,700**	**$1,165**	**$1,344**	**$28,303**	**$210**	**$3,063**	**$2,428**	**$141,497**	**$490,032**	**$23,829**	**3.5**
Total Cost / Annual Benefit	6.3	3.5	4.1	3.4	3.6	4.7	3.5	3.8	3.6	1.0	2.2	5.0	5.0	3.5			
	Sys	Soc	Soc	Sys	Sys	Sys	Sys	Sys	Soc	Soc	Sys	Sys	Sys				

(Dollars in 000's)

Internal Rate of Return = 44% (Includes societal benefits) 20-year Total Societal Benefits $1,396,325

Net Present Value @ 8% = $416 Million Dollars 20-year Total System Benefits $1,433,611

Figure 13 Cash Flow for Optimized IRR Scenario
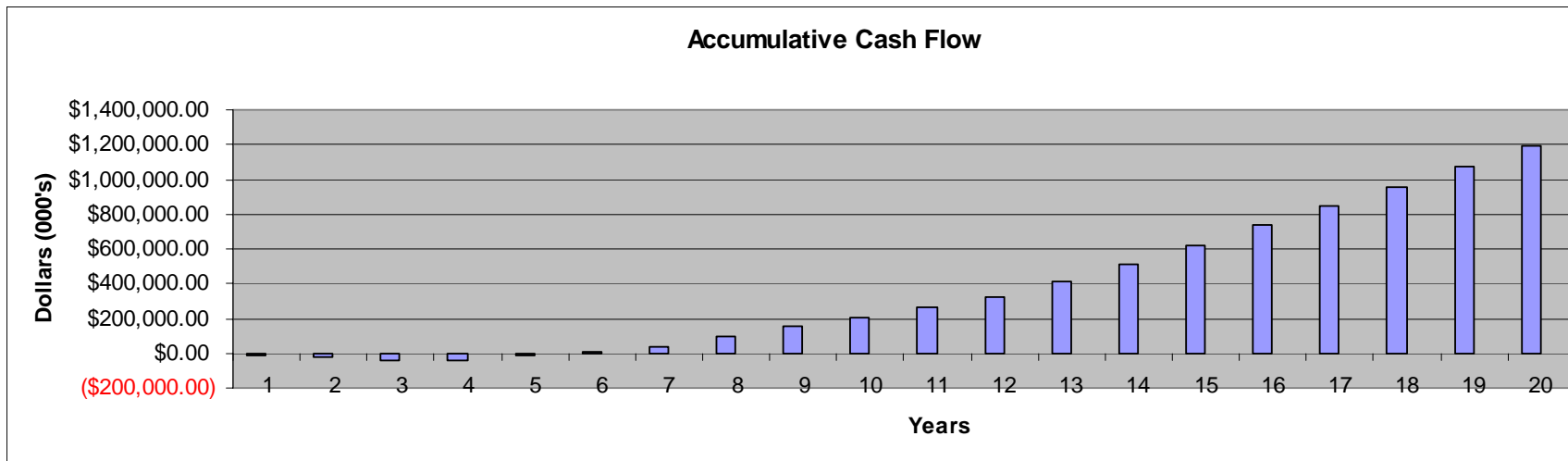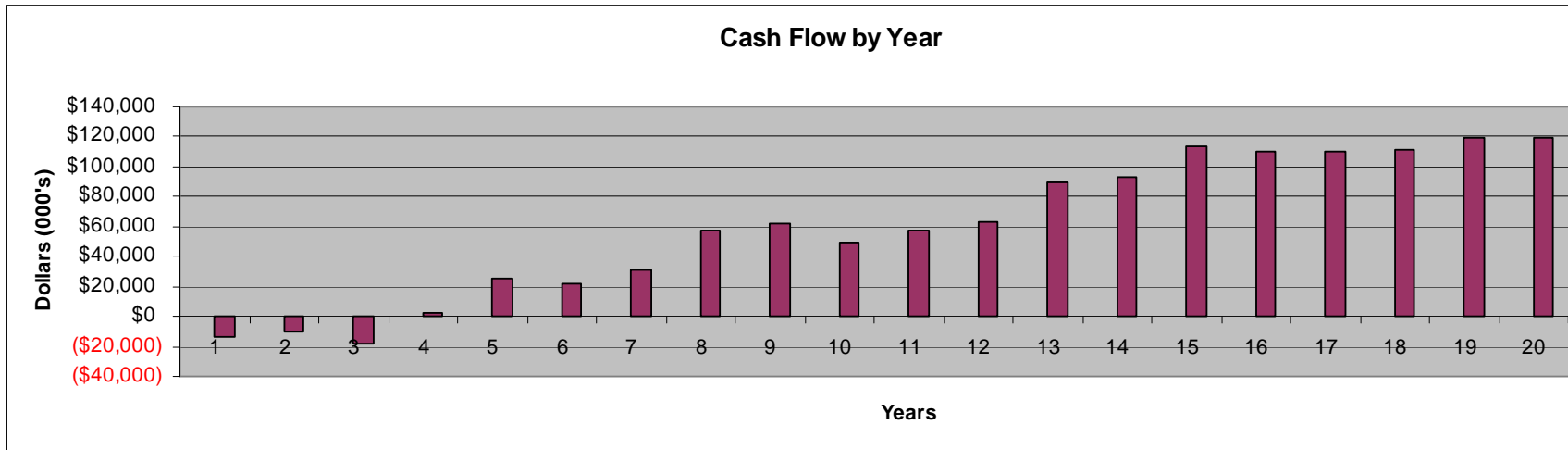
6.9.   Conclusions from the Business Case

Based on this preliminary cost-benefit analysis, there appear to be sufficient benefits – for society, the utility system, and in total (society plus the utility system) – to justify a movement of the San Diego regional grid to a Smart Grid architecture. The capital costs and operations and maintenance costs would be substantial. This level of effort will be very challenging to a host utility, especially considering other significant projects in progress and the proposed implementation schedule.

Sequencing and running the thirteen projects (improvement initiatives) as deployment programs over a long, steady period of time represents the lowest risk to the region and utility. However, programs longer than 3 years have a tendency to become sluggish and are open to many changes in scope, which can greatly reduce the effectiveness of the overall program.

The business case analysis presented results for three scenarios -- earliest positive cash flow, maximum benefits early, and optimized IRR. Each represents a different point of view and would determine how to sequence improvement initiatives. Before finalizing an implementation sequence for the integrated suite of improvement initiatives, one business case scenario must be selected. Note that the implementation plan is based on the Maximum Benefits Early scenario.

The earliest positive cash flow scenario generates a positive cash flow in a 3.5 year period; however, the sustained large benefits (> $50M/yr) do not occur until 11 years after start. The maximum benefits early scenario generates a positive cash flow in a 6 year period, and the sustained large benefits (> $50M/yr) actually occurs in the final year of the positive cash flow, some 5 years earlier than the earliest positive cash flow scenario.

7.   IMPLEMENTATION PLAN

The initial business case analysis demonstrates that a Smart Grid could yield enough benefits to the region to justify further consideration. Using the thirteen high-value improvement initiative, the project team developed an implementation plan that comprises three parts:

- Recommended Priorities – As discussed in the business case above, improvement initiatives need to be prioritized since parallel implementation of all thirteen initiatives would be too complex for reasonable achievement.

- Pathway to a Smart Grid – Once the initiatives are prioritized, they need to be sequenced as building blocks always adding abilities to the grid as the project progress.

- Recommended RD&D Projects – Since implementation of the Smart Grid would be a significant undertaking, it is prudent to consider developing and executing several research, development and demonstration projects that are smaller in scope but that test the concept of a component part of the overall Smart Grid.   Several key initiatives could require additional guidance that best comes from a smaller, "side project" that explores risks of new technologies and complexities of integration before introducing them to an operating grid. The project team developed four (4) such research and demonstration projects.

7.1.   Recommended Priorities

The project team created a prioritized list of initiatives that takes into account the business case strategy that is most desirable as well as the how the systems must be integrated to achieve the desired results. The highest priorities should create a foundation for implementing projects later in the rank order.   In addition, technology maturity, capital requirements, and length of deployment also affect whether an improvement project appears high or low in the rank order

Also, since all thirteen improvement initiatives are multi-year in nature, the integrated planning is very important to make sure that priority projects are not held up by lesser priority projects, hence the importance of the Pathway. The prioritization of the thirteen improvement initiatives are presented in the Table 24.

Table 24 Priority List of Smart Grid Improvement Initiatives

Priority	II No.	Improvement Name	Reasoning
1	7	Ethernet over Fiber	Need communications in place as soon as possible to enable the remaining improvement initiatives.
2	9	4G WiMAX Fixed - Private Wireless	Need communications in place as soon as possible to enable the remaining improvement initiatives.
3	25	Distribution (Feeder) Automation	Need distribution network sensing and control ability as soon as possible to enable the remaining improvement initiatives.
4	14	Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)	Quickly improves the network decision support tools.
5	1	GATECH IPIC Dynflo distributed series impedance sensors	The system will need current limiting and correcting tools, methods, and sensing by this time in the sequence.
6	2	I-Grid Monitoring System (by Softswitching Technologies)	The system will need dynamic thermal line load management by this time in the sequence.
7	11	Zigbee / WiMedia / WiFi - Wireless	The AMI system should be ready at this time in the sequence to take advantage of the last mile communications.
8	21	Advanced Grid Control Devices	The devices that support reliability and flexible network operations are ready for deployment. Due to the long-term deployment plan, these devices may need to start earlier in the sequence, although the communications and control may not be completely ready for the early part of the rollout.
9	5	Consumer Portal	With AMI in place, the system should now be ready to engage the consumer on several applications, all requiring a consumer portal.
10	19	Advanced Energy Storage Systems	With the above intelligence in place, the utility can now properly site advanced energy storage to aid in reliable and flexible operations.
11	17	DER-based Microgrids	With advanced energy storage in place, the system can now add distributed generation and controls for autonomous reliability.
12	12	Semi-autonomous Agents	At this point the technology maturity should be sufficient to take advantage of real-time autonomous controls within designed behavior.
13	23	Agent and Multi-Agent Systems	At this point the technology maturity should be sufficient to take advantage of real-time autonomous controls within designed behavior.

7.2. Pathway to a Smart Grid

The sequence of multiple projects depends on the business case scenario selected. Each of the three business case scenarios – earliest positive cash flow, maximum benefits early, and optimized IRR – have particular advantages. From a regional perspective, the scenario that seems most appropriate is the Maximum Benefits Early because it enables the benefits presented above to be realized by both consumers and the utility earlier than the other two scenarios. This scenario has the quickest entry of sustained system and societal benefits and provides the largest NPV with an attractive internal rate of return for the region.

Table 25 shows the rank order of Smart Grid technologies and an estimated implementation time. The implementation time is based on an assumption that the RD&D projects are started in the 2007 to 2008 time frame and that the projects are successful. Delays or technical difficulties encountered in the RD&D programs are not modeled in this analysis and could alter the proposed timeline.

Table 25 Timeline for Implementing Priority List of Improvement Initiatives

Priority	II No.	Improvement Name	Timing*
1	7	Ethernet over Fiber	2007 – 2009
2	9	4G WiMAX Fixed - Private Wireless	2007 – 2009
3	25	Distribution (Feeder) Automation	2007 – 2011
4	14	Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)	2007 – 2009
5	1	GATECH IPIC Dynflo distributed series impedance sensors	2009 – 2013
6	2	I-Grid Monitoring System (by Softswitching Technologies)	2012 – 2016
7	11	Zigbee / WiMedia / WiFi - Wireless	2007 – 2010
8	21	Advanced Grid Control Devices	2007 – 2011
9	5	Consumer Portal	2008 – 2012
10	19	Advanced Energy Storage Systems	2008 – 2014*
11	17	DER-based Microgrids	2009 – 2013*
12	12	Semi-autonomous Agents	2009 – 2011*
13	23	Agent and Multi-Agent Systems	2009 – 2013*

* Moved the improvement initiative out one or two years to accommodate probable resource limitations based on the number of project starts and the maturity of the technology.

Several factors will affect the deployment of the priority improvement initiatives. With several of the improvement initiatives, there is a spatial planning need. To achieve the maximum benefits for the regions stakeholders (utility, commercial and industrial consumers) as early as possible, it is important to start the deployments in the more densely populated regions (generally the coastal areas) and then migrate through Urban, Suburban, and Rural territories. This approach targets the areas where higher benefits are realized for each dollar of investment.

In addition, there is a need to consider overall cash flow and vendor capabilities. As has been observed in the advanced metering infrastructure initiative in California, the vendor community has demonstrated some limitations for quickly moving from the concept and prototype phase to a production mode. This issue likely applies to the WiMAX, sensors, and agents technology areas. This becomes an important consideration that must be taken into account before a complete deployment is attempted.

There is a logical phasing of these improvement initiatives to maximize the generation of benefits by grouping into a Phase 1 and Phase 2. Table 26 shows the recommended project for each phase.

Table 26 Phases of Improvement Initiative Implementation

Phase 1 (2007 – 2016)		
Improvement Initiatives	7 – Ethernet over Fiber 9 – 4G WiMAX Fixed - Private Wireless* 25 – Distribution (Feeder) Automation 1 – GATECH IPIC Dynflo distributed series impedance 2 – I-Grid Monitoring System 11 – Zigbee / WiMedia / WiFi - Wireless 21 – Advanced Grid Control Devices 14 – Advanced Visualization Methods 5 – Consumer Portal 19 – Advanced Energy Storage Systems	This grouping of improvement initiatives serves two purposes: (1) establishing the foundation for the complete Smart Grid, and (2) focuses on those initiatives most likely to improve reliability under a changing environment.
Phase 2 (2009 – 2013)		
Improvement Initiatives	9 – 4G WiMAX Fixed - Private Wireless* 12 – Semi-autonomous Agents 23 – Agent and Multi-Agent Systems 17 – DER-based Microgrids	This grouping of improvement initiatives serves two purposes: (1) expand the integration of consumer systems into the Smart Grid, and (2) provide additional options for improved reliability and economic electricity services.

 * This Improvement Initiative is implemented as needed across both phases of the deployment.

The project team believes that the transition toward a Smart Grid can be greatly enhanced by conducting an integrated Smart Grid pilot project where multiple improvement initiatives can be brought together at appropriate times in a controlled in a deliberate environment. Clearly, integration of multiple new technologies required to transform the San Diego grid intelligence is a complex requirement. One in which the industry has little experience. Thus, a Smart Grid pilot in a defined area can "debug" the process before tackling the entire region. Such a "test-bed" would demonstrate the integrated environment and results for each new improvement initiative under the above priority scheme prior to transitioning to a "production" mode. This phased approach to testing and implementation is presented in the Figure 14.

Figure 14 Approach to Testing and Implementing Smart Grid Initiatives
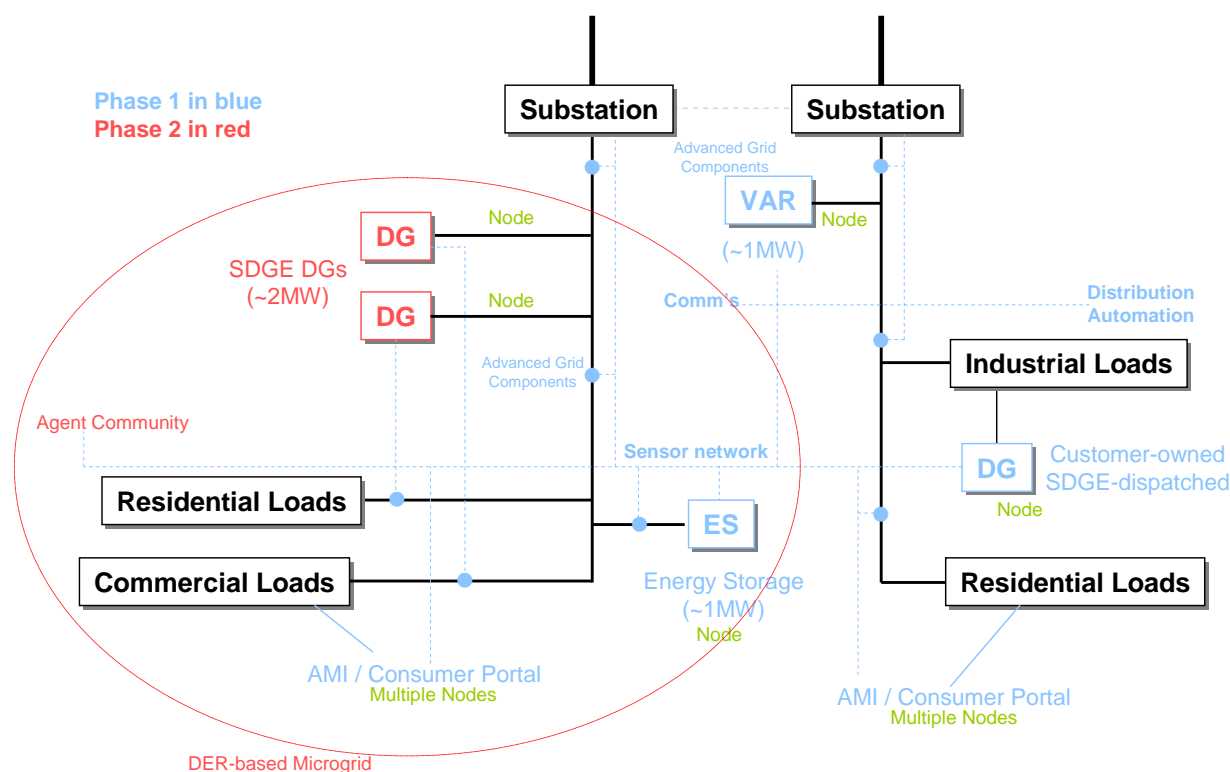
7.3.   Recommended RD&D Projects

Research, development, and demonstration projects can help to better understand how a technology operates under real-world conditions. The project team recommends executing several projects that will help to test Smart Grid strategies and technologies prior to full deployment. Table 27 shows the recommended projects.

Table 27 Timeline for Recommended Smart Grid RD&D Projects

RD&D Project	Timing	Leading Initiative
WiMAX Pilot	2007 – 2008	Midhaul Communications (II-9)
Adv. Energy Storage Pilot	2007 – 2008	AES Integration (II-19)
DER-based Microgrid	2008 – 2009	DER-based Microgrids (II-17)
Agents Pilot	2008 – 2009	Semi-Autonomous Agents (II-12)
		Agent & Multi-agent Systems (II23)

II = Improvement Initiative

7.3.1. DER-based Microgrids

This recommended RD&D project has two phases: simulation and testing, and piloting. The simulation and testing phase would utilize SDG&E's XpertSIM modeling suite to do a detailed

real-time simulation of a defined DER-based Microgrid pilot circuit / area examining potential benefits and the following trouble spots:

- Entrance to a microgrid operation from a grid-connected condition
- Operation of a microgrid scenario at peak conditions
- Exiting a microgrid operation to a grid-connected condition

7.3.2. Advanced Energy Storage

The project team recommends that an advanced energy storage system be designed to operate in conjunction with a distributed generation unit, or other form of intermittent generation to develop the test control schemes that can prove operational capabilities and flexibility, and potential economic value. For example, the integration of a 1 megawatt (MW) capacity storage device operating in conjunction with a 2 MW distributed generation unit on a critical 10 MW distribution circuit could demonstrate reliability and economic value in a real-time, time of use environment. The lessons learned on this project would also apply to the DER-based Microgrid project.

7.3.3. Agent and Multi-Agent Systems

These systems integrate utility control operations with mainstream web technologies and through multiple independent computers communicating over a network to accomplish a common objective or task. This enables agent and multi-agent systems to become adaptive, self-aware, self-healing and semi-autonomous control systems. While agents offer enormous potential benefits through autonomous monitoring and control, there are very few operational examples of Agents in electric grid application. An RD&D project is prudent to test the agents and the operation of a community of agents.

In the past, the California Energy Commission (CEC) has expressed interest in developing transmission and distribution level grid agent software. This may provide an opportunity for cost share as well as defining a detailed scope for the RD&D project.

In preparation for either approach, SAIC recommends closely following the recently kicked-off ConEd GridWise Project (use of grid agents).

7.3.4. 4th Generation WiMAX

While it might be interesting to conduct a WiMAX pilot, SAIC would suggest leaving this to the telecommunications companies at first. However, it would be advisable to become active in their efforts without leading the pilot. This would encourage the direction the telecommunications pilot would take, especially if SDG&E is financially supportive of the pilot.

7.4.   Implementation Plan Overview

While the overall concept of migrating San Diego to a Smart Grid is daunting, it is manageable. With the proper leadership, skills, and process, the results can be accomplished and the value realized. A proposed schedule for implementation of the thirteen improvement initiatives is presented in the Figure 15.

Figure 15 Recommended Timeline for Implementing Smart Grid Improvement Initiatives

ID	Task Name	Start	Finish	Duration	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	Ethernet over Fiber – Backhaul	1/1/2007	9/4/2009	140w									
2	4G WiMAX - Midhaul	7/2/2007	12/25/2009	130w									
3	Distribution Automation	1/1/2007	10/14/2011	250w									
4	Adv. Visualizaton Methods	7/2/2007	10/16/2009	120w									
5	Dynflo Distributed Series Impedence	1/1/2009	10/16/2013	250w									
6	I-Grid Monitoring System	1/2/2012	5/27/2016	230w									
7	Zigbee / WiMedia / WiFi – Last Mile	1/1/2007	10/29/2010	200w									
8	Adv. Grid Control Devices	1/1/2007	10/14/2011	250w									
9	Consumer Portal	1/1/2008	5/28/2012	230w									
10	Adv. Energy Storage	1/1/2008	7/7/2014	340w									
11	DER-based Microgrids	1/1/2009	10/16/2013	250w									
12	Semi-autonomous Agents	1/1/2009	9/7/2011	140w									
13	Agent / Multi-agent Systems	1/1/2009	10/16/2013	250w									
14	DER-based Microgrid RD&D Project	1/1/2008	5/4/2009	70w									
15	Adv Energy Storage RD&D Project	1/1/2007	2/22/2008	60w									
16	Agents RD&D Project	1/1/2008	5/4/2009	70w									
17	WiMAX RD&D Project	1/1/2007	12/14/2007	50w									

7.5. Risk Assessment

There are risks to achieving the benefits expected in this analysis. This is the main reason that SAIC recommends a Smart Grid Program approach where individual improvement initiatives are implemented over multiple years. All the individual improvement initiatives are sequenced to help mitigate risk through these deliberate rollout strategies, with consideration for:

- Learning on lower risk areas
- Sequencing initiatives such that pre-requisite initiatives are in-place when a later sequenced initiative is rolled out, enabling benefits to accumulate immediately.
- Careful roll-out strategies on high risk, high value areas
- Steady rollout strategies on remainder of areas taking into account steady staffing as well as other factors for ease and speed of rollouts

In addition to the programmatic risks discussed above, there are several other risks to the overall program that require actions. We list these risks here but readers should note that a quantitative risk analysis of the following risks and issues was not included in the scope of the study.

7.5.1. Developing a Vision of the Future Smart Grid

We recommend that the region develop a vision of the future system state that can be readily communicated internally and externally, then build carefully toward that vision during the next 10 years. This will generate a renewing practice within the whole region. This is perhaps the most important recommendation. The renewing practice will consist of modifying design and equipment specifications to incorporate forward thinking Smart Grid attributes to new projects so that they can easily be integrated into the start of a Smart Grid system as it is slowing deployed.

7.5.2. Regulatory Needs

Regulatory issues could be the highest risk factor in considering a Smart Grid. It is likely that the many of the technologies needed to enable the Smart Grid can be fully developed and commercialized. To a large extent, the regulatory environment in which the Smart Grid will be implemented could be a decisive factor. The project team recommends that regional stakeholders work with the CPUC at the beginning phases of implementation to resolve regulatory issues that may affect deployment of Smart Grid strategies and technologies. The following key regulatory issues should be considered.

- A consistent, long-term policy to provide clear market signals (real-time pricing, critical peak pricing, etc.) to consumers and third parties interested in participating energy markets through local distribution-level programs.
- Incentives to allow the use of advanced technologies that increase capacity, improve efficiency or reliability of existing resources per the EPACT 2005.
- CEC support for an in-depth evaluation of the economic benefits of commercially available voltage stabilizing technologies (SVC, D-VAR, DSTATCOM, STATCOM, SuperVAR, etc) to identify and endorse the optimum solutions.
- Policies that encourage open data access, interoperability, reliability standards, and capability to operate micro-grids in intelligent islanding modes. Open communication architecture needs to be standardized.
- New rate designs (e.g., real time pricing, premium power quality) and incentives are needed to encourage consumers and SDG&E to invest in promising advanced

technologies. Regulators and policymakers should determine if any existing law or policies could inhibit development of new rate designs (e.g., residential rate caps in AB 1X).

- Advanced Metering Infrastructure (AMI), including installation of meters, the software and the communications infrastructure required to become the foundation for a working consumer portal, is fundamental for implementing the Smart Grid. The project team assumed that AMI would be fully implemented by 2010.

7.5.3. Utility Re-Engineering

Consider that the local utility may be using existing technologies in different ways in the future:

- New approaches to system configuration and operation
- Significant workforce training
- Customer and staff tie-ins through education

7.5.4. Transformational Planning

This Smart Grid strategy is a unique vision, very different from the local utility tradition. There will be unforeseen issues emerging, often requiring different thought, objectively applied with the overall vision clearly in mind.

7.5.5. Assumptions in Benefits Assessment

The project team used assumptions to calculate many of the benefits used in the cost-benefit analysis. To increase the relevancy and applicability of information used, the project team selected values from other studies, drew from the significant experiences of the SAIC Smart Grid team[7], and extrapolated from national averages. In addition, the team conducted a sensitivity analysis on each assumed value whereby each assumed value was doubled and halved recording the internal rate of return (IRR), the percent change in total benefits and the percent change in net present value. The largest variance occurred in assuming the number of years necessary to reach average job growth in the information technology and manufacturing sectors. Doubling the value lowered the IRR by 7%. The next most extreme value was the percent decrease in interruptions which reduced the IRR by 6%. All other excursions calculated an IRR between minus 2% and plus 15%. The net present value range was plus 24% to negative 21% on a $400 million base. The benefits range was plus 12% to minus 13% on a $148 million base. A Monte Carlo simulation changing multiple variables was not performed.

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[7] See Appendix F for a list of the SAIC personnel involved in the study.

8.   APPENDIX A: GLOSSARY OF ACRONYMS

AB – Assembly Bill

AC – Alternating Current

ACSS/TW - Aluminum Conductor Steel Supported Trapezoidal Wire

ACCR - Aluminum Conductor Composite Reinforced

ACCC - Aluminum Conductor Composite Core

ACSR – Aluminum Conductor Steel Reinforced

AGC – Advanced Grid Components

AI – Artificial Intelligence

AMI – Advanced Metering Infrastructure

BPL – Broadband over Powerline

BUG – Backup Generator

C&I – Commercial and Industrial

CapEx – Capital Expenditure

CAISO – California Independent System Operator

CBM – Condition Based Maintenance

CEC – California Energy Commission

CPUC – California Public Utility Commission

CT – Current Transformer

DER – Distributed Energy Resource

DG – Distributed Generation

DOE – US Department of Energy

DR – Demand Response

DSTATCOM - Distributed Static Shunt Compensator (S&C Electric)

D-VAR - Distributed Static Shunt Compensator (American Superconductor)

EPRI – Electric Power Research Institute

FACTS – Flexible AC Transmission System

FCL – Fault Current Limiter

EPACT – Energy Policy Act

GaN – Gallium Nitride

GaAs – Gallium Arsenide

GDP – Gross Domestic Product

GFA – Grid Friendly Appliances

GHz - Gigahertz

GIS – Geographical Information System

HMI – Human Machine Interface

HTS – High Temperature Superconductor

HVAC – Heating, Ventilation and Air Conditioning

HVDC – High Voltage Direct Current

IED – Intelligent Electronic Device

IC – Integrated Communications

IEEE – Institute of Electrical and Electronics Engineers

IED – Intelligent Electroninc Devices

II – Improvement Initiative

IGBT – Insulated Gate Bi-polar Transistors

IRD – Intelligent Radio Devices

IRR – Internal Rate of Return

ISP – Internet Service Providers

KTA – Key Technology Area

kW – kilowatt

kWh – kilowatt-hour

LMP – Locational Marginal Pricing

LVDC-Low Voltage Direct Current

MGI – Modern Grid Initiative

MRTU – Market Redesign and Technology Upgrade

MW - Megawatt

O&M – Operation and Maintenance

OMS – Outage Management System

OpEx – Operational Expenditure

NaS – Sodium Sulfur

NPV – Net Present Value

PF – Power Factor

PMU – Phasor Measurement Unit

PT – Potential Transformer

PQ – Power Quality

R&D – Research and Development

RD&D – Research, Development and Demonstration

RTO – Regional Transmission Organization

SCADA – Supervisory Control and Data Acquisition

SiC – Silicon Carbide

SONET – Synchronous Optical Network

SMES – Superconducting Magnetic Energy Storage

SVC – Static VAR Compensator

STATCOM - Static Shunt Compensator (a FACTS device)

TSFM – Transmission Fast Simulation and Modeling

VRB – Vanadium Redox flow Batteries

WC – Wild Card

YBCO – Yttrium Boron Copper Oxide

9. APPENDIX B SUPPORTING BUSINESS CASE DETAILS

The following descriptions for sections of the benefits and cost summaries are provided to help the reader understand the detailed summary tables in Section 6.8 of the final report.

