2006

INTEGRATED RESOURCES PLAN

Imperial Irrigation District
Energy Department

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1. Executive Summary

The requirement for Load Serving Entities (LSE) to submit an Integrated Resource Plan (IRP), in compliance with Western Area Power Administration's ("WAPA" or "Western") Energy Planning and Management Program, was established in Section 114 of the Energy Policy Act of 1992, Public Law 102-486, and published in the Code of Federal Regulations at 10 CFR part 905.

The IRP report consists of two versions, the long version, which has to be submitted to WAPA every five years, and the short version, which has to be submitted every year between the five-year anniversaries.

The Imperial Irrigation District ("IID") issued its last IRP in 2002 for its period ending in 2001.

As the third-largest public power provider in the state, one of the IID's main functions is to generate, transmit, and distribute electricity to its customers. IID supplies electric power at retail to more than 135,000 customer accounts within its electric service area.

IID operates its own control area within the Western Electric Coordinating Council (WECC") and experienced non-coincident system peak demand of approximately 993 MW in July 21, 2006.

With a service territory experiencing a seven percent growth rate, IID has taken several innovative steps to insure system reliability and low cost for its customers.

One such step is the development of the Green Path Project; a first of its kind public-private venture between IID, Citizens Energy and the Los Angeles Department of Water and Power ("LAWDP"). This project takes advantage of the existing infrastructure thereby reducing impacts to the environment and costs to California ratepayers.

A long-term solution to reduce California dependence on imported fuel, the Green Path Project creates a transmission corridor to transport renewable resources, such as geothermal, solar, and wind energy, from the Imperial Valley to the load centers throughout California. Not only will this project boost transmission capacity and system reliability within IID's service area, it will also increase the reliability of the entire Western Region.

Another big step is IID's Board of Directors voluntary adoption of the State of California Renewable Portfolio Standard ("RPS") representing our commitment to renewable resource procurement consistent with the provisions of SB 1078.

IID's RPS goal is to assure procurement of electricity from eligible renewable resources to maintain portfolio level of a minimum 20%, measured by the amount of energy required in making retail sales of electricity under specific terms and conditions.

Also, IID's Board of Directors continue its commitment to Demand Side Management ("DSM") as a tool to mitigate cost, assist customers, and have a positive impact on the environment. IID will increase its DSM efforts in the following years in response to substantial growth in the territory, increased cost of acquisition of peaking power, customer assistance needs, and general efficiency improvement. Indeed, IID expects DSM to provide nearly 100 MW of demand relief over the next five years. This will be accomplished by the aggressive application of energy efficient programs, the introduction of demand response programs and the introduction of renewable programs.

In our 2002 IRP Report, we identified as our main goals and objectives:

- Provide Reliable Electric Power at Lowest Practicable Cost, Consistent With Sound Business Principles
- Enhance Customer Financial Stability by Providing Services which Enhance Property Values and Provide Long-Term Stability in Electric Power Rates

If we review the actual residential rates based on 2000 kWh per month usage in our 2005 Energy Report, IID has consistently been the lowest for last 10 years when compared with Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Riverside, LADWP, PG&E, very similar to APS in the average and slightly over Mexico's rate **(see Appendix C)**.

Based on these results, we believe we have been successful in accomplishing our goals, thanks to the actions taken by different groups within IID that helped to meet our stated goals over the last five years.

Among other, the main IID's overall goals and objectives for 2006 and beyond are:

- Rate stabilization
- Economic rates
- Improvement of system reliability
- Minimization of environmental impact
- Meeting of our legal and regulatory requirements

It is our corporate purpose to integrate and harmonize these four objectives. This 2006 IRP details the initiatives that IID has taken to support these goals. During the rest of the document we describe the actions that the different groups will take to meet our objectives stated in this Integrated Resources Plan.

2. Introduction

WAPA

WAPA was created under the Department of Energy (DOE) Organization Act of 1977. WAPA markets and transmits federally produced power in 15 central and western states, including California, Nevada, Montana, Arizona, Utah, New Mexico, Texas, North Dakota, South Dakota, Iowa, Colorado, Wyoming, Minnesota, Nebraska, and Kansas.

Hydroelectric power marketed by WAPA is generated by Reclamation, the U.S. Army Corps of Engineers, and the International Boundary and Water Commission. WAPA also markets a portion of the power generated by the large Navajo coal-fired plant. The current maximum operating capability of these power plants is 10,605 megawatts. WAPA also operates and maintains more than 16,854 miles of transmission lines, 258 substations, and associated power facilities.

WAPA markets and delivers hydroelectric power and related services within a 15-state region of the central and western U.S. It is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from multi-use water projects. Its transmission system carries electricity from 55 hydropower plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. Together, these plants have a capacity of 10,600 megawatts.

WAPA's 636 wholesale power customers include cooperatives, municipalities, public utility districts, and project use customers. These wholesale power customers provide power to millions of retail consumers in WAPA's geographic region. During fiscal year 1998, WAPA sold more than 45 billion kilowatt-hours of power - enough to serve nearly 14 million homes for one year.

WAPA built several parts of the important Path 15 corridor which connects power grids in the Southwest and Pacific Northwest (the rest was built by PG&E). Recently, WAPA helped remedy a transmission bottleneck near Los Banos. That bottleneck was one of the reasons for the California electricity crisis in 2000-01. Another important transmission corridor WAPA built was Path 66, paralleling Path 15.

Integrated Resource Planning was mandated by the Energy Policy Act of 1992. EPAct requires all WAPA customers to submit IRPs to WAPA every five years. This is required by language in WAPA's power sales contracts with long-term firm customers. Those customers with total energy usage or sales of less than 25 gigawatthours per year and who are not members of joint action agencies or member-based associations could submit a less complicated Small Customer Plan. Annual Reports describing progress under both reporting methods are due each year on the anniversary date of the plan's approval.

WAPA began a review of the IRP program during 1999, and after completing a public

process, revisions to the regulations became effective on May 1, 2000. IRP reporting requirements have been simplified and some information which may be considered proprietary now may be excluded. For instance, WAPA no longer require customers to provide a load forecast, only a brief summary that one was conducted.

The requirement to submit an IRP, in compliance with WAPA's Energy Planning and Management Program, was established in Section 114 of the Energy Policy Act of 1992, Public Law 102-486, and published in the Code of Federal Regulations at 10 CFR part 905.

The IRP report consists of two versions, the long version, which has to be submitted to WAPA every five years, and the short version, which has to be submitted every year between the five-year anniversaries.

The IID issued its last IFP in 2002, and 2006 is the five-year anniversary for the next report.

WAPA's IRP Report Guidelines request the following information:

Executive Summary: Plan Overview—describe the utility or utilities and customer base; regulatory oversight; issues influencing decisions, resources being evaluated, etc.

Plan components: Identification of resource options:

- *Identify resource options—supply and demand-side*
- *Include selection method/rational*
- *Include practicable options evaluated and chosen*
- *Include assumptions and cost related to options chosen*
- *Include evaluation methods*

Action plan with timeframe defined by customer with specific actions the utility will take to implement its IRP:

- *Identify planning timeframe*
- *Include customer actions to be taken to accomplish IRP goals*
- *Include milestones to evaluate accomplishment during implementation*
- *Include quantified energy and capacity benefits of each action*

Efforts to minimize adverse environmental effects of new resource acquisitions.

Ample opportunity for full public involvement in the preparation and development of an IRP (or any revision or amendment of an IRP):

- *Brief description of involvement activities*
- *Approval from governing body of each member or responsible party*

Load forecasts:

- *Statement that customer conducted a load forecast as part of the IRP*

Measurement strategies for options identified and whether objectives in the IRP are being met:

- *Provide methods of validating predicted performance*
- *Include identification of the baseline from which to measure the benefits of IRP implementation*

3. Background

IID's Organization

The Imperial Irrigation District was organized in 1911 under the California Irrigation District Act. A political subdivision of the State of California, it is a vertically integrated, publicly-owned utility operating under the laws of the State of California (California Water Code §§20500-29978) and governed by an elected five-person Board of Directors. It has a 6,471 square mile service territory in Southeastern California. This service territory includes Imperial County, a significant portion of the Coachella Valley in Riverside County, and a small portion of San Diego County. A map of the service territory is provided in Figure 1, page 23 in the Transmission Planning Section of this document.

Customer Base

As the third-largest public power provider in the state, one of the District's main functions is to generate, transmit, and distribute electricity to its customers. IID supplies electric power at retail to more than 135,000 customer accounts within its electric service area.

IID operates its own control area within the WECC and experienced non-coincident system peak demand of approximately 993 MW on July 21, 2006.

In 2005, the IID served electricity to its retail customers with 43% going to residential customers, 44.6% to commercial customers, 2.7% to agricultural, 0.5 % to industrial customers, and 9.2 to other categories. The policies for service, rates and taxes for power provided by IID to its customers are determined and set by its Board of Directors. A graph showing the current customer composition by class is attached in **Appendix A.**

Load Growth

Managing record-breaking growth, while providing customers with reliable service at the lowest possible cost, has been our top objective at IID. In 2005, our overall kilowatt sales increased by six percent while revenues totaled more than $327 million. During this same year, we experienced an 898 MW peak energy usage record set on July 18. About a year later (July 21, 2006 during the historical heat storm in California), IID experienced a new record of 993 MW peak energy usage. Also, our energy line losses went from 12.38% in 2000 to 9.69% in 2005.

With a service territory experiencing a seven percent growth rate, IID has taken several innovative steps to ensure system reliability and low cost for its customers.

Green Path

One such step is the development of the Green Path Project; a first of its kind public-private venture between IID, Citizens Energy and the LADWP. This project takes advantage of existing infrastructure thereby reducing impacts to the environment and costs to California ratepayers.

A long-term solution to reduce California dependence on imported fuel, the Green Path Project creates a transmission corridor to transport renewable resources, such as geothermal, solar, and wind energy, from the Imperial Valley to the load centers throughout California. Not only will this project boost transmission capacity and system reliability within IID's service area, it will also increase the reliability of the entire Western Region.

Resources Portfolio

IID has supplied its capacity and energy requirements with a combination of on- and off-system resources. Currently, IID's on-system generating resources consist of 85.645 MW of installed Hydro Plants, 241.48 MW of Steam Generation (including 117.48 MW of Combined Cycle), 165 MW of Simple Cycle combustion turbine generating capacity. IID also owns a one-third interest (approximately 96.6 MW) in the Yucca Axis generating facility in Yuma, Arizona (operated by Arizona Public Service Company). IID's long-term, off system resources include an approximately 15 MW interest in the Palo Verde Nuclear Generating Station located near Phoenix, Arizona, and an interest in and long-term unit contract (with associated firm transmission) for approximately 104 MW from San Juan Unit No. 3, located near Farmington, New Mexico. IID also has a 150 MW, five-year power purchase from Calpine's generating facility in Bullhead City, Arizona. In addition, IID is a preference customer for Parker-Davis power from Western Area Power Administration. On top of the listed portfolio, in order to execute the economic dispatch methodology as much as possible, IID has its day-ahead trading desk, as well as a subcontracted real-time desk, which are used very dynamically to procure resources in the spot market to better use its portfolio of resources and take advantage of the market opportunities. All those opportunities produce savings that are passed on to our customers.

Transmission

IID owns and operates its own transmission system internal to its service area, consisting of facilities operating at 230 kV, 161kV, 92kV and 34.4 kV. IID owns an undivided interest in the 500 kV Southwest Powerlink transmission line from Gila, Arizona to Imperial Valley substation. IID is interconnected with the transmission systems of Arizona Public Service ("APS"), Comision Federal de Electricidad ("CFE"), SDG&E, SCE and WAPA. IID regularly accesses bulk power markets in the Southwest to purchase and sell electric capacity and energy through high voltage transmission facilities it owns and controls. The power and energy from WAPA and other sources are transmitted over the District's facilities and WAPA's Parker-Davis transmission system to IID's service area. The power and energy are distributed to the customers of IID over distribution facilities owned and operated by the District.

Current Resources Procurement

Currently, as a result of a public Request for Proposals (RFP #484), IID ended up procuring seasonal Power Purchase Agreements (PPA) for up to 150 MW of peaking capacity from different parties. Besides such PPAs, IID's Generation Section was awarded with the Repowering of the existing 42 MW El Centro Unit #3 Steam Turbine to a 117 MW Combined Cycle Unit to be in service by summer 2009. Also, as a result of the same RFP, IID's Generation Section was awarded with the construction of about 90.7 MW of Peaking Capacity in Niland, CA. to be in service by summer 2008.

The current projection of IID loads and resources for the upcoming two-year, five-year and 10-year periods indicates that additional resources above those already secured are needed. IID has been experiencing a peak load growth of almost 50 MW for the last few years and is expected to continue with at least this trending for the future twenty years. With the current contract entitlements in place through the five-year, ten-year and twenty-year periods, the forecasted growth is such that additional resources are definitely needed at this time. Therefore, IID will continue using its current entitlements of Parker-Davis resources, other contractual entitlements and its own generation to meet its projected loads through the five- to twenty-year planning period, with supplemental purchases from bulk power markets as necessary. Also, as part of our current methodology for long-term planning and procurement for capacity and energy, we will continue studying our capacity expansion needs and will continue publishing RFPs for capacity and energy, starting with the next one in early 2007.

Competition with IID Service

IID's competition is generally the wholesale market in the Southwest and southern California. These are not any retail competition supplies and IID does not offer retail direct access.

Regulations Applicable to IID as a Load Serving Entity (LSE)

- Energy Planning and Management Program (EPACT '00)
- Imperial Country Air Pollution Control District Regulations
- South Coast Air Quality Management District Regulations

IID, like the rest of the electric utility industry, was experiencing significant changes made to the structure and regulation of the electric utility industry in California. In 2000 and 2001 wholesale prices for electricity in California and the West skyrocketed. Fortunately, IID's customers were shielded from the majority of these events because of IID's prudent planning and preparations.

