

2015 POWER SUPPLY INTEGRATED RESOURCE PLAN

CITY OF BANNING, CALIFORNIA



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2015 Power Supply Integrated Resource Plan City of Banning

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CITY PROFILE

The City of Banning (“City”), which compromises approximately 22.1 square miles, is located on Interstate 10 in the northwestern quadrant of Riverside County. The City is 85 miles east of Los Angeles, 27 miles east of the city of Riverside, and 20 miles west of Palm Springs. The City has a population of approximately 30,500 people.

PERSONNEL PROFILE

The City is governed by an elected five-member City Council. The City Council is the governing body for the City’s Electric Utility (“Electric Utility” or “Utility”) and approves all major operational decisions, including rate setting, operating budgets, power resource acquisitions, enhancement of distribution facilities and capital projects. The current council members are listed below.

Governing Body – Banning City Council

Debbie Franklin —Mayor
Art Welch—Mayor Pro Tem
Edward Miller—Councilmember
George Moyer—Councilmember
Don Peterson —Councilmember

Contact Persons

The Electric Utility currently has twenty-seven employees. Day-to-day operation of the Utility is managed by the Electric Utility Director. Any questions regarding this Integrated Resource Plan (“IRP”) can be directed to either of the following two Utility personnel:

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Banning, CA 92220
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The Electric Utility’s organizational profile is shown in **Appendix B**.

The policies for service, rates and fees for power provided by the Utility to its customers are determined and set by the City Council. Copies of the Utility’s current rate schedules are attached as **Appendix C**.

INTEGRATED RESOURCE PLAN PURPOSE AND GOALS

- State the Electric Utility's goals and objectives.
- Discuss the Utility's current energy and transmission resources, plus its current and forecasted five year energy and peak demand.
- Review and assess critical legislative/regulatory mandates and CAISO initiatives.
- Discuss the Utility's long-term power resource forecasts, including the influences of Resource Adequacy ("RA") needs, renewable energy and Renewable Portfolio Standards ("RPS") mandates, and Green House Gas ("GHG") mandates.
- Analyze the long-term (20-year forward) issues, and discuss the solutions that have already been executed or are still in the planning stages.

ELECTRIC UTILITY GOALS AND OBJECTIVES

- Provide reliable electric power at the lowest practicable cost, consistent with sound business principles, and in compliance with all regulatory mandates.
- Continue to participate with Southern California Public Power Authority ("SCPPA") members and other applicable utilities and agencies in California to ensure adequate resources and reliable electric service.
- Divest of the San Juan Unit 3 coal facility by December 31, 2017.
- Exceed the goal stated in the Banning Renewable Portfolio Standard of obtaining electricity from eligible renewable resources, which is currently 33% of its portfolio level by December 31, 2020. The California legislature recently passed Senate Bill 350, which mandates an RPS of 50% by 2030.

ELECTRIC SYSTEM FACILITIES

Through agreement with Southern California Edison Company ("Edison"), the Electric Utility's electric system ("Electric System") utilizes Edison's subtransmission system in bringing power from the California Independent System Operator ("CAISO") controlled high voltage transmission grid to the Electric System's distribution system at Banning Substation. The Utility owns two 34.4kV subtransmission circuits totaling approximately ten miles which feed each of the Electric System's six substations. These six substations have 27 circuits feeding approximately 145 miles of overhead and underground lines of 2,400/4,160Y volts and 7,200/12,470Y volts. Underground lines total approximately 22 miles or 15% of the total.

The Utility also has three small hydroelectric generating units located in the Banning Water Canyon. The two lower generating units were rebuilt in 2015 with a combined capacity of 0.48 MW and are waiting re-commissioning. The two units are projected to produce a total of approximately 4,000 MWh's of electricity each year. The upper generating unit is currently being evaluated to determine whether there is a cost benefit for rebuilding it. If rebuilt, the upper unit would have a capacity of 0.15 MW.

The following table sets forth information concerning voltages, capacities and circuits for the Electric System's six substations.

CITY OF BANNING ELECTRIC SYSTEM SUBSTATIONS

<u>Substation</u>	<u>Voltage</u>	<u>Capacity (MW)</u>	<u>Distribution Feeders</u>
34 – 4kV			
Alola #1	34.5 -2.4/4.16	3.75	2
Alola #2	34.5 -2.4/4.16	3.75	2
Alola #3	34.5 -2.4/4.16	2.00	1
Airport	34.5 -2.4/4.16	3.75	2
34 – 12kV			
22nd Street	34.5 -7.4/12.47	15.00	3
Midway #1	34.5 -7.4/12.47	7.50	2
Midway #2	34.5 -7.4/12.47	7.50	2
San Gorgonio #1	34.5 -7.4/12.47	10.00	2
San Gorgonio #2	34.5 -7.4/12.47	10.00	2
Sunset #1	34.5 - 7.4/12.47	25.00	5
Sunset #2	34.5 - 7.4/12.47	25.00	4

The Utility is in the design phase of converting the 4 kV substations, Alola and Airport, to 12 kV substations. This upgrade would include the installation of 69/34.5 – 12.47 kV transformers along with the installation of new protection and communication equipment. These improvements will allow the Utility to expand its distribution capabilities by increasing the capacity across power lines. Additionally, these upgrades will allow the Utility to more easily balance the Electric System by having only one distribution voltage.

TRANSMISSION RESOURCES

Transmission resources are an integral component of the Electric Utility's plan to provide economical and reliable electric service to its customers. The Utility currently has several firm capacity transmission agreements to deliver up to 26 MW of remote generation to the Utility's takeout point at the Devers 230 substation. In addition, the Utility has a Wholesale Distribution Access Tariff Agreement with Edison that allows the Utility to utilize Edison's distribution system to deliver electricity from the takeout point over the Devers 115 line to the Banning Substation to serve the Utility's entire retail customer load.

Effective January 1, 2003, the Utility turned over operational control of its high voltage and certain low voltage transmission entitlements to the CAISO, thereby becoming a Participating Transmission Owner ("PTO") in the CAISO. In exchange for the transfer of control to the CAISO of its transmission facilities and certain contractual transmission rights, the Utility was entitled to receive, until December 31, 2010, firm transmission rights commensurate with the transmission facilities and transmission rights which it turned over to the CAISO. After that time, the firm transmission rights converted to Congestion Revenue Rights, which are financial instruments used to offset congestion charges on the applicable transmission paths.

As a PTO in the CAISO, the Utility continues to own its transmission facilities and to be bound by its contractual arrangements. The CAISO provides to the Utility (as well as other participants) access to the CAISO Controlled Grid. However, the CAISO maintains operational control for the

benefit of all market participants by providing non-discriminatory transmission access, congestion management, grid security, and control area services.

The Utility is currently part owner of two transmission projects, and also has contractual arrangements for additional firm transmission. The following table summarizes these resources.

**CITY OF BANNING -- ELECTRIC UTILITY
FIRM TRANSMISSION SERVICE AGREEMENTS
As of June 30, 2015**

<u>Transmission Line / Path</u>	<u>Owner/Party</u>	<u>City's Capacity</u>	<u>Primary Use</u>
Mead – Phoenix	SCPPA	3 MW	PVNGS, Westwing, Marketplace
Mead – Adelanto	SCPPA	12 MW	PVNGS, Marketplace
Adelanto – Victorville/Lugo	LADWP	12 MW	PVNGS, Marketplace
Victorville/Lugo – Devers 230	LADWP	8 MW	PVNGS, Marketplace
Mead 230 – Dever 230	Edison	2 MW	Hoover

Mead-Phoenix Transmission Project. This 256-mile, 500 kV AC transmission line, which was placed into commercial operation on April 15, 1996, extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. The line is looped through the 500-kV switchyard constructed in the existing Mead Substation in southern Nevada with an initial transfer capability of 1,300 MW. By connecting to Marketplace Substation, the Mead-Phoenix Transmission Project interconnects with the Mead-Adelanto Transmission Project and with the existing McCullough Substation. Through a contract with SCPPA, the Utility is entitled to receive 3 MW of this line's transmission capacity.

Mead-Adelanto Transmission Project. Through a contract with SCPPA, the Utility is entitled to 12 MW of transmission capacity from this 202 mile, 500 kV AC transmission line, which was placed into commercial operation on April 15, 1996. This arterial line extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation. By connecting to Marketplace Substation, the line interconnects with the Mead-Phoenix Transmission Project and the existing McCullough Substation in southern Nevada. The line has an initial transfer capability of 1,200 MW.

Adelanto-Victorville/Lugo. The Utility has a contract with the Los Angeles Department of Water and Power ("LADWP") for 12 MW of firm transmission service which extends and connects the Mead-Adelanto Transmission Project to the Victorville/Lugo transmission path. This contract has a fixed price of \$0.27 per kW Month or \$3,240 per month, based on a 12 MW entitlement.

Victorville/Lugo-Devers 230. The Utility has two contracts with Edison for a total of 8 MW of firm transmission service which provides transmission for the Utility's Palo Verde Nuclear Generating Station entitlement, as well as import of additional market purchases. The cost for this service is determined based on Edison's Transmission Revenue Requirement ("TRR") and is adjusted each year. Currently the cost is \$4.67 per kW month or \$37,360 per month for an 8 MW entitlement.

Mead 230-Devers 230. The Utility contracts with Edison for a total of 2 MW of firm transmission service which provides transmission for the Utility’s Hoover entitlement. The cost for this service is determined based on Edison’s TRR and is adjusted each year. Currently the cost is \$4.67 per kW month or \$9,340 per month for a 2 MW entitlement.

EXISTING POWER SUPPLY RESOURCES

Peak demand for the Electric Utility increased annually from 41.9 MW in Fiscal Year 2010 to 46.9 MW in Fiscal Year 2013. Peak demand in Fiscal Year 2014 decreased to 40.5 MW. The decline in peak demand was due to a very mild summer, which resulted in lower demand for air conditioning. For Fiscal Years 2010 through 2015, total annual load increased from 140,770 MWh to 148,465 MWh.

As discussed above under the caption “Electric System Facilities,” the City has three small hydroelectric generating units which had previously operated infrequently and did not significantly contribute to the Electric Utility’s supply resources. However, with the two lower units being rebuilt in 2015, they will produce approximately 4,000 MWh per year, or three percent of the Utility’s power supply requirements.

The principal supply resources for the Utility are derived from the Utility’s membership in SCPPA, a joint powers authority. The Utility has purchased portions of two generating units through SCPPA consisting of (i) Unit 3 of the San Juan Generating Station (“San Juan Unit 3”), and (ii) the Palo Verde Nuclear Generating Station, Units 1, 2 and 3 and associated facilities (“PVNGS”). Additionally, the Utility has long-term contracts through SCPPA for (i) direct entitlements to the output of hydroelectric generating plants at the Hoover Dam (“Hoover Upgrading Project”), and (ii) certain power purchase agreements between SCPPA and two divisions of Ormat Technologies, Inc. relating to two geothermal energy facilities located in the Imperial Valley of California (the “Ormat Geothermal Projects”). In addition, the Utility also makes energy purchases in the wholesale market to cover its summer peaking energy and capacity requirements.

In anticipation of the shutdown of San Juan Unit 3 (which will be discussed in more detail later), the City Council approved power sales agreements to obtain capacity and energy from two new SCPPA projects, which will provide the capacity and energy needed to replace the San Juan resource. The two agreements include a 9 MW share of the Puente Hills Landfill Gas-to-Energy Facility (“Puente Hills Landfill Project”), and an 8 MW share of the RE Astoria 2 Solar Project (“Astoria 2 Solar Project”). Both of these facilities are certified renewable energy through the California Energy Commission (“CEC”) and will begin providing capacity, energy and associated renewable attributes to the Utility beginning in 2017. These two agreements are standard power purchase contracts, and do not have a “take or pay” provision.

The following table sets forth certain information regarding the Utility's power supply resources during the Fiscal Year ended June 30, 2015.

**CITY OF BANNING
ELECTRIC SYSTEM POWER SUPPLY RESOURCES
(Fiscal Year Ended June 30, 2015)**

<u>Source</u>	<u>Capacity Available (MW)</u>	<u>Actual Energy (MWh)</u>	<u>Percent of Total Energy</u>
Joint Powers Agency (SCPPA)			
San Juan	20.0	133,509	64.2%
PVNGS	2.0	19,308	9.3
Hoover	<u>2.0</u>	<u>1,588</u>	<u>0.8</u>
Subtotal	24.0	154,405	74.3
Purchased Power			
CAISO	N/A	30,245	14.6
Ormat	3.4	<u>22,951</u>	<u>11.1</u>
Subtotal		53,196	25.7
Total	27.4	207,601	100%

As noted, the Electric Utility is a member of SCPPA, a joint powers authority created for the planning, financing, acquiring, constructing, operating and maintaining of electric generating and transmission projects for participation by some or all of its members. Through its membership in SCPPA, the Utility is a participant in the following projects:

San Juan Unit 3 Power Plant

- Ownership through Joint Participation in SCPPA Project
- Capacity and Energy
20MW; 147,070 MWh annual
- Anticipated divestiture on December 31, 2017

The San Juan Generating Station consists of a four unit, coal fired steam electric generating plant located near the town of Farmington in San Juan County, New Mexico. The combined net generating capacity of the four units is 1,800 MW. San Juan Unit 3 has a maximum gross rated capacity of 540 MW and net capacity of 497 MW. The four units were put into operation between 1976 and 1982. In 1993, SCPPA and five of its members negotiated a purchase agreement with Century Power Corporation under which SCPPA purchased a 41.8% interest in San Juan Unit 3 and related common facilities of the San Juan Generating Station, entitling SCPPA to approximately 208 MW of power generated by San Juan Unit 3. SCPPA entered into power sales contracts with five members of SCPPA, including the Electric Utility. Under these power sales contracts, SCPPA sells 100% of its entitlement to capacity and energy of San Juan Unit 3 on a "take or pay" basis. The Utility has a 9.8% (20 MW) entitlement in SCPPA's interest in San Juan Unit 3. SCPPA financed its interest in Unit 3 by issuing revenue bonds in an aggregate principal amount of \$237,375,000, of which approximately \$42,935,000 in aggregate principal amount were outstanding as of June 1, 2015.

