UTILITIES DEPARTMENT
INFORMATION TECHNOLOGY DEPARTMENT

Request for Proposal (RFP) Number 152568
for Professional Services

Wireless Network Plan

Pre-proposal Teleconference: 11:00 a.m.
Thursday July 10, 2014

RFP submittal deadline: 3:00 p.m.
Tuesday, July 29, 2014

Contract Administrator: Carolynn Bissett
Email: carolynn.bissett@cityofpaloalto.org
REQUEST FOR PROPOSAL (RFP) NO. 152568
FOR PROFESSIONAL SERVICES

TITLE: Wireless Network Plan

1. INTRODUCTION

The City of Palo Alto (City) is soliciting proposals from qualified consulting firms to develop a Wireless Network Plan (Plan) with a near-term focus on Wi-Fi deployment and a long-term consideration of other wireless technologies. The preferred consultant must demonstrate prior experience working with government agencies developing plans to build broadband networks.

This Plan is a key component of the City's “Technology and the Connected City” initiative started by the Mayor and the City Council in March 2013. The initiative also includes the development of a separate Fiber-to-the-Premise Master Plan (FTTP Master Plan). The City will conduct a separate Request for Proposal (RFP) process to retain a consulting firm to develop the FTTP Master Plan. Qualified Proposers responding to this RFP may also respond to the RFP to retain a consulting firm to develop the FTTP Master Plan.

An important aspect in the development of the Plan is to determine if the City's existing 41-mile dark fiber optic backbone system (“Fiber System”) can be fully leveraged for the deployment of Wi-Fi in certain high traffic commercial zones and City parks, or for a more ambitious citywide multi-use wireless network (“wireless network”) with the capability of supporting mobile broadband for public safety staff and other field-based staff, wireless communications support for the implementation of future Smart Grid applications, in addition to providing some level of Wi-Fi broadband connectivity for the general public and businesses.

The City's Information Technology and Utilities Departments have the responsibility for developing the Wireless Network Plan.

In relation to the preparation of the Plan, it is important to consider that the City of Palo Alto is one of thirty four (34) U.S. cities that Google Fiber is working with to explore the possibility of building a high speed network. The City provided a thorough and thoughtful response to the information and data requested in the Google Fiber City Checklist by the May 1, 2014 deadline. A large amount of City and utilities-related “public” information and data, in addition to “non-public” proprietary information and data was compiled about infrastructure, infrastructure access and construction during the process of responding to the Checklist. This information and data will help to facilitate the work required to prepare the Wireless Network Plan and the FTTP Master Plan.

Below is a link to the City's website with the “public” information the City provided to Google in its Checklist response:
A link is also provided to the April 29, 2014 staff report to the City Council which provided an update about the Google Fiber City Checklist response. As indicated in the staff report, access to non-public proprietary City and utilities-related infrastructure information and data can only be obtained under the auspices of a non-disclosure agreement (Attachment H).

City Manager Report ID # 4601, (April 29, 2014) Google Fiber Update
http://www.cityofpaloalto.org/civicax/filebank/documents/40088

Proposers may also want to review the “Open Data Platform” on the City’s website as a resource for important information and data about Palo Alto:
http://www.cityofpaloalto.org/gov/depts/it/open_data/default.asp

2. ATTACHMENTS

The attachments below are included with this Request for Proposals (RFP) for your review and submittal (see asterisk):

Attachment A – Proposer’s Information Form*
Attachment B – Scope of Work/Services
Attachment C – Sample Agreement for Professional Services
Attachment D – Sample Table, Qualifications of Firm Relative to City’s Needs
Attachment E – Cost Proposal Format
Attachment F – Insurance Requirement
Attachment G – SaaS / VISA Requirements (not applicable)
Attachment H – Non-disclosure Agreement
Attachment I – Fiber Optic Backbone Map
Attachment J – EnerNex Corp: “Assessment of Smart Grid Applications”

The items identified with an asterisk (*) shall be filled out, signed by the appropriate representative of the company and returned with submittal.

3. INSTRUCTIONS TO PROPOSERS

3.1 Pre-proposal Teleconference

A pre-proposal teleconference will be held Thursday, July 10, 2014 at 11:00 a.m. In order to participate in the teleconference, please call 1-877-336-1831 using Access Code 5301570. All prospective Proposers are strongly encouraged to attend.

3.2 Examination of Proposal Documents
The submission of a proposal shall be deemed a representation and certification by the Proposer that they:

3.2.1 Have carefully read and fully understand the information that was provided by the City to serve as the basis for submission of this proposal.

3.2.2 Have the capability to successfully undertake and complete the responsibilities and obligations of the proposal being submitted.

3.2.3 Represent that all information contained in the proposal is true and correct.

3.2.4 Did not, in any way, collude, conspire to agree, directly or indirectly, with any person, firm, corporation or other Proposer in regard to the amount, terms or conditions of this proposal.

3.2.5 Acknowledge that the City has the right to make any inquiry it deems appropriate to substantiate or supplement information supplied by Proposer, and Proposer hereby grants the City permission to make these inquiries, and to provide any and all related documentation in a timely manner.

No request for modification of the proposal shall be considered after its submission on grounds that Proposer was not fully informed to any fact or condition.

3.3 Addenda/Clarifications

Should discrepancies or omissions be found in this RFP or should there be a need to clarify this RFP, questions or comments regarding this RFP must be put in writing and received by the City no later than 1:00 p.m., Wednesday, July 16, 2014. Correspondence shall be e-mailed to carolynn.bissett@cityofpaloalto.org. Responses from the City will be communicated in writing to all recipients of this RFP. Inquiries received after the date and time stated will not be accepted and will be returned to senders without response. All addenda shall become a part of this RFP and shall be acknowledged on the Proposer’s Form.

The City shall not be responsible for nor be bound by any oral instructions, interpretations or explanations issued by the City or its representatives.

3.4 Submission of Proposals

All proposals shall be submitted to:

City of Palo Alto
Purchasing and Contract Administration
250 Hamilton Avenue, Mail Stop MB
Palo Alto, CA 94301
Proposals must be delivered no later than 3:00 p.m. on Tuesday, July 29, 2014. All proposals received after that time will be returned to the Proposer unopened.

The Proposer shall submit one (1) hard copy of its proposal in a sealed envelope, labeled “Original”, addressed as noted above, bearing the Proposer’s name and address clearly marked, “RFP NO. 152568 FOR PROFESSIONAL SERVICES: WIRELESS NETWORK MASTER PLAN.” Also submit proposal in soft copy via CD or Flash Drive. [The use of double-sided paper with a minimum 50% post-consumer recycled content is strongly encouraged. Please do not submit proposals in binders].

3.5 Withdrawal of Proposals

A Proposer may withdraw its proposal at any time before the expiration of the time for submission of proposals as provided in the RFP by delivering a written request for withdrawal signed by, or on behalf of, the Proposer.

3.6 Rights of the City of Palo Alto

This RFP does not commit the City to enter into a contract, nor does it obligate the City to pay for any costs incurred in preparation and submission of proposals or in anticipation of a contract. The City reserves the right to:

- Make the selection based on its sole discretion;
- Reject any and all proposals;
- Issue subsequent Requests for Proposals;
- Postpone opening for its own convenience;
- Remedy technical errors in the Request for Proposals process;
- Approve or disapprove the use of particular subconsultants;
- Negotiate with any, all or none of the Proposers;
- Accept other than the lowest offer;
- Waive informalities and irregularities in the Proposals and/or
- Enter into an agreement with another Proposer in the event the originally selected Proposer defaults or fails to execute an agreement with the City.

An agreement shall not be binding or valid with the City unless and until it is executed by authorized representatives of the City and of the Proposer.

4. PROPOSED TENTATIVE TIMELINE
The tentative RFP timeline is as follows:

<table>
<thead>
<tr>
<th>Event</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>RFP Issued</td>
<td>July 3, 2014</td>
</tr>
<tr>
<td>Pre-Proposal Telecon</td>
<td>July 10, 2014</td>
</tr>
<tr>
<td>Deadline for questions, clarifications</td>
<td>July 16, 2014</td>
</tr>
<tr>
<td>Proposals Due</td>
<td>July 29, 2014</td>
</tr>
<tr>
<td>Finalist Identified</td>
<td>August 8, 2014</td>
</tr>
<tr>
<td>Consultant Interviews</td>
<td>August 15, 2014</td>
</tr>
<tr>
<td>Consultant selection and contract preparation</td>
<td>August 29, 2014</td>
</tr>
<tr>
<td>Contract awarded</td>
<td>September 1, 2014</td>
</tr>
<tr>
<td>Work commences</td>
<td>September 2014</td>
</tr>
<tr>
<td>Work complete</td>
<td>November 2014</td>
</tr>
</tbody>
</table>

5. INFORMATION TO BE SUBMITTED (to be submitted in this order only)

These instructions outline the guidelines governing the format and content of the proposal and the approach to be used in its development and presentation. The intent of the RFP is to encourage responses that clearly communicate the Proposer’s understanding of the City’s requirements and its approach to successfully provide the products and/or services on time and within budget. Only that information which is essential to an understanding and evaluation of the proposal should be submitted. Items not specifically and explicitly related to the RFP and proposal, e.g. brochures, marketing material, etc. will not be considered in the evaluation.

All proposals shall address the following items in the order listed below and shall be numbered 1 through 8 in the proposal document.

5.1 Chapter 1 – Proposal Summary

This Chapter shall discuss the highlights, key features and distinguishing points of the Proposal. A separate sheet shall include a list of individuals and contacts for this Proposal and how to communicate with them. Limit this Chapter to a total of three (3) pages including the separate sheet.

5.2 Chapter 2 – Profile on the Proposing Firm(s)

This Chapter shall include a brief description of the Prime Proposer’s firm size as well as the proposed local organization structure. Include a discussion of the Prime Proposer firm’s financial stability, capacity and resources. Include all other firms participating in the Proposal, including similar information about the firms.

Additionally, this section shall include a listing of any lawsuit or litigation and the result of that action resulting form (a) any public project undertaken by the Proposer or by its subcontractors where litigation is still pending or has occurred within the last five years or (b) any type of project where claims or
settlements were paid by the consultant or its insurers within the last five years.

5.3 Chapter 3 – Qualifications of the Firm

This Chapter shall include a brief description of the Proposer’s and sub-Proposer’s qualifications and previous experience on similar or related projects. Provide in a table format (see Sample Table, Attachment D) descriptions of pertinent project experience with other public municipalities and private sector that includes a summary of the work performed, the total project cost, the percentage of work the firm was responsible for, the period over which the work was completed, and the name, title, and phone number of client’s to be contacted for references. Give a brief statement of the firm’s adherence to the schedule and budget for the project. Overview of the Proposer’s firm and descriptions of relevant work performed by the Proposer within the past three years.

Experience in developing detailed cost-benefit analysis and business plans. Sample report(s) from similar projects performed within the past three years will be highly valued. A minimum of three references from projects the Proposer has contributed significant work or content.

This chapter shall include information regarding any relationships with firms and/or individuals who may submit proposals in response to the RFPs being developed.

5.4 Chapter 4 – Work Plan or Proposal

This Chapter shall present a well-conceived service plan. Include a full description of major tasks and subtasks. This section of the proposal shall establish that the Proposer understands the City’s objectives and work requirements and Proposer’s ability to satisfy those objectives and requirements. Succinctly describe the proposed approach for addressing the required services and the firm’s ability to meet the City’s schedule, outlining the approach that would be undertaken in providing the requested services.

5.5 Chapter 5 – Proposed Innovations

The Proposer may also suggest technical or procedural innovations that have been used successfully on other engagements and which may provide the City with better service delivery. In this Chapter discuss any ideas, innovative approaches, or specific new concepts included in the Proposal that would provide benefit to the City.
5.6 Chapter 6 – Project Staffing

This Chapter shall discuss how the Proposer would propose to staff this project. Key project team members shall be identified by name, title and specific responsibilities on the project. An organizational chart for the project team and resumes for key Proposer personnel shall be included. Key personnel will be an important factor considered by the review committee. Changes in key personnel may be cause for rejection of the proposal.

Listing of the proposed team members assigned to the project and the areas of responsibilities for each team member.

5.7 Chapter 7 – Proposal Exceptions

This Chapter shall discuss any exceptions or requested changes that Proposer has to the City’s RFP conditions, requirements and sample contract. If there are no exceptions noted, it is assumed the Proposer will accept all conditions and requirements identified in the Attachment C – “Sample Agreement for Services.” Items not excepted will not be open to later negotiation.

5.8 Chapter 8 – Proposal Costs Sheet and Rates

The fee information is relevant to a determination of whether the fee is fair and reasonable in light of the services to be provided. Provision of this information assists the City in determining the firm’s understanding of the project, and provides staff with tools to negotiate the cost, provide in a table (See sample Table, Attachment E).

This Chapter shall include the proposed costs to provide the services desired. Include any other cost and price information, plus a not-to-exceed amount, that would be contained in a potential agreement with the City. The hourly rates may be used for pricing the cost of additional services outlined in the Scope of Work.

Proposed budget for the evaluation project, broken down by hours and rates for each task. Costs for travel and incidentals should be included in the proposal. Include a total not-to-exceed price for the entire project.

Resumes and hourly rates for individual team members assigned to the project.

PLEASE NOTE: The City of Palo Alto does not pay for services before it receives them. Therefore, do not propose contract terms that call for upfront payments or deposits.
6. CONTRACT TYPE AND METHOD OF PAYMENT

It is anticipated that the agreement resulting from this solicitation, if awarded, will be a not-to-exceed budget per task form of contract. A Sample Agreement of Services is provided as Attachment C. The method of payment to the successful Proposer shall be on a per task basis with a maximum “not to exceed” fee as set by the Proposer in the proposal or as negotiated between the Proposer and the City as being the maximum cost to perform all work. This figure shall include direct costs and overhead, such as, but limited to, transportation, communications, subsistence and materials and any subcontracted items of work. Progress payments will be based on a percentage of project completed.

Proposers shall be prepared to accept the terms and conditions of the Agreement, including Insurance Requirements in Attachment F. If a Proposer desires to take exception to the Agreement, Proposer shall provide the following information in Chapter 7 of their submittal package. Please include the following:

- Proposer shall clearly identify each proposed change to the Agreement, including all relevant Attachments.
- Proposer shall furnish the reasons for, as well as specific recommendations, for alternative language.

The above factors will be taken into account in evaluating proposals. Proposals that take substantial exceptions to the proposed Agreement may be determined by the City, at its sole discretion, to be unacceptable and no longer considered for award.

Insurance Requirements

The selected Proposer(s), at Proposer's sole cost and expense and for the full term of the Agreement or any extension thereof, shall obtain and maintain, at a minimum, all of the insurance requirements outlined in Attachment F.

All policies, endorsements, certificates and/or binders shall be subject to the approval of the Risk Manager of the City of Palo Alto as to form and content. These requirements are subject to amendment or waiver if so approved in writing by the Risk Manager. The selected Proposer agrees to provide the City with a copy of said policies, certificates and/or endorsement upon award of contract.

7. REVIEW AND SELECTION PROCESS

City staff will evaluate the proposals provided based on the following criteria:

7.1 Quality and completeness of proposal;
7.2 Quality, performance and effectiveness of the solution, goods and/or services to be provided by the Proposer;
7.3 Proposers experience, including the experience of staff to be assigned to the project, the engagements of similar scope and complexity;
7.4 Cost to the city;
7.5 Proposer's financial stability;
7.6 Proposer’s ability to perform the work within the time specified;
7.7 Proposer's prior record of performance with city or others;
7.8 Proposer’s ability to provide future maintenance, repairs parts and/or services; and
7.9 Proposer’s compliance with applicable laws, regulations, policies (including city council policies), guidelines and orders governing prior or existing contracts performed by the contractor.

The selection committee will make a recommendation to the awarding authority. The acceptance of the proposal will be evidenced by written Notice of Award from the City’s Purchasing/Contract Administration Division to the successful Proposer.

8. ORAL INTERVIEWS

Proposers may be required to participate in an oral interview. The oral interview will be a panel comprised of members of the selection committee.

Proposers may only ask questions that are intended to clarify the questions that they are being asked to respond.

Each Proposer’s time slot for oral interviews will be determined randomly. Proposers who are selected shall make every effort to attend. If representatives of the City experience difficulty on the part of any Proposer in scheduling a time for the oral interview, it may result in disqualification from further consideration.

9. PUBLIC NATURE OF MATERIALS

Responses to this RFP become the exclusive property of the City of Palo Alto. At such time as the Administrative Services Department recommends to form to the City Manager or to the City Council, as applicable, all proposals received in response to this RFP becomes a matter of public record and shall be regarded as public records, with the exception of those elements in each proposal which are defined by the Proposer as business or trade secrets and plainly marked as “Confidential,” “Trade Secret,” or “Proprietary”. The City shall not in any way be liable or responsible for the disclosure of any such proposal or portions thereof, if they are not plainly marked as “Confidential,” “Trade Secret,” or “Proprietary” or if disclosure is required under the Public Records Act. Any proposal which contains
language purporting to render all or significant portions of the proposal “Confidential,” “Trade Secret,” or “Proprietary” shall be regarded as non-responsive.

Although the California Public Records Act recognizes that certain confidential trade secret information may be protected from disclosure, the City of Palo Alto may not accept or approve that the information that a Proposer submits is a trade secret. If a request is made for information marked “Confidential,” “Trade Secret,” or “Proprietary,” the City shall provide the Proposer who submitted the information with reasonable notice to allow the Proposer to seek protection from disclosure by a court of competent jurisdiction.

10. COLLUSION

By submitting a proposal, each Proposer represents and warrants that its proposal is genuine and not a sham or collusive or made in the interest of or on behalf of any person not named therein; that the Proposer has not directly induced or solicited any other person to submit a sham proposal or any other person to refrain from submitting a proposal; and that the Proposer has not in any manner sought collusion to secure any improper advantage over any other person submitting a proposal.

11. DISQUALIFICATION

Factors such as, but not limited to, any of the following may be considered just cause to disqualify a proposal without further consideration:

11.1 Evidence of collusion, directly or indirectly, among Proposers in regard to the amount, terms or conditions of this proposal;

11.2 Any attempt to improperly influence any member of the evaluation team;

11.3 Existence of any lawsuit, unresolved contractual claim or dispute between Proposer and the City;

11.4 Evidence of incorrect information submitted as part of the proposal;

11.5 Evidence of Proposer’s inability to successfully complete the responsibilities and obligation of the proposal; and

11.6 Proposer’s default under any previous agreement with the City, which results in termination of the Agreement.

12. NON-CONFORMING PROPOSAL

A proposal shall be prepared and submitted in accordance with the provisions of these RFP instructions and specifications. Any alteration, omission, addition, variance, or limitation of, from or to a proposal may be sufficient grounds for non-acceptance of the proposal, at the sole discretion of the City.

13. GRATUITIES
No person shall offer, give or agree to give any City employee any gratuity, discount or offer of employment in connection with the award of contract by the city. No city employee shall solicit, demand, accept or agree to accept from any other person a gratuity, discount or offer of employment in connection with a city contract.

~ End of Section ~
Attachment A
Proposer’s Information Form

PROPOSER (please print):

Name: __________________________________________________________

Address: __________________________________________________________

Telephone: _______________________ Email: _____________________________

Contact person, title, email, and telephone: __________________________
____________________________________________________________________
____________________________________________________________________

Proposer, if selected, intends to carry on the business as (check one):

☐ Individual  ☐ Joint Venture

☐ Partnership

☐ Corporation

When incorporated? ______________

In what state? _______________

When authorized to do business in California? ______

☐ Other (explain):____________________________________________________

ADDENDA

To assure that all Proposers have received each addendum, check the appropriate box(es)
below. Failure to acknowledge receipt of an addendum/addenda may be considered an
irregularity in the Proposal:

Addendum number(s) received:  ☐ 1;  ☐ 2;  ☐ 3;  ☐ 4;  ☐ 5;  ☐ 6;

Or,  ☐ _____ _____No Addendum/Addenda Were Received (check and initial).

2 PROPOSER’S SIGNATURE

No proposal shall be accepted which has not been signed in ink in the appropriate space below:

By signing below, the submission of a proposal shall be deemed a representation
and certification by the Proposer that they have investigated all aspects of the
RFP, that they are aware of the applicable facts pertaining to the RFP process, its
procedures and requirements, and they have read and understand the RFP. No
request for modification of the proposal shall be considered after its submission on
the grounds that the Proposer was not fully informed as to any fact or condition.
1. If Proposer is **INDIVIDUAL**, sign here

Date: ________________  _____________________________________

Proposer’s Signature

_____________________________________

Proposer’s typed name and title

2. If Proposer is **PARTNERSHIP** or **JOINT VENTURE**; at least two (2) Partners shall sign here:

________________________________________________

Partnership or Joint Venture Name (type or print)

Date: ________________  _____________________________________

Member of the Partnership or Joint Venture signature

Date: ________________  _____________________________________

Member of the Partnership or Joint Venture signature

3. If Proposer is a **CORPORATION**, the duly authorized officer shall sign as follows:

The undersigned certify that he/she is respectively:

_________________________________ and ___________________________

Signature       Title

Of the corporation named below; that they are designated to sign the Proposal Cost Form by resolution (attach a certified copy, with corporate seal, if applicable, notarized as to its authenticity or Secretary’s certificate of authorization) for and on behalf of the below named CORPORATION, and that they are authorized to execute same for and on behalf of said CORPORATION.

__________________________________________

Corporation Name (type or print)

By: ______________________________________   Date:  _________________

Title:__________________________________________
ATTACHMENT B - SCOPE OF WORK

City of Palo Alto
Request for Proposal (RFP) 152568
Consulting Services to Develop a Wireless Network Plan

Background Information
Palo Alto is a thriving community of approximately 64,000 people situated adjacent to Stanford University in the heart of Silicon Valley. Palo Alto is approximately thirty three (33) miles south of San Francisco and seventeen (17) miles north of San Jose. On weekdays, due to daily commuters, the population of Palo Alto increases to nearly 140,000. Palo Alto enjoys international recognition. People from all over the world come to Palo Alto for purposes of education and research at Stanford University, training or business with the high technology firms at the Stanford Research Park, or medical care at the Stanford Medical Center.

The City of Palo Alto is a charter city operating under the council manager form of municipal government. The City’s General Fund budget is $171.1 million for fiscal year 2015. The City has thirteen (13) departments. The City of Palo Alto also provides the following utility services: electric, gas, water, storm drainage, wastewater collection, water treatment and commercial dark fiber.

In 2010, 52.6% of the 27,639 housing units in Palo Alto were owner occupied, 42.5% were renter occupied and 5% were vacant. The rate of change in housing units between 2000 and 2010 was less than one percent.

Palo Alto is home to just over 7,000 businesses. The most common types of businesses are in the services sector, which make up nearly 60% of all business types. The next most popular sectors are manufacturing at 16.6% and retail at 16%.

The median household income in Palo Alto is $122,531 and the per capita income is $72,199. The median value of owner-occupied housing units is $1,000,000. As of 2010, 57% of all households in Palo Alto had an annual income of greater than $100,000.

The land area in Palo Alto in square miles is 25.87 miles. The population is concentrated on eleven (11) square miles between the Baylands/San Francisco Bay and the foothills.

The incumbent telecommunications service providers in Palo Alto are AT&T and Comcast.

Fiber System History
The Fiber System was originally conceived by the City in the mid-1990s. The City’s initial telecommunications strategy was to build a dark fiber ring around Palo Alto that would be capable of supporting multiple network developers and/or service providers with
significant growth potential. City of Palo Alto Utilities ("CPAU") has the day-to-day responsibility for operating, maintaining, expanding and marketing the Fiber System.

The first phase of the Fiber System construction occurred in 1996-1997. The initial portions of the system were constructed in a ring architecture in existing utility rights-of-way. The Fiber System was routed to pass and provide access to key City facilities and offices. The majority of the City’s business parks (e.g. Stanford Research Park) and commercial properties are also passed by the Fiber System. The original Fiber System consisted of 33 route miles with 144 or more strands of single-mode fiber along most routes. The Fiber System has been expanded to approximately 41 route miles of mostly 144- or 288-count single-mode fiber. The Fiber System is approximately 55 percent aerial and 45 percent underground. Fiber plant in residential areas is mostly aerial. Aerial plant is attached in the unrestricted power space on utility poles. The City jointly owns 5,400 of the 6,000 utility poles in Palo Alto with AT&T. For reference, a Fiber Optic Backbone Map is attached (Attachment I).

The Fiber System construction was financed internally by the Electric Enterprise Fund through a 20-year, $2 million loan at a 0% interest rate. These funds were used to construct the system and to cover operating expenses. At the end of Fiscal Year 2008, the fiber optics business completed the loan repayment to the Electric Enterprise Fund for all capital and operating expenses from the beginning of the project. A separate Fiber Optics Enterprise Fund, capable of maintaining its own capital and operating budgets and financial operating reserve, was also created. In Fiscal Year 2009, a Fiber Optics Enterprise Fund Rate Stabilization Reserve (RSR) was established.

In 2000, CPAU began to license “dark fiber” for commercial purposes. The Fiber System has high market share and brand awareness among commercial enterprises and other organizations that need the quantity and quality of bandwidth provided by direct fiber optic connections. By connecting to the City’s Fiber System, a customer gains access to their Internet Service Provider ("ISP") of choice. Many customers gain access to the Internet through the Palo Alto Internet Exchange ("PAIX", now owned by Equinix). PAIX is a carrier-neutral collocation facility and hosts over seventy (70) ISPs at their facility located in downtown Palo Alto. Commercial dark fiber customers can interconnect communications systems or computer networks across multiple Palo Alto locations and can also connect directly to their local and/or long distance carrier(s) of choice with a full range of communications services. Customers can also have redundant telecommunication connections for enhanced reliability.

CPAU currently licenses dark fiber service connections to more than ninety (90) commercial customers. Among these commercial customers are several value-added “resellers” licensing dark fiber from CPAU to deliver a variety of telecom services. The Fiber System also serves the following City accounts: IT Infrastructure Services, Utilities Substations, Utilities Engineering, Public Works, Water Quality Control Plant and Community Services. The total number of dark fiber service connections serving commercial customers and the City is approximately 250 (some customers have multiple
connections). At the end of fiscal year 2014, the licensing of dark fiber service connections resulted in a fiber fund reserve of approximately $18.6 million.

Plans to expand the Fiber System closer to some commercial areas that are at a significant distance from the backbone are ongoing. These expansion plans are typically based on identifying clusters of commercial customers with business profiles comparable to the existing customer base. In general, these customers need high bandwidth dark fiber service connections and have the technical resources to install and maintain the required transmission equipment to provision the fiber strands. Examples of Fiber System expansion opportunities include multi-tenant office buildings or office parks. In March of 2014, CPAU completed a project to install dark fiber service connections at eighteen (18) Palo Alto Unified School District facilities. The extension of the Fiber System to school district facilities brings fiber infrastructure closer to a number of residential neighborhoods distributed throughout Palo Alto. Moreover, school dark fiber connections significantly enhance the value of the system for future expansion and facilitate broadband connectivity for a key community anchor institution and other potential users.

The City has also evaluated the feasibility of expanding commercial telecommunications offerings to include new products such as managed networking services (e.g. SONET, Ethernet and wavelength services). However, staff concluded that there are multiple firmly established telecommunications providers that specialize in addressing these types of services, both locally and nationally. As a result, there is no unique opportunity for the City to capitalize in the highly competitive market for managed telecommunication services.

**Fiber-to-the-Premise Efforts**

Since the late 1990s, the City has evaluated various models to expand the City’s Fiber System for residential deployment and potential wireless applications. Due to a number of factors, the City has been unable to develop a feasible plan; however, given the upturn in the economy, the City now believes there is renewed interest from telecommunication service providers in building an ultra-high speed network in Palo Alto. On October 28, 2013, the City Council decided that the best approach to attracting these providers is to develop a FTTP Master Plan which includes an engineering study to prepare a network design, along with a cost model and business model to deploy a citywide FTTP Network. After the Master Plan is completed, the City will decide whether to seek a third party telecommunications service provider to build and operate the FTTP Network by conducting a RFP, or evaluate the feasibility of the City implementing the Master Plan on its own. A subset of this effort is to develop a complementary Wireless Network Plan.

Another anticipated outcome of developing a FTTP Master Plan and Wireless Network Plan is to define network specifications which will be used as a reference point by the City’s Planning and Community Environment Department to conduct a California Environmental Quality Assessment (“CEQA”) review prior to issuing an RFP.
Scope of Work
The City is soliciting proposals from consulting firms to develop a Wireless Network Plan that will provide the best path and business model to deploy a municipal network to support the City’s goal of becoming a “leading digital city.” The Plan will address the City’s objective to evaluate the following:

1. Wi-Fi broadband connectivity for the general public and businesses to ensure economic development, increased access to broadband and digital inclusion for all members of the community;
2. Improved wireless broadband connectivity to support public safety and the delivery of municipal services by field-based staff using a wide variety of mobile government applications over tablets, laptops and smartphones;
3. Wireless government to improve efficiency and reduce the cost of public administration.

To develop the Plan, the Proposer should consider the City Council’s vision for broadband connectivity. This vision includes the following:

• The Council’s long term vision for the community and in particular the quality of broadband connectivity in Palo Alto. Since the United States Congress enacted the Telecommunications Act of 1996, the City has been supportive of the placement of advanced communications facilities in Palo Alto. In 1997, the City Council approved four “Telecommunications Policy Statements” which laid the foundation for bringing advanced broadband services to Palo Alto;¹
• The City Council’s “Technology and the Connected City” initiative started by the Mayor and City Council in March 2013, with the goal of ensuring that residents, businesses and anchor institutions in Palo Alto have access to ubiquitous and reliable ultra-high-speed broadband connectivity;
• The appointment of a Citizen Advisory Committee by the City Manager in February 2014, to work with the City Council, Utilities Advisory Commission and City staff to review proposals and provide feedback regarding the development of the Wireless Network Plan and the FTTP Master Plan.

Deliverables
The following tasks describe the City’s expectations regarding the areas that should be addressed to assist the City in developing a Wireless Network Plan:

¹ Policy statement number 1 declared the City’s policy to facilitate the competitive delivery of conventional and advanced telecommunications services in Palo Alto in light of the Telecom Act of 1996. Policy statement number 2 declared the City’s policy to regulate these facilities in accordance with reasonable and non-discriminatory regulations. Policy statement number 3 declared the City’s policy to permit the use of the Utilities Department’s infrastructure for advance communications purposes provided such use does not unduly interfere with the City’s primary mission of providing electric utility service to its customers. Policy statement number 4 declared the City’s policy to permit interested parties to use other City property and facilities for the siting of telecommunications infrastructure, consistent with the City’s zoning, environmental, legal and other requirements.
**Task 1:** Define the fundamental action steps required to develop a wireless broadband initiative for the City, including an assessment of how the existing Fiber System and other supporting municipal infrastructure can be leveraged and maximized to deploy Wi-Fi and/or a citywide wireless network. This task should provide examples of communities that have developed effective municipal wireless networks and how these networks are used to enhance the delivery of municipal services, in addition to providing the general public and businesses with some level of wireless broadband connectivity, either as an “amenity grade” Wi-Fi service in certain areas of the community or as a citywide service that may be subscription-based.

**Task 2:** Conduct a user group “needs assessment” for a wireless network among all City departments and also assess the need for an amenity-grade or subscription-based Wi-Fi service for the general public and businesses. The primary purpose of the needs assessment is to define the City’s strategic priorities and operational needs driving the overall design standards for either a multi-use network for public safety, municipal service delivery and public access, or a network with a more limited scope.

Examples of City departments with field-based staff who may benefit from access to a multi-use municipal wireless network include:
- Planning and Building (Building Inspectors and Code Enforcement Officers)
- Community Services (Open Spaces and Recreation Staff)
- Public Works (Engineers, Inspectors and construction crews)
- Utilities (Engineers, Estimators, Inspectors and construction crews)
- Public Safety departments (Police, Office of Emergency Services and Fire) to support connectivity of field staff as well as the 911 Center and Emergency Operation Center, located in the Police Department.²

The user group needs assessment should also take into account an evaluation of the communication approaches to implement Smart Grid applications such as Advanced Metering Infrastructure (AMI) and Smart Meters. This assessment should include a review of the findings and recommendations described in the “Assessment of Smart Grid Applications for the City of Palo Alto” prepared by EnerNex Corporation (reference Sec. 4.2.3 “Proposed Smart Grid Communications Architecture” and Sec. 6.0 “Evaluation of Communication Systems Approaches” (Attachment J).

CPAU is currently conducting a Customer Connect Smart Grid Pilot Project. CPAU has deployed a 900 MHz mesh network which covers approximately 75 percent of the geographic area of Palo Alto to serve the 300 residential customers participating in the

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² Police vehicles and fire apparatus, and other field-based City staff, currently use commercial cellular networks for mobile broadband access. Public safety vehicles are equipped with Mobile Data Computers (MDCs) that provide Internet access and run a variety of specialized public safety applications, including Computer Aided Dispatch (CAD), GIS-based mapping application, and CALPHOTO, which provides officers with a photo to identify individuals. To switch from one network to another, police and fire vehicles are equipped with NetMotion software which allows the MDCs to roam between cellular and Wi-Fi networks seamlessly depending on signal strength.
pilot dispersed throughout Palo Alto. The cost of setting up this network was under $20,000. This network is capable of remotely reading and monitoring customer electric, natural gas and water meters. Monitoring devices are set up along the distribution network in a non-SCADA configuration. It is presently estimated that with equipment it is worth an additional $30,000-$50,000. The network could be expanded to cover 100 percent of the city to read all 29,000 customer accounts and 72,000 customer meters. If the pilot project proves to be successful by the end of 2015, this radio-based mesh network, along with cellular phone based backhaul, will be a strong candidate for a communication network for Smart Grid applications.

Task 2 should also include an assessment of alternatives to the commercial cellular networks currently used by the City for mobile broadband access. The objective is to meet the City’s long term needs for public safety first responders and other field-based staff dependent on reliable, high data rate mobile broadband connectivity to effectively deliver municipal services. This assessment should compare and contrast the current commercial cellular network’s strengths and weaknesses against those of a citywide multi-use Wi-Fi WAN.

Task 3: Based on the user group needs assessment, recommend wireless technology options and design considerations for either a multi-use network (municipal, public safety and public access), or a network with a more limited scope. Design considerations should include an assessment and recommendations of the following:

a. Review available City-owned assets and infrastructure to support the mounting of antennas and equipment for a Wi-Fi and/or wireless network. Assets and infrastructure include the potential use of City-controlled public rights-of-way, availability of spare dark fiber for wireless access points to support network backhaul, space on utility poles and streetlight poles, and available space in conduit. The City also has approximately 90 fiber-connected traffic signals, in addition to communication towers and multiple City-owned properties and buildings;

b. Evaluate and recommend network architecture and technology choices (e.g., Wi-Fi, 2.4/5.8 GHz Wi-Fi system, WiMAX, 4.9 GHz public safety band and 4G cellular) based on the City’s overall wireless goals and the findings identified in the user group needs assessment;

c. Evaluate and recommend wireless technology and network architecture that is flexible and scalable to meet the City’s short term objectives and also able to adapt to emerging services and applications over time;

d. Evaluate network topology based on the scope of the network and integration with the fiber system, internal data networks, and the various applications used by field-based staff;

e. Evaluate and recommend network hardware and software components required to support end users;

f. Identify potential project vendors based on network technology choices and design priorities. Examples of these vendors include: network designers, field installation contractors, application developers, systems integrators and Internet Service Providers (ISPs);
g. Define network security criteria and features and make a recommendation;
h. Develop network cost estimates based on the results of the user needs assessment, technology choices and the scope of the project;
i. Evaluate the integration of a wireless network with existing City computer systems, databases and various enterprise applications;
j. Define operational Information Technology items such as the need for a Subscriber Management System and ongoing support structures, including customer Service Level Agreements;
k. Identify the skill sets required by the City’s Information Technology and Utilities Departments to implement and operate a wireless network;
l. Define and evaluate network resilience and survivability design goals, including solar power and other emergency back-up power and network architecture operability for at least seven (7) days with no grid power, with prioritization to public safety, critical infrastructure and lifeline services. To complete the evaluation, interview the Police Department Director of Technical Services, the Director of Emergency Services and the Utilities Department Director of Engineering to develop requirements for network performance (QoS) and compliance with United States Department of Justice metrics and other public safety and critical infrastructure metrics.

**Task 4:** Analyze the advantages and disadvantages of the various business models used to deploy municipal wireless networks and make a recommendation based on the needs of the City and various potential users of the network. This analysis should include a municipal wireless program review of networks deployed in other cities. Potential business models would include, but would not be limited to the following:

- **City-owned wholesale model:** the wireless network is owned and operated by the City.
- **Privately-owned managed services model:** the wireless network is owned and operated by a service provider, but the City is an “anchor tenant” for the network.
- **Hybrid model (public-private partnership):** the City owns the network, but outsources operation and maintenance to a service provider.\(^3\)

Task 4 should also include an assessment of the legal responsibilities under the various business models and general policy development such as VLAN strategies or QoS restrictions and opportunities.

**Task 5:** Upon completion of the Wireless Network Plan, in consultation with City staff, present the findings and recommendations to the City Council, Utilities Advisory Commission, Citizen Advisory Committee and executive City staff. Based on the findings and recommendations established in the final Wireless Network Plan, and contingent upon City Council direction to proceed, develop a RFP for a vendor to build a Wi-Fi

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\(^3\)“Wireless Cities: A Strategic Roadmap.” Author: Nicola Villa, Sr., Manager, Local and Broadband Government Internal Business Solutions Group, Cisco Internet Business Solutions Group (IBSG).
system and/or a citywide wireless network. The Proposer must consider previous, current, and future planned wireless-related evaluation efforts by the City in order to avoid repeating or duplicating efforts. The City’s Project Manager will assist in identifying and understanding these efforts at the outset of this consulting engagement.

~ End of Scope~
AGREEMENT BETWEEN THE CITY OF PALO ALTO AND
FOR PROFESSIONAL SERVICES

This Agreement is entered into on this day of , , , ("Agreement") by and between the CITY OF PALO ALTO, a California chartered municipal corporation ("CITY"), and , a , located at ("CONSULTANT").

RECITALS

The following recitals are a substantive portion of this Agreement.