California shifted its electric utility industry emphasis from deregulation to decreasing its dependence on fossil fuels. The state has recognized the benefits and importance of providing more of its energy needs from renewable resources, and in 2002 passed Senate Bill (SB) 1078 which implemented a Renewable Portfolio Standard (RPS) program for California Investor Owned Utilities (IOUs). The goals of the RPS included increasing total annual retail power sales from eligible renewable resources by at least 1% per year, and attaining 20% aggregate annual retails sales by 2017. By increasing the use of renewable resources, California will decrease its dependence on the limited supply of the earth's fossil fuels, and will also decrease its contributions of emissions which could affect Global Warming.

The State's Energy Action Plan and the California Energy Commission's Integrated Energy Policy Report have stated a goal of accelerating the implementation of the State's RPS such that the 20-percent goal is met seven years early, by 2010. The California Governor, in the 2005-06 Budget Summary, also endorsed this accelerated schedule, and additionally included a goal of achieving 33% renewables by 2020 for the State as a whole.

California also passed other important legislation, including SB 1037 in September 2005 which affects publicly owned utilities, including IID. This legislation states "… (a) Each local publicly owned electric utility, in procuring energy, shall first acquire all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible. (b) Each local publicly owned electric utility shall report annually to its customers and to the State Energy Resources Conservation and Development Commission, its investment in energy efficiency and demand reduction programs. A report shall contain a description of programs, expenditures and expected and actual energy savings results."

Municipal utilities, including the IID, are currently exempt from the specific provisions set forth in SB 1078, however this legislation did require municipal utilities to develop their own renewables programs which follow the intent of SB 1078, and also mandated certain annual disclosures to customers relating to public goods expenditures and energy resource investments.

IID's Renewable Portfolio Standards

IID's Board of Directors voluntarily adopted the State of California's RPS representing our commitment to renewable resource procurement consistent with the provisions of SB 1078.

IID's RPS goal is to assure procurement of electricity from eligible renewable resources to maintain portfolio level of a minimum 20%, measured by the amount of energy required in making retail sales of electricity under the following terms and conditions:

- Among the qualifying resources in IID's RPS are: electricity produced from the following technologies constitute "eligible" resources: biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, low impact hydroelectric generation, digester gas, municipal solid waste, landfill gas, ocean wave, ocean thermal, tidal current, renewable components of sales from other parties (green tickets), or renewable distributed generation on the customer side of the meter. Facilities can be located anywhere in the interconnected transmission system located in the interconnected WECC electrical grid.

- The timing of long-term resource additions in IID's RPS: Renewable resources will be procured to the extent they fulfill unmet needs identified in IID's long-term resource procurement plan. IID will not terminate, abrogate, or otherwise replace any existing long-term contract in order to meet the renewable target portion of its energy portfolio.

- Price Benchmarking in IID's RPS: In considering the appropriate reasonable prices to be paid for renewable resources, IID will consider, but not be bound to, the price benchmarks set by the California Public Utilities Commission ("CPUC") for the State's investor-owned utilities and shall include the costs associated with transmission.

- Limit on Subsidies in IID's RPS: The procurement obligation is contingent upon IID having sufficient funds available to make "supplemental energy payments" to subsidize the above-market costs of renewable energy. Any subsidy will come from public benefit expenditures that IID is required to make pursuant to the provisions of AB 1890. Renewable energy subsidies from Public Benefits Charge ("PBC") Funds will not come at the expense of conservation programs. The availability of sufficient PBC Funds will be a de facto limit on the annual renewable purchase obligation and compliance with this Standard will be deemed achieved where noncompliance is caused by the unavailability of PBC expenditures in an amount not to exceed 20% annually.

- Regarding rate impact in IID's RPS, the goal is not to materially increase system wide rates by the addition of renewable energy resources.

Regulation Applicable to IID Customers

The regulations for retail power service to IID's customers are set by the Board of Directors through the District's retail tariff.

IID's Board of Directors is a publicly-elected five member board.

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4. IID's Accomplishments on Goals and Objectives set in 2002 IRP Report

In our 2002 IRP Report, we identified as our main goals and objectives:

- Provide Reliable Electric Power at Lowest Practicable Cost, Consistent With Sound Business Principles
- Enhance Customer Financial Stability by Providing Services which Enhance Property Values and Provide Long-Term Stability in Electric Power Rates

If we review the actual residential rates based on 2000 kWh per month usage in our 2005 Energy Report, IID has consistently been the lowest for last 10 years when compared with SCE, SDG&E, Riverside, LADWP, PG&E, very similar to APS in the average and slightly over Mexico's rate **(see Appendix C)**.

Based on these results, we believe we have been successful in accomplishing our goals, and the following paragraphs summarize the actions taken by different groups within IID that helped to meet our stated goals over the last five years:

IID Resources Planning Group

As part of the Integrated Resource Planning philosophy, the Energy Resources Planning Group does long-range corporate planning activities by performing the following tasks:

- Evaluate future resource needs to meet our growing demand
- Present balanced and responsible resource strategy to the stakeholders and the state regulatory bodies
- Meet reliability requirements
- Maintain fiscally sound financials
- Promote environmental stewardship
- Balance risk and costs

In order to accomplish these tasks, the group uses commercially available long-and short-term planning software which is widely used in the utility industry.

During the energy resources planning and procuring process, and with the goal in mind of having a clean/transparent process in the energy procurement activity, the Energy Resources Planning group established their Annual Planning Cycle **(see Appendix D).** In this cycle, we begin the load research update by September and finish by December. Then we study the Resource Mix and Transmission assessment and finalize our Base Case by January. After this, we perform Capacity Expansion Studies during the month of January to identify our 3/5/10/20 year plan that takes into consideration:

- System reliability
- System load growth
- OATT Transmission Service Requests

- Large customer needs
- Least cost to serve load considering the previous points

Based in our findings, we publish a Request for Proposal (RFP) to meet the identified needs in the Integrated Resources Plan. By July, we are typically working on contracts' negotiations to procure the products identified in our capacity expansion plan and/or RFP.

Load Forecasting Methodologies

We utilized several modeling techniques in the development of the IID load forecast update for 2006. During the development of this forecast, various modeling techniques were explored and final forecasting methodologies were chosen based on the reasonableness of the forecast outcome. Likewise, the full use of confidence and probability intervals for the development of the low and high estimates in this forecast has been limited to where reasonable outcomes were concluded.

Our inability to account for significant changes in IID requirements beginning in 1998 prevents us from knowing how to account for such occurrences in the future. For the purpose of this forecast, the load drop in energy sales in 1998 is assumed to be a one-time event. We also observed different success in modeling techniques when performed separately on Imperial Valley and Coachella Valley. There was more success in the modeling of the Coachella area as correlations between growth variables were stronger. Forecasting Imperial and Coachella valleys' loads in a combined format also improved the variance in the forecast results; however, historically IID has preferred to keep these divisions separated in the forecast. Below is a summary of how the various rate classes have been accounted for in the 2006 load forecast update:

Residential. – Residential loads for both Imperial and Coachella valleys were adjusted through a two-month smoothing process to account for differences in billing cycles, as well as weather normalization to account for differences in weather severity. Applying the number of residential customers (assumed to be the customer count for the month of December of each test year) an average kWh per customer factor was calculated. This number was used to determine the medium forecasted kWh per customer use and a 90% confidence factor was applied to compute the lower and upper bounds for the forecast. These numbers were applied to population growth factors obtained from state agencies, or actual historical IID growth factors, by division, to calculate the forecasted residential kWh sales.

General Service (GS). The assumption behind small commercial forecasting is that small commercial/ general service stays on a par with residential growth. For the Coachella Valley this held true returning a coefficient of determination (R^2) value of .95 revealing a strong positive correlation between Coachella residential load growth and Coachella general service (GS) growth. For Imperial Valley the correlation wasn't as strong; however, the historical trend appeared to still support the "small commercial follows residential" assumption. The five-year average ratio for Imperial Valley and Coachella Valley were applied to their respective residential low, medium, and high forecasts to produce the 20-year general service (GS) forecast.

General Service (GL)**.** Unlike previous year forecasts, the 2006 forecast has broken out GL and A2 energy forecasts into separate forecasts to enable for greater transparency in the forecast for comparison with actual loads. The GL energy forecast is a good scenario where data for the Coachella Valley provided greater statistical accuracy in modeling attempts than the Imperial area. For the Coachella Valley, a linear trend model was used based on the annual energy sales in the Coachella Valley and 90% confidence intervals were used to determine upper and lower bounds for the forecast. For the Imperial Valley, linear modeling and regression modeling were unsuccessful in producing reasonable results. It was determined that a five-year average of recent annual energy sales provided the most reasonable results and 90% confidence intervals were used to determine the upper and lower bounds of the forecast.

General Service (A2)**.** Large industrial customers represent significant load additions and subtractions. The following graph represents the historical kWh industrial load sales. For the purposes of this forecast, the most reasonable conclusion was to hold the medium forecast at 2005 energy levels, which assumes no gain or loss of large industrial customers. For the Imperial Valley, the upper and lower bounds for the forecast were derived by using a one standard deviation assumption, while in the Coachella Valley a 95% confidence interval was used to determine the bounds.

Other**.** For master metered sales we utilized the same growth rates as the residential class for both Imperial and Coachella valleys. For all remaining classes (agricultural power, economic development, lighting, public authorities, and interdepartmental) we utilized a simple 12-year average linear trend in forecasting load growth.

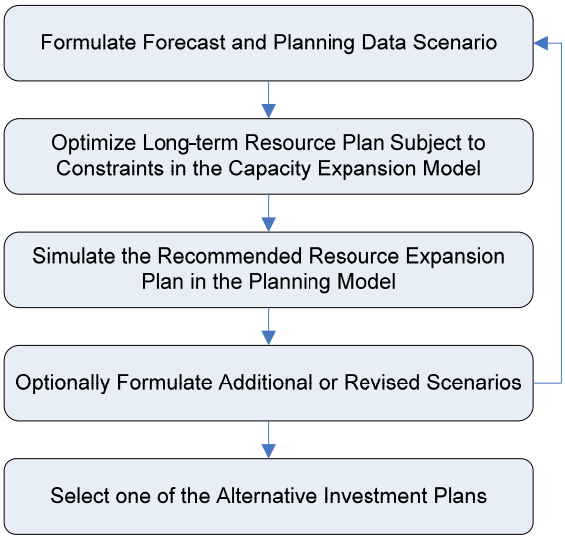
Process for the Planning of the Capacity Expansion

The Capacity Expansion module that we use for our studies answers key investment decisions:

- What to buy, lease, build (or retire)?
- How much to buy, lease, build (or retire)?
- Where to buy, lease, build (or retire)?
- When to buy, lease, build (or retire)?

The software automates screening and evaluation of generation capacity expansion, transmission upgrades, strategic retirement and other resource alternatives. It is a detailed and fast economic optimization model that simultaneously considers resource expansion investments and external market transactions.

The following flowchart shows in general terms, the steps involved in the capacity expansion analysis:



Decisions to purchase contracts, build generating units, or retire generating units are made based on market revenue and costs, including both variable and fixed cost components across the entire planning horizon.

With the Capacity Expansion software, the optimal resource expansion strategy is determined based on an objective function subject to a set of constraints. The typical criterion for evaluation is the expected present value of revenue requirements (PVRR) subject to meeting load plus reserves, and various resource planning constraints.

Request for Proposals (RFP) Process

In the RFP process, the Energy Resources Planning Group is in charge of the following processes:

- Development of the RFP documents
- Reception and evaluation of the proposals
- Development of the short list of proposals for further review
- Notification to short-listed respondents and those respondents not on short-list
- Clarification and due diligence of short-listed proposals
- Recommendation and Board review/approval of selected proposal(s)
- Notification of award to selected respondent(s)
- Initiation of negotiations with selected respondents
- Presentation to Board for review/approval of final contracts

Goals of the Request for Proposals

With the RFP process, the goals that the Energy Resources Planning Group is looking to achieve are:

- To be consistent with current utility industry practices
- To motivate a broad selection of credible proposals
- To provide for fair treatment of all bidders, protection of confidential information and a defined communications protocol.
- To enhance competition between bidders, while keeping timeline as short as possible.
- To allow, but do not favor, bids from IID internal "self build" resources
- To employ an internet-based approach to receive information/respond to bidder communications.
- To assure all bidders that no inappropriate communication or special favors are granted to any single bidder
- To have clear and concise RFP documents
- To have bidders proposing only "qualified" renewable resources
- To consider only bidders that meet credit and financial performance criteria to minimize development risks for IID
- To give all bidders comfort that IID will give serious consideration to all credible bids
- To assure bidders that IID is not using the RFP process simply as a means to justify a "self-build" or other pre-determined conclusion
- To make sure bidders have reasonable access to accurate information and prompt communications
- To give bidders reasonable amounts of time to prepare proposals
- To assure IID Board that the selected resource(s) is clearly in the best economic and "reliability" interests of the District

Supply Side Resources

IID is part of the Desert Southwest Region of the Western Area Power Administration, and has been enjoying a capacity allocation of 32.5 MW, which has provided close to 784,261,000 kWh of energy for the IID customers over the last five years.
The following table summarizes the supply-side resource options by type of generation over the last five years period that the IID has utilized to serve it native load (see **Appendix B** for a graph on energy sources used to supply system load):

Current Activities	Current kW	Current kWh
1. WAPA Parker Davis	32,500	784,261,000
2. IID Hydro	82,085	1,318,650,667
3. Coal	102,000	3,661,628,000
4. Natural Gas	424,000	2,564,689,357
5. Combined Cycle	117,480	1,436,105,243
6. Diesel	67,000	76,289,900
7. Nuclear	14,000	424,973,500
8. Additional Purchases	325,000	8,499,270,798
TOTAL	**1,164,065**	**18,765,868,465**

Accomplishments of the Energy Resources Planning Group over the Last Five Years

The Energy Resources Planning Group through its Annual Planning Cycle, Load Forecasting Methodology, Capacity Expansion Analysis, Integrated Resources Planning, Request for Proposals and Planning Modeling Software has accomplished, among other things, the following:

- RFP ending with procurement of 150 MW of a Combined Cycle Unit for up to five years (contract expires in April 30, 2007)
- RFP ending with procurement of 150 MW of seasonal products for up to 10 years (starting June 2007)
- RFP ending with Repowering of Steam Turbine into combined cycle for a new capacity of 117 (additional 75 MW)
- RFP ending with construction of Simple Cycle Gas Turbines with about 90 MW of peaking capacity
- RFP for Renewables that are in the stage of definition of short-listed candidates for possible 50 MW of Geothermal and 14 MW of Biomass projects
- Partnership with SCPPA members in Renewables RFP for potential 5 MW of wind Power Purchase Agreement from a potential 75 MW project

Demand-Side Management (DSM)/Public Programs Group

Background

As indicated above, growth in the IID service territory is driving energy sales up at a rate of 7-8% while peak demand increases at almost 12% annually. This condition of demand growth exceeding growth of energy sales further exacerbates IID's load factor. The result is the need to purchase increasingly expensive energy during peak times or the acquisition of peaking generation that remains dormant during much of the year. The net result is increasing fixed cost and/or very high purchase energy cost either of which drives rates higher. In addition, the increase in energy sales places stress on generation primarily designed for peaking capacity or increases IID's reliance on purchased power. This not only increases cost but adversely impacts reliability.

