



# SmartGridCity™ Demonstration Project Evaluation Summary

October 21, 2011

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## PREFACE

Electric distribution grids across the U.S. consist of aging infrastructure in need of upgrades. Coincidentally, customers are demanding greater efficiency and services from the grid at the same time that reliability challenges – from distributed generation such as PV Solar and demanding loads such as Electric Vehicles – loom on the horizon. U.S. utilities are considering how best to modernize their grids in a manner that optimizes investments and maximizes associated benefits, thereby creating value for customers for the least cost and risk.

In 2008 Xcel Energy, through its subsidiary Public Service Company of Colorado (“PSCO”), designed the most comprehensive smart grid demonstration project in the U.S. integrating generation, transmission, and distribution through grid data collection and analysis. The project was the Company’s approach to comprehensively understand how best to modernize its grid. The Company was interested in learning which capabilities were feasible, which were advisable, and which were ill-advised.

The purpose of this report is to review the outcomes of the evaluation phase of the demonstration project. While designed primarily to serve as an input to PSCO grid development strategy, it is intended that the document proves useful for all readers, including policy makers, customer advocates, the electric utility industry, and technology providers.

Throughout the evaluation phase MetaVu was offered full access to PSCO people, processes, and data. The evaluation phase could not have been completed without dedicated efforts from PSCO employees and business functions too numerous to mention. MetaVu would also like to recognize the supporting contributions from SmartGridCity™ technology partners Accenture, Current Group, GridPoint, OSIsoft, SEL, and Ventyx.

### **About MetaVu**

MetaVu is a recognized leader in sustainable business evaluation and advisory services, delivering the solutions companies need to innovate their products, services and business models to manage energy, social and environmental risk throughout the value chain. MetaVu’s clients in the energy industry benefit from the firm’s deep experience in business model valuation and strategy development. MetaVu helps utilities integrate customer, technology and regulatory strategies into profit-generating products and business models including demand side management, renewable energy development, and smart grid evaluation and deployment.

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## INTRODUCTION

In March 2008 Public Service Company of Colorado (“PSCO”) and a consortium of the smart grid industry’s most advanced technology companies announced their intention to build the nation’s first fully integrated smart grid demonstration project, known as SmartGridCity™.

The SmartGridCity™ demonstration project in Boulder, Colorado was specifically designed to help the utility understand which grid investments best improve electric distribution efficiency and reliability; facilitate expansion of customer energy efficiency and demand response; inform future investments; and help the utility manage reliability challenges from higher penetrations of new technologies.

The smart grid industry was in its infancy at the time. No truly comprehensive smart grid technology tests had been completed; no U.S. government grants were available; standards were fragmented and many technologies reaching the market today were still in development stages.

MetaVu was commissioned to perform a third-party evaluation of the SmartGridCity™ demonstration project to identify lessons learned and document reference information for future grid modernization strategy development, business case development, and implementation planning.

MetaVu’s evaluation indicates that the anticipated contributions were indeed delivered, and that specific demonstration project goals were satisfied by the SmartGridCity™ demonstration project. Accomplishments include:

- A comprehensive suite of smart grid technologies that could be employed to manage anticipated changes in the retail electric market has been designed, built, and is currently in operation.
- A real-world laboratory in which new utility and consumer technologies can be deployed and evaluated on an ongoing basis has been created and is currently in use.

- A ‘body of knowledge’ to inform future deployment strategy and business case development has been established, and contributions to it continue.

In the satisfaction of these goals, PSCO has learned many lessons that will help it optimize investments in the grid and make the organizational and operational changes required to maximize the benefits of those investments for customers. The Company learned which capabilities were likely to deliver value and, just as importantly, which capabilities did not. The Company also learned about barriers to, and the conditions that support, customer value creation through grid modernization.

This report summarizes the lessons learned and illustrates how the project created value for SmartGridCity™ customers, PSCO customers, and the utility while challenging conventional wisdom and providing guidance to industry suppliers, regulators, and policy makers.

### **Evaluation Overview**

This evaluation phase of the SmartGridCity™ demonstration project began with the development of a measurement and reporting framework based on emerging standards. Primary inputs included The Electrical Power Research Institute’s (EPRI) Benefit Measurement Framework and the Department of Energy/National Energy Technology Laboratory/Carnegie Mellon Smart Grid Maturity Model. MetaVu adapted the emerging standards to SmartGridCity™ learning objectives and supplemented the framework with customer and business model considerations. Eighty reference sources were consulted in the course of the evaluation.

The framework was employed to accomplish three goals established by PSCO:

- Evaluate the benefits of 61 value propositions pre-defined by PSCO and SmartGridCity™ partners at the onset of the project.

- Document measurement methods so that Company managers may use them in future business planning.
- Identify relevant risks and operational and strategic considerations identified through the evaluation process.

The evaluation process consisted of interviews, data collection and analysis, specific peer-level research, and documentation of findings. This work provides PSCO with critical data points to employ as inputs to grid development strategy. Additional input from regulators and customers, combined with some scenario analyses and inputs from SmartGridCity™ research already underway, should provide PSCO managers the information needed to facilitate grid modernization strategy and business case development, customized for specific capabilities, operating conditions, and assumptions.

### **Report Preview**

This report consists of three sections, each with a progressively greater level of detail. The Executive Summary is primarily strategic, describing value created by the project and themes that transcend any individual smart grid component or capability. The second section describes the value created by individual smart grid components. A highly detailed Appendix follows and includes evaluations of specific value propositions and a reference list.

#### **1. Executive Summary**

The Executive Summary begins by documenting the value created by the demonstration project

- For SmartGridCity™ Customers
- For PSCO Customers.

The Executive Summary continues with descriptions of themes identified in the course of evaluation that transcend more than one value proposition or SmartGridCity™ system and can serve as additional inputs into grid development strategy:

- Grid Modernization is a strategic planning process.

- Stakeholder and Customer Engagement is a platform for risk mitigation and value creation.
- Change Management is critical to maximizing the benefits of many smart grid systems.

#### **2. Value Creation by Smart Grid System**

The pre-determined value propositions were evaluated in relation to the smart grid systems that enable them. Smart grid systems are defined as a set of hardware and software that could conceivably be installed in isolation to create or support value for customers. Six distinct smart grid systems and two infrastructure systems were defined as actionable investment opportunities. By organizing lessons learned into systems, PSCO can best understand how to optimize grid modernization investments, maximize customer benefits, and reduce risks.

The systems defined include:

- Distributed Energy Resource Control/Demand Response
- Advanced Metering Infrastructure
- Distribution Monitoring
- Distribution Automation
- Integrated Volt/VAr Control
- Smart Substation Monitoring and Protection
- Communications Infrastructure
- Information Technology Infrastructure

The section begins with summary descriptions of the measurement framework, the systems themselves, and benefit, cost, and risk findings by system. Details by system follow, including descriptions of the primary goal, function, value creation, and business case considerations for each system.

#### **3. Appendices**

The Appendices provide detailed information on specific value propositions and lessons learned. A list of references that helped inform evaluation frameworks and validate evaluations of specific value propositions is also provided.



## EXECUTIVE SUMMARY

An objective evaluation of PSCO's SmartGridCity™ demonstrates that the project created significant and specific value

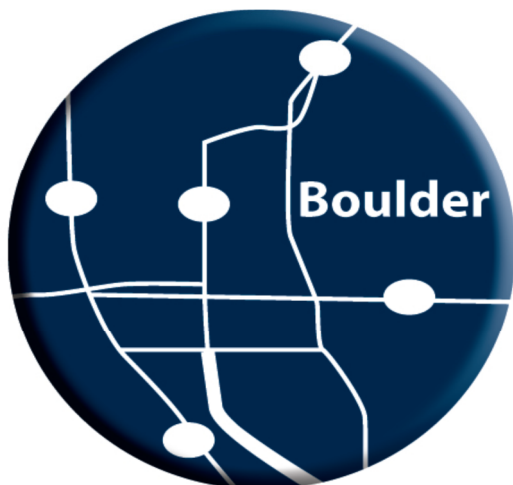
- For SmartGridCity™ customers
- For PSCO customers.

The evaluation process also identified three fundamental themes that transcend more than one value propositions or smart grid system and can serve as additional inputs into grid development strategy:

- Grid Modernization is a strategic planning process.
- Stakeholder and Customer Engagement present a platform for risk mitigation and value creation.
- Change Management can help maximize the benefits from many smart grid systems.

### Value Creation

MetaVu's evaluation found that the demonstration project investment created significant value for both SmartGridCity™ and PSCO customers. 'Value' is defined as capabilities, options, assets, or knowledge not available prior to the project that are currently delivering benefits or that will ultimately benefit customers.



### **The Project Created Value For SmartGridCity™ Customers**

Customers residing within the SmartGridCity™ footprint obtained (and will continue to receive) direct benefits from the project in several areas, including energy use reductions, reliability improvements, new rate options, new service options, and customer service level improvements. Some benefits are available only to subsets of SmartGridCity™ customers, such as those located on certain feeders or those with smart meters.

#### **Energy Use Reductions**

The average residential customer located on one of the two feeders treated with Integrated Volt/VAr Control (IVVC) experienced usage reductions resulting in annual bill savings of approximately \$18 with no reduction in service level (For more information please see Value Proposition 1.9a, 'Reduce Energy Consumption through IVVC' in Appendix 1).

#### **Reliability Improvements**

Reliability improved in SmartGridCity™ in terms of both Customer Minutes Out (CMO) and Power Quality. The Distribution Automation system, which reduces the number of customers impacted by a given outage, is estimated to have reduced CMO by over 28,000 minutes annually on each of the two feeders on which it has been installed. (For more information please see Value Proposition 4.1, 'Distribution Automation to Reduce Outage Extent' in Appendix 1.)

Distribution Monitoring, which helps utilities locate fault sources faster, is estimated to have reduced outage durations by 382,000 minutes throughout SmartGridCity™. Distribution Monitoring also offers exception reporting that proactively identifies Power Quality issues; as a result, Power Quality complaints dropped to zero annually after deployment from a baseline of over 30 complaints annually. (For more information please see Value Propositions 4.3, 'AMI to restore power faster'; 4.4, 'AMI to detect outages'; and 4.6, 'Proactively Fix Power Quality Issues' in Appendix 1.)

### ***New Rate Options***

PSCO offered three new rate options that make use of smart meter capabilities, including a Critical Peak Price rate, a Peak Time Rebate rate, and a traditional Time-Of-Use rate. Approximately 4,000 SmartGridCity™ customers are taking service under one of these rates as part of a study of the impact of rate design on customer usage and behavior. In a study conducted by PSCO in 2006 and 2007, highly motivated customers taking service under time differentiated rates reduced annual electricity spending up to \$200 each\*. (For more information please see Value Proposition 6.1, 'Increase Customer Ability to Manage Energy Bill' in Appendix 1.)

### ***New Service Options***

SmartGridCity™ customers taking part in one of the three new rate options are being offered the opportunity to participate in a study of additional impacts on demand and energy use offered by In-Home Smart Devices. In-Home Smart Device systems are currently being installed in SmartGridCity™ residences, with a total targeted installation of 1,264 systems. The In-Home Smart Device systems will allow the utility to understand and help customers manage participation in the new rates through remote operation of thermostats and plug loads.

### ***Customer Service Level Improvements***

SmartGridCity™ customers with smart meters (about half of the 46,000 premise SmartGridCity™ footprint) received two types of improved service.

- Detailed (15 minute) energy usage data is updated daily on a secure website, marking a significant improvement over traditional usage data availability. Daily updates of detailed usage data can help customers better understand and reduce energy use and even project the amount of a monthly bill.
- Real time, remote access to meter status improves responsiveness to customers in the event of an outage. Smart meters provide the customer care center with immediate indication about whether an outage has

occurred on the utility side or customer side of a meter. This capability was rated highly important in a survey of 800 PSCO customers. (Reports of outages for premises with traditional meters always prompt on-site investigations by utility personnel; in a full roll-out, associated O&M savings could be significant.)

In summary, the demonstration project created specific value and valuable options for SmartGridCity™ customers.



### ***The Project Created Value for Public Service Company of Colorado Customers***

The demonstration project also created value for all 1.36 million Public Service Company of Colorado (PSCO) electric customers. The project informed both capabilities the Company should consider, but just as importantly, those that it may want to disregard (at least presently). In doing so the Company may have avoided hundreds of millions of dollars in investments (and associated rate increases) that would have created insufficient value for customers relative to costs. In addition, PSCO electric customers will receive ongoing benefits and cost savings from the SmartGridCity™ infrastructure through ongoing testing of emerging technologies.

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\* This result should not be extrapolated to an entire population

### ***Lessons Learned will Optimize Future Investments and Maximize PSCO Customer Value***

The SmartGridCity™ demonstration project stands in stark contrast to smart grid deployments prompted by investment grants from the U.S. Government's American Recovery and Reinvestment Act (ARRA) smart grid program. Smart Grid Investment Grant awards stipulated that the grants and matching funds had to be spent quickly to stimulate the economy. Accordingly, smart grid deployments were driven by the ARRA grants' prioritization of investment over learning. The SmartGridCity™ demonstration project, however, prioritized learning over investment. A review of publicly available smart grid business cases indicates that IOUs completing full deployments are investing from \$500 to \$700 per electric customer (outliers discounted). By contrast, PSCO elected to spend approximately \$33 per electric customer to help ensure that any large investments it chooses to make in its grid will be as cost-effective as possible.

More to the point, and as described below, the actionable lessons learned in SmartGridCity™ provide real value to PSCO customers by optimizing future grid investments. Informed by the lessons from SmartGridCity™, PSCO is prepared to develop business cases with confidence and knowledge to share with stakeholders as part of a structured and informed grid strategy development and investment decision process.

Lessons from the project that help optimize smart grid investments are illustrated throughout this document, but some of the more valuable technology- and capability-specific lessons are described below. For more information on such lessons, please see the 'Value Creation by Smart Grid System' section below or even more detailed descriptions in the Appendix 1 – Value Proposition Evaluation.

### ***Distributed Energy Resource Control (DERC)/Demand Response (DR)***

'Distributed Energy Resource Control' as implemented in SmartGridCity™ consists primarily of advanced capabilities to control customer loads through home area networks, or HANs. PSCO has plans in place to complete 1,264 HAN installations from October 2011 to May 2012 in the residences of customers participating in the time-

differentiated pricing pilot. Top lessons learned about HANs include:

- HANs offer significant features beyond those available from traditional Demand Response technologies, but the impact of these features on effectiveness is not yet known and is currently under study.
- For the foreseeable future, an impractical number of pre-requisites exist for HAN technology to be effectively used to increase the utilization of renewable generation.
- HAN technology is extremely expensive and evolving rapidly, presenting high capital and technological obsolescence risk; it can also present additional utility system security risks if not carefully managed.

### ***Advanced Metering Infrastructure (AMI)***

Advanced meters offer many types of upgrades over traditional meters, facilitating time-differentiated rates, communicating with the utility in real-time, automating meter reading, sensing grid conditions, and other optional features. The options, benefits, and roles are specific to each utility and driven by existing operations, customer priorities, distribution grid strategy, rate designs, cost structures, and other factors. AMI investment choices are therefore highly complex and lessons learned are therefore very important to investment decisions. Further, since the service life of this equipment is typically 20 years or more, short term decisions have long term implications. Advanced meters have been installed in about half of the customer premises in SmartGridCity™. Top lessons learned about AMI include:

- Advanced meters offer extremely long customer payback periods if meter reading has already been automated (as it has in PSCO) and/or time-differentiated rates are adopted slowly by customers.
- Advanced meters offer capabilities likely to improve the satisfaction of some customers through the increase in ability to control energy usage and better Call Center responsiveness.
- Advanced meter and relevant communication technologies are still evolving rapidly and associated costs are dropping.
- Advanced meters can also serve as sensing

devices, reducing the need for transformer-based line sensors used in Distribution Monitoring and Integrated Volt/VAr Control.

- Enabling customer/representative access to meter functions (i.e., using meters as a home gateway) increases utility cyber security risks.

#### ***Distribution Monitoring (DM)***

Distribution Monitoring (DM) provides real-time visibility into distribution grid conditions between substations and customer premises. This visibility enables more efficient operations than traditional, substation-only monitoring provides. The capabilities of DM -- primarily more efficient troubleshooting and fault locating -- have been clearly demonstrated in SmartGridCity™. DM is operating throughout SmartGridCity™ and currently benefits 46,000 customers. Top lessons learned about DM include:

- Selective deployment of DM (for example, based on reliability and geographic needs) will increase value created per dollar of invested capital relative to universal deployment. For example, benefits are greater when deployed in areas of relatively lower reliability or time-consuming troubleshooting (i.e. rural, underground) compared to other deployment options.
- DM provides the Distribution Capacity Planning function with data to optimize upgrades and transformer sizing, which may become increasingly important as customer adoption of PV Solar and Electric Vehicles increases.

#### ***Distribution Automation (DA)***

Distribution Automation (DA) consists of a set of field hardware and software that automatically reconfigures the grid, primarily to isolate the impact of a service outage to the smallest number of customers possible. This effectively “self-heals” portions of the distribution system to minimize customer minutes out (CMO). DA provides automated control logic and remote operation capabilities not available in traditional SCADA (System Control and Data Acquisition) systems used by grid operators. DA is operating on two feeders in SmartGridCity™. Top lessons learned about Distribution Automation include:

- Selective DA deployment based on reliability

and geographic needs will improve value created per dollar of invested capital relative to universal deployment. For example, DA deployment could be limited to geographies with relatively low reliability.

- DA benefits are primarily related to reliability; economic benefits (such as capital referral resulting from improved load balancing) did not appear to justify costs in preliminary analyses when compared to reliability benefits.
- Of all smart grid systems, DA has the lowest tolerance for failure as it controls critical grid equipment and therefore must communicate accurately and regularly with internal systems.
- DA functions at the substation and feeder level and does not require centralized data processing. ‘Distributed processing’ in substations could serve as an alternative to centralized data processing and offers benefits in data latency and management.
- Reliability improvement from DA is generally a function of the number of sectionalizing devices installed; incremental improvements in reliability must be balanced against the incremental cost of devices.

#### ***Integrated Volt/VAr Control (IVVC)***

IVVC regulates feeder voltage and power factor (VAr) continuously and automatically to reduce energy usage between the substation and customer loads. Voltage is monitored near customer premises to ensure voltage levels are within requirements, while VAr is optimized through the coordinated operation of capacitor banks located throughout the grid. IVVC is functioning on two feeders in SmartGridCity™. Top lessons learned about IVVC include:

- IVVC offers high potential economic benefits to customers relative to cost through voltage optimization.
- IVVC can be deployed selectively, for example on feeders with the greatest load and voltage/VAr improvement opportunity. Though full deployment offers greater benefits relative to selective deployment, selective deployment can improve customer payback periods.

- Though IVVC benefits are significant in the aggregate and relative to cost of implementation, individual customer benefits are small enough that they will be difficult to perceive.
- IVVC investments are similar to DSM programs in that utility spending delivers benefits directly to customers but reduces a utility's opportunity to earn authorized rates of return. DSM-type mechanisms can help address this issue.

### ***Smart Substation Monitoring and Protection (SSMP)***

Smart Substation Monitoring and Protection (SSMP) offers real-time visibility into substation operating conditions, providing detailed data that can be used proactively to identify equipment malfunctions prior to failure and forensically to investigate abnormal substation events. It is functioning in four substations in SmartGridCity™. Top lessons learned about SSMP include:

- Substation-level failures are rare but have a disproportionate impact on CMO when they occur.
- Substation data may help predict substation transformer and breaker failure, but insignificant experience is available to prove or disprove such a claim due to the infrequency of such failures.
- Substation data can potentially be used forensically to evaluate failure root causes.
- Analytical tools and business process changes will be needed if substation data is to be used to predict equipment failure and reduce outage time.

### ***Communications Systems Infrastructure***

For smart grid equipment to function, a system to support the communication between smart grid technologies is required. The communications system utilized in SmartGridCity™ was designed to be reliable, robust, secure, and fast to allow for a variety of capabilities to demonstrate and test. SmartGridCity™ was equipped with a high bandwidth and low latency communications network so that current and future application testing could proceed relatively unconstrained. These capabilities were established through a variety of communications technologies, including

Broadband over Power Line (BPL), fiber optic cable, 3G Cellular, DSL, and microwave. Top lessons learned about Communications Systems Infrastructure include:

- Competing approaches to communication systems offer pros and cons in a variety of decision criteria, including Build vs. Buy; Upfront Capital Cost vs. Ongoing O&M Cost; Grow Competence vs. Hire Expertise; Accountability for Security; Bandwidth and Latency; future flexibility; and Reliability/Quality Control, to name a few.
- No single communications infrastructure type will be adequate for all geographies or capabilities. For example, SmartGridCity™ primarily utilized broadband over power line and fiber, but in locations where such infrastructure was unavailable, wireless technology was employed.
- The Geographic Information System (GIS) must be adequately detailed to support communication design and operation.
- Communications with field devices yields safety benefits (by reducing field crew exposure to hazardous conditions) as well as operating expense reductions.

### ***Information Technology Systems Infrastructure***

PSCO developed a new IT infrastructure for SmartGridCity™, maximizing the use of readily-available technology and IT best practices. The IT systems facilitate the communication and processing of smart grid data. The systems are readily scalable and can be leveraged to support future smart grid investments within PSCO. Top lessons learned about smart grid IT infrastructure include:

- Data and cyber security must be built into IT designs. Simply applying legacy policies, processes, and protocols to smart data environments can add administrative burdens, particularly in employee access management and credentialing.
- The distribution operations function may need to acquire new IT skills, while the business systems function may need to adopt new electrical engineering skills.
- Smart grid systems produce significant amounts of data. Strategies and tools should

be developed to maximize the value of available data and the benefits of smart grid investments.

- Strategies to minimize data collection, including exception reporting and, in particular, distributed (vs. centralized) data processing in the substations, are advised. Lower latency is an added benefit of distributed data processing.
- Though grid modernization offers operating cost reductions in several functions, IT support, software maintenance, and data management costs are likely to increase.

### ***Ongoing Benefits from SmartGridCity™ Infrastructure***

In addition to optimized investments from lessons learned, PSCO customers are receiving benefits from the infrastructure installed as part of SmartGridCity™. Four examples are discussed below:

- A real-world laboratory is being used to study distribution technologies and customer behaviors.
- The SmartGridCity™ customer data portal improved access to historical usage and billing data for all PSCO customers.
- IT application software is being used to support expansion of select smart grid systems to other PSCO service areas.
- IT architecture is being used to support PSCO-wide software applications.
- More uses for smart grid data will be found over time; changes in data needs may entail changes to communications requirements (speed, latency, etc.).

#### *A real-world laboratory is being used to study distribution technologies and customer behaviors*

One of the primary goals of the demonstration project was to establish a real-world laboratory to study distribution technologies and customer behaviors. The combination of line sensors, smart meters, software, and communications systems integrated into SmartGridCity™ is ideal for putting new technologies and customer program designs to the test. In addition to the aforementioned pricing and In-Home Smart Device study, PSCO is using the laboratory for a study on the impact of Electric Vehicles (EV) on the grid in conjunction

with Toyota and the University of Colorado. The pilot will gain greater understanding on EV performance, EV impact on electricity usage, and customer interaction with such technology. Other studies using the laboratory are being considered. The laboratory is available to test promising new technologies, approaches, and programs as they become available. Test results will be used to benefit all PSCO customers by optimizing capital investments and maximizing associated benefits. The laboratory is already being used to answer the questions that inform technology deployment investment decisions such as:

- What impact does a technology or program have on operations, costs, or customer behavior?
- What is the value of the impact? How does value compare to cost, and how is it likely to change over time?
- What are the drivers of value, and how can they be influenced?
- What organizational and operational changes are required to maximize benefits from the technology or program?

With answers to such questions PSCO can make the informed choices regarding studied technologies and programs and their implementation, maximizing the value of investments made on behalf of PSCO customers.

#### *The SmartGridCity™ Customer Data Portal Improves Access to Historical Usage and Billing Data*

A website portal was installed to provide smart-metered customers secure access to daily updates of detailed energy usage data. Current efforts are underway to provide energy usage data in near real-time. The portal includes enhancements that improved the user experience of all PSCO customers who access historical energy usage data from the Xcel Energy website.

#### *IT Application Software Is Being Used To Support Expansion of Select Smart Grid Systems*

The software installed to support many SmartGridCity™ systems (Open Grid, which supports Integrated Volt/VAr Control, Distribution Automation, and Distribution Monitoring) is scalable. PSCO may consider expanding these capabilities to other parts of its Colorado

distribution system without significant incremental application software cost or effort.

The Company has already used Open Grid to expand Integrated Volt/VAr Control to a feeder in Englewood, Colorado and is currently considering other expansions.

*SmartGridCity™ IT Architecture Is Being Used to Support PSCO-wide Software Applications*

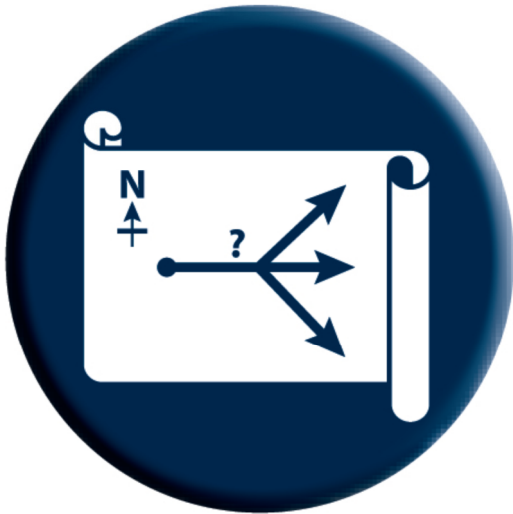
The Bus architecture employed for the first time in PSCO as part of the SmartGridCity™ demonstration project is being used to integrate data from other systems that serve PSCO customers. The Bus architecture facilitates data integration and utilization and features reduced interface maintenance costs for the Business Systems function.

## Transcendent Themes

In addition to benefits for SmartGridCity™ and PSCO customers, the demonstration project provided three themes that will serve as additional inputs to PSCO's grid modernization strategy. These themes transcend multiple value propositions and smart grid systems, but do not necessarily apply to all value propositions or smart grid systems. The three themes include:

- Grid Modernization Is a Strategic Planning Process.
- Stakeholder and Customer Engagement Is a Platform for Risk Mitigation and Value Creation.
- Change Management Can Help Maximize Benefits from Many Smart Grid Systems.

These themes are described fully below.



### **Transcendent Theme: Grid Modernization Is a Strategic Planning Process**

The electric distribution grid is an asset that utilities, including PSCO, continuously modernize; utilities have extensive experience in evaluating the benefits of new technologies relative to costs. The primary difference between grid modernization today relative to past decades is demand curve volatility related to unknown customer adoption of potentially disruptive technologies such as PV Solar generation and electric vehicles. Considering rapid technology development, market and regulatory evolution, and the significant investments required to prepare the grid for the future, the requirement to

rigorously apply strategic planning processes to govern grid modernization becomes readily apparent.

Through the perspective of an ongoing strategic planning process, the demonstration project delivered lessons that will provide exceptional value to PSCO customers in terms of optimizing future investments:

- Value is greatest on the utility side of the grid and drops as components approach premises.
- Two competing approaches to deployment speed, 'Big Bang' and 'Incremental', offer very different trade-offs in benefits, costs, and risk.

### ***Value is greatest on the utility side of the grid and drops as components approach premises.***

From an economic perspective, SmartGridCity™ data (supplemented by data from other studies as appropriate) seems to indicate that the most reliable and least controversial economic paybacks for PSCO's customers lie within the grid and not on its periphery (A full and formal Business Case must be developed to prove this hypothesis and is outside the scope of the evaluation phase).

Through careful mapping of value propositions and benefit types to SmartGridCity™ systems, and by comparing summary benefit information to investment costs and technological obsolescence risk by system, informal estimates about the value of various grid capabilities can be made. For more detailed information on benefits, cost, and risk by smart grid system please see 'Value Creation by Smart Grid System' below.

The idea that value appears to be greatest on the utility side of the grid assumes circumstances that may be unique to PSCO and cannot be extrapolated to other utilities' deployments:

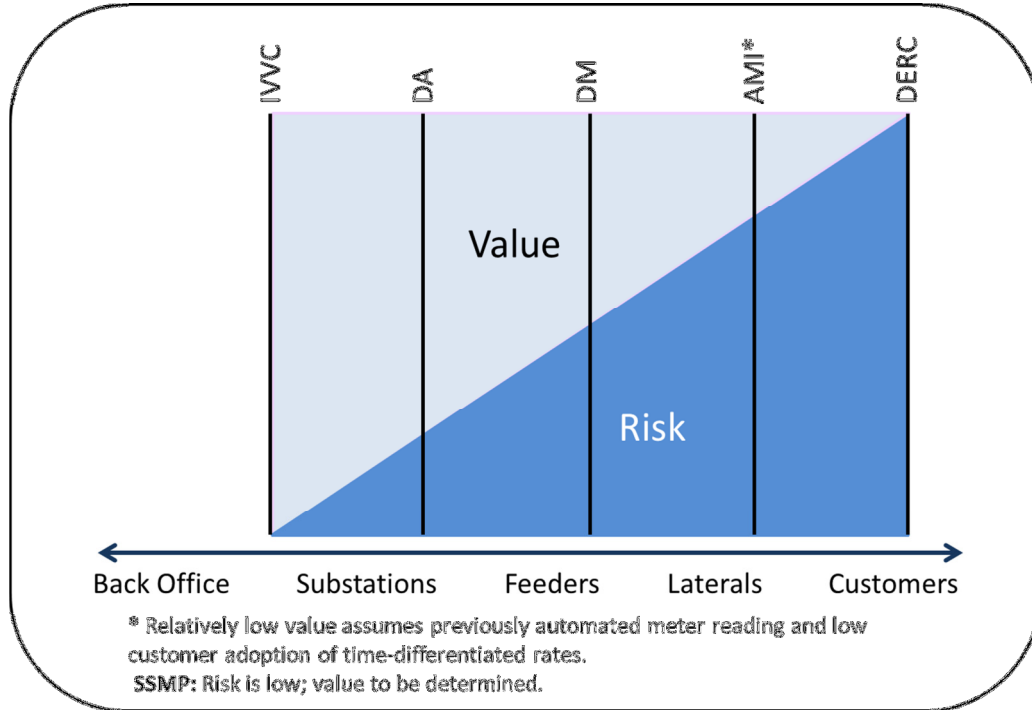
- Meter reading has already been automated, making associated savings low from AMI investments.
- Without the savings from automated meter reading, high customer adoption of time-differentiated rates would be needed to provide a reasonable payback period on AMI deployment. Aggressive implementation of time-differentiated rates carries significant customer satisfaction risk.



