City of Colton
Electric Utility Department

2012 Integrated Resource Plan

August, 2012

Table Of Contents

Chapter 1
2012 Integrated Resource Plan

Introduction

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 Integrated Resource Plan* (IRP) will outline a strategy for dealing with some of the power supply issues that the CED faces and present alternative scenarios for resource procurement that are consistent with the current legislative and regulatory constraints facing the CED. The IRP also identifies some of the regulatory requirements that impact day-to-day power supply operations of the utility.

An IRP takes into account both supply and demand side alternatives for meeting customer loads. Supply-side alternatives include the procurement of new generation and transmission resources, especially new renewable energy sources that meet California's renewable energy portfolio requirements. Demand-side alternatives include programs that reduce energy and capacity requirements during high-use periods or increase energy sales during low-load periods when the CED has surplus energy. Conservation programs, such as the CED's refrigerator replacement program and compact florescent bulb replacement program, attempt to reduce the need for additional supply side resources.

The CED believes that it is better for the community and CED itself to purchase energy from its own customers, in the form of reduced energy requirements, rather than purchasing additional generation resources.

Historically, the CED acquired new resources to meet the electricity needs of its ratepayers at the lowest possible cost. But new state and federal environmental rules that went into effect in 2011 are going to reshape the CED over the next ten years. Complicating CED's planning efforts is that generation and transmission resources have lives of 20 to 50 years and decisions made today based upon current knowledge, legislation and technology, may be the "wrong" decision or a decision that results in higher costs ten or twenty years from now.

An IRP should be updated on an annual or bi-annual basis to address changes in the operating, legislative or regulatory environment. An IRP will change as the environment that the CED and its ratepayers live in and do business in changes. The IRP is a long-term planning document although with an emphasis on the first few years of operation. Today, many utilities are planning new transmission and generation resources that will not be operational until 2018 to 2025. Because of the long planning and permitting requirements of transmission and generation resources, utilities must begin the planning process years or decades in advance of need.

An IRP is also a way for the City Council to specify its long-term goals for the Electric Department. The Colton City Council can direct the CED to acquire resources for different purposes, for example to minimize the cost of electricity for the City's ratepayers or be a greener utility than required by law or to maximize economic development within the City or to promote energy conservation. This IRP is developed to meet the following goals:

- Minimize the cost of electricity service to Colton's ratepayers;
- Optimize the use of CED's generation and transmission resources;
- Meet all state and federal legislative and regulatory requirements;
- Develop demand-side programs to reduce energy use and costs by Colton's commercial and business customers;
- Encourage economic development within Colton by purchasing resources from local generators and developing demand-side programs that encourage businesses to locate and expand within Colton.

Because of the technical nature of many of the terms used throughout this IRP, a Glossary of Terms has been included in Appendix A.

Current Energy Resources

Since the early 1980's, Colton has invested in acquiring generation and transmission resources. Due partially to its small size that makes it difficult for CED to purchase an entire generation project, CED has generally participated with other municipal utilities in acquiring resources through the *Southern California Public Power Authority* (SCPPA), a joint-power agency[1]. SCPPA identifies potential resources for ownership and the member cities can choose which, if any, of the projects they wish to participate in and the capacity amount.

Colton currently has ownership or ownership-like rights in the following generation resources:

San Juan Generating Station, unit 3	30 MW
Palo Verde Nuclear Generating Station	2 MW
Magnolia Generating Station	10 MW
Hoover Generating Station	3 MW
Agua Mansa Power Plant	43 MW
Iberdola Wind Project	1 MW
Colton Landfill	2 MW
TOTAL	91 MW

In addition, CED has an energy swap agreement with the City of Anaheim under which Colton purchases renewable energy from small hydroelectric generation facilities in southern California and then deliveries the energy to the City of Anaheim as brown energy while keeping the renewable attributes to meet RPS requirements.

[1] In addition to Colton, SCPPA participants include the Cities of Los Angeles, Glendale, Burbank, Pasadena, Azusa, Banning, Riverside, Anaheim, Cerritos and the Imperial Irrigation District.

Forecast of Demand and Energy Requirements

CED has prepared a forecast of monthly peak demand and energy requirements for the period 2011 – 2015. The forecast illustrates the impact on CED's demand and energy sales since the beginning of the current economic downturn and suggests that economic activity in the San Bernardino area is improving and with it, electric sales and revenues for the CED.

Figure 1.1 Forecast of Monthly Energy Requirements (MWh)

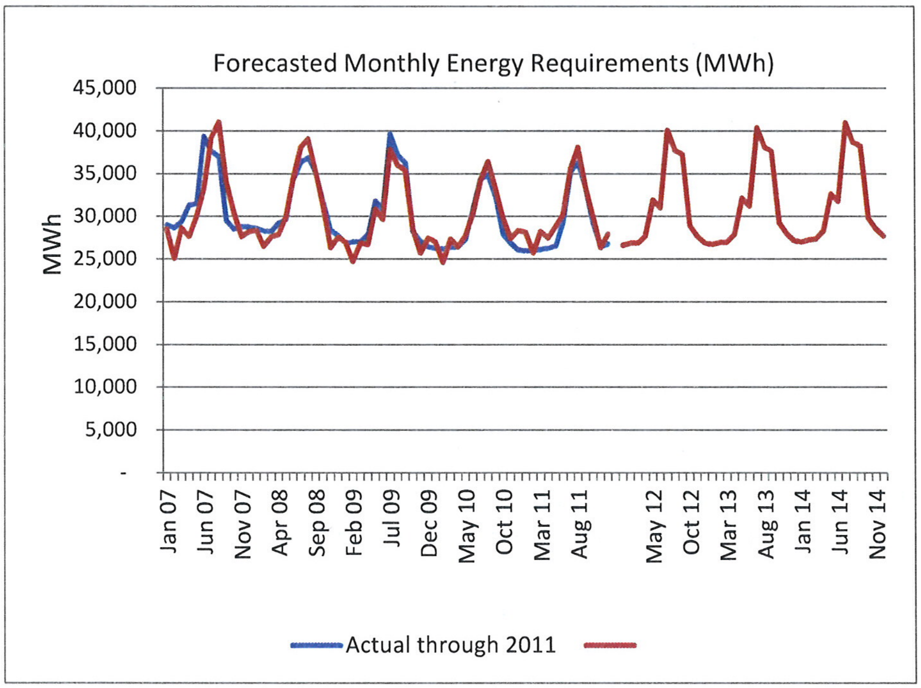
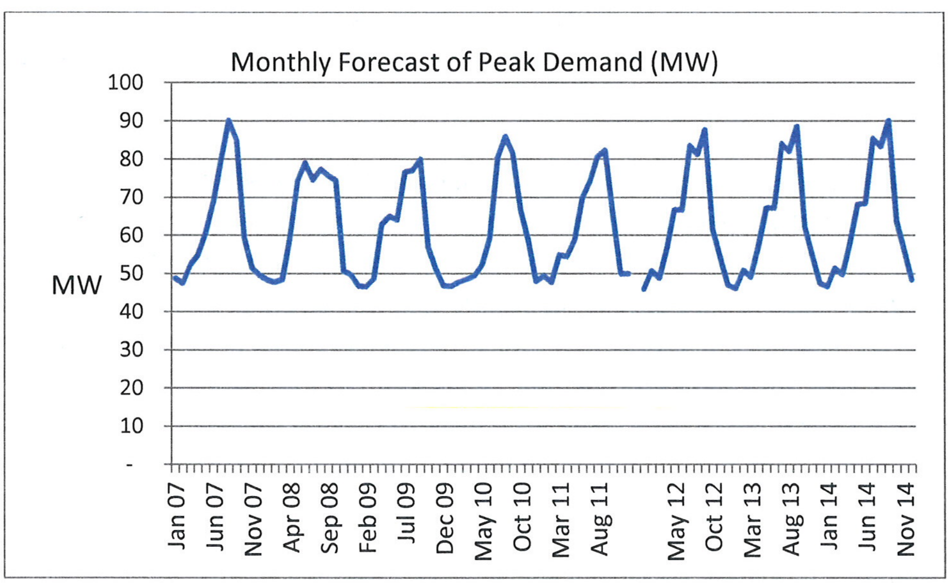


Figure 2.2 Forecast of Monthly Peak Demand (MW)



Legislative and Regulatory Requirements

For the past six years, state and federal agencies have been crafting rules for greenhouse gas reduction and environmental regulations, including renewable energy standards, and implementing new regulations intended to improve the reliability of the bulk power grid.

From the CED's viewpoint, the regulations having the greatest initial impact on costs include:

- Federal Clean-Air Act;
- California's AB 32 and SBX1-2;
- Implementation of the California Independent System Operator's Market Re-design and Technology Update;
- NERC compliance standards;

Federal Clean-Air Act

The Clean-Air Act was enacted in 1990. The Act defines the *Environmental Protection Agency's* (EPA's) responsibilities for protecting and improving the nation's air quality.

San Juan Generating Station is owned by SCPPA, PNM, APS and a number of smaller participants. CED has a 30 MW entitlement in *San Juan Unit 3* (SJ3), one of 4 units at the Station. SJ3 is CED's largest generation resource, providing approximately 65 percent of CED's annual electricity requirements.

Because of its size (1,800 MW) and location near the mouth of the Grand Canyon and initial lack of pollution control equipment San Juan has been a concern to environmentalists since the 1980's.

In 2006, *Public Service Company of New Mexico* (PNM), the plant majority owner and operator on behalf of the participants, began a $320 million emission reduction program that included bag houses and emission reduction equipment that significantly reduced particulate emissions including mercury, nitrogen oxides, sulfur dioxides and particulates.

The environmental upgrade was completed in 2009. But, in 2010, as a result of lawsuits filed by environmental groups, EPA proposed additional environmental upgrades that would require the Station to meet a nitrogen oxide emission rate of 0.05 lb/mmbtu[2] through the use of selective catalytic reduction, the *best available retrofit technology* (BART) that would reduce emissions by more than 80 percent. San Juan participants will have to meet these new limits within five years. The estimated costs of meeting the additional environmental rules will be between $750 million and $1 billion with Colton's share of costs around $18 to $20 million. The cost impacts on Colton will be felt beginning in 2013.

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[2] Mmbtu is one million btu's, a measure of heat content of fuels.

In March, 2012 the *New Mexico Public Service Commission* (NMPSC) announced that it would order PNM to look at alternatives to additional environmental upgrades including shutting down San Juan or converting some or all of the generators to gas-fired generation or renewable generator alternatives. The NMPSC is not convinced that the investment necessary to upgrade San Juan is greater than the benefits to the state. At this time, little is known about the negotiations, including the estimated costs of the alternatives or a final proposed ownership structure if units are shut-down or converted to natural gas generation but the CED is closely monitoring this critical issue.

<u>California Legislation and Regulation</u>

California legislators have passed a number of bills that impact the operations and power supply costs of CED. The specific new legislation potentially having the greatest impact on CED is AB 32, the *California Global Warming Solutions Act.*

AB 32 requires California utilities to reduce greenhouse gases associated with the generation of electricity. AB 32 also requires utilities, in conjunction with California's renewable portfolio standard requirements, codified in SB 2[3], to acquire renewable resources that have only a fraction of the greenhouse gases of traditional fossil-fuel fired generation.

Some of the major impacts of AB 32 include:

- Cap and trade emission allowance trading beginning in November 2012;
- Annual inventory of utility greenhouse gas emissions;
- Restrictions on the amount of new coal fired generation being imported into California;

In addition, AB 32 requires electric *Load Serving Entities* (LSEs) to acquire 20 percent of their retail load requirements from renewable sources for the period 2011-2013, increasing to 25 percent by 2016 and to 33 percent by 2020. These minimum renewable energy standards are called the *renewable portfolio standards* (RPS).

The RPS requirements were also legislated in SB 2 to reinforce the importance to the state of emission reduction and to remove the perception that the new regulations were introduced by a regulatory agency rather than the state legislature.

At this time, CED is not meeting its RPS requirements. 2011 renewable energy purchases were only around 7 percent, well below the 20 percent average for the first compliance period. However, CED can purchase renewable energy credits in 2012 to meet a portion of its 2011 obligations. Increasing the amount of renewable energy in CED's portfolio is one of the major tasks facing the utility going forward.

[3] Sometimes called SBX-1 2, referring to session 1 of the special legislation in the 2012 session in which it was passed

Cap and Trade

The *Cap and Trade* (C&T) program for electric utilities has begun with the first auctions in November 2012. At this time, CED is preparing for the implementation of C&T trade activities.

In 2009, CED was allocated *Emission Allowances* (EAs) from the *California Air Quality Management District* (CARB) equal to its estimated emissions. In November 2012, CED must sell at least one-third of these EA in the first C&T auction. The moneys from the sales of the allocated EAs must be put in a segregated account and then used to either purchase EAs to offset emissions or reduce emissions by more than the value of the EAs[4]. IF CED does not have enough EAs to offset its annual GHG emissions, it must purchase EAs (driving up its power supply costs).

At this time, CED is not sure that it has sufficient EAs to offset emissions so the impact of cap and trade on the utility is not known. An analysis of CED's emissions suggests that CED is approximately 30,000 to 40,000 EAs short (or about 15 percent) of actual emissions and will have to purchase these through the auction process. CED is spending considerable time attempting to determine how to comply with C&T training and pre-implementation activities, including how to participate in the EA auction in November.

California Independent System Operator (CAISO) and Market Re-Design

Prior to 2008, a utility could acquire a generation resource and transmission and schedule the energy into a *balancing area* (BA). The BA operator (*Southern California Edison* (SCE) in Colton's case) would sell energy to the utility if the utility's schedule was insufficient to meet its retail load or purchase energy if the utility scheduled too much energy into the BA. Utilities operated under a strict set of rules about the accuracy of their hourly forecast and scheduling operations and violating these rules resulted in financial penalties.

Beginning in 2004, the CAISO assumed control of most of the generation and transmission owned by California utilities.[5] The CAISO schedules and dispatches all the generation to meet load over CAISO controlled transmission. The CAISO also provides all ancillary services[6] necessary to meet the moment to moment fluctuations in energy demand.

Utilities like the CED that own or control their own generation resources can submit energy supply bids to the CAISO indicating the conditions under which they are willing to operate. Whether or not the

[4] Discussions on the potential use of money made from the EA process is still ongoing at the state legislature.

[5] The municipal utilities of Los Angeles, Sacramento, Modesto Irrigation District, Imperial Irrigation District and Turlock Irrigation District do not participate in the CAISO market directly.

[6] Electricity demand varies on a moment to moment basis and ancillary services meet these instantaneous fluctuations in demand by increasing or decreasing energy generation.

resource actually runs depends upon the contract terms, pricing and locational factors. But the utility is guaranteed that its costs are no greater than the cost of its submitted schedule[7].

The CED currently uses Shell Energy as its *schedule coordinator* (SC) to submit its daily schedules to the CAISO and to handle all daily interactions with the CAISO. The SC takes into account a variety of contractual and operating constraints on how to bid resources to the CAISO. At this time, the CED does not have the in-house expertise or staff to perform this service.

The CAISO market is only three years old and still evolving to meet new issues. At this time, CED is not prepared to take full advantage of some of the operational and transmission opportunities available to it in the new market. Of more concern is that the CED appears to be over-paying for services because of its lack of expertise in the MRTU market.

The CAISO is adopting new rules dealing with the integration of renewable resources into its hourly generation mix and allocating the costs of meeting California's loads.

Understanding the MRTU market rules is especially important in determining the best way to use Colton's *Agua Mansa Power Plant* (AMPP), the city-owned 50 MW gas-fired peaking plant (43 MW net) located within the City of Colton. AMPP provides capacity and energy to the CAISO controlled grid and acts as a physical hedge against power price spikes for the CED.

<u>Cap and Trade and MRTU</u>

One effect of the C&T regulations is that beginning January 1, 2013 wholesale prices are going to rise somewhat due to price of emission allowances. The price impact will be due to generators and POUs that are in the CAISO that cannot use freely allocated emission allowances to offset the cost of GHG emissions. The price impact has already shown itself in the forward energy markets where prices have jumped beginning January 1 2013. If an entity receives (free) allocated EAs, and can use them to offset emissions associated with wholesale purchases or sales, the value of the EAs should mitigate the price increases in the MRTU market, assuming the entity received the proper amount of EAs. If an entity did not receive the necessary amount of EAs to cover emissions, then their power supply costs will likely rise.

Until the market for GHG emissions actually begins, it will be difficult to determine the effect on the wholesale energy market. However, a range of impacts can be estimated by using a price of $20 per EA. Coal generation costs would rise by $20/MWh based upon emissions of 1 ton per MWh, while costs of natural gas generation would rise by $10/MWh based upon emissions of 0.5 tons/MWh.

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[7] There is a caveat dealing with transmission access. So long as the transmission lines have sufficient capacity, costs will not exceed the cost of meeting load with owned generation. However, if a utility does not have sufficient congestion revenue rights, then its costs can increase.

North American Electric Reliability Council Standards

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 insure 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.

Reliability standards vary slightly across NERC regions and LSE's. Electric 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 to meet different planning and reliability standards based upon their potential impact on the bulk power grid. Colton currently is in one of the lowest compliance levels (resource planner) because it is small and does not operate bulk transmission facilities.

Although CED operations cannot significantly impact the bulk power system, CED still must meet a small number of 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, CED's compliance obligations are among the least-stringent and intrusive of all entities.

In August 2012 CED meet with WECC staff to review its compliance efforts and had its first compliance audit. The audit results were good, with the WECC auditors finding no areas of non-compliance.

It is hard to overstate the importance of meeting NERC standards. Most of the standards are prudent industry standards, that is, things that a utility should be doing, but the standards formalize the documentation, 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 huge fines on entities for not being in compliance with reliability standards. While it is unlikely CED would ever 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 one million dollars per day in extreme cases for critical standards (essentially a refusal to comply with the standards), with NERC having levied fines as great as twenty-five million dollars although fines of $3,000 to $25,000 per violation are much more common.

While meeting the planning and operation standards were 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.

Risk Management

Risk management identifies the dollar amount at risk of loss due to changes in fuel prices or unanticipated outages of generation resources and recommends alternative actions to minimize this risk. The CED has not historically had significant risk management policies to prevent against over-purchasing natural gas or electric generation resources.

There are a number of ways to define and measure risk but a common risk metric is the *Value at Risk* (VAR).

The IRP proposes a risk management policy that attempts to limit the CED's VAR and requires multiple approvals for long-term firm power supply purchases to insure adequate oversight of purchases that impact the financial stability of the CED.

The major points of CED's Risk Management Policy include:

- Review by Colton's Management Services Director of any new long-term power supply purchases or firm power supply purchase exceeding $500,000 in any single month;
- Maximum monthly limits on CED's power supply VAR (or a limit on how much CED's energy costs can increase month to month);
- Required review and verification of CED's monthly energy balance;
- Review of monthly congestion costs and CRR status;
- Review of monthly costs of EA's and verification that CED has sufficient EAs to cover expected annual emissions.

Summary and Recommendations

The following recommendations are presented to lower CED's annual power supply costs and to bring CED into compliance with current RPS requirements.

- CED's annual power supply costs are high relative to other municipal utilities in the region. One of the reasons is that CED is over-resourced. CED should divest itself of either AMPP, all or a portion of San Juan 3 or the Magnolia Power Plant. At this time, it appears that the immediate financial impacts of divesting either Magnolia or AMPP are approximately the same and the final choice will depend upon the outcome of ongoing regulatory proceedings and CED's approved resource acquisition strategy;
- CED can reduce its annual transmission charges (that total about ten percent of CED's total power supply costs) by changing the contractual relationship between itself and the CAISO.
- If CED retains ownership of AMPP, it should attempt to market surplus RA capacity during the non-summer months. This RA capacity has a value of between $250,000 and $500,000 that is not currently being realized by CED;
- The cost of meeting required environmental upgrades at San Juan will be high. The CED should work closely with SCPPA to finance these costs and spread the cost over ten or more years to minimize the near-term impact.

