Colton Electric Department

2012 Business Plan

July 2012

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Executive Summary

The Colton Electric Department (CED) faces new regulatory, legislative and financial challenges in 2012 that will impact operations and costs for years into the future. This *2012 Business Plan* will identify some of the critical issues that CED faces and recommend a strategy for dealing with many of these issues.

A vibrant and profitable electric utility is critical to the financial success of the City of Colton. The CED helps fund many of the other City departments and public services through the General Fund Transfer. Competitive electric rates and individualized services provided by CED helps attract businesses to the City.

Many of the items presented in this *2012 Business Plan* address issues that were raised in the *Operational Performance Audit of the Colton Electric Utility* (Audit) prepared by Harvey M. Rose and Associates. The Audit identified areas that need improvement; the *2012 Business Plan* shows how the CED either has resolved the issue or intends to deal with many of these issues in the future.

Twenty years ago, running an electric utility basically involved buying generation and transmission resources to meet forecasted load. Even if a utility over-procured generation resources, within one or two years the growing demand for electricity would eliminate any surplus.

Today however, the engineering side of running a utility is just a small part of the management process. Lower growth rates for electricity sales due to slow economic growth and increased energy efficiency, along with legislative and regulatory changes primarily due to environmental activism, fear of dependence on foreign energy sources, the evolution of large regional transmission and generation planning entities and additional oversight by the federal government, has resulted in utilities having to spend significantly more time in regulatory, legislative and planning activities, both short and long-term.

The CED is not immune from the changes taking place in the electric utility industry. But the CED has not invested the time, effort and resources to fully understand the regulatory and legislative changes affecting the industry and the effects on the utility itself. The CED has relied on regional and statewide organizations, many of which have different priorities and requirements than the CED, to represent it in various state and regional forums[1]. Often, CED personnel are not aware of the issues that are being discussed and the impact of these issues on the CED. The CED's personnel have also not adapted to the changing legislative and regulatory environment that they now operate within, with many employees still performing the same tasks the same way they were originally trained and not aware of additional documentation obligations and reporting requirements.

As a result, the CED is incurring somewhat greater costs than necessary for power supplies and regulatory compliance. The CED needs to become more involved in California legislative and regulatory developments so that it can plan to new statewide environmental and renewable energy requirements.

This Business Plan primarily deals with organizational, legislative and regulatory issues. Some of the pressing issues of resource planning are included, but most resource planning issues are addressed in the forthcoming *Integrated Resource Plan*[2].

Utility Overview

The CED serves approximately 18,500 customers with a total annual operating budget of approximately $58 million. In 2010, the CED delivered 352,600 *megawatt hours* (MWh) of electric energy to its retail customers. By FY2014/15, the CED expects to serve almost 20,000 customers with total energy requirement of 386,000 MWh.

The CED acquires most of its energy through long term contracts with the *Southern California Public Power Authority* (SCPPA). This energy is delivered to its customers over the *California Independent System Operator* (CAISO) grid, the CED transmission contracts with other utilities and its own transmission and distribution system. The CED owns and operates four 66/12 kV substations within the City where power is transformed from 66 kV to 12 kV for delivery to its customers.

The CED has an approved budget for 42 full-time persons. Currently, the CED has about 5 vacancies in the Administration and Engineering divisions. The high number of current vacant positions is affecting

[1] These entities include the Southern California Public Power Agency, California Municipal Utilities Agency and American Public Power Association.
[2] The Audit identified the need for the CED to develop an *Integrated Resource Plan* for review and approval by the Colton City Council. The IRP is currently being completed in conjunction with the Colton Utilities Commission.

CED’s ability to perform non-critical tasks especially in the areas of engineering, legislative and regulatory compliance and power supply planning and management.

The CED is a member of SCPPA, a joint powers authority created in 1980 for the purpose of financing the acquisition of generation and transmission resources for its members. Through this membership, the CED has been able to diversify its power resource portfolio by participating with other municipal utilities in projects such as San Juan Generating Station, Palo Verde Nuclear Generating Station, Magnolia Power Plant, and Hoover Dam. The CED also relies upon SCPPA for legislative and regulatory support. SCPPA personnel represent the CED and other municipal utilities before various regulatory and legislative bodies.

The CED Mission Statement

The CED was established to provide reliable, inexpensive energy to Colton’s residents. The CED’s mission statement is:

- The Colton Electric Department is committed to providing safe and reliable services to our citizens and customers in the most affordable and environmentally sensitive manner possible.
- Each decision made by management in dealing with customers will be determined by doing what is right for both the customer and the utility.
- Our customer group not only includes the community and businesses, but also to city council, utility commissioners and city employees.
- Every staff member of the department strives to effectively communicate with each other, and with other city departments, council members, utilities commissioners, and customers.

A key strength of the utility is its reliable service and competitive rates which will continue to attract new residents and businesses to the City. The CED’s long-term objective continues to be to support the community through its obligation to serve customers based on fair and equitable cost of service with environmentally sound resources.

Power supply costs are the major portion of the CED's budget comprising over 65% of total annual costs. Managing power purchase agreements and energy contracts should be a priority of the CED in order to keep rates low.

In 2012 there are major outages planned at Magnolia Power Plant and San Juan Generating Station, two of the CED's major energy resources. Without planning and acquiring replacement energy for these resources during the outages, CED could experience substantially increased power supply costs. In addition, the United States *Environmental Protection Agency* (EPA) has mandated air quality improvement to San Juan, which will result in a large increase to San Juan's energy costs. These costs, along with renewable energy acquisition costs, will have to be factored in the CED's rates as the current and future rate structures are studied.

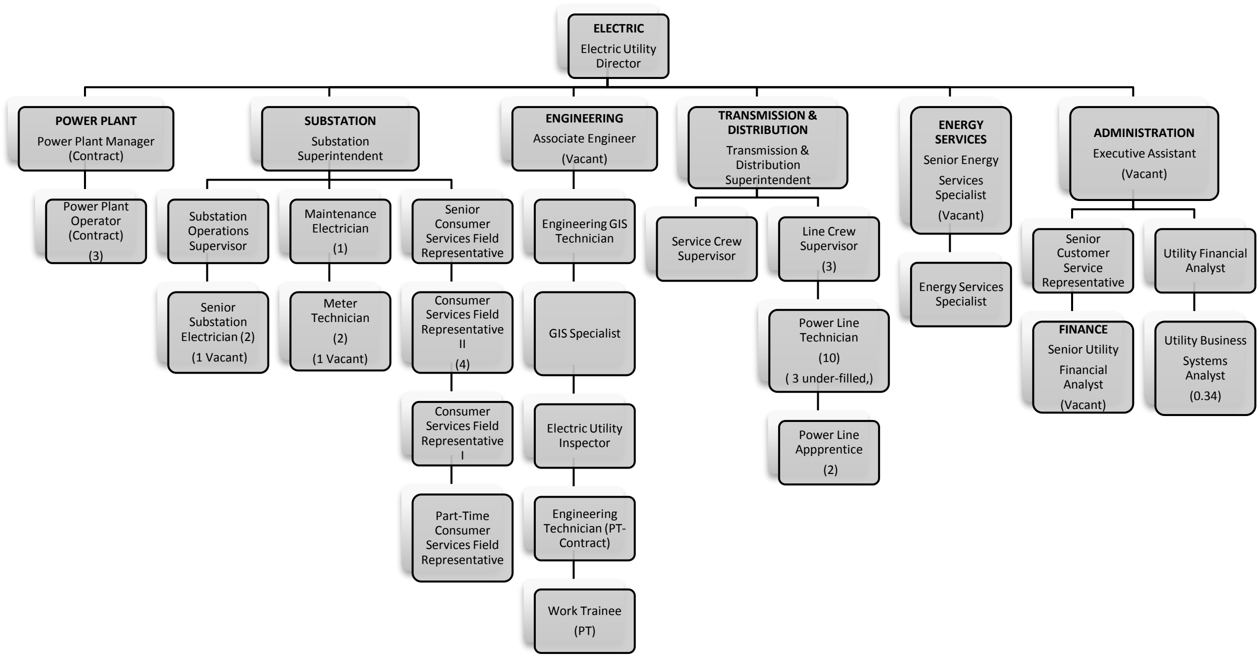
The CED Organizational Chart

The CED is organized into six divisions: Administration, Engineering, Energy Services, Transmission and Distribution, Substations and Agua Mansa Power Plant.

A major challenge facing the CED is the recent departure of key management and technical staff. There are currently twelve full-time positions vacant within the CED. There will be recommendations that some of these vacant positions be reclassified to deal with regulatory and resource planning requirements as the priorities of the utility evolve.

Administration Division

The Administration division is responsible for the oversight of the utility, development of power resources, legislative and regulatory activities, conservation and demand-side services and administrative services for the other divisions. This division has five (5) authorized full-time positions of which two, the Senior Utilities Financial Analyst and Utility Financial Analyst, are currently vacant. There are also a part-time work trainee and utility business service analyst whose position is split between the Electric and Water utilities.



One of the primary tasks of the Administration division is managing the CED's power resources portfolio.

The Administration division is also responsible for:

- Daily administrative tasks such as generation of division files, records and budgetary tasks. Tasks include budget tracking, payroll function. Staff is responsible for collection and submission of employee time sheets for accurate payroll processing to meet bi-weekly payroll requirements and provide budget analyses throughout the year for Management and City Council;
- Procurement and contract compliance is met through with purchasing of services and material. Capital and expense budget costs are controlled by personnel in this division;
- Power supply accounting and coordination with the Management Services – Finance;

- Regulatory compliance and reporting. Compilation of end of month reports on fuel usage, emissions and power generated from the plants as required by the Federal Energy Regulatory Commission (FERC) and the Energy Information Administration (EIA). A listing of all regulatory reporting requirements is provided in Attachment 1.