Figure 1 illustrates how value is greatest on the utility side of the grid and risk appears to be

greatest on the customer side of the grid.

**Figure 1 – Relationship Between Asset Location, Value, and Risk**



**Two competing approaches to deployment speed, ‘Big Bang’ and ‘Incremental’, offer very different trade-offs in costs and benefits**

Some utilities are pursuing a ‘Big Bang’ approach to grid deployment, characterized by rapid implementation of significant grid upgrades over large areas, requiring extensive capital investment. The increased cost of accelerated grid upgrades stems from both premium acquisition prices for the latest technologies as well as accelerated replacement schedules for currently adequate equipment. (Generally Accepted Accounting Principles require that any book value of equipment retired before the end of its useful life be written down to zero.)

Alternatively, the ‘Incremental’ approach is achieved through selective (as opposed to universal) deployment of smart technologies, as well as the simple practice of upgrading grid equipment as retired. Advantages of a planned and concerted pace include potentially lower overall costs, effort, and risk as technologies continue to develop. (Note that under the

incremental approach, communication and IT infrastructure investments will be required at some point to support incremental grid upgrades, and that these costs may represent a significant investment at that point.)

SmartGridCity™ taught that benefits from smart grid technologies can vary by feeder based on asset condition. For example, a feeder with higher voltages and loads will yield greater benefits from Integrated Volt/VAr Control than feeders with lower voltages and loads. This finding implies that some grid technologies can be most cost-effectively deployed on a selective, vs. universal basis. A utility need not upgrade its grid all at once, but over time based on logically prioritized geographies. The lesson is that incremental modernization is a realistic alternative to ‘all or nothing’ deployments.

The Big Bang approach does have some advantages. For example, reducing meter reading routes can only be achieved through large deployments of smart meters. In addition, lower per-unit prices are likely for equipment purchased

in large quantities. Conversely, incremental deployment takes advantage of the premise that competition will drive technology prices down while capabilities improve over time.

Either deployment approach will require significant and careful consideration of the implications for communications and IT Infrastructure design. If large scale or incremental deployment is pursued, a forward looking IT and communication strategy should be put in place to support smart grid development.



**Transcendent Theme: Stakeholder And Customer Engagement is a Platform for Risk Mitigation and Value Creation**

Utilities have always been challenged by competing interests among stakeholders (e.g. customers, regulators, advocacy groups, etc.) and have long been dependent on stakeholder to maximize the benefits of investments in programs such as Demand Side Management. Not surprisingly, smart grid investments only ‘up the ante’ on the value of stakeholder engagement. With regards to grid modernization, stakeholder engagement can help mitigate regulatory risk for some grid investments and maximize the benefits created by others:

- Definition of appropriate ‘Grid Preparedness’ levels varies by stakeholder and creates regulatory and cost recovery risk due to unknowable customer technology adoption.
- Clear rules must be established if utility development of certain smart grid capabilities is to be encouraged.

- Customer engagement is critical to the maximization of benefits from several systems.

***Definitions of appropriate ‘Grid Preparedness’ levels vary by stakeholder and create regulatory risk based on unknowable customer adoption of electric technologies.***

The Evaluation indicated that current adoption rates of new electric technologies such as PV solar and Electric Vehicles presents little threat to reliability. In the future, however, rapid and/or geographically concentrated adoption of these electric technologies could present reliability challenges. As challenges to reliability increase, the value from systems designed to improve reliability (such as Distribution Monitoring and Automation) will likely increase.

While SmartGridCity™ proved these systems do indeed provide reliability benefits today, policymakers should understand that the most valuable aspects of reliability-oriented smart grid investments relate to management of anticipated future challenges. Currently, much of PSCO is experiencing high levels of reliability. Stakeholders will need to help determine the value of preparedness for anticipated (but unknowable) reliability challenges. PSCO could then use this value determination as an input into Distribution Monitoring and Automation investment decisions. Investment decisions about other smart grid systems, such as Integrated Volt/VAr Control, may involve virtually zero uncertainty and require no customer engagement.

Customer adoption of PV solar and electric vehicles is beyond utilities’ control and is highly unpredictable as to timing and extent. Given this variability it is difficult for utilities to determine the appropriate level of readiness with which to prepare the grid. Historical distribution grid planning horizons require utilities to begin preparing for such changes far in advance, but early actions expose utilities to technology, financial, regulatory and reputation risk. Utilities are understandably concerned that hindsight will be used to judge the accuracy of their forecasts and deny cost recovery. Stakeholder engagement can be used to reduce this risk. Figure 3 illustrates the challenge utilities face in preparing for and meeting unknown levels of customer adoption of potentially disruptive technologies.

**Figure 3: Illustration of Market Adoption Rate Risk**

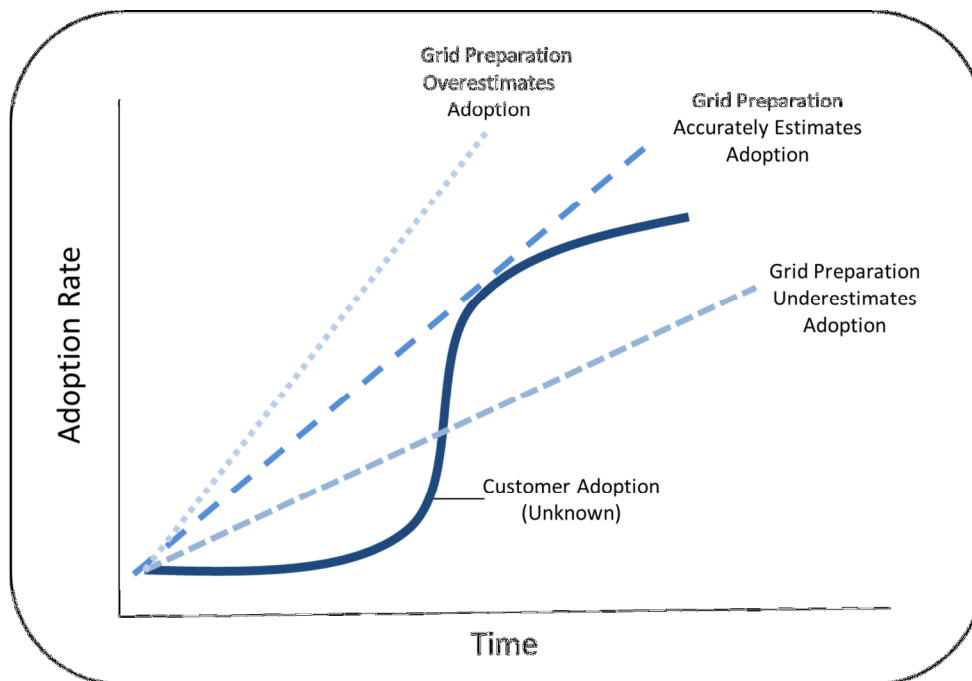


Figure 3 is intended to illustrate two points. First, classic utility planning horizons may be insufficient for customer adoption rates of new technologies. Second, it is difficult for utilities to plan for uncertain customer adoption.

In Figure 3 the lowest dashed line represents a classic utility planning and grid development horizon. The solid dark curve represents customer adoption of technologies (PV solar or Electric Vehicles) that are likely to present reliability challenges at higher penetration rates. For example, high penetration of Electric Vehicles could damage transformers due to large electricity demand. In the event customer adoption follows the curve, a grid modernized at traditional grid development rates is unlikely to be prepared for reliability challenges. Given the potential discrepancy between grid preparation and customer adoption rates, utilities may need to anticipate reliability challenges by preparing the grid with Distribution Monitoring and Automation in advance. The question is for what rate of adoption should a utility prepare the grid?

By preparing the grid at a rate represented by the middle dashed line, the utility will reduce

reliability risk for the least amount of investment. But what if the utility guesses incorrectly? The adoption curve is unknown; it is just as likely that a utility prepares the grid for an aggressive adoption rate (the top dashed line in Figure 3) that does not materialize. In such a situation, the utility has over-prepared (and over-invested in) its grid.

To summarize, the timeline of utility grid upgrades combined with the uncertainty of customer adoption presents inherent challenges to utility planners and policy makers. In many respects, investments in Distribution Monitoring and Adoption (though there are other examples) can be considered a hedge against potential reliability risks for customers. Stakeholder engagement can help establish consensus on the value of such a hedge, which PSCO can use as an input into investment decisions and to reduce associated regulatory risk.

***Clear rules must be established if utility development of certain smart grid capabilities is to be encouraged.***

Regulators play a particularly critical role in the development of smart grid capabilities. Certain

capabilities present increased risks to utilities, particularly investor-owned utilities. Utilities will likely want to be protected from these risks before investing in or enabling such capabilities. A few examples may help illustrate this issue.

Consider the concept of proactive customer outage notification. Smart grid capabilities could facilitate automated execution of telephone, text, and e-mail messages to customers about outages, including validation of outage awareness by the utility and time-to-restoration estimates. While these services might be appreciated by customers, they could increase utility risk. Customers may rely on such information over time, and use it to inform certain actions or alter established plans. In the event the information the utility provides proves to be incorrect, or is not received by a customer due to a technical issue, customers might hold the utility accountable for associated economic harm. "I was on vacation, and all my food spoiled. Had the utility's new notice system worked, I'd have called a relative to empty my refrigerator and freezer. The utility owes me \$800."

This is only one illustrative example of many smart-grid related capabilities that could increase utility risk. The example illustrates that utilities are likely to increase their risk exposure if they add services that might one day prove to become a customer satisfaction issue or increase costs for all customers.

Another smart grid capability that illustrates the concept of increased utility risk is Integrated Volt VAr Control. IVVC improves distribution efficiency, increasing the usable power delivered to customers for a given level of electric generation. But as voltage is reduced to accomplish this objective, customers use less energy. This reduces electricity sales volumes below the levels assumed in the most recently completed ratemaking process, and results in a reduced opportunity for the utility to earn its authorized rate of return. In this regard, IVVC is much like a Demand-Side Management (DSM) program. The utility makes all of the investment and incurs the rate or return risk, while the customers enjoy all of the economic benefits. Regulatory mechanisms would need to be created like those employed for DSM programs to provide equitable economic treatment in such situations and encourage utilities to invest in certain capabilities.

### ***Customer engagement is critical to the maximization of benefits from several systems***

Customers play a key role in grid modernization -- taking advantage of opportunities, driving certain types of benefits, and adopting new technologies that make the smart grid both necessary and valuable. Some smart grid capabilities and benefits affect customers directly, some indirectly, and others require customer participation in order to maximize anticipated benefits.

As just one example, time-differentiated rates present both opportunities and risks to customer satisfaction. On one hand, many customers appreciate opportunities to manage energy use and cost and may be more likely to embrace options like time-differentiated rates and Demand Response. Many other customers, however, may participate in such programs and be dissatisfied by the inconvenience required to participate, or be disappointed by the size of the economic incentives their efforts delivered.

In addition, research into other utilities' time-differentiated rate programs indicates that the manner in which these rates are introduced is critical to perception and satisfaction impact and very dependent on utility base rates. From a customer's perspective, rate *options* will generally be perceived favorably relative to rate *mandates*. This is particularly true in the electric utility industry, in which simplicity and relatively low cost have created a product category characterized by extremely low engagement and interest.

Focus groups of customers within SmartGridCity™ identified multiple educational opportunities to help manage associated satisfaction risk. An informal takeaway is that customers have a long way to go to become fluent in, let alone embrace, advanced rate designs.

The benefits associated with time-differentiated rates and advanced demand response capabilities are driven largely by customer behavior change and program participation levels. While rate designs, convenience services, communications, and education are critical to the success of these programs, an understanding of the drivers of average customer participation and response to such programs is critical to pricing, program, and promotion designs. Behavior change will vary with program design, incentive offer, and implementation scenarios (mandatory,

default/opt out, and opt in), and rigorous research is required to accurately inform deployment strategy development. A set of extensive, multi-year pilots are underway in SmartGridCity™ to obtain the thorough understanding of customer response and behavior change required.

A review of the results of PSCO's 2006-2007 time-of-use pricing study indicates that the benefits of time-differentiated rates are potentially significant. The time-of-use and in-home smart device pilot currently underway will validate the size of the opportunity.

To summarize, stakeholder engagement activities should accommodate the evolving role and contributions of customers in concert with regulatory changes (i.e. establishment of clear rules).



**Transcendent Theme: Change Management Can Help Maximize the Benefits from Many Smart Grid Systems**

As part of its SmartGridCity™ evaluation MetaVu examined the extent to which PSCO had integrated smart grid capabilities into routine operations. The examination identified examples in which the application of change management best practices could maximize the benefits of some smart grid systems. These examples are summarized into the observations listed below. In addition, MetaVu has observed that the experiences associated with operating SmartGridCity™ have institutionalized a motivating vision for grid modernization among PSCO management and individual contributors.

- The roles played by certain key assets change with smart capabilities and may require modifications to organizational structure and strategy.
- Functional areas and personnel will require new systems and tools to maximize the value of data and capabilities made available by the smart grid.
- Increased use of sophisticated equipment and capabilities enabled by the smart grid will require new and different organizational and human resource skills and capabilities if the benefits are to be maximized.

These observations are fully discussed below.

***The roles played by certain key assets change with smart capabilities and may require modifications to organizational structure and strategy.***

The increasing sophistication of many distribution grid assets implies that they will serve a greater number of purposes and business areas. The discussion below will address three of the grid assets for which changes will likely be greatest: operations centers, smart meters, and smart substations.

*Control and Operations Center(s) Example.* In a traditional utility structure, Transmission Control Center (TCC) staff and Distribution Control Center (DCC) staff are in regular contact to achieve operational tasks. IT served as a support function for both the TCC and DCC. The advancements of smart grid technology will require more integrated IT role, for example in troubleshooting smart grid technologies in the field and back office. Consequently, future integration and interaction of the TCC and DCC with the IT department's Information Operation Center (IOC) and the communications systems' Network Operating Center (NOC) will be required to optimize business functionalities. Going forward the TCC and DCC may need to consider the IOC and NOC as peers, maintaining regular communication and developing common processes and procedures to create a more interconnected environment.

For example, DCC staff may send field technicians to address faulty field equipment and determine the problem may be due to IT or communication issues. Field technicians must then ask for IT assistance resulting in extended troubleshooting time. Merging the DCC, IOC and NOC ticketing

systems to create greater alignment of troubleshooting procedures could be implemented to increase the coordination and integration of the two business areas. Greater integration could correctly identify which teams should address equipment and system issues to optimize troubleshooting.

*Smart Meter Example.* In the transition from traditional to smart meters, the meter evolves from simple measurement device to a sophisticated multifunctional instrument, incorporating data and communications technologies, diagnostic capabilities, exception reporting capabilities, and in some cases control functions. Traditionally, meters have logically been the responsibility of utilities' revenue cycle team as a result of meters' central role in revenue determination and collection.

In their new role, smart meters are valuable to many departments, including:

- Customer Care (remote meter function testing and in some cases control)
- Area Engineering (to diagnose Power Quality issues)
- Distribution Capacity Planning (to identify capacity increase needs)
- Distribution Control Center (to identify fault locations)
- Marketing (to provide services and information of value to customers)

In a smart grid deployment, organizational changes may be required to align new technical capabilities with organizational responsibilities. Questions to be answered include 'Which organization should maintain responsibility for meter operation and functionality?' and 'Are smart meters a corporate IT asset?' Utilities will need to consider which organizational structures may need to change in order to optimize benefits.

*Substation Example.* Substations offer another good example. Formerly responsible for stepping down transmission voltage and meeting power factor standards at the transmission voltage entrance, substations can play many new roles in a modernized grid and serve new internal customers. Depending on capabilities and system design, substations can serve as field data centers and communications hubs. SmartGridCity™ illustrated that substations can also effectively house many new types of equipment such as

remote controllers, data servers, sensing devices, and other components that will become critical to Distribution Operations in a modernized grid. For example, as future loads become less stable, systems will increasingly need to react to grid issues in a timely and effective manner, requiring lower latency communication capabilities for faster response. The shorter distance from field devices to data centers in substations will allow for lower latency and can serve as a collection and processing point to provide pertinent information to central, back office systems.

In summary, much of the equipment required to modernize the distribution grid resides in substations. The need to install, maintain, repair, and upgrade this equipment suggest that new substation physical designs, operating processes, and organizational changes be considered as part of grid modernization strategies.

***Functional areas and personnel will require new systems and tools to maximize the value of data and capabilities made available by the smart grid.***

Systems and tools can play a pivotal role in helping business areas and personnel to maximize the value of available data. Enhancements to existing software applications, development of free-standing applets and subroutines, and exception reporting can be useful approaches to accessing the data made available by smart grid capabilities. Systems and tools can help business areas manage practical issues that serve to reduce the adoption of new capabilities, from the complex (making sense of extremely large data sets) to the simple (user hardware upgrades).

This is particularly critical during the period of transition from a traditional grid to a smart grid, which may be lengthy. Due to its large size, smart grid upgrades can take years to complete (or even decades in the event the 'incremental' approach to grid modernization as described earlier is selected.) This implies that employees in many business functions will be forced to manage two operating models – traditional and smart – simultaneously. Information systems and tools can be designed to help employees accommodate this challenge efficiently and effectively. As just one example, the SCADA systems in use in the Distribution Control Center could be modified to let an operator know which feeders have been enabled with Distribution Automation capabilities,

and to notify the operator when Distribution Automation has instituted a configuration change.

***Increased use of sophisticated equipment and capabilities enabled by the smart grid will require new and different organizational and human resource skills and capabilities if benefits are to be maximized.***

There are many examples in which smart grid capabilities will require business functions to acquire new capabilities. In the field, smart grid systems are more sophisticated than existing equipment, and consequently require more effort and knowledge to install, maintain, and support. 'Smart' field devices are no longer simple electromechanical systems, but complex computer-driven devices. Troublemakers and linemen will need enhanced communications and information technology skills. For example, Troublemakers may have to repair communications equipment not previously used in distribution activities, requiring an entirely new skill set. Also, Information Technology help desks will require more resources and skills to support many new types of computerized field devices.

In addition to field and IT capability enhancements, Distribution Control Centers (DCC) will also need to acquire new skills, as the management of grid operations becomes more complex. The distribution of power past the substation has historically been unidirectional. In the future, higher penetrations of customer-owned generation and storage may require Dispatchers to manage multidirectional power flow (PV Solar and Electric Vehicles) as transmission operators do currently. Dispatchers have traditionally instructed field crews to make on-location changes; smart grid technologies will allow them to perform the actions remotely, or perhaps simply monitor automated system instructions. The role is changing as the technology develops, and Distribution Control Center managers may wish to consider how Dispatcher skills and competencies will need to change to maximize the value of smart grid technologies.

Even Customer Care Center skill sets may need to change. In a smart grid scenario, the nature of support customers might want to obtain from their utility is likely to change. As just one example, access to detailed usage information is likely to prompt customer questions on how to

interpret the information, how to identify the drivers of home energy consumption, and how best to save money on time-differentiated rates. These types of calls will require new skills and competencies from Call Center agents.

In Marketing and Product Development, the smart grid will change the types of Demand Side Management (DSM) programs utilities offer, the features and capabilities of such programs, and the manner in which DSM programs will be promoted. And the introduction of time-differentiated rates presents particularly challenging marketing issues. Utility marketing organizations will want to cultivate the types of creative and self-driven personality types required to identify and seize opportunities to maximize the benefits of smart grid investments.

In summary, MetaVu examined the extent to which PSCO integrated smart grid capabilities into routine operations as part of MetaVu's SmartGridCity™ evaluation. The examination documented many examples in which the application of change management best practices could maximize the benefits of smart grid capabilities in the event of future expansions. In addition, MetaVu observed that the experiences associated with operating SmartGridCity™ have institutionalized a motivating vision for grid modernization among PSCO management and individual contributors.

## VALUE CREATION BY SMART GRID SYSTEM

This section provides more detailed descriptions of the value created by various SmartGridCity™ systems. It begins with information on the measurement framework used to evaluate the systems, describes each system, and summarizes findings on economic benefits, costs, and risks by system. Each system is then described in detail:

- System objectives and functions
- Types of benefits offered by the system
- Value created for SmartGridCity™ and PSCO customers
- List of important considerations when developing a business case for the system.

### **Summary**

#### ***Measurement Framework***

PSCO executives and demonstration project leaders established three goals to maximize the value of the evaluation phase. These goals included:

- Evaluate the benefits of 61 value propositions and take other steps as necessary to inform deployment strategy and future business case development.
- Document measurement methods so that Company managers can use them as appropriate in future business planning.
- Identify relevant risks and operational and strategic considerations identified through the evaluation process.

The SmartGridCity™ evaluation framework was designed to collect, organize, and analyze data to transform a collection of findings into a usable and actionable information set and satisfy the following criteria:

- Identify lessons learned and information gleaned from the SmartGridCity™ demonstration project.
- Provide valuable quantification and perspective to inform the development of deployment strategies and business cases by PSCO managers.
- Document the measurement frameworks, assumptions, and calculations for application to specific deployment scenarios as part of future planning efforts.

Because of the developing and emerging nature of smart grid technologies and assessments, measurement standards are not yet universal. However, the various grid modernization pilots, deployments, evaluations, and assessment guidelines that have been completed or are underway were analyzed as part of the SmartGridCity™ evaluation framework development process. MetaVu completed an analysis of 12 value measurement methodologies (EPRI, NETL, DOE, etc.) and smart grid deployments (BG&E, OG&E, SCE, etc.) to inform the measurement framework used to evaluate the SmartGridCity™ demonstration project. Fifty-two additional external references (studies, papers, articles, etc.) were used to validate and/or support specific calculations for value proposition benefits. Sixteen other sources were used to develop context and application frameworks for demonstration project evaluations and findings.

The resulting evaluation framework adapted emerging standards to SmartGridCity™ learning objectives; specifically, 61 value propositions established by the project leadership team to inform business case development. (To facilitate analysis and simplify the use of value proposition findings in future business planning, MetaVu split some value propositions and added a few others, ending up with 68 value propositions in total.)

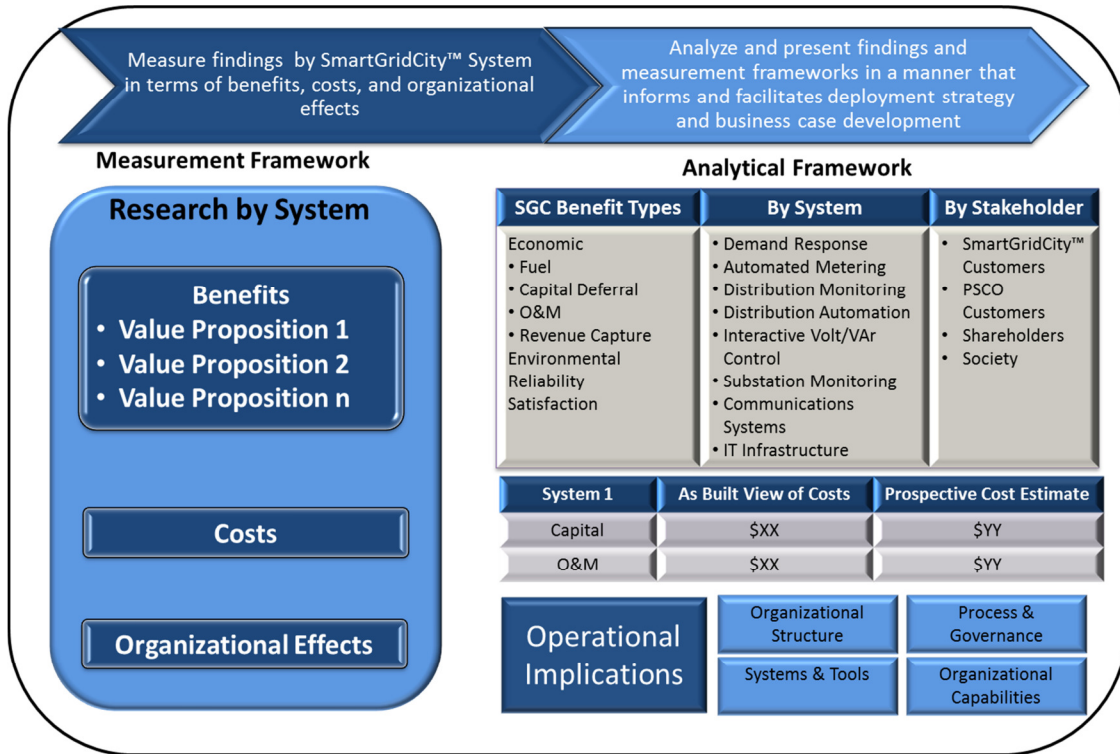
No standards exist to address the potential effects of grid modernization on customer satisfaction or utility business models, though these issues were within the scope of the evaluation phase. In these two cases, MetaVu used best practices in market research and organizational development to establish appropriate measurement frameworks. The evaluation team made extensive use of market research to measure customer perceptions and value attribution related to grid capabilities and benefits. Utility organizational and operational implications were informed by interviews and collaboration with subject matter experts of varying responsibility levels both within and external to PSCO.



MetaVu provided additional support for future business case development by quantifying ‘as built’ and ‘prospective’ deployment costs and identifying operational and strategic deployment considerations. MetaVu also synthesized evaluation findings in the context of its experience with grid modernization projects. Many

transcendent themes described in the Evaluation Summary were the result of discussions of the findings with PSCO project leaders and Business Area managers. Figure 4 illustrates the evaluation framework MetaVu developed for the SmartGridCity™ evaluation.

Figure 4 -- Illustration of Evaluation Framework



**System Descriptions**

Value Propositions are not actionable in and of themselves; benefits are delivered by SmartGridCity™ systems. In the Value Proposition analysis, at least one SmartGridCity™ system is identified as responsible for delivering the potential benefits available. A SmartGridCity™ system is defined as “a set of hardware and software that could conceivably be installed in isolation to accomplish SmartGridCity™ value propositions.”

- **Distributed Energy Resource Control (DERC):** Controls energy resources throughout the distribution grid to optimize utility operations and support time-differentiated pricing programs. Components include in-home

smart device (IHSD), smart meters, and demand response management system (DRMS) software.

- **Advanced Metering Infrastructure (AMI):** Records high-resolution usage data that is communicated automatically to the utility for billing and analysis purposes and provided to customers to enable them to change consumption behaviors. Components include smart meters, online account management (OAM), OpenGrid software, and the billing system.

- **Distribution Monitoring (DM):** Provides real-time visibility into distribution network status. Components include voltage sensors on overhead transformers, current and voltage sensors on underground transformers, Power Quality meters, synchrophasors, and OpenGrid software.
- **Distribution Automation (DA):** Reconfigures the distribution grid automatically based on electrical conditions. Components include sectionalizing devices, and DA controllers.
- **Integrated Volt/VAR Control (IVVC):** Reduces voltage and optimizes power factor automatically to improve power delivery efficiency. Components include distributed capacitor banks and controllers, line sensors, load tap changers and controllers, and a centralized data processor utilizing OpenGrid, a server-based software application.
- **Smart Substation Monitoring and Protection (SSMP):** Provides real-time visibility into substation operating conditions. Components include microcontroller-based relays, automation controllers, communications equipment, analysis engines and OSI Soft software.

### **Benefits**

A summary table of benefits by SmartGridCity™ system is offered below, rated relative to the benefits available from other systems. The values in Table 1 are defined as follows:

- High:** Substantial potential for benefit
- Med:** Moderate potential for benefit
- Low:** Minimal, if any potential for benefit
- Blank:** Benefits of a specific type were not anticipated from a particular system
- TBD:** Benefit level is dependent on a high number of variables

Please note that the table below describes relative benefits, not value. Value considers the benefits against costs and risks. The following ratings do not take into account costs or risk involved in realizing the benefits (see next section).

