Colton Electric Department

2019 Integrated Resource Plan

January 2019

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CHAPTER 1: 2019 INTEGRATED RESOURCE PLAN

Introduction

The Colton Electric Department (CED) faces new regulatory, legislative and financial challenges in 2019 as California moves towards a more centralized electricity market with more renewable resource requirements and requirements for significantly reducing carbon emissions. This “2019 Integrated Resource Plan” (IRP) will present 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 current legislative and regulatory constraints.

Perhaps the biggest changes in the 2019 IRP compared to the 2017 IRP is the late 2017 decommissioning of San Juan Generating Station, unit 3 (SJ3) and the City Council’s approval of a 15 MW geothermal purchase from the Casa Diablo Geothermal Plant near Bishop, California. Casa Diablo will provide approximately 120,000 MWh per year of renewable energy beginning as early as April 2020.

An IRP takes into account both supply and demand side alternatives for meeting retail customer electricity demand. Supply-side alternatives include the procurement of new generation and transmission resources, specifically 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 direct install program, refrigerator replacement program and commercial and residential energy saving rebate programs replacement program, attempt to reduce the need for additional supply-side resources. CED will also recommend new programs that provide better conservation options for customers.

The CED believes that it is better for the community and CED to reduce customer demand through conservation programs and rebates, rather than purchasing additional generation resources from power marketers.

Historically, the CED had sought to acquire new resources at the lowest possible cost (consistent with safety and reliability requirements) without considering environmental constraints. However new state and federal environmental rules that went into effect in 2011 and then strengthened in 2015 and again in 2018 have reshaped CED’s power resource mix. From the earlier 1980’s until 2017, CED was primarily a coal-fired utility. Today, CED is primarily a solar and natural gas utility. In three years CED will be a geothermal/solar utility.

CED’s planning efforts are complicated by the fact that generation and transmission resources have lives of 20 to 50 years. Hence, 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.

Because of changes in the operating, legislative or regulatory environment, an IRP should be updated on an annual or bi-annual basis. That way, ratepayers can be assured the CED's energy programs keep current with changes in the business and regulatory environment. The IRP is a long-term planning document 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 for many years. 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. CED is still acquiring resources to replace the San Juan Generating Station, Unit 4 (SJ4) a coal fired resource that was decommissioned in December 2017. The decommissioning of SJ4 gave CED a unique opportunity to restructure its power supply mix, increasing the amount of renewable resources, reducing carbon emissions and potentially reducing long-term power supply costs.

An IRP is also a way for the CED's governing body, the Colton 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 CED's following goals in order of importance:

- Operate the utility safely:
- Provide reliable energy to the residents and businesses in Colton;
- Develop sustainable and renewable energy;
- Meet all state and federal legislative and regulatory requirements;
- Minimize the cost of electricity to CED's business and residential customers;
- Optimize the use of CED's generation and transmission resources;
- Develop demand-side programs to reduce energy use and costs by Colton's commercial and industrial 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.

Different Markets that Affect CED

The CED participates in daily energy markets. CED also participates in a variety of transmission and environmental markets on a daily or monthly basis. The different markets CED participates in include:

1. Energy Markets: The purchase and sale of energy to meet retail load obligations on an hourly basis;

2. Capacity Markets: Three different types of capacity markets to guarantee CED can generate to meet load if required. CED must have sufficient system, local and flexible capacity each month to meet forecasted loads plus reserves;
3. Natural Gas Markets: CED must ensure that it has sufficient natural gas to meet its fuel requirements for the Magnolia Power Project and Aqua Mansa Power Project;
4. Congestion Revenue Rights (CRR) Markets: CRR is the market for transmission rights in the CAISO market. Failure to hold the appropriate CRRs could result in significant increases in monthly costs to cover congestion costs;
5. Emission Markets: The CED is allocated emission allowances to meet forecasted CO2e emissions. To the extent CED can reduce its emissions, it can sell the excess allowances.

Each of these different markets will be discussed below and how each affects CED's total costs will be explained in detail.

Significant Changes from the 2017 Integrated Resource Plan

In early 2017 there was uncertainty about the ultimate date when SJ4 would be decommissioned of the San Juan Generating Station (SJGS). CED did not know how the environmental litigation targeted at the SJGS was going to be resolved or if the proposed resolution (expending almost $1 billion dollars on new pollution control equipment at the SJGS) would be acceptable to other California utilities or the different California regulatory bodies, such as the California Energy Commission or Air Resources Board.

After months of negotiations between utilities in California, Arizona, New Mexico and Colorado and regulatory bodies in New Mexico and other states and the US Environmental Protection Agency (EPA), a compromise was reached that allowed the project participants to decommission two of the four units at the SJGS and permitted the California utilities to exit the plant.[1]

In addition, in order to meet California's new greenhouse gas (GHG) and renewable energy portfolio (RPS) requirements without significantly over-resourcing itself, CED had to sell or shut-down its share of San Juan Generating Station Unit 3 (SJ3). This could not be done without the consent of the other participants in the SJGS, most of them not bound by California's stringent GHG and RPS requirements.

With the litigation resolved in early 2017, CED began the process of replacing over 225,000 MWh (or roughly two-thirds of CED total retail load) of energy and 30 MW of capacity that was used to meet retail load requirements.

CED has completed power purchase agreements (PPA's) for 16 MW of solar generation and 10 MW of landfill gas generation to replace the SJ3 capacity that was lost in 2017. However, the landfill gas

[1] The California utilities do retain some obligations for future decommissioning, mine reclamation and other possible future environmental costs.

generation will be largely gone by 2023 as landfill gas production at the Puente Hills Landfill declines and the capacity and energy from this project will need to be replaced.

The 2017 IRP identified the need for a 15 MW baseload renewable resource in the 2021 time period both to meet retail load and to meet CED's RPS requirements. CED participated in SCPPA's 2017 RFP for renewable resources and chose the Casa Diablo IV Geothermal Plant as the resource that both met CED's load profile and had the least impact on CED's annual power supply costs.

Current Capacity Resources

Since the early 1980's, Colton has invested in generation and transmission resources to meet retail load obligations. Due partially to CED's small size that makes it difficult to purchase all the output from 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[2]. SCPPA identifies potential resources for ownership or power purchase agreements through an extensive RFP process and the member cities can choose which, if any, of the projects they wish to participate in and the capacity amount. CED can also issue its own RFPs or negotiate with generators outside of the SCPPA RFP process.

CED currently has 84 MW of generation resources that is almost sufficient to meet CED's retail load of around 85 MW but is about 15 MW short of CED's capacity requirements including reserves as established by the California Independent System Operator's (CAISO's) reliability requirements for the three summer months, July, August and September. In 2018, CED purchased capacity from Shell Energy to meet its deficiency but is still looking for system capacity for summer of 2019.

On January 1, 2017 the Puente Hills Landfill Gas[3] project came online. CED initially contracted for 10 MW of the unit but due to reduced production of biogas from the landfill, Puente Hills can only produce 7 MW in 2018 and annual output is expected to decline each year for the remaining seven to eight years of expected plant life.

Colton currently has ownership (or rights to capacity and energy) in the following generation resources:

NAME	CAPACITY
Palo Verde Nuclear Generating Station	3 MW
Magnolia Generating Station	10 MW
Hoover Generating Station	2.8 MW
Agua Mansa Power Plant	43 MW

[2] 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.

[3] The Puente Hills Landfill Gas Project may be de-rated to reflect declining natural gas production at the landfill.

Avangrid Wind Project	1.0 MW[4]
Colton Solar I (Walnut)	2.5 MW
Colton Solar II (Agua Mansa)	1.0 MW
MWD Small Hydro	3.7 MW
Gonzales Center Solar	0.5 MW
Arbor Terrace Solar	0.3 MW
Kingbird Solar Project	3.0 MW
Astoria Solar Project	7.0 MW
Puente Hills Landfill Gas Project	7.0 MW
TOTAL	83.8 MW

Forecast of Demand and Energy Requirements

CED has prepared a forecast of monthly peak demand and energy requirements for the period 2016 – 2021. The forecast is based upon state economic forecasts prepared by the California Department of Finance and shows a slight increase in future economic activity in the Riverside – San Bernardino area for the next few years. However, much of the electric demand growth is offset by additional small solar PV installations and conservation efforts.

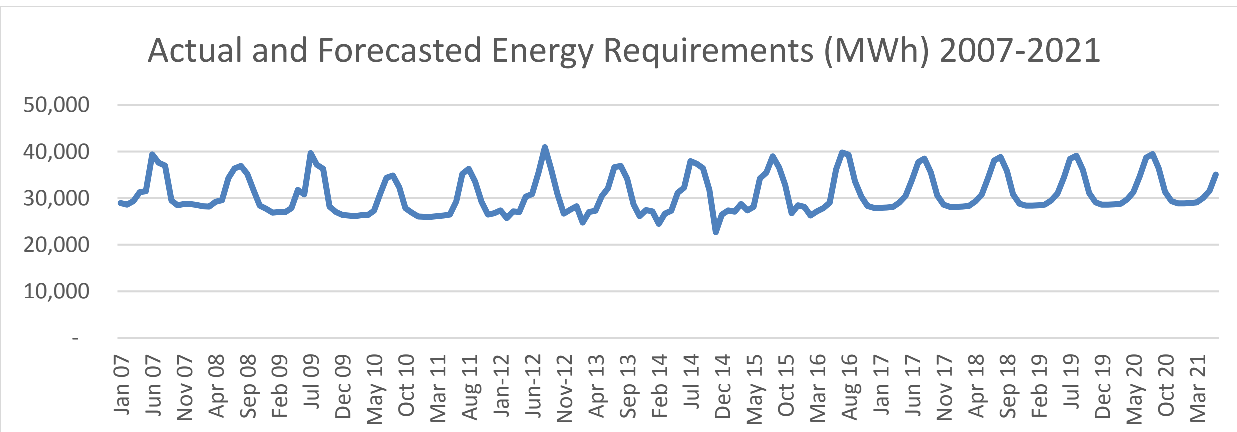

Figure 1.1

[4] Colton has a 3 MW purchase in the Iberdola Wind Project that was delivered at a fixed rate of 1 MW per hour. In a 2014 Amendment, Colton and the (then) owner Iberdola agreed that Iberdola would sell the energy into the CAISO and bill or credit CED for the difference between the contract rate and the CAISO LMP price. CED does not receive any RA capacity from this project. Iberdola was purchased by Avangrid in late 2015.

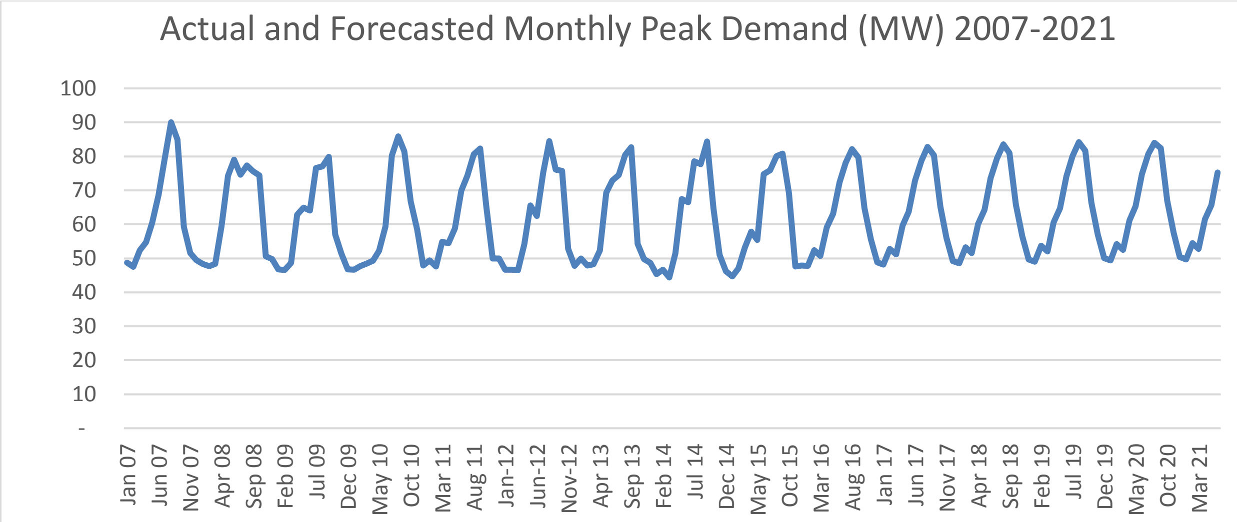

Figure 1.2

The caveat to the economic forecast is potential development in the Agua Mansa Corridor and West Valley area. Although there have been a number of proposed developments in these two areas, only two new projects have been brought online with a third scheduled for late 2018 with total load of the new projects of around 3.5 MW. As a result, the forecast needs to be watched and adjusted when new projects actually begin construction.

<u>Legislative and Regulatory Requirements</u>

For the past fifteen 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. While the current Administration seems intent on undoing many of the federal environmental programs initiated by past administrations, California is increasing its efforts to reduce GHG emissions.

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

- California's AB 32,SB 350 and SB 100 increasing renewable portfolio requirements;
- Regionalization efforts by the CAISO;
- California's proposed movement to a centralized capacity market;
- Possible changes to the cap and trade market.

<u>California AB 32, SB 350 and SB 100</u>

California legislators have passed a number of bills that affect the operations and power supply costs of CED. AB 32, the California Global Warming Solutions Act, passed in 2006. In 2015 SB 350 was passed that requires utilities, in conjunction with California's renewable portfolio standard requirements codified in

SB 2[5], to acquire renewable resources that have only a fraction of the greenhouse gases of traditional fossil-fuel fired generation. In 2018, SB 100 was passed that encourages California's electric utilities to meet 100% of their retail load with renewable, and non-carbon emitting resources by 2045 and increases the minimum requirement for renewable resources to 60% by 2030.

Some of the major impacts of AB 32 included:

- Cap and trade emission allowance trading beginning in November 2012;
- Annual inventory of utility greenhouse gas emissions;
- Prohibition of new coal fired generation transmitted into California.

In addition to the mandated GHG reductions in AB 32, electric Load Serving Entities (LSEs) were required by SB 2 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[6]. These minimum renewable energy standards are called the Renewable Portfolio Standards (RPS) requirements.

The RPS mandates were increased, with the passage of SB 350, from 33 percent in 2020 to 50 percent by 2030, with an obligation for the LSEs to increase their renewable portfolio by 2 percent per year beginning in 2021.

SB 100 further increased the RPS requirements to 60% by 2030 with a goal of having zero carbon emissions by 2045.

CED met its 2011 – 2013 RPS requirements only by claiming the cost-limitation restriction allowed in SB 2 to delay meeting its RPS requirements.[7]

CED met RPS requirements during the second compliance period (2014 – 2016) and anticipates exceeding RPS requirements in the future.

A 2016 bill, SB 859, requires larger utilities (both investor-owned and publicly owned utilities) to purchase 1 percent of their energy requirements from biomass resources. Currently, this bill does not impact CED but it is expected an additional bill expanding the purchase requirement to smaller utilities will be re-introduced in 2018. The purpose of the bill is to help biomass firms clear the forests of dead or dying trees caused by the drought and that increase the fire hazard. CED is required to create and have approved a Wildfire Prevention Plan by 2020 that details the steps that it is taking to minimize fire risk from electrical facilities within its service territory.

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

[6] In May 2013 the CEC also adopted intermediate standards governing procurement between 2016 and 2020.

[7] The CEC is still reviewing RPS compliance filings for 2011-13 and has not yet made a final determination on whether or not CED was in compliance with SB 2 for the 2011 – 2013 period.

CAISO Regionalization Efforts

In order to make it easier for California utilities to import renewable energy, particularly wind from the Montana and Wyoming area, the CAISO has proposed a western states independent system operator led by the CAISO. There are a number of issues with the CAISO's proposal that have been identified by California POU's, including the allocation of transmission costs to all western utilities, governance issues and the problem of forcing utilities in other states and other different regulatory entities to agree to the CAISO proposal. Regardless, the CAISO is proceeding with their regionalization that it sees as a key component of reducing GHG emissions.

California municipalities, in general, oppose the CAISO's desire to expand outside California. Some non-California utilities, generally those with renewable energy they would like to sell into California, support the proposal while others dislike the prospect of California attempting to require minimum amounts of renewable energy and other capacity requirements greater than those in their home state and oppose the CAISO's regionalization efforts. Other obstacles to the regional expansion of the CAISO include the problem of who would bear the cost of carbon emissions from renewable resources imported into California and the issue of stranded investment in coal plants in Utah, Wyoming, Colorado, New Mexico and Arizona.

An attempt to legislate regionalization (AB 813) was defeated in the 2018 legislative session by a coalition of publicly owned utilities and some industry groups. Whether the CAISO will continue to push for regionalization will likely depend upon the direction of the new governor, Gavin Newsom. Regardless, if California does keep its goal of acquiring all its electricity from non-carbon producing sources, it is likely that there will be some changes in the CAISO market to allow better integration of non-California resources into the California marketplace.

Centralized Capacity Market

The CAISO continues to discuss implementing a centralized capacity market where it would require new generation resources to be certain types of fuel or technology. In November 2018 FERC rejected an attempt to force the CAISO to establish a centralized capacity market in California. There is significant investor-owned and POU opposition to this idea. In effect, the CAISO is moving towards creating a single energy market in the state and utilities would become participants in a statewide financial market tied to capacity ownership. This is going to take several years to finalize (if it is ever approved) and CED will continue watching the progress and participating in the hearing process as necessary.

Cap and Trade

The Cap and Trade (C&T) program for electric utilities began with the first auction of emission allowances in November 2012. CED has included C&T requirements in its daily power resource trading activities.

In 2009, CED was allocated Emission Allowances (EAs) from the California Air Resources Board (CARB) equal to its then estimated emissions through 2020. With the decommissioning of SJ4 in 2017, CED has had a surplus of EA's and has been selling its excess EA's in the emissions markets.

CARB has been holding hearings on how best to structure the C&T market beginning in 2021. Some of the issues currently being discussed include requiring utilities to account for emissions from generation outside California that is imported as part of the Energy Imbalance Market (EIM) or to reduce the amount of EA's allocated to each utility due to the more stringent RPS requirements in the future. Currently, if the CAISO acquires energy in the EIM to meet system requirements, none of the California utilities have to acquire EA's for this energy. CARB intends to assign CAISO EIM purchases to utilities although the methodology remains undecided.

There is also a desire for a cost cap on emission costs to ensure market participants can purchase EA's without too great of a cost impact on its customers.

Risk Management

Risk management refers to actions taken to reduce the dollar amount at risk due to unforeseen changes in variables such as fuel prices, unanticipated outages of generation and transmission resources and other variables that affect utility costs or reliability.