In Fiscal Year 2015, San Juan Unit 3 provided 133,509 MWh of energy to the Utility at an average cost of delivered energy of \$64.45 per MWh.

In June 2014, the nine owners of the San Juan Generating Station reached a non-binding agreement in principle on an ownership restructuring of the San Juan Generating Station, which if implemented, would result in the shutdown of Units 2 & 3 by December 31, 2017 as part of the overall settlement of matters regarding emissions at San Juan. Most, but not all, of the regulatory approvals and other conditions have been obtained or satisfied in order to implement this proposed ownership restructuring.

In December 2014 SCPPA successfully closed the refunding of the San Juan Power Project's 2005 Refunding Series A Bonds, which resulted in gross savings of \$6.3 million and an NPV of \$4.95 million, and a new final maturity of January 1, 2017. This ensures that all San Juan Unit 3 related debt will be paid off prior to the unit shutting down December 31, 2017.

In June 2015, the nine owners of San Juan Generating Station completed developing the binding agreements necessary for the final restructuring of ownership and the shutdown of Units 2 & 3 by December 31, 2017. The individual owners obtained final approval through their various governing boards as of July 31, 2015, and are awaiting final FERC approval, which is expected shortly.

Palo Verde Nuclear Power Plant

- Ownership through Joint Participation in SCPPA Project
- Capacity and Energy
2MW; 16,750 MWh annual

Through its participation in SCPPA, the Electric Utility has an entitlement to the Palo Verde Nuclear Generating Station near Phoenix, Arizona. SCPPA, pursuant to the Arizona Nuclear Power Project ("ANPP") Participation Agreement, has a 5.91% interest in PVNGS, consisting of Units 1, 2 and 3 and certain associated facilities and contractual rights, a 5.56% ownership interest in the ANPP High Voltage Switchyard and contractual rights, and a 6.55% share of the rights to use certain portions of the ANPP Valley Transmission System in order to transmit PVNGS power to its members which are participating in the project.

SCPPA has sold the entire capability of SCPPA's interest pursuant to power sales contracts with certain of its members, including the Utility. Under the PVNGS power sales contract, the participants are entitled to SCPPA generation capability based on their respective PVNGS entitlements and are obligated to make payments on a "take or pay" basis.

Commercial operation and initial deliveries from PVNGS Units 1, 2 and 3 commenced in January 1986, September 1986 and January 1988, respectively. Transmission is accomplished through agreements with Salt River Project Agricultural Improvement and Power District, LADWP and Edison. SCPPA had outstanding approximately \$36,130,000 aggregate principal amount of bonds with respect to PVNGS as of June 1, 2015.

In response to increased competition in the electric utility business, in 1997 SCPPA began taking steps designed to accelerate the payment of all fixed rate bonds relating to PVNGS by July 1, 2004 (the "PVNGS Restructuring Plan"). Such steps consisted primarily of refunding certain outstanding bonds for savings and accelerating payments by the PVNGS project participants on the bonds issued by SCPPA for PVNGS. The PVNGS Restructuring Plan accomplishes substantial savings to

the PVNGS project participants from and after the time the principal of an interest on such fixed rate bonds were paid or provision for the payment thereof was made (i.e., from and after July 1, 2004). Under the PVNGS Restructuring Plan, the delivered cost of energy produced by PVNGS decreased significantly on July 1, 2004.

The Utility has a 1.00% entitlement interest (2 MW) in SCPPA's ownership interest in the PVNGS, the ANPP High Voltage Switchyard and the ANPP Valley Transmission System. In Fiscal Year 2015, PVNGS provided 19,308 MWh of energy to the Utility at an average cost of delivered energy of \$42.01 per MWh.

Hoover Upgrading Project

- Joint Participant in SCPPA Project
- Capacity and Energy
2MW; 1,874 MWh annual
- Expires October 1, 2067

The Electric Utility participated in the Hoover Upgrading Project which consisted principally of the upgrading of the capacity of 17 generating units at the hydroelectric power plant of the Hoover Dam, which is located approximately 25 miles from Las Vegas, Nevada. Modern insulation technology made it possible to "uprate" the nameplate capacity of existing generators. The United States Bureau of Reclamation (the "Bureau") owns and operates the Hoover Dam facility and the Western Area Power Association ("WAPA") markets the power from the facility. The Utility and certain other members of SCPPA obtained entitlements to capacity and associated firm energy which they assigned to SCPPA by agreement dated March 1, 1986 in return for SCPPA's agreement to make advance payments to the Bureau on behalf of such members. The entitlements of the Utility and these SCPPA members currently total 94 MW of capacity and approximately 107,000 MWh of associated energy annually from the Hoover Upgrading Project. As of June 1, 2015, SCPPA has outstanding approximately \$6,095,000 aggregate principal amount of bonds with respect to the Hoover Upgrading Project. The Utility has an entitlement of approximately 2 MW. In Fiscal Year 2015, the Hoover Upgrading Project provided 1,588 MWh of energy to the Utility at an average cost of delivered energy of \$35.86 per MWh.

Ormat Geothermal Projects

- Joint Participant in SCPPA Project
- Capacity and Energy
3.4 MW; 28,560 MWh annual
- Expires December 31, 2031

In 2005, SCPPA entered into a power purchase agreement (the "Ormat Power Purchase Agreement") with OrHeber 2, Inc., which is a division of Ormat Technologies, Inc. ("Ormat"). This agreement provides for the purchase of 10 MW of electric generation from a geothermal energy facility located in the Heber area of the Imperial Valley of California. In turn, pursuant to certain power sales agreements (the "Ormat Power Sales Agreements"), SCPPA agreed to sell the energy purchased by it to four of its members, including the Electric Utility. The Utility's contract share of the purchased power is 1 MW or 10% of the total 10 MW output. Under the Utility's Ormat Power Sales Agreement, the Utility pays an initial cost for delivered energy of \$57.50 per MWh, with an annual increase of 1.5%.

The Ormat Power Purchase Agreement and the Ormat Power Sales Agreements (including the City's Ormat Power Sales Agreement) have terms of 25 years from January 1 immediately following the commercial operation dates for the geothermal energy facilities. The Heber facility was completed and commenced delivering energy in January 2006, and thus the agreements relating to that facility have an expiration date of January 1, 2032.

In 2008 Ormat requested, and the SCPPA participants agreed to substitute the generating facility supplying power related to the Ormat Power Purchase Agreement. The new geothermal facility which provides power per the Agreement is the "Heber South" generating facility, which has a capacity of 14 MW versus the original Heber facility's 10 MW. The Utility's share continues to be 10%, but the actual capacity increased from 1 MW to 1.4 MW. Additionally, the Utility agreed to take 2 MW of capacity from the original Heber facility, under the same terms and conditions, thereby additionally increasing its overall capacity from 1.4 MW to 3.4 MW. With this change in facilities and increased capacity, there was an update in the pricing of the power, the original pricing methodology applies to the first 9.5 MW delivered each hour, but electricity in excess of 9.5 MW delivered any hour will be charged at an initial price of \$76 per MWh, with an annual increase of 1.5%. All other aspects of the Ormat Power Purchase Agreement remain unchanged. In Fiscal Year 2015, the Utility purchased 22,951 MWh of energy pursuant to its Ormat Power Sales Agreement at an average cost of delivered energy of \$75.54 per MWh.

FORWARD MARKET POWER PURCHASES

In addition to power supply resources associated with the Electric Utility's participation in SCPPA projects, the Utility has made energy purchases in the forward market to cover its summer peaking energy and capacity requirements. In this regard, the Utility evaluates responses to requests for proposal from various energy suppliers and selects the supplier providing the most economical cost. There is no assurance that the Utility will participate in forward market purchases in the future. For the past several years, the Utility has found that it has been more cost effective to purchase needed peaking energy in the CAISO wholesale markets. The Utility will continually monitor the CAISO wholesale markets for signs of price increases or unacceptable price volatility, and may accordingly adjust its strategies for covering and/or hedging the Utility's summer peaking energy requirements.

FUTURE POWER RESOURCES

General. The Electric Utility's current resources meet its customer demand in the months of October through May ("Winter Months"). Summer peaking requirements are purchased for the months of June through September. The quantity of peaking power actually purchased fluctuates depending on load projections. Current Utility resources are expected to cover demand during the Winter Months until San Juan Unit 3 shuts down December 31, 2017. As previously noted, the Electric Utility executed power sales agreements with SCPPA for power to replace that which was being lost with the shutdown of the San Juan Unit 3 facility. Those two projects, which will begin providing capacity and power to the Utility in 2017, are described in more detail below.

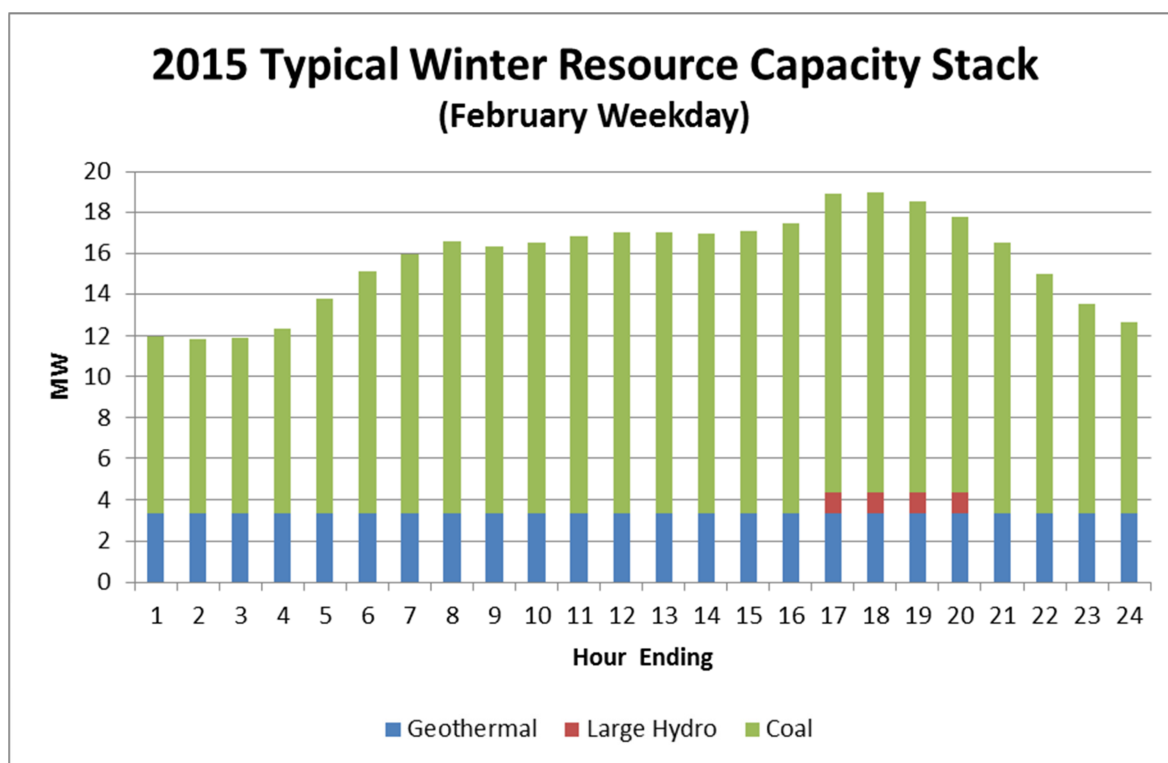
Puente Hills Landfill Gas-to-Energy Facility. The Puente Hills Landfill Gas-to-Energy Facility is an existing facility that is currently under contract with Edison. SCPPA has negotiated to start taking the output from the facility, which has a nameplate capacity of 46 MW, as of January 1, 2017. The Utility's share of the project will be 20.9302% or approximately 9.6 MW of the nameplate capacity. However, because the Puente Hills Landfill has shut down and is no longer accepting waste, the actual capacity of the facility will decrease each year at an estimated rate of 4-6%, as the

available “fuel” is depleted. The projected capacity of the facility for 2017 is estimated at 41.5 MW, which will result in the Utility receiving approximately 8.7 MW of capacity and associated energy. The project has a fixed price of \$80 per MWh and a term of 13 years. The facility is located in Los Angeles County (Whittier) near the interchange of the I-605 and CA-60 freeways, and will interconnect with the CAISO’s system at Edison’s Hillgen Substation.