**Table 1: Relative Benefits by System and Benefit Type**

	Inside Systems ←-----→ Outside Systems					
	Smart Substation Monitoring and Performance (SSMP)	Integrated Volt VAR Control (IVVC)	Distribution Automation (DA)	Distribution Monitoring (DM)	Advanced Metering Infrastructure (AMI)	Demand Response (DR or DERC)
<b>Capital Deferral</b>		High	Low	Low	High/ Low*	High
<b>O&amp;M</b>	TBD			Med	Low	
<b>Revenue Capture</b>					Low	
<b>Energy / Environment***</b>		High	Low	Low	High/ Low*	Med
<b>Reliability</b>	TBD		High	High	Low	Low
<b>Safety</b>				Med	Low	
<b>Satisfaction**</b>		Low	Low	Low	TBD	High

Table 1 notes:

- \* With (High) and without (Low) high customer adoption of time-differentiated rates enabled by Smart Metering
- \*\* Many benefits offered by smart grid systems are not readily apparent to customers and therefore offer low satisfaction benefit
- \*\*\* Green signals were not implemented as they were not shown to increase utilization of renewable energy

Note: The “Inside” systems, notably Integrated Volt/VAr Control, deliver some types of economic benefits at high and medium potential levels; the reader will observe that these capabilities require relatively little capital to implement in the next section. Conversely, the “Outside” systems, notably smart metering, offers relatively low customer benefits unless high customer adoption of time-differentiated rates is realized; the reader will observe that metering requires a great deal of capital to implement. For additional information, please see value proposition evaluation detail in Appendix 1.

**Costs and Risks**

Prospective estimates of capital costs relevant to future deployment were developed from detailed analyses of ‘as built’ costs as incurred in the SmartGridCity™ demonstration project. Prospective estimates by system incorporate likely design changes recommended by construction managers, project managers, and project leaders as a result of lessons learned through the demonstration project. Prospective estimates also reflect the fact that partner support to the extent contributed in SmartGridCity™ is not likely to be available in the future. Feeders are used as the basis of analysis as they represent a useful common-denominator. The figure below describes the likely capital costs of various systems in any future deployment.

Risk was estimated by system based on the relative technological obsolescence risk related to each system. Technology Obsolescence risk was estimated in relative terms by observing grid technology and supplier business model changes from 2007 to 2010. During this time many technologies and supplier business models evolved; some technology price points dropped, some technology features improved, and other technologies were ultimately determined to be sub-optimal. Home Area Networks were identified as particularly immature technologies in the SmartGridCity™ demonstration project, though meter technologies evolved rapidly during the evaluation period as well. The results of relative technology risk evaluations by system are presented in the chart.

**Figure 5 - Capital and Technology Risk by System**

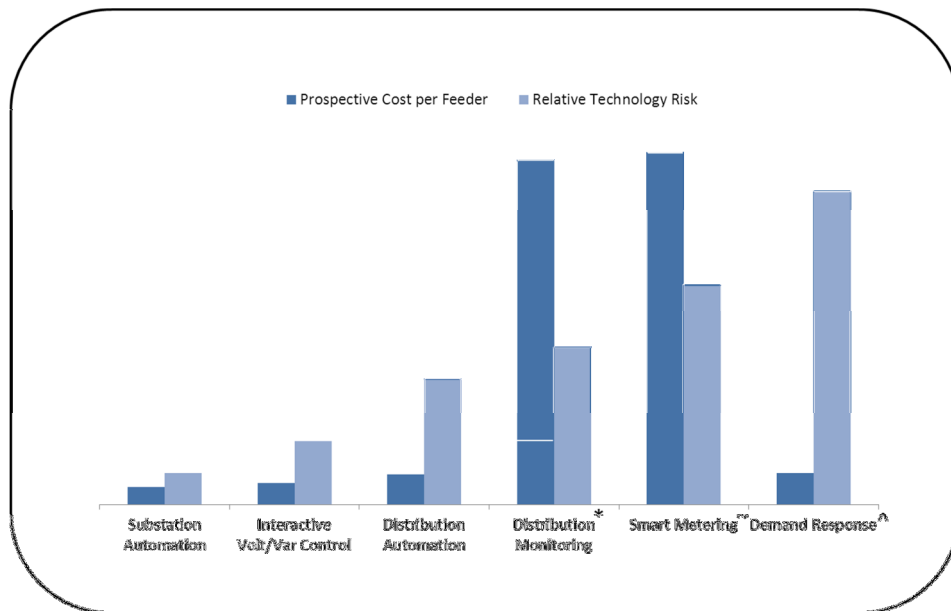


Figure 5 notes:

- ° Amounts indicated do not include fixed infrastructure capital costs.
- \* Distribution Monitoring capital cost estimate assumes transformer-based sensing; the portion above the break indicates capabilities and costs that might be duplicated with the installation of smart meters with certain sensing capabilities. (Note that the use of meters as sensing devices is contingent upon readily- and cost effectively-available data, which is in turn based on communications infrastructure design choices.)
- ~ Smart Metering capital cost estimates include communications-enabled meter and premise-variable communications costs per premise.
- ^ Demand Response capital cost estimates assume that customers purchase home energy management equipment; amounts indicated consist of equipment rebates likely paid by utility.

Figure 5 illustrates that the size of investment required to deploy smart grid capabilities per feeder and the technology risk associated with each system grows as the physical and logical location of associated hardware approaches the grid periphery.

## **Smart Grid System Value Creation Detail**

This section provides more detailed descriptions of the value created by the demonstration project for SmartGridCity™ customers and PSCO customers. Value creation detail is organized by distinct SmartGridCity™ system and presented in order of the physical location of capital investments, from the customer premise to the utility substation and through data processing.

- Distributed Energy Resource Control/Demand Response (DR)
- Advanced Metering Infrastructure (AMI)
- Distribution Monitoring (DM)
- Distribution Automation (DA)
- Integrated Volt/VAr Control (IVVC)
- Smart Substation Monitoring and Protection (SSMP)

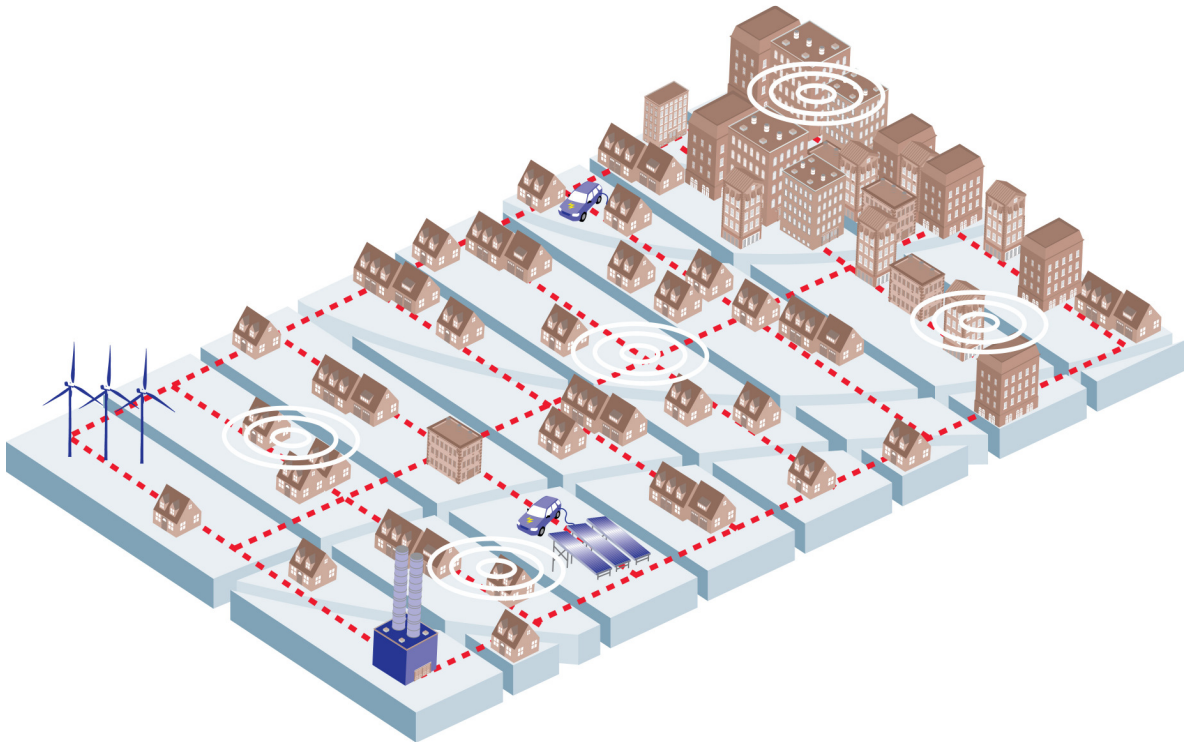
The value created by infrastructure systems is also presented:

- Communications Systems
- Information Technology Systems

Each system is described in detail in the following format:

- System objectives and functions
- Types of benefits offered by the system
- Value created for SmartGridCity™ customers and PSCO customers
- List of important considerations when developing a business case for the system

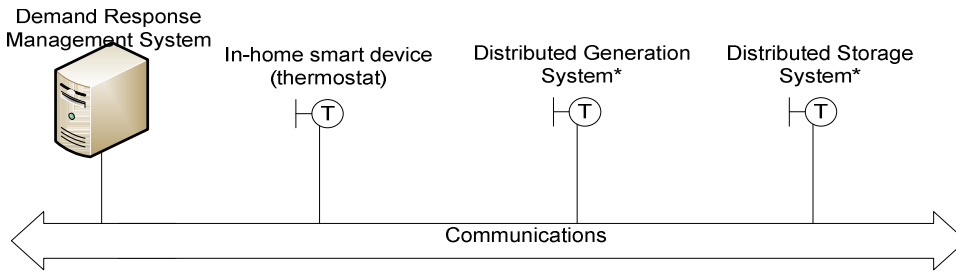
For even greater detail about lessons learned, please see Appendix 1.



**1. Distributed Energy Resource Control (DERC)**

Though envisioned to control customer loads as well as many types of distributed resources (including customer-owned equipment such as electric vehicles and PV Solar) in time, ‘Distributed Energy Resource Control’ as implemented in SmartGridCity™ consisted primarily of advanced capabilities to control customer loads through home area networks, or HANs. The table below summarizes value created by the demonstration project for SmartGridCity™ customers, PSCO customers, and the utility (in the form of lessons learned).

**Figure 1 Distributed Energy Resource Control (DERC) System**



**System Dashboard**

The following table describes the relative value provided by DERC from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for DERC.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
High	-	-	Med	Low	-	High

Capital Deferral - DERC can result in significant capital deferral for generation, but opportunities to defer distribution capacity expansion are limited.

Energy / Environment – DERC (Demand Response) is much more valuable as a capacity management tool than an energy efficiency tool. Because customer satisfaction will likely limit the number of Demand Response events that can be called, the events must be employed judiciously (i.e., on high demand days). It should be noted that DERC technology improvements offer demand response program design options that could enable changes to event flexibility, thus altering event assumptions.

Reliability – High customer adoption of DERC (Demand Response) is required before it can be counted on as an effective response to local distribution emergencies.

Satisfaction - DERC is likely to improve customer satisfaction through lower bills, as customers are likely to be paid incentives to participate.

**Summary Analysis: Distributed Energy Resource Control**

The table below summarizes value created by Distributed Energy Resource Control in the demonstration project:

Value to SmartGridCity™ Customers	Value to PSCO Customers
<ul style="list-style-type: none"> <li>SmartGridCity™ Customers were offered the opportunity to participate in a pilot of In-home Smart Devices</li> </ul>	<p>Lessons learned that will optimize investments for PSCO customers:</p> <ul style="list-style-type: none"> <li>Home Area Networks (HAN) offer customers significant capability enhancements over traditional DR programs.</li> <li>DR offers significant generation capacity deferral value (\$170/yr.) but little in the way of distribution capital deferral or energy efficiency value.</li> </ul> <p>Lessons learned that minimized risk for PSCO customers:</p> <ul style="list-style-type: none"> <li>HAN technology is extremely expensive and evolving rapidly, presenting high capital and technological obsolescence risk.</li> <li>HAN technology, when deployed such that it is interconnected with advanced utility meters, presents additional utility system security risks if not carefully managed.</li> </ul> <p>Lessons learned that will maximize benefits through operational changes:</p> <ul style="list-style-type: none"> <li>Providing customers with a green energy signal when renewable energy is high will not increase the amount of renewable generation on the system; increases in electric load that result from such signals are generally satisfied with natural gas-fired generation. Improvements in storage technologies may require this lesson to be revisited in the future.</li> <li>DR as designed could be called locally to help address distribution emergencies, but only at high customer adoption rates.</li> <li>HAN could be a valuable enabler of time-differentiated rates for customers.</li> </ul> <p>A test lab exists that will help optimize investments and maximize benefits into the future:</p> <ul style="list-style-type: none"> <li>The degree to which HAN technology increases the effectiveness of Demand Response over traditional residential Demand Response technologies is not yet known.</li> </ul>

DERC Business Case Considerations

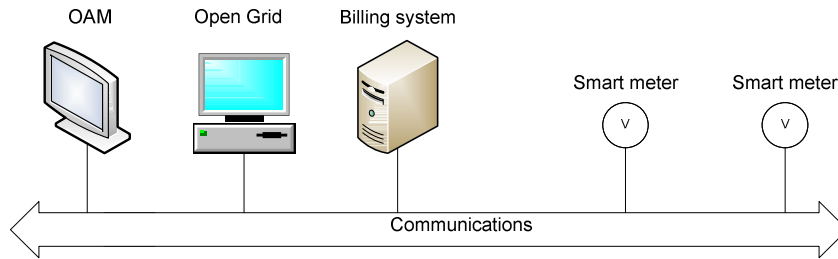
When developing the business case for DERC, PSCO is advised to consider:

- Customer Participation Levels
- Customer Behavior Change
- Comparisons to Existing DR Technologies (Saver’s Switch)
- Value of Capacity
- Technology Obsolescence Risk

**2. Advanced Metering Infrastructure**

Smart Meters record high-resolution interval data that is communicated automatically to the utility for billing and analysis purposes. This data can also be provided to customers to enable them to manage energy use. Other smart meter capabilities include two-way communications and the measurement of metrics beyond usage. Though there are alternative approaches available, smart meter capabilities can facilitate time-differentiated pricing programs. Based on external research and historic studies, MetaVu believes the time-differentiated pricing methods facilitated by smart metering could offer significant opportunities to defer capital and reduce energy usage. However, the overall impact will depend on a large number of factors, including customer participation rates and behavior change levels, system load growth, and pricing program structures.

**Figure 2 Smart Metering System**



**System Dashboard**

The following table describes the relative value provided by Smart Meters from among those types of benefits available through grid modernization:

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
High/Low	Low	Low	High/Low	Low	Low	TBD

**Capital Deferral** – If time-differentiated rates are widely adopted by customers, significant reductions in peak demand can decrease asset stress and defer capital investments. If time-differentiated rates are not widely adopted by customers, smart metering is unlikely to experience capital deferral benefits.

**O&M** – As meter reading has already been automated (and is extremely cost effective) in almost all of the PSCO service area, smart metering offers little in the way of meter reading savings. Other, smaller O&M reductions are available through reductions in troubleshooting truck rolls and shorter customer call length in the Call Center.

**Revenue Capture** – Residential theft and commercial meter configuration and equipment errors can be detected with a smarter grid, but the net increase in revenue capture is expected to be relatively small.

**Energy / Environment** - Like Capital Deferral, in order for Smart Metering to achieve significant Energy / Environmental benefits, rapid customer adoption of time-differentiated rates must be secured.

**Reliability** – Smart meters could help identify, classify and locate outages, but data levels required to complete this functionality are high. As a result, most smart grids manage outages at the neighborhood (vs. premises) level, though smart meters’ meter pinging capability can reduce over/ under estimations of outage extent.

**Safety** – Smart meters can reduce truck rolls and hazardous field investigations that positively impact safety.



### Summary Analysis: Smart Meters

The table below summarizes value created by Smart Meters in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
<ul style="list-style-type: none"> <li>• SmartGridCity™ Customers have the opportunity to participate in time-differentiated rate programs.</li> <li>• In a 2006-2007 PSCO study of time-differentiated rates, motivated customers saved as much as \$200 on their bills annually</li> <li>• Customers with smart meters can view detailed usage data throughout the month via a secure website.</li> <li>• In the event of an outage, the customer care center can remotely diagnose smart meter operation, immediately determining if the outage is PSCO’s responsibility or the customer’s responsibility to repair. (This capability was rated highly important in a survey of SmartGridCity™ Customers).</li> </ul>	<p>Lessons learned that will optimize investments for PSCO customers:</p> <ul style="list-style-type: none"> <li>• Advanced meters offer long customer payback periods if meter reading has already been automated and/or time-differentiated rates are adopted slowly by customers. Payback periods could improve if the technology is paired with high customer adoption of time-differentiated rates and as advanced meter prices drop.</li> <li>• Smart metering can reduce O&amp;M costs by decreasing truck rolls and customer care center call times.</li> <li>• Advanced meters can double as sensing devices, reducing the need for transformer-based line sensors used in Distribution Monitoring and Integrated Volt/VAR Control.</li> </ul> <p>Lessons learned that will minimize risk for PSCO customers:</p> <ul style="list-style-type: none"> <li>• Smart meter and relevant communication technologies are still evolving and associated costs are dropping.</li> <li>• Enabling customer/representative access to meter functions (i.e., using meters as a home gateway) increases utility cyber security risks.</li> </ul> <p>Lessons learned that will maximize benefits through operational changes:</p> <ul style="list-style-type: none"> <li>• Historical smart meter data can help the distribution Capacity Planning function ‘right size’ transformers and other grid components.</li> </ul> <p>A test lab exists that will help optimize investments and maximize benefits into the future:</p> <ul style="list-style-type: none"> <li>• Smart meters are one of the most critical components of the test lab as they provide detailed measurements at the customer level.</li> </ul>

#### Smart Metering Business Case Considerations

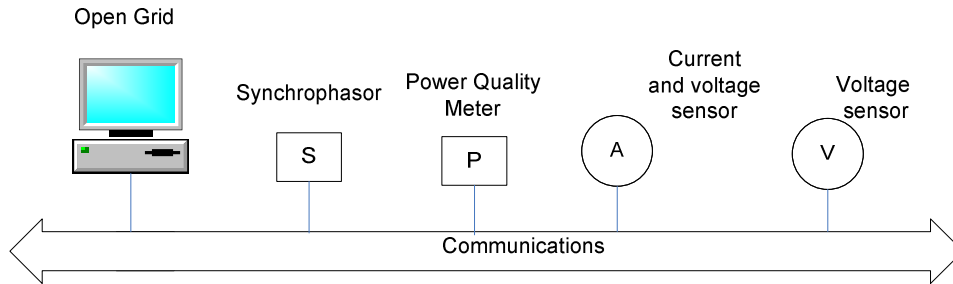
When developing the business case for Smart Metering, PSCO is advised to consider:

- Value of customer service enhancements
- Time Differentiated Rate Participation
- Customer Behavior Changes Due to Time Differentiated Rates
- Value of Meter Reading Cost Reduction
- Distribution Monitoring designs and capabilities
- Cost of Smart Meters and associated communications

### 3. Distribution Monitoring

Distribution monitoring provides real-time visibility into distribution grid conditions between substations and customer premises. This visibility enables more efficient faster problem troubleshooting and fault locating, which have been clearly demonstrated in SmartGridCity™.

**Figure 3 Distribution Monitoring System**



#### System Dashboard

The following table describes the relative value provided by Distribution Monitoring from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for DM.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
Low	Med	-	Low	High	Med	Low

Capital Deferral - DM will only minimally reduce capital expenditures as a result of better access to load information because current legacy tools are considered to be highly accurate.

O&M - O&M cost reductions are available from potential outage notification programs and reduced maintenance requirements, but such reductions are anticipated to be small.

Energy / Environment - The ability to properly size transformers through access to better load information can improve distribution efficiency but payback periods are fairly long.

Reliability - Greater visibility into the distribution grid significantly speeds fault location and Power Quality issue troubleshooting. This is particularly true for underground faults.

Safety – DM will dramatically improve troubleshooting and consequently the number of truck rolls and exposure to hazardous field conditions.

Satisfaction – Despite increases in reliability from DM, customer satisfaction will not likely improve as most PSCO customers already experience high levels of reliability.

### Summary Analysis: Distribution Monitoring

The table below summarizes value created from Distribution Monitoring in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
<ul style="list-style-type: none"> <li>Power Quality issues that typically required days or weeks to accurately identify using traditional techniques are diagnosed in minutes in SmartGridCity™.</li> <li>Faster fault identification capabilities are reducing Customer Minutes Out (CMO) by 385,000 CMO annually.</li> <li>Exception reporting enables proactive identification and resolution of Power Quality issues; complaints dropped from 37 annually pre-deployment to zero post deployment.</li> </ul>	<p>Lessons learned that will optimize investments for PSCO customers:</p> <ul style="list-style-type: none"> <li>Selective deployment of DM based on reliability and geographic needs will improve value created per dollar of invested capital relative to universal deployment.</li> <li>As PV and EV penetration grow, DM can identify and prioritize needed grid upgrades.</li> <li>DM fault location value is greater on underground conductors than it is on overhead conductors.</li> <li>DM can be used in place of AMI for outage management and Power Quality issue identification; there are valid arguments for either approach.</li> </ul> <p>Lessons learned that will minimize risk for PSCO customers:</p> <ul style="list-style-type: none"> <li>Sensors used in DM are sensitive, with failure rates in excess of that experienced with most grid equipment.</li> </ul> <p>Lessons learned that will maximize benefits through operational changes:</p> <ul style="list-style-type: none"> <li>Proactive outage notification is achievable through the implementation of DM.</li> <li>DM data can help the distribution Capacity Planning function ‘right size’ transformers and other grid components.</li> <li>When paired with AMI data, troubleshooting time can be further reduced.</li> </ul>

#### Distribution Monitoring Business Case Considerations

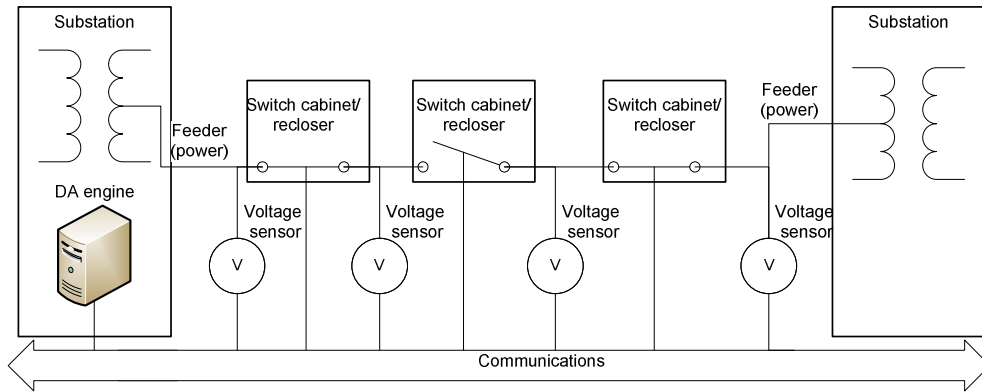
When developing the business case for Distribution Monitoring, PSCO is advised to consider:

- Value of Improved Reliability/Impacts of Deteriorating Reliability
- Feeders/Geographies Most Likely to Benefit
- Communication Requirements Necessary for Desired Level of Monitoring
- Asset Life of DM Equipment
- Cost and Risks of DM Equipment
- Value of Faster Problem Identification and Resolution

#### 4. Distribution Automation (DA)

DA is a set of field hardware and software that automatically reconfigure the grid, primarily to isolate the impact of a service outage to the smallest number of customers possible. DA provides automated control logic and remote operation capabilities not available in traditional SCADA (System Control and Data Acquisition) systems used by grid operators. The table below summarizes value creation from benefits to the participating customers in the demonstration project:

**Figure 4 Distribution Automation System**



#### System Dashboard

The following table describes the relative value provided by Distribution Automation from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for DA.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
Low	-	-	Low	High	-	Low

Capital Deferral – DA is unlikely to impact capital deferral as opportunities to shift load were found to be minimal.

Energy / Environment – Current high-voltage switching technologies cannot accommodate the frequent load shifting that would be required to balance phases dynamically and reduce line losses. Opportunities are generally small but should be re-examined as solid state switching technologies advance.

Reliability - Distribution Automation reduces CMO by isolating the outages automatically shortly after a fault occurs; customers not on the isolated segment will have power restored almost immediately.

Satisfaction – Distribution Automation can shorten outage extent but is unlikely to significantly increase customer satisfaction as reliability in PSCO is currently high.

### Summary Analysis: Distribution Automation

The table below summarizes value creation from Distribution Automation in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
<ul style="list-style-type: none"> <li>Increased reliability from a fully functioning DA system resulting in a reduction of 28,125 CMO <i>per feeder</i> per year (Installed on 2 feeders.).</li> </ul>	<p>Lessons learned that will optimize investments for PSCO customers:</p> <ul style="list-style-type: none"> <li>Selective deployment of DA based on reliability and geographic needs will improve value created per dollar of invested capital relative to universal deployment greater value.</li> <li>Significant reliability benefits are available from DA, though economic benefits (resulting from improved load balancing, for example) did not appear sufficient to justify costs in preliminary analyses. (MetaVu did not attempt to estimate the economic value customers obtain from improved reliability.)</li> </ul> <p>Lessons learned that will minimize risk for PSCO customers:</p> <ul style="list-style-type: none"> <li>Reliability improvement is generally a function of the number of sectionalizing devices installed; improvements in reliability must be balanced against the cost of the devices.</li> </ul> <p>Lessons learned that will maximize benefits through operational changes:</p> <ul style="list-style-type: none"> <li>Of all smart grid systems, DA has the lowest tolerance for failure as it controls critical grid equipment.</li> <li>Firmware and software upgrades are critical to continuous and reliable DA functionality.</li> <li>DA functions at the substation and feeder level and does not require centralized data processing. ‘Distributed processing’ could serve as a model for other smart grid systems.</li> </ul>

#### Distribution Automation Business Case Considerations

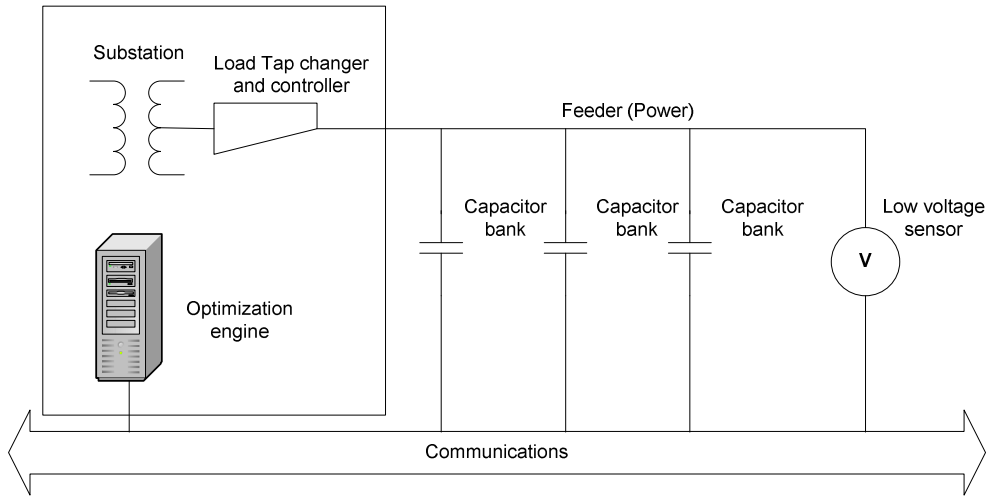
When developing the business case for Distribution Automation, PSCO is advised to consider:

- Level of Reliability Desired
- The Value Customers Assign to Reliability
- Feeders/Geographies Most Likely to Benefit
- Cost of Switching/Sectionalizing Equipment

### 5. Integrated Volt VAr Control (IVVC)

IVVC regulates feeder voltage and power factor (VAr) continuously and automatically to reduce line losses between the substation and customer loads. Voltage is monitored near customer premises to ensure satisfaction of minimums, while VAr is optimized through the coordinated operation of capacitor banks located throughout the grid. The table below summarizes value creation from benefits to the participating customers in the demonstration project:

**Figure 5 Integrated Volt VAr Control System**



#### System Dashboard

The following table describes the relative value provided by IVVC from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for IVVC.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
High	-	-	High	-	-	Low

**Capital Deferral** – In order for IVVC to delay distribution capital, feeders must be operating near capacity and be experiencing slow growth. High growth feeders are likely to be upgraded despite IVVC, and feeders not near capacity are unlikely to be upgraded at all. Generation capital deferral can be significant if a large number of feeders are treated.

**Energy / Environment** - Initial SmartGridCity™ investigations suggest IVVC may reduce end-user energy usage by up to 2.5%.

**Satisfaction** – Although significant in the aggregate, the energy usage reductions obtained by any one customer will be difficult for a customer to perceive.