IID's DSM programs have been active during this period. Several incremental program additions have been implemented such as financing for weatherization and the *CheckMe* program. However, this incremental development has not been able to keep pace with the growth in energy and demand. Table 1 indicates the program results for the last five years. This table indicates that although new elements have been added to DSM programs, results have remained relatively constant at about 5 to 7 MW. These savings produce a load factor of 34% that is consistent with the system load factor.

TABLE 1.

Historical DSM Performance

	2002	2003	2004	2005	2006
Energy Efficiency					
Demand (KW)	4,391	1,944	3,854	3,035	2,662
Energy (kWh)	20,051,849	10,490,454	6,678,265	7,610,782	6,607,277
Budget ($)	850,529	1,279,923	1,797,381	2,085,343	936,887
PV/Renewables					
Demand (KW)			15	65	49
Energy (kWh)	NA	NA	24,804	110,631	82,992
Budget ($)			52,344	181,574	136,482
Totals					
Demand (KW)	4,391	1,944	3,869	3,100	2,711
Energy (kWh)	20,051,849	10,490,454	6,703,069	7,721,413	6,690,269
Budget ($)	850,529	1,279,923	1,849,725	2,266,917	1,073,369

The magnitude of this issue becomes more imperative when other factors are considered. Over the last 10 years, federal standards have increasingly raised the bar concerning minimum efficiencies for standard technologies. California Title 24 applied to new construction has also increased the efficiency of new homes and commercial buildings. However, these aggressive steps have not halted or reduced the growth of IID's energy sales or positively impacted IID's load curve or load factor.

IID Transmission Planning Group

Background

The IID owns and operates electric generation, transmission and distribution facilities. Its generation facilities include fossil-fired and hydroelectric plants. Its transmission system and sub transmission system extends over 1,678.6 miles. Its distribution system includes 3,409.5 miles of overhead lines and 804.4 miles of underground lines.

Transmission System

IID interconnects to SDG&E, SCE, WAPA and APS. The interconnection is established at 230kV and 161kV voltage levels.

IID's electric transmission system is planned and designed to meet load and energy demand within equipment, line ratings, within accepted voltage ranges, and with the ability to preserve the connection to the interconnected system.

IID's transmission system consists of 230kV, 161kV and 92kV transmission lines. The interconnection with SDG&E and SCE is established at 230kV, with WAPA at 161kV and with APS at 69kV level through two 161kV/69kV step down transformers.

The 230kV transmission system consists of one single circuit transmission line ("S line"), between IID's El Centro Switching Station ("ECSS') and IID's/SDG&E's Imperial Valley Substation, and a double circuit radial transmission line ("Collector System") that runs across IID's service area, through four 230kV-92kV Stations. Some of these stations are used for the sole purpose of provide interconnection to generation facilities and the interconnection to SCE's Mirage-Devers Substations.

The "S Line" was constructed to provide interconnection with SDG&E, and serves as a transmission path for generation resources from SDG&E, as a delivery point.

The Collector System was constructed in 1986 and 1988 for the primary purpose of delivering over 500MW of "power generating facilities" (a.k.a. PGF resources, mostly consisting of renewable resources) contracted to SCE. Over the last several years, IID has integrated the 230kV system into the IID transmission network, capable of delivering the contractual obligations and to meet the load serving requirements of the IID control area. Currently, through the Collector System, IID provides a transmission path from the generation resources to SCE as a delivery point.

The 161kV transmission system consists of a ring across IID's service area that interconnects several 161kV/92kV transmission stations, providing transformation capacity from the 161kV system to the 92kV system. The 161kV transmission system also provides interconnection to WAPA through two 161kV transmission lines ("F and D lines"), from IID's Niland and Pilot Knob Stations to WAPA's Blythe and Knob Stations.

The 161kV transmission system was originally built in the 1940-50s as part of the expansion of the Western Area Power Administration transmission system to deliver power for the regional irrigation districts from the Parker-Davis generating facilities.

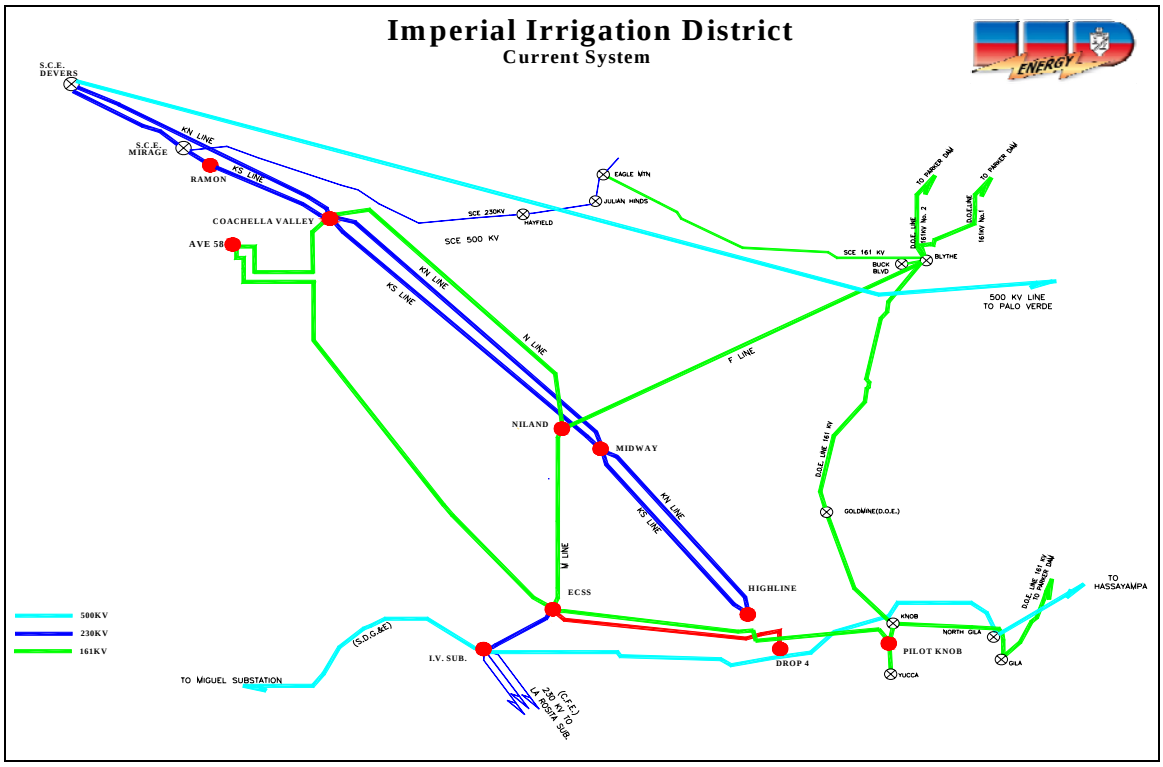
This system has helped to meet the load serving requirements for IID for over 50 years. However, as the load continues to grow in all regions of the IID service area, the need and plans to upgrade this transmission system have been reviewed for several years. The existing system has recently experienced additional stress due to generating resources constructed near the edge of the IID service territory.

IID has been tracking the proposed WAPA's 161kV cut-over to 230kV on the south of Parker Area with the intention to coordinate an IID's expansion plan with the purpose of matching WAPA's south of Parker upgrades.

The 92kV transmission system consists of multiple transmission lines that provide interconnection to the distribution substations (92kV/13kV) that are constantly constructed to provide transformation capacity to the distribution system, increasing the ability to supply the aggregate electrical demand and energy requirements of IID's customers and future customers in a good reliable manner.

The following drawing depicts the IID 230kV and 161kV transmission system as currently configured.

Figure 1. IID Transmission System



IID System Planning has been very active in the last five years in developing a plan of services for several projects to ensure a reliable transmission system. Some of these projects and upgrades consisted of increasing the transformation capacity from the 230 kV to the 92kV, cut-over portion of a remaining 34.5 kV system to 92 kV, interconnection facilities for new generation resources, increase of reactive power support through the installation of shunt capacitor banks in the transmission and distribution system as well as the construction of multiple distribution substation, transformation bank replacements and electric facility upgrades.

The projects mentioned above were performed with the purpose of providing a good reliable service to IID customers and also to allow the interconnection of new generation resources, some of them renewable.

OATT Interconnection Requests

IID at this moment has 15 proposed projects in the IID's Open Access Transmission Tariff ("OATT") generation interconnection queue, for a total of 557.8 MW, in which 218 MW are geothermal resources and 125 MW of wind resources. IID System Planning has been working in developing the transmission plan of service to allow the interconnection of these generation facilities, as well as to provide a transmission path of this generation across the IID transmission system to allow the delivery of energy to different delivery points in IID service area boundaries.

System Planning has also been very active in the last five years, in the development phase of multiple transmission projects proposed to be built in the next five years that will be described further in this document.

IID System Operations Group

Background

IID's System Operations Group has in the past five years greatly improved the support on facilitating procurement of services to help promote renewable green energy. IID has assisted several renewable projects up to final on-line production and ultimate scheduling of their energy for export.

Accomplishments

The following are highlights of accomplishments and issues addressed to help promote this alternative green energy industry:

- In 2003 IID implemented a dedicated alternative energy customer representative to address any concerns or issues pertaining to these plants. Issues range from and not limited to maintenance, operations, contractual, administrative.
- Implementation of nondiscriminatory FERC proforma OATT with associated ancillary services.
- Effectively employed an entire process to help facilitate and streamline generation interconnection and transmission service requests
- Performed system upgrades and installation of electrical devices to help grid stability and system voltage for our alternative energy customers
- IID has installed and continues to upgrade technical accounting processes and software applications to provide accurate accounting and settlements
- Energy Management Systems, Supervisory Control and Data Acquisition, metering and communication medians and devices are continuously upgraded for improved generation output tracking

IID Power Generation Group

Background

IID Generation has been active in developing renewable projects over the last five years. In the hydro arena, IID has performed major refurbishments to its hydro resources. Drop 4 Unit 2 was refurbished with a new turbine runner and a new control system to significantly improve its efficiency and increase its MWH production. The Double Weir Plant had been retired in the early 1990s. It has been refurbished with two new turbine-generator sets and a new control system, and it is producing approximately a 400 KW output of renewable energy.

Accomplishments

IID Generation is gearing up to become very active in renewable energy projects going forward. In the hydro arena, IID plans major refurbishments of five additional hydro units similar to its refurbishment of Drop 4 Unit 2. The Drop 4 Unit 1 major refurbishment is scheduled to begin in 2008 with other IID hydro units to follow annually. IID will begin the process of engineering and constructing a 481 KW mini-hydro plant at IID's Westside Main Canal Check No. 8 Structure. Also, IID is in the process of engineering and constructing a 500 KW high concentration solar PV plant using Amonix technology. IID will construct this project in partnership with San Diego State University on a five acre parcel at the San Diego State University Brawley Campus. IID has submitted an application for receiving Clean Renewable Energy Bonds to construct another 10 MW of high concentration solar PV. For 2007, IID has budgeted sufficient funds to determine the feasibility of IID developing a geothermal resource in Imperial County as a base load resource.

IID Generation is continuously performing capital projects to maintain and upgrade its generating system. IID directly maintains of 28 generating units that includes steam, combined-cycle, simple-cycle, and hydro resources. IID also has partial ownership of resources that others operate. Some examples of capital expenditures that have been performed or are in the process of being performed are a controls replacement on El Centro Unit 4 that will improve unit efficiency, a cooling tower replacement on El Centro Unit 2 that will reduce PM-10 emissions, a major refurbishment of the hybrid wet/dry cooling tower on San Juan Unit 3, replacement of the existing electrostatic precipitator with a new baghouse on San Juan Unit 3.

IID Regulatory Affairs Group

Western Area Power Administration, Energy Policy Act of 2005, Public Utility Regulatory Policies Act. Standard Revision Pre-consideration

WAPA Profile

WAPA annually markets about 10,000 MW of renewable power from 56 hydropower plants. WAPA sells and delivers about 40 percent of hydroelectric generation in the western and central United States. WAPA also markets the United States' 547 MW entitlement from the coal-fired Navajo Generating Station near Page, Arizona, and transmits power across more than 17,000 circuit-miles of high voltage transmission lines.

WAPA's mission is to market and deliver reliable, cost-based hydroelectric power and related services. WAPA's service area covers 1.3 million square miles in 15 states. WAPA sells firm and non-firm power to more than 750 customers, including municipal utilities, rural electric cooperatives, public utility and irrigation districts, Federal and state agencies, Native American tribes, and investor-owned utilities. WAPA's utility customers, in turn, provide retail electric service to millions of consumers in these central and western states: Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah and Wyoming.