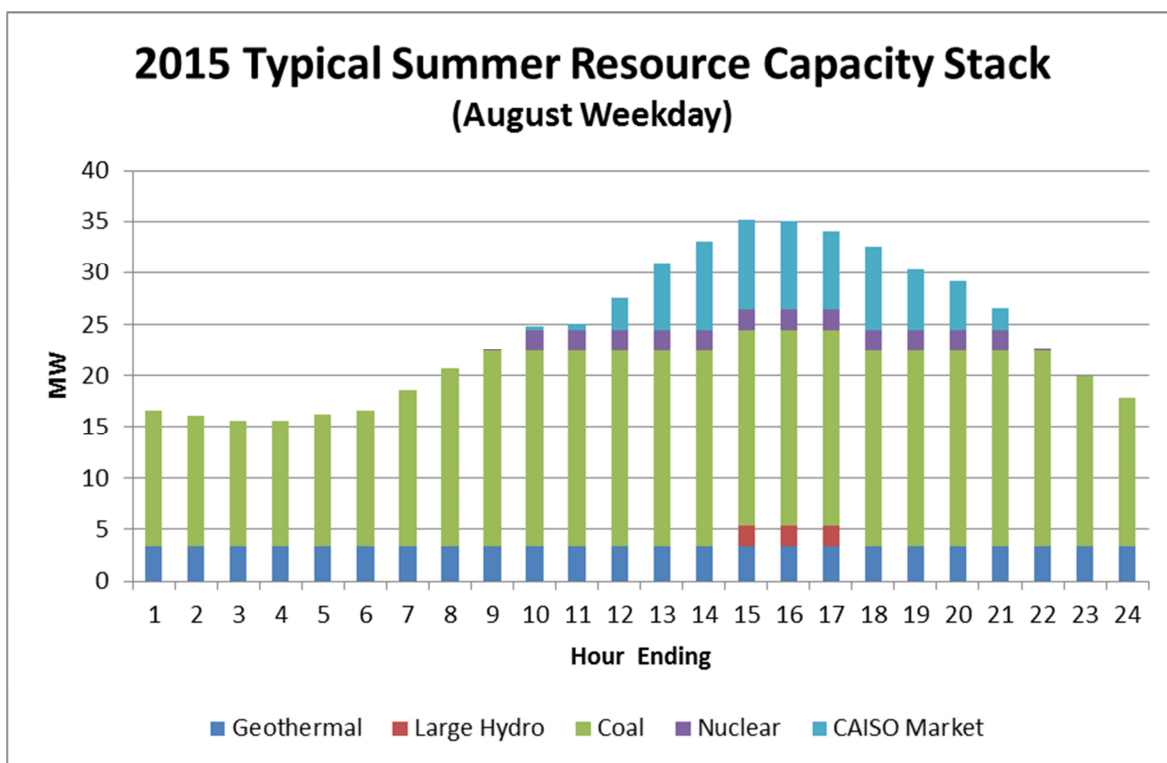
RE Astoria 2 Solar Project. The RE Astoria 2 Solar Project is being developed by Recurrent Energy (which has developed other renewable energy projects for SCPPA) and the project is scheduled to begin commercial operation in 2017. The project will be 75 MW and is the second phase of a larger project that was developed for Pacific Gas & Electric. The Utility’s share of the project will be 11% or 8 MWs of capacity. The project has a fixed price of \$63 per MWh and a term of 20 years. It is sited on approximately 840 acres in California on the border between Los Angeles and Kern Counties, and will interconnect with the CAISO system at Edison’s Whirlwind Substation.

CURRENT TYPICAL RESOURCE STACK

The following chart shows the Utility’s current resource stack for a typical day in the Winter Months. Since the Electric Utility has more than enough resources to cover its typical winter, spring, and fall loads, the Utility has no exposure to market price shocks during the majority of the year. The Utility’s resources that are not used to serve load are sold into the CAISO markets.

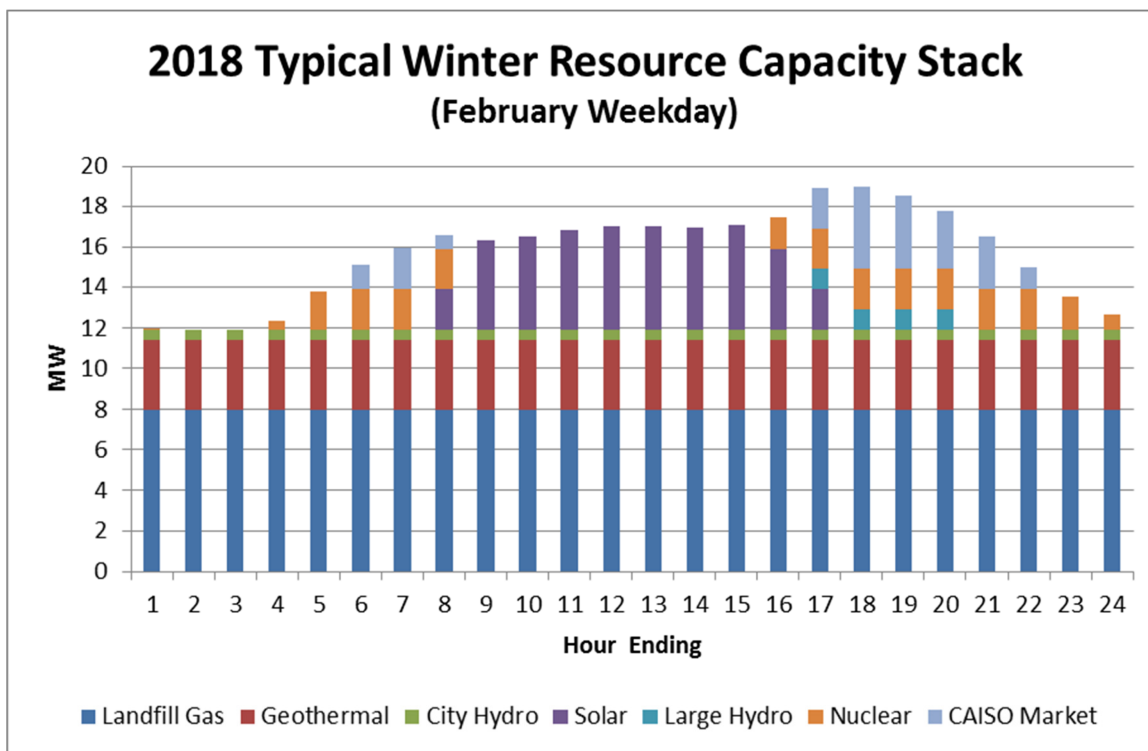


The following chart shows the Utility's current resource stack for a typical summer day. The Utility's resources are not adequate to consistently cover the peak hours from Hour Ending 10 to Hour Ending 21. In previous years, the Utility has contracted to purchase energy in the forward markets to cover these hours where the Utility is short peaking resources. However, over the last several years, the Utility has found that it is more economical to cover these summer peak shortages by purchasing energy in the CAISO wholesale markets. Since the Utility has the energy resources to cover the majority of its typical summer load, and is only short resources for the peak summer hours on unusually hot days, the Utility's exposure to market price shocks is minimal. The Utility purchases capacity in the forward markets in order to meet its CAISO RA requirements, which are 115% of its projected monthly peaks.



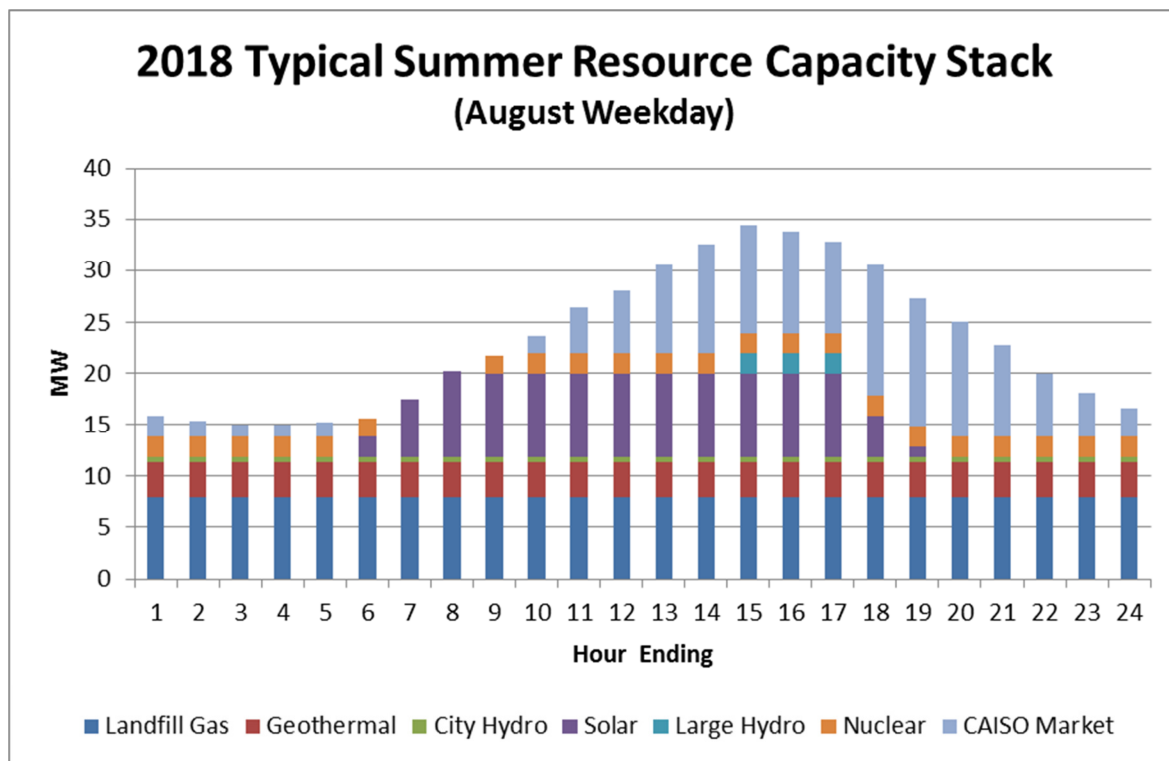
PROJECTED TYPICAL RESOURCE STACK POST SAN JUAN UNIT 3

The following chart shows the projected Electric Utility's resource stack for a typical day in the Winter Months after the divestiture of San Juan Unit 3. As discussed above, the energy from San Juan Unit 3 will be replaced by a combination of landfill gas energy and solar energy. There are several hours just prior to and after the daytime solar energy production when the Utility will need to purchase a minimal amount of energy from the CAISO markets.



The following chart shows the projected Electric Utility's resource stack on a typical summer day after the divestiture of San Juan Unit 3. As previously discussed, the Utility has found that during the last several summers it has been more cost effective to cover the summer-peak-hour resource shortages by purchasing energy in the CAISO wholesale markets. This strategy was especially optimal in the summer of 2015 due to the low mid-day real-time prices related to the overproduction from solar generation.

However, the Utility will closely monitor the CAISO markets to make sure that this strategy will continue to be optimal. If the energy prices in the CAISO markets begin to increase or become more volatile, the Utility will analyze other options to hedge this risk, such as once again purchasing energy in the forward markets.



LOAD INFORMATION

Historical and 5-Year Load Forecast:

The previous 5 year IRP covering the period from 2010 – 2014 conveyed information regarding the load forecast for the Electric Utility with an eye towards recovery from the Great Recession. Although the nation and the State have undergone a slow but steady recovery from the Great Recession, the former load projections have not materialized. The previous IRP had projected an annual load of 158,102 MWh in 2014, whereas the actual load was 148,465 MWh. There are several reasons that the load forecast missed the mark, including (i) although there has been an economic recovery, it has not been felt as strongly in the City; (ii) there was no major development in the City from 2010 – 2014; (iii) the City lost its largest industrial customer in 2010; (iv) conservation, energy efficiency programs, and improved energy efficiency technologies have reduced demand; and (v) the

increase in rooftop solar.

Although the load projections did not meet the previous IRP forecasts, the annual load did increase from 140,770 MWh in 2010 to 148,465 MWh in 2014, an increase of 5.5%. From 2010 through 2014 the annual peak demand has been variable, ranging from 40.9 MW to 46.9 MW. This variability in peak demand is directly related to weather conditions, depending upon how hot of a summer the City experiences.

The Utility is forecasting very modest annual load and peak demand increases from 2015 through 2019. These forecasted increases are based upon the assumption of a continued economic recovery. Also driving the forecasted increases are new and planned development in the City's civic center. In 2015, the Superior Court of California opened a new 68,584 square foot courthouse in the City's civic center. Additionally, the City is expecting new commercial development to support the staff and visitors of the new courthouse.

The historical peak demand and annual loads are shown in the two tables below.

Banning Peak Demand		
<u>Year</u>	<u>MW</u>	<u>%</u>
2010	45.0	-
2011	44.3	-1.6%
2012	46.9	+5.9%
2013	40.9	-12.8%
2014	42.4	+3.7%

Banning Energy Load (MWh)						
	2009	2010	2011	2012	2013	2014
Jan	11,041	10,754	10,846	10,627	11,356	10,891
Feb	9,985	9,583	9,788	9,950	9,928	9,629
Mar	10,625	10,471	10,262	10,352	10,495	10,245
Apr	10,410	9,850	9,801	10,073	10,484	10,147
May	12,316	10,416	10,385	11,474	11,598	11,670
Jun	11,423	11,977	11,643	12,634	13,578	13,295
Jul	17,463	15,317	15,088	15,674	16,804	16,839
Aug	16,048	15,911	16,836	18,582	16,565	16,007
Sep	15,002	13,748	14,201	15,409	14,308	15,498
Oct	10,671	11,074	11,648	11,743	10,849	12,350
Nov	10,106	10,454	10,353	10,271	10,350	10,455
Dec	<u>11,197</u>	<u>11,215</u>	<u>11,533</u>	<u>11,271</u>	<u>11,438</u>	<u>11,439</u>
Total:	146,287	140,770	142,384	148,060	147,753	148,465
		-3.8%	1.1%	4.0%	-0.2%	0.5%

The Utility's five-year forecasted annual loads and peak demands are shown in the tables below.

