DOCKETED	
Docket Number:	18-IRP-01
Project Title:	Integrated Resource Plan
TN #:	227658
Document Title:	2018 IID IRP
Description:	This Integrated Resource Plan document is submitted to comply with SB350 and the IRP submission guidelines for POUs.
Filer:	scott harding
Organization:	Imperial Irrigation District
Submitter Role:	Public
Submission Date:	4/12/2019 6:24:53 PM
Docketed Date:	4/15/2019

Imperial Irrigation District

Integrated Resource Plan

Energy Department –November 2018

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LIST OF ACRONYMS

ACE	Area Control Error
AGC	Automatic Generation Control
AMI	Advanced Metering Infrastructure
BA	Balancing Authority
BES	Bulk Electric System
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
BOD	Board of Directors
C&T	Cap-and-Trade
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	California Compliance Allowance
CCAR	California Climate Action Reserve
CCP	Clean Power Plant
CDD	Cooling Degree Days
CEC	California Energy Commission
CESP	Custom Energy Solutions Program
CFE	Comisión Federal de Electricidad
CFTC	Commodity Futures Trading Commission
CITSS	Compliance Instrument Tracking System Service
CMUA	California Municipal Utilities Association
CP	Coincident Peak
CPUC	California Public Utility Commission
CSI	California Solar Initiative
DER	Distributed Energy Resources
DSC	Disturbance Control Standard
DSM	Demand-Side Management
EAP	Energy Action Plan
EE	Energy Efficiency
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EM&V	Evaluation, measurement & Verification
EPA	Environmental Protection Agency
EPACT	Energy Policy Act
EPS	Electric Power System
FCV	Fuel Cells Vehicle
FEPA	Federal Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FIT	Feed-in-Tariff

GF	Generation Facility
GHG	Greenhouse Gas
GRP	Gross Regional Product
HDD	Heating Degree Days
HVAC	Heating, Ventilating and Air Conditioning
ICE	International Exchange
IID	Imperial Irrigation District
IOU	Investor-Owned Utility
IPP	Independent Power Producers
IRP	Integrated Resources Plan
ISO	Independent System Operator
JUG	Joint Utilities Group
LGIA	Large Generator Interconnection Agreement
LT	Long Term
MAPE	Mean Absolute Percent Error
MIC	Maximum Import Capability
MSSC	Most Severe Single Contingency
$MTCO_2e$	Metric Tons of Carbon Dioxide Equivalent
NAESB	North American Energy Standards Board
NCEEP	New Construction Energy Efficiency Program
NCPA	Northern California Power Agency
NEL	Net Energy for Load
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NSHP	New Solar Homes Partnership
NTTG	Northern Tier Transmission Group
NYMEX	New York Mercantile Exchange
OASIS	Open Access Same-time Information System
OATI	Open Access Transmission Initiative
OATT	Open Access Transmission Tariff
OLS	Ordinary Lease Squares
OTC	Over-the-Counter
PAC	Program Administrator Cost Test
PCC	Point of Common Coupling
PCC1-3	Portfolio Content Category 1, 2 and 3
PCT	Participant Cost Test
PHEV	Plug-In Hybrid Electric Vehicle
POU	Publicly Owned Utility
PPA	Power Purchase Agreement
PV	Photo Voltaic

R&D	Research and Development
RAM	Renewable Auction Mechanism
REC	Renewable Energy Certificate
RFP	Request of Proposal
RFQ	Request for Qualifications
RIM	Ratepayer Impact Measure Test
RPS	Renewables Portfolio Standard
RSS	Reserve Sharing Software
RTO	Regional Transmission Organization
SCPPA	Southern California Public Power Agency
SCT	Societal Cost Test
SEC	Securities Exchange Commission
SEPA	State Environmental Protection Agency
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
SIS	System Impact Study
SMUD	Sacramento Municipal Utility District
SONGS	San Onofre Nuclear Generation Station
SRSG	Southwest Reserve Sharing Group
ST	Short Term
STEP	Strategic Transmission Expansion Plan
SVERI	Southwest Variable Energy Resource Initiative's
SWOT	Strengths, Weaknesses, Opportunities and Threats
T&D	Transmission and Distribution
TES	Thermal Energy Storage
TOLSO	Transmission Owners with Load Serving Obligations
TRC	Total Resource Cost Test
VaR	Value at Risk
VER	Variable Energy Resources
VNM	Virtual Net Metering
WAPA	Western Area Power Authority
WCI	Western Climate Initiative
WECC	Western Electric Coordination Council
WREGIS	Western Region Renewable Electricity Information System
ZNE	Zero-Net Energy

EXECUTIVE SUMMARY

Imperial Irrigation District's Energy Department faces a number of challenges in the coming years. This document provides an integrated strategic approach to overcome those challenges. The effective integration of all IID resources is critical to the organizational efficiency and productivity of the district moving forward. The IID Integrated Resource Plan aims to effectively point IID's Energy Department in one direction, thus allowing the gears that turn the department to cohesively work together toward the same goals.

IRPs are commonplace in the utility world of energy planning and many states and regulatory agencies require IRPs prior to statewide and regional planning and prior to significant and important capital investments. The intention of this IRP is to refresh the most recent 2016 Integrated Resource Plan with an up-to-date resource portfolio plan that covers, at least, through 2030, beginning in 2018. Furthermore, this document addresses the requirements of the IRP Guidelines under Senate Bill 350. IID needs to address various issues that directly affect the efficient integration of energy resources, such as:

- The security of the IID Balancing Authority.
- The best mix of resources.
- Compliance with Renewable Portfolio Standards and emissions laws included the renewable portfolio changes of Senate Bill 350.
- Operational flexibility and effectiveness in renewables integration.
- An aging generation fleet, and many others.

Simultaneously, IID must meet these challenges while maintaining affordable energy rates for retail, commercial and industrial customers. As a result, IID has assessed many combinations of integrated resource portfolios to discern an approach to the numerous uncertainties that face the district.

IID has the unique opportunity to innovatively transform into an industry-leading public utility, while simultaneously conforming to the changing environment of new laws and regulations as well as the latest electric utility standards developing upon the horizon. IID is uniquely located in an area where renewable resources such as solar, geothermal and others can place IID in a leading role as a renewable resource generation hub in the state of California and the nation. This will require IID to work quickly to collaborate with neighboring utilities and other entities to provide a situation where the IID can maintain its reasonable customer rates, improve its Balancing Authority infrastructure and be a primary source for reliably delivered renewable power to Southern California and to the West, all while effectively adapting to its own obligations as a load-serving energy utility.

IID issued a Request for Proposal for an IRP consultant to validate IID's internal studies and the IRP process, as well as provide industry-leading expertise. Black and Veatch was selected and IID coordinated with them as well as with the California Energy Commission throughout the entire process of the IRP development.

GOALS OF THE IID

First and foremost, the Energy Department must be aligned with the Imperial Irrigation District's strategic plan.[1] Approved in 2016, the "five areas of focus that share a common thread of advancing the interests of the district and the customers it serves," are:

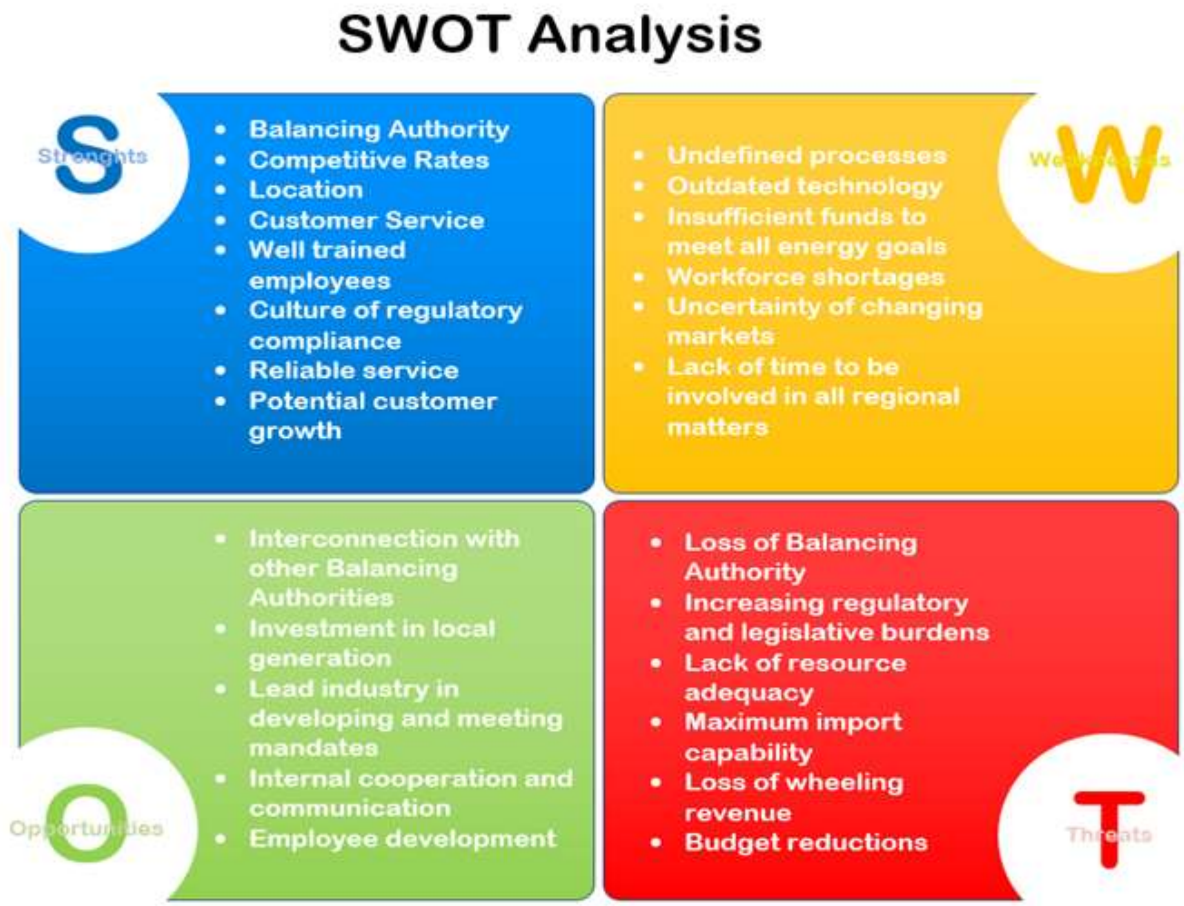
1. CULTURE OF ACCOUNTABILITY
2. ASSET OPTIMIZATION
3. MEETING CUSTOMER NEEDS
4. REGIONAL LEADERSHIP
5. FINANCIAL HEALTH

Second, due to the nature of the organization and the interdependency of IID as a local organization along with numerous federal, state and local agencies and business entities, IID is cognizant and sensitive to the various and often differing goals of these external entities. IID's publicly elected board of directors endeavors the painstaking task of balancing the goals of IID while maintaining positive relationships with external parties that collaborate with IID. These affiliations are a cornerstone of the solidity and the significance of IID to the Imperial Valley, Imperial County, Southern California and the Western United States and IID recognizes the importance of the decision-making process as a means to an end of a goal that affects many. As a result, IID has worked diligently to establish goals that provide the greatest good.

The Energy Department conducted a survey to identify the strengths, weaknesses, opportunities and threats to help the department move forward both strategically and organizationally in the most efficient manner. The following is a summary of the SWOT analysis:

[1] https://www.iid.com/about-iid/an-overview/strategic-plan

Exhibit 1: Energy Department SWOT Analysis:



GOAL OF THE IRP

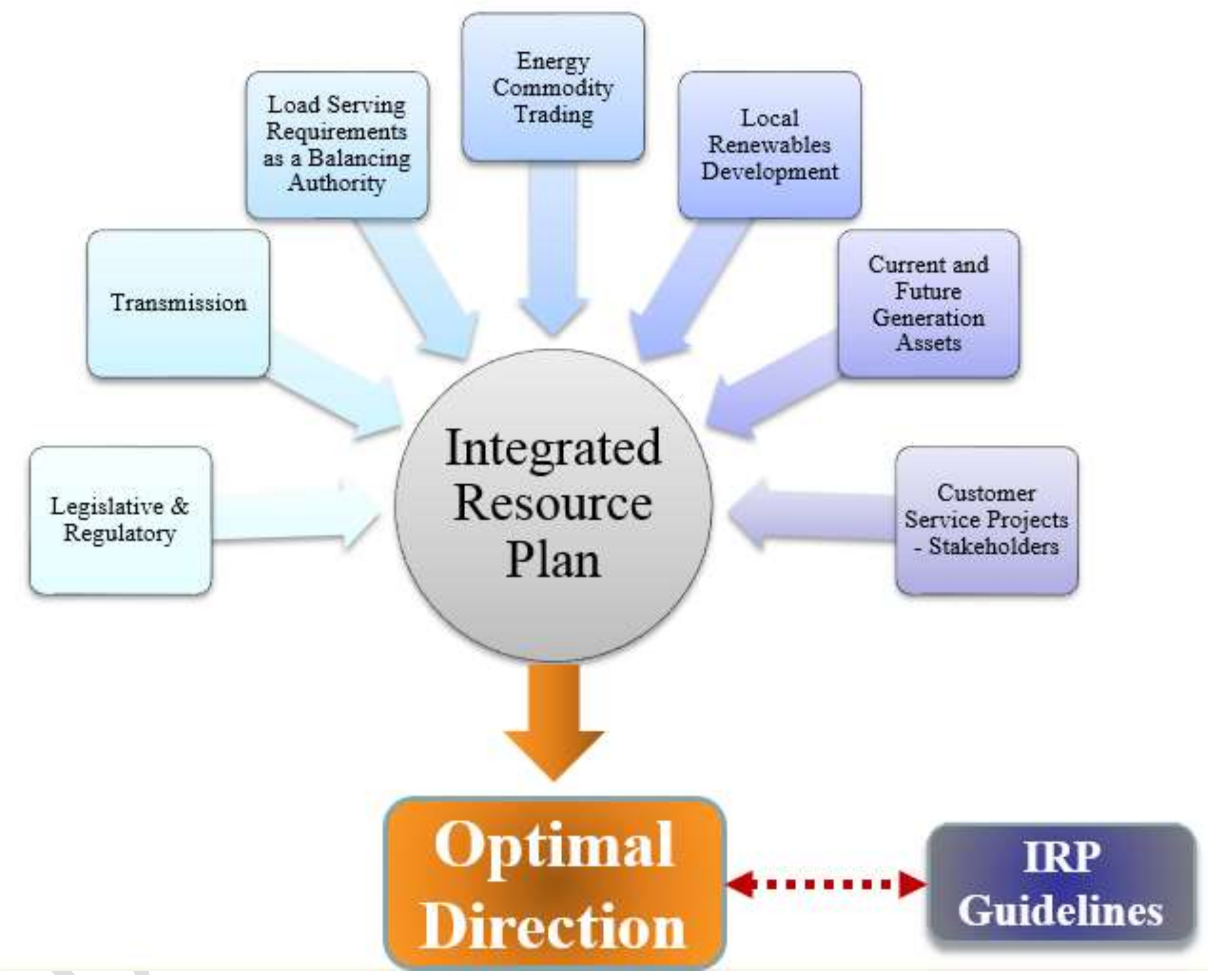
The IRP is an Energy Department-wide effort to enable the coordination and collaboration of numerous internal efforts that must be integrated to create the most optimal direction moving forward as required by SB 350. These directions will allow for critical organizational objectives to be met in the most efficient manner. Some of these objectives are:

- Creating supply plan solutions that meet current and future customer needs.
- Creating a system stability and reliability plan that ensures greater grid resilience.
- Creating a renewable energy and emissions reductions plan that meets SB 350 requirements.
- Creating an energy efficiency plan that satisfies customer satisfaction and SB 350 requirements.

A well-developed IRP should analyze and evaluate all of the relevant supply-side and demand-side resource impacts to the current and future financial health of the utility in order to arrive at a "least-cost, least-risk" solution for meeting future load serving needs in an environmentally sound and sustainable manner.

An IRP provides a public document that allows readers to delve into energy planning at IID and determine how and why IID is moving forward with various decisions that are connected to a broader scope of direction. The exhibit below illustrates the overall goal:

Exhibit 2: Goal of IRP



KEY DRIVERS OF IRP

IID has particularly focused on four key areas that are essential to all other objectives of the district. With the central goal being the obligation to serve customer needs, these four areas drive the overall goals of IID:

- **Protecting and Maintaining the IID Balancing Authority.** IID is the third largest Balancing Authority in California and the fifth largest electric utility in the state. IID's Balancing Authority status allows IID operations to control its own Area Control Error. This allows IID to provide its own reliability, rather than being controlled and operated by an independent operator, such as the California Independent Operator. The CAISO balancing authority has the potential to be much less stable for IID and its ratepayers, and IID's utilization of local area resources will facilitate a reduction of the risk and the cost of maintaining the IID BA. The integration of intermittent renewable resources across the nation will trigger the need for more dispatchable generation that has ramping/load-following capabilities and, as a result, the recent development of the Energy Imbalance Market , a new market that will provide grid stability for all transmission line owners. The status IID holds as a BA is an area that drives how the IID will plan transmission operations and expansion, procure resources, operate the system, utilize interregional partnerships and plan for extreme events.

- **Providing Competitive Rates to its Retail, Commercial and Industrial Customers.** Electricity is a fairly inelastic good, so users will moderately adjust consumption for economic reasons but, in the end, electricity is a necessity. Therefore, the rate at which the consumption is charged is something that can impact all types of customers who are contemplating moving within the IID service territory, staying within the service territory and even promoting others to migrate to this territory. As a public service company, IID has the duty and responsibility to continue to evolve as a utility that provides affordable electricity rates. This drives the goals of IID.

- **Sustaining System Reliability throughout the IID Service Area.** Since IID is not a part of the CAISO, IID has the responsibility to provide reliable power to all of its customers, even in extreme events. This is a challenge, since IID is interconnected to several other BAs, and this has an impact on the physical flow of electricity within the IID service area. IID works conscientiously to assure that the system operates properly under all conditions to the best of its ability. This drives the goals of the IID, since the effectiveness of the system reliability is disturbed by many operational characteristics of generation facilities, transmission/distribution interconnection strategies and other uncontrollable factors. As a result, regulatory compliance-based decisions and strategic expansion-based decisions, currently and in the future, consider system reliability as a foundational driving factor.

- **Expecting Environmental and Regulatory Responsibility.** With the California RPS and the Cap-and-Trade programs well underway, IID is not only required to meet these goals as a Publicly Owned Utility, but also has the social responsibility to facilitate others to meet their goals as well. IID is located at the heart of many available natural resources to develop renewable generation facilities as well as energy efficiency and conservation. This drives IID's decision-making process because many of the laws that have been developed over the past several years change the entire dynamic of strategic resource planning and the integration of resources.

The above drivers act as a catapult to the culmination of IID's paramount goal: **Meet customer needs**. IID, first and foremost, has an obligation to serve. These four key drivers are not whole and set apart from each other. They are all equally important and linked together. Each goal or objective that falls under these categories depends on the successful integration of these four drivers, with the end goal of meeting customer needs. The following exhibit attempts to illustrate this relationship between the aforementioned drivers.

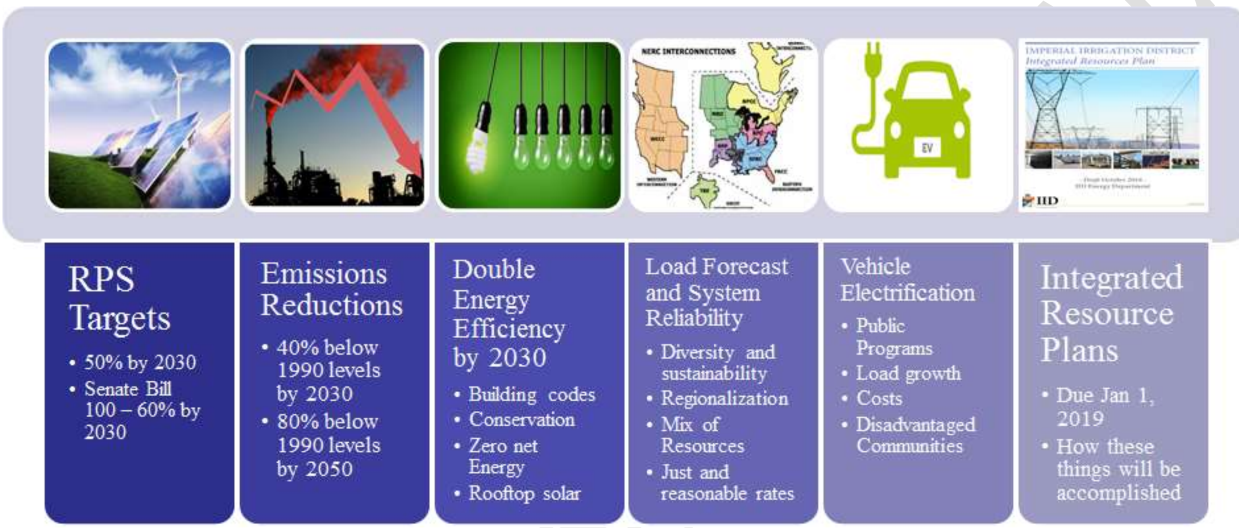
Exhibit 3: Key Drivers of the 2018 Integrated Resource Plan

As illustrated above, meeting customer needs and the four key areas that drive the rest of the goals are all intermingled as each goal and objective has an impact on other goals. This IRP attempts to provide an approach to meet the following general Integrated Resource Planning goals.

SB 350 IRP GUIDELINES

In 2015, the Clean Energy and Pollution Reduction Act passed under Senate Bill 350 in California. It has several new key objectives for publicly owned utilities, such as the Imperial Irrigation District. This law essentially is the underlying basis for this 2018 IRP. Overall, the following exhibit highlights the main requirements of SB 350:

Exhibit 4: Senate Bill 350 Requirements

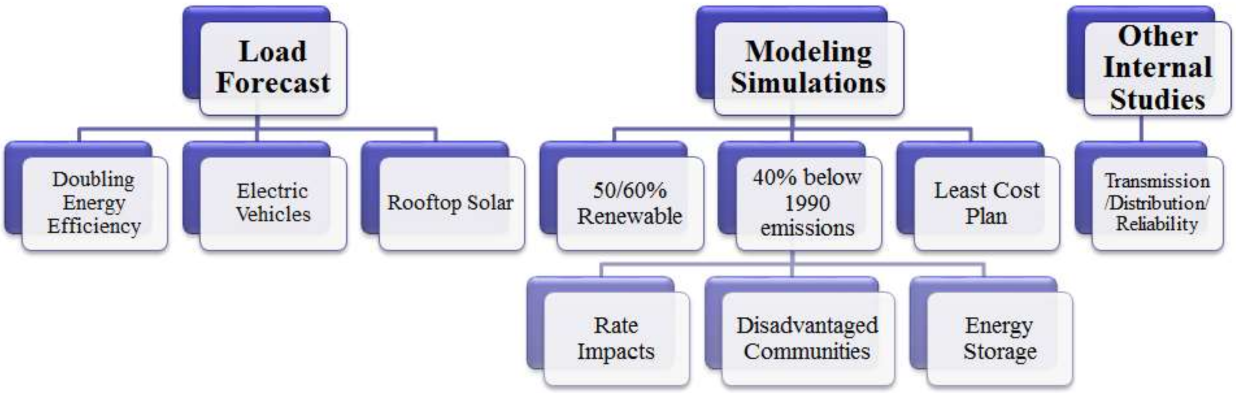


The SB 350 guidelines were used in the development of this IRP, but it is important to note that many aspects and underlying assumptions have been determined throughout 2017 and 2018 during IID's IRP process. While IID's goal is to meet and exceed all California Energy Commission requirements and recommendation for this IRP, some aspects may require revision as more details become available and as SB 100 guidelines become available. Below is an overview of the implementation of SB 350 over the past several years:

Exhibit 5: Senate Bill 350 Implementation

IID has addressed each of the requirements under the SB 350 IRP Guidelines using the following key processes:

Exhibit 6: Processes Used to Address SB 350 Requirements



In order to address all requirements under the SB 350 IRP Guidelines, and in order to provide a simple reference guide for readers and CEC staff, below is a table with the key requirements along with chapter references where the contents of the requirement can be found (greater details of these requirements are found in Chapter 1):

Exhibit 7: Senate Bill 350 IRP Requirements Reference Table

SB350 IRP Requirement Reference Table		
Key Requirement	**IID IRP Chapter/Section**	**Key Page Numbers**
Planning Horizon through 2030	The planning horizon is 2019-2030 or beyond	Throughout the Entire Document
Standardized Table Reporting (CRAT, EBT, RPT & GEAT)	Apendix A	P411-417
Specific Goals on meeting RPS and GHG Targets	Executive Summary; Chapters 1, 4-5,7-8 & Appendix C	P28-29, P37-38, P170-171, P206-224, P324-343, P347-358, P401-407, P418-443
Provide Supporting Documentation	Found within IRP; Appendicies; additional information available upon request	Throughout the Entire Document
Develop a Demand Forecast	Chapter 3	P109-155
Report the Preferred Mix of Resources	Executive Summary; Chapters 7-8 & Apendix A	P27-29, P347-358, P411-417, P 398-401
RPS and GHG Target Compliance Periods Details	Executive Summary; Chapters 1, 4-8 & Appendix C	P28-29, P37-38, P170-171, P324-343, P347-358, P401-407, P418-443
Impacts of Energy Efficiency	Chapters 3-4	P119-122, P125-132, P175-181,
Impacts of Transportation Electrification	Chapters 3 & 5	P134-135, P233-242
Address Energy Storage	Executive Summary; Chapters 1-2, 4-8	P28-29, P49, P64-66, P103, P184-185, P219-224, P343-347, P383-393
Ensure System Reliability	Chapters 2, 4 & 7	P73-80, P156-167, P298, P314
Identify Transmission/Distribution Constraints	Chapter 2 & 7	P55-58, P284-318, P394-400
Disadvantaged Communities and Local Air Pollutants	Chapters 4 & 8	P186-205, P 406
Ensure Just and Reasonable Rates	Executive Summary; Chapters 7 & 8	P30-31, P375-383, P402-405, P407-409

There are also numerous areas that the SB 350 Guidelines encourages or recommends be covered. Those are covered more in depth in Chapter 1, but the development of this IRP aims to address all requirements as well as all recommendations found in the Guidelines.

Cost and Operation Goals

- Effectively integrate renewable resources into the energy resource supply portfolio.
- Efficiently integrate transmission upgrade costs with RPS resource strategy.

- Continue to evolve the gas and energy procurement strategy in order to provide long-term budget certainty.
- Acquire cost-effective energy resources and avoid over-procurement.
- Strategically utilize the requirement of increasing renewable resources simultaneously to provide cost certainty.
- Further optimize the operation of system resources.
- Increase communication and understanding between departments.
- Continue to own and operate all major transmission lines within the IID's service territory.
- Effectively utilize resources in the area to enhance the opportunity to reduce the risk of losing reliability control of the IID BA and reduce the costs of maintaining the IID BA.
- As the Energy Imbalance Market continues to develop, IID needs continue to monitor the value of becoming an active participant or the value of being a neighbor with other participants.
- Operate the system to effectively reduce carbon footprint in all areas.
- Develop and invest in strategically placed transmission line infrastructure.

Efficiency Goals

- Implement energy efficiency programs necessary to reduce load by at least 5 percent by 2020.
- Adjust these goals annually as necessary to comply with the doubling targets of SB 350 as adopted through the CEC's guidelines.
- Provide a positive impact on utility cost by stabilizing energy consumption and reducing purchases of expensive peak power.
- Ensure the program portfolio is cost effective, thereby relieving upward pressure on rates.
- Assist schools in improving the energy efficiency of their facilities despite ever-diminishing budgets, thereby lowering energy consumption through energy efficient upgrades.
- Assist residential developers to meet the title 24 'zero net energy' standards.
- Evaluate feasibility of various new methods of distributed energy resources, electric vehicles and energy storage and implement as needed.
- Implement programs that provide greater incentives to low-income customers and disadvantaged communities for air quality equality as described in CARB's Low-Income Barriers Study.
- Assist customers by providing an opportunity to take charge of their energy utilization and, by doing so, reduce their electricity cost.
- Create and implement an electric vehicle program available to all customers and provide incentives to low-income customers and disadvantaged communities.
- Provide customers the opportunity to improve the environment by conserving energy and/or acquiring renewable energy.
- Provide income qualified residential customers with rate assistance and positively impact their families by providing energy efficiency measures that reduce their dependency on subsidies.
- Increase the awareness of energy efficiency and utilization through effective promotion of programs and energy issues and provide a forum for customer adoption of energy effective habits through energy education.

Regulatory Goals

- Meet or exceed all state and federal planning criteria for renewable resources with a goal of generating 29 percent of energy requirements from renewable sources/renewable energy by 2018, 31 percent by 2019, at least 33 percent by 2020, 40 percent by 2024, 45 percent 2027 and 50 percent by 2030.

- Continue to reduce greenhouse gas emissions to meet or exceed AB 32 and SB 350 defined goals.
- Strategically execute excess emissions allowance sales to minimize the cost impact of renewable resource integration in a non-volumetric manner.
- Track the continued implementation of regional transmission planning mandates and strategically develop consensus with FERC and jurisdictional public utility transmission providers in order to develop a coordinated strategy and tariff language under IID's Open Access Transmission Tariff that would not compromise the decision-making authority of the IID while still being able to participate in the regional planning process and comply with the regulatory requirements.

Regional Development Goals

- Encourage local economic development by developing new generation resources within the IID's service territory, whenever possible, by cost effective metrics.
- Expose natural resources for development in the Imperial Valley.
- Develop relationships and potential partnerships to minimize cost impacts of other goals.
- Closely monitor and, where necessary, meet La Quinta and other system growth requirements.

It will be a daunting task to achieve these goals all at once and it is possible that, as the IID accomplishes these goals, costs may increase, especially as IID increases its renewable resource mix. The installment of more renewable generation will help to meet many regulatory goals, such as the reduction of GHG emissions and RPS compliance, but renewable generation will also allow IID to secure a greater level of cost certainty, thus customer rate stability. With careful planning and a cohesively operating organization, IID can achieve these goals over a period of time with an approach that will be more cost effective than a status quo approach.

The 2018 IRP attempts to balance the various goals of the IID. Achieving these goals will take dedication and the longevity of management, as there is an implied amount of investment necessary to accomplish these goals.

Summary and Recommendations

Several modeling analysis were performed including transmission system modeling, operational system modeling and other modeling activities. Many of the underlying processes used to determine some of the assumptions were provided by numerous sections within IID; However, for the economic evaluation to determine the most optimal set of resources and an overall expansion plan, IID used Power Cost, Inc.'s GenTrader model.

GenTrader provides a systematic approach to assess risk exposures of asset portfolios through stochastic simulation of market price volatility, load or demand uncertainty, as well as generating unit availability. Thousands of deterministic scenarios were simulated and compared to eliminate various portfolios and narrow down to a set of portfolios to further test, resulting in a set of preferred portfolios under a given set of circumstances. Furthermore, GenTrader offers stochastic capability within the model. This was used for additional risk analysis and other scenario testing.

The following is a summary table of all studies performed and how they rank in comparison to various alternative portfolios:

Based upon the analysis and studies prepared for this report, the following major recommendations are presented:

- IID must closely monitor the Coachella Valley water agreement and how it may impact all future decisions, which would significantly reduce the IID energy load as well as drastically change the manner in which load is served;

- IID needs to closely monitor the regulations, rules and guidelines issued to implement SB 350 as well as the recently passed SB 100 that have been released/adopted to date and will continue to be released/adopted. These guidelines will be pivotal to the specific strategy of meeting statewide compliance targets in RPS, Energy Efficiency, IRP submittals, post 2030 GHG emission reduction targets, vehicle electrification, energy storage assessment and grid reliability with just and reliable rates;

- Issue a Request for Proposals for 30 MW of energy storage to be located in the Northern territory of the IID system. This addition to the IID resource portfolio will allow IID to operate more efficiently and cost effectively and provide much needed reliability benefits to the Northern territory;

- IID should consider retiring some hydro units, particularly Pilot Knob and Drop 5. If retirements are not an option, then IID needs to seek capital investment in these facilities and other hydro facilities that may provide more efficient operations and lower operations and maintenance costs.

- Over the 20-year planning horizon, IID should keep conventional generation commissioned as long as possible. These generation facilities offer much needed capacity, flexible generation, ancillary services and system resources. Replacement with similar resources contain similar costs due to the premium/debt payments that would be required for these new resources; owever, if IID decides to retire flexible capacity, IID must replace it with flexible capacity, specifically energy storage. Furthermore, in the event that the market of solar + storage provides a more competitive cost compared to IID's generation fleet, IID must complete a reliability analysis to ensure all integration costs are included in the replacement decision;

- Reinvest in IID's generation fleet to provide greater unit response and reliability. This can allow for greater unit efficiency and lower annual fixed and variable maintenance costs;

- Due to recent customer requests, it is possible to see an influx of new large commercial customers in the Northern territory of the IID system that will significantly increase the total load and energy requirements. IID needs to closely monitor the progress of these requests and make the necessary adjustments that provide an efficient, cost-effective, and reliable load-serving environment. Additionally, many aspects within this document consider assumptions that are volatile and IID will adjust accordingly, even beyond the scope of the recommendations of this document, if necessary;

- To avoid operational issues of excessive power over certain hours of the year, IID needs to explore seasonally-based resources where possible. IID is long in the winter and short in the summer. Therefore, its must-take resources are supplied throughout hours or all hours of every month of the year. IID needs to elude spending a considerable amount more than what is necessary for not only contract costs, but also integration costs, with an increase in unrealized savings in the shoulder months; however, this approach does not come without challenges, such as higher contract costs for summer months, full capacity needs not being met by renewables that are intermittent and many other factors that need to be considered;

- No sooner than 2028, the IID should enter into power supply agreements for an additional 10-15 MW of baseload renewable generation and 300-350 MW of solar generation with in-service dates of 2028-2030 to help meet RPS standards under SB 350 as well as the recently passed SB 100 and reduce GHG emissions. Renewable generation will also help reduce the price volatility of the IID's power supply costs, although the value of additional renewable resources compared to traditional non-renewable resources will depend on future pricing trends for both renewable energy and traditional resources. Additionally, IID needs to consider the impact of increased renewables and seek opportunities for flexible technologies and the addition of quick responding generation or energy storage that allows for more effective renewable integration;

- In the event that IID agrees to additional renewable generation with in-service dates prior or 2028, then IID needs to seek opportunities to reposition or sell existing high priced agreements to alleviate excess system generation and loss of controllable fuels. IID must monitor load growth and impacts of the activities on the customer side of the meter to ensure RPS compliance is met with diversified eligible resources, and if at all possible, diversified portfolio content categories;

- The need timeline for renewable resources and emission reductions depends on two key metrics:
    - IID energy sales to customers
    - Renewable production

  These metrics must be closely monitored to adjust where necessary. If load growth does not occur, then fewer renewable resources are needed and the need occurs after 2028. If load growth is faster than expected, then more renewable resources are needed and the need occurs before 2028.

- IID should diversify the resource mix it relies upon to serve load. IID needs to consider diversification in technology type, generation output stability, fuel type, land use amounts, contract structuring, generation output pattern, bond issuance strategies, debt structure planning and partnerships with neighboring utilities and groups such as the Southern California Public Power Authority. This includes transmission projects that provide access to various energy markets. Diversity in all things and all approaches will benefit IID by reducing various risks the district is exposed to;

- IID needs to adopt new energy efficiency targets that reflect SB 350 requirements. Energy efficiency and conservation is the "greenest" green of all the renewable generation methods. So, conservation, energy efficiency and demand-side management activities should continue to increase in accordance with SB 350 standards in order to reduce the IID's need for resources that are expected to be used for less than 200 hours per year. Exploring new energy efficiency/DSM technologies, time of use and interruptible rates are the first step toward achieving a higher level of demand-side management impact;

- IID needs to create an electric vehicle program available to IID customers. Studies show that each customer who plugs in can add up to 1,500-2,500 kWh/yr of customer load and a properly structured program can help alleviate over generation pressures and provide air quality equality to IID customers, and particularly, to disadvantaged communities if the program targets these areas.

- The IID should continue planning to meet GHG emission reduction legislation to reduce emissions by 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050. Proposed additions to the IID's resource mix will help reduce GHG emissions from old, inefficient internal resources, but additional reductions will be required to avoid having to purchase emission credits in the future at a potentially high cost;

- IID should further investigate the option of self-managing a "build and own" structure for solar plants and other generation facility technologies on IID-owned land as opposed to paying a developer to manage the project development. Diversity in contract structures is an important diversity in generation technology;

- The Request for Proposals process helps the developer understand what IID needs and it increases competition among the developers and thus, lowering the price and providing a sound negotiating structure for both IID and the developer. IID should use the RFP process at every opportunity, including an RFP process through SCPPA, since it is the industry standard and the most accepted and sophisticated approach that encourages IID to exclusively select the most attractive offer;

- IID's hedging program should continue in the gas and energy markets under the Energy Risk Policy. IID should anticipate the natural rise of energy and gas costs as well as emissions and renewable costs while all being directly or indirectly associated to each other. The reduction of risk through a consistent hedging program will empower IID to further ensure budgetary certainty and stabilize consumer rates;

- IID needs to invest in the required transmission and distribution projects where rate increases can be avoided. IID transmission system and the transmission system infrastructure investment is effective in protecting and maintaining the IID Balancing Authority. Additionally, some of these projects may contain greater value with an organizational shift in business activities such as economic dispatch sales and regional balancing services where the proper process infrastructure must be in place prior to new activity implementation to mitigate risk;

- IID should become a participant in the NG-IV2 project to provide additional access to markets and additional reliability stability to the IID system. While IID's imports are projected to slightly decrease due to increasing RPS requirements, benefits from building a transmission line for less than $40 million that will have access to a cheaper market help to justify the project. It can be further justified by an increase in projects connected to the IID system with off-takers outside of the IID territory paying IID's wheeling rate;

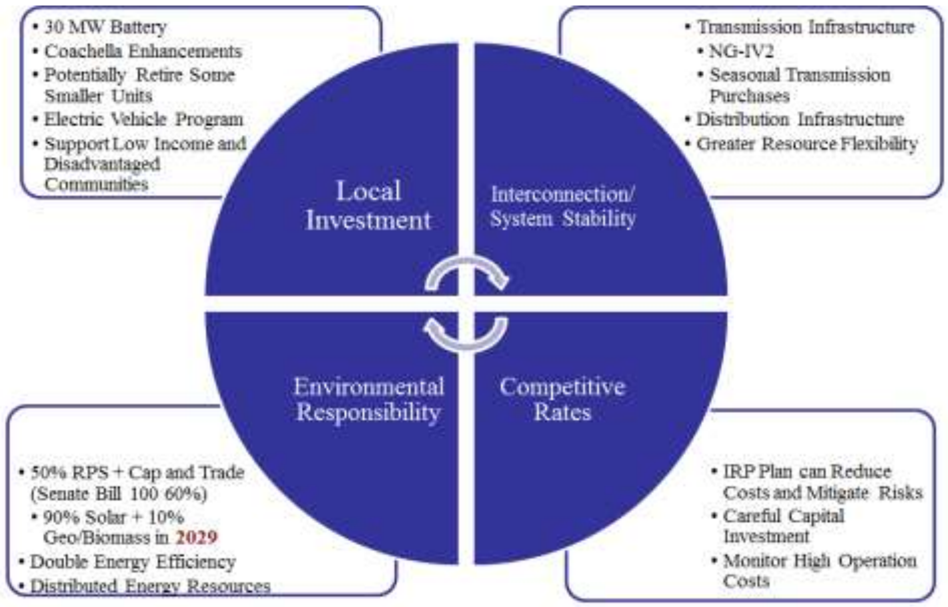
- With the IID's increased understanding of the CAISO markets and with the surplus of capacity and energy during the winter months (November through April), IID could take advantage of marketing the ancillary services of this surplus and further reduce the impact of meeting RPS/AB 32 laws. IID needs to develop a plan to implement this;

- IID needs to further explore the addition of flexible resources in IID's Northern system in the next five years as well as repower El Centro No. 4 and add energy storage when more solar is consumed to be in service between 2021 or 2025. Additional flexibility of gas fired peaking generation and grid-stabling energy storage will provide the necessary support the IID system needs to maintain reliability and potentially reduce costs when used properly in the wake of a heavy influx of intermittent renewable resource integration and customer owned generation; and

- Finally, since this IRP was developed under the purview of SB 350, there are many conclusions that are based on the elements of the SB 350 regulations. However, with the passage of SB 100, many assumptions will change and this may change IID's overall findings and recommendations. IID needs to monitor the regulatory proceeding of SB 100-related policies and ensure that any changes be reflected in the underlying assumptions for all future decisions.

The following is an illustration that provides a summary of this IRP's key findings and recommendations:

Exhibit 8: Key Findings and Recommendations



The exhibit below illustrates the key recommendations in chronological order:

Exhibit 9: Timeline of Key Elements of the Recommendations and Key Findings

2018	• Observe SB 350 and SB 100 guidelines and determine best strategies of compliance.
2018-2019	• Issue an RFP for 30 MW of energy storage with a COD of 2019-20.
2018-2020	• Create and implement an electric vehicle program where feasible.
2018-2020	• Incorporate operational practices to reduce costs and emissions while maintaining strong reliability and and environmental compliance.
2018-2026	• Complete all necesary transmission and distribution system upgrades.
2019-2023	• Update IRP.
2021-2026	• Find opportunities to reposition long or costly resources. • Re-procure where needed.
2021-30	• Monitor market oppotunities in unit replacements that provide similar system stability and reliability to the IID system.
2027-2030	• Procure a diversified mix (10 percent baseload/90 percent intermittent renewable resources) to comply with 50 percent by 2030 no sooner than the needed period.
2030 and Beyond	• Procure resources to allow for a net carbon nuetral resource supply.

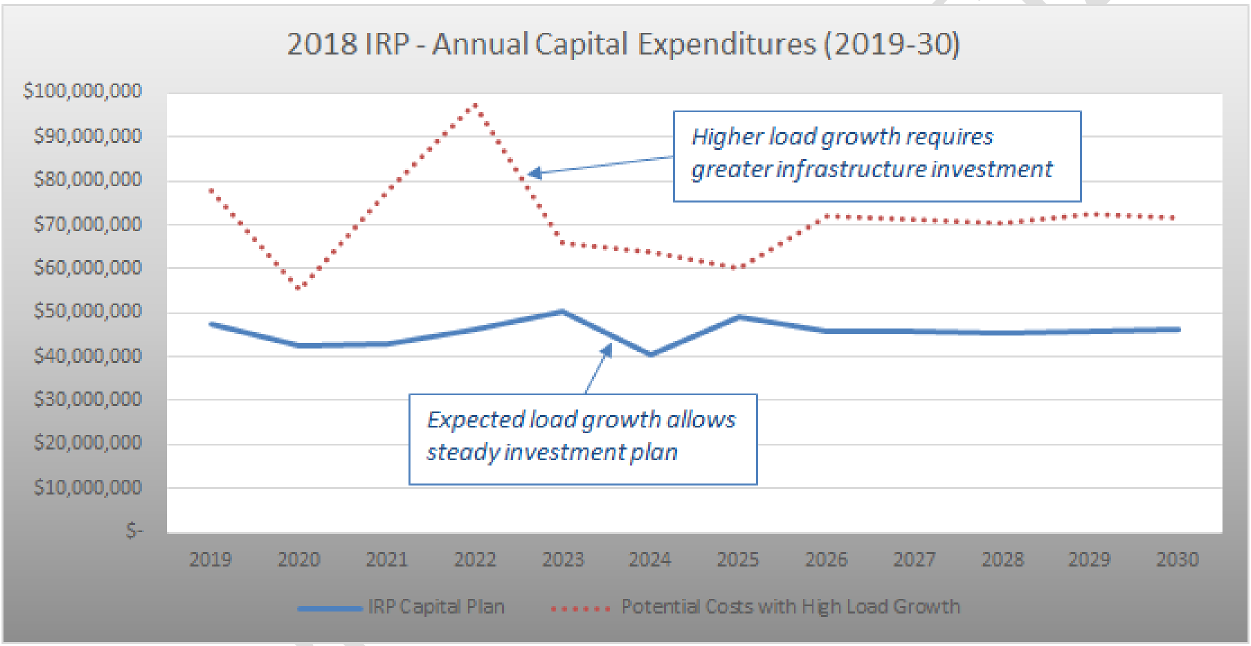
PROCESS FOR UPDATING THE IRP

The following is a schedule to update the IRP:

- At a minimum, IID will update this IRP within the next five years with a due date of Jan. 1, 2023.
- IID will begin evaluating the need for updating the IRP by June 30, 2019.
- If and when IID determines that a new IRP is needed, IID will update and approve the IRP within the five year deadline of Jan. 1, 2023.

In conclusion, it is paramount that the recommendations from this IRP, if at all possible, avoid rate impacts above and beyond standard inflation; however, if there are system investments that are absolutely necessary to maintain IID's mission as *"… a fiscally responsible public agency whose mission is to provide reliable, efficient and affordably priced water and energy service to the communities it serves,*[2]*"* then a rate study may be necessary to fully evaluate the need for any rate increases. The programs and costs that this IRP recommendations aim for the goal of reducing costs wherever possible and therefore, do not require any rate increases above and beyond standard inflation-based increases. Below is a summary of the Energy Department capital investment cost as a result of this IRP:

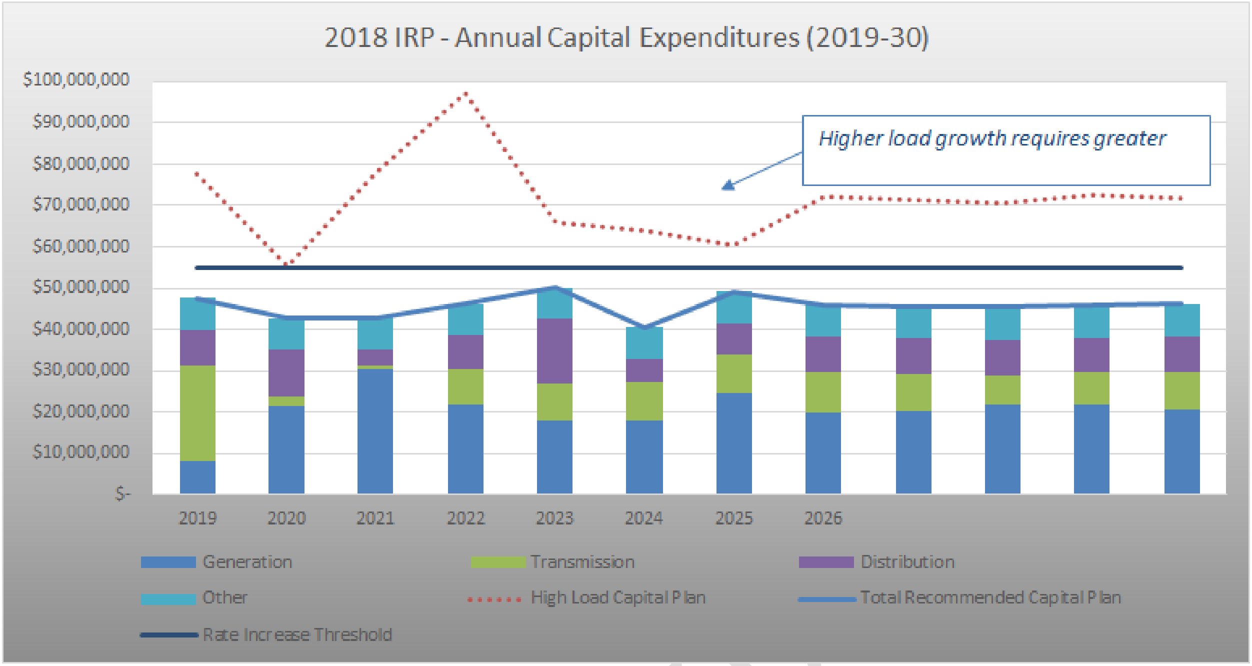
Exhibit 10: Capital Investment: Required and Potential 2019-2030 Costs



In addition to the above summary table, it is important to note that the mix of costs by each of sections in the Energy Department (generation, transmission, distribution and others) can vary based on a number of other variables and factors that are discussed more in detail within this IRP. The chart below exhibits the breakdown among the various energy sections within the department, along with their relationship to the threshold of additional rate increases (above and beyond inflation related increases):

Exhibit 11: Capital Investment: Required and Potential 2019-2030 Cost Breakdown and Rate Threshold

[2] https://www.iid.com/about-iid/an-overview


2018 IRP - Annual Capital Expenditures (2019-30)
$100,000,000
$90,000,000
$80,000,000
$70,000,000
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$-
2019
2020
2021
2022
2023
2024
2025
2026
Higher load growth requires greater
Generation
Transmission
Distribution
Other
High Load Capital Plan
Total Recommended Capital Plan
Rate Increase Threshold

CHAPTER 1: IRP PURPOSE AND APPROACH

PURPOSE AND OBJECTIVES OF THE IRP

This IRP for the Imperial Irrigation District has been prepared by IID's Energy Department to meet all the IRP requirements established by the state of California for public owned utilities. The IRP meets the specific requirements established by the California Energy Commission, including the data forms showing the projected capacity balance and other information, which are located in Appendix B of this IRP document.

The goal of this IRP is to provide IID with short- and long-term integrated plans to secure the generation and other resources needed to meet IID's overall mission. This mission is to provide reliable, efficient, and affordably priced water and energy service to the communities IID serves, while maintaining financial integrity and meeting regulatory and environmental requirements.

While this IRP accomplishes the objectives outlined above, this is a living document that will be revised and updated as conditions warrant. In any event, the IRP will be updated at least every five years, as required by the CEC.

ORGANIZATION OF THE IRP

This IRP is organized into sections that contain the following:

- Section 1 presents the overall purpose of the IRP and outlines the report organization. The regulatory IRP content requirements are also described and their location in this IRP is identified.
- Section 2 provides a description of the IID electric system, its resources and programs, and its operating responsibilities as a balancing authority.
- Section 3 provides a summary of the demand and energy forecast for IID, including a description of the forecasting methodology used.
- Section 4 identifies the need for additional resources that arise from a comparison of the IID forecast and existing resources.
- Section 5 provides a description of potential new resources and presents cost and performance information that is utilized in the economic planning model used for the study, GenTrader.
- Section 6 presents the primary modeling assumptions used in the expansion planning analysis that forms the backbone of this IRP.
- Section 7 presents the modeling results and provides a discussion of merits and ranking of the competing expansion plans.
- Section 8 provides the IRP conclusions and recommendations. This includes the preferred expansion plan and the next steps involved in realizing the development of the resources added early in that plan.

- Appendices contain the CEC IRP standardized reporting tables along with several pieces of supplemental information.

The 2018 IRP Development Process

The IID Energy Department conducts resource studies and economic evaluations to evaluate resource decisions on an ongoing basis. Several of these studies were utilized in the development of this IRP. In addition, however, IID developed the IRP through a collaborative team effort that included several IID groups and outside stakeholders. Generally, the tasks performed by these various contributing groups included:

- Identifying strategic alternatives.
- Gathering functional area input.
- Discussing key assumptions and critical issues.
- Creating viable and achievable scenarios.
- Simulating various combinations of alternatives.
- Discussing preliminary findings, refining analysis, if necessary.
- Drafting and reviewing the IRP document.
- Presenting final findings in written form.

The resulting IRP document describes the IRP process and recommends specific alternatives for IID to meet is power requirements, comply with environmental and regulatory responsibilities and to continue serving its customers in a reliable and cost-effective manner.

One important group involved in IRP development included non-IID employee stakeholders who were interested in contributing toward the IRP and decision-making process. These stakeholders consisted of the IRP working group which was presented with a description of the IRP process and the IRP draft results through two public workshops held in the Coachella and Imperial valley areas. The workshops were held on October 18, 2018 in La Quinta, California and October 20, 2018 in El Centro, California. Comments received were related to a wide range of issues including the load forecast, renewable resources, energy efficiency programs and transmission line expansion.

The comments were addressed and the contributions were welcomed additions to the preparation of this IRP.

Major Drivers and Requirements influencing the 2018 IRP

The last IRP for IID was completed in 2016. Since that time, there have been many power sector developments that strongly shaped the creation of the 2018 IRP. First and foremost, has been a series of California laws, Executive Orders, and regulations that helped to shape the objectives of this IRP and its content. In this section, a summary of the most important influences is provided. Other changes impacting the direction of this IRP from an economic and modeling standpoint—such as the IID load forecast, resource costs and fuel price projections—are discussed in subsequent sections.

SB 350 and the CEC IRP Guideline Requirements

The most important state law influencing the current IRP is the Clean Energy and Pollution Reduction Act of 2015, Senate Bill 350, which represented an aggressive step forward in the state's effort to integrate renewable energy and energy efficiency. Prior to 2015, California's controlling Renewable Portfolio Standard was set according to Senate Bill x1 2 (SBx1 2).[3] Summarized briefly, SBx 1 2 directed California's electric utilities to reach a 33 percent RPS over three compliance periods. First, utilities were directed to procure renewable energy products equal to 20 percent of retail sales by December 31, 2013. Second, utilities were directed to procure renewable energy products equal to 25 percent of retail sales by December 31, 2016. Third, utilities were directed to procure renewable energy products equal to 33 percent of retail sales by December 31, 2020, and they were required to maintain that percentage in following years.

On Oct. 7, 2015, California Governor Brown signed SB 350 into law.[4] This updated and expanded SBx 1 2's RPS standards. Specifically, SB 350 increased the state's RPS from 33 percent by 2020 to 50 percent by 2030. SB 350 doubles the existing standards for statewide energy efficiency savings in electricity and natural gas by retail customers by 2030, and encourages widespread transportation electrification. SB 350 also established the intent to expand the footprint of the California Independent System Operator to form a regional independent system operator in a larger, geographic area throughout the Western Interconnection, which would require further authorizing legislation in order to proceed.

Most recently, SB 100, which requires California to get 100 percent of its power from renewable and other zero-carbon resources by 2045, was signed by Governor Brown on September 10, 2018. SB 100 specifies intermediate milestones: 40-44 percent by 2024; 45-52 percent by 2027; and 50-60 percent by 2030.

To facilitate the development of a public utility IRPs and the consistent reporting of the results, the CEC has issued a set of IRP Guidelines that list requirements and recommendations for the IRP filing. The following is a list of items that supplement the Executive Summary and are required, or recommended by the CEC IRP Guidelines, to be part of a public utility's IRP filing:

<u>CEC IRP Guideline Document Requirements for Public Utilities:</u>

<u>Section</u> <u>Topic</u>

2A:

- Planning horizon must extend to at least 2030
- Specific goals to be met include the RPS target (50 percent by 2030) and GHG target (40 percent below 1990 levels.)

[3] The text of SBx1 2 is available here: http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html.

[4] The text of SB 350 is available at: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB 350.

2C
- Submit standardized tables
  - Capacity Resource Accounting Table (CRAT)
  - Energy Balance Table (EBT)
  - RPS Procurement Table (RPT)
  - GHG Emission Accounting Table (GEAT)

2E:
- Use or develop a demand forecast
  - Place the annual forecasted peak demand in the CRAT
  - Place the annual forecasted sales, other loads and net energy for load in EBT
  - Describe the demand forecasting methodology and assumptions

2F:
- Report the mix of resources used by the POU in CRAT, EBT, RPT and GEAT
  - Address procurement for a diversified procurement portfolio for short and long-term electricity and demand response
- The IRP must show how 50 percent RE target will by met in 2030 in EBT and RPT
- The IRP must address EE and Demand Response programs and include their impact in the CRAT and EBT
- The IRP must address energy storage
- The IRP must address transportation electrification
- The IRP must report the EV load on CRAT and EBT
- The IRP must determine the Net GHG emissions impact

2G:
- IRPs must ensure system and local reliability
  - Must include projections of peak capacity and supply and demand resources in CRATS as well as the planning reserve margin
  - Must address grid flexibility
- Must identify local transmission constrained areas
- Must include existing or emerging capacity needs from transmission constraints

2H:
- IRPs must report emissions projections in the GEAT and provide supporting information

2I:
- IRPs must ensure POU's plan to serve its customers just and reasonable rates

2J:
- IRP must ensure the goals of achieving diversity, sustainability and resilience to the bulk transmission system, distribution system and local communities
- IRP must discuss any reliability concerns of the distribution system

2K:
- IRPs must ensure the POU achieves the goal of minimizing localized air pollutants/GHG
- Must include discussion of current programs and policies in place to address local air pollution

<u>**CEC IRP Guideline Document Recommendations for Public Utilities:**</u>

<u>Section</u> <u>Topic</u>

2A:
- Encouraged to present analysis in IRP that address post 2030

2B:

- Encouraged to evaluate other scenarios and sensitivity analysis to consider cost effectiveness of alternative resource options
- Encouraged to submit analysis of alternatives

2C:
- Encouraged to submit data for multiple scenarios

2E:
- Encouraged to include other demand forecast scenarios

2F2d:
- Encouraged to provide additional info
    - POU plan to meet portfolio balance requirements
    - Any identified issues that have the potential to prevent the POU from procuring sufficient renewable resources

2F3a
- Encouraged to include programs and measures that will contribute to SB 350 EE goals
- Encouraged to identify relationship between AAEE savings assumed and IRP filing, the target established by the POU and estimates of market, economic and technically achievable EE savings from the study or studies POUs used to establish their targets
- Encouraged to include the expected quantitative impacts of planned price-sensitive demand response measures for future implementation

2F4:
- Recommended to describe possible role to address over generation and ramping concerns
- Any quantitative analysis undertaken by the POU evaluating the cost effectiveness of storage

2F5:
- Encouraged to include charging profile forecast and how a program will influence the profile
- Current amount, type and location of charging infrastructure
- Medium and heavy duty EVs
- How investments are to promote electrification and how they might align with other standards
- Plans to coordinate with other utilities
- Current or planned programs to promote EVs in disadvantaged communities
- Customer education outreach efforts
- Coordination of transportation electrification with other DERs
- Timeline and plan for collecting and sharing data

2G:
- Provide an estimate of potential over generation and curtailment and daily load profiles
- Encouraged to discuss transmission solutions to local capacity shortfalls

2I:
- Encouraged to identify elements that result in large customer impacts

2k:
- Encouraged to report how programs assist and prioritize disadvantaged communities
- Encouraged to report plans and progress results in implementing the relevant recommendations in CEC's low-income barriers report
    - Low-income customer solar programs
    - Pilot programs that provide solar for low-income customers and disadvantaged communities
- Encouraged to report on plans and progress in implementing recommendations in CARB low-income barriers study

- Encouraged to include the following:
  - Indicators used to track impacts and benefits on low-income customers
  - Strategies for maximizing the contribution of EE in disadvantaged communities
  - Transportation electrification investments, their effectiveness in improving air quality and how to coordinate with local agencies
  - Labor, workforce and training programs designed for low-income customers
  - Financing mechanisms offered by the POU to improve use by low-income customers
  - Efforts to increase contracting opportunities for small businesses in Disadvantaged communities
  - Any strategies used to maximize education and participation in clean energy and transportation programs for low-income customers

OTHER LEGISLATIVE AND REGULATORY CHANGES

In addition to SB 350, there have been a number of recent state laws and regulations that have impacted the IID IRP process. These include the following key laws and regulations:

GHG EMISSIONS REDUCTIONS

Due to the nature of the law, IID adjusted its approach to resource planning to meet the emission reduction standard.

An early California initiative for reducing GHG emissions is was Assembly Bill 32, signed into law in 2006 by former Governor Schwarzenegger. The main strategies for making these reductions were highlighted in the AB 32 Scoping Plan. The GHG reduction focus was furthered in California by Governor Brown's Executive Order B-30-15, issued on April 29, 2015, which established a California GHG reduction target of 40 percent below 1990 levels by 2030. In 2016, the Legislature passed SB 32, which formalized the 2030 GHG emissions reduction target of 40 percent below the 1990 levels set forth in Executive Order B-30-15.

In conjunction with SB 32, the Legislature passed AB 197 to provide the California Air Resources Board with further guidance in preparing an update to the Scoping Plan. On December 14, 2017, CARB approved the second update to the Scoping Plan to reflect the targets set forth in Executive Order B-30-15 and SB 32.

CARB adopted a plan to reach the 1990 levels through regulations including establishing market-based mechanisms, which have the following components:

1) Expand energy efficiency programs.
2) Achieve a statewide renewable energy mix of 33 percent.
3) Develop a Cap-and-Trade Program that links to the Western Climate Initiative partner programs to create a regional market system.
4) Establish targets for transportation related GHG emissions for regions throughout California.

5) Adopt and implement California's clean car standards, goods movement measures and the Low Carbon Fuel Standard.
6) Create targeted fees, including public goods charges on water use fees on high global warming potential gases, and a fee to fund the administrative costs of the state's long-term commitment to AB 32.

On July 26, 2018, CARB approved an overall IRP planning range between 30 and 53 MMTCO2e, as reflected in the 2017 Scoping Plan Update. CARB's proposal also included a range for IID, specifically 524,000 MTCO2e at the low end of the range, and 925,000 MTCO2e range, or 1.745 percent of the electricity sector emissions.

As stated above, Cap-and-Trade program is an important part of the CARB strategy. Recently, the Legislature has affirmed the extension of the Cap-and-Trade program through 2030 with the passage of AB 398. A detailed discussion of the Cap-and-Trade program is provided in Appendix C

Most recently, SB 100 has passed the California Assembly was signed by the Governor. SB 100 commits California to procuring energy from 100 percent carbon-emissions free resources by 2045.

Rooftop Solar Policies

SB 1 (2017) enacted Governor Schwarzenegger's Million Solar Roofs Initiative and expanded the California Solar Initiative and CEC's New Solar Homes Partnership by requiring building projects to meet minimum energy efficiency levels when applying for ratepayer-funded incentives. The statute also recommends that photovoltaic solar system components and installations meet rating standards and performance requirements.

AB 920, signed into law in 2009, implements a net energy metering rule that requires utilities to pay residential customers and businesses for excess energy produced by a customer's solar power system. AB 510 raised the cap of the number of homes and businesses that can use NEM billing from 2.5 percent to 5 percent of the electric utility's aggregate customer peak demand. The law also addresses co-energy metering between publicly owned utilities and customer-generators to compensate such generators on a time-of-use basis. The California Public Utility Commission's NEM 2.0 program, approved in January 2016, extends the NEM program for the investor-owned utility territories in California, which ensures that NEM customers continue to receive retail rates for surplus energy, but are placed on time-of-use rates. IID monitors the NEM 2.0 program for trends in implementing its own NEM rules.

On May 9, 2018, the CEC adopted 2019 Building Energy Efficiency Standards to take effect January 1, 2020. The new standards require that new home construction include the installation of solar photovoltaic systems. In promulgating the standards, the CEC acknowledged that rooftop solar generation is not intended to substantially exceed the home's electricity use. Efficiency requirements also were established for newly constructed healthcare facilities, and the 2019 standards added provisions to encourage demand responsive technologies, including battery storage and heat pump water heaters. The standards added provisions to improve residential buildings' thermal envelopes through high performance attics, walls and windows. For nonresidential buildings, the new standards work to maximum the use of LED technology. Under the new standards, nonresidential and residential buildings are expected to use less energy and require less electricity from their local utilities. IID must account for these circumstances in its procurement and planning decisions.

SB 859 – State Biomass Mandate

In September 2016, a bill was passed that requires POUs like IID to procure energy from biomass derived facilities that burn state identified 'tree mortality' fuels. Specifically, the law states:

"e) A local publicly owned electric utility serving more than 100,000 customers shall procure its proportionate share, based on the ratio of the utility's peak demand to the total statewide peak demand, of 125 megawatts of cumulative rated capacity from existing bioenergy projects described in subdivision (b) subject to terms of at least five years.

> (b) In addition to the requirements of subdivision (f) of Section 399.20, by December 1, 2016, electrical corporations shall collectively procure, through financial commitments of five years, their proportionate share of 125 megawatts of cumulative rated generating capacity from existing bioenergy projects that commenced operations prior to June 1, 2013. At least 80 percent of the feedstock of an eligible facility, on an annual basis, shall be a byproduct of sustainable forestry management, which includes removal of dead and dying trees from Tier 1 and Tier 2 high hazard zones and is not that from lands that have been clear cut. At least 60 percent of this feedstock shall be from Tier 1 and Tier 2 high hazard zones."

IID's overall requirement is expected to be an approximate $2 million impact based on current pricing. IID is working with SCPPA, CMUA and NCPA to find the most economical resource and is making progress toward the identification of that resource

Regionalization

While IID clearly lobbies against regionalization, California policy makers have, in recent years, debated the benefits of operating the Western regional grid as a single entity. The intent of regionalization in the form of an integrated western regional energy market is to facilitate grid operators' abilities to more easily and efficiently share resources throughout the western states. Regionalization in the eastern and Midwestern U.S. has shown the benefits of integrated energy markets to share resources among members.

AB813 was introduced to establish a pathway for the California Independent System Operator to form a multi-state regional transmission system organization. Although AB813 did not advance and pass into law in 2018, it remains in active discussion and would certainly impact IID as a power utility and Balancing Authority.

The current wording of AB813 does not require a utility to join or remain in a multistate regional transmission organization. Specifically, Section 8393 states that AB813 does not require any California transmission owner, retail seller, or local public owned electric utility to join or remain in a multistate regional transmission organization. The decision to join an RTO is left to the individual entity based on its preference. Should the bill progress and retain its optional language, IID will perform a detailed evaluation of the benefits and the costs prior to making a final decision.

To the degree that regionalization benefits California, IID could also benefit due to efficiencies and increased renewable energy contributions to serving load. If IID generation is the lowest cost generation to serve its load, then effectively, IID will continue to serve its load using its existing generation, and any excess generation beyond IID's load will be offered into the market to serve the load of others and IID will be paid the market price for the excess generation, thereby, making available an additional revenue stream for IID.

However, it is also acknowledged that the promise of lower power costs could also come at a cost from IID's perspective. This cost could include a loss of control as a BA, and it could lessen the socioeconomic impact of renewable energy projects in the IID service area. The net effect of the potential benefits and costs is difficult to surmise and depends on the details of the final structure of regionalization.

The intent of regionalization in the form of an integrated western regional energy market is to facilitate grid operators' abilities to more easily and efficiently share resources throughout the western states. Regionalization has been discussed by both state lawmakers and the California Independent System Operator (CAISO), which controls much of California's electric grid. Regionalization in the eastern and Midwestern U.S. has shown the benefits of integrated energy markets to share resources amongst the members.

A transition to a fully integrated electricity grid in the Western United States through the creation of a regional independent system operator is thought by many to help integrate increased renewable energy by balancing supply and demand across a larger geographic area. Currently, within the Western Interconnection, electricity is managed by 38 separate Balancing Authorities across the United States, Canada, and Mexico. All 38 BAs, including CAISO, are part of the synchronized Western Interconnection, but each BA is independently responsible for balancing supply and demand in its own territory. The BA in CA include: Balancing Authority of Northern California, California Independent System Operator, Imperial Irrigation District, Los Angeles Department of Water and Power, PacifiCorp-West, Turlock Irrigation District, Bonneville Power Administration-Transmission, NV Energy, and Western Area Lower Colorado. In order to improve reliability, cut costs, and increase efficiency, a number of these balancing authorities (and BA outside of CA) are partnering in the Western Energy Imbalance Market, which is managed by CAISO.

The EIM is a "real-time market" that adjusts for forecast errors between supply and demand every five minutes. This regional market has demonstrated numerous benefits of enhanced regional grid integration, such as reducing costs and greenhouse gas emissions; however, the EIM is limited in that it only allows for incremental adjustments to generation dispatch schedules and only captures a small portion of the region's wholesale electricity market. CAISO, Western states, and other stakeholders throughout the West are exploring the creation of the more fully integrated regional electricity market that would be managed by a single system operator and include a day-ahead market. Such a market could enhance utilities' resource planning, improve grid efficiency and reliability.

Although AB 813 stalled this year, SB 100, which requires California to get 100 percent of its power from renewable and other zero-carbon resources by 2045, was signed by Governor Brown on September 10,

2018. SB 100 specifies intermediate milestones: 40-44 percent by 2024; 45-52 percent by 2027; and 50-60 percent by 2030. The bill to begin the process of transforming CAISO into an RTO did not advance from the state Senate this year, but the effort may continue in the future. Previous efforts to create an organized market in the West have failed to advance as well. In the SB 100 signing message, Gov. Brown reiterated his desire for California to join neighboring states in a power system that integrates utilities across the West. He indicated that he believes a regionalized electric grid would enhance California's low-carbon grid by allowing California to share renewable resources with neighboring states, thereby reducing costs and increasing resiliency of the Western grid.

In a related matter, CAISO is positioning to take a large share of the West in the competition for reliability coordinator customers, the Western Electricity Coordinating Council revealed recently. WECC CEO Melanie Frye recently stated that WECC has received tentative RC commitments from balancing authorities and transmission operators representing all but 2 percent of net energy load in the West. She indicated that 72 percent of the region's load will likely sign on with CAISO's new RC, while 12 percent of load will go with SPP. CAISO's RC will dominate the West Coast, Idaho, Montana, Nevada and Utah — areas heavily represented in the EIM. Southern California's Imperial Irrigation District appears to have selected CAISO as its RC. The RC elections will give SPP a presence in 21 states, adding Arizona, California, Colorado, Oregon, Utah, Washington and what appears to be a thin slice of Nevada to the 14 states where it currently has members: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. RCs monitor compliance with NERC and regional standards, including monitoring risks, taking actions to preserve reliability and leading power restoration efforts.

AB 813 was introduced by Assemblyman Chris Holden, chairman of the Assembly Utilities and Energy Committee. AB813 would authorize CAISO's Board of Governors to submit a plan to the California Energy Commission to change the ISO's governance structure to include transmission owners from outside California. If adopted, it would be the first step in a multiyear process to make CAISO an RTO for the West. Supporters of AB 813 include Gov. Brown and the CAISO. Those who've opposed AB 813 include the Sierra Club, some municipal utilities, and some ratepayer advocates. They contend the measure would lump California in with coal-producing states, such as Wyoming, and put California at risk of greater interference from federal regulators under the Trump administration. Previous efforts to authorize CAISO's expansion have stalled during the past two years in the face of strong opposition both inside and outside of California.

AB 813 does not create a multi-state regional transmission system organization, but it provides a process for the ISO to develop a new governance structure to take the place of the current ISO governing board consisting of five members appointed by the governor of California and confirmed by the state legislature. The new governing board would be "independent," meaning not affiliated with or subject to any state policy authorities or commercial interests in the power sector. The bill required that the new governance structure shall not be implemented before January 1, 2021. The new governing board is viewed by other states as a necessary step for them to allow their jurisdictional electric utilities to participate in a CAISO-led RTO. With the new board in place, individual states could authorize or direct their jurisdictional utilities to join in forming an RTO, but these would be individual state and utility decisions that play out over years, rather than a single event in which the entire western interconnection becomes a single RTO.

Some environmental groups strongly support regional expansion as a way to integrate more renewable resources and decrease reliance on old fossil plants across the west that might not be able to compete in regional markets. Other environmental groups oppose the effort because they are concerned that regional grids will increase fossil fuel output, particularly from coal.

RTO benefits

To provide reliable electricity service, demand and supply must be continuously balanced. RTOs and ISOs are designed to choose which generators are committed and the dispatch levels to meet demand, based on resource cost and flow constraints. Existing RTOs operate day-ahead and real-time wholesale energy markets and various ancillary service markets. Some of the RTOs and ISOs also have a forward capacity market. In the day-ahead market, the RTO or ISO evaluate bids received from power plant owners/operators for power to satisfy forecast demand on an hourly basis. The RTO selects the resources to meet that demand the following day by selecting the lowest-cost resource first, then the next lowest, and so on until it has chosen enough generation to meet forecast demand. The units that are selected (clear) are obligated to provide energy during the following day for the hours that they cleared. Because the RTO selects the lowest-cost resources available to meet load, renewable generation—which has no fuel cost—is usually dispatched first. The price paid to all generators providing power within a given hour of the day is the price offered to meet the last megawatt of demand from the highest-cost power plant that clears the market. This price is called the clearing price.

Customer demand at any given hour is usually not exactly what was forecast the previous day. Therefore, RTOs operate real-time markets to account for the differences between predicted and actual demand, in 5 to 15-minute intervals. Resources bid into the real time markets (or spot markets) are cleared in a lowest to highest cost, similar to the day-ahead market. Because of renewable energy's free fuel, the more renewable energy that is available, less higher-cost fossil generation will be dispatched to meet system load. As more renewable energy is available, conventional power plants are used less, and over time, become increasingly less economical.

Key rationale and benefits for RTO-based organizations to handle the wholesale bulk power market are included in the following key table:

RTO functions	Benefits
Provide equal access to transmission system	Equal and non-discriminatory transmission system access using transparent and open access transmission tariffs (OATT)
Perform efficient market operations	Operate energy, capacity, and ancillary service markets using low-cost unit commitment and dispatch subject to transmission constraints

Facilitate large, competitive, "liquid" markets	RTO rules encourage greater market participation, greater liquidity, and pricing options for participants
Coordinate regional planning	Integrated system planning with regional expansion needs and plans
Ensure market competitiveness	Employ a market monitor to assess market competitiveness and ensure no members with market power or undue influence
Foster alternative resource options	Facilitate markets for demand response and integrate renewable resources in the resource mix
Integrate risk management tools	Provide hedging products including financial transmission rights to mitigate congestion risks

As an example, the PJM Interconnect claims that its services provide regional savings benefits of more than $2 billion annually including savings from energy production cost from $340-$445 million annually. The Midwest ISO claims similar total annual economic benefits including an estimated $180-$200 million annually for its centralized dispatch of energy operations

Many stakeholders see the benefits of moving to a RTO-based transmission organization. The efforts, resources, and dollars invested in the current RTO system make it difficult to consider reverting to another framework without significant policy backtracking. Still, there are areas where further efficiencies and market design considerations should and may be pursued to build upon the efficiencies and grid access in RTO-based regions while widening the participation in devising methods to more accurately measure value and benefits.

Opponents of AB813

Those arguing against regionalization, have stated that the Western Energy Imbalance Market is already doing a good job at allowing energy to be bought and sold as needed among Western states, without building new transmission lines from wind farms outside California to consumers in California. For example, Barry Moline, executive director of the California Municipal Utilities Association, which represents publicly owned utilities throughout the state was quoted as saying, "I don't buy the argument that we have to regionalize to take advantage of opportunities elsewhere." Creating more renewable energy sources in California and using in-state transmission lines would further the state's aims without adding risk, he said. Moreover, he said, AB813 would benefit wealthy out-of-state investors and conglomerates that want California ratepayers to pay for infrastructure from which they'd profit. "There's a lot of transmission companies and a lot of renewable resource developers that want to deliver kilowatt-hours into California," Moline said. "These folks want to make money off of California."

Expanding the Energy Imbalance Market (EIM) is already under consideration by the CAISO and is not an argument against ISO expansion or a substitute for it, because the EIM by itself does not reduce the severe western grid fragmentation that is the source of much of the unnecessary costs, pollution, and reliability risks. Coordination with the Bonneville Power Administration (BPA) has occurred for years and continues to improve. It does not substitute for or argue against western grid integration, which facilitates more robust coordination with all western utilities.

Opponents of the bill say deregulation of the market threatens the state's transition away from reliance on fossil fuels, opens it up to malicious speculation and would cost residents billions of dollars in fees. Recent newsletter articles explain that opponents raise the fear that this change would allow other states or the federal government to increase influence on California's energy future, and that the change will somehow harm disadvantaged communities in California. The basis for these claims is not substantiated.

Opponents of AB813, including some environmental groups, suggest that an RTO such as that motivating AB813 would open up California to more fossil-fuel energy sources such as that generated by coal. They also express concerns that by participating in an RTO, California would be subject to the jurisdiction of the FERC (the Federal Energy Regulatory Commission) that could under-cut California's renewable portfolio standard and efforts to reduce greenhouse gas emissions. Some attorneys note that the Supreme Court has ruled that the federal government prevails over state law.

