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Governor

THE VALUE OF DISTRIBUTION AUTOMATION

PIER FINAL PROJECT REPORT

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

The Value of Distribution Automation is the final report for contract number 500-06-012 conducted by Navigant Consulting, Inc. for the Distribution Research Program. The information from this project contributes to PIER's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-4878.

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Abstract

This study quantifies the economic benefits of integrating distribution automation into the electric distribution systems of California's investor-owned utilities. Distribution automation is a family of technologies and protocols, including sensors, processors, communications, and switches, that can remotely control and monitor certain electrical distribution system operations, with little or no human involvement. This study applies a structured approach that develops a hierarchy that links the electric industry's key business needs with distribution automation technologies by defining 12 high-level application concepts, and then analyzing each based on a set of 15 technology-based functions that provide a range of potential benefits. These benefits are organized into 10 benefit categories, which apply to one or more of three stakeholder groups: the utilities, their customers, and society.

Distribution automation could provide a maximum expected annual benefit for California of approximately $600 million. This benefit is the result of increased distribution system reliability, improved efficiency, and the ability to increase penetration of distributed energy resources, such as demand response, photovoltaics, and combined heat and power, that otherwise could not be achieved absent the flexibility offered by distribution automation. Distribution automation provides 50 percent of all benefits to utilities with the remainder split nearly equally between customers and society.

Keywords: Distribution automation, distributed energy resources, distribution system, reliability, distributed generation

Executive Summary

Purpose

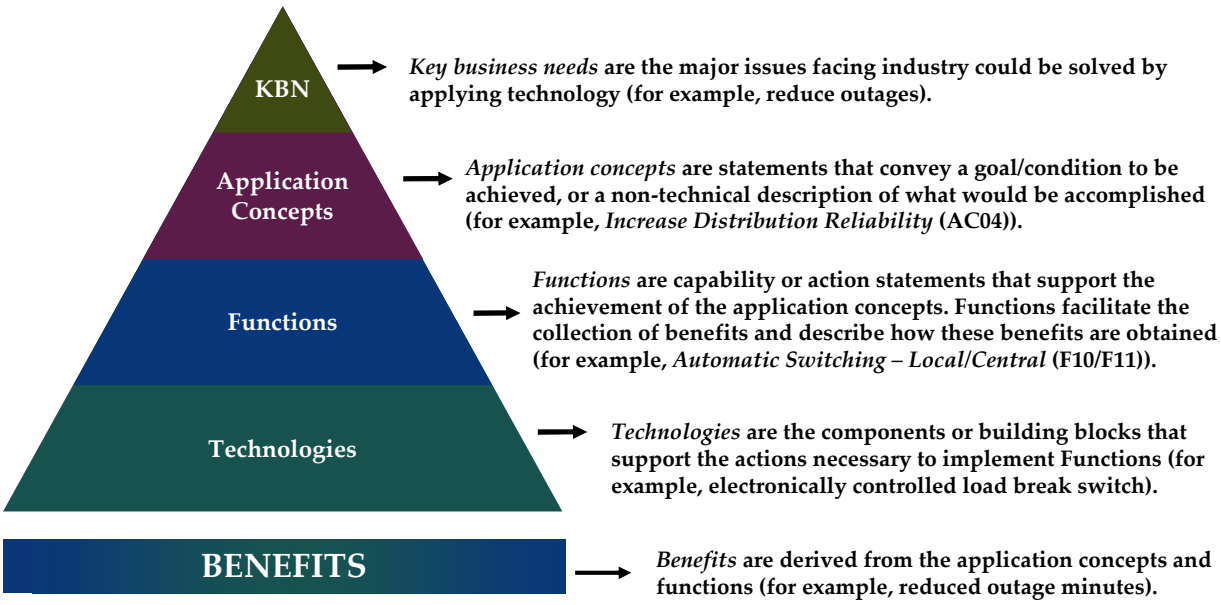
This report, *The Value of Distribution Automation*, is the second of two reports commissioned by the Distribution Research Program within the California Energy Commission's Public Interest Energy Research (PIER) Program to determine how distribution automation[1] might provide value to certain stakeholder groups, broadly defined as the three major investor-owned California electric utilities, their customers, and society. The first report, *Value of Distribution Automation Applications* (April 2007), analyzed individual distribution automation technologies qualitatively. This study quantifies the potential economic benefits of strategically using distribution automation in the electric distribution grids of California's investor-owned electric utilities: Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison. The high-level quantification of distribution automation benefits was based on a combination of published data and professional assumptions. This study builds upon the initial findings, including methods to quantify and assign benefits to stakeholders.

Method

This study uses a top-down approach. First, a set of key business needs of the California's three investor-owned electric utilities were identified (for example, reduce outages). Next, a set of high-level goals that may address those key business needs via distribution automation was developed (for example, increase distribution reliability). These goals are called application concepts. Then, a set of functions was developed, based on the capabilities of distribution automation technologies that could be used to implement the application concepts. Functions are not exclusive to a particular application concept and were sometimes combined to achieve a given application concept.

Finally, a set of potential economic benefits was defined based on 2005 data. The value of a benefit is (1) based on the California investor-owned utilities' data (or on professional judgment vetted with the utilities' expert personnel where data are insufficient) and (2) expressed in dollars per unit. Each benefit is associated with a function, and a function may have more than one benefit. Thus, depending on the market penetration of a certain function within an application concept, a total benefit can be calculated per application concept. The following diagram illustrates the hierarchy of this approach.

1. Distribution automation is a family of technologies and protocols, including sensors, processors, communications, and switches, that can remotely control and monitor certain electrical distribution system operations with little or no human involvement.



Distribution Automation Analytical Framework
Source: Navigant Consulting, Inc

The study employed an Excel-based model that enabled the mapping of functions to application concepts in various combinations, and at various market penetration levels or utilization rates in order to estimate the potential benefits of an application concept. As a simplifying assumption, benefits were calculated as if the application concept could be instantaneously and completely implemented on the existing grid.

Since some functions are not yet commercially available, three time horizons were applied: near-term (between 0 and 5 years), mid-term (between 5 and 15 years), and long-term (greater than 15 years). For example, Southern California Edison expects to automate all existing switched capacitor banks (which provide voltage and volt-amperes reactive control) by 2008, so the function *Automatic Voltage and VAR Control* (F01) is defined as near-term. Alternatively, utilities are still in the initiative/exploration stage for reliability differentiation (microgrids[2]), so the function *Automatic Islanding and Resynchronization* (F14) is defined as long-term.

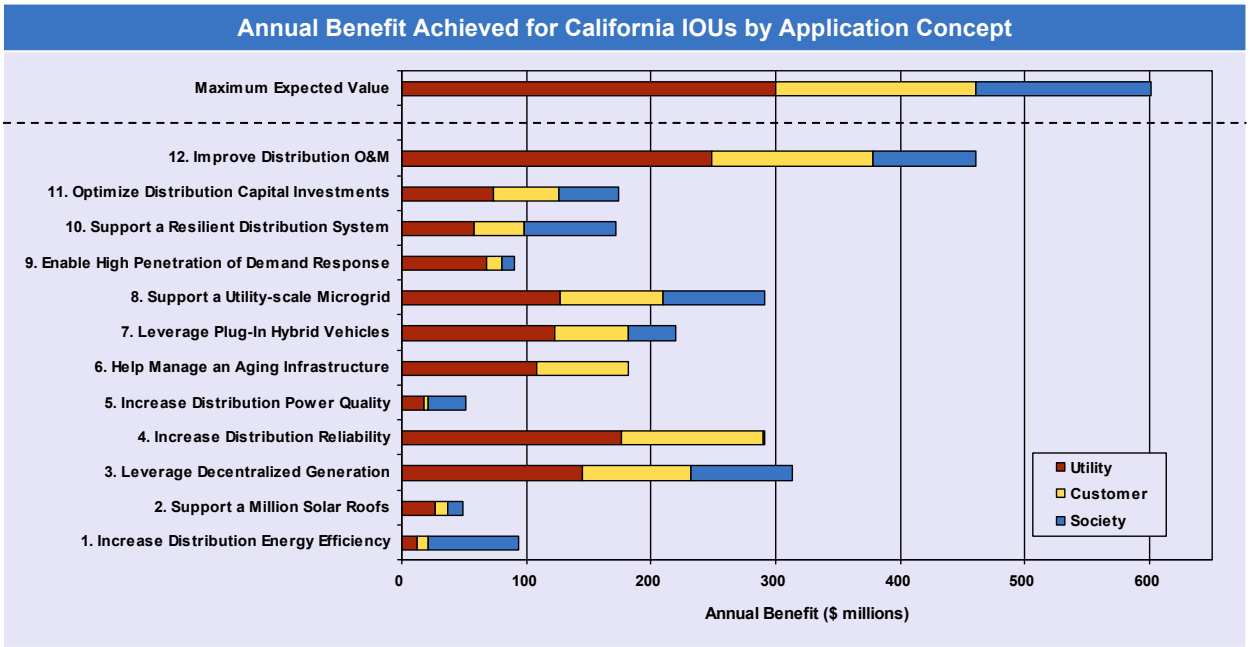
Results

A full-scale, instantaneous deployment of distribution automation in California in 2005 could produce approximately $600 million in annual benefits. The application concepts that exhibit the greatest value include those that improve reliability and reduce operations and maintenance

2. A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources that, as an integrated system, can operate in parallel with the grid or in an intentional "island" mode within a grid. (Navigant Consulting. May 2006. *Microgrids Research Assessment – Phase 2 Final Report*).

costs. Notably these are areas where utilities have traditionally sought to derive benefits via use of distribution automation technologies. The results also highlight a second area where distribution automation may provide significant benefits: leveraging distribution automation to support higher penetrations of distributed energy resources, including distributed generation, plug-in hybrid vehicles, photovoltaics (PV) and demand response technologies. Improvements in reliability represent approximately 54 percent of total benefits, with a maximum expected benefit of $292 million, while the balance of the total benefit is attributable to environmental and cost savings with 22 percent and 24 percent, respectively.

The following chart compares the relative value of the benefits derived for each application concept. It also displays a maximum expected value. Since each function may be embedded in more than one application concept, the sum of the individual application concepts does not equal the maximum expected value.



Annual Benefit of DA by Application Concept

Distribution automation provides roughly equal amounts of benefit for the collective utilities and for the public (customers and society). Distribution automation adds benefits by increasing the distribution system's reliability (decreased duration and frequency of power outages), efficiency (system and energy loss savings), and flexibility (enabling higher penetrations of distributed energy resources).

The management of an aging distribution infrastructure is one of the most important issues facing utilities nationwide. The authors postulate that utilities initially will limit distribution automation deployment to bolster their aging distribution systems; that is, maximize value by capturing the greatest net benefit by using the fewest number of functions. For all stakeholders to realize the full potential benefits of distribution automation, the Energy Commission may

need to encourage the deployment of other functions that do not provide utilities with an immediate return on their investment.

The $600 million maximum benefit may be viewed from another perspective: $312 million of the total is derived from the increased penetration of distributed energy resources achieved by distribution automation. These benefits are mostly from reliability, environmental, and cost savings categories. These incremental benefits include system benefits (increased energy loss savings and storage capacity), economic benefits (increased customer savings, and savings in transmission and distribution capital and demand losses), and environmental benefits (decreased nitrous oxides, sulfur oxides, and carbon dioxide emissions).

Recommendations

For California to achieve the maximum expected benefit from distribution automation, the Distribution Research Program should support research to answer several key questions, based on the state of the technologies associated with distribution automation, as well as the integration and implementation challenges facing California's utilities:

- Can low-cost sensors and sensor networks be developed and deployed in sufficient numbers to monitor distribution networks at a resolution sufficient for distribution automation?
- As distribution automation equipment is installed, will the resulting wide variety of new and legacy equipment communicate reliably and operate in a coordinated fashion?
- How can the large quantity of data associated with a full-scale deployment of distribution automation be managed, and how can this data be converted to useful information?

Research needs include demonstrations, performing research on specific functions, developing underlying technology required for high priority functions, and supporting standards and interoperability work. The table below lists key challenges for distribution automation penetration, along with the application concepts and functions those challenges affect.

Distribution Automation Challenge	Research Needs and Recommendations
Lack of demonstration of distribution automation value **Value is shared by utilities, customers, and society**	**Demonstrate near-term application concepts:** *Support Million Solar Roofs* (AC2) *Enable Large Penetration of Demand Response* (AC9)
Required functions are not available	**Perform research into mid-term functions:** *Automatic Conditioned Based Maintenance* (F12) – Understand correlation between equipment operating life (stress and age) and remaining life *Automatic Protection Reconfiguration* (F08) – Understand under what conditions protection schemes and settings would change *Automatic Protection Reconfiguration* (F08) – Understand how fast modes would have to change and if current technology could meet these requirements *Automatic Protection Reconfiguration* (F08) – Understand the current capability of relays and control devices to change settings
Commercial technologies do not exist to support functions	**Develop technologies that are required for mid-term functions:** *Automatic Condition Based Maintenance* (F12) – Understand which equipment and which parameters need to be measured. Understand what capabilities already exist *Automatic Condition Based Maintenance* (F12) – Develop low-cost, low power, long-life, robust sensors and sensor networks *Automatic Protection Reconfiguration* (F08) – Develop low-cost, low-power, long-life, robust sensors and sensor networks *Isolation of High Impedance Faults* (F08) – Advanced sensors that distinguish between faults and high load currents or detect fault currents that may be too weak to trigger conventional protection systems. This may include high-resolution sensors, use of fault signatures and coordinated measurement among multiple devices.
Lack of standards will slow full-scale deployment of distribution automation technologies	Support development of communication and interoperability standards where appropriate Understand back compatibility of legacy equipment and equipment that will be deployed in near future Understand the data management issue, create data hierarchy and standards for data management

Research Needs and Recommendations

Source: Navigant Consulting, Inc.

1.0 Introduction

The feasibility of meeting California's future energy demand by constructing large electric generating stations is becoming more constrained every year. Distribution automation (DA) has the potential to increase the efficiency and utilization of the electric distribution system, and enable greater cost-effective penetration of distributed energy resources (DER) as an alternative to building new central generating stations, and expanding the transmission and distribution delivery systems.