CED has not kept up with many of the legislative and regulatory requirements that have been implemented in the past few years. In particular, CED needs to work meeting the RPS and greenhouse gas emission reduction rules.

- CED must prepare to meet California's cap and trade requirements that begin in July 2012. CED must train people to deal in the newly established emission allowance markets and acquire information on CED's emissions;
- CED has fallen far behind meeting California's RPS requirements. CED must train people to participate in regulatory and legislative activities dealing with RPS rules and regulations;
- CED must either begin acquiring renewable resources and renewable energy credits or pursue regulatory permission to meet the requirements on a delayed schedule. However, CED must begin working with the California Energy Commission and push for a regulatory decision rather than delay implementation of a RPS plan;
- CED has begun the process of acquiring up to 4 MW of solar PV generation near the Colton Landfill. Purchasing 1 MW per year of PV for the next 4 years, in addition to other renewable projects that the CED is involved in, may meet the State requirements.

CED personnel are not yet trained to participate in the California wholesale energy market. CED's personnel cannot verify invoices or balance energy purchases with generation.

- CED personnel need additional training in managing transmission costs. CED is incurring significant avoidable costs because of a lack of familiarity with congestion costs, congestion revenue rights and transmission contracts;
- CED has developed a Risk Management Plan that includes medium and long-term power purchases, renewable energy and emissions. At this time, CED's Risk Management Plan is being implemented by City executive management and elected officials.

If the above recommendations are followed, including additional recommendations that are being developed on CED's transmission resources, CED can lower total power supply costs and reduce regulatory risk.

Chapter 2
Demand and Energy Requirements

Introduction

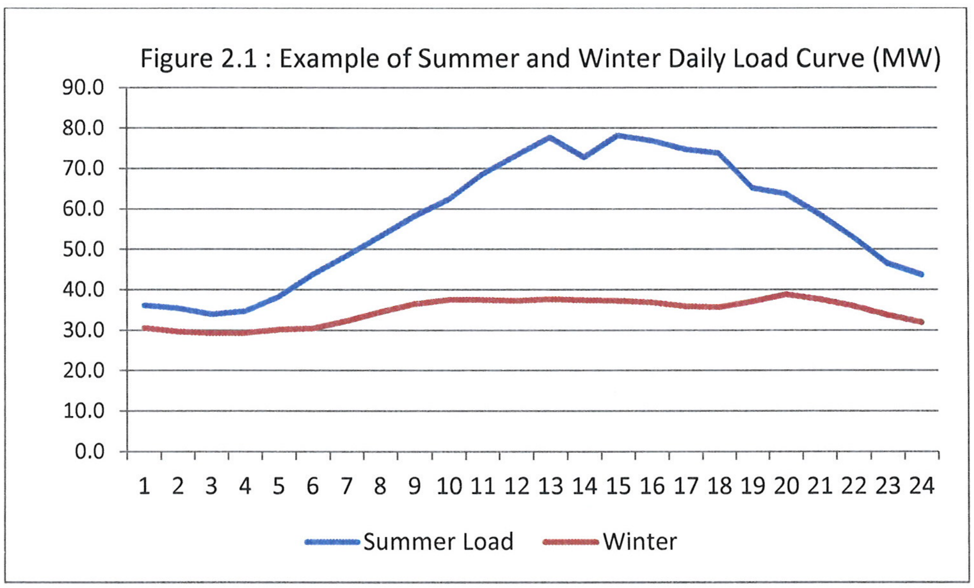
An IRP begins with a forecast of future demand and energy requirements. The demand forecast identifies how much generation capacity CED must have on a monthly basis for the next five years. The energy forecast identifies monthly energy needs and provides an estimate of monthly electricity sales to retail customers. The energy forecast also provides necessary information on the daily pattern of energy use needed to insure that the appropriate mix of generation resources is acquired.

Energy Forecast

Colton is a summer peaking utility with energy use increasing in the summer by as much as 50 percent compared to the winter months. During the non-summer months, Colton's energy use is around 25,000 MWh per month while in the three summer months energy use increases to around 37,000 MWh primarily as a result of increased air conditioning use.

Colton does not seem to have much winter heating load although extreme cold temperature does result in a small increase in energy demand.

The following figure illustrates how Colton's daily load varies between the summer and winter months.



During the winter months, load begins to build as people wake up around 0430 and prepare for work in the morning. Then the commercial industrial load begins around 0700 and stays fairly constant until around 1600 each afternoon and then begins to drop as companies start shutting down. As people arrive home, they cause the evening lighting load that causes a peak around 1900 and then load begins to decline throughout the evening before the cycle begins again the next day.

During the summer the same pattern is followed except the additional air conditioning load begins around 0700 as firms begin pre-cooling in anticipation of people arriving for work and then continues to rise during the day until around 1600 when temperatures begin moderating and people leave work. At around 1800 or 1900 there is a slight uptick in energy use due to residential lighting and air conditioning loads and demand then begins to decline as people begin going to bed around 2000.

While there is generally some increase in economic activity during the summer months, most of Colton's additional summer load is due solely to increased air conditioning use.

The above load profiles help illustrate two key points. First, Colton requires about 28 to 30 MW of baseload energy on an annual basis and secondly, Colton's summer peaks are greater than its winter peaks and require more generation capacity to meet the increased demand.

The daily load profiles also suggest that the primary drivers of electricity demand in Colton are temperature and economic activity.

High temperature results in increased air conditioning use, while economic activity (measured in terms of total employment) affects the number of commercial/industrial businesses with the City.

The relationship between monthly energy use, temperature and economic activity was analyzed to determine if a statistically valid relationship could be identified and if this relationship could be used to forecast future monthly energy requirements.

A regression analysis was performed on the data and the following equation was determined to be a good predictor of monthly energy use:

Monthly Energy Requirements = f(civilian employment, degree days heating and degree days cooling)[8]

Degree days cooling (DDC) is the sum of ((Daily High Temperature + Daily Low Temperature)/2) – 65. DDC is a measure of the daily heat build-up that results in air conditioning use. Conversely, degree days heating is equal to:

65 – ((Daily High Temperature + Daily Low Temperature)/2)

Neither DDC or DDH can be negative, so if the average daily temperature is below 65 degrees, the DDC is 0, while if DDH is greater than 65 degrees, then DDH is 0.

[8] The regression specification is:

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Civilian Employment	0.03008254	0.0007402	40.64091	8.7254E-44	0.0286	0.031565	0.0286	0.031565
DDC	25.0140536	2.16637299	11.54651	1.4904E-16	20.67597	29.35214	20.67597	29.35214
DDH	1.42558251	2.44401153	0.583296	0.56199486	-3.46847	6.319631	-3.46847	6.319631

Civilian Employment was chosen as a measure of economic activity and because the California State Department of Finance provides a forecast of Civilian Employment for 3 years into the future as part of the State Economic Forecasting Project and data is available on a monthly basis.

The following figure illustrates how the modeling performed in explaining monthly energy requirements and the 2012, 2013 and 2014 forecast.

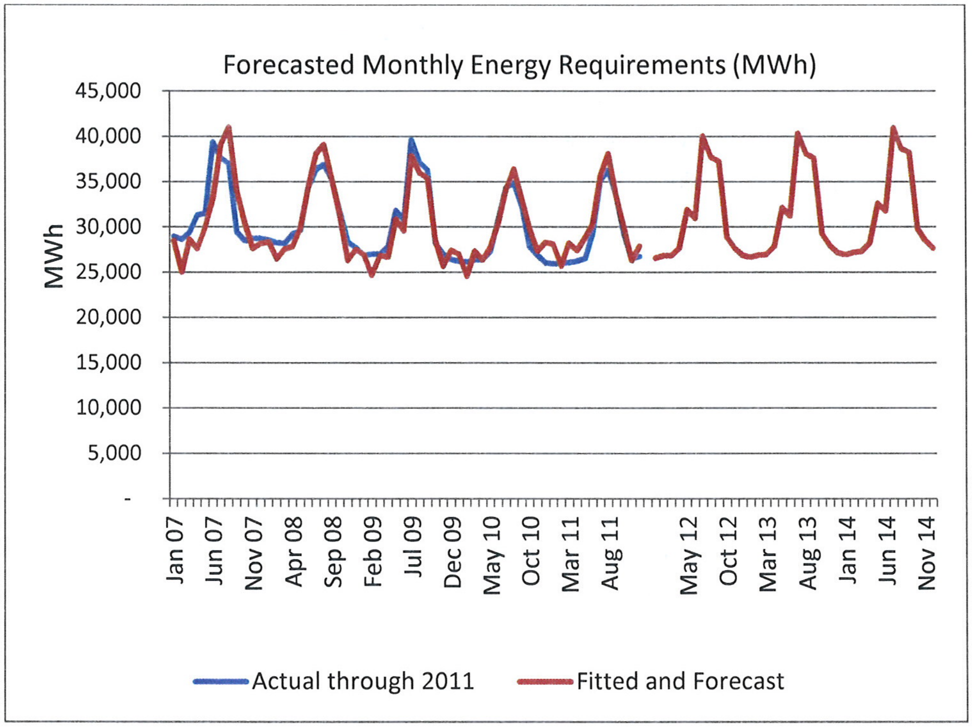


Figure 2.2: Forecasted Monthly Energy Requirements

In general, the model very slightly under-forecasts winter energy requirements (by about 2 percent) but otherwise tracks monthly energy use accurately.

The above figure also helps show what happened to the CED's financial position in 2008, 2009 and 2010. In FY 2007/08, CED's energy requirements were slightly greater than 375,000 MWh. With the beginning of the current "great recession," requirements have declined to slightly more than 354,000 MWh in FY 2009/10, a 5.5 percent reduction. 2010/2011 requirements improved very slightly in 2010/11 to 357,800 MWh. This reduction in energy requirements as a result of regional and national economic conditions has reduced CED's annual revenues by almost $3,000,000.

The forecast shows a slight improvement in energy requirements and sales from the 2010/11 levels to 362,000 MWh in 2011/12 and then to 370,000 MWh in 2012/13.

Peak Demand Forecast

Forecasting peak demand is more difficult that forecasting monthly energy requirements. Monthly energy requirements are the average of all the hourly demands during the month. Forecasting peak demand requires picking the single greatest interval during the month, in a small system which is impacted by changes in weather and where even a large motor turning on or off can cause the monthly peak demand to change.

Peak demand forecasts are necessary for the CAISO to determine how much generating capacity a utility is required to acquire. Demand forecasts are required by regulatory and operating bodies such as the California Energy Commission (CEC) which verifies CED's demand forecast and the Western Area Power Administration (Western) as a condition of receiving Hoover Dam capacity and energy.

In the CAISO market, LSE's are required to have generation capacity equal to 115 percent of their monthly forecasted peak demand. Because LSE's recognize that having excess generating capacity is expensive and might attempt to under-forecast demand, the CEC verifies any peak demand forecast on an annual basis to establish monthly capacity obligations. If the CEC determines that peak demand forecasts are incorrect, they will issue a revised peak demand forecast that must be used to determine the monthly capacity obligation.

Because of the difficulty in forecasting hourly peak demand with monthly statistical models, CED uses a capacity factor model. The capacity factor is defined as:

Capacity Factor = (Monthly Energy Requirements) / (Peak Demand * Days in Month * 24 hours per day)

The average monthly capacity factor for the past three (2009-2010 and 2011) years was calculated and then a monthly peak demand forecast was calculated based upon monthly forecasted energy requirements.

The monthly peak demand forecast is shown in Figure 2.3 below:

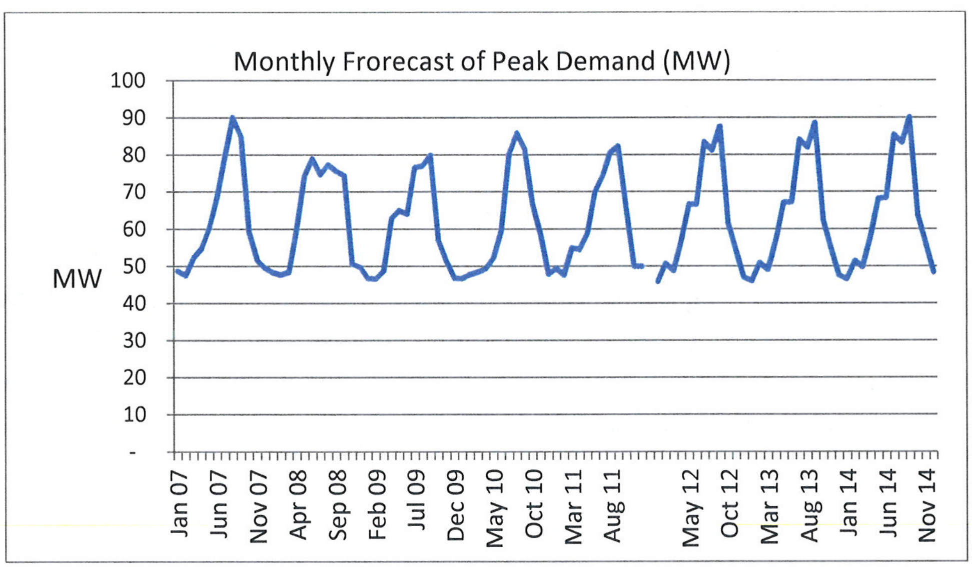


Figure 2.3: Monthly Peak Demand Forecast

The peak demand forecast shows the decline in monthly peak demands since the 2007 system peak and then forecasts a slight increase from 2011 levels as the economy improves. These monthly forecasted peak demands will be used to determine the CED's monthly capacity obligations in the future.

The monthly demand and energy forecasts for 2012 – 2017 are shown in Appendix B.

Chapter 3
Existing Resources

Introduction

The CED currently has 90 MW of capacity resources able to generate about 400,000 MWh annually at full capacity excluding the AMPP that is a peaking unit designed to operate at low capacity factors. This compares to CED's annual energy requirements of around 360,000 MWh. The following chapter discusses each of the different resources.

SCPPA

CED does not own or operate any generating or bulk power transmission facilities except the Agua Mansa Power Plant. All of CED's remaining power supply contracts are either through SCPPA or power purchase agreements with small generators within the City.

SCPPA is a joint-power agency that enters into power purchase and transmission wheeling agreements or owns generation and transmission resources on behalf of its member municipal utilities. SCPPA has no retail or wholesale load obligations.

Small utilities (such as CED) would have difficulty in acquiring financing to participate in large generation projects or transmission contracts. SCPPA enters into the agreements on behalf of its members and then guarantees any monthly financing or operating expenses by entering into power purchase agreements with member agencies. Each of SCPPA's projects has different participating utilities and only the utilities participating in a project are liable for costs associated with any project.

San Juan Generating Station, Unit 3

San Juan Generating Station (SJGS) is comprised of four units, each approximately 450 MW. Project participants include:

Units 1 and 2
- PNM: 50 percent
- Tucson Electric Power: 50 percent

Unit 3
- PNM: 50 percent
- Southern California Public Power Authority: 41.8 percent
- Tri-State Generation and Transmission Association: 8.2 percent

Unit 4
- PNM: 38.5 percent
- MSR Public Power Agency: 28.8 percent
- City of Anaheim, Calif.: 10 percent
- City of Farmington: 8.5 percent
- Los Alamos County: 7.2 percent
- Utah Associated Municipal Power Systems: 7 percent

CED's 30 MW entitlement in Unit 3 is through SCPPA's 41.8 percent ownership in Unit 3.

The SJGS is located in the four corners region, near the borders of New Mexico, Arizona, Colorado and Utah.

As the owner of SJ3, SCPPA administers the project on behalf of its participants, the Cities of Azusa, Banning, Colton, Glendale and the Imperial Irrigation District (IID).

SCPPA purchased its share of SJ3 in 1981 when the federal government was discouraging the use of natural gas for fear of dwindling supply and expected long-term shortages of residential heating fuel. In fact, the *1977 Fuel Use Act* prohibited the construction of new natural gas generation facilities. As a result, southern California municipal utilities purchased coal projects that provided long-term, stable sources of electricity at relatively low prices.

SJ3 is CED's largest single resource and generates about 250,000 MWh of energy in normal years.

Energy from SJ3 is transmitted to the Westwing substation near Phoenix under an agreement with Tucson Electric Power. From there, the CAISO delivers the energy to CED at the Vista Substation.

SJ3 Costs

The following table shows the annual costs and cost per MWh paid by the CED for energy from SJ3 between 2007/08 and 2010/11 and forecasted costs for FY 2011/12 through 2013/14.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	FY 2013/14
Total Cost	$14,097,576	$11,181,921	$14,577,414	$12,582,453	$12,799,000	$17,312,000	$17,169,000
Generation (MWh)	192,182	211,088	189,543	209,845	240,192	193,284	234,091
Average Cost/MWh	$73.40	$53.00	$76.90	$60.00	$53.30	$78.60	$71.80

Beginning in 2009, SJ3 costs have begun rising due to increased environmental regulations and several expensive maintenance requirements including the replacement of the boilers. The large jump in annual costs between 2011/12 and 2012/13 is due to the expected installation of SCRs necessary to comply with EPA's 2011 order to reduce NOx emissions from the plant.

<u>Magnolia Power Project</u>

CED has a 4 percent entitlement (10 to 12 MW) in the *Magnolia Power Project* (Magnolia) located in Burbank, California. SCPPA is the owner of Magnolia, with the other project participants including Anaheim, Burbank, Cerritos, Glendale and Pasadena.

Magnolia is a 310 MW combined cycle generator. A combined-cycle generator captures exhaust heat in a heat recovery steam boiler and uses the waste heat to produce more energy. Because of the recovery of the waste heat, Magnolia has a very high efficiency and produces much less emissions than simple-cycle generators that burn gas and emit heat and emissions through the stack.

Magnolia Natural Gas Supplies

CED's gas requirements for Magnolia are around 1,600 MMBTU/day. To meet the gas requirements, CED has entered into a number of long-term gas supply contracts.

Pinedale Project

SCPPA negotiated its first purchase of existing natural gas wells in 2005. The *Pinedale Natural Gas Project* (Pinedale) reserves are located in Sublette County, Wyoming.

Pinedale includes 38 operating oil and gas wells and associated lateral pipelines, equipment, permits, rights of way, and easements used in production.

In addition to Colton, that has 7 percent of the Pinedale Project, participants include Anaheim, Burbank, Glendale, Los Angeles, Pasadena, and the Turlock Irrigation District. Currently, Colton gets about 400 MMBTU/day from Pinedale.

The total cost of the Project was over $300 million. Los Angeles and Turlock hold their interests individually, while Anaheim, Burbank, Colton, Glendale and Pasadena have ownership through SCPPA.

Los Angeles serves as Project Manager for the overall project.

Barnett Natural Gas Reserves Project

In 2006, SCPPA members purchased natural gas reserves in Texas. The purchased assets are located in one of the most active and largest natural gas fields in North America.

The acquisition by SCPPA and Turlock Irrigation District of the *Barnett Natural Gas Reserves Project* (Barnett) is expected to yield approximately 37 billion cubic feet of equivalent proven reserves.

The operator of the properties is Devon Energy Corporation. Devon is the largest acreage holder and producer in the Barnett Shale, and at the time of purchase, had over 22 drilling rigs operating in the field.