Proponents of AB813

Those arguing for the bill said it would further California's ambitious renewable energy goals by tapping into Wyoming windmills and Arizona solar arrays, while spreading sustainable energy throughout the West. "This is the direction the grid is heading in," said Carl Zichella, NRDC's Western transmission director. "We need to be able to operate the system as a congruent whole." A set of amendments adopted was meant to ease the concerns of those who worried about linking deep-blue California with the red states of the interior West. "The purpose of the amendments is to reassure people that the progress California's been making on renewable energy and climate change are not likely to be interfered with," Zichella said. The new language included a requirement that a California TO, retail seller or publicly owned electric utility not join or remain a member of an RTO with a centralized capacity market. The amendments also insisted the state not undermine its ambitious scheme for achieving reductions in greenhouse gases and for purchasing electricity from renewable energy and zero-carbon sources.

Others argue that climate action and expansion of renewable energy is currently being held back by the inefficient patchwork of how transmission grids are managed across the west. The California Independent System Operator is the manager of most of California's transmission grid, over which electricity flows to our homes and businesses. In order to meet the ambitious climate and clean energy targets of California's landmark programs California lawmakers face a major choice: give the CAISO a chance to become a full-fledged western regional grid operator or keep the balkanized, polluting grid management system, currently in place. AB813 will allow the CAISO to work with neighbors in the West to oversee transition to a full integration of the Western grid. Other climate leaders in the West are eager to work with California on a regional electrical system that supports their clean energy resources and provides affordable access to clean energy resources in neighboring states. By helping each other out in this way, California can take better advantage of the region's clean energy. For example, instead of running gas plants in California to take up the slack when the sun goes down when California needs to meet its evening peak energy use, renewable power from other states could take up the slack. This makes for a cleaner, cheaper, and faster transition to a decarbonized energy future and will help California to meet its climate goals.

Below is NRDC's response to questions being raised by opponents of regionalization. California stands to benefit enormously by coordinating with its neighbors in an energy market that facilitates clean energy. NRDC argues that the Western grid integration would not undermine California's clean energy laws and policies. Instead, an expanded CAISO, covering more of the West, like all organizations doing business in California, would be bound by California laws. No state clean energy requirements would be eliminated. ISOs are policy takers, not policy makers. They must comply with the policy choices of the states they serve. AB813 addresses this concern by requiring the withdrawal of California utilities if the expanded CAISO fails to observe state policies.

Western grid integration would not necessarily mean more reliance on out-of-state renewable resources and less renewable production in California. Electricity markets are a two-way street. California could import low-cost renewable energy when it is plentiful elsewhere and sell excess to other states, helping manage costs, especially important to low-income communities. State studies recently concluded that access to lower-cost surplus renewable energy from around the West creates an economic magnifier effect that will reduce electricity bills for all Californians.

Western grid integration would not eliminate CAISO's accountability to the California legislature and risk attacks on state policies. Like any other organization in California, a Regional System Operator must obey all California laws. Grid integration allows for sharing of regional energy reserves, avoiding the need for duplicative power generation. AB813 retains California's right to withdraw utilities from a regional transmission organization, as the ultimate measure of accountability. Regional transmission organizations cannot ignore state recommendations. States have an influential voice in RTO decisions. When there are disagreements, they can petition for review by FERC and the courts. A regional transmission operator would not supersede state resource adequacy standards and undermine traditional state authority to establish rules to determine long-term needs and how renewable generation, demand response, and energy efficiency can meet those needs. Every Western state insists on maintaining its right to set its own resource adequacy standards. Grid integration will leave resource adequacy decisions up to the states participating in a regional transmission organization.

A core benefit of regional expansion is to enable greater exports of surplus in-state renewable generation. A process to increase export opportunities is to consolidate the 38 BAs in the West and eliminate the piling up of transmission access charges each one currently levies on every energy transaction. Coordinated scheduling of resources may help reduce grid congestion caused by bilateral deals reserving transmission rights, as WECC studies have previously shown. Expansion allows operators to use the grid more to its full capacity, reducing the need for additional transmission lines.

Supporters of AB813, including CalCCA and some environmental groups, suggest such an RTO would help advance the demand for and growth of renewable energy, as well as the ability of the power system to integrate renewable energy, and thus promote development of renewable energy in California. Supporters also observe that a change in Cal-ISO's governance structure, such as that proposed in AB813, is necessary in order for such an RTO to be implemented. As the CalCCA position materials point out, a significant challenge in building local renewable resources is ensuring sufficient value to support the cost of construction, and a significant risk to value is the expected curtailment and negative wholesale prices. A broader and more effective Western market through regionalization could lower these risks for local renewable projects. The bill would require that a future proposal for regionalizing the grid would need to be developed in an open, transparent way, and reviewed broadly by the public, the CEC, the CPUC and CARB prior to considering any actual regionalization Cal-CCA believes that a well-crafted plan will support the ability of CalCCA members to procure and build local renewable resources by creating a stronger renewable energy market…regionalization is also likely to further reduce greenhouse gas emissions by exposing coal-fired power plants to competition from cheaper clean sources."

Western grid integration would not increase the likelihood of federal preemption challenges to California's energy procurement and resource planning policies. California's ISO is already subject to federal regulation, and enhanced grid integration will not change the nature or scope of that oversight.

Background of AB813

Some opponents to regionalization argue that regionalization puts California at risk for increased intrusion by FERC and the federal government in general. In that California is already regulated by FERC for its electricity transmission and wholesale market activities, and that the Western grid is already an interconnected system covering 13 states and parts of Canada and Mexico, while every state has its own policies about greenhouse gas emissions and renewable energy sources. Problems arising from diverse states with diverse policies trying to control the outcomes of a single physically-interconnected electrical system exist today and will continue to exist with or without an RTO. (An example is the great difficulty in calculating the carbon content of electricity entering CA over its interconnections with other states.)

The US Constitution gives the federal government authority over states in matters of interstate commerce (the "commerce clause" of the constitution). This is sometimes referred to as "federal preemption" and has had vast impacts in all sorts of arenas. The Federal Power Act of 1935 designates wholesale electricity transactions and high voltage electricity transmission as interstate commerce under the Constitution, and establishes FERC as the regulatory authority to implement the FPA. There have been important updates to the FPA through federal legislation over the years, most recently the Energy Policy Act of 1992 which paved the way for wholesale power markets operated by ISOs, and the Energy Policy Act of 2005 which created a new framework for ensuring power system reliability and security in the wake of a major blackout in 2003. But the underlying FPA framework has not changed substantively. FERC has been the implementing and regulatory authority over the relevant provisions of the 1992 and 2005 acts, and the regulator of all the ISOs in the US. As a result, the CAISO is already a FERC-jurisdictional entity, and 100 percentof what it does is specified in its tariff.

Any changes to the CAISO tariff that are originated by the CAISO (in contrast to ones that are ordered by FERC) must have approval of the CAISO Board before being filed with FERC. Today's CAISO board has five members appointed by the governor of CA and confirmed by the CA Senate. So there may be concern that a board that is not CA-appointed might make different decisions about what the Regional ISO can submit to FERC, and some of those decisions might be less favorable to California. That is a plausible scenario. But the new Board is required to be "independent" which means not to have any financial or political interests with market-participating entities or specific state or local governments in the regional ISO's territory. In the end, FERC still has to rule on whatever is submitted to it, so has essentially the last word (unless the FERC decision is overturned in the courts).

The above should not be misconstrued to say that FERC regulation and authority are not problematic for states. However, with regard to AB813 and the forming of a regional ISO compared to the CAISO governance as it today there would be little difference in FERC's authority or the ability of the federal government to overrule or undermine CA policy objectives. Conversely, Texas, Hawaii and Alaska are not subject to FERC regulation because they do not engage in interstate commerce for electricity. In the case of Texas, it's because Texas doesn't conduct import and export transactions with other states; they're essentially an electrical "island" for most of the state. Such an arrangement is not practical for CA because of the reliance on imports for over 20 percent of electricity supply annually.

Gov. Brown and several prominent environmental groups including the Natural Resources Defense Council and the Environmental Defense Fund also back the measure, claiming it will cut costs for consumers and bring more clean energy into the state. They also hope the plan will phase out fossil fuel plants. Opposing environmental groups fear a regional grid could increase fossil fuel input, particularly from coal, into California's energy grid. Proponents for the measure argue that the bill would allow for electricity to be traded "more efficiently across state lines" while allowing the state to export unused renewable energy from sources such as solar and wind energy producers.

Lauren Navarro, a policy manager with the Environmental Defense Fund, told the committee the bill would "cement California's leadership" in the national movement to supply states with clean energy. "The bill enables us to use more clean energy and take dirtier resources off the grid in other states," Navarro said. "[California's] renewables are less expensive and will be chosen in other markets. This will help states transition to clean resources."

The debate on AB813 has reminded some of the state's 2000-2001 energy crisis. In those years, the state suffered a shortage of energy supply caused by market manipulations and capped retail electricity prices which led to multiple statewide blackouts and the collapse of one of the state's largest energy companies. The state Legislature's past unanimous approval of deregulation of the state's electric power system was followed by unintended consequences. Market manipulation by Enron (and possibly other entities) drove a major utility company into bankruptcy, caused blackouts and forced California residents to overpay billions of dollars. Enron was a U.S. energy-trading and utilities company that facilitated one of the biggest accounting frauds in history, using false narratives to inflate revenues. Enron was also implicated in the state's energy crisis. The Enron debacle led to the creation of the CAISO, whose board members are appointed by the governor.

High electricity prices in the beginning of the 1990s caused the CPUC to become interested in and it started promoting further competition in electricity generation to reduce electricity production costs. In 1992 the commission announced its intent to examine the current electric industry and to explore alternatives to the regulatory approach. California's electricity industry slowly evolved into a hybrid structure in the form of a Direct Access-type model that would allow both bilateral and market deals and give retail customers the choice to obtain electricity from any utility or other Energy Service Provider. The utilities would initially be forbidden to enter into long-term bilateral contracts and would be obliged to procure all their electricity through the newly established electricity market. This opened the way for CPUC's final decision in December 1995, which laid out a set of policies to create a fully competitive electricity market and to guide the utilities in restructuring their operations[5]. This would be supported by the introduction of full retail competition and the vertical unbundling of the electricity industry to enable competition[6]. IOUs divested most of their instate fossil-fuel generation and sold it to independent power producers or merchant generators. Operational control of the utility-owned high-voltage transmission grid was transferred from the IOUs to the California Independent System Operator. Before restructuring, each vertically integrated investor-owned utility performed the grid management functions for their own specific geographical area. In other areas, utilities centralized these functions in a power pool. Under restructuring, the IOUs would remain the owners of the transmission network and distribution grids in their service area and were transformed into utility distribution companies[1] and energy brokers or scheduling coordinators were formed to match electricity supply and demand in a market setting. The ISO evaluates submitted supply offers and demand bids and determines generator schedules based on the capabilities of the high-voltage transmission grid.

The California Power Exchange, was created to function as California's main SC as the primary wholesale electricity market balancing supply and demand. In the day-ahead market, with an anticipated volume of 90 percent of all trades, prices in these markets are hourly. In this market, buyers provide the amount of electricity need anticipated for each hour of the next day and the prices they were willing to pay. Sellers stated the amount of energy they could produce and the prices they required for each of those hours. Based on all the received demand and supply bids, the PX determines the highest-priced supply bid necessary for meeting demand during any given hour and that will set the single market-clearing price to be paid by all buyers to all sellers for energy purchased for that hour. The state's IOUs were required to sell and purchase all of their power through the PX until March 2002 or until the CPUC ruled that they had recovered their stranded costs.

California's economy and subsequent electricity demand grew at a high rate during the early years of restructuring. Peak demand increased about 18 percent between 1993 and 1998. During those same years,

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[5] California State Auditor (2001), *Energy Deregulation: The Benefits of Competition Were Undermined by Structural Flaws in the Market, Unsuccessful Oversight, and Uncontrollable Competitive Forces*, 2000-134.1R, Sacramento CA, www.bsa.ca.gov/bsa/, (June 2002)

[6] Joskow, P.L. (2001), 'U.S. energy policy during the 1990s', paper presented for conference on American Economic Policy During the 1990s, John F. Kennedy School of Government, Harvard University, June 27-30, 2001, econ-www.mit.edu/faculty/pjoskow/files/usen1990.pdf, (December, 2001)

insufficient new generating capacity was added to maintain reserve margins, causing California's reserve margins to fall from approximately 13 percent to approximately 4 percent. During its first two years of operations—apart from some start-up problems—the California electricity market seemed to be working mostly as designed and expected. Over time, electricity producers found that uninstructed deviations from schedules could be profitable due to the resulting problems in balancing load and generation. These imbalances caused the ISO to purchase more energy reserves from the ancillary services market to balance the grid. Furthermore, ISO operators were coping with the new uncertainties of the electricity markets, in which the system's load and generation in real time were inherently more unpredictable causing the ISO to purchase far more ancillary services than under the old vertically integrated structure.

Before the end of 1998, the ISO and the PX voiced concern to the CPUC and FERC of identified flaws in California's rules and market structure. The ISO began to express concerns about the rapid growth in electricity demand, the rapid reduction in reserve margins and the slow pace of new generation investments. In early 1999 the PX concluded that during periods of high electricity demand, market power could determine and set wholesale prices, thereby voicing its concerns about the spot market price volatility. To remedy these problems, the ISO and the PX sought to change the markets and their procedures. Within the first two years of operation, the ISO had filed 30 major revisions to its protocols with FERC. Real-time energy prices, although more volatile and peaking in times of greater demand were roughly moving with day-ahead energy prices and competitive wholesale market prices for power were reasonably close to pre-restructuring projections.

As of the beginning of 2000, in general, restructuring seemed on track. Most encountered problems were solved by changing and adding procedures and market rules. Prospects for declining overall wholesale prices seemed favorable. California's electricity grid connected California with other states and its neighboring countries. California generation facilities had roughly 55,000 MW of capacity and the state was able to import an additional 8,000 MW. California's market seemed highly competitive and had seen huge increases in both the amount and volumes of electricity trading. However, when temperatures rose during the spring of 2000, the electricity market experienced difficulties. Both California and the entire Western region experienced one of the hottest summers in decades while hydropower reserves in the Northwest were low due to a dry winter. New merchant generators had entered the electricity market by the year 2000. Many of them had bought the divested power plants from the IOUs. Hydropower, often used for generating electricity during peak demand hours, had limited availability due to the dry winter. Hydro facilities have more flexibility to provide more rapid reaction time voltage changes compared to the slower reaction of both nuclear and fossil-fuel plants run on steam, which are generally used to provide base-load power (a more steady output of electricity according to prearranged schedules). Because grid management and energy demand vary enormously during summertime peaks, large amounts of hydropower are used during the summer to meet these contingencies. Because the electricity California needed for the summer was not available from traditional out-of-state sources wholesale prices began to rise above historic levels in May 2000. In June 2000, PG&E had to interrupt service to its customers in the San Francisco Bay Area for the first time in its history, brought on by high temperatures, a disproportionate number of local generation units being unavailable, and insufficient import capacity due to a lack of transmission capacity in the Bay Area.

Throughout the 2000 summer, wholesale electricity prices in California were nearly 500 percent higher than during the same months in 1998 and 1999. SDGE was allowed to pass on its electricity wholesale prices to customers. State legislators installed a retail price cap. During the summer of 2000, CA IOUs reported huge losses because they were obliged to buy power at wholesale prices far higher than the retail rates against which electricity could be sold, however, the CPUC did not fulfill the requests for retail rate increases. Even during times of reduced electricity demand and lower temperatures, electricity wholesale prices remained above average between May and December 2000. Natural gas prices also increased in 2000 such that monthly average wholesale electricity price had risen to over $250 per MWh by December 2000. Natural gas prices in California reached their maximum in December 2000 at $58.76/MMBtu in Southern California. At such high prices for natural gas, many generators struggled to generate energy and sell it at or below the established price cap without substantial loss, resulting in deteriorating financial conditions for the utilities adversely impacting the creditworthiness of PG&E and SCE. Subsequently, the utilities stopped payments to the ISO and some small generators. The smaller generators ran up against their credit limits and stopped selling electricity to California. The CPUC approved a 10 percent electricity retail price increase by early January 2001. The allowed increase was not sufficient for the utilities to cover their ongoing wholesale power costs, nor make progress paying off their previously acquired debts. Because of the utilities' inability to pay, the ISO also became financially non-creditworthy.

Eventually, electricity producers refused to sell electricity to both the utilities and the ISO, preferring to sell their electricity in other electricity markets and other states. An accumulation of cold weather and short hydroelectric power supply resulted in a simultaneous strong need for electricity in the Pacific Northwest. By mid-January of 2001 the utilities had run out of cash and stopped paying their bills for power they had already purchased. FERC directed the ISO to ensure the presence of a creditworthy counter party to ensure financial backing for all third party energy procured for PG&E and SCE through the ISO markets. Most of California's electricity trading was conducted outside of the PX because no one was interested in dealing with the almost bankrupt PG&E and SCE. The State of California, acting through the California Department of Water Resources, began purchasing energy on behalf of the UDCs. A bill was passed authorizing the department to enter into long-term contracts for the purchase of net short electric power.

During the California electricity crisis, that ISO structure broke down and the markets at the heart of this design became dysfunctional. There were loopholes that gave people more chances to go outside the parameters they are supposed to be working within. There were no provisions in the original tariff to deal with these eventualities. Events made clear that the market design was faulty. Some of the shortages exercised during that time may have been caused by lack of coordination between balancing authorities and by individuals with knowledge on how to manipulate the system to benefit themselves. Many of the problems experienced during that era may have been avoided under the regime of a properly designed regional transmission organization.

The ISO, the PX, and the respective markets were developed and created during little more than nine months and not all the bugs were solved by the time operations began. Problems with the markets during that period have caused some to view deregulation and markets unfavorably. Properly designed markets can cause the realization of cost savings (CAISO studies show that regionalization could save up to $1.5 billion annually by 2030) as has been demonstrated by RTO markets in other regions of the US. Net demand curves (the touted duck shaped curves) show that the state's load dips in the middle of the day as solar resources increase output and then ramps up steeply in the evening as the sun sets. The steep ramps require CAISO to lean on fast-ramping generation to meet evening demand. Solar PV penetration in CA had reached the penetration level in some regions such that solar generation has to be turned off on some sunny days. Coordinated scheduling with a broader region might bring revenue to California by selling more solar to other states that would in turn save money.

In addition, a regional grid may help support California's ambitious renewable energy goals by tapping into Wyoming windmills and Arizona solar arrays, while spreading sustainable energy throughout the West. Some utilities in the west outside CA are looking for ways to procure more renewables, in alignment with California's goals. Regionalization could help California reduce carbon emissions. The rest of the west isn't going to decarbonize because California does, but they will buy cheap electrical energy, thereby indirectly reducing carbon emissions. Under regionalization, California will continue to have control over its resource decisions, CO_2 policy, generation siting, and retail rates and programs.

Impact of Regionalization to IID

To the degree that regionalization benefits California, it is also acknowledged that the promise of lower power costs could also come at a cost from IID's perspective. This cost could include a loss of control as a BA, and it could lessen the socioeconomic impact of renewable energy projects in the IID service area. The net effect of the potential benefits and costs is difficult to surmise and depends on the details of the final structure of regionalization.

Joining an RTO in other regions of the country has been an option for a utility. Each utility evaluates the benefits and costs and makes the decision to join based on the benefits to its stakeholders. The current wording of AB813 does not require a utility to join or remain in a multistate regional transmission organization. Specifically, Section 8393 states that AB813 does not require any California transmission owner, retail seller, or local public owned electric utility to join or remain in a multistate regional transmission organization. The decision to join an RTO is left to the individual entity based on its preference. Should the bill progress and remain options, IID should perform a detailed evaluation of the benefits and the costs prior to making a final decision.

As a consequence of the above points, any effort to create a new multi-state regional transmission system organization pursuant to AB813 or similar governance change will take at least three to five years before the new RTO begins formal operation with those utilities that decide to become initial members and IID's current position is opposed to this policy.

AB 2514

AB 2514 requires publicly owned utilities, such as IID, to determine targets for procurement of viable and cost-effective energy storage, to be achieved by two target dates: December 31, 2016, and December 31, 2020. These targets are to be adopted by October 1, 2014 and reevaluated not less than every three years. Publicly owned utilities are required to report on its energy storage targets and procurement to the CEC.

The CEC approved on August 1, 2018 changes to its IRP Guidelines requiring POUs to provide a narrative how, under SB 338, renewable resources, multi-hour energy storage, and distributed energy resources, including energy efficiency, are considered for meeting reliability needs during the net-peak hour.

TRANSMISSION RESOURCES

The IID's long-term transmission planning efforts are primarily centered on protecting and maintaining the IID BA and meeting retail load obligations. In addition, the IID must also provide transmission services under its *Open Access Transmission Initiative* to generators selling energy to entities outside of the IID's control area.

The IID's current long-term transmission plan meets the needs of its retail customers. The IID is also working on upgrades to its major south-north transmission lines to increase near-term export capacity to approximately 750 MVA by 2017. However, this planned transmission upgrade soon will be totally subscribed and additional south-north transmission capacity will be required to export planned generation from the Imperial County by 2016 or 2017.

It is almost a foregone conclusion that a major new transmission line will be constructed in the Imperial Valley with a number of new 500kV transmission lines proposed by private and public entities. If the IID does not develop this new line itself, the IID will work with the various project sponsors to develop a line that maximizes the benefits to the IID and its ratepayers. The IID will oppose any new lines that threaten its balancing authority rights or which could result in stranding the IID's investment in transmission resources.

Currently the IID is involved in informal, nonbinding talks with a number of different entities on possible new transmission lines, generally coming from the Yuma area to Imperial Valley substation in El Centro and then north through Imperial Valley to Devers substation in the Palm Springs area. But there is no development or planning agreements with any of these entities that would like to build the new line.

How to meet this additional demand for south-north transmission is one of the IID's most critical near-term tasks. Choosing its partners and the management and financial structure of a major new transmission line will help the IID meet its transmission obligations and protect the IID's Balancing Authority rights and protect the IID's existing transmission wheeling revenues from encroachment from other entities.

On a regional level, IID has established plans with state and regional transmission planning agencies with the recent proposal of the Strategic Transmission Expansion Plan . This plan encompasses IID's overall transmission plan that is supported by many of the projects already planned and approved.

BASECASE POWER SUPPLY PLAN ASSUMPTIONS

The planning process has resulted in a proposed generation plan that meets renewables portfolio standards and greenhouse gas emission reduction requirements, while providing a high degree of price certainty and system reliability for the period of 2019 forward.

A basic summary of the proposed resource plan, which will also be the baseline assumptions for the studies, include:

Exhibit 12: 2018 BaseCase Assumptions

Key Assumptions Modeling Simulations (IRP)
Used 2018 Load forecast for retail sales and energy requirements
Used Ventyx ST AUG19 energy/gas price forecast + 10%
Corrected online dates of the FIT projects as discussed May18
Online date of June-2020 for the GeoGen Co Geo project
Online date of Jan-2019 for the CalEnergy project
Assumed that Drop 4 is online in June18
Assumed expected generation (Contract quantity) from renewable facilities
COD of Jan 1, 2018 of 1.4MW of Biomass and Q4 1 MW to comply with SB859. Flows may occur in 2017, but no costs are assumed per direction
Assumed current efficiency of operations of the BESS facility (10MW spin; 70% ops limit)
E-Green (20-30MW from Citizens) online by June19
Updated heat rate curves to reflect the most updated data available
Updated Heber 1 10 MW Geo output projection into 33.33% of 46MW Geo output during 01/2017-01/2018, 22% of 46MW Geo output during 02/2018-12/2022
Used the '50th percentile' (expected case) for budget results and also for burns/MWH. This change is a result of the ERMG vote on 8-2-18 to that the official budgets update will occur every quarter and we can use the epected case.
Assumes market displacement sales, so the bottom line results reflect the net effect of this assumption.
Assumes the cost differntial in the 2019 budget between the market price forecast vs current forward curve/indicative prices to allign with ERMG approved purchases
Assumes the Cap and Trade auction sales are 50% of full sale. So, if the auctions are undersold, IID's consigned allowances will be undersold and IID will not have that revenue.
Assumes some market buffer due to recent volatility and price increase trends
Assumes spin requirements vary from internal single largest contingency to transmission as a single largest contigency based on history and current DA/RT trading practices.
Assumes the historically based renewable generation + 5%
Assumes most recently provided min down/up times and other unit characteristics as of June-17. These times do not incentivize cycling.
Does not assume any added units in the future; rather market energy/system dispatch fills any needs and no net impacts are assumed
No assumptions for seasonal units required during the year. Spin, regulating reserves, load and price are key drivers for unit commitment.
Assumption Pending: Excess and economic displacement sales assumed forcing units and/or mkts to run more to make the sales. No REC/emissions sales income/revenue is assumed on the bottom line per finance.
Assumption Pending: Buyout of SunPeak1 is not complete, so Aug18 and beyond include contract price increases. If buyout occurs, then fuel and purchased power will significantly decrease as SunPeak contract costs will be eliminated.
Assumption Pending: This budget version uses the previously understood $/MWh in VOM. It does not used recently discussed $VOM prices (which would greatly alter econ dispatch)

The planned resource additions are in addition to the IID's power purchase agreement with for the currently online renewable and nonrenewable facilities, procured natural gas and procured biogas to be converted to renewable energy added in recent years to the IID's resource mix. Additionally, the energy efficiency/conservation programs of load reducing, load shifting and interruptible loads that have already been installed are a part of the basecase assumptions as well.

With IID's resources, the IID will generate more than 40 percent of its annual energy requirements from renewable energy sources by 2020 and this IRP identifies potential resources to meet the 33 percent goal by 2020 and the 50 percent goal by 2030 while keeping total power supply costs relatively stable for the next several years.

A key to the IID's power planning process is to minimize the impact of changes in natural gas costs. Currently, the IID attempts to establish hedges for 36-60 months into the future. In the near term, the IID would like to increase its hedging activities to available five-year term, but is mainly focused on 3 years at this time. A longer-term hedging strategy will allow the IID to achieve price stability for a longer period in the future and, with the implementation of more renewables, the IID's volatility potential decreases since less fuel and less purchases will be needed.

It is also useful to recognize that, from a rate perspective, it is not the total power supply cost that is important but the average cost per MWh. The proposed generation mix presented in this IRP keeps average energy costs rising at a relatively low rate over the next several years.

CHAPTER 2: SYSTEM DESCRIPTION

IID's Energy Department provides electric power to more than 152,000 customers in the Imperial Valley and parts of Riverside and San Diego counties. As the sixth largest utility in California, IID controls more than 1,100 megawatts of energy derived from a diverse resource portfolio that includes its own generation, as well as long- and short-term power purchases.

As a consumer-owned utility, IID works to efficiently and effectively meet customers' demands at the best possible rates, tying the IID area's low-cost of living directly with low-cost utilities. This is accomplished by producing power supply locally, using efficient, low-cost hydroelectric facilities, steam-generation facilities, as well as several natural-gas turbines. Environmentally friendly operations are emphasized by employing as many renewable resources as available to effectively meet the state's renewables portfolio standards. IID's diverse resource portfolio provides customers with some of the lowest cost rates in Southern California and this standard of quality service will be a continued focal point of IID's future activities.

In 2017, the IID's peak demand forecast was 1,076 MW and was the all-time high system peak demand. As a Balancing Authority, the IID is required to have generation resources providing spinning reserves, non-spinning reserves, operating reserves and planning reserves, totaling about 15 percent of the forecasted load. Thus, the IID required generation resources plus purchases equal to almost 1,218 MW for the peak summer month of 2016.

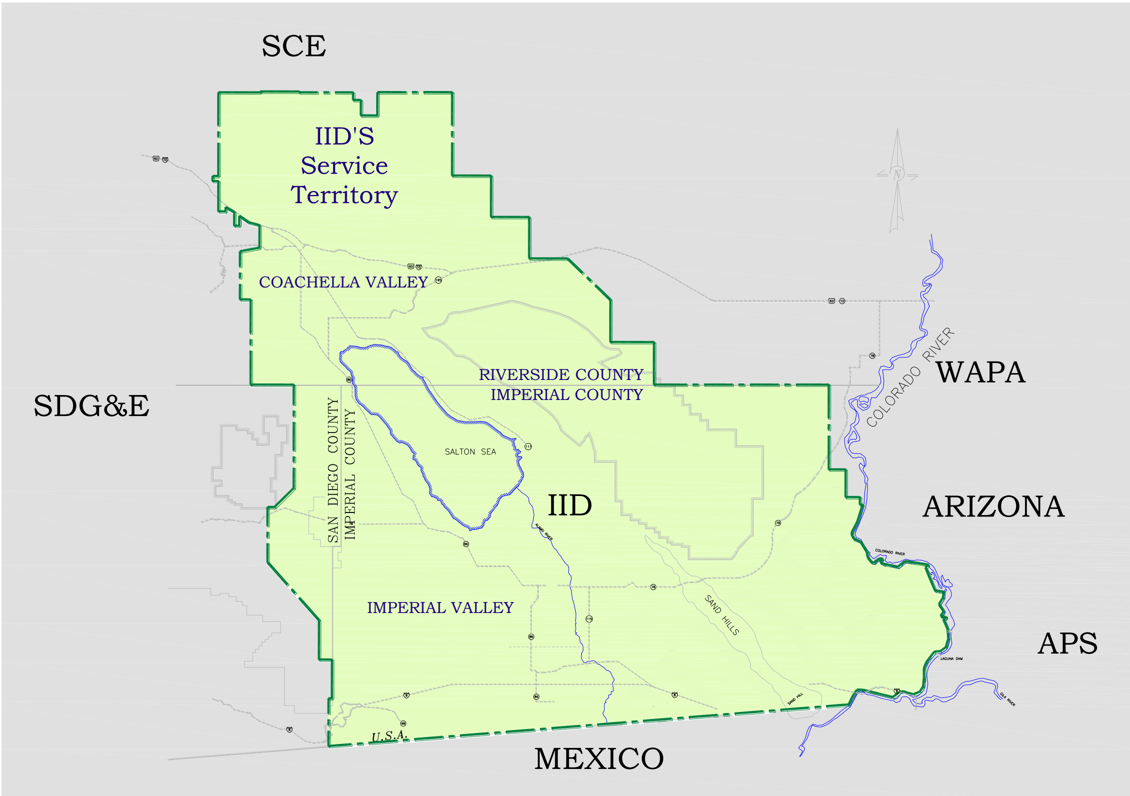
The IID meets its annual resource requirements through a mix of IID-owned generation and a number of purchase power contracts that consist of must-take contracts and call options. Due to the renewables portfolio standardand AB 32's cap-and-trade regulation, IID's resource fuel mix includes both conventional forms of generation and imported purchases, as well as renewable resources. These requirements have increased the need for a more diverse portfolio of varying fuel types to manage those fuels that do not allow economic dispatch.

THE IID'S TRANSMISSION AND DISTRIBUTION RESOURCES

The IID owns and operates electric generation, transmission and distribution facilities. The IID's service area extends over 6,471 square miles. Its transmission and sub transmission system includes approximately 1,800 miles of overhead transmission lines; its distribution system includes 4,404.3 miles of overhead lines and 1,744.1 miles of underground lines.

The following map depicts the IIDs service area and its neighboring utilities

Exhibit 13: IID Service Area and Neighboring Utilities


SCE
IID'S Service Territory
COACHELLA VALLEY
SDG&E
RIVERSIDE COUNTY
IMPERIAL COUNTY
SAN DIEGO COUNTY
IMPERIAL COUNTY
SALTON SEA
IID
COLORADO RIVER
WAPA
ARIZONA
SAND HILLS
IMPERIAL VALLEY
APS
U.S.A.
MEXICO

IID'S TRANSMISSION SYSTEM

The IIDs transmission system consists of 500kV, 230kV, 161kV and 92kV transmission lines. The transmission system is used to wheel bulk power supplies into and through the IIDs Balancing Authority. The transmission expansion plans aim to provide plans to achieve diversity, sustainability and resilience to the bulk transmission system, distribution system and local communities while improving reliability

500kV Transmission system

The IID owns a portion of the Southwest Power Link 500kV line. This transmission line connects the Palo Verde Substation, a major wholesale electric trading hub, to the North Gila 500kV-69kV Substation near Yuma, Arizona. The line continues from North Gila to the Imperial Valley 500kV-230kV Substation in El Centro. IID also owns a portion of the 500kV HANG2 line that connects Hassayampa to North Gila 500kV Substations.

230kV Transmission system

There are two major components that comprise the IIDs 230kV transmission system. The first is a single circuit line between the IIDs El Centro Switching Station in El Centro and the Imperial Valley Substation that is jointly owned by the IID and SDG&E (the "S" line). The second is a double-circuit transmission line that runs south to north through the IIDs service territory and interconnects the IIDs service territory with SCE at the Devers and Mirage substations (KN/KS lines).

The KN/KS line is also known as the IIDs "collector system" that runs south to north across the IIDs service area to SCE's Mirage Substation. One circuit interconnects at Mirage Substation and the second circuit continues west to Devers Substation through SCE's 230kV line.

Four transmission substations interconnect to the collector system (from Highline in the Southern part of the system through Midway, then Coachella Valley and finally Ramon Substation). The interconnection with SCE is established at Coachella Valley Substation with Coachella Valley - Mirage 230kV "KN" line and at Ramon Substation with the Ramon-Mirage 230kV "KS" line. The IID-SCE interconnection is defined as WECC-Path 42.

The 230kV collector system was constructed in 1983 for the primary purpose of delivering over 500MW of "power generating facilities," mostly consisting of renewable resources in the IID system and contracted to SCE at that time.

161kV Transmission System

The 161kV transmission system consists of two separate lines across the IIDs service area that interconnects several 161kV/92kV transmission stations, providing transformation capacity from the 161kV system to the 92kV system. It also provides interconnection to Western through two 161kV transmission lines, from IIDs Niland Substation to Western's Blythe substation and from the IIDs Pilot Knob Substation to Western's Knob Substation and one interconnection from the IIDs Pilot Knob Substation to the APS Yucca Substation.

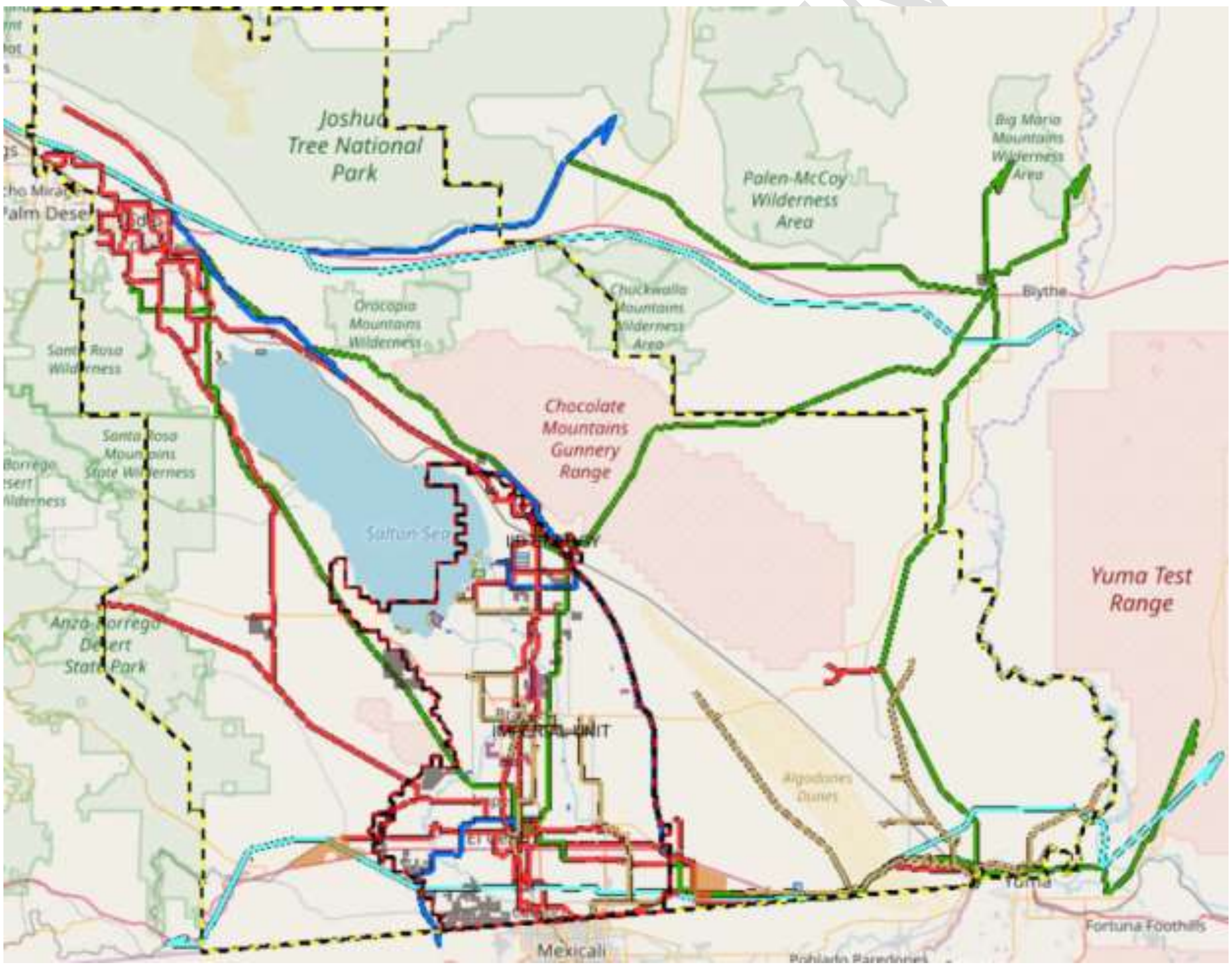
This 161kV system has met the load serving requirements of the IID for over 50 years; however, as the load continues to grow in all regions of the IID service area, planning for necessary system upgrades has been ongoing.

The existing system has also experienced additional stresses due to generating resources constructed near the edge of the IID service territory.

92kV Transmission System

The 92kV transmission/subtransmission system consists of multiple transmission lines that provide interconnection to the distribution substations (92kV/13.2kV) that are constantly constructed and upgraded to provide transformation capacity to the distribution system.

Exhibit 14: IID Bulk Transmission and Subtransmission System



GENERATION RESOURCE PORTFOLIO

The IID maintains a steady focus on diversifying its portfolio of resources to serve load, including purchases and internal generation. IID's current generating resources are shown in the exhibit below:

Exhibit 15: Loads and Resources: 2019-2038

Peak Hour Loads and Resources - 2018 IRP																				
Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
FORECASTED SYSTEM DEMAND	1,061	1,068	1,080	1,092	1,108	1,119	1,138	1,155	1,171	1,186	1,206	1,224	1,245	1,261	1,285	1,308	1,332	1,356	1,382	1,401
PLANNING RESERVES REQUIREMENT	159	160	162	164	166	168	171	173	176	178	181	184	187	189	193	196	200	203	207	210
TOTAL SYSTEM CAPACITY REQUIREMENTS	1,220	1,228	1,242	1,256	1,274	1,287	1,309	1,328	1,347	1,363	1,387	1,408	1,432	1,450	1,478	1,504	1,532	1,559	1,589	1,611
DSM PROGRAMS																				
Residential Small Business	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Key Customer	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
EXISTING DSM PROGRAM CAPACITY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
BASELOAD PLANTS/CONTRACTS																				
PALO VERDE	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PARKER-DAVIS (SUMMER)	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
HYDRO (EXISTING GREEN)	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
EXISTING BASELOAD CAPACITY	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
TOTAL BASELOAD PROJECTED REQUIREMENTS	247	247	247	247	247	247	247	247	247	247	247	247	247	247	247	247	247	247	247	247
INTERMEDIATE LOAD PLANTS/CONTRACTS																				
EL CENTRO #2	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99	99
EL CENTRO #4	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67
YUCCA	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
EXISTING INTERMEDIATE LOAD CAPACITY	241	241	241	241	241	241	241	241	241	241	241	241	241	241	241	241	241	241	241	241
TOTAL INTERMEDIATE LOAD PROJECTED REQUIREMENT	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463	463
PEAK LOAD PLANTS/CONTRACTS																				
COACHELLA	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
GT 21	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
ROCKWOOD	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
NILAND 1 &2	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86	86
Other Facilities																				
EC#3 RPWR	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Biomass	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
SunPeak Solar1 (23MW)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Community Solar Project (CSP) 20MW (COD 6/18)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
SunPeak Solar2	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Sol Orchard (20)	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Ormat Solar (10MW)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
SDSU Solar (5MW)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
FIT 1	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Regenerate Solar (30MW) (COD range from 6/15 - 12/16)	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
8minute Solar (30MW) (COD range from 9/16 - 12/16)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
SRP Geothermal 1 (CE)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
SRP Geothermal Geo Gen Co (june 15 2020)		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Geothermal 3 Ormat	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
EXISTING PEAK LOAD CAPACITY	566	570	569	569	569	569	569	637	651	666	677	693	693	693	693	693	693	693	693	693
TOTAL PEAK LOAD PROJECTED REQUIREMENTS	510	518	532	547	564	578	599	618	637	654	678	698	722	741	768	794	822	849	880	901
TOTAL OWNED RESOURCES, PURCHASES, AND DSM	899	903	903	902	902	902	902	970	984	999	1,010	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026
Minus dsm programs (PSS)	887	891	891	890	890	890	890	958	972	987	998	1,014	1,014	1,014	1,014	1,014	1,014	1,014	1,014	1,014
TOTAL PLANNING RESERVE MARGIN - PERCENT	-15%	-15%	-16%	-17%	-19%	-19%	-21%	-16%	-16%	-16%	-16%	-16%	-18%	-19%	-20%	-22%	-23%	-24%	-26%	-27%
TOTAL NEEDED (PSS)	(321)	(325)	(339)	(354)	(371)	(385)	(407)	(358)	(362)	(364)	(377)	(382)	(405)	(424)	(451)	(478)	(506)	(533)	(563)	(585)
TOTAL NEEDED WITHOUT DSM PROGRAMS	(333)	(337)	(351)	(366)	(383)	(397)	(419)	(370)	(374)	(376)	(389)	(394)	(417)	(436)	(463)	(490)	(518)	(545)	(575)	(597)

The following subsections are a brief overview of these generation resources.

HYDROELECTRIC RESOURCES

The IID has a number of small hydroelectric facilities located on the All-American Canal and nearby branches. The largest of these hydroelectric facilities is Pilot Knob, a two-unit facility with a combined nameplate rating of 33MW. The smallest unit is Double Weir with two units each with a rating of 0.28 MW.

The hydroelectric units have a combined rating of about 85 MW although, due to seasonal water flows, the summer capacity rating is approximately 32 MW of effective summer capacity where the amount of generation from the hydroelectric facilities is directly dependent upon the needs of the local area agricultural crops. Therefore, production will vary from season to season, but over the course of the year, the average hourly output from the hydroelectric facilities is approximately 32 MW.

The IID's hydroelectric projects are considered green resources and energy produced from them helps satisfy the IID's RPS requirements.

Annual energy production from the units is approximately 270,000-280,000 MWh although this value changes according to water availability.

Small Hydroelectric Project Overview

The IID has approved the construction of low head hydroelectric plants at the West Side Main Check #8 and at the Foxglove canal heading. The Check 8 project is currently in the design phase. The hydraulic turbine and generator will be provided by Spaans Babcocks. The plant will consist of two turbines and civil structures to channel water flow to the turbines. The existing check gates will be fully automated and the generation units will be unmanned and remotely controlled. The generators are rated at 219.5 kw each. The Check 8 project is expected to enter commercial operation in 2016 or 2017. The design of the Foxglove low head hydroelectric plant will commence in late 2017 with commercial operation expected in 2017 or 2018. These units will be included in IID's RPS portfolio.

Southern California Public Power Authority

The Southern California Public Power Authority is a joint action agency comprised of the cities of Los Angeles, Glendale, Burbank, Cerritos, Vernon, Pasadena, Anaheim, Riverside, Azusa, Banning and Colton and the IID (the only non-municipal member of SCPPA).

SCPPA acts as a funding entity for transmission, generation, fuel and energy efficiency projects. SCPPA will issue debt for the construction of new resources and then secure this debt with take-or-pay contracts with project participants. When IID is a party in a transaction with SCPPA and member utilities, the debt falls on SCPPA and therefore minimally impacts the IID's credit ratings. This is an unequivocal advantage of being a member of SCPPA.

Joint action entities like SCPPA allow small entities the opportunity to participate in larger, cost-effective generation resources. A publicly-owned utility that is too small to buy an entire project can enter into a take-or-pay contract with SCPPA that will aggregate the needs of all its members. SCPPA will then issue debt to construct or purchase the generation resource and recover its debt service costs through take-or-pay contracts[7] with the project participants.

The IID is a participant in two SCPPA projects, San Juan Generating Station, Unit 3 and Palo Verde Nuclear Generating Station. It has not participated in the majority of SCPPA's projects, primarily due to

[7] A take-or-pay contract means that the participants pay the cost even if no energy is produced or they choose not to dispatch the generation project.

geographical issues. The majority of SCPPA's members have transmission access to the north and east, but the IID does not have the transmission resources necessary to access many of SCPPA's projects.

San Juan Generating Station

The IID had an entitlement through SCPPA of 106MW in the San Juan Generating Station Unit 3 and may schedule from a minimum of 27MW up to the maximum of 106MW during each hour. Due to excessive emissions from energy generation and the risks associated to those emissions, IID exited the agreement early with and exit date of December 31st, 2018.

Palo Verde Nuclear Generating Station

The IID has a small entitlement (through SCPPA) of capacity in each of three units at the Palo Verde Nuclear Generating Station. The IID's total (delivered) capacity is 14MW (5MW from each of the 3 PVNGS units less losses).

One of the greatest benefits of nuclear generation is the lack of any greenhouse gas emissions. Energy from PVNGS is expensive compared to current market prices although the reduction in greenhouse gas emissions helps the IID's efforts to meet GHG emission levels.

Western Area Power Administration (Western) Parker-Davis Dam

The IID has an entitlement of 32.6MW[8] (summer) in the Parker-Davis Hydroelectric Project (Parker-Davis) in western Arizona. Energy from Parker-Davis is provided by Western at the rate of 3,679 MWh per MW of capacity per month.

Parker-Davis energy can be primarily used during the on-peak periods, although a small portion of the energy must be scheduled during the off-peak periods due to water management requirements of the Parker and Davis dams by Western.

While Parker-Davis is a hydroelectric project, it is not considered a renewable project by the state for RPS requirements. Hydroelectric projects must be less than 30MW to qualify as renewable projects.

Parker-Davis capacity is a source of inexpensive capacity and energy. As such, the IID is continually defending its allocation from claims from other eligible entities, primarily Native American tribes and the Department of Defense.

The IID's current allocation expired on January 1, 2018. Western will likely start a re-allocation of Parker-Davis' capacity in 2015 or early 2016. The IID will have to make a compelling case at Western if it hopes to retain all or most of its current capacity allocation.

Boulder Canyon Project

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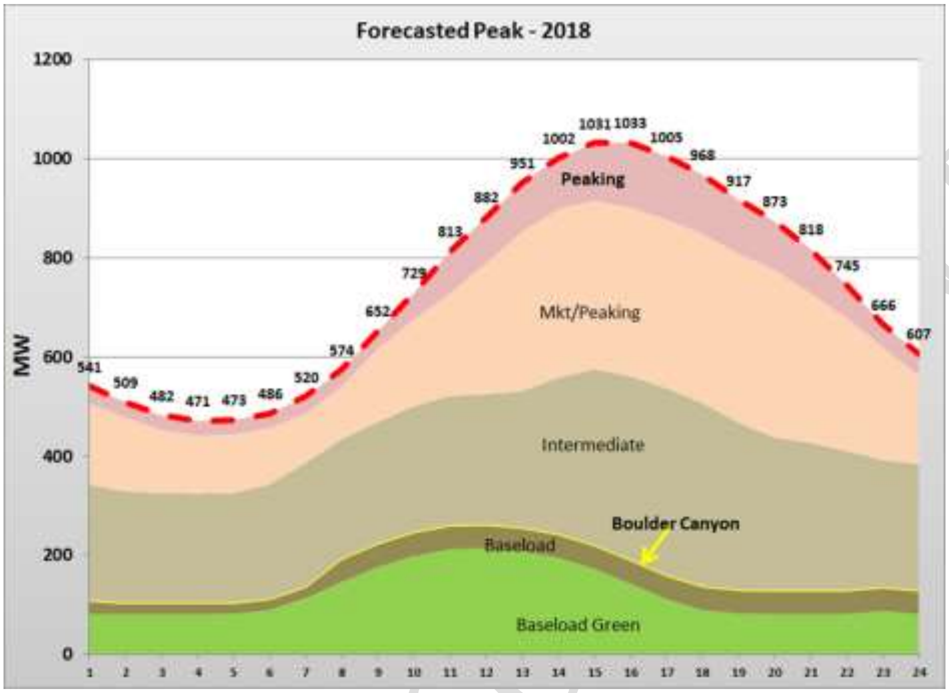
[8] During the five winter months, the monthly capacity declines to 26.3MW.

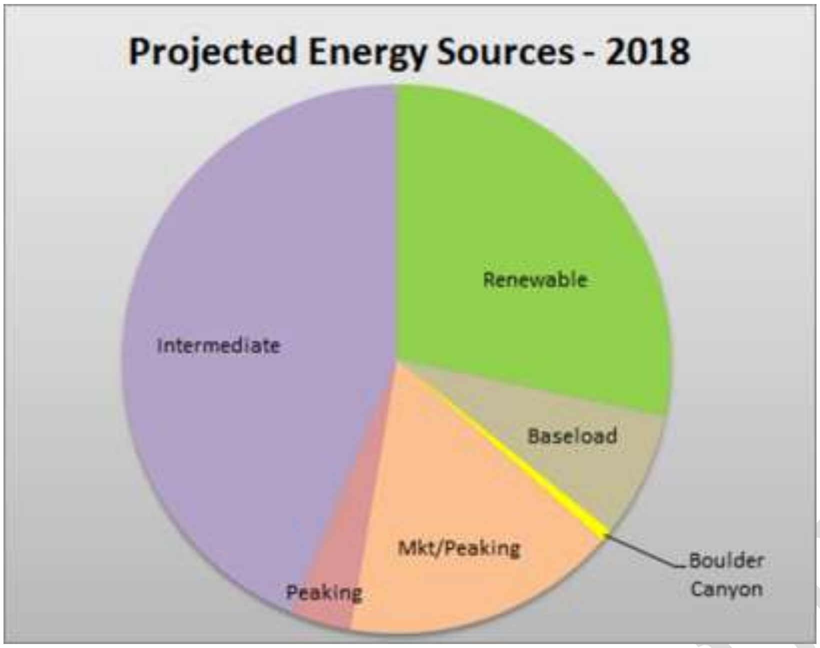
As a part of the Lower Colorado River system via the WAPA-Parker/Davis agreement, IID was allotted a portion of the upgraded Hoover Damn/Boulder Canyon Project. The amount equates to about 3MW and it will cost a range of about $25-30/MWh. The graph below demonstrates how the 3MW will fit in the IID resource stack on a forecasted peak day:

Exhibit 16: Boulder Canyon Impact on Hourly Load Stack



Over the course of the year, the Boulder Canyon Project allotment will represent about 1percent of the total supply serving the IID energy requirements. The pie graph below illustrates the annualized energy impact:

Exhibit 17: Boulder Canyon Annual Impact



YUCCA STEAM PLANT

One of the IID's most important units is the Yucca Plant in Yuma, Arizona. This steam unit has a nominal rating of 75MW (an operational rating of 70MW) and is used for energy and ancillary services, including regulation, on the IID's system. There is also an associated gas-fired turbine (19.7MW) at Yuma that is seldom used due to the poor heat rate of the unit. APS operates the Yucca Plant under an operating agreement with the IID.

INTERNAL THERMAL GENERATION

The IID owns 13 thermal generation units within its service territory, the Yucca generation facility in Yuma and also nine multi-unit hydroelectric facilities. The unit names, technology and performance are summarized in the exhibit below.

Exhibit 18: IID's Generation Resources

IID Generation Nameplate Information

Plant/Unit Name	Commercial Operation	Generator Nameplate (MVA)	Power Factor	Gross Generator Nameplate (MW)
ECGS Unit 2-1	6/19/1993	HP 0.5 psig = 35.294 MVA HP 15 psig = 40.588 MVA	85%	HP 0.5 psig = 30 MW HP 15 psig = 34.5 MW
ECGS Unit 2-2	6/19/1993	105.77	85%	89.90
ECGS Unit 30	10/5/2012	77.50	85%	65.88
ECGS Unit 31	10/5/2012	54.00	80%	43.20
ECGS Unit 32	10/5/2012	54.00	80%	43.20
ECGS Unit 4	8/14/1968	96.00	85%	81.6
Niland Unit 1	5/29/2008	71.18	85%	60.50
Niland Unit 2	5/29/2008	71.18	85%	60.50
Rockwood Unit 1	6/7/1979	Base = 37 MVA Peak = 39.880 MVA	85%	Base = 31.45 MW Peak = 33.898 MW
Rockwood Unit 2	6/7/1979	Base = 37 MVA Peak = 39.880 MVA	85%	Base = 31.45 MW Peak = 33.898 MW
Coachella Unit 1	6/8/1979	Base = 29.6 MVA Peak = 32 MVA	90%	Base = 26.64 MW Peak = 28.8 MW
Coachella Unit 2	6/11/1973	Base = 29.6 MVA Peak = 32 MVA	90%	Base = 26.64 MW Peak = 28.8 MW
Coachella Unit 3	4/17/1974	Base = 29.6 MVA Peak = 32 MVA	90%	Base = 26.64 MW Peak = 28.8 MW
Coachella Unit 4	5/28/1976	NOT LISTED	NOT LISTED	Base = 28 MW Peak = 30 MW
Yucca CT 21	12/28/1978	Base = 26.033 MVA Peak = 28.144 MVA	90%	Base = 26.64 MW Peak = 28.8 MW
Yucca Steam	3/4/1959	75	85%	63.75
San Juan Unit 3	IID Contract: 1/1/1994			Rated = 488 MW
Drop 1 Unit 1	11/16/1984	NOT LISTED	80%	1.95
Drop 1 Unit 2	10/23/1984	NOT LISTED	80%	1.95
Drop 1 Unit 3	10/19/1984	NOT LISTED	80%	1.95
Drop 2 Unit 1	12/5/1953	6.25	80%	5
Drop 2 Unit 2	12/30/1953	6.25	80%	5
Drop 3 Unit 1	2/20/1941	6	80%	4.8
Drop 3 Unit 2	11/23/1966	5.5	80%	4.4
Drop 4 Unit 1	8/9/1950	12.5	80%	10
Drop 4 Unit 2	3/30/2006	12.5	80%	9.6
Drop 5 Unit 1	3/1/1982	2.5	80%	2
Drop 5 Unit 2	3/9/1982	2.5	80%	2
East Highline Unit 1	9/12/1984	3.019	80%	2.4152
Pilot Knob Unit 1	1/31/1957	20	82.5%	16.5
Pilot Knob Unit 2	1/31/1957	20	82.5%	16.5
Double Weir Unit 1	3/20/2005	0.225	80%	0.18
Double Weir Unit 2	3/20/2005	0.225	80%	0.18
Turnip Unit 1	10/1/1964	NOT LISTED	NOT LISTED	0.42

With the exception of the Niland Units, El Centro Generation Station Unit 2 and the newly repowered El Centro Generation Station Unit 3, most of the IID's thermal resources are fairly inefficient. New baseload generation has a heat rate of around 7,600 BTU/kWh or better and new Imperial Irrigation peaking generation has a heat rate of around 9,700 BTU/kWh or better. An exception to this is the Niland Gas Turbine units, which are peaking facilities intended to be operated during on-peak periods. In the near future, and as additional renewable energy resources are put online, IID generation group will need to provide more detailed unit air quality and emission standard information so IID can develop a capital replacement plan to address the aging fleet.

Battery Energy Storage System

IID's BESS is located on the outskirts of El Centro on the site of IID's El Centro Generating Station and the adjacent Sol Orchard Solar Farm. The BESS is designed as a high power, low energy resource rated at 30 MW of power and 20 MWh of energy. The BESS consists of the following components:

- 30 separate battery banks made up of 16 strings of battery modules and components containing 5,760 Samsung lithium ion battery trays, and associated battery management system controls and monitoring equipment interconnected through a Modbus communication network

- 30 GE Brilliance inverters rated at 1.25 MVA up to 45 degrees centigrade and 1.1 MVA up to 55 degrees centigrade, with a rated power factor of +/-0.93. The inverters convert 480 volts AC to 600-800 volts DC when the batteries are charging with energy from IID's grid and 600-800 volts DC to 480 volts AC when the batteries are discharging energy to IID's grid.

- 30 GE Prolec1.25 MVA isolation transformers that transform 480 volts AC to 34,500 volts AC

- GE Mark VIe controllers designed to receive communication from and send communication to IID's Energy Management System (EMS) and GE's SCADA system, translate and send/receive corresponding commands to and feedback from the Samsung battery management system.

- 8 Trane 30 ton heat pumps and 4 Trane 25 ton air conditioning units, associated controls and dampers designed to maintain BESS building temperature, humidity and pressure within operating limits.

- Four zone fire suppression system designed by Schmidt utilizing 3-M's NOVEC fire suppression agent, early warning VESDA Laser Plus smoke detectors and secondary Kidde photoelectric smoke detectors.

- 34.5kV/92kV substation that interconnects the BESS to IID's transmission grid through the 92 kV El Centro Switching Station. The 38.2 MVA transformer that transforms voltage between 34.5 kV on the BESS side and 92 kV on the IID grid side is manufactured by Virginia Transformer.

- BESS building that houses the Samsung lithium ion batteries while the inverters and transformers reside outside the BESS building on housekeeping support pads.

Exhibit 19: BESS Layout

The BESS is controlled by IID's System Operators at IID's System Operation Center. IID's system operators instruct, via IID's EMS, to charge or discharge when the electricity demand-supply balance falls outside of thresholds. When there is excess supply on IID's grid, system operators call on the BESS to charge, absorbing electricity from IID's grid. When there is a supply shortfall on IID's grid, system operators call on the BESS to discharge energy, injecting electricity onto IID's grid. The interaction between IID's system operators and the BESS is performed automatically on a second-to-second basis through IID's EMS and SCADA system that constantly monitor the state of IID's grid and directly controls the BESS through a secure communication network. Furthermore, BESS is on Automatic Generation Control in order to respond on a second-to-second basis to voltage/frequency and energy fluctuation on the IID grid.

The BESS began commercial operation on October 1, 2016.

IID Generation Resource Capital Plan

IID maintains a short- and long-term capital expenditure plan to schedule the projected maintenance requirements on the entire fleet of generating resources. The capital expenditure plan is broken down by three categories of generator types that the IID maintains and operates. They are:

- El Centro Steam Plant (Units 2-4) and the Yucca Steam Plant (Axis and GT21)
- All hydroelectric facilities
- Other generation resources (peaking units, resource development, etc.)

Furthermore, the Generation group has defined projects that are required and also other potential projects

The following exhibit displays IID's projected capital expenditure plan for generation resource broken down by the above categories:

Exhibit 20: Forecasted Generation Capital Plan (2019-2026 years)

Generation Facilities - 2019-26 Required Capital Projects ($2018)									
Unit Type	2019	2020	2021	2022	2023	2024	2025	2026	Total
Steam Units	$ 5,494,000	$10,700,000	$11,200,000	$16,000,000	$10,700,000	$ 7,000,000	$ 7,000,000	$14,000,000	$ 82,094,000
Hydro Units	$ 102,000	$ 7,530,000	$19,037,000	$ 4,388,000	$ 4,000,000	$ 9,000,000	$ 1,250,000	$ 6,000,000	$ 51,307,000
Other Projects	$ 2,434,000	$ 3,257,000	$ 329,000	$ 1,500,000	$ 3,250,000	$ 2,000,000	$16,250,000	$ -	$ 29,020,000
Total	$ 8,030,000	$21,487,000	$30,566,000	$21,888,000	$17,950,000	$18,000,000	$24,500,000	$20,000,000	$162,421,000

Exhibit 21: Forecasted Generation Capital Plan plus Other Potential Projects (2019-2026 years)

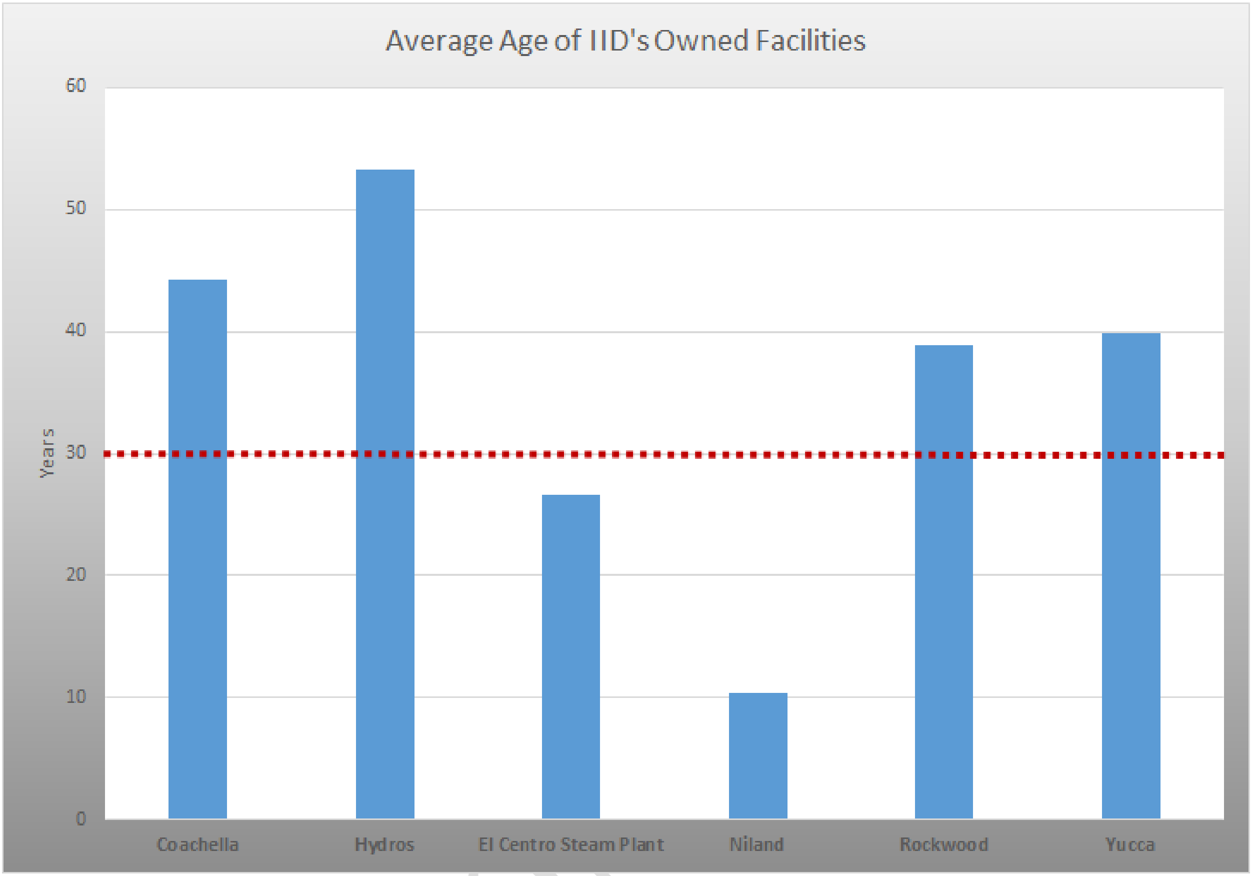
Generation Facilities - 2019-26 Required and Other Potential Capital Projects ($2018)									
Unit Type	2019	2020	2021	2022	2023	2024	2025	2026	Total
Steam Units	$11,830,000	$11,700,000	$11,700,000	$26,481,000	$12,200,000	$ 9,850,000	$ 8,500,000	$24,250,000	$116,511,000
Hydro Units	$ 398,000	$ 7,780,000	$19,037,000	$ 5,363,000	$ 4,995,000	$ 9,250,000	$ 2,245,000	$ 7,825,000	$ 56,893,000
Other Projects	$ 2,434,000	$ 3,507,000	$ 329,000	$ 1,750,000	$ 4,750,000	$ 2,250,000	$18,750,000	$ 250,000	$ 34,020,000
Total	$14,662,000	$22,987,000	$31,066,000	$33,594,000	$21,945,000	$21,350,000	$29,495,000	$32,325,000	$207,424,000

The amount of capital expenditures moving forward into the future will depend on the reliability need to keep these units vs replacement of these facilities with new renewable facilities that may not provide reliability attributes in the same manner as the current IID generation fleet.

Aging Assets

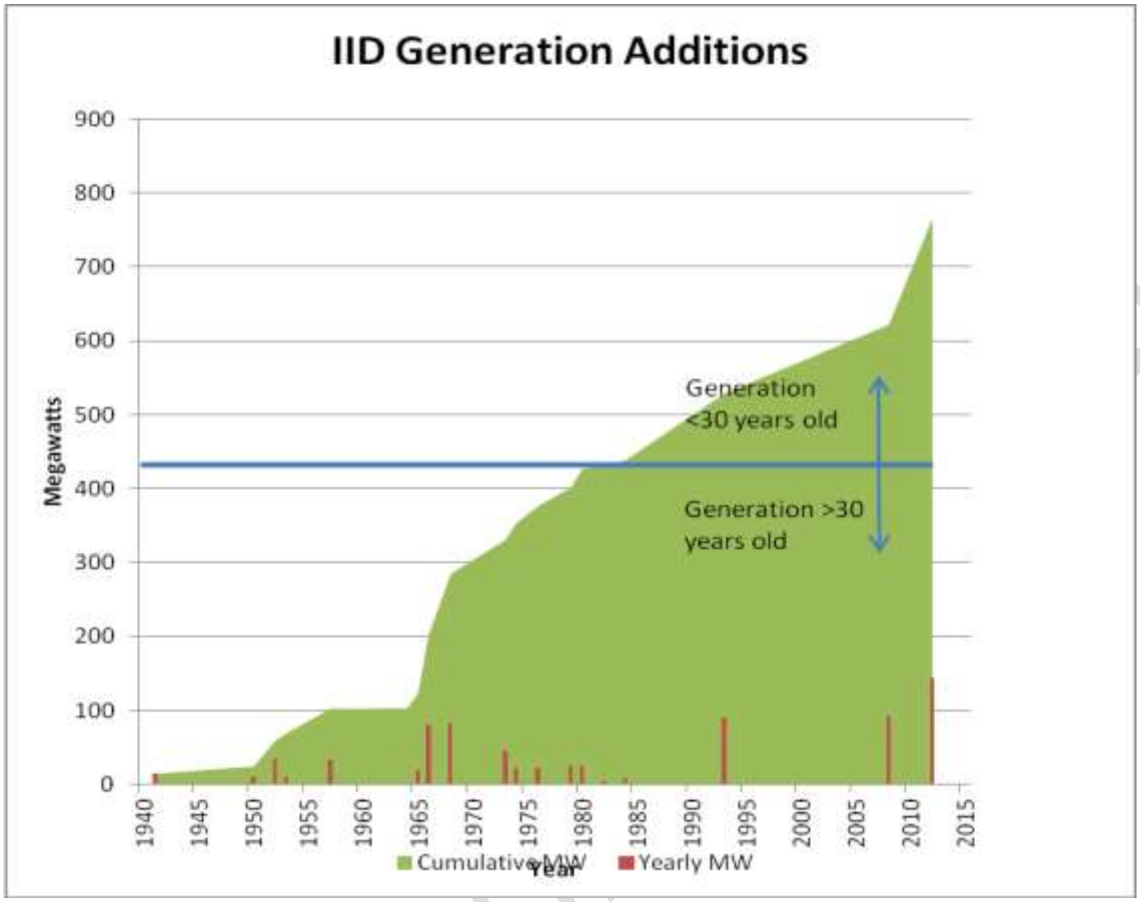
While IID has made significant investments in recent years to upgrade its generation assets with the addition of Niland Units 1 and 2 and the repowering of El Centro Unit 3, the three other IID AGC capable units, Yucca Steam Unit, El Centro Unit 4 and El Centro Unit 2 are 55 years old, 46 years old and 21 years old, respectively. With a typical plant design life of 30 years and the five plus years to develop and construct a new plant more than100 MW, consideration of future generation assets seems warranted at this time. Below is a summary of the average age of IID's owned facilities:

Exhibit 22: Average Age of IID's Generation Facilities



Additionally, below is a graph of the age of IID's installed generation resources/capacity:

Exhibit 23: IID Generation Fleet Age and Replacement Plan



As reflected in this graph, a significant amount of IID's installed resources/capacity are greater than 30 years old and IID will need to consider this as it moves forward with the evaluation of adding new resources flexible for ramping and economic dispatch. The age of the IID resources are a key factor in unit reliability and cost to maintain these facilities. However, retirements can be costly as opposed to just adding other resources like energy storage. This is discussed further later in this document.

Long Term Maintenance Plan

IID Generation Hydroelectric and thermal assets are maintained and operated according to the original equipment manufacturers recommendations. Improvements are made to each unit based on an identified need for improved safety, environmental and regulatory compliance, reliability, or efficiency. Evaluations of each units performance and efficiency is compared against a new resource to determine if an economical advantage would be gained by either a retirement or replacement of that unit. New resource that are under consideration include repowering an existing unit, addition of peaking gas turbines, addition of reciprocating engine generation, renewables, purchased power agreements as well as energy storage projects and green field construction in both the Imperial and Riverside counties.

Power Purchase Agreements

Many of the IID's resources are old and inefficient and, as a result, the IID has relied on a number of *power purchase agreements* to meet much of its energy requirements. Some of the IID's existing generation resources have been counted as operating reserves.

There are a number of components that are studied prior to entering into a PPA. These include the amount of capacity required, the amount of capacity required at different hours of the day, the structure of the PPA itself, including such things as the fixed price, the energy price and how often it is expected to be used. The second is the transmission availability and cost.

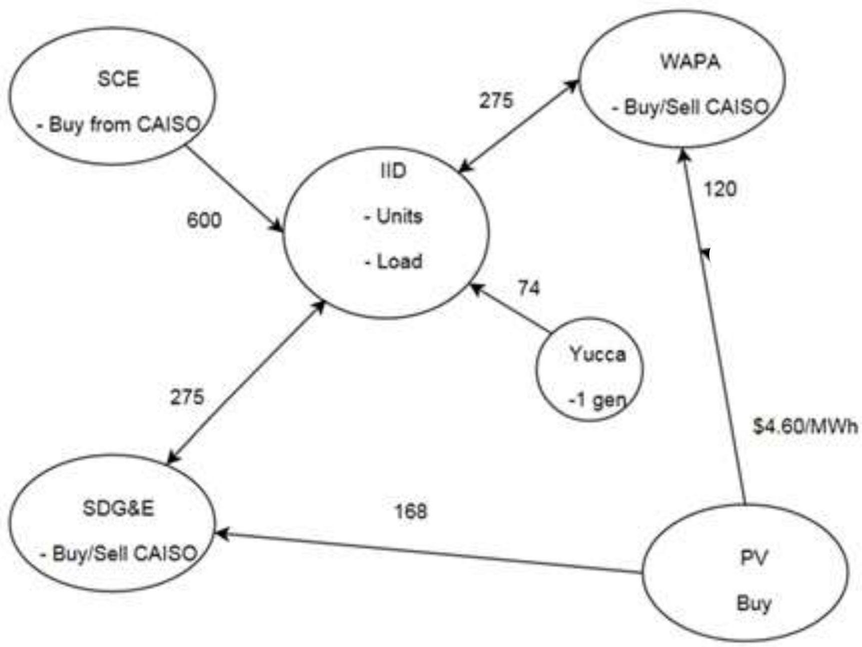
Below is a summary table of all of IID's contracts:

Exhibit 24: IID's Purchased Power Agreements

Purchased Power Agreements			
Resource Technology	Capacity (MW)	Earliest Contract Start Year	Last Contract Stop Year
Hydro	38	1988	2066
Nuclear	17	1981	2030
Solar	182	2012	2045
Biomass	47	2012	2022
Geothermal	78	2016	2050
Seasonal Contracts	Varies	Summer of each year	

The IID must always ensure that transmission exists for a new PPA. The following exhibit identifies where the IID can import energy and the approximate amount of transmission capacity available to the IID.

Exhibit 25: Import Transmission Capacity



Legend:

SCE = Southern California Edison at Mirage 230 kV

SDG&E = San Diego Gas and Electric at Imperial Valley Substation

WAPA = Western Area Power Authority at Blythe/Knob

PV = Palo Verde

The largest single purchase the IID currently has is with the San Juan Unit 3 through an agreement for partial ownership of the plant with other SCPPA members. The IID entitlement is for up to 106MW for all hours of the year. The PPA allows the IID to schedule from 20 to 106MW (before losses) and can be shut down if necessary.

The IID also relies on a number of heat-rate options for peaking capacity. A heat-rate option has a fixed price that is determined by the likelihood of energy being called upon and an energy price determined by the daily spot price of natural gas. The lower the heat rate (hence the more likely the option is to be exercised), the higher the option premium price.

For example, a heat-rate option of 7,600 BTU/kWh may have an option cost of $8.00 kW-month, while a heat-rate option with a 14,000 BTU/kWh may have an option cost of only $2.00 kW-month.

The type of option depends upon the likelihood of actually exercising the option and having to pay for the associated energy. If the option is likely to be called only a few times per year for a few hours during peak periods, then the IID would want to minimize the annual fixed cost. If the option were likely to be called multiple times each month, then the IID would be better off paying more for the option and lowering the energy costs by reducing the option heat rate.

SPOT PURCHASES

The IID has been aggressively purchasing energy in the short-term and hourly markets during the past several years. During the first quarter of 2013, IID became its own Scheduling Coordinator[9] with the CAISO and with this status, IID's real-time and day-ahead trading activities have a new paradigm of procedures and philosophy.

The development of the Real-Time Trading Floor has increased the market/economic displacement and system optimization potential in addition to the tenured Day-Ahead Trading Floor that accomplishes the same goal on a day-ahead basis. In 2015, short-term purchases (both day ahead and real time) made up almost 14 percent of total energy requirements, compared to less than 6 percent in 2007. In 2015, due to the increased integration of local renewable resources, the short-term purchases made up about 13 percent. Both groups may essentially accomplish the same goal; however, the two groups have distinct activities and accountabilities. The Day-Ahead Traders are responsible for developing the next day's load forecast for the IID system. After reviewing internal/external generating resource and intertie outages and limitations, they stack intertie resources and generating units in economic order until each hour's forecasted demand is met. While this is always done in the most economic order, there are times when resources may be dispatched out of economic order to meet system reliability and regulatory/legislative requirements. After all internal generation schedules are determined, natural gas requirements are estimated and spot market purchases are made as necessary. Each day's resource plan and initial schedules are created and submitted to the IID System Operations group for system load flow studies to verify that all reliability criteria is met. When a supply need is determined by Resource Planning, long-term natural gas and electric energy prices are obtained and deals are executed to meet the identified needs. All of the activities performed enhance system reliability and provide significant economic benefit and future energy security for the IID system.

In comparison, the Real-Time Traders monitor actual hourly system load and develop hourly load forecasts for each hour of the current day. From this they are able to determine hourly generating resource requirements and assess electricity market conditions to determine the most economic scenario to meeting hourly load requirements. This can involve the purchase of energy from third parties and/or dispatch of more economic internal generating resources. In cooperation with the IID system operators, costs and hourly balancing requirements are used to determine when energy sales or purchases are required. All of the activities performed enhance system reliability and provide significant economic benefit and energy security for the IID system.

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[9] A schedule coordinator is responsible for scheduling all generation and transmission resources under its operational control with the Western Electricity Coordinating Council and is required to staff for 24 hours of the day and maintain greater control over transmission schedules than the IID currently does.