DA can help address the following challenges:

- **Transmission Constraints**: Many existing electric transmission lines in California are congested and unable to accommodate additional generation. In addition, expanding the transmission system to bring new power plants online raises significant environmental issues, particularly for wind and solar generation, which tend to be sited in remote areas requiring extensive transmission line construction.
- **Integrated DER**: Integrating and leveraging DER, including photovoltaics (PV), combined heat and power (CHP), demand response (DR), and plug-in hybrid electric vehicles (PHEV) is a critical challenge that California must overcome to meet its environmental and energy reliability needs.
- **End-Use Technologies**: The development of increasingly diverse and sophisticated end-use technologies including smart appliances, PHEV, and DR will require a means for integration and optimization.
- **Energy Efficiency**: The distribution system accounts for a higher share of delivery losses than transmission, and may offer a larger opportunity for improvements in efficiency.
- **New Energy Business Models**: Emerging energy business models, such as aggregated DER, lack the intelligent electrical and communications infrastructures to support them.

The Energy Commission's Distribution Research Program (DRP) commissioned two studies to determine how DA provides value to certain stakeholder groups. The first study, *Preliminary Assessment: Value of Distribution Automation Applications*,[3] was issued in April 2007 and examined the results from existing and expected investments in DA by national and international utilities. This work provided a qualitative assessment of how DA adds value for improving operational efficiency, peak load management, prediction of equipment failures, and system restoration after failures.

The second study, which is the subject of this report, presents an analytical framework that quantifies DA's potential benefits if fully deployed in the service areas of California's three major investor-owned electric utilities (IOUs).[4] This study uses public data from the California

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3. Price, Snuller, et al. 2006. *Preliminary Assessment: Value of Distribution Automation Applications*. California Energy Commission, PIER. Publication No. CEC 500-2007-028.

4. The IOUs included are Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE).

Public Utilities Commission (CPUC), the Energy Commission, general rate case documents of the California IOUs, the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC), among other sources, as well as the authors' own estimates which were developed with the input of utility experts.

2.0 Methods

This study uses a top-down approach. First, a set of key business needs of the three IOUs were identified (for example, reduce outages). Next, a set of high-level goals that may address those key business needs via DA was developed (for example, increase distribution reliability). These goals are called application concepts. Then, a set of functions was developed, based on the capabilities of DA technologies that could be used to implement the application concepts. Functions are not exclusive to a particular application concept and were sometimes combined to achieve a given application concept.

Finally, a set of potential economic benefits was defined based on 2005 data. The value of a benefit is (1) based on the IOUs' data (or on professional judgment vetted with IOU expert personnel where data is insufficient) and (2) expressed in dollars per unit. Each benefit is associated with a function, and a function may have more than one benefit. Thus, depending on the market penetration of a certain function within an application concept, a total benefit can be calculated per application concept. Figure 1 illustrates the hierarchy of this approach.

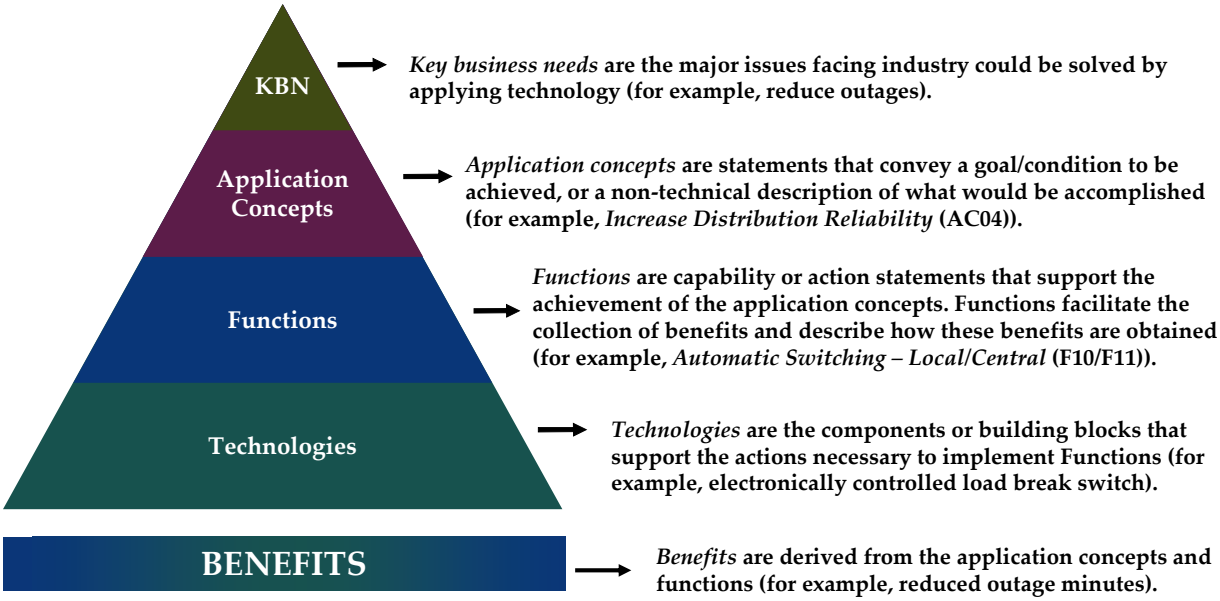

Figure 1. DA Analytical Framework
Source: Navigant Consulting, Inc

The study employed an Excel-based model that enabled the mapping of functions to application concepts in various combinations, and at various market penetration levels or utilization rates in order to estimate the potential benefits of an application concept. As a simplifying assumption, benefits were calculated as if the application concept could be instantaneously and completely implemented on the existing grid.

2.1. Application Concepts

The DRP is part of the Energy Commission's Public Interest Energy Research (PIER) Program, and as such, has an interest in understanding and supporting those technologies that directly and indirectly add value for a broad group of California stakeholders. Part of the challenge of public interest research and development is communicating very technical material in a way that both practitioners and non-practitioners understand and find useful. Application concepts are designed with this goal in mind.

Application concepts are statements that convey a goal or condition in which a significant deployment of DA could add value. These high level statements are intended to provide a non-technical description of what is to be accomplished. The application concepts developed for this study address the energy challenges identified in Section 1.0 as well others identified by the IOUs and certain interviewed customers[5], which include reliability, efficiency, and flexibility.

This study analyzed 12 application concepts[6] to enable the DRP to better understand the role that DA could play in addressing some of California's current energy challenges, and to help the DRP assess its role in influencing DA deployment.

- Increase Distribution Energy Efficiency (AC01)
- Support a Million Solar Roofs (AC02)
- Leverage Decentralized Generation (AC03)
- Increase Distribution Reliability (AC04)
- Increase Distribution Power Quality (AC05)
- Help Manage an Aging Infrastructure (AC06)
- Leverage Plug-In Hybrid Electric Vehicles (AC07)
- Support a Utility-Scale Microgrid (AC08)
- Enable High Penetration of Demand Response (AC09)
- Support a Resilient Distribution System (AC10)
- Optimize Distribution Capital Investments (AC11)
- Improve Distribution Operations and Maintenance (AC12)

The following sections describe each of the application concepts developed for this study.

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5. Customer groups include the Utility Consumers' Action Network and the San Francisco Electric Cooperative.

6. Five additional Application Concepts were eliminated from the analysis due to IOU and customer stakeholder input. These were: *Support a Retail Energy Exchange*; *Support Service Quality Choice*; *Support Economic Development*; *Public Safety*; and *Data Mining*.

2.1.1. Increase Distribution Energy Efficiency (AC01)

AB 32 (California Global Warming Solutions Act of 2006) and SB 1368 will require reductions in greenhouse gas (GHG) emissions. As DA is implemented, sensors throughout the distribution system will support better situational awareness, analytical tools will support enhanced decision-making, and control devices can take action. All of this will enable utilities to optimize the performance of the distribution system to maximize the utilization of the system and reduce energy losses. This would require resources throughout a distribution area, including capacitors, transformer load-tap changers, and voltage regulators, to have the ability to communicate and coordinate; it may also require system reconfiguration.

2.1.2. Support a Million Solar Roofs (AC02)

In 2006 CPUC approved and authorized the California Solar Initiative to achieve a goal of 3,000 MW of new, solar-produced electricity by 2017. The California Legislator in 2006 also passed the Million Solar Roofs Initiative, complementing the actions of the CPUC. The majority of PV systems will be interconnected to the distribution system. DA could provide a cost effective platform for monitoring high penetrations of PV at the distribution level.

2.1.3. Leverage Decentralized Generation (AC03)

California's Energy Action Plan II encourages distributed generation (DG), which includes both PV and CHP. DG systems produce power where it is being consumed, avoiding transmission and distribution (T&D) losses. DG can provide important benefits for utilities and their customers. While PV systems will likely be accommodated passively due to the intermittent nature of the resource, other DG resources such as CHP can be actively dispatched and controlled. In addition to enabling higher penetration of PV, *Support a Million Solar Roofs* (AC02), DA could play an important role in supporting control of these resources.

2.1.4. Increase Distribution Reliability (AC04)

Reliability improvement is one of the most common reasons cited by utilities for implementing DA. Automatic or remote controlled switches installed on distribution circuits enable utilities to isolate faults more quickly, and reduce the amount of time many customers are without power. This application, becoming known in the industry as “Fault Location, Isolation, and Service Restoration” (FLISR), can yield significant reductions in outage minutes experienced by customers. By combining FLISR capabilities with advanced sensors and controls that enable automatic condition-based equipment maintenance, DA could yield even greater reliability improvements.

2.1.5. Increase Distribution Power Quality (AC05)

Power quality can be affected by a number of factors throughout the T&D systems, but also from within the electrical systems of end users. DA can contribute to higher power quality by better controlling voltage throughout the distribution system. Sensor networks and information from DA systems will also help utilities identify and mitigate situations where power quality is below targets.

2.1.6. Help Manage an Aging Infrastructure (AC06)

Despite massive T&D capitalization efforts underway throughout the country, much of the existing infrastructure is reaching or exceeding its estimated useful life. Infrastructure failures are costly in terms of reliability impact and repair, so any ability to prevent failures or mitigate their impacts will provide significant benefits to all stakeholders. DA can add value by:

- isolating failures to limit interruption to fewer customers;
- avoiding the stress placed on aging infrastructure by "through-fault" current from conventional reclosing; and
- monitoring equipment condition to diagnose potential failures before they occur.

2.1.7. Leverage Plug-In Hybrid Electric Vehicles (AC07)

PHEVs may offer benefits that are similar to those provided by DG. For example, utilities may "dispatch" groups of PHEV for purposes such as meeting peak demand, known as vehicle-to-grid or V2G.

2.1.8. Support a Utility-Scale Microgrid (AC08)

With developments in distribution system technologies and DER, it is expected that the distribution system will evolve to include increasing levels of DG (PV and CHP), energy storage (for example, PHEV), and DR. DA will enable the implementation of microgrids which will coordinate these technologies to improve the reliability, stability, and security of the electric grid.

2.1.9. Enable High Penetration of Demand Response (AC09)

Higher penetrations of DR will be an important resource in California as peak loads continue to increase. DR can be used by system operators as a resource to mitigate increasing loads to address peak loads on the entire system, in a planning area, at a substation, and on a feeder.

2.1.10. Support a Resilient Distribution System (AC10)

Emergency response and system restoration after major events are critical to utilities and the customers they serve. Heat storms, high winds, and seismic events all pose a threat to distribution systems in California. DA will enable utilities to optimally reconfigure the distribution following major outage events, and restore service more quickly.

2.1.11. Optimize Distribution Capital Investments (AC11)

DA will enable utilities to optimize the distribution system and get better system performance from investments in capital. Greater visibility into system conditions and utilization will improve asset optimization and capital prioritization efforts. In some cases, it will be possible to defer capital investment by reconfiguring parts of the system to manage peak load conditions. It may also be possible to optimize parts of the system to improve capacity factor and resource efficiency. All of this could lead to greater capital efficiency and cost reductions related to capital.

2.1.12. Improve Distribution Operations and Maintenance (AC12)

Distribution operations and maintenance is a labor intensive business requiring highly skilled crews and expensive equipment. By applying automation and detection technologies to the distribution system, utilities can reduce the amount of time crews spend on routine activities such as switching, fault location and equipment inspection and maintenance.

2.2. Functions

The following section describes the 15 functions developed for use in this study.[7] As defined earlier, functions are the capability or action statements that support the achievement of objectives described in the application concepts. A function represents the capability that a utility would realize by implementing a DA technology or set of DA technologies. Functions fall into three action categories: observe; analyze/decide; and execute (Figure 2).

Action	Role of DA	Example Functions
Observe	Electrical and environmental sensors throughout the distribution system acquire data with a fidelity sufficient to provide a near-real time operating picture.	• Low Impact Fault Detection (F13) • DER Monitoring (F05)
Analyze/Decide	Models and algorithms turn large quantities of sensor data into information that can be used for human decision support and autonomous control.	• Optimum Power Flow Analysis (F04) • Automatic Condition-Based Maintenance (F12)
Execute	Electro-mechanical equipment responds to control decisions to perform switching and adjust operating points throughout the distribution system.	• Automatic Voltage and VAR Control (F01) • Automatic Islanding and Resynchronization (F14)

Figure 2. Overview of DA Functions
Source: Navigant Consulting, Inc.

The 15 functions are:[8]

- Automatic Voltage and VAR Control (F01)
- Automatic Feeder Reconfiguration – Single (F02)
- Automatic Feeder Reconfiguration – Multi-Level (F03)

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7. Two functions (*Automatic Phase Load Balancing* and *Real-Time Communications from the Customer to the Utility*) were specified during the study, but were not used in the analysis. Therefore, they do not appear in subsequent sections of this report.

8. Refer to Xanthus Consulting International's report, *Preliminary Assessment: Value of Distribution Automation Applications*, for further information on specific technology options.