> The Smart Grid improvement delivering the group of benefits.

Summary of Annual

> The type of benefit that has been analyzed.

> The capital cost associated with delivering this type of benefit.

> The annual O&M cost associated with delivering this type of benefit.

Upper Left

Benefit Types->	Congest	Black out	Outage		
Total CapEx->	$82,383	$5,400	$156,672		
Annual Op Ex->	$2,510	$304	$7,333		
Improvement Initiatives					
1- Dynamic Ratings	$1,920				
2 - I-Grid		$93	$2,151		
5 - Portal	$0	$93	$398		
7 - Ethernet	$228		$398		
9 - WIMAX	$228		$398		

> The monetized benefit associated with delivering this type of

> The total monetized benefit from all improvements associated with

> The ratio of the total cost to the annual benefit for this type of benefit. It approximates how many years it will take to recover

19 - Energy Storage	$8,828		$2,151	$625	$11,917
21- AGC Devices		$409	$12,488		
23 - Multi Agents		$93	$2,088	$1,250	$0
25 - DA	$228	$463	$6,199	$3,750	$1,324
Total Benefits/Year	**$13,068**	**$1,544**	**$38,626**	**$11,250**	**$25,643**
Total Cost / Annual Benefit	6.3	3.5	4.1	3.4	3.6

Lower Left

Internal Rate of Return = 26% (Includes societal benefits)
Net Present Value @ 8% = $508 Million Dollars

	Sys	Soc	Soc	Sys	Sys

> The regional rate of return calculation of all benefits against all costs for the entire suite of improvement initiatives.

> Designation of benefits category: Soc = primarily societal benefits, Sys = primarily system

> The net present value calculation of all benefits for all costs for the entire suite of improvement initiatives.

The sum of all capital costs for the entire suite of improvement initiatives.

The sum of all O&M costs for the entire suite of improvement initiatives.

The sum of all capital costs for this single improvement initiative.

The sum of all O&M costs for this single improvement initiative.

Maximum Benefits Early

Upper Right

Tax Benefit	Enviro	Totals	Total CapEx	Annual ØpEx	Total Cost / Annual Benefit
$15,241	$12,028	$490,032	$490,032		
$609	$399	$23,829			
$125		$2,045	$20,070	$602	9.8
$63		$2,489	$10,136	$1,824	4.1
$62	$139	$10,397	$9,899	$1,782	1.0

The sum of all monetized annual benefits for this single improvement initiative.

The ratio of the total cost to the total annual benefit for this type of benefit. It approximates how many years it will take to recover the cost.

The sum of all monetized annual benefits for entire suite of improvement initiatives.

	$126	$3	$6,918	$20,083	$3,615	2.9
	$619	$22	$20,180	$98,996	$3,960	4.9
$210	$3,063	$2,428	$141,497	$490,032	$23,829	3.5

Lower Right

2.2	5.0	5.0	3.5

(Dollars in 000's)

20-year Total Societal Benefits $1,396,325
20-year Total System Benefits $1,433,611

Sys Sys Sys

The sum of all monetized societal benefits for 20 years for the entire suite of improvement initiatives.

The sum of all monetized system benefits for 20 years for the entire suite of improvement initiatives.

10. APPENDIX C: SAN DIEGO CURRENT STATUS REPORT

The purpose of this report is to provide a snapshot of SDG&E's service territory to determine the state of its transmission and distribution system, the regulatory environment present, and other information such as the amount of distributed generation and renewable energy in the region. The information gathered will be used as a baseline in determining what gaps may exist between the current state and a future smart grid scenario. The overview of the current status covers the following areas:

- Grid elements

- Voice and data transport

- Related regulatory proceedings and tariffs

- Distributed energy resources

- Related policy issues

- Market Structure (direct access, restructured, etc)

- Technology inventory including cost and development trajectories

- End-use technology

10.1. Grid Elements

This section will discuss the generation, transmission, distribution, and metering assets currently existing in the SDG&E service territory.

10.1.1. Generation

In the late 1990's when California was restructuring its electric market, SDG&E divested itself of all generation assets except for nuclear generation. At that time, SDG&E sold the South Bay Power Plant and the Encina Power plant but maintained an ownership share of the San Onofre Nuclear Generation Station (SONGS). The South Bay Power Plant is owned by the Port of San Diego who contracts with LS Power to operate the facility. The Encina Power Plant is currently owned and operated by of NRG Energy Inc. Currently, both the South Bay and Encina power plants operate under RMR contracts. SDG&E and SCE are co-owners of SONGS with SDG&E owning approximately 20% of the plant.

Over the past several years, SDG&E has issued competitive solicitations for the construction of new generation facilities in their service territory. Table 1 shows the new power plant projects that have been constructed or are in the construction process.

Table 1 Planned Power Plants for the Region

Project Name	Nominal Capacity (MW)	Estimated Start Date
Miramar GT (Ramco)	46	June 2005
Palomar	541	June 2006
Otay	561	June 2008

Table 2 presents the current and projected generation resources in the region as reported in the CPUC filing for the Sunrise Power Link.[1] Note that this data only provides a general view of the region's generation resources. Specific generation resources for existing generation facilities and planned facilities are currently being developed for the new long-term resource plan.[2]

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[1] SDG&E Application (A.05-12-014) for a Certificate of Public Convenience and Necessity for the Sunrise Power Link Transmission Project (12-14-05). Note that this assumes the South Bay Power Plant is retired in 2009.

[2] SDG&E will be submitting a resource plan to the California Public Utilities Commission as part of proceeding R.06-02-013.

Table 2 Existing Generation Resources in the Region

Generation Facility	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Palomar CC	541	541	541	541	541	541	541	541	541	541	541
Miramar GT	46	46	46	46	46	46	46	46	46	46	46
Area QF's and Renewables	174	174	174	174	174	174	174	174	174	174	174
Envirepel	40	40	40	40	40	40	40	40	40	40	40
Otay Mesa CC	0	0	561	561	561	561	561	561	561	561	561
Lake Hodges Pumped Hydro	0	0	40	40	40	40	40	40	40	40	40
Calpeak Border	42	42	42	42	42	42	42	42	42	42	42
Calpeak El Cajon	42	42	42	42	42	42	42	42	42	42	42
Calpeak Escondido	42	42	42	42	42	42	42	42	42	42	42
Electrovest Otay	42	42	42	42	42	42	42	42	42	42	42
Electrovest Escondido	42	42	42	42	42	42	42	42	42	42	42
El Cajon GT	13	13	13	13	13	13	13	13	13	13	13
Encina	960	960	960	960	960	960	960	960	960	960	960
Kearny	127	127	127	127	127	127	127	127	127	127	127
Larkspur Border 1&2	92	92	92	92	92	92	92	92	92	92	92
Miramar GT 1&2	33	33	33	33	33	33	33	33	33	33	33
South Bay	702	702	702	702	0	0	0	0	0	0	0
Total Area Capacity	**2,938**	**2,938**	**3,539**	**3,539**	**2,837**	**2,837**	**2,837**	**2,837**	**2,837**	**2,837**	**2,837**

In addition to the generation presented in the table above, SDG&E has 985 GWh of renewable generation under contract. Renewable resources include biogas, biomass, wind, hydro, solar and geothermal. A recent wind project that has come online is the Kumeyaay Wind Project rated at 50 MW. SDG&E also has a contract with Stirling Energy to purchase energy from a new solar project that seeks to build 300 to 900 MW of renewable power through a Stirling engine solar project. Figure 1 provides forecast of San Diego area electric generation capacity.

Figure 1 Forecast of San Diego Area Electric Generation
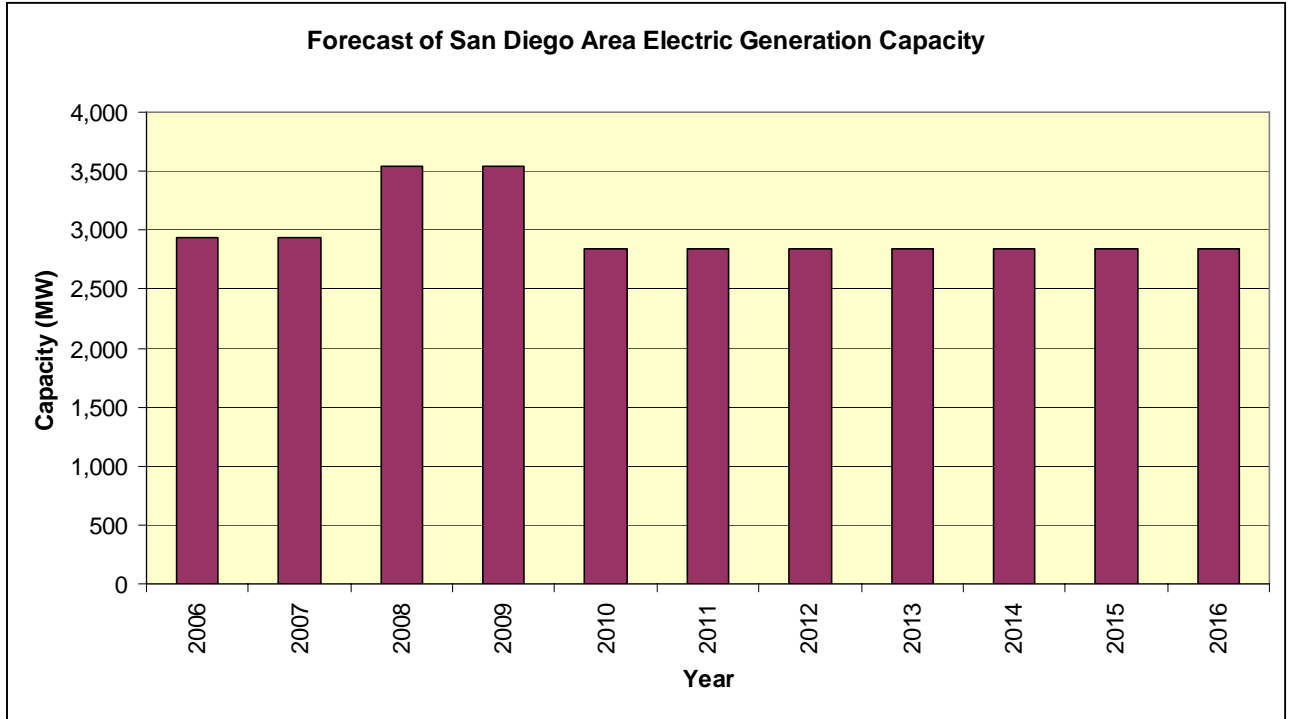
10.1.2. Transmission

The San Diego region's transmission infrastructure is typically described as being in an "electrical cul-de-sac" due to its location at the southwestern corner of California and the United States adjacent to the Pacific Ocean and the Mexican border. SDG&E's electric transmission network is comprised of 130 substations with 884 miles of 69 kV, 265 miles of 138 kV, 349 miles of 230 kV, and 215 miles of 500 kV transmission lines.[2] The 500 kV Southwest Powerlink (SWPL) connects to Arizona through a number of substations and connects to a number of generation facilities in the South and to the East. A simplified transmission topology is presented in the Figure 2.[3]

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[3] SDG&E RFO 5/24/2006 Demand Response, Renewables and Peak Capacity.

Figure 2 Simplified Transmission Topology

Figure 1
SDG&E Service Area
& Simplified Transmission
Topology
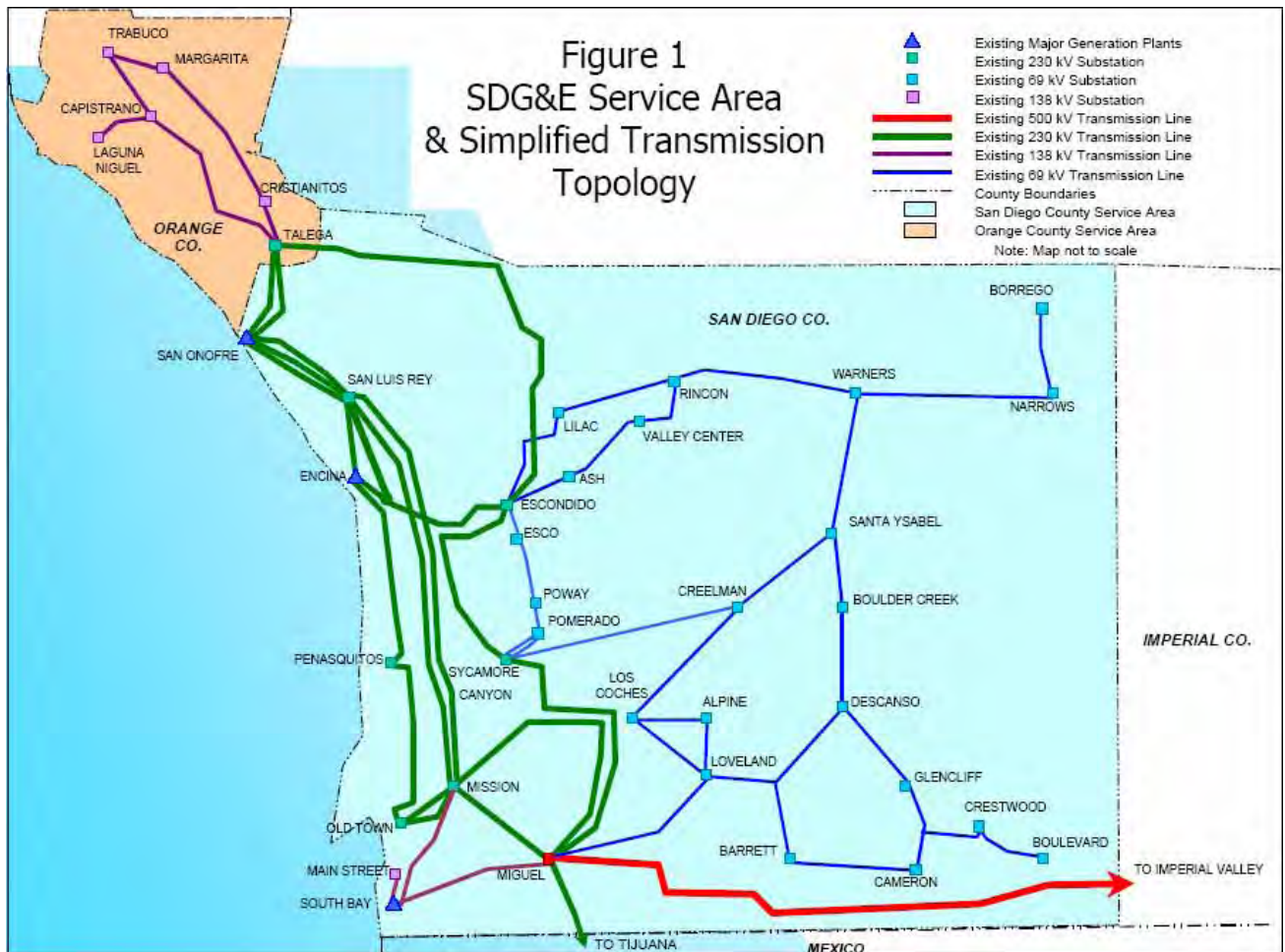
10.1.3. Distribution

The distribution system consists primarily of 12 kV and 4 kV systems that are stepped down to the customer supply voltage at or near the customer point of delivery. SDG&E is working jointly with the City of San Diego to underground a majority of the distribution lines within the city limits. This program, directed by the City of San Diego, is known as the "surcharge program" which converts overhead utilities in accordance with boundaries established by the San Diego City Council.

SDG&E's 2005 System Reliability Report[4] provides statistics for the following reliability indicators:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.

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[4]

ftp://ftp.cpuc.ca.gov/ElecReliabilityAnnualReports/2005/2005%20SDGE%20Reliability%20Report.pdf

2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.

3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.

The reported results for 2005 are presented in Table 3.

Table 3 2005 System Reliability

CRITERIA	SAIDI	SAIFI	MAIFI
Including CPUC Major Events (2005)	61.99	0.64	0.60
Excluding CPUC Major Events (2005)	58.46	0.57	0.57
10-Year Average (1996-2005) Including CPUC Major Events	103.70	0.84	0.91
10-Year Average (1996-2005) Excluding CPUC Major Events	72.33	0.75	0.91

The historical reliability indices reported by SDG&E to the CPUC shown in Table 4:

Table 4 Historical System Reliability

Year	All Interruptions Included			CPUC Major Events Excluded				
	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI	No. of Events	Event Cause(s)
1996	133.9	1.48	1.53	81.9	1.04	1.53	1	Underfrequency condition (1)
1997	89.3	0.93	1.41	89.3	0.93	1.41	0	
1998	91.6	0.94	1.09	91.6	0.94	1.09	0	
1999	65.2	0.67	0.80	65.2	0.67	0.80	0	
2000	51.9	0.57	0.75	51.9	0.57	0.75	0	
2001	68.5	0.87	0.87	52.9	0.64	0.86	7	Fires (2), Load Curtailment (4), and Interruptions Due to Non-SDG&E Facilities (1)
2002	82.5	0.81	0.61	77.2	0.81	0.61	4	Fires (2), Interruptions Due to Non-SDG&E Facilities (2)
2003	298.9	0.86	0.87	76.1	0.72	0.84	2	Firestorm 2003 (1), Wind Storm Affecting >15% of Facilities (1)
2004	93.2	0.67	0.61	78.8	0.62	0.61	5	Fires (3), Interruptions Due to Non-SDG&E Facilities (1), December Storm (1)
2005	62.0	0.64	0.60	58.5	0.57	0.57	10	Fires (4), Interruptions Due to Non-SDG&E Facilities (4), Storms (2)

10.1.4. Substations

SDG&E has a total of 277 substations. Seventeen (17) substations are classified as transmission/bulk power substations for the 500 kV and 230 kV systems. One hundred seven (107) are classified as transmission and distribution substations supporting the 230/138/69/12 kV systems. One hundred fifty three (153) are classified as distribution substations supporting the 12 – 4 kV systems. All the transmission substations are

interfaced to the SCADA (Supervisory Control and Data Acquisition) system and approximately 50% of the distribution substations are interfaced to the SCADA system.

SDG&E has a standard design for its distribution substations that specifies line termination structures, high-voltage switchgear, transformer banks, low voltage switchgear, surge protection, controls, and metering. Other devices such as power factor correction capacitors and voltage regulators may also be located at a substation.

Although no new transmission substations have been constructed in the recent years, a number of transmission substations have been planned for the next 10 years. Under a recent project, the Miguel substation was recently upgraded to increase its capacity.

SDG&E has a transmission substation (Talega) that incorporates state of the art technologies. The system was operational in 2003. The flexible AC transmission system (FACTS) installed in the SDG&E system at the Talega 138 kV substation is being applied to relieve transmission system constraints in the area through dynamic VAR control during peak load conditions. It is operating as a Static Compensator (STATCOM) with a rated dynamic reactive capacity of -/+100Mvar.

The main objectives of the Talega STATCOM are as follows[5]:

- Regulation and control of the 138 kV AC system voltage;

- Dynamic, fast response reactive power support following system contingencies;

- High reliability with redundant parallel converter design and modular construction; and

- Operational flexibility through auto-reconfiguration design

The Talega FACTS is also designed for future operation as a Back-to-Back DC-Link (BTB). The BTB System would have a power transfer rating of 50MW, and would be able to deliver power bi-directionally between the east and west buses at Talega. The DC-Links are physically in place for this future option, which would essentially require only software-based control adjustments for BTB operation.

The substation layout is presented in the Figure 3.

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[5] www.meppi.com

Figure 3 SDG&E Talega STATCOM
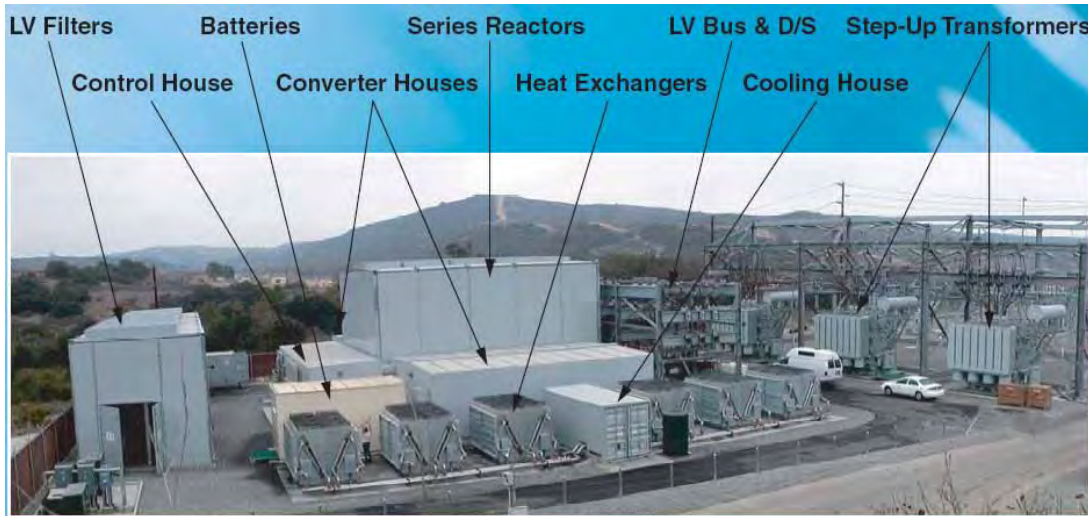
10.1.5. Meters

SDG&E supports a wide variety of electric and gas meters for transmission, distribution, and customer-service delivery of electricity and natural gas.   Electric service delivery metering includes residential, commercial and industrial (C&I) customers. Electrical transmission and distribution metering is frequently integrated digitally with the SCADA systems with the primary focus on automated substation monitoring. Service delivery metering for residential customers is primarily manual at this juncture. SDG&E currently services over 1.19 million residential customers. Service delivery metering for commercial and industrial customers is a mix of manual and automated metering data collection technology. SDG&E currently services approximately 21,700 C&I customers. Gas metering is also primarily manual in nature and includes over 832,000 customer meters.

10.1.6. Communication Systems

The SDG&E communication infrastructure consists of a microwave system, a fiber optic network, SCADA radio, cellular, voice radio and copper lines. Communication systems are used primarily for voice communication systems and data transport. These systems are addressed in more detail in the following section.

10.2. SDG&E Voice & Data Transport

The current SDG&E telecommunications infrastructure supporting voice and data transport is described in the following paragraphs. This voice and data transport has kept pace with the evolving utility technology and regulator environments using a conservative approach relying heavily on telecomm infrastructure ownership and control.   This was driven based on the need for high availability (99.999) communications and the belief that commercial telecom costs were prohibitively expensive when considering life cycle costs.

The current SDG&E telecommunications infrastructure can be broken down into the following categories:

- Mobile Workforce Voice Communications

- Mobile Workforce Data Communications

- Fixed Site Voice Communications

- Fixed Site Data Communications

It is important to note that the fixed site infrastructure often directly supports the mobile workforce infrastructure. Also, while mobile workforce communications is done primarily using wireless technologies, fixed site communications is supported by a combination of wired and wireless technology.

10.2.1. Mobile Workforce Voice Communications

The SDG&E mobile workforce voice communications is supported by three major elements as described below.

a. 900 MHz voice radio.   The trunked radio system is used for mobile field communications and operates in analog mode. This system covers the entire SDGE service territory with back-haul service provided by microwave radio and fiber optics. As a main voice radio communications system it services approximately 2,000 users. The spectrum used is owned by SDG&E and consists of 28 channel pairs each 12.5 KHz wide. These channels are non-contiguous.

b. 450 MHz voice radio. SDGE also operates and maintains a 450 MHz voice radio system that is used to provide point to point field communications for wire stringing crews during storm restoration services as well as routine operations. There are about 1,000 portable units in operation that through portable repeater interfaces can augment as back-up field communications to the trunked radio system when necessary. The spectrum used is owned by SDG&E and consists of 2 channels used for FB2 and 7 channels used for MO. Each channel is 25 KHz wide. These channels are non-contiguous.

c. Commercial carrier cellular communications. Employees can optionally carry SDG&E corporate funded cell phones or their own personal cell phones. SDG&E utilizes local cellular service for non-operational communications that could be considered to augment its private radio systems when necessary. Push-to-talk group communications technology is also used extensively by field crews and supporting business units such as Facilities Maintenance, Planners, Designers and Environmental to augment its private radio communications usage

10.2.2. Mobile Workforce Data Communications

The SDG&E mobile workforce data communications is supported by two major elements as described below.

a. 800 MHz Mobile Data Radio system. SDG&E also operates and maintains a 2 channel 800 MHz Mobile Data Radio system with about 450 users for automated service dispatch for electric and gas field technicians. This system operates at an over-the-air rate of 19.2 kbps with interfaces into SDG&E service dispatch servers. The two channel 800 MHz system consists of 10 mountain top site repeater sites with back-haul provided by microwave radio.

b. Commercial carrier wireless cards. SDG&E has come to recognize the value to mobile broadband and is currently using 1xEVDO service for employee laptop's broadband wireless connection. This is done using a PCMCIA type II card. The connection is through the public internet access and requires either external web portal based access or VPN activation to reach corporate resources.

10.2.3. Fixed Site Voice Communications

The SDG&E fixed site voice communications infrastructure comprises the following main elements:

a. Private Branch EXchange (PBX) infrastructure Time-Division Multiplexing (TDM). Legacy PBX equipment is used at a majority of SDG&E business sites. More recent procurements are using VoIP cabable PBX equipment. Interoffice trunking is supported on fiber and microwave infrastructure.

b. PBX infrastructure Voice over Internet Protocol (VoIP). SDG&E is currently trialing a VoIP solution at two locations and plans to eventually migrate to a total VoIP platform.

c. Through a system of internal leased cost routing procedures, select public telephone carrier interconnections are made to provide both PBX and typical telephone service (DOD/DID) connections for SDG&E facilities. These physical connections are accomplished through a combination of multiple T1s and Primary rate ISDN circuits.