In 2017, short-term purchases (both day ahead and real time) made up almost 13 percent of total energy requirements, compared to less than 6 percent in 2007. An expression in the generation industry is that "a utility makes best use of generation by not operating it." This implies that a utility is optimizing resources when it is able to purchase energy available in the marketplace at a lower cost than the utility's cost of generating.

The IID, with its high heat-rate generating resources, is able to reduce power supply costs by taking advantage of market opportunities when they exist. The IID's strategy has been to meet much of its energy and reliability requirements with less costly, imported energy and only have enough generation online to meet its BA obligations. There are advantages and challenges of being a balancing authority. One of the big advantages is being a self-sufficient utility that has the ability to take advantage of economic resources and pass those savings on to its ratepayers while some of the challenges are making sure that reliability and regulatory requirements are met on a daily basis.

The IID's generation resources range from hydroelectric resources on the All-American Canal System to the Palo Verde Nuclear Generation Station near Phoenix and natural gas and diesel generation within or near the IID's service territory.

Power purchase agreements include fixed-price, must-take contracts and options that satisfy the majority of the IID's energy requirements. The IID's internal gas-fired generation tends to be older, cost ineffective units (with a few exceptions). These units can be used to meet internal capacity requirements but generally are too inefficient and costly to operate for long periods of time and many have limited hours of operation due to air quality restrictions.

Balancing Authority Obligations

As a Balancing Authority in the Western Electric Coordination Council, IID. A Balancing Authority Area is an electrical system bounded by sufficient metering to measure interchange with other areas and is capable of controlling its Resources to balance net actual interchange with net scheduled interchange.is responsible for meeting the standards defined by the North American Electric Reliability Corporation for such entities to maintain reliable operation of the bulk electric system.

As a BA, the district has the obligation to:

- Match generation to load;
- Maintain scheduled interchanges with other Balancing Authorities;
- Maintain the frequency in real-time of the power system.
- Help/cooperate interconnection regulate and stabilize alternating current frequency
- Avoid overloading transmission segments
- Avoid inadvertent exchange of energy

In order to meet these obligations, the district integrates resource plans ahead of time, and maintains in real time the balance of electricity resources and electricity demand. IID must forecast hourly retail load and know the schedules of generators selling energy to entities located in other balancing authorities. The district must have sufficient generation and power purchases to meet forecasted load plus reserves.

The District is a participant in the Southwest Reserve Sharing Group. As a member of the SRSG, the District's hourly contingency reserve obligations are reduced from approximately 117 MW to around 46 MW during the summer. This Reserve obligation is determined by sending total generation and load numbers along with IID's MSSC (Most Severe Single Contingency) to the RSS (Reserve Sharing Software) every minute along with all other members' information. Based on the SRSG groups reserve requirement the numbers are then allocated back to all group members through the RSS software.

Renewable resources create a special scheduling problem for the District, particularly solar generation. These types of renewable resources are classified as intermittent resources. As cloud cover impacts solar generation, the BA is required to make up any generation shortfall. Initially the shortfall is made up from excess spin, but based on the magnitude of the cloud cover there may be situations where non-spinning resources are utilized.

Currently IID has Independent Power Producers that are both Statically and Dynamically scheduled. There are a small number of IPPs that are Pseudo Tie units, for scheduling purposes both Pseudo Tie and Dynamically scheduled units are handled the same way. The Statically scheduled generators are required to match scheduled generation to actual generation within a 2 MW band. If their generation goes to zero, the District quickly adjust their schedule to zero. For a brief period, the IID units will react to the loss of the Static IPP generation, the IID unit response will last until the schedule adjustment is fully implemented into the EMS system. The Dynamic schedules and Pseudo Tie schedules are tagged after-the fact for the amount of MWs produced for the hour. The district has implemented Dynamic scheduling which has reduced the burden of providing ancillary services and short-term replacement energy. requiring purchasers in nearby balancing authorities importing energy to have dynamic scheduling capabilities rather than providing any ancillary services for power scheduled for export.

As more solar generation is developed within the district's service territory, the district will continue to see challenges in providing quick-response to balancing loads and generation and the need for spinning and non-spinning reserves. IID currently has roughly 140MW of solar generation serving load along with about 65MW of rooftop solar. IID installed a 33MVA (20MWH) battery energy storage system in 2016, which provides quick-response to fluctuations of solar intermittent resources in IID's BA but as more solar generation is used to serve IID load the addition of more battery system capacity to absorb the fluctuations of the system is desired. The battery is able to absorb MWs in lighter load situations and generate MWs during higher load situations. Increasing battery resources within IID's BA will help offset solar intermittencies thus allowing more solar generation to come on-line without curtailments or de-rates. Currently there is another 30 MW solar plant projected to come on-line to serve IID load in 2019, however there are currently no projects to increase battery resources.

Southwest Reserve Sharing Group (SRSG)

A NERC registered entity, the Southwest Reserve Sharing Group administers requirements related to compliance with BAL-001, BAL-002, and BAL-002-WECC-2, and EOP-011.

SRSG participants share contingency reserves to maximize generator dispatch efficiency. Shared reserves decrease costs of compliance with the Disturbance Control Standard and contribute to electric reliability in the Western Interconnection. Formed in 1998 as the successor to the Inland Power Pool, the SRSG's geographic area covers the southwest United States including Arizona, New Mexico, Southern Nevada, parts of Southern California including the Imperial Valley, and El Paso, Texas.

The group's primary document is the participation agreement which was accepted by FERC in 2001. The SRSG Operating Committee is currently reviewing and providing changes to the Participation Agreement for approval. Operating Procedures are approved by the Operating Committee, and give day-to-day operating details not found in the Participation Agreement. The SRSG must report as a group whether or not it recovers from any disturbance of 816 MW or greater. All parties involved in a disturbance (including those supplying assistance) must submit the data required within five business days of the event.
Participants may count short-term purchases as reserves provided the participant has sufficient transmission to support the activation of such purchases to the load center. This includes spinning reserve purchases. IID's reserve obligation is determined by sending total generation and load numbers along with IID's MSSC (Most Severe Single Contingency) to the RSS (Reserve Sharing Software) every minute along with all other members' information. Based on the SRSG groups reserve requirement the numbers are then allocated back to all group members through the RSS software. As per SRSG Operating procedures IID must test each affected generation facility a minimum of every two years for capacity and ramp rates. IID will perform the SRSG testing in the summer of 2018.

Other Reliability Standards

Reliability Standards are the planning and operating rules that IID follows to ensure the most reliable system possible. These standards are developed by the industry using a balanced, open, fair and inclusive process managed by the NERC Standards Committee. The Committee is facilitated by NERC staff and comprised of representatives from many electric industry sectors.

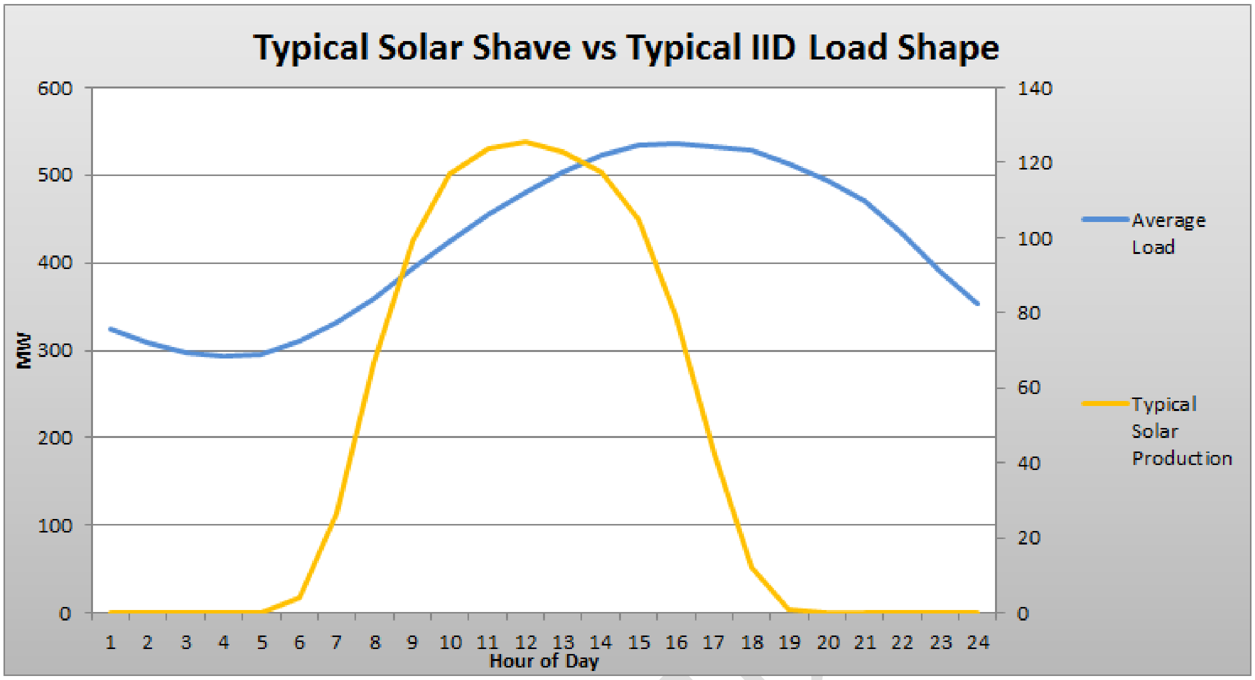
Proposed standards are reviewed and approved by the NERC Board of Trustees, which then submits the standards to the U.S. Federal Energy Regulatory Commission and Canadian provincial regulators for approval. Once approved by these governmental agencies, the standards become legally binding on all owners, operators and users of the bulk power system.

IID System Operations has implemented all the required training plans and procedures in meeting the most anticipating of the Personnel Performance, Training and Qualification (PER) standards.
When new standards are developed IID will derive an implementation plan in order to make sure that IID is compliant with all standards. Future enforcement standards include BAL-005-1, EOP-004-4, EOP-005-3, EOP-008-2. IID staff has developed plans and will be ready to comply with each standard by their respective effective dates.

Renewable Impact Overview

Renewable energy resources integrated into IID's electric power systems will bring certain changes having a significant impact on system performance and efficiency. The specific impact focus is on solar energy, the renewable resources with the most potential for significant penetration in the near term. The table below illustrates the difference between the hours that solar is available and the hours when IID's load ramps up and down throughout the day:

Exhibit 26: Solar Availability vs. IID Load Curve

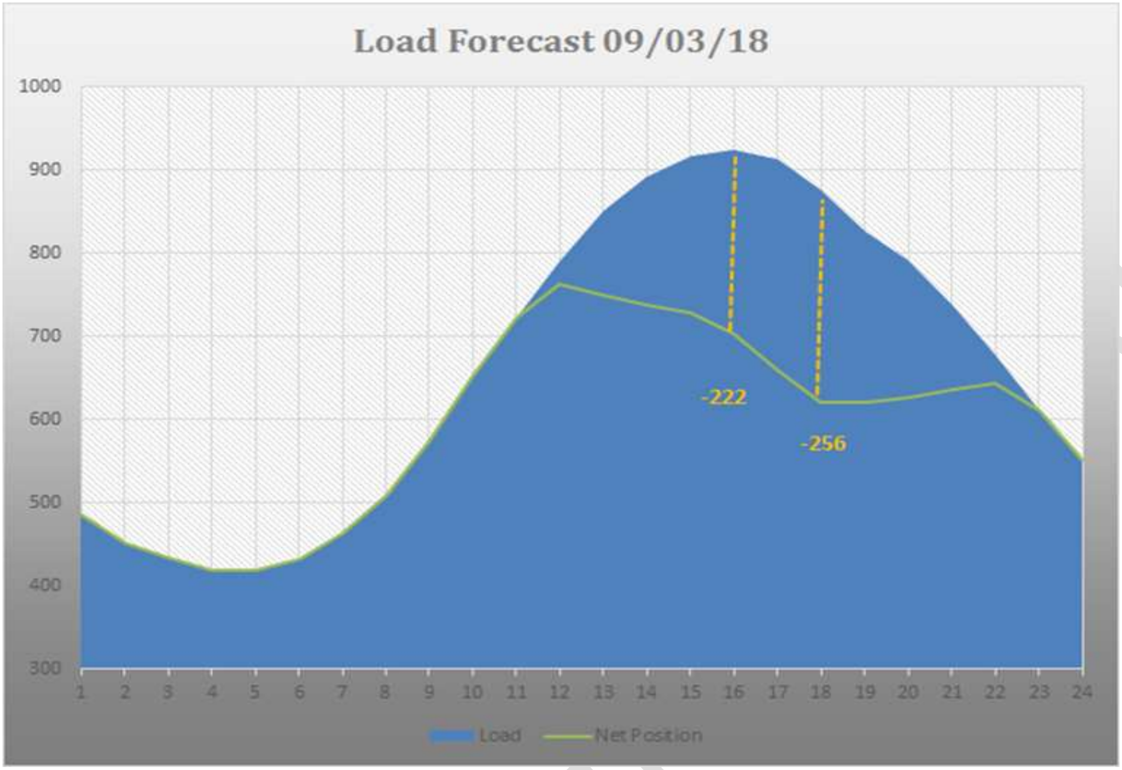


The most critical element of renewable impact would be the variability of resources and accounting for sufficient commitment and dispatch of reserve generation to guarantee the reliability of IID's system in the event that the renewable resource suddenly becomes unavailable. Furthermore, dynamically scheduling the renewable resources not a part of serving IID's load will reduce the reserve requirements. However increasing solar that serves IID's load will require new generation to ensure IID's ability to meet reserve requirements. This can be done by building new quick start gas turbines or battery storage. At this time, the District has a 33MVA 20MWH battery storage system. The battery storage system is used for reliability in order to maintain IID's CPS boundaries and to help smooth any solar swings or instant change in load. The Battery will also be black-start capable which will increase the reliability in IID's Balancing Authority. The load following of the solar will be key in reducing the impact on the system and backing the full loss of the resource.

Initially many IPPs had made the switch from Static scheduling to Dynamic scheduling as a result of BAL-002-WECC-2. Starting in 2016 a large number of the IPP plants reverted back to Static schedules. This will increase IID's reserve obligation by having to account for more Statically scheduled generation in IID's BA ancillary service.

Furthermore, SB33 requires POUs to observe the net peak demand. This is an activity that IID has already implemented into its planning activities due to the impact of a shifting load profile and the variance between the hourly demand of energy vs the resources available that also include some intermittent resources. Below is a chart that illustrates an example of how the peak hour of demand may not necessarily reflect the max net short hour:

Exhibit 27: Peak Load Hour vs Net Peak Demand

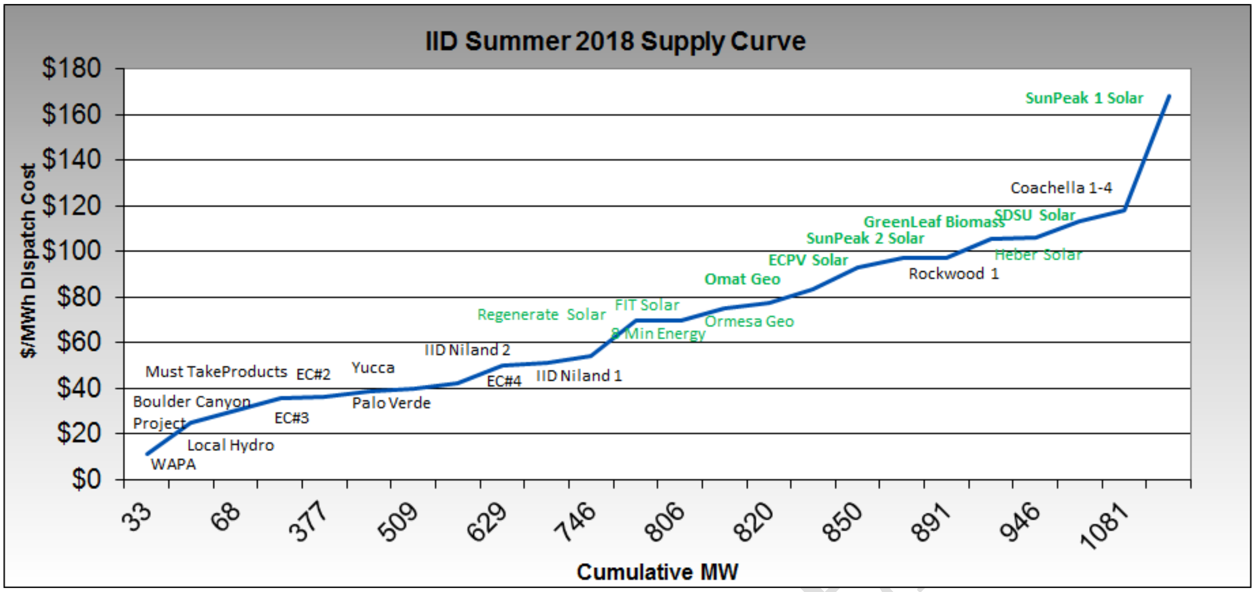


IID observes every hour of the year to ensure that supplies meet demand, even during hours when demand is not the highest. Furthermore, when the definition of “Carbon Net 0” resources is finalized, IID will plan to meet this net peak demand with its current resources along any resource that qualifies as “Carbon Net 0”.

SUPPLY CURVE WITH RPS INTEGRATION

With the recent developments in greenhouse gas requirements and renewable resource integration, the energy industry has seen a major shift in supply resource stacking and traditional supply dispatch order. In the past, a common supply curve would show the base load resources with the lowest dispatchable costs at the bottom of the curve, but with renewable contracts that are essentially must take, the supply curve is now filled with the must-take base load resources at the top of the curve since renewable prices are typically higher than conventional energy prices. This, of course, all depends on the price of natural gas and power. The graph below illustrates a traditional supply curve with the newest developments of renewable resource integration included in the curve.

Exhibit 28: 2018 Supply Curve



Ancillary Services

Ancillary services required to move energy through, out of, within or into the IID BA include:

- Scheduling, System Control and Dispatch Service: Service is required to schedule the movement of energy through, out of, within or into the IID BA.
- Reactive Supply and Voltage Control from Generation Sources Service: Service is required in order to maintain voltages in the IID transmission system within acceptable limits; IID generation must produce or absorb reactive power.
- Regulation and Frequency Response Service: Service is required to provide for the continuous balancing of resources with load and for maintaining scheduled interconnection frequency at sixty cycles per second.
- Energy Imbalance Service: Service is required when a difference occurs between the scheduled and actual delivery of energy to a load located within the IID BA.
- Operating Reserve, Spinning Reserve Service: Service is required to serve load immediately in the event of a system contingency.
- Operating Reserve, Supplemental Reserve Service: Service is required to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time.
- Generator Imbalance Service: Service is required when a difference occurs between the energy scheduled and actual delivery of energy from a generating facility located within the IID BA.

Four types of ancillary services products for IID are frequency response, regulation, spinning reserve and non-spinning reserve. Frequency response is the ability of a system or elements of the system to react or respond to a change in system frequency.

Regulation or regulating reserve is the amount of spinning reserve responsive to Automatic Generation Control. Regulating reserves are deployed to correct minute to minute deviations in system frequency or return system frequency to a desired range following a system disturbance. Regulation energy is used to control system frequency that can vary as generators access the IID's system and must be maintained around 60 hertz. Units and system resources providing regulation are certified by IID and SRSG. The generators must respond to AGC signals to increase or decrease their operating levels depending upon the service being provided, regulation up or regulation down.

NERC & FERC

NERC is the Electric Reliability Organization certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk power system. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel.

IID is impacted by regulation standards approved by NERC and FERC. Future standard development from these organizations in the come years will see an increased impact by required certification for plant operators, relay technicians, and as well any craft affecting the BES.

FERC ORDER 764

IID currently utilizes the OATI WebTrans software for transmission scheduling and currently has the capability to accommodate the intra-hour scheduling of transmission and the checkouts of intra-hour schedules with neighboring BAs. Listed below is a news event listed on the OATI company website announcing their status of compliance with FERC Order 764.

Multiple facets of intra-hour scheduling are currently in use by OATI customers. The OATI ETRM and Transmission Operations solutions will provide the increased functionality and efficiencies to meet the needs of this order through continued enhancements.

This FERC order requires each public utility transmission provider to offer intra-hourly transmission scheduling to ensure charges for energy imbalance services are just and reasonable. The intra-hour scheduling provisions provide opportunity for variable energy resources to align the energy schedules with forecasted production as conditions change within the hour.

Industry-leading OATI software solutions will provide features that allow suppliers to effectively participate in the management of resource schedules, resulting in fewer energy imbalance conditions. In addition, the ETRM (WebTrader) and transmission operations (WebTrans) suite of applications are being updated to support continued compliance with North American Electric Reliability Corporation (NERC) standards and North American Energy Standards Board business practices and provide features to efficiently manage the increase in scheduling granularity.

If a customer wanted to schedule transmission intra-hour, the customer would have to utilize an existing TSR or purchase transmission on the IID OASIS. As per the IID OATT, the lowest increment of transmission that can be purchased is non-firm hourly and firm hourly. IID does not offer an intra-hour transmission product. This can be found in the OATT under schedule 7 and schedule 8.

CURRENT ENERGY REQUIREMENTS AND SYSTEM LOSSES

In 2017, IID had energy requirements of 3,738 GWh. These energy requirements consisted of sales to end use customers (3,441 GWh) and make-up energy for system losses (296,375 MWh). System losses increase the amount of power required to serve the electric needs of IID customers and result in increased fuel costs, increased energy production or purchases, and increased use of the power system.

The table provides a comparison of IID's statistics with other balancing authorities, which illustrates that IID transmission losses (from power flow model) are within the average value of other balancing authorities.

Exhibit 29: WECC Power Flow Model Results

WECC Approved Base Case Model (2019 Heavy Summer Condition)							
No.	Balancing Authority		Generation	Net-Scheduled Interchange	Load	Transmission System Losses	Transmission System Losses in (%) of Demand
	Name	Number	(MW)	(MW)	(MW)	(MW)	(MW)
1	ALBERTA	54	10625.4	-460	10790.8	294.3	2.65%
2	APS	14	10791	2714.6	7869.8	206.7	2.56%
3	B.C. HYDRO	50	11189.3	2371	8229.4	589.1	6.68%
4	EL PASO	11	1288.4	-684	1912	60	3.04%
5	IDAHO	60	2444.2	-1552	3880.4	116	2.90%
6	IID	21	1703	568.4	1078.3	55.7	4.91%
7	LADWP	26	5994.7	-1035.5	6674.7	356.7	5.07%
8	MEXICO-CFE	20	2673.7	-279	2900.6	52.8	1.79%
9	MONTANA	62	3061	870.2	2086.8	103.2	4.71%
10	NEVADA	18	4899.9	-1803.6	6563.9	139.5	2.08%
11	NEW MEXICO	10	2443.1	-439.4	2759.8	122.9	4.26%
12	NORTHWEST	40	30530.5	3903.5	25516.5	1110.1	4.17%
13	PACE	65	10378.4	1423.7	8575.3	379.4	4.24%
14	PG&E	30	27328.7	-880	27249.6	958.7	3.40%
15	PS COLORADO	70	8046	-257.2	8163.5	139.9	1.68%
16	SAN DIEGO	22	4243.5	-179	4297	125.7	2.84%
17	SIERRA	64	2598.3	98	2430	70.4	2.82%
18	SOCALIF	24	15079	-7722.2	22333.6	467.5	2.05%
19	FORTISBC	52	1109.9	329	757	24.1	3.09%
20	WAPA R.M.	73	6040.4	560.3	5319.8	160.5	2.93%
21	WAPA U.W.	63	78.4	105.7	-37.3	10.1	37%
22	WAPA L.C.	19	3497	2044.8	1355.2	97.4	6.71%
23	AEPCO	17	435.9	-584.6	1003.7	16.7	1.64%
24	SRP	15	10080.1	2414.4	7525.5	140.8	1.84%
25	TEP	16	2220.2	-1527.1	3600.2	147.1	3.93%
ACTUAL (2014-18)							
IID							3-4%

Future challenges on the horizon include the impact of distributed generation on system losses. IID continues to manage and identify losses found in its power system. Reduction of these losses allows IID to provide a more efficient, more reliable and higher quality electric service. Additionally, IID is in the process of establishing a long-term program to reduce the transmission and distribution losses.

Potential Loss Reduction strategies include:

1. Establish distribution line re-conductor program;

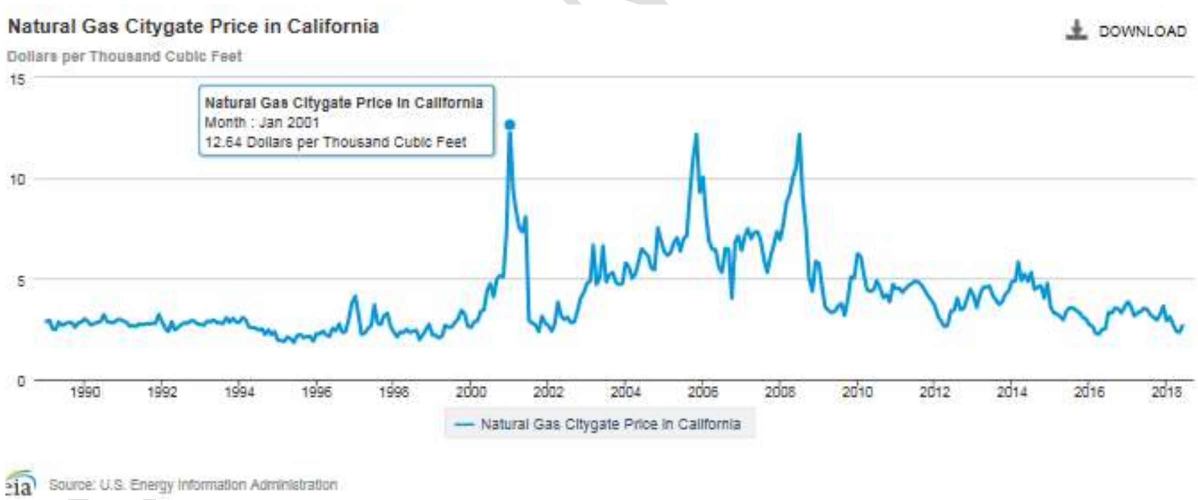
2. Install additional distribution capacitor banks, as required, to provide a consistent electric service;

3. Extend existing transmission lines to improve service to concentrated loads.

NATURAL GAS PRICES

Natural gas purchases account for anywhere between 25 and 40 percent of the IID's total power supply costs (approximately $55million or 25percent in 2017) as fuel for IID's natural-gas-fired generation fleet. The IID has a procurement program designed to reduce the volatility of the cost of purchasing natural gas for a rolling three-year period.

Natural gas prices are considered among the most volatile of commodity prices (wholesale energy prices generally trend with natural gas prices). The volatility is driven by weather and supply-demand conditions. Various long- and short-term market conditions can have a significant impact on IID's energy costs. For example, in a $10/MMbtu natural gas market where costs are expected to be high, an increase of $2/MMbtu represents an increase of 20 percent and IID would certainly notice the difference, however the expectations are already high costs. On the other hand, in a $3/MMbtu market, the IID's expectations are to have low costs, but a change of just $1.5/MMbtu represents an increase of 50 percent, where the impacts of the market change could possibly have a greater impact than the first example, if IID does not have enough natural gas procured in advance along with the expectation of low costs. Over the past five years, natural gas prices have ranged from a monthly average high of $12.50 to a low of $1.85, although daily prices have been as low as $1.75/MMbtu[10].



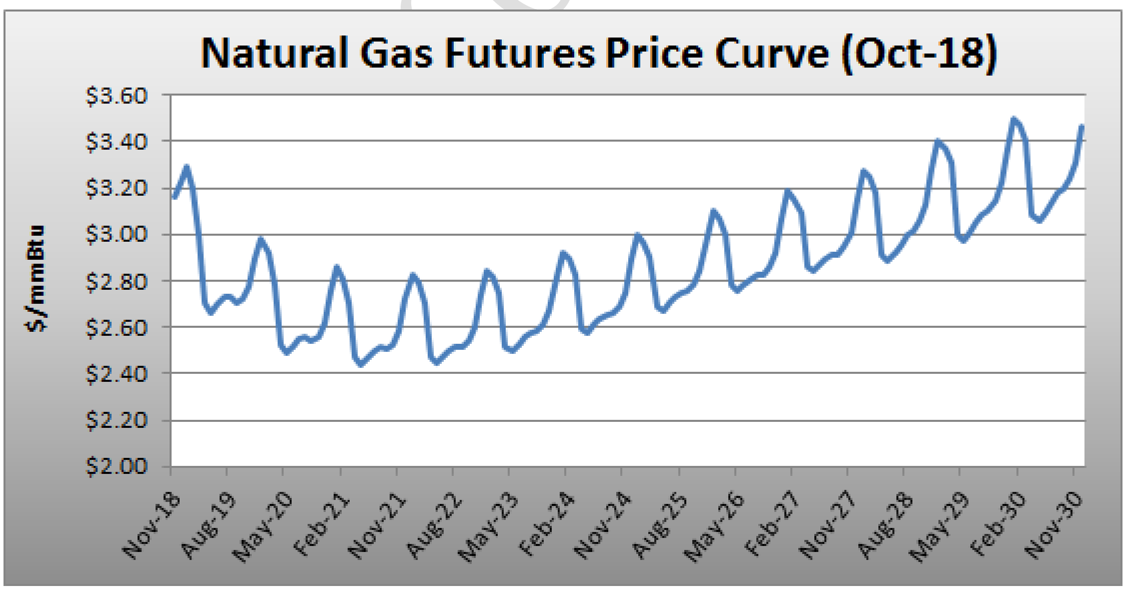
The above represents the monthly average of the day-to-day transactions at the SoCal Citygate trading hub. The SoCal Citygate trading hub is the main location to purchase natural gas for IID's owned internal

[10] Source: Energy Information Administration, Department of Energy. Regional prices have shown even greater volatility with prices in Southern California as high as $14.00/MMbtu on several days in the spring of 2008.

generation also known as native generation. As displayed above, the natural gas prices can be highly volatile ranging from the $14/MMbtu to $2/MMbtu. This wide range can cause IID's energy costs to fluctuate within the year after approval of the fuel and purchased power budget and, therefore, any price changes that are not monitored can cause an undulation throughout the entire organization. IID participates in a long-term procurement plan to hedge against these situations.

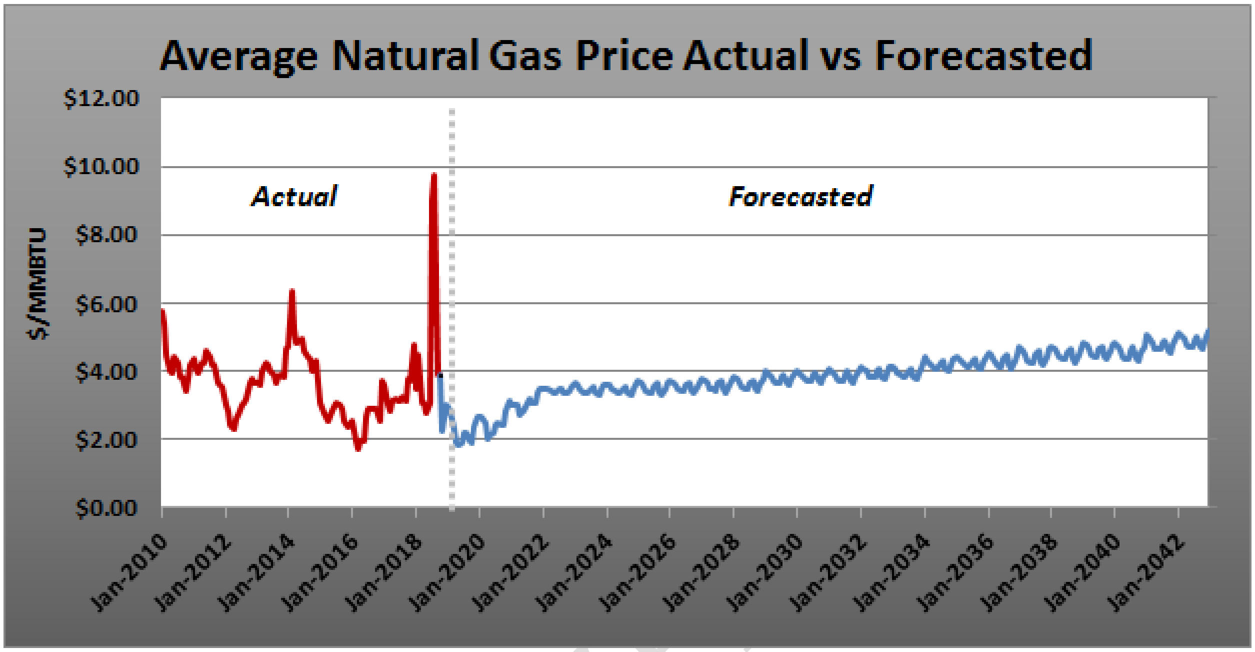
It is important to distinguish the difference between the daily spot market and the futures pricing market of natural gas. While the two are almost directly linked in terms of pricing direction and activity, the spot market and the futures market carry varying types of risk. The spot market can move 30 cents in a day and may fluctuate significantly in a matter of minutes due to its dependence on the current information of fundamental market drivers. The futures market also fluctuates significantly, but other considerations are involved, such as the future market condition of the fundamental drivers for the future traded term, which is built into the future prices. Also, the futures market can be indirectly affected by the interest rates that are also constantly fluctuating. A risk premium is added to the futures price when the futures market is contained and the risk premium is subtracted when the futures market is backwardized in comparison to the daily spot market. Additionally, the futures market can contain a higher level of uncertainty, which could increase costs since it is further in the future than the spot market. These types of distinguishable, yet unpredictable differences are part of what make the management of energy and natural gas price risks a challenging task. Below is an example of what a forward price curve looks like for the procurement of a futures gas commodities contract, which, like the spot market, changes daily.

Exhibit 30: Futures Natural Gas Price Curve (2018-2030)



The following exhibit compares the long-term volatility of the monthly average *historical* daily spot prices and the monthly average of the *projected* daily spot prices from the EIA.

Exhibit 31: Monthly Average of Daily Spot Prices (2010-2040)



While the projected monthly average of the daily spot price is different than the futures market, the trend is similar. As observed in the above graph, post-2000 prices have been extremely volatile and, even though prices have been more volatile in the past three years, IID considers the possibility of historical repetition in all resource utilization activities.

The IID has an established history of hedging its energy risks to reliably serve its customers at the most stable and lowest possible costs. Last year, the District conducted a comprehensive review of its energy risk management policy, practices and procedures and has revised its policy, practices and procedures to better position the District in the rapidly changing electric industry and energy market environment to continue to fulfill this mission. The revised energy risk management policy was approved by District's Board of Directors on October 24, 2017.

The newly revised policy provides for an energy risk management framework consisting of the following elements:

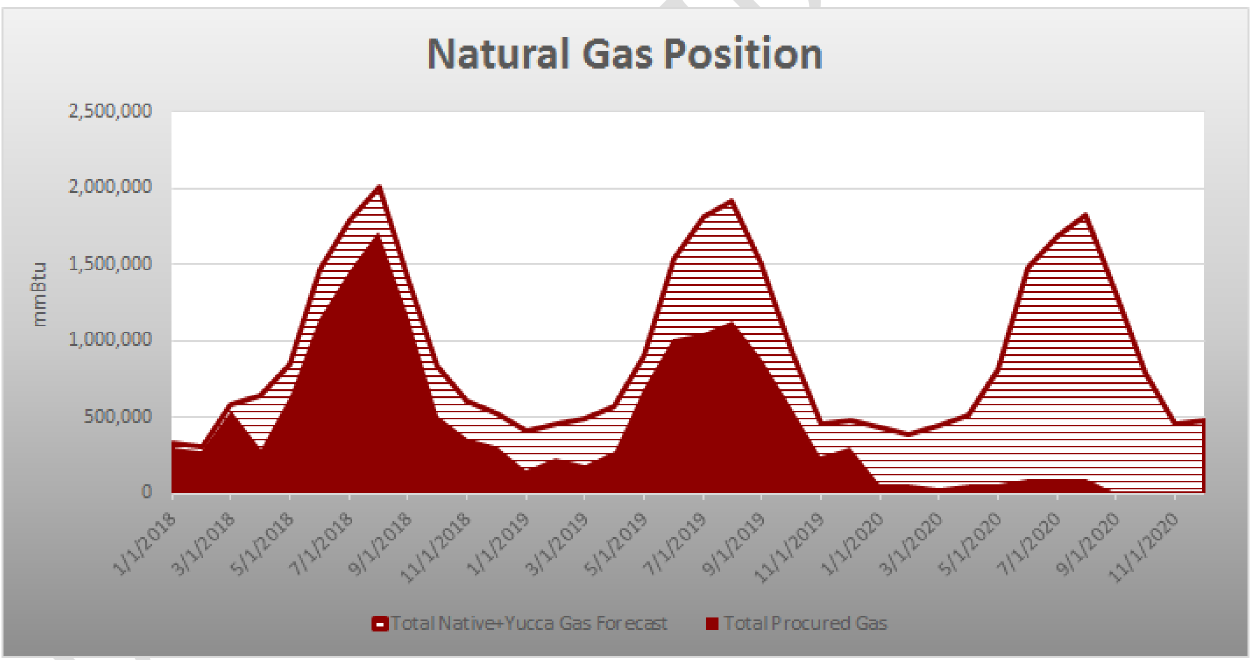
- A four-year energy risk hedging program with specific monthly energy and capacity hedging targets (as percentages of monthly energy and peak capacity requirements);
- Periodic preparation of Power Strategy Sheet and Power Resources Portfolio Risk Report which provide detailed analysis of energy hedging strategies; and

- Approval of the PSS and PRPR by the Energy Risk Management Group prior to the execution of energy hedging strategies by the district' energy division staff.

Consistent with the policy and to smoothly transition into the newly revised policy, this PRPR provides the detailed analysis of the energy hedging strategy for the calendar year 2019 only in lieu of four-year energy risk hedging plan as the new policy calls for. This PRPR also serves to provide the technical support for calendar year 2019 PSS. Staff is concurrently seeking ERMG's approval of 2019 PSS so that staff can begin implementation of the hedging strategy for calendar year 2019. Staff is planning to prepare the PRPR and the PSS for the remaining period of this hedging cycle (CY 2020-2022) in the Fall of 2019 or in 2020 for ERMG's review and approval at that time, although it appears that the amounts to be hedged for those future periods are minimal at this time.

The chart below shows IID's current natural gas position of procured natural gas and projected requirements of natural gas for the end of 2018 through 2020:

Exhibit 32: Natural Gas Procurement Program - Position



The IID observes the natural gas markets as well as energy markets continuously and manages risk of the uncertain prices of natural gas by applying four multifaceted approaches of procurement:

1. Programmatic - Layering in a set amount of natural gas periodically to ensure that the annual position requirement will be fulfilled;
2. Opportunistic - Taking advantage of opportunities in bearish markets where prices are below budget forecasted prices;

3. Defensive - Defending against budget increases in bullish markets where prices are approaching or above the budgeted prices;
4. Value at Risk - With the calculation of the budgetary Value at Risk, IID maintains the given parameters from the IID Risk Policy.

LOAD RESOURCE BALANCE

The IID's existing resources and power purchase agreements are sufficient to meet the forecasted load for 2018. By 2019, the IID is short capacity to meet forecasted load requirements during the summer months mainly due to the natural load growth projected in the load forecast.

Identifying the right mix of new resources to meet the IID's 2019 resource deficit is critical. The IID must meet regulatory requirements, such as the RPS requirements and GHG emission levels, while attempting to minimize annual costs. An incorrect resource mix could lead to higher costs than necessary or prevent the IID from meeting GHG requirements.

RENEWABLE RESOURCES

Unlike other areas of the state, the IID has a number of geothermal, solar, wind and biomass alternatives available within its service territory to meet not only its renewable-energy requirements but also other California utilities requirements as well. Estimates of the potential renewable-energy alternatives within the Imperial County range as high as 4,000MW of financially viable renewable-energy sources.

Choosing the right mix as well as type of renewable resources has and continues to be a more challenging task for the IID. The best fit of the renewable resources is found through consideration and analysis of the operational and economic effects of intermittent and base load resources. The market has continued changing making different types of renewable resources more competitive than others yet increasing operational risk associated with them. Conventional geothermal base load resources have a very limited ability to schedule and dispatch to meet hourly load profiles. Solar and wind resources are only available during certain hours and may not be available when necessary (especially wind generation, which tends to be unavailable during the peak hours of the day). Additionally, the intermittency of solar and wind resources cause IID's Balancing Authority to increase ancillary service reserves, both spinning and non-spinning. This increase in carrying spinning and non-spinning reserves also contains a hidden cost, called the integration cost that must be understood and calculated when considering the various types of renewable resources available to IID to fulfill the RPS requirement. Choosing too much of a specific technology can result in surplus energy that must be sold at a loss or could cause undesirable system instability that increases costs.

DESERT VIEW POWER PPA (GREENLEAF)

Prior to 2011, Desert View Power acquired the Colmac Biomass Plant and solicited the output of the plant to IID. IID agreed to a 10-year term PPA that places IID as the sole off-taker of the 45MW plant.

The payment for the output of the plant includes all environmental attributes, including Category 1 RPS RECs from an Eligible Renewable Resource (ERR). A part of the agreement provides that the seller has about two months out of the year to perform regularly scheduled maintenance. During these times, IID will receive about half of the total maximum plant output.

Even though the plant fully qualifies as an ERR under the CEC, which governs the RPS, the plant is located on an Indian Reservation and CARB considers this type of resource to be what is known as a "specified resource". This designation places this resource into a category that is not exempt from the cap-and-trade allowance system so the output from the plant is estimated to utilize about 15,000 MTCO2e of allowances each year. The unrealized value of this is estimated to be around $225k/yr. if the price of allowances is $15/MTCO2e.

Over the course of a year, the plant is expected to produce nearly 325,000 MWh that IID will be able to fully count towards the RPS goal.

HEBER-1 GEOTHERMAL PROJECT

In the second quarter of 2013, the IID signed a 10-year power sales agreement with SCPPA in a joint participation project with LADWP to purchase the production at the existing Heber-1 Geothermal Facility. The agreement is for 33percent of the plant output in the first three years and 22percent in the remaining term and will provide IID with about 15MW (min. of 13MW and max. of 19MW) in the first three years of the agreement starting in the end of 2015. After the first three years, IID's portion becomes 10MW (min. of 8MW and max. of 12MW). The remaining portions will be delivered to LADWP.

This contract will provide the IID with about 120,000-166,000 MWh of renewable production that is scheduled on a 7x24 base load basis. This unit is considered a base load unit that will provide the IID with 2-4percent of the total RPS requirement at a competitive price.

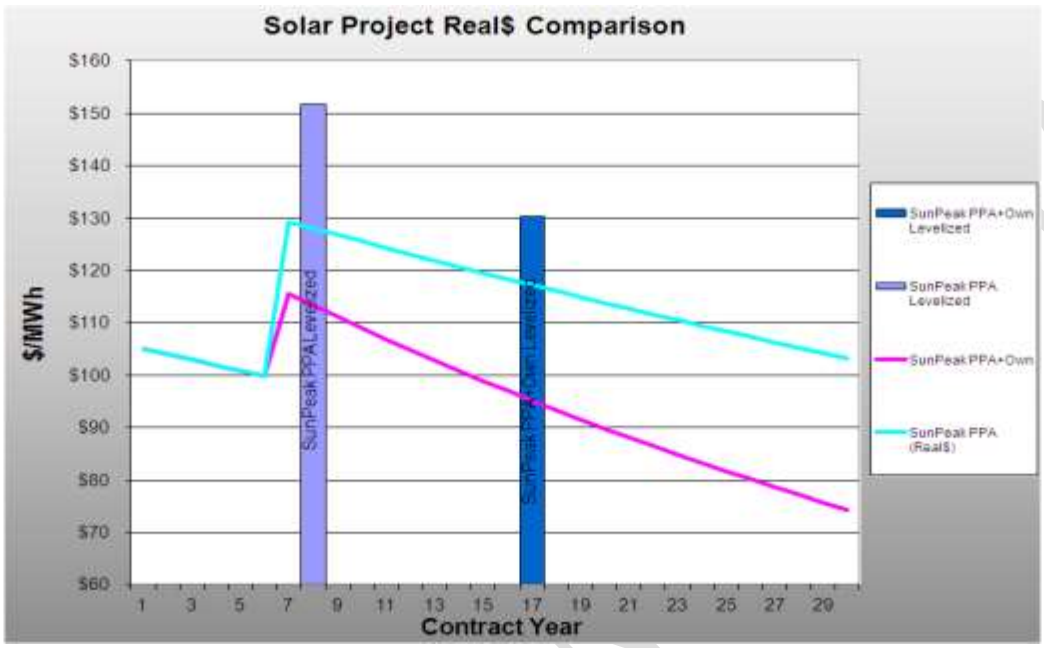
SUNPEAK SOLAR 1

In 2009, IID issued RFP No. 693 for the development of local renewable resources. Simultaneous, to this RFP, IID was observing offers available through the SCPPA renewable RFP and, as a result of both of these processes; IID selected the best project available at the time, which was for the development of a 20MW solar project located in Niland.

The IID signed a 30-year PPA for the full output of the plant, which has a maximum capacity of 23MW and provides the IID close to 46,000 MWh per year of CEC certified Category 1 Renewable-Energy Credits.

In addition to the renewable benefits of this project, IID negotiated an option-to-buy agreement which, if executed, significantly lowers the overall levelized cost of energy. The following exhibit demonstrates how the buyout option saves the IID a significant amount of money.

Exhibit 33: SunPeak No. 1 PPA Structure with Option to Buy at Year 7



SOLORCHARD SOLAR

In 2011, IID solicited offers through RFP No. 814 for the local development of renewable resources, particularly on IID-owned land near the IID El Centro Steam Generating Facility. IID was also observing offers through the open SCPPA RFP process and, as a result of these processes, IID selected the best offers. This selection included the SolOrchard Solar Project to be developed on IID-owned lands adjacent to the El Centro Steam Generating Facility.

The SolOrchard PPA is for the full output of a 20MW newly developed solar facility which provides the IID about 50,000 MWh of renewable energy. This project became commercially operational at the end of 2013.

ORMAT SOLAR

Another result of the process described above was the agreement between IID and Ormat for the full output of a newly developed solar facility. This 10MW solar project is located in the Heber area near Ormat's Geothermal Generation facilities and will generate close to 25,000 MWh annually of CEC certified renewable energy.

This contract is for the development of a thin film solar photovoltaic project and Ormat will sell IID power for a term of 20 years under the agreement and deliver the energy directly to the IID system. The project construction is currently underway and the facility is expected to be fully operational in 2014.

SunPeak Solar 2

In addition to the processes described above, the IID's Board of Directors requested an additional PPA to be signed. As a result of this process, IID signed a 30-year PPA for the full output of a 20MW solar facility, which will be located near the already commercially operating SunPeak 1 solar facility in the Niland area and will interconnect to the Niland 92kV Substation.

This project will provide IID with about 46,000 MWh of renewable generation and was commercially available at the end of 2014.

96WI 8ME, LLC

On November 18, 2014, the district executed a power purchase contract for approximately 30 MW of photovoltaic renewable energy from 8Minute Energy and Gesamp Solar, (joint venture partnership/ownership) photovoltaic project ("Calipatria Solar Complex") located within the District's electric service boundaries. The project's member interest was transferred to Solar Frontier, LLC on May 27, 2015. The project is expected to come on line no later than December 31, 2016. The term of the agreement is for 25 years from the commercial operation date. Energy generated from this contract qualifies as category 1 renewable energy 96WI 8ME, LLC

On November 18, 2014, the district executed a power purchase contract for approximately 30 MW of photovoltaic renewable energy from 8Minute Energy and Gestamp Solar, (joint venture partnership/ownership) photovoltaic project ("Calipatria Solar Complex") located within the District's electric service boundaries. The project's member interest was transferred to Solar Frontier, LLC on May 27, 2015. The project is expected to come on line no later than December 31, 2016. The term of the agreement is for 25 years from the commercial operation date. Energy generated from this contract qualifies as category 1 renewable energy.

Regenerate Power, LLC

On May 27, 2014, the district executed a power purchase contract for approximately 30 MW of photovoltaic renewable energy from Regenerate Power, LLC ("Seville Solar") located within the district's electric service boundaries. The project's member interest was transferred to Seville Solar 11, LLC on October 14, 2014. A Change of Control Agreement for Seville Solar, LLC was approved on June 30, 2015, in which Duke Solar acquired 100percent of the membership interest of Seville Solar Holdings. The project is expected to come on line by June 1, 2016. The term of the agreement is for 25 years from the commercial operation date. Energy generated from this contract qualifies as category 1 renewable energy.

GeoGenCo, LLC

On June 17, 2015, the District executed a power purchase contract for a 4 MW proof-of-concept geothermal project ("GeoGenCo Project"). The contract is unique in that it relates to a conceptual technology referred to as "down hole heat exchange" which allows for geothermal development without the need for large amounts of water as is customary in geothermal generation. The GeoGenCo Project is expected to come on line no later than June 15, 2020. The term of the agreement is for 30 years, subject to a 36-month proof-of-concept period with the potential possibility of expansion (right of first offer) up to 15 MWs.

CALENERGY, LLC

On August 11, 2015, the District executed a power purchase contract for approximately 50 MW of 'pooled' geothermal renewable energy resources from CalEnergy, LLC ("CalEnergy") located within the District's electric service boundaries, specifically from resources around the Salton Sea area. The project provides 50MW to the District from geothermal resources that total a generating capacity of 357 MW. The project is expected to begin deliveries by January 1, 2019. The term of the agreement is for 10 years from the delivery commencement date. Energy generated from this contract qualifies as category 1 renewable energy under the State's RPS program.

FEED-IN-TARIFF POWER PURCHASE AGREEMENTS

SB 1332, which was adopted in 2012, requires all investor-owned and publicly owned utilities with 75,000 or more customers to make available to its renewable generating customers a standard feed-in-tariff. The district's estimated share of the 750 MW cap is approximately 14 MWs. Staff developed program requirements and rates that incorporate the estimated cost of demand reduction, environmental attributes, avoided transmission and distribution improvement costs. The program requires a standard power purchase agreement for a period of 10, 15, or 20 years. The district received 10 FIT projects in the queue that fulfilled the District's share of the statewide cap.

SDSU/SOLORCHARD COMMUNITY SOLAR PROJECT

Unique to IID's resource stack and unique to the RPS fulfillment strategy is the contract signed with SolOrchard to develop a community solar project on San Diego State University (SDSU)-IV Campus-owned lands. This project derived from a memorandum of understanding between SDSU and SolOrchard to develop the lands adjacent to the SDSU-IV Campus into a modernized and technologically progressive solar generating facility.

There are three main elements of this agreement that make it unique to IID's resource portfolio:

1. The intention of the solar project is to develop the site into a facility that will produce renewable energy with the most advanced solar technologies available at the time of development;
2. The site will serve as an observation point/research facility to students attending the university and will be used to educate students and the public on renewable technologies;
3. The project is a community solar project, which means that IID will interconnect the facility, but every MW that is sold to IID industrial customers will be directly consuming the energy. IID will neither pay for nor receive the renewable MWh for the facility that is sold directly to the customer. SolOrchard has agreed to cooperate with IID to market the output of the facility to industrial customers, but for every MW that is not sold directly to industrial customers, IID will pay the PPA price and be able to count and receive the renewable production.

The 25-year PPA term is for the maximum of 5MW and could provide the IID up to15, 000 MWhs of CEC certified renewable energy if the project is not directly sold to IID's industrial customers.

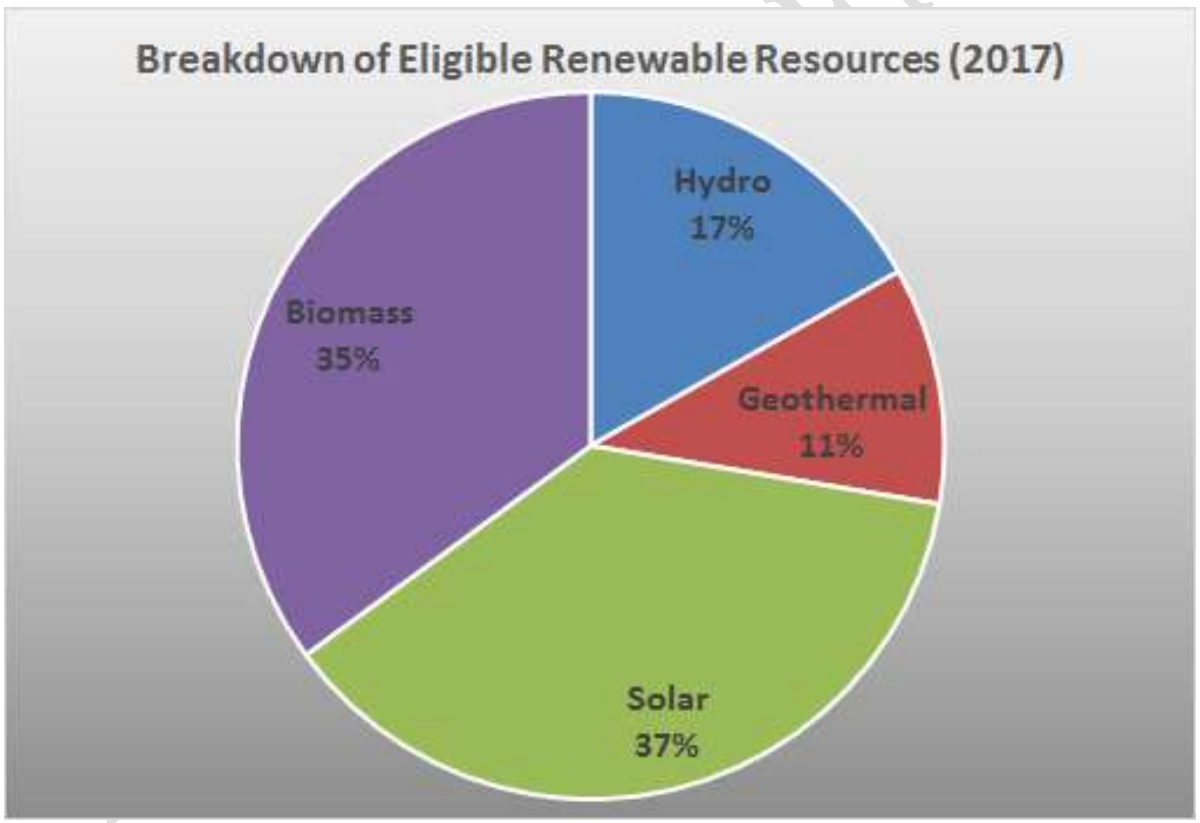
CITIZENS ENERGY E-GREEN SOLAR PROJECT

On January 9, 2018, IID reached an agreement with Citizen's Energy to develop and construct a 30 MW solar generation facility for the purpose of providing low cost solar to IID's low-income customers under the "E-Green" program. The Facility guarantees 20 MW, but Citizens is donating at zero cost, anything that is produced above 20 MW up to 30 MW. The online date is expected to before the first half of 2019. The district is currently working on the roll-out of this program.

In conclusion, although the IID has significant amounts of internally operated generation and opportunities of renewable-generation development within its service territory, it continues to look for opportunities in all renewable-energy markets and, when system reliability requirements allow, IID persistently seeks to displace internal generation with short-term purchases in the day-ahead markets and saves the internal generation for operating reserves to maximize economic opportunities.

The following exhibit is a breakdown of IID's current renewable resources.

Exhibit 34: Breakdown of IID's Current Renewable Resources



The percent of eligible renewables can be viewed in many different ways, including percent of total resource requirements/energy sales, percent of total renewable portfolio, etc. The chart above shows percentages of renewables of IID's total renewable portfolio.

The IRP planning approach identifies the most cost-effective portfolio to fulfill the energy needs of customers and includes meeting legislative, regulatory and environmental requirements. The pages that follow review these requirements as well as point out challenges for IID. Overall, IID consistently plans to meet all state and federal regulations, legislation and policy and exceeds the minimum requirements where feasible. The exhibit below demonstrates the status of current and future compliance obligations of major regulation/legislation:

Exhibit 35: Status of Compliance of Major Regulatory/Legislative Policies

Key Regulatory/Legislative Requirements		
Relative Regulation/Legislation	**Current Status of Compliance**	**Planned Status of Future Compliance**
AB802	✓	✓
SB350	NA	✓
Clean Power Plan	NA	✓
Ferc Order 1000	✓	✓
FERC Order 1000a	✓	✓
Ferc order 764	✓	✓
GHG Emissions Reductions - AB32	✓	✓
Cap-and-Trade Program	✓	✓
IID Risk Policy and Other Internal Policies	✓	✓
RPS Requirements - SBx1-2	✓	✓
NERC/FERC/WECC Compliance	✓	✓
NEM	✓	✓
SB1	✓	✓
AB2021	✓	✓
SB1037	✓	✓
Dodd-Frank	✓	✓
Renewable Auction Mechanism	✓	✓
Reporting Procedures and SOPs	✓	✓

In addition to the list above are SB32 and AB398, which are both in current compliance and plan to be in compliance.

RPS Requirements and SB 350

Another critical set of legislation are the state's statutes that target the State Renewables Portfolio Program. Prior to 2015, California's controlling Renewables Portfolio Standard was set according to Senate Bill x1 2 (SBx1 2).[11] Summarized briefly, SBx 1 2 directed California's electric utilities to reach a 33 percent RPS in three compliance periods. First, utilities were directed to procure renewable energy products equal to 20 percent of retail sales by December 31, 2013. Second, utilities were directed to procure renewable energy products equal to 25 percent of retail sales by December 31, 2016. Third, utilities were directed to procure renewable energy products equal to 33 percent of retail sales by December 31, 2020, and they were required to maintain that percentage in following years.

On October 7, 2015, California Governor Brown signed into law the Clean Energy and Pollution Reduction Act of 2015, Senate Bill 350 (SB 350).[12] This law updated and expanded SBx 1 2's RPS standards. Specifically, SB 350 increased the state's RPS from 33 percent by 2020 to 50 percent by 2030. SB 350 doubles the existing standards for statewide energy efficiency savings in electricity and natural gas by retail customers by 2030, and encourages widespread transportation electrification. With the passing of SB 350, California has the third highest RPS requirements in the nation (following only Hawaii and Vermont). The notable requirements of SB 350 are provided below.

SB 350 builds upon SBx 1 2 by requiring investor-owned utilities, local publicly owned electric utilities (including IID) and other retail sellers to obtain a "diversified and balanced energy generation portfolio," and procure the "least-cost and best-fit" eligible renewable energy resources. Concerning the RPS requirement, SB 350 requires utilities to purchase or generate renewable energy to meet new interim and end targets of 40 percent by 2024, 45 percent by 2027, and 50 percent by 2030. SB 350 also adds a long-term contracting requirement beginning in 2021, where at least 65 percent of the renewable energy procured by all utilities must be from contracts of 10 years or more or from ownership of eligible renewable resources.

<u>Solar Homes</u>

Integrated Resource Planning Requirements

SB 350 requires the CPUC to adopt a process commencing in 2017, whereby each CPUC jurisdictional load-serving entity, including IID, is to file an Integrated Resource Plan (as well as subsequent updates to the plan), to ensure that the load-serving entities meet the state's greenhouse gas emission reduction targets and procure resources to meet the 50 percent RPS by 2030 target. The plans must also minimize customer bills, ensure system and local reliability, strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities, enhance distribution systems and demand-

[13] Cal. Pub. Util. Code § 2835(a)(1).

[13] Cal. Pub. Util. Code § 2835(a)(1).

side energy management, and minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities.

By January 1, 2019, local publicly owned electric utilities with annual electrical demand exceeding 700 GWh, which IID is well above each year, must adopt an Integrated Resource Plan and a process for updating the plan at least once every five years to ensure, among other things, that the local publicly owned electric utility meets the state's applicable greenhouse gas emissions reductions targets and procures resources to meet the new 50 percent RPS by 2030 target. The local publicly owned electric utilities must submit the plan to the CEC, which will determine if the plan is consistent with the new planning requirements and provide recommendations to correct any deficiencies. SB 350 requires the CPUC to adopt a schedule of penalties for noncompliance by utilities that fail to meet their procurement requirements under the RPS. Pursuant to existing rules, noncompliance with the renewable energy resource procurement rules by local publicly owned utilities are referred to the California Air Resources Board, which may impose penalties.

Transformation of the California Independent System Operator to a Regional Organization

SB 350 also provides for the potential transformation of the CAISO into a regional organization, pursuant to a specified process through which additional transmission owners may join the CAISO with approval from their own state or local regulatory authorities, as applicable. AB 1890 established the CAISO by requiring the IOUs to divest generating resources and turn over their transmission to the operational control of the CAISO. SB 350 intends "to provide for the evolution of the Independent System Operator into a regional organization to promote the development of regional electricity transmission markets in the western states and to improve the access of consumers served by the Independent System Operator to those markets." SB 350 clarifies that this regional transformation should only occur if it is in the best interests of California and its ratepayers, and the CAISO cannot alter its obligations to the state or to electricity consumers within the state.

The voluntary transformation of the CAISO into a regional organization is to occur through additional transmission owners joining the CAISO with approval from their own state or local regulatory authorities. Before making its governance modifications, the CAISO must conduct studies of the impacts of a regional market to ratepayers, the economy, environmental impacts, and reliability and integration of renewable energy resources, among other considerations. The modeling and all underlying assumptions must be made available to the public. Appropriate revisions to CAISO's governance documents must be submitted to the Governor and the Legislature for review and approval. These studies and proposed changes to CAISO's governance structure are currently undergoing stakeholder review processes before their formal consideration by the Governor and Legislature.

On August 8, 2016, Gov. Brown issued a letter to California's Legislature stating that more time is needed to resolve all of the issues associated with transforming CAISO into a regional organization. Efforts have continued in the Legislature to define a regional organization structure with governance provisions that would ensure protection of California's policy goals while attracting participation by utilities in states located outside of California, subject to required approvals by their regulatory authorities. If a statute implementing governance modifications to permit the CAISO to transform into a regional organization are not effective by January 1, 2019, the regional transmission provisions of SB 350 will be repealed.

IID will need to monitor this activity closely and is currently monitoring the markets which can be affected by this activity. Negative prices and pricing volatility are evident and IID being well positioned with interconnection to the CAISO and the east can take advantage of opportune situations in the market that can lower costs. However, since IID is its own Balancing Authority, IID must also understand the rules and intricacies of CAISO policies in order to avoid costly risks of outside involvement.

TRACKING SYSTEMS

Similar to the Cap-and-Trade Program, the SB 350 as well as SB 100 continues the requirement from SBx 1 2 that the CEC facilitate the process of reviewing compliance for utilities in California. A part of this process is the tracking and recording of CEC approved renewable generation. CEC has appointed the Western Renewable Energy Generation Information System to carry out the task of tracking renewable energy generation from units that register in the system using verifiable data. WREGIS creates the renewable energy certificates (RECs) for this generation. WREGIS issues one WREGIS certificate for each megawatt hour of renewable energy generated by registered generation facilities. IID, as well as other users, has a private account similar to a bank account where certificates are deposited upon creation. After a certificate is created, it can be transferred, retired or exported to a compatible tracking system.

IID is currently using the WREGIS tracking system for the purposes described above and the system allows IID to fully report the most accurate data that qualifies as renewable, as determined by the CEC.

IMPACT OF RPS AND EMISSIONS

AB 32's Cap-and-Trade Program and the state RPS (SB 350) intersect for IID since, as previously mentioned, the majority of emissions reductions will come from the installation of qualifying renewable capacity. Also, AB 32 is designed to encourage low or zero emitting renewable resources for customer serving demand. Although the two pieces of legislation merge in terms of compliance optimization, there is still an undeniable cost of the installation of renewable resources. Typical renewable resources such as geothermal, solar or wind are usually non-dispatchable and do not follow any type of current market index on an incremental basis. Gas fired generation, on the other hand, is dispatchable and generally follows the daily trends of natural gas prices. Therefore, locking in renewable resource contract prices can be viewed as a form of hedging, where there is price certainty, and it is likely that the cost of other conventional energy generation will swing above and below the "locked in" prices of renewable energy should there be production from such facilities.

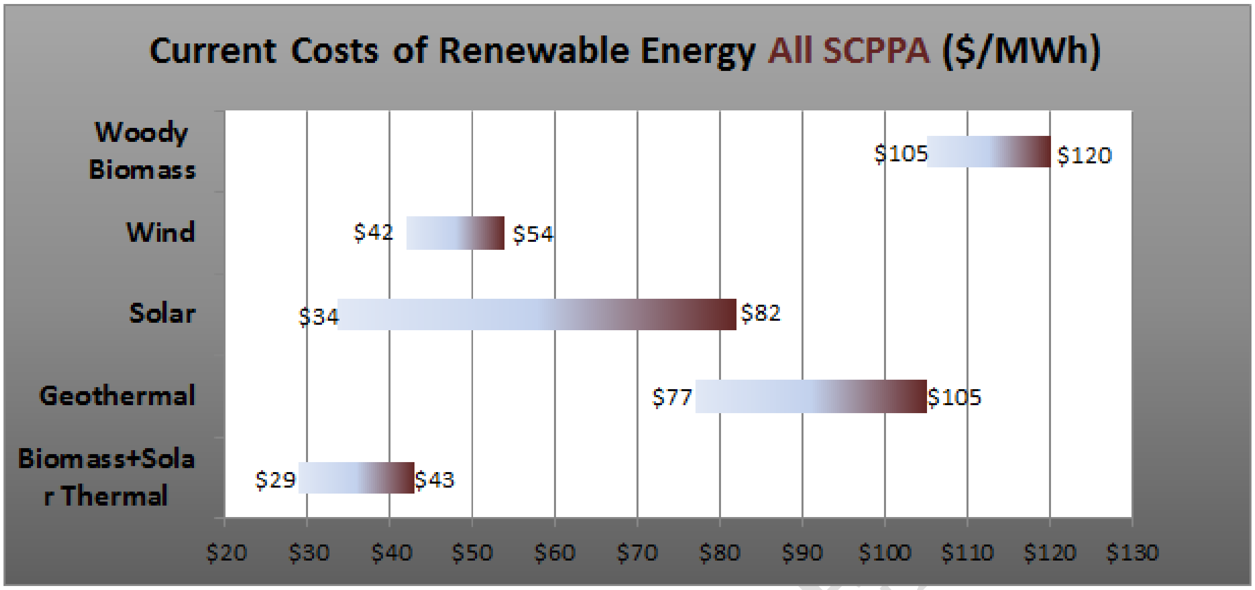
Generally speaking, the best approach is to integrate the need for renewable resources with the strategy to reduce emissions. The primary reason for this is that, as renewable resources are integrated to the IID resource portfolio, the emissions will simultaneously decrease and, therefore, make more allowances available in the Cap-and-Trade market. The revenue recognized from this type of trading activity can be netted against current renewable generation cost. See the exhibit titled "***2017 Auction Strategies and Potential Revenues with Offsets***" to view the estimated revenue potential for the second Cap-and-Trade compliance period.

RENEWABLE PRODUCT MARKETS

As previously mentioned in the Cap-and-Trade Environmental Market section, new market products in the energy industry are like any other commodity. They are subject to hourly, daily and monthly volatility and, thus, market participants will create strategies based on their company's core competencies and business model. Market participants will organize a portfolio that best suits their goals and objectives. These principles also apply to the renewable product markets. As a result, of the compliance portfolio flexibility that SB 350 provides, a diverse mix of renewable products can be included in a portfolio to mitigate cost risks and the overall impact on the cost of a given entity. In IID's case, there is an ample supply of local renewable resource generation that can be developed, or is developed, at a reasonable cost and, in turn, sold at a reasonable price to IID customers. Further, if IID chooses, there is an ample supply of renewable resources that qualify as Category 1 renewable resources in and surrounding the state of California; however, IID is currently going a step further by placing a priority on locally generated resources, since they can directly connect to the IID system and, theoretically, generate a cost savings for both the developer and IID.

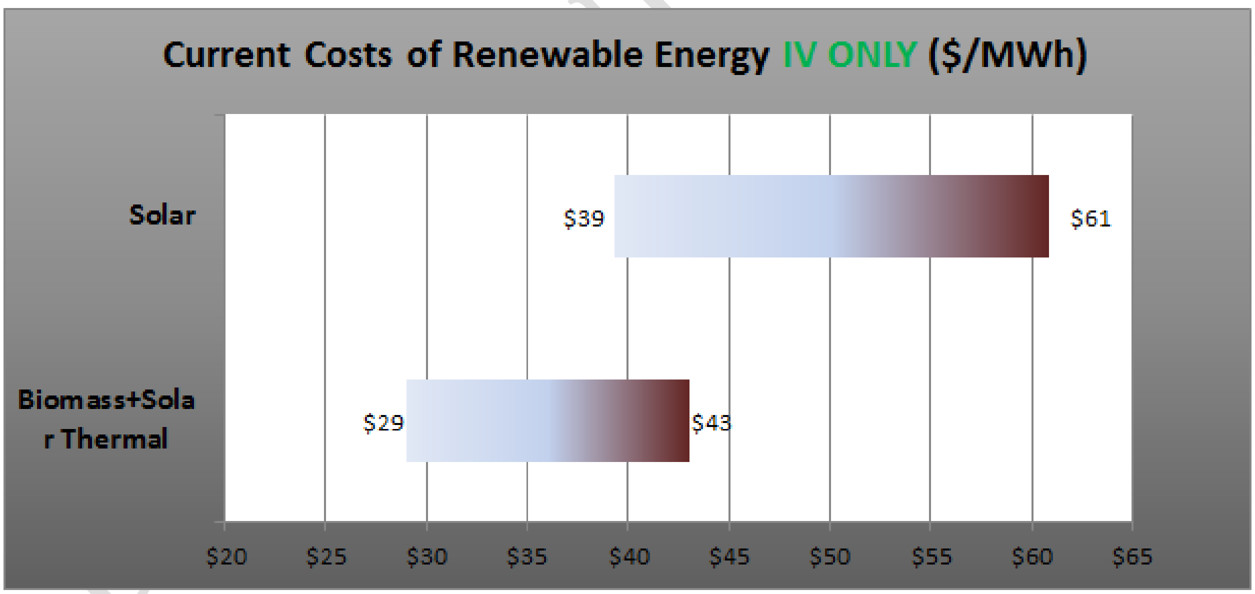
The Southern California Public Power Authority hosts a renewable RFP process on an ongoing basis. IID, as a member of SCPPA, has benefited from being a part of this RFP process by gaining access to hundreds of projects that are being offered based on the current market value characteristics. Additionally, IID can evaluate renewable generation projects and compare the projects that are being offered within the rest of the state of California with the projects that are being offered inside the IID system territory. The following exhibit examines the costs ranges of the hundreds of projects offered (as of January 2013) into the SCPPA RFP process that are located in the entire state of California and surrounding areas that qualify as Category 1 renewable resources.

Exhibit 36: SCPPA RFP Category 1 Offer Price Ranges by Technology Type



The above chart can be compared to the current offers within the IID service territory. The following shows the SCPPA RFP offers for projects to be developed in the IID system.

Exhibit 37: SCPPA RFP IID System Offer Price Ranges by Technology Type



While comparing the graphs above, there is a narrower price range per technology within the *IID service area* versus *all SCPPA* projects overall but the starting prices for the majority of the technologies are competitive within the *IID service area.* There is also quite a difference in the number of offers between the two agencies. The following exhibit shows the variance between the number of offers available to SCPPA members in the entire State of California and surrounding areas versus offers to SCPPA members inside the IID service territory:

Exhibit 38: SCPPA RFP Number of Offers in IID vs. California and Surrounding Areas

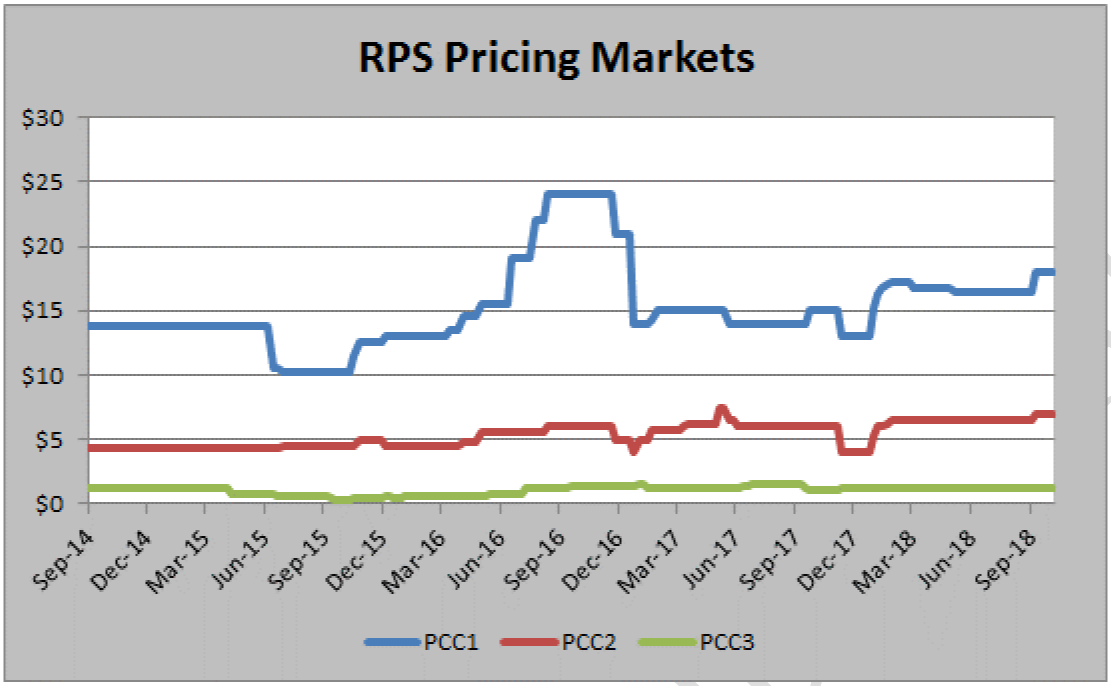
SCPPA RFP SUMMARY OF RESPONSES (ALL SCPPA vs IID Area)		
Resource Type	Total # of Proposals	# of Proposals in IID Area
Biomass+Solar Thermal	2	2
Geothermal	7	0
Solar	78	11
Wind	6	0
Wood Biomass	3	0
Total	**96**	**13**

As observed in the above table, locally developed renewable generation within the *IID service area* makes up about 14 percent of the total SCPPA project proposals. From this market participant perspective, IID is able to use both SCPPA and its own RFP process to meets its RPS targets at the least amount of cost impact to its ratepayers. Additionally, the offers continue on an on-going basis within the RFP and IID observes these offers as well as other offers to ensure that the best proposal of resources can be recommended when positions need to be filled.

IID is faced with the challenge of planning to meet its RPS targets based on the actual retail versus forecasted sales which is affected by regulatory mandates such as distributed solar. Project construction risk also has to be considered when meeting its RPS goals. When contracted projects do not meet the planned commercial operational date, the IID has to be ready to make short term modification to its renewable portfolio to ensure compliance with its targets. The volumetric, construction and performance risks associated with retail sales forecasts and the construction of renewable projects could result in IID having a short or long position during certain years.

Considering the risks mentioned above, the California Energy Commission has made available other market based renewable resources that are classified as categories ("buckets") two and three to assist the utilities in meeting their renewable requirements. The renewable resources classified as categories two and three have state mandated quantitative limitations with the overall long term State objective being to meet the RPS with California renewable resources classified as category one. The following chart demonstrates the indicative market values for the affiliated renewable energy credit associated with the three different categories as per the current market information.

Exhibit 39: Indicative Prices to Renewable Energy Products that May be Used to Fulfill the RPS



IID's organizational strategic direction is in alignment with the overall state objective to meet the renewable portfolio standards with category one. With all of the abundance of renewable resources within IID's service territory, IID strategy gives preference to renewable projects within its Balancing Authority to not only minimize system losses but also reduce its need to rely on category two or three resources. The IID Board of Directors stays committed to supporting local and California development of renewable resources. Based on their commitment and support of renewable resources, the strategy for meeting the renewable portfolio standards is first to be met with locally developed renewable resources, second with other California renewable resources and lastly with other renewable resource categories.