CITY OF BANNING
Projected Load Data 2015 - 2019

	Actual Load - 2013				Actual Load - 2014		2015 ⁽¹⁾	
	Total Load	Peak	Date of		Total Load	Peak	Total Load	Peak
	for Month	MW	Peak	Time	for Month	MW	for Month	MW
Jan	11,356	20.2	1/10/2013	19:00	10,891	19.6	10,997	19.5
Feb	9,928	20.2	2/8/2013	19:00	9,629	19.2	9,525	18.5
Mar	10,495	19.6	3/8/2013	19:00	10,245	17.6	10,714	20.3
Apr	10,484	21.8	4/29/2013	15:00	10,147	19.8	10,129	22.0
May	11,598	30.6	5/13/2013	16:00	11,670	28.4	10,630	25.3
Jun	13,578	40.9	6/30/2013	15:00	13,295	34.7	14,114	38.8
Jul	16,804	39.7	7/9/2013	16:00	16,839	41.8	14,425	34.9
Aug	16,565	40.5	8/21/2013	16:00	16,007	40.2	17,238	42.7
Sep	14,308	40.2	9/3/2013	15:00	15,498	42.4	14,590	42.0
Oct	10,849	21.3	10/1/2013	15:00	12,350	29.5	12,265	30.7
Nov	10,350	19.4	11/21/2013	18:00	10,455	19.7	10,569	19.9
Dec	11,438	22.1	12/9/2013	19:00	11,439	21.2	11,622	22.0
TOTAL:	147,755				148,465		146,818	
	2016		2017		2018		2019	
	Total Load	Peak	Total Load	Peak	Total Load	Peak	Total Load	Peak
	for Month	MW	for Month	MW	for Month	MW	for Month	MW
Jan	11,137	19.8	11,193	19.9	11,249	20.0	11,305	20.1
Feb	9,742	19.4	9,791	19.5	9,840	19.6	9,889	19.7
Mar	10,537	19.3	10,590	19.3	10,643	19.4	10,696	19.5
Apr	10,305	21.3	10,356	21.4	10,408	21.6	10,460	21.7
May	11,356	28.2	11,413	28.4	11,470	28.5	11,527	28.6
Jun	13,731	38.3	13,799	38.5	13,868	38.7	13,938	38.9
Jul	16,103	39.0	16,183	39.2	16,264	39.4	16,346	39.6
Aug	16,687	43.8	16,770	44.0	16,854	44.2	16,938	44.5
Sep	14,873	41.7	14,947	41.9	15,022	42.1	15,097	42.4
Oct	11,881	27.3	11,940	27.4	12,000	27.6	12,060	27.7
Nov	10,510	19.7	10,562	19.8	10,615	19.9	10,668	20.0
Dec	11,557	21.9	11,615	22.0	11,673	22.1	11,731	22.2
TOTAL:	148,418		149,160		149,906		150,655	
⁽¹⁾ January through October 2015 are actual numbers.								

Load Profile Information

The Electric Utility serves approximately 12,000 metered customers. The Utility's load is divided amongst the customer classes as follows:

Commercial—43%

- Time-of-Use—8%
- Large Demand—8%
- Small Demand and General—27%

Residential—47%

Other—10%

Energy Sales by Customer Class (kWh)

<u>Cal Year</u>	<u>Residential</u>	<u>Commercial</u>	<u>Industrial</u>	<u>Public Use</u>	<u>Total</u>	<u>% Change</u>
2009	68,090,000	38,986,000	17,542,000	11,790,000	136,408,000	
2010	65,417,000	40,392,000	16,907,000	10,326,000	133,042,000	-2.47%
2011	65,980,000	37,124,000	18,603,000	10,856,000	132,563,000	-0.36%
2012	69,554,000	37,570,000	22,145,000	10,137,000	139,406,000	5.16%
2013	66,885,000	37,101,000	24,949,000	9,081,000	138,016,000	-1.00%
2014	67,086,000	38,515,000	22,964,000	14,936,000	143,501,000	3.97%

IMPORTANT LEGISLATIVE AND REGULATORY MANDATES

WAPA Regulations Applicable to Banning

Resource reporting was mandated by the Energy Policy Act of 1992. The Act required all WAPA customers to submit a report to WAPA every five years. Due to policy changes, the Electric Utility transitioned to the Minimum Investment Report in 2012. However, the Electric Utility chose to prepare this IRP because prudent industry practice warrants reviewing and updating the IRP for the utility at least every five years.

Renewable Portfolio Standard

Senate Bill X1 2 (“SBX1 2”), the “California Renewable Energy Resources Act,” was signed into law by Governor Jerry Brown on April 12, 2011. SBX1 2 codifies the RPS target for retail electricity sellers to serve 33% of their loads with eligible renewable energy resources by 2020. As enacted, SBX1 2 makes the requirements of the RPS program applicable to local publicly-owned electric utilities (“POUs”) (rather than just prescribing that POUs meet the intent of the legislation as under previous statutes). However, the governing boards of POUs are responsible for implementing the requirements, rather than the CPUC, as is the case for the IOUs. In addition, the CEC is given certain enforcement authority for POUs and CARB is given the authority to set penalties.

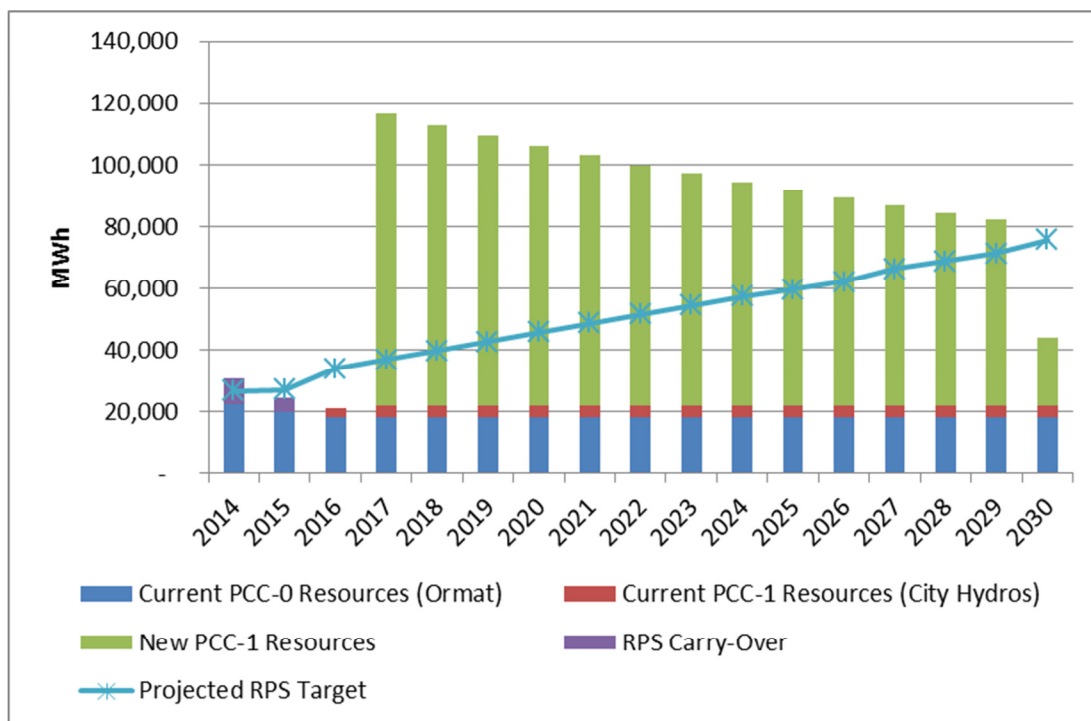
SBX1 2 requires each POU to adopt and implement a renewable energy resource procurement plan. As set out in more detail in the CEC’s RPS enforcement regulation, noted below, the plan must require the utility to procure at least the following amounts of electricity products from eligible

renewable energy resources, which may include renewable energy certificates (“RECs”), as a proportion of total kilowatt hours sold to the utility’s retail end-use customers: (i) over the 2011-2013 compliance period, an average of 20% of retail sales from January 1, 2011 to December 31, 2013, inclusive; (ii) over the 2014-2016 compliance period, a total equal to 20% of 2014 retail sales, 20% of 2015 retail sales, and 25% of 2016 retail sales; (iii) over the 2017-2020 compliance period, a total equal to 27% of 2017 retail sales, 29% of 2018 retail sales, 31% of 2019 retail sales, and 33% of 2020 retail sales.

Senate Bill 350 was signed into law by Governor Jerry Brown on October 7, 2015. Senate Bill 350 increased the RPS standard to 50% by 2030. The bill also sets intermediate goals of 40% by 2024 and 45% by 2027. As previously noted, the City’s resource mix will be approximately 75% renewable energy on or before December 31, 2017.

The bar graphs in the following chart show the Utility’s current and projected renewable energy resources. The blue line in the chart shows the Utility’s projected RPS targets, based upon the mandated RPS percentage targets and upon projected retail sales. As the chart indicates, the Utility will exceed the targets from 2017 through 2029. The one challenging year that the Utility is not projected to meet the RPS target is 2016. The Utility has several options for dealing with this challenge: (i) Solicit to buy more energy from the Ormat Geothermal Projects; (ii) purchase additional PCC-1 energy in the open markets, along with sufficient PCC-2 and PPC-3 RECs; or (iii) invoke one of the Utility’s optional compliance mechanisms, such as its Cost Limitations Policy.

The chart indicates that the Utility will also not meet the RPS target in 2030, due to the expiration of the Puente Hills Landfill Project contract. However, the Utility will most likely have replaced that energy with additional renewable energy. Even if the Utility did not procure additional renewable energy in 2030, the Utility would still be able to comply with the RPS mandate by carrying forward the excess RECs banked due to the over-compliance in previous years.



AB 32 – CALIFORNIA GHG REDUCTION MANDATE

Then Governor Schwarzenegger signed Assembly Bill 32, the Global Warming Solutions Act of 2006 (the “GWSA”), which became effective as law on January 1, 2007. The GWSA prescribed a statewide cap on global warming pollution with a goal of returning to 1990 greenhouse gas emission levels by 2020. In addition, the GWSA established an annual mandatory reporting requirement for all IOUs, POU’s and other load-serving entities (electric utilities providing energy to end-use customers) to inventory and report greenhouse gas emissions to the California Air Resources Board (“CARB”), required CARB to adopt regulations for significant greenhouse gas emission sources (allowing CARB to design a “Cap & Trade” system) and gave CARB the authority to enforce such regulations beginning in 2012.

On December 11, 2008, CARB adopted a “scoping plan” to reduce greenhouse gas emissions. The scoping plan set out a mixed approach of market structures, regulation, fees and voluntary measures. The scoping plan included a Cap & Trade program. The scoping plan is required to be updated every five years. CARB issued the proposed first update to the scoping plan update on February 10, 2014, which was approved by CARB on May 22, 2014. The scoping plan update recommends that a plan to extend the Cap & Trade program beyond 2020 be developed by 2017. In addition, CARB approved a resolution at its October 25, 2013 board meeting that directs CARB’s executive officer to develop a plan for a post-2020 program, including a cost containment mechanism, before 2018.

On October 20, 2011, CARB adopted a regulation implementing the Cap & Trade program. The Cap & Trade regulation became effective on January 1, 2012. Emission compliance obligations under the regulation began on January 1, 2013. The Cap & Trade program covers sources accounting for 85% of California’s greenhouse gas emissions, the largest program of its type in the United States.

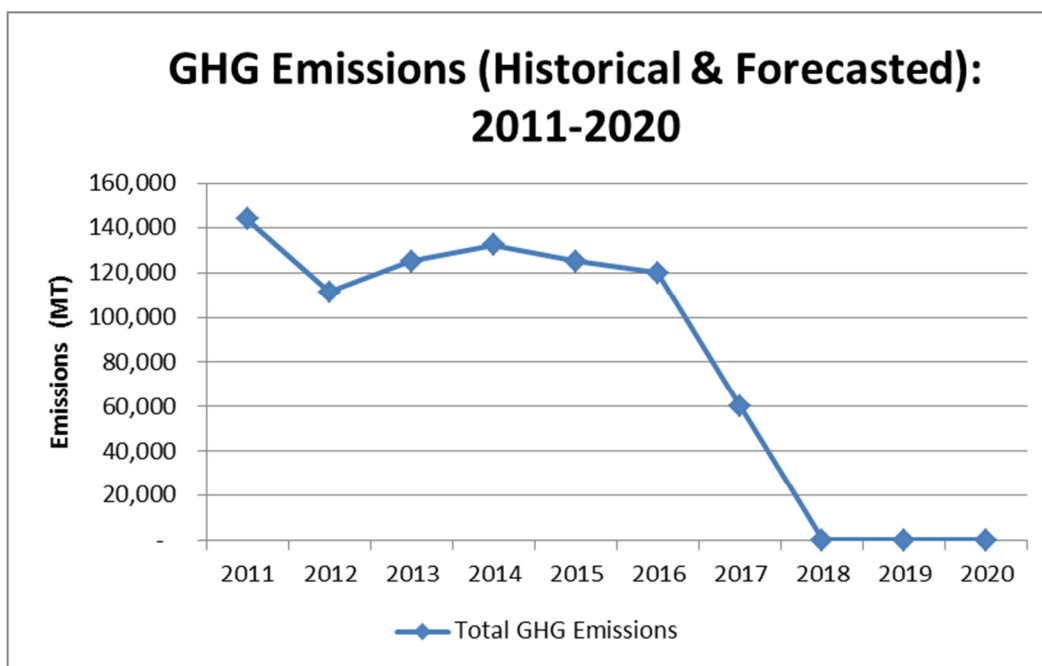
The Cap & Trade program is being implemented in phases. The first phase of the program (January 1, 2013 to December 31, 2014) introduced a hard emissions cap covering emissions from electricity generators, electricity importers and large industrial sources emitting more than 25,000 metric tons of carbon dioxide-equivalent greenhouse gases (“CDE”) per year. In 2015, the program is being expanded to cover emissions from transportation fuels, natural gas, propane and other fossil fuels. The cap will decline each year until the end of the program currently scheduled for 2020 unless otherwise extended, as expected, through an act of the State legislature.

The Cap & Trade program includes the distribution of carbon allowances equal to the annual emissions cap. Each allowance is equal to one metric ton of CDE. As part of a transition process, initially, most of the allowances were distributed for free. Additional allowances are being auctioned quarterly (auctions began in November 2012). Utilities can acquire more allowances at these auctions or on the secondary market.