A. CITY intends to ("Project") and desires to engage a consultant to in connection with the Project ("Services").

B. CONSULTANT has represented that it has the necessary professional expertise, qualifications, and capability, and all required licenses and/or certifications to provide the Services.

C. CITY in reliance on these representations desires to engage CONSULTANT to provide the Services as more fully described in Exhibit “A”, attached to and made a part of this Agreement.

NOW, THEREFORE, in consideration of the recitals, covenants, terms, and conditions, in this Agreement, the parties agree:

SECTION 1. SCOPE OF SERVICES. CONSULTANT shall perform the Services described in Exhibit “A” in accordance with the terms and conditions contained in this Agreement. The performance of all Services shall be to the reasonable satisfaction of CITY.

Optional On-Call Provision (This provision only applies if checked and only applies to on-call agreements.)

Services will be authorized by the City, as needed, with a Task Order assigned and approved by the City’s Project Manager. Each Task Order shall be in substantially the same form as Exhibit A-1. Each Task Order shall designate a City Project Manager and shall contain a specific scope of work, a specific schedule of performance and a specific compensation amount. The total price of all Task Orders issued under this Agreement shall not exceed the amount of Compensation set forth in Section 4 of this Agreement. CONSULTANT shall only be compensated for work performed under an authorized Task Order and the City may elect, but is not required, to authorize work up to the maximum compensation amount set forth in Section 4.
SECTION 2. TERM.
The term of this Agreement shall be from the date of its full execution through unless terminated earlier pursuant to Section 19 of this Agreement.

OR

The term of this Agreement shall be from the date of its full execution through completion of the services in accordance with the Schedule of Performance attached as Exhibit “B” unless terminated earlier pursuant to Section 19 of this Agreement.

SECTION 3. SCHEDULE OF PERFORMANCE. Time is of the essence in the performance of Services under this Agreement. CONSULTANT shall complete the Services within the term of this Agreement and in accordance with the schedule set forth in Exhibit “B”, attached to and made a part of this Agreement. Any Services for which times for performance are not specified in this Agreement shall be commenced and completed by CONSULTANT in a reasonably prompt and timely manner based upon the circumstances and direction communicated to the CONSULTANT. CITY’s agreement to extend the term or the schedule for performance shall not preclude recovery of damages for delay if the extension is required due to the fault of CONSULTANT.

SECTION 4. NOT TO EXCEED COMPENSATION. The compensation to be paid to CONSULTANT for performance of the Services described in Exhibit “A”, including both payment for professional services and reimbursable expenses, shall not exceed Dollars ($  ). In the event Additional Services are authorized, the total compensation for Services, Additional Services and reimbursable expenses shall not exceed Dollars ($  ). The applicable rates and schedule of payment are set out in Exhibit “C-1”, entitled “HOURLY RATE SCHEDULE,” which is attached to and made a part of this Agreement.

Additional Services, if any, shall be authorized in accordance with and subject to the provisions of Exhibit “C”. CONSULTANT shall not receive any compensation for Additional Services performed without the prior written authorization of CITY. Additional Services shall mean any work that is determined by CITY to be necessary for the proper completion of the Project, but which is not included within the Scope of Services described in Exhibit “A”.

SECTION 5. INVOICES. In order to request payment, CONSULTANT shall submit monthly invoices to the CITY describing the services performed and the applicable charges (including an identification of personnel who performed the services, hours worked, hourly rates, and reimbursable expenses), based upon the CONSULTANT’s billing rates (set forth in Exhibit “C-1”). If applicable, the invoice shall also describe the percentage of completion of each task. The information in CONSULTANT’s payment requests shall be subject to verification by CITY. CONSULTANT shall send all invoices to the City’s project manager at the address specified in Section 13 below. The City will generally process and pay invoices within thirty (30) days of receipt.

SECTION 6. QUALIFICATIONS/STANDARD OF CARE. All of the Services shall be performed by CONSULTANT or under CONSULTANT’s supervision. CONSULTANT represents that it possesses the professional and technical personnel necessary to perform the Services required by this Agreement and that the personnel have sufficient skill and experience to perform the Services assigned to them. CONSULTANT represents that it, its employees and

Professional Services
Rev. Feb. 2014
subconsultants, if permitted, have and shall maintain during the term of this Agreement all licenses, permits, qualifications, insurance and approvals of whatever nature that are legally required to perform the Services.

All of the services to be furnished by CONSULTANT under this agreement shall meet the professional standard and quality that prevail among professionals in the same discipline and of similar knowledge and skill engaged in related work throughout California under the same or similar circumstances.

SECTION 7. COMPLIANCE WITH LAWS. CONSULTANT shall keep itself informed of and in compliance with all federal, state and local laws, ordinances, regulations, and orders that may affect in any manner the Project or the performance of the Services or those engaged to perform Services under this Agreement. CONSULTANT shall procure all permits and licenses, pay all charges and fees, and give all notices required by law in the performance of the Services.

SECTION 8. ERRORS/OMISSIONS. CONSULTANT shall correct, at no cost to CITY, any and all errors, omissions, or ambiguities in the work product submitted to CITY, provided CITY gives notice to CONSULTANT. If CONSULTANT has prepared plans and specifications or other design documents to construct the Project, CONSULTANT shall be obligated to correct any and all errors, omissions or ambiguities discovered prior to and during the course of construction of the Project. This obligation shall survive termination of the Agreement.

SECTION 9. COST ESTIMATES. If this Agreement pertains to the design of a public works project, CONSULTANT shall submit estimates of probable construction costs at each phase of design submittal. If the total estimated construction cost at any submittal exceeds ten percent (10%) of the CITY’s stated construction budget, CONSULTANT shall make recommendations to the CITY for aligning the PROJECT design with the budget, incorporate CITY approved recommendations, and revise the design to meet the Project budget, at no additional cost to CITY.

SECTION 10. INDEPENDENT CONTRACTOR. It is understood and agreed that in performing the Services under this Agreement CONSULTANT, and any person employed by or contracted with CONSULTANT to furnish labor and/or materials under this Agreement, shall act as and be an independent contractor and not an agent or employee of the CITY.

SECTION 11. ASSIGNMENT. The parties agree that the expertise and experience of CONSULTANT are material considerations for this Agreement. CONSULTANT shall not assign or transfer any interest in this Agreement nor the performance of any of CONSULTANT’s obligations hereunder without the prior written consent of the city manager. Consent to one assignment will not be deemed to be consent to any subsequent assignment. Any assignment made without the approval of the city manager will be void.
SECTION 12. SUBCONTRACTING.

☐ Option A: No Subcontractor: CONSULTANT shall not subcontract any portion of the work to be performed under this Agreement without the prior written authorization of the city manager or designee.

☐ Option B: Subcontracts Authorized: Notwithstanding Section 11 above, CITY agrees that subconsultants may be used to complete the Services. The subconsultants authorized by CITY to perform work on this Project are:

CONSULTANT shall be responsible for directing the work of any subconsultants and for any compensation due to subconsultants. CITY assumes no responsibility whatsoever concerning compensation. CONSULTANT shall be fully responsible to CITY for all acts and omissions of a subconsultant. CONSULTANT shall change or add subconsultants only with the prior approval of the city manager or his designee.

SECTION 13. PROJECT MANAGEMENT. CONSULTANT will assign as the to have supervisory responsibility for the performance, progress, and execution of the Services and as the project to represent CONSULTANT during the day-to-day work on the Project. If circumstances cause the substitution of the project director, project coordinator, or any other key personnel for any reason, the appointment of a substitute project director and the assignment of any key new or replacement personnel will be subject to the prior written approval of the CITY’s project manager. CONSULTANT, at CITY’s request, shall promptly remove personnel who CITY finds do not perform the Services in an acceptable manner, are uncooperative, or present a threat to the adequate or timely completion of the Project or a threat to the safety of persons or property.

The City’s project manager is , Department, Division, Palo Alto, CA 94303, Telephone: . The project manager will be CONSULTANT’s point of contact with respect to performance, progress and execution of the Services. The CITY may designate an alternate project manager from time to time.
SECTION 14. OWNERSHIP OF MATERIALS. Upon delivery, all work product, including without limitation, all writings, drawings, plans, reports, specifications, calculations, documents, other materials and copyright interests developed under this Agreement shall be and remain the exclusive property of CITY without restriction or limitation upon their use. CONSULTANT agrees that all copyrights which arise from creation of the work pursuant to this Agreement shall be vested in CITY, and CONSULTANT waives and relinquishes all claims to copyright or other intellectual property rights in favor of the CITY. Neither CONSULTANT nor its contractors, if any, shall make any of such materials available to any individual or organization without the prior written approval of the City Manager or designee. CONSULTANT makes no representation of the suitability of the work product for use in or application to circumstances not contemplated by the scope of work.

SECTION 15. AUDITS. CONSULTANT will permit CITY to audit, at any reasonable time during the term of this Agreement and for three (3) years thereafter, CONSULTANT’s records pertaining to matters covered by this Agreement. CONSULTANT further agrees to maintain and retain such records for at least three (3) years after the expiration or earlier termination of this Agreement.

SECTION 16. INDEMNITY.

[Option A applies to the following design professionals pursuant to Civil Code Section 2782.8: architects; landscape architects; registered professional engineers and licensed professional land surveyors.] 16.1. To the fullest extent permitted by law, CONSULTANT shall protect, indemnify, defend and hold harmless CITY, its Council members, officers, employees and agents (each an “Indemnified Party”) from and against any and all demands, claims, or liability of any nature, including death or injury to any person, property damage or any other loss, including all costs and expenses of whatever nature including attorneys fees, experts fees, court costs and disbursements (“Claims”) that arise out of, pertain to, or relate to the negligence, recklessness, or willful misconduct of the CONSULTANT, its officers, employees, agents or contractors under this Agreement, regardless of whether or not it is caused in part by an Indemnified Party.

[Option B applies to any consultant who does not qualify as a design professional as defined in Civil Code Section 2782.8.] 16.1. To the fullest extent permitted by law, CONSULTANT shall protect, indemnify, defend and hold harmless CITY, its Council members, officers, employees and agents (each an “Indemnified Party”) from and against any and all demands, claims, or liability of any nature, including death or injury to any person, property damage or any other loss, including all costs and expenses of whatever nature including attorneys fees, experts fees, court costs and disbursements (“Claims”) resulting from, arising out of or in any manner related to performance or nonperformance by CONSULTANT, its officers, employees, agents or contractors under this Agreement, regardless of whether or not it is caused in part by an Indemnified Party.

16.2. Notwithstanding the above, nothing in this Section 16 shall be construed to require CONSULTANT to indemnify an Indemnified Party from Claims arising from the active negligence, sole negligence or willful misconduct of an Indemnified Party.
16.3. The acceptance of CONSULTANT’s services and duties by CITY shall not operate as a waiver of the right of indemnification. The provisions of this Section 16 shall survive the expiration or early termination of this Agreement.

SECTION 17. WAIVER. The waiver by either party of any breach or violation of any covenant, term, condition or provision of this Agreement, or of the provisions of any ordinance or law, will not be deemed to be a waiver of any other term, covenant, condition, provisions, ordinance or law, or of any subsequent breach or violation of the same or of any other term, covenant, condition, provision, ordinance or law.

SECTION 18. INSURANCE.

18.1. CONSULTANT, at its sole cost and expense, shall obtain and maintain, in full force and effect during the term of this Agreement, the insurance coverage described in Exhibit "D". CONSULTANT and its contractors, if any, shall obtain a policy endorsement naming CITY as an additional insured under any general liability or automobile policy or policies.

18.2. All insurance coverage required hereunder shall be provided through carriers with AM Best’s Key Rating Guide ratings of A-:VII or higher which are licensed or authorized to transact insurance business in the State of California. Any and all contractors of CONSULTANT retained to perform Services under this Agreement will obtain and maintain, in full force and effect during the term of this Agreement, identical insurance coverage, naming CITY as an additional insured under such policies as required above.

18.3. Certificates evidencing such insurance shall be filed with CITY concurrently with the execution of this Agreement. The certificates will be subject to the approval of CITY’s Risk Manager and will contain an endorsement stating that the insurance is primary coverage and will not be canceled, or materially reduced in coverage or limits, by the insurer except after filing with the Purchasing Manager thirty (30) days’ prior written notice of the cancellation or modification. If the insurer cancels or modifies the insurance and provides less than thirty (30) days’ notice to CONSULTANT, CONSULTANT shall provide the Purchasing Manager written notice of the cancellation or modification within two (2) business days of the CONSULTANT’s receipt of such notice. CONSULTANT shall be responsible for ensuring that current certificates evidencing the insurance are provided to CITY’s Purchasing Manager during the entire term of this Agreement.

18.4. The procuring of such required policy or policies of insurance will not be construed to limit CONSULTANT's liability hereunder nor to fulfill the indemnification provisions of this Agreement. Notwithstanding the policy or policies of insurance, CONSULTANT will be obligated for the full and total amount of any damage, injury, or loss caused by or directly arising as a result of the Services performed under this Agreement, including such damage, injury, or loss arising after the Agreement is terminated or the term has expired.
SECTION 19. TERMINATION OR SUSPENSION OF AGREEMENT OR SERVICES.

19.1. The City Manager may suspend the performance of the Services, in whole or in part, or terminate this Agreement, with or without cause, by giving ten (10) days prior written notice thereof to CONSULTANT. Upon receipt of such notice, CONSULTANT will immediately discontinue its performance of the Services.

19.2. CONSULTANT may terminate this Agreement or suspend its performance of the Services by giving thirty (30) days prior written notice thereof to CITY, but only in the event of a substantial failure of performance by CITY.

19.3. Upon such suspension or termination, CONSULTANT shall deliver to the City Manager immediately any and all copies of studies, sketches, drawings, computations, and other data, whether or not completed, prepared by CONSULTANT or its contractors, if any, or given to CONSULTANT or its contractors, if any, in connection with this Agreement. Such materials will become the property of CITY.

19.4. Upon such suspension or termination by CITY, CONSULTANT will be paid for the Services rendered or materials delivered to CITY in accordance with the scope of services on or before the effective date (i.e., 10 days after giving notice) of suspension or termination; provided, however, if this Agreement is suspended or terminated on account of a default by CONSULTANT, CITY will be obligated to compensate CONSULTANT only for that portion of CONSULTANT’s services which are of direct and immediate benefit to CITY as such determination may be made by the City Manager acting in the reasonable exercise of his/her discretion. The following Sections will survive any expiration or termination of this Agreement: 14, 15, 16, 19.4, 20, and 25.

19.5. No payment, partial payment, acceptance, or partial acceptance by CITY will operate as a waiver on the part of CITY of any of its rights under this Agreement.

SECTION 20. NOTICES.

All notices hereunder will be given in writing and mailed, postage prepaid, by certified mail, addressed as follows:

To CITY:  Office of the City Clerk
           City of Palo Alto
           Post Office Box 10250
           Palo Alto, CA 94303

With a copy to the Purchasing Manager
To CONSULTANT: Attention of the project director
at the address of CONSULTANT recited above

SECTION 21. CONFLICT OF INTEREST.

21.1. In accepting this Agreement, CONSULTANT covenants that it presently has no interest, and will not acquire any interest, direct or indirect, financial or otherwise, which would conflict in any manner or degree with the performance of the Services.

21.2. CONSULTANT further covenants that, in the performance of this Agreement, it will not employ subconsultants, contractors or persons having such an interest. CONSULTANT certifies that no person who has or will have any financial interest under this Agreement is an officer or employee of CITY; this provision will be interpreted in accordance with the applicable provisions of the Palo Alto Municipal Code and the Government Code of the State of California.

21.3. If the Project Manager determines that CONSULTANT is a “Consultant” as that term is defined by the Regulations of the Fair Political Practices Commission, CONSULTANT shall be required and agrees to file the appropriate financial disclosure documents required by the Palo Alto Municipal Code and the Political Reform Act.

SECTION 22. NONDISCRIMINATION. As set forth in Palo Alto Municipal Code section 2.30.510, CONSULTANT certifies that in the performance of this Agreement, it shall not discriminate in the employment of any person because of the race, skin color, gender, age, religion, disability, national origin, ancestry, sexual orientation, housing status, marital status, familial status, weight or height of such person. CONSULTANT acknowledges that it has read and understands the provisions of Section 2.30.510 of the Palo Alto Municipal Code relating to Nondiscrimination Requirements and the penalties for violation thereof, and agrees to meet all requirements of Section 2.30.510 pertaining to nondiscrimination in employment.

SECTION 23. ENVIRONMENTALLY PREFERRED PURCHASING AND ZERO WASTE REQUIREMENTS. CONSULTANT shall comply with the City’s Environmentally Preferred Purchasing policies which are available at the City’s Purchasing Department, incorporated by reference and may be amended from time to time. CONSULTANT shall comply with waste reduction, reuse, recycling and disposal requirements of the City’s Zero Waste Program. Zero Waste best practices include first minimizing and reducing waste; second, reusing waste and third, recycling or composting waste. In particular, Consultant shall comply with the following zero waste requirements:

- All printed materials provided by Consultant to City generated from a personal computer and printer including but not limited to, proposals, quotes, invoices, reports, and public education materials, shall be double-sided and printed on a minimum of 30% or greater post-consumer content paper, unless otherwise
approved by the City’s Project Manager. Any submitted materials printed by a professional printing company shall be a minimum of 30% or greater post-consumer material and printed with vegetable based inks.

- Goods purchased by Consultant on behalf of the City shall be purchased in accordance with the City’s Environmental Purchasing Policy including but not limited to Extended Producer Responsibility requirements for products and packaging. A copy of this policy is on file at the Purchasing Office.
- Reusable/returnable pallets shall be taken back by the Consultant, at no additional cost to the City, for reuse or recycling. Consultant shall provide documentation from the facility accepting the pallets to verify that pallets are not being disposed.

SECTION 24. NON-APPROPRIATION

24.1. This Agreement is subject to the fiscal provisions of the Charter of the City of Palo Alto and the Palo Alto Municipal Code. This Agreement will terminate without any penalty (a) at the end of any fiscal year in the event that funds are not appropriated for the following fiscal year, or (b) at any time within a fiscal year in the event that funds are only appropriated for a portion of the fiscal year and funds for this Agreement are no longer available. This section shall take precedence in the event of a conflict with any other covenant, term, condition, or provision of this Agreement.

SECTION 25. MISCELLANEOUS PROVISIONS.

25.1. This Agreement will be governed by the laws of the State of California.

25.2. In the event that an action is brought, the parties agree that trial of such action will be vested exclusively in the state courts of California in the County of Santa Clara, State of California.

25.3. The prevailing party in any action brought to enforce the provisions of this Agreement may recover its reasonable costs and attorneys’ fees expended in connection with that action. The prevailing party shall be entitled to recover an amount equal to the fair market value of legal services provided by attorneys employed by it as well as any attorneys’ fees paid to third parties.

25.4. This document represents the entire and integrated agreement between the parties and supersedes all prior negotiations, representations, and contracts, either written or oral. This document may be amended only by a written instrument, which is signed by the parties.

25.5. The covenants, terms, conditions and provisions of this Agreement will apply to, and will bind, the heirs, successors, executors, administrators, assignees, and consultants of the parties.

25.6. If a court of competent jurisdiction finds or rules that any provision of this Agreement or any amendment thereto is void or unenforceable, the unaffected
provisions of this Agreement and any amendments thereto will remain in full force and effect.

25.7. All exhibits referred to in this Agreement and any addenda, appendices, attachments, and schedules to this Agreement which, from time to time, may be referred to in any duly executed amendment hereto are by such reference incorporated in this Agreement and will be deemed to be a part of this Agreement.

25.8 If, pursuant to this contract with CONSULTANT, City shares with CONSULTANT personal information as defined in California Civil Code section 1798.81.5(d) about a California resident (“Personal Information”), CONSULTANT shall maintain reasonable and appropriate security procedures to protect that Personal Information, and shall inform City immediately upon learning that there has been a breach in the security of the system or in the security of the Personal Information. CONSULTANT shall not use Personal Information for direct marketing purposes without City’s express written consent.

25.9 All unchecked boxes do not apply to this agreement.

25.10 The individuals executing this Agreement represent and warrant that they have the legal capacity and authority to do so on behalf of their respective legal entities.

25.11 This Agreement may be signed in multiple counterparts, which shall, when executed by all the parties, constitute a single binding agreement.

IN WITNESS WHEREOF, the parties hereto have by their duly authorized representatives executed this Agreement on the date first above written.

CITY OF PALO ALTO

CONSULTANT

City Manager (Required on contracts over $85,000)
Purchasing Manager (Required on contracts over $25,000)
Contracts Administrator (Required on contracts under $25,000)

APPROVED AS TO FORM:

Senior Asst. City Attorney
(Required on Contracts over $25,000)
## Attachment D
### SAMPLE TABLE FORMAT
#### QUALIFICATIONS OF FIRM RELATIVE TO CITY’S NEEDS

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Client</th>
<th>Description of work performed</th>
<th>Total Project Cost</th>
<th>Percentage of work firm as responsible for</th>
<th>Period work was completed</th>
<th>Client contact information*</th>
</tr>
</thead>
</table>

Did your firm meet the project schedule (Circle one): Yes  No

Give a brief statement of the firm’s adherence to the schedule and budget for the project:

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Did your firm meet the project schedule (Circle one): Yes  No

Give a brief statement of the firm’s adherence to the schedule and budget for the project:

---

Did your firm meet the project schedule (Circle one): Yes  No

Give a brief statement of the firm’s adherence to the schedule and budget for the project:

---

Did your firm meet the project schedule (Circle one): Yes  No

Give a brief statement of the firm’s adherence to the schedule and budget for the project:

---

*Include name, title and phone number.

City of Palo Alto – RFP
SAMPLE COST PROPOSAL FORMAT – RFP

(The City is looking for a submittal in this format – content should match cost for scope of services required)

<table>
<thead>
<tr>
<th>Scope</th>
<th>Labor Categories (e.g., Consultant, Sr. Consultant, etc.)</th>
<th>Est. Hours</th>
<th>Hourly Rate</th>
<th>Extended Rate</th>
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<td>Task 1</td>
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<td>TOTAL NOT TO EXCEED (TASKS 1 – 3)</td>
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Attachment “F”
INSURANCE REQUIREMENTS

CONTRACTORS TO THE CITY OF PALO ALTO (CITY), AT THEIR SOLE EXPENSE, SHALL FOR THE TERM OF THE CONTRACT OBTAIN AND MAINTAIN INSURANCE IN THE AMOUNTS FOR THE COVERAGE SPECIFIED BELOW, AFFORDED BY COMPANIES WITH AM BEST’S KEY RATING OF A-:VII, OR HIGHER, LICENSED OR AUTHORIZED TO TRANSACT INSURANCE BUSINESS IN THE STATE OF CALIFORNIA.

AWARD IS CONTINGENT ON COMPLIANCE WITH CITY’S INSURANCE REQUIREMENTS, AS SPECIFIED, BELOW:

<table>
<thead>
<tr>
<th>REQUIRED</th>
<th>TYPE OF COVERAGE</th>
<th>REQUIREMENT</th>
<th>MINIMUM LIMITS</th>
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<td>EMPLOYER’S LIABILITY</td>
<td>BODILY INJURY</td>
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<td>$1,000,000</td>
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<tr>
<td>YES</td>
<td>GENERAL LIABILITY, INCLUDING PERSONAL INJURY, BROAD FORM PROPERTY DAMAGE BLANKET CONTRACTUAL, AND FIRE LEGAL LIABILITY</td>
<td>BODILY INJURY &amp; PROPERTY DAMAGE COMBINED</td>
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<td>$1,000,000</td>
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<td>YES</td>
<td>AUTOMOBILE LIABILITY, INCLUDING ALL OWNED, HIRED, NON-OWNED</td>
<td>BODILY INJURY - EACH PERSON</td>
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<td>- EACH OCCURRENCE</td>
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<td>YES</td>
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<td>ALL DAMAGES</td>
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<tr>
<td>YES</td>
<td>PROFESSIONAL LIABILITY, INCLUDING, ERRORS AND OMISSIONS, MALPRACTICE (WHEN APPLICABLE), AND NEGLIGENT PERFORMANCE</td>
<td>BODILY INJURY AND PROPERTY DAMAGE, COMBINED</td>
<td>$1,000,000</td>
<td>$1,000,000</td>
</tr>
</tbody>
</table>

THE CITY OF PALO ALTO IS TO BE NAMED AS AN ADDITIONAL INSURED: CONTRACTOR, AT ITS SOLE COST AND EXPENSE, SHALL OBTAIN AND MAINTAIN, IN FULL FORCE AND EFFECT THROUGHOUT THE ENTIRE TERM OF ANY RESULTANT AGREEMENT, THE INSURANCE COVERAGE HEREIN DESCRIBED, INSURING NOT ONLY CONTRACTOR AND ITS SUBCONSULTANTS, IF ANY, BUT ALSO, WITH THE EXCEPTION OF WORKERS’ COMPENSATION, EMPLOYER’S LIABILITY AND PROFESSIONAL INSURANCE, NAMING AS ADDITIONAL INSUREDS CITY, ITS COUNCIL MEMBERS, OFFICERS, AGENTS, AND EMPLOYEES.

I. INSURANCE COVERAGE MUST INCLUDE:
   A. A PROVISION FOR A WRITTEN THIRTY DAY ADVANCE NOTICE TO CITY OF CHANGE IN COVERAGE OR OF COVERAGE CANCELLATION; AND
   B. A CONTRACTUAL LIABILITY ENDORSEMENT PROVIDING INSURANCE COVERAGE FOR CONTRACTOR’S AGREEMENT TO INDEMNIFY CITY.
   C. DEDUCTIBLE AMOUNTS IN EXCESS OF $5,000 REQUIRE CITY’S PRIOR APPROVAL.

II. CONTRACTOR MUST SUBMIT CERTIFICATES(S) OF INSURANCE EVIDENCING REQUIRED COVERAGE.

III. ENDORSEMENT PROVISIONS, WITH RESPECT TO THE INSURANCE AFFORDED TO “ADDITIONAL INSUREDS”
   A. PRIMARY COVERAGE
      WITH RESPECT TO CLAIMS ARISING OUT OF THE OPERATIONS OF THE NAMED INSURED, INSURANCE AS AFFORDED BY THIS POLICY IS PRIMARY AND IS NOT ADDITIONAL TO OR CONTRIBUTING WITH ANY OTHER INSURANCE CARRIED BY OR FOR THE BENEFIT OF THE ADDITIONAL INSUREDS.

Rev. 11/07
B. CROSS LIABILITY

THE NAMING OF MORE THAN ONE PERSON, FIRM, OR CORPORATION AS INSUREDS UNDER THE POLICY SHALL NOT, FOR THAT REASON ALONE, EXTINGUISH ANY RIGHTS OF THE INSURED AGAINST ANOTHER, BUT THIS ENDORSEMENT, AND THE NAMING OF MULTIPLE INSUREDS, SHALL NOT INCREASE THE TOTAL LIABILITY OF THE COMPANY UNDER THIS POLICY.

C. NOTICE OF CANCELLATION

1. IF THE POLICY IS CANCELED BEFORE ITS EXPIRATION DATE FOR ANY REASON OTHER THAN THE NON-PAYMENT OF PREMIUM, THE ISSUING COMPANY SHALL PROVIDE CITY AT LEAST A THIRTY (30) DAY WRITTEN NOTICE BEFORE THE EFFECTIVE DATE OF CANCELLATION.

2. IF THE POLICY IS CANCELED BEFORE ITS EXPIRATION DATE FOR THE NON-PAYMENT OF PREMIUM, THE ISSUING COMPANY SHALL PROVIDE CITY AT LEAST A TEN (10) DAY WRITTEN NOTICE BEFORE THE EFFECTIVE DATE OF CANCELLATION.

NOTICES SHALL BE MAILED TO:

Purchasing and Contract Administration
City of Palo Alto
P.O. Box 10250
Palo Alto, CA 94303.
ATTACHMENT H
NON-DISCLOSURE AGREEMENT
BETWEEN THE CITY OF PALO ALTO AND

This NON-DISCLOSURE AGREEMENT (the “Agreement”), dated as of April XX, 2012 (the “Effective Date”), is entered into by and between the City of Palo Alto, a California chartered municipal corporation, 250 Hamilton Avenue, Palo Alto, CA 94301 (the “Disclosing Party”) and ____________________, a ____________ corporation, _____________________, ________, CA 9____ (the “Receiving Party”) (individually, a “Party” and, collectively, the “Parties”).

RECITALS

1. The Parties entered into a contract for ___________________ services as of ___________________, City of Palo Alto Contract No. ___________ (the “Contract”); the Receiving Party is providing ____________________________ to the Disclosing Party.

2. In its performance of consulting services, the Receiving Party and its authorized members, directors, officers, employees, agents and representatives will acquire and otherwise gain access to certain Confidential Information of the Disclosing Party, including the personal information of one or more electric utility customers of the City’s Department of Utilities, which is exempt from public disclosure under California Government Code section 6254.16.

3. The Disclosing Party would not share or disclose any Confidential Information to the Receiving Party but for the legal protections against unauthorized disclosures intended to be afforded by California law and this Agreement, and is relying on this Agreement in disclosing such Confidential Information to the Receiving Party.

AGREEMENT

In consideration of the foregoing recitals and mutual covenants, terms and conditions, the Parties agree, as follows:

1. Confidential Information. “Confidential Information” means any and all financial and related utility customers’ personal information of a non-public, proprietary or confidential nature, in any form or medium, written or oral, concerning or relating to the Disclosing Party (whether prepared by the Disclosing Party, its employees or agents, and irrespective of the form or means of communication and whether it is labeled or otherwise identified as confidential) that is furnished or made available to the Receiving Party by the Disclosing Party.

2. Exceptions. The Receiving Party agrees to maintain as confidential, to the extent permitted or required by applicable law, all Confidential Information furnished or otherwise made available to the Receiving Party by the Disclosing Party. Notwithstanding the foregoing and the provisions of Section 1, “Confidential Information” shall exclude (and the Receiving Party shall not be under any obligation to maintain in confidence) any information (or any
portion thereof) disclosed to the Receiving Party by the Disclosing Party to the extent that such information:

(a) is in the public domain at the time of disclosure; or

(b) at the time of or following disclosure, becomes generally known or available through no act or omission on the part of the Disclosing Party; or

(c) is known, or becomes known, to the Receiving Party from a source other than the Disclosing Party or its Representatives (as defined herein), provided that disclosure by such source is not in breach of a confidentiality agreement with the Disclosing Party; or

(d) is independently developed by the Receiving Party without violating any of its obligations under this Agreement or any other agreement between the Parties; or

(e) is legally required to be disclosed by judicial or other governmental action; provided, however, that prompt notice of such judicial or other governmental action shall have been first given to the Disclosing Party, which shall be afforded the opportunity to exhaust all reasonable legal remedies to maintain the Confidential Information in confidence, in accordance with Section 7 below; or

(f) is permitted to be disclosed by a formal written agreement executed by and between the Parties.

Specific information shall not fall within the exceptions of Sections 2(a) through 2(f) above merely because it is embraced by more general information falling within such exceptions.

3. California Public Records Act. The Receiving Party acknowledges that the Disclosing Party is a public agency subject to the requirements of the California Constitution, Article 1, Section 3 and California Public Records Act Cal. Gov. Code section 6250 et seq. The Receiving Party acknowledges that the Disclosing Party may submit to or otherwise provide access to the Receiving Party Confidential Information that the Disclosing Party or any electric utility customer of the Disclosing Party considers to be protected from disclosure pursuant to exemptions granted by applicable California law. Whether or not there is a request or demand of any third party not a Party to this Agreement (the “Requestor”) for the production, inspection and/or copying of information designated by the Disclosing Party as Confidential Information, the Disclosing Party shall be solely responsible for taking whatever legal steps the Disclosing Party deems necessary to protect information deemed by it to be Confidential Information and to prevent release of information to the Requestor (including the release of such information by the Receiving Party). Under no circumstances will the Receiving Party be permitted to comply with the Requestor’s demand for disclosure of such Confidential Information that the Disclosing Party deems confidential and not intended for disclosure to the general public, or otherwise publicly disclose the Confidential Information to any person not authorized by law to receive such information.

4. Confidential Information. As practicable, the Confidential Information shall be marked with the words “Confidential” or “Confidential Material” or with words of similar
import. The Disclosing Party shall instruct the Receiving Parties that information of a financial, personal, or proprietary nature being conveyed orally and intended by the Disclosing Party to be covered by the terms of this Agreement, is deemed Confidential Information. To the extent possible, the Disclosing Party shall endeavor to mark any electronic document intended to be covered by the terms of this Agreement with the words “Confidential” or similar words, or, if that is not possible or would be exceedingly difficult, the City shall notify the Receiving Parties (for example, by covering e-mail transmitting the electronic document) that the electronic document is Confidential Information. The City’s failure, for whatever reason, to mark any material at the time it is produced to the Receiving Party, or to notify it that oral or electronic material is Confidential Information at the time it is provided, shall not take the material out of the coverage of this Agreement for all time, and the Receiving Party shall treat the material as Confidential Information once the City has notified it that the material is to be covered by this Agreement.

5. Duty to Keep Confidential. The Receiving Party acknowledges that the Confidential Information is proprietary and a valuable asset of the Disclosing Party and agrees that the Receiving Party shall take reasonable precautions to ensure that such Confidential Information is safeguarded against disclosure to unauthorized employees or third parties.

(a) The Receiving Party shall use the Confidential Information solely as permitted by the Contract and shall not sell Confidential Information or otherwise disclose City of Palo Alto Utilities’ customers’ personal information under any circumstances and without the prior written consent of the City. The Receiving Party shall not disclose the Confidential Information, or portions thereof, to any directors, officers, partners, managers, members, employees, advisors, agents, sub-contractors and other representatives of the Receiving Party and their subsidiaries and affiliates, including, without limitation, attorneys, accountants, consultants, and financial advisors (collectively, the “Representatives”), except to those who need to know such information for the purpose of advising City and who agree to the terms of this Agreement.

(b) The Receiving Party agrees that any of the Representatives to whom the Confidential Information is disclosed will be informed of the confidential or proprietary nature of such information and of the Receiving Party’s obligations under this Agreement. The Receiving Party is responsible for any use of Confidential Information by any of its Representatives.

(c) The Receiving Party shall ensure that (i) any directors, officers, representatives, advisors and sub-contractors with whom the Receiving Party shares such information or who acquire knowledge of such information from or through the Receiving Party regard and treat such Confidential Information of the Disclosing Party as strictly confidential and wholly owned by either the Disclosing Party, and (ii) the Receiving Party shall not (and the Receiving Party shall ensure that any directors, officers, representatives, advisors and sub-contractors with whom the Receiving Party shares such information or who acquire knowledge of such information from or through the Receiving Party do not) for any reason, in any fashion, either directly or indirectly, sell, lend, lease, distribute, license, give, transfer, assign, show, disclose, disseminate, or otherwise communicate any such Confidential Information to any third
party, or misappropriate, reproduce, copy or use any such Confidential Information, in either case, for any purpose other than in accordance with this Agreement.

(d) If the Receiving Party or any of its Representatives are requested or required to disclose any Confidential Information, including terms and conditions being negotiated, by law, regulation, the applicable rules of any national securities exchange or other market or reporting system, oral questions, interrogatories, requests for information or other documents in legal proceedings, subpoena, civil investigative demand or any other similar process, the Receiving Party shall provide the Disclosing Party with prompt written notice of any such request or requirement so that the Disclosing Party has an opportunity to seek a protective order via Writ of Mandate or other appropriate remedy, or waive compliance with the provisions of this Agreement.

(e) If the Disclosing Party waives compliance with the provisions of this Agreement with respect to a specific request or requirement, the Receiving Party and its Representatives shall disclose only that portion of the Confidential Information that is expressly covered by such waiver and which is necessary to disclose in order to comply with such request or requirement. The Receiving Party and its Representatives shall cooperate in a reasonable manner with the Disclosing Party in attempting to preserve the confidentiality of the Confidential Information.

(f) If (in the absence of a waiver by the Disclosing Party) the Disclosing Party has not secured a protective order or other appropriate remedy despite attempting to do so, and the Receiving Party or one of its Representatives is nonetheless then legally compelled to disclose any Confidential Information, the Receiving Party or such Representative may, without liability hereunder, disclose only that portion of the Confidential Information that is necessary to be disclosed. In the event that disclosure is made in accordance with this subsection, the Receiving Party shall exercise, and cause its Representatives to exercise, reasonable efforts to preserve the confidentiality of the Confidential Information, including obtaining reliable assurance at the sole expense of the Receiving Party that confidential treatment shall be accorded any Confidential Information so furnished.

6. **No Liability, Reliance, or Obligation.** Except as set forth in any formal written agreement executed by and between the Parties, neither the Receiving Party nor any of its Representatives shall be entitled to rely on any statement, promise, agreement or understanding, whether written or oral, or any custom, usage of trade, course of dealing or conduct. In addition, each Party understands and acknowledges that neither the Disclosing Party nor any of its representatives, employees or agents makes any representation or warranty, express or implied, as to the accuracy or completeness of any Confidential Information, and that neither the Disclosing Party nor any of its representatives, employees or agents shall have any liability whatsoever to the Receiving Party or to any of its Representatives relating to or resulting from the Confidential Information or any errors therein or omissions therefrom.

7. **Remedies.** The Receiving Party, in recognition that an irreparable injury may result to the Disclosing Party, if any provision of this Agreement is violated, agrees that upon any breach or threatened breach of any provision of this Agreement by the Receiving Party or
any Representatives, that the City shall be entitled to seek an injunction or specific performance prohibiting such conduct or any other relief as may be permitted by law.

8. **Return of Confidential Information.** The Disclosing Party may at any time request that the Receiving Party promptly return to the Disclosing Party or destroy any or all documents or other materials containing Confidential Information of the Disclosing Party, and the Receiving Party shall immediately comply with any such request. Notwithstanding the return or destruction of the Confidential Information as contemplated by this subsection, the Receiving Party and its Representatives will continue to be bound by the terms of this Agreement with respect thereto, including all obligations of confidentiality.

9. **Survival.** The Receiving Party’s obligations of confidentiality and non-circumvention under this Agreement shall survive the termination of this Agreement for a period of not less than __________ (__) years.