WAPA operates and maintains an extensive, integrated and complex high-voltage transmission system to deliver federally generated electric power to customers and the market. Using WAPA's Federal transmission system, WAPA sells and delivers reliable electric power to most of the western half of the United States. WAPA is the third largest transmission provider in the United States.

Except for the Central Arizona Project's Navajo generation, the generation and transmission facilities from which WAPA sells power are part of 10 rate-setting systems. These are made up of 14 multipurpose water resource projects and one transmission project. The systems include WAPA's transmission facilities and power generation facilities that the Bureau of Reclamation, the U.S. Army Corps of Engineers and the International Boundary and Water Commission own and operate. Although close coordination occurs, WAPA and the generation entities are separately managed and financed. Each entity operates and maintains its portion of a multipurpose project and allocates its operating expenses among the project's purposes.

Background

Generally, the Public Utility Regulatory Policies Act of 1978 (PURPA) created a regulatory framework that "provid[ed] for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers" (16 U.S.C. §2611). PURPA's "Retail Regulatory Policies for Electric Utilities" (Title I) apply to an electric utility if it sells more than 500 million kilowatt-hours (kWh) during the year for purposes other than resale (16 U.S.C. § 2612(a)). An "electric utility" is specifically defined by PURPA as "any person, State agency, or Federal agency, which sells electricity" (16 U.S.C. § 2602(4)). A "non-regulated electric utility" is defined as "any electric utility other than a State regulated utility" (16 U.S.C. §2602(9)). Accordingly, WAPA is categorized as a non-regulated electric utility for the purpose of determining PURPA's applicability.

WAPA is predominantly a wholesaler of hydroelectricity. Most of WAPA's energy sales are for resale. However, WAPA also sells power to irrigation districts, Native American tribes, and Federal and State agencies; the majority of these sales are not for resale. Because WAPA is a non-regulated electric utility that supplies more than 500 million kWh to non-utility customers western-wide, it must comply with the regulatory framework established by PURPA.

Under 16 U.S.C. §2612(c), the Department of Energy (DOE) must publish a list of electric utilities that are either subject directly to the terms of PURPA or that are regulated by PURPA through a state regulatory authority. DOE most recently published this list in 1998, and listed WAPA as a covered utility.

Therefore, in cases where WAPA sells to non-utility customers, it is subject to the regulatory framework established by Title I of PURPA.

The recently enacted Energy Policy Act of 2005 (EPAct) made substantial changes and additions to the provisions of the PURPA. WAPA staff analyzed several sections of EPAct of 2005 to determine their applicability to WAPA. Those sections are as follows:

- Net Metering, *(Section 1251 (a) (11))*
- Fuel Sources Standard, *(Section 1251 (a) (12))*
- Fossil Fuel Generation Efficiency Standard, (*Section 1251 (a) (13))*
- Smart Metering (with Time-Based Schedules), *(Section 1252 (a) (14))*
- Interconnection, *(Section 1254 (a) (15))*

Sections 1251, 1252, and 1254 of the EPAct of 2005 require each state regulatory authority or non-regulated electric utility subject to PURPA to conduct formal assessments to consider implementing Federal standards relating to fuel sources, fossil fuel generation efficiency, net metering, smart metering, and consumer interconnections. The EPAct does not require adoption of any of the standards; however, it does necessitate consideration.

WAPA published a Federal Register Notice (FRN) on August 4, 2006 initiating its consideration of the five PURPA standards (71 FR 44276) The FRN provides the date, time, and location of the public hearing, and can be found at: http://www.wapa.gov/dsw/pwrmkt/PURPA/.

Initial Reconsideration Analysis

WAPA staff reviewed the PURPA standards on a WAPA-wide basis. These WAPA projects were included in the review:

- Amistad-Falcon Project
- Boulder Canyon Project
- Central Arizona Project

- Central Valley Project
- Falcon-Amistad Project
- Fryingpan-Arkansas Project
- Pacific Northwest / Pacific Southwest Intertie Project
- Parker-Davis Project
- Pick-Sloan Missouri Basin Program
- Provo River Project
- Salt Lake City Area Integrated Projects (Colorado River Storage Project, Collbran Project, and Rio Grande Project)
- Washoe Project

The pertinent PURPA standards and WAPA's initial analysis are described below.

Net Metering *(Section 1251 (a) (11))*

"Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period."

This standard relates to energy deliveries to electric consumers with on-site generating facilities that could be operated by the consumer to offset energy provided by an electric utility with a corresponding billing credit to that consumer. The standard cannot be reasonably applied to most customers served by WAPA because WAPA does not typically meet the entire load of its customers. A majority of customers use a combination of WAPA power, and higher priced power purchased from other suppliers or customer-owned generation, to meet their loads. Net metering would typically result in a reduction of other power supplies, not WAPA hydropower. For those few customers for which WAPA is an all-requirements power supplier, WAPA today allows net metering to offset power billing for energy delivered by WAPA. Therefore, there appears to be no need for action on WAPA's part in response to this standard.

Fuel Sources Standard *(Section 1251 (a) (12))*

"Each electric utility shall develop a plan to minimize dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies including renewable technologies."

WAPA is primarily a bulk wholesale electric provider that provides a very limited amount of energy to end-use loads. WAPA's power is marketed by individual projects primarily to preference customers, most of which are electric utilities. These electric utilities in turn blend the Federal hydropower resource into their resource base and sell it to their retail customers. WAPA does not have load growth responsibility, and does not construct any new generation.

Generation resources marketed by WAPA are renewable hydropower, with the exception of the United States Government's interest in the Navajo Generating Station (Navajo), the output of which is used to support the Central Arizona Project pumping requirements. Therefore, fuel source diversification would not be a component in managing WAPA's projects.

Fossil Fuel Generation Efficiency Standard (*Section 1251 (a) (13))*

"Each electric utility shall develop and implement a 10 year plan to increase the efficiency of its fossil fuel generation."

WAPA is primarily a bulk wholesale electric provider that provides a very limited amount of energy to end-use loads. WAPA's power is marketed by individual projects primarily to preference customers, most of which are electric utilities. These electric utilities in turn blend the Federal hydropower resource into their resource base and sell it to their retail customers. Generation marketed by WAPA is hydropower; except for Navajo surplus. The Navajo Generating Station is a joint participation project among several utilities in the southwestern United States. The United States has a 24.3% interest in the power plant, and WAPA participates on the operating committee where decisions are made regarding projects intended to increase the efficiency of the Navajo Generating Station. The Salt River Project is the operator of the Navajo Generating Station and is primarily responsible for maintaining the plan to increase the efficiency of the Generating Station. The Salt River Project is considering adoption of this standard for its generation including Navajo.

Since WAPA is not the operator of the Navajo Generating Station, and the remainder of our projects is hydropower, the requirement to develop plans to increase efficiency of fossil fuel would not be applicable to our operations.

Smart Metering (with Time-Based Schedules) *(Section 1252 (a) (14)*

''Each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology."

This standard mandates that electric utilities offer each customer information relating to time-based rates. The time-based rate would facilitate the customer's management of energy usage by time period through advanced metering and communications technology.

WAPA is a predominantly wholesale power supplier and does not have utility responsibility. WAPA does not typically meet the entire load of its customers; their remaining power is delivered from higher-priced sources. Smart metering would likely

reduce a customer's need for those resources and in almost all cases would likely have no impact on WAPA's deliveries. A very small portion of WAPA's energy is delivered to all requirements' customers who could potentially benefit from smart metering. As WAPA has received no requests to establish time-based rate schedules, there appears to be no need to adopt this standard because of lack of demand.

Interconnection *(Section 1254 (a) (15))*

"Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to, practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.''

WAPA is primarily a bulk wholesale electric provider that provides a very limited amount of energy to end-use loads. WAPA's power is marketed by individual projects primarily to preference customers, most of which are electric utilities. These electric utilities, in turn, blend the Federal hydropower resource into their resource base to sell to their retail customers. Those preference customers would principally be responsible for interconnection service "to the local distribution facilities", as opposed to WAPA.

WAPA's facilities are primarily bulk transmission system facilities. WAPA's policies and procedures for interconnections to its power system are set forth in WAPA's Open Access Transmission Tariff, dated December 2005, which is on file with the Federal Energy Regulatory Commission. These policies and procedures are used to manage all interconnection requests that WAPA receives. As WAPA has not received any requests for consumer interconnection service, there appears to be no need to propose adoption of this standard.

Next Steps

Based on initial analysis, WAPA did not propose to adopt the standards under consideration.

5. IID's 2006 IRP Objectives

Among others, the IID's main overall goals and objectives for 2006 and beyond are:

- Rate stabilization
- Economic rates
- Improvement of system reliability
- Minimization of environmental impact
- Meeting of our legal and regulatory requirements

It is our corporate purpose to integrate and harmonize these five objectives. This 2006 IRP details the initiatives that IID has taken to support these goals. The next paragraphs describe the actions that the different groups will take to meet our objectives stated in this Integrated Resources Plan.

Energy Resources Planning Group

Five, Ten and Twenty-Year Load Forecast

The IID is currently operating under a three, five, ten and twenty-year energy resources planning horizon. Under this planning horizon, IID forecasts through linear regression analysis the anticipated load requirements and available resources from 2007 to 2026. See **Appendixes E, F and G** to see the resource stack used to serve the peak load for 2006, our flexible resources plan and our updated load forecast for 2007 and beyond.

Renewable Portfolio Standards

The Energy Resources Planning Group, with the goal to start the process of procuring renewable resources, as voluntarily adopted by our Board, started with the process of publishing a "Renewables RFP" (RFP #525) during 2005 for the procurement of about 466,000 MWh per years, starting 2010 with the associated green energy credits.

During this process, we received about 18 different proposals. We followed our described RFP process and ended up with two short-listed proposals. We are currently in the process of negotiation and our negotiating team is in charge of the final process.

Loads and Resources Flexible Plan

In our loads and resources plan, we introduce the "flexible" concept. What we intend with this approach is to have fixed, long term contracts and power purchase agreements (PPAs), as well as construction for the load that is already happening with 100% certainty. We want to leave anywhere between 25 and 50 MW of load as a flexible portion filled with some type of call options, in case the expected maximum load really shows up.

Regulatory Planning

CPUC - Resource Adequacy Requirement.

Resource Adequacy Requirements were proposed in CPUC Decision (D.) 04-01-050 and discussions have continued in follow-up materials contained in (D.) 04-07-037, (D.) 04-10-035, the "Resource Adequacy Phase 2 Workshop Report June 10, 2005", and the "Workshop Report on Adequacy Issues Report" filed June 15, 2004 by the CPUC and the CEC. Provided below is a brief background of the resource adequacy requirements and its relevancy to IID.

Background.

In response to the energy crisis of 2000 and 2001 the CPUC decided to address the various processes employed by utilities in planning and procuring energy resources and the cost justification and recovery of resource procurement. The CPUC aim to create a framework that would "ensure customers within California's three largest investor-owned utilities (IOU) would receive service that is as reliable as reasonably possible, consistent with current technology and economic constraints." The result was the adoption of Decision (D.) 04-01-050 which set forth a resource adequacy requirement ("RAR"). Though the RAR framework was initially established to guide investor owned utilities ("IOUs") PG&E, SDG&E and SCE, it was decided in (D.) 04-01-050 that the RAR framework could be extended to all energy service providers ("ESPs"), load servicing entities ("LSEs"), and community choice aggregators operating within the service territories of the three IOUs. Decision (D.) 04-01-050 contains justification for imposing the RAR on LSEs through an interpretation of the CPUC Code § 394 that requires LSEs to show "technical and operational reliability". However, as discussed in Decision (D.) 04-07-037, the jurisdictional powers of the CPUC over ESP's and their ability to enforce ESP's to abide to RAR were challenged. The CPUC restated in Decision (D.) 04-07-037 their belief that the "imposition of resource adequacy requirements on ESPs is a logical implementation of our jurisdiction to determine an ESP's operational capability, because adequacy of resources directly affects an ESP's capability to operate." The RAR framework laid out in (D.) 04-01-050 requires that the IOUs and all LSEs within their service territories must meet a 15%-17% reserve requirement, phased in over four years, with complete compliance expected by January 1, 2008.

Additionally, the CPUC required that 90% of summer (June - October) peak energy requirements (including additional capacity needed to meet reserve requirements) be forward contracted one year in advance. IOUs and LSEs must also obtain 100% of energy requirements one month ahead during the summer months. Forward contracting was deemed unnecessary for the remaining seven months of the year, as research has shown utilities already have committed resources close to the 90% level during those months. The reserve requirements are to be included in the load forecasts submitted by each LSE to the CEC.

As noted above, the CPUC suggested a phase-in approach for implementing the RAR framework. This approach is consistent with the Federal Energy Regulatory Commission ideology The CPUC believes a phase-in approach would prevent short-term resource decisions that are inconsistent with California's Energy Action Plan and its preferred loading order that puts primary emphasis on demand response and energy efficiency-adding resources. However, the interim opinion regarding resource adequacy issued in Decision (D.) 04-10-035 addressed the need for an accelerated phase-in for concerns of near-term reliability addressed in Decision (D). 04-07-028.

Compliance with the RAR framework includes the preparation of load forecasts by each Utility and LSE subjected to the resource requirements. The process set forth by (D.) 04-10-050 is as follows:

1. Rather than considering projected load and resource needs only on a statewide or service territory scale, each utility would assess the different characteristics of the many planning areas within its service area – taking into account the nature of local customer load (such as specific industries, the residential mix, and related load profiles), transmission and distribution constraints, existing generation resources, land use concerns and community values.

2. Each utility would develop a base plan that would take into account least-cost resources, reliability needs, fuel diversity, and other risk management concerns. On the local level, the utility would determine the optimal way to meet demand (whether it would be through energy efficiency, demand reduction, transmission or distribution additions, distributed generation, renewables, or fossil generation).