There are a number of ways to define and measure risk but a common risk metric is the Value at Risk (VAR). VAR estimates how much a set of investments might lose (with a given probability), given normal market conditions, in a set period.

The CED has adopted a risk management policy that attempts to limit the CED's VAR and requires multiple approvals (prior to final approvals by the Colton Utility Commission and City Council) 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 Finance 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);
- 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

Because of the studies that will be presented in this IRP, CED makes the following recommendations:

- The decommissioning of SJ4 created a need for approximately 15 MW of baseload energy as a replacement of SJ4 and another 10 MW of peaking resources. CED has identified a 15 MW geothermal plant, Casa Diablo IV, that fits CED's baseload RPS requirements and presented a power purchase agreement to the Colton City Council that was approved;
- CED should continue to negotiate with the CAISO for interruptible load as a replacement for resource adequacy capacity;
- CED should continue to expand its conservation programs with a goal of reducing energy use by at least 10% in the next 4 years;
- CED needs additional solar generation in 2021-2023 to help meet the new SB 100 requirements and retail load obligations;
- In the 2023 time-period, the power purchase agreements for the MWD small hydro units, the Iberdola wind project, and the Puente Hills Landfill Gas projects will all expire. CED will need to replace the 10 MW of capacity from these resources. CED will have enough baseload energy resources to meet anticipated requirements but CED will need additional capacity resources, most likely solar PV with battery or thermal storage, to meet its capacity requirements;
- CED should investigate restarting the 250 kW cogeneration facility at the Waste Water Treatment Plant (WWTP) to reduce methane emissions and receive carbon offsets.

CED should be able to complete planning for these projects in 2019/20.

With these projects, and the decommissioning of SJ3, CED will only have two resources that emit GHG, the Agua Mansa Power Plant and Magnolia Power Plant. The AMPP emits less than 25,000 tons per year based on historic dispatch, and will not have a compliance obligation (unless it is dispatched more often resulting in higher than 25,000 tons per year). The Magnolia Power Plant will have approximately 17,000 to 20,000 tons per year once the biogas contract begins. CED will not have a compliance obligation from Puente Hills Landfill as CED is the off-taker of a power purchase agreement (PPA) and not the generator or owner of the facility. All of CED's other resources are GHG free or are small enough that they will not have a GHG compliance obligation.

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 ensure 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 40 percent compared to the winter months. During the non-summer months, Colton's energy use is around 28,000 to 30,000 MWh per month while in the three summer months energy use increases to around 39,000 to 41,000 MWh primarily as a result of increased air conditioning use.

Colton does not appear to have much winter heating load although extreme cold temperature does result in a small increase in energy demand likely due to electric space heaters.

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

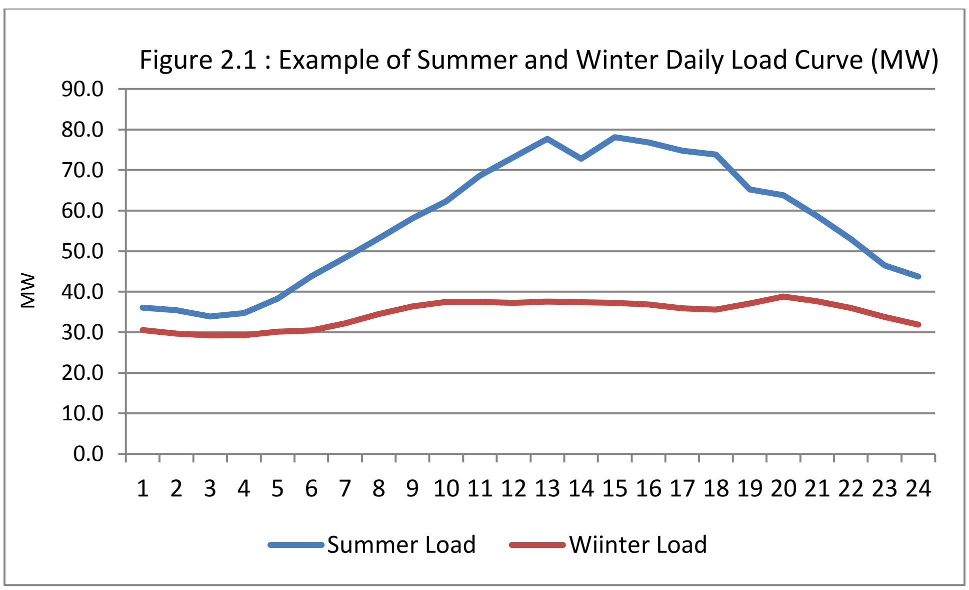

Figure 2.1

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, the early evening residential load 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 increase in energy use due to residential lighting and air conditioning loads and then demand begins to decline as people begin going to bed around 2000.

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

The above load profiles help illustrate two key points. First, Colton requires about 30 MW of baseload energy on an annual basis and secondly[8], Colton's summer peaks are greater than its winter peaks and requires more seasonal 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 in the Riverside-San Bernardino-Ontario SMSA) 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 simple 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)[9]

[8] Colton currently has 20 MW of baseload generation with another 15 MW coming online in 2020/21.

[9] The regression specification is:	*Coefficients*	*Standard Error*	*t Stat*
Intercept	13669.11854	3854.679995	3.54611
Employment	0.011112269	0.003238412	3.431394
DDC	23.78236609	1.659614166	14.33006
DDH	1.095105476	1.919996722	0.570368

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 (DDH) 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 the average daily temperature is greater than 65 degrees, then DDH is 0.

Civilian Employment in the Riverside-San Bernardino-Ontario SMSA 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 quarterly basis.

The following figure illustrates the forecast of energy requirements from July 2018 to December 2023.

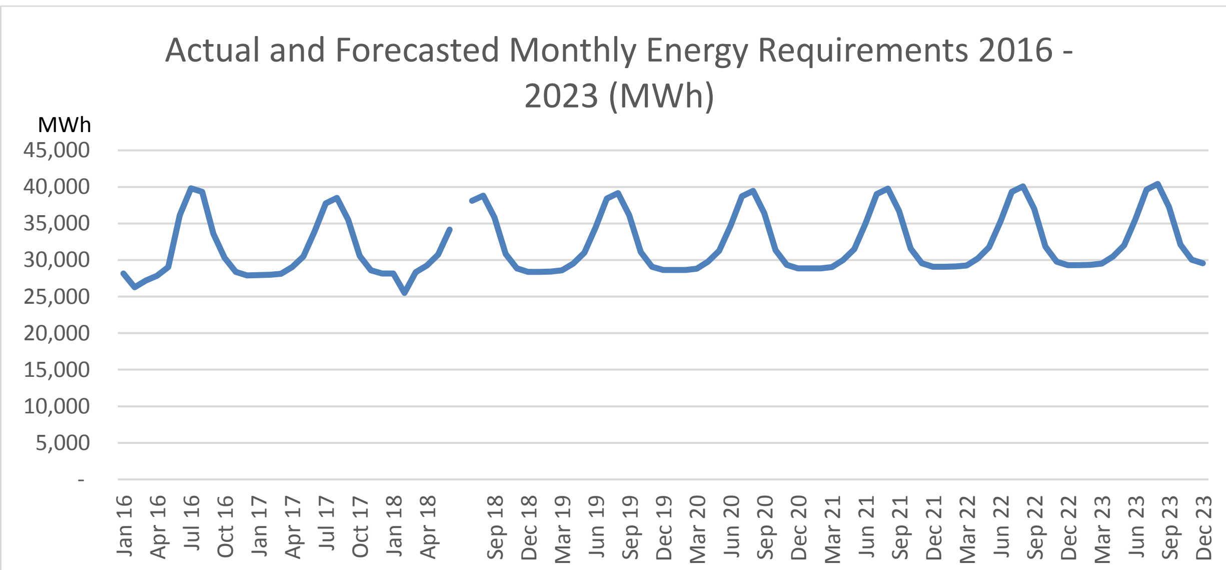

Figure 2.2

A back-cast of the model suggests a very slight under-forecast during the winter energy requirements (by about 2 percent) but otherwise the regression tracks monthly energy use accurately.

The greatest cause of forecast uncertainty is weather variability. High temperatures result in greater energy requirements while lower than anticipated temperatures result in over-forecasts.

Since 2014 energy requirements[10] have stabilized around 380,000 MWh annually although proposed economic development could increase requirements to over 400,000 MWh when the development

[10] Energy requirements are equal to sales + transmission losses + unaccounted for energy (UFE).

actually occurs. Energy sales are around 93 percent of energy requirements, so CED's sales are around 355,000 MWh.

The forecast shows a slight increase in energy requirements from 378,038 MWh in 2017/18 to 381,229 MWh in 2018/19 and then to 384,451 MWh by 2019/2020. The Department of Finance has slightly lowered its growth rate for California employment from the past few years, reflecting the age of the current economic recovery, economic uncertainty due to the national elections, actions by the Federal Reserve to tighten monetary policy and economic issues in Asia and Europe.

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.

Monthly 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 monthly peak 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 unreasonable, 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 eight years (2007 through 2015) 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:

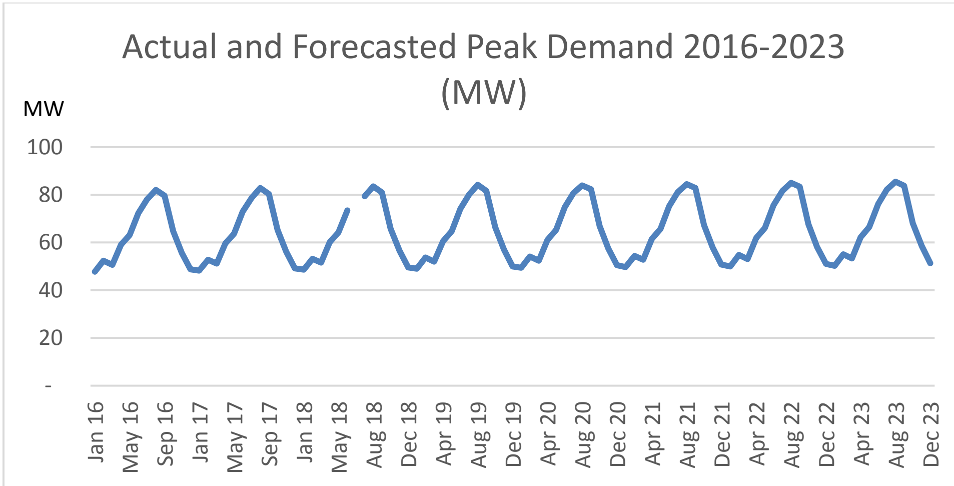

Figure 2.3: Monthly Peak Demand Forecast

The demand forecast shows a very small increase in monthly demand as self-generation and conservation offset any growth in demand. These monthly forecasted peak demands will be used to determine the CED's monthly capacity obligations in the future.

The monthly demand and energy historic and forecasted values for 2016 – 2023 are shown in Appendix B.

CHAPTER 3: EXISTING RESOURCES

Introduction

The CED currently has approximately 84 MW of capacity resources able to help meet retail load requirements. While CED currently has enough generation to meet its retail load requirements in all but the peak summer months, the decommissioning of SJ3 in 2017 resulted in CED having to acquire new generation resources to meet its capacity obligations.

The following chapter discusses each of the different resources.

SCPPA

CED does not own or operate any generating or bulk power transmission facilities except AMPP. All of CED's power supply contracts or transmission rights are either through the Southern California Public Power Authority (SCPPA) or agreements with other entities.

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

Magnolia Power Project

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. By recovering 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 to acquire long-term gas supplies from the Pinedale and Barnett gas fields and a pre-pay contract with SCPPA.

Pinedale Project

SCPPA negotiated its first purchase of existing natural gas wells in 2005. The Pinedale Natural Gas Project (Pinedale) reserves are located in west/central Wyoming.

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

Colton owns 7 percent of the Pinedale Project, with the other participants including 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.

In 2016, Ultra Energy, the site manager, declared bankruptcy. Ultra's bankruptcy has not impacted daily operations at Pinedale or resulted in increased costs for the SCPPA participants. Regardless, SCPPA is now a participant in Ultra's bankruptcy proceedings on behalf of the SCPPA participants.

LADWP serves as Project Manager for the overall project.

Barnett Natural Gas Reserves Project

In 2006, SCPPA members purchased natural gas reserves in Texas, northwest of Dallas. 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) has 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 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.

Pre-Paid Natural Gas

In 2007 SCPPA issued bonds 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 delivered by the gas supplier (J. Aron & Company) over the term of the Prepaid Natural Gas Sales Agreements is approximately 135 billion cubic feet (or 135,000,000 MMBTU).

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 delivered to SCPPA over the term of the Prepaid Natural Gas Sales Agreement (Prepay Agreement). The price that the participants pay is the daily Southern California Citygate index less (approximately) $0.70/mmbtu.

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 CED receives varies by month from a high of about 55,000 MMBTU in July and August to as little as 19,700 MMBTU in the spring.

As part of the Pre-Paid Gas Agreement, J. Aron has also agreed to remarket, on a daily or monthly basis, quantities of gas designated by SCPPA or any of the City's' agent as remarketing surplus gas might be necessary, generally when Magnolia is unavailable due to either scheduled or unscheduled outages.

Summary of Gas Contracts

The following table presents a summary of Magnolia's historical costs (including natural gas and transmission costs over LADWP's system) beginning in 2009/10.

	FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	FY 2013/14	FY 2014/15	FY 2015/16	FY 2016/17	FY 2017/18
Total Cost (000's)	$5,164	$4,949	$6,536	$6,137	$5,678	$6,145	$4,844	$4,592	$4,390
Generation (MWh)	73,788	49,738	59,906	55,769	59,906	70,008	72,405	62,069	67,360
Average Cost/MWh	$70.00	$99.50	$109.10	$110.00	$103.50	$87.70	$66.90	$74.00	$65.20

CED has tentatively negotiated a contract with Shell Energy (Shell) to partially supply Magnolia with biogas, increasing the amount of renewable energy CED produces. This will be discussed in more detail below.

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 slightly less than 1 MW of capacity in each of the three units at PVNGS.

The following table shows the historical costs of PVNGS to Colton.

	FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	FY 2013/14	FY 2014/15	FY 2015/16	FY 2016/17	FY 2017/18
Total Cost ('000's)	$706	$771	$784	$723	$745	$764	$904	$734	$678
Generation (MWh)	18,948	18,627	18,609	18,000	18,000	18,000	19,292	18,992	19,080
Average Cost/MWh	$40.70	$42.10	$38.80	$41.40	$42.40	$43.50	$46.90	$46.50	$42.10

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 original contracts expired in 2017 but in 2012, Congress extended the SCPPA participants power purchase agreements for 50 years. In exchange for this long-term extension, participants in the Uprating Project agreed to give up 5 percent of their entitlement that was given to federal agencies and Indian tribes in California and federal facilities.

Hoover is Colton's most economical resource, with delivered energy costs of less than $30/MWh.

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

	FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	FY 2013/14	FY 2014/15	FY 2015/16	FY 2016/17	FY 2017/18
Total Cost ('000s)	$75	$80	$80	$80	$83	$81	$74	$76	$76
Generation (MWh)	3,056	3,388	2,617	2,617	2,807	2,807	3,174	3,016	2,919
Average Cost/MWh	$28.90	$27.40	$27.70	$27.30	$28.70	$28.80	$23.30	$26.20	$26.04

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 2003.

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 CED's resource adequacy requirements, especially local RA capacity obligations.

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

	FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	FY 2013/14	FY 2014/15	FY 2015/16	FY 2016/17	FY 2017/18
Total Cost (000's)	$3,025	$1,449	$2,011	$5,039	$2,592	$3,000	$1,362	$1,923	$159
Generation (MWh)	30,030	15,207	26,349	19,640	20,000	20,000	9,458	11,519	7,499
Average Cost/MWh	$121.97	$137.91	$139.38	$76.77	$129.60	$150.00	$144.00	$166.90	$211.70

The above costs for AMPP do not include debt service costs that would add approximately $2,900,000 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 discussed further in the power supply cost forecast section.

In addition to providing a physical hedge against spikes in CAISO energy market prices, AMPP is a source of system, local and flexible capacity. CED spent almost a year working with the SCAQMD to acquire the necessary operating permits to qualify as a source of flexible capacity with the CAISO.

Renewable Resources

CED has power purchase agreements (PPAs) with seven entities for nine renewable projects. These are the High Wind Project, the Metropolitan Water District (MWD) small hydro power purchase agreement, Astoria Solar Project, Kingbird Solar and two small solar projects within Colton Solar 1 and 2 with SES and two small solar projects with Solar City. The Puente Hills Landfill Gas generation Project, began delivering energy to CED on January 1, 2017. Together, these resources produce between 115,000 and 130,000 MWh of energy annually or about 31 to 35 percent of Colton's total energy requirements[11].

High Wind Energy Center

The High Winds Energy Center (High Winds) is located along northern California's Montezuma Hills in Solano County, midway between 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 participant in this project.

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 of SCPPA's share or 1 MW.

Initially, Iberdola delivered 1 MW per hour to Colton regardless of the wind production. The difference was made up of energy purchased from either the CAISO or Navajo Power Plant, a coal project in Arizona. At the end of each month, Iberdola identified the amount of renewable energy provided. In 2012, Colton received about 7,024 MWh of renewable energy and 1,736 of non-renewable energy from the project.

In 2014, CED renegotiated the contract so that Iberdola only delivered wind generated energy and no coal fired generation.

The cost of energy from the High Winds Project is $53.50/MWh fixed.

This project has gone through a number of name and operator changes. Currently it is operated by Avangrid Renewables that purchased Iberdrola Renewables, the prior owner/operator.

Metropolitan Water District Small Hydroelectric Projects

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 smaller than 30 MW, they qualify as renewable energy sources under RPS rules.

On an annual basis, CED has been receiving about 6,000 MWh of renewable energy from the purchase. But as the western drought continues, the amount of energy MWD delivered on CED's behalf has declined.

CED receives 22 percent of the 17 MW total, 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

[11] One of the drawbacks of renewable energy contracts is that annual energy production depends on weather conditions so the annual forecasts of production can be substantially different than annual production

components. CED then sells the energy to the City of Anaheim at 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.

Because of the high price of the contract, in 2016 SCPPA notified MWD on behalf of CED and the other participants that it intended to cancel the contract in accordance with a unique provision in the contract that allowed either party to cancel with two years notice. MWD offered to re-negotiate the price with the SCPPA participants for the remainder of the contract life (8 more years from July 2017) and the parties agreed to a new price of $54/MWh. The new, lower price saved CED about $220,000 per year.