10. **General Provisions.**

(a) **Entire Agreement.** This Agreement contains the entire understanding between the Parties with respect to the Confidential Information and supersedes all prior communications, representations, understandings, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement. This Agreement shall apply in lieu of and notwithstanding any specific legend or statement associated with any Confidential Information transferred.

(b) **Governing Law and Jurisdiction.** This Agreement shall be interpreted and construed pursuant to the laws of the State of California without regard to its conflicts of laws principles. The Receiving Party agrees that this Agreement may be enforced in the courts of the State of California and, by executing this Agreement, the Receiving Party submits to the jurisdiction of any federal or state court in California for the resolution of any dispute under this Agreement.

(c) **Waiver; Amendment.** None of the terms or conditions of this Agreement may be amended or waived except in writing signed by the Parties. The Parties agree that no waiver, amendment, or modification of this Agreement shall be established by conduct, custom, or course of dealing. The failure by any Party at any time or times to require performance of any provision hereof will in no manner affect its right at a later time to enforce the same.

(d) **Assignment.** This Agreement shall not be assignable without the prior written consent of the non-assigning Party, and such consent may not be unreasonably withheld. Any assignment attempted in violation of this paragraph shall be void.

(e) **Severability.** If any term of this Agreement is found to be invalid by a court of competent jurisdiction then such term shall remain in force to the maximum extent permitted by law. All other terms shall remain in force unless that term is determined not to be severable from all other provisions of this Agreement by such court.
(f) **Counterparts.** This Agreement may be executed in any number of counterparts, each of which shall be deemed an original part, all of which together shall constitute one and the same instrument.

(g) **Successors and Assigns.** The benefits of this Agreement shall inure to the respective successors and assigns of the Parties hereto, and the obligations and liabilities assumed in this Agreement by the Parties hereto shall be binding upon their respective successors and assigns.

(h) **Ownership Rights Not Created.** The transfer of Confidential Information hereunder shall not be construed as granting a license of any kind or any right of ownership in the Confidential Information.

(i) **No Obligation to Disclose.** Nothing in this Agreement shall obligate the City to disclose specific Confidential Information to the Receiving Party. Such disclosures shall be at the City’s sole discretion.

(j) Each Party represents that the person signing this Agreement on its behalf is authorized to enter into this Agreement on behalf of the Party for whom they sign.

IN WITNESS WHEREOF, the Parties have duly executed this Agreement as of the Effective Date.

______________________________________________
CITY OF PALO ALTO

By: ____________________________
Title: James Keene
City Manager

_______________________________
Approved:
Valerie Fong
Director of Utilities

______________________________________________
By: ____________________________
Title: Approved as to Form

_______________________________
Grant Kolling
Senior Assistant City Attorney
ASSESSMENT OF SMART GRID APPLICATIONS
FOR CITY OF PALO ALTO

Final Report
February 2011

Prepared by:
EnerNex Corporation
Knoxville, TN
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City of Palo Alto Utilities
Assessment of Smart Grid Applications
Smart Grid Business Plan
March 4, 2011
EXECUTIVE SUMMARY

The executive summary provides summary findings and recommendations for City of Palo Alto Utilities (CPAU) staff, City Council and stakeholders. It also provides an overview of the approach and assessment results to provide context. The detail report outlining modeling approach, assumptions, and results is provided in Chapters 1 through 8.

Summary of Findings & Recommendations

Summary Findings

1. Among the full gamut of possible smart grid applications being developed in the market place today, three applications are relevant to CPAU.
   
   a. Advanced Metering Infrastructure (AMI) that enables remote meter reading and more granular and actionable usage information for customers including Meter Data Management System (MDMS) for providing billing flexibility and dynamic pricing.
   
   b. Advanced Distribution Systems including Distribution Automation (DA), distribution monitoring and advanced distribution applications to enhance reliability and more efficient management of the distribution system.
   
   c. Enhanced customer engagement for optimal use of energy and water suppliers. This aspect would require additional investment by customers in devices like In-Home-Displays for residential customers and Building Management Systems (BMS) for commercial customers. The cost of such customer devices and systems were not considered in the analysis.

2. The principle benefit of installing an AMI System in Palo Alto is related to reducing meter reading costs and efficient utilization of electricity. However due to the relatively efficient CPAU meter reading operations and comparatively lower energy efficiency savings potential in the City, these benefits are not sufficiently large to warrant an expedited implementation of AMI.
   
   a. The capital cost of implementing an AMI System for electric, gas and water meters is estimated at between $10.8 and 16.2 million, NPV. In addition, enhanced data management functionality related to consumption, rates, billing; meter and communication network maintenance; and software maintenance cost is projected to be $1.0 to 1.5 million annually in additional operating cost. Total AMI System 20 year costs range from $23.4 to 35.2 million, NPV.
   
   b. The commensurate AMI System benefits are estimated to be in the $1.2 to 1.7 million range annually, with principle benefit related to meter reader savings. Customer efficiency benefits directly related to AMI was difficult to quantify, but preliminarily it was estimated that AMI related technologies could result in electricity
consumption reduction of 0.5% for commercial customers and 1% for residential customers in the long term. No gas or water usage savings was assumed in this assessment. The estimated 20 year benefits range from $18.5 to 27.7 million, NPV.

c. Since AMI is an enabling technology, it was difficult to foresee and quantify benefits related to such technologies far into the future. Benefits related to enhanced customer service and satisfaction was also difficult to quantify.

d. With a 20 year NPV cost of $23 to $35 million and benefit of $18 to $28 million, there is no compelling quantifiable economic benefit related to replacing existing meters with smart meters. In the best case scenario, an AMI System investment is estimated at 17 years to breakeven cost recovery - this is a scenario where the costs are at the bottom of the range and the benefit is at the top of the range.

3. The business case for Distribution System Automation was not positive. Implementing a basic Outage Management System (OMS) and integration with Geographic Information System (GIS) will facilitate a more effective and efficient operations on the field. The total 20 year actual costs of implementing such a system is estimated at $3 million and several elements of such a system are already under development. The quantifiable economic benefit is lower than the capital costs with a NPV of $2.7M versus a total projected utility and customer benefit of adding up to $1.6M NPV.

4. CPAU at present has a program to provide in-home displays to residential customers and assists with upgrading building management systems at commercial customer locations. If CPAU decides to implement AMI, higher degree of customer engagement will have to occur to maximize the value of the AMI system. This includes implementing a range of customer oriented programs such as customer on-line energy usage and bill review web portal, analysis of appliance efficiency and usage pattern, and other customer conservation and energy efficiency outreach campaigns.

Summary Recommendations

1. The Smart Grid related systems are being rapidly deployed around the country. This effort is largely driven by regulatory mandates or spurred by government stimulus funds. While there are benefits associated to being an early adopter, the risk of early adoption outweighs the benefits for Palo Alto at this time.

2. It is our assessment that as Smart Grid technology standards are finalized and technology/product lines mature in the next 2-3 years, costs of implementing an AMI system would decline and benefits to Palo Alto will become more apparent. Hence, it is recommended that Palo Alto positions itself, without making any major investments at this time, to take advantage of potential opportunities that may arise in the 2012-13 period.

3. It is recommended that the City devote its effort in the following areas in the next 2 years, to learn from experience and be in a position to make decisions based on an AMI implementation road map in the 2012-13 period:
a. Develop a robust gas and water meter maintenance and replacement plan. The plan could include exploring the possibility of installing AMI enabled meters for on-going meter replacement programs that could later be networked when CPAU decides to implement an AMI system.

b. Implement Time-of-Use rates and related metering infrastructure for Electric Vehicle owners in the city to encourage charging of vehicles during off-peak hours.

c. Better understand the value of Demand Response in the City by implementing pilot programs for large commercial customers.

d. Engage with large building owners and provide incentives to upgrade their BMS to better integrate with features of smart meters; if appropriate, undertake a smart meter pilot with interested high value customer.

e. Learn from the Distribution System current sensor project now underway at CPAU and develop a long term Distribution System Automation road map.

f. Perform further analysis of potential Volt/Var energy conservation on the distribution grid.

g. Further review AMI backend software related cost estimated at $6M, as they make up 40% of the $15 million AMI implementation cost.

   i. Evaluate the City’s long term plan for SAP software use and enhancement. Harvest synergies by implementing AMI in a timeline that coincides with planned future SAP upgrades.

   ii. Look at cost effective ways to accomplish integration of future MDMS with SAP and billing.

   iii. Explore potential for outsourcing or an externally hosted service-based MDMS and billing system implementation.

4. Implementing smart grid applications effectively, with least disruptions to the organization and the community, requires long term planning. While no major capital expenditures are recommended at this time, it is recommended that CPAU allocate sufficient resources in the coming years to start this planning phase in earnest.

   a. Perform internal detailed study of IT implementation resources and dedicated IT resources required to operate and maintain Smart Grid systems.

   b. Assess new Smart Grid specific staff positions, level of in-house and consulting expertise, and compensation rates.

   c. Assess CPAU organizational structure for Smart Grid implementation and operation.
d. Develop and execute a Customer Outreach program to effectively communicate CPAU Smart Grid activities and engage external stakeholders in development and deployment process.

**Overview of Assessment Framework**

The purpose of this Assessment of Smart Grid Applications is to provide an integrated, foundational approach addressing Smart Grid strategic goals and objectives. It is intended to define the applications, functional elements and components of the Smart Grid concept as it may be deployed at City of Palo Alto Utilities (CPAU). Cost Benefit Analysis (CBA) Models are used to evaluate costs and benefits of implementing Smart Grid applications at CPAU over a twenty year period. This assessment evaluates Smart Grid technologies that can be cost effectively applied to the city’s electric, gas and water utilities. The evaluation looked into utility system improvements that will result in operational cost savings and environmental and societal benefits to the residents and businesses in Palo Alto. The goal is to determine the Smart Grid applications and technologies that best meet the City’s needs, provide a cost benefits analysis model for CPAU to use in exploring the feasibility of implementing new Smart Grid applications, and if an application is justified, develop an implementation plan for these applications in a follow-on phase.

This Smart Grid Application and Value Assessment should help stimulate discussion within the Palo Alto community and various parts of CPAU that will be responsible for performing this work. It is intended to be a resource for prioritization of efforts and the alignment of coordinated business strategies. This assessment and plan can also be used with the community to evaluate their potential benefits as an important stakeholder in order to factor customer, environmental and societal benefits into the decision making process.

**Smart Grid Overview**

The term “Smart Grid” is used to identify a movement within the electrical power industry to modernize the electricity delivery system. A Smart Grid monitors, protects and automatically optimizes the operation of its interconnected elements – from energy markets and generators through the high-voltage network and distribution system, to end-use consumers and their thermostats, electric vehicles, appliances and other household devices.

The goal of a Smart Grid is to use advanced information-based technologies and communications systems to increase grid efficiency, reliability and flexibility. It enables better use of the existing delivery infrastructure and offers benefits for both the consumer and the environment.
Figure 1-1: Smart Grid Conceptual Model (NIST)

Figure 1-1 shows the high-level conceptual model of such a Smart Grid, as developed by the U.S. National Institute of Standards and Technology (NIST) that shows the traditional electricity-carrying portions of the power system domains interconnected in a secure communications system, and most importantly, with the customer as a source of feedback and an active participant in energy conservation as well as just energy usage.

Define Smart Grid Elements

Following the development of Strategic Objectives, a list of Smart Grid Functional Requirements is created that supports these. These Functional Requirements are then mapped against proposed Smart Grid elements and components. The result is a logical grouping of functional requirements into Smart Grid elements and components.

This assessment found three smart grid applications was applicable to CPAU:

1. Advanced Metering Infrastructure (AMI) that enables remote meter reading and more granular usage information for customers including Meter Data Management System (MDMS) for providing billing flexibility and dynamic pricing.

2. Advanced Distribution Systems including Distribution Automation (DA), distribution monitoring and advanced distribution applications.

3. Enhanced customer engagement for optimal use of energy and water suppliers. This aspect would required additional investment by customers in devices like In-Home-Displays for residential customers and Building Management Systems for commercial customers.
Strategic Goals and Objectives

CPAU internal stakeholders, through a series of workshops, have developed the following Strategic Goals that are shown in Table 1-1 below. The assessment of the Qualitative Value of Smart Grid implementation on each of the defined CPAU Strategic Goals is also provided. This rating is High for high value supporting the strategic goal to Low for Smart Grid applications providing very low (or negative) value to the City.

For the strategic goals “Improve Utility Operations” shows a rating of “Medium” has been assigned. This means that Smart Grid applications supports these goals at a medium level. In the case of the strategic goal for “Reduce Management and Administration Costs”, a value of “Low” is assigned for both AMI and Distribution Automation (DA) applications since the Smart Grid applications will likely NPV costs, as the initial investment is unlikely to be recouped with the amount of on-going net operational cost savings.

<table>
<thead>
<tr>
<th>CPAU Strategic Goals</th>
<th>Smart Grid Application Value</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>AMI Application</td>
</tr>
<tr>
<td>1 Enhance Revenue</td>
<td>Low</td>
</tr>
<tr>
<td>2 Improve Distribution System Reliability and Power Quality</td>
<td>N/A</td>
</tr>
<tr>
<td>3 Improve Asset Utilization</td>
<td>Medium</td>
</tr>
<tr>
<td>4 Reduce Management and Administration Costs</td>
<td>Low</td>
</tr>
<tr>
<td>5 Improve Utility Operations</td>
<td>Medium</td>
</tr>
<tr>
<td>6 Improve Environment, Integrate Renewables and Enable Electric Transportation</td>
<td>Low</td>
</tr>
<tr>
<td>7 Enhanced Customer Experience and Empowerment</td>
<td>Uncertain</td>
</tr>
<tr>
<td>8 Efficient Use of Energy and Water Supplies</td>
<td>Low</td>
</tr>
</tbody>
</table>

Table 1-1: CPAU Strategic Goals and Value Drivers

During Smart Grid workshop sessions, CPAU developed a detailed list of Strategic Objectives as it pertains to a Smart Grid deployment. These detailed Strategic Objectives are then used in developing Smart Grid Functional Requirements. Functional Requirements are then mapped against proposed Smart Grid elements and components. Smart Grid applications and functions should directly support CPAU business objectives as identified in the workshops.

Following the development of the draft version of the Assessment of Smart Grid Applications, two review sessions were held with CPAU Utility Advisors Council Technology Committee and CPAU executive staff to assess and discuss the preliminary results, findings and recommendations.
CPAU staff have undertaken a separate survey research to understand residential and commercial customer perception of smart grid applications, the value they place on such a technology, and their concerns in implementing this technology. That survey results were not available during the time of this assessment.

**CPAU “As-Is” and “To-Be” Systems**

The present day City of Palo Alto Utilities’ customer services and power delivery systems have been, and continue to be, effectively planned, implemented and managed. Compared to other California utilities which are some of the most advanced in the country, the current CPAU systems are comparable in their technological advancement and economical effectiveness. These well managed efficient and advanced CPAU systems result in energy delivery costs that are among the lowest of all California utilities.

The current CPAU As-Is System Architecture consists of the following three main systems:

1. CPAU Information Management Systems
2. CPAU Utility Distribution Operations System
3. CPAU Municipal Communications Network

Going forward CPAU operating systems can evolve to include the following Smart Grid elements:

1. AMI system including MDMS
2. Advanced Distribution
3. Demand Response
4. Outage Management System integrated with GIS and Asset Management
5. Field Force Work Management System

This report addresses AMI system deployment and Advanced Distribution. Demand Response is limited in effectiveness in Palo Alto at this time due to customer profiles but could become an important Smart Grid application over time. Limited functionality of an Outage Management System can be implemented using information from the meter outage information report coming from an AMI System that is linked directly to the SCADA system. As the Smart Grid at CPAU develops, CPAU may want to investigate a full OMS deployment running on the SCADA platform. This can then be coupled with a Field Force Work Management System for efficient and effective crew deployment and management.

**Cost Benefit Analysis Model**

The Cost Benefit Analysis Model is performed in an Excel spreadsheet with 27 tabs. These tabs cover Smart Grid Summary and Assumptions (2 tabs), AMI Costs (6), AMI Benefits (5), Societal
Benefits (1), Advanced Distribution Costs (3), Advanced Distribution Benefits (1), Demand Response Costs and Benefits (2), Wi-Fi Communication Costs (2), and General Information (5).

The AMI system covers all the utility meters for electric, water and gas. The number of meters to be automated is shown in Table 1-2. A total of 72,421 customer meters are to be automated in a Smart Grid deployment with the majority of these being Electric Smart Meters (29,024).

<table>
<thead>
<tr>
<th>Palo Alto Retail Meter Population</th>
<th>Electric Meters</th>
<th>Residential</th>
<th>24,495</th>
<th>Commercial</th>
<th>4,529</th>
<th>Total Electric</th>
<th>29,024</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>Residential</td>
<td>20,600</td>
<td></td>
<td></td>
<td></td>
<td>Total Water</td>
<td>23,497</td>
</tr>
<tr>
<td>Gas Meters</td>
<td>Residential</td>
<td>15,300</td>
<td></td>
<td></td>
<td></td>
<td>Total Gas</td>
<td>19,900</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>72,421</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 1-2: CPAU Retail Meter Population

The AMI System costs and benefits summary are shown in Table 1-3. This shows the capital expenditures for electric, water and gas Smart Meters plus the Smart Meter installation costs and the proportional allocation of AMI network communication costs per each utility sector.

<table>
<thead>
<tr>
<th>Capital Expenditures</th>
<th>Electric</th>
<th>Capital</th>
<th>Per Meter</th>
<th>% Total Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meters</td>
<td>$3.4</td>
<td>$117</td>
<td>22%</td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>$0.4</td>
<td>$14</td>
<td>3%</td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$1.0</td>
<td>$35</td>
<td>7%</td>
<td></td>
</tr>
<tr>
<td>Water</td>
<td>$1.4</td>
<td>$72</td>
<td>9%</td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>$0.3</td>
<td>$16</td>
<td>2%</td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$0.7</td>
<td>$36</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td>$1.3</td>
<td>$66</td>
<td>8%</td>
<td></td>
</tr>
<tr>
<td>Meters</td>
<td>$0.3</td>
<td>$14</td>
<td>2%</td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>$0.7</td>
<td>$34</td>
<td>4%</td>
<td></td>
</tr>
<tr>
<td>IT Integration and Software</td>
<td>$6.0</td>
<td>$122</td>
<td>39%</td>
<td></td>
</tr>
<tr>
<td><strong>Total Capital</strong></td>
<td><strong>$15.6</strong></td>
<td><strong>$215</strong></td>
<td><strong>100%</strong></td>
<td></td>
</tr>
</tbody>
</table>

Table 1-3: AMI System Costs Summary, CapEx, $M
The AMI System total capital costs could vary in a +/-20% range around the calculated cost of $15M to $16M. This provides an estimated range from $12M to $19M for the AMI System implementation capital costs. Figure 1-2 below shows the AMI system deployment costs by segment, with $6M for the IT systems including hardware and software, and integration including consultants and City project personnel. The AMI RF field communication costs will run around $1M. The Smart Meter hardware cost is projected to be $6M with meter deployment and installation around $2M to $3M.

A graph of the AMI capital expenditure for Smart Meters, Installation and AMI Network by meter segment is shown in Figure 1-3 above. Total AMI System capital costs are projected to be $10M. Capital costs for the electric utility segment ($4.8M) is almost twice the costs of either the
water ($2.5M) or gas ($2.3M) utility segments due to the initial costs of the electric Smart Meters. Smart Meter capital costs ($6.2M) dominate the AMI System capital costs compared to the AMI Smart Meter installation ($2.4M) and AMI Communication Network ($1M).

The CPAU meter population is on the smaller size. The hardware and installation costs of the Smart Meters scale in proportion to the number of installed meters. AMI IT Systems and Integration capital costs are shown in Table 1-4 below. The AMI System software components and integration costs are independent of the number of meters installed. This represents 40% of the total AMI system costs and needs to be covered as part of the up front costs before the Smart Meters are deployed and brought on-line.

| AMI Head-end | $ 1.3 |
| MDMS         | $ 2.7 |
| System Interfaces | $ 0.8 |
| Utility Staff | $ 0.5 |
| Integration Consultants | $ 0.8 |
| IT Systems, Integration | $ 6.0 |

Table 1-4: AMI IT Systems and Integration Capital Costs

Figure 1-4 above shows the AMI IT Systems and Integration capital costs by major IT systems and resource requirement. The projected costs for IT software and integration are conservative. These costs may be 20-30% lower depending on system requirements that CPAU may implement. These cost estimates assume that the existing Automated Meter Reading (AMR) infrastructure that covers 2800 electric, 1000 gas, and 650 water AMR meters (total of 4450 AMR meters) would be replaced with more advance two-way communicating AMI meter. The assessment also includes only the incremental cost of installing automated meter dials for the gas and water meters.
Utility Annual O&M Costs and AMI Benefits

Implementation of an AMI system will provide CPAU with a collection of benefits including Customer Service improvements, Meter Reading cost savings, more efficient distribution operations avoided capital outlay and reduced utility purchases due to customer conservation and efficiency measures. These projected annual benefits at Year 6 following full deployment of the AMI system is shown in Table 1-5 adding up to $1.4M.

<table>
<thead>
<tr>
<th></th>
<th>Costs $M</th>
<th>Per Meter</th>
<th>% Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>AMI Operations</td>
<td>$0.8</td>
<td>$12</td>
<td>67%</td>
</tr>
<tr>
<td>Smart Meter Field Service</td>
<td>$0.2</td>
<td>$3</td>
<td>20%</td>
</tr>
<tr>
<td>AMI Communications</td>
<td>$0.2</td>
<td>$2</td>
<td>13%</td>
</tr>
<tr>
<td>AMI Outsourced Operations</td>
<td>$0.0</td>
<td>$0</td>
<td>0%</td>
</tr>
<tr>
<td><strong>Annual O&amp;M Expense (At Yr 6)</strong></td>
<td><strong>$1.2</strong></td>
<td><strong>$17</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Benefit, $M</th>
<th>Per Meter</th>
<th>% Total Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Service</td>
<td>$0.1</td>
<td>$2</td>
<td>8%</td>
</tr>
<tr>
<td>Meter Reading Savings</td>
<td>$0.9</td>
<td>$12</td>
<td>61%</td>
</tr>
<tr>
<td>Distribution Operations</td>
<td>$0.1</td>
<td>$2</td>
<td>8%</td>
</tr>
<tr>
<td>Revenue Enhancement</td>
<td>$0.0</td>
<td>$0</td>
<td>0%</td>
</tr>
<tr>
<td>Avoided Capital</td>
<td>$0.2</td>
<td>$3</td>
<td>17%</td>
</tr>
<tr>
<td>Demand Response</td>
<td>$0.2</td>
<td>$3</td>
<td>17%</td>
</tr>
<tr>
<td>Reduced Utility Purchases</td>
<td>$0.1</td>
<td>$1</td>
<td>5%</td>
</tr>
<tr>
<td><strong>Sum of Annual Benefits (at Yr 6)</strong></td>
<td><strong>$1.4</strong></td>
<td><strong>$19</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

Table 1-5: AMI System Annual O&M Costs and Benefits at Year 6

Demand Response is used to address peak capacity requirements, both for economic and reliability considerations. Over the last year CAISO has created market offerings for both economic and reliability demand response resources. Local capacity reliability markets must still be met by CPAU. While not an important consideration at this time due to customer load profiles, 3rd Party Demand Response Aggregators could develop cost effective programs for CPAU in the future. These Demand Response Programs will be targeted to CPAU’s large commercial customers and efficiently dispatch available load during time of CAISO system peak. Similar programs could be put into place for delivering CAISO mandated reserve capacity to meet local reliability requirements. It is estimated that 4MW of peak capacity reduction could be achieved with the implementation of a cost effective demand response system. This results in a projected annual benefit of $0.2M.

Societal AMI Benefits

Societal Benefits consist of both Society and Utility Benefits that do not have a direct economic benefit to the utility but have an impact to which a value can be assigned from the stakeholder perspective. These include reduced customer economic losses from service interruption, reduction of CO2 due to customer conservation and reduced utility vehicle usage, along with improved customer satisfaction.
The calculated total societal benefits over 20 years is $6.2M nominal and $1.5M NPV indicating that the majority of the benefits accrue in later years over the investment. Societal benefits from serving increasing Plug-in Electric Vehicle (PEV) loads and resultant CO2 transportation reduction and increasing solar deployments are not addressed in this report. Other items not addressed include microgrids, distributed energy resources, energy storage. An extensive treatment of Home Area Networks (HANs) is not developed but would be instrumental to derive maximum value from AMI system deployment.

**AMI System Total 20 Year Costs and Benefits**

The 20 Year AMI System total costs (capital and O&M) and benefits are shown in Table 1-6 below. This table shows a projected 20 Year total AMI Nominal costs of $38.8M, a NPV costs of $29.3M and a projected benefit over 20 years of $40.3M nominal and $24.7M NPV.

<table>
<thead>
<tr>
<th>20 Year AMI Totals</th>
<th>Nominal $M</th>
<th>NPV $M</th>
<th>Per Meter NPV</th>
<th>% Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>20 Year Total AMI Costs</td>
<td>14.3</td>
<td>13.5</td>
<td>169.44</td>
<td>37%</td>
</tr>
<tr>
<td>20 Year Total AMI Capital</td>
<td>24.5</td>
<td>15.80</td>
<td>198.44</td>
<td>63%</td>
</tr>
<tr>
<td>20 Yr Total AMI Costs</td>
<td>38.8</td>
<td>29.3</td>
<td>367.88</td>
<td>100%</td>
</tr>
</tbody>
</table>

Table 1-6: AMI System Total 20 Year Cost and Benefits

AMI System costs and benefits may vary +/-20% either way. Total AMI System 20 year costs range from $23 to 35 million, NPV. Total 20 year benefits range from $18 to 28 million, NPV. Provided that the AMI System costs come in on the low side and additional benefits and value are higher, a positive net benefits case would result. For the best case scenario, an AMI System investment is estimated at 17 years. The AMI System Free Cash Flow is shown in Figure 1-5 below, illustrating positive on-going operational cost savings, but not sufficiently high to recoup the initial investment.
Advanced Distribution

Advanced Distribution includes distribution automation, distribution monitoring and advanced distribution applications. The projected total field hardware capital costs (see Table 1-7 below) for upgrading the distribution system with automated circuit switchers and mid-tie autore closers is $2.4M with additional $0.6M for IT integration and software for a total outlay of $3M nominal and $2.7M NPV. The current SCADA system can be readily upgraded with applications from the supplier that is deployed at many utilities today. The 20 Year Totals for utility and customer benefits are $2.7M nominal and $1.7M NPV with the majority of the benefits due reduction in customer energy consumption that results from Volt/Var conservations and improved customer productivity due to reduction of outage hours. The Advanced Distribution unlevered free cash flow is shown in Figure 1-6 below.

<table>
<thead>
<tr>
<th>Advanced Distribution Cost and Benefits Summary</th>
<th>$M</th>
<th>$M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Expenditures</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Field Hardware</td>
<td>$2.4</td>
<td></td>
</tr>
<tr>
<td>IT Integration and Software</td>
<td>$0.6</td>
<td></td>
</tr>
<tr>
<td>Total Capital</td>
<td>$3.0</td>
<td></td>
</tr>
<tr>
<td>Annual O&amp;M Expense (at Yr 6)</td>
<td></td>
<td>$0.1</td>
</tr>
<tr>
<td>Annual Utility Benefits (at Yr 6)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fewer Outage Events - Revenue Enhancement</td>
<td></td>
<td>$0.001</td>
</tr>
<tr>
<td>Fewer Outage Reduces Restoration Costs</td>
<td></td>
<td>$0.012</td>
</tr>
<tr>
<td>Volt Var Conservation - Net Utility Impact</td>
<td></td>
<td>($0.017)</td>
</tr>
<tr>
<td>T&amp;D Capital Savings - Capital Budget Deferral - Utility</td>
<td></td>
<td>$0.000</td>
</tr>
<tr>
<td>T&amp;D Operations and Maintenance Savings - Reduced Labor</td>
<td></td>
<td>$0.004</td>
</tr>
</tbody>
</table>
Cost - Utility

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Utility Benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>T&amp;D O&amp;M Savings from Automatic Switching</td>
<td>$0.000</td>
</tr>
<tr>
<td>T&amp;D Operations Savings from Reduced Peak Load Reserve Requirements - Utility</td>
<td>$0.004</td>
</tr>
<tr>
<td>Total Annual Utility Benefits (at Yr 6)</td>
<td>$0.004</td>
</tr>
</tbody>
</table>

Adv Dist Annual Customer Benefits (at Yr 6)

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Customer Benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Volt/Var Conservation Reduced Purchases</td>
<td>$0.08</td>
</tr>
<tr>
<td>Improved Customer Productivity</td>
<td>$0.05</td>
</tr>
<tr>
<td>Total Annual Customer Benefits (at Yr 6)</td>
<td>$0.13</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Nominal</th>
<th>NPV</th>
</tr>
</thead>
<tbody>
<tr>
<td>20 Year Total Adv Dist Capital Costs</td>
<td>$3.0</td>
<td>$2.7</td>
</tr>
<tr>
<td>20 Year Total Adv Dist Utility Benefits</td>
<td>$(0.1)</td>
<td>$(0.1)</td>
</tr>
<tr>
<td>20 Year Total Adv Dist Customer Benefits</td>
<td>$2.7</td>
<td>$1.7</td>
</tr>
<tr>
<td>20 Year Total Adv Dist Benefits</td>
<td>$2.6</td>
<td>$1.6</td>
</tr>
</tbody>
</table>

Table 1-7: Advanced Distribution Costs, Benefits and Societal Benefits, $M

Figure 1-6: Advanced Distribution Unlevered Free Cash Flow

Preliminary Smart Grid Timeline

A preliminary Smart Grid timeline is shown in Figure 1-7. The timeline is based on a proposal that CPAU implement a slow rollout of the Smart Grid consisting of Smart Grid pilots followed by AMI and Advanced Distribution systems over a 12 year period. The Smart Grid pilots during the first year would allow CPAU to become familiar with supplier offerings and
capabilities in fielded demonstrations. The AMI System infrastructure deployment is over the next two years with the Smart Meter deployment planned over a 5 year period (Years 2 – 6). Following the AMI System rollout, the Advanced Distribution procurement will begin in Year 7. Rollout will begin in Year 7 with fully operational Advanced Distribution systems and field equipment completed by Year 12. Additional Smart Grid components and interfaces (OMS, Field Force Management, etc.) will continue to be phased in after Year 12.

Figure 1-7: Smart Grid Deployment Timeline

The Smart Grid deployment timeline outlined above is designed to roll out implementations in sequential order and is based on availability of CPAU resources. Limited scoped activities can still be pursued in parallel. For example the Advanced Distribution rollout can start at anytime. Smart Grid pilots and demonstrations can be performed over a 1 or 2 year time period. Determination of the Smart Grid deployment timeline will be influenced by Customer Stakeholder input. CPAU is currently conducting a Customer Stakeholder survey to assess level of Smart Grid awareness and perceived value.
1 Overview

1.1 Introduction

This Smart Grid Application Assessment is designed to establish the boundaries of the programs and applications that will make up the Smart Grid for the City of Palo Alto Utilities (CPAU). These boundaries include the scope of applications, the costs and benefit of applications by order of magnitude, and an understanding of how the applications relate to one another. The goals of the assessment are firstly to develop a assessment that prepares CPAU for the types of investments that will be required, and secondly to provide guidance to the operating units responsible for individual application areas regarding which benefits they should seek and which they should assume are delivered elsewhere. At this point, the business plan is a “straw man” intended to stimulate discussion by the stakeholders within City of Palo Alto Utilities.

The Smart Grid Application Assessment can be used to support the CPAU Strategic Plan including Mission and Vision. This assessment and a future strategic plan for smart grid implementation has to align with CPAU Stakeholder interests as shown in Figure 1-1 below: A Smart Grid Strategic Plan should support CPAU’s plans and policies and guidelines for the following CPAU functions:

1. Water, electric and gas efficiency and conservation programs, and electric demand reduction;
2. Resource Management: water, electric and gas supply acquisition, asset management and energy risk management;
3. Climate Protection: greenhouse gas reduction goals;
4. Financial Management: rates, reserves, budget and long-term financial planning;
5. Distribution System Reliability and Capital Improvement Program;
6. Information Technology deployment strategy;
7. Customer Service; programs, rates, information, communication; smart metering and billing;
8. Distributed and Local Resources;
9. Regulatory compliance and reporting; and
10. CPAU Workforce management

A Smart Grid Strategic Plan, when developed, needs to align with CPAU's Supporting Objectives and Key Strategies as outlined below:

1. Enhance customer satisfaction and utility infrastructure.
2. Employ balanced environmental solutions.
3. Provide fair and reasonable returns to the City and competitive rates to customers through
4. Municipal ownership.
5. Ensure a safe and engaged workforce.

CPAU's Key Strategies:

STRATEGY 1: Ensure a high level of system reliability in a cost effective and timely manner.

STRATEGY 2: Manage supply portfolio risk as per council policy to provide stable gas and electric rates, to preserve a supply cost advantage, and to manage business processes cost effectively.

STRATEGY 3: Improve inter- and intra-departmental business processes to reduce cost, improve efficiency and enhance information flow.
STRATEGY 4: Provide low and stable rates, adequate reserves, and budgeted transfers to the General Fund.

STRATEGY 5: Provide proactive, responsive and integrated communication to customers.

STRATEGY 6: Provide targeted customer and environmental programs and services.

STRATEGY 7: Foster a productive workplace environment that promotes safety, job satisfaction and self improvement goals.

1.2 Drivers for Change

City of Palo Alto Utilities’ power delivery system has served CPAU customers and communities very well for many decades. Investments were prudent, efficient and technologically sound, as demonstrated by energy delivery costs that have been among the lowest of all California utilities. However, the needs and expectations of customers and stakeholders have changed over the decades, while CPAU operations have not. The reasons for these changing expectations are examined below.

1.2.1 Internal Drivers

Internal drivers are those factors that have the capacity to affect City of Palo Alto Utilities’ ability to effectively deliver electricity, water and natural gas. The principle internal drivers for creating a Smart Grid are to support the City of Palo Alto Utilities’ Purpose (reliable power, at low cost, for generations), along with CPAU’s Service Plan and Guiding Principles. These internal drivers can be summarized as follows:

- **Customer (Reliability of Supply and Customer Satisfaction):** This category includes improving performance measures such as SAIDI and CAIDI, as well as newer measures such as CEMI (Customers Experiencing Multiple Interruptions) or CELID (Customers Experiencing Long Interruption Durations), for the benefit of CPAU customers. Maintaining power quality and reliability at a high level of service is a strategic goal.

- **Employees (including Safety):** One way to mitigate workforce constraints is system automation, which enables a decreasing pool of trained individuals to be used more efficiently.

- **Environment (Impacts and Conservation):** City of Palo Alto Utilities has been a sustainability and energy demand side management leader for many years, and reducing environmental impact has long guided CPAU planning and power delivery strategies.
• **Financial (Costs and Operational Efficiencies):** CPAU has made significant investment in distribution infrastructure and IT support systems. This provides City of Palo Alto Utilities with a significant opportunity to optimize recent investments as part of the Smart Grid strategy. This includes reducing system losses and improved operating efficiency by using process and materials identified in this assessment.

### 1.2.2 **External Drivers**

External drivers are those factors outside of City of Palo Alto Utilities’ control that have the capacity to impact the services that the City delivers and the manner in which it delivers them. The drivers affecting City of Palo Alto Utilities are consistent with challenges faced by many distribution utilities:

- **Customer Expectations:** One of the well-documented key issues facing City of Palo Alto Utilities is the continued, and increasing, demand and consumer dependence on electrical power. This power is expected to be clean, of digital quality, flow openly in two directions and be delivered with a high degree of reliability. All of these requirements present a challenge to the system as it exists today.

- **Demographics:** CPAU current distribution system relies on manual labor for many of the operational and restoration activities. But an ageing population and retiring skilled workforce means the City needs more efficient work processes and system automation in order to focus the limited workforce available on more skilled operations.

- **Safety:** An increased responsibility for public safety from system performance has become an expectation, and implementing a self-healing grid should serve to minimize outages, reducing the risk to both the public and workers.

- **Technology:** New resources are now available for generating, storing and delivering power. Similar to the Internet, linking communication and information technology to electro-mechanical equipment has lead to a multitude of opportunities to increase protection, monitoring and control over power delivery. Greater deployment of distributed solar PV systems and electric vehicles also will require greater control and communication technology.

- **Environment:** Concerns about climate change have manifested in the US with a looming carbon taxes, a carbon neutral requirement for CPAU operations and the need for carbon-free power generation. Public demand for sustainable solutions to power delivery and opposition to “big power” projects with large environmental footprints drive City of Palo Alto Utilities toward smaller, localized power sources and an overall increase in distributed generation.
• **Regulatory:** Much of the contemplated change in power delivery at City of Palo Alto Utilities is being mandated by the State of California and U.S. Government based on a variety of regulations and directives, the most significant being the AB32, SB17, EPA 2005, and EISA 2007. Each year sees additional energy and environmental bills introduced into legislation that put CPAU’s future at risk.

### 1.3 Smart Grid Overview

The term “Smart Grid” is used to identify a movement within the electrical power industry to modernize the electricity delivery system. A Smart Grid monitors, protects and automatically optimizes the operation of its interconnected elements – from energy markets and generators through the high-voltage network and distribution system, to end-use consumers and their thermostats, electric vehicles, appliances and other household devices.

The goal of a Smart Grid is to use advanced information-based technologies and communications systems to increase grid efficiency, reliability and flexibility. It enables better use of the existing delivery infrastructure and offers benefits for both the consumer and the environment.

![Smart Grid Conceptual Model (NIST)](image)

*Figure 1-2: Smart Grid Conceptual Model (NIST)*
Figure 1-2 is the high-level conceptual model of such a Smart Grid, as developed by the U.S. National Institute of Standards and Technology (NIST) in its Smart Grid Interoperability Framework released in January 2010. This conceptual model shows the traditional electricity-carrying portions of the power system – bulk generation, transmission and distribution – and the operations systems that monitor and control it. It also shows that these domains are interconnected in a secure communications system with energy markets, with the emerging energy service provider industry, and most importantly, with the customer as a source of feedback and an active participant in energy conservation as well as just energy usage.