10.2.4. Fixed Site Data Communications

SDG&E's fixed site data communications infrastructure consists of the following.

a. 900 MHz SCADA radio. The 900 MHz SCADA radio system utilizes both licensed and unlicensed channel assignments for use in fixed location remote load switching, system restoration, and fault monitoring throughout the service territory including Orange County. This system is used exclusively for Electric Distribution switching and consists of about 700 field units.

b. Microwave. SDG&E operates a series of thirty (30) microwave links to remote sites throughout San Diego, Imperial and Orange Counties. The majority of these sites are located on high spots (e.g. mountain tops). The links are a combination of DS3 and OC-3 level (155 Mbps) with capacities channelized down to the T1 level and below. Currently ten (10) high voltage Transmission substations are used as co-location sites for microwave radio equipments. A low capacity analog link also exists into La Mesa, Mexico.

c. Fiber optic links. SDG&E operates two protected SONET[6] fiber rings operated at OC-48 (2.4 Gbps) with tributaries off the main rings at OC-12 (622 Mbps) and OC-3 (155 Mbps) These fiber connections are used for all corporate LAN, WAN, PBX (Telephone), Radio and microwave as well as transport for Electric Transmission and Distribution Remote Terminal Unit (RTU) circuits. Additionally SDGE owns over 120 miles of 12/24/48 strand single mode fiber that could be upgraded to either OC-192 or a combination of OC-192 and Dense Wavelength-Division Multiplexing (DWDM) if traffic loads dictated. Currently, twenty three (23) substations are co-located with fiber ring termination) points (i.e. add/drop multiplexers). Design and planning are currently in progress to extend an OC-48/DWDM link from Sempra's Network Operations Center in Rancho Bernardo to Monterey Park as a back-up for SAN, e-mail and mainframe applications.

d. Outside Plant Cable. SDGE also owns about 100 miles of its own copper telephone plant consisting of varying counts of 25 to 210 pairs. This infrastructure reaches 35

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[6] A fiber optic network in a ring topology, often used to carry voice signals or Internet traffic.

substations while the topology allows for through connections (e.g. patched/punched down) back to the Telecommunications Control Center (TCC) and Mission Control Center (MCC).The outside plant cable system is used in areas where it makes economic sense rather than more expensive fiber and radio technologies, however individual pair count circuits are being replaced by in-house multiplexing technologies such as ADSL (Pair Gain Systems).

e. Asynchronous Transfer Mode (ATM) Network. SDG&E operates a 3 node OC-3 ATM cloud that is used for connectivity to Southern California Gas utility affiliate. The ATM network runs over the fiber optic capacity and staged microwave links. SDG&E primary use for this is for Time Division Multiplexing (TDM) voice trafficking (i.e. PBX to PBX call routing) and 4W analog circuits to other Sempra company operations (SoCAL gas).

f. Power Line Carrier (PLC). Older Power Line Carrier technology is run on the transmission High Voltage legs for protective relaying and low speed telemetry control purposes. This PLC service is currently not used for other communications uses and not planned for future expansion.

g. Digital Cross-connect Systems (DCS). The DCS is employed to groom capacity onto larger data pipes for sites connected to the fiber ring or the microwave network. Capacity is groomed from sub-T1 level to T1s. Because of life-cycle issues, planning and budgeting have been approved to upgrade the existing DCS with greater capacity, capability and improved fault tolerant switching.

h. Public carrier links are utilized extensively for data connection to substations and other fixed facilities and assets where private links are not available. Service may be via copper or fiber facilities maintained by the carrier.   SLAs for standard 4-wire service have been a minor concern for SDG&E SCADA usage.

i. IP Networking.   Current infrastructure utilizes IP v4 addressing and routing.

10.3. Related Regulatory Proceedings

SDG&E participates in many major regulatory proceedings at the California Public Utilities Commission (CPUC); however, five related to the Smart Grid concept include the implementation of advanced metering, the construction of a new transmission line, and broadband over power lines. Planned proceedings include a new application addressing revenue recovery.

10.3.1. Advanced Metering Infrastructure (AMI)[7]

SDG&E is currently in the process of source selection for a major customer service delivery metering technology upgrade known as Automated Metering Infrastructure (AMI). This AMI procurement is targeted to provide two-way meter communications, automated meter data collection (i.e. meter reading), and a variety of control features including support for outage management, dynamic rate structures, and demand response for load control.   The deployment of AMI will provide direct and indirect financial benefits to SDG&E and its customers. Implementation of AMI will impact not only the deployed meter population, but will require implementation of new networking technology and substantial systems integration at the head end data center. The SDG&E IT systems will be impacted by the

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[7] For more information about the AMI proceeding, see www.cpuc.ca.gov/proceedings/A0503015.htm

addition of a new head-end data collection system, meter data management system, supporting database systems and their interface with legacy applications including the Customer One CIS, OMS, Billing, Finance and other key IT applications. This work is anticipated to begin technology trials by late 2006 and result in a final AMI technology selection for deployment by mid-2008.

10.3.2. Sunrise Power Link[8]

The Sunrise Powerlink application addresses a proposed new transmission project that would consist of a new 1,000 MW - 500 kV line from the Imperial Valley substation to a substation in central San Diego County where the line would split into two 230 kV systems that would branch to two existing substations.[9] The 500 kV portion is estimated to be 75 to 105 miles. There is a potential for portions of the 230 kV systems to be underground in community-sensitive areas. Details of the exact path are currently being evaluated. The project cost estimated is between $1.015 billion to $1.437 billion.

The objective of the project is to meet region reliability requirements, expand access to renewable resources, access lower priced electricity to the east and south, and reduce congestion on SWPL. As such, the total cost of the project would be shared by the State's three IOUs (PG&E, SCE and SDG&E). SDG&E's portion of the cost would be 10% of the total project cost or $101,500 million to $143,700 million.

10.3.3. Broadband over Power Line (BPL)[10]

This proceeding establishes sufficient regulatory certainty to encourage the investor-owned electric utility companies in California to deploy BPL projects. At this time BPL deployment is necessary to understand the potential of this promising new technology. The Commission intends to encourage BPL deployment in a manner that does not harm ratepayers, that promotes accessibility to broadband networks and that contributes to California's competitive broadband market.

On September 8, 2005, the CPUC issued an Order Instituting Rulemaking (OIR) concerning BPL deployment by electric utilities in California. The OIR focused significantly on the Broadband Deployment in California report (Broadband Report) and recently adopted by the Commission in D.05-05-013 which recommended that "California should encourage deployment of BPL by its electric utilities by providing regulatory certainty". The report identifies significant potential for BPL development to realize cost effective and widely deployed broadband service. In addition, the electric utility-specific benefits identified include improving electric service and reliability through functions such as remote meter reading, detailed identification of equipment failures, diagnostic monitoring and other applications.[11]

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[8] For more information about the Sunrise Power Link Application, see www.cpuc.ca.gov/proceedings/A0512014.htm

[9] SDG&E's original application was filed as A.05-12-014. It subsequently filed application A.06-08-010.

[10] For more information about the BPL proceeding, see www.cpuc.ca.gov/proceedings/R0509006.htm

[11] http://www.cpuc.ca.gov/Published/Final_decision/49450.htm

10.3.4. Critical Peak Pricing[12]

In a December 8, 2004 Ruling by Assigned Commissioner Peevey and Administrative Law Judge (ALJ) Cooke in Rulemaking R.02-06-001, the CPUC required the California investor-owned utilities (IOUs) to submit an application presenting a 2005 default critical peak pricing structure for commercial and industrial customers on January 20, 2005. The CPUC seeks to create rates to address peak situations, which drive up resource needs but only account for a relatively small number of hours in the year.

In response to the utility applications, the CPUC adopted a decision which did not adopt a default critical peak pricing structure but did affirm the CPUC's desire to see a critical peak pricing structure adopted.[13]

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[12] For more information about the Critical Peak Pricing Application, see www.cpuc.ca.gov/proceedings/A0501017.htm

[13] See D.06-05-038.

10.3.5. California Solar Initiative[14]

In 2005, the CPUC issued a joint report with the CEC titled "Staff Solar Report." The CPUC and CEC staff report presents an analysis of key issues related to implementing what the staff is calling the California Solar Initiative (CSI).

The report proposes to consolidate existing and anticipated residential and commercial solar incentives into one program by June 2006. Eligible technologies would include photovoltaics and concentrated solar power up to 1 MW, and solar water heaters. The program would be funded through 2016 using gas and electric distribution rates. Tariff and metering requirements would be coordinated with the CPUC's demand response and distributed generation proceedings.

On January 12, 2006, The CPUC increased funding for incentives to solar projects by $300 million in 2006. That order stated the intent to develop additional policies and program elements designed to promote solar development. This order makes a commitment to provide $2.8 billion of incentives toward solar development over 11 years. Of this, $2.5 billion is for Commission-managed programs and the remainder is related to programs managed by the California Energy Commission (CEC).[15]

10.4. Related Electric Tariffs

As a utility that provides services for both electricity and natural gas, SDG&E has tariffs addressing each type of service.

SDGE customer rates are regulated by the CPUC. A General Rate Case (GRC) is the major regulatory proceeding for California utilities, which provides the CPUC an opportunity to perform an exhaustive examination of a utility's operations and costs. Typically performed every three years, the GRC allows the CPUC to conduct a broad and detailed review of a utility's revenues, expenses, and investments in plant and equipment to establish an approved revenue requirement (cite CPUC website).

10.4.1. Rate Components

Table 5 shows the components of SDG&E's Total Utility Distribution Company (UDC) rates consist. These rates do not account for the commodity cost of electricity.

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[14] See http://www.cpuc.ca.gov/static/energy/solar/index.htm

[15] http://www.cpuc.ca.gov/published/Final_decision/52898.htm

Table 5 Components of the Utility Distribution Company Rates

#	Component	Description
1	Transm	Transmission Charge - The costs of transmission facilities placed in service after the date of initial implementation of the Independent System Operator shall be recovered using the rate methodology in effect at the time the facilities go into operation. SDG&E's rates shall reflect all of the terms and conditions of existing transmission service contracts and shall recognize any wheeling revenues of existing transmission service arrangements.
2	Distr	Distribution Charge - Charges for use of SDG&E's distribution facilities. Charges are intended to recover SDG&E's costs of owning, operating, and maintaining the electrical distribution facilities including billing, meter reading, and other revenue cycle functions.
3	PPP	Public Purpose Program (PPP) Charge - A separate charge that all electric customers are required to pay that funds various public purpose programs including: 1) renewable resource energy technologies 2) energy efficiency 3) research, development and demonstration, and 4) low-income programs.
4	ND	Nuclear Decommissioning Charge - These charges include costs related to the decommissioning of a nuclear power plant. These costs will be non-by-passable until such time as the costs are fully recovered.
5	FTA	Fixed Transition Amount - Residential and Small Commercial customers benefit from reduced rates through the issuance of the Rate Reduction Bonds. The Rate Reduction Bonds were issued to enable these customers to receive a discount on their bills of no less than 10% for the years 1998 through 2002. The proceeds of the Rate Reduction Bonds are used to provide, recover, finance, or refinance transition costs and to acquire transition property. Residential and small commercial customers would continue to pay fixed transition amounts after December 31, 2001, until the bonds are paid in full by the financing entity.
6	CTC	Ongoing Competition Transition Charge - The Utility is permitted to recover authorized post rate freeze transition costs, including qualifying facilities and purchased power contracts, nuclear costs, and other transition costs incurred after the rate freeze period. These costs will be recovered through a non-residual CTC rate component on customer bills, to be determined annually.
7	RS	Reliability Services - RS costs are those costs passed on to SDG&E as a Participating Transmission Owner (PTO) by the ISO for services provided by generators to maintain system reliability. RS costs are subject to Federal Energy Regulatory Commission (FERC) jurisdiction and are recovered through a separate rate component on customers' bills. RS costs and revenues are subject to balancing account treatment as authorized by the PTO tariff filed with the FERC.
8	RDS	2006 Rate Design Settlement - Tracks the rate subsidies applied to residential usage, tiers 1 and 2. The subsidy amounts necessary to maintain the rate capping requirements for residential baseline service are tracked and distributed as adders to other residential energy rates and, if necessary, non-residential rates. The 2006 RDS Component's purpose is to provide customers with more accurate information on the cost of providing electric service. A credit or charge will appear on customer bills. Customers taking Direct Access service as of 7-26-05 will not be subject to the 2006 RDS Component while they are taking Direct Access service, including transitional bundled service. Residential Direct Access customers will receive the 2006 RDS Component credits applicable to the first two residential rate tiers.

Note: Definitions are taken from the SDGE *Electricity Tariff Book – Rule 1: Definitions*

10.4.2.   Residential Rates

The residential rate category comprises 14 rate schedules, which are listed in Table 6.

Table 6 SDG&E Residential Rate Schedules

	Schedule	Description
1	DR	Domestic Service
2	DR-LI	Domestic Service - CARE Program
3	DR-TOU	Domestic - Time-of-Use Service
4	E-LI	Service to Qualified Living Facilities
5	DM	Multi-Family Service
6	DS	Sub-metered Multi-Family Service (closed after 12/13/81)
7	DT	Sub-metered Multi-Family Service – Mobile Home Park (closed after 1/1/97)
8	DT-RV	Sub-metered Service - Recreational Vehicle Parks & Residential Marinas
9	DR-TOU-DER	Domestic Time-of-Use Service - Distributed Energy Resources
10	EV-TOU	Domestic Time-of-Use for Electric Vehicle Charging
11	EV-TOU-2	Domestic Time-of-Use for Households with Electric Vehicles
12	EV-TOU-3	Domestic Time-of-Use for Electric Vehicle Charging With A Dual Meter Adapter
13	DE	Domestic Service to Utility Employees
14	FERA	Family Electric Rate Assistance Program

Calculating Residential Bills

SDGE's residential customers are charged for electricity used within a baseline allowance and above the baseline allowance. Baseline allowance for electricity is affected primarily by Climatic Zone and time-of-year (summer or winter) as well as number of days in the billing period and how the customer heats their home and/or water.   As an example, Table 7 illustrates the baseline allowances for domestic residential (DR) service, effective 2/1/2006.

Table 7 SDG&E Electricity Rate Baseline Allowances, kWh/Day

	Climatic Zone			
Basic Baseline Allowance	**Coastal**	**Inland**	**Mountain**	**Desert**
Summer (May 1 – October 31)	10.2	11.8	15.5	17.3
Winter (November 1 – April 30)	10.8	11.5	14.6	12.0

Rates are also established for electricity used above the baseline allowance, and increase with usage above the baseline. The DR Rate Schedule shown in Table 8 illustrates this rate structure.

Table 8   SDGE DR Rate Schedule, effective 2/1/2006

Description	Transm	Distr	PPP	ND	FTA	CTC	RS	2006 RDS	UDC Total
Summer									
Baseline Energy ($/kWh)	0.00743	0.05547	0.0061	0.00046	0.0065	0.00178	0.01088	-0.03335	**0.055270**
101%-130% of Baseline	0.00743	0.06861	0.0061	0.00046	0.0065	0.01015	0.01088	-0.03469	**0.075440**
131%-200% of Baseline	0.00743	0.06861	0.0061	0.00046	0.0065	0.01015	0.01088	0.03632	**0.146450**
201%-300% of Baseline	0.00743	0.06861	0.0061	0.00046	0.0065	0.01015	0.01088	0.04539	**0.155520**
Above 300% of Baseline	0.00743	0.06861	0.0061	0.00046	0.0065	0.01015	0.01088	0.06122	**0.171350**
Winter									
Baseline Energy ($/kWh)	0.00743	0.05547	0.0061	0.00046	0.0065	0.00178	0.01088	-0.01158	**0.077040**
101%-130% of Baseline	0.00743	0.06861	0.0061	0.00046	0.0065	0.01015	0.01088	0.00519	**0.115320**
131%-200% of Baseline	0.00743	0.06861	0.0061	0.00046	0.0065	0.01015	0.01088	0.05045	**0.160580**
201%-300% of Baseline	0.00743	0.06861	0.0061	0.00046	0.0065	0.01015	0.01088	0.05927	**0.169400**
Above 300% of Baseline	0.00743	0.06861	0.0061	0.00046	0.0065	0.01015	0.01088	0.07735	**0.187480**
Minimum Bill ($/day)									**0.17**

Commodity Rates are combined with the DR schedule to determine the total rate. The summer commodity rate is $0.08490 and the winter commodity rate is $0.05793.[16]

Bills are calculated by first applying the baseline energy rates for all electricity usage within the baseline allowance, and second applying the "above baseline" rates for usage above the baseline bins, such as those listed in the DR Schedule in the previous table.

10.4.3.   Commercial/Industrial Rates

Table 9 lists the 9 commercial/industrial rate schedules.

Table 9 SDG&E Commercial and Industrial Rate Schedules

	Schedule	Description
1	A	General Service
2	A-TC	Traffic Control Service
3	AD	General Service - Demand Metered (closed after 6/30/87)
4	A-TOU	General Service - Small-Time Metered (closed after 10/1/02)
5	AL-TOU	General Service - Time Metered
6	AL-TOU-DER	General Service - Time Metered - Distributed Energy Resources
7	AL-TOU-CP	General Service-Critical Peak (Closed after 12/31/05)
8	AY-TOU	General Service - Time Metered - Optional (closed after 9/2/99)
9	A6-TOU	General Service - Time Metered - Optional

Commercial/Industrial rates do not currently have dollar amounts associated with the Rate Design Settlement (RDS) rate component.

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[16] http://www.sdge.com/tm2/pdf/EECC.pdf

10.4.4. Lighting Rates

The lighting category is comprised of 5 rate schedules that are presented in Table 10.

Table 10 SDG&E Lighting Rate Schedules

	Schedule	Description
1	LS-1	Lighting - Street and Highway - Utility-Owned Installations
2	LS-2	Lighting - Street and Highway - Customer-Owned Installations
3	LS-3	Lighting - Street and Highway - Customer-Owned Installations (closed after 6/10/79)
4	OL-1	Outdoor Area Lighting Service
5	DWL	Residential Walkway Lighting

Lighting rates are not subject to FTA, CTC and RDS rate components.

10.4.5. Commodity Rates

Commodity rates apply to all Utility Distribution Company (UDC) customers who receive bundled service.   There are 6 commodity rate schedules, as presented in Table 11.

Table 11 SDG&E Commodity Rate Schedules

	Schedule	Description
1	EECC	Electric Energy Commodity Cost
2	EECC-CPP-V	Experimental Electric Energy Commodity Cost - Domestic Critical Peak Pricing Service - Variable
3	EECC-CPP-F	Experimental Electric Energy Commodity Cost - Domestic Critical Peak Pricing Service - Fixed
4	EECC-TBS	Electric Energy Commodity Cost - Transitional Bundled Service
5	EECC-CPP	Electric Energy Commodity Cost - Critical Peak Pricing
6	EECC-CPP-E	Electric Energy Commodity Cost Critical Peak Pricing Emergency

10.4.6. Miscellaneous Rates:

The Miscellaneous category captures 26 different rate schedules.   Eight of the more applicable schedules are listed in Table 12.

Table 12 SDG&E Miscellaneous Rate Schedules

	Schedule	Description
1	BIP	Base Interruptible Program
2	OBMC	Optional Binding Mandatory Curtailment
3	SLRP	Scheduled Load Reduction Program
4	RBRP	Rolling Blackout Reduction Program
5	DBP	Demand Bidding Program
6	NEM	Net Energy Metering
7	NEM-BIO	Net Energy Metering Service for Biogas Customer-generators
8	NEM-FC	Net Energy Metering for Fuel Cell Customer-Generators

10.4.7. Electric Rate Trends

Figure 4 illustrates the trends in average annual bundled rates from 2000-2005.

Figure 4 SDGE Annual Average Bundled Customer Rates (cents/kWh)[17]

	2000	2001	2002	2003	2004	2005	38749
Residential	11.3	13.7	14.3	14.6	14.3	14.6	15.4
Small Commercial	11.7	14	16.5	16.9	17.2	16.8	15.8
Medium & Large Commercial	11.8	12.1	12.6	12.3	11.8	11.7	11.8
Agricultural	16.5	15.2	15.5	14.9	14	13.8	14.3
Street Lighting	11	12.9	14.9	15.3	16.4	16.1	14.2
System Average	11.4	12.8	13.6	13.5	13.2	13.3	13.5
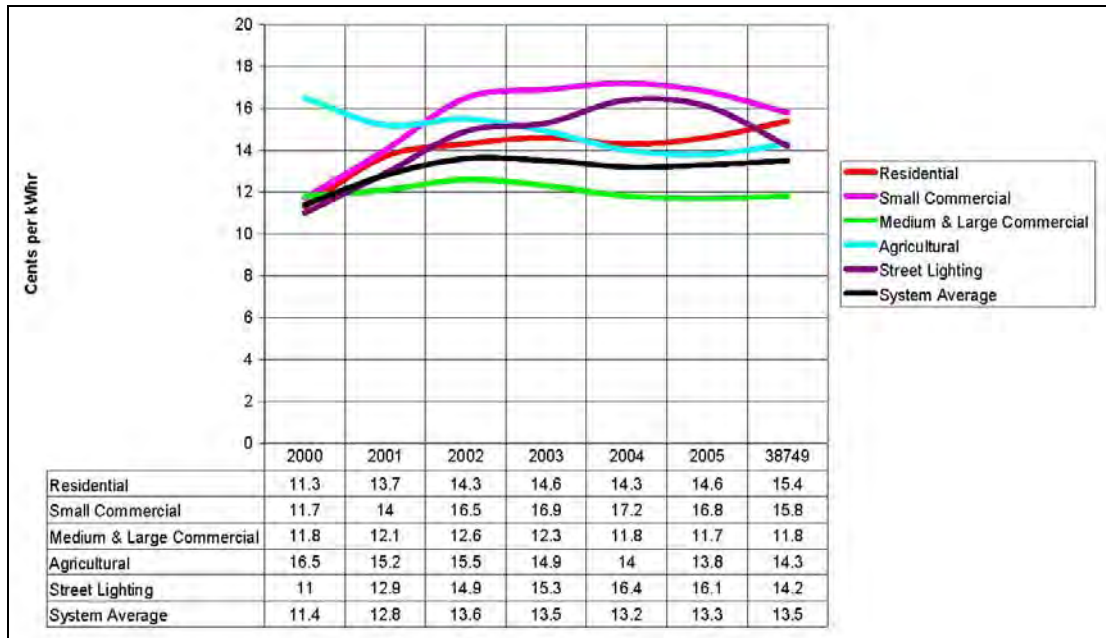
Figure 5 illustrates annual revenue requirements for transmission and distribution from 2000-2006.

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[17] CPUC website: www.cpuc.ca.gov

Figure 5 SDGE Annual Average Revenue Requirements for Distribution & Transmission

	2000	2001	2002	2003	2004	2005	2006
Distribution Revenue ($M)	539.9	547.8	564.2	589.2	598.7	730.3	802.7
Transmission Revenue ($M)	104.7	83.4	99.8	123.9	124.7	121.1	135.6
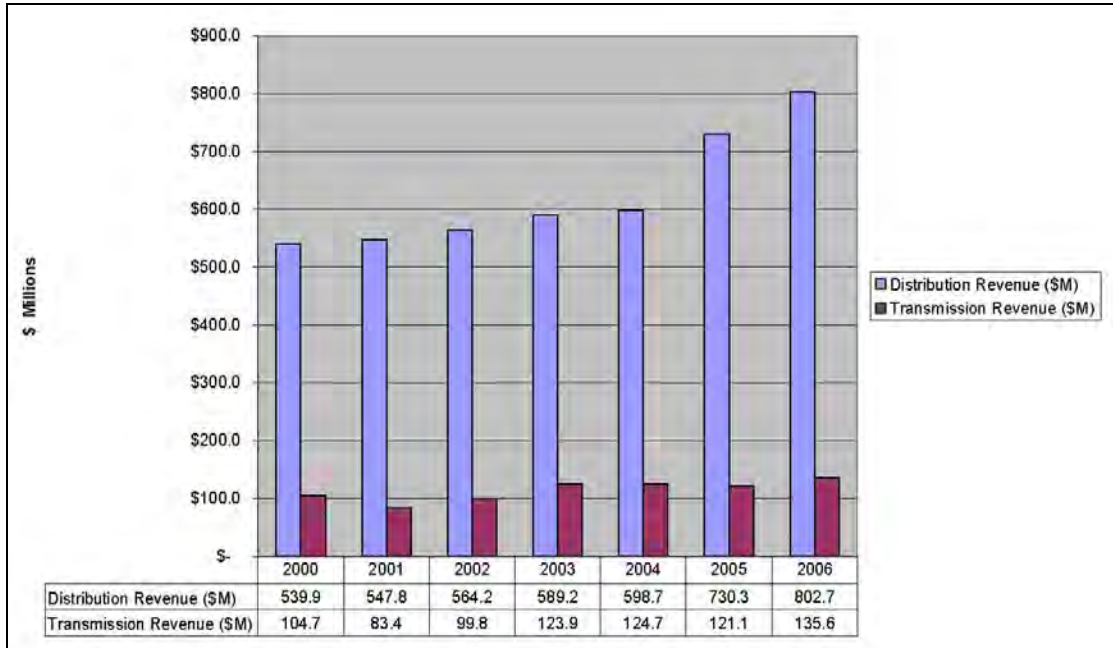
10.5. Natural Gas Tariffs

SDG&E customer rates are regulated by the CPUC. A General Rate Case is the major regulatory proceeding for California utilities, which provides the CPUC an opportunity to perform an exhaustive examination of a utility's operations and costs. Typically performed every three years, the GRC allows the CPUC to conduct a broad and detailed review of a utility's revenues, expenses, and investments in plant and equipment to establish an approved revenue requirement (www.cpuc.ca.gov).

10.5.1. Rate Components

Table 13 shows the components of the total Utility Distribution Company (UDC) natural gas rates.

Table 13 Utility Distribution Company Natural Gas Rate Components

#	Component	Description
1	Transmission	Transmission Charge - Charges that reflect SDGE's cost of transmitting natural gas from the point of supply to the local distribution system.
2	Procurement	Procurement Charge - Charges that reflect SDGE's cost of procuring natural gas.
3	PPP	Public Purpose Program (PPP) Charge - The public purpose program (PPP) surcharge is shown on a customer's bill as a separate line item. The surcharge is authorized to recover the cost of public purpose programs such as low-income assistance, energy efficiency, and public interest research and development. The Utility remits surcharge payments quarterly to the State Board of Equalization (BOE) by the last day of the month following a calendar quarter. The BOE deposits the payments in the Gas Consumption Surcharge Fund (Fund) with the State Treasurer. Utility public purpose programs are financed through monies appropriated to the Utility from the Fund by the Commission.

Unlike electric rates, PPP is not part of the bundled gas UDC rate. PPP is shown as a separate line item on a customer's bill under "Other charges".

10.5.2. Rate Categories

Gas customers are divided into two classes; core and non-core. Core customers are all residential use regardless of size and all commercial use below 20,800 therms per month and commercial use equal to or in excess of 20,800 therms per month that elect to receive core service. Non-core customers have elected not to receive core service and either use natural gas to produce electricity or have usage equal to or in excess of 20,800 therms per month.

Core Service

The Core Service rate category is comprised of 13 rate schedules, listed in Table 14.

Table 14 Core Service Rate Schedules

	Schedule	Description
1	GR	Domestic Natural Gas Service
2	G-CARE	California Alternate Rate for Energy (CARE) Program
3	GM	Multi-Family Natural Gas Service
4	GS	Sub-metered Multi-Family Natural Gas Service (Closed Schedule) (closed after 1/13/81)
5	GT	Sub-metered Multi-Family Natural Gas Service – Mobile Home Park (closed after 1/1/97)
6	GN-3	Natural Gas Service for Core Commercial Customers
7	GTC	Natural Gas Transportation Service for Core Aggregation Customers
8	GTC-SD	Natural Gas Transportation Service for Core Customers – San Diego County
9	GTCA	Natural Gas Transportation Service for Core Aggregation Customers
10	G-NGV	Sale of Natural Gas for Motor-Vehicle Fuel
11	GT-NGV	Transportation of Customer-Owned Gas for Motor-Vehicle Service
12	G-NGVR	Natural Gas Service for Home Refueling of Motor Vehicles
13	GPC	Gas Procurement for Core Customers

Non-Core Service

The Non-Core Service rate category is comprised of 6 rate schedules, listed in Table 15.

Table 15 Non-Core Service Rate Schedules

	Schedule	Description
1	GCORE	Core Subscription Natural Gas Service for Retail Noncore Customers
2	GPNC-S	Gas Procurement for Noncore Customers
3	GTNC	Natural Gas Intrastate Transportation Service for Noncore Customers
4	GTNC-SD	Natural Gas Intrastate Transportation Service for Noncore Customers - San Diego County
5	EG	Natural Gas Intrastate Transportation Service for Electric Generation Customers
6	EG-SD	Natural Gas Intrastate Transportation Service for Electric Generation Customers - San Diego County

Other Services

Table 16 includes the Other Services rate schedules.