Colton Solar 1 and Solar 2

In order to procure resources to meet the CED's RPS requirements, CED issued a RFP for renewable solar PV projects, located in the City, in October 24, 2012. Nine companies responded to the RFP. After an extended evaluation process, which included a sub-committee of the Colton Utilities Commission (Commission), CED selected Specialized Energy Solutions (SES) for ground mounted solar PV systems.

SES constructed two solar facilities in Colton. Solar 1 is a 3.0 MW facility located in the north end of the City and Solar 2 is a 1.0 MW facility located at the Agua Mansa Power Plant in the southwest portion of the City.

The initial PPA price is $80/MWh increasing at 3.5% per year. Under the terms of the PPA, CED pays SES for all energy delivered or available for delivery in the event CED chooses not to take deliveries. CED receives all environmental and capacity attributes of the project. SES was required to register the project with the California Energy Commission (CEC) and the Western Renewable Energy Generation Information System (WREGIS) so that CED would receive appropriate credit for renewable energy production. The PPA also includes a one-time right to require SES to sell the project to Colton at the end of Year 7 at a negotiated value.

In the negotiations with SES, CED anticipated purchasing the units in year 6 or 7 either using utility funds or using municipal financing. Depending upon the year that the purchase is consummated, the total cost will be around $6.3 million with an annual cost of about $425,000 or $45-48/MWh. This will significantly lower the cost of the solar project. The reason for the anticipated purchase is that it allows SES to take tax credits, unavailable to the CED, that are used to reduce the purchase price is year 7.

CED will begin setting aside Cap and Trade funds to help pay for the units in year 7. CED anticipates having $3.5 to $5.0 million available to purchase the units by 2025 assuming no changes in the state's Cap and Trade programs.

The CED leases the Walnut site from the Water Department for approximately $88,000 per year for the life of the project. The Water Department has the right to relocate or reconfigure the existing water facilities on the site if necessary for Water operations. If the Water Department's improvements impact SES generation, the Electric Department would pay SES for any lost generation or costs of accommodating the Water Department's requirements.

Astoria 2 Solar Project

In February, 2013, the City Council approved the SCPPA Renewable Development Agreement, Phase II, allowing CED to participate in the annual SCPPA Request for Proposal process for renewable energy projects. Each year, various developers submit proposed renewable projects to SCPPA. SCPPA staff and the member utilities regularly evaluate the proposals and determine interest from the various members. If there is sufficient interest, SCPPA and the members begin negotiations with the developers for a power purchase agreement (PPA). The PPA is generally between SCPPA and the developer; however each utility and its legal counsel are involved in the negotiation. In addition to the PPA, the project also involves a Power Sales Agreement (PSA) between SCPPA and each member utility, for each utility's share of the project output.

As many renewable projects are too large for smaller utilities, such as CED, to contract for individually, the SCPPA RFP process allows CED to consider participation in a wider scope of projects, generally with better pricing than if it had to negotiate a PPA by itself.

The Astoria 2 project is a 75 MW solar PV facility located in Kern County, California, that is built, owned and operated by Recurrent Energy. CED's share of the facility is 5 MW or 6.67 percent. The project is interconnected to the CAISO controlled grid, qualifying as a Power Content Category 1 resource. The project has received certification by the CEC as an RPS eligible facility and has a large generator interconnection agreement (LGIA) allowing full capacity deliverability status with resource adequacy (RA) benefits.

The contract price for energy from the project is $64.00 MW, fixed over the life of the contract, and includes system RA. This price is lower than the delivered cost of energy from the San Juan unit, and slightly lower than the cost of delivered energy from Magnolia, when the costs of emission allowances are included. The contract term for Astoria 2 is 20 years and there is a purchase option beginning after year six.

The other SCPPA participants in this project are the Cities of Azusa, Banning, and Vernon. Although this is a SCPPA project, in order to fully subscribe to the 75MW and to receive the $64.00 per MW pricing structure, SCPPA opened the project to other non-SCPPA utilities in California. The other project participants are the Cities of Lodi, Corona, Moreno Valley and Rancho Cucamonga, and the Power and Water Resources Pooling Authority (PWRPA). SCPPA is the lead agency in this project. The share of facility output for each of the participants is as follows:

Participant	Capacity	Percent Share in Project
Colton	5MW	6.67%
Azusa	2MW	2.67%

Banning	8MW	10.67%
Vernon*	30 MW	40.00%
PWRPA	10 MW	13.33%
Corona	2MW	2.67%
Moreno Valley	2MW	2.67%
Rancho Cucamonga	6MW	8.00%

*Vernon will increase its purchase from 20 to 30 MW in 2020

SCPPA's staff and legal counsel, together with each participant's staff and legal counsel negotiated the PPA between SCPPA and Recurrent Energy, and the PSA between SCPPA and each participant. Best, Best and Krieger (CED's attorney) reviewed and participated in the drafting of the Agreements.

In addition to the renewable energy and capacity rights, the PPA also includes the environmental attributes (RECs) from the output of the project. Under the terms of the PSA, the rights to these attributes (energy, capacity and RECs) will be transferred to each participant according to their project share.

The proposed PPA and Power Sales Agreements were presented to the Colton Utilities Commission at their Regular Meeting on May 12, 2014. The Utilities Commission recommended that the City Council approve the Colton Electric Department's participation in the PPA and on June 3, 2014 the City Council approved the PPA.

Once the Astoria and Antelope Solar projects were completed, CED and the City of Azusa recognized that they were both being charged around $7,000 per month for schedule and dispatch fees for both projects. CED and Azusa agreed to "trade" their share in the two units with CED taking Azusa's 2 MW in Astoria and Azusa taking CED's share in Antelope. Colton's share of the Astoria project is now 7 MW instead of the 5 MW listed above. This saved both entities $84,000 annually. Because of the difference in pricing, each year Azusa has to pay CED around $50,000 based upon the actual generation of the two projects so that each city pays what it contracted to pay originally.

<u>Kingbird Solar Project</u>

The Kingbird B Solar Project is a 20 MW PV facility located in Kern County, California that was built, owned and operated by First Solar. This project was also identified through the SCPPA RFP process.

The contract price for energy from the project is $68.75 MW, fixed over the life of the contract, and includes system resource adequacy (RA) capacity. This price is comparable, if not lower than, energy from SJ3 when the costs of emission allowances are included. The contract term is 20 years.

The other participants in this SCPPA project are the Cities of Riverside and Azusa. Colton and Azusa will each have a 3 MW (15% entitlement each) share in the project's output, and Riverside will take the remaining 14 MW (70% entitlement).

SCPPA's staff and legal counsel, together with each participant's staff and legal counsel, have negotiated the PPA between SCPPA and First Solar, and the PSA between SCPPA and each participant. Best, Best and Krieger was included in each step of the negotiation.

In addition to the renewable energy and capacity rights, the PPA also includes the environmental attributes from the output of the project. Under the terms of the PSA, the rights to these attributes will be transferred to each participant according to their project share.

As with other renewable projects, First Solar had to register the Kingbird Solar Project with the California Energy Commission and WREGIS to ensure the project participants receive RECs along with any energy.

The proposed PPA and PSA were presented to the Colton Utilities Commission for recommendation of approval at their regular meeting on September 9, 2013. The Colton Utilities Commission made a recommendation that the City Council approve the PSA between SCPPA and the City of Colton, and the City Council authorized the City Manager to execute the contract documents on September 17, 2013.

Antelope Solar Project

SCPPA negotiated a PPA with sPower Solar Holding LLC (sPower) for the output of the 55 MW Antelope DSR Solar Project (Project). CED's share of this project is 2 MW. This solar photovoltaic (PV) project is located in the City of Lancaster, in Los Angeles County and qualifies as a local capacity resource (LCR) within the CAISO. The Project interconnects to the CAISO and counts as a Power Content Category 1 resource.

The contract price of the energy from the Project is $53.75 per MWh, fixed over the 20 year term of the contract, and includes rights to both the environmental and LCR attributes. This was the lowest price CED had seen for similar solar projects at that time. CED attributes the competitive price offered by sPower to several factors:

1. The continued decline in the equipment and labor costs of solar PV projects; and

2. The Project being a part of a much larger transmission interconnection position with the CAISO, with an executed interconnection agreement of known cost exposure, and certain shared interconnection upgrades, all of which contributing to reduced cost for the Project; and

3. Economy of scale due to sPower's extensive holdings of more than 800MW of solar development assets in the general Antelope Valley area; and

4. Solar developers' mounting pressure to find off-takers so that the Project can timely come online before the end of 2016 to fully capture the benefit of federal Investment Tax Credit (ITC).

In addition to competitive pricing, the project includes a Purchase Option Agreement. The Purchase Option allows the Buyers to exercise an option to purchase the facility in years ten, fifteen or twenty, at fair market value.

The proposed Power Sales Agreement (which includes the PPA between SCPPA and sPower) were presented to the Colton Utilities Commission at their Regular Meeting on July 13, 2015 and approved by the City Council on July 21, 2015.

As discussed above, Azusa and CED "traded" their entitlements in Astoria and Antelope to reduce the annual schedule/dispatch cost of the project, so CED no longer has a share in Antelope DSR2.

Puente Hills Landfill Gas Project

In addition to its solar projects, CED is a participant in the Puente Hills Gas-to-Energy Facility that provides up to 10 MW of baseload renewable energy. The Puente Hills Gas-to-Energy facility is owned by the County Sanitation District No. 2 of Los Angeles County and began delivering energy to SCPPA on January 1, 2017.

The Puente Hills Facility has been certified by the California Energy Commission (CEC) as a renewable resource and is qualified as a portfolio content category 1 (PCC1) resource. The energy associated with this facility also qualifies for local resource adequacy (RA). The contract price for energy from the project is $80.00 MW, fixed over the 13 year contract life. This price includes both local RA and the environmental attributes (RECs) associated with the energy. This price is comparable to the delivered cost of energy it will be replacing from the SJ3 unit and to the cost of delivered energy from Magnolia, when the costs of emission allowances are included.

The contract price for power is high compared to intermittent generation resources like solar and wind but comparable to other baseload renewable resources, such as geothermal energy, and less than biomass and biogas generation many of which have energy prices above $100/MWh.

The nameplate capacity of the facility is 46 MW but the output in 2017 was approximately 30 MW, declining to approximately 27 MW in 2018. The Puente Hills Landfill closed in October 2013, which has resulted in the decline of landfill gas (fuel) that is produced during the life of this PPA. Because of this ongoing reduction of fuel supplies, the facility output will decline each year of the PPA and the energy output is expected to be reduced to less than 25 MW by the final year of the PPA, providing CED with less than 3 MW.

The other SCPPA participants in this project are the Cities of Azusa, Banning, Pasadena and Vernon. CED and Vernon will each receive 23.26% (approx. 7 MW), Pasadena will receive 30.23% (approx. 9 MW), Banning will receive 20.93% (approx. 6 MW) and Azusa will receive 2.33% (approx. 0.7 MW) of the facility output.

SCPPA's staff and legal counsel, together with each participant's staff and legal counsel, negotiated the PPA between SCPPA and the County Sanitation District No. 2 of Los Angeles County, and the PSA between SCPPA and each participant. Best, Best and Krieger (CED's city attorney) indicated no objections to the proposed Agreements.

The proposed PPA and Power Sales Agreements were presented to the Colton Utilities Commission at their Regular Meeting on May 12, 2014. The Colton City Council approved the CED's participation in the PPA on June 3, 2014.

Biogas Contract

In October, 2015 CED and Shell Energy entered into a contract whereby Shell would deliver up to 500 MMBTU/day of biogas from the Bena landfill in Kern County for use in the Magnolia Power Plant. This would have the effect of making Magnolia a baseload RPS resource and increase CED's annual renewable energy production by around 25,000 MWh.

At this time, there are questions about whether or not the landfill gas operator will proceed with the construction of the landfill gas facilities and the sale. There are a number of other uses of natural gas in the transportation sector that have more value to the biogas producer but do not have the stability of a long-term power sales agreement. Also, due to the timing of this project and the Casa Diablo Geothermal Plant, CED likely won't need the biogas for a few years (roughly 2023 or 2024). Shell (and others) have offered to purchase any production from the landfill for the first 3 to 5 years after which deliveries to CED would continue for the next 5 to 7 years.

At this time, both CED and Shell anticipate the project will eventually come online although the exact date is somewhat uncertain due to permitting problems in Kern County. The current target COD is December 31, 2020.

Summary of Renewable Resources

The following table summarizes CED's current RPS resources.

	Resource Type	Contract Start Date	Contract End Date	Nameplate Capacity (MW)	Estimated Annual Energy (MWh)	Location
High Wind*	Wind	2003	2023	4.00	6,500	Solano County
MWD Small Hydro	Hydro	2008	2023	3.80	4,500	Southern California
Colton Solar 1	solar	2016	2046	3.00	5,256	Colton, CA
Colton Solar 2	solar	2016	2046	1.00	1,752	Colton, CA
Gonzales Center	solar	2016	2046	0.50	753	Colton, CA
Arbor Terrace	solar	2016	2046	0.35	613	Colton, CA
Recurrent - Astoria	solar	2016	2036	7.00	16,500	Kern County, CA
First Solar - Kingbird	solar	2015	2035	3.00	7,096	Kern County, CA
Puente Hills	biogas	2017	2026	7.00	50,000	Industry Hills, CA
Total Renewable Energy				29.65	92,970	
* High Wind has no Resource Adequacy (RA) capacity value. Solar projects have had their RA capacity values reduced from their nameplate capacity by the CAISO.						

If the Shell biogas project goes forth, CED's renewable resources increase to almost 35 percent of total requirements with existing resources only.

Regardless of the ultimate outcome of the Shell biogas contract, additional renewable projects will be required in the 2020/22 time period. CED will have additional capacity requirements by then that will have to meet with new renewable resources.

Greenhouse Gas Emissions

In 2015, CED was emitting GHG emissions from the Magnolia, Agua Mansa and San Juan Power Plants. With the decommissioning of SJ3 in December 31, 2017 and the proposed biogas purchase from Shell, CED will be emitting less than 30,000 tons of GHG annually by 2018, down from 211,000 tons in 2015. CED's GHG emitting resources will only be Magnolia that currently emits almost 26,000 tons of GHG annually but will be reduced to around 18,000 tons if CED completes the proposed 500 mmbtu/day biogas purchase as a substitute for natural gas use and AMPP that emits about 3,500 tons per year of GHG emissions.

Transmission

The CAISO has assumed operational control of all 115 kV and above transmission[12] of all Participating Transmission Owner (PTO) utilities and several transmission owning companies. The CAISO operates this transmission to minimize daily transmission costs for California as a whole.

Each PTO charges the CAISO the total cost of its transmission plus a rate of return on any owned transmission assets. The cost 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 that is paid based upon the total metered load of the LSE. 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 per MWh regardless of the voltage 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's capacity, 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[13].

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

[12] In PG&E and SDG&E's service territory, the CAISO controls down to 66 kV transmission lines.
[13] This is done by a mathematical formula approach that creates a large enough congestion charge to push higher priced resources out of the dispatch order.

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).

There are two ways LSE's acquire congestion rights; first, through a CAISO allocation process and, secondly, a CRR auction process.

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 monthly allocation process and CRR auctions and bid against other entities for the right to recover any potential congestion charges.

The CAISO allocates its transmission capacity to LSE's based upon existing unit specific generation contracts. If an LSE has a power purchase agreement (PPA) or generator entitlement, it can request CRRs from the CAISO through an annual or monthly allocation process. Because the revenues that the CAISO receives in congestion charges should approximately equal payments to CRR owners, the CAISO is indifferent to congestion revenues paid on a specific line so long as it does not allocate more transmission capacity than available on a specific path[14].

Entities requesting CRRs on a specific path will only receive their full request if the path has excess capacity after all existing CRR holders and LSE's without rights on a particular path have applied to the CAISO for transmission rights during the annual allocation process. If the CAISO has already allocated all the CRRs on a path, the requesting entity may not receive any CRRs or only a portion of their request.

If an entity does not receive the desired allocation of CRRs, it can enter the CRR auction process. In the auction process, any (creditworthy) entity can offer to "sell" CRR revenues for a price determined in an auction along a specific transmission path. If an entity sells CRRs, it is responsible for paying the CRR costs to the purchasing entity.

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 has to pay congestion costs. That is, acquiring CRRs is not a risk free proposition. Generally however, the direction of congestion flows are fairly predictable with congestion costs higher coming towards the coasts and lower moving east although the hourly magnitude of the CRRs isn't known.

Even though CED has some transmission rights, it assigned these rights to the CAISO when it became a PTO. In exchange, it received some CRRs on the transmission paths. But the CRRs are not sufficient to completely protect CED from incurring transmission congestion costs.

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[14] For the past several years, payouts to owners of CRRs have exceeded collections from transmission owners. As a result, the CAISO is restructuring portions of the CRR market to reduce the annual deficit.

CED has the following long-term transmission contracts:

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 owns firm bidirectional service equaling 1.75% of the facility's 1,291 MW rated capability, or 22.59 MW that it has turned over to the CAISO.

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). This entitlement has been turned over to the CAISO.

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

CED has a 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. This contract terminated when the original Hoover Power Purchase terminated.

Summary of CED's Generation and Transmission Portfolio

Prior to 2013, CED did not have any transmission entitlements from Palo Verde Substation, the delivery point for energy from San Juan, to Colton. As a result, CED was paying significant congestion costs to transmit the San Juan generation to Colton. By becoming a PTO, CED was allocated about 20 MW of spring and summer CRRs and a small amount of winter and fall CRRs. But CED has to participate in the monthly CRR allocations and auctions to acquire more CRRs and protect it against congestion costs.

CED can sign power supply contracts with any generator interconnected on the CAISO grid. While the transmission costs is fixed (at least annually) congestion costs change from hour to hour depending upon CAISO loads, the location of generators and whether or not specific transmission paths have been derated for maintenance.

CED does have some CRRs to protect against congestion costs from the Phoenix area to Colton, but not enough to avoid monthly congestion payments during the winter and fall.

As a PTO, CED has been able to reduce its annual transmission costs but CED has exposure to congestion and must manage daily congestion costs more carefully than it has in the past. The majority of CED's congestion risk will remain between Palo Verde and Colton where most of CED's energy resources are located.

Future Transmission Needs

Because CED is now a CAISO Participating Transmission Owner (PTO) it does not need to acquire transmission paths between the generator and Colton loads. Instead, CED must manage the congestion risk associated with using the CAISO's system.

On most of CED's new resources (and renegotiated contracts), CED just deliveries energy to the CAISO grid at the interconnection point nearest the generator and withdraws energy to serve retail load at Vista Substation, a 500 kV substation located in Grand Terrace. CED is paid the locational marginal price (LMP) where it delivers energy to the grid and by the CAISO and is charged the LMP for energy taken by CED at Vista. In the absence of congestion and losses these two prices will be the same. With congestion and losses, the prices will vary. By acquiring CRR's between the two points, CED can ensure that it gets paid the same for energy delivers as it gets charged for energy withdrawals except for transmission losses that cannot be hedged.