### 1.4 Approach to developing the Assessment of Smart Grid Applications for City of Palo Alto

The following steps were implemented with the support of the contractor, EnerNex and subcontractor, NexLevelIT:

- a. Assist in defining elements of the Smart Grid applicable for the electric utility.
- b. Map the information flow and architecture associated with different elements of the existing electric utility’s distribution, supply, customer service, meter reading, billing and financial systems.
- c. Map the changes in information flow and architecture of each of the Smart Grid elements identified in Task b. above upon implementation of elements of the Smart Grid systems.
- d. Model the costs and benefits of implementing different elements of the system, with particular emphasis on electric smart meters and related systems.
- e. Based on City’s plans to expand the fiber optic backbone and implement a Wi-Max system, evaluate various communication medium to smart meters; compare the benefits and costs of implementing fiber or Wi-Max based communication system to other communication medium for smart meters.
- f. Prepare report outlining findings and recommendations and Smart Grid implementation timeline including feasibility studies and deployment pilots.

The following flowchart shown in Figure 1-3 illustrates the steps taken to develop the proposed CPAU Smart Grid Application Assessment.
Figure 1-3: Steps to defining the CPAU Application Assessment
1.5 City of Palo Alto Utilities Vision Statement

The drivers described here suggest that City of Palo Alto Utilities will need to transform its business to continue serving CPAU customers effectively. Like other utilities worldwide, CPAU has a vision of the distribution system that will be best able to meet the future needs of its customers: the Smart Grid. CPAU Utilities’ Vision Statement is as follow:

“CPAU will be in the top quartile nationally in providing safe and reliable gas, water, electric and wastewater collection service. By 2015, CPAU will achieve a customer satisfaction rating of overall value of at least 85%. Average customer bills for CPAU services will be no more than the average of those in surrounding communities.”

The Smart Grid can be most simply defined as increased monitoring and automation of the power delivery system through the application of advanced communications and information technologies alongside a new generation of digital electrical equipment. The purpose of the Smart Grid is to enable two-way flows of power and information to increase engagement of the consumer and increase the level of service provided by the utility.
2 Strategic Goals and Objectives

2.1.1 Strategic Goals

Based on a series of workshops with CPAU employees the following Strategic Goals were developed:

1. Enhance Revenue
2. Improve Distribution System Reliability and Power Quality
3. Improve Asset Utilization
4. Reduce Management and Administration Costs
5. Improve Utility Operations
6. Improve Environment, Integrate Renewables and Enable Electric Transportation
7. Enhanced Customer Experience and Empowerment
8. Efficient Use of Energy and Water Supplies

During Smart Grid workshop sessions, CPAU developed a detailed list of Strategic Objectives as it pertains to a Smart Grid deployment. These detailed Strategic Objectives are then used in developing Functional Requirements. Functional Requirements are then mapped against proposed Smart Grid elements and components. Smart Grid applications and functions should directly support CPAU business objectives as identified in the workshops.

During the development of the Smart Grid Cost Benefit Analysis Model in Section 7 below, detailed quantitative assessment for each benefit category was analyzed. These benefit categories align with the Strategic Goals above and their associated Strategic Objectives.

2.1.2 Strategic Objectives

During the Stakeholder workshops, a list of Strategic Objectives that align with CPAU’s Strategic Goals from above was developed. The list of Strategic Objectives is provided in Appendix C below.
The CPAU Smart Grid Strategy Goals and Objectives workshops resulted in the selection of strategic goals and the ranking of strategic objectives. These have been grouped and summarized below. Where possible a quantitative assessment for each Strategic Objective category was identified and analyzed in the Smart Grid Cost Benefit Analysis model in Section 7 below.

**Enhance Revenue**

The following is a list of strategic objectives that rated highest:

1.1 Improve billing accuracy
1.2 Increase meter accuracy to increase bill accuracy
1.8 Add new business venture
1.9 Add new product
1.10 Add new service

Secondary strategic objectives for Enhance Revenue are:

1.3 Target customer marketing
1.5 Improve billing cash flow
1.6 Recover missing revenue
1.7 Add new revenue source
1.11 Better identify energy theft
1.12 Increase revenue program participation

**Improve Distribution System Reliability and Power Quality**

The following is a list of strategic objectives that rated highest:

2.1 Detect and communicate outages sooner
2.2 Locate faults sooner
2.5 Resolve outages more quickly
2.9 Integrate distributed generation
2.11 Monitor transformer under/over loading
2.12 Optimize transformer loading
2.15 Operate distribution system in loop configuration
2.11 Improved gas and water leak detection High
2.12 Improve monitoring, recording, and mitigation of down line damage due to spikes or anomalies

Secondary strategic objectives for Improve Distribution System Reliability and Power Quality are:
2.10 Increase reliability program participation
2.14 Transformer maintenance/replacement prediction
2.16 Use auto reclosers to bring max. number of customers back on-line
2.13 Improve monitoring of voltage waveform
2.14 Improve voltage regulation and compensation
2.18 Reduce losses
2.15 Volt/VAR for conservation

Improve Asset Utilization, Reduce Management and Administration Costs

The following is a list of strategic objectives that rated highest:
3.1 Comply with laws or regulations
3.2 Reduce meter reader equipment
3.3 Reduce maintenance equipment
3.4 Optimize the communications infrastructure openness, and efficiency
3.5 Leverage existing City communications infrastructure
3.6 Reduce meter procurement costs
3.7 Improve efficiency of office support
3.8 Better identify unbilled account errors
3.9 Improve efficiency of resolving disputes
3.13 Reduce net emissions

Secondary strategic objectives for Improve Asset Utilization, Reduce Management and Administration Costs are:

3.10 Improve system planning
3.11 Defer building additional generation
3.17 Automatically perform load survey

**Improve Utility Operations**

The following is a list of strategic objectives that rated highest:

4.1 Reduce meter reader labor
4.2 Reduce maintenance labor
4.3 Reduce installation labor
4.4 Reduce customer service labor
4.5 Reduce site visits
4.6 Better identify broken meters
4.7 Better identify failed meters
4.8 Better identify misconfigured meters
4.9 Better identify communications failures
4.10 Better identify meter location
4.11 Increase meter accuracy
4.12 Better locate meters with wrong multipliers
4.13 Add workforce management system with geographic access
4.14 Add mobile workforce
4.15 Improve installation verification and maintain through operational functions
4.16 Avoid losing the field relationship and asset inspection function of current meter reading
4.17 Reduce installation errors
4.19 Reduce energy procurement costs
4.20 Reduce system energy losses
4.21 Reduce meter energy losses
4.23 Reduce calendar resets
4.25 Increase cost reduction program participation
4.26 Improve restoration time by installing field SCADA switches
4.27 Improve equipment condition based monitoring (e.g. Add remote monitoring for test stations for cathodic protection system
4.28 Improve system diagnostics (e.g. add Smart Manhole Cover to detect/prevent sewer overflows)
4.29 Ensure that organization has the retraining and process in place to make use of new system capabilities
4.30 Improve integration of weather forecasting in demand response planning

Secondary strategic objectives for Improve Utility Operations are:
4.18 Automatically perform load survey

Improve Environment, Integrate Renewables and Enable Electric Transportation

The following is a list of strategic objectives that rated highest:
5.1 Increase renewable generation
5.2 Lower energy and water losses
5.3 Lower Green House Gases
5.4 Electrify transportation
5.5 Reduce pollution
5.6 Support sustainable infrastructure
5.7 Accommodate distributed energy resources
5.8 Advance energy and water efficiency programs
5.9 Maximize recycle water usage
5.10 Minimize irrigation water loss
Enhanced Customer Experience and Empowerment

The following is a list of strategic objectives that rated highest:

6.1  Provide real-time energy usage
6.2  Access usage and billing information by Internet
6.3  Enable demand response participation
6.4  Detect and communicate outages sooner
6.5  Locate faults sooner
6.6  Resolve outages more quickly
6.7  Improve billing timeliness
6.8  Permit customized billing date
6.9  Lower customer bills
6.10 Customer feels more control
6.11 Add billing option
6.12 Add rate option
6.13 Customer is more aware of service
6.14 Customer has more choices
6.15 Customer power quality is improved and stabilized
6.16 Improved billing data presentation

Efficient Use of Energy and Water Supplies

The following is a list of strategic objectives that rated highest:

7.2  Improve monitoring/mitigation of water lifting systems during emergency situations
7.3  Decrease operating cost of water supply pumping systems / Shift water lifting load to off-peak time
7.4  Increase reliability of system during peak
7.5  Optimize water pumping load schedule
7.6  Optimize time/use back-up generation
7.7  Monitor demand/load to better understand need for back-up
Secondary strategic objective for Efficient Use of Energy and Water Supplies is:

7.1 Improve monitoring of waste water pump capacity
3 Define Smart Grid Elements

Following the development of Strategic Goals and Objectives, a list of Functional Requirements is created that supports these. These Functional Requirements are grouped into logical components and then mapped against proposed Smart Grid Elements. These Smart Grid Elements should form the foundation for the CPAU Smart Grid System Architecture.

The Smart Grid can be most simply defined as increased monitoring and automation of the power delivery system through the application of advanced communications and information technologies alongside a new generation of digital electrical equipment. The purpose of the Smart Grid is to enable two-way flows of power and information to increase engagement of the consumer and increase the level of service provided by the utility.

Figure 3-1 below graphically identifies the utility elements and applications that City of Palo Alto Utilities should consider as the building blocks of the Smart Grid and suggests how they are dependent on each other. It also highlights the fact that several customer-focused applications are heading CPAU’s way that will mandate a smarter grid.
The Smart Grid Framework diagram is arranged to indicate that the feasibility of a given element depends on some or all of the elements below it in the lower layer(s) of the diagram. For example, the full functionality of smart meters is only possible if IT and telecommunication infrastructures are in place.

**Smart Grid Foundational Elements:**

1. IT Infrastructure
2. Telecommunication Infrastructure
3. Power System

To implement a Smart Grid, CPAU must first ensure a strong foundation for grid operations. City of Palo Alto Utilities’ Smart Grid Framework should align with City of Palo Alto Utilities corporate values, purpose and business goals, and ensures prudent management of assets to ensure optimal investment in the CPAU system. Building on this framework by adding further elements of the Smart Grid will ensure maximum
benefits are realized from the implementation of Smart Grid applications. These elements include:

- Updating and integrating a new **Information Technology (IT) infrastructure**, including as a minimum an SAP Customer Relationship Management (CRM) and Financial applications, and fully integrating Geographic Information System (GIS).

- A **telecommunication infrastructure** consisting of a local area network (LAN), linked to a wide area network (WAN), and a backhaul network. This may include CPAU’s extensive fiber backbone.

- An evolution in how CPAU approaches **circuit topology**, including how CPAU designs and operates feeders providing for automatic fault location, isolation, and service restoration. (FLISR).

### 3.1.1 Fundamental Applications

With the proper Smart Grid foundation elements in place, City of Palo Alto Utilities can confidently implement those applications that have always been traditionally considered part of utility automation but which have only recently become feasible on a large scale:

- **Smart Meters** for customers and for feeder transformers

- **A Meter Data Management System** (MDMS) to process the data from the meters and to provide that data to customers

- **Distribution Automation** using field equipment capable of advanced sensing, automatic switching and peer-to-peer communications

- **A Distribution Management System** (DMS) capable of coordinating with CAISO’s Energy Management System (EMS) which monitors and controls the transmission network and transmission substations, with CPAU’s distribution automation field devices and with customers (whether they act as load or generator). This system can also be used to support emerging opportunities with CAISO’s energy market system, MRTU.

- Distribution **Substation Automation**, including upgrading of protection, control and monitoring equipment
3.1.2 **Enabled Applications**

Many new opportunities exist for CPAU customers once the grid has been modernized. We refer to these opportunities collectively as the Smart Grid-enabled applications. These are the applications that are typically discussed in newspapers and magazines whenever the term “Smart Grid” arises. Each of them is dependent on the applications lower in the Smart Grid Framework to be successful.

- Of specific interest to City of Palo Alto Utilities is **Distributed Generation (DG)**. CPAU recognizes that the current distribution system was not engineered to enable connection of a large number of DG sources, although CPAU may soon need to do so because of the drivers discussed in Section 1.2. Circuit topology changes will be critical to make DG happen.

- Similarly, **Plug-in Electric Vehicles (PEVs)** and large-scale **Energy Storage**, whether considered as either a large load or a source of stored energy, were not contemplated until very recently. It is believed that the current power system would struggle to handle interconnection of even small numbers of these elements.

- Another recently proposed concept is the **Micro-grid**, wherein a customer or series of customers can isolate themselves from the grid and operate autonomously based on internal matching of load to local generation capability. So far, micro-grids exist only as research projects in the City of Palo Alto Utilities service area or as emergency back-up units for corporate and internet data centers.

- The **Volt/VAR Optimization (VVO)** application is a very effective method of achieving network optimization and conservation energy savings that can only be fully implemented system-wide once the grid has detailed sensing and two-way communications.

- The **Operational Efficiency (OE)** suite of programs, including workforce management, diversion reduction and resource optimization, also requires a communication backbone and IT system enhancements to be successful. This application area also includes theft detection, which is dependent on the deployment of smart meters to consumers and feeder transformers. Operational Efficiency includes systems such as Outage Management System (OMS) and Field Force Work Management System (WMS).

- Achieving the peak shaving envisioned as part of a **Demand Response (DR)** program requires accurate knowledge of the loads and generation available to the system in real time, as provided by smart meters and the DMS.

- Lastly, the smart meters will create a link with the customer, namely the **Home Area Network**, which will permit in-home feedback and facilitate information provisioning through such devices.
as In Home Displays (IHD) or an internet portal. Two-way communications and IT applications will enable these types of interconnections to proliferate.

It is expected that the availability of a Smart Grid will spawn countless new technologies and uses for the grid beyond those contemplated today. It should be pointed out that the pursuit of any of the enabled applications should be in response to local drivers including best practices.

All applications being considered in this space are exciting and may represent substantial improvement over business as usual. However, they must be considered carefully because they carry a higher technological and organizational risk. Individually they may or may not add value to City of Palo Alto Utilities’ Smart Grid.

3.1.3 **Strategic Alignment**

Successful implementation of the Smart Grid is about more than just new technologies. It includes customer engagement as well as process and organizational change. The City of Palo Alto Utilities Smart Grid development aligns with its strategic goals as follows:

**Customer Operations:** It is important for City of Palo Alto Utilities to recognize the importance of the more interactive and targeted customer relationships that will be enabled by the Smart Grid. Improved customer choice, better system reliability and enhanced outage management will all contribute to City of Palo Alto Utilities achieving customer satisfaction targets. Customer Operations include those customer centric applications in which the utility plays a role as operator, but the customer also has an integral role in delivering. This role may include the customer as a user of PEV’s, or as a supplier to City of Palo Alto Utilities through demand response, load control, energy storage or net metering. Customer Operations also covers applications that support customer service including access to real-time energy consumption and troubleshooting, remote connect/disconnect, dynamic rate implementation, customer program management, and customer web portals provisioning.

**Distribution Operations:** A critical component of the Smart Grid is the operations of the Smart Grid. For every new technology deployed there will be several operational considerations. Distribution Operations include applications which, for the most part, reside in the utilities operational space, and are largely transparent to the customer.
These applications include real-time operations which handle the operational environment that the utility has in place to manage the daily state of the distribution grid. With the deployment of the Smart Grid, real-time operations are extended far into the distribution network. Applications may include Volt/VAR optimization, feeder management through load balancing and network optimization, automatic fault location, isolation, and service restoration (FLISR), micro-grid operations, and distributed generation through the dispatching, control and islanding of independent power producers.

### 3.2 Smart Grid Functional Requirements

Smart Grid consists of a collection of functionality that supports the Strategic Goals and Objectives set forth by the City of Palo Alto Utilities stakeholders. This involves actions that personnel, systems and equipment can perform to achieve a goal or end result. Use cases are utilized to support the development of Smart Grid functional and system requirements based on detailed working sessions with utility stakeholders. A list of applicable industry developed use cases is listed in Appendix A. A list of Smart Grid functions that an Advanced Metering Infrastructure System (AMI) and Advanced Distribution and Demand Response should provide has been compiled. Groupings of these functional requirements will become information and communication components of the necessary Smart Grid Elements. The Smart Grid Functional Requirements are detailed in Appendix D

### 3.3 Mapping to Smart Grid Elements

The mapping of the Smart Grid Functional Requirements to Smart Grid Elements is provided below:

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Function</th>
<th>Component</th>
</tr>
</thead>
<tbody>
<tr>
<td>TOU</td>
<td>Interval Metering and Reporting</td>
<td>MDMS/AMI/Meter</td>
</tr>
<tr>
<td>RCD</td>
<td>Remote Connect/Disconnect</td>
<td>MDMS/AMI/Meter</td>
</tr>
<tr>
<td>CAI</td>
<td>Customer Access to Information</td>
<td>MDMS/AMI/Meter</td>
</tr>
</tbody>
</table>
### 3.3.1 Smart Grid Function

The Functional Requirements listed in the previous section are logically grouped into Functional Components. These Functional Components cover aspects of Advanced Metering Infrastructure, Meter Data Management, Customer Information, Advanced Distribution, Work Management, Demand Response and Outage Management.

### 3.3.2 Scope of Smart Grid Systems

Smart Grid requirements drive the creation of Smart Grid systems. Advanced Metering Infrastructure (AMI) system is a prime example of a new technology derived from a detailed set of Smart Grid requirements. Creation of Smart Grid systems based upon carefully constructed logical components provides the Smart Grid supplier and utility opportunities to apply Smart Grid technologies that are focused to the City of Palo Alto’s needs as well as providing expandability to address additional functionality that provides increased benefits to both the utility and the customer.

Smart Grid systems consist of the hardware, software and associated system and data management applications that create a communications network between end systems at customer premises (including meters, gateways, and other equipment) and operational systems at the utility. Smart Grid systems provide the technology to allow...
the exchange of information between systems in the field, at the customer premises and systems located at the utility, both operations, engineering and corporate.

Advanced Distribution Systems covers distribution operations, automation, work management and maintenance.

In order to protect this critical infrastructure, end-to-end security must be provided across the AMI system, encompassing both the distribution grid and customer end systems as well as the utility.

### 3.3.3 Overview of Smart Grid Functional Components

This section identifies functional components which act as logical groupings for Smart Grid functions identified in the previous section. Figure 3-2: Smart Grid Functional Components shows a diagram depicting these Functional Components.
3.4 Proposed Smart Grid Elements

While there is no set industry rules defining the system design for a Smart Grid supplier solution, Smart Grid systems are mostly organized around the following system level packages.
A high level overview of Smart Grid Elements is shown in Figure 3-3 below:

Figure 3-3 Smart Grid Elements:

Customer Information System (CIS):
Maintains customer contact information, calculates and formats customer bills, receives, and applies payments for individual accounts. The system is responsible for storing customer information such as site data, meter number, rates, and program participation(s).
Finance and Billing:
System and organization responsible for customer consumption and demand validation, estimation and editing. Generates periodic bills and sends them to customers.

Meter Data Management System:
System that gathers, validates, estimates and permits editing of meter data such as energy usage, generation, and meter logs. It stores this data for a limited amount of time before it goes to a data warehouse, and makes this data available to authorized systems.

AMI - Head End System:
AMI Head End System is the AMI Supplier system that is responsible for maintaining remote two-way communications with the AMI Meters to retrieve data and execute commands. The AMI Head End System has the responsibility to balance load on the communications network resulting from scheduled meter reads, to retry meters when communications fail, and to provide clients with diagnostics and information services on the current state of the meters.

Distribution Management System:
A system that integrates the functions of SCADA, outage management, work management, distribution load management, reactive control, and asset management into a single console and set of applications.

Geographic Information System:
A system that maintains information about the power grid, location information about grid assets, as well as capabilities and relationships between assets. For example, the system would maintain capacitor banks associated with a particular meter given a particular feeder configuration.

Outage Management System:
This system is used to maintain the status of customer outage along with managing switch orders and switch operations for planned, unplanned and emergency outages. The OMS receives information from CIS, AMI, and field crews. Information collected by OMS is used to calculate grid reliability and performance indices.
Demand and Supply Resource Management:
System(s) that are responsible for maintaining supply resources that balance with load in real time or plan for the availability of supply resources over a projected time period. Demand Resource is the opposite of a Supply Resource and acts to reduce overall system demand.

Gas and Water: A collection of functions that support gas operations, engineering and maintenance. These include:
- Leak detection
- Diversion detection
- Cathodic protection system monitoring
- Remote water valve turn-on/turn-off

Backhaul or Wide Area Network (WAN)
The Backhaul or WAN will provide data connectivity across the utility service area. This network must provide adequate bandwidth to support all existing and forecasted devices, employ redundancy, and have a very high availability. Today, there is a significant amount of existing fiber optic communications infrastructure interconnecting CPAU distribution facilities within the City. The Smart Grid plan should be to fully utilize CPAU’s backhaul existing core network, which includes fiber optic. Additional point-to-point RF links may be added in order to meet loading or system performance requirements.
Field Area Network (FAN):

The FAN is typically a large collection of FAN Controllers that cover the utility service territory. The FAN Controller (radio-based collectors) will manage communications over the FAN to the electric meters; distribution meters, grid sensors, and controllers; and eventually to the HAN. Each collector will support a portion of the utility service territory, and as such, multiple collectors will be required to communicate to all field devices across the entire utility service territory.

The FAN is expected to be implemented as a wireless, IP-based network. Communication can be over unlicensed bands or licensed, if permits are available.

The FAN is typically utility owned and operated. Other approaches use third part communication providers in a managed service arrangement (i.e. cellular services dedicated to utility service level agreements.)

Customer Meters:

Advanced electric revenue meter capable of two-way communications with the utility. A device that serves as a gateway between the utility, customer site, and customer’s load controllers. The meter measures, records, displays, and transmits data such as energy usage, generation, text messages, event logs, etc. to authorized systems (i.e., the AMI NMS) and provides other advanced utility functions.

Distribution Field Devices:

Sensors, monitors and device controllers that perform a function related to the operation and maintenance of the distribution grid.

Home Area Network (HAN):

The HAN includes the utility-owned premise gateway as well as Customer owned and operated devices and systems which brokers messaging between the customer's HAN-attached devices and the utility's premise gateway

Customer HAN Devices:

Customer devices that respond to dispatch signals from the utility, either price or demand response type commands.
4 Current and Future Architectures

The City of Palo Alto Utilities information systems, processes and communication systems are described in the following review of the “As-Is” System Architecture. A “To-Be” Smart Grid Architecture is proposed that covers the Smart Grid elements and requirements developed in earlier sections.

4.1 CPAU As-Is System Architecture

The present day City of Palo Alto Utilities’ customer services and power delivery systems have been, and continue to be, very effectively planned, implemented and managed. Compared to other California utilities which are some of the most advanced in the country, the current CPAU systems are both technologically advanced and economically effective. These well managed efficient and advanced CPAU systems result in energy delivery costs that are among the lowest of all California utilities.

The current CPAU As-Is System Architecture consists of the following three main systems:

1. CPAU Information Management Systems
2. CPAU Utility Distribution Operations System
3. CPAU Municipal Network

4.1.1 Current Information Management Systems Architecture

The CPAU Information Management Systems are built around the SAP system as shown in Figure 4-1 below. The SAP Customer Care and Service system, referred to as the ISU/CCS, uploads the data from the meter reads and performs all billing, verification, invoicing and bill printing functions.

The SAP ISU/CCS system also performs other functionality including asset tracking, multiple web portal interfaces for customers, and production of a transaction database for CAISO, Northern California Power Agency (NCPA) and PG&E transactions. A limitation of the SAP asset tracking system is that all utility assets are not currently in the SAP system.
Currently, the electricity, gas and water meter data is read with handheld, mobile devices or automatic meter reading (AMR) systems and the data sent to the Itron MVRS data collection software. The Itron MVRS system in turn sends the meter reads along with billing determinants to the SAP ISU/CCS system. All billing functions including calculations with the multitier factors, verification, invoicing and bill printing are performed by the SAP ISU/CCS system. The SAP ISU/CCS system also provides information for display on the customer service portal. In addition, the SAP ISU/CC system has interfaces to the SAP Business Intelligence (BI) Reports module and to other SAP Direct Applications.

An Itron MV90 interval data collection allows commercial and industrial (C&I) customers to view interval data from their meters. This data is transmitted using a dial-up phone connection.

Implementing the information management system centered around the SAP ISU/CCS system with Itron data collection systems is a widely accepted method for utilities to manage meter data. Further this solution leverages SAP’s substantial suite of customer care and business intelligent applications yielding a high value, relatively low cost solution for CPAU.
4.1.2 Current Utility Operations System Architecture

The CPAU Utility Operations System is build around the Advanced Control System (ACS) Supervisory Control and Data Acquisition System (SCADA) shown in Figure 4-2 below. The SCADA system provides status monitoring and control of electric Remote Terminal Units (RTUs) which control components of the operational power distribution system. RTUs controlling electric distribution systems are connected using a dual redundant network. The dual redundant network communications system is the recommended configuration for systems supporting critical infrastructure.

RTUs units also control both water and gas distribution devices; however, water and gas RTUs are connected using modems, and leased lines as well as with some fiber-based network connections.

Information obtained from the SCADA system is available in Prism Reports and the information is viewable on Utility Control Center (UCC) terminals. A remote Virtual...
Private Network (VPN) connection through a firewall allows remote access using a Reflections terminal emulator.

The system operator is also able to manually push information on outages as well as the actions taken to resolve the outages to the customers. See Figure 4-3 for an example of the outage web site display.
4.1.3 Current City of Palo Alto Municipal Network Architecture

The City of Palo Alto Municipal Network is built around the city owned fiber infrastructure system shown in Figure 4-4 below. The dual redundant fiber communications backbone connects the utility’s operational system components. A dual redundant system is the standard recommended network communications architecture for systems supporting critical infrastructure.
The CPAU fiber communications network sends data to and from the electric substations, SCADA system, water and gas utility locations and other municipal buildings and facilities including 90 traffic signal locations.

### 4.2 Proposed Smart Grid Architecture

The current CPAU systems are technologically advanced and economically efficient. Recent advances in the network communications, computer systems and power system engineering fields have made possible further improvements in power system efficiency, in the utilization of renewable energy sources, and in improvements to customer services. This broad range of electric infrastructure enhancements are known collectively as the Smart Grid.

The needs and expectations of customers and stakeholders have also changed over the past decade with consumers and stakeholders now expecting cleaner, more ecologically sound and less expensive electricity. This section describes potential future Smart Grid architectures for the CPAU Information Management Systems, Operation Systems, and the City of Palo Alto Network Communications Systems.
4.2.1 Proposed Smart Grid Information Management System Architecture

The proposed Smart Grid Information Management System architecture features a new Information Technology (IT) infrastructure. An SAP PI Enterprise Service Bus (ESB) will connect the existing SAP ISU/CCS system to Smart Grid components which include the Advance Meter Infrastructure (AMI) head end, an integrated Geographic Information System (GIS), a Meter Data Management System (MDMS), an Outage Management System (OMS) and an asset management system. The ESB will also be connected to the city network. Access to the UCC operational LAN will be through a firewall which will help protect the critical infrastructure component in the UCC.

The new Smart Meter infrastructure includes the AMI Head End which receives all meter reads, and the MDMS which manages the processing of all Smart Meter and legacy meter data. Benefits of the proposed Smart Meter architecture include better outage management and the ability to better analyze utility operations. The proposed architecture will enable customer participation in future Smart Grid programs and rate structures.

Additional new Information Management infrastructure enhancements include an integrated outage management system with the ability to integrate the GIS with outage management functions to improve responses to and customer notifications of outages. The existing SAP ISU/CCS infrastructure which provides customer billing, verification and customer web portals will be augmented by a Remittance Processing system. A Customer Relationship Management (CRM) system will integrate financial functions. The GIS system will incorporate all assets in a single system allowing for improved asset management.

The proposed Information Management System Smart Grid architecture is shown in Figure 4-5 below.
Figure 4-5: Proposed CPAU Smart Grid AMI Information Management and Customer Engagement System Architecture

4.2.2 Proposed Smart Grid CPAU Operations System Architecture

The proposed Smart Grid Operations System architecture features a new Utility Control Center (UCC) operational Local Area Network (LAN). The UCC operational LAN incorporates an Oracle database (DB) which allows improved access to all utility data including ACS SCADA and outage information. The Oracle database will also allow historical analyses to improve the ability to forecast and model the CPAU operational system.

The proposed Smart Grid Operations System architecture is shown in Figure 4-6 below.
4.2.3 Proposed Smart Grid Municipal Communications Architecture

The proposed Smart Grid Municipal Communications architecture features a WiFi Wide Area Network (WAN) combined with a wireless mesh network which will transmit the electric, gas, and water meter data to the fiber infrastructure and Enterprise Service Bus (ESB).

The recommended communications system for the AMI backhaul connection to the utility fiber infrastructure is a dual-band 2.4 GHz and 5.8 GHz WiFi system implemented with IEEE 802.11n standard. The recommended AMI backhaul network will benefit from the extended range and speed benefits of the 802.11n technology in both the 2.4 and 5GHz bands, and will also be backwardly compatibility with early IEEE 802 products.
The proposed AMI mesh network will provide the communications link between the Smart Meters and the AMI head end. As described above the AMI head end will forward the meter data over the WiFi WAN to ESB and the fiber infrastructure. The 900 MHz band is the most widely supported band by Smart Meter manufacturers and one of its advantages is the availability of low cost radios. Thus the 900 MHz network solution will allow CPAU to select cost competitive Smart Meters from a wide array of manufacturers.

The proposed Smart Grid Municipal Communications Architecture is shown in Figure 4-7 below.
4.2.4 Field Force Management

Field force management is a communications system which connects mobile workers to the same services and data as are available at the office. A Field Force Management System improves field worker productivity, enhance customer service, automate paper processes, and reduce human error. Communications are typically available in workers’ vehicles as well as to hand held devices. Figure 4-8 below shows the Field Force Management System.

Field force management systems transmit information to and from utility offices through the AMI backhaul and AMI mesh networks to mobile workers in the field. Information sent can include new and updated work orders, GPS location data, and
detailed reference material for the service work required. Information from the mobile worker typically includes summaries of work performed, time spent and details of any on-site interactions with customers. Data from service calls is typically analyzed to identify potential system wide problems as well as possible improvements to service practices.

While the current manual field meter reading function may cease to exist upon full deployment of AMI meters, newer roles will emerge for CPAU staff to perform. CPAU must plan for evolving roles and work related functions in support of adoption and implementation of new Smart Grid related business process and functions. This will include staff positions to: perform annual field inspection of deployed meter installations; oversee the daily operation and maintenance of the AMI system, network communications, metering, and data management systems; respond to customer billing and meter read concerns; identify possible energy theft; perform meter data processing and analytics on customer historical data; construct customer energy profiles; engage customers proactively on AMI enabled energy conservation and demand response programs; and respond to customer generated service requests currently addressed by current field manual meter readers.

![Figure 4-8: Field Force Management and Communications](image)
5 Cost Benefit Modeling and Analysis

Implementation of a new Smart Grid system is a substantial utility investment that impacts many of the utilities’ operations and therefore requires a detailed cost/benefit analysis. The costs of developing and deploying a Smart Grid system are primarily dependent on two key design decisions:

1. Performance characteristics and different applications that utilities, regulators and customers want the new system to support (functional capability); and
2. Hardware and other engineering choices for meter integration, communication systems, advanced distribution systems, demand response systems and network management functions.

A cost-effective AMI centric Smart Grid system should minimize the system design and implementation costs and maximize the system’s functional capabilities. To achieve this requires considering the tradeoffs between different system design options and various capabilities. It is also almost certain that a Smart Grid system design that attempts to provide all the possible applications/functions to all customers all of the time will not be cost effective. CPAU should consider these cost tradeoffs and identify functions that may sound good on paper but are unlikely to provide the level of benefit to justify the investment cost in the long run.

The Smart Grid Benefit and Analysis Model should address both costs and benefits.

A. Costs - Analysis should include the expected start up and capital costs of designing, purchasing, and deploying advanced metering infrastructure, advanced distribution and demand response systems, as well as the annual expected costs of maintaining and operating these systems.

B. Tangible Benefits - Analysis should include an estimate of the present value of the potential benefits identified in the benefit cost section below over the same analysis period.
period. Benefits should all be calculated relative to the baseline conditions expected in the business as usual case.

C. Societal Benefits shall also be included in the Cost Benefits analysis. A number of non-tangible, societal benefits have been identified that are important in considering the reasonableness of the CPAU Smart Grid. These benefits include improvements in customer experience and satisfaction, reductions in energy theft, potential environmental benefits including reduction in greenhouse gases, and other societal benefits that create positive value. There may be societal benefits in the customer service improvements CPAU may expect from the Smart Grid’s ability to mitigate customer exposure to service interruptions, outage durations, and/or service degradation due to poor power quality. Because many societal benefits and costs are not quantifiable, or do not directly impact CPAU’s revenue requirements, they are included in the financial assessment separately from the quantifiable/tangible benefits calculations. Over time, however, CPAU should expect substantial benefits will be gained by the implementation of Smart Grid beyond what the numbers show. These various benefits (and potentially others) are real, even if not quantified. These benefits accrue to the residents and businesses of Palo Alto collectively. These Societal Benefits are described separately below.

1. Improvement in Customer Experience

A CPAU Smart Grid is likely to improve customer experience in numerous ways. The utility industry has conducted primary and secondary research on its customers to better understand the nature of the experience they have with them. CPAU’s customers today expect more personalized service options and simple automated choices. The heightened awareness of environmental concerns creates the opportunity for customer engagement on energy conservation, demand response and electrification of the transportation sector.

2. Energy Theft

Energy theft occurs and is a cost of doing business that is borne by all ratepayers. Any reduction in energy theft from the implementation of automated meters will enable CPAU to spread its revenue requirement over more energy sales, thus
reducing rates. CPAU should anticipate reduction in energy thefts in three (3) ways:

a. First during deployment, CPAU’s AMI meter deployment vendor will be removing every existing meter and replacing it with a new solid-state Smart Meter and the installers (both CPAU and contracted labor) will be trained to notice irregularities which can be investigated as potential theft.

b. Second, the tamper detection capability of the Smart Meter will virtually eliminate meter tampering as a source of energy theft as the meter will provide tamper notification which will be analyzed and potentially investigated for theft.

c. Third the more sophisticated Meter Data Management System (MDMS) is expected to allow reduction in energy theft essentially reduces cross subsidization and insures that costs are billed appropriately to those utilizing the energy.

3. Environmental Benefits
There are potential environmental improvements that will result from reduced generation due to energy conservation and from substituting more efficient off-peak generators for less efficient on-peak units through the use of demand response and load control. Energy conservation, based on exploiting information received from Smart Meters, has a very large potential for creating significant environmental benefits. These reductions in CO2 and greenhouse gas emissions can be quantitatively calculated and projected annually.

4. Improved Customer Security
CPAU will improve customer security because meter readers will no longer have to physically read customers meters by entering yards, or in more limited cases, customer homes. In focus groups, customers have identified safety and security as compelling benefits of Smart Metering. For example, some customers cited the need to put their dogs inside on meter reading days as a security issue because the dogs are kept as a theft deterrent. Additionally, other customers referred to the need to unlock doors or gates to allow meter reading as a security issue that will no longer exist. In all, automating the meter reading process was seen as a significant safety and security benefit from a customer perspective.

5. Non-Qualified Benefits from Smart Grid
A CPAU Smart Grid System has several capabilities that provide real options for future value that are not quantifiable today. For example, the meter has the ability to measure voltage at the premises and may be used for a variety of purposes, such as to support improved customer service, contribute to the grid asset management and to provide feedback to customer side energy management systems. Additionally, the integrated service switch has remote
load limiting capability that can be used for managing peak demand at the premises level to mitigate grid emergencies and provide a demand subscription rate option. The switch also opens on a power failure and can detect voltage on the customer side of the switch when open that provides a safety feature in the event the customer turns on a generator on their side of the meter after a power outage. This same switch can contain a randomizer to stagger the closure of the switches in an area to reduce the surge when a circuit is re-energized. These capabilities and other foundational aspects of the system continue to be explored by CPAU.

5.1 Smart Grid Cost Benefit Analysis

In developing a Smart Grid Cost Benefit Model categories for both Cost and Benefits must be identified. Cost and Benefit categories are as follows:

Cost Categories

1. AMI
   A. Capital Electric
   B. Capital Water
   C. Capital Gas
   D. Capital Infrastructure
   E. Capital IT and Implementation
   F. O&M Costs

2. Advanced Distribution
   A. Capital Infrastructure
   B. Capital IT and Implementation
   C. O&M Costs

3. Customer Engagement*
   A. Capital Infrastructure
   B. Capital IT and Implementation
   C. O&M Costs

*Note: Includes Demand Response, Costs have not been included for customer equipment costs such as In-home Displays, customer EMS for both EE and conservation.

Benefits Categories

I. Utilities Customer Service Division Benefits
   A. Meter Reading Savings – Electric/Gas/Water
   B. Billing Savings
C. Credit & Collections (C&C) Savings
D. Call Center(s) Savings
E. Miscellaneous
F. Capital Savings - Meter Reading

II. Distribution Operations Benefits
   A. Operations and Maintenance – Electric/Gas/Water
   B. Capital Savings - Electric/Gas/Water

III. Revenue Enhancement
   A. Improved theft detection and recovery
   B. Increased meter reading accuracy
   C. Unregistered meters

IV. Societal Benefits
   A. Improvement in Customer Experience
   B. Energy Theft
   C. Environmental Benefits
   D. Improved Customer Security
   E. Additional Benefits from Smart Grid Functionality

V. Advanced Distribution Benefits
   A. Increased Energy Efficiency
   B. Revenue Enhancements
   C. Improved Outage Restoration
   D. Improved T&D Operations
   E. Improvement in Customer Experience
   F. Capital Savings

VI. Customer Engagement Benefits
   A. Improvement in Customer Experience
   B. Environmental Benefits
   C. Capital Savings

Need to ensure this aligns with the final format in the report and ES.