**Summary Analysis: Integrated Volt VAr Control**

The table below summarizes value creation from Integrated Volt VAr Control in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
<ul style="list-style-type: none"> <li>For customers served by feeders 1554 and 1556, bill reduction of \$18 per customer per year was achieved due to full-time voltage reduction strategy.</li> <li>IVVC on feeders 1554 and 1556 is reducing CO2 equivalent output by 430 tons per year through energy savings.</li> </ul>	<p>Lessons learned that will optimize investments for PSCO customers:</p> <ul style="list-style-type: none"> <li>IVVC offers high potential economic benefits to customers relative to cost.</li> <li>IVVC can be deployed selectively, for example on feeders with the greatest load and voltage/VAr improvement opportunity. Though full deployment offers greater benefits relative to selective deployment, selective deployment can improve customer payback periods.</li> <li>Capital deferral from IVVC is anticipated from deferred generation capacity due to demand reduction.</li> </ul> <p>Lessons learned that will reduce risk for PSCO customers:</p> <ul style="list-style-type: none"> <li>The technology risk of IVVC is low.</li> </ul> <p>Lessons learned that will optimize benefits through operational changes:</p> <ul style="list-style-type: none"> <li>Though significant relative to costs and significant in the aggregate, the economic benefits to any individual customer from IVVC will be difficult to perceive.</li> <li>IVVC investments are similar to DSM program investments in that they deliver direct benefits to customers but reduce the utility’s opportunity to earn its authorized rate of return.</li> <li>Advanced meters can also function as sensing devices, serving as voltage end points for IVVC.</li> </ul>

Integrated Volt/VAr Control Business Case Considerations

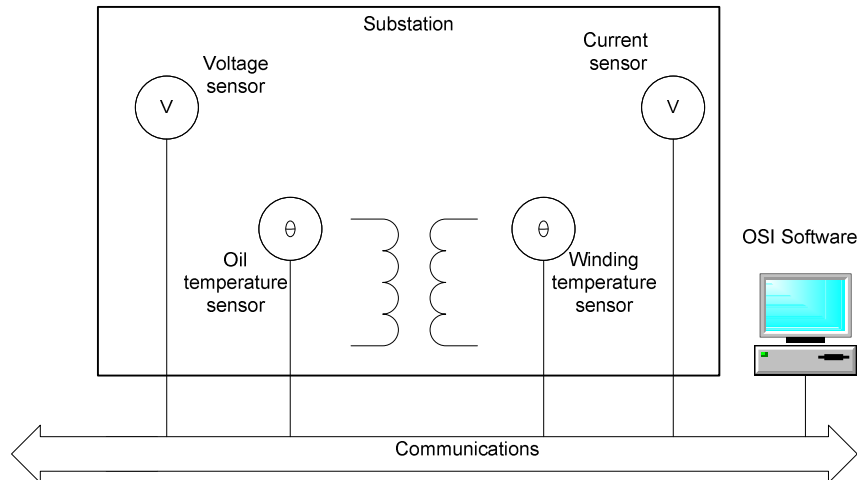
When developing the business case Integrated Volt/VAr Control, PSCO is advised to consider:

- Energy per KWh
- Incremental cost to add IVVC to a feeder
- Engineering Analysis to determine feeder-specific IVVC value
- Incentives similar to DSM programs to mitigate lost margins

## 6. Smart Substation Monitoring and Protection

Smart Substation Monitoring and Protection (SSMP) offers real-time visibility into substation operating conditions, providing detailed data that can be used proactively to identify equipment malfunctions prior to failure and forensically to investigate abnormal substation events. It is functioning in four substations in SmartGridCity™.

Figure 6 Smart Substation Monitoring and Protection System



### System Dashboard

The following table describes the relative value provided by Smart Substation Monitoring and protection from among those types of benefits available through grid modernization. Blank cells indicate that a specific benefit was not anticipated for SSMP.

Capital Deferral	O&M	Revenue Capture	Energy / Environment	Reliability	Safety	Satisfaction
-	TBD	-	-	TBD	-	-

O&M - Less than 1% of substation transformers fail per year. But when failures occur, many customers are left without power for long periods of time and are very costly to repair. Failures are so infrequent that more experience with the SSMP system is required before any conclusions can be determined.

Reliability – SSMP may be able to predict substation transformer and breaker failure and reduce CMO. It may also be able to be used forensically post-failure, adding to best practices and helping to avoid future substation outages through a continuous quality improvement process. However, failures happen very infrequently and additional experience with the SSMP system is required before any conclusions can be made.



### Summary Analysis: Smart Substation Monitoring and Protection

The table below summarizes value creation from Smart Substation Monitoring and Protection in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
<ul style="list-style-type: none"><li>Data from four SmartGridCity™ substations is being collected.</li></ul>	<p>Lessons learned that will optimize investments for PSCO customers:</p> <ul style="list-style-type: none"><li>Substation-level failures are rare but have a disproportionate impact on CMO when they occur.</li><li>Substation data may help predict substation transformer and breaker failure, but insignificant experience is available to prove or disprove such a claim.</li><li>Substation data can potentially be used forensically to evaluate failure root causes.</li></ul> <p>Lessons learned that will optimize benefits through operational changes:</p> <ul style="list-style-type: none"><li>Analytical tools and business process changes will need to be developed to make use of substation data.</li></ul>

#### Substation Monitoring and Protection Business Case Considerations

When developing the business case for Substation Monitoring and Protection, PSCO is advised to consider:

- Value Customers Place on Reliability
- Value of Greater Substation Data to Improve Reliability
- Changes in Business Processes, Resources and Management Systems to make use of Data Available
- Costs of Substation Monitoring Equipment

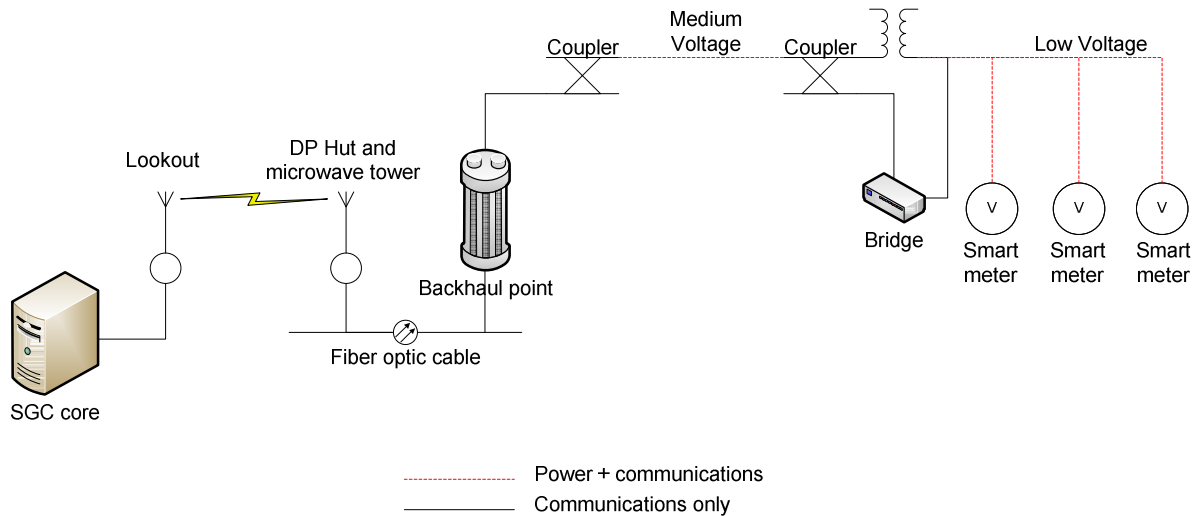
## **Smart Grid Infrastructure System Detail**

### **7. Communication Systems**

For smart grid equipment to function, a system to support the communication between smart grid technologies is required. The communications system utilized in SmartGridCity™ was designed to be reliable, robust, secure, and fast to allow for a variety of capabilities to demonstrate and test. It was equipped with a high bandwidth and low latency communications network so that current and future application testing could proceed effectively. This capability was established through a variety of communications technologies, including Broadband over Power Line (BPL), fiber optic cable, 3G Cellular, DSL, and microwave.

The system was designed to accommodate any standard internet protocol, allowing almost any type of system to be implemented over the SmartGridCity™ communications network. Since most emerging technologies use standard internet protocols, they all are able to use the existing communications infrastructure provided they can be connected to BPL or fiber optic cable.

**Figure 7 Communications System**



### **System Dashboard**

Infrastructure systems provide no direct value but enable other systems to deliver value. Accordingly, no system dashboard of relative value is required.

### Summary Analysis: Communication Systems

The table below summarizes value creation from Communication Systems in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
<ul style="list-style-type: none"> <li>A robust and effective communication system exists in SmartGridCity™ which supports and enables the smart grid technologies and associated benefits.</li> </ul>	<p>Lessons learned that will optimize investments for PSCO Customers</p> <ul style="list-style-type: none"> <li>Competing approaches to communication systems offer pros and cons in a variety of decision criteria.               <ul style="list-style-type: none"> <li>Build vs. Buy a System</li> <li>Upfront Fixed Cost vs. Ongoing Variable Cost</li> <li>Grow Competence vs. Hire Expertise</li> <li>Accountability for Security</li> <li>Bandwidth and Latency</li> <li>Future flexibility</li> <li>Reliability/Quality Control</li> </ul> </li> <li>Communications with field devices yields safety benefits (by reducing field crew exposure to hazardous conditions) as well as operating expense reductions.</li> <li>No single communications infrastructure will be adequate for all geographies or capabilities.</li> <li>GIS must be adequately detailed to support communication design and operation.</li> <li>Grid automation design must be deployed with ongoing consideration to the amount of data that it will generate and its impact. For example, line sensor report exceptions are provided instead of all data that can be measured.</li> <li>More and better uses for smart grid data will be found over time. Communication systems may be called upon to support those needs.</li> </ul> <p>A test lab exists that will help optimize investments and maximize benefits into the future:</p> <ul style="list-style-type: none"> <li>Communications Systems are some of the most critical components of the test lab as they have been designed to allow large amounts of test data to be communicated frequently with no latency.</li> </ul>

#### Communication System Business Case Considerations

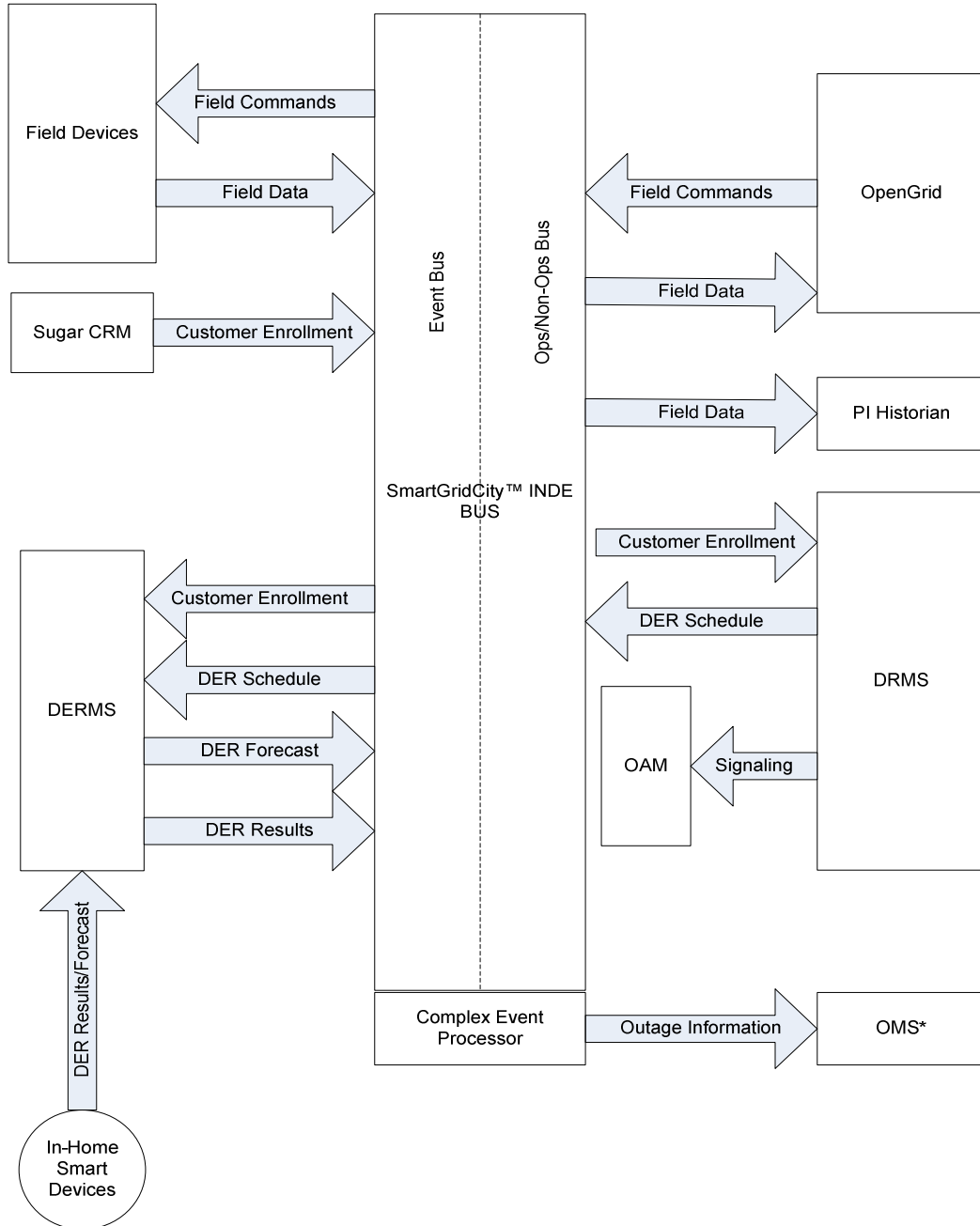
When developing the business case for a communication system for smart grid investments, PSCO is advised to consider:

- The latency and bandwidth requirements of smart grid technologies today and in the future.
- The investment and ongoing costs of various communication systems.
- Geographic capabilities and limitations of various communication infrastructures.
- Economic and technical constraints of various communication infrastructure types initial and ongoing.

## 8. Information Technology Systems

PSCO developed a new design of the IT infrastructure for SmartGridCity™, maximizing the use of readily-available technology, and systems and IT best practices. The IT systems facilitate the communication and processing of smart grid data. The systems are readily scalable and can be leveraged to support future smart grid investments within PSCO.

**Figure 8 IT Systems**



### System Dashboard

Infrastructure systems provide no direct value but enable other systems to deliver value. Accordingly, no system dashboard of relative value is required.

## Summary Analysis: Information Technology Systems

The table below summarizes value creation from IT Systems in the demonstration project:

Benefits to SmartGridCity™ Customers	Benefits to PSCO Customers
<ul style="list-style-type: none"> <li>A robust and effective suite of information technologies exists in SmartGridCity™ which supports and enables the smart grid technologies and associated benefits.</li> </ul>	<p>Lessons learned that will optimize investments for PSCO customers:</p> <ul style="list-style-type: none"> <li>The SmartGridCity™ Information Technology infrastructure is readily scalable, reducing the capital requirements and maintenance costs associated with any broader roll-out of smart grid applications in PSCO.</li> </ul> <p>Lessons learned that will maximize benefits through operational changes:</p> <ul style="list-style-type: none"> <li>Security should be built into IT designs. It may be difficult to apply legacy policies, processes, and protocols to smart data environments.</li> <li>The distribution operations function may need to acquire new IT skills, while the business systems function may need to adopt new electrical engineering skills.</li> <li>Smart grid systems produce significant amounts of data. Strategies and tools should be developed to maximize value of data and benefits of smart grid investments.</li> <li>Strategies to minimize data collection, including exception reporting, are advised. Lower latency is an added benefit of distributed data processing.</li> <li>Though grid modernization offers operating cost reductions in several functions, IT support, software maintenance and data management costs are likely to increase.</li> <li>The infrastructure must be designed to accommodate both existing systems and newer systems simultaneously.</li> <li>Information from new and old systems must be integrated as seamlessly as possible to the user.</li> </ul> <p>A test lab exists that will help optimize investments and maximize benefits into the future:</p> <ul style="list-style-type: none"> <li>Information Technology systems are some of the most critical components of the test lab as they enable processing and analysis of large volumes of test data.</li> </ul> <p>IT infrastructure investments made in SmartGridCity™ are being leveraged to benefit all PSCO customers:</p> <ul style="list-style-type: none"> <li>A dual bus architecture optimized for differing data transfer needs was utilized to support various SmartGridCity™ systems. The bus approach was so successful it has been leveraged into other IT designs and platforms that support delivery of service to PSCO customers.</li> <li>The bus architecture employed in SmartGridCity™ is anticipated to incur lower IT maintenance costs over time relative to traditional architectures, in which systems are integrated through maintenance-intensive 'point to point' system interfaces.</li> </ul>

### IT System Business Case Considerations

When developing the business case for an IT system for smart grid investments, PSCO is advised to consider:

- The Interoperability of Systems with the Current Bus Architecture
- Costs of Software Licensing, Maintenance and Potential Scalability
- Obsolescence Risk of IT Systems
- Initial and Ongoing Security Requirements
- Cost of Field and Central Hardware Support

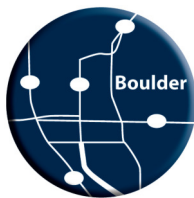
## CONCLUSION

MetaVu’s evaluation of the SmartGridCity™ demonstration project indicates that PSCO accomplished stated project objectives:

- A comprehensive suite of smart grid technologies that could be employed to manage anticipated changes in the retail electric market has been designed, built, and is currently in operation.
- A real-world laboratory in which new utility and consumer technologies could be deployed and evaluated at scale on an ongoing basis has been created and is currently in use.
- A ‘body of knowledge’ to inform future deployment strategy and business case development has been established, and contributions to it continue.

In addition, as described throughout this report, the SmartGridCity™ demonstration project provided benefits to SmartGridCity™ customers. The project also greatly benefited PSCO customers by providing insights that can be used to optimize grid investments and maximize economic, reliability, and satisfaction benefits for PSCO customers in the future. As such the demonstration project provided critical input into the Utility’s grid modernization strategy and may have avoided hundreds of millions of dollars in sub-optimal grid investments.

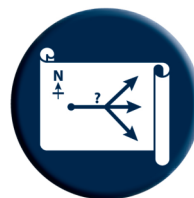
Readers are encouraged to review the information in the Appendices for more details in support of the top five findings of the evaluation phase:



The project created value for SmartGridCity™ customers



The project created value for PSCO customers



Grid Modernization is a strategic planning process



Stakeholder and customer engagement is a platform for risk mitigation and value creation



Change management can help maximize the benefits from many smart grid systems

Now that the evaluation phase is complete, PSCO is in possession of valuable inputs to its grid modernization strategic planning process. The findings in this document, combined with inputs from Company managers, executives, stakeholders, customers, and regulators, should enable PSCO to develop grid modernization strategies, business cases, and implementation plans that maximize customer benefits while minimizing costs and risk. SmartGridCity™ will continue to serve as an ongoing test bed platform for future technologies and continue to inform and help optimize investments. As a result, the SmartGridCity™ demonstration project will be perceived by many to deliver lasting value in principle and in practice. In addition, Boulder customers within the SmartGridCity™ footprint have been equipped with a robust system that provide benefits now and into the future.

## **APPENDICES**

Appendix 1 – Value Proposition Evaluation

Appendix 2 – Bibliography

## **Appendix 1 – Value Proposition Evaluation**

### **Background and overview**

The SmartGridCity™ (SGC) Value Proposition (VP) evaluation was completed during the fourth phase of the demonstration project, as one component of MetaVu's broader third-party research, evaluation and value measurement process. The VP evaluation is intended to be utilized by PSCO as inputs to create business cases for various smart grid system implementations.

The information presented in Appendix 1 is based largely on MetaVu's evaluation of the SGC VPs as established by industry partners, PSCO managers and Subject Matter Experts during the first phase of SGC in 2008. In general, evaluating a VP is based on a review and analysis of the benefits, costs and value that an organization can deliver to its customers, prospective customers, and other stakeholders within and outside the organization, or in this instance, within and outside of SGC. External research, where appropriate and relevant, supplemented analysis of internal data sources.

MetaVu developed and followed a standardized process to research and measure the benefits and lessons learned associated with each VP, adding custom calculation frameworks as appropriate to facilitate the measurement of specific VPs. The VP Analysis provides valuable insights into suitability of technologies, costs, benefits, and documented lessons learned associated with these technologies and related deployments.

The SGC VP evaluation provides a summary of quantified benefits, measurement methodologies and lessons learned to enable peer review and to advance the understanding of grid modernization value, including specific, targeted smart grid system applications.

MetaVu has prepared this work product for PSCO to be used for educational purposes and as input into specific decision scenarios. The data provided and lessons learned are intended to inform the ongoing decision-making process rather than provide detailed business cases.

Appendix 1 is organized by the following:

- Value Propositions List
- SGC Field Systems and Benefits Type
- Value Proposition Analysis Sheet Template
- Value Proposition Analysis Sheets



### **Value Propositions List**

A summary and analysis of each of the 68 value propositions is included here in Appendix 1. The value propositions are organized by the following customer benefits types:

- Economic (32)
  - Fuel Cost (9);
  - Capital Deferral (12);
  - Operations and Maintenance (10); and
  - Revenue Capture (1).
- Environmental (3)
- Reliability (11)
- Customer Satisfaction (13)
- Strategic (9)

The complete value proposition analysis sheets are included in this section in a chronological order.

#### **Economic (Fuel Cost, Capital Deferral, Operations and Maintenance, Revenue Capture)**

Through targeted smart grid investments and implementation of smart grid systems, PSCO has gained invaluable knowledge that can be leveraged to benefit customers and its grid operations. 32 value propositions were evaluated that held potential economic impacts. Each of the four Economic categories is listed below.

#### **Economic – Energy**

Nine value propositions were evaluated that held potential impacts for reduced energy usage.

<b>VP #</b>	<b>Description</b>
<b>1.7</b>	Use Demand Response as a Virtual Power Plant
<b>1.9a</b>	Reduce energy consumption through CVR
<b>2.4</b>	Fuel cost reduction through VAR reduction
<b>2.5</b>	Line loss optimization through remote switching
<b>3.4</b>	Time-of-Use and Other Intraday pricing Programs
<b>3.5</b>	Utility can reduce GHG compliance costs through Green Signals
<b>3.6</b>	Support bi-directional integration of Distributed Energy Storage
<b>5.2a</b>	Proactively replace transformer with smaller size
<b>5.2b</b>	Avoid oversizing replacement transformers

### Economic – Capital Deferral

Thirteen value propositions were evaluated that held potential for appropriate deferral of capital spending.

VP #	Description
1.1	Capital Deferral through VAR reduction
1.2a	Capital Deferral through DER/PHEV
1.2b	Transmission/Distribution Capital Deferral through DR
1.2c	Capital Deferral through Pricing
1.2d	Capital Deferral through load balancing
1.3	Capital Deferral with grid state monitoring
1.4	Avoiding asset overloads with demand response
1.5	Classify Demand Response as Operating Reserves
1.6	Use Demand Response as Planning Reserves
1.9b	Peak Capacity Reductions through Voltage Reduction
2.3	Replace meters with in-home equipment
4.2	Use DR to assist load management during outage
4.5	Use DR to avoid overloading during normal operations

### Economic – Operations and Maintenance

Ten value propositions were evaluated that held potential for reducing Operations and Maintenance costs.

VP #	Description
1.8	Dynamically load circuits to avoid overtime
2.1	Reduced OKOA through outage verification
2.2	Reduce Meter Reading Cost
2.6	Proactive notification of outages
2.8	Use AMI to reduce the number of 'special' meter reads
2.9	GIS update from grid state connectivity
4.8	Measure phase balance remotely
4.9	Troubleshooting voltage issues remotely
4.11	Remotely verify dispatch commands
6.6	Use Meter Interval Data to Reduce O&M

### Economic – Revenue Capture

One value proposition was evaluated that held potential impacts for Revenue Capture.

VP #	Description
2.7	Detect diversions

### Environmental

Three value propositions were evaluated that held potential Environmental benefits in terms of CO2 reduction.

VP #	Description
3.1	Encouraging customer adoption of Renewable DG
3.2	Enable customers to maximize use of renewable energy through generation mix signals
3.3	Carbon reduction through T&D loss reduction

### Reliability

Eleven value propositions were evaluated that held potential reliability benefits, including fault isolation, more rapid service restoration, outage prevention, and Power Quality issue reduction.

VP #	Description
4.1	Distribution automation to reduce outage extent
4.3	AMI to restore power faster
4.4a	AMI to avoid outage overprediction
4.4b	AMI to identify nested outages
4.4c	AMI to avoid outage underprediction
4.6	Proactively fix Power Quality issues
4.7	Islanding using DER during outages
4.10	DR for frequency regulation
5.1	Predict transformer failure
5.3	Measure substation transformer stress to predict failure
5.4	Measure substation breaker stress to predict failure

## Customer Satisfaction

SmartGridCity™ provided technologies that enabled new capabilities that provided insights in customer interests and motivations, responsiveness to dynamic prices, and empowers the customer to monitor and manage energy use. Thirteen Customer Satisfaction value propositions were evaluated.

VP #	Description
6.1	Increase customer ability to manage energy bill
6.2	Ability to reduce energy use through usage data access
6.3	Participation in an online green energy community
6.4	Reduce Customer Minutes Out (CMO)
6.5	Use Meter Pinging to Avoid Investigation-related Delays
6.7	Proactive Monitoring of Selected Customer Premise Circuits
6.8	Customer confident that Utility will be aware of outages
6.9	Customer confident that Utility can perform remote meter diagnostics
6.10	Customer feels empowered to manage personal energy use
6.11	Customer feels empowered to use renewable energy
6.12	Customer feels partnership with utility rather than dependency
6.13	Customer sees utility as progressive and interested in customer well-being
6.14	Use Prepaid Program as a financial controlling tool by customers

## Strategic

SmartGridCity™ provided a pilot project platform to monitor and test how the strategic nature of various smart grid field systems and technologies impacted the planning process. Nine value propositions were evaluated that were designed to inform strategic, organizational considerations.

VP #	Description
7.1	Alternative to Meter Based Business Models
7.2	Encoding Institutional Knowledge
7.3	Framework for Integrating Acquisitions
7.4	Higher Asset Utilization
7.5	Higher Share Price through Commitment to Stakeholders
7.6	Relationship with Regulators
7.7	Visible Activity in Green Technologies
7.8	Integration of new technologies into utility systems
7.9	Carbon management technologies to improve carbon output

### **SmartGridCity™ Field Systems and Benefit Types**

Value Propositions are not actionable in and of themselves; benefits are delivered by SmartGridCity™ systems. In the Value Proposition analysis, at least one SmartGridCity™ system is identified as responsible for delivering the hypothetical benefits available from each Value Proposition. MetaVu defined a SmartGridCity™ system as “a set of hardware and software that could conceivably be installed as a standalone function to accomplish value propositions.” This is not meant to imply that the systems are not integrated in SmartGridCity™. Within SmartGridCity™, these discrete systems are interoperable contributing data to and pulling data from a variety of systems connected by communications and IT platform infrastructures. The systems are:

- **Distributed Energy Resource Control (DERC):** Controls energy resources throughout the distribution grid to optimize utility operations and support time-differentiated pricing programs. Components include in-home smart device (IHSD), smart meters, and demand response management system (DRMS) software.
- **Advanced Metering (AMI):** Records high-resolution usage data that is communicated automatically to the utility for billing and analysis purposes and provided to customers to enable them to change consumption behaviors. Components include smart meters, online account management (OAM), OpenGrid software (DMS), and the billing system.
- **Distribution Monitoring (DM):** Provides near real-time visibility into distribution network status. Components include voltage sensors on overhead transformers, current and voltage sensors on underground transformers, Power Quality meters, and DMS software.
- **Distribution Automation (DA):** Reconfigures the distribution grid automatically based on electrical conditions. Components include sectionalizing devices, and a DA controller with communication.
- **Integrated Volt/VAr Control (IVVC):** Reduces voltage and improves power factor automatically to make electricity distribution more efficient. Components include distributed capacitor banks and controllers, line sensors, load tap changers and controllers, and a centralized data processor utilizing DMS software, a server-based software application.
- **Smart Substation Monitoring and Protection (SSMP):** Provides real-time visibility into substation operating conditions. Components include microcontroller-based relays, automation controller, communications equipment, analysis engines and OSI Soft database software.

## Value Propositions

### TEMPLATE VP X.X TITLE

#### Benefit Category

Type of benefit envisioned: economic, environmental, reliability, etc.

#### Enabling Field System

Field system required to create the Value Proposition's benefits

#### Hypothesis

It is a description of the value proposition and how technical factors were envisioned to result in benefits. It is an explanation of the value proposition and associated benefit opportunity in lay terms.

#### Environment outside SmartGridCity™

A listing of how the business process or technical objective is executed traditionally/outside of SmartGridCity™, including examples that illustrate implementations outside SmartGridCity™ that have similar technical goals.

#### Environment within SmartGridCity™

An explanation of how the implementation was executed or intended in SmartGridCity™ to achieve the business or technical goal, including examples of differences from implementations outside of SmartGridCity™.

#### Actions Taken

The deployment and status of associated systems in SmartGridCity™.

#### Lessons Learned

- Detailed lessons learned about the value proposition and considerations for implementation.

#### Conclusion

Summary of anticipated benefits (economic unless otherwise indicated) from the value proposition.

## VP 1.1 Capital Deferral through VAr Reduction

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Integrated Volt/VAr Control

### Hypothesis

Distribution Capacitor Banks decreases reactive power drawn from the transmission system, i.e. improving power factor in distribution and reducing the unusable amount of energy that must be generated, transmitted and distributed. If the reduction is significant at peak, and on lines near capacity, capital may be deferred or delayed.

### Environment outside SmartGridCity™

Autonomous capacitor banks reacting to local conditions; actions uncoordinated between banks; Manual capacitor banks set annually or semi-annually.

### Environment within SmartGridCity™

Centralized control of distributed capacitor banks communicating over BPL and fiber; adds additional optimization beyond autonomous capacitor banks.