The only reason that CED would acquire transmission rights in the future, rather than congestion rights, is a concern over the long-term structure of the electric industry and belief that eventually the CAISO might fail or be dissolved and the industry revert back to the pre-2000 structure.

CHAPTER 4: LEGISLATIVE AND REGULATORY ISSUES

Introduction

The past few 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, the legislation could also cause increased operating costs in the near term. 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 to acquire resources based primarily on least-cost planning considerations or reliability concerns. In many cases, utilities attempt to minimize their GHG emissions, resulting in more renewable resources and conservation activities in the overall resource mix with smaller resources often located nearer load centers.

The major legislative and regulatory initiatives facing the CED today include:

- GHG reduction, including the Federal Clean Air Act, California's AB 32 Greenhouse Gas Reduction Law and Renewable Portfolio Standards requirements, SB 350, the Clean Energy and Pollution Reduction Act of 2015, and SB 100 in 2018 further increasing RPS requirements and lowering allowable GHG emissions;
- Changes in the California wholesale electricity market including new types of flexible capacity requirements intended to help mitigate the reliability effects of renewable resources;
- The CAISO's continuing attempt to move from a California entity to a western U.S., generating and transmitting power in the 11 western states;
- Required upgrades in physical security of generation, transmission and distribution facilities;
- While not technically a resource planning issue, the state's attempt to push costs of wildfires to utilities is requiring an evaluation of transmission operating procedures and reliability in the state.

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.

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 resulted in 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 took the nation's lead 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

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.[15]

In 2015, California adopted SB 350, the Clean Energy and Pollution Reduction Act of 2015, a successor bill to AB 32. SB 350 established new clean energy and GHG reduction goals for 2030. Among the major goals of SB 350 are reducing GHG emissions by 40 percent of 1990 levels by 2030 and 80 percent by 2050. To accomplish the goal of reduced emissions, SB 350 requires utilities to double their current energy efficiency efforts, increase the proportion of renewable energy from 33 percent in 2020 to 50 percent in 2030, increase transportation electrification efforts sector and explore expanding the CAISO from a

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

California grid manager to a western state grid manager to facilitate the transmission of renewable resources from western states into California.

In September 2018, the California legislature passed SB 100 that further increased the RPS requirements. Under SB 100 utilities must procure 44 percent of retail sales by December 31, 2024, 52 percent by December 31, 2027 and 60 percent by December 31, 2030. SB 100 further states that it is the policy of the State that by 2045, renewable resources will meet 100 percent of all retail sales in the state and ensure that a zero-carbon electric system for California is achieved.

Reaching a zero-carbon producing electric system by 2045 is a challenge for publicly-owned utilities like CED that have one or two large resources relative to their load. CED has a 43 MW generator located within the City, AMPP, that under SB 100 will need to be replaced by 2045 or biogas will need to be acquired to operate the facility unless this resource is grandfathered into CED's load. If biogas supplies are not available, CED may have to remove or decommission the plant and find 43 MW of new renewable generation capacity. CED is going to attempt to work with the CEC, CPUC and CARB over the next few years to determine if AMPP has to be decommissioned and removed, how to remove it from the site and what resources will be acquired to replace it.

Cap and Trade

Under the C&T program, the total amount of emissions in tons per year in a geographic area (measured in CO_2e or carbon dioxide equivalent) is capped by CARB. CARB has estimated emissions in each industrial sector by performing audits of emissions by sector for the past three years. Each business or entity covered by the regulation was 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.

Each year CARB performs 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 $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. There is no expiration on EAs so purchasing a 2013 EA allows an entity to use that EA any time after 2013 but future EAs cannot be brought back to meet past compliance obligations. So a 2013 EA can be used to meet 2015 requirements but a 2017 EA cannot be used until 2017 or later.

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

CED has been allocated 242,470 EAs for 2019.

The freely allocated EAs can only be used to offset emissions associated with retail sales. CED cannot use any of its freely allocated allowances to offset emissions from surplus generation or generation sold into the CAISO market. As a result, CED must track all its hourly generation and emissions, determine which source of energy is used to meet retail load and which energy is surplus to load and then acquire EAs to offset emissions associated with surplus sales or purchases from the CAISO.

CED's emissions are between 30,000 tons per year and 35,000 tons per year. Since actual emissions to serve load are less than 242,470, then CED can sell excess EAs and use the revenues for reducing power supply costs by investing in conservation, renewable alternatives or energy efficiency initiatives, such as electric vehicles.

CED has developed procedures for calculating emissions, tracking CED's emissions relative to its freely allocated EAs and buying or selling EAs as necessary to remain compliant with the C&T program.

CED has additional issues dealing with AMPP. AMPP is dispatched by the CAISO and dispatch generally results in surplus energy. The CAISO adds a payment for the cost of EAs but given the price varies on a day to day basis (although the variation is currently small) CED has to ensure that it acquires EAs in the market at a price less than or equal to what the CAISO paid or risk losing money on an AMPP dispatch.

Possible Changes to C&T

The C&T program has been extended through 2030 by Assembly Bill 398 that passed on July 17, 2018.

There are likely a number of changes to the program. First, it appears that CARB is going to reduce the number of free EA's beginning in 2021 as a result of the increased RPS requirements. At this time, CED expects the allocations to be reduced by around 60 percent but don't know with certainty since CARB has not presented their proposal.

Secondly, ARB has discussed allocating EAs directly to the industrial customer rather than the serving utilities. The industrial customer will be responsible for ensuring that it has sufficient EAs to meet its emission obligations. Utilities are opposed to this approach by CARB.

Finally, CARB has proposed that utilities be responsible for emissions associated with purchases from out-of-state none-covered generators. This means if a utility purchases in the energy imbalance market or directly from an out-of-state generator that does not have a C&T obligation, the utility must acquire EAs to cover the emissions. From the utilities viewpoint, they do not know where the CAISO is acquiring energy for the imbalance market until well after the fact. This makes it difficult to determine how many EAs the utility must have prior to the verification deadlines.

At this time which, if any of the proposed changes will be adopted by CARB is unknown. CARB is currently involved in the rulemaking process for the 2021-2030 program and it could be 9 months to a year before a decision is proposed and adopted. There are 2 more years under the current rules and no urgency on the part of the legislature to make changes to C&T rules that threaten the long-term extension of C&T.

Renewables Portfolio Standard (RPS) Legislation

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

In April 12, 2011, Governor Brown signed SB 2, increasing 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 "renewable" or non-renewable." Non-renewable energy is from traditional fossil-fuel generation. Renewable energy is from renewable energy sources. Renewable energy can be further divided into two components, the energy and the renewable capacity attribute. A renewable energy generator can separate the brown energy component from the renewable energy attributes and sell the renewable energy as a REC.

For example, a wind generator in California can generate energy and sell it into the CAISO market as non-renewable 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. The use of RECs by utilities is limited by SB 2 (to 15 percent of renewable generation through 2014 and then it begins to decline) in an attempt to force utilities to match generation with loads.

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, or the green component stripped from the renewable energy.

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.

The final rules for SB 2 RPS compliance were adopted by the CEC in May, 2013. Now the utilities are attempting to understand their obligations in terms of reporting requirements and regulatory compliance especially since the CEC continues to refine and redefine the various RPS categories.

One of CED's concerns is the rules governing the use of biogas. CED believes biogas is the least expensive means of meeting its RPS requirements and has entered into a long-term biogas purchase agreement with Shell. In 2015, the CPUC's added a requirement to biogas suppliers that significantly increased the risk associated with biogas, threatening the viability of the Shell – CED purchase agreement.[16]

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 gas, would still qualify.

In the Renewable Portfolio Standard Eligibility, 7th edition (RPS Guidebook), the CEC permitted the use of biomethane provided it was produced from in-state resources and either cleaned to pipeline quality or used for generation purposes on-site. In addition, any generator using biogas would have to be re-certified by the CEC.

The RPS Guidebook is the overall regulatory guide for RPS compliance.

The CED biogas contract with Shell Energy for meeting some of Magnolia's daily gas requirements is the first biogas contract in California under the revised rules and Shell and CED met with CEC staff several times to ensure that the final contract met CEC requirements.

The CEC has gotten much more stringent in evaluating and approving renewable energy. For each renewable generator outside California, the utility must provide the WREGIS identification for the purchase and the WECC e-tag showing the time and transmission path used by the utility to bring the energy into the CAISO. Any discrepancy between the contract language, WREGIS identification and e-tag results in the energy purchase being disallowed for compliance purposes.

GHG Reduction Plans

The goal of California's environmental programs is to reduce GHG emissions and renewable resources are one way of accomplishing this. In 2016 CED's generation resources emitted 225,400 metric tons of CO2e. In 2018 CED emitted less than 25,300 metric tons of CO2e, primarily because of the decommissioning of SJ3.

Currently, CED's only GHG emitting resources are the Magnolia Power Plant and Agua Mansa Power Plant. None of CED's other generation resources emit GHG nor are any of the generation resources CED is contemplating for the future GHG producing resources.

With the Shell biogas purchase beginning in 2022, CED's GHG emissions will decline to 20,000 metric tons.

[16] The change dealt with the way suppliers would be allowed to restart gas deliveries after an outage, essentially requiring a complete verification of the quality of the biogas and increasing the cost of injecting biogas into the transmission system.

CED does not anticipate its emissions to decline below 25,000 metric tons. Magnolia and Agua Mansa will need to be available for system reliability for years into the future and CED will attempt to keep both units operating to avoid any financial impacts of retiring them before the total debt is retired and all natural gas contracts end or are sold to prevent any stranded assets.

Summary of GHG and RPS Legislation

CED did not meet the 20 percent of its retail sales from renewable sources in the first compliance period, 2011-2013 but took advantage of cost-limitation guidelines permitted in AB 32 to stay in conformance with the law. CED only had about 8 percent renewable resources as opposed to the statutory requirement of 20 percent. CED did meet the compliance period 2 requirements of 21.65 percent of retail sales from renewable sources and anticipates meeting future RPS requirements. A discussion of how CED intends to meet its future RPS requirements is presented in Chapter 8.

North American Electricity Reliability Corporation (NERC) Standards

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.

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 regulatory jurisdiction over CED.

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, the lowest classification level with the fewest reliability requirements, essentially reflecting CED's inability to significantly impact the bulk power grid.

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.

In August, 2012 CED was audited for compliance with applicable NERC reliability standards. This was the first time CED was audited and required significant preparation to insure CED met its reliability standards. Since 2012, CED has stayed in compliance with all of NERC standards and has self-certified compliance each year.

CED has been notified that its next WECC audit will be in March, 2019. At this time, it appears WECC is only interested in CED's compliance with MOD 032.1 R2 which requires CED to provide modeling data for its system to SCE or the CAISO when requested. It does not appear WECC will audit CED for cybersecurity issues or physical security requirements in 2019.

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.

To remain compliant will require establishing a process where all standards pertaining to CED are identified and updated and records are kept of all communication between CED and SCE pertaining to operations.

In 2009, NERC expanded its compliance requirements to include cyber-security. At this time, CED is likely in compliance with the new cyber-security regulations. Generally, the cyber security regulations 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 has isolated its control systems from the internet but still needs to more strictly restrict physical access to the SCADA system.

CED also entered into a cyber-security monitoring contract with Dell Secure Works. This system monitors the City's computer system looking for viruses, worms, Trojan horses and any significant upload of city data to off-site systems. Secure Works is a significant upgrade to the City's cyber security protection.

The other new area of concern is physical security concerns. As a result of several attempts across the nation to damage substations, NERC has required new physical access restrictions. Some of these CED can never meet due to the geographic constraints of where existing substations are located but most other issues can be met by better walls around existing substations and restricted access to areas where system controls and computer access is available.

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 creates 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[17].

In 2018 CED was short roughly 12 MW of summer RA. CED was able to purchase this RA in the bilateral capacity market. CED was short about 15 MW of 2019 summer RA but was able to purchase 15 MW of July-August RA and is still searching for September RA. Many of the smaller utilities are short 2019 RA because in late 2017 the CAISO adjusted the capacity value for solar generation downward, in an attempt

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

to more accurately account for the inability of solar generation to operate during peak loads, significantly reducing the amount of RA available in the market.

CED should have sufficient RA capacity by the summer of 2020 if its expected resources are constructed on time.

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. When needed, the CAISO will make supplemental procurement for RA under the CPM provisions of its tariff. As detailed in the CAISO Tariff,[18] 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 required local RA capacity.

Flexible Capacity Requirements

In 2014 the CAISO began requiring LSE's to have flexible capacity to maintain reliability as more renewable resources began supplying energy to the grid. Renewable resources such as solar, wind and small hydroelectric generation do not offer a steady flow of energy. If the wind stops blowing or a cloud obscures the sun, renewable energy production drops, often suddenly.

While the power markets are designed to operate with a small (less than 15 percent) reduction in generation, renewable resources now make us as much as 30 percent of generation offered to the CAISO each hour.

To protect the system against unanticipated reductions in renewable energy generation, the CAISO has implemented flexible capacity requirements for LSE's beginning in January 2015. Each LSE must have base flexible capacity, peak flexible capacity and super peak flexible capacity.

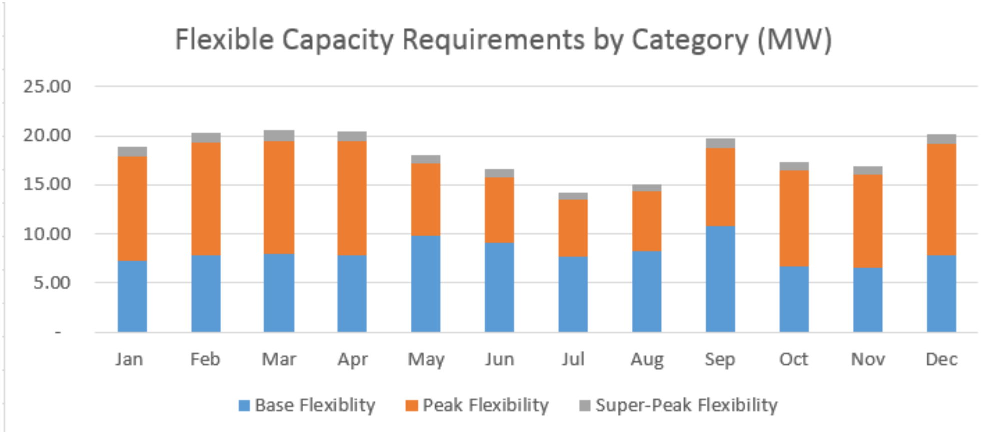
Base flexible capacity must be available each day with thermal units being allowed at least two starts per day for 6 hours per start.

Peak flexible capacity must be from generation units that have at least 30 starts per month and 3 hours per start of run time.

Super peak flexible capacity must have at least 5 starts per month and 3 hours minimum run time per start.

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

Each year the CAISO provides CED the amount of flexible capacity by type that CED must procure. The following figure presents CED's 2019 FC requirements:



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Base Flexiblity	7.29	7.85	7.93	7.88	9.87	9.08	7.75	8.24	10.80	6.67	6.50	7.77
Peak Flexibility	10.63	11.46	11.57	11.50	7.24	6.66	5.68	6.04	7.92	9.73	9.49	11.34
Super-Peak Flexibility	0.94	1.02	1.03	1.02	0.90	0.83	0.71	0.75	0.99	0.86	0.84	1.01
Total	18.86	20.33	20.52	20.40	18.01	16.56	14.14	15.04	19.71	17.27	16.83	20.11

Figure 4.1

To meet its flexible capacity requirements, CED negotiated with the South Coast Air Quality Management District (SCAQMD) to increase the number of daily starts, although the total hours of operation each year was reduced. As a result of this negotiation, which took over nine months, CED is able to use AMPP as a source of flexible capacity.

Summary of CAISO Market Modifications

In general, CED has sufficient resources to meet its capacity obligations and satisfy its energy requirements through 2017. By 2018, CED needed a small amount of system RA capacity due to the decommissioning of SJ3 and forecasted load growth that it purchased in the market. By 2019 CED is short about 15 MW of summer RA that it is looking to purchase. By 2020, CED should have sufficient capacity to meet its RA obligations assuming new contracted generation resources are constructed on time.

CED relies upon the CAISO for all ancillary services and some transmission. Shell Energy is scheduling CED's resources as CED's Scheduling Coordinator.

Wildfire Mitigation

The last two summers have seen huge, destructive wildfires throughout California. Most scientists and land management experts expect the number and size of wildfires to grow due to a changing climate, hotter temperatures and less spring and summer rainfall, resulting in more vegetation and dead trees to fuel wildfires.

In response to the devastating wildfires the past few years, California is making a number of structural planning and infrastructure changes at the state level to try to reduce the number and severity of wildfires. Of particular interest to the Colton Electric Department (CED) is "SB 1028: A Compliance Assessment of Potential Risk of Wildfires Caused by Electric Lines and Equipment."

SB 1028 requires utilities to construct, maintain and operate its electrical lines and equipment in a manner that minimizes the risk of wildfire posed by this equipment. SB 1028 also requires each POU to annually develop and submit a wildfire mitigation plan to the California Public Utilities Commission (CPUC) for review. The wildfire mitigation plan shall include:

(1) An accounting of the responsibilities of persons responsible for executing the plan.

(2) The objectives of the plan.

(3) A description of the preventive strategies and programs to be adopted by the electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires.

(4) A description of the metrics the electrical corporation plans to use to evaluate the plan's performance and the assumptions that underlie the use of those metrics.

(5) A discussion of how the application of previously identified metrics to previous plan performances has informed the plan.

(6) A description of the processes and procedures the electrical corporation will use to do the following:

(A) Monitor and audit the implementation of the plan.

(B) Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies.

(C) Monitor and audit the effectiveness of electrical line and equipment inspections, including inspections performed by contractors, carried out under the plan and other applicable statutes and commission rules.

(7) Any other information that the commission may require.

Within 30 days of submittal, the CPUC must review and comment on the utilities mitigation plan and allow the utility to make any corrections or amendments. The CPUC will then contract with a third party evaluator to conduct audits or inspections authorized by this law to determine if the utility is satisfactorily complying with its wildfire mitigation plan.

In other words, utilities must operate and maintain their systems to comply with their wildfire mitigation plan, not just develop the plan and put it on the shelf to be pulled out whenever a verifier comes by.

CED has begun development of its wildfire mitigation plan. But as the state legislature finds more issues with PG&E's vegetation management and safety inspection strategies, the requirements of the wildfire mitigation plan grow.