5.2 Cost Benefit Modeling and Analysis

A Smart Grid Cost Benefit Analysis Model has been developed and provided to the City of Palo Alto. The model is an Excel spreadsheet with multiple worksheets and a Users
Guide contained in Appendix D. The Smart Grid Cost Benefit Analysis model can be used to conduct a preliminary value assessment for planning and implementing an Advanced Meter Infrastructure (AMI) centric Smart Grid System. The Palo Alto model reflects a combined electric, water and gas utility. The User Guide will cover the three main categories of worksheets included in the corresponding model. These include:

1. Summary worksheets
2. Cost worksheets
3. Benefit worksheets

For each worksheet, a brief overview is provided with several key considerations for the sections within the worksheets. Users should be familiar with basic accounting and Excel techniques prior to accessing this CBA model.

### 5.2.1 Smart Grid Cost Benefit Analysis Model

The Smart Grid Cost Benefit Analysis Model is built on Microsoft Excel workbook with interconnected worksheets. The Model provides the user with a financial model to calculate various financial values associated with a planned Smart Grid deployment project (electric, water, and gas combined service) based on an extensive set of user inputs and assumptions. Based on these inputs and assumptions, the Smart Grid Model calculates a “net present value” (NPV) of the project cash flows and an internal rate of return (IRR).

The Model consists of multiple worksheets – many of which contain equations that reference other sheets. Inputs or assumptions entered on one worksheet may be automatically used in calculations on other worksheets. Calculations based on these inputs/assumptions may be presented in other worksheets for reporting and analysis purposes. As inputs and assumptions are changed, the project valuation calculations automatically update.

#### 5.2.1.1 Summary Worksheets

The summary sections are intended to provide a simple “snapshot” of each area in a consolidated manner.

Consistent with other sheets, the summary sheet will by default show the first 5 years of deployment, followed by years 10, 15, and 20. This is intended to provide a compact method for viewing and printing the document, however the hidden years can be displayed as needed using standard MS Excel functions.

The Summary Worksheets section contains 3 worksheets named as follows:

1. Cover Page (blue tab)
2. Smart Grid Project Summary (purple tab)

3. General Assumptions (purple tab)

The Cover Page shows the title, version and date of the business case.

The Smart Grid (SG) Project Summary worksheet has five main sections:

- **Smart Grid Business Case Model Project and Financial Summary**
  Summary of the project financial indicators, costs and benefits for the AMI business and advanced distribution business cases.

- **AMI Business Case Model Capital/O&M Costs and Benefits**
  Summary of the capital expenditures, O&M expenditures, and benefits for the AMI business case.

- **AMI Business Case Model Net Present Value Calculation**
  Summary of the Net Present Value (NPV), Internal Rate of Return (IRR) and simple payback calculations for AMI meters, calculated separately for electric, water, and gas meters.

- **Advanced Distribution Business Case Model Capital/O&M Costs and Benefits**
  Summary of the capital expenditures, O&M expenditures, and benefits for the advanced distribution business case.

- **Advanced Distribution Business Case Model Net Present Value Calculation**
  Summary of the NPV, IRR and simple payback calculations for the advanced distribution system.

The General Assumptions worksheet contains assumptions and estimates used throughout the model. It contains many parameters including revenue, sales, peak load, and the current number of meters. It also contains estimated deployment schedules, number of meter read cycles annually, estimated meter population growth, meter failure rates, component costs, optional devices, and salary schedules. General economic and labor costs are also consolidated here including the discount rate, inflation rate, overhead loading rates, and estimates of the adoption level for electric vehicles.

**5.2.1.2 Cost Worksheets**

The Cost worksheets calculate costs for components of the AMI and advanced distribution systems. Cost worksheets are identified with red tabs in the Excel spreadsheet. The model includes the following cost worksheets:

1. Capital Electric
2. Capital Water
3. Capital Gas
4. AMI Capital Infrastructure
5. Capital IT and Implementation
6. AMI O&M Costs
7. Advanced Distribution Infrastructure
8. Advanced Distribution Software and Integration
9. Advanced Distribution O&M Costs

5.2.1.2.1 AMI Cost Worksheets

The Capital Electric worksheet calculates capital costs for AMI electric meters. It contains the following two major sections:

- AMI Capital Costs for Electric System – General Inputs
  Costs for individual disconnect devices, load control devices, and prepaid meters as well as the number of new residential and commercial meters needed on a year by year basis.

- AMI Capital Costs for Electric System – Summary of Capital Expenditures
  Total capital costs on a year by year basis for residential and commercial electric meters including total costs for installation, disconnect devices, load control devices, and prepaid meters.

The Capital Water worksheet calculates capital costs for AMI water meters. It contains the following two major sections:

- AMI Capital Costs for Water System – General Inputs
  Costs for individual water meters as well as the number of new residential and commercial meters needed on a year by year basis.

- AMI Capital Costs for Water System – Summary of Capital Expenditures
  Total capital costs on a year by year basis for residential and commercial water meters including total costs for installation.

The Capital Gas worksheet calculates capital costs for AMI gas meters. It contains the following two major sections:

- AMI Capital Costs for Gas System – General Inputs
  Costs for individual gas meters as well as the number of new residential and commercial meters needed on a year by year basis.
• AMI Capitol Costs for Gas System – Summary of Capital Expenditures

  Total capital costs for residential and commercial water meters including total costs for installation on a year by year basis.

The Capitol Infrastructure worksheet calculates capital costs for the communications infrastructure needed to support AMI electric, gas and water meters. It contains the following two major sections:

• AMI Capitol for Infrastructure – General Inputs

  Costs for individual communications infrastructure components including installation costs as well as the number of new infrastructure components needed. Infrastructure components include Wide Area Network (WAN) devices and Field Area Network (FAN) connectors.

• AMI Capitol for Infrastructure – Summary of Capital Expenditures

  Total capital costs for communications infrastructure components including installation costs for the components on a year by year basis.

In addition to the costs for the base communications system needed to support the AMI meters, costs for additional communications capability are calculated in the WiFi Public Safety Works and WiFi Public Access worksheets. These worksheets are identified with blue tabs in the Excel spreadsheet. The WiFi Public Safety Works and WiFi Public Access worksheets contain cost data for the additional communications equipment needed for these enhanced capability systems. Basically enhanced communications capability is provided by increasing the number and density of the WAN and FAN devices.

The AMI Capitol IT Software Integration worksheet calculates capital costs for the software needed to support AMI electric, gas and water meters as well as other additional optional Smart Grid applications. It contains the following two major sections:

• AMI IT/Software/Integration – General Inputs

  Costs for required and optional software applications including the AMI application, billing interface, customer service interface, Outage Management System (OMS), asset management system, and Meter Data Management System (MDMS).

• AMI Capitol for IT/Software/Implementation – Summary of Capital Expenditures

  Total capital costs for required and optional software applications on a year by year basis.
The O&M worksheet calculates operation and maintenance costs needed to support AMI electric, gas and water meters as well AMI network, communications and software maintenance. It contains the following two major sections:

- AMI Operation and Maintenance Cost – General Inputs
  Operating and maintenance costs for AMI systems, software and communications equipment including the costs for personnel and outsourcing operations.

- AMI Operation and Maintenance Cost – Summary of Expenditures
  Operating and maintenance costs for AMI systems, field service, communications equipment and outsourced operations on a year by year basis.

5.2.1.2.2 Advanced Distribution Cost Worksheets

The Advanced Distribution Infrastructure worksheet calculates the cost of capital for advanced distribution components such as fault indicators, breakers, circuit tie switches and the gas cathodic protection system. It contains the following two major sections:

- Advanced Distribution Capitol for Infrastructure – General Inputs
  Costs for individual advanced distribution equipment components including installation costs.

- Advanced Distribution Capitol for Infrastructure – Summary of Capital Expenditures
  Total costs for advanced distribution equipment components including installation costs on a year by year basis.

The Advanced Distribution Software and Integration worksheet calculates capital costs for the software needed to support advanced distribution applications. It contains the following two major sections:

- Advanced Distribution IT/Software/Implementation – General Inputs
  Costs for required software applications including the advanced distribution system and the limited functionality OMS system.

- Advanced Distribution Capitol for IT/Software/Implementation – Summary of Capital Expenditures
  Total capital costs for required software applications including implementation costs on a year by year basis.
The Advanced Distribution O&M worksheet calculates operation and maintenance costs needed to support the Advanced Distribution system including software maintenance. It contains the following two major sections:

- **Advanced Distribution Operation and Maintenance Cost – General Inputs**
  Operating costs for Advanced Distribution software including the costs for personnel.

- **Advanced Distribution Operation and Maintenance Cost – Summary of Expenditures**
  Operating costs for Advanced Distribution software systems on a year by year basis.

### 5.2.1.3 Benefit Worksheets

The Benefit worksheets calculate benefits for the AMI and advanced distribution systems. Tangible benefit worksheets are identified with green tabs and the societal benefits worksheet is indicated with an orange tab in the Excel spreadsheet. The model includes the following benefit worksheets:

1. Customer Service Benefits
2. Distribution Operations Savings
3. Revenue Enhancements
4. Avoided Capital
5. Meter Reading Budget Worksheet
6. Advanced Distribution Benefits
7. Demand Response

#### 5.2.1.3.1 AMI Benefit Worksheets

The AMI Benefit worksheets calculate benefits from the electric, gas and water AMI meter systems.

The Customer Service Benefits worksheet calculates the value of customer service improvements made possible by the AMI meter systems. Benefits include savings from automated meter readings, and savings from improved billing, credit and corrections (C&C), and call center services. The Customer Service Benefits worksheet contains the following seven major sections:

- AMI Benefits – Summary of Customer Service Savings
Summary of all customer-related savings realized from use of electric, water and gas AMI meters. Includes O&M and capital savings from automated meter reads, billing, C&C, and call center services.

- **AMI Customer Service Benefits – Meter Reading Savings**
  Detailed calculation of annual savings from automated electric, gas and water meter reads over the current meter reading methods.

- **AMI Customer Service Benefits – Billing Savings**
  Detailed calculation of annual savings from improved billing services including savings from fewer bill exceptions, rebillings and errors. Includes savings from reduced labor, overtime labor and personnel benefit loading costs.

- **AMI Customer Service Benefits – Credit & Collections Savings**
  Detailed calculation of annual savings from improved theft investigations, field collections, and credit management. Includes savings from reduced labor, overtime labor and personnel benefit loading costs.

- **AMI Customer Service Benefits – Call Center Savings**
  Detailed calculation of annual savings from reduced call center volume resulting from more accurate billing, fewer meter read access problems, automated outage detection and automated restoration notification. Includes savings from reduced labor, overtime labor and personnel benefit loading costs.

- **AMI Customer Service Benefits – Miscellaneous Savings**
  Calculation of annual savings from reduction in escalated complaints and lower legal fees.

- **AMI Customer Service Benefits – Meter Reading Capitol Savings**
  Calculation of annual savings from the reduction in the number of vehicles needed by the meter readers.

The Distribution Operations Savings worksheet calculates the value of distribution improvements made possible by the AMI meter systems. Benefits include savings from improved outage management, meter inventory and distribution asset management. The Distribution Operations Savings worksheet contains the following five major sections:

- **AMI Benefits – Summary of Distribution Operations Savings**
  Summary of all distribution operations savings realized from the use of electric, water and gas AMI meters. Includes O&M and capital savings from outage management, meter inventory and distribution asset management systems.

- **AMI Distribution Operations Benefits – Outage Management Savings**
Detailed calculation of annual O&M and capital savings from improved outage management for AMI electric, gas and water meters.

- **AMI Distribution Operations Benefits – Meter Inventory Operations Savings**
  Detailed calculation of annual O&M savings from improved meter testing less the increased cost for meter refurbishment for AMI electric meters.

- **AMI Distribution Operations Benefits – Distribution Asset Management Savings**
  Detailed calculation of annual capital savings from improved substation and transformer sizing made possible by AMI’s ability to identify distribution system problems prior to overloading equipment.

- **AMI Distribution Operations Benefits – Miscellaneous Meter Reads Savings**
  Detailed calculation of annual savings from the reduction in miscellaneous meter reads needed for AMI electric, water and gas meters.

The Revenue Enhancement worksheet calculates the value of revenue enhancements made possible by the AMI meter systems. Benefits include savings from improved theft reduction and increased meter accuracy. The Revenue Enhancement worksheet contains the following two major sections:

- **AMI Benefits – Summary of Revenue Enhancement**
  Summary of all revenue enhancements realized from the use of AMI electric, water and gas meters. Revenue enhancements include improved theft reduction and recovery, increased meter accuracy, and increased detection rate for unregistered meters.

- **AMI Revenue Enhancement Benefits – Quantification of Revenue Enhancement**
  Detailed calculation of revenue enhancement benefits calculated on an annual basis from improved theft reduction, theft recovery, increased meter accuracy, and increased detection rate for unregistered meters for AMI electric, gas and water meters.

The Avoided Capital worksheet shows the value of avoided capital costs for electric meter reading and electric distribution operations.

The Meter Reading Budget Worksheet calculates the costs of meter reading currently without AMI. Calculating meter reading budget helps ensure that all costs for the new AMI meters are considered. The Meter Reading Budget Worksheet contains the following two major sections:

- **Data Collection Budget Worksheet before (without) AMI – Consolidated Budget**
  Summary of all costs associated with meter reading including labor, personnel benefits, capital expenses, office supplies, and external meter reading fees.
Data Collection Budget Worksheet before (without) AMI – Budget Assumptions

Detailed meter reading costs including salary information by job category, capital expenses for the handheld meter reading equipment, meter reading fees paid to others and office supplies.

5.2.1.3.2 Advanced Distribution Benefit Worksheet

The Advanced Distribution Infrastructure worksheet summarizes the benefits realized from the distribution automation system. It summarizes benefits for the utility, for society and for customers. It contains the following eleven major sections:

- Distribution Automation
  Summarizes customer, societal and utility benefits realized from the advanced distribution system. Includes benefits from energy efficiency, reduced outages, and improved T&D operations.

- Distribution Automation – Assumptions for Improvement in SAIFI
  Lists assumptions used in System Average Interruption Frequency Index (SAIFI) benefit calculations.

- Distribution Automation – Fewer Outage Events – Society
  Calculates the economic benefit for societal benefits realized from automated distribution improvements which reduce outages.

  Calculates revenue enhancements for the utility realized from automated distribution improvements which reduce outage durations.

- Distribution Automation – Reduced Restoration Costs
  Calculates the reduced restoration costs realized from automated distribution equipment which reduce outage durations.

- Energy Efficiency - Volt Var Conservation – Customer
  Calculates the economic savings for customers realized from automated distribution improvements which improve voltage management thus reducing energy losses.

- Energy Efficiency - Volt Var Conservation – Utility
  Calculates the economic savings for the utility realized from automated distribution improvements which improve voltage management thus reducing energy losses.
• T&D Capital Savings – Capital Budget Deferral – Utility
  Calculates the economic savings for the utility realized from automated
distribution improvements which allow capital costs to be deferred. Automated
distribution features which allow the utility to defer capital investments include
automatic feeder reconfigurations, DER monitoring and control, improved fault
detection, and automatic switching.

• T&D Operations and Maintenance Savings – Reduced Labor Cost – Utility
  Calculates the economic savings for the utility realized from automated
distribution improvements which require fewer O&M costs. Automated
distribution features which reduce the need for O&M include remotely
monitored equipment.

• T&D O&M Savings from Automatic Switching
  Calculates the economic savings the utility will realize from automated switching
which reduces the need for crews to perform switching manually.

• T&D Operations Savings from Reduced Peak Load Reserve Requirements – Utility
  Calculates the economic savings for the utility realized from reduced need for
peak load capacity.

5.2.1.3.3 Societal Benefit Worksheet
The Societal Benefits worksheet summarizes the non-tangible benefits realized from the
AMI meter systems. The Societal Benefits worksheet is identified with an orange tab in
the Excel spreadsheet. It contains the following three major sections:

• Societal Benefits - AMI
  Summarizes the societal benefits realized from the AMI meter systems. Includes
benefits for customers, society in general, and for the utility. Customer benefits
include energy efficiency and reduced energy usage from more rapid
incorporation of Photovoltaic (PV) solar power. General societal benefits include
vehicle electrification, fewer economic losses due to outages, and reduced CO2
emissions. Utility benefits include improved customer satisfaction and increased
integration of renewable energy sources.

• Societal Benefits – Parameters for calculation
  Detailed calculations for non-tangible benefits realized from the AMI meter
systems including benefits for customers, society, and the utility. Calculates
amount of power saved by customer conservation from increased EE and PV
systems including savings realized by customers.

  Includes calculations for reduced economic losses from fewer outages, estimates
of the PEV miles driven, benefits from the electrification of transportation, and
the resulting reduced CO\textsubscript{2} emissions from energy efficiency, PEVs, and energy electrification.

Also calculates benefits for the utility which include improved customer satisfaction, increased integration of renewables, peak demand reduction, increased sales from reduced outages, and reduced outage restoration costs.

- **Societal Benefits – Assumptions for calculation**

  Contains assumptions which are included in the societal benefit calculations such as the value to the utility of each 1% increase in customer satisfaction, the amount of average conservation by consumers, the number of PV systems and the monetized value of CO\textsubscript{2} reduction.
6 Evaluation of Communication Systems Approaches

Smart Grid system enhancements include infrastructure upgrades which can potentially benefit all Palo Alto public and private entities in addition to the City of Palo Alto Utilities. In particular, Smart Grid communications infrastructure investments have the potential to improve communications for the city of Palo Alto, for its businesses and for its residents and visitors.

The Wide Area Network (WAN) WiFi network used to communicate with Smart Meters could also be used to provide WiFi communications throughout the city of Palo Alto. Smart Meters are typically, although not always, considered a foundational Smart Grid system. The California Public Utilities Commission (CPUC) has mandated that Smart Meter installation be completed by all Investor Owned Utilities (IOUs) in California by the end of 2012. Although municipal utilities are not required to follow the same mandate as the California IOUs for Smart Meter installation, it is clear that Smart Meters are considered a viable initial step in implementation of the Smart Grid.

For the City of Palo Alto, this section examines the base WiFi network required to implement the Smart Meter Advanced Meter Infrastructure (AMI) system, as well as potential additional benefits of an enhanced WiFi network which could augment the base AMI system. The base communications system is discussed first, followed by a discussion of two enhanced variants of the WiFi network system.

City topology is typical for most cities in the Bay with mostly flat and accessible land with relatively dense urban environment. Some of the city stretches into the foothills where except for a couple of streets, most of the land is preserved open space. City of Palo Alto also has higher density of tree foliage than other cities which will lessen the penetration and reach of multi-GHz communication signals. All current communication methods used for Smart Grid can be used inside the City of Palo Alto including 900 MHz ISM band, 1.8GHz Cellular, and 2.4/5.8 GHz ISM band.
6.1 Base Communication

The proposed base network communications system features a WiFi WAN combined with a wireless mesh network. The recommended communications system for connection to the Smart Meters is over a 900 MHz mesh Field Area Network (FAN). The 900 MHz band is the most widely supported band by Smart Meter manufacturers and one of its advantages is the availability of low cost radios. This is based on 900MHz FHSS (Frequency Hopping Spread Spectrum) radio technology that was implemented in the early 1990s. This is similar technology that covered the Bay Area as part of the Metricom/Richochett IP system.

The recommended communications system for the AMI backhaul connection to the utility fiber infrastructure is a dual-band 2.4 GHz and 5.8 GHz WiFi system implemented with IEEE 802.11n standard. The recommended AMI backhaul network will benefit from the extended range and speed benefits of the 802.11n technology in both the 2.4 and 5.8 GHz bands, and will also be backwardly compatibility with early IEEE 802 products.

900 MHz Field Area Network (FAN) collectors will be used to transmit meter data to the dual-band 2.4 GHz and 5.8 GHz WiFi system. An estimated six (6) FAN collectors will be needed per square mile to provide coverage for the Smart Meters. The dual-band 2.4 GHz/5.8 GHz WiFi system will be connected to the current utility-owned fiber network termination points located at existing traffic control signals units (traffic hubs). The traffic hubs are currently used to provide communications from the fiber network to the city’s ninety (90) street traffic signals. In addition to the existing traffic hubs, an estimated three (3) 2.4/5.8 GHz WAN network devices will be required per square mile in the base communication system configuration. This means that in every square mile three (3) FAN controllers will be paired with three (3) 2.4/5.8 GHz WiFi units. The paired WiFi units will be used to bridge the broadband signal communication between the CPAU fiber backbone and the AMI Field Area Network (FAN). These three (3) 2.4/5.8 GHz WiFi units will communicate with one (1) 2.4/5.8GHz WiFi unit located at a traffic hub. Each fiber access/traffic hub location shall be capable of handling 3 Mbps sustained throughput.

In the base configuration, Smart Meters will communicate to FAN collectors, which will connect to Backhaul WiFi units, which in turn will connect to the existing traffic hubs
which currently connect to the existing utility fiber network. The proposed Base Communications Network is shown in Figure 6-1 below. The total number of FAN controllers is ninety (90) and the total # of WiFi units is sixty four (64). (See Table 6-1).

![Figure 6-1: Base Communications Network](image)

### 6.2 Base Communication plus Public Safety and Works

The base Smart Grid communications system can be augmented with additional hardware to support increased network functionality. For the base communications plus public safety and public works communication system, additional WAN devices will be added to increase the bandwidth available. The additional bandwidth will allow public safety and public works network data to be transmitted from anywhere in the city through the augmented Smart Grid communications infrastructure. In order to handle the additional public safety and public works data, an additional sixteen (16)
2.4/5.8 GHz WiFi units per square mile will be required. Thus for this configuration, a total of twenty (20) WiFi network devices per square mile will be required.

Public safety and public works network communications data will flow through the same network as the Smart Meter data. Public safety and public safety data will use the same communications path as well. Public safety and public works data will be transmitted to the WAN network devices, which in turn will connect to the existing traffic hubs which currently connect to the existing utility fiber network. The proposed Base Communications plus Public Safety and Public Works Network is shown in Figure 6-2 below. The total number of FAN controllers is ninety (90) and the total # of WiFi units is three hundred twenty (320). (See Table 6-1).

![Figure 6-2: Base plus Public Safety and Public Works Communications Network](image-url)
6.3 Base Communication Model plus Public Safety and Public Works and City-Wide Public Access

The base Smart Grid communications system can be further augmented with additional hardware to support city-wide WiFi access. For the base communications plus public safety and public works and city-wide public access communication system, additional WAN devices will be added to increase the bandwidth available. The additional bandwidth will allow city-wide WiFi access for the general public, for public safety and public works communications data and for Smart Meter data. In order to handle the additional public safety, public works and public access data, an additional 25 WAN network devices per square mile will be required. For this configuration, a total of 40 WAN network devices per square mile will be required.

City-wide public access, public safety and public works traffic will flow through the same network as the Smart Meter data. All traffic will use the same communications path. Public access, public safety, public works and smart meter data will be transmitted to the WAN devices, which in turn will connect to the existing traffic hubs which currently connect to the existing utility fiber network. The proposed Base Communications plus Public Safety and Public Works and City-Wide Public Access Communications Network is shown in Figure 6-3 below. The total number of FAN controllers is ninety (90) and the total # of WiFi units is six hundred forty (640). (See Table 6-1).

<table>
<thead>
<tr>
<th>Communication System</th>
<th># of FAN Controllers</th>
<th># of 2.4/5.8 GHz WiFi Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base System</td>
<td>90</td>
<td>128</td>
</tr>
<tr>
<td>Base System plus Public Safety and Works</td>
<td>90</td>
<td>320</td>
</tr>
<tr>
<td>Base System plus Public Safety and Works and Public Access</td>
<td>90</td>
<td>640</td>
</tr>
</tbody>
</table>

Table 6-1: Number of FAN Controllers and WiFi Units per System
A WiFi or cellular network would significantly benefit mobile CPAU workers who perform work in the field. As documented in an internal CPAU memo, utility department construction crews, engineers, estimators and inspectors would benefit from a WiFi network. CPAU benefits include increased productivity from access to the same data and services in the field as are available in the office. CPAU mobile employees would not have to return to the office to have access to communication services such as email. Additional benefits include improved response time and increased level of accuracy resulting from the elimination of the need to transcribe field notes back in the office.

Figure 6-3: Base plus Public Safety, Public Works and City-Wide Public Access Communications Network
6.4 AMI Using Third Party Cellular Carrier

Another communication options that is widely deployed is outsourcing the Smart Grid communication system over a Third Party Cellular Carrier using 3G CDMA or GSM, or emerging 4G WiMax. This option is shown in the Figure 6-4 below.

Figure 6-4 Base Communications Network using Outsource Third Party Cellular Provider

A separate Cost Benefit Analysis Model has been performed for this option and is discussed in Section 7.3 below.

6.5 Demand Response System Architecture

Demand Response systems have been available to the utility industry for over 50 years. Early adopters were European utilities who lacked access to capital and therefore could not afford to overinvest in generation and transmission assets. This resulted in the deployment of direct load control systems that helped the utility manage system peak. Beginning in the early 1980s municipals and rural electric cooperatives facing ratcheting demand charges from wholesale suppliers began to deploy load management systems. These direct load control systems used both low frequency power line carrier and radio communication technology. Controlled loads included air conditioners, water heaters, and space heaters. Due to regulatory reticence, load management did not catch on at
the Investor Owned Utilities due to the “Big Brother” factor. Both the California Energy Crises of 2001 and the 2003 Northeast Blackout woke regulators up to a new reality. Investigation and deployments of demand response systems has been given emphasis under current FERC policy. Rules are being defined at the Independent System Operators (ISOs) that treat Demand Response Resources with the same equality as traditional generation resources. This is spelled out in FERC Order 719. As each individual ISO including CAISO implements this mandate access to wholesale markets for demand response resources is becoming a reality. Currently demand response suppliers can submit bids to wholesale Energy Markets and soon Reliability Markets. Future development is anticipated that will allow Demand Response Resources to participate in all Ancillary Services markets including capacity, spinning reserve and regulation. Today CPAU must submit compliance to WECC/NERC mandated reliability standards which require a percentage of peak demand be maintained as reserve capacity. This reserve can be met going forward with a Demand Response Resource.

The direction of Demand Response market is changing and evolving at a rapid pace both from a market and technology point of view. With this in mind a flexible demand response architecture should be adopted. Utilities are deploying demand response programs both internally and in conjunction with third party aggregators. Large Commercial and Industrial customers represent the sweet spot with respect to cost effective demand response. This is followed by small commercial and residential loads. Emerging loads such as plug-in electric vehicles (PEVs) also represent a potential need for demand response. Each targeted market segment has communication and measurement requirements that does not lend itself to one-size fits all approach. Again flexibility is the operable word. Demand response event signals can be delivered over the utility AMI system and responses can be reported back and measurements of actual load shed metered and recorded. For utilities without AMI system or where the speed of monitoring of a demand response resource is high, broadband internet can be used. The Demand Response System Architecture is shown in Figure 6-5 below.
Figure 6-5: Demand Response System Architecture
7 Smart Grid CBA Model Analysis, Key Findings and Recommendations

The Smart Grid Systems that have been identified as part of the application assessment process include:

1. AMI
2. Advanced Distribution
3. Demand Response including Energy Efficiency and Conservation
4. Network Communications
5. Smart Meters
6. Distribution Field Devices

These Smart Grid systems are shown in Figure 7-1: Smart Grid Systems below.
7.1 Advanced Metering Infrastructure System

The Advanced Metering Infrastructure forms the foundation for most Smart Grid Implementations.

<table>
<thead>
<tr>
<th>CBA Model</th>
<th>AMI</th>
<th>Communications</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.1.1</td>
<td>Electric Only</td>
<td>Utility owned AMI</td>
</tr>
<tr>
<td>7.1.2</td>
<td>Electric Water Gas</td>
<td>Utility owned AMI</td>
</tr>
<tr>
<td>7.2.1</td>
<td>Electric Water Gas</td>
<td>AMI plus Public Safety and Works WIFI</td>
</tr>
<tr>
<td>7.2.2</td>
<td>Electric Water Gas</td>
<td>AMI plus Public Safety and Works and Public Access WIFI</td>
</tr>
<tr>
<td>7.3.1</td>
<td>Electric Water Gas</td>
<td>Outsourced Network AMI</td>
</tr>
</tbody>
</table>

Table 7-1: CPAU AMI CBA Models

The following subsections summarize the results and analysis of the Cost Benefit Analysis (CBA) Models. The CBA Base Model and variations of the Base Model will be discussed including:

There are a number of general assumptions and deployment components that are similar across all models. These are covered in the following series of tables.

<table>
<thead>
<tr>
<th>Smart Meter Deployment Schedule</th>
<th>5 years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Infrastructure, Software and IT Integration</td>
<td>2 years</td>
</tr>
</tbody>
</table>

Table 7-2: Meter and Capital Deployment Periods
The deployment periods for Smart Meters is 5 years and for Capital Infrastructure, Software and IT Integration is 2 years.

<table>
<thead>
<tr>
<th>Revenue</th>
<th>Residential</th>
<th>$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric</td>
<td></td>
<td>$ 20,617,822</td>
</tr>
<tr>
<td>Commercial</td>
<td></td>
<td>91,957,476</td>
</tr>
<tr>
<td>Water</td>
<td></td>
<td>$ 12,629,062</td>
</tr>
<tr>
<td>Residential</td>
<td></td>
<td>13,243,701</td>
</tr>
<tr>
<td>Commercial</td>
<td></td>
<td>24,762,571</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Sales</th>
<th>Electric Sales - GWhr Total</th>
<th>964</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric</td>
<td>Electric Sales- GWhr Residential</td>
<td>163</td>
</tr>
<tr>
<td></td>
<td>Electric Sales- GWhr Commercial</td>
<td>801</td>
</tr>
<tr>
<td>Water</td>
<td>Water Sales - CCF</td>
<td>5,543</td>
</tr>
<tr>
<td>Gas</td>
<td>Gas Sales in Therms</td>
<td>31,468</td>
</tr>
</tbody>
</table>

| Peak Load        | MW                         | 185 |

Table 7-3: CPAU 200/10 Revenue/Sales/Peak Load

The CPAU 2009/10 Revenue, Sales and Peak Load is provided in Table 7-3 above. CPAU Salaries Schedule for both current and Smart Grid related positions used in the study are included in Appendix B. Additional CPAU Facts used in the Cost Benefit Analysis are provided in CPAU Facts.

The Meter population growth is provided in Table 7-4 below.

<table>
<thead>
<tr>
<th>Meter Population Growth</th>
<th>Residential</th>
<th>0.5%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td></td>
<td>0.5%</td>
</tr>
<tr>
<td>Weighted</td>
<td></td>
<td>0.5%</td>
</tr>
<tr>
<td>Water</td>
<td></td>
<td>0.5%</td>
</tr>
<tr>
<td>Residential</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td></td>
<td>0.5%</td>
</tr>
<tr>
<td>Weighted</td>
<td></td>
<td>0.5%</td>
</tr>
<tr>
<td>Gas</td>
<td></td>
<td>0.5%</td>
</tr>
</tbody>
</table>
Table 7-4: Meter Population Growth

The various AMI and Advanced Distribution IT system components and budgetary costs are provided in the following Table 7-5.

<table>
<thead>
<tr>
<th>Components - AMI</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>AMI Application</td>
<td>$750,000</td>
</tr>
<tr>
<td>AMI System - Database</td>
<td>250,000</td>
</tr>
<tr>
<td>AMI System Hardware/Network</td>
<td>50,000</td>
</tr>
<tr>
<td>Billing Interface</td>
<td>$250,000</td>
</tr>
<tr>
<td>Customer Service Interface</td>
<td>$250,000</td>
</tr>
<tr>
<td>Outage Management Interface</td>
<td>$150,000</td>
</tr>
<tr>
<td>Asset Management Interface</td>
<td>$150,000</td>
</tr>
<tr>
<td>MDMS Application</td>
<td>$2,200,000</td>
</tr>
<tr>
<td>MDMS - Database</td>
<td>$250,000</td>
</tr>
<tr>
<td>MDMS System Hardware/Network</td>
<td>$50,000</td>
</tr>
<tr>
<td>IT Integration Consultants</td>
<td>$750,000</td>
</tr>
<tr>
<td>Components - Advanced Distribution</td>
<td></td>
</tr>
<tr>
<td>Adv Dist Application</td>
<td>$150,000</td>
</tr>
<tr>
<td>Adv Dist System - Database</td>
<td>50,000</td>
</tr>
<tr>
<td>OMS Lite</td>
<td>250,000</td>
</tr>
<tr>
<td>IT Integration Consultants</td>
<td>$100,000</td>
</tr>
</tbody>
</table>

Table 7-5: AMI and Advanced Distribution IT System Components and Costs

7.1.1 CBA Base Model – Electric Meters only

The CBA Base Model – Electric Meters only consists of all the following costs roll-ups. The total number of electric meters to be automated is 29,024 as shown in Table 7-6 below.

<table>
<thead>
<tr>
<th>Meter Population to Be Automated</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Meters</td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>24,495</td>
</tr>
<tr>
<td>Commercial</td>
<td>4,529</td>
</tr>
<tr>
<td>Total Electric</td>
<td>29,024</td>
</tr>
</tbody>
</table>

Table 7-6: CBA Base Model: Electric Meters only: # of Electric Meters Automated
### 7.1.1.1 Costs

The capital costs associated with installing an AMI electric meters, network communication system, meter installation along with the AMI system software and IT implementation capital is shown in Table 7-7 below.

<table>
<thead>
<tr>
<th>Capital Expenditures</th>
<th>Electric Capital</th>
<th>Per Meter</th>
<th>% Total Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meters</td>
<td>$3,393.8</td>
<td>$116.93</td>
<td>34%</td>
</tr>
<tr>
<td>Network</td>
<td>$648.0</td>
<td>$22.33</td>
<td>7%</td>
</tr>
<tr>
<td>Installation</td>
<td>$1,024.0</td>
<td>$35.28</td>
<td>10%</td>
</tr>
<tr>
<td>Water</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meters</td>
<td>$-</td>
<td>-</td>
<td>0%</td>
</tr>
<tr>
<td>Network</td>
<td>-</td>
<td>-</td>
<td>0%</td>
</tr>
<tr>
<td>Installation</td>
<td>-</td>
<td>-</td>
<td>0%</td>
</tr>
<tr>
<td>Gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meters</td>
<td>$-</td>
<td>-</td>
<td>0%</td>
</tr>
<tr>
<td>Network</td>
<td>-</td>
<td>-</td>
<td>0%</td>
</tr>
<tr>
<td>Installation</td>
<td>-</td>
<td>-</td>
<td>0%</td>
</tr>
<tr>
<td>IT Integration and Software</td>
<td>$4,790.0</td>
<td>$165.04</td>
<td>49%</td>
</tr>
</tbody>
</table>

| Total Capital              | $9,855.8         | $339.58   | 100%            |
| Annual O&M Expense         | ($At Yr 6)       | $1,245.4  | $42.91          |

Table 7-7: Total Capital Expenditures and O&M Expenses at Year 6 - Electric Meters only

### 7.1.1.2 Benefits

The AMI Benefits associated with this model include Customer Service, Meter Reading Savings, Distribution Operations, Revenue Enhancement, and Avoided Capital. These benefits are shown in an AMI electric meters, network communication system, meter installation along with the AMI system software and IT implementation capital is shown in Table 7-7.
There are minimal meter reading savings for the electric meter only case due to the fact that implementing an electric meter only Smart Grid AMI system leaves CPAU with the tasks of still utilizing meter reading crews to collect readings from the gas and water meters.

### 7.1.2 CBA Base Model – Electric, Water, Gas Meters

The CBA Base Model – Electric, Water and Gas Meters consists of all the following costs roll-ups. The total number of electric meters to be automated is 72,421 as shown in Table 7-9.

<table>
<thead>
<tr>
<th>Meter Population to Be Automated</th>
<th>Residential</th>
<th>Commercial</th>
<th>Total Electric</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Meters</td>
<td>24,495</td>
<td>4,529</td>
<td>29,024</td>
</tr>
<tr>
<td>Water</td>
<td>20,600</td>
<td>2,897</td>
<td>23,497</td>
</tr>
<tr>
<td>Gas Meters</td>
<td>15,300</td>
<td>4,600</td>
<td>19,900</td>
</tr>
<tr>
<td>Total</td>
<td>72,421</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 7-9: CBA Base Model: Electric Water and Gas Meters

#### 7.1.2.1 Costs

The capital costs associated with installing an AMI electric water and gas meters, network communication system, meter installation along with the AMI system software and IT implementation capital is shown in Table 7-10.
Table 7-10: Total Capital Expenditures and O&M Expenses at Year 6 - Electric, Water and Gas Meters

<table>
<thead>
<tr>
<th>Capital Expenditures</th>
<th>Electric</th>
<th>Capital</th>
<th>Per Meter</th>
<th>% Total Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meters</td>
<td>$3.4</td>
<td>$117</td>
<td>22%</td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>$0.4</td>
<td>$14</td>
<td>3%</td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$1.0</td>
<td>$35</td>
<td>7%</td>
<td></td>
</tr>
<tr>
<td>Water</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meters</td>
<td>$1.4</td>
<td>$72</td>
<td>9%</td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>$0.3</td>
<td>$16</td>
<td>2%</td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$0.7</td>
<td>$36</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meters</td>
<td>$1.3</td>
<td>$66</td>
<td>8%</td>
<td></td>
</tr>
<tr>
<td>Network</td>
<td>$0.3</td>
<td>$14</td>
<td>2%</td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$0.7</td>
<td>$34</td>
<td>4%</td>
<td></td>
</tr>
<tr>
<td>IT Integration and Software</td>
<td>$6.0</td>
<td>$122</td>
<td>39%</td>
<td></td>
</tr>
<tr>
<td>Total Capital</td>
<td>$15.6</td>
<td>$215</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

7.1.2.2 Benefits

The AMI Benefits associated with this model include Customer Service, Meter Reading Savings, Distribution Operations, Revenue Enhancement, and Avoided Capital. These benefits are shown in an AMI electric meters, network communication system, meter installation along with the AMI system software and IT implementation capital is shown in Table 7-11.