The Administration division is also responsible for ensuring the CED remains compliant with federal reliability and cyber-security standards.

Energy Services

The Energy Services division is responsible for providing public benefit programs to the residential and commercial customers of the CED. The division designs and markets conservation and efficiency programs to the CED customers and ensures that the CED is staying current with energy efficiency programs and legislation.

Public Benefit Programs

AB 1896 allows each publicly owned utility to collect a non-bypassable usage based charge on local distribution service of $0.00285 cents per kWh. Funds from this charge may only be used for four purposes:

- Services provided for low-income electricity customers, including but not limited to energy efficiency programs and rate discounts;
- Cost effective demand side management programs that promote energy efficiency and energy conservation;
- New investment in renewable energy resources and technologies;
- R&D programs for the public interest to advance technologies not adequately supported by competitive and regulated markets.

At this time, the CED believes that it is in compliance with its regulatory requirements under SB 2021 that established energy conservation targets for California's utilities[3].

Engineering Division

The Engineering division provides support services to the substation and transmission/distribution divisions; provides inspection services to developers for all construction needs; works with customers for planning and designing, budgeting, coordination and providing service connections to the system; and, maintains the Electric Department's GIS system information. There are 6 authorized positions in the Engineering division, which includes a utilities engineer, two GIS personnel, one full-time inspector and one part-time engineering technician. At this time, all the positions except the GIS personnel are vacant. To fill this void, the utility has contracted with an outside utility engineer to provide electrical engineering services on an "as needed" basis.

The Engineering division is responsible for professional services contract administration, local right-of-way record keeping and acquisition, surveying, underground location, work order tracking and project overview, continuing property/facility records and drafting, mapping and Geographic Information Systems (GIS) implementation.

The design section prepares complete substation and switchyard design packages, specifies purchases of all equipment, preparation of specifications, contract documents, procedures of construction contracts, and interfaces with other sections and divisions.

The system planning section conducts transmission and distribution load flow studies, prepares constructions standards, provides technical support to other sections and divisions for system upgrades and modifications, prepares planning studies, performs distribution system fault and failure analysis, manages the annual distribution transformer order including procurement, purchase and evaluation.

Because of long-term vacancies, the CED is contracting with outside engineering firms to provide design and review services. In addition, the CED has not been able to develop basic benchmarking and

[3] The Audit stated that the goals of the Public Benefit Programs need to be adopted by the City Council. The CED has filed long-term efficiency target with the State and in 2012 the California Energy Commission in its *2012 SB 1037 Working Report* stated that CED had meet its initial targets of energy efficiency.

engineering procedures. When CED is able to staff the engineering group, it will attempt to develop basic policies and procedures[4].

Transmission and Distribution

The Transmission and Distribution division is responsible for the design of major system improvements, relocations, undergrounding, and line extensions of the transmission and distribution systems. There are seventeen (17) positions within this division. Three of these positions are currently vacant.

The following services are provided by the Transmission and Distribution division:

- Design of new customer services.
- Investigation of system safety concerns.
- Development of required capital improvement plans and projects/ budgets, as well as the engineering design and management of projects.
- Development of special studies, including failure analysis reports.
- Coordination with other governmental entities and utilities for use of right-of-way and location or relocation of underground plants.
- Provide technical support necessary to comply with all applicable environmental laws and regulations while integrating environmental risks, costs, and impacts in the decision making process.
- Work with engineering/planning on the Geographic Information System.
- Replace and maintain existing infrastructure such as poles and electric lines.
- Conduct emergency and routine repairs of the system.

Statistics collected by the CED show that the Transmission and Distribution division is operating the system well, with a high degree of reliability and relatively short-duration of outages[5].

[4] The Audit identified the lack of basic benchmarking and system reliability planning as one of the CED's greatest weaknesses.
[5] The Audit states that CED does not collect standard reliability statistics but the data collected by CED is compared with standard statistics used by other municipal and investor-owned utilities.

Substation Division

The Substation division is responsible for maintaining each of the four substations and all electrical equipment for the City's water pumping and distribution system, and providing technical metering, meter reading (for both electric and water meters), and field support services to Customer Service. There are 14 positions within this division with two current vacancies.
The following services are provided by the Substation Division:

- Design, construct, contract for, and manage substations, plant switchyards, system protection.
- Substation maintenance including installation, calibration and testing of circuit breakers, relays, meters, transformers and Supervisory Control and Data Acquisition (SCADA) equipment.
- Investigation of customer service complaints and power quality issues.
- Investigation of system safety concerns.
- Research and integration of technological advances into the existing system.
- Analysis of power system and system operation.
- Perform load research, voltage profiles and contingency studies.
- Development of required capital improvement plans and projects/ budgets, as well as the engineering design and management of projects.
- Provide technical support necessary to comply with all applicable environmental laws and regulations while integrating environmental risks, costs, and impacts in the decision making process.
- Conduct emergency and routine repairs of the system.
- Provide services associated with electrical technical metering and associated equipment.
- Provide accurate and timely scheduled monthly meter reads.
- Provide timely customer connects and disconnects.
- Investigates customer energy usage patterns, high bill complaints, customer equipment access issues and power theft incidents.

Agua Mansa Power Plant (AMPP)

The Agua Mansa Power Plant is a 43 MW gas-fired peaking plant, commissioned in July 2003. The Agua Mansa Power Plant allows the Electric Utility to meet its resource adequacy requirement periods. The CED contracts with an outside firm (NORESCO) to provide maintenance and operations services for the plant.

Agua Mansa Power Plant (AMPP) is located on a 7.60 acre site in a relatively undeveloped area designated Heavy Industrial and Agriculture/Open Space in the Agua Mansa Industrial Corridor Specific Plan.

AMPP provides capacity to the CED. The facility allows the CED to meet its customer's power requirements and acts as a physical hedge for CED, reducing exposure to CAISO price market volatility. The CED will generally not pay more for energy than the cost of AMPP generation.

AMPP uses minimal process water for combustion turbine power augmentation, reduction of turbine nitrogen oxide emissions and evaporative cooling of inlet turbine combustion air. The primary source of process water for the plant is tertiary treated wastewater from the adjacent RIX facility. The RIX water is dematerialized in a modular water treatment facility prior to use in the turbine and evaporative cooler. Water introduced into the gas turbine and evaporative cooler is primarily evaporated and there is very little waste water for disposal. The waste water that is generated from the facility processes is discharged to the Santa Ana Regional Interceptor (SARI) line, an existing 12 inch industrial sewer line that is located approximately 500 feet from the facility in the Agua Mansa Road right-of-way.

The CED is also exploring the feasibility of using biogas or other renewable natural gas alternatives that could assist in meeting renewable energy resource requirements.

Operating statistics show that AMPP is being operated well with a high level of reliability. Unplanned outages or failures to start are very low in comparison to other LM 6000 generators in the region.

Summary of Personnel

The organizational chart identifies the CED's priorities as essentially protecting the reliability of the transmission and distribution system. Of the 42 full-time, and 3 part-time positions in the Department, 36 of them work in field activities, including engineering, substation and transmission/distribution. Only 9 positions, including 2 part-time employees, are responsible for power supply, regulatory compliance, energy services and administrative activities, even though these activities account for almost 75% of the total CED budget.

The areas where the CED excels in are the areas that have adequate personnel. Areas where the CED is weak, including power supply, legislative and regulatory compliance and financial oversight are areas where the CED does not currently have personnel[6].

Current Budget

The CED's budget for fiscal year 2012-201 is approximately $59.6 million. Revenues collected are sufficient to cover expenditures. An overview of fiscal year 2012-2013 budget is presented in Attachment 2 along with past years for comparison.

The top ten customers of the Electric Utility in FY 2011-2012 (in alphabetical order) include Arrowhead Regional Medical Center, Ashley Furniture, Colton Joint Unified School District, Con Agra, Inland Logistics, McCain Foods, Pacific Rail, RIX Facility, and Telco Foods.

The CED implemented a rate adjustment commencing July 2011 based on a cost of service study prepared by Baker Tilly Inc. in March 2011. The rate adjustment resulted in up to a 10% reduction for many residential utility customers.

In addition, the customers saw additional relief in the utility bill from the sunset of City's utility tax starting July 2011. The CED is currently studying rates for fiscal year 2012/13. The utility net income is expected to be positive in the future which will allow the CED to build operating reserves.

[6] The Audit suggests that CED's field operations are understaffed in comparison to other municipal utilities. The Audit does not address staffing issues in other areas.

Challenges

One of the CED's primary goals is outlined in its Mission Statement as, "The Colton Electric Department is committed to providing safe and reliable services to our citizens and customers in the most affordable and environmentally sensitive manner possible." The CED is currently able to provide safe and reliable energy services.

CED personnel should become more familiar with the California wholesale energy market and manage its generation and transmission resources more effectively. The CED is not fully compliant with all renewable energy requirements and is not currently up-to-date with environmental legislation.

The CED is also lagging in safety training and establishing safety policies and procedures for its employees, even though the CED's overall safety record is excellent. The CED's safety standards need to be updated and documented. Currently there are few written safety policies and procedures for its field personnel.

On the positive side, the CED does have very good reliability statistics and has fewer, and shorter, customer outages than many comparable electric utilities, based upon CED data[7].

The most immediate issues facing the electric utility are meeting emission requirements and meeting the State mandate of a 33% renewable portfolio standard (RPS) by 2020 and 25% by 2015[8].