Operational Impact of RPS

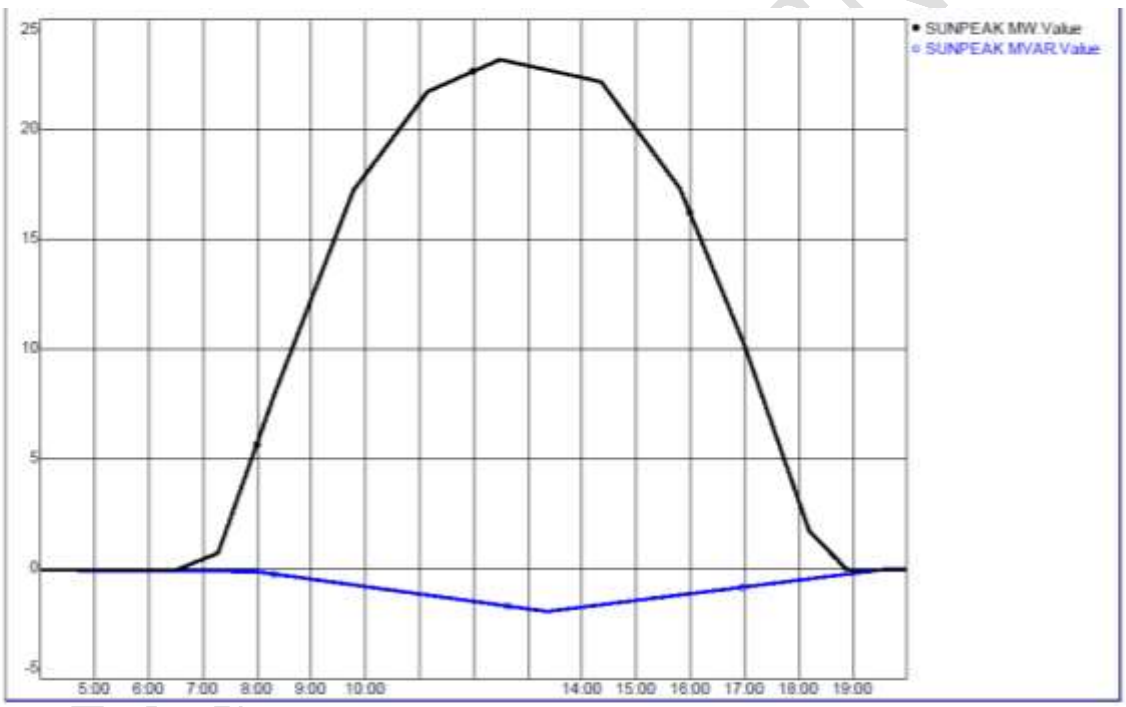
There is an array of varying types of renewable technologies that are currently available for development and/or purchase to IID. However, the bulk of the availability of renewable generation comes from intermittent resources such as solar and wind-based generation. Since IID's service territory has sufficient supply of available land, transmission, and sunshine, solar-based generation facilities will increase over the next 10-20 years. IID will utilize this availability to its fullest and meet the RPS targets in an effective manner. However, the various assortment of current solar generation technology maintains the same characteristics that can impact the performance ability of a balancing authority and control area such as the IID. These characteristics of solar technologies include:

- Intermittent – Cloud cover/or rain is unpredictable;
- Non-dispatchable/Non-Controllable – The energy is "must-take" based on weather and maintenance of the facilities;
- Low Capacity Factor – Energy is not produced at night for solar;

- Provoke increased ancillary services;
- Do not carry their own reserves – IID system will have to carry reserves during times of generation to cover the impacts of intermittency.

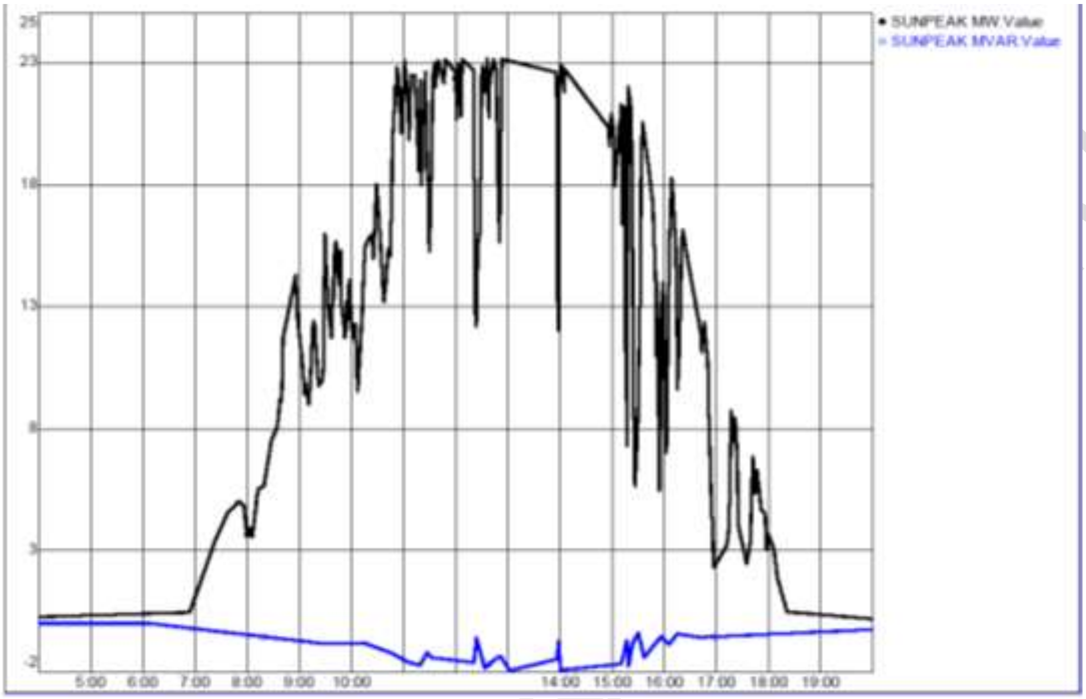
These characteristics present an undeniable problem to the system stability and reliability of the IID BA without the proper support from fast ramping gas-fired generation or storage. On a good day, the solar resource will perform as expected and the main impact the IID system would have to deal with is hour to hour variances of ramping gas-fired generation up/down to adjust the system appropriately for the increasing/decreasing level of output from the solar resources. The following is an example of an ideal day (March 13, 2017) from the solar generator currently online in Niland where the hourly and intra-hourly generation was completely driven by the abilities of the physical solar panels and no weather-related issues were experienced:

Exhibit 40: Solar Generation and MVAR Value on an Ideal Day



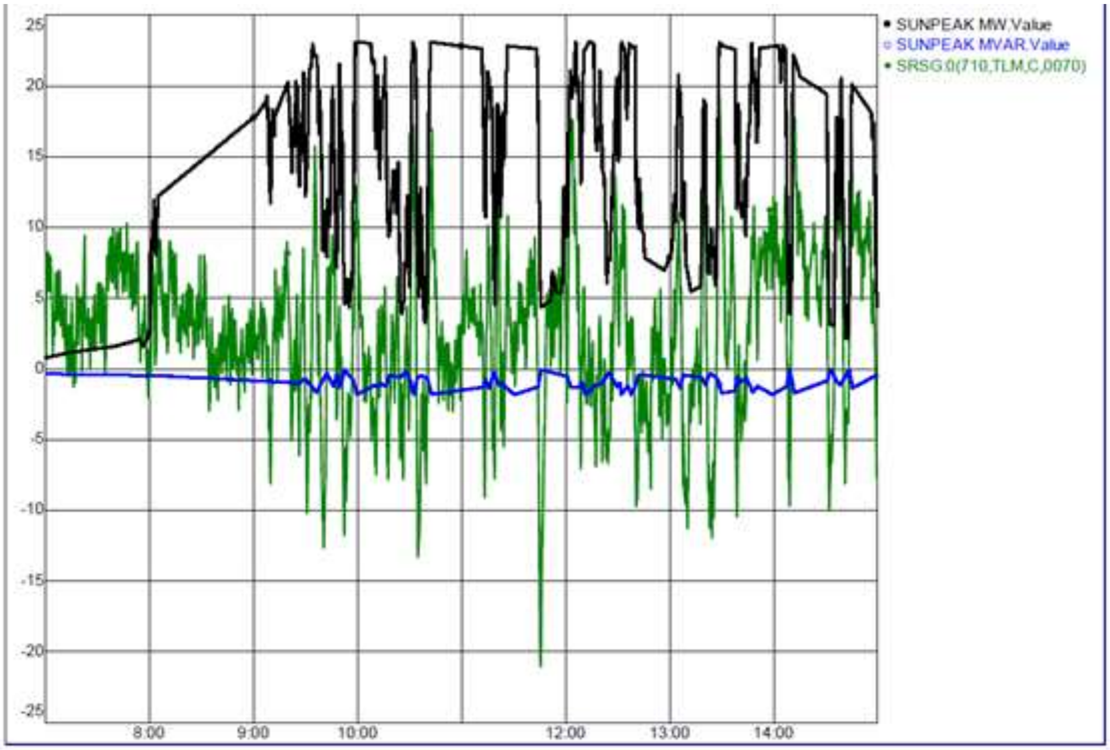
On an ideal day, there will be little inter hour impact, but IID has no control over weather-related changes. The following graph is an example of the intermittency of a currently installed solar facility in the Niland area.

Exhibit 41: Intra-hour Generation and MVAR Variability of Currently Installed Solar



As demonstrated above, this particular day (March 27, 2017) was characterized by unexpected weather changes that occurred within the day, within the hour and within the minute. The previous graph is an accurate representation of solar generation characteristics of projects interconnected to the IID BA on a day of perfect weather and solar output related factors. The above graph shows that the solar resource swings from 23MW of output all the way to 6MW of output and this presents a clear depiction of what the IID system BA needs to track and manage with limited flexible resources available. A swing of 17MW can occur within a matter of minutes and the system Area Control Error is inadvertently affected, which costs the IID excessive amounts that would otherwise not exist if the intermittent resource was not a part of the IID resource supply. This is one of the key costs of integration of renewable resources where flexible conventional generation units will have to be ramped up and down in such a manner that does not consider economic dispatch since reliability is IID's required priority. This cost of integration is sometimes ignored, so IID is constantly assessing the risks of weather-related generation volatility that, when integrated into IID's resource supply, can impact ratepayers to the extent of how much solar (or other intermittent resources) IID decides to integrate into the resource portfolio. The following chart displays how the intra-hour volatility of IID's ACE is affected by the coincidental intra-hour volatility from the solar resource in Niland.

Exhibit 42: Intra-hour Generation Variability and IID's ACE



The above chart is an example of the instantaneous impact of the intermittent solar resource in Niland, CA (black) and the coincidental ACE (green) from February 11, 2017. The ACE also is driven by other generation in the IID system, but as IID increases its solar generation in 2018 and in the next 10 years, the impact on the IID ACE variability will intensify and, thus, the costs of balancing the system ancillary services, voltage readings and load following capabilities will also amplify.

Solar resources are intermittent (i.e., schedule generation vs. actual generation will not always match), non-dispatchable resources requiring increased ancillary services since solar resources are not "static" schedules. Therefore, the levels of ancillary services (i.e., MVAR/Regulation support) are necessary to support the integration of solar resources.

Due to the inherent nature of intermittent resources, the IID BA is obligated to balance these variable generation resources with load. IID regulates these imbalances by utilizing internal generation. Generator imbalances of the actual schedule are addressed in IID's OATT Schedule 9. As a member of the Southwest Reserve Sharing Group, some of these imbalances will be reduced or covered through this membership. However, IID transmission system is currently limited and its ability to import spinning and non-spinning reserves is a risk. As a result, IID is expected to increase spinning reserves and non-spinning requirements in order to account for the intermittency of solar resources. On a normal day-to-day basis, the regulation margins of IID's Automated Generation Control (AGC) units to regulate will need to be increased for startup, shut down (i.e., sunup and sundown) and any unexpected swing of the resource. This is necessary so as not to incur NERC Control Performance Standard (CPS1 and 2), Disturbance Control Standard (DCS) and WECC Contingency Reserve Standard violations. Due to these operational limitations, IID is limited on amount of solar generation it can integrate to its system and it is not recommended to over exert the IID system's reliability threshold with excessive solar generation capacity.

ENERGY IMBALANCE MARKET

The CAISO operates an Energy Imbalance Market, which allows Balancing Authorities located outside of the CAISO the ability to utilize certain CAISO real-time market functions. A primary purpose of the EIM is to make more efficient and flexible use of the interconnected transmission grid. IID has an interest in monitoring the opportunities presented by, and limitations of, the EIM, including the EIM-related policy initiatives that may impact IID's transmission facilities and rights and solar and geothermal resources portfolio. Of closer proximity to IID, Arizona Public Service Company is an EIM participant, and El Centro Nacional de Control de Energía announced that it has agreed to explore participation of its Baja California Norte grid in the CAISO EIM real-time market. On February 8, 2018, the CAISO announced that it is beginning an initiative to explore certain enhancements to its Day-Ahead Market, and such changes may be extended as a Day-Ahead functionality in the EIM. The CAISO is continuing to develop this functionality through 2019. Simultaneously, in response to concerns raised by CARB, the CAISO has been attempting to better track the impacts carbon emissions that may result from generation located outside of California operating to serve load outside of California that otherwise would have been served by generation that is being used to supply California load through the EIM. The CAISO is filing at FERC in late August Tariff amendments that are meant partially to address CARB's concerns. These amendments reduce the magnitude of transactions in the EIM to which carbon emissions can be attributed. CARB is continuing to explore a more permanent solution to ensuring that operation of the EIM does not inadvertently increase carbon emissions.

RELIABILITY COORDINATOR

IID is in the process of obtaining Reliability Coordinator Services from a new service provider. All electric utilities that are subject to mandatory electric Reliability Standards issued under NERC must be linked to a Reliability Coordinator. The Reliability Coordinator is the highest level of authority responsible for the reliable operation of the Bulk Electric System, having a wide area view of that system. The Reliability Coordinator holds operating tools, processes and procedures to prevent or mitigate emergency operating situations in next-day analysis and real-time operations by issuing instructions to Balancing Authorities and Transmission Operators.

IID's Reliability Coordinator presently is Peak Reliability, which provides Reliability Coordinator services for the Western Interconnection. On January 2, 2018, the CAISO notified Peak Reliability that it would cease taking Reliability Coordinator service from Peak Reliability in late 2019, and in the interim, would work to establish itself as a NERC-certified Reliability Coordinator. The CAISO would provide Reliability Coordinator services to utilities located within the CAISO's own Balancing Authority Area, but the CAISO has also offered to provide Reliability Coordinator services to Balancing Authority Areas located outside of the CAISO's footprint. Subsequently, Peak Reliability announced that it cease operations by December 31, 2019. Through the spring and summer of 2018, IID explored options for receiving required Reliability Coordinator Services going forward, and upon consideration, indicated its intent to receive Reliability Coordinator services from the CAISO.

To facilitate provision of Reliability Coordinator services, the CAISO has filed with FERC proposed tariff changes, a pro forma agreement for entities to execute in order to receive Reliability Coordinator services and rates for providing such services. Assuming FERC approves the CAISO's filing in essentially the same form as filed, IID expects that the CAISO will reach out to it to discuss execution of a Reliability Coordinator Services Agreement. As indicated above, IID is required to have a Reliability Coordinator due to its being subject to NERC Reliability Standards, and would have a direct relationship with the Reliability Coordinator due to its NERC registrations as a Balancing Authority and a Transmission Operator.

BATTERY ENERGY STORAGE SYSTEM (BESS)

To address the apparent potential operational issues, IID has installed a 20MWH/33MVA battery storage facility that greatly reduces the volatility of impact from intermittent resources. IID's ability to balance its load and resources in the current environment with the solar resources on-line is compliant with NERC balancing reliability standards. In fact, IID is highly compliant based on Control Performance Standard No 1 and 2 (CPS1 and CPS2) measures. With the expectation that IID will add additional solar resources to its portfolio, IID's ability to comply with NERC balancing standards may be more of a challenge. Existing ramping capability of IID resources are limited to effectively integrate the committed solar projects while maintaining reliable operation. As additional intermittent renewable resources are added to IID's system, there will be an increased requirement for fast ramping resources that can control those fluctuations. IID has been analyzing different applications of fast ramping resources that can respond to solar intermittency. The cost of integration will be considered while analyzing future renewable projects. Additionally, the battery has an efficiency ratio of 1:.85, so the dispatch price must be at least 15percent better when strategically dispatching the battery to address system needs. Further, IID has determined that the battery storage facility installed is capable of offering black start services.

DISTRIBUTED GENERATION

Rule 21 specifies standard interconnection, operating and metering requirements for Distributed Energy Resource generators. In formal language, Rule 21 states the technical requirements for interconnection of a Generating Facility at the distribution system level and provides a directive for utilities to evaluate the impact of DER interconnected in parallel with their distribution systems.

The process of technical analysis used by IID is as follows:

- The utility receives the application and reviews it for completeness.
- Once the utility accepts the application as complete, it goes through the screening process and decides whether the Generating Facility qualifies for simplified interconnection or whether supplemental review is required. After a supplemental review is performed, the utility decides whether the generator may be interconnected subject to additional requirements, or whether the application requires an interconnection study (System Impact Study - SIS).
- If an interconnection study is needed, the utility provides the applicant with the cost and time necessary to complete the study.

Rule 21's Application to IID customers is as follows:

IID Rule 21 Clause A: APPLICABILITY. These rules describe the distributive generation interconnection, operating and metering requirements for a generating facility for interconnection to the distribution system of IID. Subject to the requirements of these rules, IID shall allow the interconnection of a GF to its distribution system.

Consistent with IEEE 1547: These rules were revised to be consistent with the requirements of ANSI/IEEE11547-2003 Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE 1547). In some cases, IEEE 1547 language was adopted directly; in others, IEEE 1547 requirements were interpreted.

These rules have been devised to maintain the spirit of both documents.

IEEE 1547-20031.3 Limitations: The criteria and requirements in the rule definition are applicable to all distributed resource technologies, with aggregate capacity of 10 MVA or less at the Point of Common Coupling, interconnected to Electric Power Systems at typical primary and/or secondary distribution voltages. Installation of Distributed Resources on radial primary and secondary distribution systems is the main emphasis of this standard, although installation of DR on primary and secondary network distribution systems is considered. This standard is based upon DR as a 60 Hz resource.

Net Energy Metering

NEM requirements can affect IID's planning, procurement and operations of resources on its system. SB 1 enacts Governor Schwarzenegger's Million Solar Roofs Initiative and expands the California Solar Initiative and CEC's New Solar Homes Partnership, by requiring building projects to meet minimum energy efficiency levels when applying for ratepayer-funded incentives. The statute also recommends that photovoltaic solar system components and installations meet rating standards and performance requirements. AB 920 is a 2009 NEM law that requires utilities to pay residential customers and businesses for excess energy produced by a customer's solar power system. AB 510 raised the cap of the number of homes and businesses that can use NEM billing from 2.5 percent to five percent of the electric utility's aggregate customer peak demand. The law also addresses co-energy metering between publicly owned utilities and customer-generators to compensate such generators on a time-of-use basis. The CPUC's NEM 2.0 program, approved in January 2016, extends the NEM program for the investor-owned utility territories in California, which ensures that NEM customers continue to receive retail rates for surplus energy, but are placed on time-of-use rates. IID has followed the CPUC NEM 2.0 program to monitor trends in NEM issues. IID has reached the 5 percent NEM cap and has established a subsequent program for distributed solar above-and-beyond the 5 percent cap.

Consistent with AB 920, the IID established a rate to purchase surplus electricity. At the end of a 12-month period, customers who are net generators will be compensated for surplus energy returned to the grid at the rate stated in the current net metering rate schedule. At the end of the 12-month period, customers that are net consumers, but in any given month within the 12-month period are a net generator, that monthly surplus energy will be tallied and credited to the customer at IID's current retail rate.

Although IID met its 50.2 MW cap in the first quarter in 2016, it extended the program by an estimated 9.6 MW to allow for customers that were in the process of submitting their applications an opportunity to participate. For the remaining customers that desire to generate all or a portion of their energy consumption, IID has developed the Net Billing successor program to continue to facilitate customer interconnection projects to IID's grid.

ENERGY STORAGE

AB 2514 requires local publicly owned electric utilities, such as IID, to determine targets for procurement of viable and cost-effective energy storage. "Energy storage" is defined by the statute to mean: "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy."[13] The statute requires local publicly owned electric utilities to adopt procurement targets through their boards by October 1, 2014, to be met by December 31, 2016, and December 31, 2020. AB 2514 requires these utilities to reevaluate those targets not less than once every three years, report on establishment of these targets to the CEC, as well as on progress on meeting these targets by January 1, 2017, and January 1, 2021. While IID has not officially identified an internal target by policy, IID has procured a 20MWh/33MVa battery storage system which fully supports the proponents of this legislation. Additionally, as a result of this IRP, IID staff will be recommending additional resources of energy storage which will well surpass the provided requirements of AB 2514.

Also, as discussed above, the CEC approved on August 1, 2018 changes to its IRP Guidelines requiring POUs to show how multi-hour energy storage meets peak demand under SB 338. This is how IID already plans for its capacity resources.

SMALL GENERATOR INTERCONNECTION

On July 21, 2016, the Federal Energy Regulatory Commission issued a Final Rule revising the *pro forma* Small Generator Interconnection Procedures and the Small Generator Interconnection Agreement. Originally adopted in FERC's Order No. 2006, the *pro forma* SGIP and SGIA govern the interconnection of small generating facilities with a capacity of 20 MW or smaller. FERC found that the impact of small generating facilities on the grid has changed since the issuance of Order No. 2006, and the high penetration of distributed energy resources will impact grid reliability if potentially adverse impacts are not sufficiently mitigated. Thus, the Commission's Final Rule requires newly interconnecting small generating facilities to ride through abnormal frequency and voltage events and not disconnect during such events. The revisions to the *pro forma* SGIA will apply on a prospective basis to new small generating facilities that execute or request the unexecuted filing of an SGIA after the Final Rule's effective date, and to existing interconnection customers that, pursuant to a new interconnection request, execute or request the unexecuted filing of an SGIA after the Final Rule's effective date.

[13] Cal. Pub. Util. Code § 2835(a)(1).

FERC also required, in a final rule issued on June 16, 2016, that transmission providers amend their Open Access Transmission Tariffs to include a modified *pro forma* SGIA to eliminate the exemptions for new wind and other non-synchronous generators from the reactive power requirement. The Commission required existing wind and other non-synchronous generators to provide reactive power if a transmission provider determines in conducting a System Impact Study for a generator upgrade that reactive power is necessary to ensure safety or reliability.

For both of these Final Rules, FERC found that transmission providers that are not public utilities must adopt the requirements of the Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888. FERC will issue a single due date for compliance filings in response to both Final Rules.

Several years prior, on November 22, 2013, FERC issued a Final Rule revising the *pro forma* SGIP and SGIA to reduce the time and costs related to the interconnection of small generating facilities, while maintaining the reliability of the grid. Specifically, FERC's Final Rule adopted six sets of reforms to the pro forma SGIP to:

1) Provide an interconnection customer with the option of requesting from the transmission provider a pre-application report providing existing information about system conditions at a possible point of interconnection;
2) Revise the 2 MW threshold for participation in the SGIP's "Fast Track Process" to be based on individual system and generator characteristics up to a limit of 5 MW;
3) Revise the SGIP's "customer options meeting" and supplemental review following failure of the Fast Track screens so that the supplemental review is performed at the discretion of the interconnection customer and includes minimum load and other screens to determine if a small generating facility may be interconnected safely and reliably;
4) Revise the pro forma SGIP Facilities Study Agreement to allow the interconnection customer the opportunity to provide written comments to the transmission provider on the upgrades required for interconnection;
5) Include energy storage devices in the *pro forma* SGIP and *pro forma* SGIA; and
6) Provide clarifications in both the *pro forma* SGIP and *pro forma* SGIA.

IID has been working in developing language and modifications to its OATT with the intent of both complying with the revised FERC language and responding to small renewable solar projects that are requesting interconnection into the IID system and would benefit by this type of language.

SMART GRID

The "smart grid" is a broad concept used to describe the interconnectivity, communication and automation of nearly all of the infrastructure and assets that make up the electric grid. From generation to consumption, smart grid infrastructure communicates in near-real time with computer systems that process and analyze large amounts of data to automate many of the functions of the electric grid. These computer systems are used to provide intelligence and automation to create a more efficient grid that detects and reacts to events so that it is “self-healing,” prevents and manages outages and optimizes the intersection between the supply and demand through price signals to the consumers and ratepayers.

The concepts and technologies that define the smart grid have evolved over time and continue to evolve. In light of this fluidity, IID has worked to stay informed of the state and federal legislative developments, while identifying smart grid opportunities to improve efficiencies in the delivery of electricity to its ratepayers. Because it is generally accepted that the communication network and metering systems are cornerstones of the smart grid, IID’s smart grid efforts have primarily focused on Advanced Metering Infrastructure, commonly known as smart meters. Efforts have included a succession of smart-meter committees and implementations to assess the current state of technology and the costs and benefits of implementing the technologies.

While the recommendations of each study may vary slightly with regard to implementing the technology based on factors such as technological maturity, internal business processes and needs and economic indicators (rate of return and return on investment), each study is consistent in concluding that there are significant operational efficiencies and positive economic rewards to be realized. In preparing for the smart grid of the future, the most recent Smart Metering Committee at IID has recommended a metering technology, which will allow the IID to migrate toward that vision over time, while avoiding the up-front expense and extensive operational changes that would be necessary with other metering technologies.

As an active member of SCPPA, IID continues to engage in smart grid discussions with neighboring public power utilities on topics including, but not limited to, smart meters, meter data management, electric vehicles, energy storage, distributed generation and demand response programs. Each of these topics will have its own set of opportunities and issues as they relate to the emergence of the smart grid. IID should continue to be proactive in engaging other utilities to understand the full impact and potential of the smart grid, as well as conducting in-house studies and pilot projects. These discussions, studies, and projects provide the data and experience necessary for consumer outreach and plan development. In preparation for the smart grid of the future, IID should continue to give special attention to fostering public dialogue to educate the IID and its ratepayers, define issues and develop in-house processes and documentation. Below is a list of specific recommendations towards those ends.

- As pricing and technologies continue to evolve, IID should continue to use the RFP process as a means to verify the conclusions and assumptions of previous committees tasked with reviewing smart grid technologies and business needs.
- Accelerate the implementation of smart meter installation in order to justify the implementation of the network communication infrastructure and fully realize the potential of smart metering.
- Draft and develop policies around the tracking, use, retention, protection and ownership of data.
- Identify potential funding opportunities and develop plans in preparation for such opportunities.

- Develop programs and rate structures (Demand-Side Management Programs and Time-of-Use Rates) now so that the IID and its customers can take advantage of smart grid technologies once they are deployed.

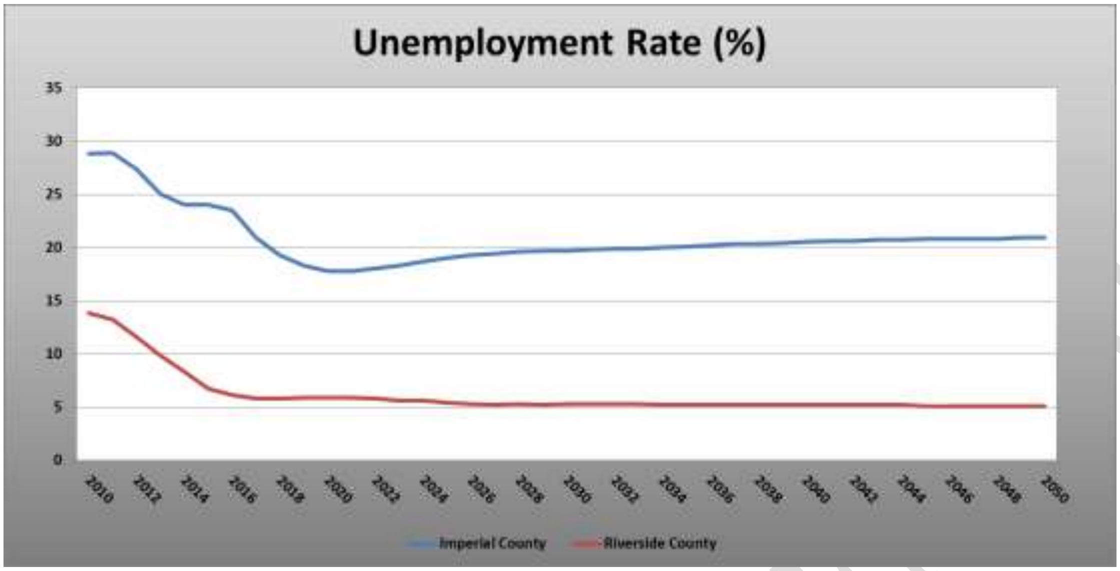
Chapter 3: Forecast of Demand and Energy Requirements

ECONOMIC FORECAST

Woods & Poole Economics, Inc provided economic forecast data that was used for the IID's load forecast analysis. According to the economic analysis of Woods & Poole Economics, Inc. the long-term outlook for the United States economy is one of steady and modest growth through the year 50. Although periodic business cycles will interrupt and change the growth trajectory, the nation's employment and income are expected to rise every year through 2050. Gross Domestic Product is forecast to grow at an average annual rate of 1.9 percent over the next three decades. Although employment growth has been uneven in recent years, with particularly sharp job losses in manufacturing, the economy is expected to produce steady job gains through 2050. In the long-run, the civilian unemployment rate is expected to be 4.8 percent by 2050. Inflation is forecast to increase from 0.3 percent in 2015 to 3.9 percent by 2050. Oil prices are expected to stabilize at an average price of $60 per barrel through 2050 but still lead to inflationary pressures late in the forecast period. Total employment is projected to increase to 284.3 million in 2050. And total residential population is projected to reach 428.1 million in 2050, up from a 2015 Census estimate of 321.4 million people; the United States is expected to remain the world's third most populous nation through 2050. Personal income per capita (in 2009 dollars) is projected to increase from $43,924 in 2014 to $66,890 in 2050. These macroeconomic projections are the national assumptions on which the 2017 regional projections are based. IID's main load service area covers two counties in California: Imperial County and part of Riverside County. It is anticipated that the long-term economy outlook for the two counties that IID serves will generally follow the same economic trend as the national assumptions provided above, with some local differences.

According to the Imperial County forecast shown in Exhibit 31, Imperial County reached its highest level of unemployment in 2010-11. The forecast predicts a steady decline in unemployment starting in 2012 and the decline is expected to continue at a steady rate until 2020 and then taper off at a slower rate of decline in 2021 and beyond.

Exhibit 43: Riverside and Imperial County Employment Outlook



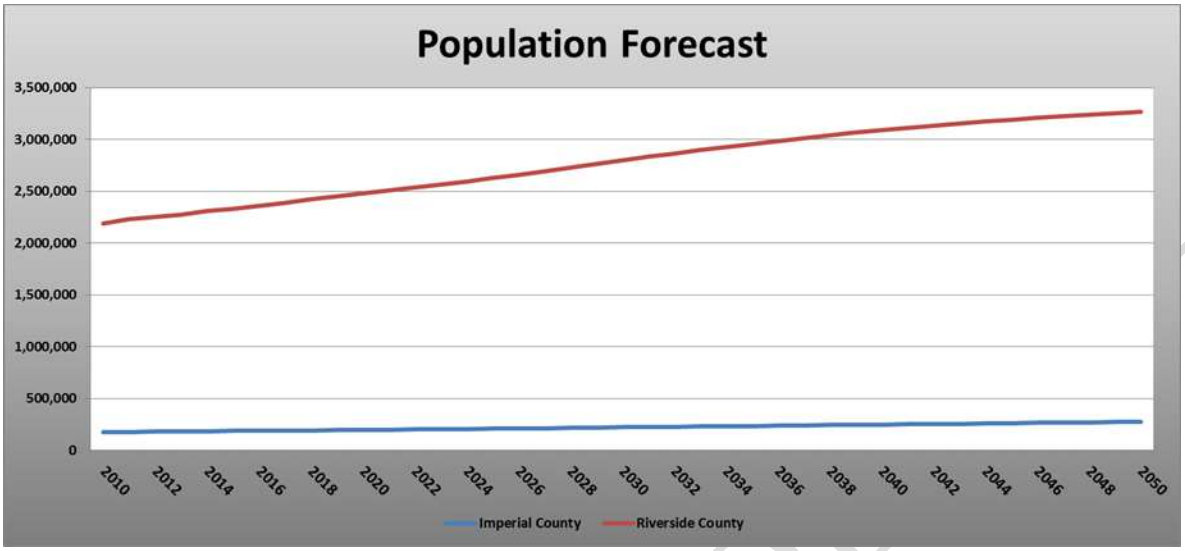
Imperial County's economy is largely agricultural. With approximately 11,700 farm workers, the county generates $2 billion of agricultural output each year. Its most prevalent commodities are cattle, alfalfa, broccoli, and lettuce. The public sector also plays a large role in the region's economy. With 18,300 workers, it is the county's largest employment sector. A substantial number of the government jobs in Imperial County are related to the two state correctional facilities, which employ a combined total of 2,000 staff and house 7,400 inmates. In effect, the high proportion of governmental and agricultural jobs that helped cushion the regional impacts of the national economic downturn will result in slower regional growth while the state and federal economies improve.

Riverside County[14] is forecasting a similar trend in unemployment rate. In 2015, the strongest areas of growth as reported by Riverside County were in leisure and hospitality (+4,400 jobs), education and healthcare (+4,300 jobs), construction (+4,200 jobs), and government (+3,600 jobs). The largest losses were in professional and business services (-670 jobs).

Over the past five years, the Riverside County population has increased at an average annual rate of 1.2 percent. A substantial portion of this growth was the result of net migration, as an average of 11,700 net migrants entered the county each year. Net migration is expected to remain positive, with an average of 14,000 net migrants entering the county each year through 2022. Net migration is expected to account for almost half of the population growth. Although IID's territory covers only the southeastern portion of Riverside County, the impact of growth in IID's Northern territory has a significant impact on energy and load growth. The following represents the recent trends in population growth and the forecasted growth in population in both Imperial County and Riverside County.

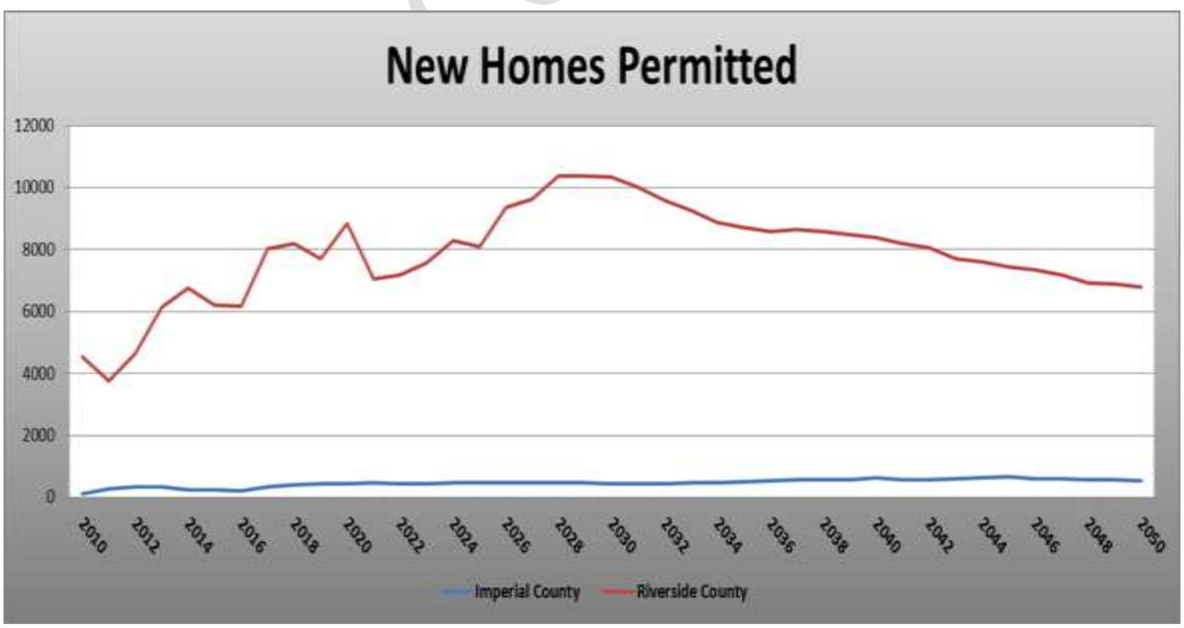
[14] http://www.dot.ca.gov/hq/tpp/offices/eab/socio_economic_files/2017/Riverside.pdf

Exhibit 32: Imperial and Riverside County Population



In the past several years, permits to build new homes declined, but the Imperial County data reveals that the number of permits taken out to build new homes took a turn and began increasing. The Riverside County areas of Coachella, Indio and parts of La Quinta represent a significant portion of IID's energy and capacity load requirement, so the economic characteristics of Riverside County maintain a heavy influence on IID's future planning outlook. Riverside County has had an increase in new homes permitted and a growth in employment. The following exhibit shows historic trends and forecast of new homes permitted.

Exhibit 33: The Number of Permits Issued to Build New Homes in Riverside and Imperial County



IID has actively engaged in encouraging development of renewable energy projects to help the Imperial County and Southern Riverside County job markets. Generally, new construction projects create around 6.5 jobs per million dollars construction cost and an additional 2.5 jobs in secondary income effects. Thus, a $250 million construction project could create as many as 2,075 (some temporary and some permanent) jobs in Imperial County[15]. The jobs created in the construction industry match the employment characteristics of the regions unemployed individuals. Therefore, it is anticipated that the newly created jobs will go to existing residents and workers rather than imported employees.

Overall Summary of Forecast

Energy Optimization & Procurement of the Energy Department at the Imperial Irrigation District has prepared the system load term load forecast of peak demands, net energy requirements and energy sales to customers within the IID service territory. This forecast will be used for district wide long term planning purposes in current planning activities for the next 20 years. In 2014, IID completed a Request for Proposals to acquire load forecasting services as well as the tools and training to allow IID staff to complete all future forecasts. The load forecast is an integral part of District planning activities, so a forecasting process that relies on industry accepted standards of practice, as well as rigorous, detailed and thorough analysis is critical to obtaining results that are both realistic and statistically sound. This approach holds true for both the 2016 load forecast as well as the 2018 forecast. Since the 2018 forecast is based upon most of the 2016 methodology, this document serves as a supplement to the original 2016 load forecast report to explain the exact process and modifications for this updated forecast.

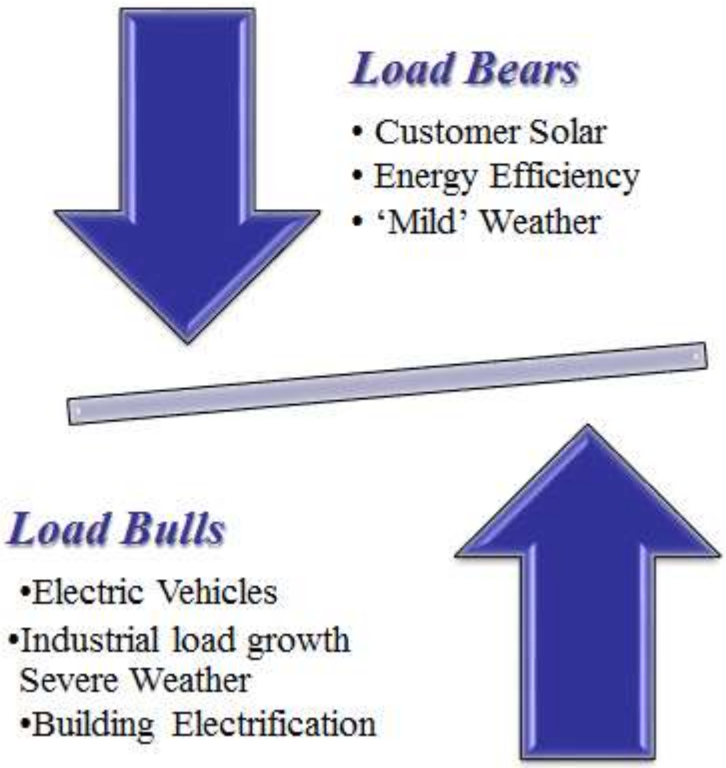
The 2018 IID Load Forecast basically uses the same methodology as the 2016 IID Load Forecast with some modifications to reflect the current economic, weather and regulatory changes. In this load forecast study, econometric approach was utilized to forecast IID's total retail sales. The Net Energy for Load forecast was derived from the total retail sales forecast and the average difference of NEL and retail sales in historical years; Coincident Peak forecast was derived from NEL forecast and historical representative load factors. The forecast is primarily driven by several key variables that have an impact on hourly/daily/monthly/yearly loads and the forecast incorporated the load impact resulting from these variables including, but not limited to:

- Weather changes
- IID Energy Efficiency programs
- IID Rooftop Photo Voltaic Solutions Programs
- Electric Vehicles programs
- New industrial load impact
- Regulatory requirement changes

[15] Summit Blue Consulting, LLC Renewable Energy Feasibility Study to the Imperial Irrigation IID from January 17, 2008.

Since these variables are uncertain the severity of their impact on load depends on how each of these variables transpire. Generally, these variables can either encourage load growth or deter it. Below is a diagram that illustrates which variables encourage load growth and which variables deter load growth:

Exhibit 33: Load Impact Variables



Different scenarios were created for each variable based on varying assumptions and the interactions and combinations of these different variables. As a result, for the 2018 forecast, three main cases were selected to represent the potential outcomes. The three cases choose for this IRP analysis are:

1. **High Case** – Combining severe weather conditions, high industrial growth, high electric vehicle penetration, low energy efficiency, and low rooftop/customer solar penetrations
2. **Mid (Expected) Case** – Combining normal weather, normal industrial growth, average electric vehicle penetration, average energy efficiency, and average rooftop/customer solar penetrations
3. **Low Case** – Combining mild weather conditions, normal economic industrial growth, low electric vehicle penetration, high energy efficiency, high rooftop/customer solar penetrations

Furthermore, there are other combinations of key significant variables that can be used to create additional forecasts. For example, other combinations consist are combining normal weather with high industrial growth and normal energy efficiency and normal rooftop/customer rooftop solar. Another example is combining the Mid Case variables with a much higher view of energy efficiency/rooftop solar impacts. Below is a table that describes the three main cases along with the 'other observations" and the forecast results provided from each process:

Exhibit 34: 2018 Load Forecast Categories

2018 Load Forecast Categories					
		CASE			OTHER OBSERVATIONS
Forecast Type	Forecast Category	Base/Expected	HIGH CASE (Severe weather, high industrial, High EV, Low EE/PV)	LOW CASE (Mild weather, normal economic industrial growth, high EE/PV, Low EV impacts)	Various results from combining High/Mid/Low projections of: EE, PV, EV, Industrial Load, Weather Regulatory Requirements & Zero Net Energy
Gross	Peak Load (MW)	✓	✓	✓	
	NEL(MWh)	✓	✓	✓	
	Energy Sales (MWh)	✓	✓	✓	
Net of EE/PV Programs	Peak Load (MW)	✓	✓	✓	
	NEL(MWh)	✓	✓	✓	
	Energy Sales (MWh)	✓	✓	✓	

Retail customer counts and sales by major customer classification as well as hourly load data generally from 2001 through 2017 (the study period) were provided by IID. The historical data regarding IID Energy Efficiency Programs and IID PV solutions Programs were provided internally by IID also. Historical and projected economic and demographic data were provided by Woods & Poole Economics, Inc. Weather data was provided by Weather Underground, Inc.

Even though the historical Net Energy for Load had an average growth rate of 1.7 percent over the last 17 years, as Figure 1-1 shows, the load of the IID System over 2009-2016 maintained a fairly flat trend. And the flat trend in the historical load growth lasted two years longer than that in 2016 Load Forecast (2016 and 2017), that is the main reason to explain why the overall average annual growth rate in 2018 load forecast declined a little compared to that of the 2016 Load Forecast. Moreover, the 2018 Load Forecast has a lower average annual growth rate of 1.2 percent for the first ten years (2018-2027), and a higher average annual growth 1.7 percent for the second ten years (2028-2037). The lower average annual growth rate 1.2 percent in the first ten forecast years (2018-2027) is mainly due to fast growth of PV+EE impact, which takes away some growth rate of IID system load. It is also due to the weather normalization impacts when bringing weather for 2018 and beyond back to normal as compared to the last several years that are considered severe weather years. With PV+EE impact reaching market saturation and an optimistic growth in economic forecast data by Woods & Poole Economics, Inc. during the second ten years, the average annual growth rate increased to 1.7 percent in 2018 Load Forecast. The same applies for CP's average annual growth rate in the next 20 forecast years since CP forecast is derived from NEL forecast and load factor. As the exhibit below shows, the CP during historical period (2001-2017) has a higher average annual growth rate reaching to 2.6 percent, this is due to that in the recent two years 2016 and 2017, the peak of the IID system jumped historically high to 1,073MW due to historically record high temperature in peak day. The tables below illustrate this comparison of the 2016 load forecast and the 2018 load forecast:

Exhibit 35: Net IID System NEL Requirements in 2016 Load Forecast vs 2018 Load Forecast

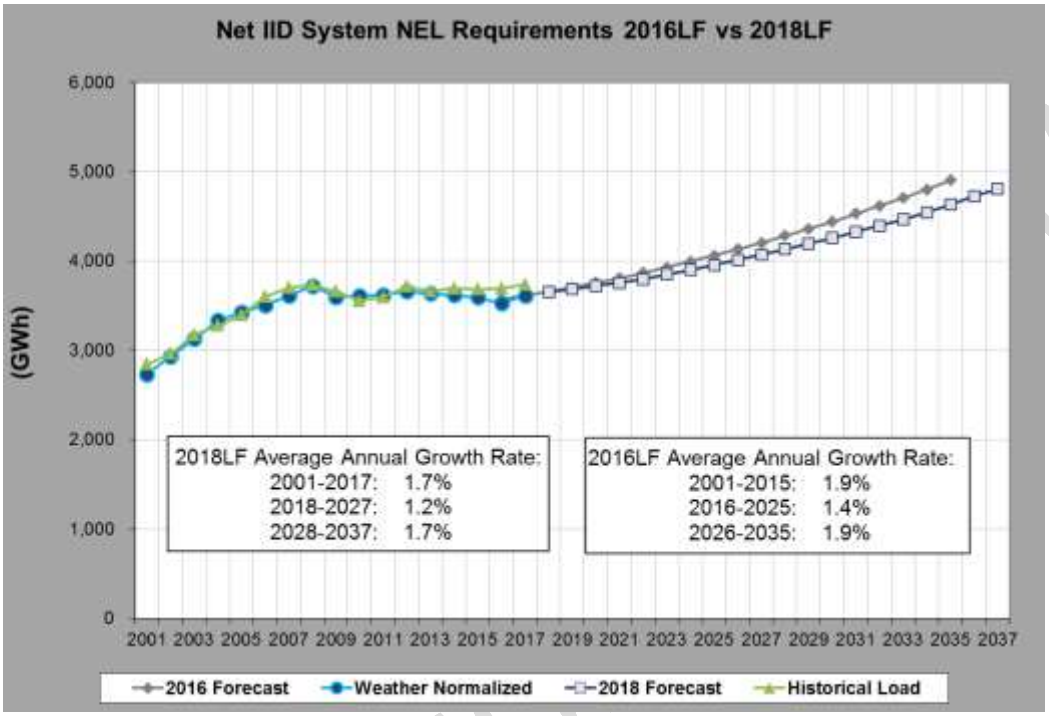
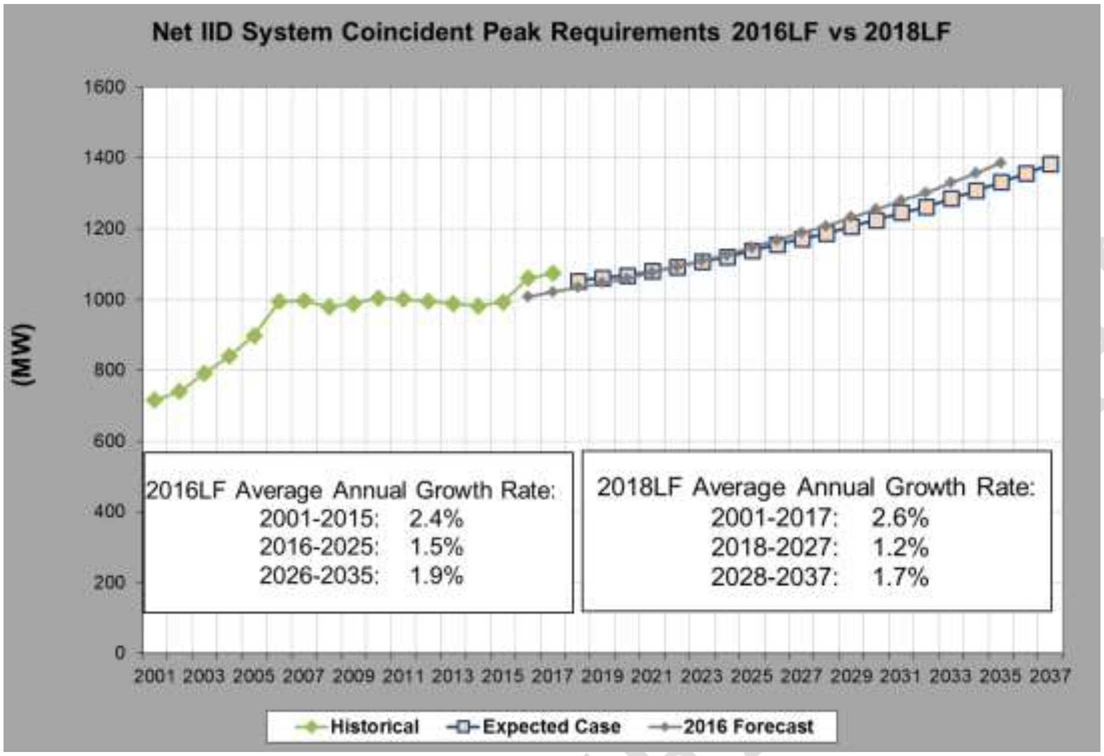


Exhibit 36: Net Coincident Peak Demand in 2016 Load Forecast vs 2018 Load Forecast



Due to the unpredictability of weather temperature for the long term forecast, and the fact that weather has an important impact on energy consumption, the 2018 IID Load Forecast provides retail sales, NEL and CP forecasts under three weather scenarios: Normal (base/expected), Mild and Severe. These weather scenarios are used to estimate the load under the normal, abnormally severe and abnormally mild weather conditions and are combined with several other variables to create three cases.

The Exhibit below depicts the projection of NEL under three scenarios in 2016 Load Forecast: the blue line is net NEL under normal weather and expected EE_PV scenario; the green dash line is net NEL under severe weather scenario and expected EE_PV; and the red dash line is net NEL under mild weather and high EE_PV scenario.

Exhibit 37: Net IID System NEL Requirements in 2018 Load Forecast

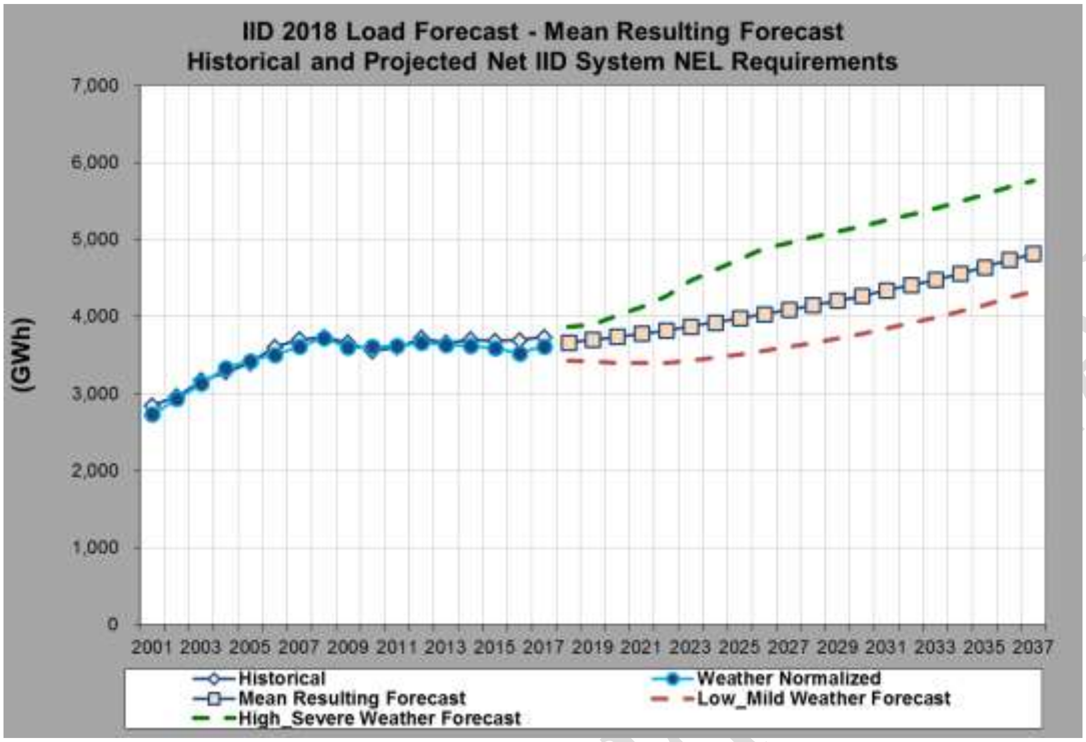
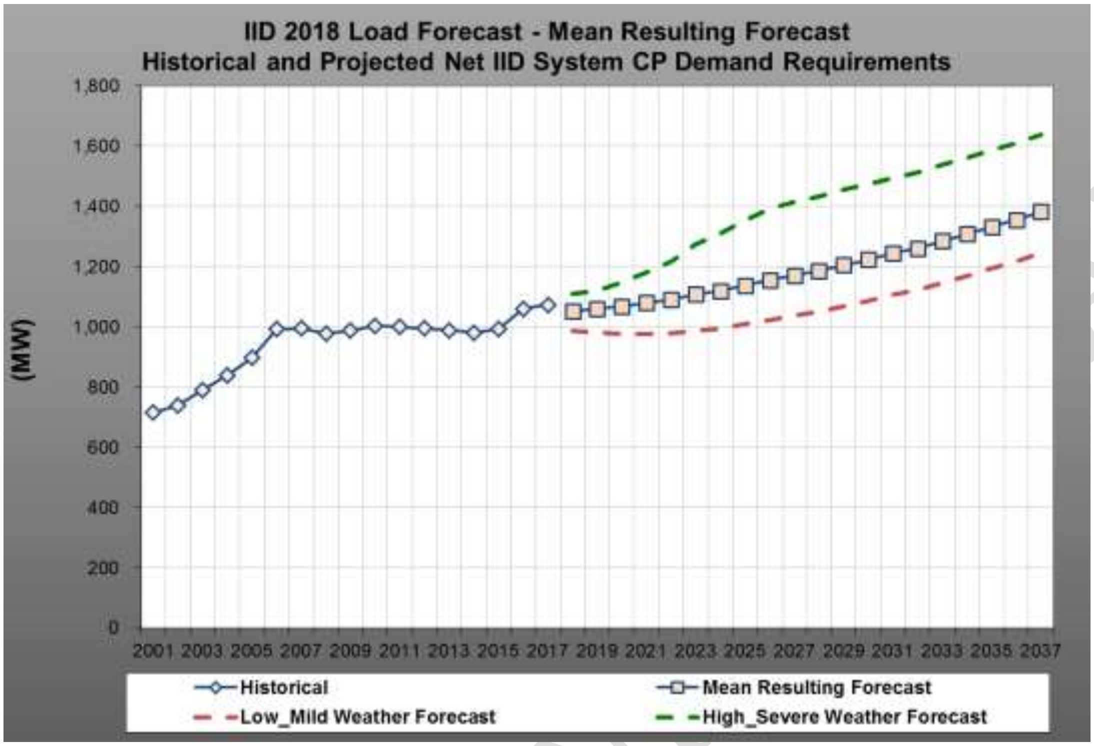


Exhibit 37 shows the projection of coincident peak under the three scenarios described above.

Exhibit 37: Net IID System CP Demand Requirements in 2018 Load Forecast



It is important to note that IID closely observed the California Energy Commission's process in state demand forecasting. In response to the savings beyond "traditional" AAEE estimated in support of SB 350 and additional achievable PV adoption, manifested through the 2019 Title 24 residential building standards update in support of Zero Nero Net Energy goals, IID 2018 load forecast adds cases of other observations to account for the two additional elements: AAEE (additional achievable energy efficiency savings) and AAPV (additional achievable PV adoption).

The table below describes the summarizes the various combinations (90 in all) of load forecasts that were observed:

Exhibit 37: Load Forecast Cases and Observations

KEY ASSUMPTIONS USED FOR VARIOUS CASES

	LOAD FORECAST CASE			OTHER OBSERVATIONS			
Key Variables of each Case	Base/Expected	HIGH CASE (Severe weather, high industrial, High EV, Low EE/PV)	LOW CASE (Mild weather, normal economic industrial growth, high EE/PV/{EV} impacts)	Base/Expected Case II: High New Industrial Growth	High AAEE/AAPV (ZNE) - State based mid case of AAEE/AAPV	Base/Expected Case II (Added New Industrial Growth)	Numerous Combinations
EE input from inte	market potential from programs	Same base case	Mkt Potential + Codes and Standards	Same base case	CEC published data (mid/mid case)	Same base case	Various
PV inputs	110.4 as per Sabrina/Lauren	Same base case	184.45 MW penetration	Same base case	505 state based AAEE/PV number and IID historical data beyond 2030	Same base case	Various
Weather	Normal weather 30 y	5% chance of occurrence (1 in 20 - Severe)	5% chance of occurrence (1 in 20 - Mild)	Normal weather 30 years	Normal weather 30 years	Normal weather 30 years	Various
EV	CEC calculated data (1.5m by 2025)	CEC calculated data (5m by 2030)	CEC calculated data (business as usual)	Same base case	Same base case	Same base case	Various
Cannabis/econom	normal economic indicator growth	Used 180MW added 50-80% LF (outside of model)	normal economic indicator growth	Used 180MW added 50-80% LF (outside of model)	normal economic indicator growth	Used 55MW added 50-80% LF (outside of model)	Various
Zero Net Energy	based on history(EE=mkt potential)	market potential from programs	Same base case	Same base case	Same base case	Same base case	Same base case
line losses	based on history	Same base case	Same base case	Same base case	Same base case	Same base case	Same base case
customer count hi	2004-17	Same base case	Same base case	Same base case	Same base case	Same base case	Same base case
retail sale historic	2000-17	Same base case	Same base case	Same base case	Same base case	Same base case	Same base case
EE historical load p	2006-2016	Same base case	Same base case	Same base case	Same base case	Same base case	Same base case
PV historical patte	2006-16	Same base case	Same base case	Same base case	Same base case	Same base case	Same base case
Economic histirical	2000-15	Same base case	Same base case	Same base case	Same base case	Same base case	Same base case
Coachella Service	In IID through forecas	Same base case	Same base case	Same base case	Same base case	Same base case	Same base case

An absolute critical variable is the Coachella Valley area as a part of IID's service territory. An agreement exists that expires in 2032 and can potentially sway the entire forecast of load and energy by separating the Northern load pocket (Coachella area) from the Southern load pocket (Imperial area). This would essentially split the loads in half or even less. For the purposes of this load forecast and this IRP, IID assumed that the agreement would be renegotiated and the IID service territory would basically stay the same. However, it is vital to note that this change will drastically alter the value and costs of all future decisions as the load forecast is a pillar of the decision making process.

The three following figures added two cases for the additional observations to address Title 20 and Title 24 AAEE and AAPV impact on IID system load (NEL), IID system sales and IID system CP. The orange color dash line assumes that all the new forecasted energy sales after 2020 are replaced by rooftop solar, besides the 110MW rooftop solar installations by IID's current customers (PV expected case),); for energy efficiency, assuming that IID not only can 100% achieve IID board adopted EE target of market potential from programs but also can achieve IID board adopted EE target of codes and standards, which is considered to address AAEE target.so the total sales after 2020 is pretty flat. The grey color dash line is another case to address AAEE and AAPV. The T20 and T24 system impact data were provided by CEC staff on Mar. 2018. The assumption is that Title 24 regulations will induce 80 percent of single family homes to be built with a PV system after 2020. The impacted savings brought by the regulations Title 20 and Title 24 is a lot more aggressive in the AAPV +AAEE mid case plugging the data provided by CEC:

Exhibit 37: All Cases plus CEC AAEE Case: Sales

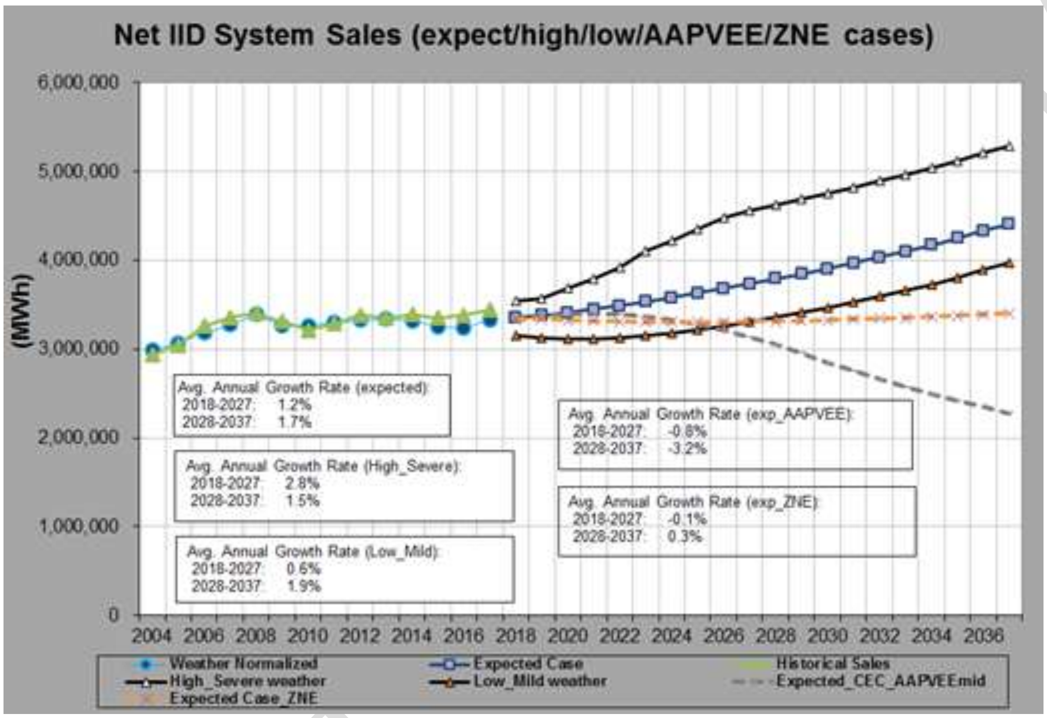


Exhibit 37: All Cases plus CEC AAEE Case: Net Energy For Load

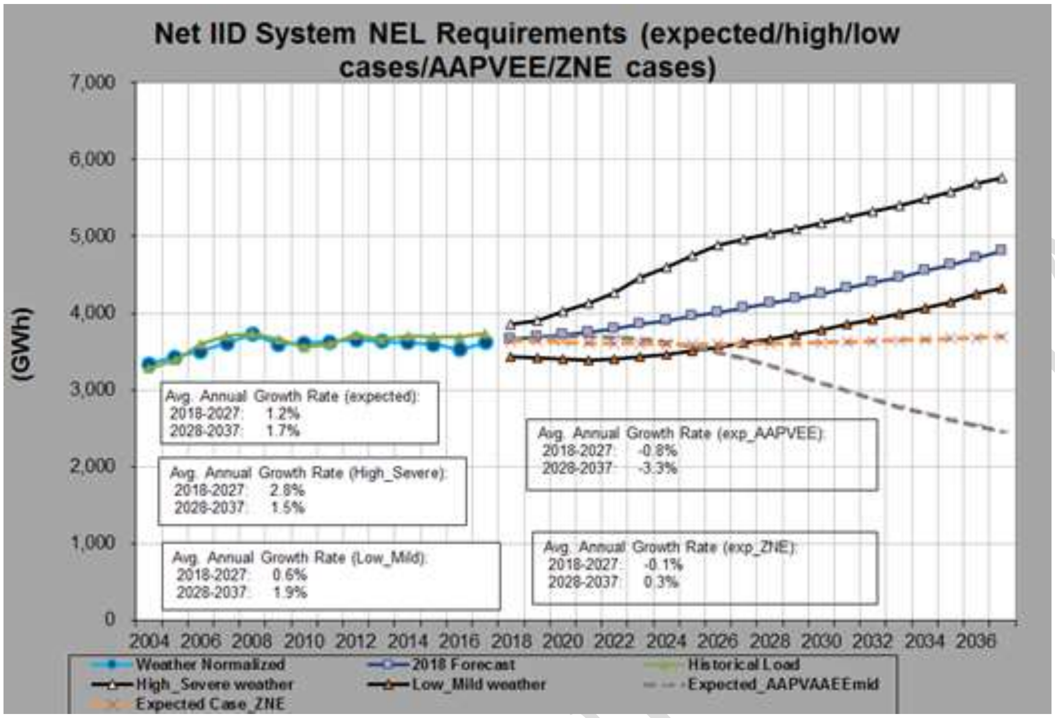
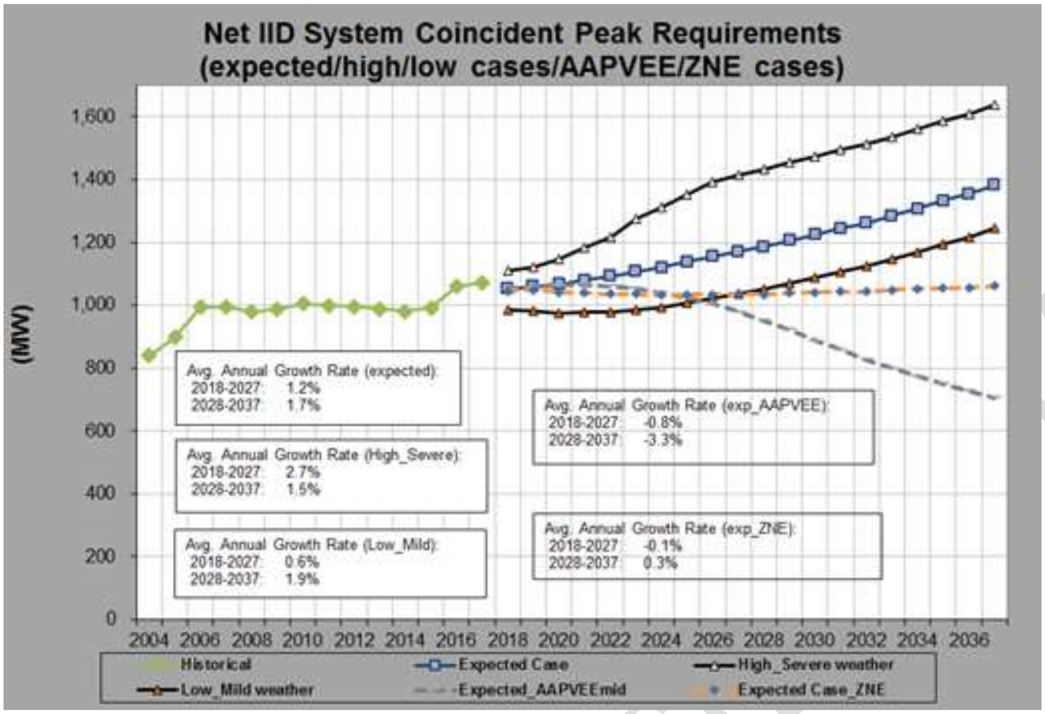


Exhibit 37: All Cases plus CEC AAEE Case: Peak Load



Among all these numerous cases of load forecast, It has been decided that three cases were chosen for the IRP main studies: the expected/base case (the blue purple square line above), the high/severe case (the black pink triangle line above) and the ZNE case (the orange blue square line above)which addresses AAEE and AAPV impact.

In the following sections, detailed descriptions on methodology modifications in the 2018 Load Forecast compared with 2016 Load Forecast and the rationale of the modifications will be given. Sample size and data sources selections will be described in more details. The regression results will be analyzed and discussed in order to lay a solid foundation for the conclusions of the 2018 Load Forecast. Finally, the limitations of the 2018 Load Forecast that have been come across during the study process and future recommendations will be discussed.

Methodology and Models Design

Model Specification

The 2018 Load Forecast uses econometric forecasting methods to forecast retail sales based on the historical monthly sales by customers' billings categories. The load forecast models are based on the ex-post model evaluation approach. That ex-post modeling approach involves using actual data with different choices of independent variables and comparing the forecasted load obtained from the models to the actual load. The models which have the lowest Mean Absolute Percent Error were selected. Model specifications are summarized below:

- The residential sales model includes the following independent variables:

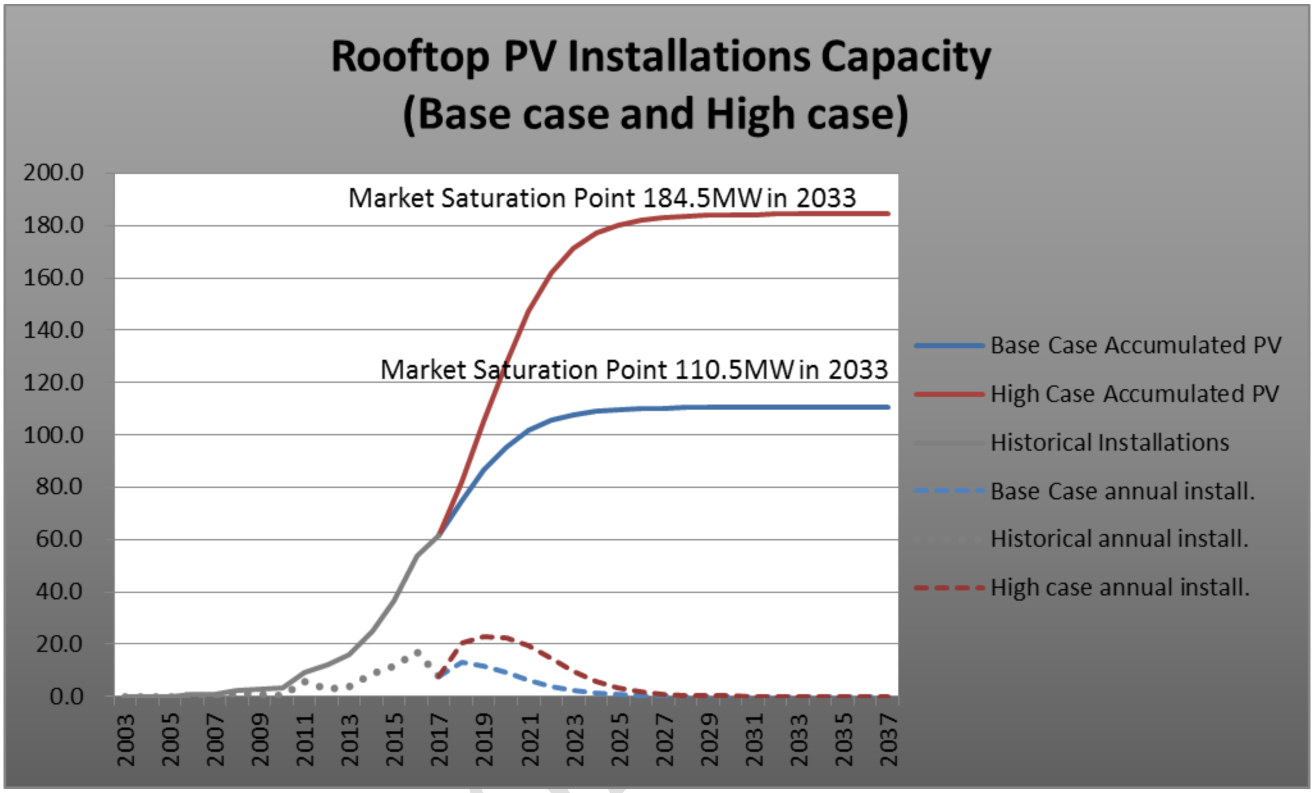
    - Weather terms that capture monthly weather variability,
    - Month dummy variables that capture additional variations not due to weather in every month of the year
    - A limited number of terms intended to address level shifts in the sales data.
    - Blended population in IID service territory
- The residential energy assistance modeling framework combines residential average usage and residential customer counts to get the total residential energy assistance sales in the 2018 Load Forecast. This is due to the relative homogeneity of the residential energy consumption patterns. The residential energy assistance sales model includes these independent variables:
    - Blended low-income population in IID service territory
    - Blended personal income in IID service territory
    - Month dummy variables that capture additional variations not due to weather in every month of the year
    - Weather terms that capture monthly weather variability,
    - A limited number of terms intended to address level shifts in the sales data.
    - Autoregressive terms
- Mobile home/recreational vehicle class sales model is a function of blended personal income, blended GRP, monthly weather variables, seasonal dummies, trend variable, and autoregressive term.
- Agricultural class sales model is a function of blended farm employment, the number of agricultural customer counts, monthly weather variables, and some limited terms to address anomalous level shifts in the usage data and autoregressive term.
- Commercial class sales model is a function of blended Gross Regional Product, blended farm employment, monthly weather variables, month dummy variables that capture additional variations not due to weather in every month of the year and autoregressive term.
- Industrial class sales model is a function of trend variable and autoregressive terms.
- Added industrial load growth scenarios are a function of internal discussion and information from various internal sections of the Energy Department.
- Lighting class sales model is a function of blended total employment in the IID service area, blended GRP in the IID service area, some limited trend terms and autoregressive terms.
- Municipal class sales model is a function of blended personal income in the IID service territory , blended GRP in the IID service area, monthly weather variables and certain limited trend terms intended to capture otherwise unexplained level shifts in the data.
- Electric Vehicle information was provided by the CEC's demand forecast groups. The CEC also provided a calculator to estimate high, low, and expected impact levels by assuming various levels of meeting the targets of EXECUTIVE ORDER B-48-18.

ROOFTOP PHOTO-VOLTAIC IMPACTS

A Bass Diffusion Model approach was adopted to estimate the rooftop PV Impact (which captures all 'behind the meter' installations) to IID system load in terms of annual capacity and energy impacts. However, under Federal and IID's monetary incentives and lower cost of solar panels during 2013-2017, IID customers who participated in IID's PV program surpassed expectations. The Net Energy Metering (NEM) program was designed to benefit IID customers who generate their own electricity (and sometimes electricity for the IID grid) using solar, wind, biogas, fuel cell or a hybrid of these technologies. IID's NEM program capacity cap was 50.2MW, as established and administered by the demand side management group, and reached 5 percent of IID's peak demand. At the end of 2015, the existing PV installations and the registered PV installations in process reached 64.5MW; above the IID NEM capacity cap of 50.2MW. In July 2016, IID made a policy decision to change its Net Metering Program to ensure that everyone pays their fair share for their use of the energy grid, including customers who choose to install rooftop solar systems on their homes. The new Net Billing Program, which was approved by the board July 2016 after extensive discussion, now aligns prices with the actual cost of providing power for all customers. This necessary solution balances the interests of every customer IID. Under the new Net Billing Program, the IID no longer provides the incentive to the customers who install rooftop PV. There is not a program capacity cap.

Since there is not a NEM program capacity cap for rooftop PV installations in IID service territories, the market saturation point in IID service territories was estimated using the National Renewable Energy Laboratory market survey and study on PV market penetration percentage and payback years (NREL, 2014). The results of the survey were used to estimate the market saturation point within the IID service territory according to the estimated payback years of PV installations. The payback years of PV installations are estimated by considering the cost of panels, Federal and IID's incentives, solar panel imports tariff, IID rates, and the output efficiency of panels. It is assumed that the federal incentive and the solar panel imports tariff balanced each other and the PV installation cost keeps no changes in the forecast years. It was assumed that 50 percent of commercial customers and 46 percent of residential customers rent their properties. It was assumed that rental properties will not install rooftop PV. Two cases for rooftop PV impacts to the forecast were analyzed. The expected case assumes that IID will no longer provide incentives for customers who install rooftop PV. The calculated market saturation point for the expected PV case is 110.5 MW total rooftop capacity in the IID service area. The high case assumes that IID provides incentive for the customers who install rooftop PV. The IID rate is increased by 7 percent and therefore changed the economic value for Rooftop solar for customers. The calculated market saturation point for the high PV impacts case is 184.5 MW total rooftop PV installed capacity in IID.