Table 7-11: AMI Benefits – Electric, Water and Gas Meters

<table>
<thead>
<tr>
<th>AMI Benefits</th>
<th>$116.6</th>
<th>$1.61</th>
<th>9%</th>
</tr>
</thead>
<tbody>
<tr>
<td>$851.8</td>
<td>$11.76</td>
<td>64%</td>
<td></td>
</tr>
<tr>
<td>110.6</td>
<td>$1.53</td>
<td>8%</td>
<td></td>
</tr>
<tr>
<td>-</td>
<td>-</td>
<td>0%</td>
<td></td>
</tr>
<tr>
<td>242.5</td>
<td>$3.35</td>
<td>18%</td>
<td></td>
</tr>
<tr>
<td><strong>Total Annual Benefits (at Yr 6)</strong></td>
<td><strong>$1,321.5</strong></td>
<td><strong>$18.25</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

AMI System costs and benefits may vary +/-20% either way. Total AMI System 20 year costs range from $23.4 to 35.2 million, NPV. Total 20 year benefits range from $18.5 to 27.7 million, NPV. Provided that the AMI System costs come in on the low side and additional benefits and value are higher, a positive benefits case would result. For the best case scenario, an AMI System investment is estimated at 17 years. The AMI System Free Cash Flow is shown in AMI System Free Cash Flow in Figure 7-2 below.
7.2 CBA Base Model Analysis - Communication Options

The CBA model has been performed for analyzing different Smart Grid Field Area Network communication scenarios. These include adding WiFi to cover Public Safety and Works and WiFi for Public Access. In addition, CPAU could outsource the AMI Field Area Network to a 3rd party cellular provider. This is shown in the Table 7-12 below.

<table>
<thead>
<tr>
<th>Communication Network</th>
<th>Equipment Costs, $M</th>
<th>20Yr Total O&amp;M Costs, $M</th>
<th>20 Yr Total Costs, $M</th>
</tr>
</thead>
<tbody>
<tr>
<td>AMI - RF Utility Owned</td>
<td>$1.0</td>
<td>$1.6</td>
<td>$2.6</td>
</tr>
<tr>
<td>AMI - RF + WiFi for Public Safety and Works</td>
<td>$2.5</td>
<td>$2.4</td>
<td>$4.9</td>
</tr>
<tr>
<td>AMI - RF + WiFi for Public Access</td>
<td>$3.9</td>
<td>$3.2</td>
<td>$7.1</td>
</tr>
<tr>
<td>3rd Party Cellular</td>
<td>$0.0</td>
<td>$2.8</td>
<td>$2.8</td>
</tr>
<tr>
<td>Fiber-to-the-Home</td>
<td>$28.8</td>
<td>$3.2</td>
<td>$32.0</td>
</tr>
</tbody>
</table>

Table 7-12: Cost Comparison of Smart Grid Field Area Network Communication Options
The categories of Smart Grid Field Area Networks analyzed include:

1. AMI FAN – RF Utility Owned
2. AMI FAN – RF Utility Owned plus city wide coverage for Public Safety and Works
3. AMI FAN – RF Utility Owned plus city wide coverage for Public Safety and Works and complete residential and commercial Public Access Wi-Fi access coverage
4. Outsourced AMI FAN coverage to a 3rd Party Cellular Provider (e.g. Verizon, AT&T)
5. City installed fiber communication to the premises (Fiber-to-the-Home, FTTH)

To provide sufficient city-wide RF coverage for the Smart Grid applications, it is estimated that CPAU would expend $2.6M to $2.8M for capital and O&M over a 20 year period for either utility owned RF FAN system or for an outsourced RF FAN system respectively. Additional city stakeholder benefit may be provided with incremental capital and O&M expenses by expanding the RF coverage to include Wi-Fi for Public Safety and Works ($4.9M total) and Public Access ($7.1M total). The proposed Fiber-to-the-Home is the most expensive method for providing Smart Grid FAN city-wide coverage as it is estimated to cost $32M to provide a communication drop to each premises.

7.3 CBA Base Model Analysis – Private Carrier Supplied AMI Communications

The CBA Base Model has been supplied so that analysis of cost benefits for outsourcing the communications network to a 3rd Party Cellular provider can be performed. This detailed cost benefit analysis was not performed as part of this report.

7.4 Advanced Distribution

Advanced Distribution includes distribution automation, distribution monitoring and advanced distribution applications. The projected total field hardware capital costs for
upgrading the distribution system with automated switches, auto-reclosers is $2.4M with additional $0.6M for IT integration and software for a total outlay of $3M nominal and $2.7M NPV. The current SCADA system can be readily upgraded with applications from the supplier that is deployed at many utilities today. The 20 Year Totals for utility and customer benefits are $2.7M nominal and $1.7M NPV with the majority of the benefits due reduction in customer energy consumption that results from Volt/Var conservations and improved customer productivity due to reduction of outage hours. This is covered in Table 7-13 and Figure 7-3 below.

<table>
<thead>
<tr>
<th>Advanced Distribution Cost and Benefits Summary</th>
<th>$M</th>
<th>$M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Expenditures</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Field Hardware</td>
<td>2.4</td>
<td></td>
</tr>
<tr>
<td>IT Integration and Software</td>
<td>0.6</td>
<td></td>
</tr>
<tr>
<td>Total Capital</td>
<td>3.0</td>
<td></td>
</tr>
<tr>
<td>Annual O&amp;M Expense (at Yr 6)</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>Annual Utility Benefits (at Yr 6)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fewer Outage Events - Revenue Enhancement</td>
<td>0.001</td>
<td></td>
</tr>
<tr>
<td>Fewer Outage Reduces Restoration Costs</td>
<td>0.012</td>
<td></td>
</tr>
<tr>
<td>Volt Var Conservation - Net Utility Impact</td>
<td>(0.017)</td>
<td></td>
</tr>
<tr>
<td>T&amp;D Capital Savings - Capital Budget Deferral - Utility</td>
<td>0.000</td>
<td></td>
</tr>
<tr>
<td>T&amp;D Operations and Maintenance Savings - Reduced Labor Cost - Utility</td>
<td>0.004</td>
<td></td>
</tr>
<tr>
<td>T&amp;D O&amp;M Savings from Automatic Switching</td>
<td>0.000</td>
<td></td>
</tr>
<tr>
<td>T&amp;D Operations Savings from Reduced Peak Load Reserve Requirements - Utility</td>
<td>0.004</td>
<td></td>
</tr>
<tr>
<td>Total Annual Utility Benefits (at Yr 6)</td>
<td>0.004</td>
<td></td>
</tr>
<tr>
<td>Adv Dist Annual Customer Benefits (at Yr 6)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Customer Volt/Var Conservation Reduced Purchases</td>
<td>0.08</td>
<td></td>
</tr>
<tr>
<td>Improved Customer Productivity</td>
<td>0.05</td>
<td></td>
</tr>
<tr>
<td>Total Annual Customer Benefits (at Yr 6)</td>
<td>0.13</td>
<td></td>
</tr>
</tbody>
</table>

| 20 Year Total Adv Dist Capital Costs          | $3.0 | $2.7 |
| 20 Year Total Adv Dist Utility Benefits       | ($0.1) | ($0.1) |
| 20 Year Total Adv Dist Customer Benefits      | $2.7 | $1.7 |
| 20 Year Total Adv Dist Benefits               | $2.6 | $1.6 |

Table 7-13: Advanced Distribution Costs, Benefits and Societal Benefits, $M
7.5 Demand Response System

Demand Response can be used to address reliability requirements. This is used to offset annual expenditures to 3rd party providers as a benefit under the AMI CBA model. In addition CPAU can implement Demand Response in support of CAISO emerging economic markets. This area is not addressed in this report.

7.6 Societal Benefits

The Societal Benefits include calculation of benefits due to reduction of CO2 from Energy Efficiency and Conservation due to Smart Grid driven customer energy reductions, and transportation offsets due to integration of customer Plug-in Electric Vehicles (PEVs). There are also societal benefits due to reduction in travel due to implementation of remote meter reading and automation of distribution operations, although these are small in comparison. The supplied CBA Model includes a worksheet for calculating Societal Benefits. These are not detailed in this report.
8 Summary of Key Findings and Recommendations

The process of developing the Assessment of Smart Grid Applications for City of Palo Alto in the previous sections has resulted in a summary of key findings and recommendations. These are presented as follows.

8.1 Summary of Key Findings

The following is the summary of findings relative to the Assessment of Smart Grid Applications for the City of Palo Alto.

1. Among the full gamut of possible smart grid applications being developed in the market place today, three applications are relevant to CPAU.
   a. Advanced Metering Infrastructure (AMI) that enables remote meter reading and more granular and actionable usage information for customers including Meter Data Management System (MDMS) for providing billing flexibility and dynamic pricing.
   b. Advanced Distribution Systems including Distribution Automation (DA), distribution monitoring and advanced distribution applications to enhance reliability and more efficient management of the distribution system.
   c. Enhanced customer engagement for optimal use of energy and water suppliers. This aspect would require additional investment by customers in devices like In-Home-Displays for residential customers and Building Management Systems (BMS) for commercial customers. The cost of such customer devices and systems were not considered in the analysis.

2. The principle benefit of installing an AMI System in Palo Alto is related to reducing meter reading costs and efficient utilization of electricity. However due to the relatively efficient CPAU meter reading operations and comparatively lower energy efficiency savings potential in the City, these benefits are not sufficiently large to warrant an expedited implementation of AMI.
   a. The capital cost of implementing an AMI System for electric, gas and water meters is estimated at between $10.8 and 16.2 million, NPV. In addition, enhanced data management functionality related to consumption, rates, billing; meter and communication network maintenance; and software maintenance cost is projected to add $1.0 to 1.5 million annually in additional operating cost. Total AMI System 20 year costs range from $23.4 to 35.2 million, NPV.
b. The commensurate AMI System benefits are estimated to be in the $1.2 to 1.7 million range annually, with principle benefit related to meter reader savings. Customer efficiency benefits directly related to AMI was difficult to quantify, but preliminarily it was estimated that AMI related technologies could result in electricity consumption reduction of 0.5% for commercial customers and 1% for residential customers in the long term. No gas or water usage savings was assumed in this assessment. The estimated 20 year benefits range from $18.5 to 27.7 million, NPV.

c. Since AMI is an enabling technology, it was difficult to foresee and quantify benefits related to such technologies far into the future. Benefits related to enhanced customer service and satisfaction was also difficult to quantify.

d. With a 20 year NPV cost of $23 to $35 million and benefit of $18 to $28 million, there is no compelling quantifiable economic benefit related to replacing existing meters with smart meters. In the best case scenario, an AMI System investment is estimated at 17 years to breakeven cost recovery - this is a scenario where the costs are at the bottom of the range and the benefit is at the top of the range.

3. The business case for Distribution System Automation were not positive. Implementing a basic Outage Management System (OMS) and integration with Geographic Information System (GIS) will facilitate a more effective and efficient operations on the field. The total 20 year actual costs of implementing such a system is estimated at $3 million and several elements of such a system are already under development. The quantifiable economic benefit is lower than the capital costs with a NPV of $2.7M versus a total projected utility and customer benefit of adding up to $1.6M NPV.

4. CPAU at present has a program to provide in-home displays to residential customers and assists with upgrading building management systems at commercial customer locations. If CPAU decides to implement AMI, higher degree of customer engagement will have to occur to maximize the value of the AMI system. This includes implementing a range of customer oriented programs such as customer on-line energy usage and bill review web portal, analysis of appliance efficiency and usage pattern, and other customer conservation and energy efficiency outreach campaigns.

8.2 Smart Grid Recommendations

The following is the summary of recommendations relative to the Assessment of Smart Grid Applications for the City of Palo Alto.

1. The smart grid related systems are being rapidly deployed around the country. This effort is largely driven by regulatory mandates or spurred by government stimulus funds. While there are benefits associated to being an early adopter, the risk of early adoption outweighs the benefits for Palo Alto at this time.

2. It is our assessment that as technology standards are finalized and technology/product lines mature in the next 2-3 years, costs of implementing an AMI system would decline and
benefits to Palo Alto will become more apparent. Hence, it is recommended that Palo Alto positions itself, without making any major investments at this time, to take advantage of potential opportunities that may arise in the 2012-13 period.

3. It is recommended that the City devote its effort in the following areas in the next 2 years, to learn from experience and be in a position to make decisions based on an AMI implementation road map in the 2012-13 period:

   a. Develop a robust gas and water meter maintenance and replacement plan. The plan could include exploring the possibility of installing AMI enabled meters for on-going meter replacement programs that could later be networked when CPAU decides to implement an AMI system

   b. Implement Time-of-Use rates and related metering infrastructure for Electric Vehicle owners in the city to encourage charging of vehicles during off-peak hours.

   c. Better understand the value of Demand Response in the City by implementing pilot programs for large commercial customers.

   d. Engage with large building owners and provide incentives to upgrade their BMS to better integrate with features of smart meters; if appropriate, undertake a smart meter pilot with interested high value customer.

   e. Learn from the Distribution System current sensor project now underway at CPAU and develop a long term Distribution System Automation road map.

   f. Perform further analysis of potential Volt/Var energy conservation on the distribution grid.

   g. Further review AMI backend software related cost estimated at $6M, as they make up 40% of the $15 million AMI implementation cost.

      i. Evaluate the City’s long term plan for SAP software use and enhancement. Harvest synergies by implementing AMI in a timeline that coincides with planned future SAP upgrades.

      ii. Look at cost effective ways to accomplish integration of future MDMS with SAP and billing.

      iii. Explore potential for outsourcing or an externally hosted service-based MDMS and billing system implementation.

4. Implementing smart grid applications effectively, with least disruptions to the organization and the community, requires long term planning. While no major capital expenditures are recommended at this time, it is recommended that CPAU allocate sufficient resources in the coming years to start this planning phase in earnest.

   a. Perform internal detailed study of IT implementation resources and dedicated IT resources required to operate and maintain Smart Grid systems.
b. Assess new Smart Grid specific staff positions, level of expertise and compensation rates. (See potential Smart Grid positions and proposed rates in Table 8-1 below.)

c. Assess CPAU organizational structure for Smart Grid implementation and operation.

d. Develop and execute a Customer Outreach program to effectively communicate CPAU Smart Grid activities and engage external stakeholders in development and deployment process.

<table>
<thead>
<tr>
<th>Smart Grid Positions</th>
<th>Annual Salary</th>
<th>Step 3 Hrly</th>
<th>Class</th>
</tr>
</thead>
<tbody>
<tr>
<td>AMI Network/System Operations</td>
<td>$82,389</td>
<td>$39.61</td>
<td>SG01</td>
</tr>
<tr>
<td>AMI Operational Systems Support</td>
<td>$77,002</td>
<td>$37.02</td>
<td>SG02</td>
</tr>
<tr>
<td>AMI Field Safety &amp; Maintenance</td>
<td>$64,459</td>
<td>$30.99</td>
<td>SG03</td>
</tr>
<tr>
<td>Supr-AMI Field Safety &amp; Main</td>
<td>$74,589</td>
<td>$35.86</td>
<td>SG04</td>
</tr>
<tr>
<td>AMI Rates and Billing</td>
<td>$77,002</td>
<td>$37.02</td>
<td>SG05</td>
</tr>
</tbody>
</table>

Table 8-1: Potential Smart Grid Positions

### 8.3 Preliminary Smart Grid Timeline

A preliminary Smart Grid timeline is shown in Figure 8-1. The timeline is based on a proposal that CPAU implement a slow rollout of the Smart Grid consisting of Smart Grid pilots followed by AMI and Advanced Distribution systems over a 12 year period (see Figure 8-1). The Smart Grid pilots during the first year would allow CPAU to become familiar with supplier offerings and capabilities in fielded demonstrations. The AMI System infrastructure deployment is over the next two years with the Smart Meter deployment planned over a 5 year period (Years 2 – 6). Following the AMI System rollout, the Advanced Distribution procurement will begin in Year 7. Rollout will begin in Year 7 with fully operational Advanced Distribution systems and field equipment completed by Year 12. Additional Smart Grid components and interfaces (OMS, Field Force Management, etc.) will continue to be phased in after Year 12.
The Smart Grid deployment timeline outlined above is designed to roll out implementations in sequential order and is based on availability of CPAU resources. Limited scoped activities can still be pursued in parallel. For example the Advanced Distribution rollout can start at anytime. Smart Grid pilots and demonstrations can be performed over a 1 or 2 year time period. Determination of the Smart Grid deployment timeline will be influenced by Customer Stakeholder input. CPAU is currently conducting a Customer Stakeholder survey to assess level of Smart Grid awareness and perceived value.

**8.4 Other Factors to be Considered**

Additional factors that are topics of discussion by Smart Grid policy decision makers include Smart Meter Accuracy and RF missions and exposure. These items are discussed below.

**8.4.1 Smart Meter Accuracy**

The following is a review of the issues related to the Smart Meter deployment at PG&E and the CPUC sponsored independent review by Structure Group, located at the following link:

“From April 1, 2010, to August 25, 2010, Structure reviewed relevant documentation related to PG&E’s SmartMeterTM equipment, systems, and processes and compared it to industry standards, independently performed customer interviews, and PG&E-provided vendor specifications and internal documentation. This evaluation principally consisted of an assessment of PG&E’s accuracy and conformity to meter standards, analytical procedures applied to customer data, business processes, and practices. Due to the number of systems and process within the PG&E framework, this Assessment reflects Structure’s opinion on only the scope of work which Structure was requested to perform.”

“Overall, Structure found that the AMI technology deployed by PG&E appears to be 1) consistent with industry standards, based upon the goals of the AMI implementation and upgrades approved by the CPUC, and 2) accurate from a metering and billing perspective. Structure identified gaps in Customer services and processes related to high bill complaints, and determined certain PG&E practices to be partially noncompliant relative to industry best practices.”

“The following Figure provides a high-level summary of Structure’s findings for each of the PG&E AMI Assessment’s areas of focus.”
### 8.4.2 Customer Information Access and Privacy

Customers have a right to access all data and information related to their activity. As required under both state and federal statutes, CPAU is required to secure access to customer information and maintain privacy and confidentiality. The City of Palo Alto already has a policy to ensure these requirements. 3rd party application providers (e.g. Google) are offering services that require customers to authorize access to customer information. The City of Palo Alto will need to develop business processes that include customer authorization to share customer’s information with 3rd parties in a secure manner and ensuring that 3rd parties information access methods prevent misuse of customer information.

<table>
<thead>
<tr>
<th>Area</th>
<th>Finding</th>
</tr>
</thead>
<tbody>
<tr>
<td>Laboratory Meter Testing</td>
<td>All of the Smart Meters tested in Structure's independent laboratory passed the accuracy testing. The Smart Meters subjected to environmental stress testing in a controlled temperature chamber at reference, high, and low temperatures all fell within the American National Standards Institute (ANSI) standards.</td>
</tr>
</tbody>
</table>
| Field Meter Testing               | - Structure’s Pass/Fail Criteria was based upon the CPUC Standard of ±2.0% for electromechanical meters and Smart Meters.  
- Of the 613 Smart Meter field tests, 611 meters were successfully tested and 100% passed Average Registration Accuracy. One meter was found to have serious errors and be malfunctioning on arrival, and one was found to have serious overt errors upon installation; these meters were therefore excluded from testing.  
- Of the 147 completed electromechanical meter field tests, 141 meters passed, and 6 failed Average Registration Accuracy. One meter was found to be non-functional, registering zero on all tests, and was therefore excluded from testing. |
| End-to-End System Testing         | By utilizing a representative, small sample size to confirm meter-to-bill system accuracy, Structure did not identify deviations during testing that indicated a systemic problem in the meter billing system's accuracy. |
| High Bill Complaint Analysis      | After reviewing and analyzing over 1,378 High Bill complaints, Structure did not identify pervasive issues with meter data or billing systems. Results from 20 High Bill Complaint Customer interviews identified service issues around complaint management by PG&E and the CPUC. |
| Best Practices Associated with Smart Meters | Structure found PG&E to have been historically in compliance, or have recently come into compliance, with the majority of industry best practices associated with Smart Meters. Structure identified several items of some concern during the Assessment, which have been recognized by PG&E, through their presentation of information, as shortcomings to be addressed. |
| Security Assessment               | Structure concluded that PG&E has developed a cyber security framework that meets the objectives established in the Smart Grid industry’s OpenSG AMI-SEC Task Force “AMI System Security Requirements” that were reviewed as part of this evaluation. |
8.4.3 RF Emissions Interference with Equipment and Human Exposure

Independent reports in California and Texas have established smart meters' accuracy, but whether the new meters emit harmful RF frequencies remains an important smart grid issue in the eyes of some consumers. A number of consumer advocate groups maintain that all electromagnetic emissions are harmful to the human body at any level. Some cities in California have decided to ban Smart Meters.

Power-industry research firm EPRI maintains that there are no studies proving that RF from smart meters causes bodily harm, except for heat increases at very high exposure RF levels than allowed by FCC regulations. Attached is a recent EPRI Report “A Perspective on Radio-Frequency Exposure Associated With Residential Automatic Meter Reading Technology, EMF Health Assessment and RF Safety, Rob Kavet and Gabor Mezei, February 2010, located at the following link:


Customer questions have arisen concerning the level of personal RF exposures and any health implications of such exposure from AMI meters within and around a residence. RF exposure limits or rules have been set by the IEEE, the International Commission on Non-Ionizing Radiation Protection and the FCC. Vast amount of research conducted in recent years to address potential health effects associated with the use of cell phones have not revealed specific biological effects, according to the report.

EPRI's February paper asserts that the FCC restricts to very low levels transmitter power and associated RF emissions. The FCC limits are more stringent than the other published guidelines and represent the most conservative values that any US government agency applies.

Smart meters have a very short duty cycle -- the time they transmit RF to the local-area network in which they participate: the equivalent of a few seconds per hour according to the paper said. In contrast, a cell phone in general has a 100% duty cycle during a call. Transmissions from a meter to a home-area network would add to the duty cycle.
People are exposed regularly to very weak RF fields from cell phones, walkie-talkies, radio and TV stations and microwave ovens. The health effects of RF from cell phones will take time to resolve.

The EPA states that despite more than two decades of research to determine whether elevated EMF exposure, principally to magnetic fields, is related to an increased risk of childhood leukemia, there is still no definitive answer. The general scientific consensus is that, thus far, the evidence available is weak and is not sufficient to establish a definitive cause-effect relationship.

Humans have been exposed to varying levels of EMF since the invention of the radio by Marconi. Peer research into potential human physiological causes and effects due to EMFs is sure to continue. A listing of recent EMF/RF studies may be found at the following link below:

http://www.ccst.us/projects/smart
Appendix A  Smart Grid Use Cases

Use cases are used to help define Smart Grid functionality. These have been collected in a Smart Grid Information Clearinghouse use case repository located at the following locations:

http://www.sgiclearninghouse.org/UseCases

Use Cases are the descriptions of smart grid applications that define the important actors, systems and technologies, and their requirements that are part of the smart grid applications. The following is a list of applicable use cases which can be reviewed for City of Palo Alto.

Customer Use Cases

B1: Multiple Clients Read Demand and Energy Data Automatically from Customer Premises
Southern California Edison
2006

B2: Utility Remotely Limits Usage and/or Connects and Disconnects Customer
Southern California Edison
2006

B3: Utility Detects Tampering or Theft at Customer Site
Southern California Edison
2006

B4: Contract Meter Reading (or Meter Reading for other Utilities)
Southern California Edison
2006

C1: Customer Reduces their Usage in Response to Pricing or Voluntary Load Reduction Events
Southern California Edison
2006

C2: Customer has Access to Recent Energy Usage and Cost at their Site
Southern California Edison
2006

C3: Customer Prepays for Electric Services
Southern California Edison
2006

C4: External Clients Use the AMI to Interact with Devices at Customer Site
Southern California Edison
C5: Customer Uses Smart Appliances
Southern California Edison
2009

C6: Customer Uses an Energy Management System or In-Home Display
Southern California Edison
2009

C7: Utility Uses AMI Data for Targeted Marketing Campaigns
Southern California Edison
2009

C8: Load Researchers Perform Analyses Using AMI Data
Southern California Edison
2009

Configuration of a Community Energy Storage (CES) Controller V3.2
EPRI Use Case Repository
2010

Configuration of a Community Energy Storage (CES) Unit V3.1
EPRI Use Case Repository
2010

Consumer Portal P6 Customer Needs Meter Device
EPRI Use Case Repository
2010

Consumer Portal Scenario P4 Customer Account Move
EPRI Use Case Repository
2010

Consumer Portal Scenario P5 Customer Sign-Up for Demand Reduction Program
EPRI Use Case Repository
2010

Consumer Portal Scenario P7
EPRI Use Case Repository
2010

Consumer Portal Scenario P8
EPRI Use Case Repository
2010

Consumer Portal Scenario P9
EPRI Use Case Repository
2010

Create Real-Time Contingency Files V0.1
EPRI Use Case Repository
2010

Create Real-Time Settlement File V0.4
EPRI Use Case Repository
Customer (residential and commercial) implements Demand Response system and responds to Demand Response signals from the utility (using AMI)
EPRI Use Case Repository
2010

Customer Communications Portal Management
EPRI Use Case Repository
2010

Customer Communications Portal Management - Security Issues
EPRI Use Case Repository
2010

Customer Communications Portal Management - System Issues
EPRI Use Case Repository
2010

Customer Communications Portal Management - Telecommunications Issues
EPRI Use Case Repository
2010

Customer Provides Photovoltaic Based Generation Source
EPRI Use Case Repository
2010

D11: Distribution Operations uses Smart Grid Technology to Enhance Outage Restoration Communications Processes
Southern California Edison
2009

D1: Distribution Operations Curtails Customer Load for Grid Management
Southern California Edison
2006

D3: Customer Installs and Uses Distributed Generation
Southern California Edison
2006

D7: Distribution Planner uses AMI to Optimize Asset Utilization
Southern California Edison
2009

D8: Planners Perform Analytics Using Historical AMI Data
Southern California Edison
2009

Developing a Pricing Signal V3.0
EPRI Use Case Repository
2010

Direct Load Control Event V3.0
EPRI Use Case Repository
2010
Distributed Energy Resource Controller Adjusts System Settings in Response to Voltage Excursion V1.1  
EPRI Use Case Repository  
2010

Field Meter Programming and Meter Firmware Upgrades V3  
EPRI Use Case Repository  
2010

I1: Utility Installs, Provisions and Configures AMI System  
Southern California Edison  
2006

I2: Utility Manages End-to-End Life-Cycle of the Meter System  
Southern California Edison  
2006

I3: Utility Upgrades AMI System to Address Future Requirements  
Southern California Edison  
2006

Last Gasp Message – Outage Notification V3.0  
EPRI Use Case Repository  
2010

On-Demand Meter Read from CIS V3.0  
EPRI Use Case Repository  
2010

P1: Utility Provides Services to Plug-in Electric Vehicle (PEV) Customer  
Southern California Edison  
2009

P2: Customer Connects Plug-in Electric Vehicle (PEV) to Premise Energy Portal  
Southern California Edison  
2009

P3: Customer enrolls in a Plug-in Electric Vehicle (PEV) Demand-Side Management Program  
Southern California Edison  
2009

Permanent Power Quality Measurement  
EPRI Use Case Repository  
2010

PEV Charging at Premise V3.0  
EPRI Use Case Repository  
2010

Plug-in Vehicles (PEV) - E - General Registration & Enrollment Process  
EPRI Use Case Repository  
2010

Plug-in Vehicles (PEV) - L1 - Customer connects PEV at Home - premise  
EPRI Use Case Repository  
2010
Plug-in Vehicles (PEV) - L2 - Customer connects PEV at Another Home
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - L3 - Customer connects PEV Outside Home Territory
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - L4 - Customer connects PEV at Public Location
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - PR1 - Customer charges the PEV
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - S1 - Customer connects vehicle to premise using Cordset EVSE
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - S2 - Customer connects vehicle to premise using Premise EVSE
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - S3 - Premise EVSE that Includes the Charger (Rev D)
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - U1 - Customer enrolls in a Utility Time of Use (TOU) program
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - U2 - Customer enrolls in a Discrete Event Program
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - U3 - Customer enrolls in a Utility Real Time Pricing (RTP) program
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - U4 - Customer enrolls in a Utility Critical Peak Pricing (CPP) program
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - U5 - Customer enrolls in an Active Management program
EPRI Use Case Repository
2010

Plug-in Vehicles (PEV) - Use Case Instructions and Status
EPRI Use Case Repository
2010

Power Quality Contracts
EPRI Use Case Repository
2010
Power Quality Event Notifications
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) - Base RTP Calculation Function
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) - Baseline Use Case
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) - DER Device Management
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) - Energy Service Provider Energy and Ancillary Services Aggregation
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) - Energy Services Provider (ESP) Customer Specific RTP Calculator
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) - Load Forecasting
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) - Top Level
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) – Customer’s Building Automation Software BAS Optimization
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) – Market Operations Ancillary Services
EPRI Use Case Repository
2010

Real-Time Pricing (RTP) – Market Operations Energy Services
EPRI Use Case Repository
2010

Remote Connect/Disconnect V3.0
EPRI Use Case Repository
2010

Remote Meter Programming of Smart Meter V3.0
EPRI Use Case Repository
2010

Remote NIC - ESP Firmware Upgrades V3.0
EPRI Use Case Repository
2010
S1: AMI System Recovers after Outage, Communications or Equipment Failure
Southern California Edison
2006

Scheduled Daily Bulk Read from AMI Head-End V3.0
EPRI Use Case Repository
2010

Utility and or Customer Provides Electrical Energy Storage in Conjunction with Photovoltaic
EPRI Use Case Repository
2010
Distribution Use Cases

Advanced Distribution Automation with DER Function
EPRI Use Case Repository
2010

Alarm Management
EPRI Use Case Repository
2010

AMI Network (Moving Data Elements from the AMI Head-End to Smart Meter & from the Smart Meter to the AMI Head-End) V3.0
EPRI Use Case Repository
2010

Asset Manager Verifies Equipment Location
EPRI Use Case Repository
2010

CES – Energy Dispatch V 3.1
EPRI Use Case Repository
2010

Circuit Reconfiguration V3.1
EPRI Use Case Repository
2010

Configuration of a Community Energy Storage (CES) Controller V3.2
EPRI Use Case Repository
2010

Configuration of a Community Energy Storage (CES) Unit V3.1
EPRI Use Case Repository
2010

Contingency Analysis - Baseline
EPRI Use Case Repository
2010

Contingency Analysis - Future Advanced
EPRI Use Case Repository
2010

D10: Field Worker Uses Consolidated Mobile Systems (CMS) for Inspection and Repair Work
Southern California Edison
2009

D11: Distribution Operations uses Smart Grid Technology to Enhance Outage Restoration Communications Processes
Southern California Edison
2009

D12: Generation Dispatch Utilizes Energy Storage to Balance Renewable Variability
Southern California Edison
2009
D14: EMS Uses Online Dissolved Gas Monitoring to Detect Emerging Failures of Transformer Banks and Take Corrective Action  
Southern California Edison  
2009

D19: System Operator Uses Monitoring Data for Condition-based Maintenance Programs  
Southern California Edison  
2009

D1: Distribution Operations Curtails Customer Load for Grid Management  
Southern California Edison  
2006

D20: Utility uses 'Beyond SCADA' Data from the Substation to Analyze System Faults  
Southern California Edison  
2009

D2: Distribution Engineering or Operations Optimize Network based on Data Collected by the AMI System  
Southern California Edison  
2006

D4: Distribution Operator Locates Outage Using AMI Data and Restores Service  
Southern California Edison  
2006

D4: Distribution Operator Locates Outage Using AMI Data and Restores Service (updated)  
Southern California Edison  
2009

D5: Power System Automatically Reconfigures for Reliability with the Help of the AMI System  
Southern California Edison  
2009

D6: Distribution Operator Controls the Distribution System using AMI Data  
Southern California Edison  
2008

D7: Distribution Planner uses AMI to Optimize Asset Utilization  
Southern California Edison  
2009

D8: Planners Perform Analytics Using Historical AMI Data  
Southern California Edison  
2009

D9 - Utility Manages Utility-Owned Distributed Generation  
Southern California Edison  
2008

Data Acquisition  
EPRI Use Case Repository  
2010

Data Acquisition and Control (DAC)  
EPRI Use Case Repository
2010

Data Acquisition From External Distribution Management System (DMS) Network Monitoring Subsystem
EPRI Use Case Repository
2010

Demand Response - Utility Commanded Load Control
EPRI Use Case Repository
2010

Direct Load Control Event V3.0
EPRI Use Case Repository
2010

Distributed Energy Resource Controller Adjusts System Settings in Response to Voltage Excursion V1.1
EPRI Use Case Repository
2010

Distributed Energy Resource Controller Produces Distribution Powerflow Forecast V1.1
EPRI Use Case Repository
2010

Earth Fault Localization
EPRI Use Case Repository
2010

Fault Isolation
EPRI Use Case Repository
2010

Field Control Request
EPRI Use Case Repository
2010

Integrated Voltage VAR (IVVC) Decentralized V3.1
EPRI Use Case Repository
2010

IVVC Centralized V3.1
EPRI Use Case Repository
2010

Last Gasp Message – Outage Notification V3.0
EPRI Use Case Repository
2010

Network Extension
EPRI Use Case Repository
2010

OMS On-Demand (Poll) V3.0
EPRI Use Case Repository
2010

OMS Ping V3.0

Assessment of Smart Grid Applications for CPA

March 4, 2011

113
Protection Engineer Changes Settings Across A Network
EPRI Use Case Repository
2010

Protection Engineer Sets up Bus Protection Based on Topology of Substation
EPRI Use Case Repository
2010

Protection Engineer Verifies Protection Models from IEC 61850 Configuration
EPRI Use Case Repository
2010

SCADA Data Update - KCPL
EPRI Use Case Repository
2010

Scheduled Daily Bulk Read from AMI Head-End V3.0
EPRI Use Case Repository
2010

Service Restoration
EPRI Use Case Repository
2010

Short Circuit Localization
EPRI Use Case Repository
2010

System Engineer Retrofits A Substation
EPRI Use Case Repository
2010

System Operator Identifies, Locates, Isolates And Restores Service After a Fault
EPRI Use Case Repository
2010

System Operator Switches Feeders Based On Contingency Analysis
EPRI Use Case Repository
2010

Training Session
EPRI Use Case Repository
2010

Utility and or Customer Provides Electrical Energy Storage in Conjunction with Photovoltaic
EPRI Use Case Repository
2010

Utility Implements Integrated Management of Distributed Energy Resources
EPRI Use Case Repository
2010
Volt VAr Dispatch, A Sub-function of Operator Switches Feeder
EPRI Use Case Repository
2010
Appendix B  CPAU Facts & Modeling Assumptions

The following CPAU Facts were collected as input to the construction and analysis of the Cost Benefit Model. Some of the financial date will have to be updated to reflect the most current data as the model is updated and used by staff. The model has flexibility built into it and to be a working model that can be updated as needed.