- Optimum Power Flow Analysis (F04)
- DER Monitoring (F05)
- DER Control by Unit (F06)
- DER Control by Class (F07)
- Automatic Protection Reconfiguration (F08)
- Isolation of Higher Impedance Faults (F09)
- Automatic Switching – Local (F10)
- Automatic Switching – Central (F11)
- Automatic Condition-Based Equipment Maintenance (F12)
- Low-Impact Fault Detection (F13)
- Automatic Islanding and Resynchronization (F14)
- Real-Time Communications from the Utility to the Customer (F15)

2.2.1. Automatic Voltage and VAR Control (F01)

Sensors, controls and communications are present throughout the distribution system to support the coordinated operation of reactive power resources, including capacitor banks, voltage regulators, transformer load-tap changers, and DER; particularly devices with adjustable power factor. Voltage and VAR control can be initiated by a system operator based on operating strategy(ies), or in response to a local or regional contingency or outage event. This function also includes the ability to adjust or optimize distribution power factor to reduce losses or meet power factor targets.

2.2.2. Automatic Feeder Reconfiguration – Single (F02)

Individual feeders can be reconfigured and optimized, including coordinated switching on the primary feeder or its laterals, or with an adjacent feeder. This may be in response to an outage, in which case a portion of the feeder load may be transferred to an adjacent feeder. It may also enable optimization of the feeder with respect to peak load levelization, resulting in improved system efficiency (capital investment and operations and maintenance costs) and reduced losses.

2.2.3. Automatic Feeder Reconfiguration – Multi-Level (F03)

Multiple distribution feeders in an area may be reconfigured and optimized, including those with tie points to one or more substations. This may be in response to an outage, in which case one or more feeders (or portions thereof) may be reconnected to restore service after widespread outages. Feeders may also be temporarily or permanently reconfigured to optimize loading on key equipment such as substation power transformers. It may also enable optimization of the feeder with respect to peak loads, which results in improved system efficiency (capital investment and operations and maintenance costs) and reduced losses.

2.2.4. Optimum Power Flow Analysis (F04)

Real-time monitoring and analysis enables real-time access of system conditions, including power flows, DER status, voltages, and distribution equipment and switch status. This enables distribution operators to make informed operating decisions with regard to system performance, reliability, power quality, losses and asset utilization. With real-time transfer of data to simulation models, it can also provide distribution system conditions and status in sufficient detail to accurately predict system response to varying load, voltage, generation, and switching configurations.

2.2.5. DER Monitoring (F05)

Individual DER units are monitored for status and output, and this information is available to utility staff in near-real-time. Utilities can track DER location and output, but this function excludes remote DER switching or control.

2.2.6. DER Control by Unit (F06)

Individual DER units are controlled independently by utilities in near real-time. Control may be accomplished by operator actions or autonomously through DA control systems. The objective is to control loading on specific equipment or circuits, or to improve distribution system efficiency and performance.

2.2.7. DER Control by Class (F07)

Individual DER units are controlled in groups or classes, typically by utilities or third-party operators, in near-real-time. Control may be accomplished by operator action or autonomously through agents that execute common control actions across multiple units. The objective is to improve distribution system efficiency and performance objectives across an area, or the power system as a whole.

2.2.8. Automatic Protection Reconfiguration (F08)

The settings of protective relaying and control devices are adjusted in response to system conditions or operator input. Sensors in the distribution system can detect changes in circuit or equipment status, current and voltage, so that protection systems can automatically adjust to changing system conditions or line configuration. This capability addresses circuit loading and two-way power flow issues associated with high DER penetration.

2.2.9. Isolation of Higher Impedance Faults (F09)

Advanced sensors provide improved protective coordination, including avoidance of unintended feeder tripping for high load currents, and to detect fault currents that may be too low to trigger conventional protection systems. This will enable faster isolation of high impedance faults, which can minimize safety hazards and reduce damage to equipment and property.

2.2.10. Automatic Switching – Local (F10)

Sensors, controls and switching devices exist that can operate autonomously in response to local system conditions. This may include local communications among a limited set of devices and local controllers. The function can be used to isolate faulted portions of distribution circuits to

reduce the duration and scope of power outages. It can also reduce the amount of time and effort required for crews to travel between switch positions to operate the devices manually.

2.2.11. Automatic Switching – Central (F11)

Switches will operate automatically in response to signals from a central distribution management system. This will require local sensors and switching devices, plus a communication and control system capable of initiating control actions from a central location.

2.2.12. Automatic Condition-Based Equipment Maintenance (F12)

Distribution equipment (for example, transformers, switches, cable, capacitors) includes sensors that can monitor its condition and report this information periodically, such as polling data to a central location. This information will be used to notify utilities when equipment condition indicates a need for maintenance, or when there is an elevated probability of failure. The objective of this function is to increase the performance and reliability of distribution equipment, while reducing the cost of maintenance.

2.2.13. Low-Impact Fault Detection (F13)

Sensors exist that can detect and isolate faults without full power reclosing, which reduces equipment damage caused by repeated through-fault currents. The speed of fault location is also increased to reduce the impact of power outages and improve power quality. The objective of the function is to reduce the stress on T&D infrastructure, which could prolong its remaining life and reduce the likelihood of equipment failure.

2.2.14. Automatic Islanding and Resynchronization (F14)

Portions of the distribution system, including loads and distributed energy resources, can be electrically islanded (isolated) from the rest of the utility system. The island can then be reconnected to the utility system when needed or desired by the microgrid operator. This capability is fundamental to the microgrid concept, which could be applied to provide value for loads within the microgrid, and also for utilities to enhance operating flexibility in portions of the system.

2.2.15. Real-Time Communications from the Utility to the Customer (F15)

Utilities can communicate directly to customers in real time to provide information such as price signals, system conditions, restoration times, and safety advisories. This capability may involve other technologies and infrastructure such as advanced metering infrastructure (AMI); the DA infrastructure also could facilitate distribution data collection and management.

2.3. Benefits

As used in this study, benefits are discrete attributes with corresponding values received by stakeholders, which were developed using IOU input and professional judgment. The model ascribes value to application concepts and functions by assembling different combinations from a standard set of benefits, according to the scenario being modeled.

This study developed ten benefit categories, into which each discrete benefit attribute/value was placed:

- Reliability (BC01)
- Power Quality (BC02)
- Customer Value (BC03)
- Energy Efficiency (BC04)
- System Efficiency (BC05)
- Environment (BC06)
- T&D Capital Savings (BC07)
- T&D Operations and Maintenance Savings (BC08)
- Theft (BC09)
- Safety (BC10)

2.3.1. Reliability (BC01)

A reduction in the number and duration of sustained outages results in faster service restoration, fewer affected customers, and reduced utility costs.

2.3.2. Power Quality (BC02)

A reduction in harmonic distortion, fewer and less severe voltage sags and surges, causes less damage to customer-owned equipment and lost production.

2.3.3. Customer Value (BC03)

Customer electric bill savings results from PV and CHP installations at customer locations.

2.3.4. Energy Efficiency (BC04)

A reduction in peak demand and energy losses results from an improved power factor, ability to reconfigure system loads, and higher DER penetration.

2.3.5. System Efficiency (BC05)

A reduction in reserve margin requirements results from higher DER penetration.

2.3.6. Environment (BC06)

Reductions in particulate (sulfur oxides and nitrous oxides) emissions and carbon footprints result from a decrease in losses and higher DER penetration, particularly renewables.

2.3.7. T&D Capital Savings (BC07)

A reduction in carrying costs based on avoided capital expenditures results from higher utilization of T&D and substation capacity and extended equipment life.

2.3.8. T&D Operation and Maintenance Savings (BC08)

A reduction in distribution equipment maintenance costs results from improved productivity of labor and improved preventative maintenance scheduling.

2.3.9. Theft (BC09)

A reduction in revenue losses results from increased visibility into system operations and monitoring of load anomalies.

2.3.10. Safety (BC10)

A reduction in the number of safety incidents results from near real-time equipment monitoring, which better enables operators' decision-making.

2.4. Analytical Framework and Timeline

The modeling in this study assumes full deployment (integration and operation) of the functions associated with the application concept being tested, primarily on the distribution system, including devices capable of central/remote and peer-to-peer communications. This effort does not include a complete business case study for DA technologies as it focuses solely on potential benefits, and excludes costs for new or expanded infrastructure necessary for full deployment. For example, this study does not incorporate the costs for installing DA technologies such as automated switches on feeders.

Each application concept is supported by a different set of functions. Each function requires certain technologies. The commercial availability of these technologies impacts the timing for the implementation of each function. Assumptions were made about when the technologies would become available for wide-scale implementation. Table 1 presents the timeline for the realization of functions. Three time horizons were used: near-term (between 0 and 5 years), mid-term (between 5 and 15 years), and long-term (greater than 15 years). For example, Southern California Edison expects to automate all existing switched capacitor banks (which provide voltage and VAR control) by 2008,[9] so the function *Automatic Voltage and VAR Control* (F01) is defined as near-term. In contrast, utilities are still in the initiative/exploration stage for reliability differentiation (microgrids[10]), so the function *Automatic Islanding and Resynchronization* (F14) is defined as long-term.

9. Price, et al 39-40.

10. A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which as an integrated system can operate in parallel with the grid or in an intentional "island" mode within a grid. (Navigant Consulting, Microgrids Research Assessment – Phase 2 Final Report, May 2006).

Function	Timeframe
1. Automatic Voltage and VAR Control	Near
2. Automatic Feeder Reconfiguration - Single	Long
3. Automatic Feeder Reconfiguration – Multi-Level	Long
4. Optimum Power Flow Analysis	Long
5. DER Monitoring	Near
6. DER Control by Unit	Near
7. DER Control by Class	Mid
8. Automatic Protection Reconfiguration	Mid
9. Isolation of Higher Impedance Faults	Mid
10. Automatic Switching – Local	Near
11. Automatic Switching – Central	Mid
12. Automatic Condition-Based Equipment Maintenance	Mid
13. Low-Impact Fault Detection	Long
14. Automatic Islanding and Resynchronization	Long
15. Real-Time Communications from the Utility to the Customer	Mid

Table 1. Timeline for Realization of Functions

Source: Navigant Consulting, Inc.

Similarly, Table 2 presents the timeframes derived for each application concept. The application concepts *Support a Million Solar Roofs* (AC02) and *Enable High Penetration of Demand Response* (AC09) can be realized within the next five years because the functions that support these application concepts are also near-term. Meanwhile, at least one of the functions that support the other application concepts is either mid- or long-term.

Application Concept	Timeframe
1. Increase Distribution Energy Efficiency	Long
2. Support a Million Solar Roofs	Near
3. Leverage Decentralized Generation	Long
4. Increase Distribution Reliability	Long
5. Increase Distribution Power Quality	Long
6. Help Manage an Aging Infrastructure	Long
7. Leverage Plug-In Hybrid Vehicles	Mid
8. Support a Utility-Scale Microgrid	Long
9. Enable High Penetration of Demand Response	Near
10. Support a Resilient Distribution System	Long
11. Optimize Distribution Capital Investments	Long
12. Improve Distribution Operations and Maintenance	Long

Table 2. Timeline for Realization of Application Concepts

Source: Navigant Consulting, Inc.

The timeline for the realization of application concepts shows that stakeholders may realize the benefits of a given application concept at different times, and that most of these will be realized over the long term. As a simplifying assumption in the model, benefits were calculated as if the

application concept could be instantaneously and completely implemented on the existing grid. Thus, only portions of the $600 annual maximum expected value of implementing DA could be realized today.

2.5. Overview of the Model

The study employed an Excel-based model that allows functions to be mapped to application concepts in various combinations at various market penetration levels or utilization rates in order to estimate the potential benefit of implementing a given concept. As a simplifying assumption, benefits were calculated as if the application concept could be instantaneously and completely implemented on the existing grid.

2.5.1. Goals and Modeling Criteria

The goal of this study is to provide DRP program managers with the size and scope of potential benefits from a full deployment of DA in California. The following criteria shaped the modeling approach where possible:

- Support both strategic and tactical program decisions.
- Create a common basis for diverse benefits accruing to multiple stakeholders.
- Identify assumptions.
- Use publicly available data.
- Use simple calculations that can be easily communicated and discussed.
- Make adjustments simple and transparent.

2.5.2. Model Structure

At the heart of the model are two tables. The first table lists the functions as rows and the application concepts as columns. The modeler assigned the appropriate set of functions to each application concept by enabling them in the intersecting cell with a Y for "Yes, include this function in this application concept." The second table again lists the functions as rows, with the benefits as columns, and assigned and enabled the appropriate benefits per function, as above. See Figure 3.

Key Points:

- Each benefit is discrete, and has a unit value that is expressed in dollars per unit.
- Benefits are calculated in terms of the maximum expected annual dollars saved (avoided costs) for the three California IOUs from a full deployment of DA.
- Benefits are attached to functions, and functions are attached to application concepts. Therefore, value can be accrued either by function or application concept, which allows the DRP to assess the value of DA at multiple levels.
- As a simplifying assumption to facilitate value comparison, benefits are applied to the model year 2005, as if all benefits could be realized instantaneously that year, even though many of the benefits will not be realizable until the mid- or long- term.

- Application concepts are composed of unique sets of functions. Functions appear in any number of application concepts as appropriate.
- Wherever possible, benefit calculations are based on published data from the CPUC, the Energy Commission, general rate case documents of the California IOUs, the EIA, and the FERC.
- In some cases, data is unavailable because it is not public or does not exist. In these cases, technical experts from NCI's Energy Practice have made assumptions based on their professional judgment and industry experience that incorporate IOU input and are tailored for each IOU (Section 2.5.3).

Figure 3 shows which functions are necessary to implement each application concept. The model then calculates the resulting benefits.