3. On a service territory-wide basis, the utility would then determine whether the optimal local solution adequately supports total resource needs and the achievement of the state's policy preference for energy efficiency and renewables, and adjusts the plan as needed to serve those broader needs.

The CPUC believes that with this form of bottoms-up approach utilities "would be able to understand the implications of its planning decisions" and are encouraging utilities to adopt this process. Several workshops have been held since the filing of (D.) 04-10-050 to provide greater clarification of load forecasting requirements. These workshops have been summarized in Decision (D). 04-10-035, and the "Resource Adequacy Phase 2 Workshop Report June 10, 2005" jointly prepared by the CPUC and the CEC load forecasts are to be prepared "on the basis of their best estimate of future customers and their loads." Though there is not a single agreed upon methodology for preparing the forecasts it is recommended that forecasts include distribution, transmission, and unaccounted for energy losses, and presume a 1-in-2 peak load conditions for each month. Note that a 1-in-2 forecast has a 50% probability of occurrence and is considered by the CEC as "normal" weather. Similarly, a 1-in-10 forecast would have only a 10% probability of occurrence and is considered to be "hotter than normal".

LSEs are to report loads separately for each IOU service territory in which the LSE

serves load. The key points of the load forecast requirements include:

• Load forecasts are based on the "best estimate" of future customer load served by the LSE.
• Load forecasts are based on 1-in-2 peak demand weather for each month.
• Load forecasts are hourly and include all losses and UFE.
• Load forecasts must be documented in terms of both methodology and input variables used to prepare the forecast.
• Hourly historic data from the previous year should be submitted along with the forecast.

Completed forecasts are to be submitted to the CEC to undergo a review process. If the CEC finds that the load forecasts are materially different then actual loads the CEC has the ability to assess penalties for the excessive deviations.

Decision (D.) 04-01-050 includes additional information related to utility resource procurement, cost justifications and utility financial capabilities, long term planning issues, consideration for distributed generation and qualifying facility generation, and energy resource mix preferences.

RAR Framework and IID.

IID's legal obligation to conform to the CPUC / CEC and the RAR framework will be decided upon by IID legal counsel and local authority before commencing on the fulfillment of the RAR requirements, to determine the degree of compliance that IID wishes to follow.

IID Demand-Side Management (DSM) / Public Programs Group

Strategy

IID is adopting a more aggressive DSM program strategy to address not only increasing energy but also to improve the load factor. This strategy includes:

- Maintaining existing energy efficiency programs while evaluating, modifying or terminating them upon cost effectiveness and ability to address customer needs and achieve results.
- Enhancing current energy efficiency programs by targeting key customer segments that will produce significant results compared to cost. One example is the current implementation of the Ag efficiency program.
- Adding new energy efficiency programs to address key areas such as new construction.
- Implementation of a residential demand response program to address residential peak demand contribution.
- Implementation of a business demand response program to further address system peak.

- Implementation of a photovoltaic (PV) and renewable energy program to provide generation located on customer premises that will be independent of fuel risk and relieve pressure on the ECA while contributing to improvement of system load factor.

DSM Programs

Over the next five years, the DSM programs are projected to contribute nearly 100 MW of demand relief. This level of DSM performance will improve system load factor, reduce the need for new generation, and contribute to stabilizing the rates. The next table provides the five-year projection for the DSM programs.

DSM Goals
5 Year Plan
Preliminary

	GOAL (MW)					
	2007	2008	2009	2010	2011	TOTAL
Residential Efficiency	2.2	2.5	2.7	2.7	2.4	12.5
CI Efficiency	2.7	4.5	6.0	6.0	6.0	25.2
Residential Demand Response	3.5	7.0	7.0	7.0	3.5	28.0
CI Demand Response	5.5	9.5	11.4	2.0	0.0	28.4
PV/Renewables	0.3	0.4	0.7	1.2	2.1	4.7
TOTAL	14.2	23.9	27.8	18.9	14.0	98.8

Time-of-Use Program (TOU)

Like most utilities, the cost to generate and purchase electricity is highest during peak hours of the day. One of the major goals of IID in 2005 was to develop new and innovative retail electric rate designs that aid in the shifting of peak demand load, accurately reflect IID's true cost of service, and provide customer choice. To keep energy costs low for our largest commercial customers, we developed the Time-of-Use Pilot rate option; the customer will pay a lower rate for electricity used during off–peak hours and a higher rate for power used during on-peak hours**.** From IID's perspective, implementing Time-of-Use (TOU) rates would result in significant cost savings, reliability/service improvements, and improved margins.

The TOU Project was developed and scheduled to rollout in phases, which include the following:

Phase I: Rollout of the optional TOU Pilot Rates for Large Commercial Customers with energy consumption of 2 MW or more during a 12-month period. The optional TOU Pilot Rates will be available for these customers in December 2006 and sunset when Phase II begins.

Phase II: Rollout the optional TOU Rates for all (approximately 200) large commercial customers with 250 KW consumption at least once during a 12 month period. TOU Rates will be available 2nd Quarter or 3rd Quarter of 2007.

Phase III: Implement mandatory TOU Rate for all large commercial customers with 350 KW or greater at least 3 times during a 12 month period. TOU Rates will be available for 2008.

Time-of-Use Pilot Schedule

Time-of-Use Pilot Schedule will be as follows:

Seasons:

Summer	May thru September
Winter	October thru April

Days/Time of Days:

On Peak	Monday thru Friday	1pm to 7pm
Mid Peak	Monday thru Friday	10am to 1pm; 7pm to 11pm
Off Peak	Monday thru Friday	11pm to 10am
	Weekends	
	Holidays	

IID is currently going through a demonstration project targeted to agricultural cooling operations in the Imperial and Coachella valleys, one that could be folded neatly into the time-of-use rates geared to the District's largest energy customers.

The new time-based rates for agricultural coolers would result in a 5-percent reduction in rates across the board, which would affect an estimated 38 such operations in the Imperial and Coachella valleys. The District's ultimate goal is to roll out TOU rates to all customer classes in an effort to use price signals to shift actual demand.

The pilot program TOU rates are expected to sunset in December 2007, at which time IID will be in a better position to evaluate their effectiveness and, possibly, broaden their application to other customer rate classes.

Transmission Planning Group

IID Transmission Expansion Plan

Over the last few years, IID has reviewed and developed a detailed long-term transmission plan (ten year timeframe) to define the transmission improvements necessary to continue meeting the load service requirements in future years. The plan has primarily focused on the upgrade of certain sections of IID's 161 kV and 92 kV transmission systems to 230 kV to integrate the existing 230 kV collector system and create a 230 kV transmission loop that will cover most of IID's service area. As well as building transmission facilities to increase transformation capacity from 230 kV to 92 kV.

These transmission upgrades and improvements will serve as a backbone to increase IID's ability to meet the significant load growth that we have experienced in the last five years and the forecasted load growth for the years to come. These upgrades will improve IID's system reliability, voltage profile and import capability into IID service area to meet its load serving needs for at least the next 15-20 years.

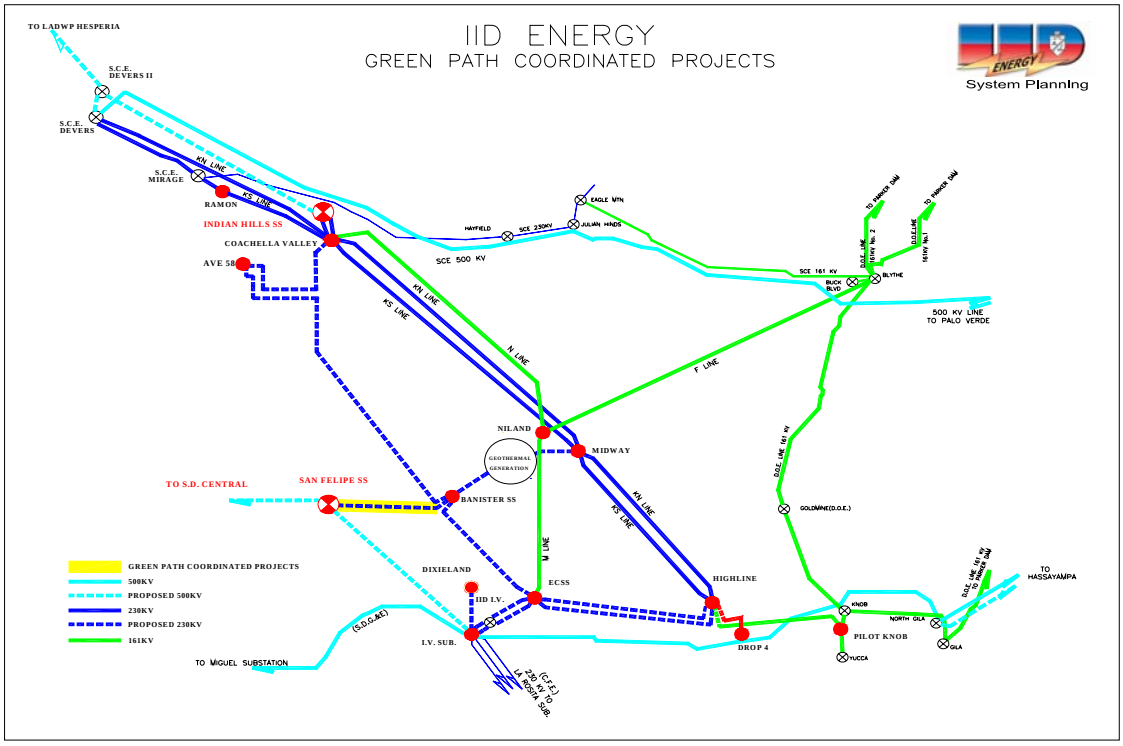
Currently, IID is working in the development activities such as permitting, environmental work, ROW assessment and preliminary engineering design. This is required for the transmission upgrade and rebuilding of certain sections of the aging 161 kV/92 kV transmission system.

Green Path Coordinated Projects

The recently approved California's RPS mandates have increased the demand and interest in developing new geothermal renewable resources in California. Especially the ones located in Imperial Valley's Salton Sea area. On October 2004, the CEC and IID had concluded that a long-term transmission study effort should be initiated to determine transmission issues related to delivering over 2000 MW of additional renewable resources out of the Imperial Valley. This effort is known as the Imperial Valley Study Group ("IVSG"). The result of the IVSG was a system of coordinated projects to facilitate the access to geothermal and solar resources located within IID service area to multiple delivery points.

IID has forged a public/private strategic partnership with Citizens Energy, LADWP, SCPPA and SDG&E to develop the Green Path Coordinated Project.

The following drawing depicts the proposed plan of service for the Green Path Coordinated Projects.



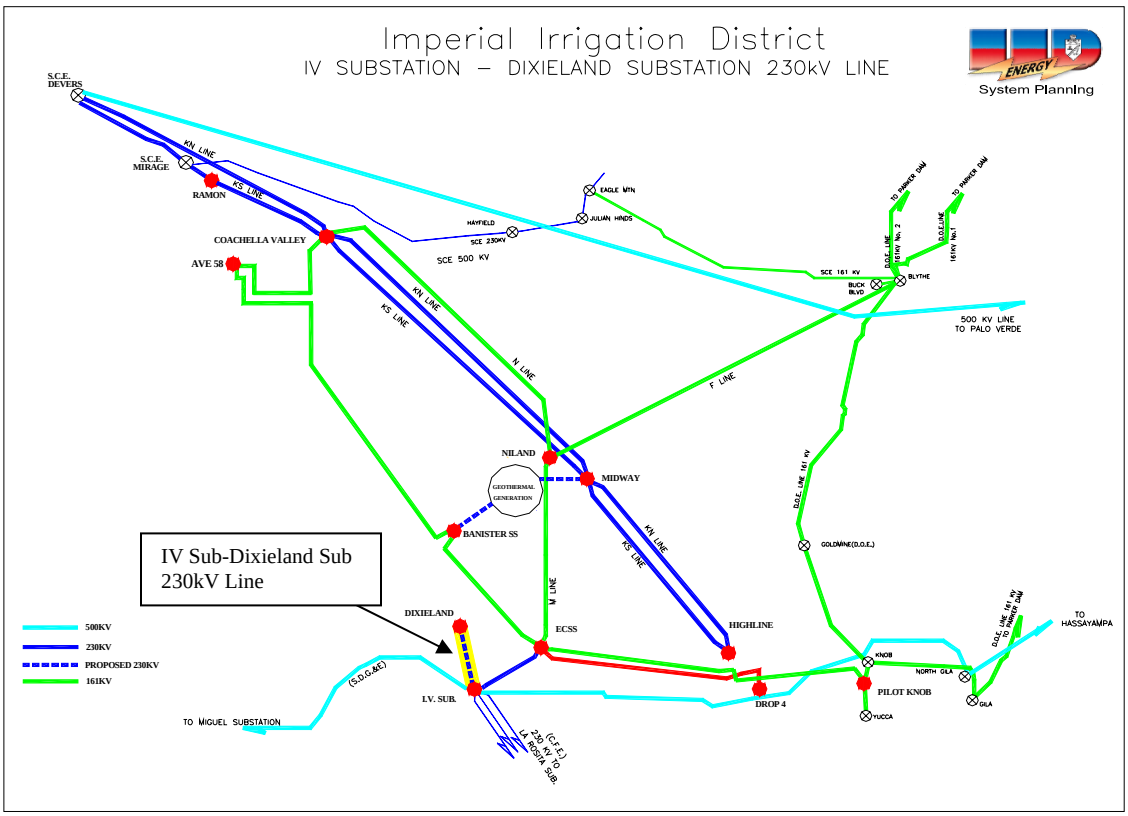
With the completion of the IVSG, it is clear that the proposed IID long-term transmission needs for both, load serving and to deliver over 2,000 MW of new renewable resources to the IID interconnection points with adjacent transmission systems, can be integrated. While the development of the renewable resources has been slow, due to execution of power purchase contracts with the regional load serving utilities, IID will continue to move forward with the long-term transmission plans and accelerate segments to facilitate additional resource deliveries and reinforce the reliability requirements to serve IID customers.