Table 16 Other Service Rate Schedules

	Schedule	Description
1	G-90	Service to Utility Employees
2	G-91	Service Establishment Charge
3	GL-1	Service From Liquefied Natural Gas Facilities - Borrego (Closed Schedule)
4	G-PUC	Surcharge to Fund Public Utilities Commission Reimbursement Fee
5	G-MHPS	Surcharge to Fund Public Utilities Commission Master-Metered Mobilehome Park Gas Safety Inspection and Enforcement Program
6	GP-SUR	Customer-procured Gas Franchise Fee Surcharge
7	G-IMB	Transportation Imbalance Service
8	G-PPPS	Tax Surcharge to Fund Public Purpose Programs
9	G-CBS	Utility Distribution Company (UDC) Consolidated Billing Service
10	G-CBC	Energy Service Provider (ESP Consolidated Billing Credit
11	G-FIG	Fiber Optic Cables

3.3.3   Trends in Natural Gas Rates

Transmission costs for SDGE remained relatively constant from 2000-2005. Costs for procuring natural gas have mirrored the national trend since 2002 and reflect a tight natural gas market. Figures 6, 7, and 8 depict average annual gas rates for three different SDGE consumer categories in the 2000-2005 timeframe.

Figure 6 SDGE Average Annual Gas Rates for Residential Customers

	2000	2001	2002	2003	2004	2005
PPP		1.86	5.41	5.95	4.7	4.35
Procurement	47.07	83.65	30.4	48.98	58.64	78.38
Transportation	44.47	40.72	44.24	47.36	42.93	50.94
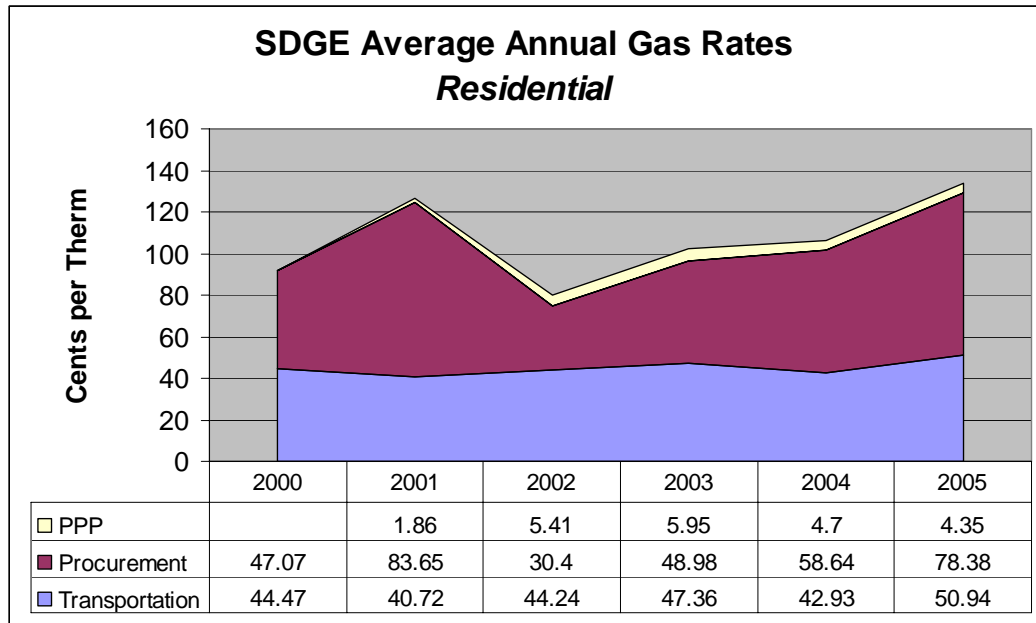
Figure 7 SDGE Average Annual Gas Rates for Core Commercial & Industrial Customers[18]

SDGE Average Annual Gas Rates
Core Commercial & Industrial

	2000	2001	2002	2003	2004	2005
☐ PPP		0.88	3.46	3.02	2.59	3.44
■ Procurement	47.07	83.65	30.4	48.98	55.32	78.38
■ Transportation	39.01	32.75	31.54	31.59	26.99	29.41
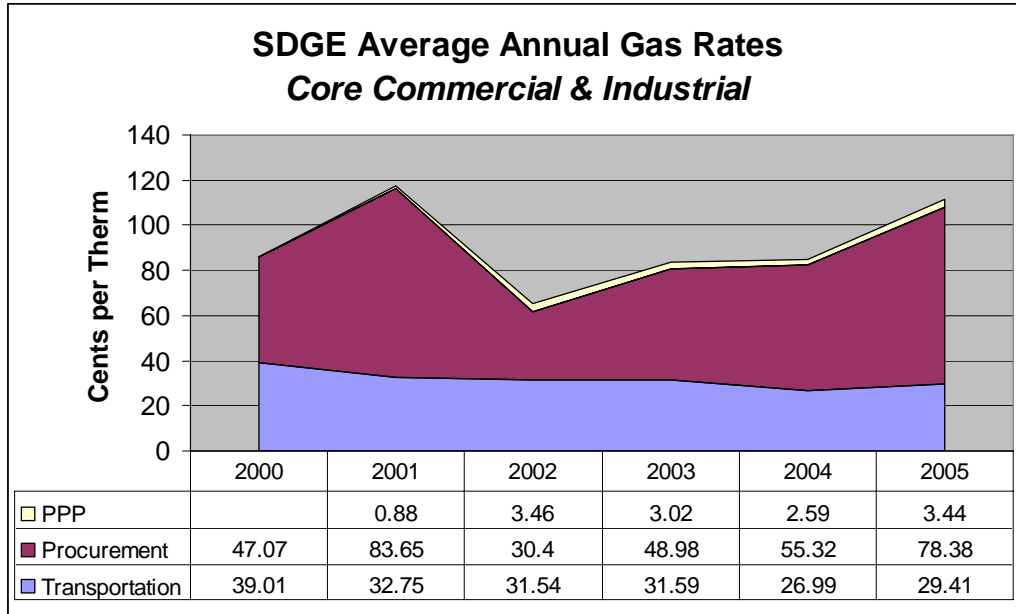
Figure 8 SDGE Average Annual Gas Rates for Non-Core Commercial & Industrial Customers

SDGE Average Annual Gas Rates Non-Core
Commercial & Industrial

	2000	2001	2002	2003	2004	2005
☐ PPP		0.55	2.78	2	1.85	1.83
■ Procurement	47.07	83.65	30.4	48.98	55.32	78.38
■ Transportation	9.69	8.8	7.45	8.51	8.32	9.77

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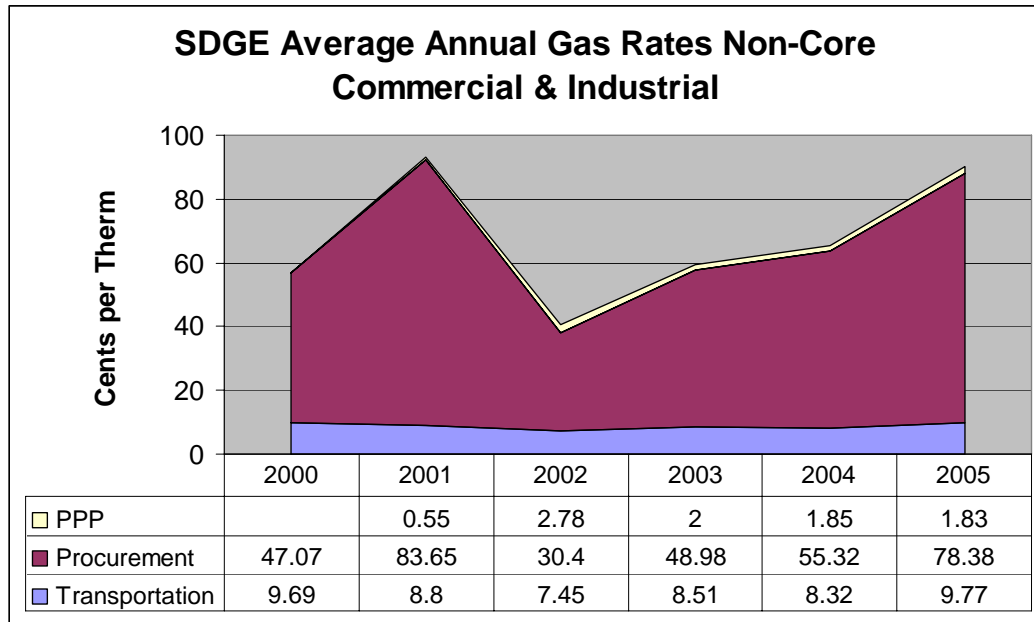
[18] CPUC website: www.cpuc.ca.gov

10.6. Distributed Energy Resources

10.6.1. Grid Connected Systems

California Public Utilities Code Section 353.1 defines Distributed Energy Resources (DER) as "…located within a single facility, less than 5 MW in size, serving on-site load or over-the-fence load, non-diesel, with best available air emissions control technology (BACT)." SDGE believes 10MW is a more appropriate upper size limit.[19]

The Public Utility Regulatory Policies Act of 1978 (PURPA) requires utilities to purchase power from Qualifying Facilities (QFs) at rates up to a utility's avoided cost.[20] QFs are defined as non-utility generators utilizing fuel sources and technologies that include, but are not limited to, biogas, biomass, geothermal, hydroelectric, wind, solar, photovoltaic, and cogeneration.

As of December, 2005, SDGE had 72 operational and non-operational qualifying facilities connected to the power grid. Table 17 provides a breakdown by facility type.

Note that not all projects included in the QF list fall within the 10 MW SDGE threshold for DER systems. The remainder of this section focuses on DER systems under 10 MW, and specifically on Cogeneration and Photovoltaic systems.

Table 17 Qualifying Facilities in SDG&E Territory

	Facility Description	# of Projects	Capacity (kW)
Non-operational	Cogeneration	8	4,895.6
	Wind Turbine	1	4
Operational	Bio-Gas	9	8351
	Cogeneration	47	336,015
	Hydroelectric	5	5,075
	Steam Turbine	2	6,034
QF Totals:		**72**	**360,974.6**

New generation in the San Diego region is trending toward lower capacity systems. Since the San Onofre and Kearny facilities that were installed in 1968, the majority of new capacity installations have been less than 75 MW, with an increasing number of units in the "under 10MW" category. Figure 9 illustrates this trend.

[19] See R.04-03-017.

[20] Note that the Energy Policy Act of 2005 modifies PURPA.

Figure 9 Number and Size of Power Plants in the San Diego Region
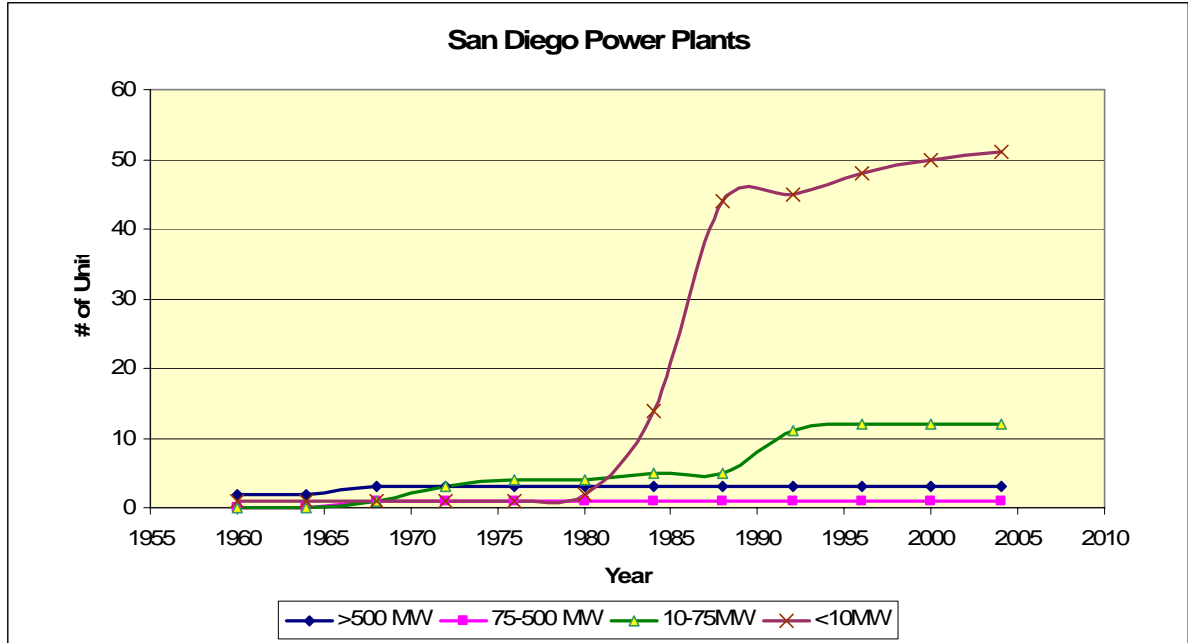
Two primary categories of are Combined Heat and Power (CHP), also referred to as Cogeneration, and Photovoltaic (PV) systems. An overview of each area follows.

Cogeneration

As of January, 2006 there were approximately 47 operational qualifying cogeneration facilities. Of these there are 34 systems less than   10 MW in the SDGE service territory that comprise roughly 56 MW of total generating capacity.[21] Two of the systems utilize steam turbines; one uses a combined cycle system; and the remaining 31 utilize gas turbines or reciprocating engines. These facilities meet the "qualifying facility" requirements of PU Code Section 218.5.

Figure 10 illustrates the cumulative number of cogeneration units installed and the cumulative installed capacity in four year intervals from 1976 to 2004.

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[21] www2.sdge.com/srac/2005.htm

Figure 10 Number of Qualifying Cogeneration Facilities and Cumulative Capacity
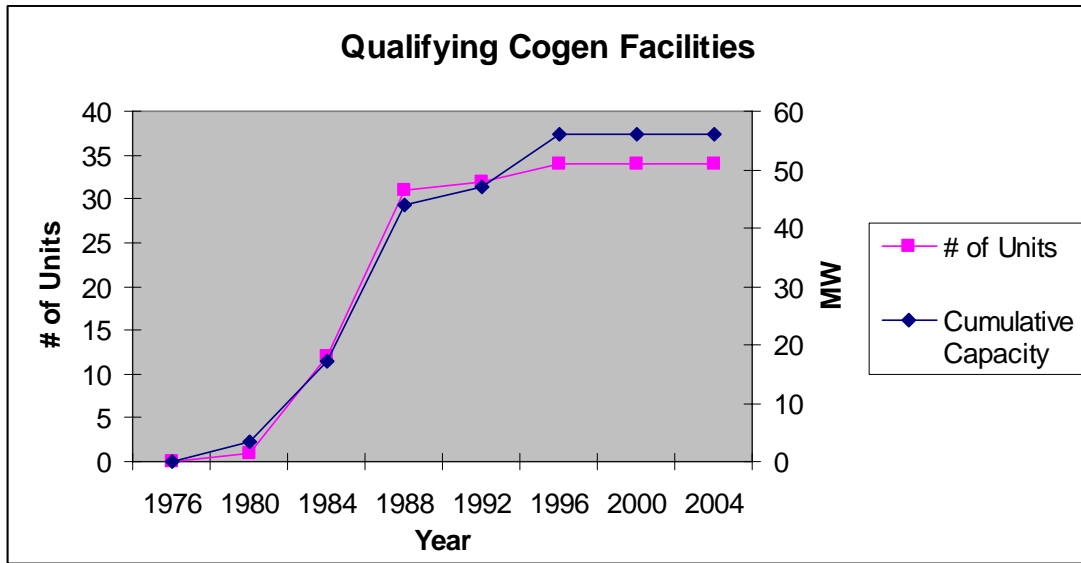
In addition to these operational facilities, there were approximately eight cogeneration facilities installed between 1986 and 1995 totaling 4.9 MW of capacity that are currently non-operational.

Figure 11 below illustrates the size distribution of current operational cogeneration facilities. Note that over 85% are less than 3 MW.

Figure 11 Distribution of Cogeneration Systems
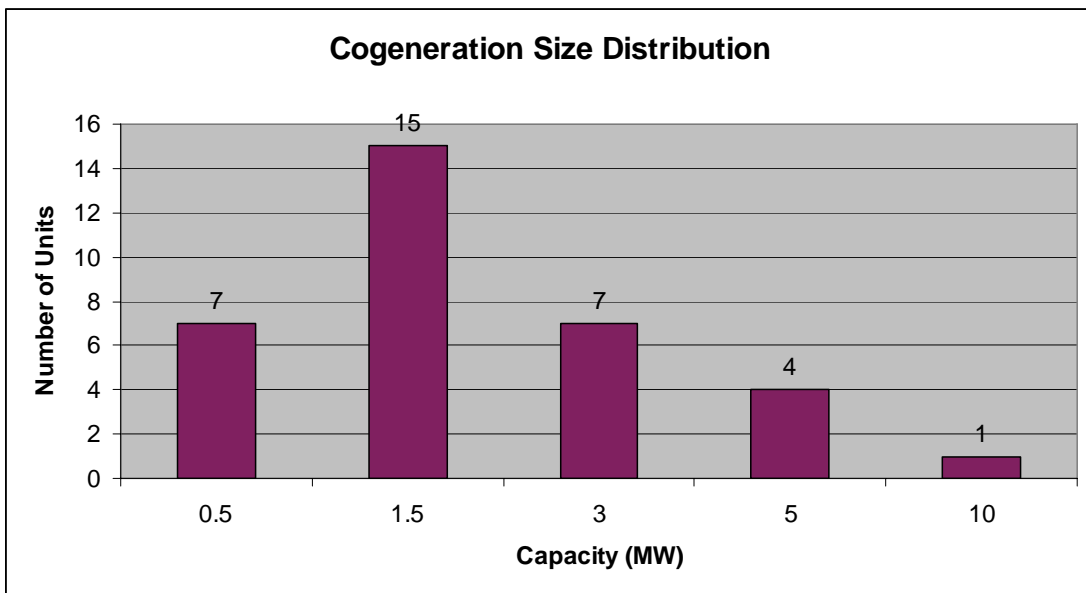
Photovoltaic (PV) Systems

As of today there are 3,724 PV systems installed in the region representing 20.4 MW of capacity. Two programs within the State provide incentives/rebates for qualifying installations. One program is funded through the CEC ERP program and the other program is funded by the Self-generation Incentive Program (SGIP). Figure 12 shows the trend in the cumulative number of PV system installation approvals over the last seven years.

Figure 12 Cumulative Number of Photovoltaics Installations
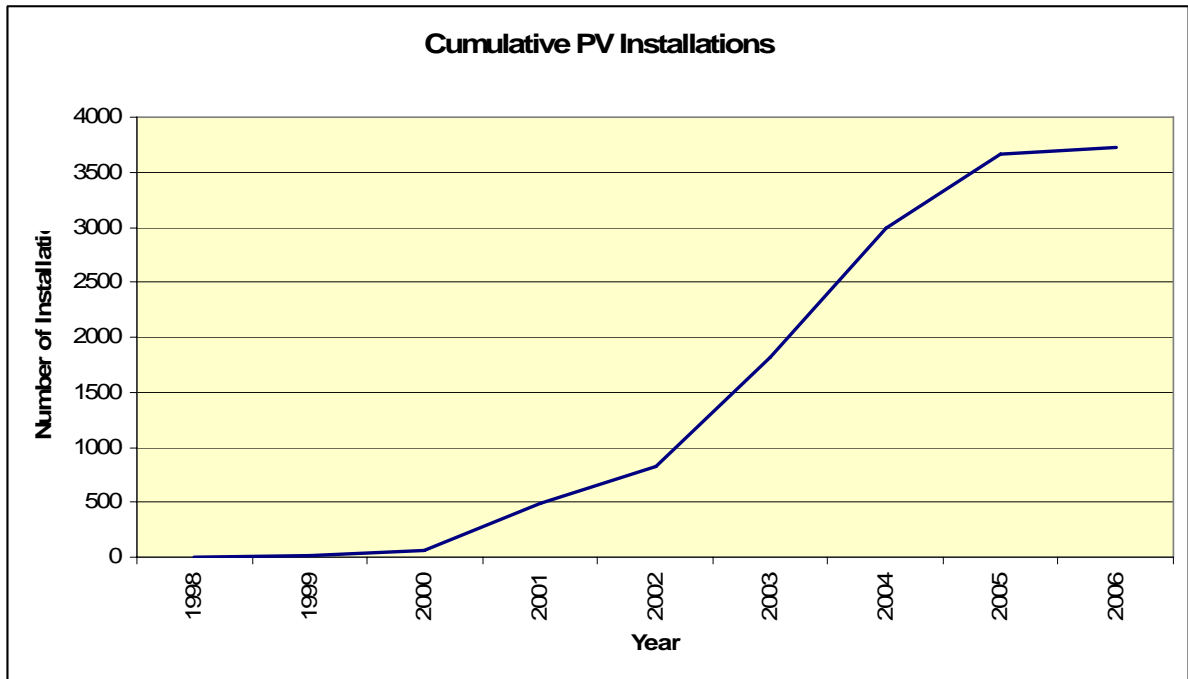
A vast majority of the completed PV systems fall within the 10 kW threshold. Figures 13 and 14 illustrate the size distribution of the systems as well as total capacity.

Figure 13 Distribution of Completed PV Systems through January, 2006
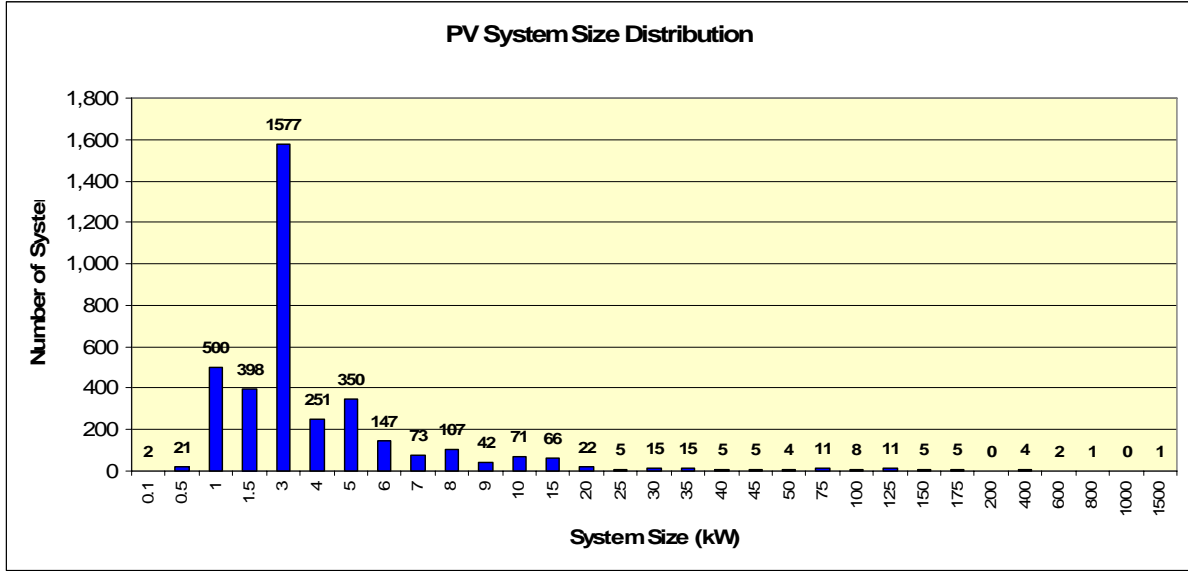
Figure 14 Cumulative Capacity of Completed PV Systems through January, 2006
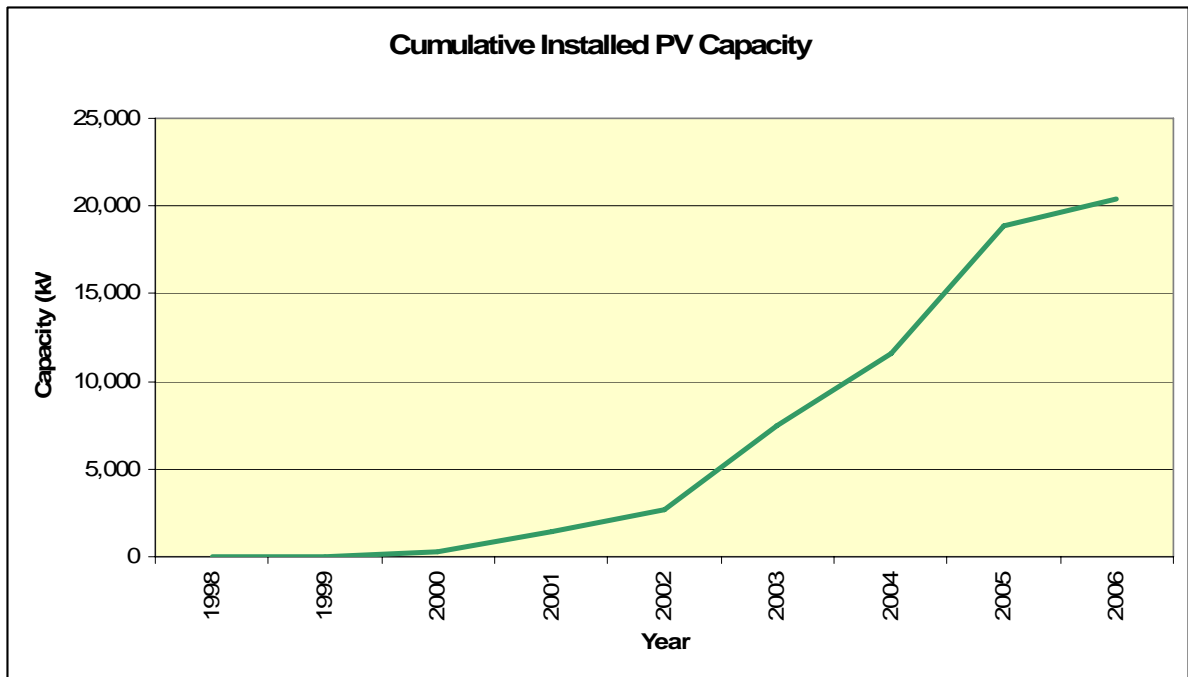
10.6.2. Back-up Generators (BUGs)

According to the CEC database of portable back-up generators, there were 619 sites with BUG capacity greater than 300 kW in the San Diego APCD as of August, 2003, with a total of nearly 435 MW of capacity.[22]   The table gives a breakdown by fuel type.

Table 18 San Diego APCD Back Up Generators (BUGs) by fuel type

Primary Fuel	# of BUGs	Capacity (kW)
Diesel	613	424,707
Natural Gas	2	652
Natural Gas/Diesel	3	9,000
Propane	1	480

4.3   Energy Efficiency

SDG&E offers a variety of energy efficiency programs addressing both electric and natural gas consumption as presented in Table 19. These programs are funded through public goods charges assessed on customers' monthly bills. The energy efficiency programs are approved by the CPUC for implementation.

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[22] http://www.energy.ca.gov/database/2004_PUBLIC_BUGS_INVENTORY.XLS

Table 19 SDG&E Rebates and Incentives

Program	Description
Express Efficiency	Rebates for installing more energy efficient equipment.
Standard Performance Contract	Cash incentives for increased energy savings at existing facilities.
Energy Savings Bid Program	Financial incentives for installing qualifying new, high efficiency equipment.
Savings by Design	Incentives for installing energy efficient equipment and systems in new construction and retrofit projects.
Sustainable Communities Program	Incentives for new construction projects to encourage sustainable building, energy efficiency and renewable power.
Small Business Super Saver	Rebates for installing more energy efficient equipment.
Statewide Business Energy-Efficiency Programs	Four investor-owned utilities teamed up to develop an energy efficiency website.
Flex Your Power	A statewide energy-efficiency marketing program that maintains a database of all California incentives programs.
On Bill Financing	Offered to qualified nonresidential customers to provide additional financing to facilitate the installation of energy efficiency measures.
Education & Outreach Programs	Provides energy efficiency information and training through seminars, classes and other energy efficiency customer events.
Residential Energy Efficiency Rebates	Rebates to residential customers and/or distributors/retailers to provide energy efficiency appliances and measures.
Other non-SDGE programs	SDG&E, through its competitive Bid process, is working with several third parties to deliver other energy efficiency programs to its nonresidential customers.

In addition to the programs administered by SDG&E, energy efficiency programs are also administered by third parties through competitive solicitations. One of the third party providers in the region is the San Diego Regional Energy Office and is currently responsible for the following programs.[23]

- Self-Generation Incentive Program: Incentives for the installation of clean distributed energy equipment

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[23] www.sdenergy.org

- San Diego Energy Resource Center: Energy Information, education and outreach

- Tax-Exempt Customer Incentive: Technical assistance and financial incentives are made available for tax-exempt customers and organizations. This is a component of the SDG&E Energy Savings Bid Program. Eligible participants include local governments, schools, colleges, universities, U.S. military facilities, as well as state and federal government.