Currently the CED is purchasing 7% of its retail energy requirements from renewable sources although it will increase this to 12% in 2012 and 15 to 17% by 2015. The CED has not devoted sufficient internal resources to either meeting the RPS requirements or examining legislative and regulatory alternatives, such as using *renewable energy credits* (RECs) to meet RPS requirements, to minimize its costs of meeting the state mandate. The RPS requirements for CED are equivalent to approximately 15 MW of baseload energy or 60 MW of solar PV generation.

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[7] The Audit points out that CED does not prepare standard measures of reliability such as the System Average Duration Interruption Index (SADIR) and System Average Frequency Interruption Index (SAFIR). CED is now working to prepare these statistics to allow direct comparison of reliability with surrounding utilities.

[8] These items were identified in the Audit although the targets are now out-of-date given the passage of SB 2.

Another significant issue the utility faces centers around maintenance of infrastructure and improving power quality. Several projects are in the planning stage that start to address this issue and include the implementation of an underground cable replacement program, replacement of transmission insulators, completion of load-carrying capability (black start at the Agua Mansa Power Plant), balancing load on circuits, and providing back-up transformers to existing transformers at the Hub Substation.

Power Supply Issues

The CED's resource mix has changed significantly over the last 10 years, most notably with the construction of the Agua Mansa Power Plant in 2003. The resource portfolio, with 91 MW of resources, is composed of a diverse mix of resources including hydro, nuclear, coal, wind, and landfill gas generation.

New legislative and regulatory requirements are impacting the way the CED plans to meet future customer load requirements. The CED did not participate in the development of RPS legislation and is lagging in developing a plan to ensure compliance with new AB 32 emission reduction obligations. Failure to meet RPS obligations and emission reduction requirements could result in fines being levied against the CED.

Market Redesign and Technology Update

The CAISO's *Market Redesign and Technology Upgrade* (MRTU) has been in operation since April 1, 2009 and, overall, the wholesale market has performed as intended. The MRTU represents a complete overhaul of California's system of wholesale power delivery as a result of the California energy crisis in 2001. While some extreme hourly prices have occurred, they have been infrequent and typically reflected actual system constraints. Concurrent with the first two years of operation, the market has experienced reduced demand influenced by the economic downturn across the state, as well as increased renewable production, high hydro generation, and high volumes of self-scheduled energy.

The MRTU market is a "closed" market where all *load servicing entities* (LSE's) bid their generation resources to the CAISO that then decides which resources should be used to meet load, based upon price, operating characteristics such as ramp rates or must-run restrictions, location, transmission constraints and emissions. The CASIO also acquires all ancillary services necessary to meet the moment to moment fluctuations in demand.

No entity's resource costs should increase due to participating in the CAISO. Inexpensive resources are dispatched to meet loads while more costly resources that are available to run are not dispatched but recover costs in capacity payments for being able to meet unanticipated loads or system contingencies.

If a unit (like AMPP) is not dispatched to meet the CED's loads, it is because the CAISO has less costly energy available and it sells this energy to the CED in place of AMPP generation. However, if prices rise above the AMPP generation cost, AMPP would be dispatched and the CED would pay the incremental cost of AMPP for load purposes.

The primary difficulty with the CAISO is the complexity of the market. The CED is currently attempting to train internal personnel to verify CAISO invoices and perform energy accounting functions to track CED's daily energy transactions and costs[9].

Refinancing of Agua Mansa Power Plant

The AMPP was financed in 2002 at a time when interest rates were significantly greater than they are now. Initial indications from the City's financial advisors suggest that the City can refinance the AMPP and realize savings of about $150,000 annually without incurring additional debt or increasing the financing period. The CED and Management Services is looking at various financing options in conjunction with the CED's capital requirements and expects to bring financing options to the City Management in mid-summer.

Resource Adequacy Program

Another key aspect of the market design that will undergo enhancements in 2012 and beyond is California's *resource adequacy* (RA) program. The CED (along with all other LSE's) provides data to the Energy Commission that prepares a monthly forecast of RA obligations. The forecast is equal to the CED's monthly coincident load with the CAISO plus the reserve margin of 15%.

[9] The Audit recommended that the CED devote a single person exclusively to managing the Shell contract to ensure that Shell is managing CED's resources correctly and taking advantage of market opportunities.

Currently, utilities contract to meet their capacity obligations through private bilaterally-negotiated contracts or from their own resources. In June 2010, the CPUC issued Decision 10-06-018 indicating that it would not move towards a centralized capacity market or a multi-year forward resource adequacy requirement, at least for the time being.

The CED currently has sufficient RA capacity to meet its requirements in the CAISO market from its own resources and does not have to purchase additional RA capacity. However, the CED can reduce its operating costs by marketing some of its surplus RA to nearby municipal utilities in non-summer months.

Local RA Capacity

Under MRTU, the CAISO may procure *Local RA Capacity* (*LRAC*) if the CAISO determines there is a capacity deficiency within a *Local Capacity Area* (*LCA*). A deficiency in LRAC can occur because individual LSEs do not demonstrate sufficient LRAC in annual or monthly resource plans or because of a collective deficiency of local capacity in a LCA. It should be noted that, according to the CAISO, the AMPP is counted as a Local Capacity Resource. When needed, the CAISO will make supplemental procurement for RA under the contract procurement mechanism provisions of its tariff described above. As detailed in the CAISO Tariff,[10] the capacity procurement costs associated with the procurement of LRAC will be allocated proportionately to all deficient LSEs within each *Transmission Access Charge* (TAC) Area, or in the case of a collective deficiency of local capacity, to all *scheduling coordinators* (SCs)[11] that serve load in the area. AMPP provides all of the CED's local RA capacity requirements.

Summary of CAISO Market Modifications

In general, the CED has sufficient resources to meet its capacity obligations and satisfy its energy requirements. Shell Energy is scheduling the CED's resources as the CED's SC. Meetings between Shell and the CED have identified a number of issues that should be investigated to reduce costs to the CED, primarily dealing with the dispatch of SJ and Magnolia. It appears that a different scheduling strategy could result in reduced costs and is currently being reviewed by CED staff.

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[10] CAISO Tariff Section 43, Capacity Procurement Mechanism.

[11] The CAISO only communicates with SC's and not with other LSE's. CED has a relationship with Shell where Shell acts as CED's SC but CED is registered as a SC with the CAISO.

The CED does not have personnel sufficiently trained in the MRTU market to adequately review invoices or verify billings from SCPPA and Shell. To rectify this, the CED personnel have begun attending CAISO training classes on settlement and market operations. Monthly invoices are also being reviewed to better understand how any surplus energy is being sold in the market and ensure monies are appropriately credited to the CED.

The CED does not reconcile energy production with daily loads and sales. Without this analysis, there is no ability to verify that the CED is actually being paid for all daily surplus energy. The CED is training people to reconcile monthly invoices and verify invoices.

Legislative and Regulatory Requirements

Federal Clean Air Act

The *Environmental Protection Agency* (EPA) in response to lawsuits from various environmental groups has issued an order requiring the owners of the San Juan Generating Station to install *Selective Catalytic Recovery* (SCR) on the four generating units, including *San Juan Generating Station, Unit 3* (SJ3) which is partially owned by the City of Colton. The estimated cost of installing a SCR on SJ3 is around $225 million or which CED would have to pay about $20 - $23 million. Under the current order, design and construction would begin in 2013 with a 2015 completion date.

SCPPA has studied the various alternatives, including non-selective catalytic recovery (NSCR), converting the units to natural gas generation or shutting some of the units down. SCPPA's analysis shows that NSCR is a better financial choice for the San Juan participants with environmental benefits close to those of SCR's. However, unless the EPA agrees with SCPPA and PNM's preferred alternative, the project participants will have to install SCR at the higher cost.

California Environmental Legislation

The umbrella legislation for California's clean air legislation is AB 32. This legislation establishes the goal of reducing emissions by California's residents and businesses from current levels back to 1990 levels. AB 32 established the *cap and trade* (C&T) approach to pollution control and indirectly required renewable energy portfolios. AB 32 has spawned significant follow-up legislation and regulatory activity to determine how to meet the goals established in the law.

With the passage of AB 32 in 2006, California is leading the nation in addressing climate change, with an overall goal of reducing GHG emissions to 1990 levels by 2020 and setting a path to further reductions by 2050. There have been several attempts at the federal level to address climate change, both through legislation and EPA regulations. With the exception of GHG reporting requirements for major sources (25,000 metric tons), federal actions have stalled. Nonetheless, California continues to push forward to reach its overall GHG emissions reductions goal.

In 2008 the *California Air Resources Board* (CARB) adopted the Climate Change Scoping Plan, which identifies measures for the various economic sectors that would achieve real GHG reductions. Several measures have been identified for the energy sector that have been or will be developed into regulations. The following charges and regulations currently apply to the CED:

- AB 32 Cost of Implementation Fee Regulation (Fee Regulation)
- Regulation for the Mandatory Reporting of GHG Emissions (Mandatory Reporting Regulation)
- Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear (SF_6 Regulation)

The 2010 Mandatory Reporting Regulation revisions increased the exemption threshold for reporting for electric generating facilities from 2,500 *metric tons* (MT) to 10,000 MT and reduced retail seller reporting obligations, as well as verification requirements.

There have been several political and legal attempts to stop and/or delay regulations developed under AB 32, on the basis of economic, environmental justice, and overall AB 32 violation claims. The two most notable are Proposition 23 and the 2011 California Superior Court Case. Proposition 23, formally called the California Jobs Initiative, which would have delayed AB 32 until such time unemployment in California dropped to or below 5.5%. California voters rejected Proposition 23 in November 2010.