Imperial Valley – Dixieland Project

The Imperial Valley Substation–Dixieland Substation 230 kV Interconnection project consists of building a new single circuit 230 kV line between Imperial Valley Substation and Dixieland Substation. The project is scheduled to be complete by the end of 2008 and also includes the associated upgrades at Dixieland Substation and Imperial Valley Substation.

This interconnection line will increase the IID import/export capability to meet the future load requirements. In addition, IID will increase the system reliability and improve the voltage profile at the Imperial Valley transmission network. The new 230 kV interconnection project will allow IID to continue importing and exporting up to its interconnection capability when 230 kV "S Line" is taken out of service (due to line maintenance or equipment failure) with no impact to the IID System reliability.

The follow drawing depicts the proposed line from Imperial Valley Substation to Dixieland Substation.



The Palo Verde – Yuma 500kV Transmission Project IID's Participation

APS is planning to construct a 500 kV transmission project from the Palo Verde hub to the North Gila 500 kV switching station. Location of the project will be approximately parallel to the existing Hassayampa-North Gila 500 kV line; however the final route selection has yet to be determined. The tentative capacity of the project will be determined based on studies that are in process to be performed and is scheduled to be placed in-service by the summer of 2010.

IID has already signed a Memorandum of Agreement (MOA) between IID, APS, SRP and Wellton-Mohawk Drainage District ("WMDD") addresses its participation with these entities in the initial work (Phase I Work) of the Palo Verde – Yuma Project.

In coordination with this project, IID is planning to construct a new 230 kV line from North Gila to Highline Station.

System Operations Group

Future Projects

IID's System Operations Group will continue improving the support on facilitating procurement of services to help promote renewable green energy. IID has assisted and will continue assisting any renewable projects requesting final on-line production and ultimate scheduling of their energy for export.

The Energy Management Systems, Supervisory Control and Data Acquisition, metering and communication medians and devises will continue their upgrading process for improved generation output tracking.

Generation Group

Future Projects

Future generation projects that are being considered, with no commitments, include:

- Repowering of the El Centro Unit 4 - 80 MW steam unit. In a repowered configuration, the unit would be approximately 240 MW.
- Installation of additional "peaking" gas turbines at the Niland Gas Turbine Plant beyond the 93 MW currently being developed.
- Construction of yet to be determined geothermal units within Imperial County.
- Construction of additional mini-hydro plants in Imperial County.

Accomplishments

IID Generation is developing two new generating resources scheduled for commercial operation in May 2008 and May 2009. The generating resource scheduled for May 2008 is a "peaking" resource with a nominal capacity of 93 MW to be located in Imperial County. It will be located at a site in Niland, CA and use a General Electric LM6000 gas turbine in a simple-cycle configuration. The LM6000 resource will use best available control technology (BACT) and dry low NOx technology to minimize harmful emissions and minimize water use, respectively. The generating resource scheduled for May 2009 is an "intermediate/base" resource with a nominal capacity of 120 MW to also be located in Imperial County. It will be located at the El Centro Generating Station and use the General Electric Frame 7EA gas turbine in a combined-cycle configuration. The 7EA resource will use best available control technology (BACT) and dry low NOx technology to minimize harmful emissions and minimize water use, respectively. The 7EA resource is a repower of the existing Unit 3; the repower will increase Unit 3 efficiency by about 30% and reduce water consumption by about 60% for every MWH generated.

IID Regulatory Affairs Group (Issues)

Future Issues and Timelines

The Governor recently signed a number of bills of high importance to SCPPA members, which IID is part of. Each of these bills takes effect on January 1, 2007. The following sections set out deadlines and timelines contained in the bills which will become law at that time. As this information is of a general nature, we'll want to rely on our company's Regulatory Affairs Group to digest the significance of these bills along with trigger dates they all contain to meet the specific requirements of each new law.

AB 32 (Nunez)

12/31/06. Entities registered with the CA Climate Action Registry by this date and with a Greenhouse Gas (GHG) reporting/verification program will not have to alter that program, except as necessary to ensure compliance

01/01/07. SB 1368 takes effect

01/01/07. Air Resources Board to adopt a list of early action emission reduction measures achievable prior to adopting market-based compliance mechanisms required by AB 32

02/01/07. The Public Utilities Commission (PUC), through rulemaking, must establish the GHG emission performance standard for all baseload generation, with the emissions rate not higher than the rate for combined-cycle natural gas baseload generation

02/01/07. Enforcement begins immediately after the standard is established

06/01/07. CEC), with PUC, ARB and other stakeholders shall establish GHG standard for municipal utilities, consistent with the PUC standard for Investor Owned Utilities (IOUs)

06/30/07. ARB must publish a list of early action gas emissions reduction measures

01/01/08. ARB to adopt statewide emissions limit on GHG emissions, including process and criteria, effective after 2020 unless amended or repealed; by 01/01/10 must adopt and enforce those measures…authorizes ARB to impose administrative, civil and criminal penalties

01/01/08. ARB to adopt regulations requiring GHG emission sources to monitor and report their emissions to the ARB

01/01/09. ARB to prepare and adopt a rulemaking scoping plan for rules and regulations and update the plan every five years

01/01/10. ARB to adopt regulations to implement measures published 06/30/07

01/01/11. ARB must adopt GHG emission limits and measure to achieve the maximum feasible and cost-effective reductions in GHG, allows the ARB to adopt "a system of market-based declining annual aggregate emission limits" or cap and trade, applicable from 01/01/12 to 12/31/20

Additional Considerations:

1) The Governor is authorized, in the event of extraordinary circumstances, catastrophic events or threat of significant economic harm, to adjust deadlines for a period not to exceed one year

2) ARB must consider environmental justice, best available science, economics as well as consult with other state agencies with jurisdiction over utilities

3) State's retail sellers of electricity must achieve at least 20% of energy sales from renewables

4) PUC, with the Independent System Operator (ISO), must consider the effects on system reliability and costs to consumers

AB 1925 (Blakeslee)

01/01/07. AB 1925 takes effect

11/01/07. CEC must:

1) Report to the legislature and recommend how the state can develop parameters on cost-effective geologic sequestration of industrial carbon dioxide, meeting with specific groups to formulate recommendations

2) Evaluate potential risks from sequestration of carbon dioxide, potential risks if sequestered carbon dioxide leaks into aquifers and liability from leakage of sequestered carbon dioxide and potentially responsible parties

3) Include the report required by AB 1925 in its 2007 Integrated Energy Policy report to the legislature

AB 2021 (Levine)

01/01/07. AB 2021 takes effect

11/01/07. By 11/01/07, and each November 1 every three years thereafter, CEC with the PUC and municipal utilities in a public process, input from other stakeholders, to identify potentially achievable cost-effective energy efficiency savings and establish annual targets for the next 10 years

01/06/08. Within 60 days of adopting annual targets, requires municipal utility to report targets to the CEC; requires the PUC to base its estimate on most recent targets of the PUC and municipal utilities

Reporting. Each municipal utility must annually report:

1) To customers and the CEC, for use in Integrated Energy Policy Report, on investments in energy efficiency and demand reduction programs describing programs, expenditures, cost-effectiveness and savings reductions

2) To the CEC sources of funding energy efficiency and demand reduction investments and assumptions used to determine cost-effectiveness

Additional Requirements:

1) Independent evaluation, measurement and verification of energy efficiency savings achieved by municipal utility programs

2) Requires the CEC to provide recommendations to the municipal utility, the legislature and the Governor if improvements can be made regarding the level of annual targets or annual targets

AB 2189 (Blakeslee)

01/01/03. When efficiency improvements are undertaken after 01/01/03 to a small hydroelectric generation facility that already meets the definition of eligible renewable resource, and if those improvements exceed 30 MW but do not increase appropriation or diversion of water, then the entire generating capacity of the facility is an eligible renewable resource.

01/01/07. AB 2189 takes effect

AB 2951 (Goldberg)

01/01/07. AB 2951 takes effect

AB 2951 allows a municipal utility to impose a fee upon a public agency - comparable to nonpublic users - for any product, commodity or service. Prior to imposing a fee, parties must meet these timelines:

1) 60 days advance notice, in writing, when fees will be increased during a public meeting

2) 30 days prior to public meeting, a public agency may request data on which the increase is based, including a meet and discuss if requested

3)120 day Statute of Limitations from the effective date of the change for the public agency to challenge. If public agency fails to pay, etc., municipal utility can take no action before 120 days has lapsed.

4) Cost of service study at least once every 10 years

Burden of Proof. Municipal utility must prove it has met the procedural requirements above, as well as the cost of service study

01/01/10. Sunset date

SB 1 (Murray)

01/01/07. SB 1 takes effect

06/01/08. Requires municipal utilities to adopt, implement and finance a solar initiative program, consistent with the CA Solar initiative adopted by the PUC for the IOUs, annually thereafter to report to customers, the legislature and the CEC related to the program and sets $784 M as the statewide expenditure for municipal utilities

SB 107 (Simitian)

01/01/05. Expands the definition of "eligible renewable resource" to include out-of-state generation if the facility began operating after 01/01/05

01/01/07. SB 107 takes effect

10/31/10. Legislature intends that the PUC and the CEC implement the RPS to attain a target of 20% of retail sales of electricity from eligible renewables by 2010. Municipal utilities are excluded from the definition of retail seller. (Legislative intent language does not have the force and effect of statutory language, but the courts may consider it if the statutory language is unclear.)

Reporting: While municipal utilities are excluded from the definition of retail seller, each municipal utility must annually report to the CEC on its mix of eligible renewable resources and their progress toward meeting their RPS.

Target: Municipal utility must have an established annual RPS standard target comparable to those for the IOUs in order for the CEC to certify eligible renewable energy resources

- Authorizes municipal utilities to sell renewable energy credits
- Requires the CEC to use eligibility criteria and conditions (under existing law developed by the CEC in consultation with the PUC and municipal utilities) for solar energy systems applicable to the CSI
- Authorizes, if the CEC provides funding for a system to verify compliance with the RPS by retail sellers, to recover all costs from user fees

SB 1210 (Torlakson)

01/01/07. SB 1210 takes effect

Eminent Domain: SB 1210 prevents issuance of a pre-judgment order of possession (public entity taking possession of property without prior notice or without the opportunity for the owner to respond or seek a hearing)

30 days: Thirty days after service of a motion for pre-judgment possession, the record owner of the property must file written opposition. An order of possession will be granted by the court if the owner does not oppose within 30 days, the public entity/plaintiff is entitled to take by eminent domain and the public entity/plaintiff has deposited with the court an amount meeting the statutory requirements of just compensation

60 days: Not less than 60 days after service, the public entity/plaintiff must set the court hearing on the motion

90 days: If the property is occupied, SB 1210 requires service of the motion on the owner 90 days prior to the hearing. The owner has 30 days to oppose the motion, which the public entity/plaintiff must reply to in not less than 15 days prior to the hearing. An order of possession will be granted by the court if the owner does not oppose within 30 days, the public entity/plaintiff is entitled to take by eminent domain, and has deposited with the court an amount meeting the statutory requirements of just compensation.

Motion Opposed: The court will grant an order of possession if the public entity/plaintiff is entitled to take by eminent domain and has deposited with the court an amount meeting the statutory requirements of just compensation. There is an overriding need for the public entity/plaintiff to take possession of the property before final judgment and substantial hardship results if the motion of possession is denied and the hardship to the public entity/plaintiff outweighs the hardship to the owner to take possession.

SB 1359 (Torlakson)

14 Calendar Days: Any person planning an excavation must contact the regional notification center at least 2 working days, and not more than 14 calendar days, prior to starting an excavation. The regional notification center will provide an inquiry identification number valid for 28 days and maintain records for no less than 3 years, and, when within 10 feet of a high priority subsurface installation, must notify the excavator and meet on site

SB 1368 (Peralta)

01/01/07. SB 1368 takes effect

02/01/07. PUC, through rulemaking, must establish the GHG emission performance standard for all baseload generation, with the emissions rate not higher than the rate for combined-cycle natural gas baseload generation

02/01/07. Enforcement immediately after the standard is established

06/01/07. CEC, with PUC, ARB and other stakeholders shall establish GHG standard for municipal utilities, consistent with the PUC standard for IOUs

No IOU or municipal utility may enter into a long-term contract (5 years) unless the baseload generation complies with the GHG emission performance standard established by the PUC and CEC.

The CEC must approve municipal utility contracts.

PUC with the ISO must consider the effects on system reliability and costs to consumers.

The PUC is also authorized to, through rulemaking, to continue, modify or replace the GHG emissions standard applicable to load serving entities…no requirement to go back to the legislature to seek further authorization.

There is no sunset date for this bill.

On July 29, 2005, Congress passed the first comprehensive energy legislation in more than a decade. President Bush signed the energy bill on Aug. 8 in a ceremony at Sandia National Laboratories in Albuquerque, making the Energy Policy Act of 2005 law.

This historic bill strengthens our nation's electrical infrastructure, reduces our dependence on foreign oil, increases conservation and expands the use of clean renewable energy, said Energy Secretary Samuel Bodman.

The Secretary went on to say, "The bipartisan efforts to craft this legislation, led in the Senate by Senators Domenici and Bingaman, have produced a bill of which we all can be proud. By encouraging greater efficiency, increased energy production in environmentally responsible ways and encouraging investment in our nation's outdated energy infrastructure, this bill takes a balanced approach and embodies the right priorities for the American people.

"This legislation helps protect our environment by supporting the development and deployment of renewable energy sources like wind and solar power, encouraging the construction of clean, safe, nuclear power plants and promoting research and development efforts to transform the way we produce and use energy in the future. This is a victory for the American people," he added.