1. To implement this Application Concept….

Application Concepts

Functions	1. Increase Distribution Energy Efficiency	2. Support a Million Solar Roofs	3. Leverage Decentralized Generation	4. Increase Distribution Reliability	5. Increase Distribution Power Quality	6. Help Manage an Aging Infrastructure	7. Leverage Plug-In Hybrid Vehicles	8. Support a Utility-Scale Microgrid	9. Enable High Penetration of Demand Response	10. Support a Resilient Distribution System	11. Optimize Distribution Capital Investments	12. Improve Distribution O&M
1. Automatic Voltage and VAR Control	Y	N	Y	N	Y	N	Y	Y	N	Y	Y	Y
2. Automatic Feeder Reconfiguration - Single	N	N	N	N	N	N	N	N	N	N	Y	N
3. Automatic Feeder Reconfiguration - Multi-level	Y	N	N	Y	N	N	N	Y	N	Y	N	Y
4. Optimum Power Flow Analysis	Y	N	N	N	Y	N	N	N	N	Y	Y	Y
5. DER Monitoring	N	Y	Y	N	N	N	Y	Y	N	N	N	N
6. DER Control by Unit	N	N	Y	N	N	N	N	Y	N	N	N	N
7. DER Control by Class	N	N	Y	N	N	N	Y	Y	N	N	N	N
8. Automatic Protection Reconfiguration	N	N	Y	Y	N	Y	Y	Y	N	Y	Y	Y
9. Isolation of Higher Impedance Faults	N	N	Y	Y	Y	N	Y	Y	N	N	N	Y
10. Automatic Switching – Local	N	N	Y	Y	N	N	Y	N	N	N	Y	Y
11. Automatic Switching – Central	N	N	N	N	N	N	N	N	N	Y	N	N
12. Automatic Condition-Based Equipment Maintenance	N	N	N	Y	N	Y	N	N	N	N	N	Y
13. Low Impact Fault Detection	N	N	Y	Y	Y	Y	N	N	N	N	N	Y
14. Automatic Islanding and Resynchronization	N	N	N	N	N	N	N	Y	N	N	N	N
15. Real-time Communications from the Utility to the Customer	N	N	N	N	N	N	N	N	Y	N	N	Y

2. these Functions are necessary….

Benefits

Functions	1. Reliability	2. Power Quality	3. Customer Service	4. Energy Efficiency	5. System Efficiency	6. Environment	7. T&D Capital Savings	8. T&D O&M Savings	9. Theft	10. Safety
1. Automatic Voltage and VAR Control	N	Y	N	Y	Y	Y	Y	Y	Y	N
2. Automatic Feeder Reconfiguration - Single	Y	N	N	Y	Y	Y	Y	Y	Y	Y
3. Automatic Feeder Reconfiguration - Multi-level	Y	N	N	Y	Y	Y	Y	Y	Y	Y
4. Optimum Power Flow Analysis	N	N	N	N	N	N	N	N	Y	N
5. DER Monitoring	N	N	N	N	N	N	N	N	N	N
6. DER Control by Unit	N	N	N	N	N	N	N	N	N	N
7. DER Control by Class	Y	N	N	N	N	N	N	N	N	N
8. Automatic Protection Reconfiguration	N	N	N	N	N	N	Y	Y	Y	N
9. Isolation of Higher Impedance Faults	Y	Y	N	N	N	N	Y	N	Y	N
10. Automatic Switching – Local	Y	Y	N	N	N	Y	N	Y	Y	N
11. Automatic Switching – Central	Y	Y	N	N	N	Y	N	Y	Y	Y
12. Automatic Condition-Based Equipment Maintenance	Y	N	N	N	N	N	Y	Y	Y	N
13. Low Impact Fault Detection	Y	N	N	N	N	N	Y	N	N	N
14. Automatic Islanding and Resynchronization	Y	N	N	N	N	N	N	N	N	N
15. Real-time Communications from the Utility to the Customer	N	N	N	N	N	N	N	N	N	N

3. and these direct and indirect benefits are enabled

Figure 3. Linkages Among Application Concepts, Functions, and Benefits

Source: Navigant Consulting, Inc.

2.5.3. Key Assumptions

Although much of the model relies on publicly available numerical data, some calculations required assumptions which were not publicly available. To test these key assumptions, the authors met with experts from each of the California IOUs. These meetings provided valuable input and validation of the assumptions and modeling approach. Table 3 summarizes the key assumptions whose values were determined from IOU discussions (highlighted in yellow).

Benefit Category	Benefits	Key Assumptions
Reliability	• Fewer outages • Shorter outages • Lower restoration costs	• SAIFI impact • CAIDI impact • Restoration costs • Customer value of service • Performance incentive payments
Energy Efficiency	• Lower distribution losses	• Power factor impact • Ability to reconfigure system • Price of energy
Transmission and Distribution Capital Savings	• Deferral of capital upgrades	• Capital savings by function • Capital budget magnitude • Capital carrying charge
Transmission and Distribution Operation and Maintenance Savings	• Labor cost reduction	• Contribution of labor to operations and maintenance costs • Labor productivity improvement • Savings from automatic switching
DER Characteristics	• Energy efficiency • Transmission and Distribution Capital savings	• DER Penetration enabled by DA

Table 3. Summary of Key Assumptions

Source: Navigant Consulting, Inc.

The following sections analyze certain significant annual benefits realized from the benefit categories of reliability, energy efficiency, T&D capital savings, and T&D operations and maintenance savings, and from a high penetration rate for DER in the hypothetical California IOU, based on values derived from and representative of the IOUs.

Reliability – Fewer Outages – Customer and Utility

The reliability benefits are calculated in the study based on changes caused by DA to one or more the following reliability metrics: system average interruption duration index (SAIDI); system average interruption frequency index (SAIFI); and customer average interruption duration index (CAIDI).[11] SAIDI is the system average duration of sustained outages and SAIFI is the system average number of sustained outages. CAIDI is the average duration of sustained

11. Impacts to events that are less than 5 minutes are considered in the power quality benefit category. These events can be characterized by the momentary average interruption frequency index (MAIFI).

interruptions per outage event. The model considers impacts to both the major and non-major reliability metrics.[12]

Figure 4 shows the assumptions for the improvements in SAIFI (non-major) as a result of four functions: *Automatic Switching* (F10/F11), *Automatic Condition-Based Maintenance* (F12), *Low Impact Fault Detection* (F13), and A*utomatic Islanding and Resynchronization* (F14). *Automatic Switching* enables the transfer of load to adjacent feeders to minimize the frequency of sustained outages. *Automatic Condition-Based Maintenance* (F12) increases early fault detection through advanced monitoring applications such as sensors that could reduce equipment failures by 75%. *Low Impact Fault Detection* (F13) discovers and isolates faults without full power reclosing, thereby decreasing the number of equipment failures. *Automatic Islanding and Resynchronization* (F14) shortens sustained outages by enabling microgrids to be created dynamically and supplied by power from DER units. In Figure 4, the white boxes show the estimated improvement in SAIFI, based on the data in the yellow boxes.

12. Major outages could include a government-declared state of emergency or outages that affect more than 15% of the system's facilities or 10% of the utility's customers, whichever is less.

Assumption for Improvement in SAIFI	
Automatic Switching (F10)	
What percent of SAIFI is caused by mainline outages?	50%
What percent of previously affected customers would not experience an interruption?	50%
What percent of the system employs automatic switching?	50%
What percent of the time is adjacent feeder capable of carrying transferable load?	75%
SAIFI improvement resulting from Automatic Switching	**= 9.4%**
Automatic Condition-Based Equipment Maintenance (F12)	
What percent of SAIFI is related to distribution equipment failures?	44%
What percent of equipment failures are reduced by early detection?	75%
What percent of equipment that impacts SAIFI has monitoring equipment?	75%
SAIFI improvement resulting from Automatic Condition-Based Equipment Maintenance	**= 25%**
Low-Impact Fault Detection (F13)	
What percent of SAIFI is caused by this type of equipment failure?	0.50%
What percent of these failures are reduced by low-impact fault detection?	90%
What percent of relevant equipment employs this capability?	100%
SAIFI improvement resulting from Low-Impact Fault Detection	**= 0.45%**
Automatic Islanding and Resynchronization (F14)	
What percent of customers are in a microgrid?	1.0%
What percent of outages would be avoided as a result of the microgrid?	90%
What percent of customers located within the microgrid do not have lines down?	50%
SAIFI improvement resulting from Automatic Islanding and Resynchronization	**= 0.45%**
Total SAIFI improvement = F10 + F12 + F13 + F14 − (F10 × F12 + F10 × F13 + F12 × F13)	**= 32.7%**

Figure 4. Assumptions for Improvements in SAIFI

Source: Navigant Consulting, Inc.

Figure 5 shows the calculation of the customer benefit of a reduction in the number of outage events by multiplying the percent SAIFI improvement by the current SAIFI. The reliability metrics are presented as the weighted average values for the three major IOUs, and so allow a representative look at the hypothetical IOU. The SAIFI improvement results in increased value to residential, commercial, and industrial customers. The reduction in outage minutes results in a reliability benefit of over $127 million for the customers of the hypothetical utility.

Fewer Outage Events - Customer			
Current SAIFI	1.066	avg. outages	
Current CAIDI	101.9	min.	
Current SAIDI	108.3	min.	
Change in SAIFI	**32.7%**		
Change in CAIDI	0.0%		
NEW SAIFI	0.781	avg. outages	
NEW CAIDI	101.9	min.	
NEW SAIDI	73.1	min.	
Change in SAIDI	35.2	min.	
Total Customer Interruption	129,108,367	min.	
Change in Outage Hours			
Residential	1,891,691	hr	Res. Customers = 3,222,048
Commercial	252,430	hr	Com. Customers = 429,955
Industrial	7,685	hr	Ind. Customers = 13,090
Total	2,151,806	hr	
Change in Unserved Energy			
Residential	1,422,990	kWh	Avg. Res. = 0.75 kW
Commercial	1,655,688	kWh	Avg. Com. = 6.56 kW
Industrial	4,305,287	kWh	Avg. Ind. = 560 kW
Total	3,494,502	kWh	
Change in Value of Service			
Residential	3,557,475	$	VOS Res. = **$2.50** per kWh
Commercial	17,755,982	$	VOS Com. = **$10.00** per kWh
Industrial	107,632,176	$	VOS Ind. = **$25.00** per kWh
Total	**127,746,534**	$	

Figure 5. Calculation of the Benefit of Fewer Outages for Customers

General rate case documents of the California IOUs establish SAIDI and SAIFI benchmark scores to measure a utility's reliability performance both during normal operations and during service restoration after abnormal events.[13] The CPUC levies a reliability penalty or awards an incentive payment if a utility's delta from benchmark (difference between SAIFI and SAIDI benchmark and current or new SAIFI and SAIDI) falls above or below the deadband zone into the liveband zone. The model calculates a utility's position within these bands before and after a change in SAIFI and SAIDI. As a result of the new SAIFI and SAIDI enabled by DA, the hypothetical utility realizes net incentive payments of $11.25 million and $19.94 million, respectively, as determined in Figure 6.

Fewer Outage Events - Utility				
	SAIFI Impact		**SAIDI Impact**	
Current SAIFI	1.066	avg. outages	1.066	avg. outages
Current CAIDI	101.9	min.	101.9	min.
Current SAIDI	108.3	min.	108.3	min.
Change in SAIFI	**32.7%**		**32.7%**	
Change in CAIDI	0.0%		0.0%	
NEW SAIFI	0.718	avg. outages	0.718	avg. outages
NEW CAIDI	101.9	min.	101.9	min.
NEW SAIDI	73.1	min.	73.1	min.
SAIFI / SAIDI Benchmark	0.99	avg. outages	94	min.
SAIFI / SAIDI Deadband	0.08	avg. outages	6	min.
SAIFI / SAIDI Liveband	0.16	avg. outages	13	min.
SAIFI / SAIDI Unit	0.01	avg. outages	1	min.
SAIFI / SAIDI Incentive per Unit	0.68	$ million per unit	1.00	$ million per unit
SAIFI / SAIDI Maximum Incentive / Penalty	11.25	$ million	11.25	$ million
Incentive Payment without DA				
Delta from Benchmark	0.07	avg. outages	14.7	min
Incentive	0.00	$ million	8.69	$ million
Incentive	0.00	$ million	-8.69	$ million
Incentive Payment with DA				
Delta from Benchmark	0.27	avg. outages	20.6	min
Incentive	11.25	$ million	11.25	$ million
Incentive	11.25	$ million	11.25	$ million
Total	**11,250,000**	**$**	**19,940,750**	$

Figure 6. Calculation of the Benefit of Fewer Outages for Utilities

13. Since the model was developed the benchmarks have been changed or eliminated.

Figure 7 shows that reducing the number of customer outage events enable utilities to avoid restoration costs. This model calculates restoration cost avoided as the product of the change in the number of outage events (product of the change in SAIFI and total customers divided by outage event size) and restoration cost (this model assumes that DA-adjusted costs are 50% of typical restoration costs to account for a utility's existing ability to capture efficiency by scheduling half of restorations as part of routine maintenance) based off authors' estimates and general rate case documents. The cost savings is $6.2 million for the hypothetical utility.

Fewer Outages Reduces Restoration Costs			
	All Outage Events	Excl. Major	Major Only
Current SAIFI (avg. outages)	1.170	1.066	0.10
Current CAIDI (min.)	139.2	101.9	377.55
Current SAIDI (min.)	147.3	108.3	38.93
Change in SAIFI of outages / major outages		**32.7%**	**0.5%**
Change in CAIDI of outages / major outages		**0%**	**10.0%**
NEW SAIFI	avg. outages	0.718	0.103
NEW CAIDI	min.	101.9	339.8
NEW SAIDI	min.	73.1	34.9
Change in SAIFI		-0.35	0.0000
Change in the Number of Outage Events		-6,181	-9
Restoration per Outage Event ($ per 200 customer outage)		**1,000**	**1,500**
Restoration Cost Avoided	$	6,181,129	13,699
Total	**6,194,828**	$	

Figure 7. Reduced Cost for Utilities from Avoiding Restoration

Energy Efficiency – Lower Distribution Losses – Society

Figure 8 shows that optimizing distribution load performance can reduce energy losses and increase effective capacity. This benefit accrues to society. Distribution losses can be reduced by improving power factor and by reconfiguring the distribution system. *Automatic Voltage and VAR Control* (F01) improves the power factor while *Automatic Feeder Reconfiguration - Single* (F02) and *Automatic Feeder Reconfiguration – Multi-level* (F03) decrease average system load losses by 2% and 4%, respectively. Average distribution circuit load is peak system load divided by a diversity factor which is then divided by the number of distribution circuits. The diversity factor accounts for the disparity between individual circuit peak and the system peak.