On December 19, 2010, the Association of Irritated Residents and a number of other associations filed suit against CARB, alleging that CARB had failed to meet its obligations under AB 32 and its administrative requirements under the *California Environmental Quality Act* (CEQA). Plaintiffs petitioned for a Writ of Mandate and the Courts had temporarily issued an injunction against implementing AB 32 measures until CARB met its CEQA requirements. In May 20, 2011 there was a temporary judicial stay on C&T but this was lifted by August 2011 and the C&T program moved forward. The C&T program was to have started in January 2012, but in early July, CARB proposed delaying the program one year to ensure that all processes and protocols are working properly.

A key portion of AB 32 is the requirement for increased energy efficiency measures and advanced lighting technologies. AB 32 requires that utilities implement all cost-effective energy efficiency measures prior to acquiring new generation resources.[12]

Cap and Trade

One of the most pressing issues facing the CED in 2012 will be implementing the C&T regulations that go into effect in July 2012.

CARB has been working on implementing a C&T program since 2006. It will be a difficult task for the CED to catch up with the regulatory requirements and then participate in the November auction process[13] restrictions and requirements for managing *emission allowances* (EAs) but the CED is devoting resources to this effort and expects to be in compliance with C&T.

Under a C&T program, the total amount of emissions in tons per year (measured in $CO2_e$ or carbon dioxide equivalents) is capped by the CARB. CARB has estimated emissions by industrial sector by performing audits of emissions by sector for the past three years with each business or entity covered by the regulation required to estimate its annual emissions and then have its emissions verified by an independent auditor approved by CARB.

[12] Refer to Chapter 4 of the IRP for information about CED' current and planned energy efficiency programs.

[13] The first auction was scheduled for August but on March 30th, CARB announced that the August auction would be a test and the August and November auctions would be combined into a single auction.

CARB then allocated each entity within each covered industrial sector EAs. If the entity accurately reported its emissions, the allocated EAs would equal the average of the annual emissions over the past three years.

Beginning in July 2012, entities that have been assigned EA will have to sell a portion of their allocated EAs in an auction process[14]. The money that is collected through the auction must be set aside to either (1) buy EAs to offset emissions by that entity during the following year or (2) invest in new pollution reduction technologies. But if a firm invests in new technologies, it still must have enough EAs to cover its annual emissions.

There is significant opposition by the municipal utilities to the requirement that a utility sell its EAs in the auction and then have to re-purchase the EAs at a later time. If prices rise between the first auction when EAs are sold and subsequent auctions when EAs are purchased then the municipal utilities might have to pay more to acquire the EAs than they received in the auction process. If the correct amount of EAs were originally allocated to each entity then they should be indifferent to the auction process but if they have to sell their EAs and then buy them back at a potentially greater price they might be significantly impacted by the must-sell requirement.

Each year CARB will perform an audit of the emissions from each entity. If an entity does not have sufficient EAs to offset all its emissions, it must either purchase EAs from another entity or pay a fine of about $50/ton for emissions above its EAs. If an entity has more EAs than emissions, it will retire its EAs to offset its emissions and it can then sell any remaining EAs and use the proceeds to invest in emission reducing technologies. Each year, the amount of EAs available and allocated to each entity will decline, forcing all entities to reduce their emissions by about 2% per year.

The CED has been allocated 234,600 EAs for the auction process but has not reported its estimated emissions nor performed the (required) annual audit of emissions. The CED has reported its electricity

[14] The exact percentage is still being negotiated.

sales and imports of energy from out-of-state sources which were used by CARB to estimate annual emissions but the CED does not currently know how accurate the CARB emission estimates are[15].

In early 2012, the CED began training staff to participate in the auction process, develop a mechanism for calculating emissions track emissions relative to its EAs and either buy or sell EAs as necessary to remain compliant with the C&T program. The CED will also have to develop financial tools to track the revenues and costs from C&T programs and restrict how these funds can be used.

Renewables Portfolio Standard (RPS) Legislation

The second major component of AB 32 was the requirement of a renewable portfolio standard for all LSEs within California. In 2009, Governor Schwarzenegger had initially used AB 32 in establishing minimum renewable energy requirements for investor-owned utilities. However, there was a debate on whether or not his Executive Order[16] could be applied to publically-owned utilities.

In April 12, 2011, Governor Brown signed Senate Bill X1-2 (SB 2), codifying into law an increase of the RPS mandate to 33% by 2020. SB 2 made significant modifications to the RPS program, including the use of multi-year compliance periods with incremental targets and the specification of minimum product content for most retail sellers' RPS portfolios that changes with each compliance period. SB 2 also modified certain delivery requirements for out-of-state resources and limited the ability to carry forward unbundled renewable energy.

A key component of RPS is the concept of a *Renewable Energy Credit* or REC. For purposes of regulatory compliance, energy is classified as "brown" or "green." Brown energy is from traditional fossil-fuel generation. Green energy is from renewable energy sources. However, green energy can be divided into two components, the energy and the green capacity attribute. A renewable energy generator or marketer can separate the brown energy component from the green energy attributes and sell the green energy attributes as a REC.

[15] CED personnel have estimated 2011 emissions at between 235,000 and 288,000 metric tonnes but these results have not been verified or audited by CARB and there are counting issues that still need to be resolved. Regardless, even the lower estimate is above the CARB EA allocation to CED.

[16] On November 17, 2008, Governor Arnold Schwarzenegger signed Executive Order # S-14-08 requiring all LSE's to meet the renewable portfolio standard.

For example, a wind generator in California can generate energy and sell it into the CAISO market as brown energy and retain the REC. The REC can then be sold to an entity that wants to offset its brown energy purchases and turn them into green energy. However the use of RECs by utilities is strictly limited by SB 2, including location of generation, time frames and types of RECs.

Compliance Categories of RPS Resources

SB 2 established three categories, or "buckets," for RPS compliant resources. It is easier to define Category 1 and 3 resources, with any green resource not satisfying either Category 1 or 3 classified as Category 2.

Category 1 green energy is bundled green energy produced within California or that has its first point of interconnection with the CAISO controlled grid or is dynamically scheduled into the CAISO. Category 3 is RECs. Category 2 is firmed and shaped green energy, or energy from renewable sources that does not meet the criteria of categories 1 or 2.

Resources must meet the following criteria during the different compliance periods.

Category	Description		Percentage of RPS Target
1	A. Energy from eligible resources that have the First point of interconnection with a California balancing authority, or with distribution facilities used to serve end-users within a California balancing authority, or; B. Are scheduled into a California balancing authority without substituting electricity from another source. If another source provides real-time ancillary services to maintain an hourly import schedule into California only the fraction of the schedule actually generated by the renewable resource will count, or; C. Have an agreement to dynamically transfer electricity to a California balancing authority.		2011 – 2014: Minimum of 50% of the energy that is counted toward the RPS target 2015 – 2016: Minimum of 65% 2017 and thereafter: Minimum of 75%
2	Firmed and shaped energy in RECs from eligible resources providing incremental electricity, and scheduled into a California balancing authority		2011 – 2014: Maximum of 50% 2015 – 2016: Maximum of 35% 2017 and thereafter: Maximum of 25%
3	Energy or RECs that do not meet the requirements of Categories 1 or 2, including unbundled RECs		2011 – 2014: Maximum of 25% 2015 – 2016: Maximum of 15% 2017 and thereafter: Maximum of 10%

One of the “clean-up” bills for SB 2 is AB 1771 (Valadao) that allows hydroelectric resources of any size to be counted as renewable resources. Currently, only hydroelectric generation less than 30 MW can be counted as a renewable resource, meaning that the CED’s entitlement in the Hoover Uprating Project cannot be counted as a renewable resource. The CED receives about 10,400 MWh annually of Hoover Uprating energy that can be counted as renewable energy under this proposed bill. This is equal to about 14% of the CED’s current renewable energy obligation. The CED believes that this bill should be supported as a way of reducing the cost of compliance with SB 2.

Another clean-up bill is SB 971 (Cannella) that revises the RPS program so that the RPS targets are based upon “net program retail sales” rather than total retail sales. “Net program retail sales” are the total retail sales of the utility minus retail sales where load was met with non-eligible hydroelectric generation. This would reduce the CED’s renewable obligations slightly in 2011-2013.

Finally, AB 1721 (Donnelly) would require the CARB and local air quality management districts to only issue a warning for the first violation of any state air pollution control law. This would help the CED avoid any penalties for CARB non-compliance.

A bill that is getting a lot of interest from municipal utilities is AB 1900 (Gatto) that allows LSE’s to use biogas as a renewable fuel regardless of source. The CED had planned to use biogas to fuel AMPP but on March 27, 2012 the CEC suspended biogas as a renewable resource except for some limited purposes, such as landfill gas or digester gas burned on-site for renewable generation purposes or biogas from California sources that can be tracked from the point of production to the generator.

The CED would like to have the option of using biogas as a renewable energy source. Biogas burned at AMPP would cost between $90 and $110/MWh, a price comparable to other renewable resources.

Failure to Meet RPS Goals

SBX1-2 applies an existing set of CARB air pollution penalties and fines to failures to meet the RPS requirements. CARB has several options available to it.[17] CARB can seek civil penalties for violations, by

[17] CARB’s general enforcement authority is in Health & Safety Code §38580, and the specific penalties that apply to failures to comply with RPS requirements are in Health & Safety Code §§42400-42410.

having the California Attorney General sue the City of Colton. The amount of the penalties depends on whether CARB views the violations has having been purely accidental, the result of negligence, occurring through a utility taking no action to comply with the RPS requirements, or being a willful and intentional violation. Accidental violations can trigger daily penalties of $1,000, and negligent violations carry daily penalties of $25,000. If the electric utility is found to have known of the violations but took no corrective action, that subjects the City to daily penalties of $40,000. If CARB views the violations as willful and intentional, it can seek daily penalties of $75,000. Finally, CARB can impose administrative penalties of up to $10,000 per day.