4.4   Demand Response / Reliability Programs

SDG&E administers in a wide variety of demand response programs aimed at reducing peak loads and providing for a more stable distribution network. These programs offer financial incentives and other benefits to customers who reduce or shift their electric loads during critical events. Table 20 lists programs that are available to SDG&E customers.

Table 20 SDG&E Demand Reduction Programs

Program	Description
Express Efficiency	Rebates for installing more energy efficient equipment.
Standard Performance Contract	Cash incentives for increased energy savings at existing facilities.
Energy Savings Bid Program	Financial incentives for installing qualifying new, high efficiency equipment.
Savings by Design	Incentives for installing energy efficient equipment and systems in new construction and retrofit projects.
Sustainable Communities Program	Incentives for new construction projects to encourage sustainable building, energy efficiency and renewable power.
Small Business Super Saver	Rebates for installing more energy efficient equipment.
Statewide Business Energy-Efficiency Programs	Four investor-owned utilities teamed up to develop an energy efficiency website.
Flex Your Power	A statewide energy-efficiency marketing program that maintains a database of all California incentives programs.
On Bill Financing	Offered to qualified nonresidential customers to provide additional financing to facilitate the installation of energy efficiency measures.
Education & Outreach Programs	Provides energy efficiency information and training through seminars, classes and other energy efficiency customer events.
Residential Energy Efficiency Rebates	Rebates to residential customers and/or distributors/retailers to provide energy efficiency appliances and measures.
Other non-SDGE programs	SDG&E, through its competitive Bid process, is working with several third parties to deliver other energy efficiency programs to its nonresidential customers.

Program	Description
Peak Day 20/20	20% bill credit for business customers who can reduce electric load by 20% on selected summer days.
Demand Bidding Program	Customers can bid a level of load reduction at an offered price for each critical event.
Critical Peak Pricing	Lower rates for businesses that agree to reduce summer energy loads during critical peak periods.
Critical Peak Pricing - Emergency	Lower rates to businesses that can reduce loads on short notice.
Base Interruptible Program	Monthly bill credits for reducing load to a pre-determined level during critical events.
Peak Generation Program	Bill credits to customers who can utilize back-up generators on short notice.
Optional Binding Mandatory Curtailment	Businesses that reduce loads on entire circuits or dedicated substations during rolling curtailments can avoid curtailments altogether.
Scheduled Load Reduction Program	Incentive to reduce electric load for a pre-determined time period during the week.
Technical Assistance/Technology Incentives	A free service by SDG&E or SDG&E will pay a portion of the costs to customer-selected third parties to determine demand response potential at businesses and financial incentives for installing demand reduction technologies.

10.7. Related Policy Issues

10.7.1. Resource Planning Loading Order

In 2003, the State of California established the Energy Action Plan, a set of energy policy goals and directions for California.[24] The Energy Action Plan includes guidance for the three major investor-owned utility's (IOUs) in California to follow for all future resource planning. The loading order creates the following list of preferential resources.

1. Energy Efficiency
2. Demand Response
3. Renewable Generation

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[24] The Energy Action Plan was updated in September 2005. For a copy of Energy Action Plan II, see http://www.energy.ca.gov/energy_action_plan/index.html.

4. Distributed Generation

5. Clean Fossil Fuel-based Generation

6. Transmission and Distribution Infrastructure

As a result, the IOUs are aggressively pursuing energy efficiency and demand response and implementing projects that are cost-effective, reliable and persistent. This loading order also changes the way that utilities have traditionally planned to meet projected loads through the addition of new traditional generation facilities and the addition of new transmission and distribution lines.

10.7.2. Renewable Portfolio Standard[25]

In 2002, Governor Davis signed bill SB1078 that requires California to generate 20% of its electricity by the year 2017. At that time, this represented the most aggressive renewable portfolio standard (RPS) in the United States. The RPS program requires retail sellers of electricity (electric corporations, community choice aggregators, and electric service providers) meet the renewable energy minimum capacity requirements. If a seller of electricity fails to procure the sufficient quantity of electricity in any given year, they must compensate for the shortfall by acquiring additional renewable resources in subsequent years. In addition, the RPS requires the CPUC to institute a process for establishing market prices for electricity generated from renewable resources and to develop a process for establishing a rank ordering and selection process of least cost and best benefit resources to fulfill program obligations.

In 2005, the state's Energy Action Plan and the CEC's Integrated Energy Policy Report (IEPR) have proposed accelerating the state goal for the RPS to meet the 20% goal by 2010, seven years earlier than originally proposed. SB 107, which was recently enacted, codifies the acceleration of the RPS as contemplated by these two policy documents.

At the time of this report, SDG&E had 985 GWh (5.7% of baseline retail) of energy under contract for renewable energy. SDG&E plans to meet the 20% requirement by 2010 through the following mix of renewable generation assets.[26] Table 21 provides a forecast of the mix of renewable energy expected by 2010.

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[25] For more information about this proceeding, see www.cpuc.ca.gov/proceedings/R0602012.htm, www.cpuc.ca.gov/proceedings/R0605027.htm, and www.cpuc.ca.gov/proceedings/R0404026.htm.

[26] R.04-04-026, April 15, 2005, Bartolomucci

Table 21 Forecast of SDG&E Renewable Portfolio – 2010

Technology	Capacity (MW)	Production (GWh)	% of Production Mix
Bio Gas	45	321	9%
Bio Mass	40	350	10%
Wind	312	975	28%
Hydro	11	21	1%
Solar	182	319	9%
Geothermal	190	1,498	43%
Total	**780**	**3,484**	**100%**

10.7.3. Resource Adequacy[27]

In 2005, the CPUC adopted a framework for resource adequacy that applies to all retail sellers of electricity (IOUs, community choice aggregators and electric service providers) stipulating the requirements for meeting adequate generation reserves. The resource adequacy requirement will be phased in during 2006 and will be fully implemented by 2008. Resource Adequacy requires the seller of electricity to demonstrate that they have acquired sufficient resources to meet the peak load of their customers and have a 15% to 17% reserve. Sellers of electricity are required to demonstrate the ability to meet 90% of their customer's load one year in advance and the ability to meet the remaining 10% one month in advance. These resources must be made available to the CAISO in order to provide reserve support.

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[27] For more information about this proceeding, see www.cpuc.ca.gov/proceedings/R0512013.htm

10.8. Market Structure

10.8.1. Historical Overview

Prior to 1998, utility companies in California provided electricity to industrial, commercial and residential customers under the regulated utility energy model. In 1994, the "Blue Book" report issued by the CPUC revealed their intention to "dissolve the old power monopolies and create an open market within two years."[28] This set in motion what eventually led to the passage of AB 1890 in 1996, which created a wholesale market for electric power in California. Under this plan, electric utilities were forced to sell off their power generation assets and become strictly a transmission and distribution provider receiving energy though the California Power Exchange.

Under the new rules, utilities were limited with respect to the cost of electricity that could be passed onto consumers. The failure of the deregulation rules was the ability to manage adverse market forces, the faulty assumption that competition would increase right away, and the miscalculation of energy providers' ability to exploit the flow of electricity for their own financial gain. By the summer of 2000, Californians had paid $10.9 billion more than what they had paid in the previous year. Since utilities could not pass along these wholesale price increases, PG&E and SCE were in dire financial straits. PG&E was actually forced into Chapter 11 bankruptcy.

A series of steps followed that attempted to mitigate the damage and stabilize the market situation. In January, 2001 Governor Davis authorized the Department of Water Resources (DWR) to purchase power on behalf of the utilities because they were in such financial straits and power providers were unwilling to enter into contracts with the financially distressed utilities. This was followed by the State Legislature allowing the DWR to enter into long-term contracts with power providers and the CPUC approving higher rates be passed on to utility customers. In addition, Assembly Bill 1X (AB1X) provided for price stability for residential customers by placing a cap on the residential baseline rate. In September 2001, retail competition finally ended and with it, deregulation of the California electricity market.

10.8.2. Current Status

California energy markets have been relatively stable since the energy crisis ended. Power plant capacity in California has increased and significant upgrades have been made to the transmission and distribution system as well.

According to the California ISO's state-of-the-market report filed with FERC for 2005, there was a 52% reduction in the cost of managing local grid bottlenecks over the previous year when the cost for fuel is normalized. Upgrades to the transmission grid decreased the inter-zonal congestion costs from $426 million to $203 million in 2005. Wholesale megawatt-hour costs, when normalized for natural gas costs, were $75.78 in 1998 as compared to $45.26 in 2005. Without the dramatic increase in natural gas costs, electricity prices would be significantly lower than they were prior to deregulation.

Also contributing to a more stable market have been numerous CPUC/CEC/utility company supported programs. These include energy efficiency, demand response and self-generation programs which will be described in more detail in Section VIII.

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[28] See www.sen.ca.gov/sor/policy/energy/History.html.

10.8.3. Future Prospects

A major challenge in the future will be the expiration of long-term DWR power contracts. Beginning in 2010, thousands of MWs of power contracts will expire (see Table 22). As these contracts expire, the utilities will once again assume responsibility for meeting their energy demand requirements.

Table 22 DWR Long Term Contract Expiration Dates[29]
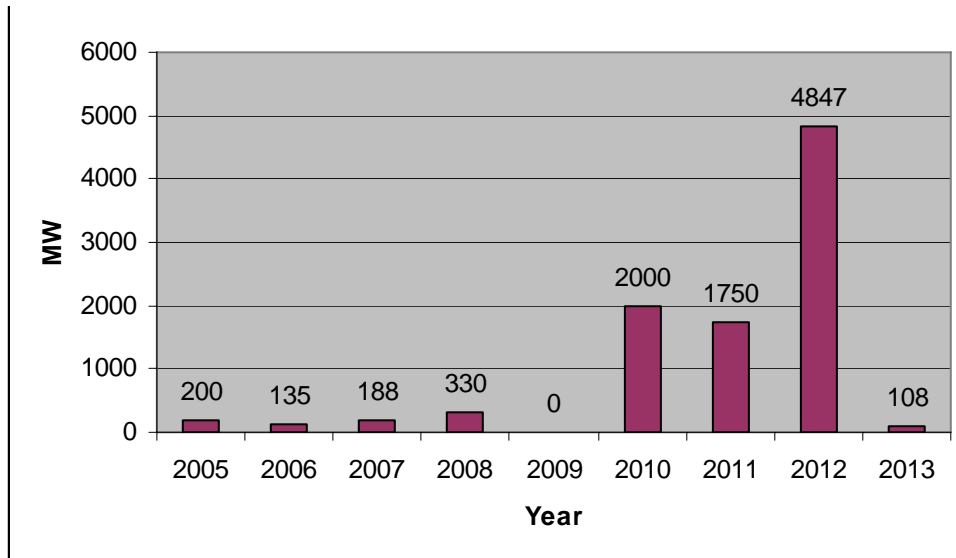
The CPUC is addressing future market structure issues with the goal of maintaining a reasonable level of market certainty while attempting to offer some level of retail choice to customers. Any structural shifts will need to be implemented well in advance of the expiration of DWR long-term contracts. One approach is the Core/Non-core market concept.

10.8.4. Core/Non-core Market Structure

The Core/Non-core structure is currently employed in the natural gas industry whereby large customers can choose their suppliers and the smaller customers receive bundled utility natural gas services. The idea is to re-introduce a limited direct access market for large electrical customers while ensuring stability in the broader energy market. The pivotal issue to implementing this structure is maintaining a certain degree supply/price certainty.

Utilities must have clear signals as to the amount of capacity they must plan for while still allowing for large customers to have the option of choice in their electricity supplier. Several options are under consideration, but they must be coordinated with the expiration of long-term DWR contracts in order to manage needed power replacement requirements.

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[29] Source: 2004 CPUC Staff Report

10.9. Technology Inventory

10.9.1. Customer Information System (CIS)

The SDG&E Customer Information System utilizes the Customer One CIS application developed in-house at SDG&E. This system was initially designed to support many different types of billing tariffs that were possible under the deregulated market for California, starting in 1998. Tariffs that are based around CPP, tiers or hourly pricing have proven to be challenging but not beyond the architecture and abilities of the current CIS.   Although some enhancements will be required for AMI implementation, it is not anticipated that any significant CIS changes would be required to support AMI based tariffs or functionality.

10.9.2. Outage Management System (OMS)

Outages are managed at SDG&E's mission control center. Outages are reported by SCADA or by customers via telephone calls into the Customer Contact Center. System operators use customer information to help isolate the potential location of the problem.

10.9.3. Supervisory Control and Data Acquisition (SCADA)

Most of SDG&E's electrical transmission substations are connected to the SDG&E Transmission Energy Management System (EMS) while many of the Distribution stations are connected to the Distribution SCADA system. Local medium voltage step-down substations do not yet have SCADA functionality.

EMS and SCADA connectivity are provided through leased lines, utility owned communication lines, microwave, and fiber network.

The primary function of the Transmission and Distribution SCADA at the substations are to provide real-time monitoring and control of substation components:

- Circuit Breakers: Transmission and distribution voltage levels
- Transformer Banks: LTC auto/manual and raise/lower commands
- Reclosers: Transmission tie-line and Distribution feeder circuits
- Ground Protection: Distribution circuits
- Capacitor Banks: auto/manual and vacuum switch open/close
- Fault Target Resets: Distribution circuits

In addition, the following functions are available to the system operators.

- Load monitoring
- Load shedding control
- Outage management & detection
- Automated power restoration
- Distribution switching & control
- Power generation and transmission line monitoring
- Transmission switching & control
- Power transient detection
- Power outage management & restoration
- System load & import monitoring

All pertinent real-time SCADA measurement data is archived so that it can be used for subsequent data analysis and report generation.

7.1   Billing Meters

Table 23 presents the most recent summary of the population of customers by customer type.

Table 23 SDG&E Customer Population by Type[30]

Month/Year	Agriculture	Lrg Com/Ind	Med Com/Ind	Residential	Schedule A6	Schedule AD	Small Com	Total
Mar-06	3,441	666	21,433	1,191,998	14	376	116,511	1,334,439
Feb-06	3,435	671	21,370	1,190,651	14	378	116,309	1,332,828
Jan-06	3,436	671	21,358	1,189,362	14	381	116,225	1,331,447
Dec-05	3,435	667	21,309	1,188,178	14	382	116,022	1,330,007
Nov-05	3,429	658	21,288	1,186,257	14	384	115,946	1,327,976
Oct-05	3,424	660	21,232	1,184,434	14	385	115,756	1,325,905
Sep-05	3,419	660	21,178	1,183,630	14	386	115,599	1,324,886
Aug-05	3,425	658	21,126	1,181,714	16	387	115,478	1,322,804
Jul-05	3,418	659	21,086	1,180,626	16	390	115,449	1,321,644
Jun-05	3,419	652	21,028	1,179,898	16	393	115,390	1,320,796
May-05	3,419	649	20,917	1,177,981	16	394	115,431	1,318,807
Apr-05	3,419	650	20,847	1,176,739	16	395	115,420	1,317,486
	3,427	660	21,181	1,184,289	15	386	115,795	1,325,752
	0.258%	0.050%	1.598%	89.330%	0.001%	0.029%	8.734%	100.000%

All residential meters are mechanical meters that are read manually by meter readers. Commercial customers with demand between 20 and 200 kW have interval meters that do not have communications. C&I customers with demand greater than 200 kW have interval meters with communication capability.

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[30]A6: Optional Time-of-Use tariff for customers with a peak demand greater than 500 kW. AD: Closed schedule that is a demand-based tariff

10.10. End-use Technology

10.10.1. Energy Efficiency

The regional energy efficiency programs provide incentives for the installation of energy efficient equipment covering the following technology areas:

- Lighting
- Lighting Controls
- Air Conditioning Equipment
- Motors / Variable Speed Drives
- Food Service Equipment
- Refrigeration
- Water Heaters
- Space Heaters
- Reflective Window Films
- Energy Star Office Equipment

10.10.2. Demand Response and Reliability Programs[31]

Technologies that have been implemented to support the demand response programs include solid state interval data recording (IDR) billing meters with communications, direct load control and distributed resource aggregation.

10.10.3. IDR Meters with Communications

SDG&E offers to its business customers several demand response programs that require IDR meters with communications. These meters, along with the communications interface, allows customers to track their energy usage on a daily basis. Customers can also track their usage on a more immediate basis (usually 20-30 minutes) during a critical event. And finally, the IDR meters provide the information necessary for SDG&E to bill customers for usage during these critical events or to calculate incentives for load reduction during these critical events.

10.10.4. Direct Load Control

SDG&E has contracted with Comverge to implement a direct load control program. This program implements a technology to manage customer end-use equipment during critical summer peak periods. The systems will cycle air conditioning equipment, electric water heaters and pump motors. The program focuses on residential customers.

10.10.5. Distributed Resource Aggregation

SDG&E has contracted with Celerity Energy to implement an aggregated network of distributed resources that can be operated in a load shedding or load transfer manner by

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[31] R.04-04-003, July 9, 2004, Sides

remotely operating natural gas or dual fueled customer-owned generators. The estimated demand response for this program is 19 MW by 2007.

10.10.6. Self Generation

The Self-Generation Incentive Program offers incentives for photovoltaics, wind turbines, fuel cells, microturbines, small turbines, IC engines and large gas turbines. The rebates range from $0.60 to $4.50 per watt (up to 5 MW). A summary of the technologies installed under this program in the San Diego region as of XX and since program inception is presented in the Table 24.[32]

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[32] www.sdenergy.com, Statewide Self-Generation Incentive Program Data, April 2006

Table 24 Summary of Technologies Installed through the SGIP Program

Technology	# of Installations	Installed Capacity (kW)	Avg. Capacity per Installation (kW)
Year = 2002			
Fuel Cell	0	0.0	0.0
Gas Turbine	0	0.0	0.0
IC Engine	2	550.0	275.0
Microturbine	1	90.0	90.0
Photovoltaic	2	73.8	36.9
Subtotal: 2002	*5*	*713.8*	*142.8*
Year = 2003			
Fuel Cell	0	0.0	0.0
Gas Turbine	0	0.0	0.0
IC Engine	3	1,460.0	486.7
Microturbine	6	450.0	75.0
Photovoltaic	6	1,971.4	328.6
Subtotal: 2003	*15*	*3,881.4*	*258.8*
Year = 2004			
Fuel Cell	0	0.0	0.0
Gas Turbine	0	0.0	0.0
IC Engine	4	2,510.0	627.5
Microturbine	5	856.2	171.2
Photovoltaic	17	946.9	55.7
Subtotal: 2004	*26*	*4,313.1*	*165.9*
Year = 2005			
Fuel Cell	0	0.0	0.0
Gas Turbine	0	0.0	0.0
IC Engine	2	1,655.0	827.5
Microturbine	2	180.0	90.0
Photovoltaic	36	4,027.8	111.9
Subtotal: 2005	*40*	*5,862.8*	*146.6*
Year = 2006*			
Fuel Cell	1	1,000.0	1,000.0
Gas Turbine	0	0.0	0.0
IC Engine	6	1,615.0	269.2
Microturbine	0	0.0	0.0
Photovoltaic	10	794.6	79.5
*Subtotal: 2006**	*17*	*3,409.6*	*200.6*
Total	**103**	**18,180.7**	**176.5**

* To Date (April 2006)

Pending projects in the program (as of April 2006) are listed in Table 25.

Table 25 SGIP Pending Projects

Technology	# of Installations	Installed Capacity (kW)	Avg. Capacity per Installation (kW)
Pending Projects			
Fuel Cell	1	500.0	500.0
Gas Turbine	3	4,867.0	1,622.3
IC Engine	1	1,495.0	1,495.0
Microturbine	2	280.0	140.0
Photovoltaic	94	18,391.7	195.7
Subtotal: Pending	*101*	*25,533.7*	*252.8*

Customers who have installed renewable DG also can use a billing system called net energy metering, or NEM. Under NEM, a customer is given retail credit for excess power generated on a monthly basis. Once a year the utility reconciles, or "trues up," the previous 12-months of performance and bills the customer for outstanding charges. While this is not a direct financial incentive, customers receive full retail credit for the excess power generated on a monthly basis, which is a form of subsidy.

11. APPENDIX C: SAN DIEGO SCENARIO DETAILS

11.1. Future Smart Grid Framework

The project team used a scenario-based approach to determine whether future economic, regulatory, technology conditions in the San Diego region would accommodate and necessitate development of a Smart Grid. This is the initial step in the process to determine the feasibility of implementing a Smart Grid in the region.

To do this, the project team forecast the future state of the region in terms of the variables identified in the scenarios. If the likely future state does not justify the need for a smart grid then the regional electrical infrastructure should continue to follow a traditional utility strategy. However, if the likely future state of the region could justify the development of a smart grid, the next step in the process is to compare the current grid infrastructure to the smart grid future infrastructure to identify what technology gaps exist. The results of the gap analysis will be a list of technologies needed to transition to a smart grid. These technologies will be evaluated through a cost benefit analysis to identify those system changes and technologies that can be cost-effectively implemented in the region. This report presents detailed information about the process used to develop the future scenarios and identifies the likely future state of the San Diego region. The San Diego Smart Grid Study process is presented in Figure 1.

Figure 1 Smart Grid Study Process
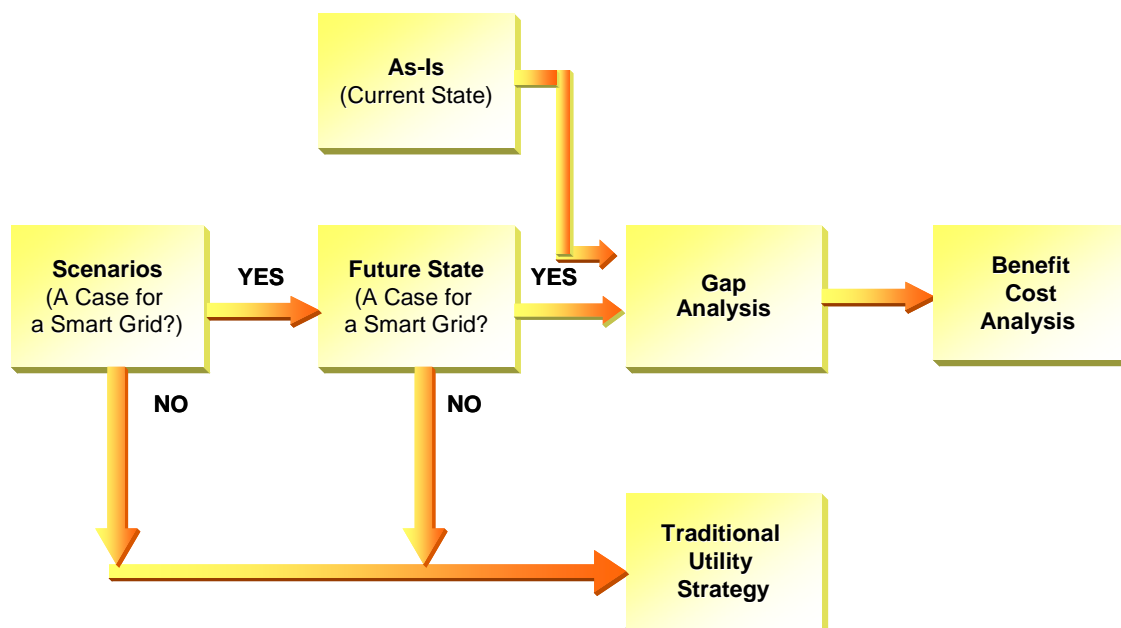
To evaluate the feasibility of implementing a smart grid in the San Diego region, the project team developed a process that included the following: defining the scenarios, identifying the areas of external influences that affect the operation and characteristics of the grid, identifying specific drivers within each area of external influence and then evaluating the impact that the drivers have on establishing a case for the implementation of a smart grid.   The elements of the of Future Smart Grid Framework areas are listed below. The report follows these topics.

1. A Case for a Smart Grid in the Region

- o Scenario Categories
- o External Influences
- o Drivers of External Influences
- o Impact of Drivers on Scenarios
- o Strongest Influences to Support a Smart Grid
- o Conclusions from Scenario Analysis
2. Likely Future State
3. Inputs for the Gap Analysis

11.2. Scenario Development

The project team developed categories of factors to be used to determine the likely future scenario for the San Diego region. These categories, which cover the spectrum of the possible scenarios for the region, are listed below.

- Economic Influences
- Environmental Regulation Influences
- Level of Technology Development.

Based on these categories, the project team developed six scenarios that examine the extreme ends of each category. Figure 2 demonstrates these scenarios.

Figure 2 San Diego Scenarios

Blue Sky	← Economic Influence →	Recession
Environmentally Friendly	← Environmental Regulation Influence →	Constrained Regulation
Breakthrough Development	← Level of Technology Development Influence →	Minimal Development
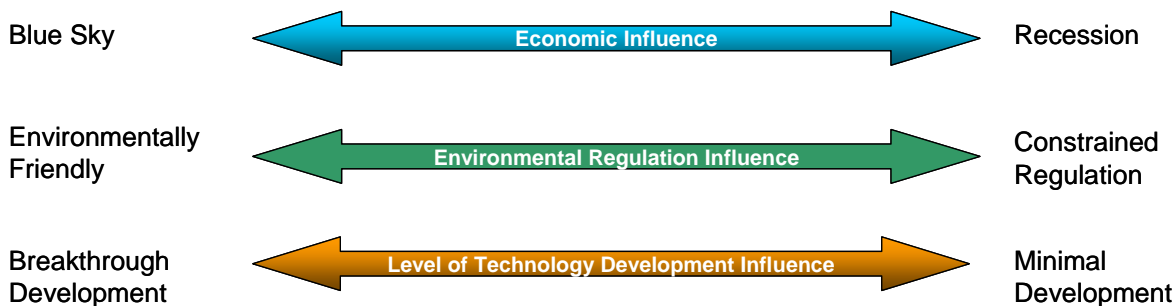
11.2.1.   Economic Influence

The project team examined a range of economic factors and constructed two scenarios that represent the extremes: recession (pessimistic) and blue sky (optimistic). Each of these scenarios is described below.

Blue Sky

Under the Blue Sky scenario, business expansion and economic growth conditions prevail. New businesses are moving into the region, which in turn increases the tax base.   Because of the strong economy, household incomes are higher along with discretionary spending. The

tourism industry also thrives. Business revenues increase and this supports the development of new advanced technologies.

Commercial and industrial customers are rapidly investing in energy efficiency, demand response technologies and on-site generation. New housing developments incorporate photovoltaic systems, energy star appliances and low-water consuming appliances and fixtures. There is increased adoption of consumer electronics which contributes to increasing electrical load growth in the residential sector. Sophisticated customers begin to adopt new energy technologies combined with time-based rate schedules that enable consumers to modify their consumption patterns based on knowledge of cost impacts

Recession

Under the Recession scenario, the business climate is very challenging and some businesses are forced to leave the region or even fold.   The tax base shrinks for state and local governments. Personal income also decreases leaving limited discretionary spending. The tourism industry contracts to significantly lower levels.

Adoption rates for advanced energy technologies are very low. Few changes are made to energy tariffs which is in part a result of the low investment levels. New building construction is minimal. Overall electrical demand growth is flat or decreasing.

11.2.2.   Environmental Regulation

The project team examined a range of factors relating to environmental regulation and constructed two scenarios that represent the extremes: environmentally friendly regulation (high level of regulation) and constrained regulation (low level of regulation). Each of these scenarios is described below.

Environmentally Friendly (High level of regulation)

Under an Environmentally Friendly Regulation scenario, regulators and legislators adopt regulations designed to protect the environment, such as air emissions standards, increased focus on renewable energy and alternate fuels in the energy industry. Both research and market acceptance of these technologies is increasing. There is also a renewed focus on energy efficiency and demand reduction programs which results in measurable improvements in efficient energy use. Costs to generate power and build new power plants and transmission and distribution infrastructure are increasing. California experiences a decrease in commercial and industrial business due to the higher costs of environmental reporting and compliance.

Under this scenario, regulators mandate reporting on greenhouse gas emissions and develop a tradable emissions credit market. Additionally, there are increased incentives and tax credits for energy efficiency, alternative fuels and hybrid vehicles.

Constrained Environmental Regulation (Low level of regulation)

Under a Constrained Environmental Regulation scenario, there is a decreased focus on renewable energy and alternate fuels in the energy industry. There is very little research and market acceptance of these technologies. Energy efficiency and demand reduction programs are not emphasized. Regulation of and permitting for new power plants and transmission and distribution infrastructure is less stringent. Costs for new power plants and transmission and distribution infrastructure are on the rise. Biomedical companies remain in the area and further develop production facilities.