DA Function	Impact	
Automatic Voltage and VAR Control	**Power Factor**	w/o DA = 0.98; w/ DA = 0.99
Automatic Feeder Reconfiguration – Multi-level	**Distribution of System Loads**	4% reduction in average losses
Automatic Feeder Reconfiguration – Single	**Distribution of System Loads**	2% reduction in average losses

Capacity Increase

Peak System Load		13,757	MW
Number of Distribution Circuits		2,703	
Diversity Factor		0.75	
Average Distribution Circuit Load		6.79	MW
Average Length of Distribution Circuit		7.5	Miles
Average Resistance of Distribution Circuit		0.2	Ohm per mile
	w/o DA	**w/DA**	
Power Factor without DA	**0.98**	**0.99**	
Distribution Circuit Load	6.92	6.85	MVA
Distribution Circuit Voltage	12.47	12.47	kV
Reduction in average losses	**0%**	**4%**	
Distribution Circuit Current	320.56	304.63	A
Distribution Circuit Line Losses	154	139	kW
Change in Distribution Circuit Line Losses		-14.9	kW
System-wide Reduced Distribution Line Losses		-40,387	kW
Substation No-Load	13,757	13,717	MW
Substation No-Load Losses	1%	1%	
Substation Load	13,895	13,852	MW
Substation Load Losses	1%	1%	
Transmission Load	14,034	13,991	MW
Transmission Losses	4%	4%	
Generation Load	14,595	14,545	MW
Total Change in Load		-49.96	MW
Capacity Value		75,000	$/MW
Total		**8,475,966**	**$**

Avoided Energy

Load Factor	0.557	
Loss Factor	0.384	
Total Change in Load	-49.96	MW
Hours per Year	8760	
Change in Energy Losses	-168,003	MWh
Energy Price	100	$/MWh
Total	**32,977,400**	**$**

Figure 8. Value to Society of Reduced Distribution System Losses

The distribution circuit load factors in the change in power factor, which is real power divided by apparent power. California ISO requires "participating utility distribution Companies maintain reactive power flow at grid interface points within the power factor band of 0.97 lag

and 0.99 lead."[14] Since most system losses occur on the low-voltage side of the transformer, the model assumes that the power factor is 0.98 without DA and 0.99 with DA.

The distribution circuit current line item factors in the reduction in peak current enabled by reconfiguring feeders to reduce their peak loads. Distribution line losses are the product of current squared (with or without DA) and average circuit resistance. The total change in losses is the kW at peak difference between generation loads with and without DA. The total benefit of $8.48 million for the hypothetical utility is the product of the total change in losses and system price of capacity in dollars per MW.

In addition, the reduced load on the system results in a reduction in the generation required. This avoided energy is the product of the loss factor, the number of hours in a year, and the total change in system load. The loss factor enables the conversion from peak losses to energy losses and is calculated as:

$$LossFactor = 0.3(LoadFactor) + 0.7(LoadFactor)^2$$

T&D Capital Savings – Capital Budget Deferral - Utility

Figure 9 shows that reducing peak load and improving system operation and maintenance can defer capital upgrades for utilities.

Function	Capital Savings
1. Automatic Voltage and VAR Control	0.0%
2. Automatic Feeder Reconfiguration - Single	1.0%
3. Automatic Feeder Reconfiguration - Multi-level	1.5%
4. Optimum Power Flow Analysis	0.0%
5. DER Monitoring	0.0%
6. DER Control by Unit	0.0%
7. DER Control by Class	0.0%
8. Automatic Protection Reconfiguration	0.0%
9. Isolation of Higher Impedance Faults	0.0%
10. Automatic Switching – Local	0.0%
11. Automatic Switching – Central	0.0%
12. Automatic Condition-Based Equipment Maintenance	2.0%
13. Low Impact Fault Detection	5.0%
14. Automatic Islanding and Resynchronization	0.0%
15. Real-time Communications from the Utility to the Customer	0.0%
NET	**8.5%**

Capacity Budget Potentially Deferrable	$226,117,333	
Peak System Load	13,757	MW
Change in Load (see Figure 8)	40.4	MW
Peak Load Reduction	0.29%	
Distributed Energy Resources (see Figure 12)	548	MW
Peak Load Reduction	3.98%	
Deferred: Direct Use of DA	8.5%	
Total Deferred	12.78%	
Carrying Charge	15%	
Capital Budget Deferred with DA	**4,334,223**	**$**

Figure 9. Value to Utilities of Capital Deferral

Automatic Feeder Reconfiguration-Single (F02), *Automatic Feeder Reconfiguration-Multi-level* (F03), *Automatic Condition-Based Equipment Maintenance* (F12), and *Low Impact Fault Detection* (F13) result in a net capital savings of 8.5%. Deferred peak load reduction is the difference between the change in distribution line losses with DA and effective capacity of DER divided by system peak. The model defers only the capacity and substation portions of the capital budget because only those feeders and substations scheduled for upgrades can be deferred. As a result of the

14. California ISO. 2006. Voltage and VAR Control. Procedure No. T-105. Version No. 3.1.

deferrals and applying a carrying charge, the value of the deferred capital budget is $4.3 million for the hypothetical utility.

T&D Operations and Maintenance Savings – Reduced Labor Cost – Utility

Figure 10 shows that DA can increase the productivity of the hypothetical utility's labor force, thereby decreasing its distribution operations and maintenance expenses. The model estimates the labor savings component of operations and maintenance expenses by FERC category. The operations and maintenance expenses and the percentage of labor for each expense are obtained from FERC Form 1 and SCE's 2006 General Rate Case, respectively. The total labor productivity improvement is the sum of productivity improvements to line items 583-Overhead Line Expenses, 584-Underground Line Expenses, 592-Maintenance of Station Equipment, 593-Maintenance of Overhead Lines, and 594-Maintenance of Underground Lines.

The labor productivity improvement for each cost category is the product of the FERC Form 1 line item, percent labor, and percent DA Savings.

FERC Form 1 Data	Hypothetical Utility (2005)	Percent Labor
FERC Form 1 -- Distribution Expenses: Operations	$132,095,130	
580 - Operation Supervision and Engineering	$14,039,835	20%
581 - Load Dispatching	$2,334,328	50%
582 - Station Expenses	$9,543,571	80%
583 - Overhead Line Expenses	$11,909,625	40%
584 - Underground Line Expenses	$9,504,127	80%
585 - Street Lighting & Signal System Expenses	$780,996	85%
586 - Meter Expenses	$10,351,303	85%
587 - Customer Installations Expenses	$14,241,953	85%
588 - Miscellaneous Expenses	$59,038,751	50%
589 - Rents	$350,641	0%
FERC Form 1 -- Distribution Expenses: Maintenance	$169,432,139	
590 - Maintenance Supervision and Engineering	$1,856,426	10%
591 - Maintenance of Structures	$1,420,000	50%
592 - Maintenance of Station Equipment	$12,158,416	50%
593 - Maintenance of Overhead Lines	$118,754,793	20%
594 - Maintenance of Underground Lines	$14,940,947	25%
595 - Maintenance of Line Transformers	$2,589,085	55%
596 - Maintenance of Street Light & Signal Systems	$3,547,470	30%
597 - Maintenance of Meters	$2,907,510	65%
598 - Maintenance of Miscellaneous Dist Plant	$11,257,493	0%
Total Distribution Expenses	**$294,555,417**	

Labor Productivity Improvement, T&D O&M	
Automatic Voltage and VAR Control	
583 - Overhead Line Expenses: % DA Savings	1.00%
584 - Underground Line Expenses: % DA Savings	0.50%
	$85,665
Automatic Feeder Reconfiguration (Single & Multi-level)	
583 - Overhead Line Expenses: % DA Savings	1.00%
584 - Underground Line Expenses: % DA Savings	0.50%
	$85,665
Automatic Condition-Based Equipment Maintenance	
592 - Maintenance of Station Equipment	
Percent of equipment that can be monitored remotely	33%
Percent reduction of inspection interval due to remote monitoring	33%
Total 592 Labor Productivity Improvement: % DA Savings	10.9%
593 - Maintenance of Overhead Lines	
Percent of equipment that can be monitored remotely	10%
Percent reduction of inspection interval due to remote monitoring	33%
Total 592 Labor Productivity Improvement: % DA Savings	3.3%
594 - Maintenance of Underground Lines	
Percent of equipment that can be monitored remotely	50%
Percent reduction of inspection interval due to remote monitoring	33%
Total 592 Labor Productivity Improvement: % DA Savings	16.7%
	$2,062,121
The resulting Utility Benefit from these DA Functions is $2,233,432.	

Figure 10. Distribution Operation and Maintenance Labor Cost Savings for Utilities

For *Automatic Voltage and VAR Control* (F01) and *Automatic Feeder Reconfiguration* (F02/F03) assumptions include improved productivity by 1% on overhead equipment and 0.5% on underground equipment. *Automatic Condition-Based Equipment Maintenance* (F12) reduces the inspection interval based on estimates for the percent of equipment that can be remotely monitored with DA. The total benefit from the improved productivity of labor as a result of implementing all of the DA functions is $2.23 million for the hypothetical utility.

T&D Operation and Maintenance Savings – Automatic Switching – Utility

Figure 11 shows that automatic switching can reduce the labor and equipment expense or increase the switching costs avoided and vehicle savings related to sending a crew into the field to conduct switching for utilities.

T&D O&M Savings from Automatic Switching		
Higher Utilization of Crew Time		
CAIDI	101.9	Min
Actual Crew Time Factor	2	
2 man crew for 3 switching events	3.396	hrs
Cost of crew	300	$ per hr
Number of outages without DA	39,086	outage events
Switching Costs	39,823,430	$
Number of outages with DA	35,422	outage events
Switching Costs	36,089,984	$
Number of outages avoided	3,664	outage events
Switching Costs Avoided	**3,733,447**	$
Reduced Vehicle Miles Driven		
Miles per event	20	
Number of events avoided	3,664	
Vehicle cost per mile	2	$ per mile
Vehicle Savings	**146,573**	
Total	**3,880,020**	$

Figure 11. Utility Operations and Maintenance Savings from Automatic Switching

Model assumptions include a doubling of CAIDI (Actual Crew Time Factor = 2) for the 2 man crew for 3 switching events to adjust average interruption duration for repair hours, etc. Switching costs is the product of twice CAIDI, cost of crew, and avoided outage events. Vehicle savings is the product of miles per event, vehicle cost per mile, and avoided events. The total savings of $3.9 million sums switching costs avoided and vehicle savings for the hypothetical utility.

Distributed Energy Resources Assumptions

Figure 12 shows the impact of a "high" penetration scenario for DER calculated in terms of capacity, energy, and loss savings for all three stakeholder groups. DER includes PV, CHP, PHEV, and DR technologies. The penetration targets for PV and CHP are from the Energy Commission's DG roadmap.[15] The model assumes that 20% of the PV, CHP, and DR capacity requires DA technologies in order to achieve "high" penetration. All circuits require DA for the distribution system to utilize the Vehicle-to-Grid (V2G) capability of PHEVs.

	PV	CHP	DR	PHEV	TOTAL
Percent of System Peak (or no. of cars)	5.0%	5.5%	10.0%	333,333	
Percent of Circuits Requiring DA to Support High Penetration Levels	20%	20%	20%	100%	
System Peak = 13,757 MW					
Increased System Capacity (U)					
Capacity Enabled by DA (MW)	138	151	275	500	
Net Deration Factor	0.40	0.90	0.90	0.15	
Effective Capacity (MW)	55	136	248	75.0	
Contribution to Reserve Margin (MW) (Res. Margin = 15%)	65	160	291	88	
Capacity Value ($ per MW-yr)	75,000	75,000	75,000	75,000	
Capacity Value ($)					**45,339,556**
Society's Value from Reduced Electricity Generation (S)					
Capacity Factor	0.18	0.85	0.01	0.01	
Energy (MWh)	86,768	1,014,103	24,763	7,500	
Incremental Societal Value ($ per MWh)	10	10	10	10	
Total Energy Value ($)					**11,331,335**
Customer Energy Savings (C)					
Net Customer Energy Value ($ per MWh)	20	10	175	175	
Total Customer Savings					**17,522,346**
Reduced Demand and Energy Losses (S)					
Demand Losses (MW) (Peak Losses = 12.27%)	6.8	16.7	30.4	9.2	
Capacity Value ($ per MW)	75,000	75,000	75,000	75,000	
Value of Demand Loss Savings ($)					**4,729,338**
Loss Factor	0.60	0.38	0.90	0.90	
Energy Losses (MWh)	6,389	47,777	2,735	828	
Energy Value ($ per MWh)	100	75	175	175	
Total Value of Energy Loss Savings ($)					**4,845,732**

Figure 12. Value of Incremental DER Supported by DA

15. Rawson, Mark and John Sugar. 2007. *Distributed Generation and Cogeneration Policy Roadmap for California*. California Energy Commission. Publication No. CEC-500-2007-021.

During the system peak hour of 3 to 4 PM, average PV system output is 0.47 kW per kW of nominal DC system size, which is 91% of maximum PV output. Figure 13 illustrates the fact that the potential for PV to help meet California ISO system peaks is sensitive to the time and duration of the peak. PV supply declines sharply in the late afternoon, when California ISO system peaks are still ongoing.[16] Therefore, this model assumes a net deration factor for PV of 0.40. The net duration factor accounts for intermittency and/or availability of a resource at the time of circuit or system peak.

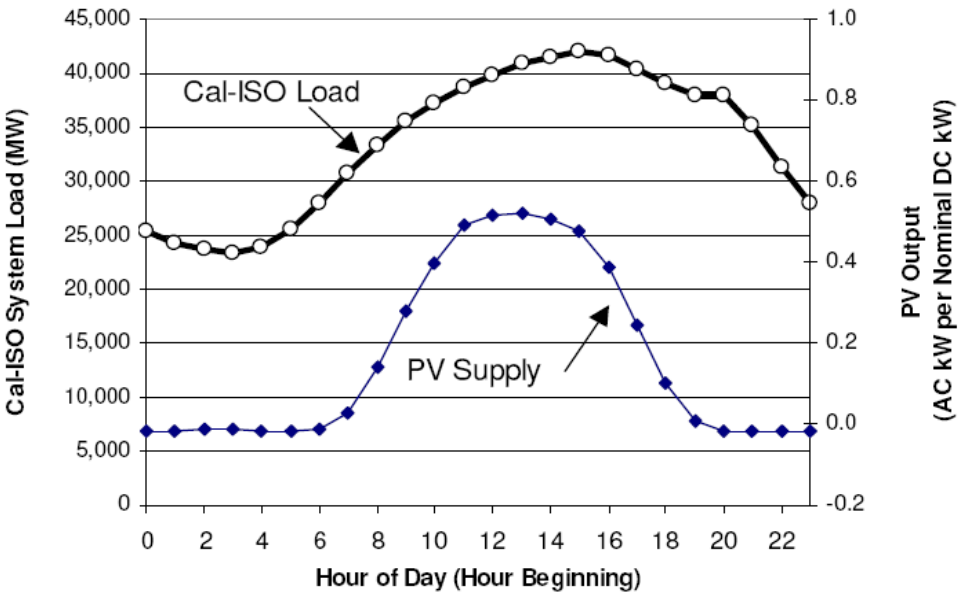

Figure 13. California ISO Load and PV Supply on Summer Peak Days (Typical)

Source: *Measured Performance of California Buydown Program Residential PV Systems*. Regional Economic Research, Inc., and California Energy Commission.