Colton's City Attorney believes that if the electric utility does not comply with the RPS requirements after receiving a notice of violation and correction from the CEC, CARB's first enforcement step would be imposition of administrative penalties. This could occur if the electric utility tries to adopt RPS cost caps or a delayed implementation schedule that CEC staff feel are not consistent with the law, or if the electric utility simply refuses to comply. If Colton simply ignores the administrative penalties and does not comply with the RPS requirements, the City Attorney believes CARB could seek $40,000 daily penalties for the City's knowing refusal to take corrective action[18].

Tradable RECs for RPS Compliance

After issuing several proposed decisions, in March 2010 the CPUC issued decision 10-03-021 formally authorizing the use of Tradable Renewable Energy Credits (TRECs) for RPS compliance. REC-only transactions are those that expressly convey only RECs and not energy; or transactions that transfer both RECs and energy, where the energy associated with the RECs does not serve California customer load.[19] Bundled transactions, which involve both energy and credits, are those that serve California load

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[18] Memorandum from Andrew Morris of BBK to David Kolk, April 16, 2012.

[19] California Public Resources Code 25741 requires that RPS-eligible energy must also be delivered to California customers in order to be counted for RPS compliance. Pub. Res. Code § 25741(a) provides:

> "Delivered" and "delivery" mean the electricity output of an in-state renewable electricity generation facility that is used to serve end-use retail customers located within the state. Subject to verification by the accounting system established by the commission pursuant to subdivision (b) of Section 399.13 of the Public Utilities Code, electricity shall be deemed delivered if it is either generated at a location within the state, or is scheduled for consumption by California end-use retail customers. Subject to criteria adopted by the commission, electricity generated by an eligible renewable energy resource may be considered "delivered" regardless of whether the electricity is generated at a different time from consumption by a California end-use customer.

without intermediary transactions that in effect substitute energy that is not RPS-eligible for energy that is eligible.[20]

One month after issuing its "final" decision, the CPUC granted a stay of its TREC Decision in April 2010, while it considered two petitions to modify the Decision.[21] On August 25, 2010, the CPUC issued a proposed decision that would lift the stay and grant some of the modifications sought in the petitions to modify.

Finally, on January 13, 2011 the CPUC approved its Renewable Energy Credit (REC) decision (D.11-01-025) authorizing the use of RECs for RPS compliance. The CED will endeavor to take full advantage of RECs to meet its RPS obligations, including the issuance of a REC-only RFP in 2011.[22] It should be noted that, despite the very positive development of a final REC decision and SB 2, much uncertainty remains regarding REC transactions, particularly regarding the procedures and processes for out-of-state REC transactions.

Summary of GHG and RPS Legislation

The CED is preparing for the impact of the Clean Air Act and AB 32. The potential financial impacts of EPA actions on the CED's entitlement in San Juan will result in cost increases for the CED beginning in 2013. If SCPPA agrees to finance the required environmental upgrades, the initial cost impact will be reduced but the CED would still see additional costs of $1.5 to $1.8 million annually beginning in 2013 as its share of required environmental upgrades.

The best alternative for the CED would be for the EPA to agree to allow SJ participants to use NSCR to reduce emissions. This will achieve almost the same reduction in nitrogen oxides, sulfur dioxides, CO_2 and mercury emissions but at a much lower cost. To this end, the CED has begun discussing the issue with local federal legislators.

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[20] D.10-03-021, pp. 2-3.
[21] One petition to modify was filed jointly by SCE, SDG&E and PG&E while the other was filed by the Independent Energy Producers Association (IEPA).
[22] At the time of this writing, CED is in early negotiations for a potential unbundled, California-generated REC transaction in response to an unsolicited offer.

The CED has instituted an internal training program for complying with C&T. The CED personnel are attending C&T training programs held by SCPPA and CARB. But at this time, the CED does not know if the allocated EAs provided by CARB are sufficient to offset the cost of purchasing EAs for actual emissions.

The CED also is not currently in compliance with the RPS standards. The CED only has about 7% renewable resources as opposed to the statutory requirement of 20% although it anticipates increasing its renewable portfolio to 17% by 2015. For 2011 and 2012, the CED can purchase RECs rather inexpensively to bring its renewable portfolio up to 12% but it will still be short about 28,000 MWh per year for 2011, 2012 and 2013. If energy from the Hoover Uprating Project becomes eligible as a renewable energy source, the CED's shortfall will be only 18,000 MWh for the first compliance period.

CED is currently studying alternatives to increase its renewable resource purchases without having a large rate impact on its ratepayers including requesting additional time to meet RPS requirements from the CEC.

The CED needs to participate in various legislative and regulatory forums to try to mitigate the financial impacts of emission caps and RPS obligations. The CED should be trying to relax SB 2 limits on using RECs for RPS compliance (which is allowed if the CEC agrees) and allow the use of large hydroelectric and biogas to meet RPS requirements.

NERC Compliance

As a result of the electricity blackouts in the northeast in the 1960's, the *North American Electric Reliability Council* (NERC) was formed. The purpose of NERC is to ensure the reliability of the bulk power system. NERC established 9 reliability regions in the country responsible for maintaining reliability through the development of reliability standards that each *load serving entity* (LSE) must meet. The *Western Electric Coordinating Corporation* (WECC) is responsible for reliability in the western states[23].

Standards vary slightly across NERC regions and LSE's. In general, entities are classified as independent system operators, balancing authorities, bulk transmission owners, generation owners and resource planners. Each of the different classifications have different levels of compliance requirements and have

[23] This issue was raised in the Audit in Section 1 where the Audit stated that "Colton Electric has only an informal program in place to ensure compliance with NERC standards."

to meet different planning and reliability standards based upon their potential impact on the bulk power grid. The CED currently is in one of the lowest compliance levels (resource planner) because it is small and does not operate bulk transmission facilities.

Even though the CED cannot significantly impact the bulk power system, it still must meet reliability standards, including preparing annual forecasts of demand, providing transmission system data to Southern California Edison (SCE) and providing information on its electrical system to regional transmission planners.

At this time, the CED’s compliance obligations are among the least-stringent and intrusive of all entities. However, in August 2012 the CED will meet with WECC staff to review its compliance efforts and it is possible that Colton will have to meet additional compliance standards in the future. The Utility Director has assumed the role of Compliance Officer in anticipation of the NERC audit.

It is hard to overstate the importance of meeting NERC standards. Most of the standards are prudent industry standards, that is, actions and practices that a utility should be doing, but the standards formalize the reporting and audit obligations of the utility. No longer can a utility just say that they are meeting standards, they have to be able to prove that they doing what the standards require. In addition, NERC has the ability to impose fines on entities for not being in compliance with reliability standards. While it is unlikely the CED would have significant fines for non-compliance so long as a good-faith effort to meet applicable standards was made, failure to demonstrate compliance could result in fines of up to $1 million per day in extreme cases for critical standards (essentially a refusal to comply with the standards), with NERC having levied fines as great as $25 million although fines of $3,000 to $25,000 per violation are much more common.

While meeting the planning and operation standards are of immediate concern, new standards on cyber-security and critical infrastructure will likely require additional work by the CED. This will include limiting access to areas where system operation software and control equipment is maintained and protecting system software from internet attack by either isolating computers, printers and ancillary equipment from the internet or installing multiple layers of security to prevent remote access or hacking.

Major Customer Improvement Projects

In 2012 and 2013 the CED will be working with other entities and regional governments to substantially improve the infrastructure of Colton. Some of the major projects are identified below.

Colton Crossing Infrastructure Upgrade

Colton Crossing Project will separate the at-grade crossing of Union Pacific Rail Road Company (UPRR) and Burlington Northern Santa Fe (BNSF) railroad track by constructing a railroad bridge over the BNSF railroad track. The project limits are approximately Mt. Vernon Ave. on the east side and Rancho Ave. on the west side. This project will affect number of existing utilities that crossed the UPRR tracks including Colton Electric infrastructure. The scope of the project is:

- 3rd Street - Relocation of existing overhead 12KV distribution lines currently on joint-use agreement with SCE.
- 4th Street – Undergrounding of existing overhead fiber optic communication cable.
- 9th Street – install a new duct bank to relocate existing underground 12KV distribution lines and communication cables. The duct bank will also be used to underground all existing overhead 12KV distribution lines. Existing vaults will all be upgrade/replace at this location.

City of Colton and UPRR have completed an agreement to address the funding and construction mechanism of this project.

Hunts Lane Grade Separation

Hunts Lane Grade Separation Project will separate the existing Union Pacific Rail Road Company (UPRR) railroad track by constructing a bridge over the existing railroad. Colton Electric needs to relocate and/or upgrade some of its existing overhead and underground 12KV distribution lines within the project area. SANBAG is the lead agency for the project and Cooperative Agreement is already in place to address all the funding, right of way and construction aspects of this project.

Laurel Street Grade Separation

Laurel Street Grade Separation Project will separate the existing Burlington Northern Santa Fe (BNSF) railroad track by constructing a railroad bridge over a depressed Laurel Street. Colton Electric needs to relocate and/or upgrade some of its existing overhead 12KV distribution lines within the project area. SANBAG is the lead agency for the project and a Cooperative Agreement will be adopted and address all the funding, right of way and construction aspects of this project.

Summary of Projects

The CED will incur substantial expenses relocating and upgrading transmission and distribution facilities around these projects. The CED should become more aggressive ensuring that all its costs associated with customer initiated projects are recovered. The CED needs to better track, through its work order system, costs associated with customer initiated projects and ensure that it recovers all costs associated with any customer projects[24].