Exhibit 38: PV new and accumulated installations capacity in Expected Case and High Case in 2018 Load Forecast



The blue dashed line is the new PV capacity installed annually in the expected case scenario. The blue solid line is the accumulated PV installations capacity in the expected case scenario. The red dash line is the new PV capacity installed annually in the high case scenario. The red solid line is the accumulated PV installed capacity in the high case scenario. Both the new PV installations capacity and accumulated PV installations capacity are higher in the high case than in expected case. The difference is due to different market saturation points assumptions, namely, 110.5 MW in the expected case and 184.5MW in the high case.

Energy Efficiency Portfolio Impacts

The Energy Efficiency program impact projection is based on EE activities over the historical period 2006-2017. Several discounting factors are used to degrade long-term cumulative EE program impacts:

- End-use degradation factor
- Market saturation factor
- End-of-life impact factor
- Baseline shift impact factor and contingency factor.

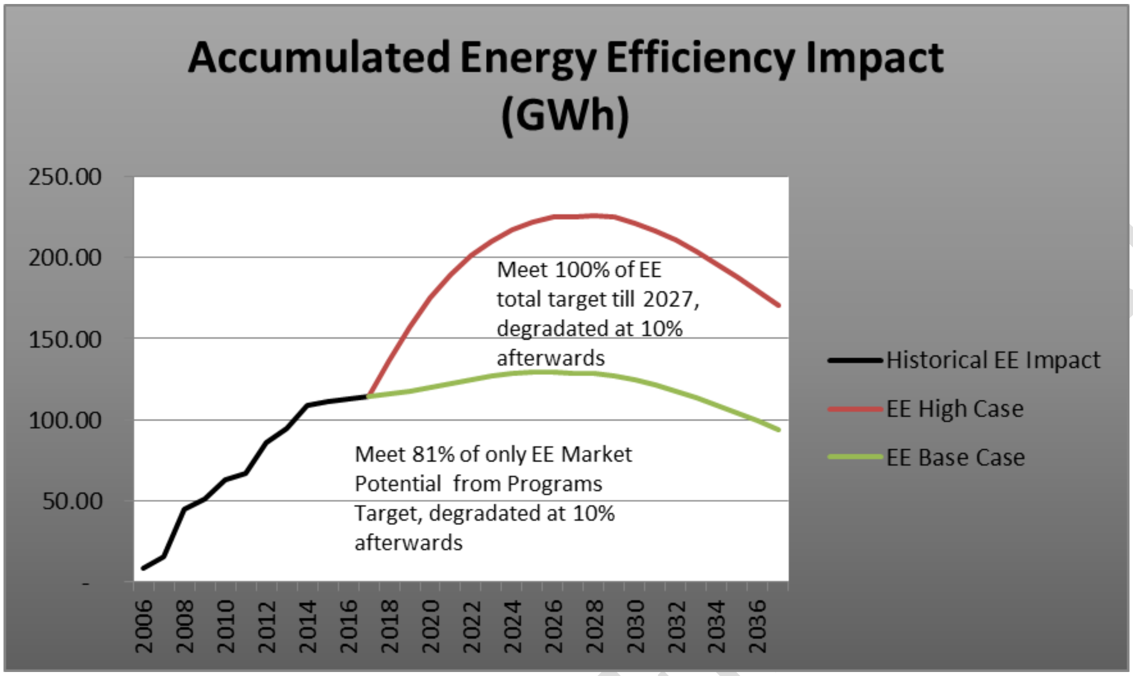
These factors add up to 10 percent degradation rate per year. The annual EE program impact in the forecast years is projected based on IID Board of Directors adopted annual electric energy efficiency program targets for the years 2018-2027 (refer to Exhibit 39). The new adopted Energy Savings Target for 2018-2027 contains the two categories MWh from Market Potential from Programs and MWh from Codes and Standards. The MWh from Market Potential from Programs in the Energy Savings Target is consistent with the old Energy Savings Target. The codes and standards includes the savings from other areas and programs which were not previously included. Therefore, in the expected case, it is assumed that the energy savings under Market Potential from Programs is the EE target most likely to be achieved. It was assumed that 81 percent of the target amount is met in the forecast years, based on IID's historical performance. The market saturation point is reached in 2027; a 10 percent degradation rate is applied to project the annual EE program impact after 2027. Exhibit 40 shows historical EE impact, EE impact in the expected case (green solid line), and EE impact in the high case (solid red line). For the EE high case, energy savings targets are the sum of the Market Potential from Programs categories and the Codes and Standards two categories. In the high case, 100 percent of the target amount is assumed to be met in the years 2018-2027. The market saturation point is reached in 2027, after witch a 10 percent degradation rate is applied to project the annual EE program impact after 2027.

Exhibit 39: IID board adopted Energy Saving Targets for 2018-2027

Year	MWh (Market Potential from Programs)	MWh (Codes and Standards)	New EE Targets (MWh)
2018	15674	17801	33475
2019	16075	17685	33760
2020	17209	16743	33952
2021	18051	14181	32232
2022	18225	12669	30894
2023	17917	10751	28668
2024	17432	10253	27685
2025	16930	9778	26708
2026	15703	9324	25027
2027	15658	6777	22435

The green line in the chart below depicts the annual EE program impact projection based on the assumptions that EE program ends in 2027; only 81 percent of the target amount to be met in the forecast years according to IID's historical performance during the program execution years, no targets needed to be met after 2027; and with a 10 percent degradation rate annually. In the high case, 100 percent of the target amount is assumed to be met in the years 2018-2027. After 2027, no targets needed to be met; and with a 10 percent degradation rate annually.

Exhibit 40: EE Annual Accumulated Degraded Energy Impact in the Expected and High Cases



The California Energy Commission encourages POUs to identify the relationship between the AAEE savings assumed in the IRP Filing and the statewide SB350 energy efficiency doubling targets adopted by the CEC. On Dec. 2018, CEC provided IID CEC's AAEE doubling target for IID. In IID's IRP filing, the AAEE savings target is using IID board adopted Codes and Standards target. The below table is a comparison between CEC's AAEE target and IID's AAEE target and the resulting system peak and energy impact. We can see that the two sets of targets are very consistent especially in the first 5 years in terms of system peak and energy impact.

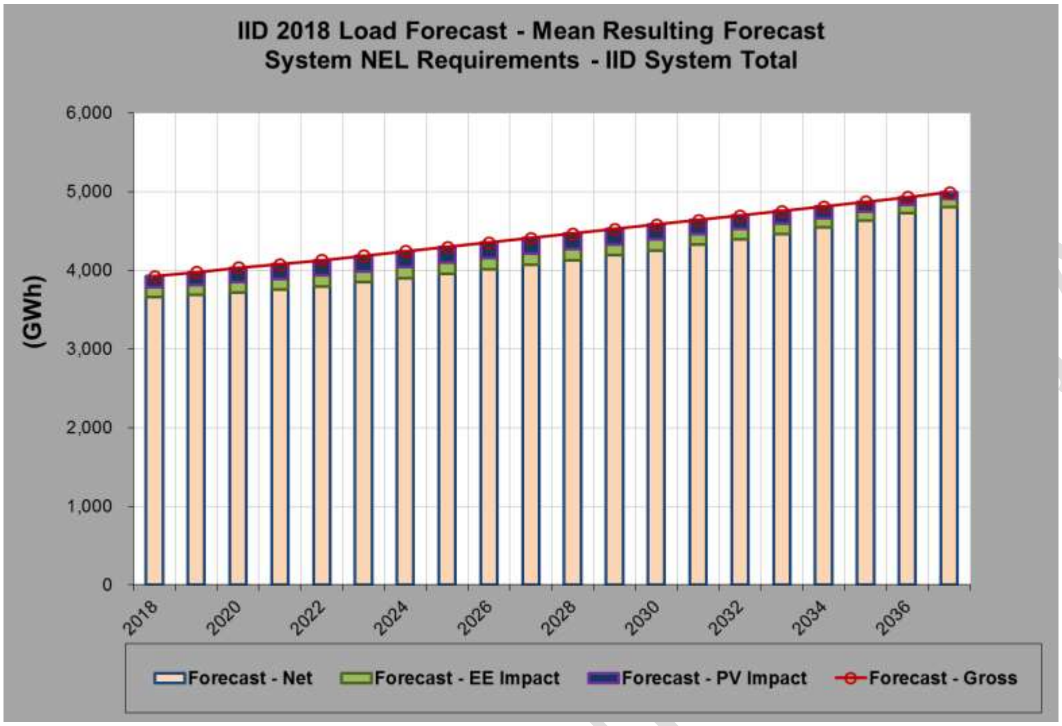
Exhibit 40: Comparison between IID's AAEE targets and CEC's AAEE doubling targets

Year	The AAEE targets in the ZNE low case (MWh)	The AAEE doubling Targets CEC provided (MWh)	EE Peak impact in the current ZNE Low case (MW)	EE Energy impact in the current ZNE Low case (MWh)	EE Peak impact in the CEC AAEE doubling target case (MW)	EE Energy impact in the CEC AAEE doubling target case (MWh)
2018	17,801	16,000	52.77	136,719	52.21	134,918
2019	17,685	16,000	57.96	156,807	56.93	153,501
2020	16,743	17,000	62.69	175,079	61.84	172,360
2021	14,181	18,000	66.41	189,803	66.83	191,175
2022	12,669	18,000	69.34	201,716	71.38	208,283
2023	10,751	18,000	71.29	210,213	75.37	223,371
2024	10,253	17,000	72.74	216,876	78.51	235,466
2025	9,778	17,000	73.75	221,897	81.17	245,850
2026	9,324	16,000	74.13	224,734	82.88	252,968
2027	6,777	14,000	73.67	224,696	83.78	257,329
2028	8,051	12,000	73.66	225,957	84.92	262,277
2029	7,245	10,000	72.91	224,719	84.98	263,661
2030	6,521		71.58	221,470	84.19	262,146

PV + EE Impact to Net and Gross NEL and CP

The exhibit below shows EE and PV impact for the expected case. The columns and lines chart shows the relationship of NEL, PV impact, and EE impact. The pie chart shows the EE and PV impact as a percent of NEL. Exhibit 42 shows the impact for the low/mild case.

Exhibit 41: Gross/Net NEL and EE and PV impact in 2018 Load Forecast (Expected Case)



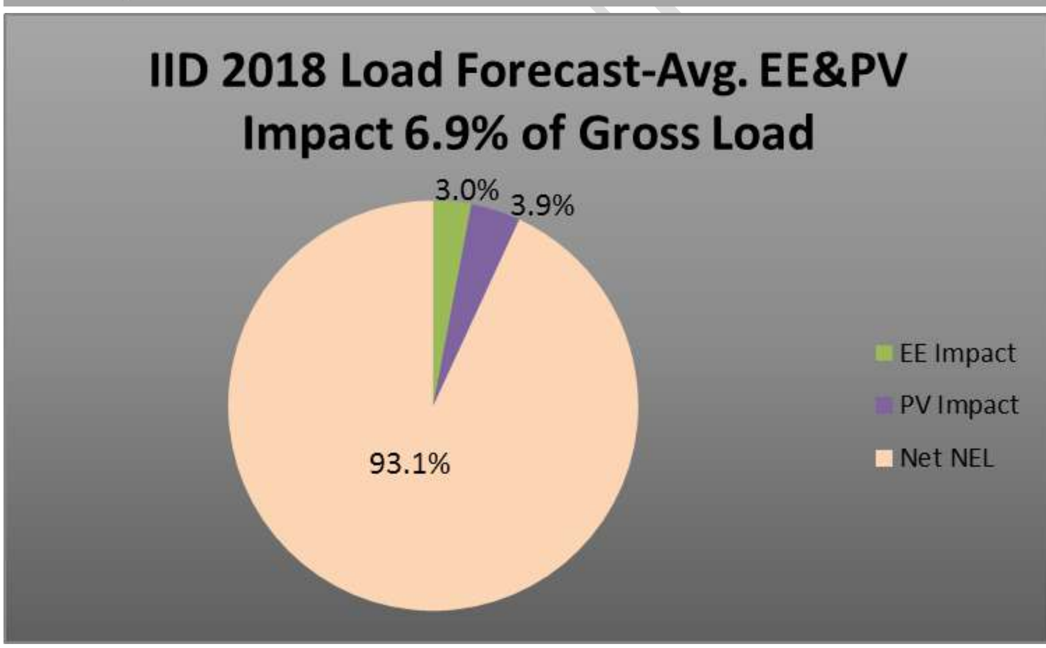
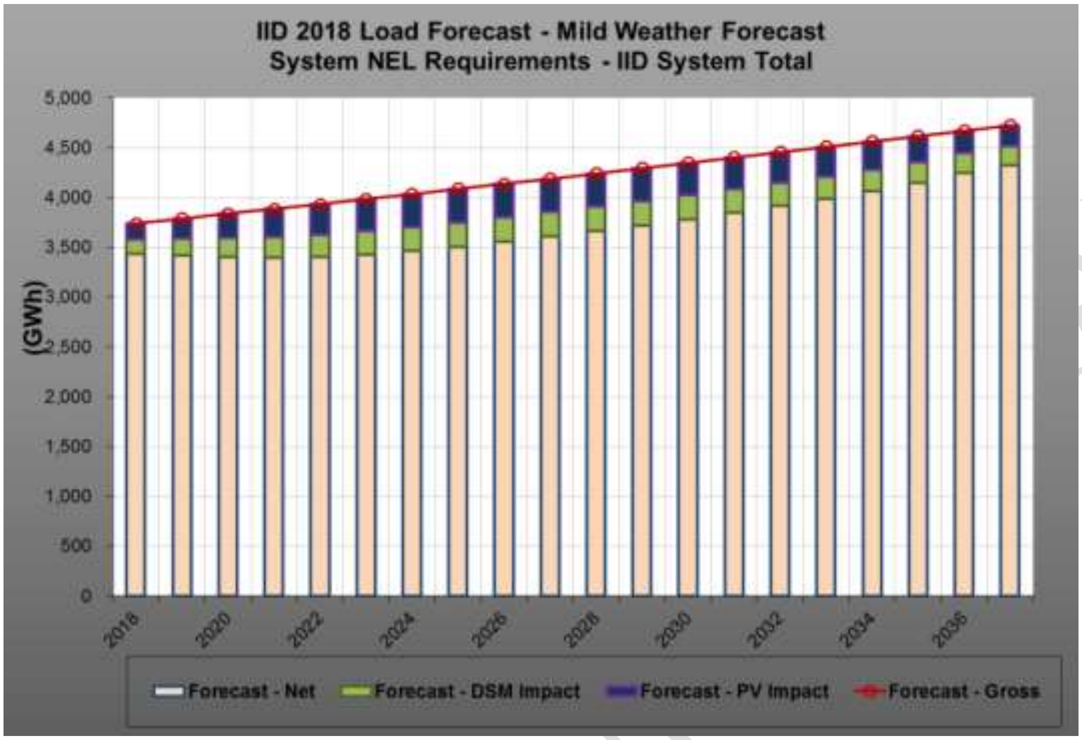
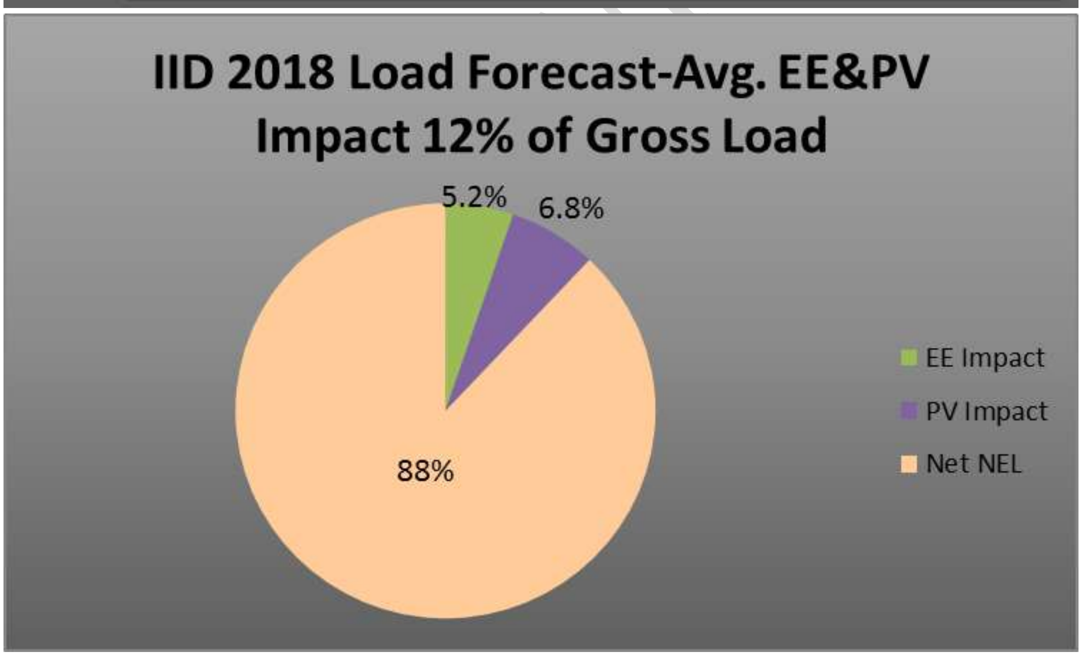


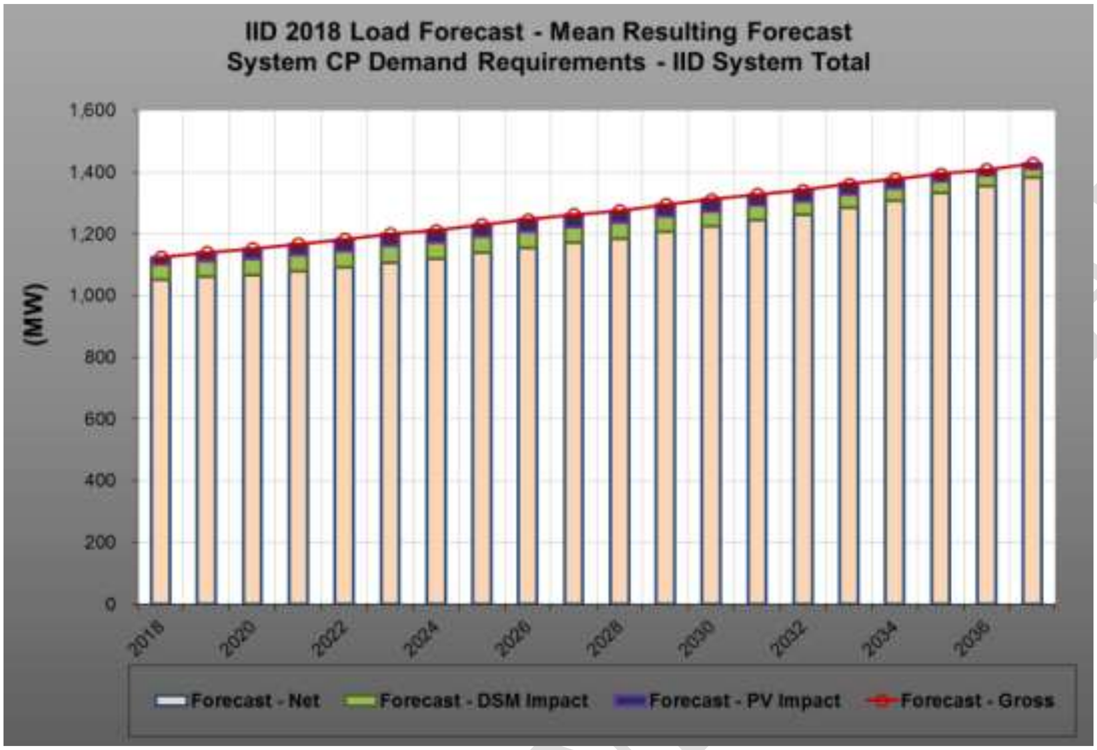
Exhibit 42: Gross/Net NEL and EE and PV impact in 2018 Load Forecast (Low-mild Case)





PV and EE impacts on coincident peak are shown in Exhibit 43. The columns and lines chart shows the relationship of coincident peak, PV impact, and EE impact. The pie chart shows the average EE and PV impact as a percent of coincident peak.

Exhibit 43: Gross/Net CP and EE&PV impact in 2018 Load Forecast (Expected Case)



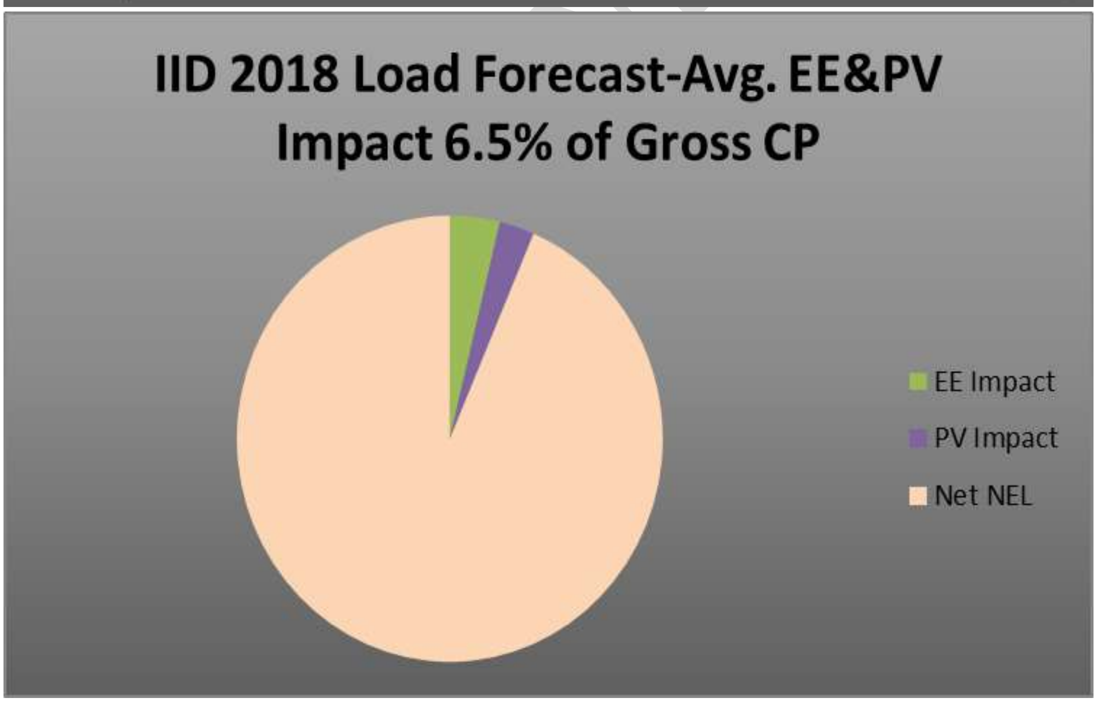
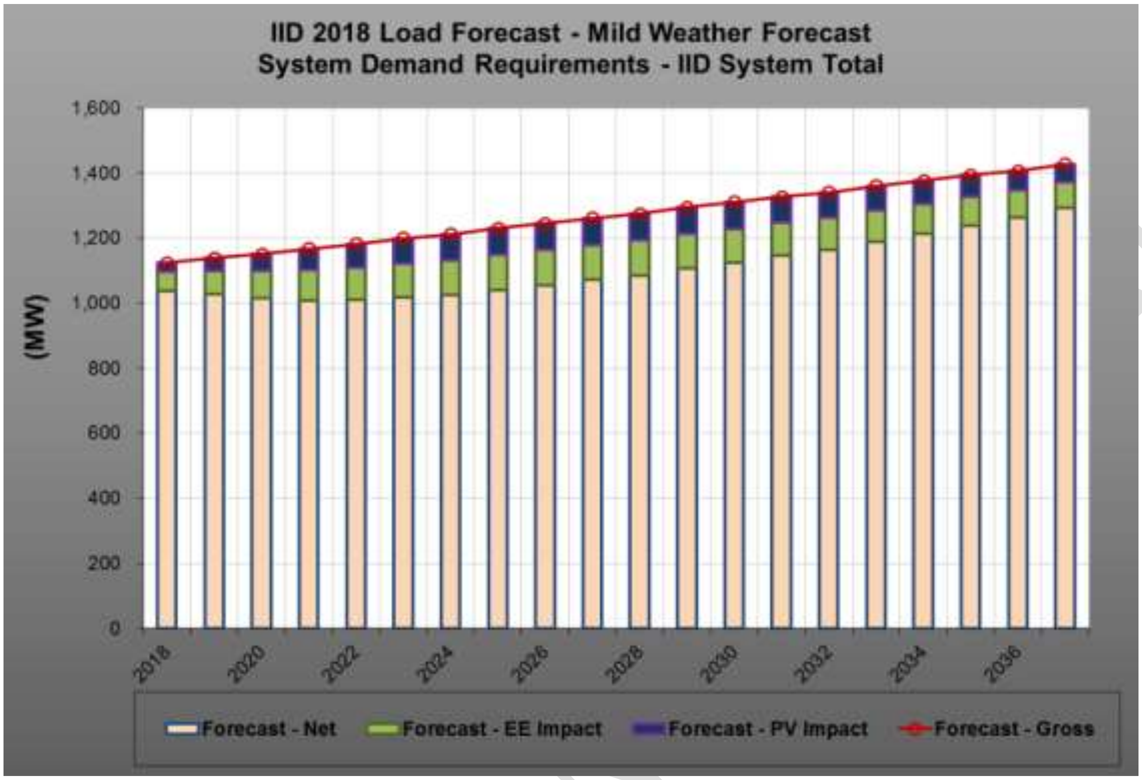
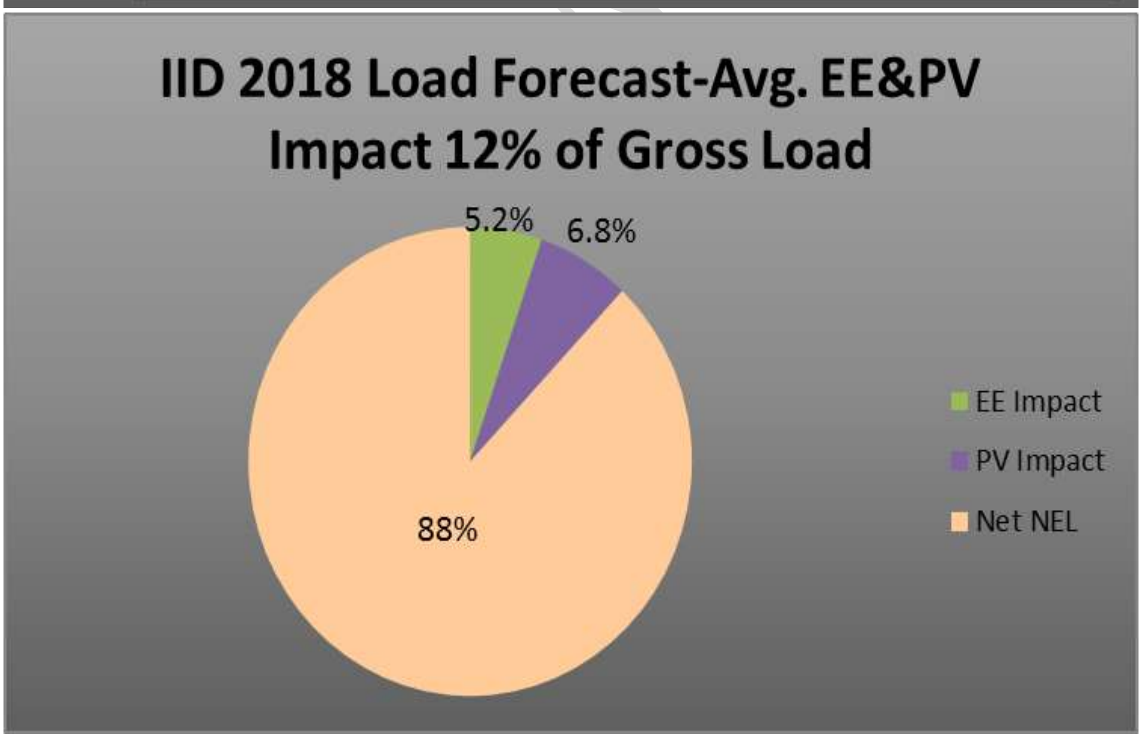


Exhibit 44 shows the average EE and PV impact on coincident peak for the Low/mild case.

Exhibit 44: Gross/Net CP and EE&PV impact in 2018 Load Forecast (Low-mild Case)





Mild, Base and Severe Weather Scenarios and Range Forecast

Ambient temperature has a big effect on IID demand. A weather normalization methodology has been applied to the long-term load forecast. In previous IID long term load forecasts, 65 years of historical weather temperature data was used to calculate normalized weather temperature. Recent years temperatures have been higher than longer term historical averages. Both 30 years normalized weather temperatures and 67 years normalized weather temperature were tested to determine the appropriate data set to use for weather normalization. The test result supports using 30 years normalized weather temperatures data. Thirty years normalized weather temperatures appear to be industry standard used in long term load forecasting in the electric energy industry. Therefore, in this forecast, 30 years normalized weather temperatures are used instead of the 67 years used in previous forecasts at IID. Exhibit 45 shows the calculated normalized weather temperatures normalized weather temperatures used in the 2018 Load Forecast.

Exhibit 45: Base/Mild/Severe Weather HDDs and CDDs in 2018 Load Forecast (30 years)

Computed Normal			Computed Mild			Computed Severe		
Average of all Complete Months over entire data set			1 in 20 cases of all Complete Months over entire data set			1 in 20 cases of all Complete Months over entire data set		
Month	NormalHDD	NormalCDD	Month	MildHDD	MildCDD	Month	SevereHDD	SevereCDD
1	294	1	1	135	1	1	452	1
2	157	12	2	72	11	2	242	14
3	60	97	3	28	83	3	93	110
4	16	210	4	7	181	4	24	240
5	1	434	5	0	373	5	1	495
6	0	669	6	0	576	6	0	763
7	0	864	7	0	743	7	0	985
8	0	865	8	0	743	8	0	986
9	0	668	9	0	575	9	0	762
10	5	334	10	2	287	10	7	380
11	106	47	11	49	40	11	163	54
12	332	1	12	153	1	12	511	1
Annual	970	4,202	Annual	446	3,613	Annual	1,493	4,791

Cooling degree days have the heaviest influence on IID's total energy use. Exhibit 46 shows cooling degree days used in the normal/mild/sever weather scenarios.

Exhibit 46: Weather Scenarios (30 years vs 67 years): Normal/Mild/Severe

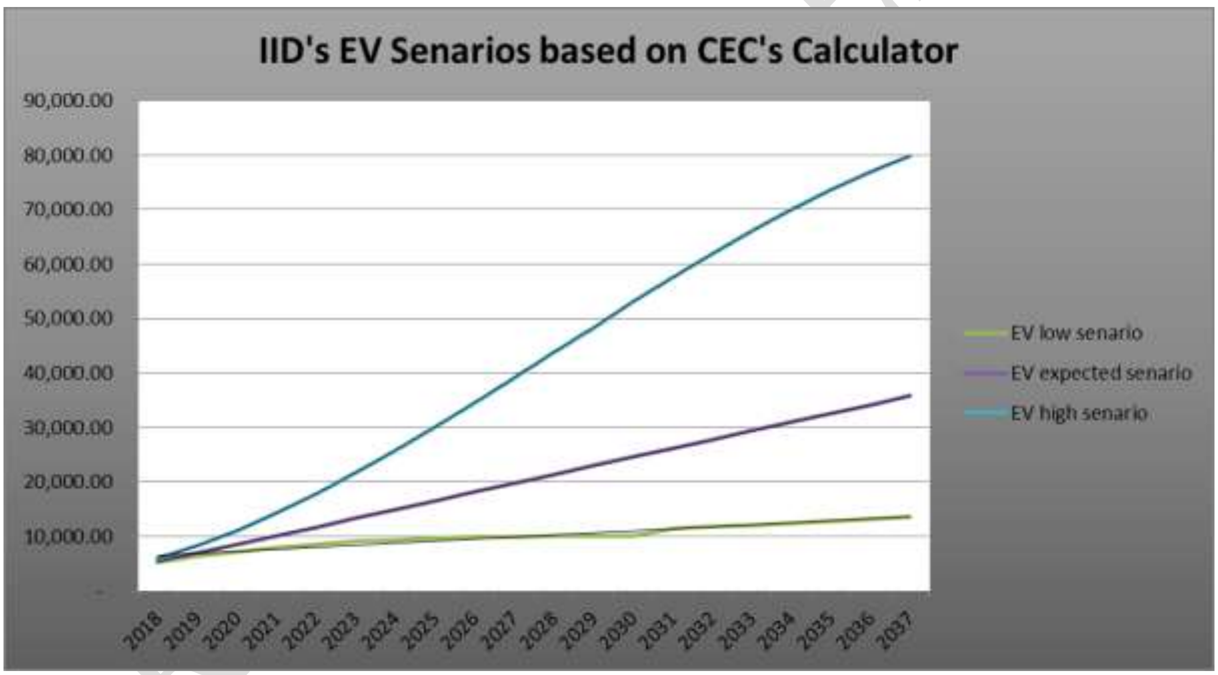
The most recent 30 years show greater volatility in weather and this volatility is reflected in the load forecast by providing a wider range of potential outcomes and also impacts the starting point of the first year of the projection. More specifically, since the recent two years 2016 and 2017 were extremely hot years, the actual heating degree days are higher than the severe weather range, which only happens under small probability of 1 in 20 cases in the past 30 years. Both the Net Energy for Load growth and the Coincident Peak growth are impacted by the extreme hot weather in the years 2016 and 2017. By using normalized weather temperatures in the 20 years of projection, the projected NEL in the first forecast year is lower than the most recent two years actual demand.

ELECTRIC VEHICLES

POUs are required to address transportation electrification in the IRPs adopted and submitted to the Energy Commission pursuant to SB 350. California Energy Commission staff developed a spreadsheet-based tool to assist POUs in estimating and reporting on the energy and emissions impact of light-duty plug-in electric vehicle penetration in their service territories. The calculator tool is noted to have been developed in consultation with the Air Resources Board, California Public Utilities Commission, and California's privately owned utilities. It uses data from various sources to estimate energy and emissions over time associated with displacing gasoline-powered light-duty vehicles with PEV in any year from 2017 to 2030. This tool captures nominal vehicle population decline after its first sale, and travel decline as the vehicle ages. Concurrently, improving gasoline and PHEVs fuel economy and declining carbon intensity gasoline and power generation use in future years are also quantified (CAFE standards), yielding more accurate estimates. Additional data is used to project the annual electricity consumption over time of the representative ("composite") PEVs deployed in each year.

As a POU, IID addressed transportation electrification in the 2018 load forecast by using CEC's calculator (version 3.5-3). POUs are not required to make specific assumptions about the number of PEVs deployed in any year. However, utilities do need to choose the future statewide PEV deployment scenario goal. In IID's electric vehicles energy consumption projections in the 2018 load forecast, three scenarios have been created according to CEC's EV policy drivers' assumptions: EV low scenario, EV expected scenario, and EV high scenario. IID's EV low scenario uses CEC's business as usual scenario (green line in Exhibit 47). Business as usual trajectory keeps the historic Federal, State, and Local incentives and consumer acceptance. IID's EV expected scenario (purple line in Exhibit 47) is based on Executive Order B-16-12, and Senate Bill 1275 (2014), which set a goal of achieving 1 million Zero-emission vehicles by 2023 and achieving 1.5 million ZEVs by 2025, including required infrastructure. IID's EV high scenario (blue line in Exhibit 47) is based on 5 million PEV by 2030. Since the calculator only projects EV penetration through 2030, and the forecast years in IID's 2018 load forecast is through 2037, the projection of EV energy consumption during 2031-2037 is estimated using trend/regression analysis.

Exhibit 47: IID's EV Scenarios based on CEC's calculator

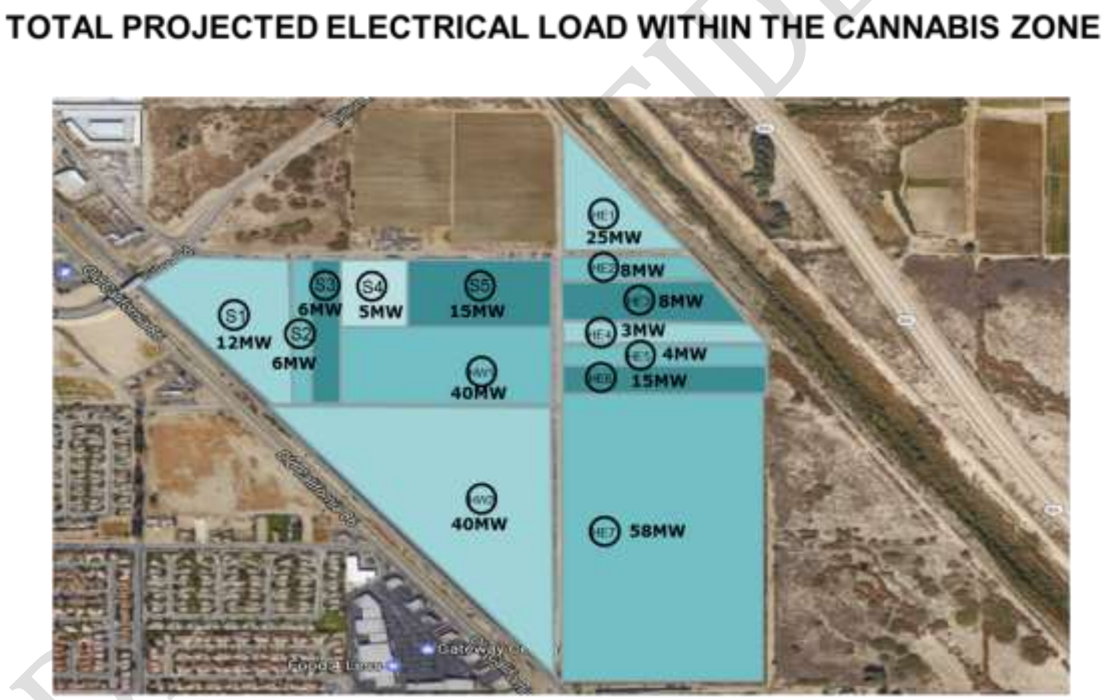


NEW INDUSTRIAL LOAD (CANNABIS)

On November 8, 2016, Californians approved Proposition 64, the California Marijuana Legalization Initiative that made it legal for individuals to grow and consume marijuana for recreational purposes on and after November 9, 2016. Proposition 215 in 1996 had already legalized the medical use of marijuana in California. Proposition 64 made it legal for persons of age 21 and older to grow and consume marijuana for recreational purposes in a private home or a licensed business establishment. Individuals could also share limited amounts of marijuana with each other. The sale of recreational marijuana became legal on January 1, 2018, although consumption of marijuana in public places remains illegal. California is the fifth state to legalize the recreational use of marijuana after Colorado, Washington, Oregon, and Alaska. Legalization creates concerns from an energy point of view because cultivation can be quite energy intensive.

The projection of cannabis energy usage is important in the long term load forecast developed by IID since it is known that production of marijuana is energy intensive especially for indoor production. However, historical data on the production and consumption of marijuana is scarce because of the illegal nature of these activities in the past. Information regarding cannabis load projections was obtained from IID's Distribution Planning & Engineering. According to the information provided, the city of Coachella has designated an undeveloped land east of Grapefruit Blvd and South of Ave. 48 as a cannabis growing area. Electrical Load requested from individual cultivators varies from 3 to 40 MW per parcel. Based on the total projected load for the area (245MW), the need for 2 substations (120MW each) and a 230 KV transmission line have been identified. The city of Coachella is setting up a community facility district (CFD) to provide local city backed bonds for the capital necessary for the infrastructure needs for this new industrial park. Exhibit 48 shows total projected electrical load within the Cannabis Zone.

Exhibit 48: Total Projected Electrical Load Within the Cannabis Zone



Due to the uncertainty associated with cannabis production, three scenarios for cannabis load were developed to access the uncertainties. The three cases are the business as usual case, new industrial load medium case, and new industrial load high case. For the business as usual case for cannabis load, used in the expected case of the 2018 Load Forecast, it is assumed that load growth from increased cannabis production has been included in the economic growth projection, and is not considered as a separated energy demand category. For the new industrial load medium case, the low projection provided from IID's

Distribution Planning & Engineering section was used. For the new industrial load high case, the high projection provided from IID's Distribution Planning & Engineering section was used. Furthermore, there are numerous interconnection applications above and beyond the amounts assumed at the time of the load forecast study. IID continues to monitor this situation to identify which of the applications will come to fruition and impact IID load. Exhibit 49 shows new industrial peak impact and energy impact for both the medium case and the high case. Cannabis load business as usual case peak impact and energy impact are assumed to be included in the other energy sales categories. Since the load factor of New Industrial is not available, it is assumed that New Industrial's load factors are the same as IID's total system load factors.

Exhibit 49: New Industrial Peak Impact and Energy Impact for medium case and high case

	New Industrial Med Case		New Industrial High Case	
Year	Peak Imapct(MW)	Energy Impact (KWh)	Peak Imapct(MW)	Energy Impact (KWh)
2018	-	-		-
2019	-	-		-
2020	10	35,345	20	76,373
2021	15	52,125	41	144,743
2022	20	69,089	62	223,816
2023	25	86,184	104	352,812
2024	30	103,639	127	427,610
2025	35	122,956	150	502,149
2026	45	156,079	173	570,041
2027	50	173,886	177	581,693
2028	55	189,972	180	592,882
2029	55	189,358	180	591,567
2030	55	189,148	180	591,494
2031	55	189,065	180	591,876
2032	55	189,257	180	593,067
2033	55	188,599	180	591,581
2034	55	188,393	180	591,547
2035	55	188,231	180	591,654
2036	55	188,489	180	593,141
2037	55	187,817	180	591,580

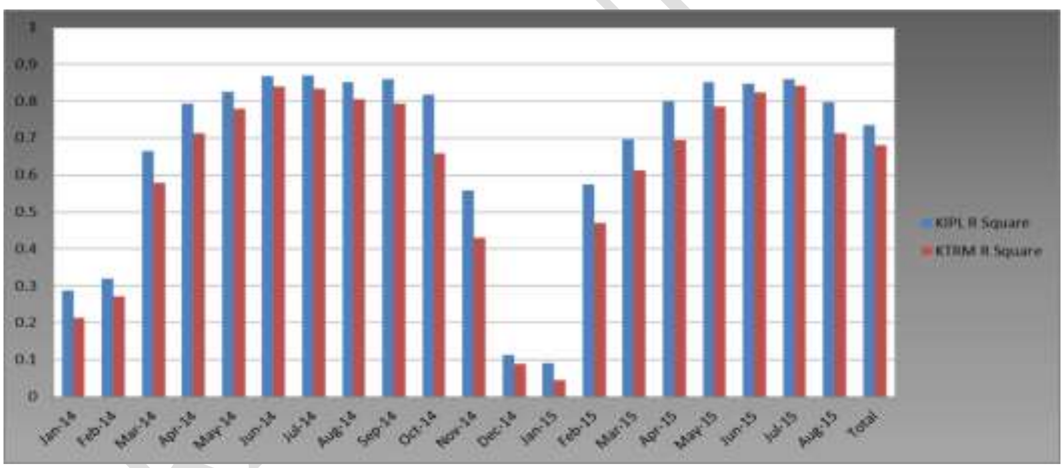
DATA SOURCES AND SAMPLES DESIGN

The data for number of customer accounts, energy sales, NEL, CP, PV installation capacity, and Energy Efficiency programs impact was collected and maintained by IID staff. Energy sales, NEL, and coincident peak data was generally available and analyzed over the January 2001 through December 2017 time period. Energy Efficiency programs impact data was available and analyzed for January 2006 through December 2016 (Note: Energy Efficiency programs impact data on 2017 was not yet available at the time of this analysis, so estimated data was used for 2017. The estimation is based on 2017 IID EE target and 2016 target achieving percentage). PV installation capacity data was available and analyzed for the January 2003 through December 2017 period.

WEATHER DATA

Two weather stations are known to be located within the IID service territories. The weather stations are the Imperial County Airport (KIPL) weather station located in Imperial County and the Desert Resorts Regional Airport (KTRM) weather station located in Riverside County. An hourly load vs hourly weather temperature analysis determined that the weather data from the Imperial County weather station (KIPL) in Imperial County has the best correlation to the IID system load of the two weather stations. Exhibit 50 shows the R squared results of a correlation regression analysis of hourly load vs hourly weather temperature for the time period from January 2014 to August 2015.

Exhibit 50: Correlation between IID system load and KTRM vs KIPL weather data

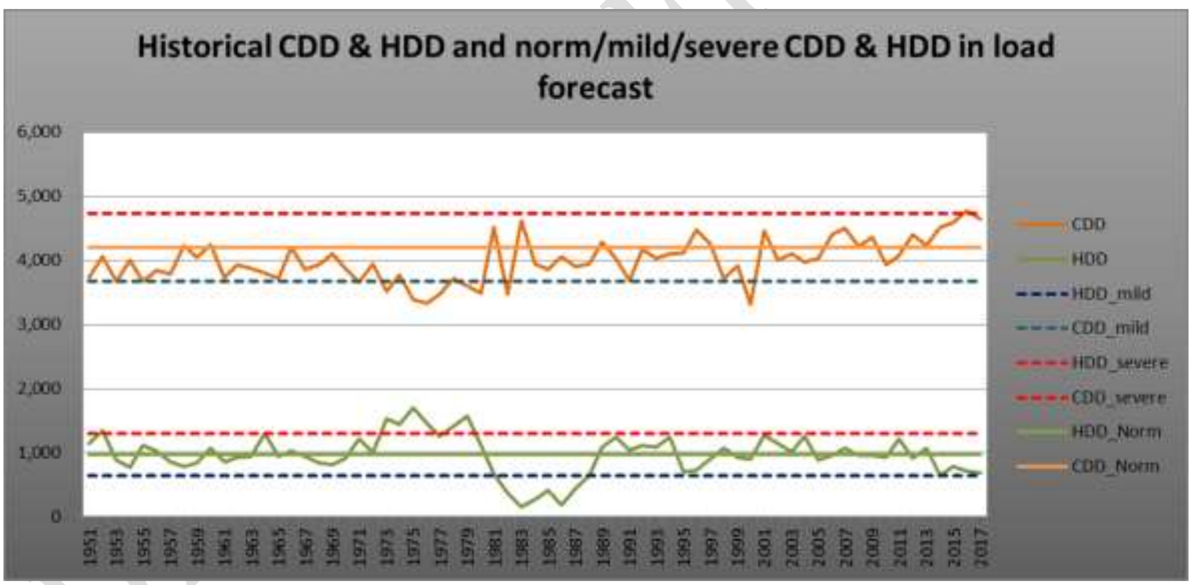


The red columns are the R Squared of the regression models for each month for the weather station KTRM. The blue columns are the R Squared of the regression models by each month for the weather station KIPL. The independent variable is hourly weather temperature for each month. The dependent variable is hourly IID system net load for each month. The KIPL weather station data shows better correlations for all months of the test period, indicating that the weather data from KIPL is more significantly correlated with IID system load. Therefore, data from the KIPL weather station data was used for the load forecast analysis.

Thirty historical years' temperatures, downloaded from the Underground Weather website, were used as the weather data (1988-2017) inputs for the 2018 Load Forecast study. The raw weather data is the daily average temperature, which is converted into Heating Degree Days and Cooling Degree Days. HDD is defined as the number of degrees that a day's average temperature is below 65° Fahrenheit. CDD is defined as the number of degrees that a day's average temperature is above 65° Fahrenheit. One-in-Twenty (Level of significance: 5 percent on each tail) two tails t-Distribution test was used to estimate the normalized HDD and CDD, severe HDD and CDD (right tail), mild HDD and CDD (left tail). Exhibit 51 demonstrates historical actual annual CDD and HDD (1951-2017), the orange solid line is the actual CDD, the red dash line is the calculated severe CDD, the orange solid line is the calculated normal CDD, the blue dash line is the calculated mild CDD. The actual annual CDD line moves up and down around the calculated normal CDDs line, the calculated severe-normal-mild range tries to bracket the actual CDD line. There are a few instances where the actual orange line moves outside of the range.

The green solid line in the exhibit below is the actual HDD, the red dash line is the calculated severe HDD, the green solid line is the calculated normal HDD, and the blue dash line is the calculated mild HDD. The actual annual HDD line moves up and down around the normal HDD line. The calculated severe-normal-mild range brackets most of the movement, but there are some instances when the actual line moves outside of the range. The movement outside the severe to mild HDD range represents the 5 percent probability that the actual weather temperature will be outside the range.

Exhibit 51: Historical CDD & HDD and norm/mild/severe CDD & HDD in 2018 load forecast



Economic Data

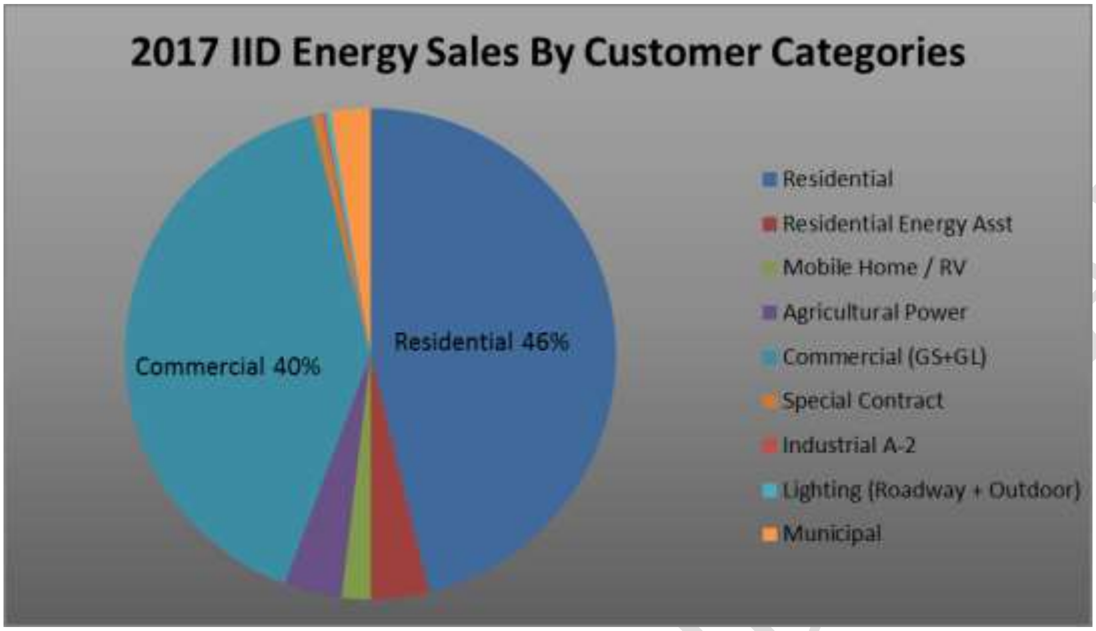
Historical and projected economic and demographic data were provided by Woods & Poole Economics. The most recent data set available at the time of the study is based on historical years' data from 1970 through 2015. The IID service territory covers both Imperial County and part of Riverside County. The two counties have different economic and demographic attributes in terms of county population, households, employment, personal income, and gross domestic product, which are used as independent variables in the 2018 Load Forecast. Therefore, the data for each county was blended using a weighted average derived from 2017 energy sales data. A 59 percent weight was used for Riverside County and a 41 percent weight was used for Imperial County.

Economic data used in the load forecast regression models are population, total employment, farm employment, retail employment, personal income, and gross regional product/GRP. Exhibit 52 shows the annual growth rate of the economic variables used in the 2018 load forecast. The table in Exhibit 52 shows that all variables except farm employment have positive growth over the forecast horizon. The variables that are forecast to have higher average annual growth rates compared to the growth rates used in the 2016 forecast are shown in red, whereas, variables with slower annual growth rate are shown in green. The population, gross regional product, and farm employment variables are used to forecast the residential and commercial customers categories, the two main IID customer categories. These variables generally have a slower growth rate than forecast at the time the 2016 load forecast was developed. The slower growth predictions for these variables contributes to the resulting 2018 load forecast having slower annual growth rate compared to the 2016 load forecast results.

Exhibit 52: Average Annual Growth Rate of Load Forecast Economic Data 2018

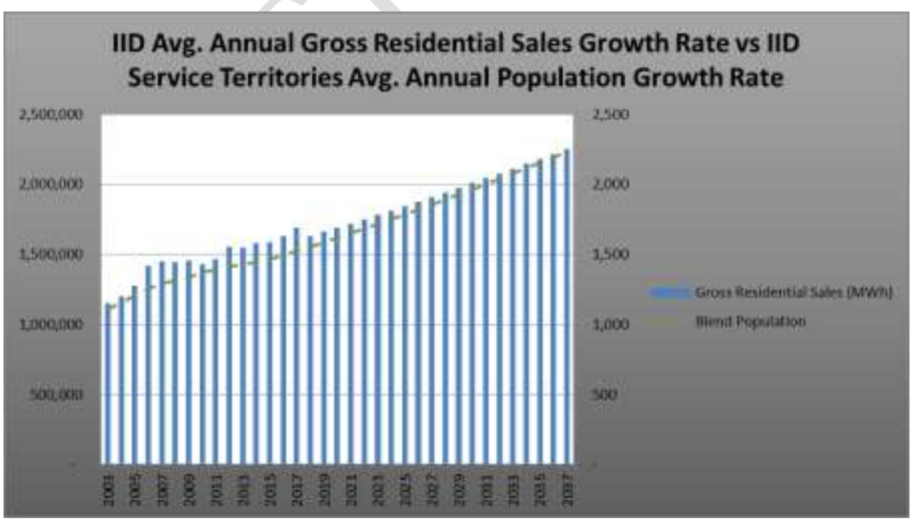
		Population	Total Employment	Farm Employment	Retail Employment	Personal Income	Gross Regional Product
2018 LF Economic Data	2018-2027	1.97%	2.30%	-0.06%	3.14%	3.39%	3.01%
	2028-2037	1.84%	1.96%	-0.33%	2.84%	2.81%	2.67%

Exhibit 53: 2017 IID Energy Sales by Customer Categories



IID residential sales accounted for about 46 percent of IID total energy sales in the year 2017. IID electric energy sales by customer categories for 2017 are shown in Exhibit 53. Commercial sales accounted for about 40 percent of 2017 IID total energy sales. All other customer categories accounted for 14 percent of IID total energy sales in 2017. Residential customers and commercial customers are the main contributors to IID system load growth. The residential demand regression analysis results indicate that residential load growth can be mostly explained by blend population growth. Exhibit 54 shows that blend population growth has a similar trend as residential sales growth though the load forecast period.

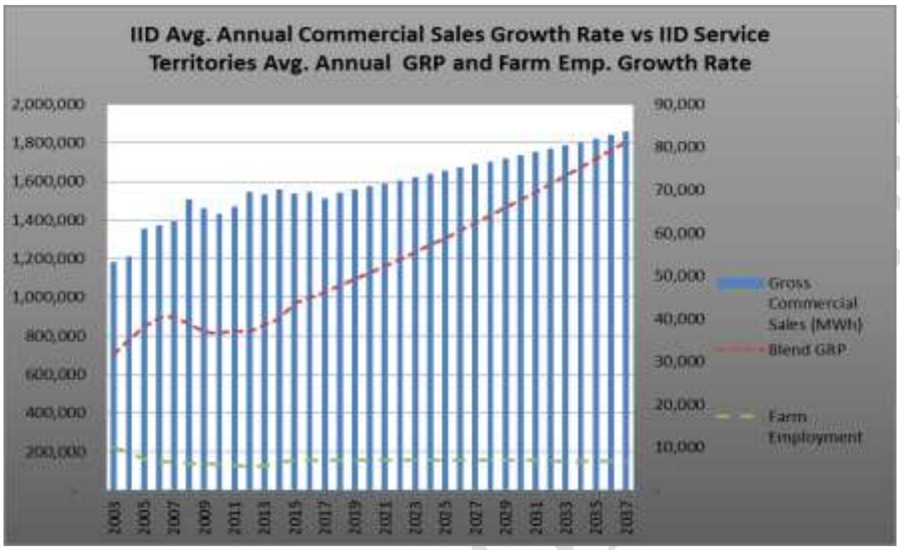
Exhibit 53: IID Gross Residential Sales Growth Rate vs Blend Population Growth Rate



Year	Gross Residential Sales	Blend Population
2003-2017	2.8%	2.3%
2018-2027	1.8%	2.0%
2028-2037	1.6%	1.8%

For the historical period 2003-2017, average population growth rate is 2.3 percent. Average residential sales growth rate is 2.8 percent. During the first ten forecast years (2018-2027), average population growth rate is 2 percent, whereas average residential sales growth rate is 1.8 percent. During the second 10 forecast years (2028-2037), avg. population growth rate is 1.8 percent and average residential sales growth rate is 1.6 percent.

Exhibit 54: IID Commercial Sales Growth Rate vs Blend Gross Regional Product Growth Rate



Year	Gross Comm. Sales	Blend GRP	Blend Farm Emp.
2003-2017	1.8%	2.7%	-2.6%
2018-2027	1.0%	3.0%	-0.1%
2028-2037	1.0%	2.7%	-0.3%

In the commercial sales regression analysis, blend Gross Regional Product and farm employment were identified as significant predictors of commercial sales. The resulting commercial sales forecast is shown in Exhibit 54. During the historical period (2003-2017), average GRP growth rate is 2.7percent, average commercial sales growth rate is 1.8 percent, and average farm employment growth rate is -2.6percent. During the first ten years of the forecast period, average GRP growth rate is 3 percent, average commercial sales growth rate is 1 percent and average farm employment growth rate is -0.1 percent. Subsequently, during the second ten forecast years (2028-2037), average GRP growth rate is 2.7 percent, average commercial sales growth rate is 1.0 percent, and average farm employment growth rate is -0.3 percent. That Blend GRP variable alone has faster annual growth rate than Commercial Sales. By adding the Blend Farm Employment variable that exhibits flat or negative growth rate results in the growth rate of the regression result for Gross Commercial Sales to have a slower growth rate, more indicative of past trends. Hence, the ex-post model evaluation test of adding the variable farm employment has less error.

ANALYSIS OF REGRESSION RESULTS AND CONCLUSIONS

The 2018 Load Forecast methodology uses econometric models to analyze historical data to forecast future outcomes. Using the statistical software, EViews, and Ordinary Lease Squares Regression techniques, each category of customer sales and customer counts was developed as a statistically significant model. Sample Equations for forecasting IID's sales are documented below.

RESIDENTIAL SALES MODEL

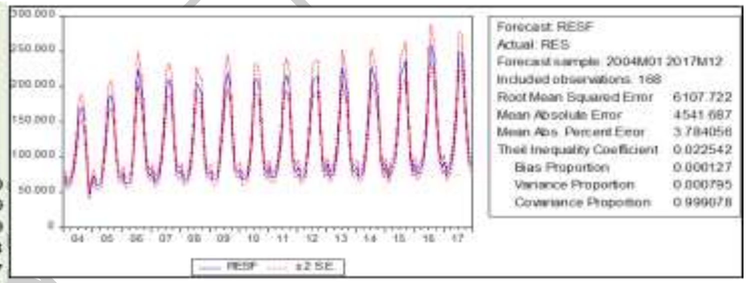
Exhibit 55 shows the residential sales regression analysis results. The model is statistically significant for R-squared, t-statistic, and F-statistic. All the signs of the coefficients meet expectation. Residential sales make up to 45 percent of total IID system sales. The MAPE is 3.78 percent when the historical data (2004-2017) is input into the model.

Exhibit 55: 2018 Load Forecast Residential Sales Regression Model

Dependent Variable: LOG(RES)
Method: Least Squares
Date: 01/16/18 Time: 10:19
Sample: 2004M01 2017M12
Included observations: 168

Variable	Coefficier	Std. Error	t-Statistic	Prob.
C	4.802465	0.405174	11.85285	0
@MONTH=2	-0.17695	0.025275	-7.00085	0
@MONTH=3	-0.17591	0.037982	-4.63141	0
@MONTH=4	-0.17974	0.048286	-3.72237	0.0003
@MONTH=5	-0.10218	0.058105	-1.75852	0.0807
@MONTH=6	-0.06413	0.073368	-0.87408	0.3835
@MONTH=7	-0.01467	0.090447	-0.16221	0.8714
@MONTH=8	-0.13454	0.097591	-1.37865	0.1701
@MONTH=9	-0.07656	0.08891	-0.86112	0.3905
@MONTH=10	-0.11233	0.069744	-1.61058	0.1094
@MONTH=11	-0.17936	0.050111	-3.57917	0.0005
@MONTH=12	-0.14344	0.033536	-4.27725	0
W_CDD_N	0.000615	7.47E-05	8.228975	0
W_HDD_N	0.000287	0.000121	2.365956	0.0193
W_CDD_N(-1)	0.000665	7.50E-05	8.875355	0
W_HDD_N(-1)	-4.66E-06	0.00012	-0.03887	0.969
TREND(11:2004)=0	-0.40339	0.054767	-7.36555	0
LOG(BLENDPOP)	0.894492	0.054076	16.54148	0

R-squared	0.988107	Mean dependent v	11.62321
Adjusted R-square	0.986759	S.D. dependent va	0.440794
S.E. of regression	0.050722	Akaike info criteri	-3.02397
Sum squared resid	0.385901	Schwarz criterion	-2.68926
Log likelihood	272.0139	Hannan-Quinn crit	-2.88813
F-statistic	733.0902	Durbin-Watson sta	2.164059
Prob(F-statistic)	0		



COMMERCIAL SALES MODEL

Commercial customer sales constitute 40 percent of total IID system sales in 2017. Exhibit 56 shows commercial sales model used in the 2018 Load Forecast. In the commercial sales regression analysis, blend Gross Regional Product and farm employment were identified as significant predictors of commercial sales. By adding the Blend Farm Employment variable that exhibits flat or negative growth rate results in the growth rate of the regression result for Gross Commercial Sales to have a slower growth rate, more indicative of past trends. When plugging historical data (2001-2017) into the model, the MAPE is 3.79 percent.

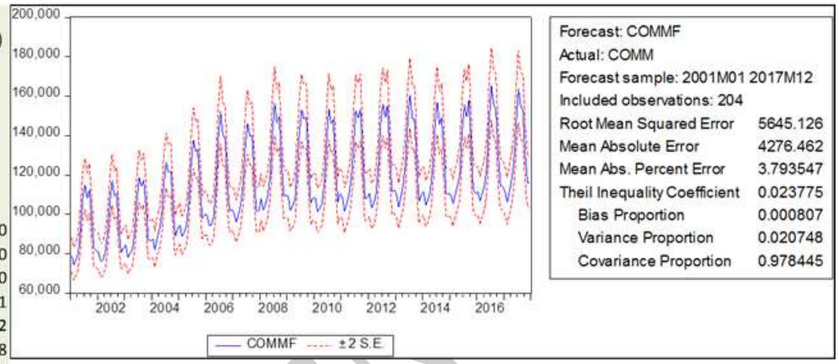
Exhibit 56: 2018 Load Forecast Commercial Sales Regression Model

Dependent Variable: LOG(COMM)
Method: ARMA Conditional Least Squares (Marquardt - EViews legacy)
Date: 01/11/18 Time: 10:28
Sample: 2001M01 2017M12
Included observations: 204
Convergence achieved after 4 iterations

Variable	Coefficier	Std. Error	t-Statistic	Prob.
C	8.587562	0.487247	17.62465	0
LOG(BLENDGRP)	0.331055	0.042283	7.829564	0
LOG(BLENDEMP_FR	-0.24842	0.037117	-6.692878	0
@MONTH=2	-0.07671	0.022894	-3.350778	0.001
@MONTH=3	-0.08062	0.031077	-2.594362	0.0102
@MONTH=4	-0.08747	0.035908	-2.436001	0.0158
@MONTH=5	-0.06057	0.045474	-1.331979	0.1845
@MONTH=6	-0.01104	0.061598	-0.179228	0.858
@MONTH=7	-0.01509	0.078406	-0.192411	0.8476
@MONTH=8	-0.10559	0.085644	-1.232889	0.2192
@MONTH=9	-0.04717	0.077911	-0.605391	0.5457
@MONTH=10	-0.09246	0.059103	-1.564375	0.1194
@MONTH=11	-0.10577	0.035853	-2.950163	0.0036
@MONTH=12	-0.0029	0.018773	-0.154708	0.8772
@YEAR<2008	-0.06464	0.013372	-4.83365	0
W_CDD_N	0.000218	6.84E-05	3.193727	0.0017
W_HDD_N	-0.00011	0.000106	-1.053069	0.2937
W_CDD_N(-1)	0.000205	6.79E-05	3.02503	0.0028
AR(3)	0.158013	0.074186	2.129963	0.0345

R-squared	0.935275	Mean dependent var	11.64799
Adjusted R-squarec	0.928978	S.D. dependent var	0.196504
S.E. of regression	0.052368	Akaike info criterion	-2.97252
Sum squared resid	0.507352	Schwarz criterion	-2.663479
Log likelihood	322.197	Hannan-Quinn criter.	-2.847507
F-statistic	148.5144	Durbin-Watson stat	2.130792
Prob(F-statistic)	0		

Inverted AR Roots	0.54	-.27+.47i	-.27-.47i



All the rest of IID customer categories only make up about 14 percent of IID total system sales. Statistically, all the models used in 2018 Load Forecast are significant. However, models are more reliable the larger the customer population. Small customer categories are subject to more error because of the small sample size.

AGRICULTURAL SALES MODEL

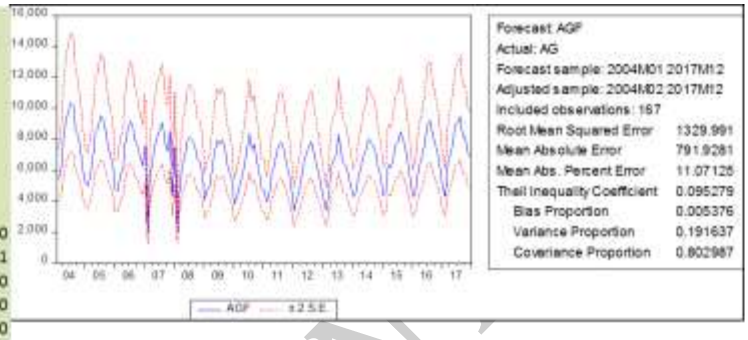
Within the agricultural customer sales model the sign of the coefficient of weather variable HDD is different from other customer sales models. The results indicate that higher CDD result in less energy consumption. The regression equation shows a negative sign for the HDD variable even though all the other statistic values are significant. After consulting IID customer account billing staff, it was learned that the farmers in IID service territory do not work all four seasons of the year due to the extremely hot summer temperatures and the extremely mild winter temperatures in this area. Temperature in the winter are accommodating for the crops grown in the IID service territory. Winter is the busier season for farmers in this area. Therefore, temperatures that contribute to lower HDD, are better temperatures for crops to grow resulting in more energy consumption for agricultural customer sales. Exhibit 57 shows agricultural sales model used in the 2018 Load Forecast.

Exhibit 57: 2018 Load Forecast Agricultural Sales Model

Dependent Variable: LOG(AG)
Method: ARMA Conditional Least Squares (Marquardt - EViews legacy)
Date: 04/25/18 Time: 09:51
Sample (adjusted): 2004M02 2017M12
Included observations: 167 after adjustments
Convergence achieved after 10 iterations

Variable	Coefficier	Std. Error	t-Statistic	Prob.
C	6.944817	0.380154	18.26845	0
LOG(BLENDEMP_FRM)	0.332204	0.206686	1.607287	0.11
C_AGF	0.00139	0.000175	7.927391	0
W_CDD_N	0.000323	5.68E-05	5.680113	0
W_HDD_N(-1)	-0.00123	0.000153	-8.02766	0
TREND(2:2007)=0	-0.21376	0.167597	-1.27547	0.204
TREND(2:2008)=0	-0.04109	0.17973	-0.22859	0.8195
AR(1)	0.497642	0.072527	6.861503	0

R-squared	0.804365	Mean dependent \	8.767545
Adjusted R-squared	0.795752	S.D. dependent va	0.327326
S.E. of regression	0.147931	Akaike info criteri	-0.93742
Sum squared resid	3.4795	Schwarz criterion	-0.78806
Log likelihood	86.27454	Hannan-Quinn crit	-0.8768
F-statistic	93.39087	Durbin-Watson sta	2.321513
Prob(F-statistic)	0		
Inverted AR Roots	0.5		



Overview of Study Results and Conclusions

Net Energy for Load (NEL), energy sales, and coincident peak (CP) for both gross and net values are forecast under base, severe, and mild weather scenarios, expected, high, and AAEE Energy Efficiency program scenarios, expected, high, and AAPV rooftop PV program scenarios, expected and high new industrial scenarios, and low, expected, and high electrical vehicles scenarios in the IID 2018 Load Forecast. Since the combinations of different scenarios can have so many different load forecast results due to volatilities of the market, uncertainties of various policies, and variations of people's decisions and behaviors. Three load forecast scenarios, employing a subset of all the possible combinations above, were defined to represent the range of expected differences in forecast resulting from the many possible combinations. The load forecast cases (and combinations of scenarios) used in the IRP analysis are expected case (base weather, expected EE and PV, expected EV), low case (mild weather, high EE and PV, low EV) and high case (severe weather, low EE and PV, high new industrial, high EV).

The following is a brief description of each of the various types of forecasts:

- Energy Sales are representative of the energy sold to all IID customers. It is the sum of the actual energy consumption for all IID customers in the monthly billing accounts.
- Net Energy for Load (NEL) is representative of the energy consumption including losses and IID consumption. The losses include not only the losses which are experienced over lengths of transmission and distribution lines, but also include the energy consumed in the stations services

and the difference between the sales billing cycle and the meter calendar cycle. NEL is the monthly data from the meters which are calculated based on the calendar months while energy sales are the monthly data from the billing data which are calculated based on finance's billing cycles. Normally, billing cycles lag the calendar months. The lag can result in calculated losses being negative in some months. For example, the meter data could be from the calendar month September, whereas the billing data for September may be for the energy consumption starting from some day in August through some day in September. Since the weather temperature is higher in August than in September, the energy sales billing data could be higher than the meter data on September. Hence the calculated losses could be negative for that month.

$$NEL = Energy\ Sales + Losses$$

- Coincident Peak (CP) is representative of the energy demand among all categories of customers that coincides with the highest total demand on the system for one hour.
- Gross results are representative of the load levels for energy demand that is grossed up assuming that the estimated impacts of EE and PV programs were zero.
- Net results are representative of the load levels for energy demand that is net of the estimated load impacts regarding EE and PV programs. It is the energy demand that needs to be met by IID system central resources rather than distributed generating resources such as rooftop PV. The following equations are the basic premise of the gross forecast calculations:

$$Gross\ NEL - Net\ NEL = (DSM + PV) \times \frac{1}{(1 - Loss\ Rate)}$$

$$Gross\ CP - Net\ CP = (DSM + PV) \times \frac{1}{(1 - Loss\ Rate)}$$

Note: There is a loss rate included in the Gross and Net difference calculation. This denotes that losses would be associated with supply side resources (e.g., a central generating station), while DSM or distributed PV would imply a reduction in losses because those resources would be located at the point of usage and therefore avoid the losses which would otherwise be experienced over lengths of transmission and distribution lines.

Exhibit 58 shows the resulting gross NEL for the historical and forecast periods for the expected case.

Exhibit 58: Net NEL in 2018 Load Forecast for the Expected Case

IID 2018 Load Forecast		
Year	Gross NEL(G	Growth Rate
2003	3173	
2004	3280	3.37%
2005	3395	3.51%
2006	3604	6.16%
2007	3703	2.75%
2008	3736	0.89%
2009	3662	-1.98%
2010	3555	-2.92%
2011	3599	1.24%
2012	3719	3.33%
2013	3662	-1.53%
2014	3699	1.01%
2015	3687	-0.32%
2016	3695	0.22%
2017	3738	1.16%
2018	3658	-2.14%
2019	3687	0.79%
2020	3722	0.95%
2021	3754	0.86%
2022	3798	1.17%
2023	3850	1.37%
2024	3902	1.35%
2025	3957	1.41%
2026	4014	1.44%
2027	4072	1.44%
2028	4133	1.50%
2029	4194	1.48%
2030	4256	1.48%
2031	4328	1.69%
2032	4396	1.57%
2033	4467	1.62%
2034	4546	1.77%
2035	4631	1.87%
2036	4726	2.05%
2037	4805	1.67%

Exhibit 59 shows the net coincident peak for the expected case for the 2018 forecast.

Exhibit 59: Coincident Peak in 2018 Expected Case Load Forecast

IID 2018 Load Forecast		
Year	Gross Peak(I	Growth Rate
2003	792	
2004	840	6.06%
2005	898	6.90%
2006	993	10.61%
2007	996	0.23%
2008	979	-1.66%
2009	988	0.92%
2010	1004	1.61%
2011	1000	-0.37%
2012	995	-0.55%
2013	988	-0.65%
2014	982	-0.68%
2015	992	1.07%
2016	1060	6.84%
2017	1073	1.24%
2018	1052	-1.95%
2019	1061	0.80%
2020	1068	0.67%
2021	1080	1.15%
2022	1093	1.16%
2023	1108	1.37%
2024	1120	1.08%
2025	1138	1.67%
2026	1155	1.43%
2027	1171	1.46%
2028	1186	1.22%
2029	1206	1.75%
2030	1224	1.49%
2031	1245	1.68%
2032	1261	1.30%
2033	1285	1.89%
2034	1308	1.77%
2035	1332	1.87%
2036	1356	1.77%
2037	1382	1.95%

Energy sales have the same trend as NEL because NEL forecast is derived from energy sales forecast. The long term load forecast is a range forecast instead of an exact point forecast due to the fact that long-term weather temperatures are quite variable and unknown. Three different weather scenarios (base, severe, mild) create a ranged forecast. Although, the expected forecast may be used as a single point of reference for various activities, it is recommended that the ranged forecast is considered in all long term planning activities to capture the unpredictable impact of weather changes on load. Consider the forecast as a range helps long term planning activities capture the varying possibilities of needs because of uncontrollable risks and the relationship of demand and supply. The weather impact (mild/expected/severe) on the gross result of the load forecast expected case is shown in Exhibit 60. The net peak and net energy results are shown in Exhibit 61.