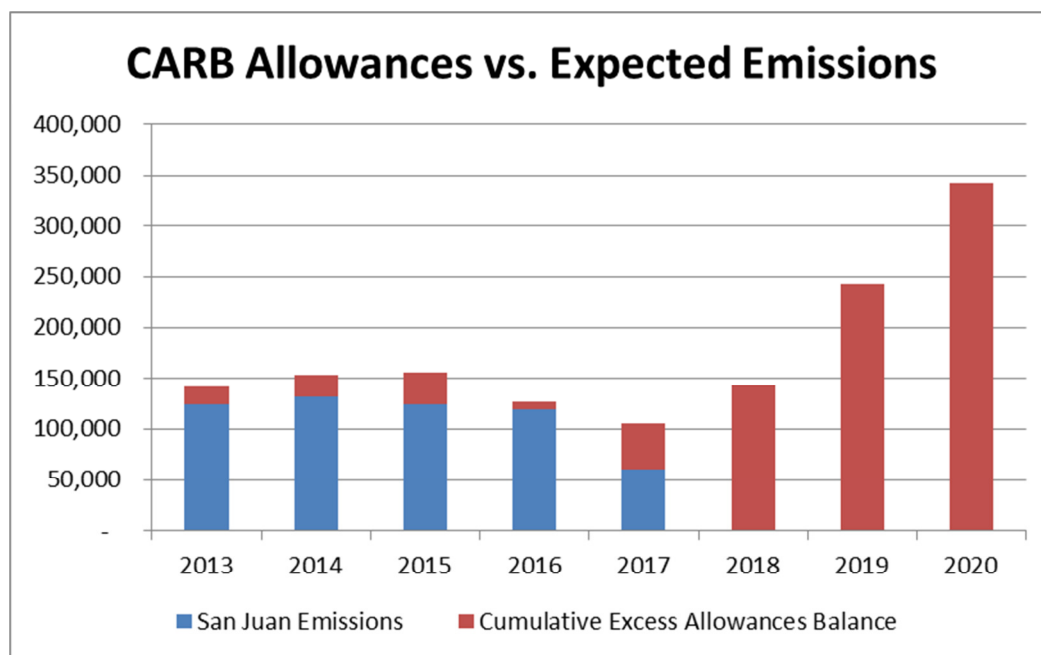
The Electric Utility is unable to predict at this time the full impact of the Cap & Trade program over the long-term on the Utility or on the electric utility industry generally or whether any additional changes to the adopted program will be made. Since the advent of the Cap & Trade program in 2012, regulations by the CARB have provided the electric sector, including the Utility, with nearly sufficient allocated greenhouse gas allowances or credits to cover existing operations in meeting retail load obligations. As a result, there have been minimal to moderate additional costs to the Utility in managing the need for additional allowances required for retail obligations. However, with the Utility’s divestiture of San Juan Unit 3, scheduled for December 31, 2017, and the execution of the power sales agreements for renewable energy to replace San Juan, the City’s resource mix will be

approximately 75% renewable energy and nearly 90% emissions free (the Palo Verde Nuclear and Hoover Large Hydro generating facilities, while not considered renewable energy, do not produce emissions). This will result in a significant reduction in the potential adverse impact of the Cap & Trade program and any other State or Federal program.

The following chart shows the historical and forecasted GHG emissions for which the Utility will have a Cap & Trade compliance obligation. The projections assume that San Juan Unit 3 will only produce approximately half of its usual output in its final year of operation. This assumption is based upon the fact that the maintenance on San Juan Unit 3 will likely drop off in the year prior to it being decommissioned.



The following chart shows both (i) the covered Cap & Trade emissions liability of the Utility due to electricity imported into California from the San Juan Unit 3 coal plant; and (ii) the ***cumulative*** amount of ***excess*** Cap & Trade allowances that the Utility will have after submitting the required allowances to the CARB to cover each year's emissions liability. Due to the fact that the Utility will continue to receive its allotment of free allowances after the divestiture of San Juan Unit 3, the Utility is projected to start banking a substantial amount of excess allowances beginning in 2018. The value of these excess allowances would offset a portion of the costs associated with the premature closure of San Juan Unit 3. The Utility would be able to use the value of these excess allowances for the benefit of its ratepayers.



SB 1368 – EMISSION PERFORMANCE STANDARD

Senate Bill 1368 became effective as law on January 1, 2007. It provides for an emission performance standard (“EPS”), restricting new investments in baseload fossil fuel electric generating resources that exceed the rate of greenhouse gas emissions for existing combined-cycle natural gas baseload generation. Senate Bill 1368 allows the CEC to establish a regulatory framework to enforce the EPS for POUs such as the Utility. The CEC regulations prohibit any investment in baseload generation that does not meet the EPS of 1,100 pounds of carbon dioxide per MWh of electricity produced, with limited exceptions for routine maintenance, requirements of pre-existing contractual commitments, or threat of significant financial harm.

In January 2012, the CEC initiated a review of the regulations for enforcement of the EPS for POUs to ensure there is adequate review of investments in facilities that do not meet the EPS. On March 19, 2014, the CEC issued its Final Conclusions in the EPS proceeding. The CEC proposed to require each POU to file an annual notice identifying all investments over \$2.5 million that it anticipates making during the subsequent 12 months on non-EPS compliant baseload facilities to comply with environmental regulatory requirements. This requirement would be waived for any POU that has entered into a binding agreement to divest within five years of all baseload facilities

exceeding the EPS. A final regulatory package was unanimously adopted at the CEC's June 18, 2014 business meeting.

CAISO FLEXIBLE RESOURCE ADEQUACY INITIATIVE (FRAC/MOO)

Given the increasing amount of intermittent resources, such as solar and wind, that are anticipated to come online in the foreseeable future, CAISO is anticipating significant changes in operational needs within its system. Historically, utilities and the CAISO have dealt with supply uncertainty by imposing a Resource Adequacy margin that each utility must meet; normally 15% additional capacity above the monthly peak demand of each load serving entity.

In response to the issue of increasing intermittent resources, in 2015 the CAISO started imposing a flexible RA requirement for each load serving entity (flexible resources are capable of ramping up and down quickly to respond to intermittent resources.) In order to meet this new flexible RA requirement, in the normal course of buying its annual system RA products the Utility has made sure that the RA products that they purchase possess the flexible attribute. Since flexible RA products are only slightly more expensive than standard system RA products, this change has had minimal effects upon the operating costs of the Utility.

ENERGY EFFICIENCY PROGRAMS

The Utility's Public Benefits department administers low-income assistance programs as well as rebate programs for energy efficiency. During the most recent fiscal year, Banning spent \$107,978 in Energy Efficiency programs, which have provided 75,066 kWh in energy savings. It should be noted that the City is located in an economically disadvantaged area. A significant portion of the City's population is either low income or senior citizens living on a fixed income. Due to the economic demographics of the City's population, the City Council has given guidance to the Utility to make assistance to low-income customers a priority. Therefore, a significant portion of Public Benefits dollars are utilized to provide low-income assistance through reduced rates.

The following is a list of the primary programs offered by the Utility's Public Benefits department.

Program Descriptions

- Air Conditioner: Monetary incentives to replace an existing central air conditioning unit with a new high-efficiency unit.
- EnergyStar® Appliances: Monetary incentives for purchasing products that meet the Energy Star® criteria.
- EnergyStar® Refrigerator: A monetary incentive for replacing an old inefficient refrigerator with a new energy efficient unit.
- Recycle: Rebates offered to remove and recycle operating old and inefficient refrigerators and freezers.
- Energy Weatherization: Monetary incentives to replace inefficient materials with products that will improve the energy efficiency of their facility and reduce energy use.

- Shade Tree: Rebates offered to plant shade trees around homes to help reduce the amount of energy used for air conditioning.
- Commercial Programs: Monetary incentives for commercial customers to install more energy-efficient equipment such as lighting, signage, refrigeration, etc.
- New Construction: Monetary incentives for new construction projects that exceed the energy efficiency above California's Title 24 standards.
- Energy Audits: Provides customers with a variety of recommendations for reducing energy consumption.
- Low Income Assistance: An electric utility reduced Baseline Rate for qualified customers. As mentioned above, a significant portion of the Public Benefits funds are spent providing low income assistance.

Major Program Changes

One of Banning's current goals is to expand participation in its commercial retrofit and refrigeration programs, primarily through the adoption of significantly increased monetary incentives. To accomplish this goal, in 2015 the Utility implemented a new program for business customers called the Business Energy Efficiency Funds, or "B.E.E.F." For businesses deciding to participate in the program, an independent energy-efficiency specialist conducts a small-business energy survey to identify lighting, refrigeration, motors, air conditioning tune-ups, and other qualifying potential energy-efficiency upgrades. There is no cost to the business for this energy survey. A report is generated listing recommended energy-efficient retrofits. Each recommendation includes the cost to perform the retrofit, anticipated annual energy savings, and simple payback.

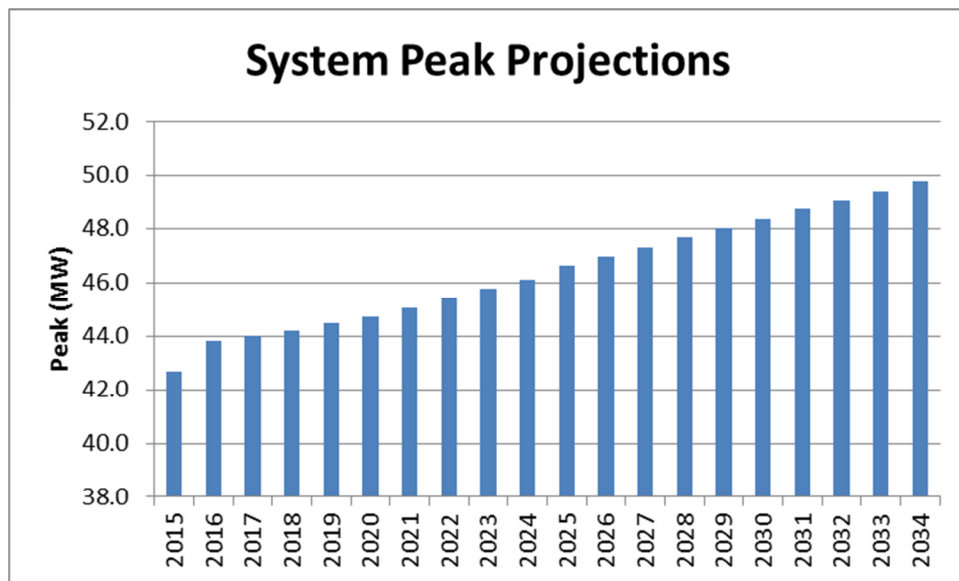
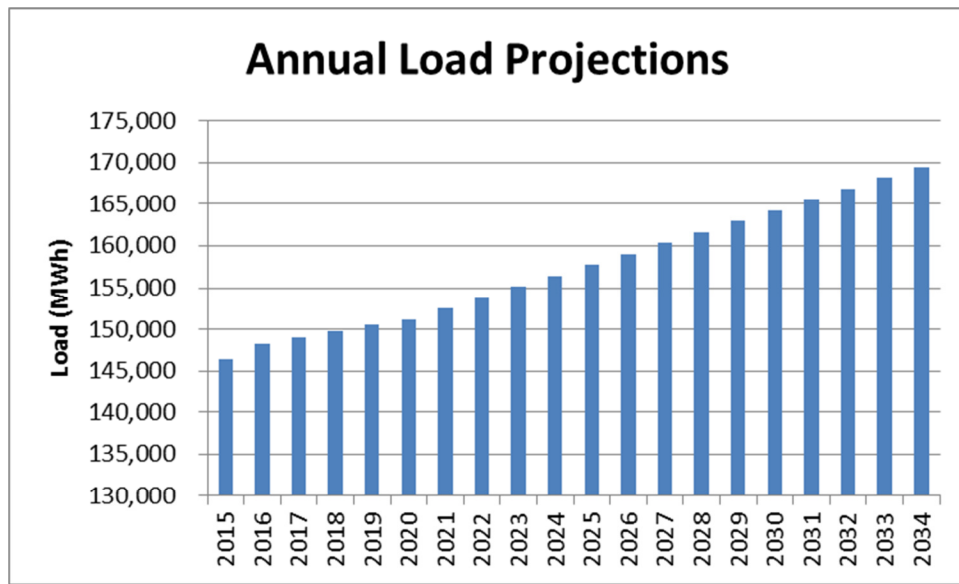
Businesses will then have the option to select the recommendations they consider a priority to install, based upon the anticipated savings and the cost of the energy-efficiency upgrades. Once the selection is finalized, certified installers are scheduled to complete the work at the facility. The Utility will pay up to \$2,750 for the recommended retrofits selected, with no or minimal copays to the business. The following table gives examples of the copays at differing levels of upgrade costs:

Upgrade Costs	Business's Copay	Amount Paid by Utility
\$1,000	\$0	\$1,000
\$2,000	\$100	\$1,900
\$3,000	\$250	\$2,750

The B.E.E.F. program has been well received by the City's business community, and participation has been strong.

LONG-TERM FORECASTS

The Utility expects to continue losing some load to distributed generation such as customer-owned solar. However, the load projections are expected to grow in the future due to the planned development of several large housing communities starting in the next several years. The Rancho San Geronio project is planning on developing 3,385 single-family dwellings. The Butterfield – Pardee Homes project is scheduled to build 4,862 single-family dwellings. For the annual load and peak projections shown in the charts below, it was assumed that two hundred new houses would be built each year from 2020 through the end of the projection period. It was also assumed that there would be additional commercial development to support the increased population.



IMPORTANT SECONDARY RESOURCE PLANNING ISSUES

Customer PV Solar

Under Senate Bill 1, the Electric Utility was mandated to spend \$1.96 million of Public Benefits funds to provide rebates for the installation of photovoltaic systems. The Electric Utility has already exceeded this mandate, providing \$2.5 million in solar rebates prior to 2014.

In response to the State of California's goal of reaching 12,000 MWs of distributed solar by 2020, combined with the declining cost curves of rooftop solar over the past several years, the Utility has seen an accelerating increase in the number of customers installing rooftop solar. As of October 2015, the Utility had 183 customers with rooftop solar, equaling 1.1 MWs of output capacity.

The current net energy metering structure that is standard in California has resulted in cross-subsidies between solar and non-solar customers. Non-solar customers appear to be paying an inordinate portion of the fixed costs of running a utility and maintaining the grid and distribution systems. The City Council has given guidance that the Utility should avoid cross-subsidies between customers whenever possible. As part of the Utility's Cost of Service Analysis that is planned to be conducted in 2016, this issue of solar cross-subsidization will be evaluated and addressed.