Colton has a 9 percent entitlement in the project. The other SCPPA participants are Anaheim, Burbank, Pasadena, and the Turlock Irrigation District. (Turlock holds its interest individually). Currently, Colton receives about 400 MMBTU/day from the Barnett Project.

For economic, environmental, and reliability reasons, SCPPA members have invested heavily in base-load natural gas generation. This acquisition helps ensure the firm delivery of natural gas at stable prices in a highly volatile natural gas market.

Pre-Paid Natural Gas

SCPPA Bonds were issued in 2007 for the purpose of funding a lump-sum prepayment of future natural gas deliveries to the Project Participants over the next 30 years.

The total aggregate quantity of gas to be delivered by the gas supplier (J. Aron & Company) over the term of the Prepaid Natural Gas Sales Agreements is approximately 135 billion cubic feet.

SCPPA entered into separate Gas Supply Agreements with each of the Project Participants. Each gas supply contract provides for the discounted sale to Participants, on a pay-as-you-go basis, of all of the natural gas to be delivered to SCPPA over the term of the *Prepaid Natural Gas Sales Agreement* (Prepay Agreement).

The CED has an 11 percent share of the pre-paid natural gas supplies. The other SCPPA participants are Anaheim, Burbank, Glendale and Pasadena. The amount of daily gas varies by month from a high of about 64,000 MMBTU in July and August to as little as 22,000 MMBTU in the spring.

A fixed quantity of natural gas will be delivered over approximately 30 years by J. Aron & Company, with specified daily quantities of gas each month to delivery points on the natural gas pipelines that serve the Participants.

Under the structure of the Prepaid Natural Gas Project, J. Aron has also agreed to remarket, on a daily or monthly basis, quantities of gas designated by SCPPA or its agent at such times as these services may be necessary.

<u>Summary of Gas Contracts</u>

The following table summarizes CED's long-term gas contracts and costs:

	Prepay	Pinedale	Barnett	Total
Volume, dth per day	1,049	385	365	1,799
Production RelatedExpenses, $ per dth				
O&M		-1.73	-0.66	
Depletion Expense		-1.79	-1.63	
Debt Interests		-2.20	-1.86	
Subtotal Expenses		-5.72	-4.15	
Sale of Liquids		0.42		
Sale of Gas at Pool Index		3.29	3.30	
Gain/Loss		-2.01	-0.85	
Gas Cost, City Gate				
Purchase of Gas at City Gate Index	3.17	3.62	3.62	
Pre-pay discount	-0.75			
Swap Price	5.82			
Hedge Cost	3.65			
Loss on Production		2.01	0.85	
Gas Cost, City Gate	**6.07**	**5.63**	**4.47**	**5.65**
Fees to Marketers				
Contract Premium to Index	2.45	2.01	0.85	2.03

NOTES

The Index is the one year strip at the indicated delivery point as of February 24

The Pre-pay city gate index is seasonally adjusted per contract. The pre-pay cost is the $3.17/MMBTU index less the pre-pay discount of $0.75

Pinedale gas is sold to BP at the Opal Index and bought back from BP at the City Gate Index

The Pinedale volume is the 3Q 2011 volume adjusted for new production and declines

The Barnett volume is the 3Q 2011 volume adjusted for new production and declines. Barnett production is sold to Devon Energy and the money goes to purchase gas at City Gate

Summary of Magnolia Costs

The following table presents a summary of Magnolia's annual costs (including natural gas) between 2007/08 and 2010/11 and forecasted values for the following three years.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	FY 2013/14
Total Cost	$6,720,622	$6,295,353	$5,163,581	$4,9494,111	$6,536,000	$6,137,000	$6,197844
Generation (MWh)	64,403	67,305	73,788	49,738	59,906	55,769	59,906
Average Cost/MWh	$107.7	$93.50	$70.00	$99.50	$109.10	$110.00	$103.50

Palo Verde Nuclear Generating Station (PVNGS)

PVNGS is located near Phoenix, Arizona. The total capacity of the three generators is more than 4,000 MW. SCPPA owns 225 MW of capacity of which Colton has a 1.3 percent entitlement, or about 3 MW.

Power from the PVNGS is transmitted over the Mead-Phoenix/Mead-Adelanto projects and then over LADWP lines from Adelanto to SCE lines at Lugo for delivery to Colton.

Palo Verde is operated by APS and jointly owned by APS, Salt River Project, Southern California Edison Co., El Paso Electric Co., Public Service Co. of New Mexico, SCPPA and the Los Angeles Department of Water & Power.

CED has approximately 1 MW of capacity in each of the three units at PVNGS.

The following table shows the annual and forecasted costs of PVNGS to Colton.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	FY 2013/14
Total Cost	$1,815,431	$2,720,925	$852,216	$706,431	$1,075,190	$1,078,456	$1,085,022
Generation (MWh)	15,577	17,955	17,859	17,215	19,615	19,615	19,615
Average Cost/MWh	$54.20	$50.70	$47.70	$46.10	$44.60	$44.80	$45.10

Hoover Uprating Project

The Hoover Dam in Nevada is one of the most important power facilities for Southern California, with a total capacity of over 1,950 MW divided between Nevada, Arizona and California and over 1,000 MW delivered to southern California utilities.

In 1983, the generators at Hoover had to be replaced. SCPPA participants paid for the replacement which resulted in an additional 80 MW of generation capacity that was divided among the SCPPA participants (the Uprating Project).

The contracts for the uprating project expire in 2017 and legislation to reallocate the Hoover capacity away from California to Nevada and Arizona was recently extended by the US Congress. Colton's entitlement of 3 MW would be reduced by about 5 percent. However, the contracts would be extended for 50 years, insuring that Colton's entitlement would not be threatened again.

Hoover is Colton's most economical resources, with energy costs of less than $32/MWh.

The following table shows Colton's historical and forecasted costs for Hoover.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	FY 2013/14
Total Cost	$73,278	$75,618	$74.968	$84,341	$80,937	$82,051	$82,532
Generation (MWh)	3,420	3,352	3,056	3,388	2,617	2,617	2,617
Average Cost/MWh	$21.40	$22.60	$24.50	$24.90	$30.93	$31.40	$31.50

Agua Mansa Power Plant

The AMPP is a 43 MW (net) GE LM-6000 natural gas fired generating facility located in Colton. The AMPP became commercially operational in 2004.

AMPP was designed as a peaking facility to operate only a few hours per day, primarily during the summer on-peak periods. AMPP is too inefficient to operate as a baseload resource in comparison to other generation units in the CAISO. Instead, AMPP provides other benefits to the CED in terms of acting as a physical hedge against price spikes in the CAISO market and meeting most of CED's resource adequacy requirements.

The following table shows AMPP's annual costs and generation.

	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11
Total Cost	$3,927,011	$3,260,209	$3,025,775	$1,449,905
Generation (MWh)	50,868	52,280	30,030	15,207
Average Cost/MWh	$77.20	$62.40	$100.80	$95.30

The above costs for AMPP do not include debt service costs that would add approximately $3,220,000 annually to total cost, approximately doubling the average cost per MWh.

Beginning in 2011/12, the energy from AMPP is included in the total cost of non-firm and day-ahead purchases. This will be further discussed in the power supply cost forecast section.

Renewable Resources

CED has *power purchase agreements* (PPAs) with three renewable projects, the Colton Landfill, High Wind Project and Metropolitan Water District (MWD). Together, these three resources produce between 20,000 and 25,000 MWh of energy annually or about 6 to 7 percent of Colton's total energy requirements.

High Wind Energy Center

The *High Winds Energy Center* (High Winds) is located along northern California's Montezuma Hills in Solano County, midway between the population centers of San Francisco and Sacramento. It is one of the largest wind projects in California.

In September 2003, SCPPA member cities of Anaheim, Azusa, Colton, Glendale, and Pasadena joined together in a long-term agreement to purchase wind energy through power marketer Iberdrola Renewables from the owner FPL Energy. Merced Irrigation District is also a customer at this project site.

The site has 90 Vestas V80, 1.8MW wind turbines with a total generating capacity of 162 MW. SCPPA's share is 30 MW, or 20% of the project output and CED's share is 3 percent or 1 MW.

The cost of energy from the High Winds Project is $53.50/MWh and Colton receives about 8,500 MWh annually from the project.

Colton Landfill

The Colton Landfill is a biogas generation facility located on the southwest portion of Colton on the site of the County landfill. A collection system collects biomethane released by the decomposition of trash buried in the landfill and then uses this biomethane as fuel for several small generators located at the site. Hourly generation can be as much as 1.2 MW but depends upon a variety of factors such as wind, temperature and moisture that affect the speed of decomposition and efficiency of collection.

Landfill generators generally have a life of around 12 – 15 years with biomethane production beginning to decline around ten years after the landfill has been closed.

The cost of energy from the Colton Landfill is $90/MWh. In 2011/12 Colton will receive about 8,000 MWh from the Colton Landfill.

<u>Metropolitan Water District Small Hydroelectric Projects</u>

SCPPA purchased up to 17 MW of power, generated from four small hydroelectric generating plants located along the *Metropolitan Water District* (MWD) distribution system. Output is dependent on water flow from the State Water Project. Because each of the four projects is less than 30 MW, they qualify as renewable energy sources under RPS rules.

CED receives 22 percent, or up to 3.7 MW, of any generation as a renewable energy supply. CED separates the energy into two components, brown energy and the green renewable capacity components. CED then sells the energy to the City of Anaheim and the hourly index price for the CAISO and keeps the green renewable energy capacity component for RPS compliance.

The net result of the sale of the MWD energy is that CED keeps the renewable energy credit at a cost equal to the difference between $95/MWh (the purchase price from MWD) and the CAISO index price. For the past year, this spread has been around $45- 50/MWh. However, CED does not receive any energy from the MWD projects.

On an annual basis, CED has been receiving about 10,000 MWh annually from the purchase.

<u>Summary of Renewable Resources</u>

CED currently has about 26,000 MWh annually of renewable energy or about 7 percent of total sales. Under SB 2, CED is required to purchase or generate about 70,000 MWh annually during the period 2011-2014. A portion of the shortfall can be satisfied by the purchase of *Renewable Energy Credits* (RECs) in the marketplace but CED will still be short some 15,000 – 17,000 MWh of renewable energy that it should begin acquiring as quickly as possible, subject to cost limitations.

<u>Transmission</u>

In addition to its generation resources, CED owns or contracts for significant transmission resources to transmit (or wheel) energy from the various generation resources to Colton.

CED's transmission costs are about $3.1 million per year. Controlling CED's transmission costs are a key component of any power supply cost containment strategy.

Almost all of CED's energy is transmitted over CAISO transmission facilities.

CAISO Transmission

The CAISO has assumed operational control of all 220 kV and above transmission of all *participating transmission owner* (PTO) utilities and the 115 kV and 69 KV transmission of PG&E and SDG&E. The CAISO operates all this transmission to minimize daily transmission costs for the system as a whole.

Each PTO utility charges the CAISO the total cost of its transmission plus a rate of return on any owned transmission assets. The charge is called a utilities *transmission revenue requirement* (TRR). The CAISO aggregates the TRRs of all PTOs and then divides this amount by the forecasted energy use on its system for the year in order to develop a transmission wheeling rate. This rate is a "postage stamp" rate paid by the entity that takes final delivery of the energy. It is called a postage stamp rate because every entity pays the same amount regardless of the voltage (so long as it is above 115 kV) or how far energy is wheeled across the system.

Any generator or load can use the CAISO system. To manage the use of the transmission system, the CAISO uses congestion pricing. In effect, if entities schedule more energy over a transmission path than the path can transmit, the CAISO begins adding a congestion charge to encourage entities to either move energy to other transmission paths or to back generation down over that path. The CAISO keeps increasing the congestion charge until generation is reduced to the transmission limits over a specific path[9].

Congestion charges can be quite high over some constrained paths, often more than the price of energy being transmitted over these lines.

The congestion charge is a tradable commodity with entities being allowed to purchase and trade the rights to receive congestion charges over a specific transmission line segment. These rights to receive congestion charges are known as *congestion revenue rights* (CRRs).

Load serving entities that use a specific transmission path are eligible to receive an allocation of free CRRs tied to the length of their ownership or power sales purchases from specific generators. Generally, only about two-thirds of the capacity in a generator is allocated CRRs with the utility (or LSE) subject to congestion charges for the remaining capacity. If the LSE wants to protect itself against congestion charges for all its generation, it will have to participate in the CRR auctions and bid against other entities for the right to recover any potential congestion charges.

The risk of a CRR is that if a LSE has CRRs over a particular path and the congestion changes to the opposite direction, the owner of the CRRs now has to pay congestion costs. That is, acquiring CRRs is not a risk free proposition.

[9] This is actually done by a mathematical formula approach that creates a large enough congestion charge to push higher priced resources out of the dispatch order.

CED has the following entitlements to transmission service associated with High Voltage Transmission Facilities:

Mead-Adelanto Project

The Mead-Adelanto Transmission Project is comprised of a 500 kV alternating current transmission line extending between the Marketplace Substation in southern Nevada and Adelanto Switching Stations near Victorville.

The City of Colton is entitled to firm bidirectional service equaling 1.75% of the facility's 1,291 MW rated capability, or 22.59 MW.

Mead-Phoenix Project

The Mead-Phoenix Transmission Project is a 500 kV alternating current transmission line a 500 kV alternating current transmission line extending between Westwing and Perkins Substation. CED is entitled to firm bidirectional service equaling 0.2308% of the facility's 1,923 MW rated capability, or 4 MW.

CED also has an entitlement in the 500 kV alternating current transmission line extending between Perkins and Mead Substations. With regard to this component, the City of Colton is entitled to firm bidirectional service equaling 0.2308% of the facility's 1,923 MW rated capability, or 4 MW.

The Mead-Phoenix Transmission Project includes a segment of Marketplace-McCullough transmission line, a 500 kV alternating current transmission line extending between the Marketplace and McCullough Switching Stations.

As part of both the Mead-Adelanto and Mead-Phoenix Transmission Projects, CED is entitled to firm bidirectional service equal to its transmission entitlements in Mead-Phoenix and Mead- Adelanto between McCullough and Marketplace (4 MW in Mead-Phoenix and 22.59 MW in Mead-Adelanto).

Adelanto-Victorville/Lugo

The Adelanto-Victorville/Lugo path is comprised of 500 kV alternating current transmission facilities extending between the Adelanto Switching Station, the Victorville Switching Station, and the midpoint of the Lugo-Victorville 500 kV line.

CED is entitled to firm bidirectional service over this path in an amount up to its transmission service entitlement in the Mead-Adelanto Project (i.e., 22.59 MW).

Lugo/Victorville 500 kV to Vista 230 kV

CED's 21 MW entitlement to firm unidirectional network service from the midpoint of the Lugo/Victorville 500 kV line to the Vista Substation 230 kV Substation is derived from two separate agreements with the *Southern California Edison Company* (SCE):

- One agreement providing for 3 MW of service.

- One agreement providing for 18 MW of service.

Mead 230 kV to Vista 230 kV

Colton's 3 MW entitlement to firm unidirectional network service from the Mead Substation 230 kV bus to the Vista Substation 230 kV bus is derived from a firm transmission service agreement with SCE.

Devers Substation to Vista 230 kV

CED's 14.043 MW entitlement to firm unidirectional network service from the Devers Substation to the Vista Substation 230 kV bus is derived from a firm transmission service agreement with SCE.

<u>Summary of CED's Generation and Transmission Portfolio</u>

CED has sufficient transmission contracts to bring energy from all its resources to the City except for SJ3 where CED depends upon CAISO transmission. CED does have some CRRs to protect against congestion costs from the Phoenix area to Colton, but not enough to avoid monthly congestion payments.

CED is also paying congestion charges for energy transmitted within the LA basin to Vista substation that might be able to be protected with CRRs.

CED is currently planning on changing its transmission contracts from its existing transmission contract (ETC) status to a Participating Transmission Owner (PTO) status. As a PTO, CED should be able to reduce its annual transmission costs but CED will have much more exposure to congestion and will have to manage daily congestion costs more closely than it has in the past. The majority of CED's congestion risk will remain between Palo Verde and Colton, where it currently is.

Chapter 4
Legislative and Regulatory Issues

Introduction

The past seven years have seen legislative and regulatory bodies impose numerous environmental and operating requirements on electric utilities. While the new legislation will reduce *Greenhouse Gas* (GHG) emissions and result in less pollution, the legislation will also cause increased operating costs in the near term while likely reducing costs in the future. The legislative and regulatory activities have also significantly changed the way utilities plan for and acquire new transmission and generation resources. No longer do utilities plan solely to acquire the least-cost resources. Utilities also have to explicitly address regulatory issues that limit their ability to acquire renewable energy supplies from economic resources due to geographical limitations on the location of these resources and transmission congestion issues.

The major legislative and regulatory initiatives facing utilities today include:

- GHG reduction, including the Federal Clean Air Act and California's AB 32 Greenhouse Gas Reduction Law and renewable portfolio standards;
- Changes in the California wholesale electricity market.
- North American Electricity Reliability Corporation's (NERC) Operating Standards and cyber-security requirements;

Implementing many of the requirements is difficult due to over-lapping regulatory bodies that may or may not have jurisdiction on some issues. For example, until 2011, California required both the *Public Utilities Commission* (CPUC) and *California Energy Commission* (CEC) to regulate RPS compliance. However, the CPUC did not have jurisdiction over publically-owned utilities and the CEC does not (generally) have the ability to enforce their decisions. In many situations, local regulatory bodies, such as the Colton City Council, were able to declare themselves in compliance with state renewable energy requirements. As a result, both federal and state legislatures have resorted to putting the enforcement of new rules under environmental bodies such as the federal *Environmental Protection Agency* (EPA) and the *California Air Resource Board* (CARB) that have jurisdiction over local utilities regardless of conflicting regulatory overlaps.

Federal Clean Air Act

The greatest immediate financial impact on CED is due to more rigorous enforcement of the Federal Clean Air Act at SJ3. SJ3 was one of the largest emitters of nitrogen oxides in the west but between 2006 and 2010 installed new environmental controls that reduced daily emissions by up to 80 percent and significantly reduced mercury and carbon dioxide emissions. The cost of this environmental upgrade was $320 million and CED's share was approximately $5.45 million.

Even with the environmental upgrade completed, EPA was required to open another investigation on regional haze caused by San Juan as the result of a lawsuit filed by the Sierra Club and *Natural Resources Defense Council* (NRDC). At the conclusion of the investigation, EPA ordered the San Juan owners to install *Selective Catalytic Reduction* (SCR) equipment on the plants at a cost of between $750 million and $1.0 billion and have the upgrades completed by 2017.

CED's cost-share of these cost upgrades would be between $18 – 23 million, with the cost impacts beginning in 2013.

The San Juan participants appealed EPA's initial decision and requested that they be allowed to install *non-selective catalytic reduction* (NSCR) equipment that would reduce emissions by 80 to 90 percent of the SCR levels but at only around 10 percent of the total cost.

In 2011, EPA rejected the San Juan owner's proposal and reaffirmed their initial decision on the need to install SCRs but gave the owners of San Juan five years to complete the work rather than three as initially proposed. However, this did not change the schedule for SCPPA participants.

PNM also filed suit against the EPA requesting a stay of EPA's order. In March, 2012 the 10th Circuit Court of Appeals rejected PNM's request for stay and ordered work to proceed on the environmental upgrades.