PHEV was examined for its potential as a source of distributed generation. The number of PHEVs assumed was based on market penetration of 1 million cars in California. Their typical demand is 1.5 kW, based on the assumption that PHEVs will use standard outdoor plugs at 120 volts.[17] The value proposition assumes the PHEV can generate back-up power during outages, or supply power to the grid during peak loads (V2G).[18] The net deration factor of 0.15 assumes that less than 20% of PHEVs will be connected to charging stations at time of peak (PHEVs will otherwise be in use or disconnected from distribution system). The system utilizes PHEV and DR for 100 hours per year, which represents 1.1% of the total hours in a year. The net deration

16. Scheuermann, Kurt, et al. *Measured Performance of California Buydown Program Residential PV Systems*. Regional Economic Research, Inc., California Energy Commission.

17. Frank, Andrew Alfonso. 2006. *Plug-In Hybrids: The New Focus for the Future of Transportation*. http://www.renewableenergyaccess.com.

18. Price, et al 95-96.

factors for CHP and DR are based on 90% availability. The loss factor is the conversion from peak losses to energy losses. The loss factor has been estimated for PV, DR, and PHEV, because the resources are not used during all hours of the year.

Energy (MWh) output is the product of gross capacity, net deration factor, and capacity factor multiplied by 8,760 hours. Incremental societal value, capacity value of $75,000 per MW-yr, and net customer energy value are the authors' estimates. Demand losses are the product of effective capacity and total peak loss while energy losses are the product of capacity factor, loss factor, and demand loss. The energy value ($ per MWh) is the average price of energy for the DER. DR and PHEV are used exclusively at the time of peak, offsetting the highest priced energy. The benefit of higher DER penetration enabled by DA is $83.8 million, plus $1.4 million for capital deferral included in Figure 9 for the hypothetical utility and its customers.

3.0 Results

3.1. Results by Application Concept

A full-scale deployment of DA in California in 2005 could have produced approximately $600 million[19] in annual benefit (

Figure **14**). The application concepts that exhibit the greatest value pertain to managing reliability and reducing operations and maintenance costs, where utilities have historically sought benefits from DA technologies. The results also show that DA can provide benefits by supporting higher penetrations of distributed energy resources, including CHP, PV and PHEVs.

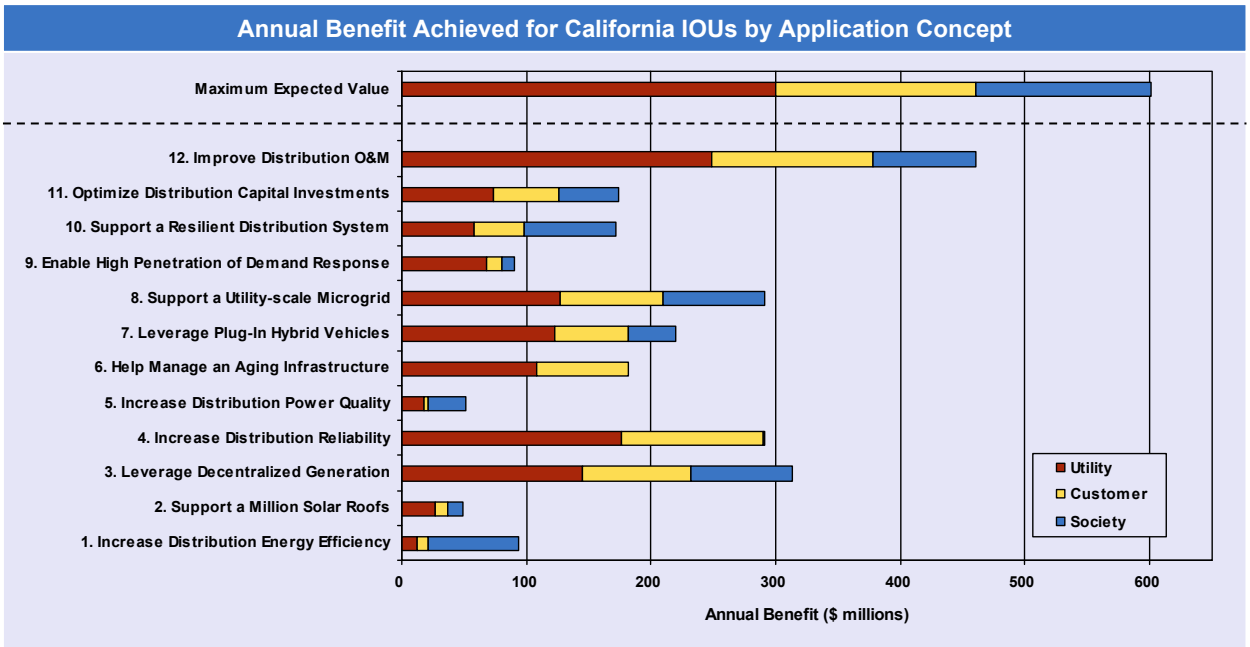

Figure 14. Annual Benefit of DA for California by AC and Stakeholder

3.2. Results by Stakeholder

Implementing an application concept unlocks many direct and indirect benefits for the three stakeholder groups – utilities, customers, and society. Table 4 summarizes benefits by application concept and stakeholder for California. Interestingly, DA provides equal amounts of benefit for utilities and the public (customers and society), $299 million and $302 million respectively. The public benefits are split nearly evenly between customers ($161 million) and society ($141 million). *Improving Distribution Operations and Maintenance* (AC12) provides the greatest utility and public benefit. *Increase Distribution Energy Efficiency* (AC01) results in the smallest utility benefit ($12 million). *Support a Million Solar Roofs* (AC02) results in the smallest public benefit ($22 million). Refer to Appendix A for detailed results by application concept.

19. The benefits for individual application concepts overlap, therefore the maximum expected value does not equal the sum of all application concepts.

Application Concept	Utility	Public Benefits		Total
		Customer	Society	
1. Increase Distribution Energy Efficiency	$12	$9	$73	$94
2. Support a Million Solar Roofs	$27	$9	$13	$49
3. Leverage Decentralized Generation	$145	$87	$81	$313
4. Increase Distribution Reliability	$176	$114	$1	$291
5. Increase Distribution Power Quality	$18	$4	$30	$51
6. Help Manage an Aging Infrastructure	$108	$73	$0	$181
7. Leverage Plug-In Hybrid Vehicles	$123	$59	$38	$220
8. Support a Utility-Scale Microgrid	$128	$82	$82	$291
9. Enable High Penetration of Demand Response	$68	$13	$10	$90
10. Support a Resilient Distribution System	$58	$40	$73	$171
11. Optimize Distribution Capital Investments	$73	$53	$48	$174
12. Improve Distribution Operations and Maintenance	$249	$129	$83	$460
13. Maximum Expected Value	$299	$161	$141	$601

Table 4. Summary of Benefits by Application Concept ($ in millions)

3.3. Results by Benefit Meta-Group

The ten benefit categories were organized in three meta-groups to determine how much benefit was ascribable to each:

Reliability:

- Reliability (BC01)
- Power Quality (BC02)
- Customer Value (BC03)

Environmental:

- Energy Efficiency (BC04)
- Environment (BC06)

Cost Savings:

- System Efficiency (BC05)
- T&D Capital Savings (BC07)
- T&D Operations and Maintenance Savings (BC08)
- Theft (BC09)
- Safety (BC10)

Figure 15 presents the results in these three meta-groups for California. Reliability represents approximately 54% of total benefits with a maximum expected benefit of $292 million, while environmental and cost savings split the remainder with 22% and 24%, respectively. *Improve Distribution Operations and Maintenance* (AC12) and *Improve Distribution Reliability* (AC04) provide the greatest reliability benefits. *Improve Distribution Operations and Maintenance* (AC12) and *Support a Million Solar Roofs* (AC02) results in the lowest reliability benefits while *Increase Distribution Energy Efficiency* (AC01) results in the lowest cost savings benefits, with annual benefits of $5 million and $11 million, respectively. *Automatic Condition-Based Equipment Maintenance* (F12) enables the greatest benefit in the reliability meta-group of $126 million or

48% of total benefits. *Automatic Feeder Reconfiguration-Single/Multi-level* (F02/F03) enable the greatest benefit in the environmental meta-group of $22 million or 70% of total benefits. *Automatic Switching-Local/Central* (F10/F11) enable the greatest benefit in the cost savings meta-group of $13 million or 38% of total benefits.

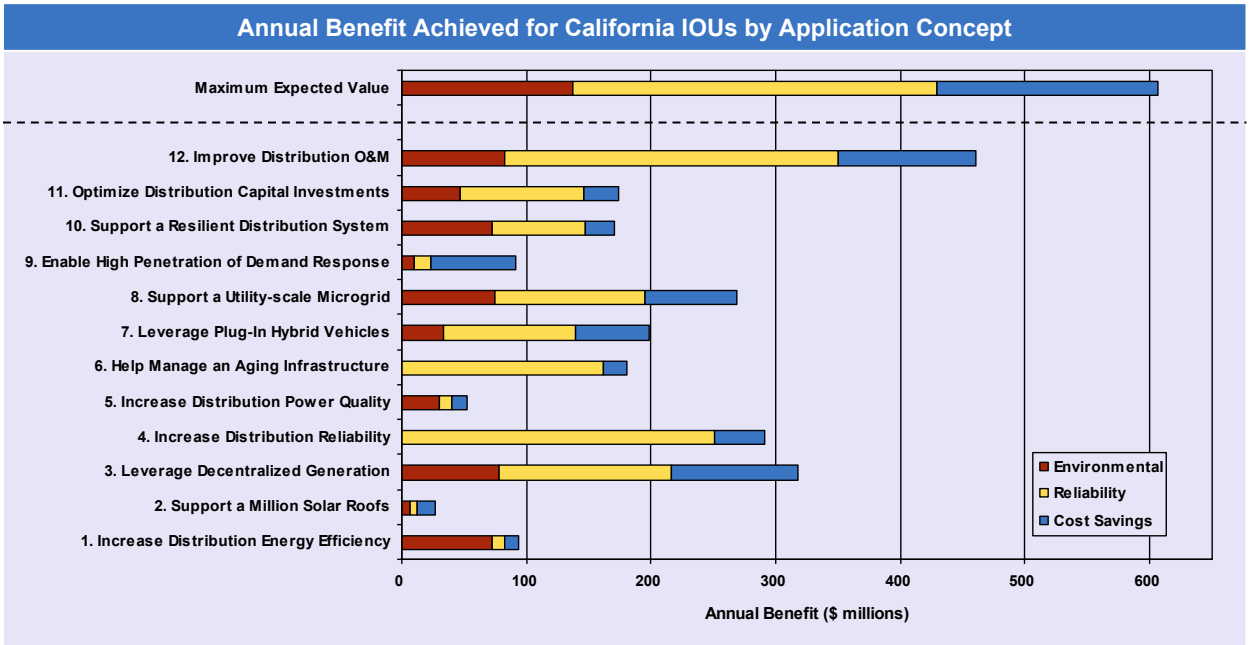

Figure 15. Annual Benefit of DA by Application Concept and Benefit Meta-Group

3.4. DA and Distributed Energy Resources (DER)

A key result of this analysis is demonstrating how DA can be used to create more value from DER. DER includes PV, CHP, PHEV, and DR technologies. DA would increase the penetration of DER, exploit its strengths, and mitigate its limitations (chiefly the lack of utility control over output). For example, under both *Leverage Decentralized Generation* (AC03) and *Support a Utility-scale Microgrid* (AC08), utilities can both monitor and control DER by unit and class to help manage the system peak.

High penetrations of DER enabled by DA could create benefits of $312 million per year for California (Table 5). DG's contribution of $154 million is consistent with the Energy Commission's 2020 Vision of a cost-effective, highly competitive DG industry where DG and cogeneration meet over 25% of total peak demand.

Table 5 shows the specific results for DA's value related to DER for California. Capacity includes capacity value, capacity reserve margin, and capacity deferral. Loss Savings includes customer, demand, and energy losses. Environmental includes the reduced emissions of carbon dioxide, sulfur oxides, and nitrous oxides due to incremental DG. Results for Table 5 for the state of California follow similar methodology as shown in Figure 12 for the hypothetical IOU.

DER	Capacity Value (million)	Energy Value (million)	Value of Loss Savings (million)	Environmental Value (million)	Total Value (million)
Photovoltaics	$27	$4.7	$15	$2.0	$49
Combined Heat and Power	$64	$35	$61	$(6.4)	$154
Demand Response	$67	$0.74	$22	$0.33	$90
Plug-In Hybrid Vehicles	$14	$0.15	$4.4	$(0.11)	$18

Table 5. Benefits of the Incremental Penetration of DER Enabled by DA

3.5. DA Deployment Pathways

It is unlikely that a utility would deploy all the functions and implement all the application concepts described in this report simultaneously. More likely, utilities will look for early high-value application concepts that could better justify high initial costs. After these early application concepts are deployed, additional functions could be added to enable more application concepts.

Two potential pathways to wide-scale deployment of DA were chosen based on a strategic imperative (for example, reduce costs, improve reliability, exploit customer resources, or reduce GHG) and to add as few functions as possible in a sequence that enabled more application concepts. For example, *Help Manage an Aging Infrastructure* (AC06) requires just three functions (Figure 16). Adding three more functions would enable *Increase Distribution Reliability* (AC04). Adding two more functions after that would enable *Increase Distribution Power Quality* (AC05). At this point, all functions would be in place to enable *Support a Resilient Distribution System* (AC10).