### Actions Taken

Integrated Volt/VAr Control (IVVC) is active on two feeders: 1554 and 1556

### Lessons Learned

- Value realized from fuel reduction is greater than value realized from capital deferral (Note: Fuel cost reduction through VAr reduction is addressed in VP 2.4).
- As an automated system, VAr reduction involves no adoption or business process issues and is therefore ideal for selective application.
- Distribution capital deferral only occurs on feeders near capacity that are experiencing low load growth.
- Distribution capacity is added in increments of 5 MVA minimum and usually 16 MVA (new feeder). Incremental capacity improvements, such as those offered via VAr reduction, are not generally sufficient to alter decisions to add distribution capacity.
- Capacitor Bank installations is less beneficial on underground feeders than on overhead feeders because of the higher inherent capacitance in these cables, i.e. better power factor under typical peak load conditions and also less voltage drop per unit length.
- With further development, sensors at the end of feeders could be replaced with smart meters to support IVVC.

### Conclusion

Capital benefits likely, but relatively low. Capital can be deferred in specific situations. In SmartGridCity™, due to load configurations, minimal capital delay found. Theoretical capital deferral of up to two years can be achieved in ideal, feeder-specific situations.

## VP 1.2a Capital Deferral through DER/PHEV

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

Distributed energy resources located near demand will reduce the amount of energy that must be distributed through the feeders. If these resources can be relied upon, capital for increased capacity may be deferred or delayed.

### Environment outside SmartGridCity™

Capacity planning done a few years out based on historical capacity, growth expectations.

### Environment within SmartGridCity™

Same as outside SGC; however SGC will enable better decisions from more data available about demand.

### Actions Taken

DERC systems are being utilized to manage Demand Response systems in SGC.

### Lessons Learned

- No capacity deferral because DERs not shown to generate power reliably during peak load (e.g., solar PV sometimes generates no power during system peak, especially if peak falls at 6 or 7 PM).
- PHEV storage is not likely to be a reliable or economically feasible source of capacity for many years.
- Increased DER penetration and utility control reliant on marketing and program communications.
- Distributed Generation (DG) can “mask” true system demands, complicating operating decisions by Distribution Control Center and Commercial Operations at high penetration levels and possibly impacting local reliability if not appropriately planned.
- Installed DG capacity was 4% of demand as of 2009 in Boulder.
- Learned that many types of Distributed Energy Resource (DER) are not sufficiently reliable or correlated with peak load to enable reduced capacity in distribution design.

### Conclusion

Benefits are unlikely. MetaVu recognizes regulatory requirements and yet inconclusive NERC effort to count capacity value from variable generation (IVGTF). Per current requirements, capacity (generation, transmission, and distribution) must be designed for peak load and capacity; therefore intermittent resources are insufficiently reliable to permit reductions in capacity designs at this time. This will likely change if the availability of PV solar and distributed storage increases dramatically.



## VP 1.2b Transmission and Distribution Capital Deferral through DR

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

The utility can reduce the demand during peak periods by controlling customer loads. If this reduction is significant and reliable, capital for increased capacity may be deferred or delayed.

### Environment outside SmartGridCity™

In the existing Saver's Switch program demand response is primarily limited to large, industrial customers and requires significant payments by the utility to enroll customers; primarily focused on generation capacity.

### Environment within SmartGridCity™

Demand response at the customer level is primarily controlling air conditioner loads during hot days. Currently, few numbers of other devices are being controlled.

### Actions Taken

DR as implemented in SmartGridCity™ offers additional functionality and convenience for customers over the existing Saver's Switch program. Installation of 1,264 in-home smart devices as part of the time-differentiated rate pilot has already begun.

### Lessons Learned

- Generation benefits from Demand Response (See Value Proposition 1.6) are much larger and more certain than the transmission and distribution benefits of Demand Response.
- Distribution capacity expansions are generally planned in increments of 5 MW or greater; to realistically defer T&D capacity expansion, DR penetration of ~1 MW or more per feeder (about 1,000 participants, or 70% of the customers with central air conditioning) is required.
- DR as implemented in SGC offers additional functionality and convenience for customers over existing Saver's Switch program. Next generation DR will require bidirectional communications, while the existing Saver's Switch program consists of unidirectional communications.
- Product development historically worked with generation and commercial operations; may need to start working with distribution capacity planning and Distribution Control Center (DCC) to design DR programs of benefit to DCC.

### Conclusion

Generation capacity deferral benefits are likely, but less certain for T&D capacity expansion. With high customer penetration rates, capital deferral of up to \$32.75 per DR participant with central air conditioning per year may be possible.

## VP 1.2c Capital Deferment through Pricing

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

By implementing critical peak pricing (CPP) or other similar pricing schemes, the utility can incent customer to reduce demand during peak periods. If this reduction is significant and reliable, capital for increased capacity may be deferred or delayed.

### Environment outside SmartGridCity™

Pricing programs not done for residential customers due to high cost of interval meters.

### Environment within SmartGridCity™

Smart meters with interval data enable time of use pricing; pilot pricing programs are evaluating customer behavior in response to different tariffs.

### Actions Taken

Pricing pilot began in October 2010 to increase understanding of various program characteristics on impact.

### Lessons Learned

- Billing services will need to accommodate interval data and be able to produce accurate bills for complex pricing programs.
- Time-differentiated rate benefits are highly variable and driven by participation levels, degree of behavioral change, program and incentive designs, and other factors such as capacity costs.
- Based on the PSCO 2006-2007 TOU-CPP Pricing Study, it was learned that pricing programs are likely to have significant impact on system demand at peak.
- Difference in behavior change between voluntary and mandatory program implementation is critical to the calculation of this value proposition and is among the issues being tested in the current pricing pilot.

### Conclusion

Benefits are likely and potentially high based on PSCO 2006-2007 TOU-CPP Pricing Study; however, customer adoption rates must be high and/or behavior change must be significant if implementation is to be cost-effective. Research showed generation, transmission and distribution capacity cost reduction of \$33.62 per customer per year. (Research also showed significant energy reductions from participating customers; please see Value Proposition 3.4 for additional benefits.)

## VP 1.2d Capital Deferral through Load Switching

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distribution Automation

### Hypothesis

At system peak, some feeders are operating near capacity while others have significant capacity available. If some of the load can be reliably shifted from the highly utilized feeder to the lower utilized, capital for increased capacity may be deferred or delayed.

### Environment outside SmartGridCity™

Configurations are set a few times per year based on load profiles from previous years and are re-evaluated based on distribution models.

### Environment within SmartGridCity™

Same as outside SmartGridCity™; no new activities are being done. Better information from actual data may be used to make different decisions on load shifting.

### Actions Taken

Distribution Automation is functioning as designed on two feeders in SGC.

### Lessons Learned

- Requires reliably uncorrelated loads on nearby feeders to alter capacity planning decisions.
- Capability would require many switches on multiple feeders in order to achieve balanced loads during peak.
- Distribution capital deferral only occurs on feeders near capacity that are experiencing low load growth.
- Distribution capacity is added in increments of 5 MVA minimum and usually 16 MVA (new feeder). Incremental capacity improvements, such as those offered via load switching, are not generally sufficient to alter decisions to add distribution capacity.

### Conclusion

Benefits are unlikely due to the absence of required conditions.

## VP 1.3 Capital Deferral with Grid State Monitoring

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distribution Monitoring  
Smart Substation Monitoring

### Hypothesis

Higher resolution models and more information will allow the capacity planning teams to make better decisions and not over-build unnecessarily. This will delay or defer capital dollars in system capacity.

### Environment outside SmartGridCity™

Generation, transmission and substation systems are monitored and voltage, load and other data is stored. The distribution system is modeled based on expected characteristics. The data and model are used for planning for system capacities.

### Environment within SmartGridCity™

Higher resolution data about the distribution system (i.e. underground loads, all transformer voltages and customer usage data in 15-minute intervals) is collected. This additional information can be used to make better capacity decisions.

### Actions Taken

Data is being collected from the distribution system for single phase underground circuits and smart meters (throughout SmartGridCity™). Distribution data is also being collected from four substations.

### Lessons Learned

- Electric Distribution Engineering will have more data available to determine the optimum investment plans that will maximize reliability and performance and optimal cost.
- Distribution Asset Analysis (DAA) software is used for capacity planning outside SmartGridCity™ and is sufficiently accurate for distribution operations and capacity planning decisions; SmartGridCity™ data could be integrated into DAA for maximum benefit.
- The standard for all new XE substation monitoring is 3-phase voltage and load; in this regard SmartGridCity™ offers no new capabilities at the substation or beyond for capacity planning purposes.
- Feeder capacity upgrade decisions are made in step increments of 5 – 16 MW; additional information will not affect distribution capacity decisions based on increment sizing.

### Conclusion

Grid state monitoring benefits are primarily related to reliability. Capital deferral benefits unlikely to justify grid state monitoring investment from an economic perspective. For more on grid state monitoring's reliability benefits, please see Value Propositions 4.3, 4.6, 5.1, 5.3, and 5.4.

## VP 1.4 Avoiding Asset Overloads with Demand Response

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

Demand response (DR) events can be called when assets are in (or approaching) overload conditions. Avoiding overload conditions can significantly extend the life of assets because overloading is a primary driver of failure.

### Environment outside SmartGridCity™

Demand response is primarily limited to large, industrial customers with ISOC programs. Residential and small commercial customers can participate in Saver's Switch program which cycles air conditioner compressors.

### Environment within SmartGridCity™

Demand response is at the residential level, primarily controlling air conditioner loads during hot days. Few numbers of other devices are being controlled. This control can be done at the system level and is capable of handling asset specific programs.

### Actions Taken

DR programs are not yet established for feeder level control because low penetration will make such implementation infeasible. Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available in 2012.

### Lessons Learned

- There are no baseline measurements outside of SGC to evaluate transformer overloads. Transformer overloads are estimated based on monthly usage data and load modeling.
- To achieve this value proposition, the Distribution Control Center (DCC) must have the capability to call DR events for the premises attached to the overloaded asset.
- If implemented, the DCC and Power Operations will need to coordinate DR events to minimize potential impact to customer satisfaction.
- Exceptionally high customer penetration rates are required to avoid asset overloads with DR. (1000 Gen kW, i.e. 971 participants)
- This benefit would need to have the capability to identify and aggregate DR potential by asset.
- Benefits are greater with underground (UG) rather than overhead (OH) feeders because of (i) heat dissipation on OH vs. UG and (ii) cost and time of repairs.
- If DR reaches sufficient scale and penetration, programs will need to be developed to enable events by distribution asset. Current programs are only designed at the substation level or transmission area.

### Conclusion

Capital deferral is plausible, but difficult to quantify due to high variability in correlating overloading to impact on asset life.

## VP 1.5 Classify Demand Response as Operating Reserves

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

The value (and opportunity cost) of spinning reserves is much greater than the value of non-spinning reserves. Improved responsiveness and verification of DR made available through smart grid capabilities makes it possible to call upon, and verify, load reductions within the 10 minute window required for classification as spinning reserves. Two-way communications also enable customer override options, which can reduce DR impact.

### Environment outside SmartGridCity™

DR is currently available for residential customers through the Saver's Switch program.

It may be possible to upgrade Saver's Switch technology to provide some SmartGridCity™-related attributes once smart meters are installed.

### Environment within SmartGridCity™

SGC's in-home smart devices (IHSDs) are essentially the same as Saver's Switch, but with several beneficial features:

- Faster response and two-way communications (to verify load reduction).
- Customer control via Internet (for convenience).
- Improved customer service (AC temp settings, override options, plug loads, etc.).

### Actions Taken

DERC is available to execute DR events within the 10-minute time frame required to qualify for spinning reserves.

### Lessons Learned

- Modification of WECC regulations to enable DR to be classified as spinning reserves is required.
- Many regional transmission authorities already accept DR to qualify as spinning reserves.
- Saver's Switch technology cycles A/C compressors on and off from a population of participating customers in cycles, while IHSDs change the thermostat settings of A/C units for all participating customers at once. This can offer greater responsiveness but increased volatility.
- Customers do take advantage of override options; an SCE study of small commercial customers indicated that 20% of events are overridden even when penalties are assessed.
- PSCO DR study underway in SmartGridCity™ will examine the change in impact resulting from differences between Saver's Switch and IHSDs.

### Conclusion

Benefits likely and high assuming regulatory hurdles cleared. \$9.55 per year in reserve reduction value can be avoided per customer with central air conditioning controlled by the utility.

## VP 1.6 Use Demand Response as Planning Reserves

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

Public utility commissions require regulated utilities to submit Integrated Resource Plans periodically to indicate how capacity needs will be met. To the extent DR can be used to reduce capacity needs, generation increases can be delayed or avoided.

### Environment outside SmartGridCity™

DR is currently available from residential customers through the Saver's Switch program.

It may be possible to upgrade Saver's Switch technology to provide some SmartGridCity™-related attributes.

### Environment within SmartGridCity™

SmartGridCity™'s IHSDs have several beneficial features that might increase market penetration above Saver's Switch levels:

- Customer control via Internet (for convenience)
- Improved service levels (AC settings, override options, plug loads)

### Actions Taken

Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available by year-end 2012.

### Lessons Learned

- SmartGridCity™ did not attempt to quantify the benefits of DR on commercial customer demand.
- Commercial customers with smaller controllable loads (roughly under 25 kW) can find it difficult to overcome the start-up costs for DR participation (other than Saver's Switch). DR as implemented in SmartGridCity™ may provide opportunities to access this market segment.
- A significant customer penetration rate is required for DR to be valuable for use as planning reserves. This is particularly true of residential premises as a result of typically smaller loads.
- Commercial Operations requires approximately 20 MW minimum controllable load to represent practical value in power operations.

### Conclusion

Benefits are likely and high. Capital benefits of \$159.65 per customer per year with central air conditioning controlled by an in-home smart device (IHSD) can be realized.

## VP 1.7 Use Demand Response as a Virtual Power Plant

### Benefit Category

Economic (Energy)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

Commercial Operations utilizes extremely sophisticated software and decision support algorithms to identify least cost resources as it makes generation utilization decisions on a real time basis. Large scale Demand Response programs could be quantified and incorporated into the list of resources available to call upon. In theory, Demand Response could serve as a resource that is cheaper than traditional generation on a per MW or per MWh basis. Power Operations would make the determination to use Demand Response within criteria established by Marketing and Regulators.

### Environment outside SmartGridCity™

Today Commercial Operations uses Demand Response to manage load, not to manage energy.

### Environment within SmartGridCity™

In-home smart devices enable the utility to control various loads within the customers' premises, primarily central air conditioning, by adjusting the thermostat. These events can be called by commercial operations as a source of energy, providing opportunities for trading profits.

### Actions Taken

Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available by year-end 2012.

### Lessons Learned

- There is a practical limit to the number of DR events customers will tolerate. Further study is needed to quantify this effect since it depends on a number of factors such as the type of DR event and duration (increasing thermostats one degree versus turning off a compressor).
- With limited opportunities to use DR, it is best to employ DR for capacity reductions (relatively larger financial benefit) than for energy reductions.
- While DR works well as a demand (kW) management tool it is not a strong energy (kWh) management tool.
- Increased availability data available from SGC capabilities creates new DR product and business models. For example, today's limitations on DR events (i.e. 15 per year/5 degrees A/C) could be modified to hundreds of events at 1 degree
- Commercial Operations requires approximately 20 MW minimum controllable load to represent practical value in power operations.
- Using DR as a source of energy when economic conditions warrant is likely to exhaust customer patience.
- A/C units use a great deal of energy to restore desired room temperatures at the conclusion of a control event (rebound).
- Controlling plug loads yields energy savings many times smaller than the energy savings from A/C control.

### Conclusion

Benefits are available but relatively small. Purchased power/fuel cost savings per customer with central air conditioning controlled by IHSD = \$1.13/year.



## VP 1.8 Dynamically Load Circuits to Avoid Overtime

### Benefit Category

Economic (O & M Cost)

### Enabling Field System

Distribution Monitoring

### Hypothesis

Effective capacity ratings are a function of temperature because at colder temperatures more heat is dissipated and assets can handle higher loads. When an asset fails, the dispatch team will restore customers however possible, including overloading circuits. If circuits are loaded beyond their specified ratings, a field crew will be dispatched to repair the failure and relieve the overloaded assets, incurring overtime if necessary to do so.

If the actual capacity of a line is higher than a specified rating due to weather, the Distribution Control Center (DCC) can intentionally overload a circuit beyond its specified rating. This would allow a field crew to repair the failure during the course of normal operations rather than during overtime.

### Environment outside SmartGridCity™

Some assets (substations) have summer and winter ratings. Most devices have a single set of ratings (warning, alarm). When an asset is being used in the warning or alarm condition, the situation causing the overload is repaired as quickly as possible including having crews work in off-hours.

### Environment within SmartGridCity™

The assets can have real time ratings based on current temperatures and loads. Crews will only be dispatched in off-hours to repair the cause if the assets are in “real-time” warning or overload, and not if they are below these thresholds even if they are above the nominal thresholds.

### Actions Taken

Load data is being captured in real time, making the capability of dynamically loading circuits feasible.

### Lessons Learned

- Operators have different styles for operating equipment: some will be more aggressive and others are more cautious; specific standards do not exist or may not be followed.
- The DCC will need to adjust to real-time dynamic ratings instead of the static ratings currently in use.
- The described capability is only required when operating near thresholds or in overload conditions; occurs very rarely in Boulder due to excess capacity, though frequently in Denver Metro.
- Benefits are unlikely to be a significant as highest loads most often occur when temperatures are high, limiting the availability of conditions required for this benefit to be likely.
- The DCC frequently overloads circuits beyond nameplate during outages to minimize customer impact.

### Conclusion

Benefits are likely but relatively low. Estimated overtime costs savings of \$1,200 per year in Denver Metro; no savings in Boulder because feeder overloading rarely occurs, therefore rarely requiring overtime.

## VP 1.9a Reduce Energy Consumption through Voltage Reduction

### Benefit Category

Economic (Energy)

### Enabling Field System

Integrated Volt/VAr Control

### Hypothesis

Voltage is set at the feeder level to maintain customers' voltage well above the minimum threshold of 114 V. Traditionally voltage must be set at levels with a high safety margin to ensure that the voltage does not drop below the threshold during peak load conditions. Due to practical constraints this voltage setting stays fixed for longer time periods. However, today the powerful communication infrastructure of SmartGridCity™ allows better monitoring throughout the line, especially near the customer premises, effectively reducing the safety margin required. As voltage is reduced, there is a proportional reduction in energy usage. This control function is often referred to as Conservation Voltage Reduction (CVR).

### Environment outside SmartGridCity™

Voltage is set at the substation transformer by *manually* configuring the load tap changer. The LTC setting is based on the measured voltage at the feeder and the *estimated* voltage throughout the distribution system. Traditionally, load tap changers and switched capacitor banks are operated as completely independent (stand-alone) devices, with no direct coordination between the individual controllers and there are minimal feedback loops to ensure customer voltage is within specification.

### Environment within SmartGridCity™

The feeder voltage is dynamically regulated up or down *automatically* based on near real-time voltage *measurements* throughout the distribution system. Approximately 10-12 sensors per feeder are used, and these are located at strategic points where customer voltage is expected to be most varied from feeder voltage.

### Actions Taken

Integrated Volt/VAr Control (IVVC) is functional on 2 feeders, 1554 and 1556.

### Lessons Learned

- Distribution Control Center will utilize additional information provided by the IVVC system to set the ideal voltages.
- IVVC has high potential benefits relative to cost.
- SGC's Distribution Monitoring system was utilized to identify the ideal locations for IVVC system sensors.
- Moderately accurate model of the distribution system required to determine sensor locations and voltage drop between sensors and premises.
- Targeted customer voltage 115V, but not all customers will be at that level due to variations on the feeder.
- IVVC investments are similar to DSM program investments as they are delivered by the utilities but benefit customers by reducing energy usage.

### Conclusion

Benefits are likely and high. Significant energy usage and fuel cost reduction noted. Reducing the average voltage from 121 to 116 full-time yields energy reductions of approximately 2.7% on average, or 207kWh per residential customer annually (worth \$8 per residential customer in avoided fuel to the utility, and \$18 in savings annually per residential customer served by an equipped substation assuming \$.087 per kWh).

## VP 1.9b Peak Capacity Reductions through Voltage Reductions

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Integrated Volt/VAr Control

### Hypothesis

During power shortage voltage is set at the feeder level near the minimum threshold of 114 V. This is done in extreme cases to avoid outages, but will also compliment HB 1037 demand reduction requirement. Better monitoring throughout the line, especially near the customer premises will reduce the safety margin required. As voltage is reduced during peak demand months July and August, there is a proportional reduction in generation capacity

### Environment outside SmartGridCity™

Voltage is set at the substation transformer by changing the load tap changer (LTC). The LTC setting is based on the measured voltage at the feeder and the estimated voltage throughout the distribution system. There are minimal feedback loops to ensure customer voltage is within specification.

### Environment within SmartGridCity™

The substation voltage is set automatically based on voltage measurements throughout the distribution system. Approximately 10-12 sensors per feeder are used, and these are located at strategic points where customer voltage is expected to be most varied from feeder voltage.

### Actions Taken

Integrated Volt/VAr Control (IVVC) is functional on 2 feeders, 1554 and 1556.

### Lessons Learned

- Distribution Control Center will utilize additional information provided by the IVVC system to set the ideal voltages.
- IVVC has high potential benefits relative to cost.
- SGC's Distribution Monitoring system was utilized to identify the ideal locations for IVVC system sensors.
- With further development, smart meters could serve as IVVC system sensors.
- Moderately accurate model of the distribution system required to determine sensor locations and voltage drop between sensors and premises.
- Target Customer Voltage could be reduced to 114V during power shortage and still be within ANSI C84 limit

### Conclusion

Benefits are likely and high. A 5% reduction in voltage during critical peak will reduce demand by 3.25%. (A prospective benefit of \$14M in deferred Generation Capacity if deployed on 40% of PSCO's substations.)

## VP 2.1 Reduced OKOA through Outage Verification

### Benefit Category

Economic (O & M Cost)

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Smart meters can report in their status both on a regular basis and on demand, when pinged. This can be used to verify that an outage has occurred. When a customer reports an outage, the Customer Care Center (CCC) can ping the meter and determine if the meter has power. If so, the outage is the customer's responsibility to fix and a truck roll can be avoided. This will significantly reduce the number of OK on arrivals (OKOAs).

### Environment outside SmartGridCity™

If customer reports an outage, the CCC or Distribution Control Center (DCC) dispatches a troubleman.

### Environment within SmartGridCity™

When a customer calls in to report an outage, the CCC or DCC can "ping" a meter to verify power is out. If the meter appears to have power, the CCC or DCC informs the customer that the problem is inside the customer's premises.

### Actions Taken

SmartGridCity™ consists of 23,000 customers with smart meters; all are 'pingable' by the DCC or CCC.

### Lessons Learned

- SGC systems that impact a small percentage of a user's responsibility are not being readily adopted or being integrated into existing systems or processes. For example, DCC and CCC do not fully utilize "pinging" capability due to small percentage (5% and 0.5%, of customers with smart metering capability, respectively).
- In extremely rare circumstances (<2% of SGC outages), a faulty meter connection block causes an outage for which PSCO is responsible to fix that a meter ping would indicate is a customer's responsibility to fix, according to PSCO.
- Integration with IVR system could enable customers to self-serve meter pingging to reduce number of live calls.
- Smart meters introduced new point of failure: connection block between meter and premise wiring, according to PSCO.
- It is very easy for customers to report an outage; but hard to get customers to cancel outage reports when service is restored. Meter pingging can help with this situation.
- Only saves O&M if someone had to be called in for overtime; assumed that someone's OT costs would have been saved during escalated operations.
- Learned that meter pingging capabilities are likely to reduce OKOAs.
- Reductions in field time investigating outages will result in increased safety.

### Conclusion

Economic benefits are likely but small. A reduction of 110 OKOAs for SGC per year are possible. \$2,700 savings for 23,000 smart meters (\$0.12/customer) per year.

Customer satisfaction benefits are significant; the ability of the CCC or DCC to let a customer know immediately whether or not the problem was the customer's responsibility to fix (rather than waiting for a troubleman to investigate) was rated second highest capability in importance (next to energy use and cost) in a survey of 800 PSCO customers.

## VP 2.2 Reduce Meter Reading Cost

### Benefit Category

Economic (O&M Cost)

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Reduce manual or drive-by meter reading with fully automated meter reading. This Value Proposition relates to the capability of communicating remotely with meters. Among many other benefits, remote meter communication offers the opportunity to read electric meters without pedestrian manual meter readers or radio-equipped drive-by meter reading vehicles.

### Environment outside SmartGridCity™

PSCO: In general, meters read via radio-equipped vehicles.

NSP: In general, meters read via CellNet (fixed wireless network).

SPS: In general, meters read via manual meter readers.

### Environment within SmartGridCity™

Smart meters in areas with remote communications capabilities can be read remotely without meter readers or drive-by meter reading vehicles.

### Actions Taken

Within SmartGridCity™ 23,000 meters are being read remotely on a daily basis with accuracy in excess of 99.5% monthly, the best of any meter data collection method employed by PSCO.

### Lessons Learned

- Ideally, all meters within a meter reading route must be upgraded to reduce meter reading costs and to allow for modeling of such things as transformer loading.
- Improvements in process efficiency gained in one area may require a review of processes, resources and budget allocations in others.
- Staffing levels in meter reading may reduce as meter reading is conducted remotely.
- Savings are highly dependent on existing meter reading approach. For example, PSCO's already low meter reading costs (drive-by radio system) would yield less savings versus replacement of more expensive pedestrian meter reading.
- Battery-powered, under-glass upgrades that permit gas meters to communicate once monthly with smart electric meters are now available. This capability enables remote gas meter reading through electric meters with remote communications capabilities.

To enable savings via elimination of meter reading routes:

- Meter change-out should be implemented 100% within a defined geography.
- In geographies with overlapping gas service, gas meter communications capabilities should be installed simultaneously with electric meter communications to optimize meter reading savings.

### Conclusion

Benefits are likely but relatively small. O&M expenses reduced \$0.84 per premise per year.

## VP 2.3 Replace Meters with In-Home Equipment

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

A complex, home area network that measures all electrical usage inside the premises could replace meters attached outside the premises. This would reduce the costs of installing and replacing meters.

### Environment outside SmartGridCity™

Electrical use is measured via meters connected between the service and the premises. The meters are primarily located outside the premises and exposed to significant weather and other forces.

### Environment within SmartGridCity™

Not implemented in SmartGridCity™ as in-home technology is not sufficiently mature to utilize as envisioned.

### Actions Taken

Not implemented in SmartGridCity™.

### Lessons Learned

- Interoperability of systems, including a lack of standards, guidelines and related data security measures discourage replacement of revenue-grade metering hardware.
- Updates to regulatory rules required, such as Colorado PUC Rules 3300-3306 governing the ownership, accuracy, location, testing, and servicing of meters, in order to realize the benefits of this VP.
- Technology has not yet matured to the point where meters can be replaced by in-home equipment. Meters could be moved to the transformer since manual meter reading may no longer be required; however, this has other issues such as accessibility for repairs or replacement.
- Learned that maturity of in-home technologies is inadequate for usage measurement.

### Conclusion

Benefits are unlikely due to limitations in existing technologies, resulting in excessive risk. It was not practical or prudent to pursue in SmartGridCity™.

## VP 2.4 Fuel Cost Reduction through VAr Reduction

### Benefit Category

Economic (Energy)

### Enabling Field System

Integrated Volt/VAr Control (IVVC)

### Hypothesis

IVVC decreases reactive power, improving power factor and reducing the unusable amount of energy that must be generated. This reduction in generation requirements saves fuel costs or purchased power costs.

### Environment outside SmartGridCity™

Autonomous capacitor banks reacting to local conditions; actions uncoordinated between banks; Manual capacitor banks set annually or semi-annually.

### Environment within SmartGridCity™

Centralized control of distributed capacitor banks communicating over BPL and fiber; adds additional optimization beyond autonomous capacitor banks.

### Actions Taken

Active on 2 feeders, 1554 and 1556 and is controlling power factor.

### Lessons Learned

- As an automated system, VAr reduction involves no adoption or business process issues and is therefore ideal for selective application relative to universal deployment.
- Opportunity for benefits is a function of both energy usage and power factor.
- Learned that power factor improvement is a simple and cost effective way to reduce fuel cost. Active on 2 feeders, 1554 and 1556 and is controlling power factor.

### Conclusion

Benefits are likely and high. Fuel costs savings of approximately \$ 4,800 per feeder per year on average; not applicable to all feeders. (This is worth \$1.92 per customer in operational benefits assuming 2500 customers per feeder)

## VP 2.5 Line Loss Optimization Through Remote Switching

### Benefit Category

Economic (Energy)

### Enabling Field System

Distribution Automation

### Hypothesis

Redistributing system load can reduce system losses by balancing the  $I^2R$  losses. Since  $I^2R$  losses are proportional to the square of the current, balancing the currents to have them equal on lines of similar resistance will optimize losses. This can be done through frequent grid reconfigurations based on better load information.

### Environment outside SmartGridCity™

Grid configuration is set approximately twice per year based on historical load profiles. Grid reconfiguration is done in real time only for outages or other unusual events; it is not done for line loss optimization.

### Environment within SmartGridCity™

Using better load information and remote switching capabilities, grid reconfiguration can be done in real time to minimize line losses. Capability to switch loads remotely and automatically based on electrical characteristics has been proven using the DA system.