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 in order 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 relatively small monthly cost 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 $0.00029/kWh public benefit charge (PBC) that raises approximately $1,000,000 annually for public benefit programs and Cap and Trade (C&T) funds. The public benefit programs funded by the PBC include; Energy efficiency and energy conservation, cost effective DSM services, assistance provided for low income electricity customers, investment in renewable energy resources and research, development and demonstration projects. The C&T funds have been used to fund larger capital programs, such as replacement of city air conditioners and construction of new electric vehicle chargers in the City. C&T funds are also being set aside in a sinking fund to help pay for two small solar projects that CED will change from a power purchase agreement to a city owned resource in 2023.

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 a customer’s energy use, without impacting their lifestyle, by using more energy efficient appliances and equipment. Examples of conservation programs offered by CED include energy efficient lighting, web-shopping for energy efficient appliances, refrigerator replacement, building envelope upgrade rebates and energy efficiency audits with direct installation.

By offering rebates, providing energy efficient equipment at no or little cost, and by educating people and businesses on how to reduce their energy costs, CED avoids having to purchase additional energy in the market and helps reduce the overall costs for all Colton ratepayers.

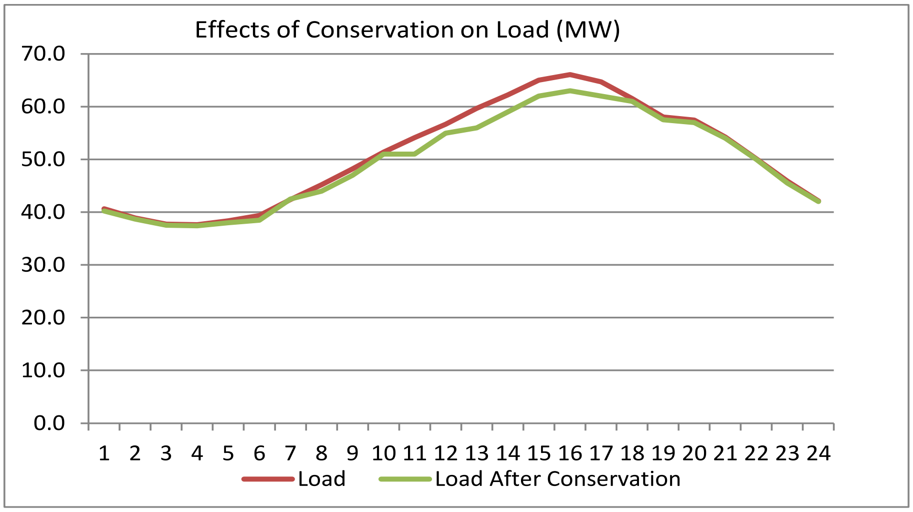


Figure 5.1: Effects of Conservation Programs on Load

DSM Programs

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

Energy costs vary hourly 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 may cost two or three times more than 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.

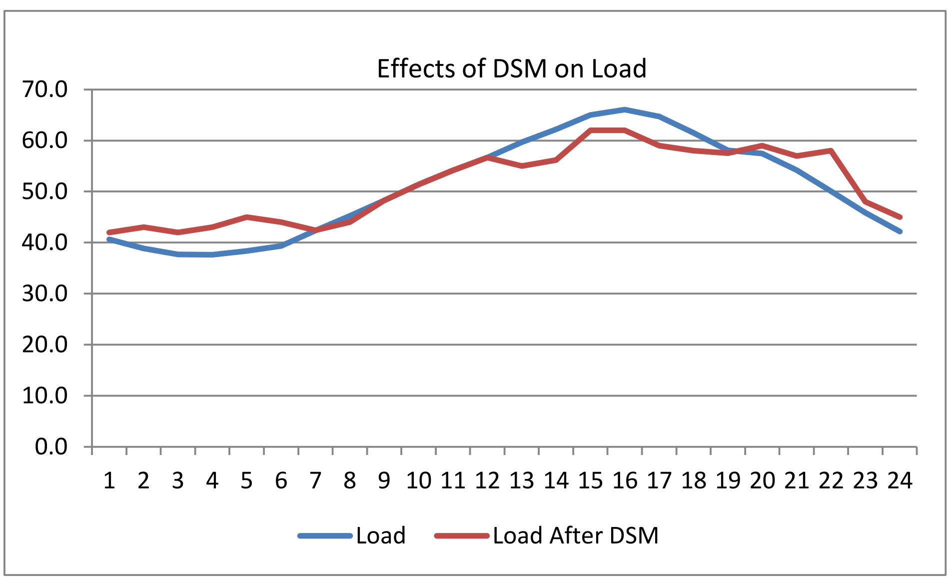


Figure 5.2: Effects of DSM Programs on Load

In the last few years, as the amount of solar generation capacity in the CAISO market has increased so dramatically, the historic relationship between hour of day and wholesale cost has changed. Today, the most expensive energy tends to be between 1600 and 2000 as solar generation is declining from its daytime peak production, while in the past the most expensive energy was in the 1300 to 1800 time period as low efficient resources were used to meet load.

With the changes in wholesale cost, CED is now encouraging different behavior by its commercial and industrial customers. CED would like its customers using energy during the day-light hours rather than the evenings and night-time periods when natural gas fired generation is primarily being used to meet load requirements.

Evaluating Conservation and DSM Programs

There are three general ways to evaluate conservation and DSM programs; by their impact on the customer, the utility, and 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. Participating customers will see their energy costs decline, but non-participating customers have to cover the loss of revenue. From the participating customer's viewpoint, the refrigeration program is a good program that reduced their individual 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 not lower costs, or costs may decline slightly, but not 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.

Because 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, generally result in lower costs of purchasing energy without any lost revenues, and therefore, are almost always easier to financially justify than conservation programs. For example, encouraging a manufacturing facility to operate at night, while using the same amount of energy, results in lower costs and greater revenues to the utility. This happens because the retail cost of off-peak energy is usually much higher than the revenue CED receives by selling the excess energy in the off-peak wholesale market. 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 standard DSM programs but has successfully negotiated several DSM projects for individual customers. 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, reducing costs to both the participating customers and non-participating customers.

One of the important programs that CED would like to implement in the near future is a load-shedding program that will compensate business customers to reduce load during periods of high system stress, such as when a transmission line or generator fails, and the CAISO asks LSE's to voluntarily reduce load in advance of issuing mandatory load shedding programs. CED has proposed a load-shedding program to the CAISO but has not yet received permission to implement it.

Regulatory Requirements

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. Compliance with these regulations is enforced by the CEC 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 a 3,100 MWh reduction in energy use, increasing to over 4,500 MWh by 2020.

In 2015, California passed SB 350 increased targets for conservation to roughly 25 percent of current energy use by 2030, a very aggressive target but achievable over the next 12 years.

CED Programs

CED is currently offering the following conservation/DSM programs to residential and business customers in Colton:

Residential

- Energy Efficiency Upgrade Rebates
- AC Tune-Up Rebate
- Air Conditioner Upgrade and Replacement Program
- Refrigerator Replacement Program
- Residential Energy Audit Program and Direct Installation
- Residential Web-shop for LED, Smart Power Strips and Smart Thermostats
- Residential Weatherization Rebates
- Treebate
- Living Wise School Program
- Low Income Assistance and Medical Baseline Billing Level Pay Billing

Commercial/Industrial

- Lighting and Equipment Upgrade Rebates
- Online Energy Review for TOU accounts

- Commercial Energy Audit and Direct Installation
- Keep Your Cool Program
- Hospitality Energy Audit and Direct Installation

Residential Program Details

Energy Efficiency Upgrade Rebates: CED offers varying rebates on a number of home energy efficiency improvements. Currently CED offers rebates on: Occupancy sensors, smart thermostats, energy star ceiling fans, box fans, pool pumps, solar attic fans, whole house fans, room ACs, evaporative coolers, solar tube lights, energy star clothes washer, energy star dishwasher and energy star refrigerators. Customers who participate in the rebate program will experience a reduction in their annual energy costs.

AC Tune-Up Rebate: This program offers a rebate for preventative maintenance on residential customer AC units up to 5-tons in size. The program requires the customer to select their own licensed AC contractor that will replace filters, check refrigerant levels and adjust the AC unit to minimize seasonal air conditioning costs.

Air Conditioner Upgrade and Replacement Program: This program offers up to $150/ton rebate to replace a SEER 11 or lower AC system with a SEER 16 or higher AC system. Upgrading AC systems will significantly lower residential customer's energy costs.

Refrigerator Replacement Program: CED will provide a new ENERGY STAR refrigerator to replace an existing inefficient refrigerator to qualified customers for the low cost of $240. The customer is charged $20 a month for 12 consecutive months. To qualify for the new refrigerator, customers must have an older, inefficient refrigerator that CED can recycle. Since 2011, 149 customers have participated in the refrigerator replacement program. CED has saved over 61,239,000 kWh annually and a lifetime savings of 612,390,000 kWh.

Residential Energy Audit: CED residential customers with energy usage of over 10,000 kWh annually can qualify to participate in a residential energy audit. Participants can be eligible for additional direct install opportunities depending on audit recommendations. For customers who previously participated in an energy audit in the past two years with over 10,000 kWh of annual consumption they can participate in up to $500 of direct install measured recommendations.

Residential WebShop: CED residents can now purchase LED light bulbs, smart power strips, holiday lights and smart thermostats from the comfort of their own home. CED provides up to $50.00 per FY to buy down the cost of these items. The customer can order directly from CED's website and the items are shipped directly to the customer's home at no cost and with free shipping.

Residential Weatherization Rebates: CED offers residential customers rebates for installing replacement windows and insulation in their homes. Windows must meet Energy Star approval with a U-Factor less than 0.35 and SHGC less than 0.30 at a rebate amount of $4.00 per sq. ft. Insulation may be added to the attic, and/or exterior walls. Rebates will also be provided for radiant barrier installed within the attic space. Insulation and radiant barrier must meet the following R-Values:

Attic Insulation - Minimum R-30 Rebate is $0.40 per sq. ft.
Radiant Barrier - Minimum R-19 Rebate is $0.30 per sq. ft.
Exterior Walls - Minimum R-13 Rebate is $0.20 per sq. ft.

Treebate**:** CED residents are offered up to $50.00 a tree to plant an approved tree on their property that would reduce their energy bill by providing shade to their home. Residents have a maximum of 5 trees a lifetime.

Living Wise Program: The Living Wise Resource Action Program provides over 500 energy efficiency and water conservation kits to 6th grade Colton Unified School District students. As part of the program students and parents will install resource efficiency measure in their homes. Students and parents learn how to measure pre-existing devices to calculate saving that is generated by their efficiency upgrade. The goal of the program is to change customer behavior and experience energy savings from their actions.

Low Income Assistance and Medical Baseline Billing: CED also provides programs to help low income customers and those with medical conditions that require medical equipment to reduce their monthly energy bills. CED customers with qualifying medical conditions receive an adjustment to increase the baseline kilowatt hours on their utility bill. The baseline is increased so that the kilowatt hours that are used for life sustaining medical equipment are charged at a lower tier. These programs are not designed to conserve energy but instead recognize that the CED has an obligation to provide some level of financial assistance to low income customers.

CED has two different programs to assist low income customers, the Low Income Assistance Program and the Low Income Community Solar Program. The Low Income Assistance Program (LIAP) provides an additional 139 kWh to qualifying low income households at CED's Tier 1 prices of $0.08/kWh. The Low Income Community Solar program uses the City's internal solar generation as a community solar program, giving each qualifying customer additional kWh's each month at CD's lowest tier pricing of $0.08/kWh. This has allowed some households to receive more income assistance each year than in the past.

In Fiscal year 2017/18 CED had 787 low income customers participate in CED's LIAP. This allowed customers who received high bills during summer months, to receive up to a $12/month in energy credits to reduce their bill. In FY 2017/2018, $121,973 was provided by the CED to low-income Colton residents.

Level Pay Plan: CED provides assistance to customers who are in need of stabilizing their energy bills. Residents with at least 13 months of utility service at their current address may choose to sign up to stabilize their energy bills and pay a consistent set dollar amount all year long. The dollar amount is based on the customer's annual consumption, in the 13th month a true up is applied.

Low Income Mobile Home Energy Efficiency (EE) Program: in partnership with Southern California Gas Company (SCGC), CED offers mobile home building envelope and lighting retrofits to qualifying customers at the same time as SCGC. SCGC provides gas and water saving efficiency measure direct installation.

Digital Monthly Newsletter on Energy Efficiency: commercial and residential customers receive a monthly newsletter that provides current information on energy efficiency (EE) and energy education. It is emailed in a digital print format but also includes video clips on EE. We also post the articles from the newsletter to CEDs social media platforms.

Multifamily Energy Efficiency Direct Install Program: apartment complexes throughout CED territory can apply to have common area EE upgrades in lighting, thermostats and AC tune-ups.

Commercial/Industrial Program Details

Lighting and Equipment Upgrade Rebates: Commercial and industrial buildings can benefit from substantial rebates given for improving lighting and equipment by increasing energy efficiency and lowering consumption. CED offer $.10 per kWh saved on the projected first year of savings.

Online Energy Review for TOU accounts: Automated energy is an online energy review CED offers to its TOU (Time of Use) customers. Automated energy provides access to specific interval meter data through their website.

Commercial Energy Audit: Small commercial businesses that use less than 30 kW annually qualify to participate in CED commercial energy audit. Businesses can be eligible for additional direct install opportunities depending on audit recommendations. CED is offering $1,000 of direct install measured recommendations. This is a program to assist small businesses who are concerned with their energy consumption and want to learn how they can minimize their usage, shift their load, and save on energy costs.

Keep Your Cool Program: This program began in FY2013/2014 and has been one of CED's most popular programs. Small commercial business that have inefficient refrigeration, lighting and cooling such as mini marts and fast food restaurants benefit from participating in this program. CED will provide up to $3,000 per location in energy efficiency upgrades.

Hospitality Audit and Direct Installation Program: CED assists hospitality businesses in energy efficiency upgrades. The goals of this program are to; provide a comprehensive energy audit, proposal that provides energy reducing measures and the savings calculations if installed, along with energy management recommendations.

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, CED contracts with AESC, to provide program savings verification and has the programs on a rotating cycle.

Electrification Programs

CED has developed a plug in electric vehicle (EV) strategy to advance EV's in support of City policy to promote alternative fuel transportation. CED began installing EV chargers on City property as a demonstration program in late 2011. The demonstration program provided EV Level 2 charging service at two (2) locations, City Hall and the Public Works Yard. CED has also been awarded a Department of Energy (DOE) Grant through the Southern California Public Power Authority (SCPPA) to install four level II public charging stations in the City of Colton.
The two sites selected that met the grant criteria were Arrowhead Regional Medical Center and Fiesta Village Family Fun Park. Both businesses are one mile from the freeway, allowing commuters to conveniently charge in the City of Colton off the Interstate 215 and Interstate 10 freeways. Both have chosen the EV dual Level 2 charging systems.

CED was also awarded grant funding from South Coast Air Quality Management District (SCAQMD) in 2017 to install 3 curbside EV chargers in a Disadvantaged Community area designated portion of a multifamily housing area. These units were successfully installed and residents in the area who did not have a place to charge now have a source without losing any parking spaces.

With the success of the grants, CED secured the City Council's approval for EV Charging as an ongoing program. This action allowed CED to strategically expand this service while providing the necessary flexibility to respond to the evolving EV market. The program allows for future installations of additional charging stations based on customer demand and staff's evaluation of sufficient utilization and investment payback. Staff expect to move forward sensibly and only after justification of each station as approved by the CED Utility Director.

Beyond this awarded grant, staff plans to pursue additional funding for upcoming charger installations. Council action is requested to approve CED Utility Director Authority to accept the CEC grant, and apply for and accept any additional EV charger infrastructure grants that may become available, so long as new grants do not encumber City spending beyond approved CED budgets.

To make the EV Charge Program more enticing and increase utilization CED created EV charging pricing as a volumetric rate. Volumetric pricing at a price per kWh is similar to selling electricity at a price per kWh, or gasoline fuel sold at a price per gallon. CED has set the cost for use of these stations at a rate of $0.20 a kWh. Typical charge time for a full EV charge is approximately 2 hours. Pricing for Level 2 AC charging service is designed to recover costs for electric service and energy charges, installation and maintenance costs, program administration costs, and public benefits charges.

CED also developed an EV Level 2 charging rebates for residential and commercial customers who install the chargers in the City of Colton service territory. Customers can receive up to a $500 rebate for every permitted charger installed.

The benefits of EV's and EV charging infrastructure investment from CED is the following:

- Load Growth
- GHG mitigation
- Enrollment in the Low Carbon Fuel Standard Benefit
- Meeting State and Federal EV goals and objectives

To secure future funding for EV expansion, CED enrolled in the Low Carbon Fuel Standard Program. The California Air Resources Board (CARB) developed the Low Carbon Fuel Standard (LCFS) program in compliance with AB 32 (the Global Warming Solutions Act of 2006) to reduce the carbon intensity of transportation fuels used in California by 10% by 2020. Under the LCFS, providers of alternate fuels generate credits that can be sold to producers of traditional fossil fuels, helping those entities meet AB 32 emission reduction requirements. Electric utilities that provide electricity to charge Electric Vehicles (EVs) and electric forklifts are eligible to receive LCFS credits based on the number of EVs in their service territory. CARB approved the City of Colton Electric Department's (CED) application to participate in the LCFS program in 2014, and has been allocating LCFS credits to CED since then.

In order to be eligible to receive LCFS credits for transportation fuel supplied, the City must use all credit proceeds to benefit current or future EV customers, educate the public on the benefits of EV transportation, provide rates that encourage off-peak charging and minimize grid impacts, and provide CARB with an annual compliance report. Options include providing rebates to EV owners with registered vehicles in Colton, funding the installation of public EV chargers, developing low income EV incentive programs, and local business work place charging incentives. Staff returned to Council in January, 2019 with a recommendation on how to utilize the LCFS credit funds as a result of CARB developing legislation on allowable expenditure of funding for electric utilities.

After a court ruling that found procedural issues related to the original adoption of the LCFS, CARB re-adopted the LCFS regulation in September 2015, and the changes went into effect on January 1, 2016. The regulation provides for LCFS credits to be generated by electric utilities for providing the electricity for charging EVs. These credits are allocated by CARB based on the number of EVs registered in the electric utility service territory. Under CARB's formula, each EV generates approximatively 2 LCFS credits per year.

CED accumulation of LCFS credits from 2014 to 2017 have been sold and will be budgeted specifically to provide the following:

- Used EV rebate for residents
- Low income used EV rebate for residents
- Electric Forklift Rebates

Projected EV Growth in Colton

Energy Storage Programs

AB 2154 requires the CED to evaluate the cost effectiveness of energy storage programs, such as batteries, compressed air systems, Ice Bear small thermal energy storage systems and other ways of storing surplus energy, usually generated during the off-peak periods, to be used during high demand periods.