Exhibit 60: 2018 Load Forecast Expected Case Gross CP and NEL in Base/Severe/Mild Weather Cases

	LF Expected Case (mild weather)		LF Expected Case (expected weather)		LF Expected Case (severe weather)	
Year	Gross CP(MW)	Gross NEL (MWh)	Gross CP(MW)	Gross NEL (MWh)	Gross CP(MW)	Gross NEL (MWh)
2018	1,070.80	3,740,593	1,124.60	3,928,541	1,183.30	4,133,568
2019	1,085.20	3,791,058	1,139.70	3,981,267	1,199.30	4,189,437
2020	1,096.90	3,842,420	1,152.00	4,035,339	1,212.30	4,246,598
2021	1,112.50	3,886,383	1,168.20	4,081,084	1,229.30	4,294,454
2022	1,126.70	3,935,798	1,183.20	4,133,184	1,245.10	4,349,672
2023	1,142.30	3,990,609	1,199.70	4,190,873	1,262.60	4,410,674
2024	1,154.00	4,042,513	1,212.00	4,245,549	1,275.70	4,468,523
2025	1,172.20	4,094,756	1,231.00	4,300,459	1,295.80	4,526,503
2026	1,187.10	4,146,929	1,246.70	4,355,303	1,312.30	4,584,406
2027	1,202.50	4,200,600	1,262.90	4,411,860	1,329.50	4,644,229
2028	1,214.70	4,254,971	1,275.80	4,469,148	1,343.10	4,704,805
2029	1,233.60	4,309,259	1,295.70	4,526,350	1,364.10	4,765,285
2030	1,249.20	4,363,703	1,312.10	4,583,747	1,381.50	4,825,976
2031	1,264.70	4,418,196	1,328.60	4,641,267	1,398.90	4,886,819
2032	1,276.90	4,472,874	1,341.50	4,699,019	1,412.50	4,947,928
2033	1,296.10	4,527,784	1,361.70	4,757,006	1,434.00	5,009,279
2034	1,311.90	4,582,942	1,378.40	4,815,224	1,451.60	5,070,861
2035	1,327.80	4,638,443	1,395.20	4,873,768	1,469.30	5,132,781
2036	1,340.20	4,694,599	1,408.30	4,933,023	1,483.20	5,195,460
2037	1,360.00	4,750,767	1,429.10	4,992,362	1,505.20	5,258,250

Exhibit 61: 2018 Load Forecast Expected Case Net CP and NEL in Base/Severe/Mild Weather Cases

	LF Expected Case (mild weather)		LF Expected Case (expected weather)		LF Expected Case (severe weather)	
Year	Net CP(MW)	Net NEL (MWh)	Net CP(MW)	Net NEL (MWh)	Net CP(MW)	Net NEL (MWh)
2018	998.10	3,469,748	1,052.20	3,657,696	1,111.20	3,862,723
2019	1,005.80	3,496,590	1,060.60	3,686,799	1,120.40	3,894,969
2020	1,012.40	3,528,897	1,067.70	3,721,817	1,128.30	3,933,075
2021	1,024.00	3,559,692	1,080.00	3,754,393	1,141.40	3,967,762
2022	1,035.70	3,600,407	1,092.50	3,797,793	1,154.80	4,014,281
2023	1,049.90	3,649,889	1,107.50	3,850,153	1,170.80	4,069,954
2024	1,061.20	3,699,218	1,119.50	3,902,255	1,183.40	4,125,229
2025	1,079.00	3,750,856	1,138.20	3,956,560	1,203.20	4,182,603
2026	1,094.60	3,805,127	1,154.50	4,013,501	1,220.40	4,242,604
2027	1,110.50	3,860,354	1,171.30	4,071,614	1,238.10	4,303,983
2028	1,124.10	3,918,510	1,185.60	4,132,687	1,253.20	4,368,345
2029	1,144.00	3,976,799	1,206.40	4,193,891	1,275.20	4,432,826
2030	1,161.10	4,036,257	1,224.40	4,256,301	1,294.10	4,498,530
2031	1,180.90	4,104,991	1,245.00	4,328,062	1,315.70	4,573,614
2032	1,196.30	4,170,005	1,261.20	4,396,151	1,332.60	4,645,059
2033	1,219.00	4,237,665	1,285.00	4,466,887	1,357.50	4,719,160
2034	1,240.90	4,313,732	1,307.70	4,546,014	1,381.30	4,801,651
2035	1,264.40	4,395,529	1,332.10	4,630,854	1,406.60	4,889,867
2036	1,287.30	4,487,196	1,355.70	4,725,621	1,431.00	4,988,057
2037	1,312.60	4,562,907	1,382.10	4,804,501	1,458.60	5,070,390

In addition to weather impacts, rooftop PV installations, energy efficiency programs, electric vehicles, and new industrial load can impact future demand. The impact of these variables is influenced by government policies, market mechanisms, and people's decision making processes and behaviors. The 2018 IID Load Forecast results have different scenarios for each of these variables to capture the range these variable might contribute to resulting future demand. The tables presented in the Exhibits below list the energy impact and peak impact of each of these variables under different scenarios. Exhibit 62 shows PV peak impact and energy impact under both PV expected case and PV high case; Exhibit 63 shows EE peak impact and energy impact under both EE expected case and EE high case; Exhibit 64 shows EV peak impact and energy impact under EV expected case, EV low case and EV high case.

Exhibit 62: PV Peak Impact and Energy Impact (expected case, high case)

	PV Expected Case		PV High Case	
Year	Peak Imapct(MW)	Energy Impact (KWh)	Peak Imapct(MW)	Energy Impact (KWh)
2018	28.09	129,918,713	30.86	143,045,573
2019	32.46	149,631,547	39.43	182,511,669
2020	35.83	164,472,635	47.90	221,218,779
2021	38.13	174,125,513	55.21	254,154,237
2022	39.56	179,565,718	60.69	278,134,603
2023	40.39	182,142,781	64.28	293,058,464
2024	40.85	182,978,466	66.42	300,977,417
2025	41.07	182,640,100	67.57	304,190,587
2026	40.97	180,983,658	67.98	304,019,052
2027	40.99	179,762,195	68.28	303,166,227
2028	40.51	176,457,792	67.94	299,645,854
2029	40.28	174,246,123	67.82	297,001,645
2030	40.08	172,127,493	67.67	294,221,336
2031	38.01	162,428,573	65.64	283,775,237
2032	36.94	156,864,829	64.63	277,553,286
2033	35.44	149,567,597	63.17	269,570,850
2034	32.19	135,202,245	59.91	254,305,476
2035	27.76	116,170,899	55.49	234,380,856
2036	21.27	88,910,729	49.00	206,234,111
2037	18.31	76,180,726	46.04	192,624,183

Exhibit 63: EE Peak Impact and Energy Impact (expected case, high case)

	EE Expected Case		EE High Case	
Year	Peak Imapct(MW)	Energy Impact (KWh)	Peak Imapct(MW)	Energy Impact (KWh)
2018	46.34	115,959,592	52.77	136,719,179
2019	45.75	117,404,355	57.96	156,807,260
2020	45.50	119,624,590	62.69	175,078,532
2021	45.49	122,305,870	66.41	189,802,682
2022	45.52	124,860,176	69.34	201,716,411
2023	45.47	126,909,187	71.29	210,212,771
2024	45.31	128,359,848	72.74	216,876,494
2025	45.04	129,258,198	73.75	221,896,845
2026	44.48	129,071,318	74.13	224,734,161
2027	43.97	128,866,621	73.67	224,695,744
2028	43.52	128,700,644	73.66	225,957,171
2029	42.71	127,279,197	72.91	224,719,352
2030	41.63	124,855,036	71.58	221,469,525
2031	40.34	121,642,911	69.78	216,622,476
2032	38.90	117,824,665	67.63	210,530,137
2033	37.34	113,553,639	65.21	203,490,041
2034	35.70	108,958,568	62.60	195,752,662
2035	34.01	104,146,974	59.86	187,527,860
2036	32.31	99,208,118	57.04	178,990,492
2037	30.61	94,215,560	54.18	170,285,319

Exhibit 64: EV Peak Impact and Energy Impact (expected case, high case)

	EV low case		EV expected case		EV high case	
Year	Peak Imapct(MW)	Energy Impact (KWh)	Peak Imapct(MW)	Energy Impact (KWh)	Peak Imapct(M	Energy Impact (KWh)
2018	1.68	5,328	1.75	5,556	1.89	6,012
2019	1.99	6,324	2.20	6,996	2.62	8,316
2020	2.26	7,200	2.68	8,520	3.49	11,100
2021	2.50	7,944	3.18	10,092	4.50	14,292
2022	2.69	8,556	3.68	11,700	5.62	17,856
2023	2.85	9,048	4.20	13,332	6.84	21,732
2024	2.96	9,420	4.70	14,952	8.11	25,836
2025	3.05	9,684	5.22	16,584	9.49	30,144
2026	3.10	9,864	5.73	18,216	10.89	34,584
2027	3.14	9,984	6.24	19,824	12.32	39,132
2028	3.16	10,056	6.73	21,420	13.73	43,728
2029	3.18	10,104	7.24	23,016	15.23	48,372
2030	3.18	10,116	7.74	24,600	16.69	53,028
2031	3.58	11,376	8.25	26,196	18.10	57,492
2032	3.69	11,748	8.73	27,792	19.42	61,848
2033	3.82	12,120	9.25	29,400	20.78	66,024
2034	3.94	12,504	9.76	30,996	22.02	69,948
2035	4.05	12,876	10.26	32,604	23.17	73,596
2036	4.16	13,248	10.74	34,200	24.15	76,920
2037	4.29	13,620	11.27	35,796	25.13	79,848

Note: since the load factor of EV is not available, it is assumed that EV's load factors are the same as IID's total system load factors.

Although there are many different combinations of scenarios due to interactions of different variables such as EE, PV, EV, new industries, and weather, three main cases among them are considered as the main load forecast results: expected case (base weather, expected EE and PV, expected EV), low case (mild weather, high EE and PV, low EV) and high case (severe weather, low EE and PV, high new industrial, high EV). The load forecast high case is the highest load level among all the load forecast results; the load forecast low case is the lowest load level among all the load forecast results; the load forecast expected case is the combination of all the expected cases of all variables. Exhibit 65 shows IID total system net NEL growth rate under three main cases: expected, high and low; Exhibit 66 shows IID total system net CP growth rate under the three main cases: expected, high and low; and Exhibit 67 shows IID total energy sales growth rate under the three main cases: expected, high and low.

Exhibit 65: IID 2018 Load Forecast Net NEL Growth Rate (Expected/High/Low Cases)

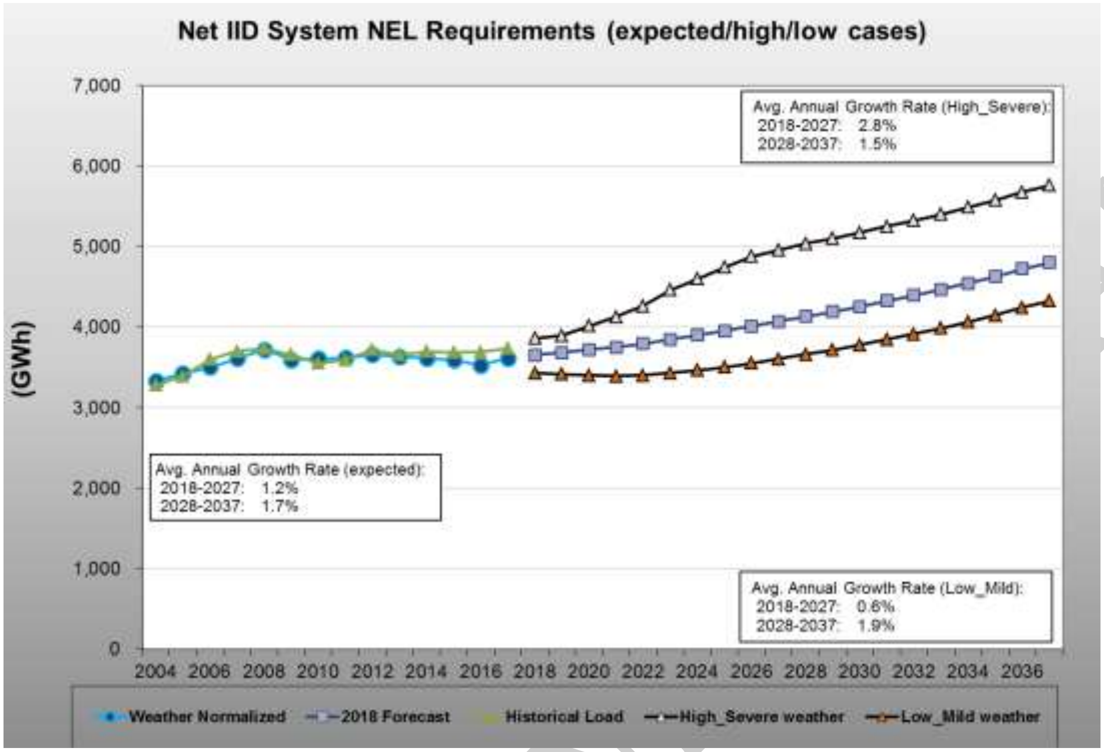


Exhibit 66: IID 2018 Load Forecast Net CP Growth Rate (Expected/High/Low Cases)

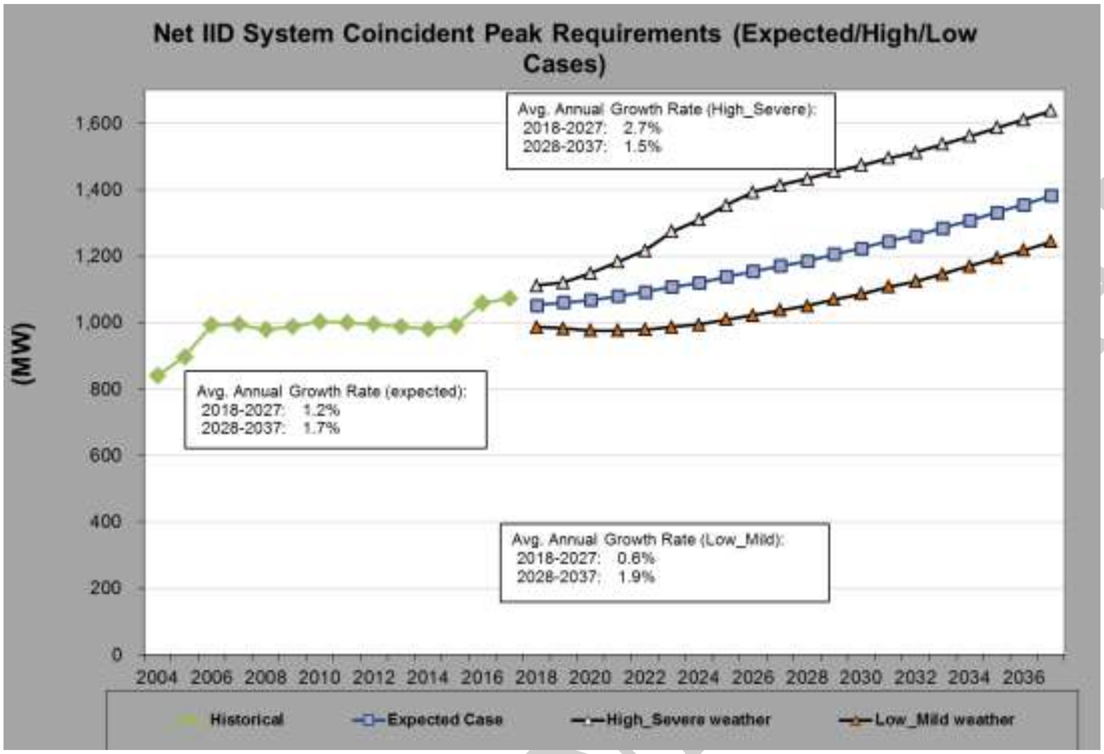
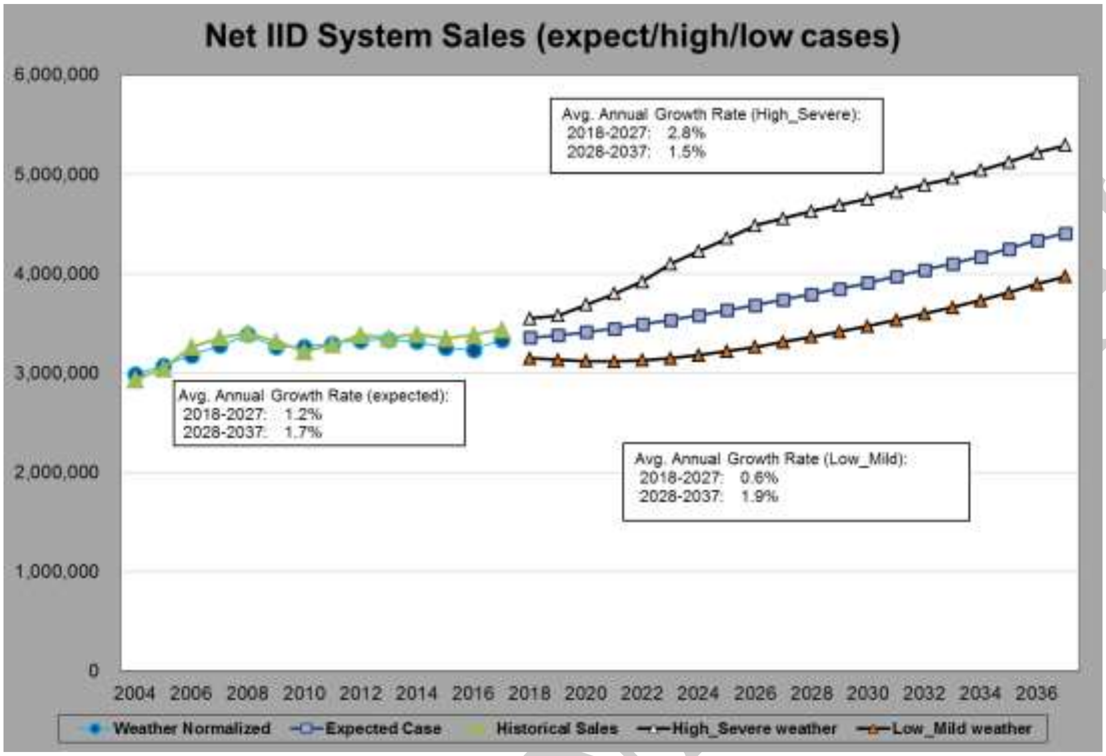


Exhibit 67: IID 2018 Load Forecast Energy Sales Growth Rate (Expected/High/Low Cases)



The range of the system demands in the 2018 Load Forecast is wider than that in 2016 Load Forecast. The wider range is expected to improve IID's ability to plan for load related risk and volatility. The expected range that future IID systems load is likely to be within was forecast using 90 percent confidence intervals. Regular updates to adjust for the changes in the underlying assumptions are required to confirm accuracy in the forecasts.

Chapter 4: The IID Need for Additional Resources

The need for additional IID resources can be determined through a comparison of the existing IID resources and the load forecast plus planning reserve margins. This comparison is commonly called a balance of loads and resources. When there are additional planning objectives such as meeting certain renewable energy requirements and GHG reductions, the BLR is supplemented with this information to determine when additional resources are needed on a system.

In the last IRP issued in 2016, IID was short in 2016 by about 300MW, but with the repowered El Centro Unit No. 3 as well as added renewable resources, IID decreased its short position significantly. The short position included a delay of 30MW of solar projects. In the summer of 2015, IID was short about 212MW which was met with seasonal energy products and in the summer of 2017, the IID is short about 202MW. An increase of about 25-30MWs of short position is added to each year in the subsequent years. Also, IID was short about 320 MW and IID has been aggressively exploring and pursuing various types of resources to meet these needs, including renewables, generic seasonally shaped market power, energy storage and many others in order to meet these coming needs. Additionally, IID has signed numerous renewable-resource contracts that help reduce the short position and become a more environmentally friendly utility.

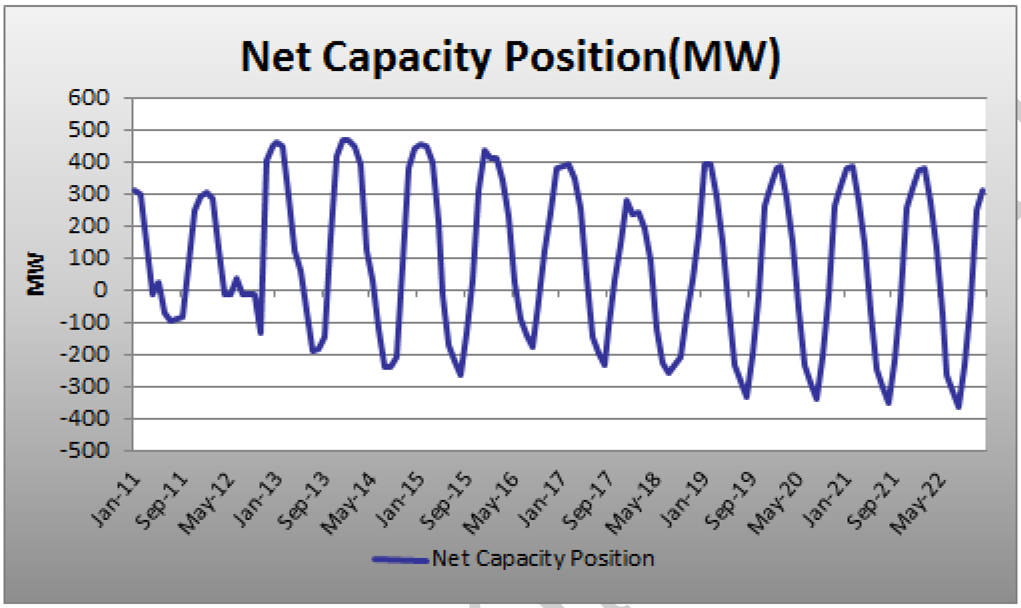
When choosing how to meet the IID's net short position, a number of factors must be taken into consideration, including the impact of new generation resources on:

- Ability to provide necessary ancillary services to meet Balancing Authority obligations and meeting reliability standards;
- Renewable-portfolio standards;
- Greenhouse gas emissions;
- Total power supply costs; and
- IID's financial conditions.

Capacity Deficit

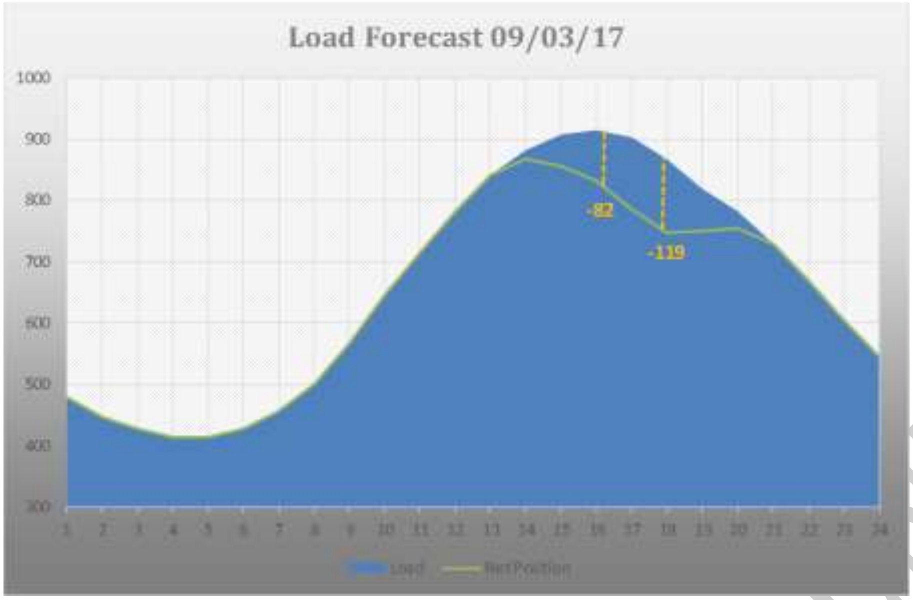
The IID observes the peak of each month compared to the supplies expected to be available in an supply/demand analysis. The graph below describes the monthly capacity position where above zero is a long position and below zero is a short position:

Exhibit 44: Monthly Net Capacity Position (MW)



Even though the IID must acquire sufficient capacity to meet its forecasted loads, it must be careful that it does not pay for energy in excess of its load requirements. The IID's capacity requirements are primarily in the April through October time period with excess capacity in the November through March time period. Additionally, it is important to note that the net capacity position max hour may not necessarily match the peak load hour, especially as more and more intermittent resources become commercially operational. The graph below illustrates how the hour of peak load (1600) does not match the hour of the shortest position:

Exhibit 45: Monthly Net Capacity Position (MW)



TYPES OF GENERATION RESOURCES

There are three basic kinds of generation resources: base load, peaking and intermediate. Acquiring the right mix of resources is necessary to meet load at the lowest cost.

BASELOAD RESOURCES

Baseload resources have a capacity factor[16] of between 60 and 100 percent. Baseload resources are characterized by high construction costs and relatively low energy costs. Baseload resources include coal, nuclear, hydroelectric run-of-river and combined cycle generation. In addition, geothermal generation is usually classified as a base load resource since it is intended to operate for all hours.

RENEWABLE (GREEN) RESOURCES

Renewable resources that qualify as a CEC certifiable renewable resource typically contain a wide range of availability in the inter-hour. Green resources such as biomass and geothermal tend to have higher capacity factors ranging from 60-95 percent. However, green resources such as wind and solar generation have lower capacity factors ranging anywhere from 20-40 percent and are heavily dependent on non controllable factors related to weather. In a solar resource, if the scheduled output is 20MW in a given hour, but suddenly clouds cover a portion or all of the sunlight providing the fuel to the solar panels, then the

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[16] The capacity factor is defined as the ration of actual generation to potential generation and is calculated as: Annual Capacity Factor = (actual generation during the year)/ (8760*unit capacity). Capacity factors can also be calculated by month with the formula being changed to reflect energy generated during the appropriate time period divided by the potential generation during the time period.

actual output becomes 11MW. This 9MW loss must be made up by other resources in the IID system and can present an operational pressure to the IID system stability.

Peaking Resources

Peaking resources have low capital costs but high fuel and operating costs. Examples of peaking resources include combustion turbines and older, inefficient generation facilities. Additional ramping generating facilities will be needed if the IID adds any additional capacity of solar or intermittent resources. As additional intermittent renewable resources come online, IID will need to place special attention on the reliability condition of the IID system to closely monitor system stability. As outlined earlier in this document, intermittent resources may cause reliability instabilities that will require the IID to possibly acquire additional quick responding generation, such as peaking resources.

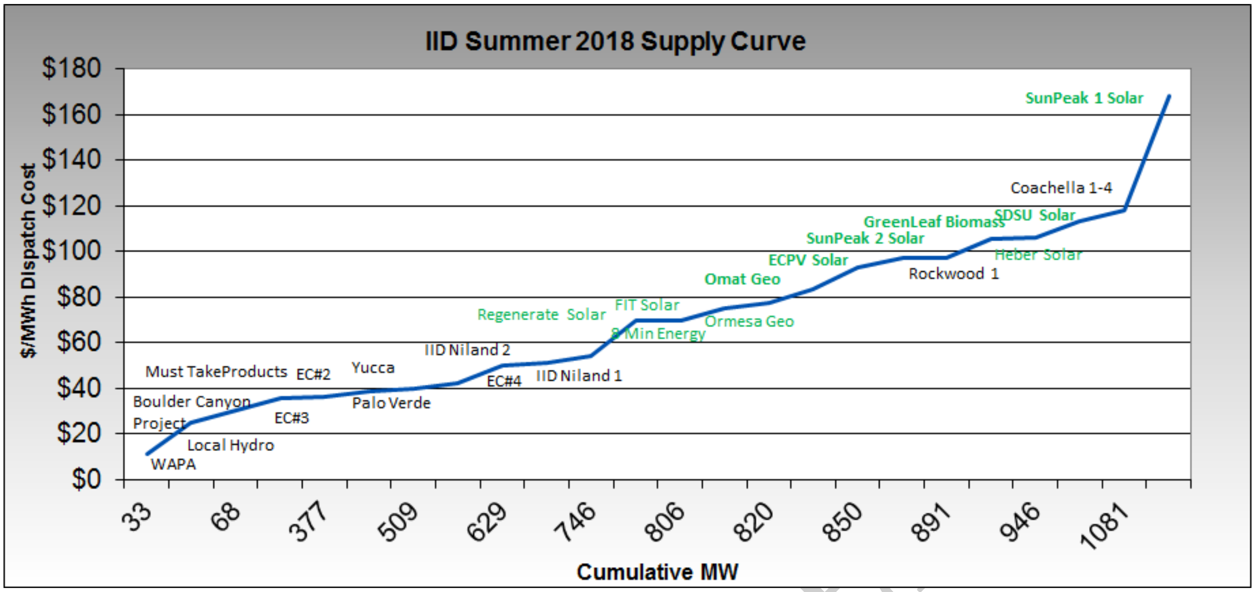
Intermediate Resources

Intermediate resources are, by elimination, resources that are neither peaking nor base load resources. There are few examples of actual intermediate resources other than hydroelectric resources (with water storage rather than run-of-river) and combined cycle resources. However, many of the modern technologically advanced combined cycle resources are used as base load resources because of their high efficiency.

Supply Curve with RPS Integration

With the recent developments in greenhouse gas requirements and renewable resource integration, the energy industry has seen a major shift in supply resource stacking and traditional supply dispatch order. In the past, a common supply curve would show the base load resources with the lowest dispatchable costs at the bottom of the curve, but with renewable contracts that are essentially must take, the supply curve is now filled with the must-take base load resources at the top of the curve since renewable prices are typically higher than conventional energy prices. This, of course, all depends on the price of natural gas and power. The graph below illustrates a traditional supply curve with the newest developments of renewable resource integration included in the curve.

Exhibit 46: 2013 Supply Curve



Capacity versus Energy Charges

Unless the energy is bought for all hours of the day (a base load purchase), power purchase agreements include a capacity charge. The capacity charge is the reservation charge for energy and is priced as a cost per kW-month or a fixed charge for the right to generate energy from the contracted capacity.

The capacity charge will vary depending upon the expected use of the generator. An agreement that anticipates that the generation facility will be used sporadically during the peak periods of the month will have a higher capacity price than an agreement that contemplates frequent use.

Energy can be priced a number of ways. Generally, the price is quoted in the price per MWh – for example, $50/MWh.

When calculating the total delivered cost of energy, both the capacity and energy cost must be included. Knowing how the resource will be used is important in determining what type of resource will minimize total costs.

Generally, base load resources have a high capacity factor (reflecting the high capacity costs associated with building base load generation) and low energy costs. Peaking resources generally have low capacity costs but high energy costs.

If the unit will to be operated as a peaking facility or with a low capacity factor, the best, or most economic choice of resources, are those with low capacity costs and high energy costs. If the unit is going to be purchased to meet base load requirements, then a purchase with a high capacity cost and a low energy cost is generally most economic.

Technological Advancements as a Result of Changing Laws

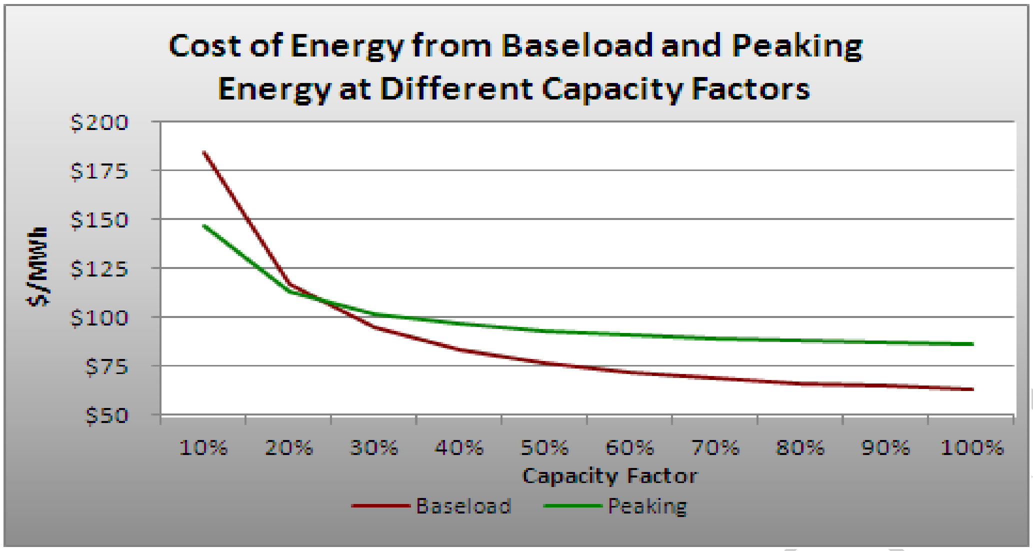
In the United States, a change in law may present a competitive opportunity for entrepreneurs and industrialists to research and develop new technologies or improvements to existing technologies to decrease the cost of production, and thus reduce the cost impact to the affected compliant entity and public. With these improvements, IID has the opportunity to aid in the development of new technologies that allow the Imperial Valley to be at the forefront of making renewable energy easier to integrate and less expensive.

IID has explored various technologies that help increase the efficiency in geothermal and solar power generation and the continued approach in a prudent manner will allow IID to reduce costs for the IID ratepayer. Recently, IID made state and national news by taking a significant step in working with the county of Imperial to advance a joint effort that would lead to the restoration of the Salton Sea, protect public health, benefit the local economy and the vast wildlife that depends on the sea, all while protecting IID's Energy Balancing Authority. This effort, along with developments in renewable-generation technologies, will work together to allow IID to move forward as a leading publicly-owned utility.

Summary of Resource Types

Baseload resources are characterized by high capacity costs and low energy costs and peaking resources are characterized by low capacity and high energy costs. The following exhibit shows the average cost of peaking and base load generation resources at different capacity factors.

Exhibit 47: Conventional Resource Cost: Baseload vs. Peaking



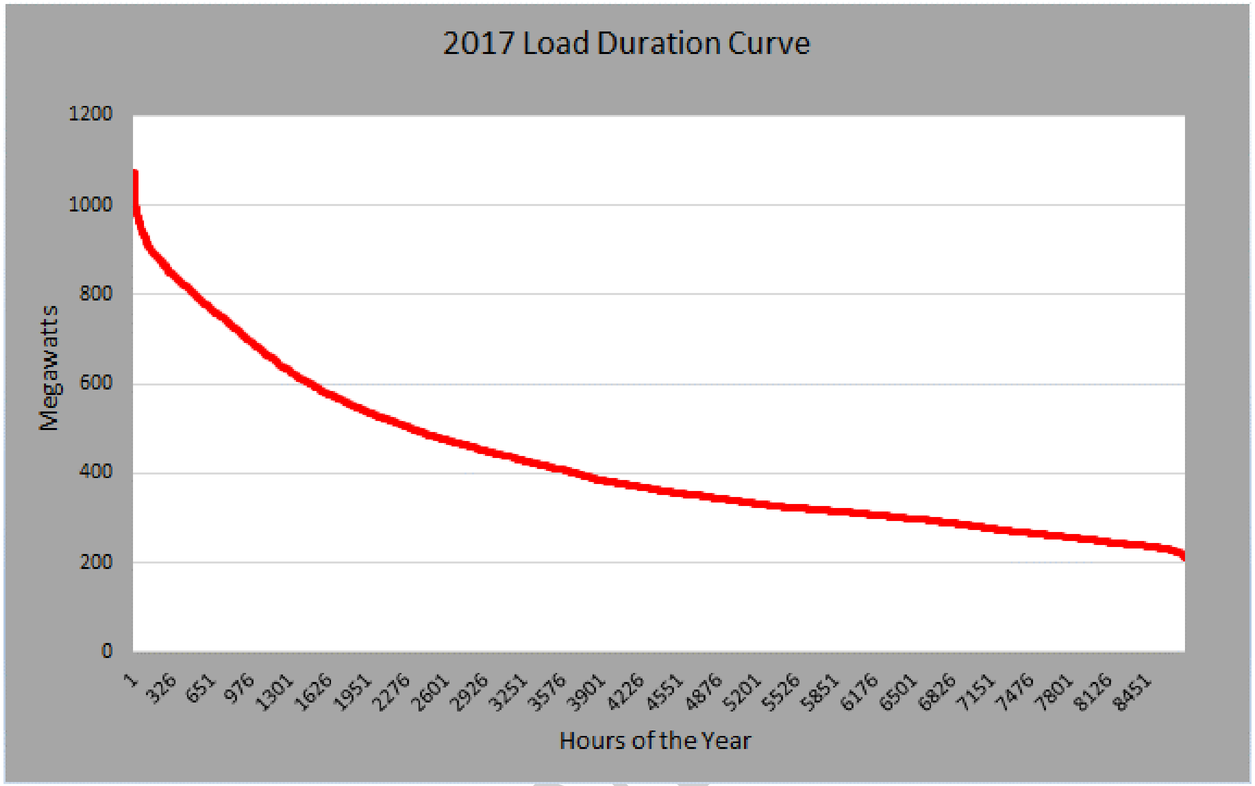
At low capacity factors, the capacity cost of base load resources dominates the total cost of generation, while at high capacity factors, the high energy and operating costs dominate total costs of peaking resources. As a result, base load resources should only be acquired when the expected capacity factor is going to be above 60 percent and peaking resources should only be used when the expected capacity factor is below 25 percent.

An important screening tool for identifying the type of resources required by the IID is determining the approximate capacity factor of potential new resource additions. Once the capacity factor is identified, appropriate technologies can be specified.

Load Duration Curve

Another useful screening tool for the type of resources needed in the future is the load duration curve for the IID. The load duration curve shows how many hours each year load exceeds specified amounts and provides information on the characteristics of new resources required by the utility.

Exhibit 48: 2012 Load Duration Curve



Several interesting facts can be drawn from the load duration curve. First, base load requirements are around 350MW. Baseload resources are available for dispatch all hours of the year (excluding planned and forced outages). Generally, a utility should acquire enough base load resources so that it is slightly long, around 2,000 hours of the year (or roughly 20 percent of the time). The IID has control over the dispatch of its resources and can back down the many of the natural gas generation plants to reduce any surplus energy.

The second important fact to recognize is that IID's loads are only above 800MW for around 500 hours of the year and above 900 MW for less than 150 hours of the year. This means that the IID is required to purchase expensive peaking capacity during the summer months to meet load that only occurs for less than 150 hours.

As will be shown in a later section, demand-side management programs can reduce the daily peak demands and reduce the need for expensive peaking capacity. If the IID can implement 50 MW of demand-side programs, it would be displacing generation resources that are only used around 150 -200 hours per year, primarily during the high-cost, on-peak hours.

The load duration curve shows that the IID should acquire around 400 MW of peaking capacity or energy required only around 25 percent of the time. This type of energy comes from power purchase agreements and combustion turbines or older, inefficient gas and steam units that have low capacity costs. This means that IID should acquire seasonal (1-3 months of the year) call options where some may be called upon more often with a strike price that is expected to be competitive to the market spot price and also IID should acquire some call options that will only be used a few times with a strike price that is “out-of-the-money” so that the IID pays a diminutive option premium. This allows IID to reduce the overall cost to supply power to the consuming rate payer.

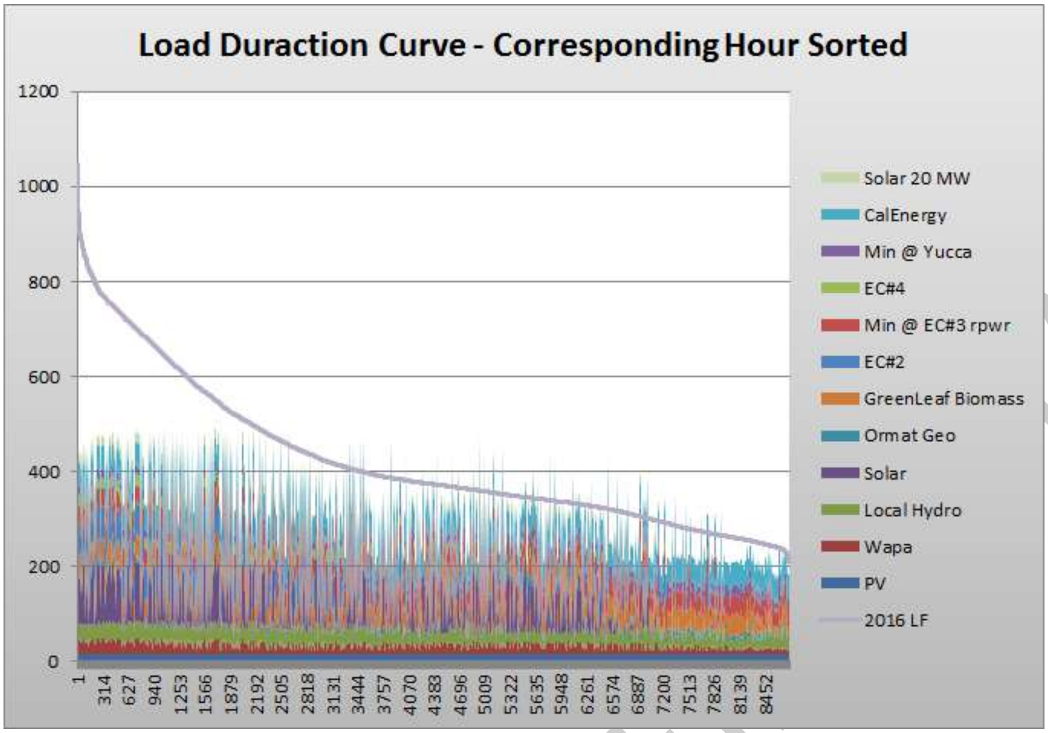
This indicative analysis shows that to meet annual load requirements the IID requires approximately 375-400 MW of peaking energy (a capacity factor of 1 to 25 percent), 350–400 MW of base load energy (a capacity factor of 60 to 100 percent) and 300 MW of intermediate capacity or energy available for load with a capacity factor of between 25 and 60 percent.

Load Duration Curve for Future Years & Baseload Resources

Currently, the IID is challenged with this conventional goal of meeting resource requirements at a minimal cost combined with the requirement of meeting RPS targets. Most renewable resources are not dispatchable and are considered must take in most circumstances. Geothermal and biomass resources, which contain a capacity factor of about 90-95percent will be stacked at the bottom of the stack as usual with other typical base load resources; however, other renewable resources, such as solar generation, would also be stacked at the bottom of the stack, even though the annual capacity factor is anywhere between 23-33 percent, much greater than a typical base load resource. With the requirement of energy (MWhs) RPS targets and the capacity (MW) planning strategy, IID is forced to take more capacity in certain hours than what customer demand requires.

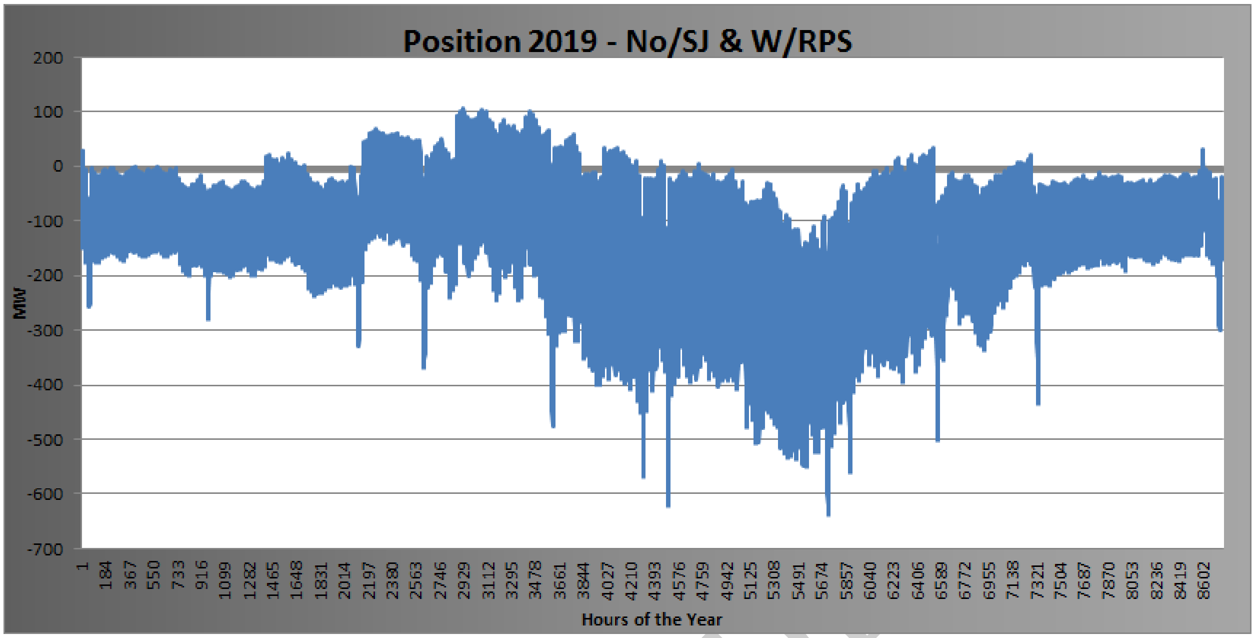
The following exhibit illustrates this challenge in the load duration curve projection for 2019 and the stack of expected must-take/base load resources over the course of the year.

Exhibit 49: 2019 Load Duration Curve with Must-Take/Baseload Resources



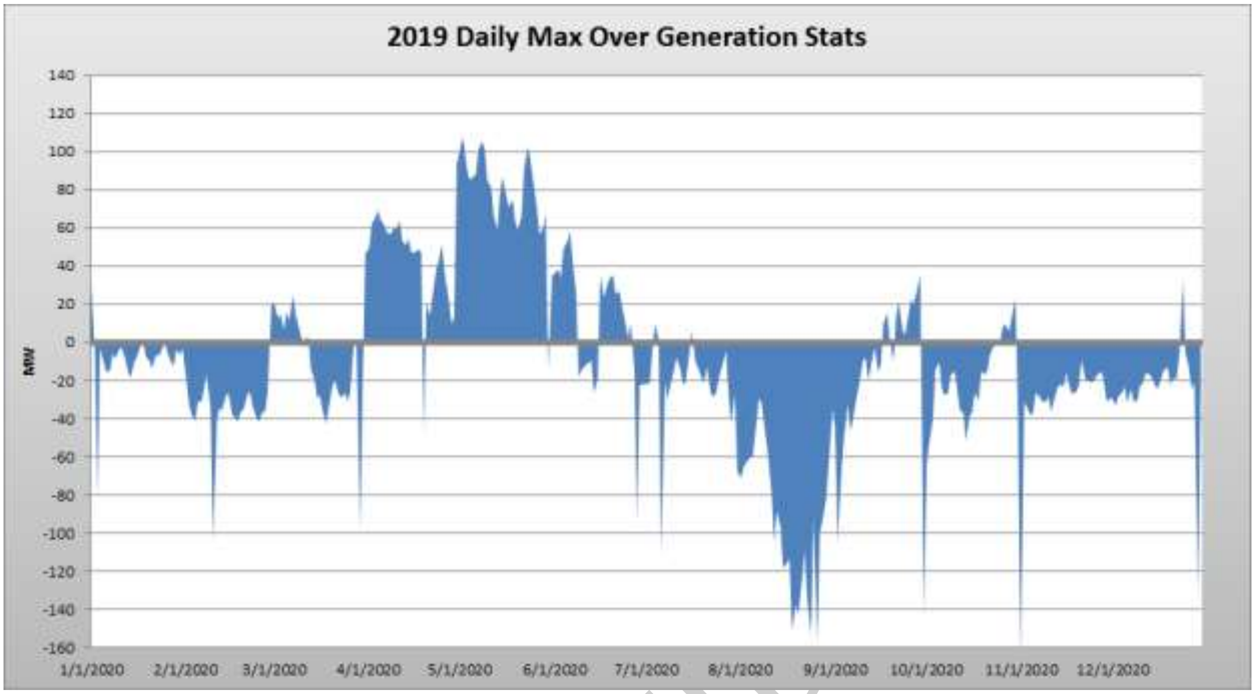
As shown on the previous page, there are a few hours (600-900) where IID may potentially be long with must-take resources. This has a cost and a market risk associated with it. With the requirement to continue to bring on more renewable resources to meet the RPS requirement, IID could minimize the risk of being long in the winter time by continuing to consider seasonal contracts that are economical. This is a challenge because most renewable developers need guaranteed annual contracts for the financing of projects. Technology types that qualify as renewable, such as biogas (particularly in state biogas), that allows IID to flexibly dispatch the renewable resource at a competitive price, could have operational benefits but have regulatory, volumetric and cost risks associated with it. There are a lot of regulatory risks with out-of-state biogas as well as a limited supply in state. Another way to observe this is by looking at the net position on an hourly basis, using 2019 as an example year:

Exhibit 50: Hourly Net Position and Excess Generation Forecast



A more palatable way to observe this is by looking at the daily max vs the supply where above zero represents excess generation to be sold at fluctuating prices that may result in higher costs:

Exhibit 51: Daily Max Excess Generation Forecast



Using a load duration curve and hourly/average position are a screening tool that provides a starting point for more exhaustive analysis. The price that the IID pays for different types of resources will ultimately impact the optimal amount of each type of resource that the IID purchases.

TRANSMISSION COSTS AND LOSSES

Whenever the IID purchases energy from outside its service territory, it must purchase transmission capacity. Transmission costs vary according to the contract path that the IID uses.

Purchases from the CAISO are expensive, generally around $10-$15/MWh higher than IID's other liquid trading hub at Palo Verde. The CAISO adds an export fee that includes ancillary services, grid management charges and other costs that purchasers within its balancing authority must pay. The IID also does not know if it will be required to pay any congestion charges on the CAISO system, although generally congestion from the CAISO to the IID is low. Selling energy into the CAISO does expose the IID to potentially high congestion charges.

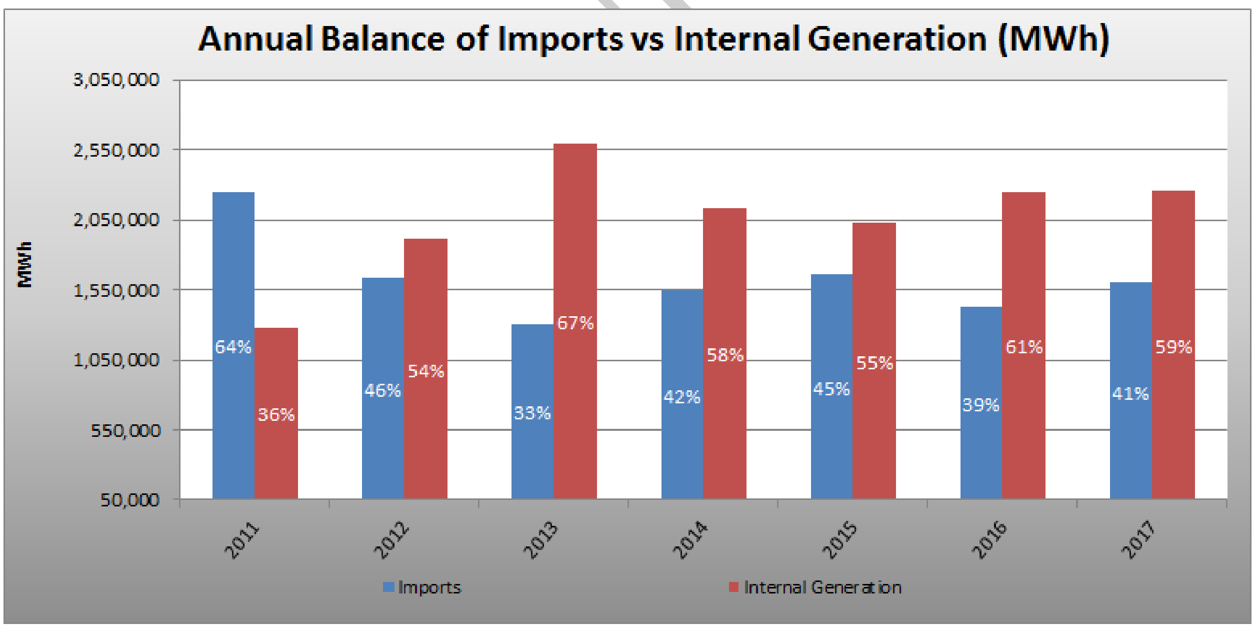
Purchases from east of the Colorado River tend to have lower transmission charges than from the CAISO, generally around $5-$8/MWh. However, if the energy passes through multiple balancing authorities or substations controlled by different entities, the transmission charges are "pancaked" on top of each other and transmission charges can quickly escalate.

The IID also has to account for transmission losses. Some entities (such as the CAISO) deliver the contracted amount and charge the IID for losses. Others just deliver the contracted amount less losses.

Generally, the magnitude of losses faced by the IID is around three to five percent, although they can be considerably higher if the generation source is in Utah or Colorado.

When the IID makes its purchasing decisions, it also includes both transmission costs and any associated losses. The IID needs to continue to expand its transmission infrastructure to reduce the exposure to high transportation line losses. Transmission expansion will also allow the IID to access other liquid energy markets that are advantageous when stacking resources to serve load. Additionally, transmission resources that contain both import and export capabilities allow for potential energy sales to further reduce cost impacts of operating the system. The IID intends to sustain a healthy balance of serving load with imports and internal generation. If IID is dependent upon too much internal generation, then when observing numerous outage/emergency risks over the course of every hour of each year moving forward, the IID would need to build a "more than expected" amount of internal generation to cover the ancillary service requirements and other reliability requirements needed to operate the system reliably. This approach can be quite costly. On the other hand, if the IID is dependent upon too much import capacity, then the inevitability of transmission line outages can cause an equally problematic situation when observing every hour of each year moving forward. The following exhibit shows the annual balance of imports vs. internal generation for 2011-2017.

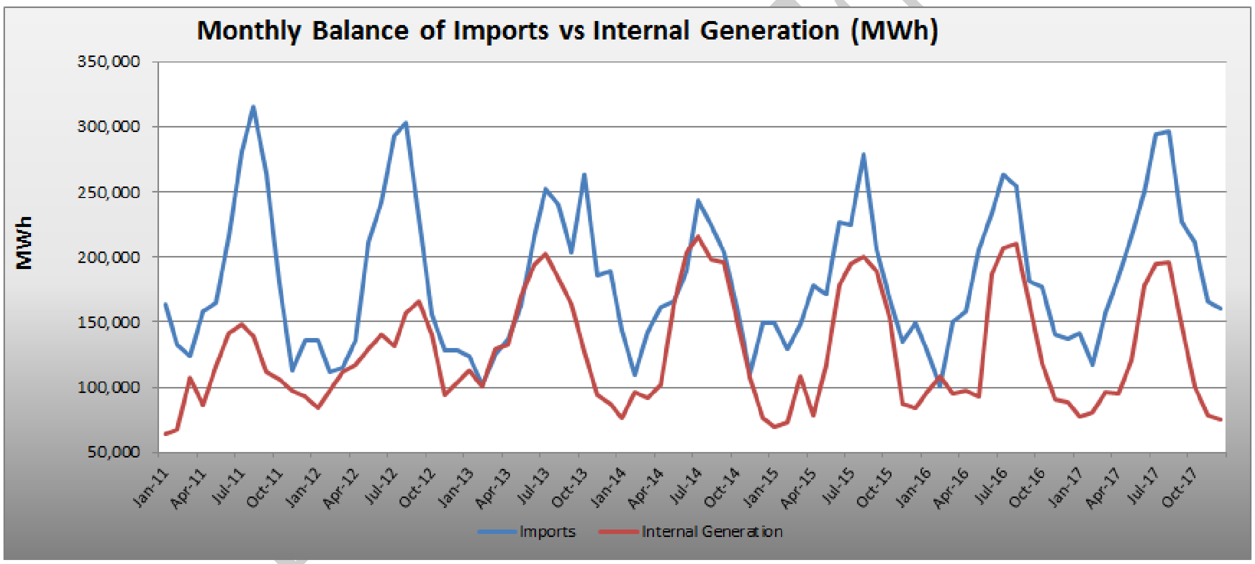
Exhibit 52: Imports vs. Internal Generation by Year (2011-17)



Historically, the IID experienced higher levels of imports due to the economic viability of accessing external markets, but when renewable resources located within the IID territory become commercially operational, as was the case in 2012, the internal generation will increase and the need for economic displacement imports will naturally decrease. This evolution of operating practices must be balanced to ensure that IID is compliant with regulatory and legislative policies and, at the same time, taking advantage of energy market opportunities with a salubrious balance of imports and internal generation. Further, the RPS required renewable resources should be factored into the balance formula since they are not dispatchable and are essentially all must take causing a growing trend of more internal generation than imports. This will be discussed further in chapters 10 and 11.

While the summer and winter loads are extremely atypical from each other, IID maintains a good balance of imports and internal generation to serve load. However, on a monthly basis, the balance can shift due to generator outages, transmission line outages, and other force majeure events that can shift the balance of imports and internal generation. The following exhibit shows the month-to-month balance for the last two years considering the various month-by-month situations that have caused the disparity of imports and internal generation.

Exhibit 53: Imports vs. Internal Generation by Month (2011-17)



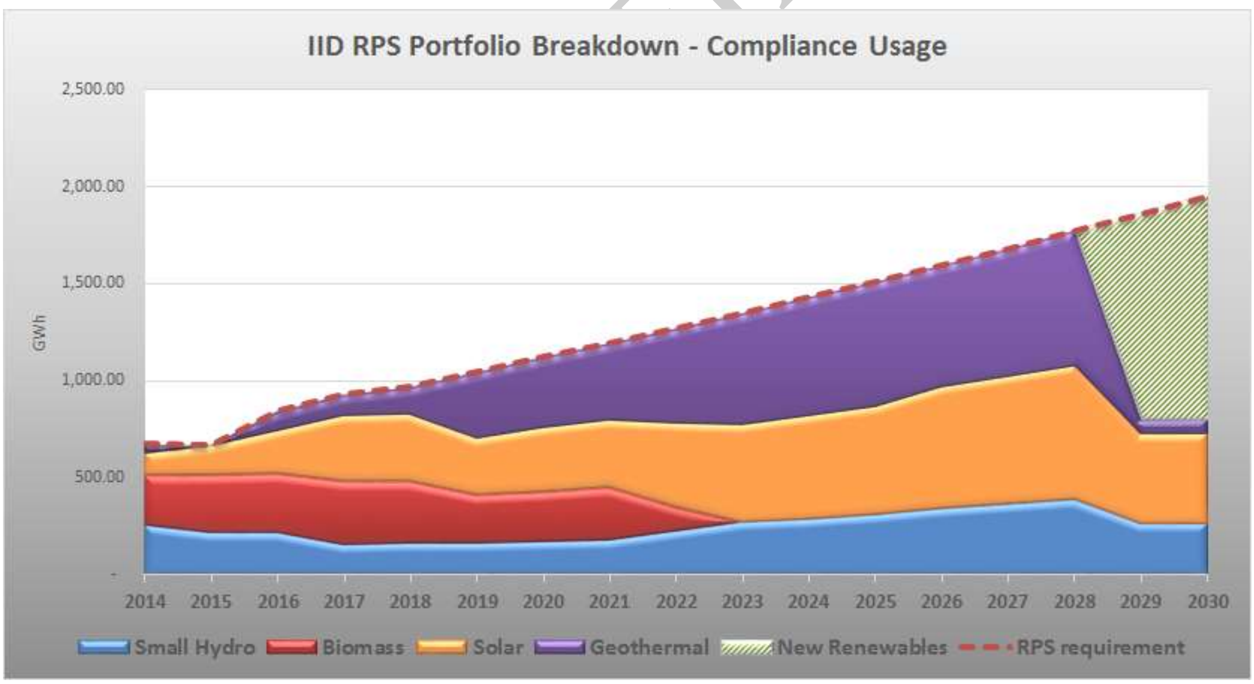
In addition to the annual and monthly observation of balancing supplies between imports and internal generation to serve the IID load, IID must also consider the impact of exported generation. The IID system area contains thousands of megawatts of either already existing or potential resources for development that can be wheeled through the IID service territory to serve load in other areas to the north, west and east. As RPS requirements grow over time for the state of California, there is a good possibility that the other states will follow the aggressive and high level of RPS requirements. Since IID is an area rich in renewable resources, IID must consider the possibility for higher revenue streams from exporting energy to other areas.

IID must also continue to observe, understand and communicate the benefits and risks associated with increasing activities with other balancing authorities such as the CAISO. Other balancing authorities have their own separate standards that may not necessarily prioritize the needs of IID. This can result in curtailed energy schedules and high congestion or locational marginal prices. On the other hand, other balancing authorities encompass the benefit of an access to other markets for wheeling service revenues and even energy sales from the IID generation. IID must consider these dichotomies when integrating all energy resources and planning for the future.

OVERALL RESOURCE NEEDS

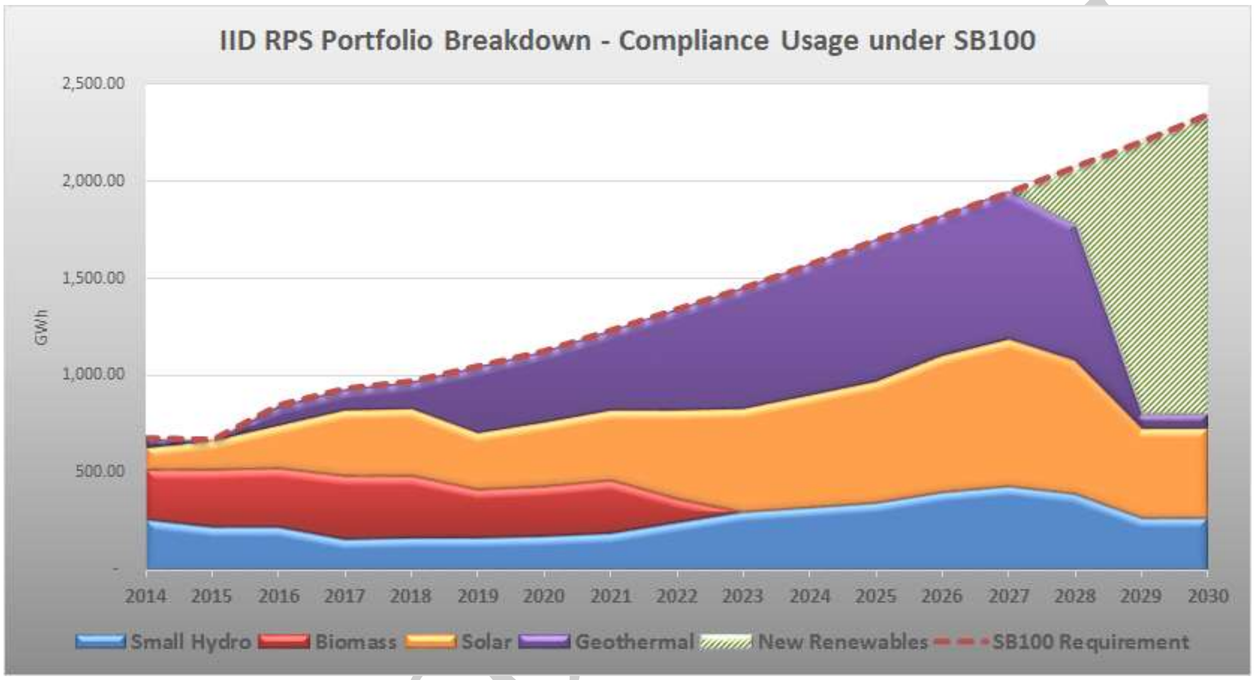
Based on analysis, IID will need to consider new peaking units or energy storage added around 2019 and 2026, other new quick responding resources must be considered in 2019-2030 if retirements are above and beyond the recommended retirements. The IID's supply acquisition units will need to constantly procure seasonally shaped resources every year during the summer months. These seasonal needs can range from 100-385MW usually shaped around the peaking months of May-October. These additional resources are not only to meet forecasted capacity needs, but also to enhance the reliability of the IID system when renewable resources are integrated moving forward. The exhibit below represents the estimated renewable resource diversity for 2014-2030.

Exhibit 54: Resource Diversity by Resource Type 2014-2030



The following exhibit depicts how the short RPS position and annual generation position can be filled in the case of SB 100:

Exhibit 55: Resource Diversity by Resource Type 2014-2030 under SB 100



Traditional Baseload resource needs are set to zero since the amount of base load resources should not exceed winter loads and most of the base load needs moving forward will be filled with renewable resources, which can have various output efficiencies for contrasting technologies. The renewable-resource additions will be most likely be base load that are must take and non-dispatchable.

Energy Efficiency and Demand Side Management Programs

California leads the nation in energy efficiency and renewable energy programs. . Rigorous environmental regulations and evolving energy policy place the state at the forefront of environmental stewardship.

Energy agencies within the state adopted an Energy Action Plan that has been a catalyst for numerous energy-related policies. In 2003, the EAP established a “loading order” for the acquisition of new resources that prioritizes energy efficiency. Since that time, a number of state-mandated regulations have been enacted to support this policy, such as Senate Bill 1037. SB 1037 requires public and private gas and electric utilities to first acquire all available energy efficiency and demand reduction resources that are cost effective, reliable and feasible before conventional generation or other resources.

IID is committed to investing in all available energy efficiency and demand reduction as a supply resource. The IID offers a variety of conservation and DSM programs intended, in part, to alleviate electric generation requirements and avoid expensive peak purchases of power on the market. Conservation programs are designed to reduce the total amount of energy used while DSM programs are designed to shift energy use from high cost periods to low cost periods and reduce the cost of supplying customers.

New legislation, emerging technologies and evolving customer preferences are defining IID's energy efficiency and demand-side management programs.

Exhibit 56: Conservation and Daily Load

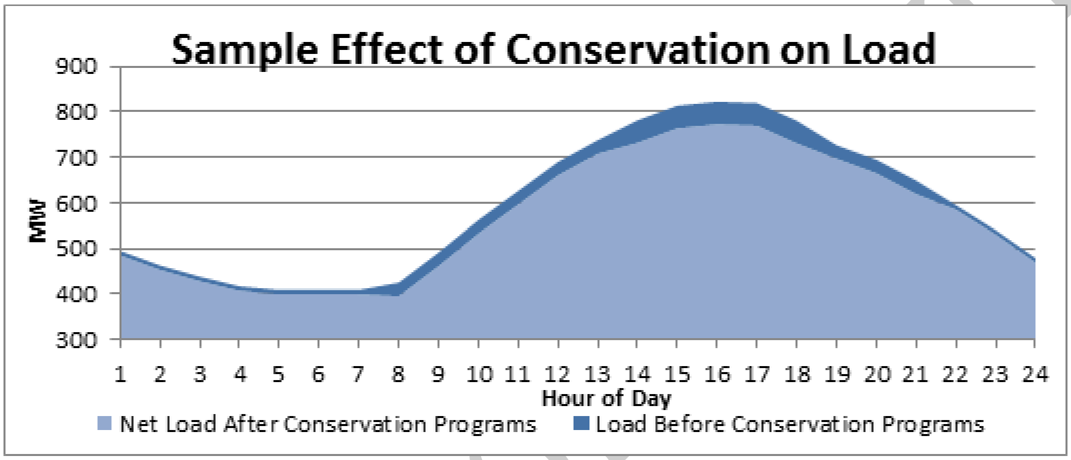
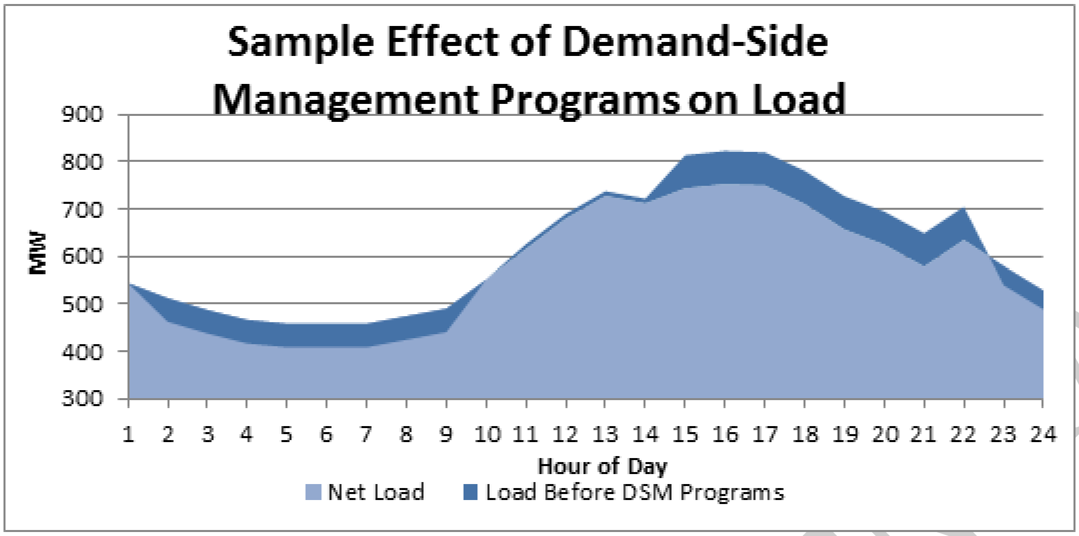


Exhibit 57: DSM and Daily Load



Currently, most programs within the IID's portfolio are conservation programs with the goal of reducing the customer's consumption and cost of energy; however, future programs may be designed to shift customer on-peak use to off-peak hours.

Evaluation of Programs

Conservation and DSM programs can be evaluated in a number of ways. Prior to implementation, and periodically throughout an existing program, cost-effectiveness tests are applied to determine if the investments are comparable to, or better than, the range of other available resource options. There are five industry-standard cost-effectiveness tests used to compare the benefits of energy efficiency with the costs to invest in implementation of the efficiency measures.

As a general rule, California utilities deem a total resource cost of "1" or greater as an indicator of a cost-effective program. However, comprehensive evaluation using a combination of the various tests provides for more definitive assessment of impacts and effects the program will have. Benefits and costs used to evaluate cost effectiveness of energy efficiency and DSM programs and services are identified in the exhibit below. The following is a summary of the five approaches to evaluation:

1. Participant Cost Test – This approach provides an assessment of the costs and benefits from the perspective of the customer installing the measure(s). PCT of 1 or above indicates that the customer will see net savings over the expected useful life of the measure.

2. Utility/Program Administrator Cost Test – Opposite of the PCT, this approach assesses the costs and benefits from the perspective of the utility implementing a program. A positive PAC result indicates that the costs to save energy are less than the utility's cost to deliver the same power. Additionally, the customer's average bill should reduce once the measures are implemented.

3. Ratepayer Impact Measure Test – This test evaluates the potential impact the program may have on the overall electric rates. As RIM results tend to be negative, many utilities, including

IID, emphasize the results of PAC tests over RIM to balance the distribution of rate impacts.

4. Total Resource Cost Test – As the primary evaluation approach, the TRC illustrates the total benefits and costs to both participating and nonparticipating customers. This test shows the net benefits of the program as a whole without regard as to who (utility or customer) pays the cost of the measure(s) installed.

5. Societal Cost Test – The SCT includes both costs and benefits that are not captured monetarily in the TRC such as greenhouse gas reductions or other environmental benefits.

Exhibit 58: Cost/Benefits of Conservation and DSM

COMPONENT	PCT	PACT	RIM	TRC	SCT
Energy and capacity-related avoided costs		Benefit	Benefit	Benefit	Benefit
Additional resource savings				Benefit	Benefit
Non-monetized benefits					Benefit
Incremental equipment and installation costs	Cost			Cost	
Program overhead costs		Cost	Cost	Cost	Cost
Incentive payments	Benefit	Cost	Cost		
Bill savings	Benefit		Cost		

Source: California Public Utilities Commission (CPUC). (2001). California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects. www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

California Assembly Bill 2021 (Levine) that was signed into law in 2006 expanded upon several existing energy efficiency policies, including SB 1037. Among other mandates, it requires all publicly-owned utilities to perform third-party measurement and verification studies of their conservation and DSM programs. These independent program evaluations, commonly referred to as EM&V, are performed by third parties to provide an unbiased assessment of programs as well as measurement and verification of energy, demand and peak savings generated through the portfolio. IID's EM&V plan consists of evaluation of its programs on a bi-annual basis, covering programs for a two-year cycle. Not all programs will be evaluated in each evaluation cycle. Programs that generate the most energy savings will be routinely assessed while others will be included on an as-needed basis.

Evaluation results allow the IID to determine if its programs are effectively reducing energy use by its residential and commercial customers. Using information from this report, local demographics and the

IID's overall strategic goals, existing programs are assessed to determine if more cost-effective programs should be expanded at the expense of some of the less effective programs. Programs that only benefit participating customers may be scaled back or eliminated unless they have significant environmental or other societal benefits to the IID that cannot be quantified for customers. At times, the IID, at its sole discretion, may invest in programs or projects with lower TRC values if they align with specific strategic or policy-driven goals.

ENERGY EFFICIENCY PORTFOLIO TARGET

Assembly Bill 2021 also requires each publicly owned utility to identify all potentially achievable cost effective electricity efficiency savings and shall establish annual targets for energy efficiency savings and demand reduction for the next 10-year period. IID has joined together with California Municipal Utilities Association in partnership with Northern California Power Agency) and the Southern California Public Power Authority to collaborate on the development of individual utility energy efficiency and demand-reduction targets. The targets are based on a methodology developed by the Rocky Mountain Institute, an independent organization with well-accepted energy efficiency expertise in the industry. The RMI model is designed to estimate the technical (full extent of energy efficiency potential without regard to practicality or costs), cost effective and feasible energy efficiency potential.

Consistent with provisions of AB 2021, the targets adopted in 2014 by IID's Board of Directors were re-evaluated in 2016 and new figures were adopted the exhibit below reflects IID's current MWh targets by program year through 2027.

Assembly Bill 2227 (Bradford, 2012) modified the evaluation period for energy efficiency targets from every third year to every forth for the subsequent years.

Senate Bill 350 (De León) enacted the "Clean Energy and Pollution Reduction Act of 2015" which established targets to increase retail sales of renewable electricity to 50 percent and double the energy efficiency savings in electricity and natural gas by end uses by 2030. IID is evaluating emerging technologies and innovative program concepts to develop a multi-year running program portfolio to meet the energy efficiency targets set forth by this legislation. In the upcoming target setting process, criteria specific to the doubling of energy efficiency targets of SB 350 will be incorporated into the analysis to establish the roadmap that IID will use in an effort to meet the substantially increased targets by 2030. In the interim, IID has performed preliminary analysis to determine the most cost-effective approach to increasing energy savings toward the mandated goals given current funding levels. Based on these results and absent additional funding for the energy efficiency portfolio, the Energy Department may consider reallocation of a larger portion of the overall energy efficiency public program budget toward the Customs Energy Solutions program to capture savings from a customer segment with the largest potential.