Reporting of greenhouse gas emissions is voluntary as there is no mandated tradable emissions credit market. Incentives and tax credits for energy efficiency and alternative fuels are reduced.

11.2.3.   Technology Development

The project team examined a range of factors relating to technology development and constructed two scenarios that represent the extremes: breakthrough development and minimal development. Each of these scenarios is described below.

Breakthrough Technologies

Under the Breakthrough Technologies scenario, there are major advancements in generation, communication and energy efficiency/demand reduction technologies. A major advancement in technology is defined by providing ten times the functionality at one-tenth the cost. A summary of the types of technologies that would likely advance under this scenario follows.

Generation technologies:

- Fuel cells
- Wind Generators
- PV
- Wave Energy
- Gas Turbines
- Geothermal
- Energy Storage

Communication technologies:

- Cellular
- BPL
- Satellite
- Fiber Optics

Energy Efficiency / Demand Reduction technologies:

- Smart Appliances
- Wireless Controllers

Technology advances result in increased functionality and drastically lower costs. This scenario also includes advancements in the following control technologies: sensors, predictive maintenance, and artificial intelligence.

Minimal Technology Advancements

Under the Minimal Technology Advancements scenario, existing technologies do not become more efficient or enable users to manage their energy consumption. There are only marginal advancements in generation, communication and energy efficiency/demand reduction

technologies. There are only marginal increases in technology functionality. Costs remain flat or increase only slightly. The minimal technology advancement scenario results in a lack of new infrastructure to support advanced control technologies.

11.3. External Influences

The project team identified five categories of external influences that will affect whether or not the region can substantiate the implementation of a smart grid. The five areas of external influence are as follows:

- Change in Electric Load

- Change in Legislation

- Change in Regulations

- Change in Environmental Conditions

- Change in Technology Development

These influences directly affect the requirements of the utility's level of service, the rules of operation that the utility and other electric service providers must follow, and the technologies that potentially affect the daily operation of energy supply and energy consumption.

Legislation addresses the impact of laws passed at the federal and state levels and regulation addressed the ruling and directives as governed by the CPUC. Environmental conditions consist of those occurrences that include natural and man-created disasters and the depletion of natural resources.

11.3.1.   Factors of External Influences

Associated with each area of external influence are factors that affect the direction and magnitude of the influence. These drivers – or factors – are presented in the form a fishbone diagram for the purposes of the analysis. Figures 3 through 7 present the fishbone diagram for each area of external influence.   A driver followed by the initials "WC" indicates that the driver is a Wild Card. This means that a driver does not have a high probability of happening but could have an impact on the grid.

Figure 3 Factors Affecting Electric Load

Change of Electric Load

Weather

Manufacturing

Culture/People profile

Water/Gas

LNG terminal

Economic Development

Change in Federal presence

Change in Infrastructure

Business Profile

Airport Moves/Expands

CA Solar Initiative
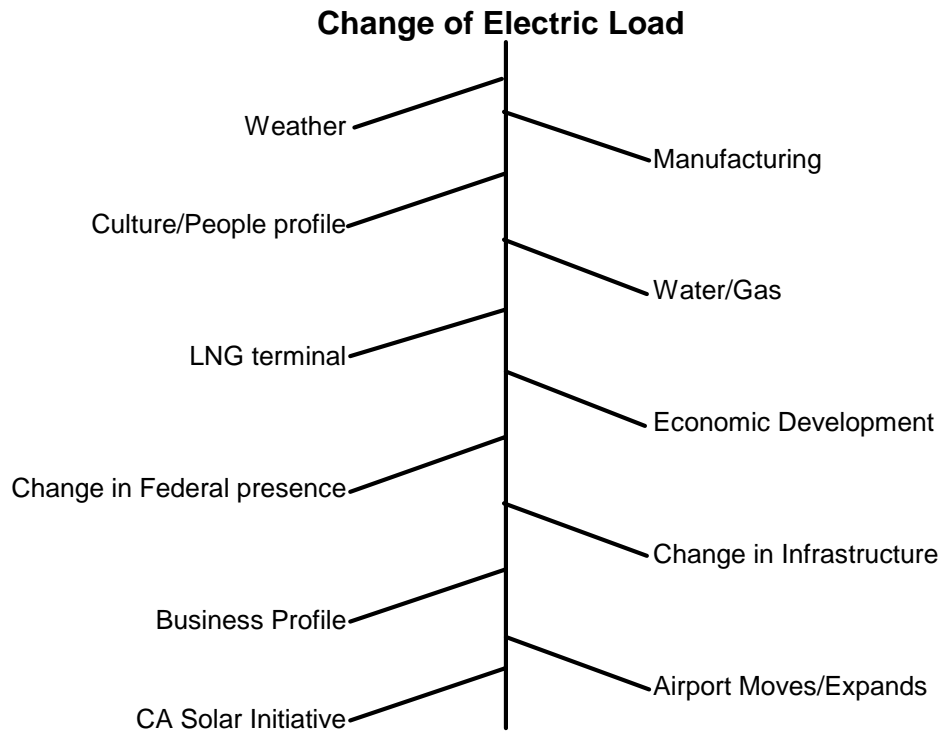
Figure 4 Factors Affecting Legislation

Change in Legislation

EPACT 2005

Long-term commitment
to PTC (WC)

GFA Act (WC)

Municipalization

Change in Utility Structure

Deregulation

Incentives

Title 24

Renewable Portfolio Standards

Resource Adequacy

GHG trading (WC)
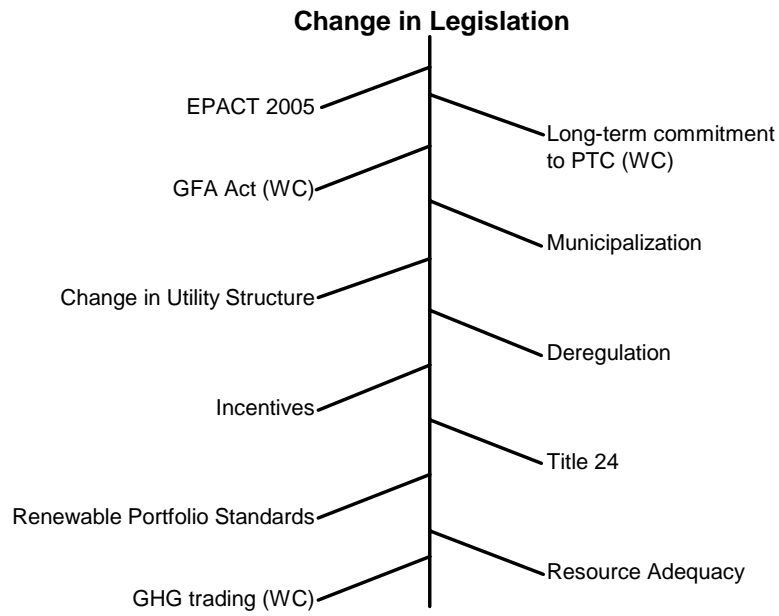
Figure 5 Factors Influencing Changes in Regulation

Change in Regulation

Tariffs

Loading order

LMP 2007 -08

Reliability Rules

FERC Orders

Incentives
 utilities
 consumers

Long term Market Incentives

ERO reliability enforcement

Change in ISO (WC)
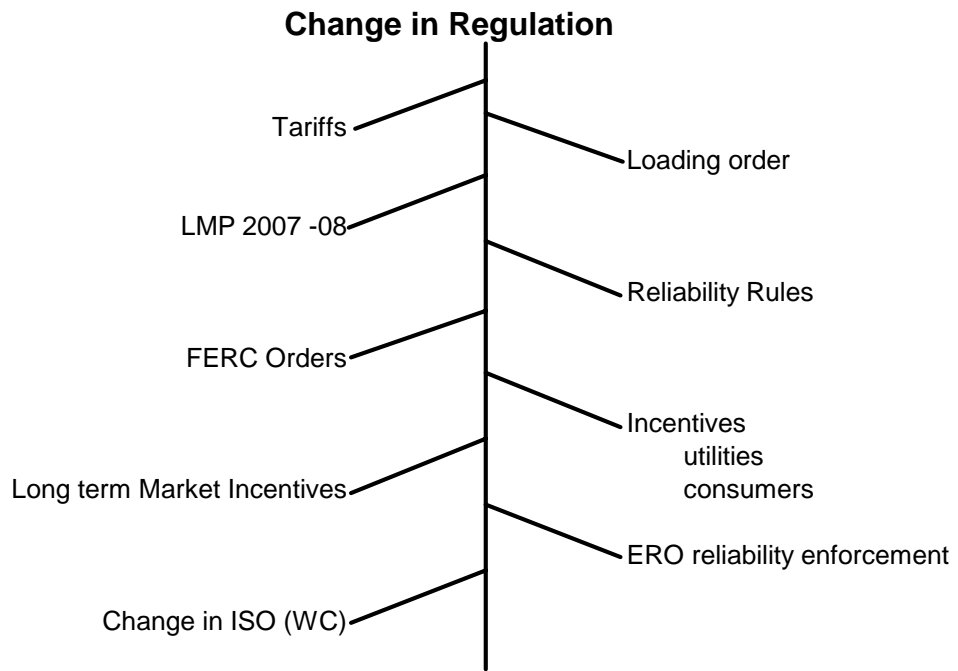
Figure 6 Factors Affecting Environmental Conditions

Change in Environmental Conditions

Earthquake

Firestorms

Terror Attack

Tsunami (WC)

Natural Gas

New Fuels

Gasoline

Adoption of Kyoto (WC)

Delivery
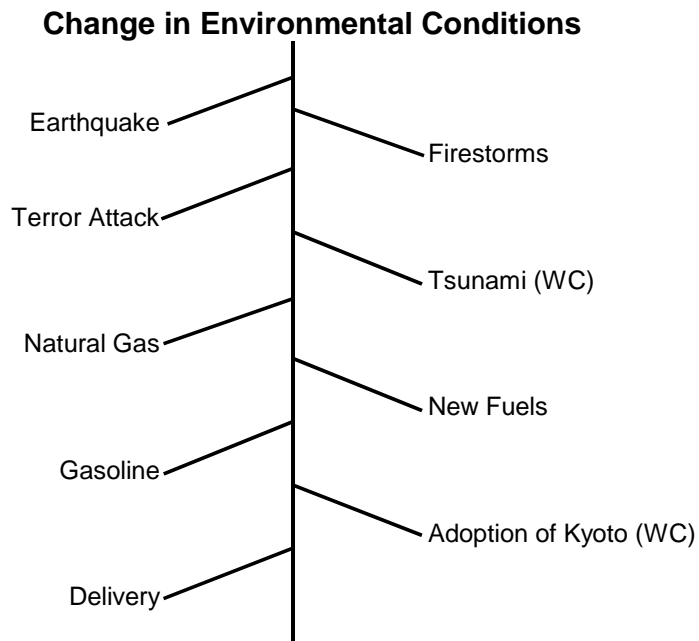
Figure 7 Factors Affecting Technological Change

Change in Technology

Communication Infrastructure

Advanced Storage

Communication Standards

Shift from central generation
to distributed generation

Wave Energy (WC)

Zero Energy Homes

Industry Standards

Infusion of Nanotechnology (WC)

Reduced cost
of power electronics
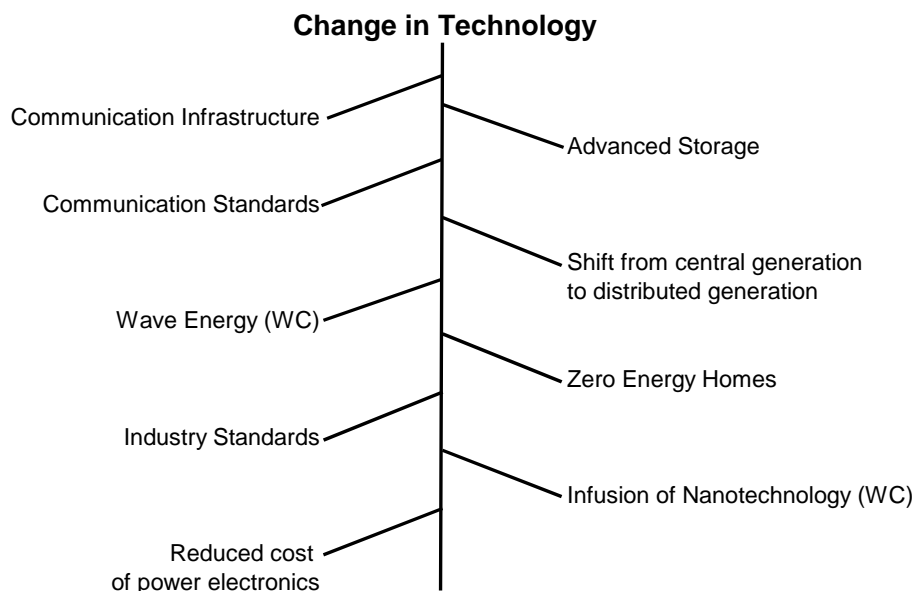
11.3.2. Impact of Drivers on Scenarios

To determine the case for a smart grid for each scenario, the project team mapped each driver to the scenarios for which it would have an impact. Next, the team defined a trend for each driver that is projected to occur under the defined scenario. For example, in the Blue Sky scenario economic development is projected to have an increasing trend where as in the Recession scenario it is projected to have a decreasing trend.

Tables 1 through 6 summarize the drivers and their assumed trends for each scenario.

Table 1 Summary of Blue Sky Scenario

External Influence	Driver	Scenario Trend
Environment	New fuels	Increased Availability
Environment	Natural Gas	Increased Availability
Environment	Gasoline	Increased Availability
Legislation	Change in utility structure	Market-based
Legislation	Deregulation	Increasing Customer Choice
Legislation	Renewable Portfolio Standards	Increased Renewables
Legislation	Commitment to PTC (WC)	Long Term
Legislation	Incentives	Reduction in Incentives
Load	Business Profile	Growth
Load	Culture/People Profile	Growth
Load	Economic Development	Growth
Load	Manufacturing	Growth
Regulation	Tariffs	Increase Time-based rates
Regulation	Reliability Rules	Alternate Approaches
Regulation	ERO reliability enforcement	Increasing
Regulation	Incentives	Reduced Incentives
Regulation	Time Horizon of Market Incentives	Short Term
Technology	Communication Infrastructure	Increasing Bandwidth
Technology	Advanced Storage	Increased Availability
Technology	Zero Energy Homes	Increased Availability
Technology	Reduced cost of power electronics	Increased Availability
Technology	Communication Standards	Increasing Standards
Technology	infusion of nanotechnology (WC)	Increased Availability
Technology	Wave Energy (WC)	Increased Availability
Technology	Industry Standards	Increasing Standards

Table 2 Summary Recession Scenario

External Influence	Driver	Scenario Trend
Environment	Natural Gas	Reduced Supply
Environment	Gasoline	Reduced Supply
Legislation	Deregulation	Increasing Regulation
Legislation	Incentives	Increasing Incentives
Legislation	Resource Adequacy	Reduced Infrastructure Requirements
Legislation	Commitment to PTC (WC)	Short Term
Legislation	Change in Utility Structure	More Regulation
Legislation	Renewable Portfolio Standards	Decreased Renewables
Load	Economic Development	Decreasing Activity
Load	Business Profile	Decreasing Growth
Load	Culture/People Profile	Decrease Adoption
Load	Manufacturing	Decreased Activity
Regulation	Incentives	Increased Incentives
Regulation	ERO Reliability Enforcement	Increasing Reliability
Regulation	Time Horizon of Market Incentives	Long Term

Table 3 Summary of Environmentally Friendly Scenario (High Level of Regulation)

External Influence	Driver	Scenario Trend
Environment	Adoption of Kyoto (WC)	Increased Regulation
Environment	Gasoline	Decreasing Supply
Environment	Natural Gas	Decreasing Supply
Environment	New Fuels	Increased Availability
Legislation	Title 24	Increased EE Requirements
Legislation	Commitment to PTC (WC)	Long Term
Legislation	Renewable Portfolio Standards	Increased Renewables
Legislation	Deregulation	Increasing Customer Choice
Legislation	Incentives	Increasing Incentives
Legislation	GHG Trading (WC)	Developing Market
Legislation	GFA Act (WC)	New Appliance Standards
Load	California Solar Initiative	Increased Adoption
Load	Business Profile	Decreasing Growth
Load	Culture/People Profile	Decreased Adoption
Load	Change in Infrastructure	No Change
Regulation	ERO Reliability Enforcement	Increasing Enforcement
Regulation	Incentives	Increased Incentives
Regulation	Loading Order	Maintain Ranks in Order
Regulation	Reliability Rules	Status Quo
Regulation	Tariffs	Status Quo
Technology	Advanced Storage	Increasing Development
Technology	Shift from Central to Distributed Generation	Increasing Cost Effectiveness
Technology	Zero Energy Homes	Increasing Technology Advancement
Technology	Communication Infrastructure	Increasing Infrastructure
Technology	Communication Standards	Increasing Standards
Technology	Wave Energy (WC)	Increasing Technology Advancement

| Technology | Industry Standards | Increasing Standards |

Table 4 Summary of Constrained Regulation Scenario (Low Level of Environmental Regulation)

External Influence	Driver	Scenario Trend
Environment	New Fuels	Status Quo
Legislation	Deregulation	Increasing Regulation
Legislation	Title 24	Status Quo
Legislation	GHG trading (WC)	Status Quo
Legislation	Commitment to PTC (WC)	Short Term
Legislation	GFA Act (WC)	Status Quo
Legislation	Incentives	Reduction in Incentives
Legislation	Renewable Portfolio Standards	Decreased Renewables
Load	Economic Development	Increased Development
Load	Culture/People Profile	Increased Adoption
Regulation	ERO Reliability Enforcement	Increasing Enforcement
Regulation	Change in ISO (WC)	Reduced Control
Regulation	Incentives	Reduced Incentives
Regulation	Loading Order	More Reliance on Gen and Trans
Regulation	Reliability Rules	Status Quo
Regulation	Tariffs	Status Quo
Technology	Shift from Central to Distributed Generation	Increasing Shift
Technology	Wave Energy (WC)	Status Quo

Table 5 Breakthrough Technology Development Scenario

External Influence	Driver	Scenario Trend
Environment	Terror Attack	Proactive Planning
Environment	Firestorms	Proactive Planning
Environment	Tsunami (WC)	Proactive Planning
Environment	Earthquake	Proactive Planning
Legislation	Title 24	Increased EE
Legislation	Change in Utility Structure	Market-based
Legislation	Resource Adequacy	Modified Definition of Reserves
Legislation	Utility Regulation	Move toward Deregulation
Legislation	Renewable Portfolio Standards	Increased Renewables
Legislation	GFA Act (WC)	Increase Market Penetration
Legislation	EPACT 2005	Increased Tax Incentives
Legislation	GHG trading (WC)	Active Market
Legislation	Incentives	Increasing Incentives
Legislation	Commitment to PTC (WC)	Long Term
Load	Economic Development	Increased Development
Load	Weather	Increased Impact
Load	Culture/People Profile	Increased Adoption
Load	Water/Gas	Increase Costs
Load	Change in Infrastructure	Increased Infrastructure
Load	Manufacturing	Increased Manufacturing
Load	California Solar Initiative (WC)	Increased Adoption
Load	Business Profile	Increasing Growth
Load	LNG terminal	Increased Availability/Stability
Regulation	Tariffs	Increase Time-based Rates
Regulation	LMP 2007 -08	Implemented
Regulation	ERO Reliability Enforcement	Increasing Reliability
Regulation	FERC Orders	Increased Federal

		Regulation
Regulation	Loading Order	Maintain Ranks in Order
Regulation	Change in ISO (WC)	Reduced Control
Regulation	Reliability Rules	Alternate Approaches
Regulation	Incentives	Increased Incentives
Regulation	Time Horizon of Market Incentives	Short Term
Technology	Advanced Storage	Increasing Storage Options
Technology	Communication Infrastructure	Increasing Infrastructure
Technology	Shift from Central to Distributed Generation	Increasing Shift to Distributed
Technology	Zero Energy Homes	Increasing Technology Advancement
Technology	Communication Standards	Increasing Standards
Technology	Infusion of Nanotechnology (WC)	Increasing Market Penetration
Technology	Reduced Cost of Power Electronics	Increasing Cost Reductions
Technology	Industry Standards	Increasing Standards
Technology	Wave Energy (WC)	Increased Technology Advancement

Table 6 Minimal Technology Development Scenario

External Influence	Driver	Scenario Trend
Legislation	Utility Regulation	Increasing Regulation
Legislation	Title 24	Status Quo
Legislation	EPACT 2005	Increased Tax Incentives
Load	Economic Development	Decreasing Development
Load	Water/Gas	Decreasing Availability
Regulation	ERO Reliability Enforcement	Increasing Enforcement
Regulation	Loading Order	Maintain Ranks in Order
Regulation	FERC Orders	Status Quo
Regulation	Reliability Rules	Status Quo
Regulation	Tariffs	Status Quo
Technology	Communication Infrastructure	Increasing Infrastructure
Technology	Reduced Cost of Power Electronics	Increasing Cost Reductions
Technology	Industry Standards	Increasing Standards
Technology	Communication Standards	Increasing Standards

11.3.3. Strongest Influences to Support a Smart Grid

To determine which influences most strongly supported a smart grid, a group of smart grid experts worked as a focus group to assess the drivers within each of the external influence categories. The experts assigned a score of one (1) through ten (10) to represent the likely level of impact that a driver would have on the operation or demands of the electric grid. One (1) represents little or no influence and ten (10) represents a major or substantial influence. Next, the experts determined if the impact would make a case for substantiating a case for a smart grid. This was applied by a score of one (1) or zero (0) with one meaning that it made a case. The final score for each driver was calculated by multiplying the impact score by the case for smart grid score.

Next, the scores from the four experts were averaged to develop an Average Composite score for each driver. The drivers ranked by highest score (i.e. highest impact) making a case for a smart grid are presented in Appendix B.

The top ranked drivers for supporting the case for a smart grid under the six scenarios are as follows:

- Blue Sky Scenario (Average Score of Top Drivers = 10.0)
    - o Load

- o Business Profile
- o Cultural and People Profile
- o Economic Development
- o Manufacturing Industry
- o Legislation
- o Change in Utility Structure
- o Technology
- o Communication Infrastructure
- o Advanced Storage

- Recession Scenario (Average Score of Top Drivers = 4.6)
  - o Regulation
  - o Incentives
  - o ERO Reliability Enforcement
  - o Legislation
  - o Incentives
  - o Deregulation
  - o Environment
  - o Natural Gas

- Environmentally Friendly Scenario (Average Score of Top Drivers = 8.4)
  - o Legislation
  - o Title 24
  - o Commitment to PTC (WC)
  - o Renewable Portfolio Standards
  - o Environment
  - o Adoption of Kyoto (WC)
  - o Technology
  - o Shift from Central to Distributed Generation
  - o Advanced Storage
  - o Zero Energy Homes
  - o
  - o

- Constrained Environmental Regulation Scenario (Average Score of Top Drivers = 5.5)
  - Load
  - Economic Development
  - Cultural and People Profile
  - Regulation
  - ERO Reliability Enforcement
  - Change in ISO (WC)
  - Legislation
  - Deregulation
  - Technology
  - Shift from Central to Distributed Generation

- Breakthrough Technology Development Scenario (Average Score of Top Drivers = 9.2)
  - Load
  - Economic Development
  - Regulation
  - Tariffs
  - LMP 2007 -08
  - Legislation
  - Title 24
  - Change in Utility Structure
  - Environment
  - Terror Attack
  - Technology
  - Advanced Storage
  - Communication Infrastructure
  - Shift from Central to Distributed Generation

- Minimal Technology Development Scenario (Average Score of Top Drivers = 5.6)
  - Regulation
  - Loading Order
  - ERO Reliability Enforcement
  - Legislation
  - Deregulation

- o Technology
- o Communication Infrastructure
- o Reduced Cost of Power Electronics
- o Industry Standards
- o Communication Standards

11.4. Conclusions from Scenario Analysis

The project team developed a composite score for each scenario by averaging the score for the drivers that might influence each scenario. The team established three score ranges to represent how favorable a scenario is to the smart grid concept. The resulting score values are defined in Table 7.

Table 7 Scenario Scoring Ranges and Definition

Score	Case for a Smart Grid?
0.0 – 3.3	Not a Case for a Smart Grid
3.3 – 6.7	No Definitive Case for a Smart Grid
6.7 - 10	Favorable Case for a Smart Grid

The result of "No Definitive Case" indicates that there is not a strong case either for or against a smart grid. In this case, a decision to move forward with a smart grid will need to take into account additional factors (e.g., change in business processes, system expansion plans, equipment replacement projects, etc.) or through a strategy of incremental improvements combined with continued evaluation of smart grid options.

The composite score for each scenario considered is summarized in Table 8.

Table 8 Scoring for Future San Diego Scenarios

Scenario	Score
Blue Sky	7.4
Recession	2.2
Environmentally Friendly	5.6
Constrained Environmental Regulation	2.2
Breakthrough Technology	7.2
Minimal Technology Development	2.6

The scoring indicates that the Blue Sky and Breakthrough Technology Development Scenarios represent a favorable case for a smart grid. The Environmentally Friendly scenario falls in the

upper range of the No Definitive Case category. The three scenarios of Recession, Constrained Environmental Regulation and Minimal Technology Development fall into the Not a Case for a Smart Grid scoring range. These results are presented graphically in the Figure 8.

Figure 8 Scoring for Future San Diego Scenarios
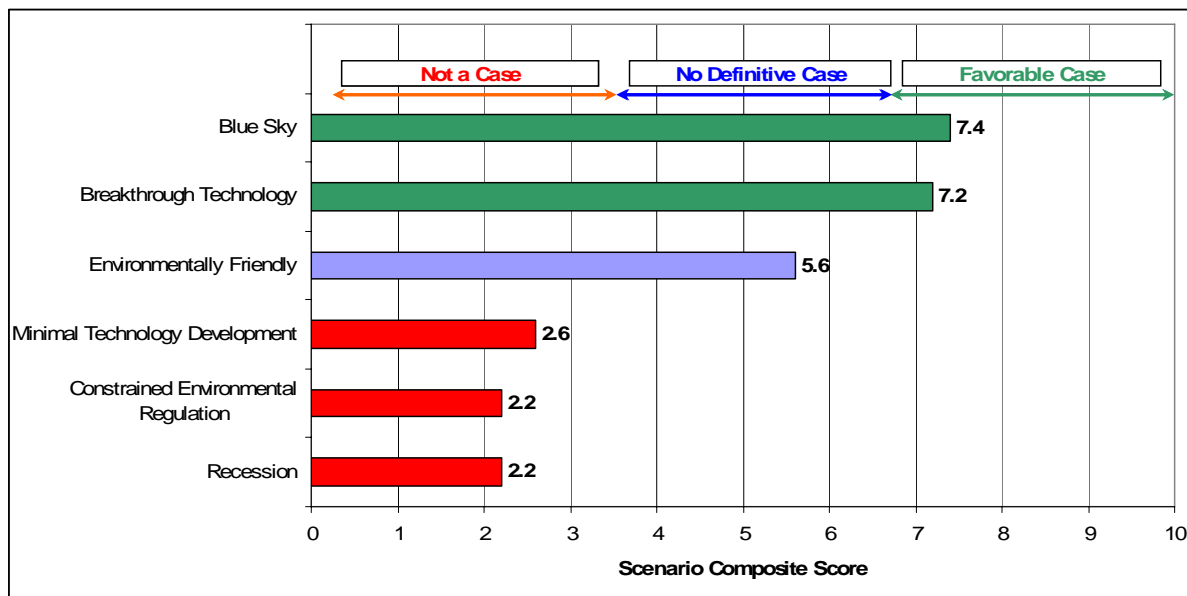
11.5. Likely Future State

The analysis of the scenarios in the previous section demonstrated that under certain scenarios, the circumstances could exist to support implementation of a smart grid in the San Diego Region. In this section, a forecast of the future is made and analyzed to determine if the likely future is a scenario that makes a case for the implementation of a smart grid.