Energy Storage

Assembly Bill No. 2514 ("AB 2514") requires each local publicly owned electric utility to initiate a process to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems to be achieved by December 31, 2016, and December 31, 2021. AB 2514 indicates that publicly owned electric utilities need only adopt energy storage procurement targets if the targets are deemed to be appropriate, technologically viable, and cost effective. AB 2514 states that the governing board of each publically owned electric utility shall adopt procurement targets, if determined to be appropriate, by October 1, 2014, and reevaluate this determination not less than once every three years.

To comply with AB 2514, in March of 2012 the Electric Utility officially opened proceedings to determine if it was appropriate for the Electric Utility to set energy storage procurement targets. In conjunction with SCPPA, the Electric Utility hired a third-party consultant, Navigant Consulting, Inc. ("Navigant") to perform a study on the costs and benefits of current energy storage technologies. Navigant created a framework and decision making tool for identifying, quantifying, and monetizing the benefits of energy storage systems. The Electric Utility utilized this tool in assessing the cost effectiveness and viability of procuring energy storage systems by the established target dates. Additionally, the SCPPA Energy Storage Working Group provided SCPPA members with their energy storage research paper entitled "Summary Review of the Technological Capabilities and Economics of Energy Storage System Development."

Based upon the modeling performed with the Navigant decision making tool, together with the SCPPA Energy Storage Working Group research, the Electric Utility determined that procuring energy storage systems is not cost effective at this time. Accordingly, on September 23, 2014, the City Council adopted Resolution No. 2014-65, indicating that the Electric Utility will not be adopting energy storage procurement targets at this time, due to the lack of cost-effective options. The Electric Utility will continue to monitor the energy storage industry as it matures, and will

reevaluate the cost effectiveness of energy storage systems as the cost structures decline and/or as the benefits increase.

Electric Vehicles

The State of California has set a goal of having 1.5 million zero emission vehicles on the roads by 2025. It is anticipated that the majority of these zero emission vehicles will be electric vehicles. As battery storage technology improves, the costs for electric vehicles will continue to decline, which will result in a higher participation in electrical vehicle ownership within the Utility's territory. In anticipation of these changes, the City recently received a grant to have an electrical vehicle public charging station constructed in the McDonald's parking lot. In connection with the Utility's Cost of Service Analysis that is scheduled to be conducted in 2016, the impact of electric vehicle charging on the Utility's costs will be analyzed, and appropriate rate structures will be identified.

The Utility, along with SCPPA and its other members, are working together to facilitate the electrification of the transportation sector throughout the region. The goals of these efforts include:

- Developing a set of industry-accepted Best Practices in electric vehicle program development and adoption programs to create a consistent platform and structure for utilities to implement transportation electrification plans and implementation strategies.
- Creating programs that provide a seamless transition for consumers to move into the electric vehicle market through education and assistance on the purchasing, ownership, operation and maintenance of electric cars and trucks.
- Continuing to assess the need and economic viability of utility investment(s) in charging equipment and infrastructure with consideration of public and private partnerships, government and private grants, government surcharges and other possible alternatives.

SUMMARY AND CONCLUSIONS

The last five years have been challenging for California electric utilities, including the City's Electric Utility. New and evolving technologies, such as distributed rooftop solar and battery storage, are changing the landscape of the electric utility industry. More pertinent to the Utility, the increase in governmental regulatory programs has created numerous challenges for the Utility, and has applied upward pressure upon the Utility's operating expenses. The last five years have seen the implementation of the State of California's Cap & Trade program and the State's RPS program. Additionally, the federal Environmental Protection Agency has imposed strict regulatory mandates upon the San Juan Generating Station.

Fortunately, the Utility's decision to divest itself of San Juan Unit 3 has provided solutions to the majority of these regulatory challenges. After San Juan Unit 3 has been divested by December 31, 2017, the Utility will no longer own or be a party to power purchase agreements for energy produced with fossil fuels, and therefore will no longer have a compliance obligation under the Cap & Trade program. Additionally, since the Utility has chosen to replace the energy from San Juan Unit 3 with all renewable energy, the Utility will have greatly exceeded the mandates of the RPS program. Once the Puente Hills Landfill Project and the Astoria 2 Solar Project come online in 2017, the Utility's energy portfolio will contain renewable energy greater than 70% of retail sales, already far exceeding the State's RPS mandate of 50% renewable energy by 2030.

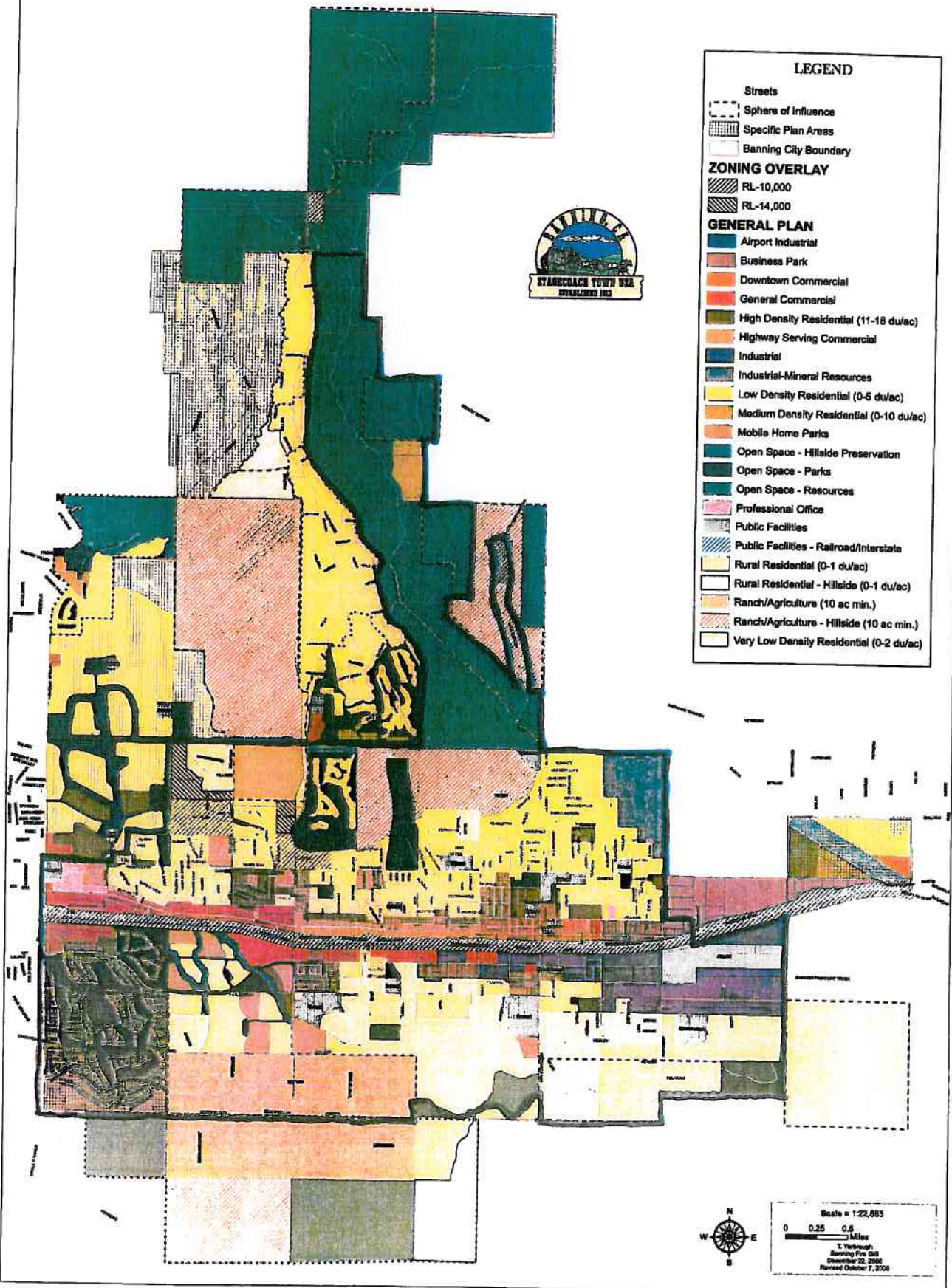
The Utility still faces several challenges, though. If the Rancho San Gorgonio and Butterfield – Pardee Homes residential projects come to fruition, and the Utility’s annual loads and summer peaks increase as projected, sometime in the early-to-mid 2020’s the Utility may need to augment its strategies for covering/hedging its summer peaking requirements. Additionally, The Puente Hills Landfill Project contract ends in 2030, and the Ormat Power Sales Agreement ends in 2031. The Utility will eventually need to begin planning to replace these resources. However, these challenges are further out into the future. Currently, the Electric Utility is extremely well positioned to meet its energy needs and its regulatory obligations for the next five years and beyond.

PUBLIC PARTICIPATION

Banning holds bi-monthly City Council meetings open to the public. Meetings are held on the second and fourth Tuesday of every month. Meeting agendas are published and posted at City Hall and on the City website the week prior to the meeting.

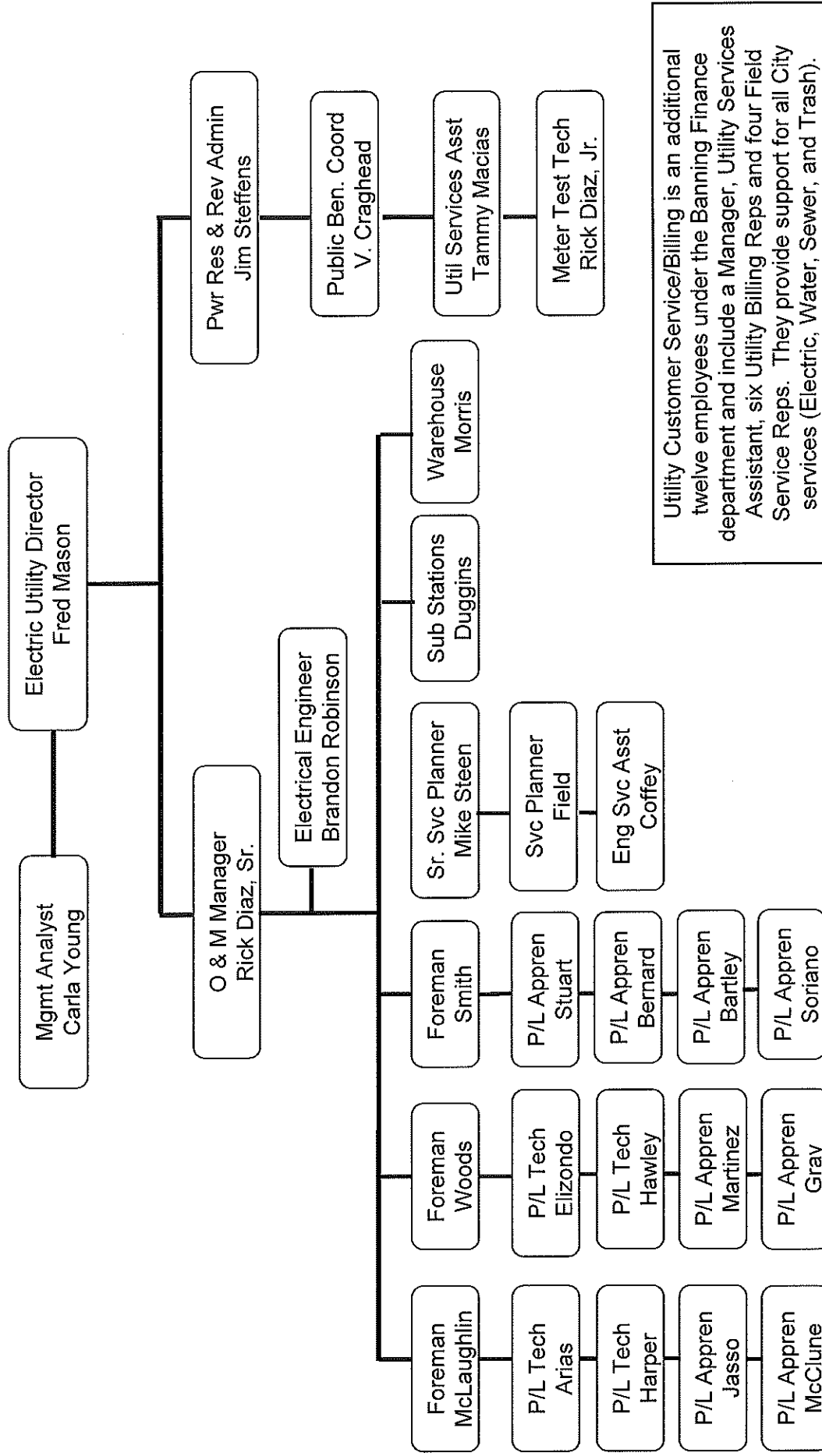
APPENDIX A – MAP OF UTILITY SERVICE AREA

CITY OF BANNING GENERAL PLAN WITH ZONING OVERLAY



APPENDIX B – ELECTRIC UTILITY ORGANIZATIONAL CHART

City of Banning – Electric Utility Department



APPENDIX C – CURRENT RATE SCHEDULES

CITY OF BANNING

ELECTRIC UTILITY RATE SCHEDULE

May 2013

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CITY OF BANNING
Electric Division

GENERAL PROVISIONS

A) SYSTEM COST ADJUSTMENT FACTOR

The System Cost Adjustment Factor (SCAF) is a charge per kWh that is used to ensure an adequate revenue stream to cover all costs incurred by Banning's electric system, and will be assessed to all customer classes. System costs will include: Power purchases, debt service, transmission, distribution and O&M expense, as well as all overhead costs of the electric system including inter-fund transfers.