The San Juan owners are evaluating their options, that include shutting down some or all of the units at the plant, converting some of the units to natural gas and installing SCRs on the remaining units or proceeding with the installation of SCRs. Currently, engineering studies have begun in anticipation of installing the SCRs.

Shutting down the facility at this time is not a realistic alternative because of the outstanding debt on the project and coal contracts that would have to be paid regardless of whether or not the plant was operating. In addition, the participants would have to acquire replacement energy for the lost production. Converting some of the units to natural gas fired generation would require a significant financial investment by the participants. The best alternative for CED appears to be installing NSCR at a fraction of the cost of SCRs and agreeing to shut units down in the future[10].

In March 2012 the *New Mexico Public Service Commission* (NMPSC), ordered an inquiry into alternatives for San Juan. Options that are to be studied include conversion of the plant to a renewable site and natural gas generation rather than coal generation. At this time, it is not known what the NMPSC will determine and then order PNM to do and how this would affect the other participants.

[10] Of course, this could always change depending upon what financial arrangements between the project participants are ultimately negotiated.

The investment in SCRs also opens a different issue at the state regulatory level. SB 1368 prohibits investment in new coal resources by California LSE's. The *National Resource Defense Council* (NRDC) and other environmental groups have requested the Energy Commission to block investment in San Juan (and other coal plants owned or the source of power for power contracts) for the SCRs by California utilities. If the CEC agrees with NRDC, utilities that have invested in coal plant upgrades could be found non-compliant with SB 1368 and further investment blocked. How this would impact SCPPA's obligations under the Clean Air Act to reduce emissions from San Juan and SCPPA's contractual obligations under the power purchase agreement would have to be determined.

State Clean Air 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 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 statewide 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 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 apply to 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 starting in 2012

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 percent. 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 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 cap and trade 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.[11]

Cap and Trade

The most immediate issue facing 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, but not impossible, task for the CED to catch up with the regulatory requirements and not incur CARB penalties for exceeding its emission allowances.

Under a C&T program, the total amount of emissions in tons per year (measured in CO2e or carbon dioxide equivalents) is capped by 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.

CARB then allocated each entity within each covered industrial sector *emission allowances* (EA). 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 November 2012, entities that have been assigned EA will have to sell these EAs in an auction process. 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 that are cost effective. But if a utility invests in new technologies, it still must have enough EAs to cover its annual emissions.

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

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 the EAs necessary to offset its emissions and can then sell any remaining EAs.

Each year, the amount of EAs available and allocated to each entity will decline, forcing all entities to reduce their emissions by about 1 percent per year in aggregate.

At this point, CED does not know with any precision what its emissions for 2009, 2010 and 2011 were. CED has been allocated 234,600 EAs for the auction process but has not reported its estimated emissions nor performed the annual audit of emissions for some prior years. CED has reported its 2011 electricity sales and imports of energy from out-of-state sources which were used by CARB to estimate annual emissions and is awaiting results from a third-party verifier on the accuracy of its estimates.

Initial estimates suggest that CED's emissions are between 255,000 tons per year and 265,000 tons per year. If actual emissions are less than 234,600, then CED can sell excess EAs and use the revenues for reducing power supply costs by investing in renewable alternatives. If actual emissions are greater than 234,600 tons, then CED will have to purchase EAs.

CED personnel are being trained to participate in the auction process, including developing a mechanism for calculating emissions, track CED's emissions relative to its EAs and either buy or sell EAs as necessary to remain compliant with the C&T program. 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.

<u>Renewables Portfolio Standard (RPS) Legislation</u>

The second major component of AB 32 was the requirement of a renewable portfolio standard for all LSEs within California. Governor Schwarzenegger has 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 could be applied to publically-owned utilities.

In April 12, 2011, Governor Brown signed SB 2, codifying into law an increase of the RPS mandate to 33 percent 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 can separate the brown energy component from the green energy attributes and sell the green energy as a REC.

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 limited by SB 2.

Compliance Categories of RPS Resources

SB 2 established three *Power Content Categories* (PCC), or "buckets," for RPS compliant resources. PCC 1 is bundled green energy produced within California or that has its first point of interconnection with the CAISO controlled grid. PCC 3 is RECs.

PCC 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.

Categories (Buckets)	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 Califonria balancing authority, or; B. Are schedule into a California Balancing auhority without substituting elelctricity from another source. If another source provides real-time ancillary services to maintain an hourly import schedule. 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 resources will count, or; C. Have an agreement to dynamically transfer electricity to a California balancing	Period 1: Minimum of 50% of the energy that is counted towards RPS target Period 2: Minimum of 65 percent Period 3: Minimum of 75%
2	Firmed and shaped energy or RECs from eligible resources providing incremental electricity and scheduled into a California balancing authority	Period 1: Maximum of 50% Period 2: Maximum of 35% Period 3: Maximum of 25%
3	Energy or RECs from resources that do not meet the requirements of categories 1 or 2, including unbundled RECs	Period 1: Maximum of 25% Period 2: Maximum of 15% Period 3: Maximum of 10%

The legislative and regulatory process for SB 2 has not yet been completed. The CEC is still holding hearings on a rulemaking for the 33% RPS standard and several bills are being heard in the legislature to clarify portions of SB 2.

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 CED's entitlement in the Hoover Uprating Project cannot be counted as a renewable resource. 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 percent of CED's current renewable energy obligation. 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 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 CED avoid any penalties for CARB non-compliance.

In March, 2012 the CEC issued a *Notice to Consider Suspension of the RPS Eligibility Guidelines for Biomethane.* In this Notice, the CEC stated that it did not believe that biogas injected into the interstate pipeline system qualified as a renewable resource. Onsite uses of biogas, such as a landfill, would still qualify.

CED would like to be able to use biogas in the AMPP to reduce the cost of compliance with RPS standards. Having biogas generation not counted as a RPS eligible resource would reduce the options available to CED to meet RPS standards.

A bill introduced by Gatto (AB 1900) would explicitly require the CEC to treat biogas as a RPS eligible resource and is supported by the CED.

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.[12] Bundled transactions, which involve both energy and credits, are those that serve California load

[12] 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.[13]

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.[14] 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. CED will endeavor to take full advantage of RECs to meet its RPS obligations, including the issuance of a REC-only RFP in 2012.[15] 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

CED is not prepared for the impact of the Clean Air Act and AB 32. The potential financial impacts of EPA actions on SJ will result in cost increases for CED beginning in 2013. If SCPPA agrees to finance the SCR upgrades, the cost impact will be mitigated but CED would still see additional costs of $1,350,000 – $1,500,000 annually.

The best alternative for 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, CED has begun discussing the issue with local legislators.

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

CED also is not in compliance with the RPS standards. CED only has about 7 percent renewable resources as opposed to the statutory requirement of 20 percent. For 2011 and 2012, CED can purchase RECs rather inexpensively to bring its renewable portfolio up to 11 or 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, CED's shortfall will be only 18,000 MWh for the first compliance period.

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[13] D.10-03-021, pp. 2-3.

[14] 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).

[15] 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.

If CED's planned solar PV resources come on-line in 2015 (further discussed below), CED's renewable percent climbs to almost 17.5 percent. However, this will still be below the statutory requirement of 25 percent for the second compliance period.

A discussion of how CED intends to meet its RPS requirements is given in Chapter 6.

North American Electricity Reliability Corporation (NERC) Standards

In August, 2012 CED was audited for compliance with applicable NERC reliability standards. This was the first time CED is audited and required significant preparation to insure CED met its reliability standards.

NERC was established in 1968 to coordinate electricity operations of the bulk power system following the great *Electricity Blackout of 1965*. NERC established nine reliability coordinating regions, separated electrically from each other. The largest reliability region is the *Western Electric Coordinating Corporation* (WECC) that includes 9 western states and parts of western Canada and Baja Mexico.

WECC has jurisdiction over CED.

In 2007, NERC was given the authority to establish and enforce reliability standards. Most reliability standards are simple prudent utility operating requirements. However, NERC requires documentation that utilities are actually following these standards. No longer can a utility just state that it is in compliance, it must document compliance and prove that its documentation is accurate through a relatively rigorous process.

There are different reliability standards for entities based upon their ability to affect the bulk power system. Independent system operators have the most elaborate requirements, with balancing authorities having the next most elaborate set, followed by bulk transmission owners and generators and then distribution providers.

CED is currently classified as a resource planner but may be upgraded to a generation owner in the next year due to its ownership and control of the AMPP. This will add to CED's annual compliance reporting obligations.

CED's obligations under currently applicable requirements are to prepare an annual forecast of demand and energy requirements, provide 66 kV planning and operating information to the local transmission provider (SCE) and provide information on relay settings to SCE.

The information required to meet the reliability standards is not difficult. However, CED has never documented why it established current relay settings or other information about its system. The documentation process is fairly stringent, requiring copies of all correspondence and emails between CED and SCE or the CAISO.

CED is currently NERC compliant. To remain compliant will require establishing a process where all standards pertaining to CED are identified and updated whenever communication between CED and SCE occur.

Beginning in 2009, NERC expanded its compliance requirements to include cyber-security. At this time, CED is likely not in compliance with the new cyber-security regulations. Generally, the cyber security regulations will require isolating system control equipment from the internet, restricting access to areas where system control and data acquisition (SCADA) computer equipment is located and other minor actions necessary to limit access to control equipment away from unauthorized individuals. CED is working on becoming cyber-security compliant.

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 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.

There are two primary components to the MRTU market. First, the CAISO provides all ancillary services to California participants. Ancillary services include those services necessary to meet moment-to-moment changes in energy demand. This includes such things are regulation, local voltage support, spinning reserves and stand-by reserves.

Ancillary Services

Energy demand is not constant. Demand varies second by second as retail customers turn equipment on and off in different parts of the state. On a real time basis, California's load can vary by several hundred MW from moment to moment. This moment to moment variation is met by generators that can increase or decrease generation on a real-time basis.

Spinning reserves are generators that are on and available to meet load within 10 minutes. AMPP actually can meet the spinning reserve requirements of the CAISO and is eligible to bid into the CAISO ancillary services market.

Non-spinning reserves are generators that can go from a cold shut-down state to generation within one hour.

All these different generators have a spatial component. A generator in Sacramento cannot meet increased electricity demands in San Bernardino County, so spinning and non-spinning generation is located throughout the state.

In addition, a region using more energy than it has coming into the area needs to have additional generation (or transmission capacity) to increase generation and voltage in an area.

The second part of the MRTU market allows LSE's to purchase energy, either in the day ahead, hour-ahead and day-ahead markets, necessary to meet load.

The CAISO acquires conducts a daily auction to buy ancillary services for the state and then charges all LSE's based upon their 6 minute average loads.

Energy Markets

The MRTU market is a "closed" market where all 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 ramps 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 generation costs should increase due to participating in the CAISO. Efficient resources are dispatched to meet loads while less efficient 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 CED's loads, it is because the CAISO has less expensive energy available and it sells this energy to CED in place of AMPP generation. But if prices rise above the AMPP generation cost, AMPP would be dispatched and CED would pay the incremental cost of AMPP for load purposes but receive the wholesale price for any remaining generation that is then sold in the CAISO market.

The primary difficulty with the CAISO is the complexity of the market. CED does not currently have people with necessary skills to bid the resources into the CAISO system and so relies on Shell. But then CED does not the internal expertise to verify where CED acquired its daily energy, whether from CED resources or from the market, and how much CED paid for energy, ancillary services and transmission.

Resource Adequacy Program

Another key aspect of the market design that will undergo enhancements is California's *resource adequacy* (RA) program. CED (along with all other LSE's) provides data to the Energy Commission that provides a monthly forecast of RA obligations. The forecast is equal to CED's coincident load with the CAISO plus the reserve margin of 15 percent[16].

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 CPUC concluded that the existing RA contracting mechanisms and practices are sufficient and that the proposals may pose challenges for non-utility load serving entities.

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.

[16] The CAISO is studying requiring utilities to have capacity to meet their non-coincidental load

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 CPM provisions of its tariff described above. As detailed in the CAISO Tariff,[17] the CPM 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 that serve load in the TAC Area.

AMPP provides all of the CED's local RA capacity.

Summary of CAISO Market Modifications

In general, CED has sufficient resources to meet its capacity obligations and satisfy its energy requirements. CED relies upon the CAISO for all ancillary services and some transmission. Shell Energy is scheduling CED's resources as CED's SC. Meetings between Shell and CED identified a number of issues that are increasing costs to CED, primarily dealing with the dispatch of SJ and Magnolia. It appears that a slightly different scheduling strategy could result in reduced costs for CED but the proposed strategy has never been approved by CED management for various reasons.

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, 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 moneys are appropriately credited to CED.

CED does not reconcile energy production with daily loads and sales. CED does not have the internal ability to verify that CED is actually being paid for all daily surplus energy. With the addition of a new analyst, CED will begin tracking daily energy production and reviewing CAISO invoices.

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

Chapter 5
Conservation and Demand-Side Management

Introduction

Conservation and *demand-side management* (DSM) programs attempt to change how much and when residents and businesses use energy to reduce their costs without changing the way they live or do business. In effect, conservation and DSM programs attempt to encourage people to become more efficient, reducing energy costs in the process.

Because of the small costs of electricity to most residential customers, it is difficult to provide incentives to encourage them to make significant capital improvements for energy savings. However, commercial and industrial customers can make significant capital improvements to reduce energy use or change production hours to reduce costs.

CED's conservation and DSM programs are funded by a $0.00285/kWh public benefit charge that raises about $1,000,000 annually for public benefit programs that include conservation, DSM, low income and renewable energy programs.

Conservation Programs

Conservation refers to programs designed to reduce total energy use, regardless of when energy is used. In effect, conservation programs help people reduce their energy use without impacting lifestyle by using more energy efficient appliances and equipment. Examples of conservation programs offered by CED include energy efficient lighting, refrigerator replacement and energy audits.

By offering rebates or just giving away energy efficient equipment, CED avoids having to purchase energy in the market and helps reduce costs for all Colton ratepayers.

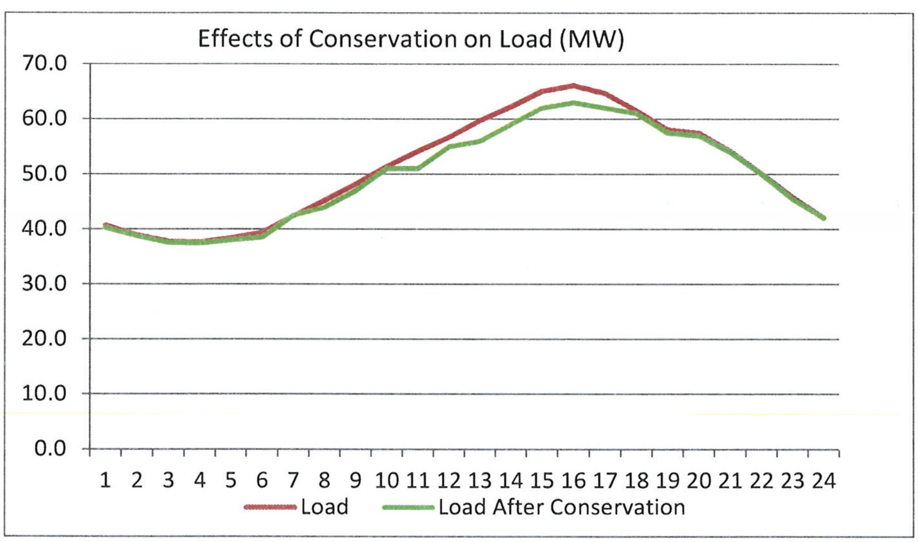

Figure 5.1: Effects of Conservation Programs on Load

DSM Programs

DSM programs differ from conservation programs in that the program goal is not necessarily to reduce energy use but change the timing of use. While almost all conservation programs are DSM programs, not all DSM programs are conservation programs.

Energy costs vary by hour each day with energy use during the on-peak or high use periods much more expensive than energy use during the off-peak or low-load hours. During summer high-use periods, energy often costs two or three times the cost during the off-peak or low-load periods. By providing incentives, such as offering time-of-use pricing or equipment that shifts energy use to off-peak periods, CED can smooth its daily load curve and lower the cost of acquiring energy for all its customers.

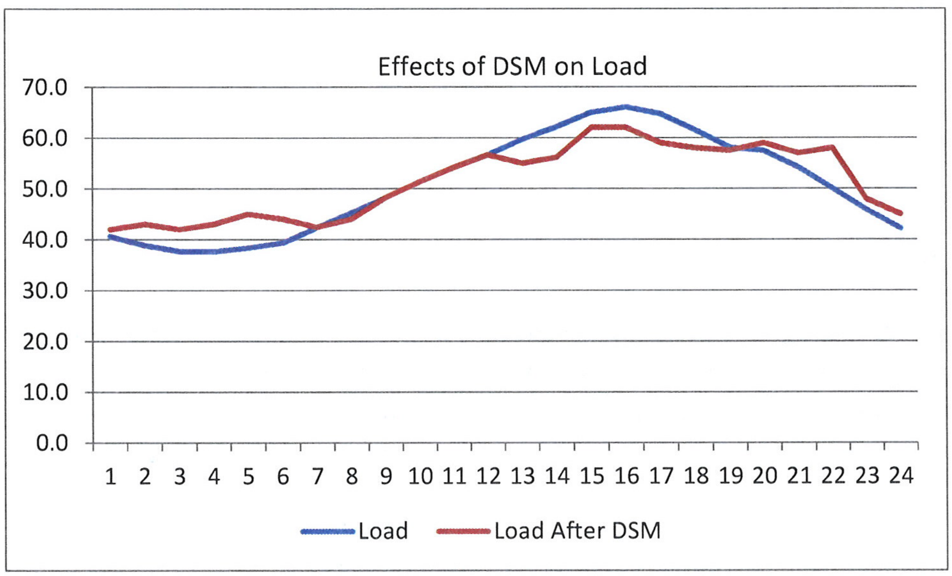

Figure 5.2: Effects of DSM Programs on Load

Evaluating Conservation and DSM Programs

There are three general ways to evaluate conservation and DSM programs – by their impact on the customer, their impact on the utility and their impact on society.

A refrigeration replacement program reduces the amount of energy used by a customer but it also reduces the revenues received by the utility that might have to be paid for by other, non-participating customers. But the participating customer will see their energy costs decline. From this customer's viewpoint, the refrigeration program is a good program that reduced their costs.

From the utility's viewpoint, the refrigeration program reduced both costs (by reducing the amount of energy that it had to purchase) and revenues (by the value of reduced sales to the customer). Depending upon the utility's cost of acquiring capacity and energy, the program may result in lower revenues but even lower costs or costs may decline but not by as much as the revenue loss.

The final way to evaluate conservation programs is to include the impacts on society of conservation programs, including the negative effects of pollution and other societal impacts.

Now that CED has to include the costs of renewable energy and emission offsets in evaluating conservation programs, it is becoming easier to financially justify conservation programs.

DSM programs, since they generally result in lower costs of purchasing energy without any lost revenues are always easier to financially justify than conservation programs. For example, encouraging a manufacturing facility to operate at night but use the same amount of energy results in lower costs with no impact on revenues. However, since no manufacturer would generally operate at night without some benefit, the lower costs of acquiring energy can be passed directly to the firm without impacting non-participating customers.

At this time, CED does not offer any DSM programs. In the past, CED did offer customers discounts for operating during off-peak periods but these programs have expired. As will be discussed below, because of the large amount of surplus off-peak energy generated by CED's resources, CED can offer low-cost energy to firms that are willing to shift their energy use to off-peak periods and reduce costs to both the participating customers and non-participating customers.