The drivers that have been previously identified as creating an external influence on the operational requirements of the grid were selected for the appropriate trend that is anticipated in the future for the San Diego region. Then the scores of the focus group were applied and used as the basis to determine a composite score for the likely future state. The drivers, anticipated trends, and scores for the likely future state are presented in Table 9.

Table 9 Likely Future State

External Influence	Scenario	Driver	Scenario Trend	Average Composite Score
Environment	Blue Sky	New fuels	Increased Availability	7
Legislation	Blue Sky	Change in Utility Structure	Market-based	10
Legislation	Blue Sky	Renewable Portfolio Standards	Increased Renewables	8
Load	Blue Sky	Business Profile	Increasing Businesses	10
Load	Blue Sky	Culture/People Profile	Increasing Population	10
Load	Blue Sky	Economic Development	Increase Economy	10
Regulation	Blue Sky	Tariffs	Increase Time-based rates	9
Technology	Blue Sky	Communication Infrastructure	Increasing Bandwidth	10
Technology	Blue Sky	Zero Energy Homes	Increased Availability	9
Technology	Blue Sky	Communication Standards	Increasing Standards	8
Environment	Environmentally Friendly	New Fuels	Increased Availability	6
Legislation	Environmentally Friendly	Title 24	Increased EE Requirements	9
Legislation	Environmentally Friendly	Renewable Portfolio Standards	Increased Renewables	8
Load	Environmentally Friendly	California Solar Initiative	Increased PV Installations	7
Regulation	Minimal Technology Change	Loading Order	Maintain Ranks in Order	6

Regulation	Minimal Technology Change	FERC Orders	Status Quo	0
Regulation	Minimal Technology Change	Reliability Rules	Status Quo	0
Load	Recession	Manufacturing	Decreased Manufacturing	0
Environment	Breakthrough Technology	Firestorms	Proactive Planning	7
Load	Breakthrough Technology	LNG terminal	Increased Installations	4
Regulation	Breakthrough Technology	ERO Reliability Enforcement	Increasing Enforcement	9
Regulation	Breakthrough Technology	Change in ISO (WC)	Reduced Control	7
Technology	Breakthrough Technology	Shift from Central to Distributed Generation	Increasing DG Installations	9
Total Score				7.1

The Likely Future State Scenario has a composite score of 7.1 which falls in the range of the Favorable Case for a smart grid as presented in the scenario analysis conclusions. Thus, the Likely Future Case suggests a desirable climate for the implementation of a smart grid strategy for the San Diego Region.

11.6. Inputs for the Gap Analysis

The gap analysis identifies what technology and regulatory changes are necessary to transform the existing or currently planned electric grid into a smart grid in the future. The project team analyzed the Likely Future State to determine the smart grid attributes that will be required based on the anticipated future. For each external influence, the future technology requirements have been identified and are presented in Tables 10 through 14.

Table 10 Smart Grid Technologies Related to Load Growth

External Influence	Driver	Trend	Smart Grid Technologies
Load	LNG terminal	Increased Installations	Decision support
Load	Business Profile	Increasing Businesses	DER and supporting technologies/processes, new tariffs, AMI, consumer portals, decision support, Distributed intelligent control systems (agents), DG interconnection standards, advanced protective relaying, GIS
Load	California Solar Initiative	Increased PV Installations	DER residential and farms, inverters, DC microgrids, AMI, consumer portals, decision support, advanced controls, Distributed intelligent control systems (agents)
Load	Culture/People Profile	Increasing Population	DER, demand response - and supporting technologies/processes, new tariffs, AMI, consumer portals, decision support, Distributed intelligent control systems (agents), DG interconnection standards, advanced protective relaying, GIS
Load	Economic Development	Increase Economy	DER, demand response - and supporting technologies/processes, new tariffs, AMI, consumer portals, decision support, Distributed intelligent control systems (agents), DG interconnection standards, advanced protective relaying, GIS
Load	Manufacturing	Decreased Manufacturing	None

Table 11 Smart Grid Technologies Related to New Technologies

External Influence	Driver	Trend	Smart Grid Technologies
Technology	Communication Infrastructure	Increasing Bandwidth	Advanced sensors (system and condition) - leading to availability of all needed information thus enabling advanced simulation and modeling, leading to reduced operating risk, increased asset utilization
Technology	Shift from Central to Distributed Generation	Increasing DG Installations	DER and supporting technologies/processes, new tariffs, AMI, consumer portals, decision support, Distributed intelligent control systems (agents), DG interconnection standards, advanced protective relaying
Technology	Zero Energy Homes	Increased Availability	DER including storage, consumer portals, AMI, advanced protective relaying, smart appliances
Technology	Communication Standards	Increasing Standards	Integrated communications based on the specific standard(s), AMI enabled, smart sensors leading to all needed information

Table 12 Smart Grid Technologies Related to New Regulation

External Influence	Driver	Trend	Smart Grid Technologies
Regulation	ERO Reliability Enforcement	Increasing Enforcement	Advanced sensors (system and condition), integrated communications - leading to availability of all needed information to support ERO requirements
Regulation	Tariffs	Increase Time-based rates	AMI, consumer portal, agent software, interconnection standards, advanced protective relaying
Regulation	Change in ISO (WC)	Reduced Control	Decision support
Regulation	Loading Order	Maintain Ranks in Order	Demand Response, Renewable DER and farms, energy storage, advanced controls, consumer portals, AMI
Regulation	FERC Orders	Status Quo	None
Regulation	Reliability Rules	Status Quo	None

Table 13 Smart Grid Technologies to Support New Legislation

External Influence	Driver	Trend	Smart Grid Technologies
Legislation	Title 24	Increased EE Requirements	DER including storage, consumer portals, AMI, advanced protective relaying
Legislation	Change in Utility Structure	Market-based	Integrated Communications, advanced sensors, AMI - to provide data and communication to support market based operations.
Legislation	Renewable Portfolio Standards	Increased Renewables	Renewable "farms" and supporting technologies/processes, decision support, advanced control systems (agents), advanced protective relaying

Table 14 Smart Grid Technologies to Support Affects of the Environment

External Influence	Driver	Trend	Smart Grid Technologies
Environment	Firestorms	Proactive Planning	Advanced controls, decision support, GIS, integrated communications, advanced condition sensors, distributed intelligent control systems (agents)
Environment	New Fuels	Increased Availability	DER and supporting technologies/processes, new tariffs, AMI, consumer portals, decision support, Distributed intelligent control systems (agents), interconnection standards, advanced protective relaying

The project team consolidated the technologies from the above tables and divided them into two tiers: one of near term actions and another of mid-term actions. This provides a more focused priority grouping of technologies that would be necessary to change the existing infrastructure to smart grid system.

Tier 1: Near Term Actions:

- Implement advanced metering infrastructure (AMI) as a supporting technology for consumer DER, consumer portal deployment.

- Include distributed energy resources (particularly renewables) at consumer and supplier (farm) level.

- Implement substation automation to provide system and condition information to operations, maintenance, and planning

- Install advanced protective relaying deployment to enable data collection and local "self-healing" actions to complement new opportunities associated with decentralized generation

- Install advanced controls for both decentralized (including distribution automation (DA)) and substation automation (SA) and centralized to handle a wide variety of generation sources

- Implement decision support (GIS based) to support the operation of a growing amount of decentralized generation

Tier 2: Mid-Term Actions:

- Evaluate dynamic rating technologies for opportunities to better optimize assets and generate revenue

- Monitor energy storage as a an emerging DER technology for both the supplier and consumer side

- Monitor advanced instrument transformer technologies

- Work with CPUC on methods to balance consumer and company interests (tariff designs, fair "de-coupling")

- Work with consumer advocacy groups to educate them on smart grid opportunities

The Modern Grid Initiative Key Technology Areas (KTAs) are presented in the Figure 9. This shows the systems view of how the technologies can be integrated to form a smart grid system. In this view, the advanced grid components are the basic building blocks of the system and sensing, communications, and controls are overlaid in order to optimize the full benefit of the components.

Figure 9 Modern Grid Initiative – Key Technology Areas
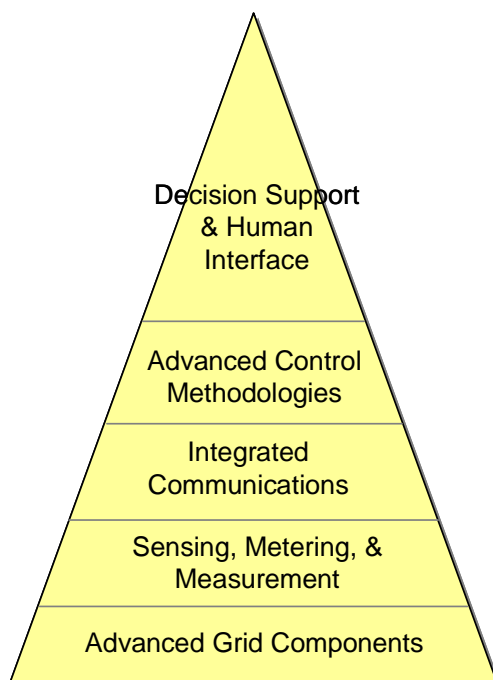
The Probable Future State smart grid technologies are presented in terms of the KTAs as follows:

11.6.1.   Advanced Grid Components

Deployment of distributed energy resources (DER) both at the consumer side and system side is expected to grow substantially in the San Diego area. Advances in DER technology including storage should be monitored and considered as part of the Integrated Resource Plan.

- Improvement Initiatives

- DER and supporting technologies/processes

- New tariffs

- Advanced Metering Infrastructure (AMI)

- Consumer Portals

- Decision Support

- Distributed Intelligent Control Systems (agents)

- DG Interconnection Standards

- Advanced Protective Relaying

- Solutions to voltage, thermal, and stability issues identified by distribution and transmission planners should consider advanced technologies as solutions.

- Improvement Initiatives

- Advanced Conductors

- Fault Current Limiters

- FACTS devices

- New tariffs

11.6.2.   Sensing Metering and Measurement

Deployment of the planned AMI project will enable SDG&E to collect consumer data, support the future deployment of consumer portal technologies and interface with the expected widespread deployment of consumer side DER and demand response. The selection of the AMI technologies should consider the need to interface consumer information with other system operating and equipment condition information, future SCADA upgrades, and be capable of integrating with other enterprise-wide processes and technologies in the future.

Improvement Initiatives

- Advanced Metering Infrastructure (AMI)

- Consumer portal technologies (Intelligrid, Broadband Energy Networks)

- Advanced protective relaying interfaces (Schweitzer-type) to interface with DER

Substation Automation using Schweitzer-type devices is needed to sense system data, process equipment condition data and perform local autonomous protective functions. These information and control functions are necessary (although not sufficient) to ultimately achieve a self-healing grid in the San Diego area. Integration of these functions with AMI and SCADA is needed to ensure all users (operations - for real time operations, what-if scenario simulations, asset optimization, and day ahead planning, engineering, planners, maintenance, etc.) have access to these capabilities.

Improvement Initiatives

- Substation automation technologies

- Schweitzer-type devices

- Local autonomous control algorithms

- Integration with central operations center

In addition to the data acquisition capabilities of AMI (for consumer data) and SA technologies (for system operating data such as watts, vars, volts, amperes, power factor, etc), technologies to monitor the health of critical system assets (lines, transformers, capacitors, etc.) are needed.

This information will improve the maintenance program by providing the data needed to support an effective condition based maintenance program. Additionally, sensor technologies for both system and condition data are expected to advance rapidly in the future. These technologies should be closely monitored.

Improvement Initiatives

- Dynamic line rating technologies (IPIC temperature sensors, Intelicis wireless sensors, Valley Group CAT-1 tension monitors, EPRI Videosagometer)

- Fiber optic instrument transformers

- EPRI and Southwest Research Institute backscatter technologies

- I-Grid wireless sensors for power quality (PQ) monitoring

11.6.3.   Integrated Communications

Consumer data, system operating data, and equipment condition data should be integrated and made available to all users. The communication architectures among AMI, substation automation, SCADA, Operation Center(s), and end use control devices should be seamlessly interfaced and operate at the required speed(s) for the associated applications.

Improvement Initiatives

- Internet2 (IPv4, IPv6)

- Ethernet over Fiber

- BPL

- 4G WiMAX Fixed - Private Wireless

- 3G Wireless Voice & Data - 1xEVDV / UTMS

- Zigbee / WiMedia / WiFi - Wireless

11.6.4.   Advanced Control Methodologies

The transition from a centralized model to a more decentralized one as the deployment of DER (at both the consumer and system levels) increases, will require changes to how the system is operated. Incorporation of distribution automation technologies should be considered. A general shift to local autonomous control systems (agent and multi-agent) should also be expected.

Improvement Initiatives

- Consortium for Electric Reliability Technology Solutions (CERTS) Microgrid

- Agent and Multi-Agent Systems

- Substation Automation

- Distribution (Feeder) Automation

- Web Services and Grid Computing

11.6.5. Decision Support and Human Interface:

The time for human operators to make operating decisions is shrinking rapidly. Advancements in autonomous control system agents are expected to unburden the operator; however, the operator will continue to be needed to "supervise" the automated controls and to act on situations requiring his attention. Advanced visualization technologies including GIS as an entry platform for all users should be considered. More specific platforms should be considered based on the user; that is, operation managers will need a specific set of tools to assist them, but asset managers, engineers, maintenance staff, etc. may all need a different view.

Improvement Initiatives

- GIS, Color Contour Maps
- 3-D visualization
- Semi-autonomous Agents
- Advanced Pattern Recognition
- Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)
- AI-based Weather and Load Forecasting Methods (Numerical Weather Prediction)

These initiatives will be refined and screened in the cost benefit analysis portion of the study.

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11.7. External Influence Drivers

Tables 15 through 19 provide the main external influences on the main drivers of change in the San Diego region.

Table 15 Electric Load Drivers

External Influence	Driver	Description
Load	Business Profile	Business Segment Characteristics: Number, type, industry, location, number of Employees, Energy Intensity
Load	Change in Infrastructure	Impact of changes in mass transit, maglev train, harbor activity, airport expansion
Load	Culture/People Profile	Residential Segment Characteristics: Number, households, housing density, income, rent/own, location, occupations, attitudes to technology, attitudes to change, adoption of electronic technology.
Load	Economic Development	Measure of business prosperity in terms of construction, spending, investment, jobs
Load	LNG terminal	Level of natural gas supply and price stability
Load	Manufacturing	Manufacturing Industry Characteristics: Type of industry, outsourcing, central/distributed, energy intensity, jobs
Load	California Solar Initiative	Level of PV penetration into the region
Load	Water and Gas	Supply, demand, costs, elasticity
Load	Change in Federal Presence	Impact of base closures and consolidation at federal facilities in the region
Load	Weather	Impacts of weather on load for annual consumption, peak demand, natural gas consumption
Load	Airport Moves or Expands	Impact of the airport expansion or relocation within the region

Table 16 Legislation Drivers

External Influence	Driver	Description
Legislation	Change in Utility Structure	Changes in the utility business structure on terms of reliability performance requirements, capacity markets, power quality performance requirements, rate base determination, incentive-based profit model.
Legislation	EPACT 2006	Impact of tax treatment and policy changes identified in the Energy Policy Act of 2006
Legislation	GFA Act (WC)	Requirement for new appliances to have a grid friendly technology incorporated
Legislation	GHG trading (WC)	Methodology to trade green house gas reductions / increases
Legislation	Incentives	Tax incentives for energy efficiency, alternate fuels, green power, etc.
Legislation	Commitment to PTC (WC)	Impact of long term commitment to production technology credits
Legislation	Municipalization	Rules at allow cities to act as utilities for both infrastructure and aggregation
Legislation	Deregulation	Level of regulation including direct access, generation ownership, POLR, etc
Legislation	Renewable Portfolio Standards	The extent that utilities are required to incorporate renewable generation into their asset mix of generation
Legislation	Resource Adequacy	The extent and method that utilities are required to include reserves in their inventory of generation. Modifications to definitions of spinning reserve
Legislation	Title 24	Level of energy efficiency and demand response required for new construction and remodel projects

Table 17 Regulation Drivers

External Influence	Fish Bone Component	Description
Regulation	Change in ISO (WC)	Modification of ISO Area of Control
Regulation	ERO reliability enforcement	Reliability Enforcement
Regulation	FERC Orders	Level of Federal Regulation
Regulation	Incentives	Level of Incentives for EE and DR
Regulation	LMP 2007 -08	Implementation of Zonal Pricing
Regulation	Loading order	Priority of EE & DR , Renewables then Gen and Transmission
Regulation	Time Horizon of Market Incentives	Extent that industries can rely on ongoing incentives for products
Regulation	Reliability Rules	The extent and method that utilities are required to address T1/G1 loss of resources
Regulation	Tariffs	Level of market-based rate structures

Table 18 Environmental Drivers

External Influence	Fish Bone Component	Description
Environment	Adoption of Kyoto (WC)	Environmental Regulation
Environment	Earthquake	Planning for Event
Environment	Firestorms	Planning for Event
Environment	Gasoline	Reduction of Gasoline Resources
Environment	Natural Gas	Reduction of Natural Gas Resources
Environment	new fuels	Development and Availability of New Fuels
Environment	Terror Attack	Planning for Event
Environment	Tsunami (WC)	Planning for Event

Table 19 Technology Drivers

External Influence	Fish Bone Component	Description
Technology	Advanced Storage	Advancements in Storage Technologies
Technology	Communication Infrastructure	Advancements in Communication Infrastructure
Technology	Communication Standards	Advancements in Communication Standards
Technology	Industry Standards	Advancements in Industry Standards
Technology	Infusion of Nanotechnology (WC)	Advancements in Nanotechnology
Technology	Reduced Cost of Power Electronics	Advancements in Cost Reduction of Power Electronics
Technology	Shift from Central to distributed generation	Advancements in generation costs, efficiency, cost effective emissions control, grid friendly electrical interface
Technology	Wave Energy (WC)	Advancements in Wave Technology
Technology	Zero Energy Homes	Advancements in Home Energy Technology

11.8. Scoring and Ranking of Drivers

Tables 20 through 25 show the scores of the drivers for each scenario.

Table 20 Blue Sky

External Influence	Driver	Average Composite Score
Load	Business Profile	10
Legislation	Change in utility structure	10
Load	Culture/People Profile	10
Technology	Communication Infrastructure	10
Load	Economic Development	10
Load	Manufacturing	10
Technology	Advanced Storage	10
Regulation	Tariffs	9
Legislation	Deregulation	9
Technology	Zero Energy Homes	9
Technology	Reduced Cost of Power Electronics	9
Legislation	Renewable Portfolio Standards	8
Technology	Communication Standards	8
Regulation	Reliability Rules	8
Regulation	ERO Reliability Enforcement	8
Technology	Infusion of Nanotechnology (WC)	8
Environment	New Fuels	7
Environment	Natural Gas	6
Legislation	Commitment to PTC (WC)	6
Technology	Wave Energy (WC)	6
Technology	Industry Standards	6
Environment	Gasoline	6
Legislation	Incentives	5
Regulation	Incentives	4

Regulation	Time Horizon of Market Incentives	3

Table 21 Recession

External Influence	Driver	Average Composite Score
Regulation	Incentives	6
Regulation	ERO Reliability Enforcement	5
Environment	Natural Gas	4
Legislation	Deregulation	4
Legislation	Incentives	4
Legislation	Resource Adequacy	3
Regulation	Time Horizon of Market Incentives	3
Load	Economic Development	3
Environment	Gasoline	2
Legislation	Commitment to PTC (WC)	2
Legislation	Change in Utility Structure	1
Legislation	Renewable Portfolio Standards	0
Load	Business Profile	0
Load	Culture/People Profile	0
Load	Manufacturing	0

Table 22 Environmentally Friendly (High Level of Environmental Regulation)

External Influence	Driver	Average Composite Score
Technology	Advanced Storage	9
Technology	Shift from Central to Distributed Generation	9
Legislation	Title 24	9
Technology	Zero Energy Homes	8
Environment	Adoption of Kyoto (WC)	8
Legislation	Commitment to PTC (WC)	8
Legislation	Renewable Portfolio Standards	8
Regulation	ERO Reliability Enforcement	7
Regulation	Incentives	7
Technology	Communication Infrastructure	7
Environment	Gasoline	7
Load	California Solar Initiative	7
Environment	Natural Gas	7
Legislation	Deregulation	7
Environment	New Fuels	6
Load	Business Profile	6
Regulation	Loading order	6
Technology	Communication Standards	6
Technology	Wave Energy (WC)	6
Legislation	Incentives	5
Technology	Industry Standards	5
Load	Culture/People Profile	5
Legislation	GHG trading (WC)	5
Legislation	GFA Act (WC)	4
Load	Change in Infrastructure	1
Regulation	Reliability Rules	0
Regulation	Tariffs (SB1x)	0

Table 23 Constrained Regulation (Low Level of Environmental Regulation)

External Influence	Driver	Average Composite Score
Technology	Shift from Central to Distributed Generation	7
Regulation	ERO Reliability Enforcement	7
Load	Economic Development	6
Legislation	Deregulation	5
Load	Culture/People Profile	4
Regulation	Change in ISO (WC)	4
Legislation	Title 24	3
Regulation	Incentives	2
Legislation	GHG trading (WC)	2
Regulation	Loading order	2
Legislation	Commitment to PTC (WC)	2
Legislation	GFA Act (WC)	1
Environment	New Fuels	0
Legislation	Incentives	0
Legislation	Renewable Portfolio Standards	0
Regulation	Reliability Rules	0
Regulation	Tariffs (SB1x)	0
Technology	Wave Energy (WC)	0

Table 24 Breakthrough Technology Development

External Influence	Driver	Average Composite Score
Regulation	Tariffs	10
Technology	Advanced Storage	10
Legislation	Title 24	9
Technology	Communication Infrastructure	9
Technology	Shift from Central to Distributed Generation	9
Regulation	LMP 2007 -08	9
Environment	Terror Attack	9
Legislation	Change in Utility Structure	9
Load	Economic Development	9
Load	Weather	9
Regulation	ERO Reliability Enforcement	9
Technology	Zero Energy Homes	9
Legislation	Resource Adequacy	8
Regulation	FERC Orders	8
Legislation	Deregulation	8
Technology	Communication Standards	8
Technology	Infusion of Nanotechnology (WC)	8
Legislation	Renewable Portfolio Standards	8
Load	Culture/People Profile	8
Load	Water/Gas	8
Regulation	Loading order	8
Technology	Reduced Cost of Power Electronics	8
Legislation	GFA Act (WC)	8
Load	Change in Infrastructure	8
Load	Manufacturing	8
Load	California Solar Initiative (WC)	8

Environment	Firestorms	7
Regulation	Change in ISO (WC)	7
Regulation	Reliability Rules	7
Legislation	EPACT 2006	7
Legislation	GHG trading (WC)	7
Legislation	Incentives	6
Regulation	Incentives	6
Technology	Industry Standards	6
Technology	Wave Energy (WC)	6
Legislation	Commitment to PTC (WC)	6
Load	Business Profile	6
Environment	Tsunami (WC)	6
Environment	Earthquake	6
Load	LNG terminal	4
Regulation	Time Horizon of Market Incentives	3

Table 25 Minimal Technology Change

External Influence	Driver	Average Composite Score
Regulation	ERO Reliability enforcement	7
Legislation	Deregulation	6
Regulation	Loading Order	6
Technology	Communication Infrastructure	5
Technology	Reduced Cost of Power Electronics	5
Technology	Industry Standards	5
Technology	Communication Standards	5
Legislation	Title 24	2
Legislation	EPACT 2005	0
Load	Economic Development	0
Load	Water/Gas	0
Load	Weather	0
Regulation	FERC Orders	0
Regulation	Reliability Rules	0
Regulation	Tariffs (SB1x)	0

12. APPENDIX D: METHOD FOR CALCULATING BENEFITS

This section provides detailed information about the method the project team used to estimate the benefits of the improvement initiatives identified in the gap analysis. The project team conducted a gap analysis to determine what technology improvement initiatives would be necessary to move the current electric infrastructure in the direction of a smart grid. The team identified the 26 improvement initiatives:

- GATECH IPIC Dynflo distributed series impedance sensors
- I-Grid Monitoring System (by Softswitching Technologies)
- Fiberoptic PT and CT meters
- Wireless, intelligent system sensors for condition information
- Consumer Portal
- Internet2 (IPv4 IPv6)
- Ethernet over Fiber
- BPL
- 4G WiMAX Fixed - Private Wireless
- 3G Wireless Voice & Data - 1xEVDV / UTMS
- Zigbee / WiMedia / WiFi - Wireless
- Semi-autonomous Agents
- Advanced Pattern Recognition
- Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)
- AI-based Weather and Load Forecasting Methods (Numerical Weather Prediction)
- Geospatial Information Systems
- DER-based Microgrids
- Various High-Efficiency & Renewable DG
- Advanced Energy Storage Systems
- Electric Loads as a Reliability Resource
- Advanced Grid Control Devices
- ACSS/TW, ACCR, and ACCC
- Agent and Multi-Agent Systems
- Substation Automation
- Distribution (Feeder) Automation
- Web Services and Grid Computing

To reduce this list to a manageable number of projects, the project team conducted a cost benefit analysis to determine which improvement initiatives would yield the greatest benefits.

The project team developed the following list of benefits and developed a method to calculate values for each benefit related to a specific improvement initiative.

- Reduced congestion costs

- Tax savings to the utility due to increased depreciation

- Reduction in forced outages/interruptions

- Increased security and tolerance to attacks/ natural disasters

- Reduced blackout probability

- Increased capital investment efficiency due to tighter design limits and optimized use of grid assets

- Reduction in forced outages/interruptions

- Reduction in restoration time and reduced operations and management due to predictive analytics and self healing attribute of the grid

- Increased integration of distributed generation resources and higher capacity utilization

- Environmental benefits gained by increased asset utilization

- Power quality, reliability, and system availability and capacity improvement due to improved power flow

- Other benefits due to self diagnosing and self healing attribute of the grid

Below we present the method for calculating the benefits associated with all 26 improvement initiatives identified in the gap analysis, including the factors assessed and the calculation used. Note that the order in which the initiatives are presented below differs from the list provided above, which is in the same order as appears in the main report. We changed the order because there are many benefits that are shared among improvement initiatives. So, to avoid duplicative text, we simply grouped together at the end those improvements that yield benefits already presented.

12.1. GATECH IPIC Dynflo Distributed Series Impedance Sensors

Implementing this improvement initiative would reduce costs associated with congestion and increase tax savings to the utility because of a depreciation increase. Detailed information on how the project team calculated each of the resulting benefits is presented below.

12.1.1. Reduction in Congestion Costs

The following table shows the formula for calculating the reduction in congestion cost for this improvement initiative.

Benefit Type	Factor A	Factor B	Factor C	Calculation
Reduction in congestion cost	TOU pricing	MWH on congested Transmission nodes	Percent increase in Transmission Line capacity addition due to better sensing	A*B*C

Factor A - TOU Pricing is the Time-of-Use pricing for the Improvement Initiative under analysis. Since this project increases transmission line capacity, the TOU pricing occurs at a peak time where this new capacity can be exploited for maximum gain. The value of TOU Pricing will be the maximum value of energy measured in dollars per megawatt-hour.

Factor B - The MWH that can be released is identified by the present congestion on the transmission nodes.

Factor C – The percent increase in transmission line capacity due to the installation of the project's improved sensing. The sensing will determine a real time rating based upon the real time temperature of the transmission conductor.

Calculation – The calculation is the product of the three factors resulting in a benefit measured in dollars per year. The increase in transmission capacity times the price of energy for the capacity times the hours per year that this situation occurs results in the total benefit.

12.1.2. Tax gain from Depreciation Increase

The following table shows the formula for calculating the tax savings to the utility derived from the depreciation increase associated with this improvement initiative (IPIC Dynflo Distributed Series Impedance Sensors).

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Calculation
Tax gain from Depreciation Increase	Utility Corporate Tax Rate	II1 Cost of Construction	Depreciation Period of new assets for II1	Construction Years II1	Operating and Maintenance expenses from construction of project for II1	A*B/C

Factor A – The Utility Corporate Tax Rate is the tax rate that the utility pays in its federal tax filing.

Factor B – The cost of construction is the price of the project to include engineering, materials, installation and testing of the application to ensure it delivers the desired benefits.

Factor C – The depreciation period is the financial life of the installation for tax purposes. This value is not the expected life of the newly installed assets.