The SCAF shall be calculated quarterly for the periods (January-March, April-June, July-September, and October-December) and shall become effective the first day of the 2nd quarter following the calculated period (i.e. January-March SCAF would become effective July 1st).

The SCAF shall be determined using the following formula and be expressed to the nearest \$0.0001 per kWh:

$$\text{SCAF} = (a+b+c+d-e)/f$$

Where:

a = revenue from retail sales during the period.

b = revenue from bulk sales to other utilities.

c = fees collected from contractors in aid of construction or for other services provided.

d = miscellaneous revenues.

e = total cost of Banning's electric system including power purchases, debt service, transmission, distribution and operating expense, as well as all overhead costs of the electric system including inter-fund transfers.

f = the retail energy sales during the period in kWh.

SCAF will not exceed \$0.02/kWh during any quarter. The uncollected revenue in excess of the \$0.02 cap, if any, will be carried over as an expense in the next quarter. The Electric Utility shall maintain an operating reserve of \$3M. Surplus revenue, if any, collected during any fiscal year, will be set aside in the Capital Improvement fund for system upgrades and future improvements.

B) PUBLIC BENEFITS CHARGE

All bills rendered under the above rate shall be subject to the Public Benefits Charge as established by the City Council.

General Provisions (continued)

C) SEASONS

The Summer season shall commence at 12:00 a.m. on the first day in June and continue until 12:00 a.m. on the first day in October of each year. The Winter season shall commence at 12:00 a.m. on the first day in October of each year and continue until 12:00 a.m. on the first day in June of the following year. Utility bills generated during each applicable season will reflect any appropriate seasonal rate variances.

CITY OF BANNING
Electric Division

SCHEDULE A

RESIDENTIAL SERVICE

A) APPLICABILITY

This schedule is applicable to single family and multiple family accommodations devoted primarily to domestic use, and includes services for lighting, cooking, heating and power consuming appliances.

B) CHARACTER OF SERVICE

Alternating current with regulated frequency of 60 hertz, delivered at 120 or 240 volts, single phase, as may be specified by the Division.

C) TERRITORY

Within the area served by the City of Banning

D) RATES

	<u>Per Meter Per Month</u>
Customer Charge	\$ 3.00
Energy Charge	<u>Per kWh</u>
Baseline Service	
All kWh	\$.1688
Low Income Qualified Baseline Service	
All kWh as described below	\$.0972
Non-baseline Service (Winter)	
All kWh above baseline through 1,000	\$.2190
All kWh above 1,000	\$.2880
Non-baseline Service (Summer)	
All kWh above baseline through 1,500	\$.2190
All kWh above 1,500	\$.2880

Schedule A – Residential Service (continued)

Non-baseline service includes all kWh in excess of applicable baseline allowance as described below.

E) MINIMUM CHARGE

The Customer Charge plus the Energy Charge shall be subject to a minimum charge of \$3.00 per billing cycle.

F) MINIMUM REQUIREMENTS

1. Meter: All services shall be through one meter.

2. Multiple Family Dwellings

Whenever two or more individual family accommodations (in an apartment house, duplex, court, mobile home park, etc.) receive electric service from the Division through a master meter, the service shall be billed under this Schedule. The customer charge per month will be \$3.00 multiplied by the number of individual dwelling units served. The baseline service allocation shall be 308 kWh per month multiplied by the number of individual dwelling units served, plus additional baseline kWh as specified below. In no case shall the base rate billing be less than the Minimum Charge.

3. Energy Surcharge

The charges in the above rate are subject to California State Energy surcharge tax and shall be adjusted accordingly.

G) LOW INCOME SENIOR CITIZEN SERVICE

Upon application to the City, each eligible low-income senior citizen (62 years or older) residential customer shall pay a customer charge of \$1.00 only. The customer shall notify the City when the conditions of the application are no longer valid.

H) LOW INCOME QUALIFIED BASELINE SERVICE

Upon application to the City, each approved low-income residential customer shall be placed on the Low Income Qualified Baseline rate as described below. The customer shall be required to recertify their eligibility on an annual basis. Failure to recertify will result in removal from the Low Income Qualified Baseline rate.

I) BASELINE SERVICE

All domestic customers on this schedule are entitled to an allocation of a baseline quantity of electricity that is necessary to supply the minimum energy needs of the average residential user. The total baseline allocation to a customer is the sum of all

Schedule A – Residential Service (continued)

applicable baseline quantities described in items 1 through 6 shown below. However, the Low Income Qualified Baseline rate will only be applied to items 1 and 2. If a Low Income Qualified customer is also eligible for items 3 through 6, any baseline allocation in excess of 1 and 2 will be charged at the regular Baseline Service rate:

	kWh Per <u>Month</u>
1. For basic standard residential use	308
2. For air conditioning use during June through September.	250
3. For life support devices	500
4. For all-electric residential heat use during November through March	498
5. For all-electric basic residential use (year around)	150
6. For residential water-well pump use (year around)	500

The all-electric residential heat allowance applies only to residences in which the sole source of heat consists of electric resistance heating. Upon application to the City, the account of each eligible customer shall be provided with the all-electric allocation, including heat use and the year around basic residential use to cover water heaters and cooking.

J) LIFE SUPPORT DEVICES

1. Medical Baseline Allocation: Upon application to the City, the account of each eligible residential customer will be provided a year-around Medical Baseline Allocation.
 - a. Eligibility: For an account to be eligible for the standard Medical Baseline Allocation, the residential customer will provide certification as set forth in Paragraph E below to the City that:
 - (1) Regular use in the customer's home of one or more medical life support devices is essential to maintain the life of a full-time resident of the household; and/or
 - (2) A full-time resident of the household is a paraplegic, hemiplegic, quadriplegic, multiple sclerosis, or schlerodemic patient.
 - b. Life-support Devices

The account of each eligible residential customer will be provided a standard Medical Baseline Allocation following certification acceptable to the City that a full-time resident of the household requires the regular use in the customer's home of one or more life-support devices.

Schedule A – Residential Service (continued)

Life-support devices means those devices or equipment which utilize mechanical or artificial means to sustain, restore, or supplement a vital function, or mechanical equipment which is relied upon for mobility both within and outside of buildings. Life-support devices or equipment include the following:

Aerosol Tent	Electrostatic Nebulizer
Compressor	Electric Nerve Stimulator
Iron Lung	Ultrasonic Nebulizer
Pressure Pump	Motorized Wheel Chair
IPPB Machine	Kidney Dialysis Machine
Suction Machine	Respirator (all types)
Oxygen Generator (Electrically Operated)	

c. Paraplegic, Hemiplegic, Quadriplegic, Multiple Sclerosis or Scherodemic Patients

The account of each eligible residential customer, who provides certification that a full-time resident of the household is a paraplegic, hemiplegic, quadriplegic, multiple sclerosis or scherodemic patient or suffers from abnormality of centrally controlled body thermostat will be provided a standard Medical Baseline Allocation in consideration of special heating and/or cooling needs.

d. Hardship Cases

If the customer believes that the life-support device and/or a patient's space conditioning equipment (as set forth in Paragraph B and C above) requires more than 500 kWh per month to operate, the customer may apply for a higher allocation than the standard Medical Baseline Allocation. Upon receipt of such application, the City shall make a determination if any additional monthly baseline quantity is required to operate the device or equipment based on the nameplate rating and operating hours. The monthly amount of the Medical Baseline Allocation shall be increased to the number of kWh so determined.

e. Certification

The City may require the following Certification:

- (1) The Customer shall have a medical doctor or osteopath licensed to practice medicine in the State of California provide the City with a certification letter, acceptable to the City. The letter shall describe in detail the type of life-support device(s) regularly required by the patient and the utilization requirements, and/or certify that the full-time resident is a paraplegic, hemiplegic, quadriplegic, multiple sclerosis, or scherodemic patient; or
- (2) County, State, or Federal agencies, using an established notification letter to electric utilities, shall provide the City with information relative to a

Schedule A – Residential Service (continued)

patient who regularly requires the use of a life-support device in a customer's residence.

Within 15 days after acceptance of the above certification, the City will provide a Medical Baseline Allocation to the customer's account. The City may require a new or renewed application and/or certification when needed, in the opinion of the City.

f. Termination of Use

The Customer shall notify the City of termination of use of equipment or devices set forth above.

K) WATER WELL PUMPS

This allocation is for Banning Electric Utility customers that are not connected to the City's water distribution system, and have a water well onsite. Customers must request this designation, and an onsite inspection must be completed before the allocation is authorized.

CITY OF BANNING
Electric Division

SCHEDULE B

SMALL GENERAL SERVICE

A) APPLICABILITY

Applicable to service for all types of uses, including lighting, power and heating, alone or combined.

B) CHARACTER OF SERVICE

Alternating current with regulated frequency of 60 hertz single-phase, three-phase, or a combination single and three-phase served through one meter, at a standard voltage not to exceed 240 volts, or as may be specified by the Electric Division. When the energy use for this service exceeds 5,000 kWh per month, the City will install a demand meter. If the maximum demand exceeds 20.0 kW in any three months during the preceding 12 months, the service will be transferred to Schedule C.

C) TERRITORY

Within the area served by the City of Banning.

D) RATES

	<u>Per Meter</u> <u>Per Month</u>
Customer Charge	\$ 9.00
Energy Charge (to be added to Customer charge)	
All kWh, per kWh	\$.1958

E) MINIMUM CHARGE

The Customer Charge plus the Energy Charge shall be subject to a minimum charge of \$9.00 per billing cycle.

Schedule B – Small General Service (continued)

F) SPECIAL CONDITIONS

1. Voltage: Voltage will be supplied at one standard voltage.
2. Billing Demand: Billing demand shall be the kilowatts of measured maximum demand, but no less than 50 percent of the highest demand established in the preceding eleven (11) months. Billing demand shall be determined to the nearest 1/10 kW.
3. Maximum Demand Measurement: In any month shall be the maximum average kilowatt input, indicated or recorded by instruments to be supplied by the Electric Division, during any 15 minute interval in the month. Where demands are intermittent or subject to violent fluctuations, a five minute interval may be used.
4. Temporary Discontinuance of Service: Where the use of energy is seasonal or intermittent, no adjustment will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.
5. X-Ray Installations: Where the utility installs standard transformer capacity requested by the customer to serve an x-ray installation, the customer charge will be increased by \$1.00 per kva of transformer capacity requested.
6. Energy Surcharge: The charges in the above rate are subject to California State Energy surcharge tax and shall be adjusted accordingly.

CITY OF BANNING
Electric Division

SCHEDULE C

GENERAL AND INDUSTRIAL SERVICE

A) APPLICABILITY

Applicable to service for large general and industrial establishments. This schedule is limited to customers with demands below 500.0 kW. Customers with demands exceeding 500.0 kW must receive service under Schedule TOU.

B) CHARACTER OF SERVICE

Alternating current with regulated frequency of 60 hertz, three-phase, or a combination single and three-phase served through one meter, at a standard voltage not to exceed 480 volts, or as may be specified by the Electric Division. All customers will have a demand meter. If the Maximum Demand drops below 20.0 kW for 12 consecutive months, the customer will be transferred to Schedule B.

C) TERRITORY

Within the area served by the City of Banning.

D) RATES

	Per Meter Per Month <u>Summer</u>	Per Meter Per Month <u>Winter</u>
Customer Charge	\$12.00	\$12.00
Demand Charge (to be added to the Customer Charge)		
All kW of billing demand, per kW	\$17.50	\$ 11.95
Energy Charge (to be added to the Demand Charge)		
All kWh, per kWh	\$.1692	\$.1587

E) MINIMUM CHARGE

The monthly minimum charge shall be the Demand Charge.

Schedule C – General and Industrial Service (continued)

F) SPECIAL CONDITIONS

1. Voltage: Voltage will be supplied at one standard voltage.
2. Billing Demand: Billing demand shall be the kilowatts of measured maximum demand, but no less than 50 percent of the highest demand established in the preceding eleven (11) months. Billing demand shall be determined to the nearest 1/10 kW.
3. Maximum Demand Measurement: The measured maximum demand in any month shall be the maximum average kilowatt input, indicated or recorded by instruments to be supplied by the Electric Division, during any 15 minute interval in the month. Where demands are intermittent or subject to violent fluctuations, a five minute interval may be used.
4. Temporary Discontinuance of Service: Where the use of energy is seasonal or intermittent, no adjustment will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.
5. X-Ray Installations: Where the utility installs standard transformer capacity requested by the customer to serve an x-ray installation, the customer charge will be increased by \$1.00 per kva of transformer capacity requested.
6. Power Factor Adjustment: When the billing demand has exceeded 200.0 kW for three consecutive months, a kilovar hour meter will be installed as soon as practicable and thereafter until the billing demand has been less than 150 kW for twelve (12) consecutive months. The charges will be adjusted each month for the power factor as follows:
 - a. Reactive Energy Charge (kvarh)

The Reactive Energy Charge shall be based on the lagging kilovar-hours (kvarh) recorded during each Billing Period, dependent upon the Average Power Factor during the billing cycle. If reactive energy is unknown, or unmetered, due to a metering malfunction then the Reactive Energy Charge will be based upon the average kvarh used from a similar billing period.

Schedule C – General and Industrial Service (continued)

b. Reactive Energy Charge Rate

Power Factor Range	Rate
0.99-1.00	\$ -
0.95-0.98	\$ 0.00088
0.90-0.94	\$ 0.00167
0.80-0.89	\$ 0.00509
0.70-0.79	\$ 0.00853
0.60-0.69	\$ 0.01185
0.00-0.59	\$ 0.01293

7. Energy Surcharge: The charges in the above rate are subject to California State Energy surcharge tax and shall be adjusted accordingly.

CITY OF BANNING
Electric Division

SCHEDULE TOU

LARGE GENERAL AND INDUSTRIAL SERVICE

A) APPLICABILITY

Applicable to service for all types of uses, including lighting, power and heating, alone or in combination. This rate shall be mandatory for customers whose monthly demand exceeds 500.0 kW for any three months during the preceding 12 months. Any customer whose monthly maximum demand has fallen below 450.0 kW for 12 consecutive months may elect to take service on any other applicable schedule. This schedule is an option for customers whose monthly demands are between 200.0 kW and 499.9 kW; however, participation for one year in the rate is required.