With the exception of hydroelectric pumped storage units that CED has been attempting to acquire since the mid-1990s, storage facilities remain too expensive to be used for CED peak shaving. Storage does appear economically feasible for retail customers that face a high demand charge that can be reduced for a few hours each day. CED is working with several retail customers with short, intermittent demand spikes to find suitable sites for retail energy storage.

CED has worked extensively with SCPPA to evaluate Ice Bear systems that use off-peak energy to create ice to reduce on-peak AC requirements. CED is installing 12 Ice Bear systems on City facilities to test the operation and cost-effectiveness of the units.

CED will continue following technological advances to identify when small scale energy storage systems become cost effective.

Summary of Conservation and DSM Programs

CED's conservation programs have met State goals for energy savings. In 2013 CED redesigned its Public Benefits Program and significantly increased its outreach and offerings and in the last five years has continued to upgrade its programs and add more options for customers.

CED has been 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 210 hours per year. However, CED has to plan to meet this load at a cost of around $300,000 to $450,000 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 SB 2 and AB 32 conservation requirements. Both SB 2 and AB 350 require CED to reduce energy by at least 20 percent from baseline growth by 2030. 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 and residential customers. The increased savings goals also include new building and appliance standards (Title 20 and 24) that significantly increase the energy efficiency in new buildings. With these new standards, it is difficult to achieve any additional savings in new construction, forcing utilities to concentrate on existing buildings for energy savings.

Future Program Potential for Conservation and DSM Programs

CED has been investigating the potential of behavior changing software programs for energy savings potential in the future. Currently CED has not installed smart meters (real-time metering) and would need to do so in order to use this type of analytical software to calculate energy savings by behavior change. Both SCE and SoCal Gas have implemented programs that show residential customers how their energy use compares to their neighbors and which appears to be successful in convincing people who use more energy than their neighbors to reduce energy use.

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 energy 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 and energy loss price risk.

The single largest risk exposure that CED faces is a rapid increase in SoCal city gate natural gas costs that results in an increase in the CAISO LMP. With the decommissioning of SJ3, CED is purchasing most of its energy in the CAISO market. The LMP is primarily set by the price of natural gas which has been fairly high relative to the past few years recently due to the outages of Southern California Gas' (SoCalGas) Aliso Canyon natural gas storage facility and interruptions on the interstate pipelines that bring natural gas into Southern California.

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

Market-Price risk is the risk associated with entering into long-term contracts and then having the wholesale energy price fall such 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 at lower costs.

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. Currently, one of the regulatory issues that CED is attempting to deal with is the additional cost of complying with environmental regulations as California looks to reduce its GHG emissions over the next 25 years.

An example of regulatory risk is SJ3. In the late 1970's, utilities were prohibited from using natural gas for electricity generation. So CED, along with other SCPPA members, began investing in coal plants. 30 years later, natural gas is plentiful but the state and nation are 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 as its primary fuel source, spent millions of dollars to mitigate the air quality impact of high emission coal resources and extricate itself from its coal-fired generation contract.

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. For example, each day that the Magnolia Power Plant is out of service results in CED incurring additional costs depending upon the price of natural gas, replacement energy purchases and potentially capacity costs depending upon CAISO costs.

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 and cannot hedge its losses.

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. Nor can CED control the actions of its contracted generation resources or regulators.

Regardless of its inability to control the actions of the market or other entities, CED can design its resource acquisition strategy to minimize the financial impact of forecast and market risk. CED only deals with companies that have good credit ratings and periodically reviews these ratings. CED also reduced the amount of excess generation in its resource portfolio since 2017 when SJ3 was decommissioned.

CED also uses AMPP as a physical hedge against spikes in CAISO energy prices. If energy prices are below the cost of AMPP, CED purchases in the CAISO energy market. If energy prices are above AMPP generation costs, CED generates. In either case, CED's costs cannot exceed the cost of AMPP.[19]

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, proposed new capacity market structures, RPS and energy efficiency requirements along with proposed new environmental rules are straining CED's ability to identify and comply with all the relevant regulatory requirements.

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[19] A slight caveat – the CAISO will not dispatch AMPP for a spike of three or four hours in the day-ahead market. So for any short time period CED could purchase above the cost of AMPP generation.

Development of a Risk Management Plan

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 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.

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

Specific objectives, listed in order of priority[20], to achieve this mission include:

1. Providing 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 resulting in the lowest possible price to CED's ratepayers;
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.

[20] Although safety is not mentioned in this discussion of financial goals, a safe working environment is the major goal of CED at all times.

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 Finance Director who performs 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.

<u>Organizational Structure</u>

CED is a small organization that currently outsources the daily scheduling and communications with the CAISO. CED has hired Shell as its SC and 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;
- 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;
- SES for energy from Colton Solar 1 and Colton Solar 2;
- Solar City for energy from the Gonzales Center and Arbor Terrace Solar Projects;
- The City of Anaheim for the MWD energy swap;
- Transmission costs from SCE, LADWP and Burbank for non-CAISO transmission service;
- Management and operation costs of the AMPP.

Once an invoice is received, energy production and costs are verified against monthly forecasts of power supply created as part of CED's annual budget review process. In addition, an hourly balance of all energy purchases and sales is created to ensure CED can account for all energy purchased or sold by CED to retail and wholesale customers.

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 issue 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 Finance Director acts as CED's Risk Management Officer (RMO). The RMO must agree with CED's forecasts of the expected financial impacts of any proposed long-term firm power supply purchase or hedging contract in excess of one year. In general, the Finance Director 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 2019/20 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.

CED's current fixed price resources of Astoria, Kingbird, Puente Hills Landfill Gas Generator, Colton Solar 1 and 2, Gonzales and Arbor Terrace, Magnolia Power Project, Palo Verdes Nuclear Generating Station, Hoover and MWD produce about 41.5 MW. With AMPP, CED's self-generation is about 72 MW and can generate all but about 765 MWh of CED's energy requirements that CED will have to purchase from the CASIO at market prices. Even an average price three times the expected price is less than a $100,000 increase in annual energy costs.

CED is also at risk of summer 2019 capacity costs. CED was about 13-15 MW short of forecasted load plus reserve obligations and is likely going to have to rely on the CAISO to purchase this capacity for some summer months. This could cost as much as $225,000 based upon three times last year's prices – expensive, but still within the CED's VAR.

By summer, 2020 CED is almost back in resource balance needing just 3 or 4 MW of RA during the summer months.

CED uses approximately 1,650 MMBTU/day of natural gas for the MPP and another 2,200 MMBTU if AMPP operates for 5 hours. 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.

Historically, one area that CED had little or no control over was congestion risk. Since mid-2012 CED has been actively managing its congestion risk and has significantly reduced monthly congestion costs. With the addition of CDIV into its generation mix, CED will need to continue managing congestion and loss risk. 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 or manage the risk by acquiring CRRs.

CED reviews all CAISO invoices on a daily basis as they are received from Shell and verifies 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 RMO 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.

In December 2011, FERC issued FERC Order 741 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 of each year. CED has prepared and filed its RMP with the CAISO and agreed to perform the required periodic evaluations of market risk and congestion risk. The CAISO has accepted CED's past RMP filings and in 2016 performed an audit of CED's RMP for completeness and agreed CED's RMP meet all regulatory requirements.

CHAPTER 7: RENEWABLE RESOURCES

Introduction

Renewable resources are resources that do not require fossil fuels (coal, natural gas or petroleum products) to generate electricity. Renewable resources include solar, including both solar photovoltaic and solar thermal plants, wind, geothermal, small hydroelectric, biomass and biogas. A brief discussion of the pros and cons of each type of renewable resource is provided below. This Chapter discusses which renewable resources will minimize the rate impacts on CED's ratepayers of meeting RPS standards.

Solar Photovoltaic (PV)

PV is the most successful 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.

PV differs from solar thermal in that PV converts solar energy directly into electricity while solar thermal uses heat to power generators.

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-production has lowered the construction price from roughly $3/watt to the current price of around $0.35/watt.

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

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 maximum 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 require additional non-PV capacity available to meet its peak load requirements.

The CAISO has noticed the changing shape of daily energy demand due to solar production. Historically, energy prices were greatest in the mid-afternoon due to air conditioning demand. As a result of solar PV production, daily demands are now greatest during the morning and late afternoon/early evening and energy prices are actually lowest during the mid-afternoons when solar PV production is highest.

This is one of the primary reasons the CAISO began implementing flexible capacity requirements.

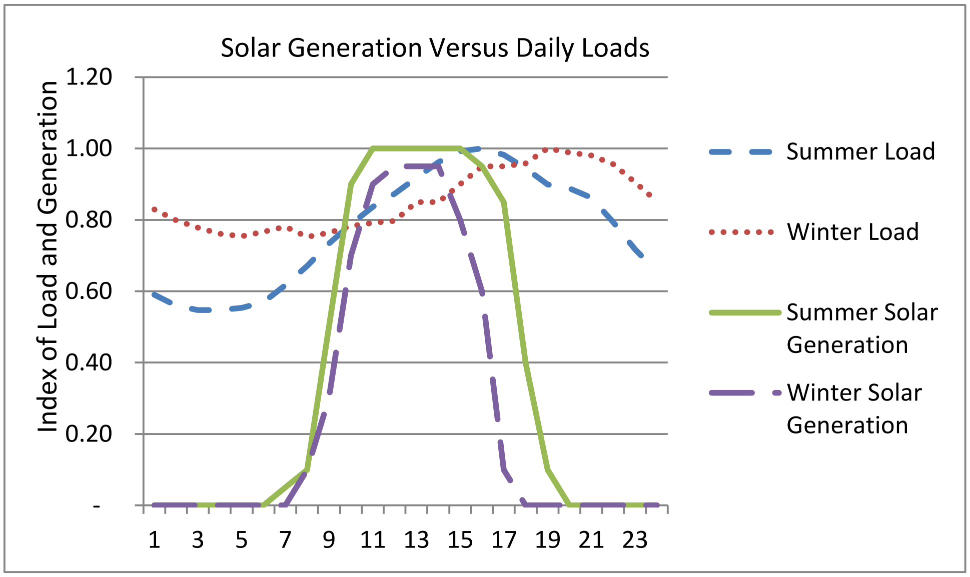

Figure 7.1: Index of Solar PV Generation versus Hourly Load

The above figure shows that during the summer months, PV generation begins to decline even as retail loads are high, resulting in CED having to keep additional thermal capacity available to meet loads. 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 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 turn a turbine.

There are two major kinds of solar thermal generators. The Luz “trough” type, where fluid is sent through a pipe. Parabolic mirrors focus sunlight heating the fluid 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.

Figure 7.2 – Luz Thermal Solar Facility Near Barstow

The other type, unofficially known as a "steam on a stick" has an array of mirrors that focuses sunlight on a boiler that creates steam that is used to power the generator.

A picture of the 377 MW Ivanpah solar thermal project in eastern Riverside County shows how the array of mirrors focuses the sunlight unto the top of a tower where the steam is created to power a generator.

Figure 7.3: Ivanpah Thermal Storage Facility in Eastern Riverside County

Solar thermal projects tended to be larger than PV projects to justify the higher cost of generators but since the decline in PV prices in the last few years, many of the proposed 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.

Many new solar thermal projects have different kinds of storage, such as batteries or molten sodium, to extend the daily generation capabilities into the peak periods. While this makes it more useful in meeting evening peak loads, the additional costs also make solar thermal projects more expensive. With the declining cost of battery storage, solar PV generation tied to battery systems is becoming more common. The downside of this is that a portion of the system output has to be used for battery charging. For example, if there is a 50 MW solar PV system that is designing a battery system to extend generation 3 hours in the evening, 150 MWh of daily production has to be used to charge the battery system before losses and as much as 225 MWh if losses are 30 percent (which is not uncommon). That means during the winter months as much as half of the total output of the facility is being used for storage, while in the summer perhaps as much as 33 percent of daily output is being used for storage. This does not include the cost of the batteries themselves, which can cost as much as $1,000,000 per MW. Obviously, the choice over how much storage is needed for how long is something that each project has to consider carefully.

Wind

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 energy is inexpensive and generally abundant but the operational issues associated with it have not yet been fully resolved. Wind energy may be plentiful and then disappear from the grid all at once if the wind stops blowing. As a result of the lack of a reliable supply, the CAISO derates the capacity from wind resources almost to zero and requires entities with wind resources to have flexible capacity available to make up any reduction in generation.

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 count as renewable resources only if they are smaller 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 (none of which have passed Congress).

The major problem with small hydroelectric facilities is that there are few places in California where new hydroelectric facilities can be constructed. California's hydroelectric production has actually declined over the past ten years as hydroelectric facilities have been taken out of service for environmental considerations.

Hydroelectric is a good source of energy especially when storage (such as pumped-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 and the recent 2009 – 2016 drought 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. Biomass generation costs $85 – $110/ MWh or more, compared to as little as $35/MWh for solar and $45-60/MWh for wind. The biggest advantage of biomass is that it is a firm, baseload renewable resource and can be counted on for generation.

In 2016, SB 859 was introduced in the California senate that requires most of the state's utilities to enter into power supply contracts with biomass generators. Biomass generation is seen as a way of getting rid of trees in California's forests that have died as a result of the prolonged drought and bark beetle infestation.

SB 859 was signed by Governor Brown in September 2016. Investor and large publicly owned utilities must enter into power supply contracts for at least five years for up to 125 MW of biomass generation. For now, SB 859 does not affect CED but there is concern that in the 2019 legislative session the size limitations of utilities will be reduced, possibly requiring CED to purchase a small amount of biomass generation.

Geothermal

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 Southern California publicly owned utilities including Riverside Public Utilities department, Los Angeles Department of Water and Power and the City of Banning.

The biggest problem with developing geothermal generation in the Imperial Valley 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 geothermal developers from getting project financing until the wells have been drilled and are producing. The high upfront drilling cost has slowed the development of geothermal energy in the western states.

New geothermal energy costs are between $70/MWh to $105/MWh.

From an operational viewpoint, geothermal facilities are more attractive than many other renewable alternatives because the power is firm but the unit generation can be increased and decreased depending upon system conditions.

In addition to Imperial County, other notable geothermal fields in California include the Geysers fields in northern California and the Mammoth Lakes area where the Casa Diablo IV Geothermal Plant is located.

Biogas

Biogas is methane collected from the decomposition of plant and waste materials. There are a number of biogas facilities that use cow manure, landfills and other waste sources 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 can be an inexpensive way to meet RPS goals. 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. This was because utilities were entering into agreements for biogas from landfills across the nation and then transmitting the biogas into California. Except none of the biogas actually was transmitted across the country, it was just an accounting process to allow California utilities to bring low-cost gas into the state and call it renewable. The CEC took notice and addressed the issue.

In the 7th Edition of the "RPS Guidebook" the CEC approved biogas generation with a number of restrictions. Biogas can be used to meet RPS requirements if the biogas is produced within California, if the biogas can be cleaned and injected into the interstate pipeline system and the gas can be tracked to the generator. Biogas can also be used to power onsite generators where the energy is transmitted to the grid.

Energy from biogas costs between $70 and $90/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 has a biogas contract with Shell Energy. Shell will purchase biogas produced at a landfill in Kern County where the biogas is cleaned, dried and blended with natural gas to achieve the required purity and fuel content to inject into the interstate pipeline system for delivery to Magnolia.

Waste Water Treatment Plant Cogeneration Facility

Prior to 2013, the Colton Waste Water Treatment Plant captured methane emissions from the decomposition of solid waste and used it to power a small generator (250 kW) at the plant. In 2010 the unit was shut down due to maintenance issues and has never been restarted. Instead, the methane is flared (or burned). The value of energy produced by the cogeneration facility is about $240,000 annually.

The CED is evaluating the cogeneration facility to determine if it can be economically retrofitted or repaired. An initial evaluation of the facility shows some of the major components can be used but a large investment will be required to make the plant workable.

Renewable Resources That Meet CED's Needs

CED will need additional baseload energy to help replace SJ3. Puente Hills is a good intermediate resource until a long-term contract is executed although by 2020 CED needs approximately 15 MW of baseload generation and some seasonal peaking generation. The renewable resources that best meet CED's requirements are a combination of 13 to 15 MW of baseload generation (geothermal, biomass or biogas) in 2020 and 10-15 MW of intermittent resources (wind, solar PV) over the next few years.

CED's power purchase agreement with Ormat for Casa Diablo IV will satisfy CED's baseload energy requirements, leaving CED only 10 – 15 MW of peaking resources short.

Biogas can be used as a fuel for either Magnolia or AMPP. If used at Magnolia, the fuel cost of renewable energy will be around \$72-\$78/MWh (assuming \$12/MMBTU of biogas delivered) while AMPP would generate renewable energy at a cost between \$90-99/MWh. The higher cost at AMPP is due to the much worse heat rate of the unit compared to Magnolia.

Finally, small PV projects within or near Colton would be the next most attractive renewable resource.

The following table provides an idea of the cost of bundled energy and capacity from various technologies:

Technology	2017 RFP
Intermittent	
Solar thermal	-
Wind	\$47 - \$73
Solar Photovoltaic	\$35 - \$110
Small Hydroelectric	\$55
Energy Storage	Pricing is contingent on a number of factors including length of required storage
Baseload	
Biomass	\$95 - \$125
Geothermal	\$70 - \$105
Biogas/ Landfill Gas	\$92 - \$103

Table 7.1: Renewable Prices

SB 2 established 3 compliance periods for meeting RPS requirements, 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%. The CEC also instituted additional compliance targets during the third compliance period.

SB 350 continued the requirement for renewable energy until 2030 with a 50 percent requirement generally increasing by 2 percent per year from 2020 to 2030.

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.

The CEC has also created a new category of PCC called PCCZero. This PCC covers renewable contracts entered into prior to 2010 and helps meet the total RPS requirement but does not count as a specific PCC renewable resource. Currently, three of CED's renewable resources are categorized as PCCZero.

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.

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 two 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.

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.

While WREGIS tracks RECs, it does not track the California RPS requirements. It is up to the individual utility to be able to prove that its resources satisfy the PCC restrictions of SB 2. This has become a significant bookekeeping and verification effort for the CED based upon the initial CED filings with the CEC.

CED's Renewable Requirements and Potential Costs

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.

By acquiring renewable resources in a slow, planned phased-in approach and by planning to own the generation resource after the initial six year period when tax credits are available to private firms, CED can minimize its power supply costs. This proposal would meet the Colton City Council's cost-limitation criteria established in R-103-11.

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 meet CED's loads. In addition, the legislative and regulatory requirements that CED must meet in the next few years have been identified and the additional constraints they put on the resource planning process.