The CED Capital Improvement Projects

The Substation and Transmission/Distribution Divisions have identified the following priority capital projects for the next three years[25].

Capital Maintenance Program

There have been a number of studies of why electrical distribution systems have failures. For joint overhead-underground systems, such as Colton's, failures on the underground and overhead portions of the system tend to be due to different factors. Most of the outages within Colton in the past two years have been due to failure of aging underground distribution wire.

[24] The Audit recommends that CED better track employee hours and project costs but does not specifically include recommendations on customer initiated projects. However, without better information on CED's costs of providing service, CED cannot appropriately charge the customer for work done on their behalf.

[25] The Audit suggests a Ten-Year Capital Project Plan. However, given current staffing issues, it is not possible to prepare a ten-year plan at this time.

Underground failures tend to be due to the age of the wire. Overhead outages tend to be more random and accidental, such as wind, trees limbs, bird and other animals causing a fault, automobile accidents and other disruptive events.

The CED has proposed a capital replacement program for upgrading system reliability by replacing aging infrastructure (excluding any possible improvements to the Agua Mansa Power Plant). The Electric Department has proposed replacing all wood poles within the City greater than 50 years old within the next 20 years and underground wire greater than 20 years old over the next 10 years. In addition, the CED has proposed adding approximately 50 breaker fuses at critical junctions within the next 5 years and within the next 3 years upgrading its SCADA system to permit additional metering points to identify short circuits quickly and perform testing and maintenance on its 25 MVA transformers.

The proposed equipment replacement program would require approximately $1.9 million annually for the first 3 years and then $1.75 million for the remaining 12 years. Currently, the CED has approximately $1.2 million budgeted for capital replacement annually, so the program would require a minor increase in annual capital improvement budget. By increasing the target dates by 5 years for wood pole and underground wire replacement, the capital replacement goals could be met with the current annual expenditure level.

The Cable Replacement Project will identify and replace 15kv 750mcm, 4/0 and 1/0 primary underground cables that show sign of deterioration. Inspection and testing of cable installed prior to 1990 will identify the specific cables that need to be replaced. This project will provide increased reliability to the electrical distribution system.

Substation Upgrades

The following substation upgrades are required for the CED’s 66 kV substations. North Substation, the CED’s newest 66 kV substation, does not require any upgrades at this time.

Hub Substation

- Oil containment for 3-transformers
- Oil containment (or replacement) for 5 – 72.5kV oil circuit breakers

- Nitrogen systems for 3-transformers
- Detailed drawing revisions by professional engineering firm
- 66kV protection relays replacement

To improve safety at the Hub Substation, CED is studying the cost of installing blast walls around the Hub transformers. CED is currently hoping to fund an 8 foot high blast fence with funding available in the 2012-13 Budget to reduce the risk of injury from a possible transformer explosion.

Century Substation

- Oil containment for 2-transformers
- Nitrogen systems for 2-transformers
- Detailed drawing revisions by professional engineering firm
- 66kV protection relays replacement
- Battery bank load discharge test and possible replacement (pending test results)

Drews Substation

- Detailed drawing revisions by professional engineering firm
- Battery bank load discharge test and possible replacement (pending test results)
- **H**ospital 12kV line differential relays replacement

Fiber Optic Cable System Upgrade/Repair

The City relies on an internal fiber optic system to maintain communications. This system is old and in need of repairs and upgrades. Portions of the system are being repaired or replaced as time warrants but without replacing some of the main lines, the system will continue to deteriorate, resulting in reduced reliability within the next five years.

Arc flash study

Arc flash is an electrical short circuit, where a high level of current passes through air. Arc flashes cause electrical equipment to explode, resulting in an arc plasma fireball with temperatures exceeding 35,000° F (the surface of the sun is 9000° F). These high temperatures cause rapid heating of surrounding air and extreme pressures, resulting in an arc blast. An arc blast is the explosive expansion of both the surrounding air and the metal in the arc's path. In an arc blast, vaporized solid metal conductors expand several thousand times their original volume and can travel at speeds in excess of 700 mph. The result of this violent event is usually destruction of the equipment involved, fire, and severe injury or death to any people nearby. The explosion takes less than one second and produces a brilliant flash, intense heat, and a pressure blast potentially equivalent to several sticks of dynamite.

The NFPA70E states electrical equipment should not be worked on while in an energized state. However, the equipment is considered to be energized until verified it has been de-energized. During the verification process the employee is potentially exposed to energized electrical parts. This exposure of the employee to energized parts places a requirement on the employer to provide Personal Protection Equipment (PPE). The NFPA70E outlines what type of PPE is required to be provided by the employer. The CED has two options to determine the type of PPE that complies with the NFPA70E:

- NFPA70E, 2004, article 130.3 states, "A flash hazard analysis **shall** be done in order to protect personnel from the possibility of being injured by an arc flash."
    - This option requires the employer to provide either an independent outside source or a qualified internal source to perform this analysis in accordance with the calculations defined by the NFPA70E or IEEE 1584. This option defines what level of PPE is required.
- NFPA70E, 2004, article 130.7(C-9) "Selection of Personal Protective Equipment" states, "When PPE is selected in **lieu** of flash hazard analysis, Table 130.7 (C-9a) **shall** be used to determine the hazard/risk category for a task."
    - This option requires the employer and the employee to make the determination of what level of PPE is required. This option shall **NOT** be used if the system has a short-circuit capacity or fault clearing times greater than what the tables were designed for.

There are three ways that arc flash energy can be decreased. First, the available short circuit current from the utility could be decreased (probably not possible). Second, the impedance in the local power distribution system could be increased (may be difficult and/or expensive). Third, the trip time of protective devices could be decreased. One of the more common suggestions to reduce arc flash energy is circuit breaker trip adjustment. The adjustment of circuit breaker tripping devices can decrease the amount of Arc flash energy that is the result of a fault. Care must be taken when implementing this solution, as protective device coordination may be affected when reducing the trip time of protective devices. However, this is probably the only viable alternative for the CED.

AMPP Upgrades

A reliability issue that comes up occasionally is installing black-start capability at the AMPP. AMPP relies on system power in order to start. Black-start generators can be installed at the plant to provide the necessary energy to start the plant. Generally, black-start capability is expensive and might not be used but once or twice in a decade.

The CED has identified alternatives to installing black-start generators at the plant, including back-feeding from the back-up generators at Arrowhead Regional Medical Center or just attempting to start the units manually. So far, NORESCO personnel have been able to start the plant without installing black-start generators by using temporary diesel engines. The Medical Center would probably be reluctant to back-feed the unit if it had to divert its emergency generation and was unable to meet internal emergency loads.

At this time, black-start capacity is probably a lower priority compared to other issues facing the CED.

Summary of Capital Replacement Requirements

The following table summarizes the proposed annual capital costs required to maintain the electrical distribution system in a reliable manner consistent with current environmental laws.

Proposed Capital Replacement Program Annual Costs

	Pole Replacement (20-year cycle)		Underground Line Replacement (10-year cycle)		Breaker Fuses (5 year cycle)		Substation Transformer Maintenance		SCADA Upgrades	
	Number of Poles	Cost	600 Foot Sections[1]	Cost	Fuses per year	Cost	2 Year Cycle	Cost	Cost	TOTAL ANNUAL COST
2012/13	80	$ 640,000	77	$ 924,000	10	$ 20,000	3	$ 75,000		$ 1,659,000
2013/14	80	$ 652,800	77	$ 942,480	10	$ 20,400	3	$ 75,000		$ 1,690,680
2014/15	80	$ 665,856	77	$ 961,330	10	$ 20,808	3	75,000	50,000	$ 1,772,994
2015/16	80	$ 679,173	77	$ 980,556	10	$ 21,224			50,000	$ 1,730,953
2016/17	80	$ 692,757	77	$ 1,000,167	10	$ 21,649				$ 1,714,573
Total										$ 8,568,200

Summary and Conclusion

The CED has identified variety of major issues that must be dealt with over the next several years. These issues include:

Power Supply

The CED needs to bring its power supply costs in line with surrounding utilities to lower retail rates. The CED will analyze and implement programs to:

- Change the CED's transmission status with the CAISO to minimize transmission costs;
- Change the CED's dispatch strategy for generation resources on congested paths;
- Acquire renewable resources to meet RPS obligations;
- Determine how to minimize the impact of Cap and Trade legislation on the CED's ratepayers;
- Developing in-house skills to adequately participate in the MRTU market and verify costs and account for all energy purchases and sales;
- Marketing the CED's surplus RA capacity to surrounding utilities and power marketers;
- Renegotiating interconnection fees with generators interconnected with the CED's transmission and distribution facilities.

Conservation and Demand-Side Management

The CED receives about $750,000 in public benefit funds to design and implement low income, conservation and demand-side management programs. The CED has done a good job of reducing energy consumption by its customers but should change the emphasis of its programs so that all customers benefit from the CED's programs. The CED will:

- Increase sales of the CED's surplus off-peak energy to increase revenues (discussed more in the attached Integrated Resource Plan);
- Meet AB 2021 State established conservation goals.

Legislative and Regulatory Obligations

The CED has not participated fully in the legislative and regulatory process to protect the interests of its ratepayers. The CED will:

- Participate in various legislative and regulatory forums to protect the CED's interests;
- The CED should participate fully in activities sponsored by Southern California Public Power Authority (SCPPA), California Municipal Utilities Association (CMUA and the American Public Power Association (APPA) which allows the utility to monitor and participate in legislative issues, pool resources, and share best business practices.

Organizational Issues

The CED has a number of vacancies and training issues that need to be addressed. The CED will implement the following actions:

- Ensure the CED has the appropriately trained personnel to successfully operate in the new California energy market. This means that CED employees need to be trained both internally and externally to participate in the MRTU market and understand the legislative and regulatory constraints affecting CED.