B) CHARACTER OF SERVICE

Alternating current with regulated frequency of 60 hertz, three-phase, or a combination single and three-phase served through one meter, at a standard voltage not to exceed 480 volts, or as may be specified by the Electric Division.

C) TERRITORY

Within the area served by the City of Banning.

D) RATES

Charges are calculated for customer billing using the components shown below:

	Per Meter <u>Summer</u>	Per Month <u>Winter</u>
Customer Charge	\$340.00	\$ 340.00
Demand Charge (to be added to Customer Charge)		
All kW of non-time related component, per kW	\$ 8.50	\$ 12.00
Plus all kW of on-peak billing demand, per kW	\$ 18.08	N/A
Plus all kW of mid-peak billing demand, per kW	\$ 4.88	\$ 0.00
Plus all kW of off-peak billing demand, per kW	\$ 0.00	\$ 0.00

Schedule TOU – Large General and Industrial Service (continued)

Energy Charge (to be added to the Customer and Demand Charges)

	<u>Summer</u>	<u>Winter</u>
All kWh of on-peak energy, per kWh	\$.1298	N/A
Plus all kWh of mid-peak energy, per kWh	\$.0960	\$.1098
Plus all kWh of off-peak energy, per kWh	\$.0698	\$.0748

E) SPECIAL CONDITIONS

1. Time Periods: Time periods are defined as follows:

On-Peak	Noon to 6:00 p.m. summer weekdays except holidays
Mid-Peak	7:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays except holidays. 7:00 a.m. to 11:00 p.m. winter weekdays except holidays.
Off-Peak	All other hours

Holidays are New Year's Day (January 1), Washington's Birthday (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

2. Voltage: Voltage will be supplied at one standard voltage.
3. Maximum Demand: Maximum demands shall be established for on-peak, mid-peak, and off-peak periods. The maximum demand for each period shall be the measured maximum average kilowatt input, indicated or recorded by instruments to be supplied by the Electric Division, during any 15 minute interval, but (except for new customers or existing customers electing Contract Demand as defined in these Special Conditions) not less than the diversified resistance welder load computed. Where demands are intermittent or subject to violent fluctuations, a five minute interval may be used.
4. Billing demand: The Demand Charge shall include the following billing components. The Time Related Component shall be for the kilowatts of Maximum Demand recorded during the monthly billing period for each of the On-Peak, Mid-Peak, and Off-Peak time periods. The Non-Time Related Component shall be for the total kilowatts of demand recorded in the demand period with the highest Maximum Demand during the monthly billing period. Separate Demand Charges for the On-Peak, Mid-Peak, and Off-Peak time periods shall be established for each monthly billing period as applicable. The Demand Charge for each time period shall be based on the maximum demand for that time period occurring during the respective monthly billing period. The Maximum Demand shall be determined to the nearest 1/10 kW.

Schedule TOU – Large General and Industrial Service (continued)

5. Contract Demand: A contract demand will be established by the City, based on the applicant's demand requirements for any customer newly requesting service on this schedule and for any customer of record on this schedule who requests an increase or decrease in transformer capacity.

A contract demand arrangement is available upon request for all customers of record on this schedule. The contract demand will be used only for purposes of establishing the minimum demand charge for facilities required to provide service under the rate and will not be otherwise used for billing purposes.

The contract demand is based upon the nominal kilovolt-amperes rating of the City's serving transformer(s) or the standard transformer size determined by the City as required to serve the customer's stated measurable kilowatt demand, whichever is less, and is expressed in kilowatts.

6. Minimum Demand Charge: Where a contract demand is established, the monthly minimum demand charge shall be \$1.00 per kilowatt of contract, but not less than \$500.00.
7. Excess Transformer Capacity: Excess Transformer Capacity is the amount of transformer capacity requested by a customer in excess of that which the City would normally install to serve the customer's Maximum Demand. Excess Transformer Capacity shall be billed at \$1.00 per KVA per month.
8. Power Factor Adjustment: When the billing demand has exceeded 200.0 kW for three consecutive months, a kilovar hour meter will be installed as soon as practicable and thereafter until the billing demand has been less than 150 kW for twelve (12) consecutive months. The charges will be adjusted each month for the power factor as follows:

- a. Reactive Energy Charge (kvarh)

The Reactive Energy Charge shall be based on the lagging kilovar-hours (kvarh) recorded during each Billing Period, dependent upon the Average Power Factor during the billing cycle. If reactive energy is unknown, or unmetered, due to a metering malfunction then the Reactive Energy Charge will be based upon the average kvarh used from a similar billing period.

Schedule TOU – Large General and Industrial Service (continued)

b. Reactive Energy Charge Rate

Metered - per kvarh per Power Factor level below

Power Factor Range	Rate
0.99-1.00	\$ -
0.95-0.98	\$ 0.00088
0.90-0.94	\$ 0.00167
0.80-0.89	\$ 0.00509
0.70-0.79	\$ 0.00853
0.60-0.69	\$ 0.01185
0.00-0.59	\$ 0.01293

9. Temporary Discontinuance Of Service: Where the use of energy is seasonal or intermittent, no adjustment will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.
10. Supplemental Visual Demand Meter: Subject to availability, and upon written application by the customer, the City will, within 180 days, supply and install a City owned supplemental visual demand meter. The customer shall provide the required space and associated wiring beyond the point of interconnection for such installation. Said supplemental visual demand meter shall be in parallel with the standard billing meter delineated in Special Condition 3 above. The reading measured or recorded by the supplemental visual demand meter are for customer information purposes only and shall not be used for billing purposes in lieu of meter readings established by the standard billing meter. If a meter having visual display capability is installed by the City as the standard billing meter, no additional metering will be installed pursuant to this Special Condition.

One of the following types of supplemental visual demand meters will be provided in accordance with provisions above at no cost to the customer: Dial Watt-meter, Recording Watt-meter, or Paper-Tape Printing Demand Meter.

If the customer desires a supplemental visual demand meter having features not available in any of the above listed meters, such as an electronic microprocessor-based meter, the City will provide such a supplemental visual demand meter subject to monthly charge, if the meter and its associated equipment have been approved for use by the City. Upon receipt from the customer of a written application the City will design the installation and will thereafter supply, install, and maintain the supplemental visual demand meter subject to all conditions

Schedule TOU – Large General and Industrial Service (continued)

stated in the first and last paragraph of this Special Condition. For purposes of computing the monthly charge, any such supplemental visual demand meter and associated equipment shall be treated as Added Facilities. Added investment for computing the monthly charges shall be reduced by the City's estimated total installed cost at the customer location of the Paper-Tape Printing Demand Meter offered otherwise herein at no additional cost.

The City shall have sole access for purposes of maintenance and repair to any supplemental visual demand meter installed pursuant to this Special Condition and shall provide all required maintenance and repair. Periodic routine maintenance shall be provided at no additional cost to the customer. Such routine maintenance includes changing charts, inking pens, making periodic adjustments, lubricating moving parts and making minor repairs. Non-routine maintenance and major repairs or replacement shall be performed on an additional cost basis with the customer reimbursing the City for such cost.

11. Contracts: An initial three-year facilities contract may be required where an applicant requires new or added serving capacity exceeding 2,000 KVA.
12. Auxiliary/Emergency Generation Equipment: Auxiliary/ Emergency Generation Equipment is the customer-owned electrical generation equipment normally used for auxiliary, emergency, or standby electrical generation purpose. Auxiliary/Emergency Generation Equipment may be used by a customer to serve that customer's load only during a Period of Interruption, and only when such loads are isolated from the City's system. Other than for Auxiliary/Emergency generation or service, all service under this rate schedule is applicable only for service supplied by the City.
13. Removal From Schedule: Customers receiving service under this schedule whose monthly Maximum Demand has registered below 450.0 kW for 12 consecutive months may be changed to another schedule.
14. Energy Surcharge: The charges in the above rate are subject to California State Energy surcharge tax and shall be adjusted accordingly.

CITY OF BANNING
Electric Division

SCHEDULE SLS

UNMETERED STREET LIGHTING SERVICE

A) APPLICABILITY

Applicable for unmetered lighting of public streets, highways and thorough-fares, including City owned and City operated public parks and parking lots which are opened to the general public.

B) TERRITORY

Within the area served by the City of Banning.

C) RATES

<u>Customer Class</u>	<u>Monthly Charges</u>
Residential (Rate A)	\$2.00
Small Commercial (Rate B)	\$2.80
Large General & Industrial (Rate C)	\$4.45
Time-of-Use (Rate TOU)	\$6.00
Lights on abutting property	\$6.00

D) SPECIAL CONDITIONS:

The above charges shall be placed on applicable customers' City Utility bills.

CITY OF BANNING
Electric Division

SCHEDULE OLS

OUTDOOR LIGHTING SERVICE
(SECURITY)

A) APPLICABILITY

Applicable to all customers for outdoor area security lighting service furnished from dusk to dawn, supplied from existing overhead facilities. The Division will install, own operate and maintain the complete lighting installation, including customer owned support.

B) TERRITORY

Within the area served by the City of Banning.

C) RATES

Per Lamp
Per Month

(Fixture installed on existing support)

100 Watt Sodium Vapor	(9,500 Lumen)	\$ 14.29
150 Watt Mercury Vapor	(16,000 Lumen)	21.44
175 Watt Sodium Vapor	(7,000 Lumen)	25.01
200 Watt Sodium Vapor	(16,000 Lumen)	28.59
250 Watt Sodium Vapor	(25,000 Lumen)	35.73
400 Watt Mercury Vapor	(20,000 Lumen)	57.17

Per Pole
Per Month

Pole (Department owned wood pole installation)

20' or 35' Wood Pole \$ 2.95

D) SPECIAL CONDITIONS

1. Voltage: Service under this schedule will be supplied at a single-phase voltage from the Electric Department's existing overhead lines.
2. Rates: The above lamp rates are applicable to Department-owned outdoor area lighting equipment mounted on existing Department owned poles or on customer owned supports acceptable to the Department.

Schedule OLS (continued)

3. Standard Equipment: Lighting equipment will consist of a Department standard overhead outdoor sodium vapor luminaries with photo electric switch, support and one overhead service drop not to exceed 100'.
4. Height: Mounting height of 175 watt lamp will be approximately 25 to 30 feet, and mounting height of 400 watt lamps will be approximately 30 feet.
5. Nonstandard Installation: A customer who requests more than one wood pole, or other than wood poles shall install the poles at the customer's expense. The standard sodium vapor luminaire will be provided and installed by the Department.
6. Lump Sum Payment: Customers who do not wish to pay monthly pole charge, may pay a non-refundable amount for the installation of standard wood pole or other pole as the customer desires. The pole will remain the property of the customer at termination of service.
7. Service Contract: A contract for a period of one year will be required for initial installation of facilities under this schedule, and will remain in effect from month to month thereafter subject to termination or cancellation under terms stated therein.
8. Maintenance: Lamp maintenance will be done during regular working hours as soon as reasonably possible after the customer has notified the Department of service failure. Monthly bills will not be adjusted because of a lamp outage.
9. Relocation of Poles: Relocation of an outdoor area lighting installation at the customer's request or because of government requirements will be made providing the customer pays the entire cost of such relocation.
10. Billing: Billing for an installation will be to only one account. Prorated billings to more than one account for a unit, or a combination of units will not be made. If the customer prefers to pay on an annual basis, payment shall be done and payable in advance.
11. All Night Service: The Department's dusk to dawn, all night service is based on a lighting period of approximately 4,380 hours per year.
12. Discontinuance of Service: If the customer discontinues service during the first three years of service, there will be a \$100.00 charge to remove the service and equipment.
13. Location of Poles: Poles will be located in areas where they may be serviced by truck.
14. Waiver: Customer must execute a waiver in order to participate in this program.

CITY OF BANNING
Electric Division

SCHEDULE MS

MUNICIPAL SERVICE

A) APPLICABILITY

Applicable to City of Banning municipal service for all types of uses, including lighting, power and heating, alone or combined (excludes enterprise fund accounts).

B) CHARACTER OF SERVICE

Alternating current with regulated frequency of 60 hertz single-phase, three-phase, or a combination of single and three-phase served through one meter, at a standard voltage not to exceed 240 volts, or as may be specified by the Electric Division.

C) TERRITORY

Within the area served by the City of Banning.

D) RATES

	<u>Per Meter</u> <u>Per Month</u>
Customer Charge	n/a
Energy Charge (to be added to Customer charge)	
All kWh, per kWh	\$.0923

E) MINIMUM CHARGE

Municipal services are not assessed a minimum charge.

F) SPECIAL CONDITIONS

1. Voltage: will be supplied at one standard voltage.
2. Energy Surcharge: The charges in the above rate are subject to California State Energy surcharge tax and shall be adjusted accordingly.

CITY OF BANNING
Electric Division

SCHEDULE EV

ELECTRIC VEHICLE PUBLIC CHARGING

A) APPLICABILITY

Applicable to the charging of electric vehicles at City-owned public charging stations within the City of Banning.

B) CHARACTER OF SERVICE

Alternating current with regulated frequency of 60 hertz single-phase, three-phase, or a combination of single and three-phase served through one meter, at a standard voltage not to exceed 480 volts, or as may be specified by the Electric Division.

C) TERRITORY

Within the area served by the City of Banning.

D) RATES

	<u>Per kWh</u>
Residents of Banning	\$.1688
Non-Residents	\$.2880

E) MINIMUM CHARGE

Electric vehicle public charging is not assessed a minimum charge.

F) SPECIAL CONDITIONS

1. Voltage: will be supplied at one standard voltage.
2. Energy Surcharge: The charges in the above rate are subject to California State Energy surcharge tax and may be adjusted accordingly.