Exhibit 59: Program Level Results – Net Energy (MWh) Savings at the Customer Meter

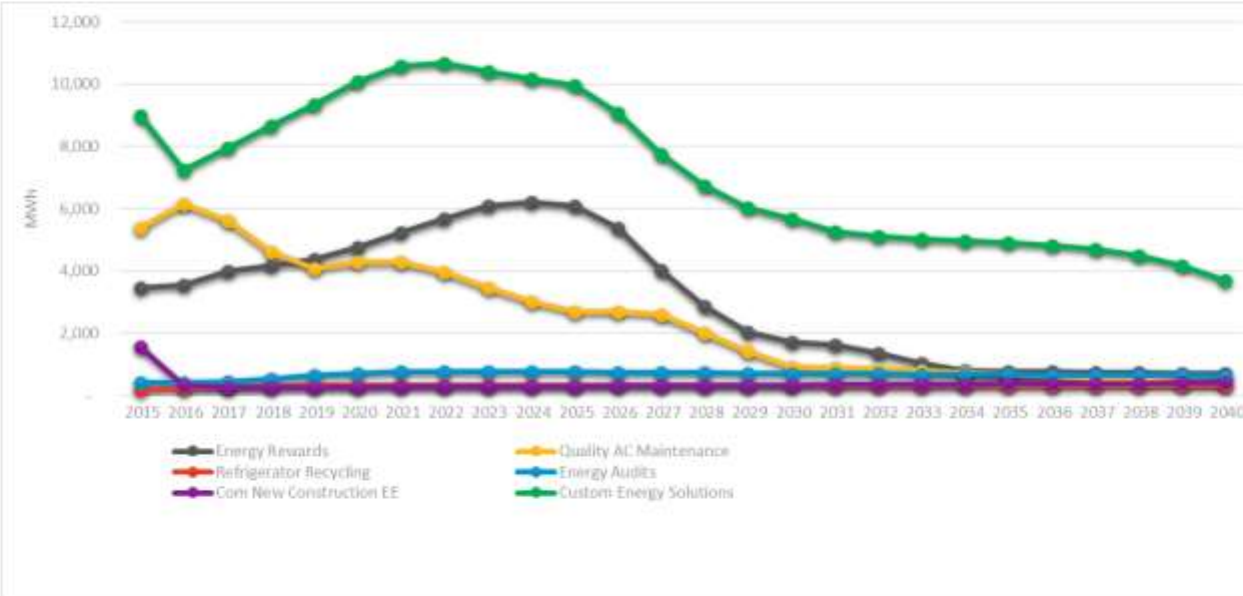
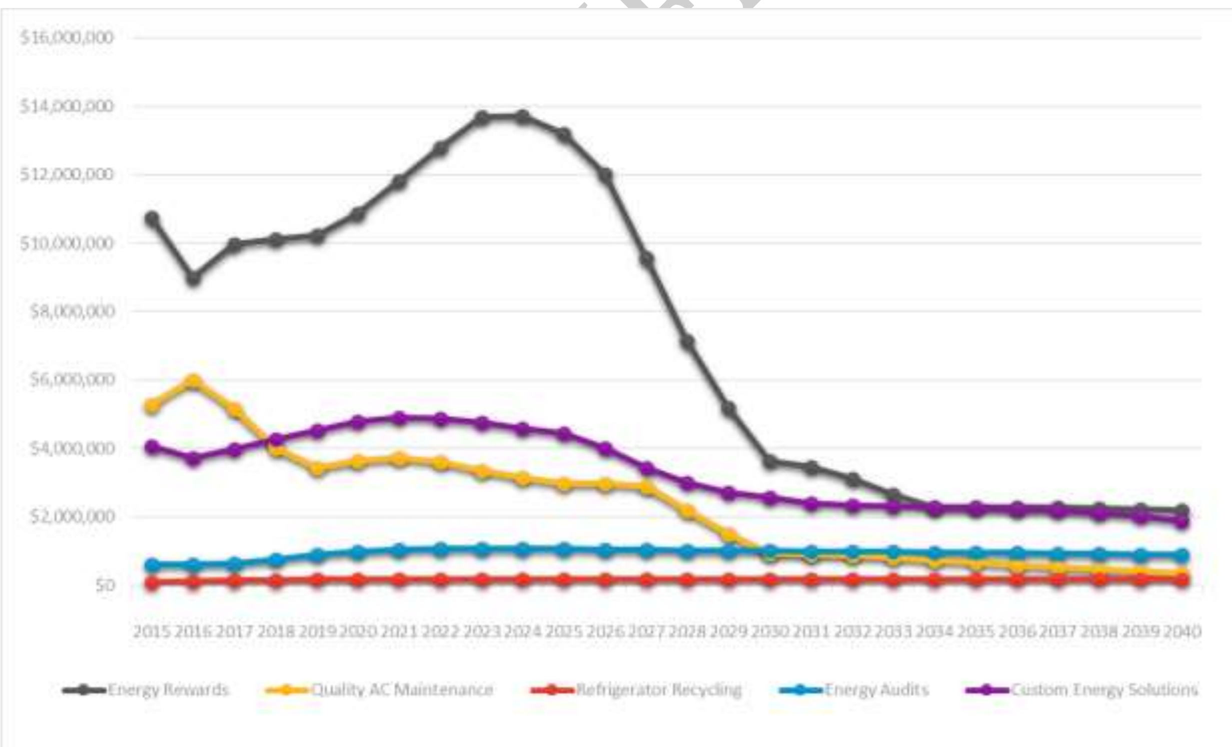


Exhibit 60: Program Cost to the Utility

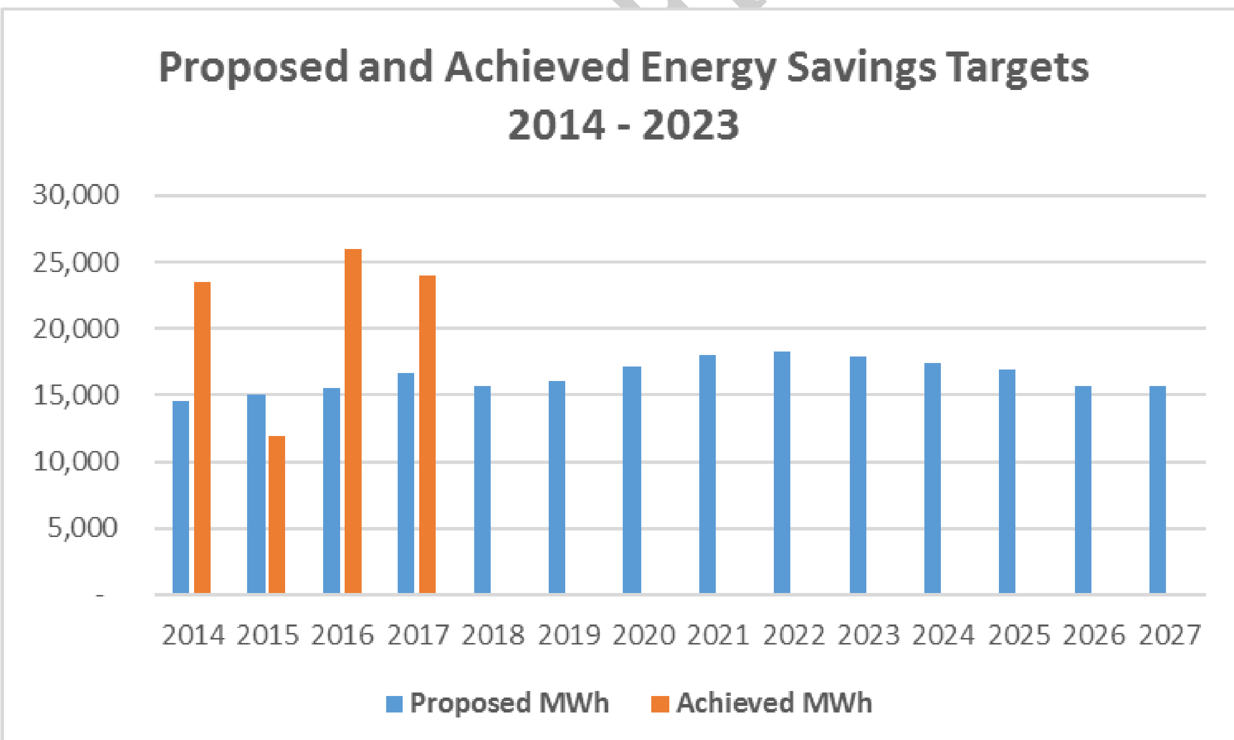


In 2015, Assembly Bill 802 (Williams) was also passed into law, replacing the existing AB 1103. AB 802 sets the framework for a new energy use disclosure program, which will allow owners and operators of commercial and multifamily buildings containing 50,000 square feet and more to better understand their energy consumption through standardized energy use metrics of 12 months of historical whole-building utility data. The whole-building energy use approach depicts how the building is performing as an entire system, facilitating building owners to make more effective decisions on energy efficiency upgrades. As energy targets are reevaluated as per AB 2227, legislation, Title 24 requirements, rooftop solar and IID's public program budget will be considerable factors in the adoption of the new figures.

On August 3, 2015, the Environmental Program Agency, under Section 111(d) of the Clean Air Act, finalized the Clean Power Plan, a rule that sets performance rates and individual state targets for carbon dioxide emissions from existing power plants. California's 2030 goal is 828 pounds per net megawatt hour, which is lower than most states as California's state regulations are already amongst the most stringent in the nation. The CPP was met with several legal challenges and on February 9, 2016, the Supreme Court issued a stay on the enforcement of the plan halting its implementation pending the resolution of the challenges. IID will continue to prepare for potential compliance should the legislation be upheld.

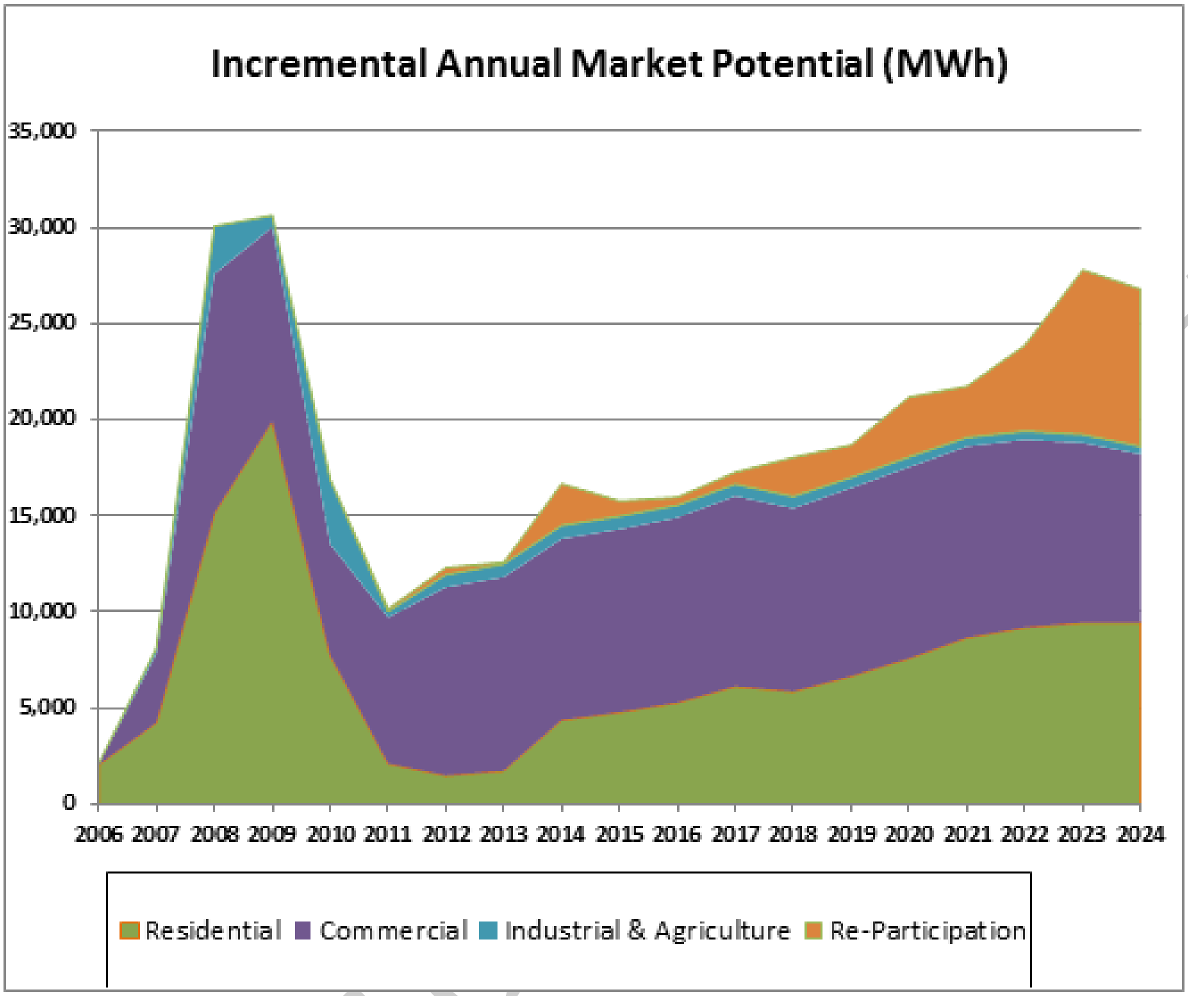
Through the IID's energy efficiency efforts, from 2009 through 2017, has reported saving over 165,996 megawatt hours saved.

Exhibit 61: Proposed and Achieved Energy Savings Targets



These targets consist of energy savings and demand-reduction potential in existing buildings and new construction for residential, commercial and industrial sectors. Figures are reported to the state and published annually in the Energy Efficiency in California's Public Power Sector report.

Exhibit 61: Incremental Annual Market Potential for Energy Savings



Source: 2017 IID Energy Efficiency Resource Assessment Model – Electricity & Natural Gas

Effects of Existing Programs

To support the state's long-term energy goals, a number of mandates have been implemented to not only encourage but to prioritize investments in all available energy efficiency and demand-reduction resources that are cost effective, reliable and feasible. As such, California utilities are to first meet load with these investments prior to procurement of other resources. On an annual basis, IID and other utilities report investment funding, cost-effectiveness methodologies and independent evaluations to the board, the state and our customers.

From 2015 through 2017, conservation programs implemented by the IID saved participating customers approximately 52,562.43 MWh in energy savings 17.74 in peak MW savings. The most successful programs, in terms of energy saved, has been the Custom Energy Solutions Program. Overall reported savings were a result of various measures within the residential and commercial sectors.

Exhibit 61: Summary of 2015-2017 Energy Savings

		Resource Savings Summary					Cost Summary	
Program Sector	Category	Units Installed	Gross Annual Energy Savings (kWh)	Net Coincident Peak Savings (kW)	Net Annual Energy Savings (kWh)	Net Lifecycle Energy Savings (kWh)	Utility Incentives Cost ($)	Total Utility Cost ($)
Appliances	Res Clothes Washers	497	87,957	-	76,523	841,748	49,628	56,400
HVAC	Res Cooling	86,850	37,792,638	11,129	31,881,855	106,447,453	7,081,139	8,446,814
Lighting	Res Lighting	5,845	216,037	215	208,461	1,098,706	72,660	91,523
Pool Pump	Res Pool Pump	938	1,289,670	222	1,122,013	11,220,129	147,786	277,023
Refrigeration	Res Refrigeration	1,538	472,272	47	354,495	2,859,096	102,100	161,083
HVAC	Res Shell	420,645	1,080,683	1,465	940,194	18,689,600	307,121	471,045
Comprehensive	Res Comprehensive	1,968	548,502	90	437,716	1,625,303	373,587	521,824
HVAC	Non-Res Cooling	11,171	4,706,883	1,359	3,821,214	39,718,135	1,675,792	1,945,738
Lighting	Non-Res Lighting	8	13,983,265	2,922	11,607,859	219,600,037	1,157,733	2,163,352
Process	Non-Res Pumps	1	130,926	17	111,287	2,225,742	13,263	22,830
Refrigeration	Non-Res Refrigeration	4	941,311	107	791,530	14,832,273	172,280	300,408
HVAC	Non-Res Shell	3	1,119,569	110	940,438	23,510,949	89,566	131,273
Process	Non-Res Process	1	247,515	24	209,150	3,764,703	44,553	54,814
Comprehensive	Non-Res Comprehensive	50	74,616	28	59,693	179,078	29,045	56,198
Total		**529,520**	**62,691,845**	**17,735**	**52,562,429**	**446,612,953**	**11,316,252**	**14,700,324**

Description of Existing Programs

The 2018 program portfolio is structured to allow IID to meet their annual target of 15,674 MWh. An overview of each program is provided below.

RESIDENTIAL PROGRAMS

Residential Energy Audits - This program allows residential customers to quantify energy consumption and to determine measures that can be applied to make the customer's home more energy efficient.

Energy Rewards Rebate Program - This program offers residential prescriptive rebates for qualified energy efficient measures such as air conditioners, ENERGY STAR® refrigerators, windows, attic insulation and pool pumps. New to the 2016 program is the ENERGY STAR® clothes washer incentive.

Refrigerator Recycling - The IID offers a $50 incentive and free refrigerator pickup with proper recycling services to our customers. This program targets older, less efficient units and those kept in basements or garages.

Quality AC Tune-Up - This program provides maintenance services designed to improve the operating efficiency of existing central air conditioners or heat pumps. The most recent program design included the addition of an efficient fan controller measure.

Payment Assistance - The IID offers income-qualified assistance programs designed to help customers meet their energy needs. Rate discounts are offered to income-qualified customers and a special rate is offered for those using critical medical equipment. A financial assistance program is also offered to customers facing financial crisis that are at risk of disconnection for nonpayment.

Commercial Programs

Custom Energy Solutions Program - CESP offers financial incentives to commercial customers intended to offset the cost to purchase and install qualifying energy efficiency measures. The measures must retrofit, replace or upgrade old equipment with new, energy-efficient technologies that exceed the applicable Title 24 energy efficiency requirements.

New Construction Energy Efficiency Program - NCEEP is a non-residential new construction and renovation energy efficiency program that combines an integrated design process with financial incentives for energy-saving design at least 10 percent above the current Title 24 requirements.

Commercial Energy Audits - This program allows commercial customers to meet with an energy specialist to evaluate their business' current energy use and identify ways in which to reduce their consumption, making their facility more energy efficient.

Energy Rewards Rebate Program - IID offers nonresidential customers prescriptive rebates for qualified energy-efficient measures. Measures must retrofit, replace or upgrade old equipment with new, energy-efficient technologies that meet and exceed the Title 24 standards. Qualifying product categories include programmable thermostats, HVAC equipment and motors.

The IID is also looking to new and emerging technologies such as home energy management systems and smart thermostats that offer customers new opportunities to manage their energy use. As these devices become more economic and integrated with each other, customer systems will offer automatic responses to changing utility price signals in real time, optimizing the operation of key appliances and energy systems to manage peak demand and reduce costs.

Rates

The IID also offers interruptible and high-voltage rates for its large commercial and industrial customers.

Key Customer Demand Response Program (Interruptible Load Program) - This program was developed in 2010 with a target participation of 25MW within three years. Program guidelines require enrolled large commercial and individual customers with onsite back up generation to curtail a minimum of 500kW upon timed notice by IID. Failure to curtail contracted reductions will result in a financial penalty. This generation can be used to reduce load during times of system stress either due to transmission or generation curtailments or if load exceeds forecasted demand.

High Voltage Rate Discount Program - Under this program, customers take electric services at 34.5 kilovolts or above at a single point of interconnection. The customer maintains all necessary step-down transformation and facilities beyond the transformer, which IID would normally own. In return, IID will provide a discount on the maximum demand energy charge and energy cost adjustment charge. The reduced electric rate offsets some of the customer's costs for the facilities, maintenance and necessary substation equipment.

Renewable-Energy Programs

In 2018, 35 percent of IID's overall generation delivered to customers will come from renewable energy sources. To help customers fully benefit from investments in various renewable options, the IID offers retail renewable programs for customers interested in meeting all or a portion of their load with a renewable resource.

Green Energy Rate

IID has developed a new Green Energy Rate Program that allows customers to designate how much renewable energy they wish to be served with. Customers who elect participation in the new Green Energy Rate Program, can choose to be served with an even greater percentage of renewables, up to 100 percent.

The program launched in the last quarter of 2018 and it is estimated that it will increase customers' per kilowatt-hour rate by $0.013 to $0.02. The monthly rate will fluctuate based on IID's cost to procure renewable resources.

The program will be open to all electric customers, with an exception for customers who have installed on-site renewable systems or wholesale power customers receiving standby service.

The district has allocated 5 megawatts in the initial offering of the program; however, additional megawatts may be added to the program if customer demand warrants an increase.

A champion for renewable energy, IID has invested millions of dollars in incentives to help customers take part in its renewable energy programs, including issuing rebates, weatherizing homes, tuning-up AC units and offering savings on energy and excess power sold to IID through net metering and net billing programs.

Net Energy Metering

Net Energy Metering is a program that was designed by the demand side management group to benefit IID customers who generate their own electricity using solar, wind, biogas, fuel cell or a hybrid of these technologies. The program included generating facilities up to 1MW and was offered on a first-come, first-served basis. IID's NEM program capacity is 50.2MW, 5 percent of IID's peak demand.

An installed bidirectional meter records the amount of energy (in kWh) delivered by the IID to the customer's premise, which is called net consumption. It also records the amount of energy (in kWh) generated by the customer's generating system, which was not consumed by the premise and thus returned to the IID's electrical grid. This is referred to as net generation. The net difference between these two amounts is what IID uses to create the participating customer's monthly bills.

Consistent with AB 920, the IID established a rate to purchase surplus electricity. At the end of a 12-month period, customers who are net generators will be compensated for surplus energy returned to the grid at the rate stated in the current net metering rate schedule. At the end of the 12-month period, customers that are net consumers, but in any given month within the 12-month period are a net generator, that monthly surplus energy will be tallied and credited to the customer at IID's current retail rate.

Although IID met its 50.2MW cap in the first quarter in 2016, it extended the program by an estimated 9.6MW to allow for customers that were in the process of submitting their applications an opportunity to participate. For the remaining customers that desire to generate all or a portion of their energy consumption, IID has developed the Net Billing successor program to continue to facilitate customer interconnection projects to IID's grid.

Exhibit 62: Net Energy Metering Program Installation Summary

Category Type	Total Systems Installed	Installed Capacity (kW)	Total Generation (kWh/yr)
Residential	4,017	24,933	53,945,906
Commercial	190	32,616	80,034,811
Government	10	911	1,967,788
Total	4,217	58,460	135,948,505

Net Billing Program

The Net Billing Program, successor to the Net Metering Program, is designed to benefit customers who generate their own electricity using solar or wind. The program paves the way for new solar development while at the same time reducing cross-customer subsidization between those with and without solar. Net consumption is billed to customers on each regular billing frequency and not aggregated to a 12-month period. Any net generation is compensated on each billing cycle at the applicable Distributive Self-Generation Service Rate. This is a variable rate and based on IID's lowest solar contract cost as which IID procures solar generation. The rate will be modified as deemed necessary by IID's board of directors.

Exhibit 63: Net Billing Program Installation Summary

Category Type	Total Systems Installed	Installed Capacity (kW)	Total Generation (kWh/yr)
Residential	775	3,950	8,474,241
Commercial	14	2,938	6,345,151
Total	789	6,887	14,819,392

Feed-In Tariff

SB 32, enacted in 2009, required the IID to implement a Feed-in-Tariff. The FIT program was adopted and approved by the IID Board of Director during the second quarter of 2013. In anticipation of the adoption of the program, IID accepted applications for the FIT program on a first-come, first served basis, which has been fully subscribed since January 16, 2013. The tariff provides a simple mechanism for small renewable generators (less than 3MW) to sell power to the utility at predefined terms and conditions, without engaging in contract negotiations.

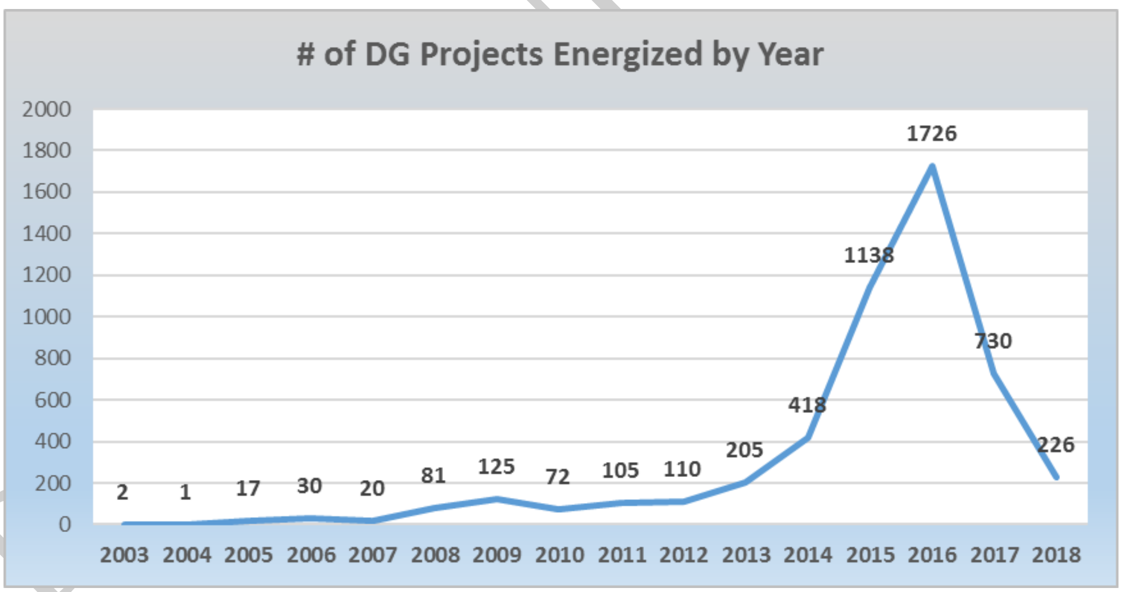
SB 1332 established Feed-in Tariff program caps determined by the ratio of the utility's 2011 peak demand to the 2011 statewide peak demand. For IID, this cap is estimated to be approximately 13 MW.

Eligibility criteria for IID's FIT consists of the following:

1) The project must be located within the IID service territory;
2) The project must be between 1kW and 3MW;
3) The project must be located and interconnected in a manner that optimizes deliverables of generation to load centers; and
4) The project must install eligible renewable generation.

Through the tariff, IID will purchase all generation from the facility and all Renewable-Energy Credits will belong to IID. Generating Facilities participating in the Feed-in Tariff program may not offset load at the site/facility nor are they eligible for any other IID for renewable technologies program (i.e., net metering rate, virtual net metering rate, etc.). Feed-in Tariff program participants also may not receive rebates from IID's SB1 PV/Solar Solutions Program.

Exhibit 64: Number of Distributed Generation Energized per year through 2018



ENERGY STORAGE SYSTEMS

As renewable-energy generation tends to be variable, intermittent and off peak, energy storage systems may optimize the use of significant additional generation that will be entering the grid on an accelerated basis as a result of California's energy goals. The state has declared that expanding the use of energy storage systems can reduce costs to ratepayers, reduce emissions from fossil fuel generation and enable and accelerate the implementation of more renewable generation and its integration in California's electrical system.

On September 29, 2010, the California Legislature enacted AB 2514 directing the California Public Utility Commission and governing board of a local publicly-owned electric utility to initiate proceedings prior to March 1, 2012, to determine energy storage procurement targets, if any. This legislation, considered the foremost statute relating to utility procurement of energy storage systems, asserts a number of findings regarding the value of energy storage and barriers that hinder timely implementation.

As part of the proceeding, the board of directors considered a variety of possible policies to encourage the cost-effective deployment of energy storage systems, including refinement of existing procurement methods to properly value energy storage systems. As required AB 2514 in 2014 the IID Board of Directors, as the governing board of IID, adopted an energy storage system procurement target of “0” due to the time and effort necessary to successfully complete planning and implementation of the reliability projects. As required by statute, the target was reevaluated in September of 2017. The IID board approved Resolution No. 20-2017 that adopted a procurement target of up to 5 MW to be achieved by December 2021 if such target is deemed viable and cost-effective.

Battery Energy Storage System

In November of 2015, the IID held a groundbreaking ceremony to mark the start of construction of their new 30 MW, 20 MWh lithium-ion battery storage system. The battery will increase reliability across the IID grid by providing the ability to balance power and integrate solar while providing spinning reserve and “black start” power restoration capabilities. The project is one of the largest of its kind in the western United States. It will consist of associated controllers, a substation and a 92 kV interconnection. The project will use environmentally safe lithium-ion batteries. Some of the benefits of the project are as follows:

- Reliability – This project adds reliability to the IID grid, the district can use the battery system to “black start” units at the El Centro Generation Station, one of IID’s main internal sources of generation.

- Environmental – The battery storage system will smooth power supplies and acts as a spinning reserve, assignments that typically require expensive fossil fuel generation.

- Economic – Reduction in IID operating costs in the first year and throughout the lifetime of the project which provides significant cost savings to rate payers.

The BESS project was completed in mid-2016.

Other Investments

From time to time, the IID invests in pilot projects to assess the impact, benefits and performance of new and emerging technologies or to test concepts for suitability. These pilots may result in implementation of full-scale programs if it meets cost effectiveness, qualifications or policy-driven goals. Examples of these investments may include:

- Development of emerging technologies for the market via a small-scale program designed to demonstrate the costs and benefits to decision makers and increase market penetration in the technology market.

- New combinations of existing and new technologies, control systems or software to dramatically increase the anticipated savings from each component of the system due to synergies between components, which may be implemented elsewhere.

IID, in its sole and absolute discretion, determines if funds shall be made available and what technologies and/or approach, if any, will be used to pilot a program. Projects that are typically deemed ineligible for funds consist of unproven new technology, tool development, research and development or completion of product development as well as demonstration projects, R&D prototypes, and limited production technologies that cannot support an effective regional energy efficiency program.

The IID welcomes the opportunity to collaborate with other agencies on energy efficiency, renewable or other sustainable projects and programs. Collaborative efforts allow the agencies to share resources that benefit both the utility and our ratepayers while providing detailed information that helps determine whether the utility and its ratepayers will benefit from large scale investments.

e-*GREEN PROGRAM*

The Imperial Irrigation District initiated a process to bring inexpensive utility scale solar to its low-income residents and the ability to "go-green" to individual households. IID evaluated multiple community solar programs including Sacramento Municipal Utility District's SolarShares, Los Angeles Department of Water and Power's RepowerLA and Salt River Project's EarthWise Energy. Each of these programs have excellent benefits and were crafted in a manner most appropriate to the individual utility.

IID reviewed its customer needs, its available resources, and developed its own unique solar program entitled eGreen. The eGreen Program was customized to bring solar energy to low-income families while benefiting from IID's ability to acquire attractive energy pricing. eGreen allows IID's customers to reap the benefits of clean, renewable solar power without the need for on-site installation.

To bring solar power to its low-income customers, IID developed a structure that will brings together the following:

- Minimal interconnection costs.
- Aggressive pricing on utility scale solar component parts.
- The value of Renewable Energy Credits.
- The value of Federal Investment Tax Credits (to the Generator).
- IID's own public programs.

eGreen will allow all IID customers to benefit from solar without concern of property ownership, structural integrity or financial ability. eGreen enhances the ability for all IID customers to benefit from solar.

To present robust and accurate information about community based e-green solar, the team examined IID's current distributed generation programs, as well as other utilities' mechanisms for launching customer choice programs.

In its analysis of a community based "e-Green" solar program, the team defined business objectives as:

- Increase public understanding of solar energy and its role in IID's renewable transformation.
- Create an attractive program in which all customer classes can enroll while being viable, economic and sustainable for IID.
- Assure simplicity for customers and IID (administrator) alike.
- Alleviate the potential load and revenue losses to the utility.
- Integrates easily into IID's billing system.
- Apply Renewable Energy Credits to Renewables Portfolio Standard.
- Reduce risk to IID and its customers by structuring program funding by participants.

Customer benefits or the reasons customers choose to participate include:

- Leverages economies of scale.
- Offers lower cost of electricity and stable rates.
- No up-front costs, drop-out penalties or system maintenance.
- No hassle with contractors or red tape.
- Available to all customers, except existing Net Energy Metering (NEM) and Virtual Net Metering (VNM) customers.
- Increases customer access to solar.

And, there are IID benefits, as well:

- Gives customers a choice.
- Increases proactive customer engagement and loyalty.
- Can be strategically sited.
- Maximizes production.
- Optimal distribution grid benefit and control.
- Apply RECs to RPS.
- Provide a "green" component for low-income customers.

While identification of the benefits seemed intuitive for the team, the operational and financial analysis proved to be more complex. Resource Planning conducted a comparison of net operational cost impacts on various potential "e-Green" solar projects. This comparison is based on numerous production cost model simulations that compare how adding a resource will affect daily dispatch operations over a 20-year period. These studies include integration cost such as, ancillary services, loss of flexibility, ramping needs, operating reserves, etc.

The first operational study included multiple new facilities: 5 MW, 10 MW, 20 MW, 20 MW (phased in) and existing Feed-In Tariff (FIT) 2 MW (a breakdown of FIT prices can be shown in Appendix B) with contract prices varying from \$40-\$70/MWh (no escalation). The study concluded, using the existing FIT projects was the least expensive operational costs since these projects are already part of IID's portfolio.

Any current IID solar project would yield the same results. The integration of a new facility would cause risks of ancillary service impacts, larger amounts of excess generation, slightly higher system costs, and risk of customer participation (which could cause a cross-customer class cost subsidization).

Based on the first study, management provided the team with a 20 MW project with a $50/MWh contract price with a buyout option in year seven. The team evaluated four buyout scenarios: buyout at a Fair Market Value of $100, $50, $30, and $15 million. The study concluded the buyout option would need to be in the range of $15-$20 million, but the risks of ancillary service impacts, larger amounts of excess generation, slightly higher system costs, and risk of customer participation (which could cause a cross-customer class cost subsidization) would still exist.

The third operational study helped mitigate the excess generation by the applying term sales. Term sales are sold at forecasted annual market prices at a cost lower than a purchase price which are based on historical sale data. Two sale volumes were analyzed: 20 MW and 50 MW, along with different sale periods: off-peak hours and all hours of the day (24 hours, 7 days), with contract prices ranging from $30-$50/MWh. During this time, the team was provided legal opinion regarding the use of SB 1 funds (Appendix E), these funds were applied to the FIT projects. The study concluded a 20 MW phased in project with 20 MW of off peak term sales was the least expensive, in terms of operational cost. The excess generation that comes with a new facility is sold back to the market, therefore recovering some of the costs of integrating the new resource to the IID supply stack. The operation cost savings by utilizing term sales for the new 20 MW facility would be $10,006,000 (NPV) over a 20-year period. Please note: term sales would still cause risk and IID's risk policy would have to be modified and approved. By adding a new 20 MW facility, it would create a cross-customer class cost subsidization if IID does not fully subscribe the 20 MW.

At the request of management, the team evaluated only the 20 MW new facility at $30/MWh with additional scenarios: high market price forecasts, economic sales, 3.5 percent, 6 percent, 11 percent spin requirements and shutting down one unit in the winter and summer. These scenarios would mitigate the ancillary services impact and excess generation. The study concluded that all scenarios yielded operational savings for IID, but the greatest savings came from economic sales. The last study conducted was built off the previous study and combined 3.5 percent spin requirement, economic sales and shutting down one unit in winter and summer. This scenario would yield the greatest savings of $344,058,000 over a 20-year period (NPV). Please note: economic sales, reducing spinning reserves and shutting down one unit would cause risk and IID's risk policy would have to be modified and approved. By adding a new 20 MW facility, it would create a cross-customer class cost subsidization if IID does not fully subscribe the 20 MW.

A high level of the multiple studies conducted are shown in the illustration below, the full detail with analysis can be found in Section 5.3.

Exhibit 65: History of operational studies

<u>Recommendation for Community based "e-Green" Solar Program:</u>

After evaluation of various solar structures, IID entered into a 23-year power purchase agreement with Citizens Energy Corporation. for 30 MW of solar energy to serve approximately 15,000 low-income electric customers under the district's eGreen Program. The solar project will be located on approximately

200 acres of district-owned land, leased to Citizens, and connected to IID's electric system. The district will use the energy purchased from the project to lower the energy bills of its qualified low-income customers many of which reside in areas designated as disadvantaged communities by CalEPA and CalEnviroScreen related to SB 535. Citizens Energy, a nonprofit energy company with a robust portfolio of utility-scale solar projects, has an existing commitment through its stake in the Sunrise Powerlink transmission line running through the Imperial Valley to invest in programs that serve low-income customers in IID's service area.

The eGreen Program is intended to serve IID's low-income residential energy assistance program participants. Those participants currently receive an on-bill subsidy through IID's REAP. The power purchase agreement is for a 23-year term with a beginning cost of $29.75 per MWhr. There are certain market conditions at this time that may drive an increase in the per MWhr price; those price increases will be subject to future review and approval by the IID Board of Directors. There is optionality at the end of the PPA term for IID (1) to purchase the facility' (ii) agree to a new PPA; or (iii) decommission the project. The target commercial operation date for the generation is Jun 2019; that date may change based upon the permitting and interconnection processes. Staff is working on guidelines for the eGreen Program and will bring those back to the board for review and approval prior to commercial operation of the generating facility.

The PPA is for 30 MW; 20 MW is procured by IID and 10 MW donated to IID by a Citizen Energy sole purpose entity to serve its commitment to Imperial County's low-income ratepayers. The PPA has a beginning price per MW/hr of $29.75 for the 20 MW; when the contributed 10 MW is factored in, the effective price per MW/hr is $19.83. The PPA includes an annual price escalation of 0.5 percent for the entire 23-year term.

The project's output is expected to qualify as a Category 1 resource under the California Public Resources Code portfolio content category requirements. IID will work with Citizens to ensure the project is pre-certified through the California Energy Commission.

IID will assume all costs of transmission-provider interconnection facilities and network upgrades for the plant's physical connection to the IID system. Citizens is responsible for all customer-interconnection facility costs, as those terms are defined in IID's open access transmission tariff. IID will support Citizens in the permitting process through the County of Imperial for the solar plant. IID will be responsible for permitting the interconnection facilities and any network upgrades.

The generation addition will have an approximate annual financial impact of $2.6 million. These costs will be paid utilizing the public benefit fund balance account until funds have been depleted at which time the funding source will be reassessed for potential funding from the public benefit charge or the energy cost adjustment.

eGreen Enrollment

eGreen will automatically enroll REAP customers when they renew their annual participation. IID's goal is to have 100 percent allocation of its REAP customers to eGreen. Once all REAP customers have transitioned to eGreen, the remaining MW may be offered to customers and businesses until the entire system capacity has been fully allocated. Program levels will be analyzed monthly in order to confirm allocation.

eGreen Ancillary Benefits

- Solar generation pricing is lower than on-peak energy market pricing.
- Dispatch flexibility, IID can shut down or sell the energy output during favorable market conditions, further increasing cost savings.
- Project owner will operate and maintain the facility; costs are imbedded in the price of energy.
- Production parameters are established in the long-term agreement between IID and developer.

IID believes eGreen better serves its customers by providing long-term benefits, particularly for IID's low-income-qualifying customers residing with areas designated as disadvantaged communities as defined in SB 535.

Alternatives:

An alternative would be to implement a larger new facility of 20 MW. In previous production cost modeling studies, risks associated with implementing a new 20 MW facility were identified and the final operational study was conducted to mitigate ancillary services impact and excess generation. The table below shows high level issues with potential solutions; based on management decision, only potential solutions highlighted in red were studied (ancillary services and excess generation impact). When the team studied economic sales, reducing spinning reserves, and shutting down a unit, these impacts helped mitigate ancillary service impacts and excess generation. Therefore, the studies concluded the combination of the three scenarios would have the greatest operation cost saving for a NPV 20-year period of $344,058,000. Please note: these scenarios have not been approved by departments and/or management and are theoretical for the case of the study. IID will have to modify various business activities to ensure economic value of the "e-Green" Solar program and to mitigate or control risks.

Exhibit 66: Potential Risks

Potential Solutions to Cost Impacts of Adding 20 MW	
Issue	**Solution**
Ancillary Service Impact	Apply battery settings to address this issue;
	Explore the purchase of ancillary services from neighboring markets;
	Explore new quick responding generation additions
Excess Generation	Explore unit economic cycling; Explore seasonal unit shutdown alternatives;
	Term sales or economic dispatch sales
Slightly Higher System Costs	RFP process can reduce contract costs through greater negotiating leverage
Risk of Customer Participation	Require developer to commit to assisting IID with Marketing Campaign

The final two operational studies reviewed a new 20 MW facility at $30/MWh project coming online mid-2018, with taking into consideration various system scenarios being implemented. The studied scenarios were evaluated based on mitigating ancillary service impacts and excess generation. Consequently, when we combine all system changes previously tested through a coordinated effort, then value can be added. Please note: the system changes (economic sales, reduce spinning reserves and shutting down a unit) would also add value in the case that does not add 20 MW new facility (IID's current portfolio).

Exhibit 67: "e-Green" Solar Operational Impact Study Scenarios

Community Solar Operational Impact Studies			
Facility Type	**Capacity (MW)**	**System Scenario**	**COD**
New Facility	20MW @ $30	Expected Price Forecast	6/1/2018
		High Market Price Forecast	
		Economic Sales	
		3.5% Spin Requirements	
		6% Spin Requirements	
		11% Spin Requirements	
		1 unit required winter; 3 units required in summer	

The key assumptions used in the operational study were:

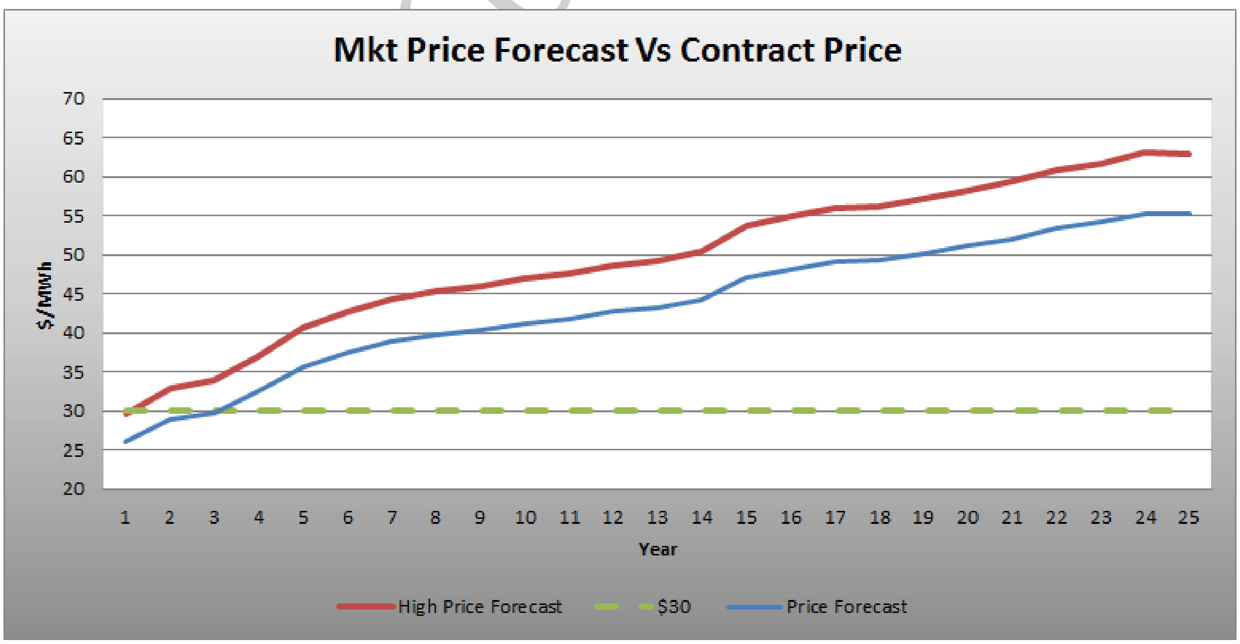
- Expected Price Forecast:
    - 2016 Load forecast.
    - Spring 2016 LT price forecast +10 percent
    - 100 percent of the "e-Green" Solar Project 20 MW project is sold to customers simultaneous to the Commercial Operation Date of the project built and throughout the life of the project. If the project is not sold, then there will be additional costs that will affect

the Rates side. This does not consider the additional costs of revenue losses that may occur if project.
- All projects online and producing as expected by their respective CODs.
- Assumes the contract costs can be achieved through the procurement process. If there is escalation in the contracts of pricing differences, then results will vary.
- 5 percent interest rate in NPV calculations.

- High Market Price Forecast
  - Use high price forecast of gas/energy prices.
- Economic Dispatch Sales
  - Assumes that the day ahead/real time groups economically dispatch to serve load and sell to all accessible markets; separate from term sales.
- 3.5percent, 6percent, and 11percent Spin Requirement Scenarios
  - IID would buy spinning reserves to cover difference of spin with solar vs 3.5percent, 6 percent, and 11 percent.
- Seasonal Unit Requirement
  - 1 unit only required during the winter; 3 units only required during the summer.

The market price was evaluated at two different levels; the expected market price forecast and high market price forecast. The high market price forecast was evaluated because it represents the 90th percentile of probability distribution using multipliers generated from the Monte Carlo Stochastic analysis. The pricing scenarios are not meant to represent specific future market circumstances but instead are intended to represent the potential price impact of a collection of uncertainties around key market factors affecting the cost and availability of future gas supply. Below is a chart to reflect the $30 contract price, along with the two different market price forecasts.

Exhibit 68: Forecasted market price versus contract price



The table below show the results of the operational study indicating the net present value (NPV) for the multiple scenarios over a 20-year period (chart below are in thousands). All operational studies contain the sale of excess generation (MWh) into the market over the 20-year period.

Exhibit 69: Net Present Value of Annual Costs: System Solutions Tests

System Solutions Test Results								
Year	Expected Price Forecast	High Market Price Forecast	Economic Sales	3.5% Spin Requirements	6% Spin Requirements	11% Spin Requirements	1 unit required winter; 3 units required in summer	Econ Sales + 3.5% Spin + 1/3 units in winter/summer
NPV	$4,062,420	$4,359,610	$3,727,790	$3,751,769	$3,751,822	$4,062,420	$3,757,525	$3,718,362
Rank	6	8	2	3	4	6	5	1

<u>*Alternative 1*</u>

As shown from the table above, the operational NPV with bringing on a new 20 MW solar project is $4,062,420,000, with the expected price forecast over a 20-year period. The production cost model simulations indicated the combination of 3.5 percent spinning reserves, economic sales and shutting down one unit had the greatest operational cost impact of $344,058,000. Each of these system wide changes assume a coordinated effort within the Energy Department to ensure risks associated with each system change are mitigated to the greatest extent possible.

<u>*Alternative 2*</u>

Another option to mitigate excess generation, would be economic sales. The operational impact study revealed economic sales had the second greatest operational savings of $334,630,000 (NPV over a 20-year period). Economic sales would be evaluated on an hourly basis and would utilize internal generation to ramp up/down depending on the market prices. IID's current risk policy does not allow for economic sales; prior to implementing, the policy must be amended and approved.

<u>*Alternative 3*</u>

Another option to reduce operational cost would be to reduce spinning reserves from the current 11 percent to either 6 percent or 3.5 percent; both indicated savings. Spinning requirements are based on several hourly varying requirements from the Southwest Reserve Sharing Group (SRSG) and the Western Electricity Coordinating Council. Under normal circumstances, a Balancing Authority is required to maintain, at a minimum, reserves equal to the loss of the Most Severe Single Contingency or the reserve amount equal to the sum of three percent of the load (generation minus station service minus net actual interchange) and three percent of net generation (generation minus station service). IID must maintain at least 50 percent of its contingency reserves as spinning reserves. Spinning reserve is the on-line reserve capacity that is synchronized to the electric grid and ready to meet electric demand within 10 minutes of a dispatch instruction. Spinning reserve is needed to maintain frequency stability during emergency conditions and unforeseen load swings. The operational savings associated with reducing the spinning reserves from 11percent to 6 percent and 3.5 percent are $310,598,000 and $310,651,000, respectively.

The table below breakdowns the estimated cost to operate at 3.5 percent, 6 percent, and 11 percent spinning reserves. For example, looking at year 2019, if IID were to reduce their spinning reserves from 11 percent to 6 percent, the estimated cost savings would be $2,038,219 and if IID were to further reduce their spinning reserves to 3.5 percent, the estimated cost savings would be $3,057,329.

Exhibit 70: Breakdown of estimated costs of spinning reserves

Est. Spinning Reserve Costs							
Year	Load	3.5% spin	6% Spin	11% Spin	Est. Cost of Spin (3.5%)	Est. Cost of Spin (6%)	Est. Cost of Spin (11%)
2017	3,616,064	126,562	216,964	397,767	$ 1,392,185	$ 2,386,602	$ 4,375,438
2018	3,655,924	127,957	219,355	402,152	$ 1,407,531	$ 2,412,910	$ 4,423,668
2019	3,705,854	129,705	222,351	407,644	$ 1,426,754	$ 2,445,864	$ 4,484,083
2020	3,759,566	131,585	225,574	413,552	$ 1,447,433	$ 2,481,314	$ 4,549,075
2021	3,810,615	133,372	228,637	419,168	$ 1,467,087	$ 2,515,006	$ 4,610,844
2022	3,868,314	135,391	232,099	425,515	$ 1,489,301	$ 2,553,088	$ 4,680,660
2023	3,929,522	137,533	235,771	432,247	$ 1,512,866	$ 2,593,484	$ 4,754,721
2024	3,994,922	139,822	239,695	439,441	$ 1,538,045	$ 2,636,648	$ 4,833,855
2025	4,062,922	142,202	243,775	446,921	$ 1,564,225	$ 2,681,528	$ 4,916,135
2026	4,133,278	144,665	247,997	454,661	$ 1,591,312	$ 2,727,964	$ 5,001,267
2027	4,206,233	147,218	252,374	462,686	$ 1,619,400	$ 2,776,114	$ 5,089,542
2028	4,284,380	149,953	257,063	471,282	$ 1,649,486	$ 2,827,691	$ 5,184,100
2029	4,362,150	152,675	261,729	479,836	$ 1,679,428	$ 2,879,019	$ 5,278,201
2030	4,441,207	155,442	266,472	488,533	$ 1,709,865	$ 2,931,197	$ 5,373,860
2031	4,532,628	158,642	271,958	498,589	$ 1,745,062	$ 2,991,535	$ 5,484,480
2032	4,617,573	161,615	277,054	507,933	$ 1,777,766	$ 3,047,598	$ 5,587,263
2033	4,705,857	164,705	282,351	517,644	$ 1,811,755	$ 3,105,865	$ 5,694,087
2034	4,802,727	168,095	288,164	528,300	$ 1,849,050	$ 3,169,800	$ 5,811,299
2035	4,905,833	171,704	294,350	539,642	$ 1,888,746	$ 3,237,850	$ 5,936,058
2036	5010318.582	175,361	300,619	551,135	$ 1,928,973	$ 3,306,810	$ 6,062,485
2037	5113746.972	178,981	306,825	562,512	$ 1,968,793	$ 3,375,073	$ 6,187,634

<u>*Alternative 4*</u>

Another option to reduce operational costs would be to shut down one (1) unit in the summer and winter; therefore, only three (3) units would be running in the summer and one (1) in the winter. The unit chosen to shut down was based on unit heat rate. By shutting down one unit, it would mitigate the excess generation with bringing on a new 20 MW facility. The operational cost savings (NPV over a 20-year period) is $304,895.

In summary, a combination of all three scenarios provided the greatest NPV operational cost saving over a 20-year period. A summary of the cost savings associated with each scenario are below along with the ranking.

Exhibit 71: Operational Cost Savings

Operational Cost Savings					
	Economic Sales	3.5% Spin Requirements	6% Spin Requirements	1 unit (Winter); 3 units (Summer)	Econ Sales, 3.5% Spin, 1/3 units in winter/summer
NPV Savings	**$ 334,630.00**	**$ 310,651.00**	**$ 310,598.00**	**$ 304,895.00**	**$ 344,058.00**
Rank	2	3	4	5	1

Financial Analysis

The Finance Rates Section analyzed the "eGreen" Solar Rates, Estimated Number of Subscriptions and Revenue Loss based on a proposed 20 MW Power Purchase Agreement for 25 years. The exhibit below shows the comparison of the cost of solar installation on a kWh basis for a customer in relation to IID's retail energy kWh rate and the "e-Green" solar rate options. The "eGreen" solar rate options include the fixed cost recovery portion of the base energy retail rates, which were determined from the latest retail electric cost-of-service study performed for IID, and the inclusion of the contract price and cost obligations under the Regenerate purchased power agreement that is intended to be utilized for the "eGreen" solar program. This includes the estimated annual payments totaling up to $43.6 million that is applied against the cost of energy which is $37.95/MWh. The annual cross-customer class cost subsidization is approximately $2.3 million (if 20 MW is fully subscribed then the subsidy would be eliminated). All this equates to the "eGreen" Solar Rate. **The rates do not include any program administration, marketing, and SAP billing configuration.**

Furthermore, after receiving offers from community solar developers, below is a summary of the selected offer that provided a 20 MW solar farm where 10MW would be donated by the developer:

Exhibit 72: E-Green Solar Project Total Cost Comparison

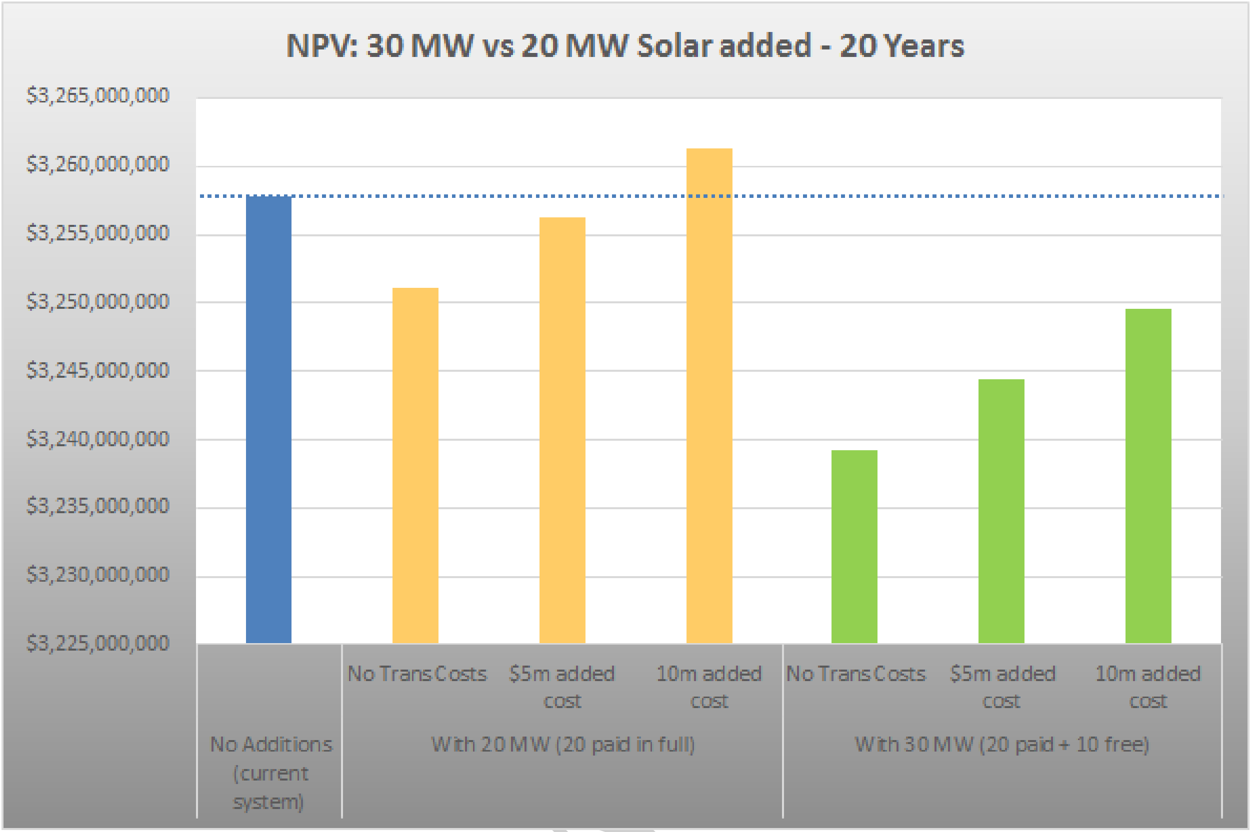


Exhibit 73: "e-Green" Solar Rate Options

Customer Class	Cost of Solar Installation $/kWh		Existing kWh Rate	Community Solar Regenerate PPA
	Low	High		
Residential	0.1400	0.1700	0.1169	0.1471
Small Commercial	0.1300	0.1600	0.1201	0.1403
Large Commercial	0.1300	0.1600	0.0930	0.1289
Agricultural Pumping	0.1300	0.1600	0.0952	0.1430
Municipal Service	0.1300	0.1600	0.1141	0.1359

If a 20 MW "eGreen" Solar program will be implemented at once or phased in approach. The estimated number of customers listed below will be required to participate in order to fully subscribe the program. These numbers were calculated using average kWh consumption loads.

Exhibit 74: Customer Subscription for 20 MW "e-Green" Solar Program

Customer Class	Potential System Size (kW)	Estimated Number of Customers to Enroll
Residential	1,000	2,036
Small Commercial	2,000	1,728
Large Commercial	13,000	360
Agricultural Pumping	2,000	580
Municipal Service	2,000	765
Total	20,000	5,469

If the FIT option was implemented for the "eGreen" Solar program, below is the estimated number of participants to fully subscribe the program.

Exhibit 75: Customer Subscription for 2 MW "e-Green" Solar Program

Customer Class	Potential System Size (kW)	Estimated Number of Customers to Enroll
Residential	100	204
Small Commercial	200	173
Large Commercial	1,300	36
Agricultural Pumping	200	58
Municipal Service	200	76
Total	2,000	547

The estimated annual cost impact has been determined using the billing rate option. The cross-customer class cost subsidization was calculated using the generation from the solar system as indicated under the draft Regenerate PPA. The annual impact to all retail electric customer is estimated at $2.3 million if the 20 MW program are not fully subscribed. Since this resource is not needed by IID, factored in is an estimated revenue for any excess energy sold in the open market to offset the annual impact to customers. **The annual cost impact does not include any program administration, marketing, and SAP billing configuration.**

Exhibit 76: Estimated Cost Impact

Annual Estimated Impact

Customer Class	Estimated Cost Impact Regenerate PPA
Residential	$ 202,013
Small Commercial	$ 456,244
Large Commercial	$ 2,411,452
Agricultural Pumping	$ 309,419
Municipal Service	$ 446,584
Subtotal	$ 3,825,711
Value of Solar	$ 1,487,624
Net Impact	**$ 2,338,087**

Therefore, the optimal option would be to use an existing resource so that we implement a pilot "eGreen" program and set lower rates that will incentivize participation while minimizing cost impact and give an opportunity for some revenue recovery.

Additionally, IID can apply a portion of the PBC Fund Balance to help offset the price – the amount will be based on management decision.

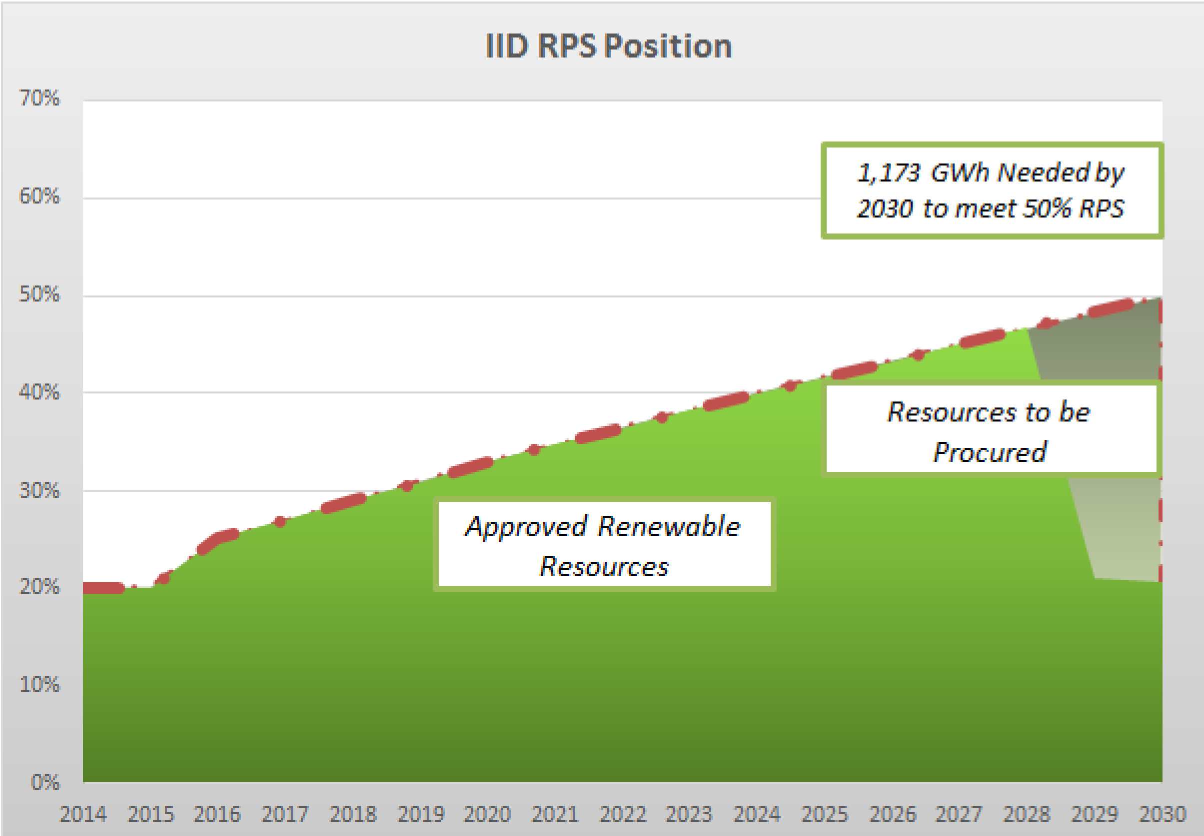
<u>E-Green Energy Program</u>

In terms of developing a Green-e Energy Program it is recommended that participating customers enroll for a flat per MWh monthly fee. This will provide businesses an easy, low-cost way to demonstrate compliance in corporate sustainability objectives. Sacramento Municipal Utility District currently offers a Green-e Energy program in which it voluntarily accepts and supports the Green-e Energy Code of Conduct and Customer Disclosure Requirements and independent verification methods. The Green-E Energy logo means:

- The renewable energy option contains only new renewable resources.
- The sources of energy supplying the renewable energy option are independently verified by Green-e Energy, operated by the non-profit Center for Resource Solutions.
- The purchaser of a Green-e Energy Certified renewable energy option is the sole "owner" of the environmental attributes of a specific megawatt hour (MWh) of energy added to the grid. Independent verification ensures that no MWh are double-counted.
- The company offering the certified renewable energy option agrees to abide by the Green-e Energy Code of Conduct and Customer Disclosure Requirements governing its ethical treatment of customers.

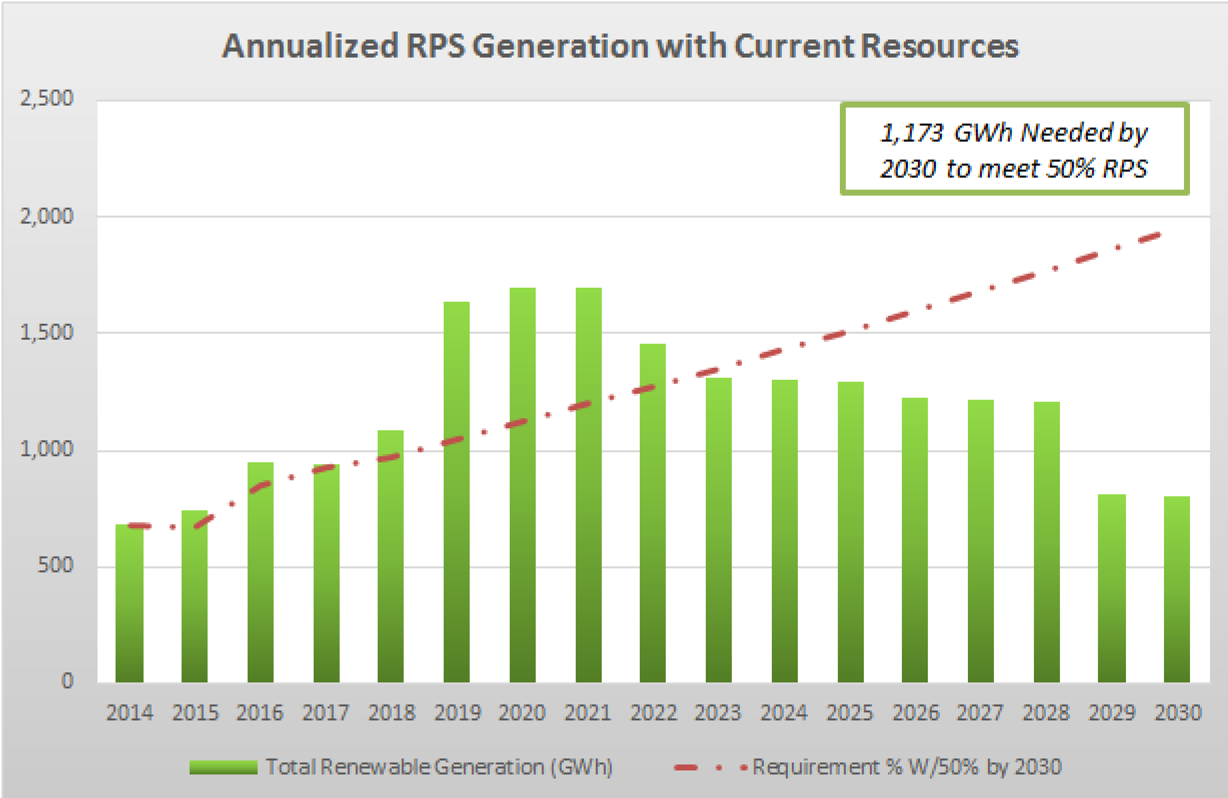
In April 2016, IID's Resource Planning Unit evaluated the impact of selling RECs. The first graph below is the expected case of RPS position, which uses various types of RECs as the measuring unit and is based on normal weather conditions:

Exhibit 77: RPS Position with Current Resources and Carry Over



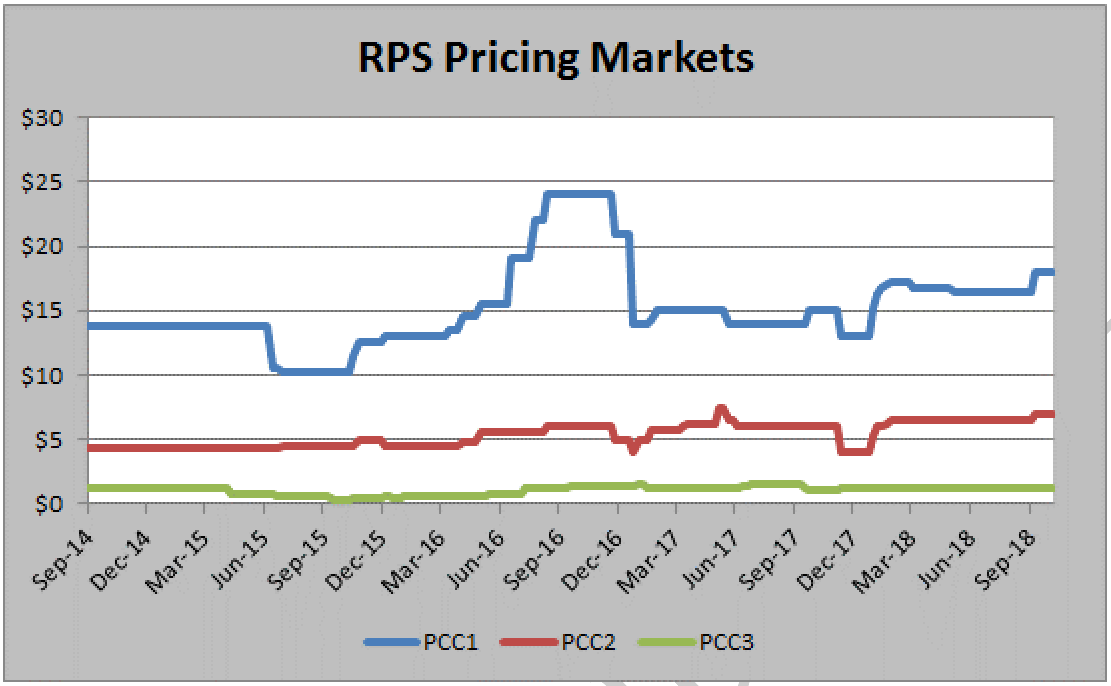
The chart below shows the REC production by year. Please note, any excess RECs generated in a given year can be retired with the same value for a future period up to 36 months. This is why the first Chart 2 shows a short position in 2025, but the chart below indicates its occurrence sooner:

Exhibit 78: RPS Position with Current Resources and Carry Over



As described by the current RPS law and will be described by the upcoming RPS guidelines post 2020, IID can utilize "compliance mechanisms" such as Portfolio Content Categories to minimize cost and operational impacts of RPS compliance. For example: the market value of Portfolio Content Category (PCC) 1 is $13.50/MWrec. A "bundled" product would be the value of the REC + index energy $/MWh. The Index $/MWh = $30/MWh, PCC1 REC $/MWrec = $13.50, then the total renewable energy value = $43.50/MWh. Below is a chart of RPS pricing markets for each Portfolio Content Category from September 2014 thru March 2016:

Exhibit 79: RPS Pricing Markets



It is important to note that IID's current position of RPS is mainly a result of lower than expected load growth, higher than expected production from RPS facilities and over procurement of RPS resources. Also, the occurrence of non-flexible generation is apparent as IID moves forward with obtaining the RPS compliance. The exhibit below is a forecast of the seasonal over generation for the next five years:

Exhibit 80: Excess Generation Forecast

Over Generation Stats			Summer		Winter	
Year	# hours	MWh	# hours	MWh	# hours	MWh
2016	825	17,241	NA		825	17,241
2017	2,064	66,140	562	25,049	1,502	41,092
2018	26	2,562	26	256	0	0
2019	252	4,775	145	3,376	107	1,399
2020	184	3,443	116	2,595	68	848

As a result, Resource Planning has indicated 2017 is an ideal year to test an RPS sale due to the following:

- The RPS position is very comfortable.
- The hourly excess generation is projected to be high.
- The 2016 market pricing is very low, which translates to a lower sale price.
- A sale in 2016 would likely be much lower than current IID renewable costs.

- A sale could help recover some, but not all the net impact from renewables.
- The 2016 summer capacity (non-natural gas) is needed due to Aliso Canyon concerns.

Some key considerations in a sale are as follows:

- 2017 is an ideal year to test an RPS sale, but the winter of 2016 is a great option, due to the following:
  - *RPS position very comfortable and hourly excess generation is projected to be high.*
  - *A sale could help recover* ***some*** *of the net impact from renewables; but not all.*
- RPS Carry-Over
  - *CEC requires WREGIS retirement within 36 months of REC generation.*
  - *Studies show that consistent over production or low loads could cause RECs to build up over a concentrated period to the point that there will be too many RECs to be within the 36 month retirement period and;*
- RFP for sale of RPS products
  - *Several parties have expressed interest ranging from $18.50-$22.50/REC + index.*
- IID Risk Policy
  - *Need to check with Risk Management to explore if portfolio sale of excess energy/RECs should fall under current language of risk policy.*
- Balancing requirements of Seller vs Buyer
  - *Agreement needs to limit the amount IID will balance over/under generation or be 0.*
  - *Extra costs of balancing can range from $20-30/MWh.*
  - *Generation/Schedule Imbalance Risk.*

Resource Planning has indicated four methods of sale:

1. Unit Specific Sale:
   a. Market not close to IID costs.
   b. For example: ask price can be $55-60, but loss of about $35/MWh.
2. RPS Portfolio sale at IID weighted average Variable System Cost:
   a. Ask price needs to be above the variable system cost levels to cover market risks (reserves, etc.).
3. Unit specific sale at IID incremental system cost.
4. Unit specific sale at current market price:
   a. For example: $43.50/MWh, no more $50/MWh less than IID costs.

Furthermore, the hours that could be sold that already correlate to the hours where IID is long in overall generation are highlighted in green in the exhibit below using 2017 as the example year:

Exhibit 81: Best Hours to Schedule an RPS Sale

2017											
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
(4)	(15)	(18)	18	49	(31)	(60)	(121)	(31)	(16)	9	(12)
5	(5)	(6)	33	70	(3)	(32)	(90)	(7)	(2)	(17)	(3)
11	1	3	43	85	19	(9)	(66)	12	9	(9)	4
12	4	5	48	95	35	8	(48)	26	14	(6)	6
8	1	3	46	98	43	17	(41)	29	12	(8)	2
(7)	(16)	(12)	41	107	57	27	(40)	20	(3)	(21)	(11)
(32)	(36)	(11)	65	129	76	42	(26)	33	1	(31)	(28)
(25)	(24)	25	93	137	68	38	(28)	52	33	(10)	(20)
15	8	50	96	125	42	8	(57)	36	43	19	4
46	23	52	86	102	3	(30)	(107)	(2)	22	19	25
49	23	45	74	75	(43)	(74)	(164)	(51)	(5)	14	33
47	25	31	57	44	(88)	(118)	(216)	(101)	(35)	7	35
48	22	19	36	10	(133)	(165)	(270)	(150)	(65)	(2)	35
44	17	8	15	(22)	(175)	(202)	(313)	(192)	(93)	(13)	28
35	10	(8)	(8)	(55)	(211)	(234)	(348)	(222)	(121)	(32)	11
(1)	(13)	(29)	(27)	(83)	(242)	(261)	(375)	(252)	(155)	(79)	(19)
(48)	(56)	(69)	(63)	(115)	(272)	(289)	(404)	(288)	(191)	(120)	(64)
(96)	(105)	(108)	(98)	(142)	(293)	(313)	(417)	(293)	(187)	(145)	(104)
(106)	(131)	(130)	(106)	(139)	(285)	(304)	(393)	(262)	(177)	(142)	(109)
(102)	(127)	(138)	(111)	(123)	(253)	(275)	(360)	(237)	(162)	(134)	(106)
(95)	(118)	(128)	(102)	(108)	(224)	(245)	(326)	(202)	(137)	(122)	(99)
(74)	(95)	(102)	(73)	(72)	(178)	(200)	(273)	(156)	(104)	(99)	(83)
(45)	(62)	(67)	(36)	(23)	(121)	(146)	(213)	(104)	(66)	(71)	(56)
(18)	(34)	(38)	(4)	18	(71)	(96)	(160)	(59)	(34)	(41)	(30)

A unit specific or portfolio based sale would require hourly analysis. All methods provide a revenue stream and can recover costs, but the market costs will need to be evaluated. A REC program will not reduce participating customer bills, but will provide green attributes for a fixed cost on top of the monthly bill.

<u>Customer Education and Survey</u>

Although significant time and resources have been dedicated toward development of this business case, it lacks one very important element - a survey of our customers. In order to achieve full subscriptions for the Community Solar and "e-Green" Energy programs, it is critical that we understand demographics, new product acceptance and customer attitudes and expectations. It is therefore, the team's recommendation to first develop a market study or survey to gauge the level of interest for a "e-Green" solar program and a Green-e Energy Program. Concurrently, an educational outreach effort should be conducted to inform customers of the benefits of such programs.

While this particular study analyzed a bevy of factors and considerations, IID will need to continue to run assessments that fully consider pros and cons of various application of this type of program. Additionally, a comprehensive analysis should be completed with the benefits clearly outweighing the costs in order to begin implementing a specific application.

Chapter 5: Potential New Resources

Base on the need for additional resources identified in the previous chapter, IID developed cost and performance information for several resource options that are combined into expansion plans in Chapter 7. In this chapter, the cost and performance assumptions for the candidate resources are presented and discussed.

Several key aspects of IID's current energy portfolio environment highlight the organization's key factors in consideration of the best mix of future resource portfolio. The following are the key considerations IID is currently scrutinizing:

- **San Juan Project** - IID has exited the San Juan Project at the end 2017. IID currently receives into its service territory about 106MW of baseload energy/capacity from San Juan Unit 3. This capacity has been fully replaced with renewable generation and as load grows and more renewables come online, IID will need to install quick responding generation.
- **Renewables Portfolio Standard and Emissions Reduction Requirements -** IID is mandated to achieve California's RPS target of 33percent of delivered energy coming from renewable resources by 2020 and 2030 and beyond as required under SB 350. IID's service territory encompasses significant renewable resources, primarily solar, geothermal, and wind, in addition to IID's All-American Canal hydro resources.
- **Load Growth Volatility –** IID recognizes the extreme potential for a wide array of outcomes in the load forecast. With energy efficiency and conservation programs increasing the overall impact, the load growth could be flat or negative. However, if the economy vastly improves and the weather is more severe than normal, then the growth could be faster than expected. In either case, IID must observe these positions in order to be fully aware of how much and when to add or subtract resources in the most economical and reliable manner.
- **Increasing Renewable Generation within IID's Transmission System -** IID has long had renewable generation connected to its transmission system, largely geothermal generation operating 24/7 at relatively constant levels. With the growth in solar and wind development and the variability of their output over the course of a day, there will likely be an increasing need for regulation on the part of IID's AGC capable and peaking units.
- **Maintaining a Robust Reliable Environment** – One of IID's key overall drivers, as outlined previously in this document, is to maintain the balancing authority with a well-balanced, reliability-driven environment. Any resources in consideration to be added to IID's resource portfolio must be scrutinized from a reliability perspective.
- **Cost Competitiveness** – As a part of IID's overall mission, the Energy Department is constantly motivated to provide the best fit, least cost alternative to serve IID customers.