- Build and train an adequate, knowledgeable staff, including evaluating the need for each new position as it becomes vacant to see if the position still meets the needs of the CED. This does not mean or imply any lay-offs or restructuring of the CED personnel.

- The CED needs to emphasize safety issues including developing a written set of safety policies and procedures. CED staff, working with the International Brotherhood of Electrical Workers (IBEW) has begun a new safety program and established an internal safety committee to identify safety issues within the CED[26].

[26] The Audit identified the need for a Safety Officer and written safety procedures. A Safety Committee comprised of CED management and field crews has been created and tasked with developing safety procedures and a training schedule for CED field personnel. As part of the written safety procedures, CED safety statistics will be developed.

Customer Service Policy

The CED is working with Management Services to review the current tariff structure and customer fee structure to determine if rates and fees are established correctly. Some of the items to be studied include:

- Reviewing the CED's current rates to determine if they are collecting the correct amount of money from each customer class and are not over or under-collecting revenues;
- Analyzing the current fee structure to determine if it is appropriate;
- Ending all special contracts with customers that take service from the CED whose initial contracts have expired and moving them to the correct rates;
- Identifying the cost of meeting legislative and regulatory activities and communicate these costs to the CED's ratepayers.

The above recommendations are not all encompassing and it is likely that other measures to help meet the CED's Mission Statement will be identified. But these are a good first step in increasing efficiency and reducing the cost of providing electricity to Colton's residents and businesses.

Many of the above actions being taken by CED are in response to the Harvey Rose Audit on the operations of the CED. Not all the recommendations in the Audit are addressed right now, simply due to the large number of issues that must be addressed.

Attachment I

Regulatory Filing Requirements

REPORT / FILING	DESCRIPTION	REPORTING	DUE BY	AGENCY	ADDITIONAL DESCRIPTION
AB 162 - Power Source Disclosure Updated	See CEC 1305	ANNUAL	JUNE 1	CEC	
AB 2021 Energy Effciency Targets - part of IEPR	Annual targets for energy efficiency savings and demand reduction for next 10-year period and the basis for establishing those targets	EVERY TWO YEARS		CEC	
AB 32 GHG Reporting	Mandatory emission reporting for importers of electricity into California	ANNUAL	JUNE 1	CARB	Data reporting regarding MWH and emissions of imported energy resources
AB 32 GHG Verification	GHG Emissions verification for Facilities and Power Importers as covered entities	ANNUAL	SEPTEMBER 1	CARB	Outside verification of energy imports and emissions for CA power generators
AB 380	IEPR Resource Adequacy Policies and Protocols	EVERY TWO YEARS			
AQMD Title V AER program??		ANNUAL	MARCH 2	SCAQMD	
ARB Emissions Compliance	Auctions/Misc Cap n Trade Program details	ANNUAL-COMPLIANCE PERIOD?			CITSS program??
CAISO RA Reporting		MONTHLY?		CAISO	
CARB GHG (Facility portion)	Mandatory emission reporting for generators of electricity in California		APRIL 1	CARB	
CEC 100 Integrated Energy Policy				CEC	
CEC 1304 -Schedules 1 & 2- Quarterly Fuel/Electricity Report	Power Plant Generation and Fuel Quarterly Reports	QUARTERLY	FEB/MAY/AUG/NOV 15	CEC	This form provides electric generation and fuel use information related to power plant operations.
CEC 1304 -Schedule 3	Power Plant Environmental Annual Report	ANNUAL	FEBRUARY 15	CEC	The data submittals provide environmental information related to water and biological resources used by power plants in California.
CEC 1305 - Power Disclosure Program - may satisfy the RPS obligations TBD	Annual Power Disclosure Program spreadsheet-Power Content Labels (copies that were provided to customers)	ANNUAL	JUNE 1	CEC	Details of power content i.e. renewables, wind, etc % for disclosure to customer base. Starting CY 2008 we reported actual instead of Calif. %, as per requirements
CEC 1305 Verification	Annual Outside Verification- may be coordinated by SCPPA	ANNUAL	JUNE 1	CEC	Certified Public Accountant in good standing or Governing Board approval
CEC 1306A Sch 1 & 2 - Quarterly Sales Report	Electricity MWH Sales/Revenue by Month and Customer Classification (NAICS)	QUARTERLY	Q1-May 15, Q2-Aug 15, Q3-Nov 15, Q4-Feb 15	CEC	
CEC 1306C				CEC	
CEC 1306D				CEC	
CEC 1311	Annual fiscal year expenditures in EE , DR programs by category; expected & actual EE savings	ANNUAL	MARCH 15	CEC	
CEC 1344				CEC	
CEC 1345				CEC	
CEC 1346				CEC	
CEC 1347				CEC	
CEC 1348				CEC	
CEC 2505				CEC	
CEC 2514 (Energy Storage)	Energy storage services procurement targets, if appropriate	ANNUAL	MARCH 1, 2012 open a proceeding with governing board, Oct. 1, 2014 adopt targets, Dec. 31, 2016 report target activity, Jan 1, 2017 Report to CEC, Adl Report re targets Dec 2021 - report to CEC by Jan 1, 2022	CEC	Evaluate evey 3 years, energy storage application must be cost-effective, may use as RA, inlcude in planning reserves
				CEC	
				CEC	
				CEC	
				CEC	
Climate Action Reporting	TCAR emissions reporting if participating in voluntary program	ANNUAL	JUNE 1	TCR	Voluntary Program
Climate Action Verification	TCAR emissions verification if participating in voluntary program	ANNUAL	OCTOBER 1	TCR	Voluntary Program
DOE 92-41-NG (Import/Export)					
DOE Gas Imports					
EIA 767 (Plant Operation Report)	Steam -Electric Power Plant Operation and Design Report	ANNUAL	TERMINATED EIA-860/923 covers it	EIA	50 MW or higher combined nameplate
EIA 826	Random selection of EIA 861 reporters - for selected month	MONTHLY		EIA	Annual report of MWh generation, $ sales and purchases of energy.

EIA 860	Annual Electric Generator Report	ANNUAL	FEBRUARY 15	EIA	Electric utility and non-utility generator-specific plant data, including in-service date, prime movers, generating capacity, energy sources, existing and proposed generators, county and state location, ownership, and FERC qualifying facility status.
EIA 861	Annual Electric Power Industry Report	ANNUAL	APRIL 30	EIA	Online report imports/exports/generations, advanced meter data, EE programs and costs, revenue by customer class
EIA 871	Com'l Building Energy Consumption Survey	PER CEC REQUEST	PER CEC REQUEST	EIA	Special Request for Commercial Building energy consumption-as authorized by specific customer
EIA 906				EIA	
EIA 923	Power Plant Operations Report- supplementary	MONTHLY	Electric power generation, fuel consum ption, fossil fuel stocks, delivered fossil fuel cost and quantity	EIA	Power plant data
EIA 923S	Power Plant Operations Report	ANNUAL	APRIL 30	EIA	
EPA GHG Report	Mandatory Reporting for Power Plant Facilities of Emissions	ANNUAL	MARCH 31	EIA	Online e-GGRT tool
FERC 423 (Gas Cost/Vol)	Cost and Quality of Fuels for Electric Power Plants	MONTHLY		FERC	
FERC 552	Natural Gas Purchases/Sales affecting Price Indices per FERC order 704 - over 2.2 Million Btu annually	ANNUAL	MAY 1	FERC	Natural Gas Purchases/Sales affecting Price Index DA and Term
FERC 714 (Control/Plan'g Area Report)	Electric Control and Planning Area Report	ANNUAL	JUNE 1	FERC	
FERC 714 (Hourly loads)	Electric Control and Planning Area Report	ANNUAL	JUNE 1	FERC	
FERC 715 (Trans Planning Report)	Annual Transmission Planning and Evaluation Report	ANNUAL	APRIL 1	WECC	Applies to utilities that operate transmission facilities at or above 100kV. Not applicable to Glendale. Filled out only the Identification and Certification Form nominating WECC to make submittals on behalf of Glendale.
GASB - 53 Compliance	Annual listing of end of Fiscal Year open positions (Future Trades) to review whether these are reportable items	FISCAL YEAR	JUNE 30	INTERNAL AUDIT TO?	Listing of all open trades: Long Term Contracts,Term, DA, gas, transmission and electric that could be termed a derivative. Evaluate each for "outside" of normal trading activity.
NERC Compliance	Ongoing activity to document compliance obligations based upon NERC registered entities	AUDIT AS SCHEDULED	Non-Compliance should be self-reported	NERC	Procedures in place, document activity and compliance to requests for data
PDCI Sales Contract Rate Calcs					
RPS Compliance Program	See CEC 1304		JUNE 1	CEC	
SB 1 Solar Program	New program in 2008 to install 660 MW of PV in POU areas by 2016	ANNUAL	MAY 1	CEC	
SB 17	Modernization of CA T&D systems - Smart Grid deployment plans	ANNUAL?	JULY 1	CEC	Unsure if POUs are required
SB 1037 Energy Effciency				CEC	
SB 1368 Emissions Performance Standards	Established a standard for baseload generation owned or long-term contracts of POUs of 1,100 lbs CO2 per MWh	BEFORE APPROVAL		CEC	Requires posting of notices of deliberations on long-term investments on the CEC website
SCAQMD Form 500-N	Violation of Title V Permit Emissions for Power Plants	Verbal Report the next hour, Follow-up with form within 72 hours	Emissions violations must be reported immediately as there isa substantial penalty for non-reporting	SCAQMD	CEMS records, equipment failure record, calculations of lbs. exceedances
SCAQMD Forms 500-ACC	Annual Title V Compliance Report for Power Plants	ANNUAL	Emissions violations must vbe reported immediately as there isa substantial penalty for non-reporting	SCAQMD	Compliance activities Forms 500-N
SCAQMD Forms 500-SAM	Semi-Annual Title V Compliance Report for Power Plants	Last day of FEB, AUGUST	Violations and compliance to Title V terms and conditions, certification of compliance activities	SCAQMD	Compliance activities Forms 500-N
SF6 Emmisions	On line reporting	ANNUAL		EPA	
WAPA IRP Progress Reports	IRP- Power resource needs and evaluate new energy resources,energy savings, integrated approach to resource mix	Annual Update/ 5-Year Full Plan	FEBRUARY for ANNUAL /5 YEAR FROM ANNIVERSARY DATE OF APPROVAL	WAPA	
WECC Demand/Energy Load Survey	Forecast load data, generation, EE, outage info	ANNUAL	FEBRUARY	WECC	Part of BA report to WECC
WECC Hourly Load Data	Per WECC request NERC MOD-017	ANNUAL	Generally February	WECC	Could be part of BA report to WECC
WECC Unscheduled Flow Mitigation	Report for two years previous - flow on transmission lines to pay for WECC unscheduled flow maintenance and tracking	ANNUAL	JANUARY 30	WECC	Actual energy gnerated, imported, exported and system load for previous 3 years
WREGIS Reporting of LFG/Renewables	On-line upload of Renewable MWH	MONTHLY	WREGIS determined cut-off date for	WREGIS	For Dual Fuels need to put% in for Fuels