<table>
<thead>
<tr>
<th>CPAU Facts</th>
<th>Electric Utility</th>
<th>Natural Gas Utility</th>
<th>Water Utility</th>
<th>Combined Utilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility Operating Parameters</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual Retail Sales Revenues</td>
<td>$92,000,000</td>
<td>$48,000,000</td>
<td>$26,000,000</td>
<td>$166,000,000</td>
</tr>
<tr>
<td>Net Assets</td>
<td>$301,000,000</td>
<td>$81,000,000</td>
<td>$77,000,000</td>
<td>$459,000,000</td>
</tr>
<tr>
<td>Utility Load</td>
<td>190 MW peak 1 TWh/year</td>
<td>3.3 million MMBtu/year base load of 5,000 MMBtu/day</td>
<td>4.6 billion gallons</td>
<td>N/A</td>
</tr>
<tr>
<td>Annual Load Growth, %</td>
<td>0.2%</td>
<td>flat</td>
<td>declining</td>
<td>N/A%</td>
</tr>
<tr>
<td>Electric Utility Load Factor</td>
<td>60%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Utility Summer Load Factor</td>
<td>53%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total number of employees</td>
<td>106</td>
<td>45</td>
<td>44</td>
<td>205</td>
</tr>
<tr>
<td>Load by customer class</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- residential</td>
<td>15%</td>
<td>15%</td>
<td>15%</td>
<td>15%</td>
</tr>
<tr>
<td>- Non-Residential</td>
<td>85%</td>
<td>85%</td>
<td>85%</td>
<td>85%</td>
</tr>
<tr>
<td>Number of retail meters</td>
<td>28,900</td>
<td>23,400</td>
<td>19,700</td>
<td>72,200</td>
</tr>
<tr>
<td>Number of new customers/year, %</td>
<td>0.2%</td>
<td>0.2%</td>
<td>0.2%</td>
<td>0.2%</td>
</tr>
<tr>
<td>Number of Service Orders</td>
<td>14,800</td>
<td>13,500</td>
<td>11,200</td>
<td></td>
</tr>
<tr>
<td>Number of retail meters by customer class</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Residential</td>
<td>24,495</td>
<td>20,600</td>
<td>15,300</td>
<td>60,400</td>
</tr>
<tr>
<td>- Non-Residential</td>
<td>4,529</td>
<td>2,897</td>
<td>4,600</td>
<td>12,000</td>
</tr>
</tbody>
</table>
**Length of distribution system feeder/pipes**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>446 miles of primary distribution lines: 193 of underground distribution lines; 12 miles of 60kV subtransmission lines</td>
<td>353 miles of gas main and service lines</td>
</tr>
</tbody>
</table>

**Number of distribution system substations**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>One 115kV/60kV Transmission substation, one 60kV/12kV switching substation and eleven 66kV/12kV substations</td>
<td>2 Gas Delivery/Pumping Stations</td>
</tr>
</tbody>
</table>

**Number of distribution feeders**

<table>
<thead>
<tr>
<th>Value</th>
<th>50</th>
</tr>
</thead>
</table>

**Number of distribution tie switches**

<table>
<thead>
<tr>
<th>Value</th>
<th>75</th>
</tr>
</thead>
</table>

**Number of meter reading staff and annual cost**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>6 Meter reader and 1 Meter Reader Lead $288,158</td>
<td>6 Meter reader and 1 Meter Reader Lead $248,347</td>
</tr>
</tbody>
</table>

**Total customer service center staffing level and budget**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>5 CSRs, 2CSS, 2 CSS Lead, 1 Admin $681,799</td>
<td>5 CSRs, 2CSS, 2 CSS Lead, 1 Admin $621,485</td>
</tr>
</tbody>
</table>

**Annual turn-on/off requires; new service request**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>9,649</td>
<td>7,914</td>
</tr>
</tbody>
</table>

**% of total customers annual with turn-on/off request; new service request**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>33%</td>
<td>34%</td>
</tr>
</tbody>
</table>

**Distribution System Performance**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIDI - minutes</td>
<td>52.86</td>
<td>66.51</td>
<td>51.57</td>
</tr>
<tr>
<td>SAIFI - minutes</td>
<td>0.61</td>
<td>0.56</td>
<td>0.39</td>
</tr>
<tr>
<td>CAIDI - outage minutes/customer interruption</td>
<td>86.88</td>
<td>118.36</td>
<td>131.97</td>
</tr>
</tbody>
</table>

**City Statistics**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land Area</td>
<td>23.7 sq.mi.</td>
</tr>
<tr>
<td>Land Area - Developed - sq. mi.</td>
<td>15.9</td>
</tr>
</tbody>
</table>
### CPAU Solar Program

<table>
<thead>
<tr>
<th>Year</th>
<th>Residents</th>
<th>CPAU Solar Program</th>
<th>PV installations</th>
<th>PV MWs installed - MWs</th>
<th>Average Annual Energy production @ 1800kWhr/kW</th>
<th>Capacity - MWhr</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td></td>
<td></td>
<td>400</td>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2030</td>
<td></td>
<td></td>
<td>2000</td>
<td>10</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### CPAU 2009 Metering Dept Budget

<table>
<thead>
<tr>
<th></th>
<th>Water</th>
<th>Electric</th>
<th>Gas</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regular Salaries</td>
<td>110,853</td>
<td>108,586</td>
<td>108,083</td>
<td>327,522</td>
</tr>
<tr>
<td>Temporary Salaries</td>
<td>40,929</td>
<td>2,224</td>
<td>2,224</td>
<td>45,376</td>
</tr>
<tr>
<td>Overtime</td>
<td>5,966</td>
<td>5,000</td>
<td>4,973</td>
<td>15,939</td>
</tr>
<tr>
<td>Benefits</td>
<td>106,570</td>
<td>94,611</td>
<td>92,683</td>
<td>293,864</td>
</tr>
<tr>
<td>Contract Services</td>
<td>12,464</td>
<td>16,068</td>
<td>11,437</td>
<td>39,969</td>
</tr>
<tr>
<td>Supplies and Material</td>
<td>1,376</td>
<td>1,882</td>
<td>6,682</td>
<td>9,940</td>
</tr>
<tr>
<td>Vehicles</td>
<td>10,000</td>
<td>19,977</td>
<td>8,537</td>
<td>38,514</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>288,158</td>
<td>248,347</td>
<td>234,618</td>
<td>771,123</td>
</tr>
</tbody>
</table>

### CPAU 2009 Staff Allocation

<table>
<thead>
<tr>
<th></th>
<th>Electric</th>
<th>Fiber</th>
<th>Gas</th>
<th>Water</th>
<th>WWC</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Admin- total</td>
<td>5.72</td>
<td>1.3</td>
<td>2.33</td>
<td>1.97</td>
<td>0.25</td>
<td>11.57</td>
</tr>
<tr>
<td>CSD - CSR</td>
<td>2.59</td>
<td>2.61</td>
<td>2.55</td>
<td>1.25</td>
<td>7</td>
<td>9</td>
</tr>
<tr>
<td>CSD-Meter Reading</td>
<td>2.32</td>
<td>2.31</td>
<td>2.37</td>
<td>1</td>
<td></td>
<td>7</td>
</tr>
<tr>
<td>CSD - credit collection</td>
<td>1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Admin and Other</td>
<td>1.08</td>
<td>0.7</td>
<td>0.78</td>
<td>0.79</td>
<td></td>
<td>3.35</td>
</tr>
<tr>
<td><strong>CSD-total</strong></td>
<td>6.99</td>
<td>0.7</td>
<td>5.7</td>
<td>5.71</td>
<td>1.9</td>
<td>21</td>
</tr>
<tr>
<td>Category</td>
<td>Value 1</td>
<td>Value 2</td>
<td>Value 3</td>
<td>Value 4</td>
<td>Value 5</td>
<td>Total</td>
</tr>
<tr>
<td>-----------------------</td>
<td>---------</td>
<td>---------</td>
<td>---------</td>
<td>---------</td>
<td>---------</td>
<td>-------</td>
</tr>
<tr>
<td>Engineering - total</td>
<td>16.55</td>
<td>0.55</td>
<td>10.31</td>
<td>7.37</td>
<td>7.22</td>
<td>42</td>
</tr>
<tr>
<td>Marketing - total</td>
<td>5.6</td>
<td>1.05</td>
<td>0.9</td>
<td>1.45</td>
<td>0</td>
<td>9</td>
</tr>
<tr>
<td>Operations - FSR</td>
<td>0.74</td>
<td>2.13</td>
<td>1.79</td>
<td>1.67</td>
<td></td>
<td>6.33</td>
</tr>
<tr>
<td>Operations - other</td>
<td>62</td>
<td>3.13</td>
<td>26.13</td>
<td>24.02</td>
<td>15.39</td>
<td>130.67</td>
</tr>
<tr>
<td>Operations - total</td>
<td>62.74</td>
<td>3.13</td>
<td>28.26</td>
<td>25.81</td>
<td>17.06</td>
<td>137</td>
</tr>
<tr>
<td>Resource Mgmt</td>
<td>5.35</td>
<td>0</td>
<td>4.1</td>
<td>1.75</td>
<td>0</td>
<td>11.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>102.95</td>
<td>6.73</td>
<td>51.6</td>
<td>44.06</td>
<td>26.43</td>
<td><strong>231</strong></td>
</tr>
</tbody>
</table>
## Appendix C CPAU Strategic Objectives

During the Stakeholder workshops, a list of Strategic Objectives that align with CPAU’s Strategic Goals was developed. The list of Strategic Objectives is provided in Table D-1 below.

### Table D-1: CPAU Strategic Goals and Objectives

| Combined Inputs |  
|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
|                 |  
| 1               | Enhance Revenue |  
| 1.1             | Improve billing accuracy | H |
| 1.2             | Increase meter accuracy to increase bill accuracy | H |
| 1.3             | Target customer marketing | M/H |
| 1.4             | Reduce "idle usage" | L |
| 1.5             | Improve billing cash flow | M |
| 1.6             | Recover missing revenue | M/H |
| 1.7             | Add new revenue source | M/H |
| 1.8             | Add new business venture | H |
| 1.9             | Add new product | H |
| 1.10            | Add new service | H |
| 1.11            | Better identify energy theft | M/H |
1.12 Increase revenue program participation | M

2 Improve Distribution System Reliability and Power Quality

2.1 Detect and communicate outages sooner | H
2.2 Locate faults sooner | H
2.3 Avoid emergency load shedding | L
2.4 Reduce grid instability | L
2.5 Resolve outages more quickly | H
2.6 Shift demand to off-peak | L
2.7 Add to capacity buffer | L
2.8 Switch fuels dynamically | L
2.9 Integrate distributed generation | H
2.10 Increase reliability program participation | M
2.11 Monitor transformer under/over loading | H
2.12 Optimize transformer loading | H
2.13 Increase transformer reliability | L
2.14 Transformer maintenance/replacement prediction | M
2.15 Operate distribution system in loop configuration | H
2.16 Use auto reclosers to bring max. number of customers back on-line | M
2.17 Improved gas and water leak detection | High
2.18 Improve monitoring, recording, and mitigation of down line damage due to spikes or anomalies | H
2.19 Improve monitoring of voltage waveform | M
2.20 Improve voltage regulation and compensation | M
### Assessment of Smart Grid Applications for CPA

**2.15** Volt/VAR for conservation: L

**2.16** High side LTC: VL

**2.17** Improve harmonic mitigation: L

**2.18** Reduce losses: M

### Improve Asset Utilization, Reduce Management and Administration Costs

**3.1** Comply with laws or regulations: H

**3.2** Reduce meter reader equipment: H

**3.3** Reduce maintenance equipment: H

**3.4** Optimize the communications infrastructure openness, and efficiency: High

**3.5** Leverage existing City communications infrastructure: H

**3.6** Reduce meter procurement costs: H

**3.7** Improve efficiency of office support: H

**3.8** Better identify unbilled account errors: H

**3.9** Improve efficiency of resolving disputes: H

**3.10** Improve system planning: M

**3.11** Defer building additional generation: M

**3.12** Defer building additional T&D: L

**3.13** Reduce net emissions: H

**3.14** Reduce meter inventories: L/M

**3.15** Reduce inventory expenses: L/M

**3.16** Improve tax position: L

**3.17** Automatically perform load survey: M/H
## Improve Utility Operations

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>4.1</td>
<td>Reduce meter reader labor</td>
<td>H</td>
</tr>
<tr>
<td>4.2</td>
<td>Reduce maintenance labor</td>
<td>H</td>
</tr>
<tr>
<td>4.3</td>
<td>Reduce installation labor</td>
<td>H</td>
</tr>
<tr>
<td>4.4</td>
<td>Reduce customer service labor</td>
<td>H</td>
</tr>
<tr>
<td>4.5</td>
<td>Reduce site visits</td>
<td>H</td>
</tr>
<tr>
<td>4.6</td>
<td>Better identify broken meters</td>
<td>H</td>
</tr>
<tr>
<td>4.7</td>
<td>Better identify failed meters</td>
<td>H</td>
</tr>
<tr>
<td>4.8</td>
<td>Better identify misconfigured meters</td>
<td>H</td>
</tr>
<tr>
<td>4.9</td>
<td>Better identify communications failures</td>
<td>H</td>
</tr>
<tr>
<td>4.10</td>
<td>Better identify meter location</td>
<td>H</td>
</tr>
<tr>
<td>4.11</td>
<td>Increase meter accuracy</td>
<td>H</td>
</tr>
<tr>
<td>4.12</td>
<td>Better locate meters with wrong multipliers</td>
<td>H</td>
</tr>
<tr>
<td>4.13</td>
<td>Add workforce management system with geographic access</td>
<td>H</td>
</tr>
<tr>
<td>4.14</td>
<td>Add mobile workforce</td>
<td>H</td>
</tr>
<tr>
<td>4.15</td>
<td>Improve installation verification and maintain through operational functions High</td>
<td>H</td>
</tr>
<tr>
<td>4.16</td>
<td>Avoid losing the field relationship and asset inspection function of current meter reading High</td>
<td>H</td>
</tr>
<tr>
<td>4.17</td>
<td>Reduce installation errors</td>
<td>H</td>
</tr>
<tr>
<td>4.18</td>
<td>Automatically perform load survey</td>
<td>M/H</td>
</tr>
<tr>
<td>4.19</td>
<td>Reduce energy procurement costs</td>
<td>H</td>
</tr>
<tr>
<td>4.20</td>
<td>Reduce system energy losses</td>
<td>H</td>
</tr>
<tr>
<td>4.21</td>
<td>Reduce meter energy losses</td>
<td>H</td>
</tr>
</tbody>
</table>
### Assessment of Smart Grid Applications for CPA

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>4.22</td>
<td>Reduce battery replacement</td>
<td>L</td>
</tr>
<tr>
<td>4.23</td>
<td>Reduce calendar resets</td>
<td>H</td>
</tr>
<tr>
<td>4.24</td>
<td>Reduce meter reprogramming</td>
<td>L</td>
</tr>
<tr>
<td>4.25</td>
<td>Increase cost reduction program participation</td>
<td>H</td>
</tr>
<tr>
<td>4.26</td>
<td>Improve restoration time by installing field SCADA switches</td>
<td>H</td>
</tr>
<tr>
<td>4.27</td>
<td>Improve equipment condition based monitoring (e.g. Add remote monitoring for test stations for cathodic protection system)</td>
<td>H</td>
</tr>
<tr>
<td>4.28</td>
<td>Improve system diagnostics (e.g. add Smart Manhole Cover to detect/prevent sewer overflows)</td>
<td>H</td>
</tr>
<tr>
<td>4.29</td>
<td>Ensure that organization has the retraining and process in place to make use of new system capabilities</td>
<td>H</td>
</tr>
<tr>
<td>4.30</td>
<td>Improve integration of weather forecasting in demand response planning</td>
<td>H</td>
</tr>
</tbody>
</table>

#### Improve Environment, Integrate Renewables and Enable Electric Transportation

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>5.1</td>
<td>Increase renewable generation</td>
<td>H</td>
</tr>
<tr>
<td>5.2</td>
<td>Lower energy and water losses</td>
<td>H</td>
</tr>
<tr>
<td>5.3</td>
<td>Lower Green House Gases</td>
<td>H</td>
</tr>
<tr>
<td>5.4</td>
<td>Electrify transportation</td>
<td>H</td>
</tr>
<tr>
<td>5.5</td>
<td>Reduce pollution</td>
<td>H</td>
</tr>
<tr>
<td>5.6</td>
<td>Support sustainable infrastructure</td>
<td>H</td>
</tr>
<tr>
<td>5.7</td>
<td>Accommodate distributed energy resources</td>
<td>H</td>
</tr>
<tr>
<td>5.8</td>
<td>Advance energy and water efficiency programs</td>
<td>H</td>
</tr>
<tr>
<td>5.9</td>
<td>Maximize recycle water usage High</td>
<td>H</td>
</tr>
<tr>
<td>5.10</td>
<td>Minimize irrigation water loss</td>
<td>H</td>
</tr>
</tbody>
</table>
## Enhanced Customer Experience and Empowerment

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>6.1</td>
<td>Provide real-time energy usage</td>
</tr>
<tr>
<td>6.2</td>
<td>Access usage and billing information by Internet</td>
</tr>
<tr>
<td>6.3</td>
<td>Enable demand response participation</td>
</tr>
<tr>
<td>6.4</td>
<td>Detect and communicate outages sooner</td>
</tr>
<tr>
<td>6.5</td>
<td>Locate faults sooner</td>
</tr>
<tr>
<td>6.6</td>
<td>Resolve outages more quickly</td>
</tr>
<tr>
<td>6.7</td>
<td>Improve billing timeliness</td>
</tr>
<tr>
<td>6.8</td>
<td>Permit customized billing date</td>
</tr>
<tr>
<td>6.9</td>
<td>Lower customer bills</td>
</tr>
<tr>
<td>6.10</td>
<td>Customer feels more control</td>
</tr>
<tr>
<td>6.11</td>
<td>Add billing option</td>
</tr>
<tr>
<td>6.12</td>
<td>Add rate option</td>
</tr>
<tr>
<td>6.13</td>
<td>Customer is more aware of service</td>
</tr>
<tr>
<td>6.14</td>
<td>Customer has more choices</td>
</tr>
<tr>
<td>6.15</td>
<td>Customer power quality is improved and stabilized</td>
</tr>
<tr>
<td>6.16</td>
<td>Improved billing data presentation</td>
</tr>
</tbody>
</table>

## Efficient Use of Energy and Water Supplies

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>7.1</td>
<td>Improve monitoring of waste water pump capacity</td>
</tr>
<tr>
<td>7.2</td>
<td>Improve monitoring/mitigation of water lifting systems during emergency situations High</td>
</tr>
<tr>
<td>7.3</td>
<td>Decrease operating cost of water supply pumping systems / Shift water lifting load to off-peak time</td>
</tr>
<tr>
<td></td>
<td>Description</td>
</tr>
<tr>
<td>---</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>7.4</td>
<td>Increase reliability of system during peak</td>
</tr>
<tr>
<td>7.5</td>
<td>Optimize water pumping load schedule</td>
</tr>
<tr>
<td>7.6</td>
<td>Optimize time/use back-up generation</td>
</tr>
<tr>
<td>7.7</td>
<td>Monitor demand/load to better understand need for back-up</td>
</tr>
</tbody>
</table>
Appendix D  Smart Grid Functional Requirements

Smart Grid consists of a collection of functionality that supports the Strategic Goals and Objectives set forth by the City of Palo Alto Utilities stakeholders. This involves actions that personnel, systems and equipment can perform to achieve a goal or end result. Use cases are utilized to support the development of Smart Grid functional and system requirements based on detailed working sessions with utility stakeholders. A list of applicable industry developed use cases is listed in Appendix A. A list of Smart Grid functions that an Advanced Metering Infrastructure System (AMI) and Advanced Distribution and Demand Response should provide has been compiled. Groupings of these functional requirements will become information and communication components of the necessary Smart Grid Elements.
## Smart Grid Functional Requirements

The AMI system permits the utility to remotely read meter data in intervals so that customers may be billed on their time of use, and demand can therefore be shifted from peak periods to off-peak periods, improving energy efficiency.

<table>
<thead>
<tr>
<th>TOU</th>
<th>Interval Metering and Reporting</th>
<th>The AMI system permits customers’ electrical service to be remotely connected or disconnected for a variety of reasons, eliminating the need for utility personnel to visit the customer premises.</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMR1</td>
<td>Read data remotely</td>
<td>A client (e.g. the MDMS) can read data from meters remotely</td>
</tr>
<tr>
<td>IMR2</td>
<td>Record interval data</td>
<td>Meters record data in configurable intervals.</td>
</tr>
<tr>
<td>IMR3</td>
<td>Can remotely set</td>
<td>A client (e.g. the MDMS or DR controller) can adjust how often a set of meters records or reports time-of-use data</td>
</tr>
<tr>
<td>IMR3.1</td>
<td>Can remotely set</td>
<td>A client (e.g. the MDMS or DR controller) can remotely adjust how often a set of meters stores data</td>
</tr>
<tr>
<td>IMR3.2</td>
<td>Can remotely set</td>
<td>A client (e.g. the MDMS or DR controller) can remotely adjust how often a set of meters transmits data</td>
</tr>
<tr>
<td>IMR4</td>
<td>Read data remotely</td>
<td>A client (e.g. Customer Service) can read an individual meter or set of meters</td>
</tr>
<tr>
<td>IMR5</td>
<td>Record interval data</td>
<td>Field personnel can read the meter electronically from the customer premises</td>
</tr>
<tr>
<td>IMR6</td>
<td>Meter reports data without prompting</td>
<td>Meters can report data, logs and events without being requested to do so</td>
</tr>
<tr>
<td>RCD</td>
<td>Remote Connect/Disconnect</td>
<td>The AMI system permits customers’ electrical service to be remotely connected or disconnected for a variety of reasons, eliminating the need for utility personnel to visit the customer premises.</td>
</tr>
<tr>
<td>RCD1</td>
<td>Remote Connect/Disconnect</td>
<td>On request</td>
</tr>
<tr>
<td>------</td>
<td>--------------------------</td>
<td>------------</td>
</tr>
<tr>
<td>RCD2</td>
<td>Remote Connect/Disconnect</td>
<td>On no-pay</td>
</tr>
<tr>
<td>RCD3</td>
<td>Remote Connect/Disconnect</td>
<td>On zero prepayment balance</td>
</tr>
<tr>
<td>RCD4</td>
<td>Remote Connect/Disconnect</td>
<td>At a scheduled time</td>
</tr>
<tr>
<td>RCD5</td>
<td>Remote Connect/Disconnect</td>
<td>By field person at premises</td>
</tr>
<tr>
<td>RCD6</td>
<td>Remote Connect/Disconnect</td>
<td>If unauthorized distributed generation is detected</td>
</tr>
<tr>
<td>RCD7</td>
<td>Remote Connect/Disconnect</td>
<td>On outage (to isolate generation)</td>
</tr>
<tr>
<td>RCD8</td>
<td>Remote Connect/Disconnect</td>
<td>On demand response</td>
</tr>
<tr>
<td>RCD8.1</td>
<td>Remote Connect/Disconnect</td>
<td>On demand response</td>
</tr>
<tr>
<td>RCD8.2</td>
<td>Remote Connect/Disconnect</td>
<td>On demand response</td>
</tr>
<tr>
<td>RCD9</td>
<td>Remote Connect/Disconnect</td>
<td>Automatically attempts reconnect</td>
</tr>
</tbody>
</table>
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Customers can view a variety of information being gathered by their meter, permitting them to make energy-efficient choices and to shift demand to off-peak periods. Customers may access this information through a variety of methods. Functions in this category represent a matrix of the type of information and the ways in which it may be reported to the customer.

<table>
<thead>
<tr>
<th>CAI</th>
<th>Customer Access to Information</th>
<th>reconnects may be specified.</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAI1</td>
<td>Customer Access to Information</td>
<td>Customers can view their energy usage</td>
</tr>
<tr>
<td>CAI1.1</td>
<td>Customer Access to Information</td>
<td>Customers can view whether the meter is connected to the AMI or home networks</td>
</tr>
<tr>
<td>CAI1.2</td>
<td>Customer Access to Information</td>
<td>Customers can view their demand</td>
</tr>
<tr>
<td>CAI1.3</td>
<td>Customer Access to Information</td>
<td>Customers can view their peak demand</td>
</tr>
<tr>
<td>CAI1.4</td>
<td>Customer Access to Information</td>
<td>Customers can view an estimate of the cost of their energy usage (with disclaimers)</td>
</tr>
<tr>
<td>CAI1.5</td>
<td>Customer Access to Information</td>
<td>Customers can view an estimate of their current rate (with disclaimers)</td>
</tr>
<tr>
<td>CAI1.6</td>
<td>Customer Access to Information</td>
<td>Customers can connect equipment to the meter capable of reading pulse data to judge energy (e.g. building management systems, HVAC)</td>
</tr>
<tr>
<td>CAI1.7</td>
<td>Customer Access to Information</td>
<td>Customers can view the time of day at the meter</td>
</tr>
<tr>
<td>CAI1.8</td>
<td>Customer Access to Information</td>
<td>Customers can know when there are outages in their area</td>
</tr>
<tr>
<td>CAI1.9</td>
<td>Customer Access to Information</td>
<td>Customers can view information messages sent by the utility</td>
</tr>
<tr>
<td>-------</td>
<td>--------------------------------</td>
<td>---------------------------------------------------------</td>
</tr>
<tr>
<td>CAI2</td>
<td>Customer Access to Information</td>
<td></td>
</tr>
<tr>
<td>CAI2.1</td>
<td>Customer Access to Information</td>
<td>Customers can view measurements of the service at their site.</td>
</tr>
<tr>
<td>CAI2.2</td>
<td>Customer Access to Information</td>
<td>Customers can view whether their electrical service has been purposely disconnected</td>
</tr>
<tr>
<td>CAI2.3</td>
<td>Customer Access to Information</td>
<td>Customers can view whether a demand response event is underway.</td>
</tr>
<tr>
<td>CAI2.4</td>
<td>Customer Access to Information</td>
<td>Customers can view their prepayment balance and an estimate of the time remaining before their balance is zero.</td>
</tr>
<tr>
<td>CAI3</td>
<td>Customer Access to Information</td>
<td></td>
</tr>
<tr>
<td>CAI3.1</td>
<td>Customer Access to Information</td>
<td>Customers can access their information on their monthly bill.</td>
</tr>
<tr>
<td>CAI3.2</td>
<td>Customer Access to Information</td>
<td>Customers can access their information the day after the measurements are taken.</td>
</tr>
<tr>
<td>CAI3.3</td>
<td>Customer Access to Information</td>
<td>Customers can access their information the interval after the measurements are taken.</td>
</tr>
<tr>
<td>CAI3.4</td>
<td>Customer Access to Information</td>
<td>Customers can access their information when they contact customer service</td>
</tr>
<tr>
<td>CAI4</td>
<td>Customer Access to Information</td>
<td></td>
</tr>
<tr>
<td>CAI4.1</td>
<td>Customer Access to Information</td>
<td>Customers can access their information on the meter display</td>
</tr>
</tbody>
</table>

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### CAI4.2 Customer Access to Information
Customers can access their information on their own display on the premises.

### CAI4.3 Customer Access to Information
Customers can access their information from the web site.

### CAI4.4 Customer Access to Information
Customers can access their information by contacting customer service.

### CAI4.5 Customer Access to Information
Customers can access their information from other mechanisms, such as cell phones.

### CAI5 Customer Access to Information
Remotely change display format

#### CAI5.1 Customer Access to Information
Remotely change display format
Customer service can change the information displayed on the meter.

#### CAI5.2 Customer Access to Information
Remotely change display format
Customer Service can change the information displayed on the customer's in-home display.

### DR Demand Response
The utility can notify customers through the AMI system that demand reduction is requested for the purposes of either improving grid reliability, performing economic dispatch (energy trading), or deferring buying energy. There are many different options for demand response programs, so a utility may select several complete sets of functions from this category.

#### DR01 Demand Response
The Grid Control Center can initiate demand response events to reduce peak demand for the purpose of improving reliability and addressing emergencies.

#### DR01.1 Demand Response
The Market Operations group can initiate demand response events to either bid into markets for revenue enhancement/

#### DR01.2 Demand Response
The Market Operations group can initiate demand response events to prevent the need to buy energy at higher costs.

#### DR01.3 Demand Response
<table>
<thead>
<tr>
<th>DR02</th>
<th>Demand Response</th>
<th>Enrollment</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DR02.1</td>
<td>Demand Response</td>
<td>Enrollment</td>
<td>Customers must enroll in the demand response program.</td>
</tr>
<tr>
<td>DR02.2</td>
<td>Demand Response</td>
<td>Enrollment</td>
<td>All customers participate in the demand response program.</td>
</tr>
<tr>
<td>DR02.3</td>
<td>Demand Response</td>
<td>Enrollment</td>
<td>Customers participate in the demand response program by default but may choose to opt out of the program permanently (as opposed to overriding particular events).</td>
</tr>
<tr>
<td>DR03</td>
<td>Demand Response</td>
<td>Override</td>
<td></td>
</tr>
<tr>
<td>DR03.1</td>
<td>Demand Response</td>
<td>Override</td>
<td>Customers can choose not to participate in a demand response event.</td>
</tr>
<tr>
<td>DR03.2</td>
<td>Demand Response</td>
<td>Override</td>
<td>Customers must participate in all demand response events of this type.</td>
</tr>
<tr>
<td>DR04</td>
<td>Demand Response</td>
<td>Signal</td>
<td></td>
</tr>
<tr>
<td>DR04.1</td>
<td>Demand Response</td>
<td>Signal</td>
<td>The Demand Response Controller signals a specific energy price that will be in effect during the demand response event.</td>
</tr>
<tr>
<td>DR04.2</td>
<td>Demand Response</td>
<td>Signal</td>
<td>The Demand Response Controller signals a change in energy price that will be applied during the demand response event.</td>
</tr>
<tr>
<td>DR04.3</td>
<td>Demand Response</td>
<td>Signal</td>
<td>The Demand Response Controller signals the requirement for demand reduction to take effect now, without any further specification.</td>
</tr>
<tr>
<td>DR04.4</td>
<td>Demand Response</td>
<td>Signal</td>
<td>The Demand Response Controller signals that demand is to be reduced to a particular limit during the demand response event.</td>
</tr>
<tr>
<td>DR05</td>
<td>Demand Response</td>
<td>Incentive</td>
<td></td>
</tr>
<tr>
<td>DR05.1</td>
<td>Demand Response</td>
<td>Incentive</td>
<td>The utility pays customers to participate in the demand response program.</td>
</tr>
<tr>
<td>DR05.2</td>
<td>Demand Response</td>
<td>Incentive</td>
<td>The utility charges customers a penalty if they do not participate in the demand response program.</td>
</tr>
<tr>
<td>DR05.3</td>
<td>Demand Response</td>
<td>Incentive</td>
<td>The utility encourages customers to participate in demand response programs by providing a better energy price than they would otherwise pay.</td>
</tr>
<tr>
<td>DR05.4</td>
<td>Demand Response</td>
<td>Incentive</td>
<td>The utility encourages customers to participate in demand response programs through public education campaigns.</td>
</tr>
<tr>
<td>DR06</td>
<td>Demand Response</td>
<td>Mechanism</td>
<td></td>
</tr>
<tr>
<td>DR06.1</td>
<td>Demand Response</td>
<td>Mechanism</td>
<td>The Demand Response Controller reduces demand by disconnecting customers’ service using the remote disconnect on the meter.</td>
</tr>
<tr>
<td>DR06.2</td>
<td>Demand Response</td>
<td>Mechanism</td>
<td>The Demand Response Controller reduces demand by adjusting equipment on the customer premises, such as a thermostat, air conditioner, or pool pump, through a home communications network.</td>
</tr>
<tr>
<td>DR06.3</td>
<td>Demand Response</td>
<td>Mechanism</td>
<td>The Demand Response Controller reduces demand by informing a customer building management system, which takes corrective action.</td>
</tr>
<tr>
<td>DR06.4</td>
<td>Demand Response</td>
<td>Mechanism</td>
<td>The Demand Response Controller reduces demand by adjusting equipment on the customer premises, such as a thermostat, air conditioner, or pool pump, through direct input/output connections.</td>
</tr>
<tr>
<td>DR07</td>
<td>Demand Response</td>
<td>Customer Classes</td>
<td></td>
</tr>
<tr>
<td>DR07.1</td>
<td>Demand Response</td>
<td>Customer Classes</td>
<td>The demand response program applies to residential customers.</td>
</tr>
<tr>
<td>DR07.2</td>
<td>Demand Response</td>
<td>Customer Classes</td>
<td>The demand response program applies to commercial customers.</td>
</tr>
<tr>
<td>DR07.3</td>
<td>Demand Response</td>
<td>Customer Classes</td>
<td>The demand response program applies to industrial customers.</td>
</tr>
<tr>
<td>DR07.4</td>
<td>Demand Response</td>
<td>Customer Classes</td>
<td>The demand response program applies to types of customers other than residential, commercial, or industrial.</td>
</tr>
<tr>
<td>DR08</td>
<td>Demand Response</td>
<td>Notification to Customer via</td>
<td></td>
</tr>
<tr>
<td>DR08.1</td>
<td>Demand Response</td>
<td>Notification to Customer via</td>
<td>The Demand Response Controller notifies customers that an event is progress through</td>
</tr>
<tr>
<td>Code</td>
<td>Category</td>
<td>Description</td>
<td></td>
</tr>
<tr>
<td>--------</td>
<td>---------------------------</td>
<td>----------------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>DR08.2</td>
<td>Demand Response</td>
<td>The Demand Response Controller notifies customers that an event is progress through the display on the customer premises.</td>
<td></td>
</tr>
<tr>
<td>DR08.3</td>
<td>Demand Response</td>
<td>The Demand Response Controller notifies customers that an event is progress via telephone or pager.</td>
<td></td>
</tr>
<tr>
<td>DR08.4</td>
<td>Demand Response</td>
<td>The Demand Response Controller notifies customers that an event is progress via the utility web site or email.</td>
<td></td>
</tr>
<tr>
<td>DR09</td>
<td>Demand Response Customer Selection</td>
<td>The Demand Response Controller permits groups of customers to be selected for demand response.</td>
<td></td>
</tr>
<tr>
<td>DR09.1</td>
<td>Demand Response Customer Selection</td>
<td>The Demand Response Controller permits groups of customers to be selected for demand response by the substation they are connected to.</td>
<td></td>
</tr>
<tr>
<td>DR09.2</td>
<td>Demand Response Customer Selection</td>
<td>The Demand Response Controller permits groups of customers to be selected for demand response by the feeder they are connected to.</td>
<td></td>
</tr>
<tr>
<td>DR09.3</td>
<td>Demand Response Customer Selection</td>
<td>The Demand Response Controller permits groups of customers to be selected for demand response arbitrarily, with no restriction on who can be in a group.</td>
<td></td>
</tr>
<tr>
<td>DR10</td>
<td>Demand Response Advance Notice</td>
<td>The Demand Response Controller notifies the selected meters of the upcoming demand response event a day before the event will occur.</td>
<td></td>
</tr>
<tr>
<td>DR10.1</td>
<td>Demand Response Advance Notice</td>
<td>The Demand Response Controller notifies the selected meters of the upcoming demand response event an hour before the event will occur.</td>
<td></td>
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<tr>
<td>DR10.2</td>
<td>Demand Response Advance Notice</td>
<td>The Demand Response Controller notifies the selected meters of an upcoming demand response event only when the event starts.</td>
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<tr>
<td>DR11</td>
<td>Demand Response Compliance Feedback</td>
<td>The utility needs to know by the next day which customers participated in demand response.</td>
<td></td>
</tr>
<tr>
<td>Description</td>
<td>Type</td>
<td>Feedback</td>
<td>Description</td>
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<tr>
<td>DR11.2</td>
<td>Demand Response</td>
<td>Compliance Feedback</td>
<td>The utility needs to know the same day which customers participated in demand response.</td>
</tr>
<tr>
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<td>Demand Response</td>
<td>Aggregate Response Feedback</td>
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</tr>
<tr>
<td>DR12.1</td>
<td>Demand Response</td>
<td>Aggregate Response Feedback</td>
<td>Clients of the AMI system (e.g. Market Operations) require precise information about how much demand response was achieved from a given resource in a short period of time (minutes)</td>
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<tr>
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<td>Demand Response</td>
<td>Multiple Events</td>
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<tr>
<td>DR13.1</td>
<td>Demand Response</td>
<td>Multiple Events</td>
<td>Several demand response events can be underway at a time for a particular meter.</td>
</tr>
<tr>
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<tr>
<td>DR14</td>
<td>Demand Response</td>
<td>Estimation Feedback</td>
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<tr>
<td>DR14.1</td>
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<td>Estimation Feedback</td>
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<tr>
<td>DR14.2</td>
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<tr>
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### Plug-in Electric Vehicles (PEV)

PEV acts as DER and Energy Storage. PEV is enrolled in utility programs and participates in electrical wholesale markets for energy, capacity and ancillary services.

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<td>DMA07</td>
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<td>Automatic Feeder Reconfiguration – Single Level</td>
<td>Multiple distribution feeders in an area may be reconfigured and optimized, including those with tie points to one or more substations.</td>
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<tr>
<td>DMA08</td>
<td>Distribution Automation</td>
<td>Automatic Feeder Reconfiguration – Multi-Level</td>
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<tr>
<td>DMA09</td>
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<td>DMA10</td>
<td>Distribution Automation</td>
<td>Automatic Protection Reconfiguration</td>
<td>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.</td>
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<tr>
<td>DMA11</td>
<td>Distribution Automation</td>
<td>Isolation of Higher Impedance Faults</td>
<td>Sensors, control and switching devices exist that can operate autonomously in response to local system conditions.</td>
</tr>
<tr>
<td>DMA12</td>
<td>Distribution Automation</td>
<td>Automatic Switching – Local</td>
<td>Switches will operate automatically in response to signals from a central distribution management system.</td>
</tr>
<tr>
<td>DMA13</td>
<td>Distribution Automation</td>
<td>Automatic Switching – Central</td>
<td>Distribution equipment includes sensors that can monitor its condition and report this information periodically, such as polling data to a central location.</td>
</tr>
<tr>
<td>DMA14</td>
<td>Distribution Automation</td>
<td>Automatic Condition Based Equipment Maintenance</td>
<td>Sensors exist that can detect and isolate faults without full power reclosing, which reduces equipment damage caused by repeated through-fault currents.</td>
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<tr>
<td>DMA15</td>
<td>Distribution Automation</td>
<td>Low impact fault detection</td>
<td>Portions of the distribution system, including loads and distributed energy resources, can be electrically islanded (isolated) from the rest of the utility system with the microgrid operator reconnecting to the grid when desired or needed.</td>
</tr>
<tr>
<td>DG</td>
<td>Distributed Generation</td>
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<td></td>
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<td>DG1</td>
<td>Distributed Generation</td>
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<td>DG4</td>
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</tr>
<tr>
<td>DG5</td>
<td>Distributed Generation</td>
<td>Dispatch of DG by class</td>
<td></td>
</tr>
</tbody>
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The Advanced Distribution system can be used to detect, measure, regulate and dispatch distributed generation by customers.

- **DG1**: Meters can measure either energy usage or energy generation.
- **DG2**: Meters can measure multiple generation sources at a customer site.
- **DG3**: Meters can be remotely configured to report when more energy is being produced than used.
- **DG4**: The Grid Control Center can initiate distributed generation in order to reduce peak load or adjust VARs.
- **DG5**: Individual DER units are controlled in groups or classes in near-real time. Control may be accomplished by operator action or autonomously through agents that execute common control actions across multiple units.

Utility provides PV services for customer including real-time monitoring, recording, trending and performance analysis of customer PV systems.
Appendix E  Smart Grid Elements and Components

The Functional Requirements listed in the previous section Appendix D are logically grouped into Functional Components. These Functional Components cover aspects of Advanced Metering Infrastructure, Meter Data Management, Customer Information, Advanced Distribution, Work Management, and Outage Management. Detailed descriptions of the Smart Grid Elements and their components are provided below.

Metering

Metering Services

Metering services provide the basic meter reading capabilities for generating customer bills. Different types of metering services are usually provided, depending upon the type of customer (residential, smaller commercial, larger commercial, smaller industrial, larger industrial) and upon the applicable customer tariff.

Periodic Meter Reading

Traditionally for residential customers and the smaller C&I customers, periodic meter reading services are performed monthly via a meter reader, possibly using handheld or mobile meter reading tools. It takes the current index reading from the meter and records it for billing and other purposes. For Time-of-Use (TOU) data from net metering or other TOU meters, intervals can be established such as “on-peak” and “off-peak”, as defined in the utility’s tariffs. In some utilities or under certain circumstances, actual meter reading is done less frequently, and bills rely on meter reading estimates which are “trued up” later.

In AMI systems, periodic meter reading will retrieve interval data (usually hourly data but possibly 15-minute or 5-minute data). The frequency of retrieving the data from the meter can vary from every 5 minutes, to hourly, to daily, and to monthly.
Among the benefits of AMI for periodic meter readings are the increased accuracy (fewer estimated reads, more exact reading dates/times), and the availability of the to-date meter readings during the billing cycle.

**On-Demand Meter Reading**

Traditionally, on-demand meter reading is performed by sending a meter reader to the meter site around the time requested for the meter reading. Typically reasons for on-demand meter readings include:

- Move in / move out
- Limited usage tariffs
- Billing questions by the customer
- Revenue protection concerns

AMI systems will permit on-demand reads to take place almost immediately or more precisely at the scheduled date and time.

**Net Metering for DER**

When customers have the ability to generate or store power as well as consume power, net metering is installed to measure not only the flow of power in each direction, but also when the net power flows occurred. Often Time of Use (TOU) tariffs are employed.

Today larger C&I customers and an increasing number of residential and smaller C&I customers have net metering installed for their photovoltaic systems, wind turbines, combined heat and power (CHP), and other DER devices. As plug-in hybrid electric vehicles (PHEVs) become available, net metering will increasingly be implemented in homes and small businesses, even parking lots.

AMI systems can facilitate the management of net metering, particularly if pricing becomes more dynamic and/or more fine-grained than currently used for TOU rates.