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 the deficit CED faces in meeting the legislative and regulatory requirements of AB 32 and RPS requirements and the impact of the SJ3 decommissioning in 2017. Then another scenario adding CD IV to the resource mix was performed. This allows for both the calculation of the financial impact of CD IV on CED's power supply cost and identifies where CED is short capacity and energy in the next five years.

An important 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 $2,900,000 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, when doing a power supply analysis, all costs of power supply, including debt, should be considered in power supply costs.

Load Duration Curve

CED's load duration curve was calculated for use 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 suggests what portion of load could be met by each type of resource, baseload, peaking or intermediate.

The load duration curve (LDC) shows that CED's current baseload generation (Magnolia, Puente Hills and PVNGS) do not meet CED's baseload requirements of around 35 MW.

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

The load duration curve also shows that that CED's peak loads only exceed 70 MW for about 210 hours per year. If conservation and DSM programs can 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.

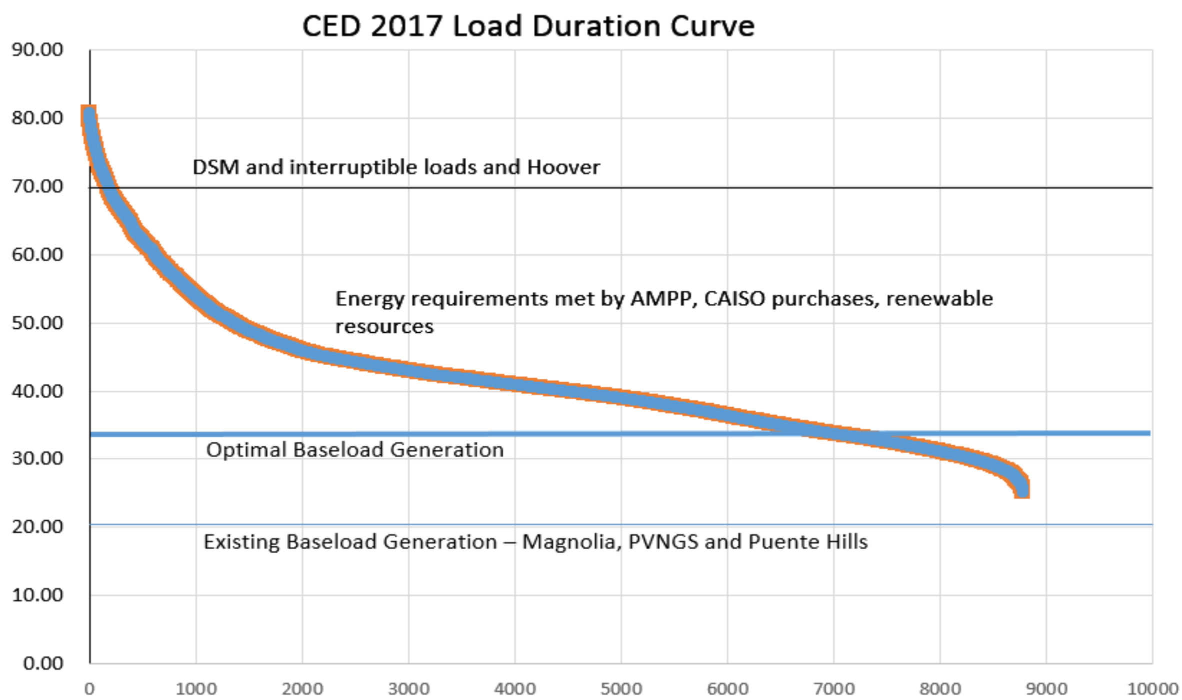

Figure 8.1: CED's 2017 Load Duration Curve

The analysis of the LSCs shows that CED is currently short energy, including during the off-peak periods which are becoming the most expensive energy during the day because it tends to be natural gas fired. During the day, solar PV generation tends to keep the price of energy down especially during the summer months.

CED will be purchasing more energy from the CAISO as it replaces the energy that it lost when SJ3 was decommissioned. However, CED's annual energy costs should decline as CED's energy purchases from the CAISO will be less than the cost of SJ3 energy.

A Base Case generation simulation was performed for the period 2017/18 through 2020/21 to determine how well CED's current resources met the different requirements of CED's power supply mix, in particular:

1. Does CED have or plan to acquire sufficient capacity to meet monthly loads, including system capacity, local capacity and flexible capacity requirements?
2. Can CED's generation mix meet its energy requirements?
3. Does CED's existing and planned resources meet RPS requirements;
4. Does CED's generation existing and planned resources result in GHG reductions over time?
5. Does CED's existing and planned resources result in power supply cost stability in accordance with ED's risk-management goals?

The Base Case only included CED's existing resources and planned purchase of 500 MMBTU/day of biogas in the early 2020 period.

With its existing generation resources only, CED is short 13 MW during the summer months in 2018/19 and has to make short-term RA capacity purchases. The shortfall increases to 14 to 15 MW during the summer months and 5 to 10 MW during the late spring months in 2019/2020. By 2020/21 the capacity shortfall rises to 18 MW during the summer months and 5 to 10 MW in the shoulder months.

Because of the capacity associated with AMPP, CED is not short any local or flexible capacity.

CED can meet almost all of its energy requirements if it chose to dispatch AMPP to meet load. This would result in CED's power costs significantly increasing as AMPP's cost to generate is around $55/MWh compared to CAISO energy costs of around $40/MWh. In addition, AMPP cannot generate at less than 37 MW so CED would have significant surplus energy, especially during the off-peak periods that it would be selling at a loss.

AMPP is also a high GHG emitter. AMPP emits almost 0.55 tons of CO2e per MWh so using AMPP to meet load results in roughly 24 tons of CO2e per hour at a carbon cost of $360/hour (at $15/ton) in additional to normal fuel and O&M expenses. This compares to a carbon cost of roughly $6/MWh from Magnolia and close to zero for renewable resources or purchases. Using AMPP to meet much of ED's physical energy requirements would result in a significant increase in CED's overall GHG emissions.

Without its existing RPS resources, CED renewable generation will peak at approximately 113,000 MWh per year of renewable generation in 2018/19 and then begin declining as Puente Hills output declines and the High Winds and MWD contracts expire in 2023. By 2023 CEDs total RPS generation would stabilize around 27 percent, as opposed to the 30 percent plus that is required by state legislation.

Finally, CED's power costs could start showing significant volatility as daily electricity costs track daily natural gas costs. While in some years, this could result in lower costs, in other years CED could see its power supply costs rise significantly without taking steps to hedge daily natural gas costs.

Overall, using CED's existing resources to meet loads does not result in meeting most of CED's goals and regulatory requirements and could result in significantly greater power supply costs than are available with other resource mixes.

<u>Biogas Purchase</u>

In 2015, CED entered into a purchase agreement with Shell Energy for up to 500 MMBTU/day of biogas from the Bena Landfill in Kern County. This biogas would meet approximately one-third of Magnolia's daily gas requirements. CED receives about 75,000 MWh per year of energy from Magnolia so converting one-third of daily gas requirements to biogas would result in approximately 25,000 MWh of green energy. There are three primary markets for biogas in California. First, as a fuel for generation, second as a transportation fuel under the Federal Renewable Fuel Standard (RFS)[21] and finally to meet low carbon fuel standards (LCFS)[22] under the California Air Resources Board.

Biogas can be used to create low carbon, low emission fuels. Various entities in the transportation sector need to accumulate credits to meet their federal and state emission reduction obligations.

The price of credits in the RFS and LCFS markets varies and is often greater than the value of RECs created by using biogas for electricity generation. Producers like the option to shut-down deliveries to generators so that they can sell in other markets. But, without a long-term guaranteed purchaser, the biogas producer cannot secure the necessary funding.

Bena Energy, the source of CED's biogas, wants to capture the greater value of biogas in the RFS and LCFS markets whenever their price is above the value of RECs. But unlike the REC market, there is no long term market for RFS and LCFS credits, so Bena cannot use the future value of these two uses to secure the needed funding to construct the landfill gas treatment facility needed to clean and mix biogas to the necessary quality to inject into the intra-state natural gas pipelines.

Under the initial rules estalished by the CEC, Bena was willing to sell the total output of biogas to CED. However, the CPUC modified the rules in 2015, requiring additional testing and cleaning under certain conditions. This made the cost of creating biogas uneconomic for only electricity generation.

Bena proposed reducing the daily volume of biogas to CED from 1,500 mmbtu/day to 500 mmbtu/day. They would use the remaining 1,000 mmbtu/day for fuels to sell into the RFS and LCFS markets. The guaranteed revenue stream from CED would allow them to secure the needed financing to construct the facility.

By reducing daily volume form 1,500 mmbtu/day to 500 mmbtu/day, CED would reduce the amount of renewable energy from roughly 75,000 MWh per year to 25,000 MWh. This is still enough renewable energy to meet 43 percent of CED's total energy requirements with existing resources but by 2027 CED would have to acquire roughly 50,000 MWh of renewable energy to meet SB 350 requirements.

Base Case Scenario

The base case scenario examines CED's power supply costs with only existing resources and the Bena biogas purchase and the demand and energy forecast prepared using the model presented in Chapter 2. The simulation covers the period 2017/18 through FY 2020/21. The simulation does not include any additional conservation or DSM measures to attempt to reduce CED's monthly peak demands beyond the current programs.

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[21] Federal Renewable Fuel Standard (RFS) regulated by the EPA. This is the program that deals with RINS. https://www.epa.gov/renewable-fuel-standard-program

[22] California program. Low Carbon Fuel Standard (LCFS) regulated by CARB. https://www.arb.ca.gov/fuels/lcfs/lcfs.htm

SCPPA budget projections for the period 2017/18 through 2020/21 were used in the simulations.

In 2017/18, total power supply costs are forecasted to be $36.73 million down from $39.85 million in 2016/17. The decline was primarily due to the decommissioning of SJ3 in December 2017 that allowed CED to acquire more economic sources of energy.

Overall, power supply costs remain rather stable from 2017/18 through 2020/21 even as loads increase slightly, with customer solar installations offsetting about half (or more) of new load growth. CED's renewable percentage will be around 30 percent, depending upon when the new renewable resources actually come online.

Biogas Scenario Analysis

With the purchase of 500 MMBTU/day of biogas, CED can increase the percentage of renewable resources in its portfolio for around $2.0 million per year[23]. The reduction in CO2e emissions from Magnolia is roughly 10,000 tons/year with a value of $150,000 per year.

A biogas purchase increases the percentage of renewable resources in CED's portfolio but does not increase the amount of capacity or energy in the portfolio. The analysis had to look at the additional cost of the biogas compared to natural gas and determine if CED could acquire renewable energy less expensively than $60/MWh without over-resourcing itself.

CED also has the ability to lay the biogas off to fuel makers as a source of low-carbon fuel. CED has already been offered $14.00/MMBTU for its biogas for the first half of the contract period or a profit of $730,000 per year for the first three to five years. CED is currently finalizing this offer because of the effects of CED's other renewable resource, Casa Diablo IV.

Casa Diablo IV Simulation

The 2017 IRP identified the need for an additional 10 to 15 MW of baseload energy to meet its load forecast beginning in 2021. Ormat Nevada, Inc. (dba ORNI 50, LLC) submitted a proposal through the SCPPA RFP process for a 25 MW baseload renewable, geothermal, with resource facility, with resource adequacy (RA) attributes in Mono County, California. The capacity factor for the facility is approximately 95%. The facility will have a direct interconnection into the CAISO, allowing the energy from the facility to qualify as a PCC1 resource for RPS.

CED staff evaluated Ormat's proposal and determined that this project is a good fit for its resource portfolio because it is a baseload renewable resource, with RA, and qualifies as PCC1 energy for RPS

[23] The biogas cost is $10.85/MMBTU plus a transmission cost of $0.50-$0.75/MMBTU. Assuming the higher cost, the delivered cost of biogas to Magnolia will be around $11.60/MMBTU so the annual cost will be 500 MMBTU/day * 365 days/year * $11.60/MMBTU or 500*365*$11.60 = $2,117,000/year. However, Shell will purchase any surplus gas under existing agreements, resulting in a slight reduction in the total cost.

compliance. Commercial Operation Date (COD) of the facility is no later than July 1, 2021, with a possibility of an earlier COD in April 2020.

SCPPA's staff and legal counsel, together with each staff from CED and Banning, entered into PPA negotiations in January 2018. At the onset, the PPA price was $76.50 per MW. The SCPPA team has negotiated the price down to $68.00 per MW, for a 25-year term. This is an annual savings to CED of $1,191,360, or a total savings of $29,784,000 over the 25-year term of the PPA. The price per MW includes resource adequacy (RA) and environmental attributes (renewable energy credits, or RECs).

The $68 PPA price is higher than current proposals for solar PV; however, solar PV is only available during daytime hours, unless some form of storage is added to the facility which extends generation by 2 to 4 hours each evening but reduces energy production during the day. A recent analysis of solar PV with sufficient storage to essentially make the intermittent solar consistent with baseload shows the cost would be approximately $67 MW. The $68 MW price negotiated is reasonable for CED and its ratepayers with little risk because Ormat is guaranteeing the RA capacity for the life of the project and CED only has to pay for energy as it is delivered.

The SCPPA Board of Directors approved the Power Purchase Agreement and the Power Sales Agreements for Colton and Banning on October 18, 2018.

The geothermal simulation was performed beginning in July, 2020. Adding the 15 MW of baseload energy to CED's resource mix immediately resulted in a reduction in system RA capacity with short-term monthly RA purchases declining to around 2 MW during the summer months. This reduces RA costs by almost $270,000 per year in comparison to the non-geothermal case.

Secondly, the purchase reduced CED's CAISO energy purchases by almost 125,000 MWh per year with a value of around $5.6 million.

Third, CED does have a slight surplus of energy in the winter and spring off-peak periods, resulting in the sale of roughly $800,000 of surplus energy. CED would have preferred a geothermal contract of 10 to 13 MW beginning in 2020 in order to avoid any surplus energy but in order to make the power purchase agreement work for all participants, CED had to purchase an additional 2 MW of capacity three or four years before actual need.

Finally, the geothermal purchase creates an additional $500,000 to $700,000 of C&T moneys that could be used to reduce renewable power supply costs although CED has better uses for the money by investing in electric vehicles, new infrastructure and more conservation activities.

The net result of the geothermal purchase is to raise power supply costs by $2.5 to $3.0 million in comparison to the Basecase scenario. However, the percentage of CED's RPS generation increases to over 60 percent (approximately 224,000 MWh of renewable energy is generated from CED's resources to meet a retail load of around 370,000 MWh) and CED's GHG emissions continue declining in accordance with AB 32. Finally, CED's power supply cost volatility declines because of Ormat's obligation to provide RA capacity for the contract life even if the unit has a catastrophic break-down.

In other words, CED is well positioned to meet all RPS and GHG requirements with power supply costs that are almost constant for the next ten years.

<u>Cogeneration, Biogas, Additional Solar and Conservation</u>

The next simulation that was performed assumed SJ3 was operational until the end of 2017, a 250 kW cogeneration unit at the City's Waste Water Treatment Plant (WWTP) was restored, 3 MW of solar was installed at either the WWTP where the existing sludge drying beds currently are and additional conservation activities reducing load by about 2 MW were installed or south of the RIX facilities along Bustamante Rd.

Overall, this scenario results in about $80,000 annually increased costs compared to the baseline simulation primarily due to slightly higher costs from the new solar facility within the City compared to alternatives outside the City.

Colton's WWTP is one of the few remaining WWTP's that still uses drying beds to dry the waste sludge so that it can be transported from the site to disposal areas outside the LA Basin (generally Barstow or into Arizona). In 2018, the WW division began installing a centrifuge at the WWTP. The centrifuge spins the waste, separating the water from the remaining waste that can be hauled to a disposal area without the need for onsite storage while drying.

The centrifuge eliminates the need for drying beds, a source of groundwater contamination. The drying beds at the WWTP take up about 7 acres with the possibility of using additional land to achieve 10 acres. This is enough to build a 2 – 2.5 MW solar facility at the site on land that has no other viable use.

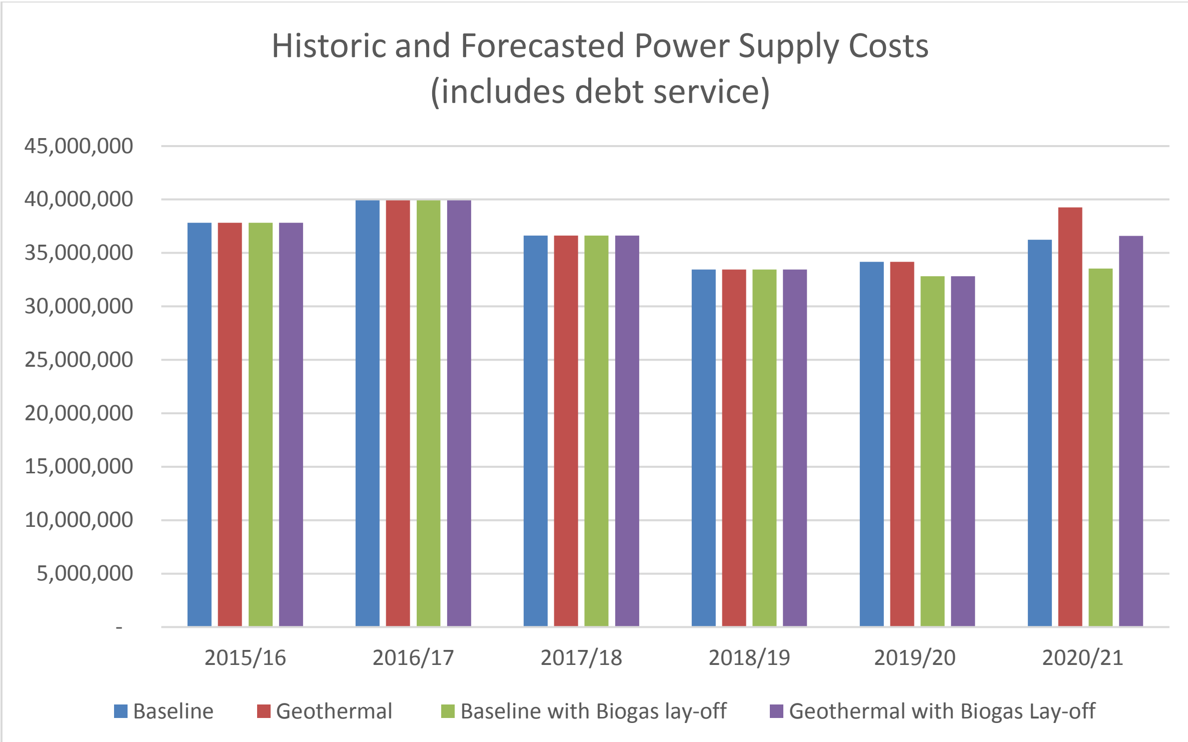
Finally, CED needs to expand its conservation and demand side management efforts to achieve another 1 – 2 MW of load reduction.