Factor D – The construction years is the length of time in years required to complete the installation of the project. This value is used in the cash flow calculation.

Factor E – The operating and maintenance expenses measured in dollars per year is used in the cash flow calculation.

Calculation – The calculation is Factor A times B divided by C. The cost of construction times the tax rate divided by the depreciation years result in a credit to the corporation that can used to offset income.

12.2. I-Grid Monitoring System (by Softswitching Technologies)

Implementing this improvement initiative would reduce the number of forced outages and service interruptions, increase system security and tolerance to attacks or natural disasters, and reduce the probability of blackouts. Detailed information on how the project team calculated each of the resulting benefits is presented below.

12.2.1. Reduction in Forced Outages and Interruptions

Benefit Type	Factor A	Factor B	Factor C	Factor D	Calculation
Reduction in forced outages/interruptions	Cost per complaint	Pre-project interruption complaints	Percent reduction in Complaints	Percent of benefit attributable to I-Grid systems	A*B*C*D

Factor A- Cost per complaint regarding interruptions. This includes call reception, documentation, problem resolution and closure

Factor B – The current number of interruption complaints.

Factor C – The percent reduction in interruption complaints resulting from the implementation of the project. Since this is a future condition, it must be estimated. The sensitivity analysis will show that a large increase or decrease in this estimate will only slightly change the overall profitability of the total improvement initiatives.

Factor D – The percent of the benefit shared by this improvement initiative. The total benefit is divided among all of the improvement initiatives that contribute to the benefit realization.

The Calculation is the product of the factors. The reduction of complaints times the cost per complaint is a straightforward calculation of benefit.

12.2.2. Increased Security and Tolerance to Attacks and Natural disasters

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Calculation
Increased security and tolerance to attacks/ natural disasters	Pre-project customer minutes per interruption	% drop in interruption hours post project	system $ value per customer minute	Percent Benefit applied to I-Grid	Pre-project interruptions per year	A*B*C*D*E

Factor A – Present customer minutes of interruption is a known quantity.

Factor B – The decrease in interruption minutes after the project must be an estimate and is tested with the sensitivity analysis.

Factor C – The cost of a customer minute of interruption is a quantity that was estimated for SDG&E, but the value has been calculated at other utilities.

Factor D – The percent of the benefit shared by this improvement initiative. The total benefit is divided among all of the improvement initiatives that contribute to the benefit realization.

Factor E – The number of interruptions per year. This is a known quantity.

Calculation – The total benefit is the product of the factors. The reduction of interruption minutes times the cost per interruption minute is a straightforward calculation and benefit.

12.2.3. Reduced Blackout Probability

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Factor F	Factor G	Factor H
Reduced blackout probability	Demand Response Potential MW	Percent Efficiency of Demand Response Program	System Load MW	Maximum Reserve in Percent of Load	MW lost in 2003 Blackout	$ societal cost of 2003 Blackout	% benefit assigned to I-Grid Systems	Historical Frequency of large scale Blackout

Factor A – The potential MW that can be called upon during a power shortage to reduce demand within 15 minutes or less.

Factor B – The efficiency of realizing potential MW of demand response.

Factor C – The system load in MW.

Factor D – The percentage of generation reserve to be held as a hedge against unexpected loss of generation.

Factor E & F – The MW lost in the 2003 Blackout and the societal cost of that blackout adjusted for load growth and inflation.

Factor G – The percent of the benefit shared by this improvement initiative. The total benefit is divided among all of the improvement initiatives that contribute to the benefit realization.

Factor H – The frequency at which major blackouts occur.

Calculation – The calculation is $(((A*B/C)*(D*C))*(F/E)*G)/H$. The theory of this benefit is that if one increased ones reserves, one would increase the likelihood of surviving a blackout. The cost of a blackout is the (F/E) factor measured in dollars per megawatt. The amount of generation or loss of load is (A*B). The impact to the system is a percent increase generation (or loss of load) expressed as (A*B/C). The amount of reserves held is the (D*C) expression. Grouping expressions provides a percentage increase in reserves times the amount of the reserves for a MW increase in reserves. Multiply that times the cost of an avoided blackout and divide the resultant by the number of years between blackouts to yield a cost per year of avoided blackout benefit.

12.3. Fiberoptic PT and CT Meters

Implementing this improvement initiative would increase capital investment efficiency due to tighter design limits and optimized use of grid assets. The method for calculating this benefit is presented in the following table.

Benefit Type	Factor A	Factor B	Factor C	Calculation
Increased capital investment efficiency due to tighter design limits and optimized use of grid assets	Cost of traditional HV PT/CT	Cost of Fiberoptic HV PT/CT	Number of PT/CT units installed per year	(A-B)*C

The benefit philosophy here is that the difference in price between the technologies times the number of units that are installed per year results in a total benefit.

Factor A – This represents the cost of the current technology for high voltage (HV) potential transformers (PT) and current transformers (CT).

Factor B – This represents the projected cost of the fiberoptic technology for high voltage potential and current transformers

Factor C – The estimated number of units that would be implemented in the existing grid system

12.4. Wireless, intelligent system sensors for condition information

Implementing this improvement initiative would reduce forced outages and interruptions, reduce restoration time and reduce operations and management due to predictive analytics and the self- healing attribute of the grid, increase integration of distributed generation resources and result in a higher capacity utilization, yield environmental benefits due to increased asset utilization. Detailed information on how the project team calculated each of the resulting benefits is presented below.

12.4.1. Reduction in Forced Outages and Interruptions

Benefit Type	Factor A	Factor B	Factor C	Factor D	Calculation
Reduction in forced outages/interruptions	Interruptions avoided pre-project	Percent increase in avoided Interruptions post-project	Restoration Cost per Interruption	Percent benefit applied to wireless condition info	A*B*C*D

Factor A – The interruptions avoided are derived from sensors sending pattern recognition information about incipient failures, most commonly, underground cable faults. Other pre-project avoided interruptions may include any predictive technology used in a substation or transmission environment which directs that equipment be taken out of service prior to its imminent failure.

Factor B – The increase in avoided interruptions must be estimated.

Factor C – The Restoration cost per interruption.

Calculation – The benefit is the product of the factors. The interruptions avoided times the cost of an interruption results in the benefit.

12.4.2. Reduction in Restoration Time and Reduced Operations and Maintenance

Benefit Type	Factor A	Factor B	Factor C	Calculation
Reduction in restoration time and reduced operations and management due to predictive analytics and self healing attribute of the grid	pre-project restoration costs in $/year	Percent reduction in restoration costs post project	Percent of benefit attributable to II4	A*B*C

Calculation – The benefit result is the product of the factors. The present restoration costs times the percent reduction stemming from the implementation of the improvement initiative times the percent of benefit attributable to this improvement initiative.

Factor A – This represents the historical annual cost of outage restorations for the region

Factor B – The estimated percent reduction in restoration costs to the region due to the implementation of the Smart Grid technologies

Factor C – The estimated percent of the benefit that is attributable to this improvement initiative.

12.4.3. Increased Integration of Distributed Generation Resources and Higher Capacity Utilization

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Calculation
Increased integration of distributed generation resources and higher capacity utilization	MW consumer DG installed	% DG made dispatchable by consumer portal	avg run hr/yr of consumer DG	$/Mwh to run DG	TOU pricing $/MWh under DG operation hours	A*B*C*(E-D)

Calculation – The difference between the sale price and the cost to run generation resources times the annual hours of run time times the capacity of generation installed times the percent of generation made dispatchable by the consumer portal.

Factor A – This represents the installed capacity of consumer distributed generation (DG) systems in the region

Factor B – The estimated percent of the installed DG units that could made to be dispatchable through a consumer portal

Factor C – The average number of run hours per year of consumer-owned DG

Factor D – The average cost of fuel and O&M to operate a DG unit in terms of $/MWh

Factor E – The cost of electricity to all consumers during times when the DG units could be dispatched (proxy is the TOU tariff)

12.4.4. Environmental benefits gained by increased asset utilization

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Factor F	Factor G	Calculation
Environmental benefits gained by increased asset utilization	Present day NOX pounds per MWh	Renewable DG Size in MW	DG SOX Pounds per MW	Cost of Sox emissions in $/pound	Cost of NOx emissions in $/pound	% benefit assigned to Wireless Systems	avgas run hr/yr of consumer DG	((A*E)+(C*D)) *F*B*G

Calculation – The pollutant generated in pounds per megawatt-hour times the cost in dollars per pound yields a dollar per megawatt-hour result. That result times the generator size in megawatts times the generator run time in hours per year yields the total annual benefit.

Factor A – This represents the average pounds of NOx per MWh for the region

Factor B – The estimated capacity of fossil fuel based generation that can be displaced by renewable DG

Factor C – The average number pounds of SOx per MWh for the region

Factor D – The average value of SOx emissions for the region in $/lb

Factor E – The average value of NOx emissions for the region in $/lb

Factor F – The estimated percent of the benefit that is attributable to this improvement initiative.

Factor G - The average number of run hours per year of consumer-owned DG

12.5. Consumer Portal

Implementing the consumer portal would reduce forced outages and interruptions, improve power quality, reliability, and system availability and capacity due to improved power flow, yield societal benefits including job creation and increased economic activity measured by gross regional product (GRP), and reduce congestion costs.

12.5.1. Reduction in Forced Outages and Interruptions

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Factor F	Factor G	Calculation
Reduction in forced outages/interruptions	System number of C&I customers	% drop in sustained Interruptions	cost/customer/one -hour event	Pre-project customer hours per interruption	number of total interruptions per customer per year	Percent of C&I Customers impacted by outage	Percent of benefit attributable to Portal (II5)	A*B*C*D *E*F*G

Calculation – The number of commercial and industrial customers time the percent impacted by an outage times the interruptions per year yields the number of impacted C&I customers per year. The cost per customer hour is an EPRI derived number and when multiplied by the hours per interruption results in a cost per customer interruption.

The customers impacted by interruption times the cost per customer interruption results in the total benefit of costs per year for reducing interruptions.

Factor A – This represents the total number of commercial and industrial (C&I) customers in the region

Factor B – The estimated percent reduction of sustained interruptions to the C&I customers

Factor C – The average cost per customer (lost revenue, lost production, lost products, etc.) for a one hour outage

Factor D – The historical average duration of each outage per C&I customer in the region

Factor E – The historical average number of outage per C&I customer in the region

Factor F – The estimated percent of C&I customers impacted by an outage.

Factor G - The estimated percent of the benefit that is attributable to this improvement initiative.

12.5.2. Improved Power Quality, Reliability, and System Availability and Capacity

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Factor F
Power quality, reliability, and system availability and capacity improvement due to improved power flow	System number of C&I customers	Percent PQ problems avoided post project	Cost per customer per one-second event	Percent of benefit attributable to II5 Systems	Percent of C&I Customers sensitive to PQ	Number of PQ Events per C&I per Year

Calculation - (A*B*C*D*E*F) -The number of power quality sensitive customers is calculated as the total number of commercial and industrial customers times that estimated percentage deemed sensitive to power quality events. The cost per customer for a one second event was determined by EPRI. The number of power quality events avoided by a self healing grid is estimated as a percentage. The product of the C&I PQ sensitive customers times the cost of a one second event times the percent of problems avoided through the self healing feature of the grid yields a total benefit for PQ improvement.

12.5.3. Societal Benefits - Job creation and Increased GRP

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Factor F	Factor G	Calculation
Societal Benefits including Job creation & increased GRP	Business Revenue per job	Manufacturing Jobs in San Diego County	Information Technology Jobs in SD County	10 Average Year growth in IT and Manuf. Jobs	Average Job growth in San Diego County	Years to reach Average Job growth in IT & Manuf.	Percent of benefit attributable to Portal	G*(C+B)*(E-D)*A/F

Calculation – The sum of the power quality sensitive jobs (C+B) times the difference in growth rates (E-D) between the average growth rate and the actual growth rate in PQ sensitive areas times the average business revenue per job divided by the years to attain the average growth rate results in the total annual societal benefit.

12.5.4. Reduced Congestion Costs

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Factor F	Calculation
Reduction in congestion cost	Demand Response Potential MW	Percent Efficiency of DR Program	DER injection point LMP Max	Hours of DR required per year	Percent of benefit assigned to portal	Benefit % not covered in AMI Project	A*B*C*D*E*F

Calculation – The megawatts of potential demand response times the efficiency of the demand response program times the hours of demand response required per year times the emissions price for the sum of SOX and NOX yields a total congestion benefit. That total benefit multiplied by the percentage of the benefit assigned to Agents and multiplied again by the percentage assigned to benefits not covered by the AMI Project results in the specific benefits attributable to the semi-automatic agents.

12.6. Semi-autonomous Agents

Implementing semi-autonomous agents would yield environmental benefits gained by increased asset utilization. Detailed information on how the project team calculated each of the resulting benefits is presented below.

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Factor F	Factor G	Factor H
Environmental benefits gained by increased asset utilization	Demand Response Potential MW	Percent Efficiency of DR Program	NOx avoided in Pounds per MWh	Cost of NOx emissions in $/pound	Cost of Sox emissions in $/pound	Sox avoided in Pounds per MW	Hours of DR required per year	% DR benefit assigned to Agents

Calculation – A*B*G*H*((C*D)+(E*F)) - The megawatts of demand response potential times the efficiency of the DR Program yields the actual DR Response. This is then multiplied by the hours of DR required and the Price per hour to yield a total congestion benefit. That total benefit multiplied by the cost of emissions in dollars per megawatt hour and the percent attributable to the semi-automatic agents to yield the benefit.

All other benefits in this area have already been calculated in other Improvement Initiatives. They are shared benefits with other initiatives.

12.7. Advanced Visualization Methods (POM, ROSE, FFS, OPM, etc)

Implementing advanced visualization methods would reduce blackout probability. Detailed information on how the project team calculated each of the resulting benefits is presented below.

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Factor F	Factor G	Factor H
Reduced blackout probability	Present Deviation forecast to actual in MW	MW % Increase Deviation forecast to actual	System Load MW	MW lost in 2003 Blackout	$ societal cost of 2003 Blackout	Percent of benefit attributable to AVM	Maximum Reserve in % of Load	Historical Frequency of large scale Blackout

Calculation – ((A*B)/(C*G))*(C/D)*E*F/H – The theory of this benefit is that a change in increasing the load forecast results in a greater control of the generators matching the load, thus increasing the likelihood of surviving a blackout. The percentage of impact of a blackout is the (C/D) factor. The amount of generation impacted is (A*B). The dollar impact to the system is (C/D)*E. The amount of reserves held is the (C*G) expression. Grouping expressions provides a percentage increase in generation (A*B) times the amount of the reserves (C*G) times the dollar

impact ((C/D)*E) of an avoided blackout divided by the number of years between blackouts yields the cost per year of avoided blackout benefit.

All benefits in this area have already been calculated in other Improvement Initiatives. They are shared benefits with other initiatives.

12.8. Geospatial Information Systems

This improvement initiative would provide the following benefits: other benefits due to self-diagnosing and self-healing attribute of the grid and improved power quality, reliability, and system availability and capacity due to improved power flow.

12.8.1.   Other Benefits due to Self-diagnosing and Self-healing Attribute of the Grid

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Calculation
Other benefits due to self diagnosing and self healing attribute of the grid	% Transformer Units identified for life extension by identification of through faults	# of transformers on transmission system	Years of life extension	Cost of average transformer on system	Utility Corporate Tax Rate	A*B*C*D*E

Calculation – This benefit relies on a GIS System to help identify faults, their relative fault current values and associating them to a transformer. The identification of these units can then trigger life extension measures, thus extending the useful life of the transformer. The value of that life extension is calculated by taking the cost of the transformers that would have had to be replaced and avoiding the finance charges through the years of life extension.

Improved Power Quality, Reliability, System Availability and Capacity due to Improved Power Flow

Benefit Type	Factor A	Factor B	Factor C	Calculation
Power quality, reliability, and system availability and capacity improvement due to improved power flow	% Lightning recognition events identified and tied to component failure and upgrade	Lightning interruption s per year	Restoration Cost / Interruption	A*B*C

Calculation – This benefit relies upon a GIS System to correlate lightning events to a utility asset. Multiple failures signal improvement potential leading to upgrade of facilities to better withstand a lightning event. The value of the benefit is calculated as a decrease in restoration costs for avoided lightning related interruptions.

12.9. DER-based Microgrids

Integrating distributed energy resource-based microgrids into the existing utility infrastructure would reduce congestion costs. The calculation used to determine the benefits associated with this improvement initiative are shown below.

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Calculation
Reduction in congestion cost	DER injection point LMP Max	Micro-grid capacity MW	Cost of DER energy as $/MWh	Depreciation time of DER capacity (years)	Hours of Peak Load per year	(A-C)*B*E/D

Calculation – The value of this benefit is simply the volume of energy generated on the micro-grid during peak hours times the difference between the sale price and cost to generate.

12.10. Various High-Efficiency and Renewable Distributed Generation

Integrating high-efficiency and renewable distributed generation on the utility system would reduce peak demand. The method used to calculate these benefits is provided below.

Benefit Type	Factor A	Factor B	Factor C	Factor D	Calculation
Reduction in peak demand	Cost of energy from present sources $/MW	Cost of DG in $/MWh	avg. run hr/yr of DG	DG Size in MW	(A-B)*C*D

Calculation – The value is based upon a more efficient renewable and DG generator benefit calculated as the volume of electricity times the difference in sales price and cost to generate energy.

12.11. Advanced Energy Storage Systems

Using advanced energy storage systems would reduce congestion costs. The method for calculating these benefits is provided below.

Benefit Type	Factor A	Factor B	Factor C	Factor D	Calculation
Reduction in congestion cost	injection point LMP Max	Energy storage capacity MW	Cost of storage energy in fuel costs as $/MWh	Hours of stored energy use per year	(A-C)*B*D

Calculation – The value is based upon charging the storage battery off peak (Factor C) and selling the volume (B*D) in the peak hours (D) at a peak price (A).

12.12. Electric Loads as a Reliability Resource

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Factor F
Reduced blackout probability	Maximum MW support to system instability from GFA Devices	System Load MW	Maximum Reserve in % of load	MW lost in 2003 Blackout	$ societal cost of 2003 Blackout	Historical Frequency of large scale Blackout

Calculation – ((A/(B*C))*(B/D)*(E/F) - The theory of this benefit is that an automated demand response initiated by remote appliance controls will reduce load at critical times thus increasing the likelihood of surviving a blackout. The percentage of impact of a blackout is the (A/B*C) factor. The amount of generation impacted is (A). The dollar impact to the system is (A/B*C)*E. The amount of reserves held is the (B*C) expression. Grouping expressions provides a percentage increase in generation (A/B*C) times the amount of the reserves (B*C) times the dollar impact ((B/D)*E) of an avoided blackout divided by the number of years between blackouts (F) yields the cost per year of avoided blackout benefit.

12.13. Advanced Grid Control Devices

This improvement initiative also would reduce forced outages and interruptions and increase capital investment efficiency due to tighter design limits and optimized use of grid assets. The calculation methods for these benefits are shown below.

12.13.1. Reduce Forced Outages and Interruptions

Benefit Type	Factor A	Factor B	Factor C	Factor D	Calculation
Reduction in forced outages/interruptions	Number of transformers on transmission system	Cost of average transformer on system	Transformer Life extension % due to less fault current	Life of transformer	A*B*C/D

Calculation – The reduction of fault current through a transformer reduces wear inside the tank because the windings experience less bending force thus keeping the winding more stable. The value of the benefit lies in the number of transformers time the cost of the transformers to which the fault current reduction applies times percent of life extension divided by the life of the transformer population.

12.13.2. Increased Capital Investment Efficiency

Benefit Type	Factor A	Factor B	Factor C	Calculation
Increased capital investment efficiency due to tighter design limits and optimized use of grid assets	Cost of >10,000 Amp interrupting duty cutouts, line switches and disconnects purchased annually	Cost of line reactors purchased annually	Equipment price adder for >10,000 amp ratings (2)	(A+B)*(1+C)

Calculation – The value of fault current reduction below 10,000 amperes reduces the purchase cost of distribution equipment as a higher rating is required beyond 10,000 amperes. The value of the benefit takes the cost of equipment greater than 10,000 amperes in interruption rating times the price adder for this equipment.

12.14. Agent and Multi-Agent Systems

Integrating agent and multi-agent systems into the existing electric infrastructure would increase integration of distributed generation and capacity utilization and yield other benefits due to self-diagnosing and self-healing attributes of the grid. The calculation method for determining the value of these benefits is shown below.

12.14.1. Increase Integration of Distributed Generation and Capacity Utilization

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Calculation
Increased integration of distributed generation resources and higher capacity utilization	Hours per Year	Average LMP ($/MW)	Distribution Losses pre-project	% Reduction of Distribution Losses post-project	% of benefit attributable to Multi-Agent Systems	A*B*C*D*E

Calculation – The value of the benefit is the value of the energy associated with the reduction in losses. The loss reduction times the hours per year yields the energy consumed by the losses and when multiplied by the average price per energy unit, results in an annual benefit.

12.14.2. Other Benefits Due to Self-diagnosing and Self-healing Attributes of the Grid

Benefit Type	Factor A	Factor B	Factor C	Factor D	Factor E	Calculation
Other benefits due to self diagnosing and self healing attributes of the grid	Revenue/Distribution Customer/hour	Utility Profit as %	Pre-project interruption Hours	Percent decrease in interruption hours post project	Percent of benefit attributable to Multi-Agent Systems	A*B*C*D*E

Calculation – The loss of utility revenue, and hence profit during power interruptions is the value of this benefit. The value is calculated by taking the Interruption Hours and multiplying by the Revenue per Interruption Hour times the percent decrease in interruptions times the utility profit percentage.

12.15. Substation Automation

Integrating substation automation capabilities into the existing electric grid would reduce restoration time and necessary operations and management due to predictive analytics and self healing attribute of the grid. The calculation method for estimating the value of this benefit is shown below.

Benefit Type	Factor A	Factor B	Calculation
Reduction in restoration time and reduced operations and management due to predictive analytics and self healing attribute of the grid	System O&M Maintenance Budget	SA % Improvement Potential	A*B

Calculation – The benefit is based upon the historical experience of installing substation automation enabling conditioned based maintenance. The value of the benefit is the Substation O&M maintenance budget times the experiential percent improvement.

12.16. Other Improvement Initiatives

The benefits for the following improvement initiatives have already been calculated and share benefits with other initiatives.

- Internet2 (IPv4 IPv6)

- Ethernet over Fiber

- BPL

- 4G WiMAX Fixed - Private Wireless

- 3G Wireless Voice & Data - 1xEVDV / UTMS

- Zigbee / WiMedia / WiFi – Wireless

- Advanced Pattern Recognition

- AI-based Weather and Load Forecasting Methods (Numerical Weather Prediction)

- Distribution (Feeder) Automation

- Web Services and Grid Computing

- ACSS/TW, ACCR, and ACCC

13. APPENDIX F: SAIC SMART GRID TEAM BIOGRAPHIES

Key Personnel	Project Title	Relevant Experience
Steve Pullins (SAIC)	Utility Business and Operations Performance	Has 29 years of experience in the utility industry in operations, maintenance, systems engineering, training, and project development. He currently manages the nation's Modern Grid Initiative for the 21st Century, as well as the corporation's business and technology efforts in power system optimization, manages RTO/ISO operations process and markets development, and manages strategic consulting on utility enterprise business performance. He has successfully managed large Operations and Maintenance organizations, as well as large multi-discipline projects. He has extensive experience in leadership development, performance enhancement, and business transformation. Mr. Pullins has worked across the utility sector from fuel cycle to generation to T&D. He holds a BS and MS in Engineering.
John Westerman (SAIC)	Senior Program Manager	Has more than 18 years experience in the development, evaluation, application, and testing of energy technologies. He has supported energy technology evaluation activities for the California Energy Commission, the Electric Power Research Institute, the Gas Research Institute, the U.S. Army Construction Engineering Research Laboratory (a division of the U.S. Army Corps of Engineers), U.S. Department of Energy, New York State Energy Research and Development Authority, and numerous utility companies. Mr. Westerman was a Finalist in 1998 for the Computerworld Smithsonian Awards in the category of Innovative Application of Information Technology in Energy and was recognized in 2003 with and Award of Excellence from the US Army Corps of Engineers - Engineering Research and Development Center. Mr. Westerman a member of the SAIC team that conducted the Regional Energy Infrastructure Study for SDREO and is currently the Chairman of the San Diego Regional Chamber of Commerce Energy Committee. Mr. Westerman has an MBA from the University of San Diego and a BS in Physics from the University of California, San Diego.
Craig Rizzo (SAIC)	Operations Research in Energy	Has 10 years experience in project management and the development and implementation of analytic capabilities to support strategic management decisions. Currently at the National Energy Technology Laboratory managing multiple projects in the areas of distributed generation, energy security, natural gas infrastructure modeling and analysis, and electric transmission and distribution modernization. Prior to joining SAIC, Mr. Rizzo served as an officer in the Air Force for over 8 years where he managed strategic planning efforts that involved 12-year modernization strategies for combat aircraft, space and missile systems. He analyzed the technical merits of critical Department of Defense space, communications and control systems. He has designed and implemented validation methodologies for electronic warfare system modeling efforts, and planned and analyzed the results of multiple weapon system field and flight tests. He holds a BS in Engineering and Operations Research and MS in Operations Research.

Key Personnel	Project Title	Relevant Experience
Dale Bradshaw (Electrivation)	Utility Technology Strategies	Has more than 30 years of utility experience in <u>technology development and application, including transmission reliability and security, fuel cells, distributed energy resources, wide area networks, and network simulation</u>. He has been a national level advisor to Department of Energy and California Energy Commission transmission and distribution programs as well as advanced transmission and distribution planning. Mr. Bradshaw is well published and holds a BS and MS in Engineering, MBA, and ABD in Nuclear.
David Cohen (Infotility)	Consumer Energy Management and Distributed Energy Resources	Has more than 20 years experience in <u>energy management</u>. Currently acting CEO and CTO of Infotility responsible for the company's operations, product marketing, vision and strategy. Prior to Infotility, he was vice president of business solutions of Silicon Energy, a leading provider of <u>enterprise energy management software and solutions, where he managed the development and was the creator of the Distributed Energy Manager software Suite for networking, managing, and controlling distributed energy resources</u>. Previously, Mr. Cohen consulted on web-based energy information solutions and energy software products, including a variety of senior management, engineering, software development, and marketing assignments. He holds a BS Environmental Management and MS Energy Management. Additionally, he serves on the Board of Directors of GeoPraxis, Inc., previously served as vice president of the Colorado Solar Energy Industries Association, and the on the Board of the Colorado Renewable Energy Society.
Joe Darrieulat (SAIC)	Communications Systems Engineering	Has 26 years of experience in systems development for government and commercial customers. Specializes in <u>communications solutions architecture, wireless networking, realtime and non-realtime simulation technology, realtime control systems</u>, and project planning and execution. Experienced leading systems engineering activities on number of contracts. Performed full life cycle functions including concept development, requirements analysis, systems design, systems development, systems integration, systems verification, and systems operations and maintenance. Experienced software architect and developer. <u>Work experience in web and SOA architecture development</u>. Experienced systems administration and systems programmer including configuring computer systems, developing device drivers, networking equipment and security appliances. He holds a BS and MS in Computer Science.
Jesse Harmon (SAIC)	Transmission and Distribution Operations and Advanced Control Methods	Has nearly 30 years of transmission and distribution engineering and management experience with utilities. He has had responsibility in areas of engineering, maintenance, and system operations. For example, he has recently <u>managed implementation projects with utilities in the areas of transmission and distribution network and substation automation, enterprise information management, maintenance and work management, and complex control center automation</u>. Prior to consulting, he worked at GPU, Solaris Power, and Pennsylvania Electric. Mr. Harmon holds a professional engineer's license.

Key Personnel	Project Title	Relevant Experience
Joe Miller (JAM Enterprises)	Utility Operations and Engineering	Has 28 years as a senior utility manager (VP, Illinois Power) with extensive experience in leading engineering, planning, project management, and operational organizations. Particularly effective in diagnosing and resolving organizational, process, and technical issues, and leading change management efforts to ensure successful implementation. His career has been in technical and management positions in the T&D business and nuclear generation with the majority as a senior manager. He has both corporate and field experience leading large organizations for 17 years. Mr. Miller holds a BS and MS in Engineering and a PE license.