**Paycheck Matching**

Today, depending on the utility bills arrive monthly, quarterly or yearly and not on a schedule selected by the customer, rather they are based on a schedule that matches the meter reading schedules. Small scale trials have proven that for customers who are living on the margin and miss occasional payments, that matching the date and
frequency of the customer’s paycheck reduces the number of late or missing payments significantly, cutting collection costs and reducing the cost to all customers.

AMI systems provide the flexibility to provide customers with bills when the customers prefer to receive them.

**Revenue Protection**

*Tamper Detection*

Non-technical losses (or theft of power by another name) has long been an on-going battle between utilities and certain customers. In a traditional meter, when the meter reader arrives, they can look for visual signs of tampering, such as broken seals and meters plugged in upside down. During the analysis of the data, tampering that is not visually obvious may be detected, such as anomalous low usage.

With AMI systems, smart meters can immediately issue “tampering” alarms that are set off by a number of different sensors and routines in the meter. These tampering actions can include meter removal, tilt, and unauthorized access attempts (smart meters cannot be plugged in upside down).

*Anomalous Readings*

Some anomalous readings in the meter can trigger warning events which can be immediately investigated to determine if they are legitimate (people are on vacation or the factory has shut down an assembly line) or if they are due to tampering, such as wiring around the meter.

*Meter Status*

Some theft of power has occurred by the bypassing of the meter for a few days between scheduled readings by a meter reader. AMI systems will permit the status of meters to be verified at any time during the reading cycle.

*Suspicious Meter*

Some theft of power has occurred by the replacement of a certified meter with a “slow run” meter. AMI systems with smart meters will have each meter “registered” with an identity that cannot be tampered with without showing evidence of that tampering.
Remote Connect / Disconnect

Remote Connect for Move-In

The customer initiates a request to move into a location that has electric service but is currently disconnected at the meter. The request can be for immediate action or for a connection at a specific date and time.

Traditionally, utilities send a metering service person to connect the meter. With an AMI system, the connection can be performed remotely by closing the remote connect/disconnect (RCD) switch, using the following steps:

- At the appropriate date and time, read the meter to get the latest reading and to verify that the meter is functional.
- Determine there is no backfeed current detected by the meter
- Issue the connect command to the meter
- Verify that the meter is connected

Remote Connect for Reinstatement on Payment

Once a customer pays who was disconnected due to non-payment (or works out some mutually accepted agreements), the meter needs to be reconnected by closing the remote connect/disconnect (RCD) switch. The same process as for a move-in would be used.

Remote Disconnect for Move-Out

Traditionally, move-outs are handled by performing a special meter read (“soft” disconnect) around the time of the move-out. Since the power is not actually disconnected, this method can lead to illegal use of power after the move-out and before the next move-in.

With an AMI system, a move-out can have a “hard” disconnect that opens the RCD switch, typically using the following steps:

- Verify that the meter can be disconnected remotely
- Issue the disconnect command at the appropriate date and time
- Verify that the meter is disconnected
- Read the meter for the final billing.
In conjunction with the next meter reading during a move-in connection, any delta between the readings can be detected as a possible tampering or illegal usage of power.

**Remote Disconnect for Non-Payment**

The cost of collections is high, typically higher yet is the cost of disconnecting a customer – not only the lost revenue, but the cost of two special trips to the location, one to turn the power off and eventually another to turn it back on again. While remote disconnects are still pricy today, they offer a much lower cost for turning the power off and once customers understand that a disconnect can be done immediately, collections costs also seem to decline.

**Remote Disconnect for Emergency Load Control**

Some customers could get special rates if they agree to the temporary suspension of electric service in support emergency load shed activities. This is an alternative to wide-scale rolling blackouts and circuit level interruptions. Customers who choose to participate in such a program are eligible to have their power cut during the critical periods.

This type of selective black-out provides the means for reducing power demands on the overall grid while selectively maintaining service to critical customers such as public infrastructure (i.e. traffic lights) and medical facilities.

**Unsolicited Connect / Disconnect Event**

Unsolicited connect/disconnect events can be caused by a number of activities, covered in the following Functions:

- Meter manually switched off by utility employee, including both valid and invalid switching
- Meter manually switched off by unknown party, including both valid and invalid switching
- Software/hardware failure switches meter off/on (also includes unauthorized command causing switch)
- Miscellaneous event causes meter to switch off/on
- Meter manually switched on by utility employee, including both valid and invalid switching
Meter manually switched on by unknown party, including both valid and invalid switching

**Meter Asset Management**

**Connectivity Validation**
Determinations that the customer is connected to the grid and even with the right signally which phase and circuit they are on. In several reviews of customer connectivity today for utilities the phase information is missing from many single phase connections and in some cases the circuit information is missing or wrong. Validation helps with making sure the data analysis is correct for engineering studies and other purposes.

**Geo-Location**
In asset data bases today many meters are literally miles (kilometers) from their physical location in the real world. During the installation of the meters GPS or other geo-location techniques can be used to provide accurate information on the meter’s location. If the location of the meter accidentally is changed in the database it is possible to flag the problem. This is possible since the location of the circuit is known, helping to eliminate problems that creep in over the long life of electric (gas and water) networks.

**Battery Management**
If there were no smart meters, there would be no need to do battery management, so the benefit only works for smart meter equipped networks. In an operational world the meters communicate more, running the battery down faster. It is important to have good battery management or the cost of maintaining the system will skyrocket. Remote battery monitoring (as part of the regular communications) can help deal with battery replacement planning and battery life extension.

**Advanced Distribution**
The AMI advanced metering system will extend the utility’s sensing capabilities and communication infrastructure further down the distribution system while enabling a host of grid network optimization applications and services. This use case describes several scenarios in which the distribution network automatically reconfigures using a combination of distribution automation devices and AMI system functions, either by making use of data provided by the AMI meters or by providing better coordinated
actions through the AMI communications network itself. By moving intelligence out into the grid enabled with AMI communications, the utility can provide more predictive and targeted response actions to both optimize performance and mitigate system abnormalities and reducing outage minutes, resulting in enhanced reliability and power quality for customers. AMI enabled Advanced Distribution can potentially address many distribution network issues related to feeder loading and efficiency, voltage profiles, reliability, power quality, etc. by optimizing the coordination of switching devices and VAR resource controllers at a more localized level. Using the information that AMI can provide such as voltage and current measurements at customer sites, in addition to information provided by existing systems such as SCADA, the utility’s ability to improve the quality and efficiency of network optimization applications and services increases significantly.

**Distribution Automation (DA)**

Today’s distribution network operations are characterized by disparate, special purpose applications that are largely uncoordinated. The anticipated network optimization applications that stand to benefit from integrating AMI with Advanced Distribution include:

- Loss Analysis
- Fault Location, Isolation and Service Restoration
- Contingency Analysis
- Feeder Reconfiguration
- Load shedding and load curtailment
- Protection Re-coordination
- Voltage and VAR Control
- Pre-arming of Remedial Action Schemes
- Intelligent Alarm Processing
- Transformer voltage regulation
- Load forecasting and state estimation
- Automatic feeder and capacitor bank switching
- Power Quality Monitoring and Reporting
- Power Quality Contract Compliance
Possible AMI outputs that may serve these functions include:

- real time voltage
- real time current
- power consumption by time interval
- average voltage at customer site
- voltage variations seen by the customer
- harmonics (voltage and/or current)
- power production by customer-supplied distributed generation
- customer power factor

The business value arising from performing automated system reconfiguration with AMI data includes:

- Remote monitoring of fault indicators reduces the need to dispatch field maintenance staff, and can reduce the time to locate fault sources and resolving distribution grid issues.
- Optimizing capacitor bank switching keeps customer voltage within band and permits more distributed generation. More distributed generation in turn avoids future transmission grid investments.
- The ability to ramp off load rather than shutting down entire regions (substations, blocks, cities) improves reliability and increases customer satisfaction. It also reduces the time required to completely restore power.

These applications can be separated into two categories – on-line and off-line.

- The on-line category can be considered a classification of real-time monitoring and control. Examples of this category include intelligent alarming processing, coordinated volt/VAR control, and fault location.
- The off-line category involves evaluation of information gathered by the AMI system from a historical perspective. Applications of this type generally retrieve data from a data historian that is periodically populated with new data from the AMI system. Examples of this category include feeder optimization, load forecasting, and power quality contract compliance.

Both on-line and off-line categories of applications using AMI include two types of scenarios:

- Distribution automation devices or other types of utility equipment use the AMI network to communicate.
- Network optimization applications use data captured by AMI meters, optionally augmented by information captured by the parallel distribution automation system.
DA Equipment Monitoring and Control
Some utilities are planning to use the AMI system for distribution automation, as a minimum for direct monitoring and more sophisticated control of capacitor banks and voltage regulators on feeders, rather than relying on local actions triggered by time, current, or voltage levels. Others also would like to monitor and control automated switches and fault indicators if the AMI network were able to stay alive during grid power outages, presumably via battery backup for critical nodes.

Use of Smart Meters for Power System Information
If more sensors were available in the distribution network, it would be possible to do distribution SCADA, with the deployment of smart meters and a near real-time communications network, it is possible to pick a sub-set of the smart meters and use them as bell weather devices in the grid to provide a distribution SCADA like capability. In addition some utilities are installing smart meters in place of RTUs for extending their current SCADA system further into the grid.

Power System Security/Reliability
As interference with the operation of the distribution grid becomes more common, it becomes more and more important to monitor the integrity of the grid at all times. Smart meters offer a way to get a “heart beat” from the whole of the distribution system on a regular basis thus providing assurance that the grid is intact. That it has not been attacked by a mad man in a backhoe or a copper thief with a chainsaw.

Power System Protection
Overloads on the system once were not a big issue devices could operate at two or even three times their rated capacity for several hours on a peak day. Today devices have been engineered to run at loads much closer to their ratings, and overloads of several hours can cause degradation in the devices. By being able to monitor the load on the device and with the deployment of direct load control or disconnect switches, the load on the device can be managed until it can be replaced or upgraded, the same goes for other physical assets that may be de-rated, allowing at least some of the lights to stay on.
Site/Line Status

Tag out procedures are supposed to render a segment of the network dead and safe to work on, unfortunately with the addition of true distributed generation, it is possible to have an islanding failure and to have a line that the crew expects to be ready for work, to actually still be live. With the correct smart metering system and the right connectivity mapping, it is possible to use the smart meters to determine if any power is still flowing through the lines. With the potential for the sales of plug-in electric vehicles to ramp up quickly in the next decade and the lack of proper protection schemes this may become an even larger issue.

Automation of Emergency Response

Today in a fire, the fire department normally handles the disconnection of the power and other utilities from the involved structures. Often with a fire axe! With the advent of remote disconnects in the meters it will be possible to cut the power to the structure, as well as gas and other utilities. This makes it easier to restore service after small problems and to more rapidly remove a possible source of problems from the structure.

Dynamic Rating of Feeders

Operators can dynamically rate feeders based on the more accurate power system information retrieved via the AMI system from strategic locations. This permits the operators to decide when they can run feeders beyond their ostensible ratings or when to perform multi-level feeder reconfigurations to balance the loads and avoid overloads.

Outage Detection and Restoration

Outage Detection

Today the majority of real time information about a customer, comes from the customer, they pick up the phone and call about issues they have, such as an outage, and provide information to the utility. In the future, the smart meter will be able to provide up to date information about the customer and the status of their service.

Scheduled Outage Notification

For either scheduled outages for maintenance or for notification of a customer that the power is out in their home when they are at work or away from home, smart metering provides a needed piece. For scheduled outages, if there are in home displays deployed
the metering system can provide the outage times and durations to the customers directly impacted and no others. This minimizes possible security issues of the information getting into the wrong hands as security systems that require power stop functioning, etc. It also helps with the number of phone calls that have to be placed to customers to let them know that maintenance is happening. With the connectivity verification, it is possible to really know who is on a specific path and to accurately manage the outage. For unscheduled outages, it possible to use the information coming from the meters to let customers know that they will be returning to a location with no power (water, gas) and that will let them make alternate plans, rather than walking into a surprise.

**Street Lighting Outage Detection**

Street lighting can be critical to safety and crime-prevention, and yet monitoring which street lights are out is currently performed haphazardly by civil servants and concerned citizens. AMI systems could be used to monitor these lights.

**Outage Restoration Verification**

Restoration verification has the metering system report in as the power it returned to the meters. This alert function is built into many meters that are being deployed as smart meters today and includes a timestamp for the restoration time. For some utilities this is improving their IEEE indices, since their crews may take several minutes to complete other actions before reporting the power back on. It can also be used to help isolate nested outages and help the field crews get to the root cause of those nested outages before they leave the scene.

**Planned Outage Scheduling**

Ideally, planned outages should be done at a time when they have the least impact on the customers. Today CPAU uses a rule of thumb about when to take a planned outage, in the future with a complete data set it is possible to adjust the time of the outage to correspond with the lowest number of customers demanding power. This minimizes the impact to the customers.

**Planned Outage Restoration Verification**

In completing work orders, it is useful to know that all of the customers that were affected by the work order have power and that there are no outstanding issues that
need to be corrected, prior to the crew leaving the area. The ability to “ping” every meter in the area that was affected by the work order and determine if there are any customers who are not communicating that they have power is useful to minimize return trips to the work area to restore single customers.

**Calculation of IEEE Outage Indices**

Today the IEEE indices are manually calculated in most utilities and they are not up to date, since the information needed to track them comes from field reports and other documents that do not feed into a central location. Additionally since not every single point is tracked in any system for outages, it is impossible to accurately determine the indices. Most utilities have gotten very good at the development of indices that are very close to the reality that their customers are seeing and to the limits of the information available.

**Call Center Unloading**

Today CPAU relies on customers to call in when there is an outage; this normally is one of the factors in sizing call centers and staffing them. When smart metering is deployed in the right way, it is possible for the system to determine where the outages are and to let the utility call the customer with an outage message and an estimated time to repair. In the long run this will reduce the loading on the call center during periods of high outage levels.

**Demand Management**

**Direct Load Control**

Direct Load Control provides active control by the utility of customer appliances (e.g. cycling of air conditioner, water heaters, and pool pumps) and certain C&I customer systems (e.g. plenum pre-cooling, heat storage management). Direct load control is thus a callable and schedulable resource, and can be used in place of operational reserves in generation scheduling. Customer like it (if it is invisible), because they do not have to think about it, they sign up, allow the installation and forget it.

AMI systems will enhance the ability of utilities to include more customers in (appropriate) programs of direct load control, since it will increase the number of
appliances accessible for participation in load control, and will improve the “near-real-time” monitoring of the results of the load control actions.

**Demand Side Management**

Management of the use of energy is important in a number of ways. Demand Side Management is a step beyond just tariff based load reduction. It assumes that customer will setup or allow to be set up equipment to reduce load when signals are sent to the customer’s location. The customer is in charge of making demand side management decisions.

**Load Shift Scheduling**

Given the ability to get customers to shift load when requested, and to do bottom up simulation it becomes possible to work with customers who have the ability to shift load to different times of the day or week. This ability to do load scheduling could have an impact on transmission and other capital expenses.

**Curtailment Planning**

To do proper load reduction, for either de-rated equipment or for planned outage or even to deal with load growth that has gotten ahead of system upgrades takes having data on what the loads are and what can be curtailed. In California, load curtailment has been called rolling blackouts, the best that can be done without an ability to control the demand on the system in a more granular fashion. By using curtailment planning, notice can be given in advance to the impacted customers and they have enough time to respond if they have an option in their contract to keep the power on.

**Selective Load Management through Home Area Networks**

With the deployment of home area networks the utility can choose to manage the load on the grid, to manage peak, to manage customer bills, to allow for a generation or transmission issue to be corrected or other reasons. This can permit, with the right equipment the reduction in the need for reserve margin in generation and for rolling reserve, the selective load management becoming a virtual power plant that is a callable and schedulable asset.
Plug-in Hybrid Vehicle (PHEV) Management

Depending on how plug-in hybrids are sold and how the consumers take to them, they may either become one of the largest new uses of power or they may not have an impact. A major problem is that planners are now assuming that they will be mobile generation plants, that the drivers will burn fuel and store power in the battery to be drawn during the peak times while parked in the company garage. Others have assumed that the cars will become the largest new consumer of power in the downtown grid, an overstressed part of the grid already.

How plug-ins are managed and how consumers will use them is a social experiment. What is not is that they will draw a large amount of power from somewhere and have the potential to store a lot of power for later use. How the power company measures which car provides or takes how many megawatt hours and proves it and bills for it, will be an interesting change. Smart meters can help with this if the right standards are place to deal with communication from the car to the meter.

Power Quality Management

Power Quality Monitoring

Today for some larger customers and at select locations on the grid CPAU is able to monitor harmonics, wave form, phase angles and other power quality indicators. The need continues to grow as large screen televisions and other consumer electronics devices are increasingly adding harmonics to the system. With the newest metering technology some power quality monitoring is built into the meter and more is on the way. While not every house needs to monitor power quality, a percentage of the meters deployed should probably have this advanced capability.

Asset Load Monitoring

With Connectivity Verification and Geo-Location information it is possible to group the devices in a tree structure that correctly shows connection points in the grid. With the ability to read intervals from the meters it is then possible to build a picture of the load that each asset (e.g. transformers, conductors, etc.) are subjected to. This allows an operator to monitor heavily loaded assets and look for ways to off load some of the demand from that asset. It also allows a maintenance planner to prioritize what
maintenance should be done to maximize the reliability of the grid, as part of a reliability centered maintenance program.

**Phase Balancing**

One of the least talked about issues with losses in the distribution grid today is single phase load and the imbalance it can cause between the phases. These losses have seldom been measured in the grid and little study has been done of the amount of phase imbalance on the grid today. In early studies the chronic phase imbalance in several circuits that were monitored averaged over 10 percent. While correction is hard when the circuit is run as single phase laterals, in many cases there is enough load on the feeder portion of the circuit to allow rebalancing of the circuit to eliminate more than half of the chronic phase imbalance.

**Load Balancing**

Where there is an option to move a portion of the load from one circuit to another, the instrumentation is not always available to make good choices or to be able to forecast the load in a way that makes the movement pro-active instead of reactive. Automated feeder switches, and segmentation devices are becoming more and more common in the grid. The ability to use metering data to support the operation of these devices will only increase their value to the grid operator. Today with information only at the substation end of the circuit, it is tough to determine where on the circuit the load really is and where to position segmentation and when to activate a segmentation device when more than one is available. Operators today typically learn the right way by trial and error on the system.

**Distributed Energy Resource (DER) Management**

In the future, more and more of the resources on the grid will be connected to the distribution network and will complicate the operation of the grid for the future. Failure to integrate these resources into the grid and understand their impact will only degrade the operation of the grid and its reliability. It is no longer an option to deal with distributed resources, the time for refusing to allow them has passed. The only choice is to either embrace them and manage their impact or ignore them and suffer the consequences.
**Direct Monitoring and Control of DER**

Some DER units at customer sites could be monitored in “near-real-time” and possibly directly controlled by the utility or a third party (e.g. an aggregator) via the AMI system, in an equivalent manner to load control.

**Shut-Down or Islanding Verification for DER**

Each time an outage occurs that affect the power grid with DER, the DER should either shut down or island itself from the rest of the grid, only feeding the “microgrid” that is directly attached to. In many cases the shut-down or islanding equipment in smaller installations is poorly installed or poorly maintained. This leads to leakage of the power into the rest of the grid and potential problems for the field crews.

Each time an outage occurs, meters that are designed to monitor net power can tell if the islanding occurred correctly, if they are installed at the right point in the system. This reporting can minimize crew safety and allow the utility to let the customer know that maintenance is required on their DER system. In most cases when the islanding fails, other problems also exist that reduce the efficiency of the DER system, costing the customer the power that they expected to get from the system.

**Net and Gross DER Monitoring**

There are two different generation results from distributed generation, the gross output of the device and the net input into the grid, after the owner takes their needed energy. The two can be very different at times when the DER is creating most power the owner may also be drawing so heavily that the net result to the grid is still negative. At other times, the demand from the owner may be less than the output, even though the output may be well under the design output of the device.

Some utilities have decided to reward renewable generation owners on the gross output, while other utilities have decided to reward them on the net output, possibly with TOU rates. But to manage a utility and the reliability of the grid it is important to know both the net and the gross output of the device for simulation, load forecasting and for engineering design.
**Energy Storage Charge/Discharge Management**

If someone has installed distributed storage, when should it be topped off, and when should the storage discharge? Today’s answer is to use a timer in most cases or a phone based trigger. For one utility the use of electric thermal storage for winter heat and time of use tariffs that encouraged topping up at a specific time of the day resulted in the destruction of a number of pieces of equipment on the grid as demand exceeded the local ability to supply that demand. The attempt to improve the load factor on the grid with this storage system resulted instead with demand that exceeded all expectations.

Smart metering with a home area network capability can trigger each storage device based on the total load in the area, leveling out the peaks in the system and providing better use of generation resources that may be variable in nature.

**Supply Following Tariffs**

DER has a strong probability of having a large percentage of renewable generation which has a strong variable component. Since the supply will be variable and highly variable on short notice, it may be that to avoid either a large component of rolling reserve that uses fossil fuels, it may be that a supply following tariff could be possible. It would require a very high speed forecasting system, excellent weather information and near real time communications to devices in the homes and in businesses with almost instant response. This is a tall order in today’s world, but the cable companies have proven that millions of devices are possible to broadcast to in near real-time, so it is possible.

Smart meters on the right communications network and with the right in home gateway could provide a piece of this supply following tariff system.

**Small Fossil Source Management**

There is a large amount of diesel generation that is installed on customer sites to deal with outages on the grid. Some companies are now forming to manage these resources, not for outage, but for peak power production, bidding into the market a few megawatts at a time. While the use of these resources is a good thing, the penetration of private companies will never be as complete as if the utility were to work with their customers to equip most of this generation with controls and monitoring equipment.
Whether the utility operates and maintains these resources or allows third parties to take responsibility is not important. What is important is that smart metering can reduce the cost and complexity of making these resources available. In California more than 2,000 Megawatts of generation are already installed, more than enough to end most rolling blackouts (if the resources are in the right areas).

**Engineering**

*Right-of-Way Management*

Momentary outages normally increase as vegetation grows back in an area and starts to become potential issue for overhead lines. Smart metering allows the return of momentary outage information and allows the outage counts to be overlaid on a GIS system. This allows the planners to better target vegetation management people to the right locations. In the underground world, cable failures and splice failures can be found early, prior to a complete failure.

*Local Load Forecasting*

Given the ability to draw a full data set from the field, it is now possible to forecast local loads and generation that can be used to prepare for and to set prices for both demand and supply.

*Simulations of Responses to Pricing and Direct Control Actions*

As more detailed information is available through AMI systems on regional and local loads and generation, it will be possible to assess the responses of both customers and the power system to price-related actions as well as direct control actions. This ability to simulate the market a day or more in advance should allow for better planning and for the system to run with smaller amounts of rolling reserve and ancillary services.

*Asset Load Analysis*

With the ability to have a real load history on a specific asset and to be able to do bottom up forecasting, the same can be done for assets in the connection tree. This should allow planners and others to see potential problem areas before they really exist.

*Design Standards*

Many of today’s standards assume that complete data is not available so there are factors of safety built into the calculations at each step of the design process for the
transmission and distribution grid to make sure that the design is useful for its full design life. The improvement in load and demand data from the smart meters will make it possible to remove many of the rules of thumb and design to the real needs of the customers.

**Maintenance Standards**

Maintenance is done with incomplete information. So the maintenance standards allow for this, in some cases too much maintenance is done and sometimes too little is done, standards call for the best possible maintenance planning that incomplete information can provide. The good news is that the reliability of the system is very high, better than any other service (including telecommunications and cable TV) that is available to a customer. The bad news is with all the retirements in the industry, the experienced technicians that are required to make the judgment calls in the field will all be replaced in a few years. Improving the standards for maintenance with better information will mean that the new field workers will be routed to the highest priority work almost every time.

**Rebuild Cycle**

When is the right time to rebuild a circuit and how much of it really needs to be upgraded? Today with the information at, CPAU hangs some recorders and uses a few weeks or months of data from a few locations to determine what to rebuild. With improved data sets and the improved standards it is possible to actually determine the sections of the grid to rebuild and how much to reinforce them.

**Replacement Planning**

Equipment replacement is based on the estimated load or a load study that is normally conducted with less than perfect information. This has resulted in the engineering team being conservative and over sizing many of the replacement equipment. Smart metering offers better information to make better sizing decisions.

**Work Management**

**Work Dispatch Improvement**

Today CPAU uses manufacturers’ recommendations, models, estimates, and visual inspection to determine when a lot of maintenance work should be done. While it
works, in some utilities it means more maintenance than others think is required and in others it means less. In almost every case, some maintenance is performed that is not really required for reliability centered maintenance strategies. When smart metering information is available and used to do asset loading analysis and other data analysis, work can be more accurately dispatched to the crews in the field improving reliability in the system for the same number of jobs completed.

Order Completion Automation
Some utilities have the field crew log the completion of their job prior to packing up; others want the crew ready to roll prior to completion of the order. Some want the crews to look around before leaving, some want the crew to leave and let the customers call if there is still an issue in the area. With smart metering, as restoration alerts come in, it is possible to automate the time the job was completed and some of the closing paperwork, allowing the crew to stay in the field longer each day and to do less paperwork overall.

Field Worker Data Access
Today if a line worker wants to know the status of an area of the grid, she can measure power flow, she can look at meters or he can call dispatch. Access to near real time information on the status of the customers close to the worker’s location is limited today. With the deployment of smart metering, depending on how the software is configured and the security setup, it may be possible for a field worker to get access to the a near real-time map of the status of the customers in their working area, minimizing the need for dispatch to tell the worker where to go next and what to do.

With experience, field workers have proven to be very good at determining where in their work area a likely root cause is, based on outage information, reducing the time it takes to find the cause and start the repair work.

Reliability Centered Maintenance (RCM) Planning
Today CPAU guesses at the loading on devices using models, and uses that information to develop a reliability centered maintenance plan. Based on that information CPAU does its best to perform the maintenance that the system requires to make sure that
people have power. With the ability to do load monitoring and load forecasting more accurately, preseason maintenance can be scheduled based on the facts that the system generates. While it will never prevent all failures in the system, use of this information and a well designed RCM plan can result in significantly less outage for non-natural disaster causes.

**Enhanced Customer Experience / Customer Services**

*Remote Issue Validation*

When a customer calls today with a problem, other than twenty questions on the phone or rolling a truck to the location, there is no way to understand if the customer really knows what the problem is or if they do not understand the problem. Use of near real time information from smart meters can allow the customer service representative (CSR) to provide better information to the customer and to provide better advice on what to do with the current situation. It can also reduce the dispatch of trucks for customer complaints. In general it reduces both call volume and call handling times.

*Customer Dispute Management*

The most frequent customer dispute is a high bill. They complain about the meter reading being wrong. In truth there are enough meter reading errors that high bills are a fact of life. But the ability to check the current meter reading directly from the meter while the customer is on the phone and re-calculate the bill if the bill was high, and to end the post call investigation, by being able to directly validate the customer dispute reduces the time to clear a complaint that is non-phone time and it reduces the call handling time of the life of the dispute. It is not unusual that the initial call time goes up, since the CSR has to explain how they are getting the information and may have to have the customer walk to the meter while on the phone and verify the numbers that show on the meter. This has reduced monthly disputes with chronic callers over a period of 3 to 6 months in most utilities that have this ability.

*Outbound Customer Issue Notification*

Not only can customers be called at work for problems with outage, but other problems can be determined and customers notified, in one case, a meter looked like it had been tampered with, but the customer had a complaint about low voltage on file. A review of the situation determined that one of the wires was probably loose in the customer’s
breaker panel. That call resulted in the customer hiring an electrician and fixing a number of electrical problems in their home that the electrician uncovered while fixing the loose wire in the panel. This is one example of a number of proactive actions that can be taken with the customer to help them be safe and know what is going on with their energy consumption. Similar work was undertaken on behalf of a water company and a number of beyond the meter leaks were identified with night time readings on homes with high water bill complaints.

**Customer Energy Advisory**

Some utilities have undertaken to provide a customer energy consumption advisory that allowed customers to indicate what they have for energy consuming devices and information about their home. In return, the utilities rank their consumption against similar homes and provide feedback on the equipment and appliances that were consuming significant energy.

This advisory can even suggest what should be replaced and the payback period on the replacement, based on energy usage. The comparison allows customers to see how they did against similar customers and where they ranked in energy consumption. This has been very useful in getting customers to pay more attention to their consumption.

**Customer Price Display**

To make a realistic decision about using or not using energy and water, customers need to know how much it will cost. As we have seen with gasoline the global consumption decreased very little (in reality only the projection of growth in consumption declined, not the actual usage) when the price tripled at the pump in many countries. Electricity, gas and water today are in the noise of running a household for most families and for many the cost does not enter the top five costs for the household. To this end, making a decision to consume energy and water is easy.

For a most businesses and a small percentage of residential customers this is not true and they have strong motivation to conserve power. With critical peak pricing or time of use pricing and rising prices for energy and water, the percentage of the average family income consumed by these utilities will no longer be noise and having information about pricing, will drive some conservation. Expect that customers will need to know the price to wash a load of clothes, not the price of a kilowatt hour.
Tariffs and Pricing Schemes

Tariff Design

Today a sample of the customers is used to determine what the customer profile should be and how that profile should be priced. In many cases the classification of the customers is very broad and does not really take into account the different ways that customers actually consume power.

For example, a young educated single male living in an apartment may have a lower usage than the young family across the hallway and they may both pay the same per kilowatt-hour of power.

However, the young male many actually cost the utility more to serve, since the load factor for that single male may be much lower than the load factor for the young family. By being able to provide accurate data, better tariffs can be designed and better segmentation done to support a fair power price.

Rate Case Support

Today to get almost any change in what can be charged to the customers or what is placed in the rate base, it requires a rate case. In some rate cases the documents filed fill rooms and rooms in a building, mostly because the issues can be handled in a black and white manner. Experts are required to testify on many aspects of the rate case using data from other locations, since the complete data set to answer the question does not exist at the utility. While experts will not go away, and there will still be a lot of estimating, it is important to realize that smart meters provide a large data set to assist with the rate cases.

Tariff Assessments

Do critical peak tariffs create the response expected, does it do it for all segments of customers, and does it impact some customer segments more harshly than others. Use of smart meter data allows a better review of how the customers are responding to the tariffs and how to re-work them to better fit the needs of the society.

Cross Subsidization

An issue that is raised over and over again is cross subsidization of customers, one group of customers paying part of the cost of another group of customers. By having
complete data on each and every customer, subsidization arguments no longer fall on “I think” arguments, but fall into the “I know” allowing the decision makers to only have intended subsidies.

*Customer Segmentation*

Customer segmentation has traditionally been done by industry or by segment or by customer type, not by the actual needs or profile of the customers. Regulators have never had enough data to make segmentation decisions that really classify customers together by the way they consume power and their needs for power quality or their creation of power quality issues that the utility needs to fix. Smart metering can provide the data to make meaningful segmentation decisions.

*Customer Education*

Customers today call the call center and receive bills. They have little interaction with their utilities, less than 40% of the customer base interacts with the utility annually. The majority of the call volume is related to outage or other power quality issues. The second highest interaction reason is billing issues. If the industry is to be successful in changing people’s habits and helping to reduce consumption, then there will need to be more interaction with customers, some on billing issues, some on power quality, but more on the way they consume power and what they have for appliances.

AMI systems will provide a means of interacting more with the customer, but only if the customer understands the capabilities – as well as being assured that AMI systems are not “Big Brother” watching over them.

*Dynamic Pricing and Demand Response*

Dynamic Pricing and Demand response is a general capability that could be implemented in many different ways. The primary focus is to provide the customer with pricing information for current or future time periods so they may respond by modifying their demand. This may entail just decreasing load or may involve shifting load by increasing demand during lower priced time periods so that they can decrease demand during higher priced time periods. The pricing periods may be real-time based
or may be tariff-based, while the prices may also be operationally-based or fixed or some combination. As noted below, real-time pricing inherently requires computer-based responses, while the fixed time-of-use pricing may be manually handled once the customer is aware of the time periods and the pricing.

Sub functions for demand response, which may or may not involve the AMI system directly, could include:

- Enroll Customer
- Enroll in Program
- Enroll Device
- Update Firmware in HAN Device
- Send Pricing to device
- Initiate Load Shedding event
- Charge/Discharge PHEV – storage device
- Commission HAN device
- HAN Network attachment verification (e.g. which device belongs to which HAN)
- Third Party enroll customer in program (similar to, but not the same as the customer enrolling directly)
- Customer self-enrollment
- Manage in home DG (e.g. Micro-Combined Heat and Power)
- Enroll building network (C&I – e.g. Modbus)
- Decommission device
- Update security keys
- Validate device
- Test operational status of device

**Real Time Pricing (RTP)**

Use of real time pricing for electricity is common for very large customers affording them an ability to determine when to use power and minimize the costs of energy for their, one aluminum company cut the cost of power by more than 70% with real time pricing and flexible scheduling. The extension of real time pricing to smaller customers and even residential customers is possible with smart metering and in home displays. Most residential customers will probably decline to participate individually because of the complexity of managing power consumption, but may be quite willing to participate if they are part of a community whose power usage is managed by an aggregator or energy service provider.

**Time of Use (TOU) Pricing**

Time of use pricing creates blocks of time and seasonal differences that allow smaller customers with less time to manage power consumption to gain some of the benefits of
real time pricing. This is the favored regulatory method in most of the world for dealing with global warming.

Although Real Time Pricing is more flexible than Time of Use, it is likely that TOU will still provide many customers with all of the benefits that they can profitably use or manage.

**Critical Peak Pricing**

Critical Peak Pricing builds on Time of Use Pricing by selecting a small number of days each year where the electric delivery system will be heavily stressed and increasing the peak (and sometime shoulder peak) prices by up to 10 times the normal peak price. This is intended to reduce the stress on the system during these days.

California is the largest proponent of this tariff program at this time. Most of the California utilities would prefer an incentive program instead to encourage the same behavior. There is some question as to whether retailers in unregulated markets would have to pass thru the Critical Peak Pricing to customers or if they could offer a flat price and hedge the risk of the critical peak pricing.

**Peak Time Rebate**

An alternative to Critical Peak Pricing (CPP) is the application of Peak Time Rebate (PTR). The customer is provided an incentive based on their ability to reduce demand during times when market prices for electricity are extremely high. This reduction is measured against the customer’s baseline over the previous days. The measured reduction from the computed baseline during a Demand Response event is used to calculate a rebate that the customer earns per each kW of peak reduction during the demand response event. This incentive is provided to only those customers who enroll in a PTR program and actively participate. This avoids having to implement a CPP program along with calculating and posting CPP pricing to all customers. Typical PTR incentive runs from $0.75 - $1.25 / kW reduction per hour per event.
**Water and Gas Functions**

**Gas and Water Metering**

Interval metering can be provided to gas and water users. For high usage customers this can be used to determine usage profiles for customers to review and adjust business processes or improve efficiency and reduce consumption.

**Leak Detection**

In the world of gas and water, non-revenue water and leaking gas pipes are important to track down. In the water industry, use of pressure transducers on smart meters has proven useful when doing minimum night flows to find unexpected pressure drops in the system. Normally the need is one pressure transducer meter per 500 to 1000 customers in an urban environment.

**Water Meter Flood Prevention**

With a disconnect in the water meter, it is possible if there is a sudden increase in flow and a drop in pressure that is sustained and unusual, that the disconnect can be activated and prevent flooding. Much work will have to be done in the control software algorithms to make this a useful benefit and not one the shuts off the water when the sprinkler system and the shower are both running.

**Gas Leak Isolation**

Similar to flood prevention, again the software needs to get much better or their needs to be a gas leak sensor in the structure that communicates with the meter.

**Pressure Management**

If there is a home area network, then shut off devices or throttling devices can be attached to specific water taps and the gas meter can communicate to thermostats and water heater controls to manage the rate of consumption in the location and help with pressure management on critical days.

**External Party Information**

**Customer Access to Data through Third Party Providers**

Customers should be provided with the ability to release their consumption usage information to third parties of the customer choosing.
Customer Data Rights Issues

Customer privacy data rights must align with state and federal laws and policies. Third Party access must comply with all statutes and maintain rigorous access policies related to this data.

Security

Securability

Utility must protect the system against a wide variety of emerging cyber security threats. The design of security must cover the following aspects:

- Securability - is similar to manageability in the way it affects the solution. Securability includes the following features:
  - Authentication - is the establishment of the validity of the originator (system process or user) of a transmission or message.
  - Authorization - is the verification of a system process or individual user’s right to access specific system resources.
  - Accounting – is the monitoring, logging and alerting of system events and user of process transactions.
  - Confidentiality - is the assurance that information is not disclosed to unauthorized persons, processes, or devices.
  - Data Integrity - is the assurance that data is unchanged from its source and has not been accidentally or maliciously modified, altered, or destroyed.
  - Non-repudiation - is the assurance that the sender of data is provided with proof of delivery and that the recipient is provided with proof of the sender’s identity, so neither can later deny having processed the data.
  - Availability - is the assurance that allowing the sharing of information will not create situations in which authorized users are denied service.

The mission critical functions of the Smart Grid demand a dependable security solution. Not only is it essential to protect privacy of consumer’s usage data, but it is even more critical to ensure that malicious organizations or individuals are not able to access security vulnerabilities that allow them to issue commands that impact the operational network. Addressing these vulnerabilities is covered under ongoing efforts at NIST and NERC. Given that the grid communications network consists of multiple
interlinked technologies, end-to-end encryption and application-layer security must be considered. This ensures integrity regardless of any individual weak or misconfigured links along the communication path. NIST supported Smart Grid Interoperability Program has produced a reference document Guidelines for Smart Grid Cyber Security, NIST Information Report IR-7628, August 2010, that provides recommended cyber security strategies, methods, practices and technologies for the utility industry to adopt. These guidelines cover:

- Smart Grid Cyber Security Strategy
- Security Architecture and Security Requirements
- Supportive Analyses and References

**NERC CIP**

The utility must implement and be prepared to implement all FERC mandated cyber security standards that NERC develops and regulates. The current physical and cyber security standards are covered under Critical Infrastructure Policy standards. The system must be designed with flexibility to add security throughout the Smart Grid system over time.