Regulatory Requirements

Even though properly designed conservation and DSM programs results in lower costs for all ratepayers within Colton, CED does have regulatory requirements under SB 2 to reduce total energy use by 5 percent through conservation programs by 2020. In addition, CED must meet annual conservation targets set by AB 2021 and enforced by the Energy Commission and CARB.

In 2007, AB 2021 established a California goal of reducing energy consumption by 10 percent by 2016. In 2011, CED's conservation target was about 3,100 MWh reduction in energy use, increasing to over 4,500 MWh by 2020.

CED has exceeded its state mandated conservation goals, primarily due to the success of various lighting retrofit programs that has replaced inefficient lighting with energy efficient lighting. However, going forward, CED will have a more difficult time reaching its annual goals as energy savings in non-lighting applications are more difficult to realize.

CED Programs

The major commercial program has been lighting rebates that paid $200 per kilowatt reduced.
From 1997 to 2005, CED spent $87,730, reducing demand by 428 kilowatts and saving approximately 1,250,000 kilowatt-hours per year.

In 2004, CEU had a consultant perform audits for 868 businesses to identify needs and opportunities for improving energy efficiency. The audits found that lighting upgrades at these customers had a potential for reducing demand by 2,026 kilowatts and saving 7,145,213 kilowatt-hours annually.

In 2005, a free direct install lighting program was implemented to facilitate lighting upgrades. This program replaced inefficient lighting with up to date systems at 250 businesses and reduced demand 158 kilowatts saving 742,093 kilowatt-hours annually. The program cost $185,212.

CED's 2007 - 2008 free direct install lighting program cumulatively served 572 customers and reduced peak demand by 649 kW saving customers 2,212,289 kWh. The program's cost was $505,937 and saved customers an average of $450 dollars annually.

In 2009 - 2010 the commercial lighting program concentrated on completing the medium and small business free lighting upgrades and to provide rebates to retrofits large facilities that had used HID and 8 foot inefficient fluorescent lamps to single and multiple fixtures with high output t-5 lamps with appropriate daylighting and occupancy sensing controls. Together these projects replaced more than 10,612 fixtures and lamps at a cost of $400,659.

The peak demand savings especially with the day lighting controls was conservatively calculated to be 436 kW and the annual energy savings was 61,650,096 kWh. The expected net GHG saving was calculated to be more than 266,747 tons. Controls that reduced or turned off lights when adequate daylight was available or when an area was empty was very cost effective.

Current Residential Customer Programs 2010-2011

All 16,000 Colton residential customers have been provided with two free compact fluorescent lamps. The lamp uses 15 watts to provide the light of a 60 watt incandescent lamp. The other is a higher output lamp that provides the light of a 75 Watt lamp and uses less than 20 Watts. The amount spent on this program was $116,944. The program reduced peak demand by 179 kilowatts and energy usage was reduced by 1,248,000 kilowatt-hours per year. The total lifecycle carbon saving was calculated to be equal to 4,550 tons of CO_2.

The CFL mailing program sent out 112,000 lamps to 16,000 customers reducing demand by 4,126 kW and providing a cumulative saving of 17,977 Megawatt-hours. CED has ended its programs for mass distribution of compact fluorescent lamps to residential customers due to the low cost and easy availability of CFLs at many retail outlets.

Home energy audits are available to customers with high energy bills. In addition, online energy audit and conservation information is available through the "Apogee Interactive" website.

Low Income Customer Programs

2,299 low income customers participated in CED's once a year one $150 credit on electric charges. This allowed customers who received high bills especially during summer months to not be burdened with a difficult to pay bill. In 2011, $346,875 was provided by the CED to low-income Colton residents.

In 2010-11, 94 customers were assisted by a refrigerator replacement program that provided a new energy saving refrigerator and recycled the old refrigerator. $51,198 was spent on refrigerators resulting in a 10 kW peak demand reduction and a lifecycle savings of 6,164,928 kWh.

City Facilities

All traffic signals were retrofitted with LED energy saving lights. The $245,000 project reduced demand by 62 kilowatts and saved 550,000 kilowatt-hours a year, saving $85,000 a year in energy costs.

CED did its first small demonstration LED project in the city by installing 58 recess can down lights at the police department where reliability is as an important concern as energy saving.

CED will also upgrade City-owned air conditioners and lights as part of the 2012 energy efficiency program.

Measurement and Verification Activities

CED is required to have a third-party *Metering and Verification* (M&V) program to verify the claimed energy savings from different programs. Currently, a California consulting firm, E3, is used to verify savings and benefits. Alternative calculations may also be used for some measures.

Proposed CED Energy Efficiency Programs for 2011-2012

Residential Programs

CED will continue its low-income residential refrigerator replacement. CED will budget $32,000 to reduce peak demand by 24 kilowatts, save 155,680 kilowatt-hours annually and 2,802,240 kilowatt-hours over the life of the refrigerators.

Low income assistance will reach more customers, but will remain capped at $150 per year. Currently, about 7 percent of the households in Colton participate in this program. Under this program, customers can have up to 1 month of free electricity (up to $150) if they are having difficulty paying their monthly electricity bill.

CED will complete the surveys of 1,000 of the highest energy using residences and the results of the study will be used to plan for programs in the following year to provide the most cost effective energy solutions to customer problems.

Energy Efficiency Rebates

CED will propose a Home Improvements Energy Efficiency Program beginning in late 2012 that offers rebates to CED ratepayers for installing energy efficiency equipment at their home. Energy efficiency products that will be covered will include occupancy sensors, pool pumps, solar attic fans, wholehouse fans, room air conditioners and ceiling fans.

Commercial

Specific measures for cooling and refrigeration will be funded. Programs under consideration are for markets, restaurants, and large office and school buildings.

Summary of Conservation and DSM Programs

CED's conservation programs have met its state goals for 2010 energy savings but are significantly lagging 2011 goals. CED should develop DSM programs concentrating on cutting its on-peak demand and shifting energy from on to mid-peak periods.

CED's peak loads exceed 70 MW for only 80 hours per year. But CED has to plan to meet this load at a cost of around $250,000 to $400,000 annually. By developing load shifting and interruptible load programs targeted at these few hours of the year, CED can lower it costs and reduce costs to both the participating and non-participating customers.

CED also has to ensure that its planned conservation and DSM programs are in compliance with the new SB 2 and AB 32 conservation requirements. Both AB 32 and SB 2 require CED to reduce energy by at least 5 percent by 2016. Because CED has concentrated on lighting programs in the past, it will be difficult to meet these new goals without working closely with local businesses as opposed to residential customers.

Chapter 6
Risk Management

Introduction

As a small utility primarily concerned with meeting retail load requirements, CED generally assumes a risk-averse posture. CED prefers certainty in total power supply costs rather than risk upward price movements in the energy market. CED does not speculate in the market and attempts to purchase energy only to meet retail load requirements.

CED's exposure to risk comes in a number of ways. For example, CED faces forecast risk, market-price risk, regulatory risk, supply risk, counter-party risk and other types of business risk. A relatively new source of risk is the development of the MRTU market and transmission congestion price risk.

Forecast risk is the cost associated with over or under-forecasting CED's retail requirements and having either too much or too little energy that it needs to buy at higher than expected costs or sell energy from existing contracts at a loss;

Market-Price risk is the risk associated with entering into long-term contracts and then having the wholesale price fall so that CED could have purchased the energy less expensively. Conversely, if CED chooses not to enter into a contract at current prices and then prices rise, CED could be criticized for not locking in prices.

Regulatory risk is the added cost of changes in the regulatory process or new regulations that increase CED's cost of doing business. The greatest fear of regulatory risk is that CED takes actions to meet current regulations and then the regulations are changed in such a manner that CED incurs costs to both undo earlier actions and then has to spend money to meet the new regulations.

An example of regulatory risk is SJ3. In the late 1970's, utilities were prohibited from using natural gas for electricity generation. So Colton, along with other SCPPA members, began investing in coal plants. 30 years later, natural gas is plentiful but the nation is concerned about air quality and Congress and EPA have implemented new laws and regulations intended to reduce emissions from coal-fired generation. CED, which had invested in coal generation, must now spend millions of dollars to mitigate the air quality impact of high emission coal resources.

Supply risk is the chance that contracted sources of energy is not delivered for any reason, resulting in CED having to incur additional costs to replace the energy.

Counter-Party risk is the risk that a counter-party defaults on its obligations and CED incurs a financial penalty attempting to replace energy contracted from the counter-party. To minimize this risk, CED attempts to insure that its counter-parties are financially sound and contractually bound to meet their supply obligations.

Transmission congestion risk is now one of CED's biggest concerns. CED has acquired generation resources and fuel supplies that meet most of its daily load requirements. However, other than through the acquisition of CRRs, CED cannot easily hedge its congestion risks. The best that it can do is review congestion costs[18] and insure that CED's SC, Shell, attempts to schedule resources to avoid any significant congestion costs and to acquire as many CRRs on the transmission paths used to bring resources to Colton as possible.

CED cannot avoid risk. Daily or hourly energy requirements cannot be forecast with a high degree of certainty weeks or months in advance of need. CED cannot control the actions of its counter-parties or regulators.

Regardless of its inability to control the actions of the market or other entities, CED can design its resource acquisition strategy minimize the financial impact of forecast and market risk. CED has fixed the price of roughly 80 percent of its energy requirements for the next few years, attempting to minimize the impact of sudden price spikes in the power markets. CED only deals with companies that have good credit ratings and periodically reviews these ratings.

An area of concern to CED is regulatory risk. CED is having significant problems keeping current with GHG legislation, including new C&T and RPS requirements being implemented simultaneously. The implementation of the MRTU market structure, RPS and energy efficiency requirements along with proposed new environmental rules are straining CED's ability to identify and comply with all the regulatory requirements.

<u>Development of a Risk Management Plan</u>

Risk Management means limiting and reducing risk associated with CED's business activities that could result in economic loss. Risk management includes activities that identify, measure, assess, limit and reduce risk. As related to the use of derivatives, risk management means reducing risks in the broad sense of the term, including activities that select one type of risk over another when is considered more tolerable but it does not include activities that increase risk.

From a risk management perspective, CED's primary objective is to meet its retail energy and regulatory requirements. Power supply activities are to be focused around these objectives. Taking any unnecessary risk in order to arbitrage market opportunities or risks unrelated to CED's normal power supply business activities is considered inappropriate. Power transactions made with the sole intent of maximizing revenues could expose CED to unnecessary financial risks and are generally prohibited.

Risk management in this context is defined as financial risk management.

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[18] CED is now obligated to review its exposure to transmission congestion costs on a monthly basis to meet CAISO risk management requirements.

CED's primary mission is serving the electricity needs of CED's customers.

Specific objectives, listed in order of priority, to achieve this mission include:

1. Providing low-cost electric power to its customers through the use of CED's generation resources and wholesale natural gas and power purchases.
2. Providing a reliable supply of natural gas for CED's generation units to support the objective of providing reliable electric power.
3. Optimizing CED's generation and transmission resources to ensure that they are used in the most economical way.
4. Acquiring natural gas and wholesale power at prices that allow CED to maintain stable and competitive retail rates.
5. Given the reliability of supply of natural gas and stability of prices of natural gas and wholesale power as top priorities, obtaining the lowest reasonable natural gas and wholesale market prices.

Individuals or groups responsible for purchasing energy, capacity, natural gas and transmission for CED may not engage in activities that expose CED to speculative commodity trading risk. Any activities that are not related to CED's normal power supply business and have the effect, or potential, of increasing financial risk is to be avoided.

Speculative risk means any risk that is engaged in for its own sake and is not a business risk. For example, an exposure to fluctuations in energy future prices is considered speculative if a position is taken, for example a contract for natural gas or energy is purchased or sold, when there is no need or intent to deliver energy. A speculative risk is unrelated to production and delivery of electricity to CED's retail customers and could be avoided without any financial penalty to CED.

The *Risk Management Policy* (RMP) articulates CED's objectives, techniques and controls for managing such risks related to wholesale energy markets. The RMP scope covers all wholesale capacity, energy and natural gas contracts within or considered for CED's portfolio. Policy implementation, compliance and revision will be reviewed and approved by City's Management Services Director who will act as the Risk Management Officer.

To the extent feasible, given political, regulatory and environmental constraints, CED shall insure that the cost of its fuels, energy and related transmission resources shall remain competitive over the long term. Therefore, CED shall conduct its fuel and energy procurement in a manner necessary to compete successfully in the marketplace as a cost hedger. Fuel procurement activities will be conducted under the same risk management principles and procedures as power supply.

Organizational Structure

CED is a small organization that currently outsources the daily management of its resource portfolio. CED has hired Shell as its SC and, on a daily basis, Shell schedules CED's resources to meet daily forecasted load.

In a classic "front office – middle office – back office" organizational structure, Shell functions as the "front office," scheduling resources to meet load in conformance with applicable contracts.

Most of CED's resources are power purchase agreements or wheeling agreements with SCPPA. SCPPA is responsible for verifying the invoice from the project manager or owner and then each participant is responsible for verifying their share of the project monthly costs. SCPPA also invoices CED for its share of various natural gas purchases through SCPPA.

In addition to SCPPA, each month CED receives invoices from:

- Shell for all CAISO costs, including use of the CAISO controlled grid, ancillary services, the gas "floating for fixed" swap and the purchase and sale of imbalance energy;
- SCE for wheeling services over existing transmission paths and several customer service projects on behalf of CED;
- Colton Landfill for the purchase of up to 2 MW of renewable energy;
- The Cities of Burbank and LADWP for transmission service for MPP;
- Bureau of Reclamation and Department of Energy for CED's share of the Hoover Uprating Project;
- The City of Anaheim for the MWD energy swap;
- Management and operation costs of the AMPP.

Once an invoice is received, energy and costs are verified against monthly forecasts of power supply created as part of CED's annual budget review process.

As part of the middle office function, CED should verify total energy deliveries against load and verify that CED accounts for all energy purchases, generation and sales (energy balance).

The Colton Finance Department serves as the "back office." Only when invoices have been received and verified will the Finance Department issue a check for payment. No one in the front office (Shell) or middle office may issues checks for payment for power supply costs or expenses for CED.

At this time, CED does not have an internal counter-party policy. CED only purchases or sells to CAISO approved counter-parties or with entities approved by SCPPA and operates under the CAISO or SCPPA policies for counter-parties.

Colton's Management Services Director (MSD) acts as CED's Risk Management Officer. The MSD must agree with the expected financial impacts of any proposed long-term firm power supply purchase or hedging contract in excess of one year. In general, the MSD must verify that CED is entering into a power purchase agreement for the purpose of meeting load requirements and not for speculating in forward markets.

Value at Risk

The *Value at Risk* (VAR) is used by CED as a measure of power supply risk. The VAR is an estimate of the potential change in portfolio value (which may consist of several commodities such as electricity prices and natural gas prices) or cost parameters given a level of statistical confidence over a pre-defined holding period (day, month, year).

CED's targeted VAR is:

- CED will have a budget VaR of less than 5 percent of total energy and capacity costs at least one month ahead;
- CED will have a budget VaR of less than 10 percent of total capacity and energy costs prior to the beginning of the fiscal year;
- CED will have a budget VaR of less than 20 percent of total capacity and energy costs prior to the beginning of the second year.
- CED will have a budget VaR of less than 30 percent of total capacity and energy costs prior to the beginning of the third year.

CED's current resource mix satisfies its targeted VAR. CED's 2012-13 VAR is about 5 percent, or an increase in natural gas costs of 50 percent will result in an increase of about $1,500,000 in total power supply costs, primarily through increased costs of non-firm purchases in the CAISO market.

The greatest financial risk to CED is an extended outage of SJ3. Because of the take-or-pay requirements in the power purchase agreement with SCPPA, if SJ3 were to suffer an extended forced outage, the cost of replacement energy could be as much as $700,000 per month during the summer months and $500,000 per month during the winter months.[19]

CED uses approximately 1,650 MMBTU/day of natural gas. Due to its pre-pay gas agreements and entitlement in the Pinedale and Barnett producing fields, CED does not have any significant exposure to increases in natural gas costs. On the other hand, CED does not benefit from declines in natural gas costs except through purchase in the CAISO marketplace.

Currently, one area that CED has no control over is congestion risk. CED has had several months since 2008 in which congestion costs exceeded $200,000 due to a high congestion costs from Phoenix to the Los Angeles basin, the transmission path used by SJ3.

If Shell or CED realizes that a transmission path is constrained and congestion costs are greater than the SJ3 cost less the LMP, Shell has been instructed to attempt to minimize CED's use of that path in excess of CED's CRRs. In most cases, this means CED will generally pay one or two days of congestion before reducing schedules over a path.

[19] These costs are based upon a $50/MWh cost of replacement energy. At current natural gas price costs, the estimate would be about $400,000 during the summer and $275,000 during the low load months.

The difficulty with transmission congestion is that the congestion costs are not known until after day-ahead bids are received by the CAISO. If congestion costs were known in advance, then entities could decide whether or not to use a congested path. But since congestion costs depend upon who is planning to use a transmission path, entities make their generation plans and then take the risk of congestion.

Shell does not participate in the CRR auctions on behalf of CED. Shell does submit CED's requests for CRR's as a LSE to the CAISO and verifies that CED receives an allocation of CRRs. But Shell does not buy CRRs for CED in excess of allocated CRRs even on congested paths.

CED reviews all CAISO invoices as they are received from Shell and attempts to verify energy balances and CRR costs. CED also monitors changes to the invoices as the CAISO makes its periodic reruns of costs.

Summary of Risk Management Activities

In order to minimize CED's exposure to significant changes in power supply costs and to provide an additional layer of administrative review, CED has implemented a RMP. The primary components of the RMP include:

- Review by Colton's MSD of any long-term power supply purchases or firm power supply purchase exceeding $500,000 in any single month;
- Maximum monthly limits on CED's power supply VAR;
- Required review and verification of CED's monthly energy balance;
- Review of monthly congestion costs and CRR status;
- Review of monthly costs of EA's and verification that CED has sufficient EAs to cover expected annual emissions.

CED still needs to develop a formal risk oversight process to insure that all activities are being accurately performed. However, CED's risk exposure is often the result of a lack of internal expertise to manage its power supply costs.

In December 2011, FERC issued FERC Order 741[20] requiring that all entities dealing in ISO's with congestion pricing verify that they are managing the risk of their congestion costs through a documented risk-management plan by April 1, 2012. CED has prepared and filed its RMP with the CAISO and agreed to perform the required periodic evaluations of market risk and congestion risk.

[20] The Colton City Council approved filing the City's Order 741 response on June 3, 2012.

Chapter 7
Renewable Resources

Introduction

Renewable resources are resources that do not require fossil fuels to generate electricity. Renewable resources include solar, including both solar photovoltaic and solar thermal plants, wind, geothermal, biomass and biogas. A brief discussion of the pros and cons of each type of renewable resource will be provided below. This Chapter will attempt to identify which renewable resources will minimize the rate impacts on CED's ratepayers of meeting RPS standards.

A key portion of SB 2 allows publicly owned utilities, such as the CED, to delay adding renewables to its generation portfolio if the cost limitation aspects of SB 2 are in 399.15. Subsection (b) allows the CEC to delay a particular utility's implementation of RPS if the CEC finds any of several criteria are met. Subsection (c) calls for the CEC to establish cost limitations for each utility's compliance with the RPS standard. 399.15 does not apply directly to local publicly owned electric utilities like the City of Colton. Instead, 399.30 allows the boards of local publicly owned electric utilities to adopt "Cost limitations for procurement expenditures consistent with [399.15(c)]"

Instead of the CEC establishing the cost limitations as they do for investor-owned utilities, the Colton City Council is allowed to establish cost limitations subject to CEC review of the reasonableness of the limitations. 399.15(d) calls for the CEC to set the cost limitation at a level that avoids "disproportionate rate impacts," so that is the standard that the City Council should consider in adopting Colton's RPS policy.