### Actions Taken

Distribution Automation is implemented and active on 2 feeders, 1554 and 1556.

### Lessons Learned

- Remote operation switches are expensive and have a limited number of switch operations, thus are not frequently activated; further, line balancing could require many switches to be activated along many different feeders to optimize losses.
- This value proposition should be re-evaluated in the event of significant switching equipment technology developments.
- The Distribution Control Center (DCC) is primarily focused on reliability; therefore monitoring line loss optimization in real time is not a priority.
- Most of the decisions that are made regarding configuration perform reasonably well to minimize losses over the year; lines are generally well balanced with minimal switching.
- Whenever a switch is made, there is extra current through the line which causes stress on all the components.
- DA has the lowest tolerance for failure of the smart grid systems as it controls critical grid equipment and therefore must communicate accurately and regularly with internal systems.
- Redistribute system load through remote grid reconfiguration.

### Conclusion

Benefits are unlikely. Fuel savings (\$2,700 per feeder) did not justify incremental investments in large number of switches necessary to realize benefits.



## VP 2.6 Proactive Notification of Outages

### Benefit Category

Economic (O&M)

### Enabling Field System

Distribution Monitoring

### Hypothesis

Smart meters, combined with remote, real-time communications, enable the capability for the utility to become aware of an outage before a customer has an opportunity to call the utility. The concept is to pair this capability with automated customer outreach to let a customer know that the utility has become aware that power to the customer's premise is out. Benefits include improvements in customer satisfaction and reduced customer contact center call volumes and O&M expenses.

### Environment outside SmartGridCity™

Traditionally, utilities have only been alerted to outages as a result of customers' calls (with the exception of large outages such as feeder lockouts).

### Environment within SmartGridCity™

In SGC, transformer sensors can send a "last gasp" signal when power is lost. The utility is aware of the outage without the customer calling in, and Call Center resources may be used to proactively contact affected customers.

### Actions Taken

Not implemented in SGC as a result due to the high cost of outbound telephone calling. PSCO is currently evaluating the use of recently available technologies (e.g. digital, social network, etc.) to realize this capability in a more cost effective manner.

### Lessons Learned

- A formal program with optional registration would be required to enable customers to set their own preferred parameters (media, rules, hours, etc.).
- Customers interested in this capability scored middle of the pack compared to other SGC capabilities on 'willingness to pay' in survey.
- This feature would ideally be established as part of OAM (online account management) so that customers could self-maintain preferred parameters; the execution of this capability via telephone yielded unfavorable cost/benefit analysis.
- Recruiting would ideally be included as part of the process of establishing new service for customers.
- Meters may lose power intermittently or may occasionally be unresponsive to communications; to prevent false positives, there must be a delay or secondary check before an outage is verified.
- Estimated that accurate cell phone numbers are available for about 38% of PSCO customers.
- Learned that execution of this capability via telephone yielded unfavorable cost/benefit analysis.

### Conclusion

Benefits are unlikely by phone. Estimated benefits are \$0.09 per smart metered customer per year. Customer satisfaction benefits may also be available from this capability.

## VP 2.7 Detect Diversions

### Benefit Category

Economic (Revenue Capture)

### Enabling Field System

Distribution Monitoring  
Advanced Metering Infrastructure

### Hypothesis

Most businesses utilize inventory controls to compare the amount of product supplied to the amount of product billed as a check. The SGC concept is to measure kWh at the transformer level and compare it to kWh billed at meters associated with the transformer to identify missed billings.

### Environment outside SmartGridCity™

There are currently no checks to routinely compare kWh supplied against kWh billed. The meter reading team currently audits about 2,000 (commercial) electric meters annually in PSCO, finding an error rate of 5% (100 meters) and additional revenues of about 0.15% of billings (\$1.5 million) annually.

### Environment within SmartGridCity™

Cumulative totals of energy usage for all meters on a transformer can be compared to the energy through that transformer; major discrepancies may be diversions or metering errors and can be investigated. In addition, for smaller premises such as residential, unusual usage patterns can be detected from interval data and investigated.

### Actions Taken

Shifted focus to commercial customers' metering errors as a larger revenue capture opportunity relative to cost.

### Lessons Learned

- The most common forms of residential theft - failing to report a move-in and unauthorized re-establishment of service after credit cut-off - do not require grid upgrades to enable them to be recognized.
- Larger opportunities are available from detecting billing errors for commercial customers (wrong scaling factor, one phase not being measured, etc.) than from detecting residential theft.
- Implementation of this feature can also improve the accuracy of the GIS database.
- Two options are available for identifying commercial meter errors :
  - Traditional kWh meters on transformers with software to compare transformer readings to associated premise readings; or
  - Increase use of transformer sensors over current SGC design (add current and voltage sensors to all 3 phases).
- For residential diversion, software that can 'read' premise interval data and check for anomalies that might indicate theft could be developed.
- Learned that incremental costs required to identify low levels of residential theft did not justify implementation.

### Conclusion

Benefits are likely but relatively low. Estimated benefits are \$95.46 per metered commercial transformer per year.

## VP 2.8 Use AMI to Reduce the Number of ‘Special’ Meter Reads

### Benefit Category

Economic (O&M)

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Smart meters, combined with remote, real-time communications, enable the capability for the utility to read meters for billing purposes ‘at will’. This capability was envisioned to reduce O&M costs by reducing in-person meter reads for move-ins and move-outs. However in-person meter reads are rarely used for move-ins and move-outs (see below). This Value Proposition was therefore modified to examine the value of remote meter reading to reduce any type of in-person meter reads, for example to investigate suspected meter tampering or malfunctions.

### Environment outside SmartGridCity™

In most jurisdictions utilities are permitted to pro-rate a customer’s bill based on the number of days (out of a meter reading cycle) that the customer occupied a premise. Thus no ‘in person’ meter reads are required for move-ins and move-outs.

### Environment within SmartGridCity™

With remote, real-time meter reading capabilities it is possible to bill the customer for the usage actually consumed by the customer prior to moving out to the nearest interval (15 minutes in SGC). While this capability offers no opportunity for O&M savings today, it could provide increased customer satisfaction opportunities.

### Actions Taken

Remote, real-time meter reading capabilities are available for approximately 23,000 premises equipped with smart meters in SGC.

### Lessons Learned

- Call Center personnel have successfully used available customer interval data to resolve high bill complaint calls without having to order a special meter read (via identification of past usage patterns to help customers recognize potential consumption explanations).
- Interval data from meters could provide insight to users in regards to malfunctioning equipment or tampering.
- Through traditional metering methods, pro-rating for move-ins and move-outs was necessary. Meter reading as implemented in SGC enables actual usage calculations to the nearest day for move-ins and move-outs and may represent a customer satisfaction improvement opportunity.
- Learned that Colorado rules allow utilities to pro-rate bills for move-ins and move-outs to avoid special meter reads. As a result, special meter reads consist mainly of meter investigations from high bill complaints.

### Conclusion

Benefits are likely but relatively low.

## VP 2.9 GIS Update from Grid State Connectivity

### Benefit Category

Economic (O&M)

### Enabling Field System

Distribution Monitoring  
Advanced Metering Infrastructure

### Hypothesis

The electrical network topology can be verified using the communications infrastructure. This information can be used to update the GIS systems or alert GIS operators to discrepancies, to ensure that the mapping is an accurate representation of the electrical grid.

### Environment outside SmartGridCity™

GIS information is input or updated when new electrical installations are installed. Changes are made in the field or field personnel identify a discrepancy between the actual installation and the mapping representation. Updates are performed manually by the GIS team

### Environment within SmartGridCity™

The connectivity between the transformers and the smart meters is verified based on the signal strength of the meter communications. If this connectivity differs from the GIS database, an update or alert is triggered.

### Actions Taken

Dig-it project updated GIS with include new communications information. SGC demonstrated that the cost of integrating DM with GIS far exceeded the benefits. Not implemented in SGC as a result.

### Lessons Learned

- Numerous GIS errors found during SGC implementation due to high number of installations; not a feature of SGC specifically, but coincidental benefit.
- Learned that the GIS system needs to contain information on communications assets in addition to the electric grid assets traditionally maintained in GIS. This is necessary for trouble-shooting, maintenance and expansion of the intelligent grid. It also assumes that the systems used in conjunction with the GIS system (e.g. design tools) are updated to support this enhanced environment.
- SGC highlighted the fact that GIS data was insufficiently detailed to be used as basis for field communications designs that utilize electrical infrastructure.
- Automating the GIS update process is risky because primary source for all geographic information; automated alerts to discrepancies is a very good method.

### Conclusion

Benefits are unlikely as very little is spent on GIS updates annually.

## VP 3.1 Encouraging Customer Adoption of Renewable DG

### Benefit Category

Environmental

### Enabling Field System

Distribution Monitoring  
Advanced Metering Infrastructure  
Integrated Volt/VAr Control

### Hypothesis

Extensive penetration of renewable DG such as PV Solar presents opportunities and challenges. The potential opportunities include reduced capacity, energy, and environmental costs, while the observed challenges include: 1) economic equity to those customers who do not own DG; and 2) potential reductions in both generation and distribution grid reliability.

### Environment outside SmartGridCity™

Customer DG is accounted for via net metering, an approach that provides ‘hidden’ subsidies from customers to DG owners under current rules/rates. Distribution grid reliability can be affected at high levels of DG penetration, including harmonic distortion and exacerbation of any frequency dips that might occur.

Net metering ‘masks’ the actual demand a customer would require should DG production drop, providing no visibility to Power Operations.

### Environment within SmartGridCity™

- Dual metering combined with SGC communications-enabled controls could help Distribution Control override PV inverter shut-off in appropriate situations.
- Grid upgrades such as Volt/VAr control (VP 1.9 and 2.4) can help manage high levels of DG penetration and maintain distribution grid reliability.
- Dual metering ‘unmasks’ potential system demand.

### Actions Taken

Insufficient penetration of renewable DG existed in SGC to enable full quantification of this capability.

### Lessons Learned

- The role of DCC will become much more challenging as renewable DG penetration grows. Previously concerned only with 1-way power flow, DCC capabilities will need to adopt the skill sets of transmission operations.
- Grid upgrades facilitate (but are not required for) dual metering of customer-owned generation that could eliminate hidden subsidies.
- Relatively minor grid events, such as momentary voltage or frequency dips, can cause large scale drops in DG production as DG inverters ‘trip off’ (as designed).
- Existing inverter/interconnection standards must be modified to allow automated response to grid disturbances based on extended grid state awareness. This is required to maintain reliability and worker safety as DG penetration increases.
- Distributed Storage (See VP 3.6) can also help manage DG.
- Learned that several SGC capabilities increase PSCO’s ability to reliably accommodate increased penetration of renewable DG.

### Conclusion

Environmental benefits are likely. Economic benefits are unlikely as current tariffs result in “hidden” subsidies of renewable DG owners, estimated at \$6 million annually by 2015.

## VP 3.2 Maximize Customer Use of Renewable Energy Through Generation Mix Signals

### Benefit Category

Environmental

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

The concept is to provide customers with signals -- Green/Use for times when renewable generation is a relatively high portion of the total and Red/Conserve for times when renewable generation is relatively low. In theory customer response to these signals could conceivably reduce a utility's CO<sub>2</sub> output.

### Environment outside SmartGridCity™

Energy Mix signals could be provided to customers without SmartGridCity™ capabilities (for example through text messages, e-mails, etc.).

There is a reduced ability for a utility to control a customers' loads as indicated by energy mix absent SmartGridCity™ capabilities; see VP 1.5-1.7.

### Environment within SmartGridCity™

Customers' In Home Smart Devices could be used to display energy mix signals.

Customers' In Home Smart Devices could be used to control customers' loads as indicated by energy mix.

### Actions Taken

Green signals were not implemented in SGC.

### Lessons Learned

- Signal design is not as easy as is commonly supposed and can lead to unanticipated consequences if not properly done. For example, green signaling could create demand that may outstrip renewable generation, requiring fossil fuel generation to fill gaps renewables could not meet.
- Providing energy mix signals in real time would provide confidential information that energy traders/generators could use to manipulate market prices, raising costs per kWh for all customers.
- Several conditions are required for customers to 'switch' usage to times when renewable energy is plentiful:
  - The green signal must be preceded by a 'red signal' to create pent-up demand.
  - The customer must be aware of the signals and act accordingly, though analysis of historical data indicates most signaling would occur at night.
  - Under current regulatory framework a utility will not be allowed to increase customer loads (during green signal) due to a conflict of interest.
- Research indicates that some customers (42%) are interested in receiving Green Signals, though this was the lowest interest level recorded among SGC capabilities surveyed.

### Conclusion

Benefits are unlikely as increased usage during periods of high renewable energy mix does not result in a decrease of fossil fuel-fired generation.

## VP 3.3 Carbon Reduction through T&D Loss Reduction

### Benefit Category

Environmental

### Enabling Field System

Integrated Volt/VAr Control (IVVC)

### Hypothesis

If line losses are reduced, the amount of energy production required will also be reduced, and there will be a commensurate reduction in carbon dioxide equivalent (CO<sub>2</sub>e) emissions.

### Environment outside SmartGridCity™

Autonomous capacitor banks react to local conditions. Of which, actions are uncoordinated between capacitor banks. Manual capacitor banks are set annually or semi-annually. Voltage levels are set at the feeder with minimal feedback from distribution system. Grid configuration is set approximately twice per year to minimize I<sup>2</sup>R losses.

### Environment within SmartGridCity™

Centralized control of distributed capacitor banks communicating bi-directionally over BPL and fiber; adds additional optimization beyond autonomous capacitor banks. Feeder voltage is set automatically based on voltage measurements throughout the distribution system. Using better load information and remote switching capabilities, grid reconfiguration can be done in real time to minimize line losses.

### Actions Taken

IVVC is particularly effective at reducing energy use and is implemented on 2 feeders, 1554 and 1556.

### Lessons Learned

- Environmental benefits are closely correlated to fuel usage, especially on the margins.
- See VPs 1.9 and 2.4.

### Conclusion

Benefits are likely and high. CO<sub>2</sub>e reduction of approximately 500 tons per feeder for IVVC per year is feasible (3.1% total reduction vs. untreated feeder).

## VP 3.4 Time-of-Use and Other Advanced Pricing Programs

### Benefit Category

Economic (Energy)

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Increasing the transparency of costs to the retail level as those costs vary to the utility by time of day/day of year has been proven through various studies to reduce peak demand and in some cases overall energy usage. Smart meters enable advanced pricing through their ability to record energy use by the time over which it is used.

### Environment outside SmartGridCity™

Traditional meters only measure energy used on a monthly basis. This level of granularity is insufficient for most advanced pricing programs.

### Environment within SmartGridCity™

Smart meters can measure and record individual customer usage down to 15, 10, or even five minute increments (15-minute intervals are currently used in SGC).

### Actions Taken

Advanced pricing pilot began in October 2010 as a separate effort.

### Lessons Learned

- TOU program benefits vary dramatically with participation rates, program designs, incentives, and climate.
- Smart meters are not absolutely necessary for TOU rates; some meter collections methods using existing meters may be viable options. Investigation of these options may be advisable.
- The pilot is not attempting to quantify benefits of advanced TOU pricing on commercial customer demand and usage. As a large customer subset, the benefits from commercial customer participation in advanced pricing programs are expected to be significant.
- As the links between individual customer usage extends back to Energy Supply and strengthens over time, it may make sense to employ retail measurement intervals that are important to Energy Supply and Commercial Operations. For example, since Commercial Operations is held to a 10 minute generation availability standard, the measurement of customer usage in 10 minute intervals could support advanced rate designs and Demand Response incentives that prove more valuable to Energy Supply and Commercial Operations.
- Self-selection bias inherent in voluntary advanced pricing study designs makes it difficult to generalize findings to full roll out.

### Conclusion

Benefits are likely and potentially high. Estimated benefits are expected to be \$86.11 per participating customer per year. Benefits highly variable based on customer adoption rate and degree of behavior change.



## VP 3.5 Utility Can Reduce Carbon Compliance Costs through Green Signal

### Benefit Category

Economic (Energy)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

Green Signals would not create RECs. However, a Green Signal program might be effective at getting people to shift energy usage to times when renewable energy is plentiful. In rare instances, this will reduce costs (but not carbon). When renewable energy is “plentiful” is defined as an *instance in which no peaking plants are operating AND base load + renewable > energy demand*. This condition means energy is being dumped. It only occurs rarely for a few hours at a time, as base load cannot be ramped down further or fast enough for short timeframes. By selling extra power, rather than ‘dumping’ extra power, purchased renewable power waste costs can be reduced and wind production tax credits (PTC) can be taken.

### Environment outside SmartGridCity™

Energy Mix signals could be provided to customers without SGC capabilities (for example through text messages, e-mails, etc.). There is a reduced ability for a utility to control a customers’ loads as indicated by energy mix absent SGC capabilities; see VP 1.5-1.7.

### Environment within SmartGridCity™

Customers’ In-home smart devices could be used to display energy mix signals.  
Customers’ In-home smart devices could be used to control customers’ loads as indicated by energy mix.

### Actions Taken

Not implemented in SmartGridCity™.

### Lessons Learned

- Providing energy mix signals in real time would provide confidential information that energy traders and generators could use to manipulate market prices, leading to higher costs per kWh for all customers.
- Several conditions are required for customers to ‘switch’ usage to times when renewable energy is “plentiful”:
  - The green signal must be preceded by a ‘red signal’ to create pent-up demand.
  - The customer must be aware of the signals and act accordingly, though analysis of historical data indicates most signaling would occur at night.
  - Under current regulatory framework a utility will not be allowed to increase customer loads (during green signal) due to a conflict of interest.
- Research indicates that some customers (42%) are interested in receiving Green Signals, though this was the lowest interest level recorded among SGC capabilities surveyed.
- Learned that the opportunity to reduce carbon compliance costs is rare and that significant practical impediments to implementation exist.

### Conclusion

Benefits are unlikely due to practical considerations. Provision of real-time energy signals could result in market manipulation and higher kWh costs.

## VP 3.6 Support Bi-Directional Integration of Distributed Energy Storage

### Benefit Category

Economic (Energy)

### Enabling Field System

Integrated Volt/VAr Control

### Hypothesis

Distributed Energy Storage (DES), owned by customers or a utility, offers significant potential benefits in distribution system reliability and increased utilization of renewable generation. While the cost of DES is generally prohibitive today, technology improvements & manufacturing economies of scale may make integration economically viable in the future. Smart capabilities will be needed to integrate DES into the grid.

### Environment outside SmartGridCity™

Occasionally, renewable generation is so plentiful that base load generation must be 'backed down' (or run superfluously) at great expense. DES could store this 'excess' generation for later use. High penetrations of renewable distributed generation can introduce reliability issues (See VP 3.1) that DES can help manage.

### Environment within SmartGridCity™

SGC communications capabilities and software enable:

- Automated optimization of DES.
- Placement of DES farther 'down the grid' than otherwise available (generally limited to substations in absence of SGC)
- Optimized use of PHEVs as DES

### Actions Taken

Not implemented in SmartGridCity™.

### Lessons Learned

- DES may make it easier for utilities to comply with Renewable Energy Standards (RES).
- Recognition/classification of energy from DES that has been charged by renewable generation as renewable energy will be important.
- The cost effectiveness of DES may improve as its use in RES compliance is considered. Rather than 'dump' power from base load plants as a result of temporary renewable energy surpluses, surpluses could be stored for later use, offsetting power that would otherwise be generated by natural gas plants.
- While centralized, large-scale storage may have cost benefits over DES, DES offers important distribution system reliability benefits that centralized storage does not offer.
- DES may also offer benefits unrelated to renewable generation, such as deferring capital associated with substation upgrades.
- DES from PEVs (plug-in electric vehicles) are anticipated to be extremely small for many years to come due to several factors:
  - PEV availability (in total and at specific times) is likely very low.
  - PEV owners are likely to demand high compensation levels, but a solution might be utility PV battery ownership/leasing.
- Learned through peer-level research, and to limited extent SGC, that economic benefits were small relative to the likely cost of acquiring power from PHEVs. Conservation voltage reduction (VP 1.9), Power Factor improvement (VP 2.4), and communications capabilities would support DES integration in the future.
- Regulatory protection would be required if the utility generated signal model is used.

### Conclusion

Benefits are unlikely due to unfavorable economics. 500 MWh of storage capacity (10% of the storage of 500,000 PHEVs) would be needed to save \$ 500,000 per year in wind curtailment costs.

## VP 4.1 Distribution Automation to Reduce Outage Extent

### Benefit Category

Reliability

### Enabling Field System

Distribution Automation

### Hypothesis

The distribution automation system senses a fault, and changes the state of switches, reclosers and switch cabinets to isolate as much of the line as possible surrounding the fault and restore power to those customers not in the isolated area.

### Environment outside SmartGridCity™

Distribution automation systems are installed in numerous, high trouble or high value locations. These systems are primarily Intelliteam system made by S&C using radio communications.

### Environment within SmartGridCity™

Distribution automation system uses SEL controller equipment and logic, and fiber communications.

### Actions Taken

Within SmartGridCity™ eight sectionalizing devices are installed on four feeders to create two loops are currently active.

### Lessons Learned

- Manufacturer recommended firmware and software updates should be implemented as specified. Early in the demonstration project, the DA system reported a switch closed that was in fact open, leading to customer service interruption. This issue has since been corrected via firmware upgrades.
- Smart grid field hardware should go through same the standards qualification process as traditional hardware. SEL equipment did not go through normal standards qualification process. As a result, replacement parts and test equipment present logistical challenges.
- Alerts for Distribution Control Center (DCC) staff regarding the operating status of the DA system would provide benefits. It is difficult for DCC staff to determine whether lack of response from a DA controlled asset is hardware-, software- or communications-related.
- Learned that the technology was practical but data accuracy is essential to the functionality of the system.
- Selective deployment of DA in less accessible areas or geographies with low reliability will improve value created per dollar of invested capital relative to universal deployment.

### Conclusion

Reliability benefits are likely and high. DA is anticipated to reduce 28,125 CMO per year per feeder in SmartGridCity™.

## VP 4.2 Use DR to Assist Load Management During Outage

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

During outage conditions, dispatchers will find a way to restore power as quickly as possible. This sometimes results in overloading circuits temporarily or making other sub-optimal configuration decisions.

### Environment outside SmartGridCity™

During outage conditions, dispatchers will find the best configurations to accommodate existing loads. This may involve stressing equipment beyond normal or ideal operating conditions.

### Environment within SmartGridCity™

During outage conditions, dispatchers can call Demand Response (DR) events to reduce loads, which give them more flexibility in configuring the grid and reducing equipment stress.

### Actions Taken

DR programs are not yet established for feeder level control because low penetration will make such implementation infeasible. Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available in the autumn of 2011.

### Lessons Learned

- Changes to regulations (to allow for isolated DR events) or operations protocols (to call PSCO wide events during isolated outages) are required to make use of DR for localized load management.
- Dispatch does not currently engage commercial operations to call DR events nor does it have control over events. Coordination with commercial operations or control would be required.
- There is a practical limit to the number of DR events customers will tolerate.
- Frequent use of DR as a reliability tool may exhaust customer willingness to participate.
- Increased availability data available from SGC capabilities creates new DR product and business models. For example, today's limitations on DR events (i.e. 15 per year/5 degrees A/C) could be modified to hundreds of events at 1 degree.
- DCC requires approximately 1 MW minimum controllable load per feeder to represent practical value in distribution operations. This typically represents as much as 100% penetration of customer with central air conditioning (CAC) on some feeders.
- With limited opportunities to use DR, it is best to employ DR for capacity reductions (relatively larger financial benefit) than for reliability improvements.
- Learned that exceptionally high customer penetration rates are required per feeder to avoid asset overloads with DR.

### Conclusion

Benefits are plausible but low for DR to assist in improving reliability.

## VP 4.3 AMI to Restore Power Faster

### Benefit Category

Reliability

### Enabling Field System

Distribution Monitoring

### Hypothesis

When an underground fault occurs, Troublemens will know which segment of line is faulted. This will save the troubleshooting time and the number of fuses used to isolate the problem.

### Environment outside SmartGridCity™

Troublemens isolate a segment of line by disconnecting surrounding transformers and replacing a fuse; if it holds, the problematic line has been identified; if it blows, a fuse is installed in another location. This is repeated until the location is confirmed. In some areas and situations, the troubleman uses fault finding equipment for this purpose.

### Environment within SmartGridCity™

Sensors between the feeder and fault will see the current spike. Those downstream of the fault will not. By looking at these feeder reports, the troubleman will know immediately which segment of line is faulted and can isolate it.

### Actions Taken

Line sensors are active and in use on underground feeders and transformers.

### Lessons Learned

- With optional upgrades smart metering can deliver most of the benefits of line sensors, although with pros and cons.
- Smart meter and related communication costs are dropping, which may increase the feasibility of using smart meters as line sensors.
- With appropriate communications infrastructure, smart meters with optional equipment upgrades, might be able to replace line sensors' fault locating capabilities with software that maps meters to transformers and phases.
- In SGC, current sensors were only installed on underground lines. It is typical to identify fault location on overhead lines due to visible problems.
- This saves time by reducing troubleshooting time, and also saves fuses because line testing by blowing a fuse will decrease. Extra fuses are used in approximately 10% of underground primary faults and cost approximately \$130 per fuse, including truck fuel savings.
- There is value in monitoring all three phases. Underground sensors often installed on 1/3 phases with the expectation that a fault on any one phase will occur on all three phases. This was found not to be the case as faults are often only on one phase.
- Learned that line sensors on underground feeders are highly effective at identifying underground fault locations and that transformer-based line sensors are an alternative to AMI-based fault detection.
- Reducing time to troubleshoot in the field will significantly improve employee safety by decreasing exposure to daily hazards.

### Conclusion

Reliability benefits are likely and high. Greater than 30 minutes of savings can be achieved per underground outage leading to a reduction of 160,000 CMO in Boulder, or a 20% decrease in CMO from underground fuse outages.

## VP 4.4a AMI to Avoid Outage Overprediction

### Benefit Category

Reliability

### Enabling Field System

Distribution Monitoring  
Advanced Metering Infrastructure

### Hypothesis

AMI and grid sensors provide information which can be used to determine exactly which sections of line are live and which ones are experiencing an outage. This information can be used to avoid incorrect predictions by OMS (specifically assuming multiple small outages are a single large outage), and send the trouble crews to the correct location.

### Environment outside SmartGridCity™

If multiple small outages occur near each other, OMS assumes it was a larger outage. Crews are often sent to the wrong locations and have to spend additional time identifying the correct locations.

### Environment within SmartGridCity™

Detailed knowledge of the grid state shows exactly which lines are out and will not over predict the outage. Even if OMS over predicts, the dispatcher or field crew can quickly see the mistake in OpenGrid and identify the correct locations.

### Actions Taken

DM and AMI are active within SGC.

### Lessons Learned

- This capability improved remote fault reporting and dispatch efficiency.
- Troubleshooter effectively utilized mobile data terminals to verify where the problem exists during the troubleshooting process.
- This capability would be more beneficial in the areas where distance between devices can be quite far than in Denver Metro where devices are close together.
- Learned that smart meters and DM do offer improvements in outage extent determination over OMS.
- Selective deployment of DM in more rural, less accessible geographies may provide greater troubleshooting value per dollar invested relative to universal deployment.

### Conclusion

Reliability benefits are likely and relatively low. A reduction of 22,500 CMO per year in SmartGridCity™ is anticipated.

## VP 4.4b AMI to Identify Nested Outages

### Benefit Category

Reliability

### Enabling Field System

Distribution Monitoring  
Advanced Metering Infrastructure

### Hypothesis

AMI and grid sensors provide information which can be used to determine if power has been restored to all customers in a given area. During storms and escalated operations, a large outage may be fixed while the small outage behind it may still need attention, however the field crews may not know about the small outage and assume power has been fully restored.

### Environment outside SmartGridCity™

When a large outage is fixed, dispatch will attempt to call a sampling of customers to verify that power has been restored; however, it cannot always be verified due to customers who are picking up the phone, work load in the operations center, etc.

### Environment within SmartGridCity™

When a large outage is fixed, OpenGrid shows where power has and has not been restored. Dispatchers or trouble crews can then ping meters to check status and verify that there are no nested outages or alert crews if there are.

### Actions Taken

DM and AMI are active within SGC.

### Lessons Learned

- Repair crews prioritize largest outages during escalated operations. Some identified nested outages may not be fixed while a crew is in a nearby area if there are other large or high priority outages.
- AMI and DM provide improvements in outage extent determination over OMS.
- There have been 20 nested outages in Boulder since July 2008, nine of which caused by a single storm in April 2009.
- Reducing time to troubleshoot in the field will significantly improve employee safety by decreasing exposure to daily hazards.
- Selective deployment of DM in more rural, less accessible geographies may provide greater troubleshooting value per dollar invested relative to universal deployment.

### Conclusion

Reliability benefits are likely and high. Potential CMO reduction of up to 200,000 minutes in SGC, or approximately nine minutes per customer per year is achievable.

## VP 4.4c AMI to Avoid Outage Underprediction

### Benefit Category

Reliability

### Enabling Field System

Distribution Monitoring  
Advanced Metering Infrastructure

### Hypothesis

AMI and grid sensors provide information which can be used to determine exactly which sections of line are live and which ones are experiencing an outage. This information can be used to avoid incorrect predictions by OMS. Specifically assuming single customer calls are isolated, rather than wide-spread problems, and can send trouble crews to the correct location

### Environment outside SmartGridCity™

During some off-hour outages (such as overnight), few people may call in to report problems. OMS may identify the outage as small and isolated when in fact it is larger and more widespread. The troubleman will start investigations at the wrong location and restoration will be slower.