The new laws affect WAPA, utilities, and the consumers. The law repeals the Public Utility Holding Company Act and reforms the Public Utility Regulatory Policy Act. Several sections have direct implications to WAPA's activities and business practices. It also encourages needed investment in the nation's infrastructure, helps boost electric reliability and promotes a diverse mix of fuels to generate electricity. The two-year extension to the wind production tax credit means WAPA is likely to see additional interconnection requests from wind generators. The law also offers benefits to electricity consumers and encourages energy-efficiency and conservation.

Major sections of the more than 1,700-page legislation address:

- Reliability of the electricity system
- Critically needed investments in energy infrastructure
- Stable, diverse fuel supply for electricity generation
- Protection for electricity consumers and markets
- Energy efficiency and wise energy use

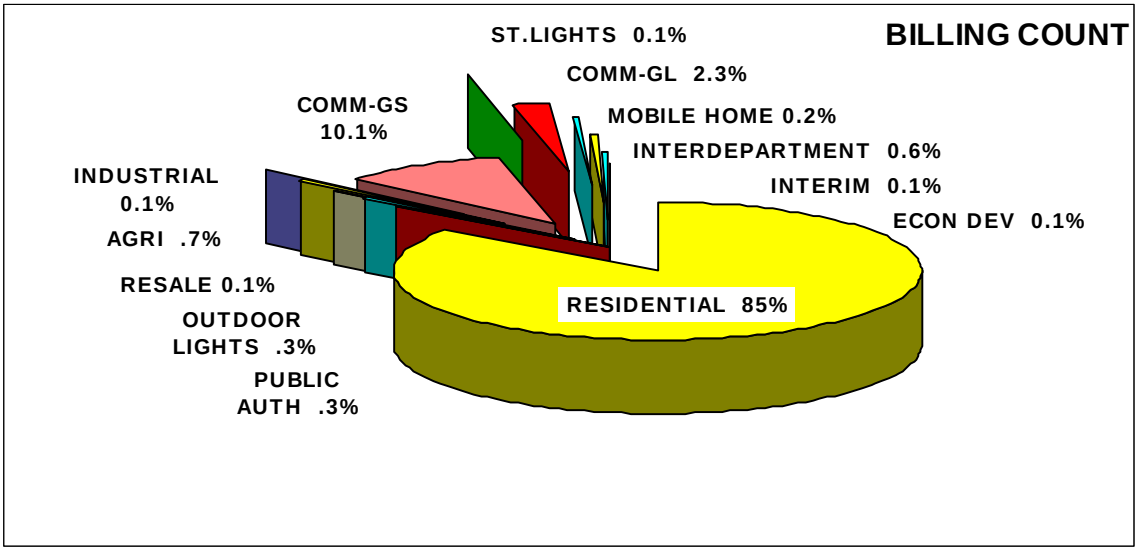
By supporting new energy-efficient technologies, the Energy Policy Act of 2005 provides venues for the government to offer every American better energy security at lower costs. More money is being spent on energy-efficiency research today than ever before, said Energy Secretary Samuel Bodman in praising the passage of the landmark legislation. Here's a rundown on the bill's conservation and efficiency investment provisions:

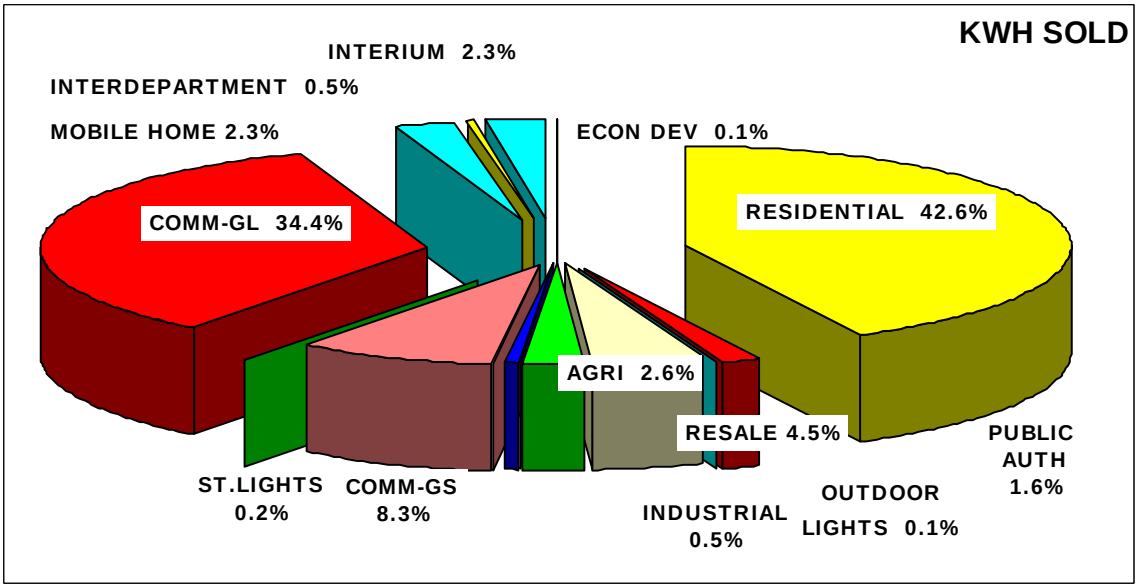
- *Promoting residential efficiency.* Technology offers the possibility of a "zero-energy" home. The average American home loses between 10 and 50 percent of its energy through inadequate insulation and inefficient lights and appliances. The law supports research that promotes advances in energy efficiency and offers consumers tax credits for making energy-efficiency improvements in their homes.
- *Increasing appliance and commercial product efficiency.* The law sets new minimum energy-efficiency standards for a range of consumer and commercial products, including heaters, refrigerators, and lighting units. It also encourages the sale and production of energy-efficient products, which increases the supply of available energy, helping families meet their bottom lines. Tax credits are available for highly efficient central air conditioners, heat pumps, and water heaters, as well as to upgrade thermostats, install exterior windows and stop energy waste.
- *Reducing Federal government energy use.* The Energy Policy Act of 2005 calls on Federal agencies to lead by example and improve their energy efficiency. It reauthorizes the Energy Savings Performance Contract program, which allows private contractors to help Federal agencies improve the energy efficiency of their facilities. The bill also sets aggressive new goals for Federal energy efficiency and requires agencies to purchase Energy Star products.
- *Modernizing domestic energy infrastructure.* The legislation helps modernize our aging energy infrastructure to help reduce the risk of large-scale blackouts and minimize transmission bottlenecks. This is accomplished by repealing outdated rules that discourage investment in new infrastructure, offering tax incentives for

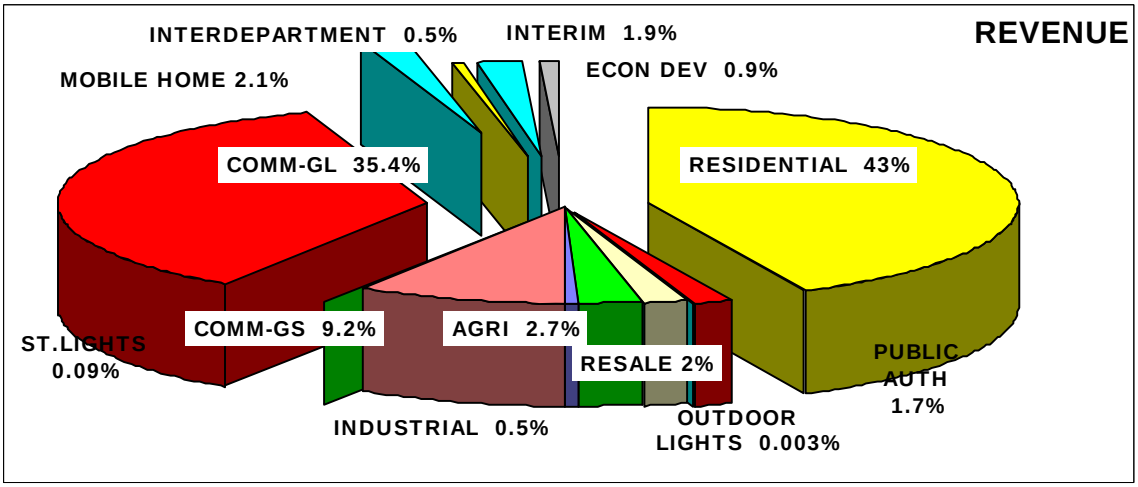
new transmission construction and encouraging development of new technologies, such as superconducting power lines, to make the power grid more efficient.

- *Diversifying the nation's energy supply with renewable sources.* The new law promotes the use of renewable energy sources with tax credits for wind, solar and biomass energy, including the first-ever tax credit for residential solar energy systems. The law also expands research into developing hydrogen technologies and establishes a flexible, national Renewable Fuels Standard to encourage greater use of renewable fuels like ethanol and biodiesel.
- *Supporting a new generation of energy-efficient vehicles.* The legislation provides up to $3,400 per energy-efficient hybrid, clean-diesel, and fuel-cell vehicle in tax credits to consumers who purchase these cars, based on their fuel savings potential. Some of these cars can travel twice as far as conventional vehicles on one gallon of fuel, reducing U.S. dependence on foreign energy sources while producing lower emissions.

APPENDIX A.


BILLING COUNT
ST.LIGHTS 0.1%
COMM-GL 2.3%
COMM-GS 10.1%
MOBILE HOME 0.2%
INTERDEPARTMENT 0.6%
INTERIM 0.1%
ECON DEV 0.1%
INDUSTRIAL 0.1%
AGRI .7%
RESALE 0.1%
RESIDENTIAL 85%
OUTDOOR LIGHTS .3%
PUBLIC AUTH .3%


KWH SOLD
INTERIUM 2.3%
INTERDEPARTMENT 0.5%
MOBILE HOME 2.3%
ECON DEV 0.1%
COMM-GL 34.4%
RESIDENTIAL 42.6%
AGRI 2.6%
RESALE 4.5%
PUBLIC AUTH 1.6%
ST.LIGHTS 0.2%
COMM-GS 8.3%
INDUSTRIAL 0.5%
OUTDOOR LIGHTS 0.1%


REVENUE
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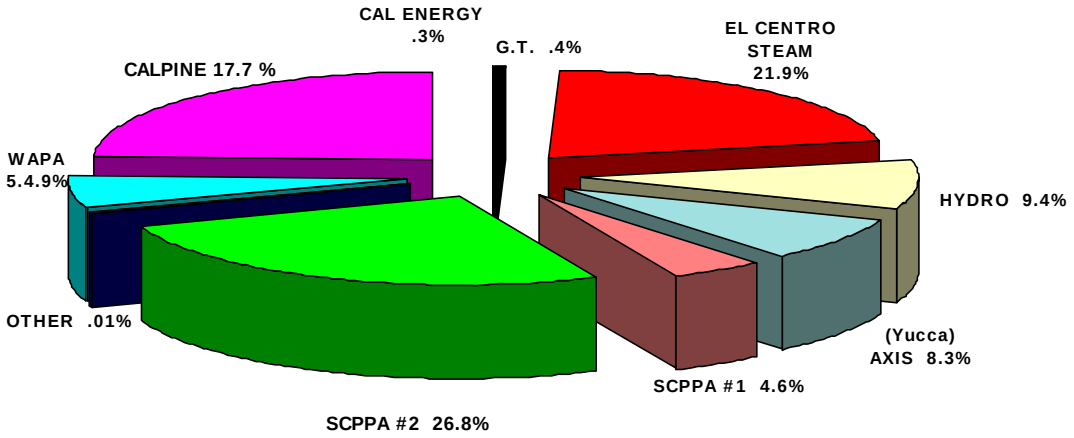
INTERIM 1.9%
MOBILE HOME 2.1%
ECON DEV 0.9%
COMM-GL 35.4%
RESIDENTIAL 43%
COMM-GS 9.2%
AGRI 2.7%
ST.LIGHTS 0.09%
RESALE 2%
PUBLIC AUTH 1.7%
INDUSTRIAL 0.5%
OUTDOOR LIGHTS 0.003%

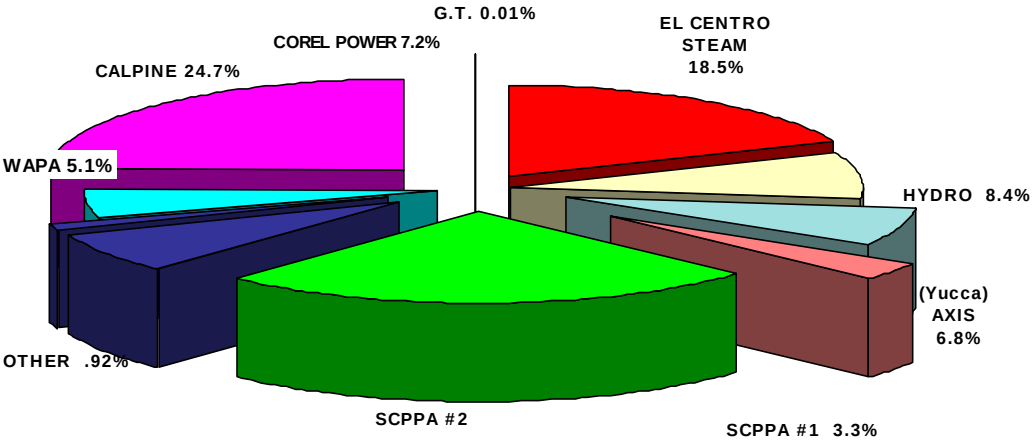
APPENDIX B.