This scenario results in slightly higher annual power supply costs in 2021 through 2023 of roughly $80,000 per year in comparison to the base case, not including the (unknown) initial costs of repairing the WWTP cogeneration facility. CED's renewable resources are increased by about 8,000 MWh or about 1 percent but CED meets all of its RA requirements.

Right now, the financial viability of the WWTP cogeneration facility is unknown. The cogeneration facility was used at the plant for years as a means of disposing of the methane. However, the plant broke down in the 2010 time-frame and was never repaired. In the next few months, CED will investigate the feasibility of repowering the cogeneration facility or replacing the existing equipment with newer technology such as the Capstone micro-turbines as a way of reducing methane emissions and generating onsite power for the WWTP.

<u>Summary of Simulation Results</u>

The following graph compares the annual power supply costs under the different scenarios. A striking fact is that regardless of which resource plan CED ultimately chooses, costs are within 5 to 7 percent of each other.



Storage Options

California Assembly Bill 2514 (AB 2514) requires the governing board of each publicly-owned utility (POU) to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems. Each governing board must make its initial determination on target energy storage levels by October 1, 2014 and no less than every 3 years thereafter.

Energy storage systems include large batteries, compressed air systems, thermal energy storage that produces ice during the off-peak periods for use for air conditioning during the on-peak period and other technologies. Energy storage systems not considered under AB 2514 includes hydroelectric pumped-storage systems.

Electric storage systems use less expensive energy for charging and store this energy for periods of high cost. Typically this means charging during off-peak periods and releasing energy into the grid during high cost periods, generally the on-peak periods or morning ramp periods when energy demand is increasing rapidly.

A financial analysis of electric storage systems is very dependent upon the expected use of the system. Storage often makes financial sense for a retail customer who can charge their storage system with off-peak energy that can be used during the on-peak period, reducing high on-peak energy charges and cutting demand costs. Storage systems may also make financial sense for intermittent generators, such as wind and solar producers, who want to deliver a firm, known quality of energy to its wholesale customers. Storage systems do not appear to make financial sense for a utility that has excess generation capacity available to meet unexpected energy demand, such as the CED.

The large amount of intermittent renewable generation coming online during the next few years to meet California's renewable energy standards (RPS) requirements is stressing energy systems in the western states. The demand for traditional thermal resources is actually declining during the early afternoon hours but increasing in the late afternoon and early evening hours when solar PV production declines but customer demand remains high.

Requiring thermal resources to be available to back-up intermittent resources is expensive. Start-up costs are high and a gas-fired generator (such as the Agua Mansa Power Plant) may cost $3,000 to $5,000 to start even if they are intended to operate for just a few hours. Many gas-fired generators that cannot be started in a few hours are backed down to minimum operating levels and generate surplus energy during low load periods.

To address the capacity problems with intermittent resources, California is requiring investor-owned utilities to acquire 1,325 MW of energy storage by 2020. POU's are required to periodically investigate the cost-effectiveness of energy storage and, once found cost-effective, to establish a procurement target.

A difficulty in analyzing storage systems is that their value is very dependent upon the specific use of the storage system.

The primary problem with storage systems is they are very expensive. Large batteries cost $1 million to $2 million per MW with the average cost of energy between $200 and $400/MWh. For comparison, the cost of energy from AMPP is around $180/MWh when capacity (debt costs), energy and O&M costs are included.

CED, can currently rely on the CAISO to meet moment to moment fluctuations in demand for a cost of around $30 to $50/MWh (although during some short periods the cost could be much higher). There is no need to invest in new storage systems when a utility is over-resourced and can generate less expensively than purchasing a new storage system.

A key point is that there are situations where storage systems make sense from the customer's viewpoint. For example, if a customer is away from home during the day and uses a solar PV system to charge their storage system, they could essentially meet their entire energy needs for the cost of the solar PC system and storage system. Currently the equipment would cost around $25,000 to $50,000 but might be more affordable in the next few years.

CED performed an analysis of the cost of meeting one additional MW of load on its system and compared the cost of purchasing additional Resource Adequacy (RA) capacity for 3 months of the year and meeting the additional load with its own resources the remainder of the year compared to a lithium ion battery storage system, currently the least expensive storage system (other than pumped-storage).

CED can purchase 3 months of RA capacity for around $9,000 plus energy charges of $18,400 (for a four-hour daily block) or about $27,400. A comparable cost of Lithium – Ion batteries would be around

$220,000. However, this analysis ignores that the lithium – Ion battery would be available all 365 hours of the year. If the battery were priced for just 3 months, the cost would be around $54,000, just about $19,000 (or almost 60% more) more than the cost of just purchasing capacity and energy.

The difficulty with making an analysis is that the battery cannot be shaped to meet CED's annual requirements. Any purchase results in excess capacity that just exacerbates CED's surplus energy position in the non-summer months. This also assumes that a 1 MW battery costs proportionately the same as a 4 MW battery (or a 1 MW battery costs one-fourth as much as a 4 MW battery which currently is not true).

A more viable alternative at this time is thermal energy storage (TES). TES uses off-peak energy to create ice that is used for air conditioning needs during the day. TES systems are almost cost-effective for certain customer uses (such as a new fitness center) especially if the customer faces real-time pricing. TES systems may make financial sense from the customer's viewpoint but not from the CED's viewpoint at this time. CED is investigating rebates or special off-peak charging rates to assist customers to install TES systems.

Because of this financial analysis, CED has recommended that the City Council not establish storage targets for the CED at this time but revisit the economic feasibility in three years as required by the law.

Future Resource Requirements

In addition to the possibility of renovating the cogeneration facility at the WWTP CED will require an additional 10 – 15 MW of peaking resources in the 2023 time period as the MWD, Puente Hills and Avangrid contracts expire. Solar resources appear to be the least expensive way of meeting this capacity shortfall. While CED can participate with SCPPA members on an RFP, it can also issue another RFP to identify the feasibility of constructing approximately 5 MW of solar PV generation at the WWTP and along the west side of the Santa Ana River, south of the RIX facility. At these two sites CED (or the City) has sufficient land to construct about 5 MW of solar PV generation. Solar PV generation may be less expensive if constructed in the high desert in larger projects but CED has been successful in constructing solar PV facilities in the City on CED's side of the meter. This results in savings of about $15/MWh by avoiding transmission access charges, congestion and losses. CED is going to need to carefully analyze the delivered cost of solar PV both in and out of the City to determine which is the most financially attractive alternative in the next two years so that the capacity is available by 2023.

Summary

The financial analysis presented above shows that of the alternatives, the 15 MW geothermal purchase plus 500 MMBTU of biogas in the 2023 time period plus 2 MW of additional conservation programs results in the lowest power supply costs that meets CED's load requirements, RPS requirements and GHG reduction requirements. The feasibility of a 250 kW cogeneration facility should be studied.

If the proposed resource plan is followed, CED will remain in compliance with state RPS requirements and GHG reduction requirements. CED will only have Magnolia and AMPP as GHG emitters that in total produce about 20 to 25,000 tons of GHG emissions, compared to the 211,000 tons of GHG emissions in 2016, the last full year of SJ 3 generation.

CED will have a capacity shortfall in 2023 as several of its power purchase agreements terminate and should start planning for another 5 MW power purchase by 2021 for a plant either in the City or within Riverside, San Bernardino or Imperial Counties depending upon the proposed cost and conditions.

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.

CAISO: The California Independent System Operator

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.

CO2e: Carbon dioxide equivalent emissions. The total impact of all emissions measured in terms of the equivalent amount of CO2 that has the same environmental effect.

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.

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.

NERC: North America Electric Reliability Corporation. The federal entity charged with overseeing the reliability of the US electric grid.

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.

SCPPA – the Southern California Public Power Authority, a joint power agency that finance's generation and transmission projects for its members, including the City of Colton. The member agencies are Los Angeles Department of Water and Power and cities of Glendale, Burbank, Pasadena, Anaheim, Riverside, Colton, Cerritos, Banning and Azusa and the Imperial Irrigation District.

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, generally equal to forecasted sales plus transmission losses plus reserve requirements.

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: FORECAST OF MONTHLY DEMAND AND ENERGY REQUIREMENTS

	Historic and Forecasted Energy Requirements (MWh)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
2007	28,986	28,634	29,388	31,324	31,502	39,368	37,639	37,009	29,487	28,497	28,773	28,750	379,356
2008	28,570	28,285	28,222	29,250	29,580	34,329	36,353	36,911	35,199	31,620	28,373	27,728	374,419
2009	26,871	27,016	27,011	27,874	31,805	30,806	39,652	37,165	36,294	28,203	27,048	26,419	366,164
2010	26,244	26,172	26,378	26,364	27,281	30,868	34,371	34,870	32,297	27,852	26,884	26,063	345,645
2011	25,969	25,996	26,106	26,282	26,515	29,284	35,190	36,300	33,528	29,215	26,451	26,777	347,614
2012	26,600	26,800	26,800	27,600	31,900	31,000	40,100	37,700	37,200	28,900	27,600	26,900	369,100
2013	28,281	24,790	27,038	27,329	30,486	32,091	36,657	36,935	34,141	28,682	26,139	27,447	360,016
2014	27,180	24,500	26,665	27,300	31,135	32,260	37,943	37,402	36,451	31,800	22,700	26,450	361,786
2015	27,387	27,100	28,750	27,365	28,100	34,265	35,504	38,970	36,600	32,800	26,775	28,446	372,062
2016	28,156	26,200	27,200	27,837	29,026	36,152	39,794	39,245	33,300	30,013	27,462	28,000	372,385
2017	28,239	26,268	28,460	27,487	30,323	35,163	40,867	40,656	34,918	31,932	27,265	27,962	379,540
2018	28,235	25,413	27,574	26,746	28,609	33,563	42,266	41,279	34,368	29,374	25,619	26,384	369,430
2019	28,398	25,664	28,584	29,525	31,014	34,461	38,417	39,148	36,126	31,093	29,092	28,626	380,148
2020	28,625	25,891	28,813	29,762	31,262	34,737	38,724	39,461	36,415	31,342	29,325	28,855	383,211
2021	28,854	26,120	29,043	30,000	31,512	35,014	39,034	39,777	36,706	31,592	29,560	29,086	386,299
2022	29,085	26,351	29,276	30,240	31,765	35,295	39,346	40,095	37,000	31,845	29,796	29,319	389,412
2023	29,318	26,584	29,510	30,482	32,019	35,577	39,661	40,416	37,296	32,100	30,035	29,553	392,549

	Historic and Forecasted Monthly Peaks (MW)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Peak
2007	49	47	52	55	60	69	80	90	85	59	52	49	90
2008	48	48	48	60	74	79	75	77	76	74	51	50	79
2009	47	47	49	63	65	64	77	77	80	57	51	47	80
2010	47	48	48	49	52	59	80	86	81	67	58	48	86
2011	49	50	51	52	53	54	55	56	57	58	59	60	60
2012	61	62	63	64	65	66	67	68	69	70	71	72	72
2013	73	74	75	76	77	78	79	80	81	82	83	84	84
2014	45	47	44	52	67	67	79	78	84	65	51	46	84
2015	45	47	53	58	55	75	76	80	81	69	48	48	81
2016	50	50	49	55	58	84	80	81	75	73	56	50	84
2017	48	46	55	53	68	84	85	91	88	70	50	49	91
2018	47	53	47	53	55	77	86	86	75	67	50	47	86
2019	49	54	52	61	65	74	80	84	82	66	57	50	84
2020	49	54	52	61	65	75	81	84	82	67	58	50	84
2021	50	54	53	62	66	75	81	85	83	67	58	51	85
2022	50	55	53	62	66	76	82	85	83	68	58	51	85
2023	50	55	53	62	66	76	82	86	84	68	59	51	86

APPENDIX C: POWER COST SUPPLY SIMULATIONS
(Monthly Power Supply Costs $)

Base Case - With Biogas													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
2013/14	3,342,263	3,860,797	3,573,853	3,224,435	3,465,833	3,000,335	2,798,369	2,809,674	2,810,546	2,652,514	3,006,245	3,258,493	37,803,358
2014/15	2,987,443	3,590,615	3,447,583	3,684,837	2,673,178	2,594,672	2,374,206	2,614,680	2,542,255	4,558,226	2,732,100	2,497,388	36,297,184
2015/16	3,330,396	3,339,667	3,155,044	3,507,622	2,678,199	2,810,657	2,774,633	2,795,480	2,979,548	4,799,766	2,899,344	2,753,018	37,823,374
2016/17	3,104,674	3,536,196	3,489,171	3,780,860	2,933,652	2,970,766	2,855,059	3,128,700	2,960,834	5,027,678	2,980,919	3,164,827	39,933,335
2017/18	3,257,767	3,494,587	3,307,704	3,553,854	2,838,199	2,817,252	2,430,959	2,794,279	2,417,140	4,629,941	2,616,034	2,456,181	36,613,897
2018/19	2,874,561	3,111,755	2,911,406	3,117,851	2,347,960	2,336,463	2,299,638	2,666,133	2,284,777	4,458,719	2,420,896	2,607,706	33,437,866
2019/20	2,848,332	3,090,832	2,880,864	3,121,647	2,365,337	2,442,760	2,284,457	2,619,540	2,448,618	4,630,530	2,610,475	2,826,039	34,169,431
2020/21	3,131,212	3,379,023	3,165,877	3,377,838	2,600,597	2,677,810	2,514,719	2,667,923	2,498,184	4,675,070	2,658,988	2,879,415	36,226,657
Base Case - Laying off Biogas													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
2013/14	3,342,263	3,860,797	3,573,853	3,224,435	3,465,833	3,000,335	2,801,528	2,809,674	2,810,546	2,652,514	3,006,245	3,258,493	37,806,517
2014/15	2,987,443	3,590,615	3,447,583	3,684,837	2,673,178	2,594,672	2,385,816	2,614,680	2,542,255	4,558,226	2,732,100	2,497,388	36,308,794
2015/16	3,330,396	3,339,667	3,155,044	3,507,622	2,678,199	2,810,657	2,785,193	2,795,480	2,979,548	4,799,766	2,899,344	2,753,018	37,833,934
2016/17	3,104,674	3,536,196	3,489,171	3,780,860	2,933,652	2,970,766	2,856,388	3,128,700	2,960,834	5,027,678	2,980,919	3,164,827	39,934,663
2017/18	3,257,767	3,494,587	3,307,704	3,553,854	2,838,199	2,817,252	2,430,959	2,794,279	2,417,140	4,629,941	2,616,034	2,456,181	36,613,897
2018/19	2,874,561	3,111,755	2,911,406	3,117,851	2,347,960	2,336,463	2,299,638	2,666,133	2,284,777	4,458,719	2,420,896	2,607,706	33,437,866
2019/20	2,678,607	2,937,532	2,711,139	2,957,397	2,195,612	2,278,510	2,114,732	2,449,815	2,284,368	4,460,805	2,446,225	2,656,314	32,171,056
2020/21	2,961,487	3,225,723	2,996,152	3,213,588	2,430,872	2,513,560	2,344,994	2,498,198	2,333,934	4,505,345	2,494,738	2,709,690	34,228,282
Geothermal Case - With Biogas													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
2013/14	3,342,263	3,860,797	3,573,853	3,224,435	3,465,833	3,000,335	2,801,528	2,809,674	2,810,546	2,652,514	3,006,245	3,258,493	37,806,517
2014/15	2,987,443	3,590,615	3,447,583	3,684,837	2,673,178	2,594,672	2,385,816	2,614,680	2,542,255	4,558,226	2,732,100	2,497,388	36,308,794
2015/16	3,330,396	3,339,667	3,155,044	3,507,622	2,678,199	2,810,657	2,785,193	2,795,480	2,979,548	4,799,766	2,899,344	2,753,018	37,833,934
2016/17	3,104,674	3,536,196	3,489,171	3,780,860	2,933,652	2,970,766	2,856,388	3,128,700	2,960,834	5,027,678	2,980,919	3,164,827	39,934,663
2017/18	3,257,767	3,494,587	3,307,704	3,553,854	2,838,199	2,817,252	2,430,959	2,794,279	2,417,140	4,629,941	2,616,034	2,456,181	36,613,897
2018/19	2,874,561	3,111,755	2,911,406	3,117,851	2,347,960	2,336,463	2,299,638	2,666,133	2,284,777	4,458,719	2,420,896	2,607,706	33,437,866
2019/20	2,848,332	3,090,832	2,880,864	3,121,647	2,365,337	2,442,760	2,284,457	2,619,540	2,448,618	4,630,530	2,610,475	2,825,553	34,168,945
2020/21	3,317,052	3,566,382	3,370,371	3,594,883	2,881,575	3,019,823	2,782,356	2,980,412	2,808,749	4,954,104	2,895,347	3,102,030	39,273,084
Base Case - Laying off Biogas													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
2013/14	3,342,263	3,860,797	3,573,853	3,224,435	3,465,833	3,000,335	2,801,528	2,809,674	2,810,546	2,652,514	3,006,245	3,258,493	37,806,517
2014/15	2,987,443	3,590,615	3,447,583	3,684,837	2,673,178	2,594,672	2,385,816	2,614,680	2,542,255	4,558,226	2,732,100	2,497,388	36,308,794
2015/16	3,330,396	3,339,667	3,155,044	3,507,622	2,678,199	2,810,657	2,785,193	2,795,480	2,979,548	4,799,766	2,899,344	2,753,018	37,833,934
2016/17	3,104,674	3,536,196	3,489,171	3,780,860	2,933,652	2,970,766	2,856,388	3,128,700	2,960,834	5,027,678	2,980,919	3,164,827	39,934,663
2017/18	3,257,767	3,494,587	3,307,704	3,553,854	2,838,199	2,817,252	2,430,959	2,794,279	2,417,140	4,629,941	2,616,034	2,456,181	36,613,897
2018/19	2,874,561	3,111,755	2,911,406	3,117,851	2,347,960	2,336,463	2,299,638	2,666,133	2,284,777	4,458,719	2,420,896	2,607,706	33,437,866
2019/20	2,678,607	2,937,532	2,711,139	2,957,397	2,195,612	2,278,510	2,114,732	2,449,815	2,284,368	4,460,805	2,446,225	2,655,828	32,170,570
2020/21	3,147,327	3,413,082	3,200,646	3,430,633	2,711,850	2,855,573	2,612,631	2,810,687	2,644,499	4,784,379	2,731,097	2,932,305	37,274,709