Despite avoidance of "disproportionate rate impacts" being a crucial aspect of the law, the term isn't defined. None of the legislative history of the law or any of the Assembly and Senate analyses explains what it means. It appears that CEC is still working out what standards will apply to the publicly owned utilities as part of an ongoing rulemaking process.[21]

On March 1, 2012 the CEC put out a draft set of regulations that would deal with publicly owned utilities' RPS cost limitations.[22] But even that draft set of regulations does not explain or address the issue, it just repeats the language of the statute

The result is that no one knows at this point how aggressive CED can be in setting a RPS cost limitation. CED is allowed to avoid "disproportionate rate impacts," and what that means must still be determined in conjunction with the CEC.

CED is planning on meeting with the CEC staff to attempt to determine if the potential high cost of meeting SB 2 requirements might allow CED additional time to meet SB 2 RPS standards but until the CEC makes a determination, CED must anticipate having to meet all SB 2 requirements.

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[21] http://www.energy.ca.gov/portfolio/documents/index.html
[22] http://www.energy.ca.gov/2012publications/CEC-300-2012-001/CEC-300-2012-001-SD.pdf

Solar Photovoltaic (PV)

PV is the most obvious renewable resource. PV panels convert sunlight into direct current (DC) electricity and then an invertor system converts the DC energy to alternating current (AC) energy for use on the electric grid.

Five years ago PV was generally considered too expensive for use in large power generation facilities but a huge drop in price of price of solar panels due to over-capacity and a decline in new solar PV projects due to the world-wide recession has caused PV prices to decline by 20 to 30 percent.

As a result of the price decline, a number of thermal solar projects have been re-engineered to use PV rather than the original solar thermal design.

In spite of the price decline, energy from PV still costs more than $100/MWh although a number of government subsidies and tax incentives may result in a wholesale price of around $85/MWh in some cases.

PV generation usually begins around 0830 in the morning and reaches maximum output around 2 hours later. Output begins to decline around 1530 each afternoon and is usually not available by 1730 or earlier. Output varies significantly during the year with winter generation sometimes as little as 60 percent of summer capacity.

Because many utilities, including CED, peak later in the day due to a combination of lighting load and air conditioning loads, solar PV is not always available during the highest use periods of the day. This means that a utility may have to have additional non-PV capacity available to meet its peak load requirements.

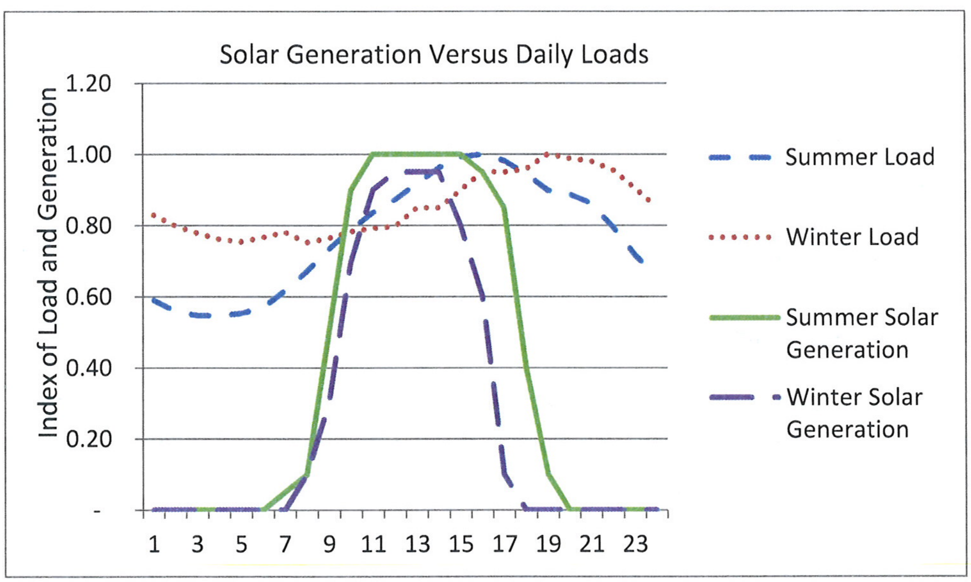

Figure 7.1: Index of Solar PV Generation versus Hourly Load

The above figure shows that during the summer months, PV generation begins to decline even as loads are high, resulting in CED having to keep capacity available to meet loads, while during the winter months the PV generation is not available at all during the peak periods (that occur later in the day). This mismatch of load requirements and generation significantly reduces the value of PV to CED.

The greatest benefits of PV are that it can be constructed in small areas, is relatively inexpensive and generally does not create off-peak surplus energy.

Solar Thermal

Solar thermal generation differs from PV in that sunlight is turned into heat that is then used to create steam and heat a turbine. Currently, there is more solar thermal generation in California than PV but that should change in a few years as more PV projects come online.

There are two major kinds of solar thermal generators. The Luz "trough" type, where a high temperature oil is sent through pipe. Parabolic mirrors focus sunlight heating the oil to around 800 degrees which is then used to turn water into steam to power a generator. There are a number of these projects in the Barstow and Harper's Lake region of San Bernardino County.

The other type is SCE's Solar 2 project, unofficially known as a "steam on a stick" where an array of mirrors focuses sunlight on a small area that creates steam that is used to power the generator.

A picture of Brightsource's Ivanpah project near Blythe shows how the array of mirrors focuses the sunlight unto the top of a tower where steam is created to power a generator.

Solar thermal projects tended to be larger than PV projects to justify the higher cost of generators but since the decline in PV prices, many of the solar thermal projects have been converted to PV.

Solar thermal projects tend to generate a bit later in the day than PV projects, making them more attractive as a capacity source since they become more coincident with utility peak loads.

Most new solar thermal projects have different kinds of heat storage, such as molten sodium, to extend the daily generation capabilities. While this makes it more useful in meeting evening peak loads, the additional costs also make solar thermal projects more expensive.

<u>Wind</u>

The expansion of wind energy is creating significant problems on the western transmission grid. If a large amount of wind generation is available, thermal resources have to remain available in the event the wind stops and generation drops significantly. Wind is inexpensive and generally abundant but the operational issues associated with it have not yet been fully addressed.

Wind energy has the greatest potential when paired with storage, including batteries, pumped storage or some other firming resource that reduces the moment to moment generation changes.

Small Hydroelectric

Hydroelectric facilities currently only count as renewable resources if they are less than 30 MW and do not interfere with run-of-river conditions (that is, no reservoirs or storage with a minor exception for small conduit generation from new reservoir construction).

There are a number of bills that attempt to count large hydroelectric generation as renewable but so far, none of them have passed the California legislature although large hydroelectric generation does count in federal RPS proposals.

The major problem with small hydroelectric facilities is that there are few places in California where new hydroelectric facilities can be constructed.

Hydroelectric is a good source of energy especially when storage is included and energy can be dispatched to meet load requirements.

Biomass

Biomass generation is the production of energy using plant material, such as trees, plants, crop cuttings and other plant sources. There are only a few biomass generators in southern California mostly burning crop cuttings and dead trees remaining from the bark beetle infestation in the late 1990's – 2000's in the San Bernardino mountains.

Even though the raw resource is cheap, most of the facilities have very high costs due to the labor necessary to gather the fuel stock.

There is an ongoing attempt in Colton to develop a biomass facility using the sludge from the RIX facility. It is not known if this project will ever be developed in light of the difficulty the project has had getting the required permits from CARB and other state agencies.

Geothermal

CED is currently a participant in the development phase of a SCPPA geothermal project in Imperial County. Geothermal resources use high-temperature brine (300 – 700 degrees) created by underground lava flows as the heat source for generating electricity.

Imperial County has some of the best geothermal resources in the world and currently produces about 1,600 MW of geothermal energy, primarily for SCE and the Riverside Public Utilities Department.

The biggest problem with geothermal generation is that the brine is highly caustic and corrodes steel pipe in several months. As a result, tungsten and stainless steel pipe has to be used at very high cost (as much as $1,800 per foot) driving up the cost of production. In addition, there is no guarantee that when a geothermal well is drilled that it will hit a viable brine source. Since each well costs about $10,000,000 to drill, the cost of drilling failures is very high and has prevented the geothermal industry from getting financing until the wells have been drilled and are producing.

Geothermal energy costs are between \$105 and \$125/MWh.

Biogas

Biogas is methane collected from the decomposition of plant and waste materials. There are a number of biogas facilities that use cow manure as the decomposing material and then collect the gas, remove impurities and inject the gas into the interstate pipeline system where it is burned in power plants.

Biogas is an inexpensive and easy way to meet RPS goals. However, California has not yet approved future biogas from outside California as a renewable resource. In March 2012, the CEC suspended the use of biogas as a renewable fuel except for limited cases of landfill gas and digester gas. However, biogas that was injected into the interstate pipeline system does not currently count as a renewable fuel.

If biogas is ultimately approved as a renewable fuel, CED could purchase biogas as a fuel for either Magnolia or AMPP and use it for generation without creating any additional surplus energy.

Energy from biogas can cost as little as \$70/MWh if used in a high-efficiency power plant (for example, the Magnolia project). If used as a fuel for AMPP, renewable energy would cost around \$90-\$99/MWh.

CED does purchase the biogas generation from the Colton landfill that collects gas from the decomposing waste and then uses IC engines to run generators. The generation is performed onsite because the gas is too polluted to be injected into the pipeline system.

Renewable Resources That Meet CED's Needs

CED does not currently need any additional baseload energy. The renewable resources that best meet CED's requirements are wind, biogas and small PV facilities.

Even though wind generation does not have a significant capacity value, CED has a capacity firming source with AMPP and wind energy can be used to offset fossil fuel generation. If CED is unsuccessful in convincing the CEC to extend the compliance period for meeting RPS goals, CED would attempt to purchase 2 to 3 MW of wind generation as the least-cost means of meeting RPS requirements.

Biogas can be used as a fuel for either Magnolia or AMPP. If used at Magnolia, the cost of renewable energy will be around \$70-\$75/MWh while AMPP would generate renewable energy at a cost between \$90-99/MWh. The higher cost at AMPP is due to the higher heat rate of the unit compared to Magnolia.

The CEC is currently holding a proceeding on whether or not biogas from out-of-state sources will count as a renewable resource. The use of biogas for onsite generation is not under review but as soon as the biogas is injected into the pipeline system, the CEC apparently believes that biogas cannot be tracked and may not be reducing fossil fuel generation in California. For that reason, the CEC has determined that biogas delivered from off-site sources does not count as a renewable resource.

Finally, small PV projects within the City would be the next most attractive renewable resource.

The following figure presents the range of costs of renewable resources in the market.

	Renewable Project Price Range Offered to SCPPA ($/MWh)	
	2009/10 RFPs	2011 RFPs
Technology		
Wind	$55 - $115	$63 - $102
Small Hydrogeneration	$50 - $100	
Solar Thermal	$180 - $210	
Photovoltaic	$115 - $210	$81 - $160
Energy Storage	$90 - $120	
Biomass	$100 - $150	$82 - $108
Geothermal	$70 - $135	$90 - $110
Convential Generation		
Simple Cycle	$230 - $250	
Combined Cycle	$75 - $145	

Table 7.1: Renewable Prices

Current Status of CED Renewable Energy Efforts

SB 2 established 3 compliance periods, 2011-2013, 2014-2016 and 2017-2020. During the first compliance period, utilities are required to meet a target of 20% of all retail sales to be provided by qualified renewable resources. During the second compliance period, 25% of all retail sales must come from renewable resources and by the end of the third compliance period, the minimum percentage of renewable resources is 33%.

In addition to the minimum percentages of retail load met by renewable resources, renewable resources are further disaggregated to the type of renewable resources, with minimum amounts of each category required during each compliance period.

The first type of renewable resource category or Portfolio Content Category (PCC) is renewable resources located within California where the energy and green attributes are delivered to the utility for resale to its retail customers.

The second type of PCC is when an energy generation source (like wind or solar) that varies from hour to hour is delivered on an even basis during the day. Hourly fluctuations are usually made up by non-green generation but only the actual green energy can be counted towards RPS requirements.

The third type of PCC is Renewable Energy Credits (RECs), where a green provider produced green energy and sold the energy into a power pool, or to an end-user, and kept the green attributes. The renewable energy attributes, or RECs, can be registered and used for up to 3 years.

During the first compliance period, at least 50% of the renewable resources must be from PCC 1. The amount increases during the second period to 65% and then to 75% in the third compliance period.

While PCC 1 is increasing, PCC 3 is decreasing, declining from a maximum of 25% of RPS requirements in compliance period 1 to 15% in compliance period 2, and to 5% in compliance period 3. By 2017, RECs can only be used only to make up a small portion of RPS requirements.

The following table shows the maximum RECs (PCC3) and minimum California renewable energy (PCC1) amounts for each compliance period:

	Min PCC 1	PCC 2	Max PCC 3	Renewable Energy Required
2011	34,000		13,600	**68,000**
2012	34,000		13,600	**68,000**
2013	34,000		13,600	**68,000**
2014	51,000		12,750	**85,000**
2015	51,000		12,750	**85,000**
2016	51,000		12,750	**85,000**
2017	71,400		4,760	95,200
2018	79,050		5,270	105,400
2019	84,150		5,610	112,200
2020	84,150		5,610	112,200

Table 7.2: CED's Renewable Requirements by PCC

There is no maximum or minimum for PCC 2 so long as the energy in the other two categories meets their compliance period obligation.

CED currently has 3 renewable resources, a 1 MW wind energy purchase from the High Winds Project between Sacramento and San Francisco, a landfill gas generation project that produces up to 1.2 MW per hour, depending upon the production of biogas at the landfill, and a small hydroelectric purchase from the Metropolitan Water District (MWD). MWD historically produces at less than 1 MW per hour although production varies by season.

The following table shows the CED's production by PCC from the 3 resources by year.

Resource	PCC 3 MWD	PCC 1 Colton LF	PCC 1 Iberdola	Total
2011	8,124	6,570	7,111	21,805
2012	8,124	6,570	8,760	23,454
2013	8,124	6,570	8,760	23,454
2014	8,124	6,570	8,760	23,454
2015	8,124	6,570	8,760	23,454
2016	8,124	6,570	8,760	23,454
2017	8,124	6,570	8,760	23,454
2018	8,124	6,570	8,760	23,454
2019	8,124	6,570	8,760	23,454
2020	8,124	6,570	8,760	23,454

Table 7.3: CED's Existing Renewables by PCC

With its current renewable resources, CED has approximately 6% of its retail sales met by renewable resources.

During the first compliance period, CED can use RECs to meet a portion of its RPS requirements. CED can purchase up to 25% of its 20% RPS goal, or 5% of its total retail energy sales. This equates to about 17,000 RECs per year for 2011, 2012 and 2013.

Currently, CED does not have any unbundled RECs other than MWD and can increase the percentage of renewables in its portfolio to around 9% by purchasing RECs during the first compliance period. During the second and third compliance period (2014-2016 and 2017 and thereafter) the percentage of RPS requirements that can be met by RECs declines and CED's renewable percentage also begins to decline in the absence of renewable purchases.

The CEC has proposed a grandfathering provision for renewable resources acquired prior to 2010 that could increase the amount of RECs that CED could purchase. Under this proposed rule, renewable energy resources in place on January 1, 2010 contracted for at least 10 years in term would not be counted into any PCC category. Instead, they would reduce the total amount of renewable energy required on a MWh for MWh hour basis. The PCC minimum and maximum PCC categories would then be applied to the remaining RPS requirements.

As an example, CED has a RPS requirement of approximately 68,000 MWh in 2011-13. CED's 3 renewable resources generate about 21,800 MWh per year. This existing renewable generation reduces CED's RPS shortfall to 46,200 MWh. The 3 PCC categories would then be applied to the remaining 46,200 MWh, so that CED would need 23,100 PCC 1 resources and no more than 11,550 MWh (25% of the 46,200 MWh) of PCC3 resources (RECs). This allows CED increase its RPS share to about 10% in the first compliance period.

This interpretation helps CED by increasing the amount of RECs CED can purchase, because the maximum purchase of RECs is based upon the remaining RPS obligation. In the "old" method, CED could purchase up to 17,000 RECs to use towards meeting the RPS goal, while in the second, grandfathered scenario, CED could only purchase about 11,500 RECs (25% of 39,400 MWh). But CED had already purchased about 8,000 RECs from MWD that now do not count against the annual limit. As a result, CED can purchase about 5,500 more RECs annually than under the original interpretation by the CEC.

CED does have some discretion about how quickly it meets the SB 2 mandated goals. The City Council can set targets that result in Colton meeting the 33% renewable targets at a date later than 2020. SB 2 allows publicly owned utilities to set cost limitations on annual renewable procurement expenditures.

In December 2011, the Colton City Council adopted R-103-11 which capped the potential rate increase due to higher prices for renewable resources to 2% per year. The 2% rate increase is equal to approximately $1.15 million per year that CED must spend on renewables until it meets its RPS requirements.

To stay compliant with the cost limitation rules, CED must comply with a formalized CEC approval process of its renewable procurement plan.

The CEC must agree with the cost limitations adopted by the Colton City Council. In establishing the cost impact, the CEC will rely upon:

i) The most recent renewable energy procurement plan;
ii) Procurement expenditures that approximate the expected cost of building, owning and operating eligible renewable resources;
iii) The potential that some planned projects may be delayed or cancelled.

The CEC will ensure that the cost limitation is set at a level that avoids disproportionate rate impacts and that all costs of procurement are counted towards the procurement limitation.

However, the CED is not allowed to count any indirect costs including the loss due to the sale of excess energy.

In order to establish that CED will not meet the timeframes established in SB 2, the City Council must hold a public hearing prior to January 1, 2013. At this hearing, the Council is required to adopt a renewable energy procurement plan that results in the City meeting the 33% RPS standard. The public hearing must be open and CEC staff members will be invited to attend.

CED must then provide the renewable procurement plan, annual planned dollar expenditures, identified projects and other information as requested to the CEC for approval. If the CEC determines, after an evidentiary hearing, that the procurement plan is in violation of SB 2, the CEC will forward the violation to the CARB for determination of penalty.

The City Council must hold these hearings and make the finding that CED is in compliance with its renewable procurement plan on an annual basis until it is in compliance with SB 2.

Western Renewable Energy Generation Information System (WREGIS)

Utilities in California, and the rest of the western states, use the WREGIS to keep track of renewable resources and the purchase and sale of RECs.

Every green generator is required to register their generation facility with WREGIS. All generation from the facility is them reported to WREGIS on an hourly basis. WREGIS is also responsible for auditing the reported generation values.

WREGIS treats generated electricity as having 2 components, an energy component and a renewable component. If the energy is sold as green energy, the renewable component is transferred to the purchaser. If the energy is sold as brown energy, the generator retains the environmental attribute and it becomes a REC.

WREGIS tracks the history of the REC from the hour it was produced until when it is retired for compliance purposes. If an entity has a compliance obligation of 1,000 MWh of green energy, it must retire 1,000 RECs that were generated during the appropriate compliance period. All RECs must be retired within 3 years of generation or else they expire with no value.

CED has an account with WREGIS through SCPPA. As CED purchases renewable energy, the REC is transferred from the producer's account to CED's account. In 2012, once CED purchases its maximum RECs, it will retire all the 2011 RECs as part of its compliance requirements.