Fiscal Year 2012-2013 Budget

Budget

Electric Department

by Division & Category

Fiscal Year 2012-2013

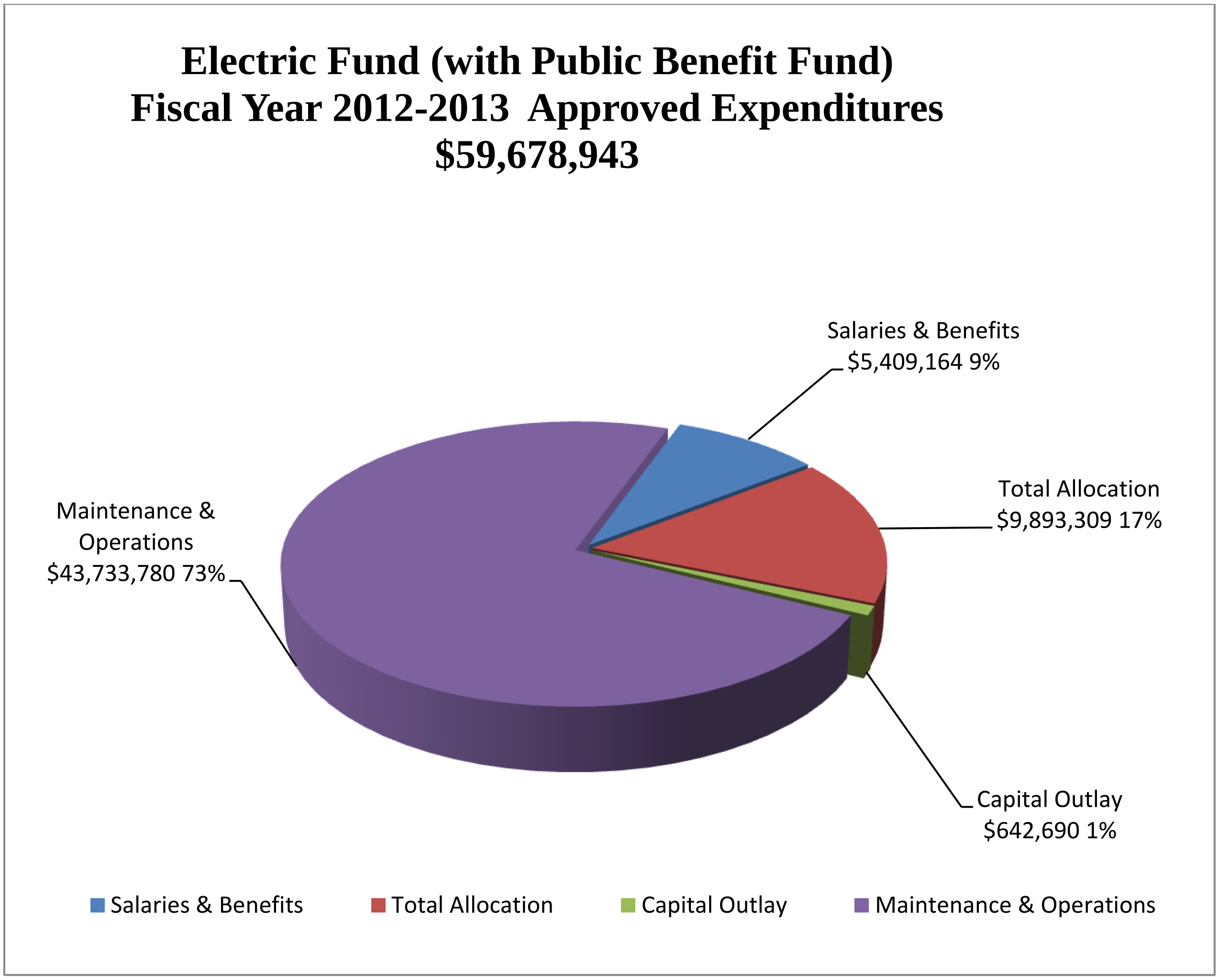
Electric Utility Divisions	Actual FY 2009-2010	Actual FY 2010-2011	Budgeted FY 2011-2012	Budgeted FY 2012-2013
Budget	**$54,301,042**	**$57,820,050**	**$59,483,008**	**58,649,810**
Electric Utility - Administration	$16,156,200	$15,707,267	$18,667,225	$17,581,739
Electric Utility - Engineering	$895,872.00	$618,067.98	$817,547	$821,710
Electric Utility - Substation	$1,635,882	$1,730,194	$1,850,869	$1,756,237
Electric Utility - Transmission/Distribution	$2,731,794	$3,075,004	$2,896,945	$3,168,414
Electric Utility - Rates, Regs, & Energy	$9,948	-$26,083	($5,032)	$14,958
Electric Utility - Purchase Power, Transmission/ISO	$27,117,111	$26,746,594	$28,839,877	$29,702,409
Electric Utility - New Development	$90,073	$312,066	$395,314	$488,009
Electric Utility - Agua Mansa Power Plant	$3,662,698	$1,661,739	$4,501,407	$4,492,006
Electric Utility - Street Lighting	$377,119	$395,813	$388,030	$388,030
Electric Utility - Power Resource Development	$28,505	$7,266.87	$191,180	$25,937
Electric Utility - Meters	$77,699	$204,814	$210,361	$210,361
Electric Utility - Public Benefit	$1,518,141	$2,446,741	$0	$0
Electric Utility - Underground Utilities	$0	$1,439	$313,560	$0
Electric Utility - N Substation Capital Improvement	$0	$2,874,803	$0	$0
Electric Utility - Energy Efficiency & Conservation	$0	$575,400	$415,725	$0

Electric Utility - Public Benefit Fund**	$0	$1,488,922	$1,822,403	$1,029,133

**Separate fund in 2010-2011

*certain amounts for debt and capital outlay reclassified to balance sheet.

Electric Utility Fund, by Category (Does not Include Public Benefit)	Actual FY 2009-2010	Actual FY 2010-2011	Budgeted FY 2011-2012	Budgeted FY 2012-2013
Budget	**$54,301,042**	**$55,374,749**	**$59,483,008**	**58,649,810**
Salaries and Benefits	$4,873,137	$5,006,442	$5,444,260	$5,409,164
Maintenance & Operations	$41,381,872	$38,350,645	$45,745,700	$42,942,130
Capital Improvements/Outlay	$197,089	$3,843,955	$167,951	$642,690
Total Allocations	$7,848,944	$8,173,705	$8,273,064	$9,655,826


Electric Fund (with Public Benefit Fund)
Fiscal Year 2012-2013 Approved Expenditures
$59,678,943
Salaries & Benefits
$5,409,164 9%
Total Allocation
$9,893,309 17%
Capital Outlay
$642,690 1%
Maintenance &
Operations
$43,733,780 73%
Salaries & Benefits
Total Allocation
Capital Outlay
Maintenance & Operations

Fiscal Year 2012-13

Revenues Summary

	Budgeted FY 2012-2013	Estimate FY 2013-2014	Estimate FY 2014-2015
Revenue	**$59,180,984**	**$61,141,907**	**$62,364,745**
Residential	$16,019,016	$16,531,928	$16,862,567
Commercial	$14,540,634	$15,006,210	$15,306,334
Industrial	$25,403,237	$26,216,622	$26,740,954
Public Benefit	$ 634,295	$ 657,319	$ 670,465
Sale to City Departments	$ 729,535	$ 752,893	$ 767,951
Other Revenue	$ 2,488,562	$ 1,976,932	$ 2,016,471

Fiscal Year 2012-2013

Expenses Summary

(With Public Benefit)

	Budgeted FY 2012-2013	Estimate FY 2013-2014	Estimate FY 2014-2015
Budget	**$59,678,943**	**$61,019,383**	**$62,239,770**
Salaries and Benefits	$ 5,409,164	$5,664,208	$5,777,492
Maintenance & Operations	$43,733,780	$46,573,142	$47,504,605
Capital Improvements/Outlay	$ 642,690	$174,736	$178,230
Total Allocations	$ 9,893,309	$8,607,295	$8,779,441