Application Concepts

Functions	1. Increase Distribution Energy Efficiency	2. Support a Million Solar Roofs	3. Leverage Decentralized Generation	4. Increase Distribution Reliability	5. Increase Distribution Power Quality	6. Help Manage an Aging Infrastructure	7. Leverage Plug-In Hybrid Vehicles	8. Support a Utility-Scale Microgrid	9. Enable High Penetration of Demand Response	10. Support a Resilient Distribution System	11. Optimize Distribution Capital Investments	12. Improve Distribution O&M
1. Automatic Voltage and VAR Control	Y	N	Y	N	Y	N	Y	Y	N	Y	Y	Y
2. Automatic Feeder Reconfiguration - Single	N	N	N	N	N	N	N	N	N	N	Y	N
3. Automatic Feeder Reconfiguration - Multi-level	Y	N	N	Y	N	N	N	Y	N	Y	N	Y
4. Optimum Power Flow Analysis	Y	N	N	N	Y	N	N	N	N	Y	Y	Y
5. DER Monitoring	N	Y	Y	N	N	N	Y	Y	N	N	N	N
6. DER Control by Unit	N	N	Y	N	N	N	N	Y	N	N	N	N
7. DER Control by Class	N	N	Y	N	N	N	Y	Y	N	N	N	N
8. Automatic Protection Reconfiguration	N	N	Y	Y	N	Y	Y	Y	N	Y	Y	Y
9. Isolation of Higher Impedance Faults	N	N	Y	Y	Y	N	Y	Y	N	N	N	Y
10. Automatic Switching – Local	N	N	Y	Y	N	N	Y	N	N	N	Y	Y
11. Automatic Switching – Central	N	N	N	N	N	N	N	N	N	Y	N	N
12. Automatic Condition-Based Equipment Maintenance	N	N	N	Y	N	Y	N	N	N	N	N	Y
13. Low Impact Fault Detection	N	N	Y	Y	Y	Y	N	N	N	N	N	Y
14. Automatic Islanding and Resynchronization	N	N	N	N	N	N	N	Y	N	N	N	N
15. Real-time Communications from the Utility to the Customer	N	N	N	N	N	N	N	N	Y	N	N	Y

Figure 16. Application Concepts and Required Functions

Source: Navigant Consulting, Inc.

The two pathways examined are:

1. Enhancing Reliability while Reducing Costs – the application concepts identified below would be implemented in the following order:

- AC06 – Help Manage an Aging Infrastructure
- AC11 – Optimize Distribution Capital Investments
- AC04 – Increase Distribution Reliability
- AC12 – Improve Distribution Operations and Maintenance
- AC10 – Support a Resilient Distribution System
- AC05 – Increase Distribution Power Quality

2. Exploiting Customer Resources and Managing GHGs – the application concepts identified below would be implemented in the following order:

- AC09 – Enable High Penetration of Demand Response
- AC02 – Support a Million Solar Roofs
- AC03 – Leverage Decentralized Generation
- AC07 – Leverage Plug-In Hybrid Electric Vehicles
- AC01 – Increase Distribution Energy Efficiency

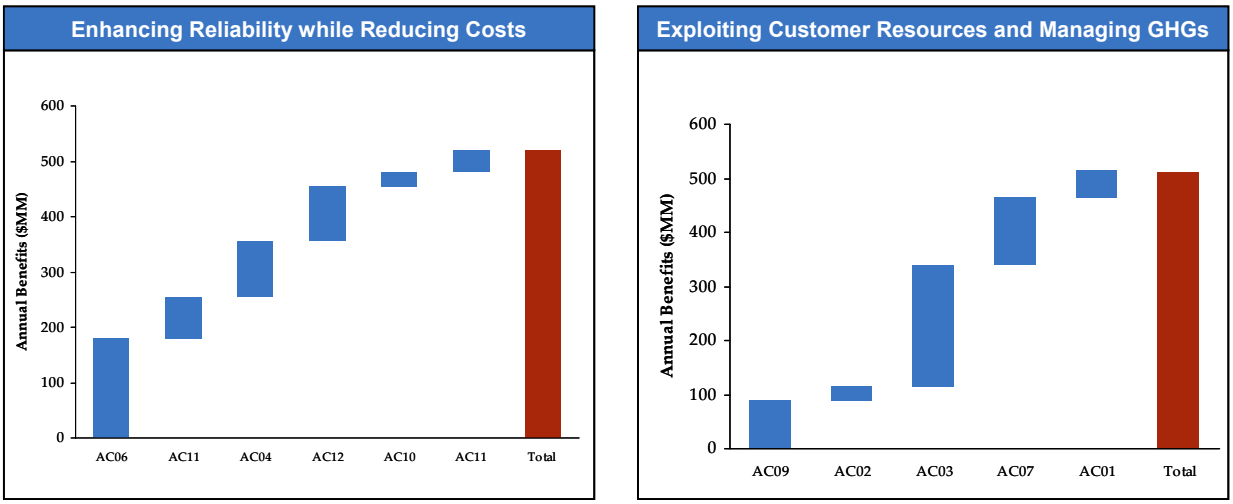

Figure 17. Benefits Along DA Deployment Pathways

Either of these pathways would lead to over $500 million in annual benefits (Figure 17). Both pathways start with just a few functions and continue to add functions and extract additional benefits. These are just two of many possible pathways and are a simplified perspective on a very complex issue for utilities. However, it illustrates an important issue in deploying DA technology. The initial investment in DA to create the platform may be larger than the initial benefits (Figure 18). Once this initial investment is in place, the benefits of DA may hit a tipping

point and further penetration may not need DRP support. Understanding the expected long-term benefits and costs along these pathways is key to making investment and policy decisions related to DA.

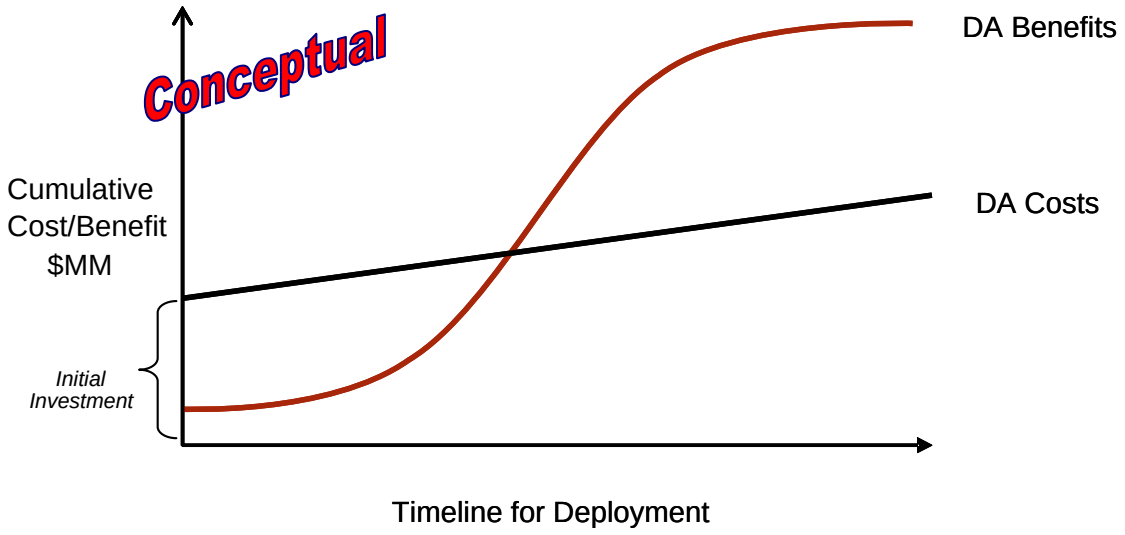

Figure 18. Conceptual Costs and Benefits of DA Along DA Deployment Pathways
Source: Navigant Consulting, Inc.

4.0 Recommendations

The Value of Distribution Automation analysis was aimed at answering key technology strategy and management questions for the DRP, including:

- Should the DRP make research and development investments in DA?
- What technologies need development?
- What research questions should the DRP pursue?
- How should DRP address the research needs?

The following recommendations respond to these questions.

4.1. Should the DRP Make Research and Distribution Investments in DA?

The results of this study confirm that a broad deployment of DA in California would yield significant benefits to utilities, its customers, and society. Deployment of DA technologies will be fundamental to achieving the capabilities of a modern distribution infrastructure. In addition to increasing the reliability, efficiency, and flexibility of the distribution system, DA will make vital contributions to integrating high penetrations of DER, reducing GHG emissions, and supporting new approaches to infrastructure planning and development.

Current challenges for implementing DA include: a lack of low-cost sensors and sensor networks in the distribution system; communication and coordination between new and legacy distribution equipment; and the tremendous amount of data that will be created (and be required) by DA. Given California's role as an energy leader in the United States, the DRP is uniquely positioned to support the development of DA technologies.

4.2. What Are the Research, Development, and Demonstration Needs?

This study found that *Support a Million Solar Roofs* (AC02) and *Enable a High Penetration of Demand Response* (AC09) are the only application concepts that can be implemented in the near term (Table 2). Demonstrating the value of DA, particularly these application concepts, is crucial to the commercialization of new technologies needed to support DA. The value of DA is shared by utilities, customers, and society, and even within a utility, value cuts across internal utility business units. Understanding and demonstrating how this value can be unlocked and equitably shared among stakeholders is a research need. In addition, developing uniform protocols within these demonstrations can accelerate the integration of a given technology in California's service areas.

The Energy Commission can support development of specific functions. The calculation of value in this study relies on tying measurable benefits to DA functions. A measure of the importance of a function is how frequently it is required to enable one of the 12 application concepts (applicability). Another measure of the importance of a function is its contribution to benefits (impact). Figure 19 shows the importance of each function. (Refer to Table 1 and Table 2

for the time horizon of each function: near-term (between 0 and 5 years), mid-term (greater than 5 and 15 years), and long-term (greater than 15 years). In Figure 19, functions that have greater impact and applicability are in the upper right quadrant. Accordingly, these functions should receive the most support early on. *Automatic Voltage and VAR Control* (F01), *Automatic Feeder Reconfiguration – Multi-level* (F03), and *Automatic Switching – Local* (F10) are near-term function that have both high applicability and impact based on the state of technology development and integration on the distribution system.

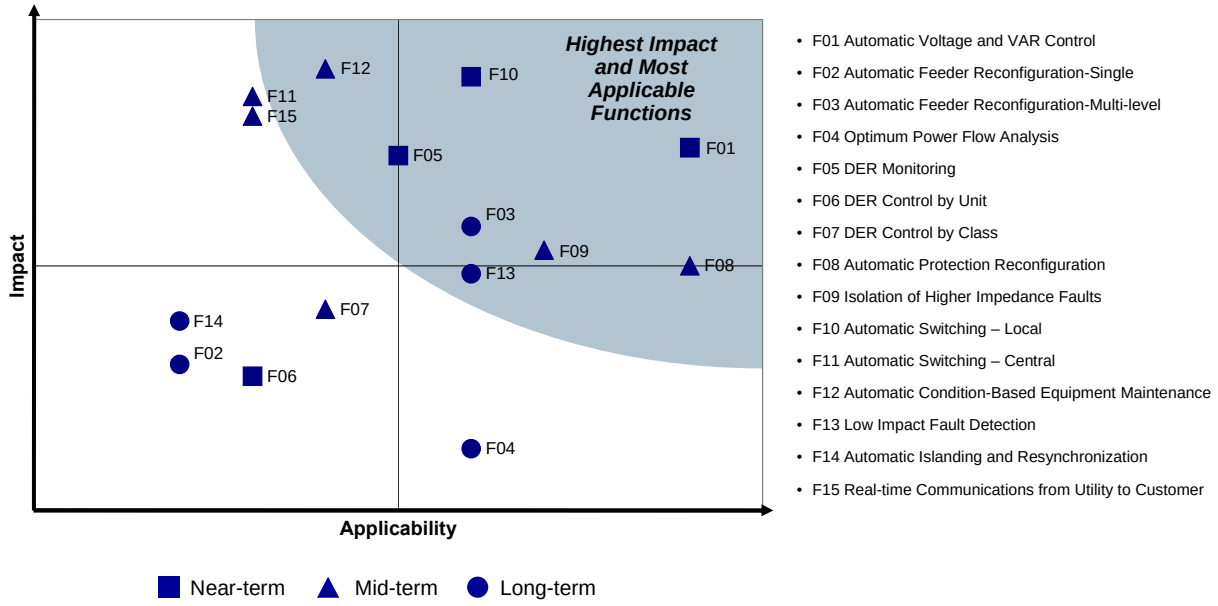

Figure 19. Impact and Applicability of Functions
Source: Navigant Consulting, Inc.

The most critical functions, in terms of technology development and DA deployment are those that have high applicability and impact, but are not currently available (that is, mid- to long-term). These would include, from right to left and top to bottom in the graph, *Automatic Protection Reconfiguration* (F08), *Isolation of Higher Impedance Faults* (F09), *Automatic Feeder Switching* (F03), *Low Impact Fault Detection* (F13), and *Automatic Condition-Based Equipment Maintenance* (F12). Specific research related to understanding the technical and operational requirements of these functions is needed, and would benefit from DRP support.

New technology may also need to be developed for some of these functions. Section 2.1 defined functions as capabilities that a utility would realize by implementing a DA technology. The authors assumed a broad family of DA technologies and did not specify how or which technologies would be implemented. Although some of these technologies currently exist at the transmission level and in other industry applications, they may not have been implemented in an electric distribution environment for technical or economic reasons.

DA presents specific challenges due to the nature of electric distribution service, the scale of the distribution system, and the diversity of the equipment, both in terms of age and configuration. Figure 20 summarizes some of these specific capabilities and needs.

Technology	Capability or Feature	DA Technology Need
Sensors	• Electrical parameters • Equipment condition • Environmental conditions	• Low-Impact Fault Detection • Automatic Condition-Based Equipment Maintenance
Communications	• Performance characteristics • Medium: wireless, BPL, fiber • Interoperability	• Interoperable communications between new and legacy equipment • High speed communications
Processing and Agents	• Intelligent electrical devices • Local/remote processing • Device autonomy	• Automatic Protection Reconfiguration • Automatic Voltage and VAR Control • DER Monitoring
Information Management	• Data mining • Data integration • Consistency	• Data management • Consistency and validation
Visualization	• Decision support tools	• Optimum Power Flow Analysis

Figure 20. Capabilities and DA Technology Needs by Category
Source: Navigant Consulting, Inc

4.3. What Research Questions Should the DRP Pursue?

The DRP can add value by supporting DA research for the technology needs in Figure 20. However, based on the public interest objectives of the program, and the ongoing activity by equipment suppliers and utilities, the authors believe that DRP research can be leveraged by other PIER programs such as Distributed Energy Resource Integration and Demand Response.