While WREGIS tracks RECs, it does not track the California PCC. It is up to the individual utility to be able to prove that its resources satisfy the PCC restrictions of SB 2.

CED's Renewable Requirements and Potential Costs

The following figure provides an idea of how much renewable energy (in addition to its existing resources) CED needs in the future to meet its RPS requirements:

As the figure shows, in 2011 CED begins with a deficit of 39,000 MWh of renewable energy, with the deficit increasing to over 80,000 MWh by 2020.

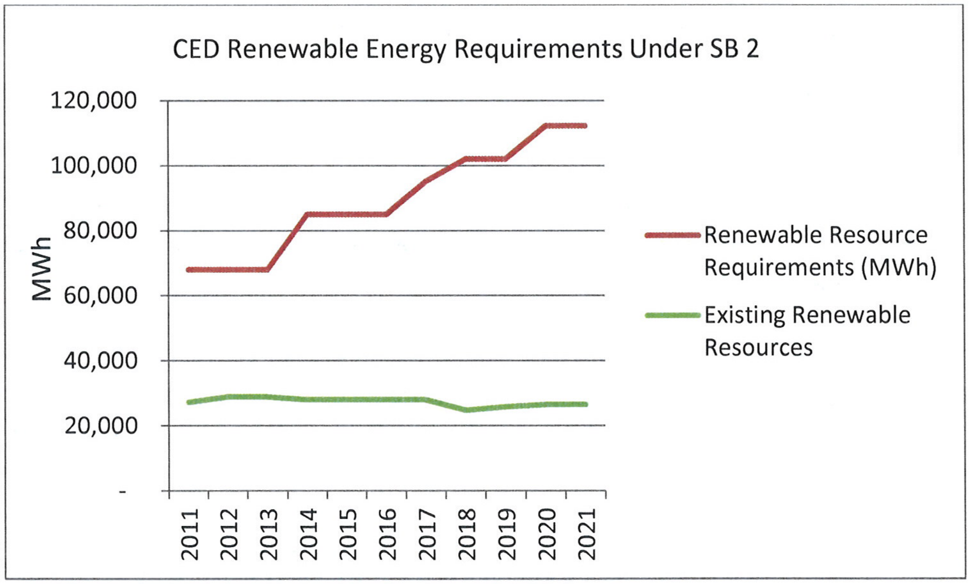

Figure 7.2: CED Renewable Energy Requirements

Also, CED's current renewable resources decline (as a percentage of total load) due to the reduction in allowed purchases in unbundled RECs in each compliance period.

The following table provides an estimate of how much it would cost to meet the renewable energy requirement in each compliance period, using solar PV or biomass/biogas/geothermal generation.

	Annual Cost of Meeting 20% RPS Requirement	Annual Cost of Meeting 25% RPS Requirement	Annual Cost of Meeting 33% RPS Requirement
with Solar PV	$ 2,670,943	$ 3,960,165	$ 5,986,086
with geothermal/biomass	$ 2,796,702	$ 4,416,443	$ 7,179,924
Long-term PPA	$ 4,102,350	$ 4,874,800	$ 7,730,800

Table 7.4: Annual Cost of Meeting RPS Standards

The table shows that with current energy prices, CED will need to spend about $2.6 to $3.0 million annually to meet its 20% RPS requirements.

When the RPS requirement increases to 25%, CED's cost of meeting its procurement requirements increases to between $4.0 and $4.9 million annually:

Finally, when CED has to meet the 33% RPS requirement, costs will increase to between $6.0 and $7.7 million annually if CED enters into long-term power sales agreements (PSAs) for the renewable energy. If the City owns the resources, the additional costs in excess of natural gas generation will decline beginning in about year 15.

The above cost estimates assume that CED's resource mix remains fairly constant. If CED is able to eliminate some of its current surplus capacity, the costs of meeting the RPS standards will decline.

An interesting aspect of renewable energy is that utilities that enter into PSAs will pay the developer high prices for the life of the PSA and then have to go out and negotiate new contracts at high prices. This is because the majority of a renewable resources cost is debt service. Once the debt is retired, renewable resources are very inexpensive, with only annual operations and maintenance costs.

But if a utility continues to purchase only the energy (as opposed to the project itself) it continues to pay for the debt of each generation resource, locking itself into a cycle of purchasing from resources with high energy costs.

If a utility purchases the renewable generation resource, once the debt is retired the cost of the renewable resource is very low and renewable resources can help lower long-term power supply costs.

In California, a general statement would be the large utilities (SCE, PG&E, SDG&E, LADWP and SMUD) are purchasing renewable resources while the smaller utilities are entering into long-term PPAs.

CED will likely need some additional capacity and energy over the next decade, but not in the next year or two.

In the early 2000's CED forecasted faster economic growth than eventually occurred. CED acquired generation resources to meet this forecasted load growth. Today, CED has the necessary generation resources to meet its retail load requirements and most new resource acquisitions for the next few years will result in surplus energy. The only exception would be some solar PV generation that would not be surplus during the summer on-peak periods. SB 2 (and the pre-rulemaking draft regulations) explicitly prohibits CED from counting the increased power supply costs due to the sale of surplus energy as a cost of acquiring renewables.

CED Renewable Energy Procurement Plan

In order to begin the process of acquiring 33% of its resources from renewable energy sources, CED should begin with 1-4 MW of solar PV within the City. However, rooftop PV is significantly more expensive than central generation projects. Rooftop solar can cost more than twice the cost of solar PV farms. Costs may be as much as $6,000 to $7,000 per kW for rooftop solar as compared to around $3,000 per kW for a central plant. Also, ownership of the green capacity attribute can be questioned if rooftop solar is constructed. Because of these factors, rooftop solar is not a likely alternative.

A $3,000 per kW construction cost equates to $3.0 million per MW to build. 1 MW of solar PV generates about 2,190 MWh per year at a construction cost of around $90/MWh and a total cost (including O&M) of around $105 - $110/MWh. This estimated cost does not include any land acquisition or transmission costs.

The reason the market price is currently around $80- $85/MWh is due to federal tax subsidies that allow private firms to recover their capital investment within 7 years. However, a municipal utility cannot make use of this subsidy. As a result, many publicly owned utilities (POUs) enter into PSA's that have a buy-out option after 7 years. The builder recovers his entire investment and some profit during the first 7 years and then the POU finances the cost of buying the project which has now been fully depreciated.

If the POU chooses not to purchase the project, it will pay approximately \$90 - \$110/MWh for energy while if it does purchase the project its costs would be significantly less.

Each MW of solar PV requires about 5 acres of flat land with no hills to the south or west of the project that could cast shadows over the solar panels. Costs can also be reduced if the facility is connected directly to CED's distribution facilities rather than use the CAISO-controlled transmission facilities (and pay the CAISO wheeling charge).

There are only a few areas within Colton that meet these criteria. These are the areas near the Agua Mansa power plant that has some limited potential areas and the Colton Landfill. Of these two potential areas, the landfill appears to have the least cost (depending upon what the County charges CED) and the least attractive alternative use.

Landfills are a good location for solar PV. For some extended period after the landfill closes no significant retail or commercial activity can occur on that site due to methane leaks. These methane leaks do not impact solar PV development. Even ground shifting at the facility does not significantly affect the solar PV facility, although some realignment of the support structures might be required. There are already some solar PV facilities constructed on landfills with others proposed.

The landfill is approximately 113 acres, of which 88 acres is used for solid waste disposal, enough for up to 16 MW of solar generation. It is not known how much of the facility is available for solar PV production, although it is likely a relatively small amount.

A meeting with the County Solid Waste Disposal Division to determine the terms that they want to lease the site to the City was held on August 13. The County is tentatively willing to provide an option to lease up to 40 acres next to the landfill, without any particulars, at a cost of \$1,000 per month for 24 months. Once the PV project is operating, the price will be 3 to 5% of the gross revenues received by the builder.

CED does not have \$6 - \$7 million available to build a small solar PV facility. CED will have to enter into a PPA with a developer to fund, construct, own, operate and sell renewable energy to CED. The best way to find this type of entity is to issue a Request for Proposals (RFP) for a solar development on the identified land at the site.

The RFP should ask for proposals to build approximately 1 MW of solar PV energy each year for the next 4 years and sell the energy to CED. The developer will be responsible for acquiring all environmental permits (which should be minimal), construction, interconnection, metering, operation and maintenance of the facility.

One of the advantages of solar PV facilities is that it can be constructed in phases. The developer can permit up to 4 MW but build the 4 MW over 4 years. Or, they could build it all at once and sell the energy and RECs on the open market while CED increases it annual capacity purchase. This staged process will likely result in a somewhat higher price per MWh to the CED but not high enough to justify contracting for all 4 MW at one time.

By acquiring renewable resources in a slow, planned phase-in, CED can minimize the cost of acquiring renewable resources to its ratepayers, meet SB 2 requirements and have time to develop a comprehensive long-term RPS strategy that CED can afford. This proposal would meet the Colton City Council's cost-limitation criteria established in R-103-11.

But even with the construction of 4 MW of solar PV between 2013 and 2016, CED would only have 10% of its load met with renewable resources, well below the 25% RPS requirement for 2017. CED will have to begin identifying specific baseload renewable projects, just as geothermal or biomass generation, beginning in the 2018 time period.

Chapter 8
Generation Resource Planning

Introduction

The previous sections of the IRP have identified CED's existing generation and transmission resources, conservation and DSM programs helping shape CED's loads and the legislative and regulatory requirements that CED must meet in the next few years.

In this Chapter, the costs of meeting CED's loads will be forecasted under a variety of different planning assumptions.

First, a base case will be identified that is meeting forecasted loads with no change in CED's current generation resources. This scenario will identify how short CED is from meeting the legislative and regulatory requirements of AB 32 and RPS requirements.

A second scenario is presented in which CED sells a portion of the AMPP during the winter months and as RA capacity and new resources are acquired to meet RA, local RA and RPS requirements.

A key point to recognize is that although CED's budgeted power supply costs do not include debt service costs associated with AMPP they are accounted for in the power supply simulations. The annual debt service of around $3,200,000 for AMPP is accounted for in the City's debt costs and is not treated explicitly as a power supply cost for budgetary purposes; however, all costs of power supply, including debt, should be considered when modeling supply costs. All other debt costs (primarily SCPPA's debt costs associated with purchasing transmission and generation units) are included in the following analysis.

Load Duration Curve

CED's load duration curve was calculated as a screening tool for the planning scenarios. The load duration curve ranks CED's 8,760 hourly loads from highest to lowest and then shows what portion of load is met by each resource.

The load duration curve shows that CED's 45 MW of baseload energy (Magnolia, SJ3, Colton Landfill, High Winds and PVNGS) meets all of retail load requirements in all but 3,000 hours per year and generates significant surplus energy during this time.

For the load during the highest 3,000 hours of the year, CED relies on energy from Hoover and High Winds for peaking and AMPP and market purchases for intermediate requirements.

The load duration curve also shows that that CED's peak loads only exceed 70 MW for about 80 hours per year. If DSM programs can be designed to reduce peak loads by 10 MW, CED can reduce the cost of meeting retail requirements between $250,000 and $400,000 annually. The majority of the savings would be due to reduced RA requirements with the remainder due to energy prices that are usually greatest during Colton's high load periods.

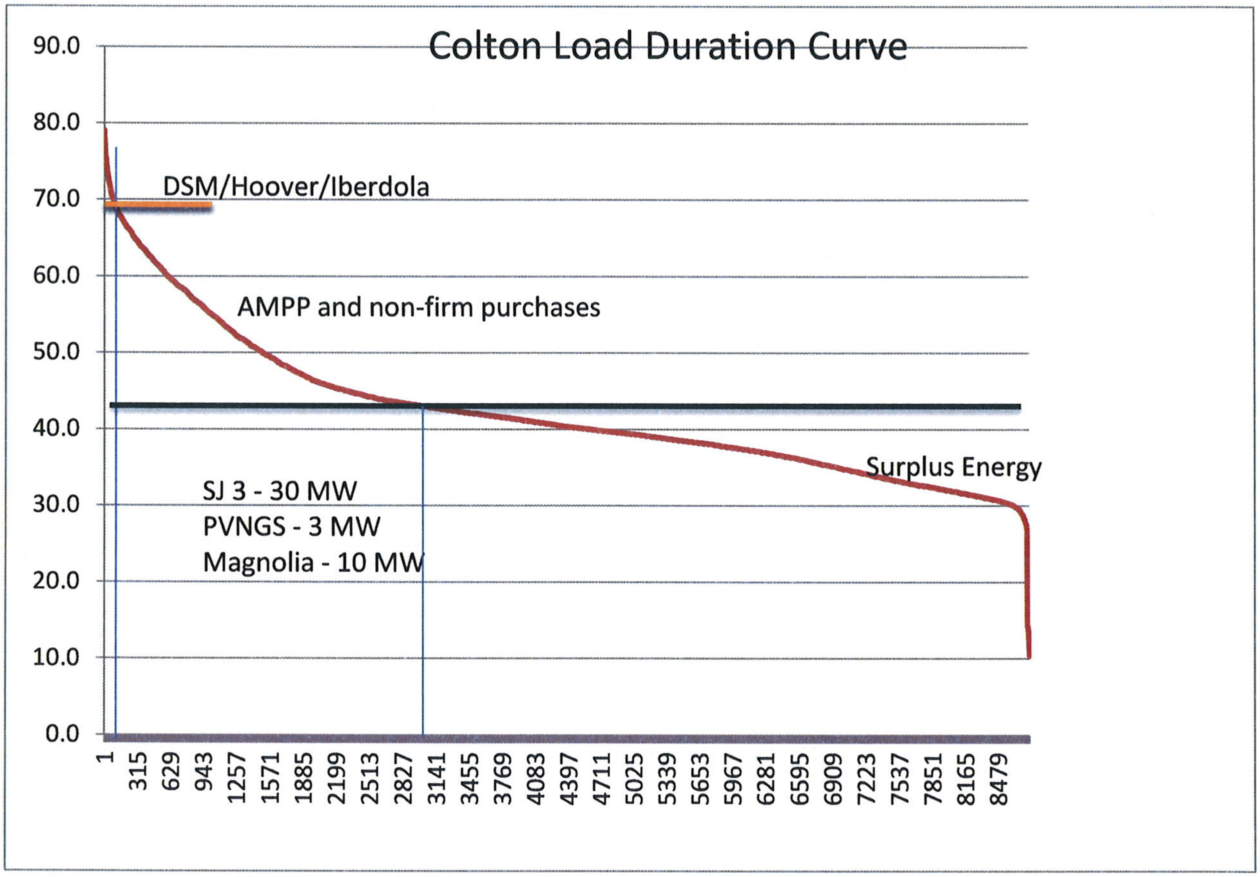

Figure 8.1: CED's Load Duration Curve

<u>Base Case Scenario</u>

The base case scenario examines CED's power supply costs with only existing resources and the demand and energy forecast prepared using the model presented in Chapter 2. The simulation extends only through FY 2015/16, a shorter time period than most planning scenarios. The model does not include any additional DSM measures to attempt to reduce CED's monthly peak demands.

The analysis begins with a "backcast" of 2011/12 to verify the overall accuracy of the simulation model. First, hourly loads were reduced by 1 MW, the High Winds generation. Then Hoover was dispatched between *Hour Ending* (HE) 1200 and HE 2100, the on-peak periods. Then, CED's 42 MW of baseload resources were dispatched. Finally, any remaining energy requirements were met by either AMPP or market purchases.

If Magnolia was not available and CED's gas purchases moved to AMPP, then AMPP was less expensive to dispatch that short-term CAISO purchases. If Magnolia was available, then CAISO purchases are less expensive than AMPP.

The model showed that CED was long, or had surplus energy, of 38,170 MWh during the year. CED went into the market to purchase, or used surplus natural gas from Magnolia to generate at AMPP, about 23,702 MWh during the high load months of June, July, August and September.

All monthly costs for CED's SCPPA resources were based upon the monthly budgeted values. SCPPA will bill its members based upon the budgeted costs and then refund any unspent moneys at the end of the year.

Total generation and transmission charges were $31,909,000 in this scenario. The total 2011/12 power supply budgeted estimate is $31,463,697 a difference of $450,000 or less than 1.5 percent. This suggests that the simulation model is doing a reasonable job of simulating power supply costs. There was no attempt in the simulation to adjust any of the SCPPA budgets from forecasted to actual costs.

The primary reason for the difference is the sharp decline in natural gas prices that reduced the cost of CAISO ancillary services and purchases in the non-firm market. However, while the cost of purchasing ancillary services and energy went down, so did the revenues CED received for surplus energy.

For the period 2011/12 through 2014/15, the simulation model shows CED's total power supply costs as:

	Fiscal Year 2011/12	2012/13	2013/14	2014/15	2015/16
Forecasted Total Power Supply Costs (000s) including AMPP debt	31,909,462	35,836,700	33,906,141	33,150,206	35,070,726
Excluding AMPP debt	(3,200,000)	(3,050,000)	(2,900,000)	(2,900,000)	(2,900,000)
	28,709,462	32,786,700	31,006,141	30,250,206	32,170,726
Average Cost ($/MWh)	88.0	96.1	89.6	86.2	89.6

Table 8.2: Forecasted Total Power Supply Costs Base Case

AMPP debt is treated separately because of the City's budget process that accounts for debt separate from the power supply budget. From a planning perspective, all resource costs should be included regardless of where the costs are included in the City's accounting system.

The sharp jump in 2012/13 average energy costs is due to a variety of factors. First, Magnolia is scheduled for a five-month outage beginning in November, 2012. Then, SJ3 is scheduled for a one or two-month outage in October and November, 2012. Also, beginning in July 2012 CED will begin paying for the SJ3 SCR upgrades. When SCPPA finances the SCR's, CED will receive any pre-construction payments back.

During outages, CED continues to pay the monthly minimum charges to finance debt and operations and, in the case of SJ3, still pays coal costs as the mining operations continue. In addition, CED must acquire replacement energy for energy to meet its loads.

CED intends to move gas supplies from Magnolia to AMPP to generate during the peak periods when Magnolia is down and should require little, if any, off-peak energy.

However, when SJ3 is down, CED will have to purchase energy to meet load. It is estimated that the cost of replacement energy will be around $400,000 per month. If natural gas prices remain at current low levels, the total impact of the outages could be held to around $800,000.

CED anticipates using $1,000,000 from its SCPPA overpayments to help mitigate the price increase. CED is also exploring the cost of purchasing an off-peak energy option for October, 2012. The option will cap the cost of off-peak energy and allow CED to use AMPP as a physical hedge during the on-peak period.

The SJ3 SCR upgrades are expected to cost CED about $20 million in total. Assuming SCPPA finances the SCR's for ten years, the monthly cost to CED will be around $130,000 or $1,600,000 per year. This additional cost will extend through the planning period.

In 2013-14, total power supply costs drop back to $31,000,000. There is no need to buy replacement energy for San Juan or Magnolia and costs return to 2011-12 levels with the exception of the SCR debt payments.

There are a number of actions that CED can take to attempt to mitigate the increasing power supply costs. These include:

- Changing CAISO transmission status from Existing Transmission Contracts (ETC) to Participating Transmission Owner (PTO);
- Changing the Dispatch strategy to minimize transmission congestion costs;
- Attempt to sell AMPP RA capacity during the non-winter months;
- Attempting to sell surplus off-peak energy to Colton retail customers to reduce their energy costs but increasing revenues to the CED.