### Environment within SmartGridCity™

All meters that are without power will report the outage even if no customer calls in and the correct isolation device will be identified.

### Actions Taken

DM and AMI are active within SGC.

### Lessons Learned

- This capability improved remote fault reporting and dispatch efficiency.
- AMI and DM provide improvements in outage extent determination over OMS.
- Troubleman effectively utilized mobile data terminals to verify where the problem exists during the troubleshooting process.
- Underprediction occurs almost exclusively in overnight outages when most customers are asleep; at other times there are sufficient calls to identify the larger outage.
- Reducing time to troubleshoot in the field will significantly improve employee safety by decreasing exposure to daily hazards.
- Selective deployment of DM in more rural, less accessible geographies may provide greater troubleshooting value per dollar invested relative to universal deployment.

### Conclusion

Reliability benefits are likely but relatively low. CMO Reduction of 1,500 minutes in SGC.



## VP 4.5 Use DR to Avoid Overloading During Normal Operations

### Benefit Category

Economic (Capital Deferral)

### Enabling Field System

Distributed Energy Resource Control

### Hypothesis

During outage conditions, dispatchers will find a way to restore power as quickly as possible. This sometimes means overloading circuits temporarily or making other sub-optimal configuration decisions.

### Environment outside SmartGridCity™

During outage conditions, dispatchers will find the best configurations to accommodate existing loads. This may involve stressing equipment beyond normal or ideal operating conditions.

### Environment within SmartGridCity™

During outage conditions, dispatchers can call Demand Response (DR) events to reduce loads, which give them more flexibility in configuring the grid and reduce equipment stress.

### Actions Taken

DR programs are not yet established for feeder level control because low penetration does not warrant effort. Results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available in the autumn of 2011.

### Lessons Learned

- Dispatch does not currently engage commercial operations to call DR events nor does it have control over events; coordination with commercial operations or control would be required.
- There is a practical limit to the number of DR events customers will tolerate.
- Frequent use of DR as an asset overloading avoidance tool may exhaust customer willingness to participate.
- Increased availability data available from SGC capabilities creates new DR product and business models. For example, today's limitations on DR events (i.e. 15 per year/5 degrees A/C) could be modified to hundreds of events at 1 degree.
- DCC requires approximately 1 MW minimum controllable load per feeder to represent practical value in distribution operations; this represents 100% penetration of customer with central air conditioning (CAC) on some feeders.
- With limited opportunities to use DR, it is best to employ DR for capacity reductions (relatively larger financial benefit) than for asset overloading avoidance.
- Learned that exceptionally high customer penetration rates are required per feeder to avoid asset overloads with Demand Response (DR).

### Conclusion

Benefits are plausible but low for DR to avoid overloading during normal operations.

## VP 4.6 Proactively Fix Power Quality Issues

### Benefit Category

Reliability

### Enabling Field System

Distribution Monitoring  
Advanced Metering Infrastructure

### Hypothesis

Grid sensors and smart meters collect data on a regular basis. With automated analytics and pre-defined threshold conditions, Power Quality issues can be identified and corrected before they become problematic.

### Environment outside SmartGridCity™

The following process occurs:

- A customer complains about Power Quality issue.
- The service investigation team attaches diagnostic tools to measure Power Quality and returns later to retrieve tools and download data.
- The engineering team analyses data and determines resolution.

### Environment within SmartGridCity™

The following process occurs:

- OpenGrid alerts engineering team to conditions outside tolerances.
- Engineering team retrieves and analyses data from OpenGrid and determines a resolution.

### Actions Taken

AMI and DM are actively used in SmartGridCity™.

### Lessons Learned

- Voltage distribution problems that typically required days or weeks to properly identify using traditional techniques are diagnosed in minutes in SGC.
- Service investigations is an internal, salaried team, and no O&M savings will be realized in the near term; a larger rollout could affect staffing levels and increase O&M savings.
- Daily exception reporting from OpenGrid requires minimal effort to identify problems, and only moderate effort to determine solution.
- Thresholds to determine “abnormal” conditions require iteration to find balance between false positives and missed issues.
- DM reporting reliably and proactively identifies voltage issues.

### Conclusion

Reliability benefits are likely and high. Voltage complaints dropped from an average of 30 per year to 0 in SGC after implementation.

## VP 4.7 Islanding Using DER During Outages

### Benefit Category

Reliability

### Enabling Field System

Distribution Automation

### Hypothesis

When an outage occurs, micro grids can be created by isolating a group of premises in which there are Distributed Energy Resources (DER). These resources can provide power to the neighboring premises restoring power faster.

### Environment outside SmartGridCity™

Normal outage restoration procedures to bring power to as many people as possible as quickly as possible. Most areas use manual switching and distribution automation in very few areas.

### Environment within SmartGridCity™

Knowledge of fault location, loads and distributed resources allows operators to create islands using remote switching. DER could possibly be engaged to provide power to neighboring premises.

### Actions Taken

Not implemented in SGC as a result of this issue and current IEEE 1547 standard.

### Lessons Learned

- DER penetration is not nearly significant enough to provide power to surrounding premises during an outage (penetration must be greater than 20% to enable islanding in residential areas).
- Standards (IEEE 1547) preclude this capability because DER is required to disengage during outages to protect worker safety.
- Field crew processes need to be drastically changed if DER is able to provide power during outages.
- Rates and regulations may need modification because individuals are currently only permitted to sell to the utility and not to other customers.
- Further analysis required as penetration increases to incident generation and load as both are highly dependent on time of day and time of year.

### Conclusion

Reliability benefits are unlikely. Minimal benefits are possible at the current penetration levels. DG penetration of 20% or higher is required.

## VP 4.8 Measure Phase Balance Remotely

### Benefit Category

Economic (O&M)

### Enabling Field System

Distribution Monitoring

### Hypothesis

Every district performs phase balance adjustments on a number of feeders every year, typically seven-eight per district. In order to do this, power measurements must be taken throughout the feeder to determine which loads to shift.

### Environment outside SmartGridCity™

Circuits for balancing are determined from feeder SCADA data. Crews are sent to attach sensors to various points on the phases to determine loads to move to restore balance.

### Environment within SmartGridCity™

SGC data, including customer load and sensor data, can provide the information required for phase balancing without sending crews to attach and retrieve meters.

### Actions Taken

Measurements are being taken as part of normal SGC operations in OpenGrid.

### Lessons Learned

- DM could proactively identify load balancing issues such as voltage sags and  $I^2R$  losses, but further study is needed to determine whether transformer sensor or meter aggregation is the best approach.
- Further research is required to determine the size of the opportunity.
- Since proactive DM measurement is a new capability, effective use of this information requires new business process to proactively rebalance phases prior to customer experiencing Power Quality issues.
- Can use load data from customer meters to determine phase balance and any need to improve it.
- Depending on who would be doing the phase balance measurements and what other duties they have, this may not impact O&M savings in the near term.

### Conclusion

Benefits are likely but relatively low. \$1,500 O&M cost reduction per division per year that can avoid sending crews by using smart grid data.

## VP 4.9 Troubleshooting Voltage Issues Remotely

### Benefit Category

Economic (O&M)

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Many customer Power Quality issues can be detected and investigated using smart meters and/or line sensors.

### Environment outside SmartGridCity™

The following process occurs:

- A customer calls complaining of Power Quality issues (light flicker, spikes and sags, etc.).
- A Troubleman responds to call and if he can't identify the problem service investigation (SI) gets involved.
- The service investigation team attaches diagnostic tools to measure Power Quality and returns later to retrieve tools and download data.
- SI attaches a Power Quality meter to the premises and then retrieves it about a week later, and downloads data.
- Engineer analyses data and determines problem and resolution.

### Environment within SmartGridCity™

The following process occurs:

- OpenGrid alerts engineering team to conditions outside tolerances.
- Engineering team retrieves and analyses data from OpenGrid and determines a resolution.

### Actions Taken

Smart meters and line sensors are collecting data and can be used for Power Quality analysis.

### Lessons Learned

- Service investigations is an internal, salaried team, and no O&M savings will be realized in the near term. A larger rollout could affect staffing levels and increase O&M savings.
- Voltage complaint frequency in SGC was extremely low (approximately 30 per year prior to implementation), but was reduced to 0 following implementation of intelligent technology.
- Learned that voltage issues can be proactively identified and investigated using remote technologies and effectively eliminated complaints.
- Reducing need to troubleshoot in the field will significantly improve employee safety by decreasing exposure to daily hazards.

### Conclusion

Voltage complaints dropped to 0 after SGC implementation. O&M benefits are likely but relatively low. O&M savings of \$650 per year in SmartGridCity™ could be achieved if staffing levels are changed or resources can be redeployed to other tasks.

## VP 4.10 DR for Frequency Regulation

### Benefit Category

Reliability

### Enabling Field System

Distribution Energy Resource Control

### Hypothesis

Momentary imbalances between supply and demand will cause changes in system frequency. Actions will be taken to re-balance supply and demand balance and restore the frequency back to normal. Demand Response (DR) could be used to reduce demand and Distributed Storage (DS) could be used to increase supply when balancing is needed.

### Environment outside SmartGridCity™

Standard tools, such as increasing generation in real time, are used to manage supply and keep the system in balance.

### Environment within SmartGridCity™

Additional tools, such as load reduction from DR and increasing supply from DS, to keep the system in balance could be possible. As demand outpaces supply, DR events can be called to increase demand on the system or energy from DS could be supplied.

### Actions Taken

Preliminary results of a wide-scale test to quantify the potential benefit of residential DR in SGC will be available in the autumn of 2011.

### Lessons Learned

- DR has a 15-minute response time; frequency regulation requires 4-6 second response time or shorter. DR as implemented in SGC will be insufficient for regulating frequency.

### Conclusion

Benefits are unlikely as implemented. PSCO is currently considering distributed data processing infrastructure designs that may enable this capability.

## VP 4.11 Remotely Verify Dispatch Commands

### Benefit Category

Economic (O&M)

### Enabling Field System

Distribution Monitoring  
Advanced Metering Infrastructure

### Hypothesis

Commands sent from the distribution control center do not always reach the target and the field hardware does not always operate. Confirmation that the operation took place is sometimes required and can be done from remote sensing or visual inspection.

### Environment outside SmartGridCity™

After a dispatcher sends a command, if there is evidence that the operation failed, a field crew will be sent to the relevant location to verify operation success or failure

### Environment within SmartGridCity™

After a dispatcher sends a command, there will be evidence in line sensor and smart meter data that the operation succeeded or failed, and no crews will need to be sent

### Actions Taken

Smart meters and DM are actively collecting data in SGC that can be used to verify dispatch commands.

### Lessons Learned

- Field crews are only sent if there is evidence that the command failed to operate the device; this happens very rarely.
- Data to determine if a switch worked is generally available in SCADA.
- Selective deployment of DM in more rural, less accessible geographies may provide greater troubleshooting value per dollar invested relative to universal deployment.

### Conclusion

Benefits are likely but relatively low. Minimal benefits expected due to the rare occurrences where crews are sent to verify an event.

## VP 5.1 Predict Transformer Failure

### Benefit Category

Reliability

### Enabling Field System

Distribution Monitoring

### Hypothesis

Historical load information and up-to-date transformer performance characteristics can identify transformers that are close to failure. These transformers can be replaced before causing an unplanned outage.

### Environment outside SmartGridCity™

Transformers are used until failure, or until the thermal protection element trips. When either event happens an unplanned outage occurs. The transformer is then replaced immediately or within 24 hours.

### Environment within SmartGridCity™

Transformer load information can be used to estimate effective age of the transformer and estimated time to failure. Transformer characteristics change before failure, and analytics evaluating characteristics and comparing to transformers nearby can alert to incipient failure

### Actions Taken

DM is actively collecting data in SmartGridCity™. Transformers failures are 0.4% per year.

### Lessons Learned

- Transformer replacement program effective in previous years, but was phased out. In the event of broader deployment, it may be beneficial to re-examine the practice using smart grid data.
- Predicting transformer failure produces the following types of benefits: increase in reliability numbers because an outage is planned; reduction in O&M cost because overtime is not needed; shorter outages because no waiting is required for a truck roll; increase in customer satisfaction because of knowledge of planned outage and timing of outage.
- Process for identifying incipient failure not a specific algorithm, but instead, a troubleshooting analysis of over or under voltage on the transformer, which is found to be caused by shorting between nearby windings.
- Learned that this capability did proactively identify transformers in need of replacement in SGC.

### Conclusion

Reliability benefits are plausible but relatively low. Total CMO reduction estimated at 1,650 minutes for SGC per year.



## VP 5.2a Identify and Replace Oversized Transformers

### Benefit Category

Economic (Energy)

### Enabling Field System

Distribution Monitoring

### Hypothesis

No load losses are approximately proportional to the size of the transformer. By reducing the size of the transformer to slightly larger than the required capacity as opposed to much larger sizing, no-load losses can be reduced.

### Environment outside SmartGridCity™

Standard distribution transformers (50 kVA) are installed for all residential situations. Transformers are only replaced after failure or when a thermal element cutoff occurs. Then they are up-sized. Transformers are never resized proactively.

### Environment within SmartGridCity™

Load on a transformer is examined. If peak demand is found to be significantly lower than the transformer size, it can be replaced with a lower transformer size to reduce no-load losses.

### Actions Taken

Load measurement is currently active in SmartGridCity™. Transformers are not being replaced based on this information.

### Lessons Learned

- Improved granularity of data through DM provides more accurate guidance on transformer sizing and reduces incidence of oversizing.
- Requires engineering analysis on all transformers to determine candidates for proactive replacement. It may be possible to automate initial transformer candidate screening to identify the best transformers.
- Commercial transformers are sized to customer specifications, which often grossly overestimate demand and increase no-load losses (commercial customers base transformer size on system capacity which is usually more than double highest demand).
- Learned that while retroactive replacement of oversized transformers was not cost effective (See VP 5.2b), benefits exist for right sizing transformers at routine replacements.

### Conclusion

Benefits are plausible going forward, but savings of reduced transformer size does not match cost of replacement. The payback period is approximately 35-70 years.

## VP 5.2b Avoid oversizing replacement transformer

### Benefit Category

Economic (Energy)

### Enabling Field System

Distribution Monitoring

### Hypothesis

When a transformer fails, the field crew replaces it with the next larger standard size. If this is oversized, no-load losses are increased unnecessarily.

### Environment outside SmartGridCity™

When a transformer fails, or the thermal protection element cuts out, the element is replaced immediately to restore power. The transformer is replaced soon after with the next larger standard sized transformer.

### Environment within SmartGridCity™

When a transformer fails or the thermal protection element cuts out, the historical load on the transformer can be examined to determine the appropriate replacement size.

### Actions Taken

Load measurement is active in SmartGridCity™. Transformers are not being replaced based on this information.

### Lessons Learned

- Field crews performing transformer replacement will need to refer to OpenGrid to analyze data before sizing replacement.
- Algorithms for determining appropriate transformer replacement size needs to be developed and implemented.
- Material and labor are approximately equal for transformer installation.
- Losses occur every year of transformers use. It can be 30 years or more for distribution transformers before they are replaced.
- Learned that while retroactive replacement of oversized transformers was not cost effective, benefits exist for right sizing transformers at routine replacements.

### Conclusion

Benefits are plausible but small. Energy savings of \$4,200 are possible in PSCO per year, accumulating each year over the life of transformers.

## VP 5.3 Measure Substation Transformer Stress to Predict Failure

### Benefit Category

Reliability

### Enabling Field System

Smart Substation Monitoring and Protection

### Hypothesis

Substation transformer failures are rare, but when they do happen, they are large events causing long outages for many customers. By using SGC data, it may be possible to predict and prevent substation transformer outages through proactive maintenance.

### Environment outside SmartGridCity™

Many different generations of equipment are in use because of long life of substation equipment. Primarily equipment that is monitoring electrical and temperature information and sending to SCADA for use in real time alarms. Many components of the equipment are electro-mechanical.

### Environment within SmartGridCity™

Devices are microcontroller based, collecting more data at higher frequency rates. Such equipment can perform complex analyses on microcontroller based information using external equipment.

### Actions Taken

Four substations and eight substation transformers have been upgraded in SGC to use Smart Substation Monitoring and Protection (SSMP) equipment.

### Lessons Learned

- Small footprint, only 4 substations in all of PSCO, makes process changes difficult to handle new data.
- Substation data can potentially be used forensically to evaluate failure causes and predict failure. The validity of this VP should be evaluated in the future as additional study is required.
- Substation transformer failures are very rare (0.8% per year).
- When failures do happen, very large impact on CMO, number of customers, etc.
- Analytical tools and business process changes will need to be developed to make use of substation data and to predict equipment failure to reduce outage time.
- Reducing time to troubleshoot substation equipment will significantly improve employee safety by decreasing exposure to hazards.

### Conclusion

Reliability benefits are plausible. 1,320 CMO per transformer monitored and 0.6% chance of predicting a failure per transformer monitored; capital savings of \$8,400 per year per transformer failure avoided.

## VP 5.4 Measure Substation Breaker Stress to Predict Failure

### Benefit Category

Reliability

### Enabling Field System

Smart Substation Monitoring and Protection

### Hypothesis

Substation breaker failures are rare, but when they do happen, they are large events causing long outages for many customers. By using SGC data, it may be possible to predict and prevent substation breaker outages through proactive maintenance

### Environment outside SmartGridCity™

Many different generations of equipment are in use because of long life of substation equipment. Primarily equipment that is monitoring electrical and temperature information and sending to SCADA for use in real time alarms. Many components of the equipment are electro-mechanical.

### Environment within SmartGridCity™

Devices are microcontroller based, collecting more data at higher frequency rates. Such equipment can perform complex analyses on microcontroller based information using external equipment. Measuring breaker characteristics including wear is one form of analysis conducted by such equipment.

### Actions Taken

Implemented on four substations in SmartGridCity™ with approximately 28 distribution breakers actively monitored.

### Lessons Learned

- Small footprint, only 4 substations in all of PSCO were equipped with SSMP, therefore it was difficult to change existing processes to optimize the use of new data, including different methods for data management.
- Substation data can potentially be used forensically to evaluate failure causes and validate the feasibility of this value proposition in the future, but additional study is required.
- Substation breaker failures are very rare (0.5% per year), but if they do occur, can have significant impact on customers CMOs.
- Reducing time to troubleshoot substation equipment will significantly improve employee safety by decreasing exposure to hazards.

### Conclusion

Reliability benefits are plausible. 25 CMO reduction per breaker monitored per year is achievable.

## VP 6.1 Increase Customer Ability to Manage Energy Bill

### Benefit Category

Customer Satisfaction

### Enabling Field System

Advanced Metering Infrastructure  
Distributed Energy Resource Control

### Hypothesis

SGC capabilities enable customers to better manage their energy bill, primarily through better knowledge and to support participation in real time pricing plans. Demand Response technologies help customers manage usage billed through Time of Use (TOU) pricing plans more conveniently. In addition, use of DR technologies is an excellent way to increase the energy and money saved beyond participation in advanced pricing plans.

### Environment outside SmartGridCity™

Flat energy rates (¢/kWh) do not offer customers an opportunity to reduce their energy bill simply by modifying when they use energy. The Saver's Switch program offers customers a basic but effective way to reduce their energy bill using DR via an annual \$40 incentive.

### Environment within SmartGridCity™

SGC capabilities (specifically, smart meters) provide customers with the opportunity to reduce their energy bills by participating in TOU pricing plans (non-SGC enabled customers can also participate in TOU pricing plans). Customers billed through TOU pricing can reduce their bills simply by modifying when they use energy. SGC capabilities also enable DR technologies that are more advanced than the current Saver's Switch.

### Actions Taken

23,000 smart meters installed in SGC to facilitate advanced pricing, including Web-based portal technology and DR.

### Lessons Learned

- The convenience and simplicity of the presentation of energy data and tools to customers impacted their willingness to participate.
- Only customers who actively manage their usage will experience larger bill reductions in the short term. Less diligent customers will experience reduced bill changes.
- Bill impact benefits will be mitigated somewhat over time through future rate cases. To the extent sales volumes drop for an entire population with access to dynamic pricing, fixed costs are spread over fewer kWh, increasing the rate per kWh.
- Customers are able to employ some level of DR technology without SGC capabilities (Saver's Switch).
- Customers are able to employ DR technology with or without the utility's involvement.
- Cyber security issues must be addressed at the meter and with the IHSD to protect customers.

### Conclusion

Economic (electric bill) benefits are potentially high for motivated customers. Based on PSCO's 2006-2007 study of time-differentiated rates, voluntary participants in a Critical Peak Pricing program saved an average of approximately \$200 annually over standard rates and baseline usage. (Critical Peak Pricing rates are different in SmartGridCity™, and the current time-differentiated rate study was designed to approximate a default, as opposed to voluntary, introduction of time-differentiated rates. SmartGridCity™ participant savings are likely to be different as a result of these changes.)

## VP 6.2 Ability to Reduce Energy Use Through Usage Data Access

### Benefit Category

Customer Satisfaction

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

SGC capabilities provide customers with next-day access to their energy usage in 15-minute intervals through a secure internet website (portal). It is anticipated that such access will better help customers understand how much energy is used to operate various home equipment. It is further anticipated that this understanding will lead to appropriate changes in behavior that will reduce energy usage and corresponding carbon dioxide equivalent (CO<sub>2</sub>e) emissions.

### Environment outside SmartGridCity™

Customers today have little understanding of how equipment and usage impact energy bills. Historically, usage detail has been limited to a single figure (kWh for the month). This level of detail is insufficient to help customers understand what actions they can take, or which specific equipment usage modifications to make, to reduce energy usage and corresponding CO<sub>2</sub>e emissions.

### Environment within SmartGridCity™

The combination of smart meters with advanced meter communications enables 15-minute interval usage data to be uploaded to a secure, customer-accessible website on a daily basis. Customers can access their data from any internet-accessible computer to view historical usage from the previous day clear back to the same day the previous year.

### Actions Taken

15-minute interval usage data from smart meters is being collected and updated daily to a secure website. Current PSCO studies underway to refine impact estimate.

### Lessons Learned

- Customers responded better when metrics were presented in terms they could easily relate to (e.g. miles driven per year vs. tons of CO<sub>2</sub>e; dollars saved vs. kWh saved).
- Customer Care Center employees are using 15-minute interval data to reduce call handle time and frequency of meter tests for customers with high bill complaints. For more information please see VP 6.6, 'Use meter interval data to reduce O&M expenses'.
- Web portal implementation choices (using Flash software to present 15-minute interval data quickly, securely, and efficiently to customers) do not readily enable tracking of the pages users have visited, user visit frequency, or user visit duration. This information would be helpful in evaluating the impact of usage data access more precisely.
- Cyber security at the meter will be important to protect customer usage data.

### Conclusion

Benefits are plausible. External research indicates 8% reduction in energy use per customer per year is possible.

## VP 6.3 Participation in an Online Green Energy Community

### Benefit Category

Customer Satisfaction

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Customers with Smart Meters have the opportunity to take advantage of many new capabilities, including the ability to view electricity usage data in 15-minute intervals via a secure website. The online green energy community is a supportive tool for these capabilities, enabling users to share success stories and best practices in energy conservation with each other. It's also an opportunity for the utility to post its own energy conservation tips and promote energy efficiency and demand response programs.

### Environment outside SmartGridCity™

Customers today have little understanding of how equipment and usage impact energy bills. Historically, usage detail has been limited to a single figure (kWh for the month). This level of detail is insufficient to help customers understand what actions they can take, or which specific equipment usage modifications to make, to reduce energy usage and corresponding carbon dioxide equivalent (CO<sub>2</sub>e) emissions. The reliability of related information sources, particularly on the internet, is often questionable.

### Environment within SmartGridCity™

Customers with Smart Meters are able to access 15-minute interval usage data through a secure website on a one-day delay. The online green energy community adds to this capability by providing an opportunity for customers to educate each other, share successes and best practices, and compare results in order to maximize the value of interval data access in reducing energy usage.

### Actions Taken

Numerous independent networking sites already exist today; therefore the online green energy community was not implemented.

### Lessons Learned

- An online energy community would require dedicated resources to promote the community, monitor user interactions, identify educational opportunities, and execute promotional efforts associated with energy efficiency and demand response.
- To encourage customer adoption and involvement in the community, Marketing will likely need to allocate resources and effort towards educating customers on the benefits of using such a community.
- Based on findings from a 2006-2007 PSCO study of time-differentiated rates, very few customers would utilize a PSCO online green energy community.

### Conclusion

Benefits are unlikely. Customer survey results indicate that very few customers would currently utilize an online green energy community. In SGC, 17% of customers surveyed indicated they would use such as service; 12% in PSCO.

## VP 6.4 Improved Satisfaction via Reduced Customer Minutes Out (CMO)

### Benefit Category

Customer Satisfaction

### Enabling Field System

Distribution Monitoring  
Distribution Automation  
Substation Monitoring

### Hypothesis

A variety of SGC Systems (Distribution Monitoring, Distribution Automation, and Substation Monitoring) offer improvements in CMO as part of their value propositions. CMO improvements should translate to improved customer satisfaction. Customer research was conducted to understand how much residential customers value reliability improvements.

### Environment outside SmartGridCity™

Reliability is a top priority for PSCO distribution and substation operations. A significant amount of resources are dedicated to measuring and analyzing reliability and identifying and resolving reliability issues. PSCO's Outage Management System (OMS) is a valuable tool in reliability improvement efforts. PSCO customers have an expectation of reliability (i.e. it is a cost of doing business vs. a perceived added benefit).

### Environment within SmartGridCity™

A variety of SGC systems provide additional capabilities to reduce outage frequency and duration (see VPs 4.1, 4.3, 4.4, 4.7, 5.1, 5.3, and 5.4).

### Actions Taken

CMO has reduced 30% after SGC systems implementation.

### Lessons Learned

- Most (residential) customers appear to be satisfied with the existing level of reliability.
- Compared to other smart grid capabilities, customers place a relatively low value on additional improvements in reliability.
- If risks to reliability (PV solar, Electric Vehicles, etc.) are not managed well and reliability decreases, then customer interest in reliability would likely be dramatically greater.
- Service in Boulder was already extremely reliable before SGC, with SAIDI figures in the top quartile of US cities (IEEE, 2006).
- Though CMO did improve 30% after implementation of SGC systems, a 30% improvement translates to a relatively short improvement in total time when viewed in the context of already exceptional reliability performance (25 minutes per year).
- Greater value per dollar of investment may be achieved with selective deployment of DM and DA in low reliability or less accessible geographies.
- As greater DG penetration creates instability on the grid, DA and other systems may require faster processing which could lead to distributed processing compared to the current centralized processing model to address latency.

### Conclusion

Benefits are unlikely. In a survey of 800 PSCO customers regarding the relative importance of various smart grid benefits, reduced duration and frequency were scored as 8<sup>th</sup> and 10<sup>th</sup> lowest out of 11 benefits measured.



## VP 6.5 Use Meter Pinging to Avoid Investigation-related Delays

### Benefit Category

Customer Satisfaction

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

The SGC implementation included the capability to communicate with smart meters remotely in real time. This capability ('pinging the meter') can be used to determine power status at the meter, including voltage, current, and other conditions. Pinging can be used to let a customer know immediately if an electrical problem is the customer's responsibility or PSCO's responsibility to fix.

### Environment outside SmartGridCity™

Traditionally the only way to determine whether or not a customer's service issue is within the home (on the customer's side of the meter/customer responsibility) or outside the home (on PSCO's side of the meter/PSCO's responsibility) is to send a qualified electrician to investigate.

### Environment within SmartGridCity™

With meter pinging a Customer Contact Center (CCC) or Distribution Control Center (DCC) employee can determine whether or not a customer's service issue is PSCO's responsibility without having to roll a truck.

### Actions Taken

Both the CCC and DCC have the capability to ping all 23,000 smart meters in Boulder.

### Lessons Learned

- The pinging capability is not likely utilized as fully in the SGC pilot as it would be in a full roll out.
- While CCC and DCC employees can take steps to identify whether or not a premise has a pinging capability, no alert exists that indicates if a premise has a pinging capability. About 50% of the premises in Boulder have pinging capabilities, or about 2% of PSCO electric meters. This penetration level is insufficient to justify large scale process changes in the CCC or DCC.
- Pinging capability is not generally as valuable in widespread outages as it is in single premise trouble reports.
- In extremely rare circumstances (<2% of SGC outages), a faulty meter connection block caused an outage for which PSCO was responsible to fix, that a meter ping would indicate is a customer's responsibility to fix.
- Learned that this capability is highly valued by customers.

### Conclusion

While O&M benefits are likely and relatively low, a survey of 800 PSCO customers regarding the relative importance of various smart grid benefits, "Knowing the responsible party to fix an outage" scored 2<sup>nd</sup> highest out of 11 benefits measured (Energy Use and Cost).

## VP 6.6 Use Meter Interval Data to Reduce O&M

### Benefit Category

Economic (O&M Cost)

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Smart meters are used to collect usage data over specific (e.g. 15 minute) time intervals. While this data is generally intended to be used for advanced pricing programs such as Time of Use (TOU) and Critical Peak Pricing (CPP), there are other benefits. For example, Call Center agents can access and review this detailed usage data to help a customer understand why his or her electric bill might be higher than normal (house guests, introduction of new loads, weather-induced extensive AC usage, etc.). Helping a customer identify why a specific electric bill might be high is expected to 1) reduce the time required to handle a high bill complaint call; 2) increase the number of high bill complaint calls resolved without a 2<sup>nd</sup> call; or 3) reduce the number of meter tests ordered.