Can low-cost sensors and sensor networks be developed that can monitor the distribution network at a resolution sufficient for DA?

DA will require numerous sensors throughout the distribution system. These sensors must measure electrical parameters (for example, voltage, current, frequency), environmental parameters (for example, temperature, pressure, vibration), and equipment condition parameters, in order to observe the distribution system at a level of detail sufficient to support decision-making and execute control actions. These sensors must be inexpensive, require little or no maintenance, and be capable of performing reliably in harsh environments for many years. They must also be easy to install in a wide variety of equipment configurations.

Will a wide variety of new and legacy equipment communicate reliably and operate in a coordinated fashion?

Obtaining the data from a broad deployment of distribution sensors will require a communications network. This network must support a variety of wired and wireless media, and be compatible with existing and emerging communications protocols. Moreover, the

communications network must reliable and secure enough to support the real-time operation of the electric power system.

How can the large quantity of data associated with a full-scale deployment of DA be managed, and how can this data be converted to useful information?

Like the deployment of AMI, DA will create a flood of data that must be stored, validated, and analyzed to create the information that will inform operating decisions. Beyond that, the balance between local/autonomous and central/controlled operations must be explored.

4.4. How Should the DRP Address Research Needs?

The DRP should address research needs that can resolve the challenges facing DA. Research needs include demonstrations, performing research on specific functions, developing underlying technology required for high priority functions, and supporting standards and interoperability work. Recommendations can be found in Figure 21.

DA Challenge	Research Needs and Recommendations
Lack of demonstration of DA value	**Demonstrate near-term application concepts:**
Value is shared by utilities, customers, and society	*Support Million Solar Roofs* (AC2)
	Enable Large Penetration of Demand Response (AC9)
Required functions are not available	**Perform research into mid-term functions:**
	Automatic Conditioned Based Maintenance (F12) – Understand correlation between equipment operating life (stress and age) and remaining life
	Automatic Protection Reconfiguration (F08) – Understand under what conditions protection schemes and settings would change
	Automatic Protection Reconfiguration (F08) – Understand how fast modes would have to change and if current technology could meet these requirements
	Automatic Protection Reconfiguration (F08) – Understand the current capability of relays and control devices to change settings
Commercial technologies do not exist to support functions	**Develop technologies that are required for mid-term functions:**
	Automatic Condition Based Maintenance (F12) – Understand which equipment and which parameters need to be measured. Understand what capabilities already exist
	Automatic Condition Based Maintenance (F12) – Develop low-cost, low power, long-life, robust sensors and sensor networks
	Automatic Protection Reconfiguration (F08) – Develop low-cost, low-power, long-life, robust sensors and sensor networks
	Isolation of High Impedance Faults (F08) – Advanced sensors that distinguish between faults and high load currents or detect fault currents that may be too weak to trigger conventional protection systems. This may include high-resolution sensors, use of fault signatures and coordinated measurement among multiple devices.
Lack of standards will slow full-scale deployment of DA technologies	Support development of communication and interoperability standards where appropriate
	Understand back compatibility of legacy equipment and equipment that will be deployed in near future
	Understand the data management issue, create data hierarchy and standards for data management

Figure 21. DA Research Needs and Recommendations

Source: Navigant Consulting, Inc

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Glossary

AB 32	Assembly Bill 32
AC	application concept
AMI	advanced metering infrastructure
BC	benefit category
BPL	broadband over power lines
CAIDI	customer average interruption frequency index
California ISO	California Independent System Operator
CHP	combined heat and power
CPUC	California Public Utilities Commission
DA	distribution automation
DC	direct current
DER	distributed energy resources
DG	distributed generation
DR	demand response
DRP	Distribution Research Program
EIA	Energy Information Administration
Energy Commission	California Energy Commission
F	function
FERC	Federal Energy Regulatory Commission
FLISR	fault location, isolation, and service restoration
GHG	greenhouse gas
IOU	investor-owned utility
kW	kilowatt
MAIFI	momentary average interruption frequency index
MW	megawatt
MWh	megawatt-hour

NCI	Navigant Consulting, Inc.
O&M	operations and maintenance
PG&E	Pacific Gas and Electric
PHEV	plug-in hybrid electric vehicle
PIER	Public Interest Energy Research
PV	photovoltaic
RD&D	research, development, and demonstration
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SB 1368	Senate Bill 1368
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
T&D	transmission and distribution
V2G	vehicle-to-grid
VAR	volt-ampere reactive

Appendix A: Detailed Results by Application Concept

The following tables present total values for the service areas of California' three major IOUs by benefit category and Stakeholder for each application concept.

Benefit Category	Utility	Customer	Society	Total
Reliability	$0	$6,674,749	$0	$6,674,749
Power Quality	$2,075,285	$2,075,285	$0	$4,150,570
Customer Value	$0	$0	$0	$0
Energy Efficiency	$0	$0	$69,851,738	$69,851,738
System Efficiency	$2,256,263	$0	$0	$2,256,263
Environment	$0	$0	$2,289,704	$2,289,704
T&D Capital Savings	$1,894,398	$0	$0	$1,894,398
T&D Operations and Maintenance Savings	$738,930	$0	$0	$738,930
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$883,051	$883,051
Total by Stakeholder	$12,175,161	$8,750,034	$73,024,493	$93,949,688

Table 6. AC01 – Increase Distribution Energy Efficiency

Benefit Category	Utility	Customer	Society	Total
Reliability	$0	$0	$0	$0
Power Quality	$0	$0	$0	$0
Customer Value	$0	$5,206,089	$0	$5,206,089
Energy Efficiency	$0	$0	$6,141,088	$6,141,088
System Efficiency	$14,566,235	$0	$0	$14,566,235
Environment	$0	$0	$1,123,621	$1,123,621
T&D Capital Savings	$436,734	$0	$0	$436,734
T&D Operations and Maintenance Savings	$0	$0	$0	$0
Theft	$0	$0	$0	$0
Safety	$0	$0	$0	$0
Total by Stakeholder	$15,002,970	$5,206,089	$7,264,709	$27,473,768

Table 7. AC02 – Support a Million Solar Roofs

Benefit Category	Utility	Customer	Society	Total
Reliability	$41,610,999	$45,200,811	$0	$86,811,810
Power Quality	$9,708,618	$2,075,285	$0	$11,783,903
Customer Value	$0	$39,566,672	$0	$39,566,672
Energy Efficiency	$0	$0	$75,559,538	$75,559,538
System Efficiency	$71,162,877	$0	$0	$71,162,877
Environment	$0	$0	$2,354,420	$2,354,420
T&D Capital Savings	$7,272,137	$0	$0	$7,272,137
T&D Operations and Maintenance Savings	$18,792,253	$0	$0	$18,792,253
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$0	$0
Total by Stakeholder	$153,757,170	$86,842,768	$77,913,958	$318,513,896

Table 8. AC03 – Leverage Decentralized Generation

Benefit Category	Utility	Customer	Society	Total
Reliability	$129,706,481	$113,819,026	$0	$243,525,506
Power Quality	$7,633,333	$0	$0	$7,633,333
Customer Value	$0	$0	$0	$0
Energy Efficiency	$0	$0	$0	$0
System Efficiency	$0	$0	$0	$0
Environment	$0	$0	$5,401	$5,401
T&D Capital Savings	$8,648,988	$0	$0	$8,648,988
T&D Operations and Maintenance Savings	$24,978,618	$0	$0	$24,978,618
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$883,051	$883,051
Total by Stakeholder	$176,177,705	$113,819,026	$888,452	$290,885,182

Table 9. AC04 – Increase Distribution Reliability

Benefit Category	Utility	Customer	Society	Total
Reliability	$2,087,469	$1,504,917	$0	$3,592,386
Power Quality	$4,047,285	$2,075,285	$0	$6,122,570
Customer Value	$0	$0	$0	$0
Energy Efficiency	$0	$0	$28,824,464	$28,824,464
System Efficiency	$934,860	$0	$0	$934,860
Environment	$0	$0	$943,985	$943,985
T&D Capital Savings	$5,163,977	$0	$0	$5,163,977
T&D Operations and Maintenance Savings	$481,965	$0	$0	$481,965
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$0	$0
Total by Stakeholder	$17,925,841	$3,580,202	$29,768,449	$51,274,492

Table 10. AC05 – Increase Distribution Power Quality

Benefit Category	Utility	Customer	Society	Total
Reliability	$89,581,928	$72,855,475	$0	$162,437,403
Power Quality	$0	$0	$0	$0
Customer Value	$0	$0	$0	$0
Energy Efficiency	$0	$0	$0	$0
System Efficiency	$0	$0	$0	$0
Environment	$0	$0	$0	$0
T&D Capital Savings	$7,122,696	$0	$0	$7,122,696
T&D Operations and Maintenance Savings	$6,411,364	$0	$0	$6,411,364
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$0	$0
Total by Stakeholder	$108,326,273	$72,855,475	$0	$181,181,749

Table 11. AC06 – Help Manage an Aging Infrastructure

Benefit Category	Utility	Customer	Society	Total
Reliability	$40,967,407	$43,893,415	$0	$84,860,821
Power Quality	$9,708,618	$2,075,285	$0	$11,783,903
Customer Value	$0	$9,143,589	$0	$9,143,589
Energy Efficiency	$0	$0	$31,147,563	$31,147,563
System Efficiency	$35,111,444	$0	$0	$35,111,444
Environment	$0	$0	$1,666,882	$1,666,882
T&D Capital Savings	$1,103,580	$0	$0	$1,103,580
T&D Operations and Maintenance Savings	$18,792,253	$0	$0	$18,792,253
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$0	$0
Total by Stakeholder	$110,893,588	$55,112,289	$32,814,445	$198,820,322

Table 12. AC07 – Leverage Plug-In Hybrid Electric Vehicles

Benefit Category	Utility	Customer	Society	Total
Reliability	$33,056,097	$39,832,468	$0	$72,888,565
Power Quality	$9,051,243	$2,075,285	$0	$11,126,528
Customer Value	$0	$35,629,172	$0	$35,629,172
Energy Efficiency	$0	$0	$72,753,271	$72,753,271
System Efficiency	$51,309,936	$0	$0	$51,309,936
Environment	$0	$0	$2,371,504	$2,371,504
T&D Capital Savings	$3,120,282	$0	$0	$3,120,282
T&D Operations and Maintenance Savings	$13,817,707	$0	$0	$13,817,707
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$883,051	$883,051
Total by Stakeholder	$115,565,550	$77,536,925	$76,007,826	$269,110,301

Table 13. AC08 – Support a Utility-Scale Microgrid

Benefit Category	Utility	Customer	Society	Total
Reliability	$0	$0	$0	$0
Power Quality	$0	$0	$0	$0
Customer Value	$0	$13,000,365	$0	$13,000,365
Energy Efficiency	$0	$0	$9,261,631	$9,261,631
System Efficiency	$65,548,059	$0	$0	$65,548,059
Environment	$0	$0	$331,967	$331,967
T&D Capital Savings	$1,965,305	$0	$0	$1,965,305
T&D Operations and Maintenance Savings	$0	$0	$0	$0
Theft	$0	$0	$0	$0
Safety	$0	$0	$0	$0
Total by Stakeholder	$67,513,364	$13,000,365	$9,593,598	$90,107,327

Table 14. AC09 – Enable High Penetration of Demand Response

Benefit Category	Utility	Customer	Society	Total
Reliability	$31,588,164	$38,027,188	$0	$69,615,352
Power Quality	$3,059,243	$2,075,285	$0	$5,134,528
Customer Value	$0	$0	$0	$0
Energy Efficiency	$0	$0	$69,851,738	$69,851,738
System Efficiency	$2,256,263	$0	$0	$2,256,263
Environment	$0	$0	$2,289,704	$2,289,704
T&D Capital Savings	$1,894,398	$0	$0	$1,894,398
T&D Operations and Maintenance Savings	$14,042,707	$0	$0	$14,042,707
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$883,051	$883,051
Total by Stakeholder	$58,051,061	$40,102,473	$73,024,493	$171,178,027

Table 15. AC10 – Support a Resilient Distribution System

Benefit Category	Utility	Customer	Society	Total
Reliability	$40,967,407	$50,568,163	$0	$91,535,570
Power Quality	$5,060,827	$2,075,285	$0	$7,136,112
Customer Value	$0	$0	$0	$0
Energy Efficiency	$0	$0	$45,862,361	$45,862,361
System Efficiency	$1,482,245	$0	$0	$1,482,245
Environment	$0	$0	$1,503,150	$1,503,150
T&D Capital Savings	$1,241,238	$0	$0	$1,241,238
T&D Operations and Maintenance Savings	$19,274,218	$0	$0	$19,274,218
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$883,051	$883,051
Total by Stakeholder	$73,236,220	$52,643,448	$48,248,562	$174,128,230

Table 16. AC11 – Optimize Distribution Capital Investments

Benefit Category	Utility	Customer	Society	Total
Reliability	$129,706,481	$113,819,026	$0	$243,525,506
Power Quality	$9,708,618	$2,075,285	$0	$11,783,903
Customer Value	$0	$13,000,365	$0	$13,000,365
Energy Efficiency	$0	$0	$79,113,369	$79,113,369
System Efficiency	$67,804,322	$0	$0	$67,804,322
Environment	$0	$0	$2,621,671	$2,621,671
T&D Capital Savings	$10,982,399	$0	$0	$10,982,399
T&D Operations and Maintenance Savings	$25,460,583	$0	$0	$25,460,583
Theft	$5,210,285	$0	$0	$5,210,285
Safety	$0	$0	$883,051	$883,051
Total by Stakeholder	$248,872,688	$128,894,676	$82,618,092	$460,385,455

Table 17. AC12 – Improve Distribution Operations and Maintenance