Cost Mitigation Measures

CAISO Transmission Contracts

Following the energy crisis of 2000-2001, the CAISO began re-designing the California wholesale electricity market. One of the issues that the CAISO had was how to encourage transmission owners to turn functional control of transmission over to the CAISO. Without control of transmission, the CAISO could not dispatch resources in least-cost order without concern over its ability to transmit the energy to load centers.

Transmission owners and those with existing transmission contracts were offered two primary choices. They could either continue to maintain their existing transmission resources and pay whatever the cost of this transmission was. These entities are called *Existing Transmission Contracts*, or ETCs. The other option was to turn control of transmission resources over to the CAISO and become a *Participating*

Transmission Owner, or PTO. The CAISO would assume all costs associated with the transmission contracts and pay a rate of return on any transmission investments made by the PTO.

The CAISO would create a High Voltage and Low Voltage transmission rate for PTO's. The CAISO's cost of paying for all transmission contracts would be recovered through a *Transmission Revenue Requirement* (TRR) account and the transmission rate would be equal to the TRR divided by forecasted energy used by California ratepayers.[23]

Alternately, an entity could choose to retain its existing transmission contracts. In this situation, the CAISO would administer the contract but the entity would have its transmission rights preserved. The entity would pay whatever the contract costs were and retain whatever contractual rights it had over a transmission path.

CED choose to become an ETC. CED opted to continue paying for its existing transmission contracts and forego any return on its investment in the Mead-Phoenix and Mead-Adelanto Transmission Projects.

CED is re-evaluating its transmission status. An initial analysis suggests that CED can reduce its annual transmission costs by approximately $1,000,000 by changing from an ETC to PTO status. The exact amount depends upon a variety of issues concerning Magnolia transmission and displacement contracts between CED, the Los Angeles Department of Water and Power (LADWP) and Burbank.

Congestion Costs

Another area of concern is CED's congestion costs. CED has been paying congestion costs on the Mead-Phoenix line for energy from SJ3. CED is not able to secure sufficient CRRs to fully hedge its exposure to transmission congestion from Westwing Substation in Phoenix to midpoint Adelanto-Lugo and has been paying significant congestion costs over this transmission path for energy that in many hours has been surplus to its loads. As a result of this analysis, Shell has been directed to attempt to minimize the use of transmission in excess of CED's allocation of CRRs. This could result in 10 MW of SJ3 generation being sold at Westwing rather than into the CAISO market.

The CAISO was required by FERC to implement a congestion pricing scheme to manage transmission use as part of the MRTU market process. Congestion pricing works much like a toll road where as more people use the toll lanes, the price increases. In the same manner, as more generators want to use a particular transmission path, the cost of using that path increases.

Any entity can purchase the congestion rights along a path and receive the congestion revenues from all entities using that path. LSE's are allocated some congestion revenue rights (CRRs) along specific paths that are used to bring resources into the LSE's load in annual and quarterly congestion auctions.

[23] Currently the High Voltage Transmission Rate is $6.7562/MWh and the Low Voltage Rate is $5.2647/MWh.

CED has been allocated around 22 MW of congestion rights on the transmission paths it uses to bring SJ3 to Colton. So CED does not have enough CRRs to totally protect itself from paying congestion charges.

Over the past few years, CED has been paying significant congestion charges to bring power from the Phoenix area to Colton. To reduce these costs, CED has implemented a new dispatch structure. During periods of high congestion charges, CED will sell any SJ3 energy in excess of its CRRs at Westwing Substation[24] and purchase energy from the CAISO, if needed, to meet load. This will help reduce CED's annual transmission costs.

Surplus RA Capacity

CED has 90 MW of RA resources. During the summer, high load periods, this is enough capacity to meet its reliability requirements. But during the six month period November through April, CED's loads drop and it has between 20 and 30 MW of excess RA capacity. This RA capacity is worth about $300,000 per year if marketed. In the past, CED has not marketed this capacity to other entities. CED intends to begin marketing this capacity and attempt to recover some costs associated with the AMPP.

Surplus Energy

If CED could sell 50 percent of this surplus energy to retail customers at the low off-peak price of $0.08/kWh (roughly half of CED's current retail rate) CED could increase revenues by about $1,600,000 to $2,000,000 per year in comparison to selling surplus energy in the MRTU imbalance energy market.

While the surplus energy has more value than CED is currently receiving, because CED cannot know if customers will take advantage of the off-peak energy, no dollar impacts have been included in the power supply cost simulations.

Summary of Cost Control Measures

CED should be able to reduce its power supply costs by 2013 and beyond by changing the way it schedules and dispatches energy and changing its transmission status with the CAISO. These two changes should reduce costs by $900,000 to $1,400,000 per year. There is another $1,000,000 in potential revenue if CED begins marketing its excess energy and capacity but it is unknown how long it will take to realize any revenues from these sources.

CED has already begun the studies necessary to change its transmission status. The next period for filing for a change with the CAISO is July 2012 with a potential for the request to be approved effective January 1, 2013. CED will be required to inform the CAISO of its intent, allow the CAISO to determine which of its lines qualify for PTO status, then file a request for transmission revenues at FERC (which will likely be challenged by other CAISO member agencies) that, once approved, will become effective.

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[24] Westwing is near the PVNGS in the Phoenix area and is a major trading hub

Forecasted Energy Costs with Cost Mitigation Efforts

The following table shows the impact of CED's planned cost mitigation efforts. Only the impacts of the change in CED's transmission status and scheduling and dispatching procedures and RA sales are included because CED cannot control how much and when it will be able to market its surplus energy to retail customers.

	Fiscal Year 2011/12	2012/13	2013/14	2014/15	2015/16
Forecasted Total Power Supply Costs (000s) including AMPP debt	31,909,462	35,836,700	33,906,141	33,150,206	35,070,726
Excluding AMPP debt	(3,200,000)	(3,050,000)	(2,900,000)	(2,900,000)	(2,900,000)
	28,709,462	32,786,700	31,006,141	30,250,206	32,170,726
Average Cost ($/MWh)	88.0	96.1	89.6	86.2	89.6
Forecasted Total Power Supply Costs (000s) with Cost-Mitigation Measures and AMPP debt	31,659,462	35,586,700	33,506,141	32,750,206	34,670,726
Average Cost ($/MWh)	87.3	95.4	88.5	85.2	88.6
Reduction in Annual Costs	250,000	250,000	400,000	400,000	400,000

Table 8.3: Base Case Forecast with Cost Mitigation Efforts

CED will still realize an increase in 2012/13 power costs, although a smaller impact, due to the need to acquire replacement energy during the Magnolia and SJ3 outages. However, costs will decline in 2013/14 and 2014/15 from 2012/13 levels but CED is still likely to realize a slight increase in costs from 2011/12 levels due to the impacts of the SJ3 environmental upgrades.

CED will partially mitigate the 2012/13 increase in power supply costs by withdrawing monies paid to SCPPA (up to $1,500,000) and being re-paid for SJ3 funds spent on the SCR construction when SCPPA ultimately finances the SCRs.

Solar PV Scenario

In Chapter 6, a proposed plan for constructing up to 4 MW of solar PV on the Colton landfill was developed. 4 MW of solar PV is not sufficient to meet CED's RPS obligations but meets the cost limitation criteria of no more than a 2% increase in annual costs when the above market prices of CED's existing renewable resources are accounted for. There is no consensus on how to estimate the effects on total rates due to the acquisition of renewable resources. By comparing the cost of energy from the CAISO day-ahead market with the actual price of paid for renewable energy resources, it appears CED is paying slightly more than $1.1 million for renewable energy when the 4 MW of proposed solar PV is constructed. This is approximately a 1.9% increase in rates to CED's customers.

CED will still have to acquire some additional renewable resources between 2013 and 2016. It appears that the most attractive alternative, from a cost limitation viewpoint, would be increasing the amount of in-state wind energy purchases by 1 or 2 MW.

If CED determines that it will proceed with the proposed solar PV project, the forecasted power supply costs would be:

Forecasted Total Power Supply Costs (000s) with Cost-Mitigation Measures and AMPP debt	31,659,462	35,586,700	33,506,141	32,750,206	34,670,726
	-	-	-	-	-
Average Cost ($/MWh)	87	95	89	85	89
	-	-	-	-	-
Reduction in Annual Costs	250,000	250,000	400,000	400,000	400,000
Forecasted Costs	28,709,462	32,636,700	30,706,141	29,950,206	31,870,726
Total Annual PV Cost excluding taxes, profits	205,198.63	410,397.26	615,595.89	820,794.51	820,794.51
Total Power Supply Costs	28,914,661	33,047,097	31,321,737	30,771,000	32,691,521

Table 8.4: Power Supply Costs with PV Purchase

No AMPP Scenario

An area of interest to many Colton ratepayers and elected officials is the AMPP. Ratepayers are concerned that AMPP is causing their rates to rise because it is not operating and many people do not see the financial benefits of the plant.

A preliminary analysis of the AMPP was performed by removing the AMPP from CED's resource mix and re-analyzing future power supply costs without AMPP in the resource mix beginning in 2012/13. The analysis suggests that AMPP lowers CED's power supply costs but not enough to offset debt service costs at the current low price of natural gas. As a result, total power supply costs rise with AMPP in the resource mix.

AMPP brings a number of benefits to CED. First, it offsets the cost of purchasing both RA and LRA capacity. Second, it becomes a physical hedge against high CAISO energy prices, insuring that the price of energy purchased by CED does not exceed a fixed ratio against natural gas prices.[25] Finally, it becomes

[25] AMPP is bid into the CAISO market each day at an energy price equal to 9.1 times the natural gas price. If natural gas prices were $2.50/MMBTU, energy from AMPP would be offered at $22.75/MWh. So long as CAISO prices were less than $22.75/MWh, the plant would not be dispatched. But if CAISO energy prices exceed $22.75/MWh due to transmission or generation outages or just increases in demand, the plant would be dispatched and CED's price capped at $22.75/MWh regardless of what the CAISO price was.

a guaranteed source of energy to Colton in the event of regional power outages, assuming that the plant can be started.[26]

Without AMPP, CED would have to purchase RA capacity in the market. During the summer months this capacity would cost about $2,000 to $2,500 per MW. CED would have to purchase approximately 244 MW of RA capacity to meet its regulatory requirements in 2012/13 at a cost of $609,000, increasing in 2013/14 to $642,000.

CED would also have to purchase 64,000 MWh of energy annually, primarily during the summer high-cost periods. Generally, CED takes advantage of the current low energy prices and displaces generation from AMPP with market purchases. However, without AMPP, CED would have to either enter into hedges, power supply purchases or take the risk of purchasing in the market.

An analysis of CED's power supply costs shows that when debt service costs of AMPP are included the net impact on CED's customers is to increase total costs by about $3,400,000 or roughly 6 percent of retail rates even when the cost of additional RA and energy are accounted for.

This initial analysis needs to be greatly expanded before a final decision is made. While AMPP may currently be a factor in high power supply costs, there may be other alternatives that result in lower rates while maintaining the high degree of reliability that AMPP provides CED's ratepayers.

For example, selling CED's share in Magnolia may result in lower rates since this unit has very high scheduling costs and is a must-run unit that results in significant surplus energy.

Both AMPP and Magnolia contribute to CED's surplus energy issues. In addition, the high cost of scheduling and dispatching Magnolia reduces the potential energy savings associated with the project. It might very well be that CED could reduce costs by selling Magnolia more than AMPP even though CED's share of the Magnolia plant is much smaller than AMPP

Also, no decision should be made on AMPP until a final decision SJ3 is made. CED can attempt to sell one of its three major generation sources, SJ3, Magnolia or AMPP. However, CED cannot lose two of these units without assuming significant risk of increases in its power supply costs.

If CED must meet RPS obligations, it can likely do this least expensively by keeping ownership in AMPP and replacing energy currently provided by Magnolia with renewable sources. If CED does not have to acquire renewable energy, it can likely meet its retail energy requirements by using Magnolia for energy and purchasing RECs and RA to meet its regulatory obligations.

Summary and Conclusion

The analysis presented here is a beginning of CED's attempts to reduce its power supply costs and make them more comparable with neighboring electric utilities. The analysis shows that CED can lower annual

[26] AMPP does not have black-start capability or the ability to start without an external power supply source. However, AMPP staff has been able to start with the external power supply source in tests and feel comfortable that in most cases they can start the facility.

power supply costs by divesting either Magnolia or AMPP, but determining which one will require substantially more analysis and consideration of a variety of factors not addressed in this initial study.

The analysis of CED's power supply costs also shows that CED's total power supply costs should remain fairly constant for the next four years other than the additional cost of meeting SJ3 environmental upgrades. The most important issue currently facing CED is the final resolution of the environmental issues at SJ3 that are significantly increasing the cost of energy to CED's ratepayers.

Appendix A

Glossary of Terms

Arbitrage: The risk-free exploitation of temporary market price anomalies in related commodities or instruments, generally by the purchase of a commodity or instrument that is relatively low in price and the sale of the commodity or instrument that is relatively high priced. In order to be market neutral, the purchase and sale of the commodities or instruments should be simultaneous.

Call Option: An option that gives the buyer (holder) the right, but not the obligation, to buy a futures contract (enter into a long futures position) for a specified price within a specified period of time in exchange for a one-time premium payment. It obligates the seller (writer) of an option to sell the underlying futures contract (enter into a short futures position) at the designated price, should the option be exercised.

Cost VaR (Value at Risk): Cost VaR summarizes the expected maximum "cost" exposure over a target horizon with a given confidence level. For example, if trends indicate that an expected (or average) cost is $100 but volatility indicates that this cost may fluctuate wildly, VaR will capture the magnitude of this volatility as a summary number. This number, or estimate, can then be added to average or expected cost in order to measure the impact of volatility on potential cost.

Counterparty: A party on either side of a transaction (i.e. purchasing counterparty as opposed to a selling counterparty). External transacting parties such as the CAISO and NYMEX are not included in calculating counterparty credit exposures.

Counterparty VaR: the dollar estimate of the risk that subsequent changes in market price will result in increased counterparty credit exposure.

Credit VaR: The statistical estimate of potential losses in a portfolio due to changes in counterparty credit ratings.

Derivative: Any financial instrument, such as a future contract, swap or option, which derives its value from the value of an underlying security or physical commodity.

Discretionary resource: Resources that are flexible in their dispatch and, as a result, are often managed as options in the sense that they may or may not be scheduled for dispatch. Discretionary resources contain less contractual scheduling limitations than must-take resources.

Displacement: The replacement of one generation resource with the matching amount of another competitively priced resource. Displacements provide for economic optimization of discretionary resources.

Electric Capacity: The maximum amount of electric power available for generation or use, usually expressed in kilowatts (kW) or megawatts (MW).

Electrical Energy: The generation or use of electric power over some period, usually expressed in megawatthours (MWh), kilowatthours (kWh) or gigawatthours (GWh).

Exercise Price: Also known as the strike price. The price at which futures are brought or sold if an option is exercised.

Hedge Book: the portfolio of long and short positions as they relate to load balancing. The hedge book differs from the trade book in that it is a collection of transactions initiated for the sole intent of achieving load balance. While the hedge book can share similar characteristics with the trade book (i.e. futures and options positions can exist in both books) the hedge book is not designed to maximize profits. The hedge book is designed to mitigate exposure to risk associated with load variability and volatility in cost.

Least Cost Supply Portfolio: the mix of resources which optimizes the cost/risk profile of the utility. For example, if the utility is risk adverse, a least-cost supply mix may have a higher cost than a supply mix that exposes the utility to greater fluctuations in volatility and reliability.

Load balancing: Meeting fluctuations in demand for power.

Load Management: Economic reduction of electric energy demand during a utility's peak generating periods. Load management differs from conservation in that load management strategies shift the use of energy while conservation programs reduce the demand for energy.

Optimization: The process of utilizing strategies and instruments to optimize economic benefits associated with load and resource management. Optimization differs from trading in that the strategic rationale for a transaction is the driver rather than the economic benefit alone. Trading functions are designed to form a commodity position with the intent of speculating on market arbitrage opportunities.

Option: A contract that gives the holder the right, but not the obligation, to purchase or sell the underlying commodity at a specified price during a specified time period.

Premium: The price of an option.

Prompt Month: The month following the current operating month.

Put Option: An option that gives the buyer, or holder of the contract, the right but not the obligation to sell a futures contract at a specific price during a specific time period in exchange for a one-time premium payment. It obligates the seller, or writer, of the option to buy the underlying futures contract at the designated price should the option be exercised at that price.

Speculation: The taking of an unhedged position (short or long) with the intent of holding the position in anticipation of changes in market prices.

Stop-Loss: A benchmark or "trigger" point at which a position will either be covered or closed. If a position is "out of the money" the amount "out of the money" will be limited by a stop-loss limitation. For example, if a stop-loss limit is $100,000, a corresponding position should be covered or closed if it is out of the money $100,000 or more.

Supply Requirements: Those requirements related to reliability and reserve standards mandated by the requirements of regulatory agencies of competent jurisdictions.

Swap: A custom-tailored, individually negotiated transaction designed to manage financial risk. In a typical commodity or price swap parties exchange payments based upon the change in the price of a commodity or market index while fixing the price they effectively pay for the physical commodity. The transaction enables each party to manage exposure to commodity price or index values. Settlements are made in cash.

Transaction Liquidity: The existence of sufficient volume of transactions of a particular product and commodity that generally assures a party's ability to locate a counterparty that is willing to either buy or sell the product in question.

Uncovered Option: An option on an underlying asset for which the seller is not long (in the case of a call option) or short (in the case of a put option) the underlying commodity.

Underlying Commodity: The commodity upon which the value of a derivative is dependent.

Volatility: The magnitude and frequency of changes in prices over time. Standard deviation is a measure of volatility.

Wheeling: In the electric market wheeling refers to the interstate or intrastate sale of electricity or the transmission of power from one system to another

WECC: The Western Electric Coordinating Council a regional reliability council created and recognized by the North America Electric Reliability Council is responsible for establishing guidelines and procedures related to the reliable electric operation of the 11 western U.S. states as well as parts of Canada and Mexico.

WSPP: The Western Systems Power Pool is a power pool comprised of most western utilities and power marketers. A significant development of WSPP is the WSPP agreement, a standardized enabling agreement, or master contract, utilized by over 200 utilities, marketers and other entities across the U.S.

Appendix B

Colton Electric Department 2012-2012 Demand and Energy Forecast

Year	Month	Forecasted Load (GWh)	Actual Load (GWh)	Forecasted Peak (MW)	Actual Peak (MW)
2012	Jan	26.6	27.4	46	46.7
2012	Feb	26.8	24.8	51	46.7
2012	Mar	26.8	28.1	49	46.5
2012	Apr	27.6	27.0	57	54.2
2012	**May**	**31.9**	**30.4**	**67**	**65.6**
2012	**Jun**	**31.0**	**30.9**	**67**	**62.5**
2012	**Jul**	**40.1**	**35.5**	**83**	**75.5**
2012	Aug	37.7		81	
2012	Sep	37.2		77	
2012	Oct	28.9		62	
2012	Nov	27.6		54	
2012	Dec	26.9		47	
2012	TOTAL	369.1		88	

May and June Actual Load values are for comparison with Forecasted Load.

Year	Month	Load (GWh)		Peak (MW)	
2013	Jan	26.7		464	
2013	Feb	26.9		51	
2013	Mar	27.0		49	
2013	Apr	27.8		57	
2013	May	32.1		67	
2013	Jun	31.2		67	
2013	Jul	40.3		84	
2013	Aug	38.1		82	
2013	Sep	37.6		78	
2013	Oct	29.2		62	
2013	Nov	27.9		55	
2013	Dec	27.2		47	
2013	TOTAL	372.2		89	