### Environment outside SmartGridCity™

Traditionally usage data is not very granular, available only on a monthly basis. Neither customers nor Call Center employees have visibility to interval usage data. High bill complaints are typically resolved only after extensive time on the phone, elevation to a supervisor, or through a meter test requiring a truck roll.

### Environment within SmartGridCity™

With access to interval data a Call Center employee can identify dates and even hours of high usage and suggest potential explanations. A customer might respond with “Oh, that’s when we got our hot tub” or “Right, my sister’s family was here and we used the space heater”.

### Actions Taken

Historical 15-minute interval data is available for all 23,000 smart meters in SGC.

### Lessons Learned

- The access to interval data is not likely utilized as fully in the SGC pilot as it would be in a full roll out.
- While Call Center employees can take steps to identify whether or not interval data is available for a given premise, no alert that the data is available for a given premise is routinely provided through CRS.
- Approximately 50% of the premises in Boulder have available interval data, or about 2% of PSCO electric meters. These penetration levels are insufficient to fully change Call Center processes or employee behaviors. As a consequence SGC pilot results likely underestimate the true O&M reductions that result from the availability of interval data.
- Learned that the Call Center can use interval data to better manage high bill complaint calls.
- Call Center employees may need to spend more time with customers to evaluate usage data. Currently, Call Center employees have incentives to take high numbers of calls per day and not to lengthen call time.
- There will be a need to rebalance the budget to ensure increased costs for the Call Center are fully covered.

### Conclusion

Benefits are likely but relatively low. O&M Costs reduced are anticipated to be \$0.013 per smart metered customer per year.

## VP 6.7 Proactive Monitoring of Selected Customer Premises Circuits

### Benefit Category

Customer Satisfaction

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Advanced DR devices in customers' premises can be used to investigate the health of appliances and circuits into which they are incorporated. These capabilities could lead to the utility offering a new service to customers.

### Environment outside SmartGridCity™

There are no capabilities for a utility to check on the health of an appliance or circuit within a customer's premise.

### Environment within SmartGridCity™

SGC communications capabilities, combined with customers' advanced DR devices, enable the utility to investigate the health of appliances and circuits into which these devices are incorporated.

### Actions Taken

Not broadly implemented due to security-related delays in release of in-home smart devices required to enable this capability.

### Lessons Learned

- Appliance-based monitoring is more practical in residential environments than circuit-based monitoring and a high number of customers are willing to pay for this type of service.
- Software would need to be developed to periodically collect premise circuit data, store it for future use, compare it to new data as collected, identify troubling variations, and report exceptions to the Call Center (for proactive outreach to customer) or customer via automated communications.
- These capabilities have not been broadly tested. A formal product development investigation of this potential service is indicated.

### Conclusion

Benefits are plausible. 65% of customers surveyed (Denver Metro) were highly interested in this service, above the median compared to other services/benefits measured. The service also scored the highest on a 'willingness to pay' measure of all other services/benefits measured; 52% would pay up to \$1.00 per month.

## VP 6.8 Customer Confident That Utility Will Be Aware of Outages

### Benefit Category

Customer Satisfaction

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Customer knows that utility can detect outages automatically.

### Environment outside SmartGridCity™

Without smart grid capabilities, utilities are dependent upon customers calling in to report outages.

### Environment within SmartGridCity™

In SGC, current and voltage sensors in the field, combined with grid communications capabilities and back-office software, enable the utility to be notified of outages at the transformer level without customer intervention.

### Actions Taken

Within SGC, 4,700 transformers are being monitored 24/7 for outages. Identified transformer-level outages are automatically posted to OMS.

### Lessons Learned

- The meter pinging capabilities available to the Customer Care Center for 23,000 meters in SGC could be utilized to identify single-premises outages. An automated pinging program could be employed to contact the meters on a periodic basis (15-minute intervals) and report unfavorable findings to OMS when encountered.
- Transformer-level outage monitoring works, but is expensive given the ratio of customers per transformer and is not adequate to replace premises-level outage detection.
- Distribution transformer-level outages are accurately reported by existing line sensor technology.
- Single-premises outages on distribution transformer phases with more than one premise are not reported to OMS in real-time today (though these meters can be pinged to verify if they are receiving electricity).

### Conclusion

Benefits are likely. 73% of customers surveyed rated PSCO's capability to detect outages without any intervention as highly important. This capability was one of the highest-rated SGC capabilities measured in the survey (top quartile).

## VP 6.9 Customer Confident that Utility Can Perform Remote Meter Diagnostics

### Benefit Category

Customer Satisfaction

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

The customer will be aware of the utility's ability to perform remote diagnostics and understand whether the issue is the responsibility of the customer or the utility. This awareness could positively impact the satisfaction of the customer.

### Environment outside SmartGridCity™

Troublemakers must be dispatched to investigate outages reported by customers. It can take 30 minutes or longer for a troublemaker to travel to a premise and determine the party responsible to repair an outage.

### Environment within SmartGridCity™

Smart Meters, combined with grid communications capabilities and back office software, allow Call Center agents the ability to remotely determine whether or not an outage is the customer's responsibility to fix or the utility's.

### Actions Taken

Both the CCC and DCC have the capability to ping all 23,000 smart meters in Boulder.

### Lessons Learned

- The pinging capability is not likely utilized as fully in the SGC pilot as it would be in a full roll out.
- While Call Center and Dispatch employees can take steps to identify whether or not a premise has a pinging capability, no alert that the pinging capability is available for a given premise is routinely provided through the systems they use. About 50% of the premises in Boulder have pinging capabilities, or about 2% of PSCO electric meters. These penetration levels are insufficient to justify large scale process changes in Call Center or Dispatch.
- Pinging capability is not generally as valuable in widespread outages as it is in single premise trouble reports.
- In extremely rare circumstances (<2% of SGC outages), a faulty meter connection block causes an outage for which PSCO is responsible to fix that a meter ping would indicate is a customer's responsibility to fix.
- Learned that this capability is highly valued by customers.

### Conclusion

Benefits are likely. A survey of 800 PSCO customers regarding the relative importance of various smart grid benefits, "knowing the responsible party to fix an outage" scored 2<sup>nd</sup> highest out of 11 benefits measured.

## VP 6.10 Customer Feels Empowered to Manage Personal Energy Use

### Benefit Category

Customer Satisfaction

### Enabling Field System

N/A

### Hypothesis

SmartGridCity™ offers many capabilities – dynamic pricing, demand response, and access to detailed usage data, among others – to help customers feel empowered to manage personal energy use.

### Environment outside SmartGridCity™

Customers feel they have little influence over their electric bills. They have no provider choice and don't understand the actions they can take to reduce their use and cost.

### Environment within SmartGridCity™

Capabilities offered through grid upgrades offer customers increased opportunities to manage personal energy use. It is believed that enhanced ability to control energy use (and cost) will help customers feel more empowered and satisfied with their utility.

### Actions Taken

AMI capabilities have been implemented for 23,000 customers in SGC to facilitate time-of-use rates. A survey was completed about customer interest in, and willingness to pay for such capabilities.

### Lessons Learned

- As customer electricity options evolve, the importance of customers' utility perceptions to the utility's business model increases.
- 64% of PSCO customers expressed an interest in participating in time-of-use rates.
- To encourage greater customer awareness and involvement in smart grid programs, Marketing will have to allocate resources and effort in communicating the customer and utility's role in the steps necessary to empowering the customer to manage their personal energy use.
- Customers' experience with a capability must be in large enough numbers for a sufficient-enough length of time to measure the impact on perceptions (for example, of increased empowerment).
- Customer usage of personal consumption data falls off rapidly under current rate structures.

### Conclusion

Benefits are likely. A survey of 800 PSCO customers indicated that capabilities to help manage energy use and cost scored the highest in importance among all SGC capabilities queried.

## VP 6.11 Customer Feels Empowered to use Renewable Energy

### Benefit Category

Customer Satisfaction

### Enabling Field System

N/A

### Hypothesis

SmartGridCity™ capabilities – including demand response, in home devices, and grid communications – enable opportunities to incorporate greater levels of renewable generation. It is thought these capabilities will provide customers with an increased perception of empowerment to manage the environmental impact of their energy use.

### Environment outside SmartGridCity™

Customers feel they have little influence over their environmental impact.

### Environment within SmartGridCity™

The capabilities required to offer green signaling and control of customer loads is available in SGC.

### Actions Taken

Green signaling was not implemented in SGC as a result of issues around its feasibility. A survey of customers that included testing of the concept was completed.

### Lessons Learned

- Providing real-time information on renewables mix was impractical in present regulatory environment and could be counterproductive in both environmental impact and cost reduction.
- Relative to other smart grid capabilities and benefits, the interest in this concept was one of the lowest surveyed outside of Boulder (second only to participating in an online green energy community) and below the median even among Boulder customers.
- As customer electricity options evolve, the importance of customers' utility perceptions to the utility's business model increases.
- Customers' experience with a capability must be in large enough numbers for a sufficient-enough length of time to measure the impact on perceptions (for example, of increased empowerment).
- Providing green signals in environments such as entire neighborhoods could potentially provide benefits.

### Conclusion

Short-term benefits are unlikely for a macro environment. In addition to the challenges described in VP 3.2 and 3.5, green signaling scored very low in importance compared to all smart grid benefits queried.

## VP 6.12 Customer Feels Partnership with Utility Rather Than Dependency

### Benefit Category

Customer Satisfaction

### Enabling Field System

N/A

### Hypothesis

SmartGridCity™ offers many capabilities – dynamic pricing, demand response, and access to detailed usage data, among others – to help customers feel a partnership with their utility rather than dependent upon their utility.

### Environment outside SmartGridCity™

Customers feel they have little influence over their utility. They can't use provider choice to register their preferences and perceive that they are dependent on their utility.

### Environment within SmartGridCity™

Capabilities offered through grid upgrades offer customers increased opportunities to manage personal energy use. It is believed that enhanced ability to control energy use (and cost) will help customers feel more like a partner with, and less like a dependent of, their utility.

### Actions Taken

AMI and smart portal capabilities have been implemented for 23,000 customers in SGC to facilitate time-of-use rates.

### Lessons Learned

- As customer electricity options evolve, the importance of customers' utility perceptions to the utility's business model increases.
- Customers' experience with a capability must be in large enough numbers for a sufficient-enough length of time to measure the impact on perceptions (for example, increased partnership).
- A key issue for the utility for building a partnership with the customer is managing expectations.
- Learned that while smart grid technologies can provide the customer with many options, expectations must be properly established and maintained if the customer is to feel partnership with utility.

### Conclusion

Benefits are likely based on overall research findings. Capabilities to help manage energy cost scored the highest among all SGC capabilities investigated in a survey of 800 PSCO customers. Customer experience with smart grid capabilities is insufficient to measure impact on partnership perception at the time of this analysis.



## VP 6.13 Customer Sees Utility as Progressive and Interested in Customer Well-Being

### Benefit Category

Customer Satisfaction

### Enabling Field System

N/A

### Hypothesis

SmartGridCity™ and future smart grid deployments may indicate to customers its commitment to its community, customers and the environment and consequently improve customer satisfaction.

### Environment outside SmartGridCity™

Due to the nature of the electric and gas utility business, Xcel Energy is not a highly environmentally friendly organization.

### Environment within SmartGridCity™

Pursuing smart grid upgrades which can lead to environmental improvements and customer well-being, such as reduced customer bills.

### Actions Taken

N/A

### Lessons Learned

- PSCO has the opportunity to communicate positive investments in smart grid technologies and related benefits. As customers have more time to become comfortable with the systems and understand their benefits, customer overall satisfaction may improve.
- To encourage greater customer awareness and involvement in smart grid programs, Marketing will have to allocate resources and effort in communicating to the customer the environmental and customer benefits available from deployed smart grid technologies.
- PSCO has not taken full advantage of the SGC demonstration project in this manner.

### Conclusion

Benefits are plausible. Approximately 88% of SmartGridCity™ participants surveyed rated overall satisfaction with Xcel Energy as 'positive' or 'neutral' while the same figure for PSCO at-large customers is 83%.

## VP 6.14 Use Prepaid Programs as a Financial Controlling Tool by Customers

### Benefit Category

Customer Satisfaction

### Enabling Field System

Advanced Metering Infrastructure

### Hypothesis

Prepaid programs enable customers to pay their energy consumption in advance via pay stations located throughout a service area or using an Internet based software. Payment options will provide participants better control of their energy usage/bill and facilitate better management of their bills. High visibility of customer energy usage and remaining account balances will help participants keep from getting behind in their electricity bills and may motivate them to save energy.

### Environment outside SmartGridCity™

Utilities deal with a certain segment of customers who regularly have difficulty paying their bills, resulting in costly write-offs for utilities. Under pressure to reduce those write-offs, some utilities established large deposits for new accounts and high fees for disconnections and subsequent reconnections.

### Environment within SmartGridCity™

Smart meters report data to the utility on a daily basis, making prepayment a viable option. Prepaid programs allow payment challenged customers to pay as they go without having to make any large deposits in advance. By reviewing their daily energy usage and remaining balance, customers may also feel more conscientious and conservative about their electricity consumption resulting in less energy consumption.

### Actions Taken

15-minute interval usage data is being collected and updated to a secure website daily for customers with smart meters.

### Lessons Learned

- Contrary to conventional wisdom, customers who use prepaid programs are extremely satisfied with their participation.
- Multiple benefits extend to all customers from such programs, including reduced bad debt, collections and interest expenses.
- 24/7 billing system in order to process ongoing customers' payments as well as near real-time payment process may be necessary to support the prepaid program demand.
- Key factors for prepaid programs success is ease of access to forms of payment such as Internet, kiosks, phone, etc. Infrastructure and capabilities from SmartGridCity™ are suitable for a prepaid program to be implemented in the future.
- Definition of a standard policy for the program including shut offs, debt accounts, repayment plans, etc. helps to set the limits and rules for the program.

### Conclusion

Benefits are plausible. External research indicates that it may be possible to achieve up to 12% energy savings in the first year a program is implemented.

## VP 7.1 Alternative to Meter Based Business Models

### Benefit Category

Strategic

### Enabling Field System

N/A

### Hypothesis

The utility may be able to operate different business models than in the past. Where historically the utility has delivered power and charged customers, smart grid technologies can enable alternative business models. These business models are still being envisioned and developed, but smart grid technologies, specifically AMI and Distributed Energy Resources, will likely play a role in any new business models.

### Environment outside SmartGridCity™

Meters are located outside of customers' premises and must be read monthly by drive-by or manual meter readers. Saver's Switch or other programs are available to residential or commercial customers respectively that allow the utility to control loads in exchange for payments or rebates.

### Environment within SmartGridCity™

Smart meters record interval data and communicate it to the utility automatically. Loads can be controlled with the customer's consent in exchange for rebates or payments through in-home smart devices. Distributed Generation and Storage systems can be monitored and controlled in real time.

### Actions Taken

No alternatives to meter-based business models have been implemented within SmartGridCity™.

### Lessons Learned

- While a utility considers these new business models, it must also take into account the chance that regulators could require the utility to share the infrastructure or information with other businesses, meaning the utility could be participating in an unregulated market and face tough competition. The utility may be able to manage this issue, but it could be different than existing business models and experience.
- Learned that lack of maturity in the in-home smart device (IHSD) industry precludes many such business models at present.

### Conclusion

MetaVu's preliminary analysis of alternative business model-markets indicates that significant opportunities and risks could exist in the future. Given PSCO's existing capabilities with traditional energy delivery, management, conservation and related programs, MetaVu believes that participation and success within alternative business models based on energy data utilization and two-way customer communications is highly plausible. Timing considerations and extent of preparation to enter alternative business model-based markets are strategic corporate decisions and fall outside the scope of SGC. Opportunities will exist for PSCO to develop alternative business models that utilize smart grid technologies.

## VP 7.2 Encoding Institutional Knowledge

### Benefit Category

Strategic

### Enabling Field System

N/A

### Hypothesis

The installation of SmartGridCity™ and the systems within it could codify knowledge that has been historically retained by employees. This could result in making other employees more effective, especially as staff change jobs.

### Environment outside SmartGridCity™

Many processes are done specific ways because employees have experience and knowledge. For example, a dispatcher may know the operating range for a given measurement although it is not explicitly written. This can lead to a knowledge gap when the employee moves to a different role and a new employee begins. It may take a long time for the new employee to learn these facts, and mistakes are likely in the interim.

### Environment within SmartGridCity™

In SmartGridCity™, some of the nuances are encoded in the systems. For example, the operating range may be part of the software checks being performed and will not require an operator to instinctively know if the asset is out of tolerance.

### Actions Taken

Systems that contributed to this capability in SGC include: Geographic Information System (GIS) enhancements, Distribution Monitoring (DM) and Distribution Automation (DA).

### Lessons Learned

- A vast amount of institutional knowledge that resides within PSCO employees is not necessarily documented. This increases the time to train new employees when existing people change roles or leave the company, which could become more significant as many employees are approaching retirement age.
- In certain cases, increased automation also requires higher levels of data accuracy versus manual processes (e.g. pole location and customer by phase).
- Learned that SGC capabilities do improve documentation of grid designs and management processes.

### Conclusion

Examples of how SmartGridCity™ and smart grid technologies can be used to standardize knowledge and processes include:

- DM system assists in troubleshooting efforts and requires less institutional knowledge. For example, detailed mapping of the distribution grid can be accessed through OpenGrid requiring less experience to fully understand the geography of the grid.
- The engineers estimate peak loading on feeders based on the current on one phase and calculations. Within SmartGridCity™, the actual peak loading is measured and no calculations or technical knowledge is required.
- In the substations, step-down transformers are used so that measurements can be taken at low voltage levels. However the ratios for the step-down transformers are not documented within SCADA and it is the responsibility of the operators to know if the voltages are within acceptable ranges. Using the SmartGridCity™ systems and hardware, the actual voltage can be shown or appropriately scaled, and it is not required to rely on operator knowledge.

## VP 7.3 Framework for Integrating Acquisitions

### Benefit Category

Strategic

### Enabling Field System

N/A

### Hypothesis

SmartGridCity™ could provide valuable experience for understanding how to best integrate the technologies and processes that would accompany an acquisition. This would give Xcel Energy more strategic flexibility in pursuing acquisitions because the subsequent integration would be less intrusive and expensive.

### Environment outside SmartGridCity™

Past mergers and acquisitions by the entities that make up Xcel Energy have been slow and expensive, such as the merger between NSP and New Century Energies.

### Environment within SmartGridCity™

SmartGridCity™ provides an experience base and set of documentation to facilitate integration of acquisitions. It was envisioned that the efforts required to integrate a brand new set of systems in SmartGridCity™ would be similar to those of acquired company.

### Actions Taken

Examples of processes and capabilities improved within SGC include those found in distribution capacity planning, DR program designs and distribution engineering, to name a few.

### Lessons Learned

- Since there was minimal legacy data imported as part of the SGC demonstration project, experience in importing legacy data from an acquired grid's operations is limited.
- The framework for maximizing process integration was not developed as part of the SGC demonstration project because of the low likelihood of an Xcel Energy acquisition in the near-term.
- Learned that the improvement in processes and capabilities that grid modernization offers could conceivably provide benefits when integrating distribution grids of acquired entities.

### Conclusion

The potential for having an acquisition integration framework based on the SmartGridCity™ experience does not appear to MetaVu to be overly significant. MetaVu expects that if Xcel Energy were to acquire another utility, the company would want to integrate the systems as much as possible. Due to the fact SmartGridCity™ systems run in an isolated environment, and that utility distribution grids are highly heterogeneous in composition and character, the demonstration project experience may not be directly applicable to a utility acquisition.

## VP 7.4 Higher Asset Utilization

### Benefit Category

Strategic

### Enabling Field System

N/A

### Hypothesis

By having better visibility and control of distribution loads, Xcel Energy can maximize the use of its generation facilities and contracts. This will reduce its desirability as an acquisition target. If the assets were vastly underutilized, a competitor or other utility may want to purchase Xcel Energy and use increased profits by improving asset utilization.

### Environment outside SmartGridCity™

Real time load data is available for the substation and feeders, but there is no real-time information about the distribution system or customer loads. The utility can control some loads, including the residential Saver's Switch program which turns off customers' air conditioning compressors.

### Environment within SmartGridCity™

With real-time visibility and control through programs such as Demand Response (DR), the utility will be able to reduce the difference between demand peaks and normal usage, and thereby increase generation asset utilization. This reduction between peak and normal times will require less excess capacity for safety margins.

### Actions Taken

N/A. Existing PSCO asset utilization is not significantly underutilized relative to other utilities and therefore would not be a contributing factor in a potential acquisition.

### Lessons Learned

- Underutilized distribution assets would never be enough reason for one utility to acquire another. However, if there is excess generation capacity either through owned plants or from contracts, it may make a utility an acquisition target.
- With the exception of DR and generation, smart grid systems were not found to significantly improve asset utilization.
- The DR program instituted in SGC is similar to the Saver's Switch program. Data from the pilot program will be available in 2012 and beyond to confirm any differences. MetaVu expects the incremental capabilities of Demand Response over Saver's Switch will not be significant enough to materially change utilization levels to the point where it will affect takeover strategies.
- Use of sufficiently greater consumption data along with analytics developed as part of the SGC project showed that existing Saver's Switch locations with defective equipment, and that they could be remotely identified, allowing for targeted maintenance.

### Conclusion

MetaVu believes the strategic benefit of this value proposition is low. Xcel Energy uses sophisticated algorithms to predict demand based on historical loads, new developments, consumption trends and more. In addition, there is accurate load data available from nearly all substations in PSCO. MetaVu does not feel that the additional distribution grid information will make a material difference and significantly change capacity utilization.

## VP 7.5 Higher Share Price through Commitment to Smart and Green Technologies

### Benefit Category

Strategic

### Enabling Field System

N/A

### Hypothesis

The SmartGridCity™ demonstration project and other smart grid activities will demonstrate to stock analysts and other relevant parties that Xcel Energy is committed to maximizing overall stakeholder value which will increase share price.

### Environment outside SmartGridCity™

Xcel Energy has invested or participated in many projects that demonstrate its commitment to all stakeholders. These include high levels of wind-sourced energy, a battery storage project, and others.

### Environment within SmartGridCity™

The SmartGridCity™ demonstration project was an illustration of Xcel Energy's commitment to preparing for the future while addressing the needs of many different stakeholders. The perception on the link between environmental performance and stock valuation is mixed.

### Actions Taken

N/A. The exact impact on share price is dependent on the specific mix selected.

### Lessons Learned

- Knowledge and experience gained from SmartGridCity™ may improve operations or investment strategies and increase returns to shareholders.
- As with other utility investments regulatory alignment is critical to achieving desired results, particularly since regulatory policies are still evolving.
- Learned that the proper mix of technologies and implementation strategies are likely to result in favorable economic benefits.

### Conclusion

MetaVu does not feel that the SmartGridCity™ project will significantly increase share price because of the demonstration project. There are many other corporate characteristics that have immediate and direct influence on share price versus integrating smart grid systems and green technologies. MetaVu believes that the "commitment to stakeholders" will not significantly impact share prices in the short-term.

## VP 7.6 Relationship with Regulators

### Benefit Category

Strategic

### Enabling Field System

N/A

### Hypothesis

With the experience gained from SmartGridCity™, PSCO can help shape state and federal policies and regulations. This could improve relationships with regulators and potentially lead to more favorable treatments.

### Environment outside SmartGridCity™

PSCO has invested or participated in many renewable energy and carbon abatement projects. These include high levels of wind-sourced energy, a battery storage project, and others

### Environment within SmartGridCity™

The SmartGridCity™ demonstration project, in part, explored the potential beneficial environmental impact from smart grid systems and customer facing programs. This is an additional environmental project in PSCO's portfolio.

### Actions Taken

N/A. This shared vision may reduce regulatory risk associated with stranded costs.

### Lessons Learned

- Because PSCO operates in a regulated environment, improved relationships with regulators that may result from grid modernization might help increase a utility's opportunity to earn its authorized rate of return.
- PSCO can use the SmartGridCity™ experience to provide details for testimony or other discussions to support investment and operational decisions.
- Learned that early and frequent interaction with regulators throughout the grid modernization development process is necessary to create a shared vision for the grid and associated value, as well as develop the most effective regulatory framework.

### Conclusion

With the experience gained in SmartGridCity™, PSCO has the information necessary to develop a business case for regulatory review while identifying smart grid investments and how such investments will benefit customers and grid operations.



## VP 7.7 Visible Activity in Green Technologies

### Benefit Category

Strategic

### Enabling Field System

N/A

### Hypothesis

If PSCO takes positive, visible steps to demonstrate its commitment to green technologies, relationships with customers and the community could be improved. This could lead to less resistance and opposition, and provide PSCO with more flexibility in meeting its corporate goals.

### Environment outside SmartGridCity™

PSCO has invested or participated in many renewable energy and carbon abatement projects. These include high levels of wind-sourced energy, a battery storage project, and others.

### Environment within SmartGridCity™

The SGC demonstration project was an illustration of PSCO's commitment to green technologies. There were many aspects of the demonstration project that were designed to reduce energy usage or carbon dioxide equivalent (CO<sub>2</sub>e) emissions.

### Actions Taken

As implemented in SGC, systems such as power factor improvement and conservation voltage reduction have shown to have positive environmental impacts such as fuel efficiency.

### Lessons Learned

- Many SGC capabilities offer direct customer participation opportunities, such as DR, time-of-use pricing and increased access to energy use data, may improve relationships with the customer and community-at-large.
- PSCO has not taken full advantage of the SGC demonstration project in this manner.
- Learned that the SmartGridCity™ demonstration project has contributed to PSCO's position as an environmental leader.

### Conclusion

Improved reputation among the community could be moderately beneficial through lower resistance to regulatory proposals. If customers and other community members are satisfied with the products and services that PSCO provides, including those provided in an environmentally responsible manner, they may be less critical of the utility.

## VP 7.8 Integration of New Technologies into Utility Systems

### Benefit Category

Strategic

### Enabling Field System

N/A

### Hypothesis

The SmartGridCity™ demonstration project experience will help PSCO determine how to implement and integrate new technologies to drive fundamental changes to the business.

### Environment outside SmartGridCity™

Power is generated at centralized facilities, transmitted to the substations and distributed throughout the grid. Power flow on the distribution network is primarily unidirectional, from the substation to the customer. Premises with distributed generation systems are mostly treated as normal loads with reduced demand and consumption.

### Environment within SmartGridCity™

Increased information will allow the utility to monitor power flows more accurately, and enable the utility to move away from the vertically integrated model. Power can be sourced from a variety of facilities, including traditional centralized generation plants as well as distributed generation and storage systems. Distributed generation sites are not just a reduced load, but a partner in delivering energy.

### Actions Taken

The implementation of a ubiquitous communications infrastructure serving both overhead and underground facilities is a key factor to SGC and all other future activities.

### Lessons Learned

- Systems changes required to integrate SGC technologies are known to many of the relevant employees and business areas.
- The data gathered from smart grid technologies can be used to understand how the business model and operations could change and prepare the utility for the future.
- Learned that the environment SGC created is ideal for technology and implementation testing that will continue to facilitate the integration of new technologies into utility systems and that personnel are generally very accepting of the new technologies.
- Legacy and new technologies will need to be integrated and function seamlessly during implementation.

### Conclusion

The SmartGridCity™ experience could be valuable in integrating new systems and processes into the existing business as the utility prepares for new opportunities. The primary example of SGC technologies that have been leveraged into utility processes and systems is the INDE BUS architecture.

## VP 7.9 Carbon Management Technologies to Improve Carbon Output

### Benefit Category

Strategic

### Enabling Field System

N/A

### Hypothesis

The SmartGridCity™ systems could be used to track, measure and manage carbon dioxide equivalent (CO<sub>2</sub>e) emissions and related characteristics.

### Environment outside SmartGridCity™

CO<sub>2</sub>e emissions are measured at the generation stations. Some emissions changes are difficult to attribute to specific programs, specifically residential programs because there is insufficient data.

### Environment within SmartGridCity™

Additional data about customer consumption patterns and response to smart grid programs can be used to attribute emissions reduction to specific programs. SmartGridCity™ provides the capabilities to track reductions of overall consumption or loads shifted to different time periods. These capabilities can be used to evaluate emissions reduction programs.

### Actions Taken

As implemented in SGC, systems such as power factor improvement and conservation voltage reduction have shown to have positive environmental impacts such as fuel efficiency.

### Lessons Learned

- Without the customer-level CO<sub>2</sub>e emission tracking capabilities provided by SGC, many program benefits would be estimated using basic estimation tools, leading to sub-optimal investment strategies.
- PSCO's recently implemented environmental management information system (EMIS) was designed to track emissions for all operating sources.
- Learned that SmartGridCity™ systems provide the capabilities to track reductions of overall consumption or loads shifted to different time periods.

### Conclusion

Benefits plausible, the effectiveness of existing tools and processes are sufficient to prepare the utility to measure and manage CO<sub>2</sub>e emissions and related characteristics. Programmatic reporting benefits may be utilized at the customer-level that would enhance programs that result in carbon dioxide equivalent (CO<sub>2</sub>e) emissions reduction.

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