2004



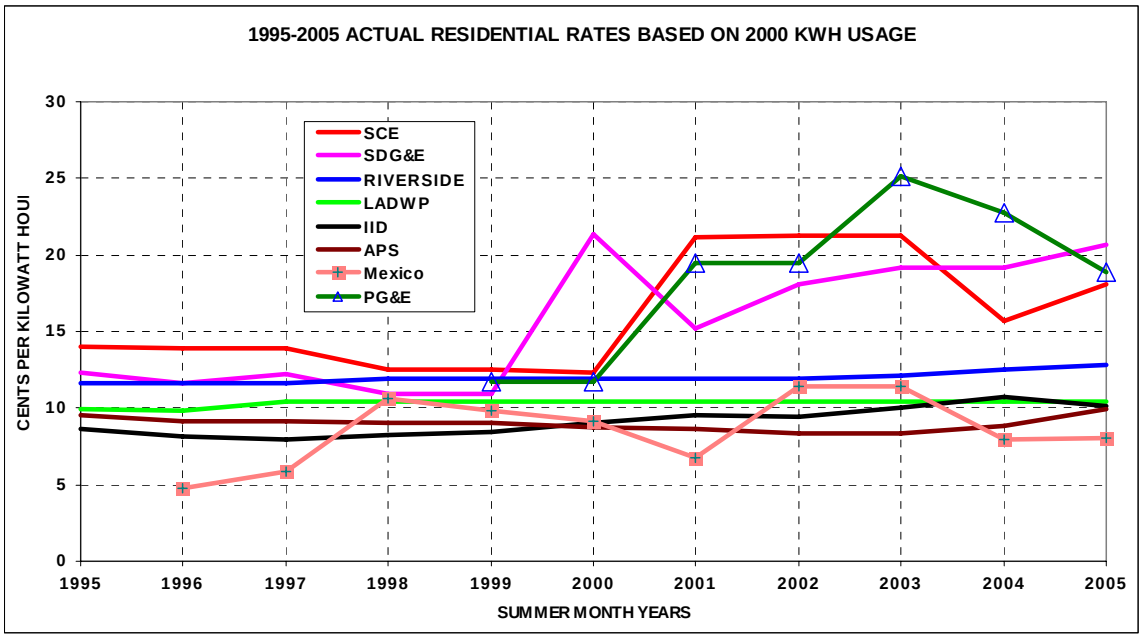
Note: Includes Resources Required to meet Customer Loads of 3,320,797,183 KWh and Inter-Utility Sales of 55,924,000 KWh in 2004.

2005



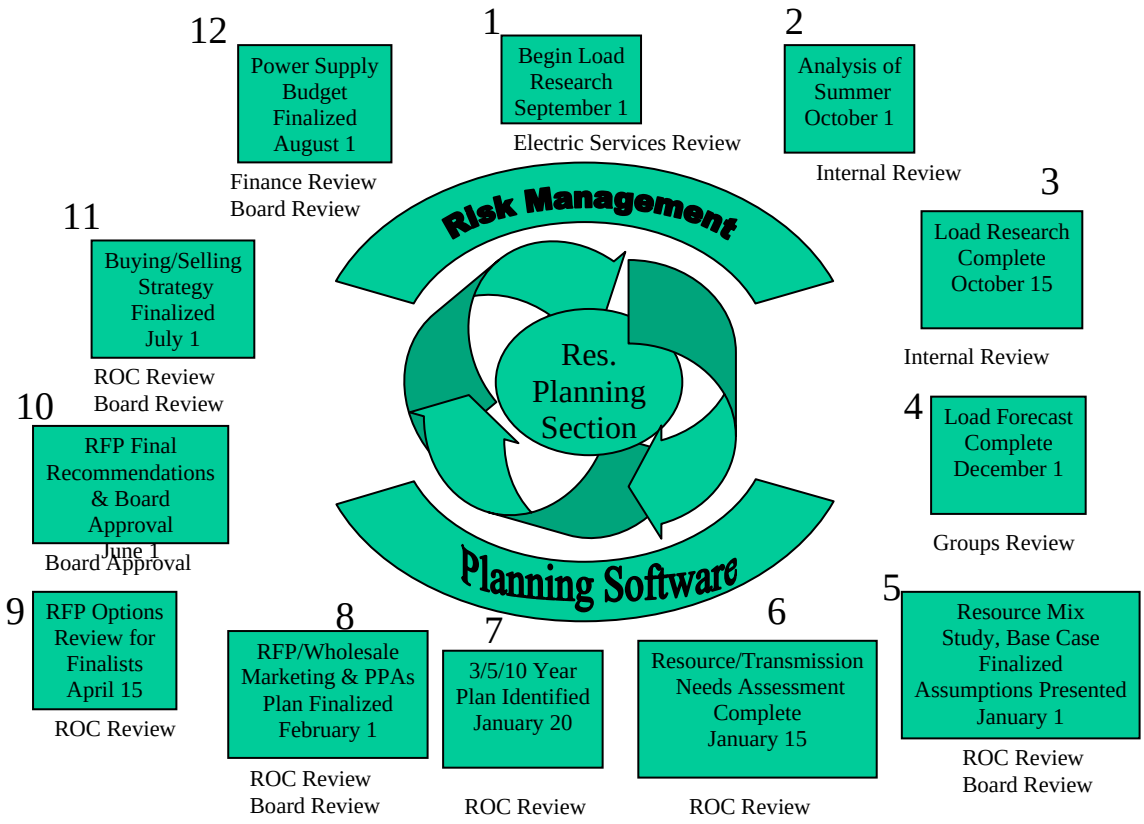
Note: Includes Resources Required to meet Customer Loads of 3,449,757,905 kWh and Inter-Utility Sales of 150,670,000 kWh in 2005.

APPENDIX C.


1995-2005 ACTUAL RESIDENTIAL RATES BASED ON 2000 KWH USAGE
CENTS PER KILOWATT HOUI
30
25
20
15
10
5
0
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
SUMMER MONTH YEARS
SCE
SDG&E
RIVERSIDE
LADWP
IID
APS
Mexico
PG&E

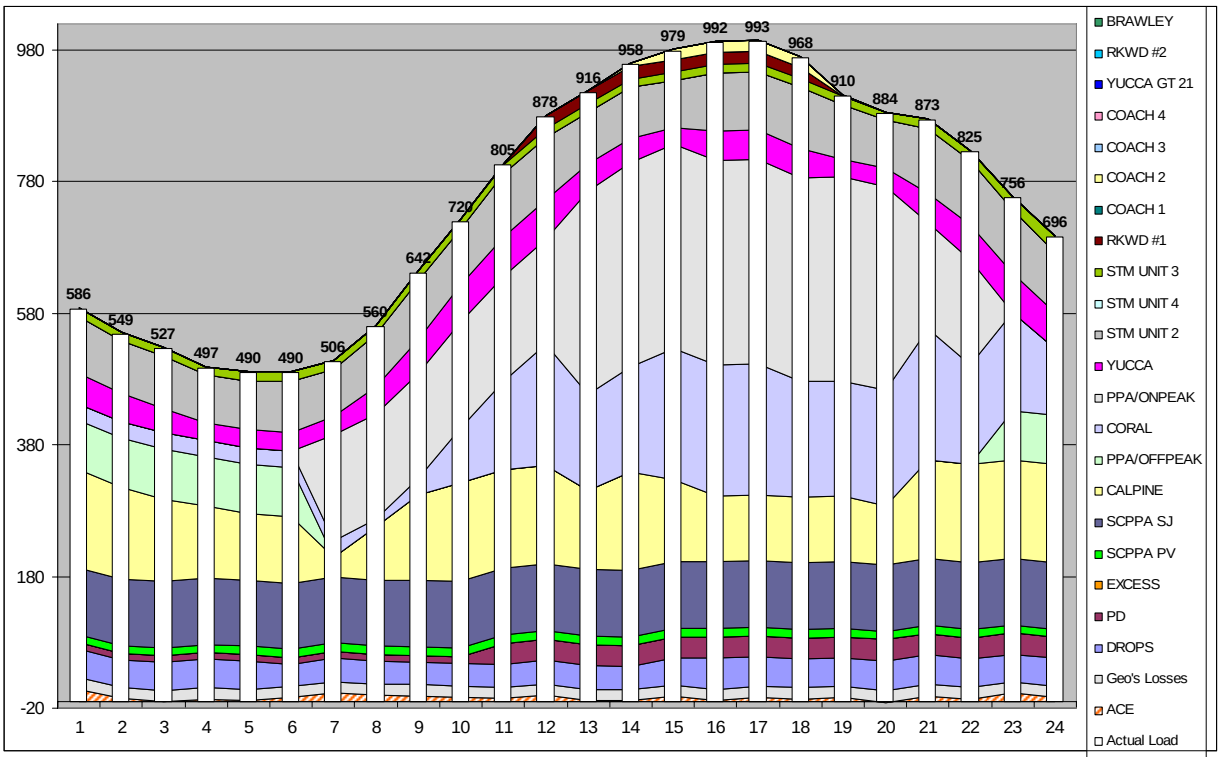
APPENDIX D.

Annual Integrated Resources Planning Cycle



APPENDIX E.

Resources Stack to Serve Load on the Peak Day of 2006.



APPENDIX F.

FLEXIBLE RESOURCES PLAN

SUMMARY OF IID'S ANNUAL PEAK DEMAND LOAD AND RESOURCES (MW) FOR 2007 AND BEYOND

ALTERNATIVE RESOURCE PLAN- YEAR	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
FORECASTED SYSTEM DEMAND - MW	**1026**	**1041**	**1088**	**1134**	**1181**	**1227**	**1274**	**1320**	**1367**	**1413**	**1460**
PLANNING RESERVES REQUIREMENT - MW	154	156	163	170	177	184	191	198	205	212	219
TOTAL SYSTEM CAPACITY REQUIREMENTS- MW	**1180**	**1197**	**1251**	**1304**	**1358**	**1411**	**1465**	**1518**	**1572**	**1625**	**1679**
DISTRICT-OWNED RESOURCES AND PURCHASES - MW											
BRAWLEY	18	18	18	18	18	18	18	18	18	18	18
COACHELLA	80	80	80	80	80	80	80	80	80	80	80
EL CENTRO	232	232	190	190	190	190	190	190	190	190	190
ROCKWOOD	42	42	42	42	42	42	42	42	42	42	42
YUCCA	101	101	101	101	101	101	101	101	101	101	101
SAN JUAN	102	102	102	102	102	102	102	102	102	102	102
PALO VERDE	14	14	14	14	14	14	14	14	14	14	14
CALPINE / CALPINE REPLACEMENT	150	150	150	150	150	150	150	150	150	150	150
GUEPARD	0	0	0	0	0	0	0	0	0	0	0
SALTON SEA 6	0	0	0	0	0	0	0	0	0	0	0
CORAL POWER	25	0	0	0	0	0	0	0	0	0	0
RELIANT	0	0	0	0	0	0	0	0	0	0	0
PARKER-DAVIS (SUMMER)	33	33	33	33	33	33	33	33	33	33	33
HYDRO	32	32	32	32	32	32	32	32	32	32	32
RFP #484 PRODUCTS - MW	**150**	**240**	**357**	**357**	**357**	**257**	**257**	**257**	**257**	**257**	**207**
FUTURE RFP - MW						**90**	**90**	**90**	**90**	**90**	**90**
FUTURE RFP - MW										**90**	**90**
TOTAL (NET SUMMER CAPACITY) - MW	**978**	**1043**	**1118**	**1118**	**1118**	**1108**	**1108**	**1108**	**1108**	**1198**	**1148**
CUMMULATIVE NEW RESOURCES NEEDS - MW	**202**	**154**	**132**	**186**	**240**	**303**	**357**	**410**	**464**	**427**	**531**
PLANNED PURCHASES	205	155	100	105	155	220	275	320	355	320	410
PLANNED GREEN ENERGY DEVELOPMENT PROJECTS											
BIOMASS, WIND, SOLAR & SMALL GEOTHERMAL - MW			35	85	85	85	85	90	110	110	120
PLANNED TOTAL NEW RESOURCE ADDITIONS - MW	**205**	**155**	**135**	**190**	**240**	**305**	**360**	**410**	**465**	**430**	**530**
TOTAL PLANNING RESERVE MARGIN - PERCENT	**15.3%**	**15.1%**	**15.2%**	**15.4%**	**15.0%**	**15.2%**	**15.3%**	**15.0%**	**15.1%**	**15.2%**	**15.0%**

APPENDIX G.

	Total System Monthly Peak Demand Forecast (MW) as of Data Available by 9/1/2006													
	January	February	March	April	May	June	July	August	September	October	November	December	Peak	Adjusted Peak
2007	391	385	461	514	765	906	995	940	858	717	444	432	995	**1026**
2008	402	397	474	533	781	943	1041	978	885	743	461	448	1041	**1041**
2009	413	410	487	557	797	979	1088	1016	912	770	477	463	1088	**1088**
2010	424	422	500	586	814	1016	1134	1054	939	796	494	478	1134	**1134**
2011	435	435	513	607	830	1052	1181	1092	966	823	511	493	1181	**1181**
2012	446	447	526	634	846	1089	1227	1130	993	849	528	509	1227	**1227**
2013	457	460	539	659	863	1125	1274	1168	1020	876	544	524	1274	**1274**
2014	468	472	551	683	879	1162	1320	1206	1047	902	561	539	1320	**1320**
2015	478	485	564	708	895	1198	1367	1244	1074	929	578	554	1367	**1367**
2016	489	497	577	733	912	1235	1413	1282	1101	955	594	569	1413	**1413**
2017	500	510	590	758	928	1271	1460	1320	1128	982	611	585	1460	**1460**
2018	511	522	603	783	944	1308	1506	1358	1155	1009	628	600	1506	**1506**
2019	522	535	616	807	961	1344	1553	1396	1182	1035	644	615	1553	**1553**
2020	533	547	629	832	977	1381	1600	1434	1209	1062	661	630	1600	**1600**
2021	544	560	642	857	993	1417	1646	1472	1236	1088	678	646	1646	**1646**
2022	555	572	655	882	1010	1454	1693	1510	1263	1115	694	661	1693	**1693**
2023	566	585	667	907	1026	1490	1739	1548	1291	1141	711	676	1739	**1739**
2024	577	597	680	932	1042	1527	1786	1586	1318	1168	728	691	1786	**1786**
2025	588	610	693	956	1059	1563	1832	1624	1345	1194	744	706	1832	**1832**
2026	599	622	706	981	1075	1600	1879	1662	1372	1221	761	722	1879	**1879**