This approach involves careful analysis of the various affects that any added resources can have on overall customer rates

- **Growing and Highly Variable Demand** - IID's system load continues to grow, particularly at the Northern end of the system in Riverside County. In addition, the IID electric system experiences significant seasonal swings in load.
- **Aging Assets** - While IID has made significant investments in recent years to upgrade its generation assets with the addition of Niland Units 1 and 2 and the repowering of El Centro Unit 3, the three other IID AGC capable units, Yucca Steam Unit, El Centro Unit 4 and El Centro Unit 2 are 54 years old, 45 years old and 20 years old, respectively. With a typical plant design life of 30 years and the five plus years to develop and construct a new plant greater than100 MW, consideration of future generation assets seems warranted at this time. Below is a graph of the age of IID's installed generation resources/capacity. As reflected in this graph, a significant majority of IID's installed resources/capacity are greater than 30 years old.
- **Resource Operating Permit Limitations** - Besides looking at the capacity of IID's generation resources, the operating hours and/or capacity factor limitations of those resources should also be considered and evaluated. For example, over the past two years, 2011 and 2012, the capacity factor limit on El Centro Unit 4 was either bumped into or exceeded, forcing IID to take mitigating measures. Significant operating permit hours and capacity factor limits on the following IID generating resources currently exist and could become more restrictive in the future:
  - El Centro Unit 4 has an annual capacity factor limit of 30 percent.
  - Each Coachella gas turbine has an annual 200-hour limit.
  - Each Rockwood gas turbine has an annual 1,000-hour limit. Each Niland gas turbine has an annual 3,000-hour limit.

TYPES OF GENERATION RESOURCES

There are three basic kinds of generation resources: base load, peaking and intermediate. Acquiring the right mix of resources is necessary to meet load at the lowest cost.

BASELOAD RESOURCES

Baseload resources have a capacity factor[17] of between 60 and 100 percent. Baseload resources are characterized by high construction costs and relatively low energy costs. Baseload resources include coal,

[17] The capacity factor is defined as the ration of actual generation to potential generation and is calculated as: Annual Capacity Factor = (actual generation during the year)/ (8760*unit capacity). Capacity factors can also be calculated by month with the formula being changed to reflect energy generated during the appropriate time period divided by the potential generation during the time period.

nuclear, hydroelectric run-of-river and combined cycle generation. In addition, geothermal generation is usually classified as a base load resource since it is intended to operate for all hours.

Renewable (Green) Resources

Renewable resources that qualify as a CEC certifiable renewable resource typically contain a wide range of availability in the inter-hour. Green resources such as biomass and geothermal tend to have higher capacity factors ranging from 60-95 percent. However, green resources such as wind and solar generation have lower capacity factors ranging anywhere from 20-40 percent and are heavily dependent on non-controllable factors related to weather. In a solar resource, if the scheduled output is 20 MW in a given hour, but suddenly clouds cover a portion or all of the sunlight providing the fuel to the solar panels, then the actual output becomes 11 MW. This 9 MW loss must be made up by other resources in the IID system and can present an operational pressure to the IID system stability.

Peaking Resources

Peaking resources have low capital costs but high fuel and operating costs. Examples of peaking resources include combustion turbines and older, inefficient generation facilities. Additional ramping generating facilities will be needed if the IID adds any additional capacity of solar or intermittent resources. As additional intermittent renewable resources come online, IID will need to place special attention on the reliability condition of the IID system to closely monitor system stability. As outlined earlier in this document, intermittent resources may cause reliability instabilities that will require the IID to possibly acquire additional quick responding generation, such as peaking resources.

Intermediate Resources

Intermediate resources are, by elimination, resources that are neither peaking nor base load resources. There are few examples of actual intermediate resources other than hydroelectric resources (with water storage rather than run-of-river) and combined cycle resources. However, many of the modern technologically advanced combined cycle resources are used as base load resources because of their high efficiency.

Capacity versus Energy Charges

Unless the energy is bought for all hours of the day (a base load purchase), power purchase agreements include a capacity charge. The capacity charge is the reservation charge for energy and is priced as a cost per kW-month or a fixed charge for the right to generate energy from the contracted capacity.

The capacity charge will vary depending upon the expected use of the generator. An agreement that anticipates that the generation facility will be used sporadically during the peak periods of the month will have a higher capacity price than an agreement that contemplates frequent use.

Energy can be priced a number of ways. Generally, the price is quoted in the price per MWh – for example, $50/MWh.

When calculating the total delivered cost of energy, both the capacity and energy cost must be included. Knowing how the resource will be used is important in determining what type of resource will minimize total costs.

Generally, base load resources have a high capacity factor (reflecting the high capacity costs associated with building base load generation) and low energy costs. Peaking resources generally have low capacity costs but high energy costs.

If the unit will to be operated as a peaking facility or with a low capacity factor, the best, or most economic choice of resources, are those with low capacity costs and high energy costs. If the unit is going to be purchased to meet base load requirements, then a purchase with a high capacity cost and a low energy cost is generally most economic.

Technological Advancements as a Result of Changing Laws

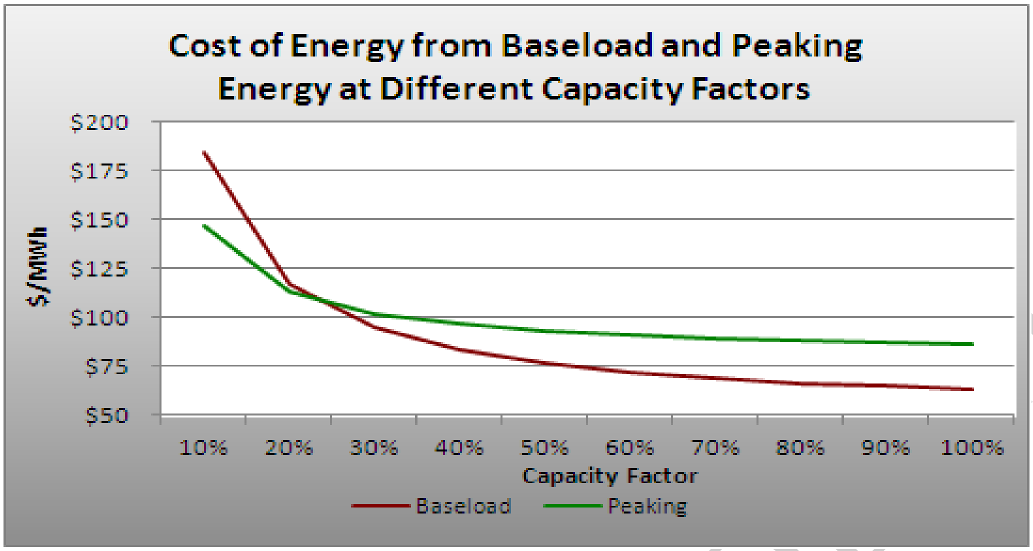
In the United States, a change in law may present a competitive opportunity for entrepreneurs and industrialists to research and develop new technologies or improvements to existing technologies to decrease the cost of production, and thus reduce the cost impact to the affected compliant entity and public. With these improvements, IID has the opportunity to aid in the development of new technologies that allow the Imperial Valley to be at the forefront of making renewable energy easier to integrate and less expensive.

IID has explored various technologies that help increase the efficiency in geothermal and solar power generation and the continued approach in a prudent manner will allow IID to reduce costs for the IID ratepayer. Recently, IID made state and national news by taking a significant step in working with the county of Imperial to advance a joint effort that would lead to the restoration of the Salton Sea, protect public health, benefit the local economy and the vast wildlife that depends on the sea, all while protecting IID's Energy Balancing Authority. This effort, along with developments in renewable-generation technologies, will work together to allow IID to move forward as a leading publicly-owned utility.

Summary of Resource Types

Baseload resources are characterized by high capacity costs and low energy costs and peaking resources are characterized by low capacity and high energy costs. The following exhibit shows the average cost of peaking and base load generation resources at different capacity factors.

Exhibit 82: Conventional Resource Cost: Baseload vs. Peaking



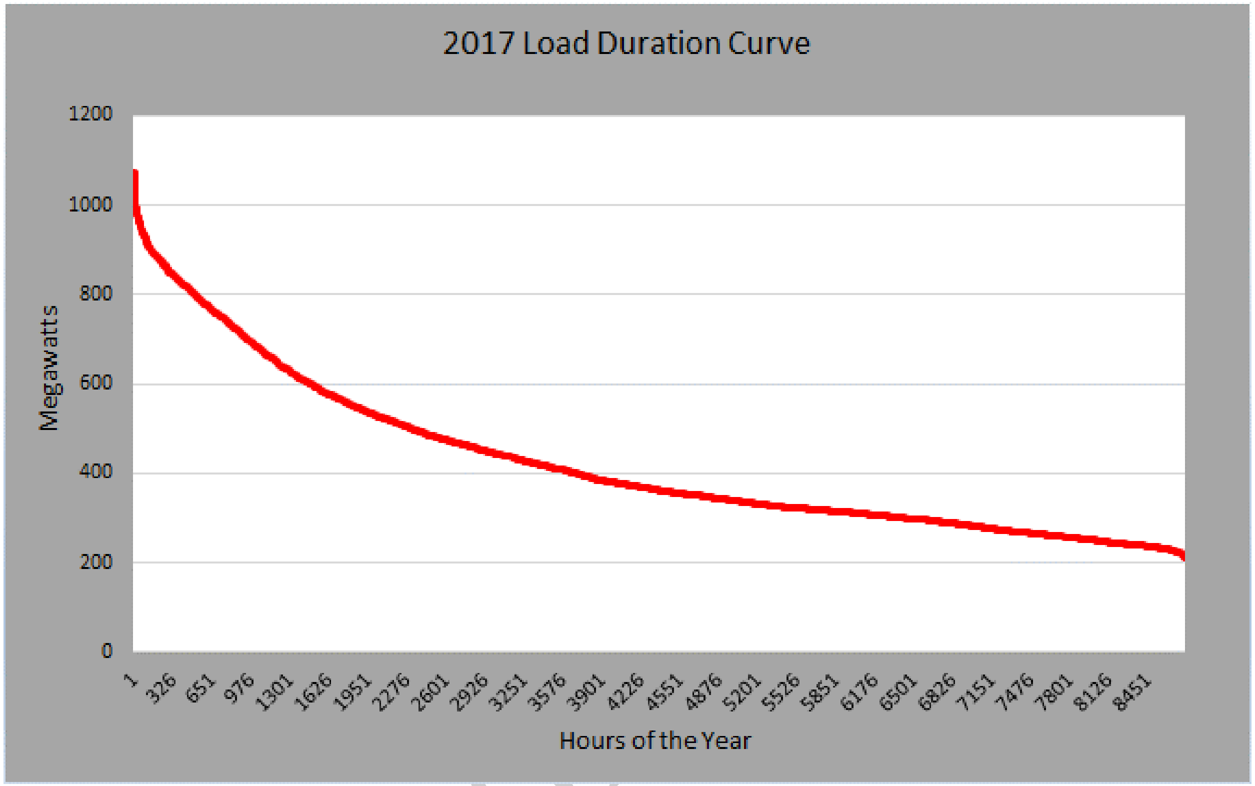
At low capacity factors, the capacity cost of base load resources dominates the total cost of generation, while at high capacity factors, the high energy and operating costs dominate total costs of peaking resources. As a result, base load resources should only be acquired when the expected capacity factor is going to be above 60 percent and peaking resources should only be used when the expected capacity factor is below 25 percent.

An important screening tool for identifying the type of resources required by the IID is determining the approximate capacity factor of potential new resource additions. Once the capacity factor is identified, appropriate technologies can be specified.

Load Duration Curve

Another useful screening tool for the type of resources needed in the future is the load duration curve for the IID. The load duration curve shows how many hours each year load exceeds specified amounts and provides information on the characteristics of new resources required by the utility.

Exhibit 83: 2012 Load Duration Curve



Several interesting facts can be drawn from the load duration curve. First, base load requirements are around 350MW. Baseload resources are available for dispatch all hours of the year (excluding planned and forced outages). Generally, a utility should acquire enough base load resources so that it is slightly long, around 2,000 hours of the year (or roughly 20 percent of the time). The IID has control over the dispatch of its resources and can back down the many of the natural gas generation plants to reduce any surplus energy.

The second important fact to recognize is that IID's loads are only above 800MW for around 500 hours of the year and above 900 MW for less than 150 hours of the year. This means that the IID is required to purchase expensive peaking capacity during the summer months to meet load that only occurs for less than 150 hours.

As will be shown in a later section, demand-side management programs can reduce the daily peak demands and reduce the need for expensive peaking capacity. If the IID can implement 50MW of demand-side programs, it would be displacing generation resources that are only used around 150 -200 hours per year, primarily during the high-cost, on-peak hours.

The load duration curve shows that the IID should acquire around 400 MW of peaking capacity or energy required only around 25 percent of the time. This type of energy comes from power purchase agreements and combustion turbines or older, inefficient gas and steam units that have low capacity costs. This means that IID should acquire seasonal (1-3 months of the year) call options where some may be called upon more often with a strike price that is expected to be competitive to the market spot price and also IID should acquire some call options that will only be used a few times with a strike price that is "out-of-the-money" so that the IID pays a diminutive option premium. This allows IID to reduce the overall cost to supply power to the consuming rate payer.

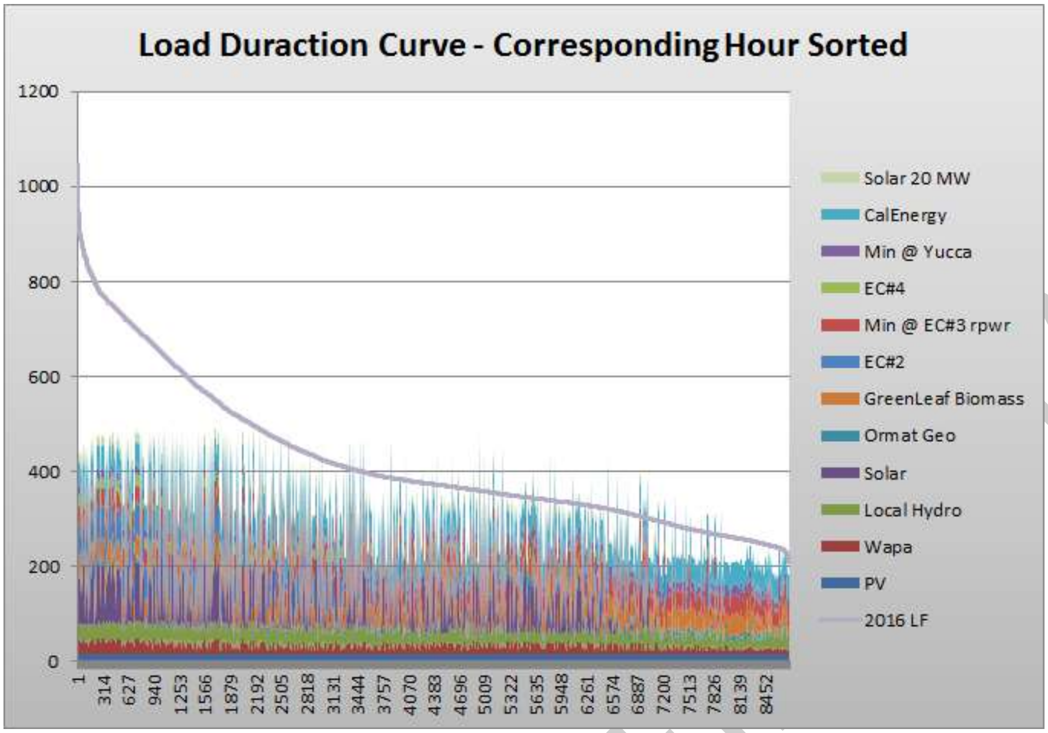
This indicative analysis shows that to meet annual load requirements the IID requires approximately 375-400 MW of peaking energy (a capacity factor of 1 to 25 percent), 350–400MW of base load energy (a capacity factor of 60 to 100 percent) and 300 MW of intermediate capacity or energy available for load with a capacity factor of between 25 and 60 percent.

Load Duration Curve for Future Years & Baseload Resources

Currently, the IID is challenged with this conventional goal of meeting resource requirements at a minimal cost combined with the requirement of meeting RPS targets. Most renewable resources are not dispatchable and are considered must take in most circumstances. Geothermal and biomass resources, which contain a capacity factor of about 90-95percent will be stacked at the bottom of the stack as usual with other typical base load resources, However, other renewable resources, such as solar generation, would also be stacked at the bottom of the stack, even though the annual capacity factor is anywhere between 23-33percent, much greater than a typical base load resource. With the requirement of energy (MWhs) RPS targets and the capacity (MW) planning strategy, IID is forced to take more capacity in certain hours than what customer demand requires.

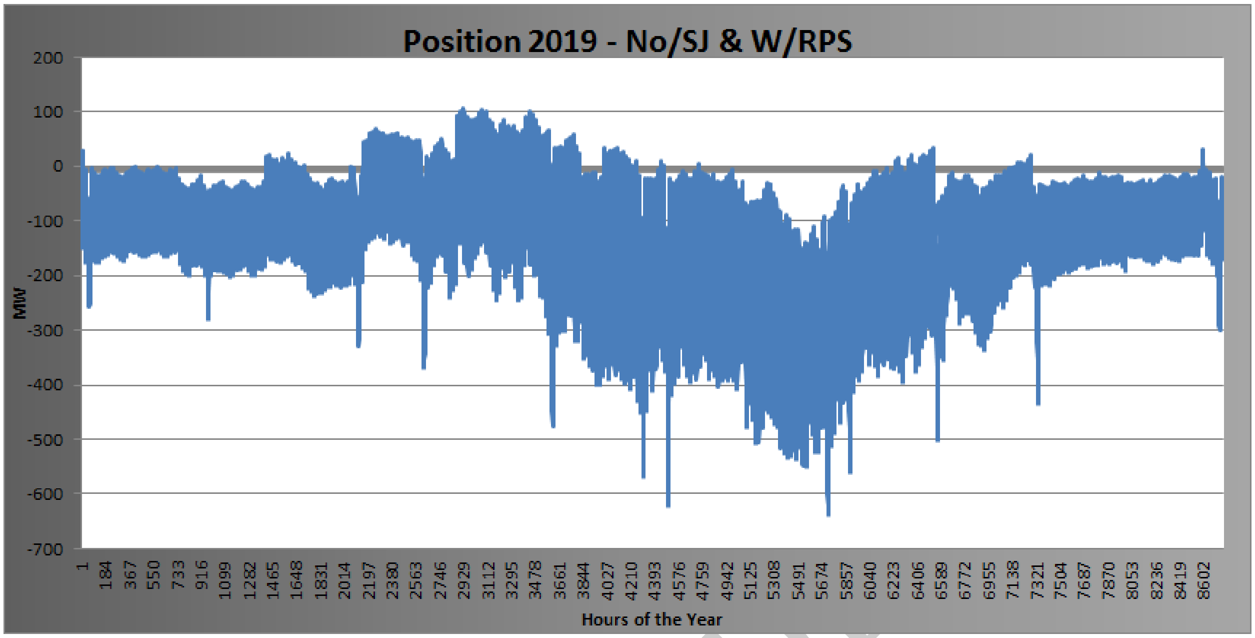
The following exhibit illustrates this challenge in the load duration curve projection for 2019 and the stack of expected must-take/base load resources over the course of the year.

Exhibit 84: 2019 Load Duration Curve with Must-Take/Baseload Resources



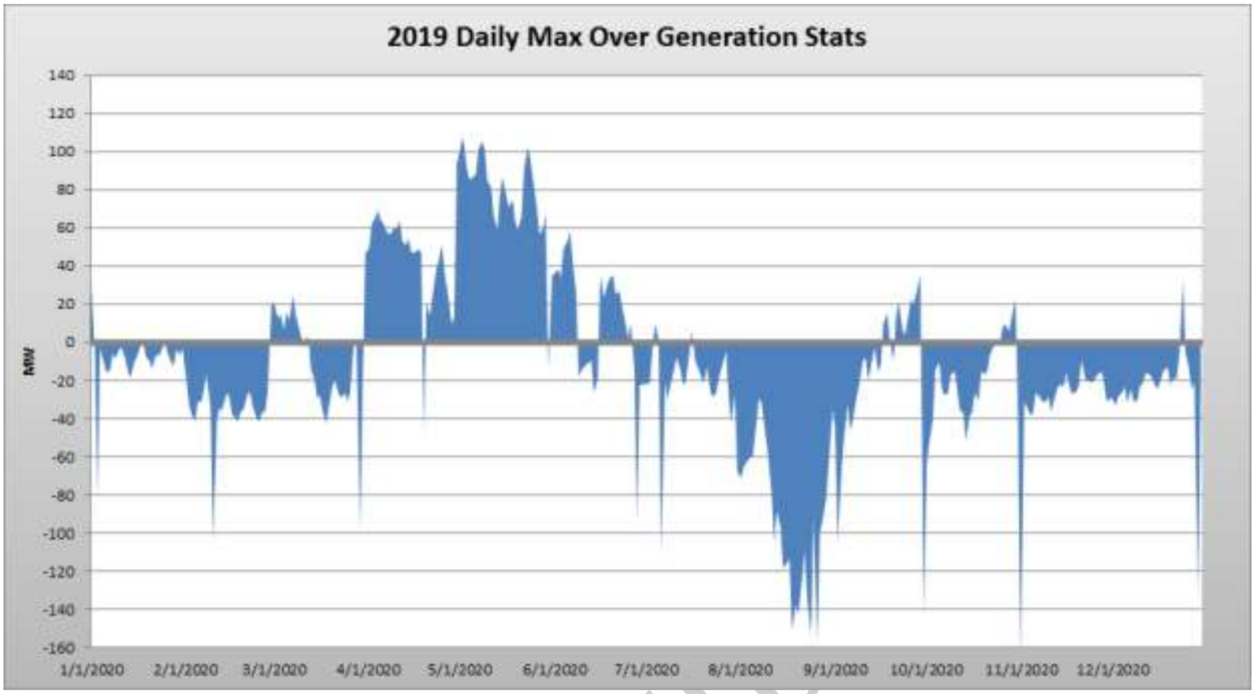
As shown on the previous page, there are a few hours (600-900) where IID may potentially be long with must-take resources. This has a cost and a market risk associated with it. With the requirement to continue to bring on more renewable resources to meet the RPS requirement, IID could minimize the risk of being long in the winter time by continuing to consider seasonal contracts that are economical. This is a challenge because most renewable developers need guaranteed annual contracts for the financing of projects. Technology types that qualify as renewable, such as biogas (particularly in state biogas), that allows IID to flexibly dispatch the renewable resource at a competitive price, could have operational benefits but have regulatory, volumetric and cost risks associated with it. There are a lot of regulatory risks with out-of-state biogas as well as a limited supply in state. Another way to observe this is by looking at the net position on an hourly basis, using 2019 as an example year:

Exhibit 85: Hourly Net Position and Excess Generation Forecast



A more palatable way to observe this is by looking at the daily max vs the supply where above zero represents excess generation to be sold at fluctuating prices that may result in higher costs:

Exhibit 86: Daily Max Excess Generation Forecast



Using a load duration curve and hourly/average position are a screening tool that provides a starting point for more exhaustive analysis. The price that the IID pays for different types of resources will ultimately impact the optimal amount of each type of resource that the IID purchases.

TRANSMISSION COSTS AND LOSSES

Whenever the IID purchases energy from outside its service territory, it must purchase transmission capacity. Transmission costs vary according to the contract path that the IID uses.

Purchases from the CAISO are expensive, generally around \$10-\$15/MWh higher than IID's other liquid trading hub at Palo Verde. The CAISO adds an export fee that includes ancillary services, grid management charges and other costs that purchasers within its balancing authority must pay. The IID also does not know if it will be required to pay any congestion charges on the CAISO system, although generally congestion from the CAISO to the IID is low. Selling energy into the CAISO does expose the IID to potentially high congestion charges.

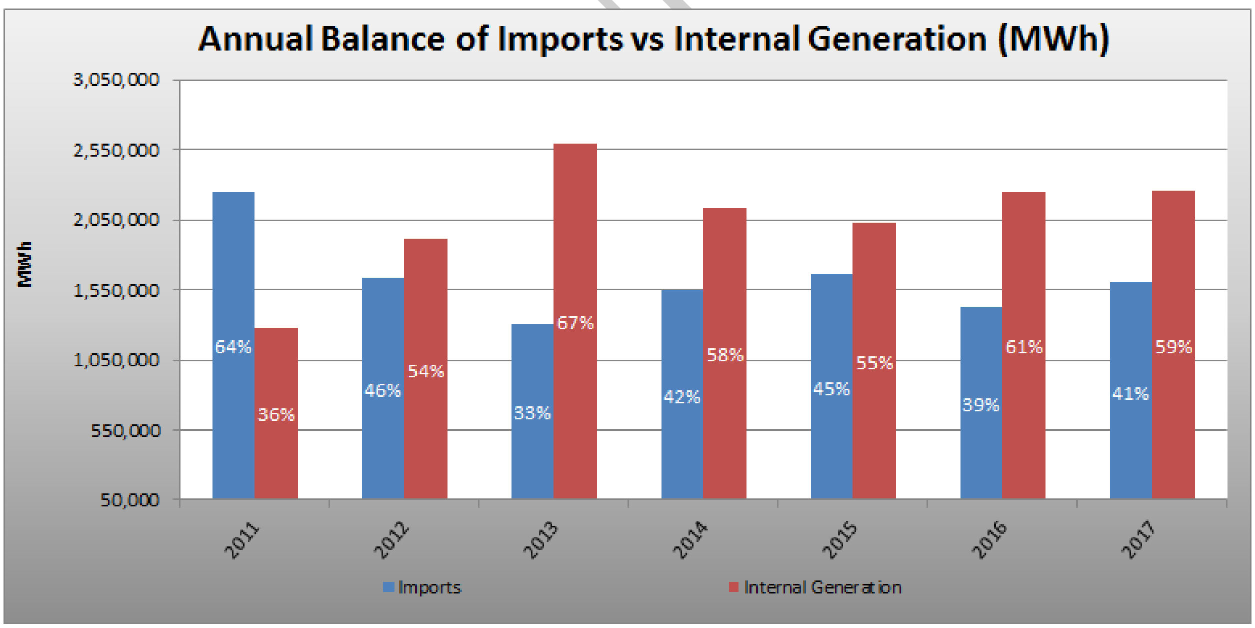
Purchases from east of the Colorado River tend to have lower transmission charges than from the CAISO, generally around \$5-\$8/MWh. However, if the energy passes through multiple balancing authorities or substations controlled by different entities, the transmission charges are "pancaked" on top of each other and transmission charges can quickly escalate.

The IID also has to account for transmission losses. Some entities (such as the CAISO) deliver the contracted amount and charge the IID for losses. Others just deliver the contracted amount less losses.

Generally, the magnitude of losses faced by the IID is around three to five percent, although they can be considerably higher if the generation source is in Utah or Colorado.

When the IID makes its purchasing decisions, it also includes both transmission costs and any associated losses. The IID needs to continue to expand its transmission infrastructure to reduce the exposure to high transportation line losses. Transmission expansion will also allow the IID to access other liquid energy markets that are advantageous when stacking resources to serve load. Additionally, transmission resources that contain both import and export capabilities allow for potential energy sales to further reduce cost impacts of operating the system. The IID intends to sustain a healthy balance of serving load with imports and internal generation. If IID is dependent upon too much internal generation, then when observing numerous outage/emergency risks over the course of every hour of each year moving forward, the IID would need to build a “more than expected” amount of internal generation to cover the ancillary service requirements and other reliability requirements needed to operate the system reliably. This approach can be quite costly. On the other hand, if the IID is dependent upon too much import capacity, then the inevitability of transmission line outages can cause an equally problematic situation when observing every hour of each year moving forward. The following exhibit shows the annual balance of imports vs. internal generation for 2011-2017.

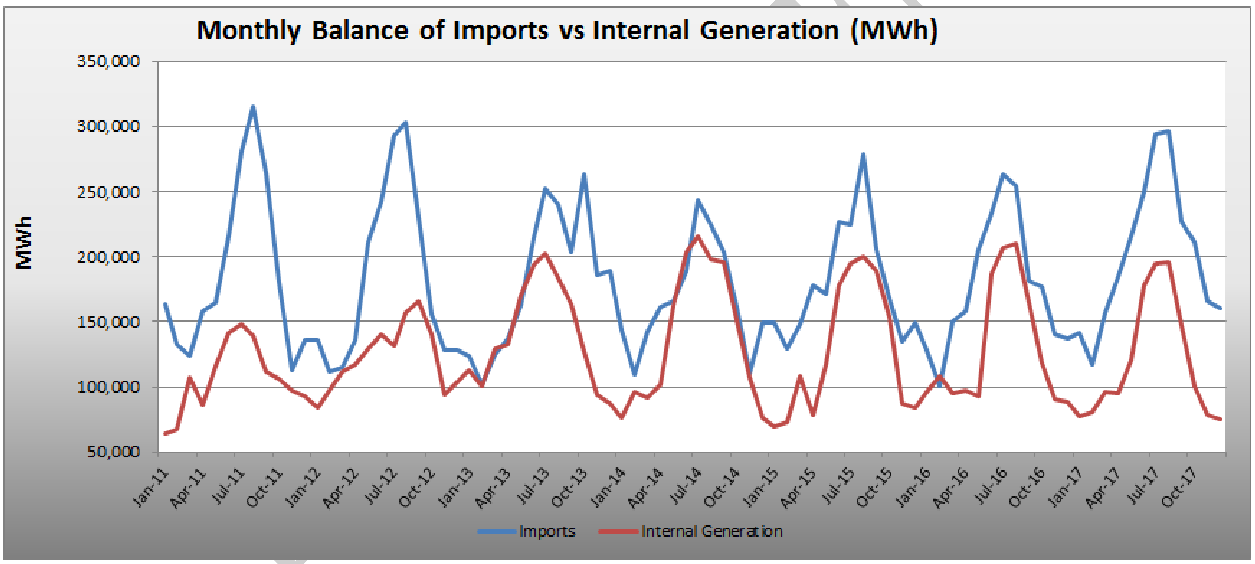
Exhibit 87: Imports vs. Internal Generation by Year (2011-17)



Historically, the IID experienced higher levels of imports due to the economic viability of accessing external markets, but when renewable resources located within the IID territory become commercially operational, as was the case in 2012, the internal generation will increase and the need for economic displacement imports will naturally decrease. This evolution of operating practices must be balanced to ensure that IID is compliant with regulatory and legislative policies and, at the same time, taking advantage of energy market opportunities with a salubrious balance of imports and internal generation. Further, the RPS required renewable resources should be factored into the balance formula since they are not dispatchable and are essentially all must take causing a growing trend of more internal generation than imports. This will be discussed further in chapters 10 and 11.

While the summer and winter loads are extremely atypical from each other, IID maintains a good balance of imports and internal generation to serve load. However, on a monthly basis, the balance can shift due to generator outages, transmission line outages, and other force majeure events that can shift the balance of imports and internal generation. The following exhibit shows the month-to-month balance for the last two years considering the various month-by-month situations that have caused the disparity of imports and internal generation.

Exhibit 88: Imports vs. Internal Generation by Month (2011-17)



In addition to the annual and monthly observation of balancing supplies between imports and internal generation to serve the IID load, IID must also consider the impact of exported generation. The IID system area contains thousands of megawatts of either already existing or potential resources for development that can be wheeled through the IID service territory to serve load in other areas to the north, west and east. As RPS requirements grow over time for the state of California, there is a good possibility that the other states will follow the aggressive and high level of RPS requirements. Since IID is an area rich in renewable resources, IID must consider the possibility for higher revenue streams from exporting energy to other areas.

IID must also continue to observe, understand and communicate the benefits and risks associated with increasing activities with other balancing authorities such as the CAISO. Other balancing authorities have their own separate standards that may not necessarily prioritize the needs of IID. This can result in curtailed energy schedules and high congestion or locational marginal prices. On the other hand, other balancing authorities encompass the benefit of an access to other markets for wheeling service revenues and even energy sales from the IID generation. IID must consider these dichotomies when integrating all energy resources and planning for the future.

CANDIDATE RENEWABLE RESOURCES

Solar energy resources are an obvious candidate renewable resource for IID's consideration given the geographic location of IID. The table below lists cost and performance information for the solar resources considered in this IRP.

Exhibit 30: Cost and Performance for Candidate Solar Resources

Generic Unit Cost and Operating Characteristics						
Unit Characteristics	Abbreviations	GE*	LG*	BM*	PV*[1]	WT*[2]
	Units	Geothermal Steam Turbine	Landfill Gas	Biomass	Photovoltaic	Wind Turbine
Online Year		2019	2019	2019	2019	2019
Summer Capacity	MW	10	10	10	10	10
Winter Capacity	MW	10	10	10	10	10
Full Load Heat Rate	HHV, Btu/kWh	0	8,910	13,648	0	0
SO2 Emission Rate	(lb/MMBtu)	0	0	0	0	0
NOX Emission Rate	(lb/MMBtu)	0	0	0	0	0
CO_2 Emission Rate	(lb/MMBtu)	0	0	0	0	0
Fixed O&M	2017 $/kW-yr	110.00	40.00	95.00	12.00	40.00
Variable O&M	2017 $/MWh	0	5.00	4.00	0	0
Forced Outage Rate	%	20.00%	30.00%	30.00%	0.00%	0.00%
Maintenance Outage Rate (MOR)	%	0.00%	0.00%	0.00%	0.00%	0.00%
Overnight Construction Cost	2017 $/kW	3,500	3,250	4,000	1,600	1,500
Book Life	Years	20	20	20	20	20
Tax Life	Years	5	5	5	5	5
Debt/Equity Ratio	%	50/50	50/50	50/50	70/30	70/30
Debt Interest Rate	%	7.00%	7.00%	7.00%	7.00%	7.00%
After-tax Return on Equity	%	4.80%	4.80%	4.80%	4.80%	4.80%
Weighted Average Cost of Capital	%	6.92%	6.92%	6.92%	6.92%	6.92%
Property Tax Rate	%	0.00%	0.00%	0.00%	0.00%	0.00%
Insurance Cost	%	1.00%	1.00%	1.00%	1.00%	1.00%
Composite Tax Rate	%	39.55%	39.55%	39.55%	39.55%	39.55%
Levelized Carrying Charge	%	9.31%	9.31%	9.31%	8.17%	8.17%

* For calculating REC prices the levelized carrying charge was reduced to reflect incentives and rebates.

1 Assumes a technology cost improvement of 4%/year through 2020 and 3% through 2041.

2 Assumes a technology cost improvement of 1%/year through 2020 and 0.50% through 2041.

In addition to the above resources, IID tested combinations of renewable resources and storage resources. Solar + Storage was studied frequently at a price of $45-50/MWh (all in cost) with 300 roundtrips per year.

SMALL HYDROELECTRIC FACILITY EXPANSION

The IID also has been exploring the currently existing infrastructure to develop small hydroelectric facilities. Across the hundreds of miles of canal systems that IID owns and operates, a preliminary analysis has determined that there are about 12-14 sites worth of further hydroelectric facility development exploration and analysis. The third party preliminary analysis reveals that a total of up to 30MW is possible when aggregating all 14 sites. The IID is currently exploring the potential for self-development on these projects since the analysis shows a lower cost when IID manages the development of these projects. These projects contain much of the already needed infrastructure and would provide state qualifying eligible renewable resource production at a minimal cost in comparison to other renewable technologies if the IID moves forward on all or any combination of these projects.

LOCAL GEOTHERMAL PROJECTS

IID is currently investigating several local geothermal projects, both existing facilities and to be newly developed generating facilities.

IID has abundant opportunities to explore currently existing geothermal projects that have expiring contracts with SCE between 2018 and 2023. Some of these geothermal facilities are quite old and the age

OTHER RENEWABLE PROJECTS

In addition to geothermal resources, the IID is investigating other types of renewable resources, including thermal solar generation, wind, biomass and biodiesel.

BIODIESEL

At least three firms in Imperial County are now engaged in the production of biodiesel from algae or waste to energy. During photosynthesis, an alga captures carbon dioxide and sunlight and converts it into oxygen and biomass. The production of biofuels from algae does not result in a reduction of carbon dioxide in the environment because the carbon dioxide is released when the biofuel is burned.

Algae-produced biofuel can be used as fuel for some of the IID's existing thermal resources.

Algae can be grown in briny water and salt water, making it a potentially good fit for the poor quality of water in the Imperial Valley around the Salton Sea.

Currently, algae biodiesel is expensive with costs exceeding $17/MMbtu. However, within the next few years algae-based fuels should significantly decline in cost as new technologies are used to grow and convert algae into fuel.

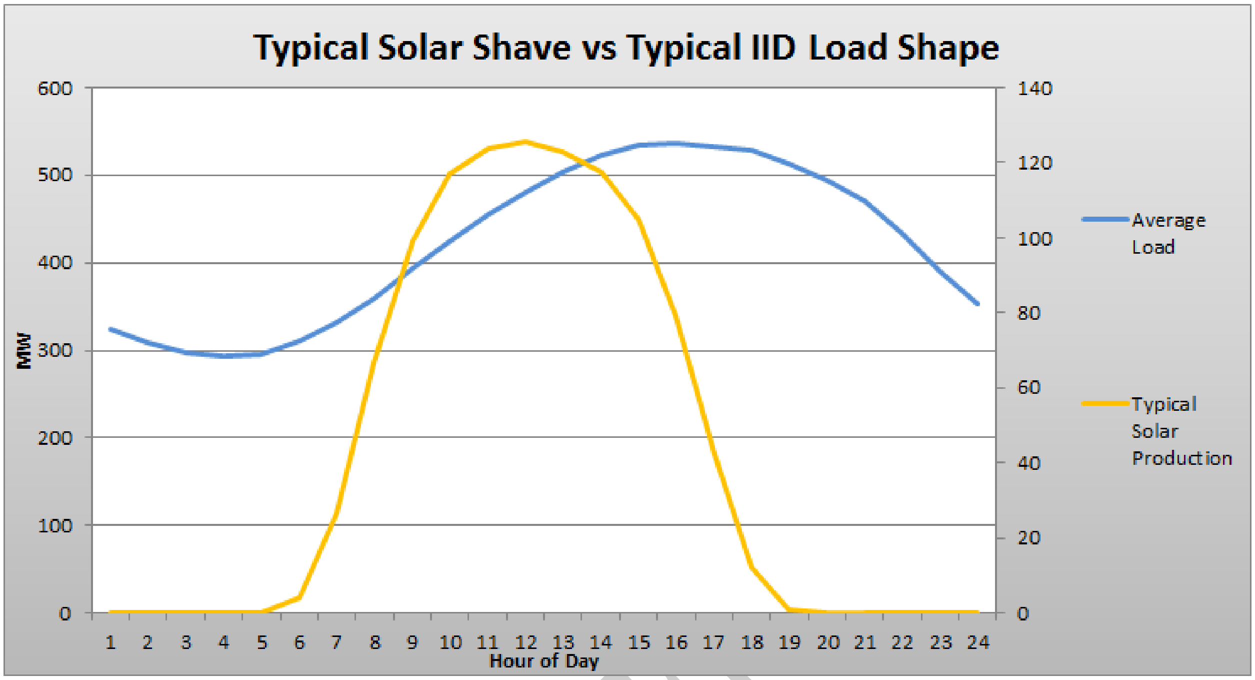
To conclude, the resources that the IID will acquire in the next few years will be based upon proven technologies used across the world. The IID is already looking into the third compliance period, which starts in 2017, and the technologies that will assist in meeting the additional RPS goals of 33 percent by 2020 and GHG emission reduction requirements.

The next section discusses how the IID chooses new generation resources to add to its resource portfolio.

STORAGE RESOURCES

Renewable energy resources integrated into IID's electric power systems will bring certain changes having a significant impact on system performance and efficiency. The specific impact focus is on solar energy, the renewable resources with the most potential for significant penetration in the near term. The table below illustrates the difference between the hours that solar is available and the hours when IID's load ramps up and down throughout the day:

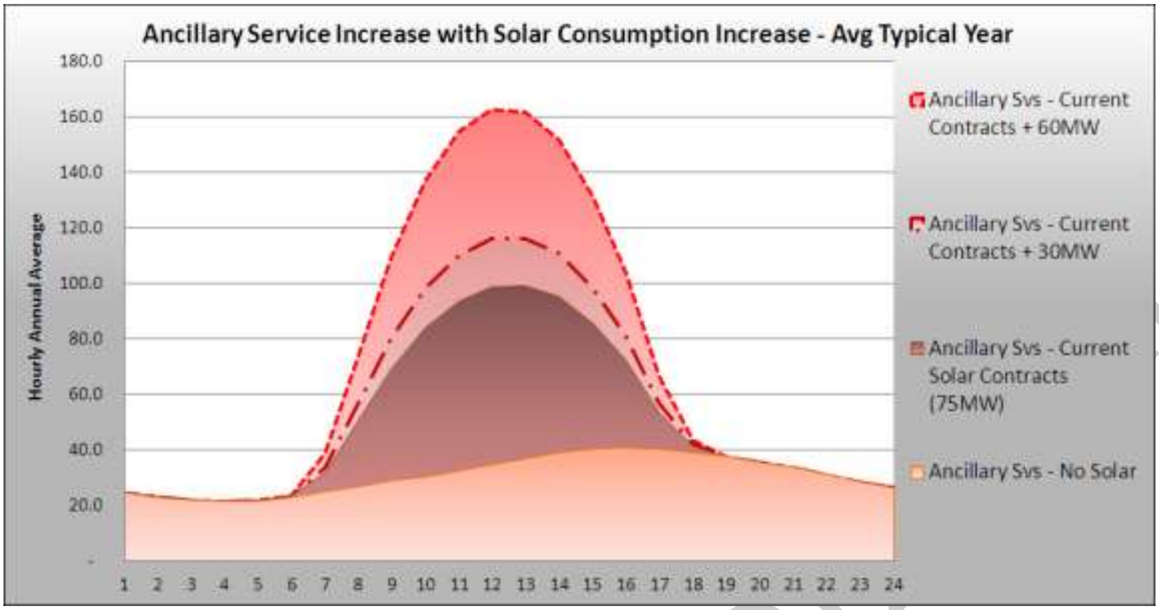
Exhibit 89: Solar Availability vs. IID Load Curve



The IID is studying a number of potential resources to meet future requirements. While many of the resources are renewable resources using proven technologies, several of the renewable resources are experimental. The IID is analyzing a number of potential resources to especially remedy the integration of intermittent resources while meeting the RPS requirements.

The exhibit below is a graph that depicts the possible operational impacts of providing ancillary services for intermittent resources.

Exhibit 90: Typical Year Representation of Ancillary Services Increases when Adding Solar



BATTERY STORAGE

IID issued a Request for Qualification and that will be followed with the issuance of a Request for Proposal for the installation of a Battery Energy Storage System. The intermittency of solar resources would be alleviated should the IID choose to imbed a quick responding resource to mitigate the impacts of solar integration. IID System Operations determined that the BESS characteristic necessary for the IID to maintain a Balancing Authority include:

Quick response – the system can respond faster than ramping or starting existing assets. It can be integrated into IID SCADA to respond to AGC. Multiple mode settings to provide customizable performance.

- Provides ramping support.
- Provides regulation up/down.
- Decreases outage events.
- Potential shutdown of IID units for significant periods.
- Provides additional capacity to the IID system.
- Help absorb ACE imbalance when IID is long.
- Provide incremental energy to the system as a spinning reserve.
- Reasonable O&M costs.
- Provide a reasonable response time for IID to make the best operational and economic decisions.
- IID solar portfolio = 138MW (planned and actual)

Many of these characteristics of use can be automated and several of the modes are constantly being calculated by the BESS to provide the most optimal settings in any given system situation.

However, the BESS is like any other battery in that it can deteriorate and degrade faster if not set up and used properly due to the nature of batteries. The life of the battery heavily depends upon:

- Rate of charge
- Rate of discharge
- Depth of charge

The IID needs to ensure that the benefits outweigh the costs in battery storage since there are many risks associated with the development and operation of battery storage. Some of the risks include:

- Cost structure must be strategically arranged to reflect various performance risks/parameters of use to IID.
- Many reliability/system operations related benefits can only be used by SOC personnel and not by the Trading Floor.
- Risks are higher after the first several years of use since the BESS may deteriorate faster than anticipated if not used within the warranty limitations.
- Term of contract must reflect a low-risk approach to the IID, considering the cost structure.
- After 15 minutes of use of automatic scheduling, other resources will need to ramp up.
- Large battery storage projects of varying technologies are not that common and a large-sized battery storage project as a demo project contains many risks.
- A solar charging energy storage project has not been done before and, therefore, there is no data on what is the best way to operate the plant.
- Counterparty risk is heavily dependent upon experience and consistent delivery of products and if a battery storage developer does not have experience in developing or a record of consistent delivery of their offered technology, IID is absorbing a considerable amount of risk.
- The location of the project can impact the overall effectiveness of the BESS.
- Many unquantified possible benefits come with battery storage, which can be hard to quantify. Some of the unquantified benefits:
- Reduced maintenance costs to IID generation assets.
- Reduced usage of IID assets with time-of-use constraints.
- Reduced environmental footprint.
- Improved response time.
- Ability to bank inexpensive power.

To encourage a competitive process to possibly acquire a battery storage project, IID is issuing an RFP to meet IID's needs moving forward. As more intermittent renewables are integrated into the IID system, IID needs to prepare for the acquisition of quick-responding generation, like a battery storage project.

In August of 2016, IID began operations of its 20MWH, 33 megavolt battery energy storage system that will provide operational support for years to come. It is located next to the energy generation station at El Centro and was developed to mitigate stability and power quality issues as renewable energy sources are integrated into the local grid.

The project is one of the largest of its kind in the western United States and leading energy companies are now looking towards IID as a leader in battery storage development. IID will use the BESS to complement the integration of renewable resources, such as solar, by adding stability and improving power quality while meeting California's aggressive renewables portfolio standards. It will also be used to add reliability to the IID balancing authority where the district can use the BESS to "black start" units in the generation fleet.

In addition to the environmentally friendly nature of the BESS, it will help smooth power supplies and act as a spinning reserve and ancillary service resource that is typically required by other expensive resources. With this in mind, the reduction in operating costs are expected in the first year of operations and throughout the lifetime of the project. This resource will provide significant savings to the IID ratepayer when used appropriately.

Additional energy storage will be needed and economically viable as costs decrease and renewable penetration increases to 50percent.

Other Energy Storage

The IID also has the opportunity to explore the option of pump storage since there are many hydroelectric facilities that could be altered at a relatively low cost to provide quick-responding generation (within seconds) to help with the integration of renewable resources. Particularly, the project at Pilot Knob is an untapped resource that contains a higher capacity output than what is being produced. The facility is 33 MW in capacity, but typically produces no more than 12 MW due to the lack of canal flow for agricultural water demand. Pilot Knob hydro-plant consists of two 16.5 MW generators, was built in 1957 and has a 55-foot head. The facilities are in working condition. In the last 10 years, Pilot Knob only generated for about 7 MW out of the 33 MW plant total generator's capacity, mainly using YCWUA water. The plant on average generates only four months during the year, and only one month (July) during the summer. The lower basin of the hydro-plant is normally spilled into Mexico. Regularly, 26MW of the plant capacity are not utilized because of the lack of extra volumes of water spilled into Mexico.

IID needs to confirm the feasibility of converting Pilot Knob hydro-plant into a "pump-storage" facility. The old Alamo canal (approx. one mile long) can be expanded to fit the needed dimensions for the plant reservoir. A back-of-the-envelope assessment performed 10 years ago concluded that it was possible to obtain up to 6 hours of at least 25 MW of peak energy/day. The construction of the reservoir and the pumping station will be the majority of the capital investment. The plant will be an excellent peaking resource with environmental attributes, and will have the ability to back up solar generation due to the non-coincidence of solar generation curve vs. IID's system demand curve. The units could also provide the following ancillary services:

a. Spinning reserves
b. VAR/voltage support
c. Regulation
d. Voltage support
e. Ramp up
f. System stability services
g. Automated Generation Control (AGC)
h. Decrease in outage events

The most critical element of renewable impact would be the variability of resources and accounting for sufficient commitment and dispatch of reserve generation to guarantee the reliability of IID’s system in the event that the renewable resource suddenly becomes unavailable. Furthermore, dynamically scheduling the renewable resources not a part of serving IID’s load will reduce the reserve requirements. However increasing solar that serves IID’s load will require new generation to ensure IID’s ability to meet reserve requirements. This can be done by building new quick start gas turbines or battery storage. At this time, the District has a 33MVA 20MWH battery storage system. The battery storage system is used for reliability in order to maintain IID’s CPS boundaries and to help smooth any solar swings or instant change in load. The Battery will also be BlackStart capable which will increase the reliability in IID’s Balancing Authority. The load following of the solar will be key in reducing the impact on the system and backing the full loss of the resource.

Initially many IPPs had made the switch from Static scheduling to Dynamic scheduling as a result of BAL-002-WECC-2. Starting in 2016 a large number of the IPP plants reverted back to Static schedules. This will increase IID’s reserve obligation by having to account for more Statically scheduled generation in IID’s BA Ancillary Service. The table below displays some of the cost and performance data for storage resources considered in this IRP:

Exhibit 91: Cost and Performance for Candidate Storage Resources

Energy Storage Cost and Performance Data															
SYSTEM DESCRIPTON	Installed Cost ($/kWh) 2	Maturity (1 lo-5 hi)	Capacity (MW)	Discharge Duration (hours)	MWh	Capital Cost	$/kw-month	Energy Density (kWh/m3) Total	Energy Volume (kWh/ton) Total	Roundtrip Efficiency	Min. Rate of Charge & Discharge	Maintenance	Cycle Life (at rated capacity)	Full Ramp Req. (sec./min.)	Calendar Life (years)
30 MW/120 MWh Beacon Solar Storage - Flywheel	220	2	30	4	120	26,437,000	$ 2.45	15	11	83%	0%	Low	15000	1 sec	30
125 kW/500 kWh Pilot Building Block - Flywheel	960	2	0.125	4	0.5	480,000	$ 10.67	6	5	80%	0%	Low	15000	1 sec	30
Project 1 - Frequence Responce Lithium-Ion BESS	450	5	20	0.5	10	4,500,000	$ 1.25	NA	NA	87%		Low	NA	NA	15
Project 2 - Resource Adequacy Lithium-Ion BESS	450	5	10	4	40	18,000,000	$ 10.00	NA	NA	87%		Low	NA	NA	15
10 MW / 40 MWh with 20 year 100% capacity guarantee @ 365 full DOD cycles per year; pricing inclusive of the Eos Aurora DC Zinc Hybrid BESS, plus PCS, Controls, EPC, and 480VAC interconnection installed and COD in 1Q18.	450	5	1	4	4	1,800,000	$ 10.00	23	25	87%	0%	Low	5000	< 1 seconds	15
Liquid Air ES STANDALONE 1	900	2	50	4	200	##########	$ 10.00	92	128	55%	10%	Med.	unlimited	30 sec	30
Liquid Air ES STANDALONE 2	500	2	50	8	400	##########	$ 11.11	92	128	55%	10%	Med.	unlimited	30 sec	30
Liquid Air ES PEAKER PLANT 1	900	2	25	4	100	90,000,000	$ 10.00	97	134	65%	10%	Med.	unlimited	30 sec	30
Liquid Air ES PEAKER PLANT 2	500	2	25	8	200	##########	$ 11.11	97	134	65%	10%	Med.	unlimited	30 sec	30
CAES	1500	5	160	48	7680	##########	$200.00	n/a	n/a	75%	i Gen 65% Co	Low	unlimited	32 MW/min	30
20MW/80MWh (AC) Antelope Storage Flow Battery project*.	625	3	20	4	80	50,000,000	$ 20.83	1.28	1.28	74%	no min.	Med.	unlimited	<1 second	10
Sunverge One - 7.76 kWh*	1066	5	1.55	4	6.2	6,609,200	$ 17.77	NA	NA	NA	NA	Low	8,000 cycles	NA	20
Sunverge One - 11.64 kWh*	812	5	2.33	4	9.32	7,567,840	$ 13.53	NA	NA	NA	NA	Low	8,000 cycles	NA	20
Sunverge One - 15.52 kWh*	685	5	3.1	4	12.4	8,494,000	$ 11.42	NA	NA	NA	NA	Low	8,000 cycles	NA	20
Sunverge One - 19.40 kWh*	609	5	3.88	4	15.52	9,451,680	$ 10.15	NA	NA	NA	NA	Low	8,000 cycles	NA	20
ReFlex ESS (125 kW / 500 kWh) Vanadium Flow Battery	640	5	0.125	4	0.5	320,220	$ 10.67	11.7	0.25	70%-75%	1%	Med.	Unlimited	< 0.1 sec	20
Uni.System ESS (5 MW / 20 MWh)* Vanadium Flow Battery	562	5	10	4	40	22,464,000	$ 9.36	11.7	0.25	70%-75%	1%	Med.	Unlimited	< 0.1 sec	20
Uni.System ESS (5 MW / 30 MWh)* Vanadium Flow Battery	488	5	10	6	60	29,289,600	$ 12.20	11.7	0.25	70%-75%	1%	Med.	Unlimited	< 0.1 sec	20
Uni.System ESS (5 MW / 40 MWh)* Vanadium Flow Battery	450	5	10	8	80	36,028,800	$ 15.01	11.7	0.25	70%-75%	1%	Med.	Unlimited	< 0.1 sec	20

Ancillary services required to move energy through, out of, within or into the IID BA include:

- Scheduling, System Control and Dispatch Service: Service is required to schedule the movement of energy through, out of, within or into the IID BA.
- Reactive Supply and Voltage Control from Generation Sources Service: Service is required in order to maintain voltages in the IID transmission system within acceptable limits; IID generation must produce or absorb reactive power.

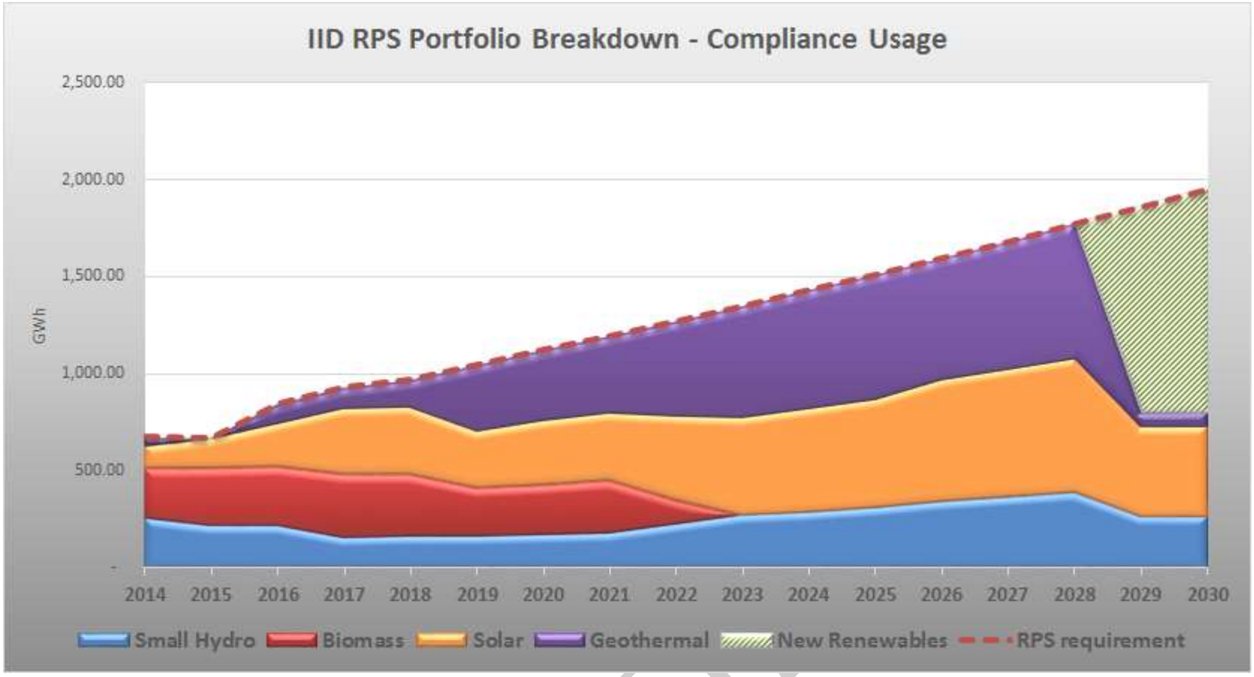
- Regulation and Frequency Response Service: Service is required to provide for the continuous balancing of resources with load and for maintaining scheduled interconnection frequency at sixty cycles per second.
- Energy Imbalance Service: Service is required when a difference occurs between the scheduled and actual delivery of energy to a load located within the IID BA.
- Operating Reserve, Spinning Reserve Service: Service is required to serve load immediately in the event of a system contingency.
- Operating Reserve, Supplemental Reserve Service: Service is required to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time.
- Generator Imbalance Service: Service is required when a difference occurs between the energy scheduled and actual delivery of energy from a generating facility located within the IID BA.

Four types of ancillary services products for IID are frequency response, regulation, spinning reserve and non-spinning reserve. Frequency response is the ability of a system or elements of the system to react or respond to a change in system frequency.

Regulation or regulating reserve is the amount of spinning reserve responsive to Automatic Generation Control. Regulating reserves are deployed to correct minute to minute deviations in system frequency or return system frequency to a desired range following a system disturbance. Regulation energy is used to control system frequency that can vary as generators access the IID's system and must be maintained around 60 hertz. Units and system resources providing regulation are certified by IID and SRSG. The generators must respond to AGC signals to increase or decrease their operating levels depending upon the service being provided, regulation up or regulation down.

Due to the nature of technologies that are online for most of the time (>90 percent) compared to intermittent technologies that are online for less hours depending on weather related factors, IID considers the balance between these baseload type of resources compared to the intermittent type of resources. The following exhibit is a projection of the renewable resource generation in IID's resource portfolio

Exhibit 92: Actual and Forecasted Renewable Technology Breakdown



REQUEST FOR PROPOSALS

Energy project procurement is most economical when conducted through a Request for Proposals. This process allows developers to compete and IID to maintain a clear picture of meeting IID's needs. In April 2009, the IID issued a RFP from geothermal developers within Imperial County. The purpose of the RFP was to contract for approximately 50 MW of geothermal generation by 2013 to meet the IID's renewable-energy requirements and greenhouse gas emission reduction requirements at the lowest cost; however, the timelines of possible delivery of geothermal resource generation has been delayed due to additional opportunities of renewable resources. Several other RFPs were issued or addressed through SCPPA's open RFP process between 2013 and 2017 for mostly renewable resources and seasonal energy. These RFPs resulted in new resources already brought online or will become

The IID also wants to investigate the possibility of a joint public-private partnership with geothermal developers to develop IID-owned lands with geothermal potential located near the Salton Sea.

The purpose of a public-private partnership would be to allow the IID to take advantage of tax incentives available to private entities while at the same time using tax-free financing to further reduce costs.

The IID has received proposals from essentially all of the geothermal developers located in Imperial Valley.

The IID will issue RFPs to address any future needs and to address the preferred resource mix needs as a result of this IRP. The preferred resource mix is discussed later in this document.

THERMAL GENERATION

The IID has been evaluating other thermal generation resources proposals. These proposals range from long-term power purchase agreements to asset ownership of generation constructed by other entities.

The IID has identified the appropriate amount of generation by type (base, peaking and intermediate generation). Some of the types of thermal resources that IID may consider with additional analysis are listed below.

POTENTIAL GAS-FIRED PEAKING ADDITIONS

Niland Peaker Expansion Option

1. Plant Functional Requirements
   - Peaking energy resource
   - Black-start capable
   - 10-minute start capable
   - Minimal or no net water use (expected to be a zero discharge facility)
   - 100 MW

2. Permitting Considerations
   - Permitting will be through the California Energy Commission and Imperial County Air Pollution Control IID.
   - The availability and cost of emissions offsets are not known at this time.
   - Water use will likely be an issue. The only source is potable water from the Golden State Water Company. For this reason Niland was not considered a good candidate for baseload generation when compared to El Centro, even with dry cooling. However, permit limits to discharge wastewater to the ditch are being reduced to the point that incoming canal water to the plant will not meet the discharge criteria.
   - Given that NGTP Units 1 and 2 were designed with minimal water use in mind, similar practices will likely be required again. Hence, for gas turbines, the use of dry, low NOx combustion systems and an air-cooled chiller are likely outcomes. Reciprocating engines, with their low water use (air-cooled radiators), could also be an attractive option.
   - Niland Substation is not that big, and is largely constructed with wooden support structures. Interconnecting an additional 100 MW into Niland Substation may trigger upgrades to the substation. To the extent that upgrades are triggered, that may influence how big a project to build.

3. Project Key Features
   - Engine Options
     - Gas Turbines
       1. With LM6000s already at the site, a logical choice is additional LM6000s. The LM6000PF is a later dry, low NOx version of the LM6000. GE has said that it avoids the issues that IID has experienced with the PDs at Niland. In addition,

aside from the combustion system, the turbo machinery is the same as the PD, allowing common spare parts and training. Like the existing two units, this addition would likely utilize SPRINT and an air-cooled chiller.

- Multiple Reciprocating Engines
    1. GE Jenbacher J920[18], J624
    2. Rolls-Royce Bergen B35:40V12AG, B35:40V16AG, B35:40V20AG
    3. Wartsila 9L34SG, 16V34SG, 20V34SG, or 18V50SG
    4. With multiple engines, this option would offer a relatively constant heat rate over the range of loads.
    5. In the smaller engine sizes, building a 100MW plant is possible but would involve a plethora of engines.
    6. With air-cooled radiators, reciprocating engines would offer very low water usage.
    7. Reciprocating engines may require a larger footprint than gas turbine options, particularly with smaller engines and/or larger plant sizes.

- Air cooling for auxiliaries
- Black-start generator
- Fuel gas compressors (gas turbine options only)
- As part of the project, and with a larger plant, add a Admin./Control Room/Maintenance Shop Building
- Expand existing air and water systems to support new units

Reciprocating Engines

Additionally, the IID is currently studying reciprocating natural-gas-fired peaking generation. Reciprocating engines can acquire full load status in three minutes or less and maintain quick responding generation capability to help with the integration of renewable resources. These units are fairly inexpensive and can be modularly located near a supply resource pocket and function similarly as a peaking generator, but have the ability for higher levels of rapid response flexibility. Reciprocating engines are also a good resource to provide VAR support, system stability, AGC, spinning resources, automated scheduling, long lasting generation output and voltage support at a relatively low cost. IID needs to compare these units to any other peaking resource or quick responding resource that the IID is considering.

Potential Gas Fired Intermediate Additions

El Centro No. 4 Repower

Plant Functional Requirements

- Baseload energy resource

[18] The J920 is in service but has not yet been deployed to the U.S. Plans are to do so in the next year.

- Utilize existing Unit 4 steam turbine, condenser and cooling tower
- Duct firing for peaking

1. Permitting Considerations

- If output is limited to a less than 50 MW increase, than permitting should not need to go through the California Energy Commission. This would place a cap of 130-135 MW on the project. For a larger output, permitting would need to go through the California Energy Commission and should be very similar to permitting the Unit 3 Repower. For the purposes of this study, a ceiling output of 129.5 MW at average annual conditions was assumed.
- Permitting would still involve the Imperial County Air Pollution Control IID
- Retirement of the existing Unit 4 boiler should provide at least a partial source of emissions offsets as well as freeing up the existing Unit 4 water consumption for use by the repowered Unit 4.
- A new interconnects to IID for the gas turbine generator, including a transmission line similar to Unit 3, would be required. It is not known whether there is a spare position in the El Centro Switching Station to accommodate this new connection.

2. Project Key Features

- Gas Turbine Options
  - Given that ECGS already has GE 7EA and SGT-800s gas turbines installed, introducing a third turbine model would be an added complication for operation and maintenance.
  - It appears there is room for a 1x1 GE 7EA in place of the old Unit 3 and Unit 4 boilers.
  - To increase turndown as compared to Unit 2, it may be possible to add additional catalyst to allow operation into ranges where the turbine is outside its normal emissions-compliant operating range but within permitted stack emissions. This approach has been used on some 7EAs in Texas.
  - The recoverable exhaust energy of a single 7EA is ~60 percent of the existing Unit 4 boiler heat input into the steam cycle. Duct firing could be used to "tune" the heat input into the steam cycle. However, duct firing is only available on IID's current units when they are taking of Automated Generation Control. So, the value of duct burners can be negated by the value of taking a unit off AGC and this factor was taken into consideration on the production cost modeling of these units.
  - There appears to be insufficient room to replicate the new Unit 3 2x1 Siemens SGT-800 combined cycle without impacting the standby diesel generator and possibly interfering with parts of Unit 3 such as the PDC and central drain sump.
- Refurbish the steam turbine
  - Unit 4's turbine is of a more modern design than Unit 3's original turbine having steam seals and reheat.
  - Unit 4 was recently bore scoped and was considered to be in good condition. In addition, the control system has been upgraded.

- It is unlikely that the full 80 MW output of the steam turbine could be used as the extractions would be closed off and all steam going into the steam turbine would exit the turbine exhaust. In addition, it may not be possible to always achieve the 1,000 degrees Fahrenheit main and reheat steam temperatures given that the exhaust temperature for a 7 EA is about the same. Additional study, engaging Westinghouse (now Siemens Orlando) is needed to fully understand the viability of this option.
    - Reusing the turbine could offer significant cost savings (a comparably sized turbine would cost in excess of $20 million).
    - At the same time, using parts of Unit 4 would create an exposure to seismically strengthen parts of the turbine building; however, the risk should be small since by using the same steam turbine, extensive structural modifications should not be needed.
- HRSG with duct burners, although as previously mentioned, the actual use and value of duct burners will depend on the ability to use duct burners when the unit is taken off AGC, so this benefit also has actual usage risks that may not pay back the investment for this benefit.
    - This would furnish some peaking capacity.
    - Duct firing also offers a way to fully utilize the steam turbine capacity.
- Air cooling for auxiliaries
- Demolition of Unit 3 and 4 boilers
    - The best location for the gas turbine(s) is where the Unit 3 and 4 boilers are located so the HRSG(s) are close to the steam turbine.
    - The boilers will have to be demolished some time.
- Add auxiliary steam system connecting Units 2, 3 and 4 to allow for faster startups by using steam from another unit to pull and maintain vacuum.

Medium-Sized Combined Cycle New Build

1. <u>Plant Functional Requirements</u>

- Baseload energy resource
- 130-150 MW
- Located near Coachella

2. <u>Permitting Considerations</u>

- No site identified as yet; presumably near Coachella Substation with good access to the IID 230kV bus.
- Permitting will be through the California Energy Commission and South Coast Air Quality Management IID.
- Permitting will require use of the Application for Certification process and will likely be more involved than permitting the Unit 3 Repower.
- The availability and the cost of emissions offsets are unknown.

- A study needs to be conducted to determine if the current reliability operator system and current injection wells will be sufficient to meet production of water needed and disposal of waste water streams.
- A new interconnect to IID will be required; the extent of which is unknown.

3. Project Key Features

- Given that ECGS already has GE 7EA and SGT-800s gas turbines installed, introducing a third turbine model would be an added complication for operation and maintenance.
- Potentkial for HRSG with duct burners
- New steam turbine and condenser
- Air cooling for auxiliaries

Peaker Plant New Build

1. Plant Functional Requirements

- Peaking energy resource
- Black-start capable
- 10-minute start capable
- Minimal water use
- 100 MW

2. Permitting Considerations

- No site identified as yet.
- Permitting will be through the California Energy Commission and Imperial County Air Pollution Control IID.
- The availability and cost of emissions offsets is not known at this time.
- Water use will likely be an issue as at Niland unless there is a source of reclaimed, degraded or ground water for use. Like at Niland, a minimal water use plant design may be needed if only Colorado River or potable water is available. Reciprocating engines, with their low water use (air-cooled radiators), could also be an attractive option.
- A new interconnect to IID will be required; the extent of which is unknown.

3. Project Key Features

- Engine Options
    - Gas Turbines
        1. With LM6000s already in use at Niland, a logical choice is additional LM6000s. Like the existing NGTP units, a Coachella peaking plant would likely utilize SPRINT. Whether dry, low NOx or water injection is used for the combustion system will likely depend on the availability of water.

2. For a Greenfield project another strong candidate is the LMS100. The water injected variant offers turndown to 25 percent. Thus it could offer the range in power of two LM6000s in one engine although at a slightly worse heat rate.

- Multiple Reciprocating Engines
  1. GE Jenbacher J920[19], J624
  2. Rolls-Royce Bergen B35:40V12AG, B35:40V16AG, B35:40V20AG
  3. Wartsila 9L34SG, 16V34SG, 20V34SG, or 18V50SG
  4. With multiple engines, this option would offer a relatively constant heat rate over the range of loads.
  5. In the smaller engine sizes, building a 100MW plant is possible but would involve a plethora of engines.
  6. With air-cooled radiators, reciprocating engines would offer very low water usage.
  7. Reciprocating engines may require a larger footprint than gas turbine options, particularly with smaller engines and/or larger plant sizes.

- Air cooling for auxiliaries
- Black-start generator
- Fuel gas compressors (gas turbine options only)

Below is a summary of the cost and performance data for all conventional generation considered in this IRP:

Exhibit 93: Cost and Performance Data for All Conventional Resources Studied

[19] The J920 is in service but has not yet been deployed to the U.S. Plans are to do so in the next year.

Conventional Resources: Cost and Perfomance Data									
Asset Type	**Combined Cycle**			**Combustion Turbine**			**Reciprocating Engines**		
Model Designation	**1 x 1 F Class**	**2 x 1 F Class**	**2 x 1 Small Advanced Class**	**1 x 0 F Class with SCR**	**1 x 0 LM6000 with SCR**	**1 x 0 LMS100 with SCR**	**18 MW x 3 with SCR**	**18 MW x 6 with SCR**	**18 MW x 12 with SCR**
Installed Cost (Includes Owners Cost and IDC, 2018 $/KW)									
CAISO	1563	1100	1050	671	1403	1342	1806	1537	1354
Summer Ratings (Summer=June-August)									
Max Capacity (MW)	353	707	806	225	55	113	55	109	219
Max Heat Rate (HHV, Btu/KWh)	6500	6490	6300	9800	9500	8800	8300	8300	8300
Min Capacity (%)	50%	24%	20%	43%	40%	25%	8%	4%	2%
Min Capacity (MW)	177	172	161	97	22	28	5	5	5
Heat rate (50% load)	7500	7490	6800	11800	13100	10600	9700	9700	9700
Heat rate (75% load)	6700	6690	6600	10600	9900	9400	8700	8700	8700
Min Heat Rate (HHV, Btu/KWh)	7500	7900	8100	14000	13400	14200	10800	10900	11000
Extreme summer Ratings 106F									
Max Capacity (MW)	342	685	762	217	46	99	54	106	214
Max Heat Rate (HHV, Btu/KWh)	6600	6600	6400	10000	9900	9000	8400	8400	8400
Heat rate (50% load)	7600	7600	6900	12000	13600	10900	9800	9800	9800
Heat rate (75% load)	6800	6800	6700	10800	10300	9700	8800	8800	8800
Winter Ratings (Winter=September-May)									
Max Capacity (MW)	364	729	834	243	56	115	55	110	220
Max Heat Rate (HHV, Btu/KWh)	6600	6590	6410	9500	9300	8600	8300	8300	8300
Heat rate (50% load)	7000	6990	6900	12100	11900	10400	9700	9700	9700
Heat rate (75% load)	6700	6690	6600	10000	10000	9400	8700	8700	8700
Min build requirement	1	1	1	1	1	1	1	1	1
Technical life	30	30	30	20	20	20	20	20	20
Start time (mins)	30	30	30	11	10	10	5	5	5
Min up-time(Hrs)	8	8	8	4	2	2	1	1	1
Min down-time(Hrs)	8	8	8	4	2	2	1	1	1
Min Capacity (%)	50%	24%	20%	43%	40%	25%	8%	4%	2%
Min Heat Rate (HHV, Btu/KWh)	7500	7900	8100	14000	13400	14200	10800	10900	11000
Variable O&M (2018 $/MWh)	3.40	3.00	3.90	10.60	9.50	7.30	6.40	6.40	6.40
Fixed O&M (2018 $/KW-year)-West	11.40	7.40	6.90	9.50	31.50	15.90	31.50	16.70	12.70
Maintenance Rate (hours per year)	444	444	444	168	168	168	168	168	168
Forced Outage Rate (hours per year)	263	263	263	175	175	175	175	175	175
Ramp Rate (%/minute)	11%	11%	13%	16%	90%	43%	75%	75%	75%
Start Costs									
Cash Start Costs (2018 $/start) incl MM	14000	28000	30000	14000	0	0	0	0	0
Fuel Start Costs (MMBtu start fuel/start)	1100	2200	2400	120	40	40	25	50	100
Emission Rates (with controls) (lbs/MMBtu)									
CO2	115	115	115	115	115	115	115	115	115

VEHICLE ELECTRIFICATION POTENTIAL

IID has studied the potential impacts of providing a program(s) that incentivize customers to buy and utilitize electric vehicles. The main goal was to analyze any impacts on the utility and the consumer to explore any realizable value in a program that complies with SB 350s guidelines. Some of the key considerations that are important in a vehicle electrification program and its costs and benefits are as follows:

- *Cost per mile*
- *Driving range*
- *Energy input to IID system*
- *Charging time*
- *Type of Vehicle (BEV/PHEV)*
- *Consumer Perspective*
- *Program risks*
- *Vehicle Market Share*

Nationally, the number of electric vehicles is increasing significantly due to better technology, state regulation and lower vehicle prices; as a result of this several nationwide pilot programs are put in place for Battery Electric Vehicles and Plug-In Hybrid Electric Vehicle. Integrating Electric Vehicles have a direct impact to utility energy grid, and there are many variables we need to take in consideration for move to the Vehicle Electrification Programs, such as types of charging stations, electric vehicles characteristics, possible charging hours during the day, and how these variables affect energy utilities system.

Light Duty Vehicle Sales

In the last years California has increase the electric vehicles sales; since 2011 to Aug'16 the total national sales were 496,190 and California had 231,482 this represents the 47 percent [1]. If we compare the month of August of 2016 national sales was 14,973 and in California 7,786 this gave a participation of 52 percent [1] of electric vehicles. Most of these sales are concentrates in the metropolitan areas such as Los Angeles, Sacramento, San Francisco, San Diego, etc. where utility companies put in place rebate programs to promote vehicle electrification especially on residential customers.

Light Duty Charging Stations

In the market exist three charging stations categories, that are "Level 1" based on a 120V circuit, "Level 2" a 240V circuit, and "Level 3" a DC/fast-charging. A summary of charging time and costs are show below.

Exhibit 94: BEV & PHEV Changing Stations Categories Summary

Charging Time	Cost (dlls.)	BEV (hrs.)	PHEV (hrs.)
Level 1 (120V)	0-600	12-71.5	3-16.5
Level 2 (240V)	500-12,660	2.5-21	1-4.5
Level 3 (480V)	8,500-50,000	< 0.5	< 0.3

For Level 1 the cost is for the plugging cord, no electric circuit modification is needed and can be connected to the normal 120V receptacles (electric outlets) at home.
Regarding Level 2 in last year and 2016 charger installation increase due to the Federal tax credit which depends on the size of the vehicle and its battery capacity and can go up to 1,000 dollars [2], also utilities are offering rebates that can go up to 500 dollars [3] for residential installations. Most of the utilities that offers this rebates program are expecting more Level 2 residential installations, and a typical setup is a 240-V system based on a 30 Amps circuit. Manufacturing companies are investing on optimize Level 2

chargers, in the market it is available only the 30-amp system, they are working on 40-amp or higher systems that can reduce in half the charging time in comparison with the existing 30-amp system. Additionally, the amperage of the chargers used in each vehicle can change the charging times. The table below illustrates these time variances:

Exhibit 95: Charing Time Variances of Level 2 Changing Station

Level 2 (240V)			
Amps	kWh	Charging Time * (hrs.)	Charger Cost Only **
30	7.2	4.17	$ 689.00
40	9.6	3.13	$ 835.00
50	12	2.50	$ 899.00
70	16.8	1.79	$ 2,195.00
80	19.2	1.56	$ 2,195.00

*** Consider a fully charge of a 30kWh battery.**

**** Do no include permit and installation cost.**

A typical charger size for a level 2 is a 30 amps system which can fully charge a 30kWh battery in approximately 4.17 hours, as we increase the amperage we reduce the charging time. Level 2 chargers can go up to 80 amps, and by moving to this amperage rating charging time can be reduce to 1.56 hours. Customers need to take in consideration that increasing the amps reduce charging time and also increase the cost of the charging stations.

No plans for the near future for Level 3, this will be commercial only.

[1] http://www.pevcollaborative.org/pev-sales-dashboard

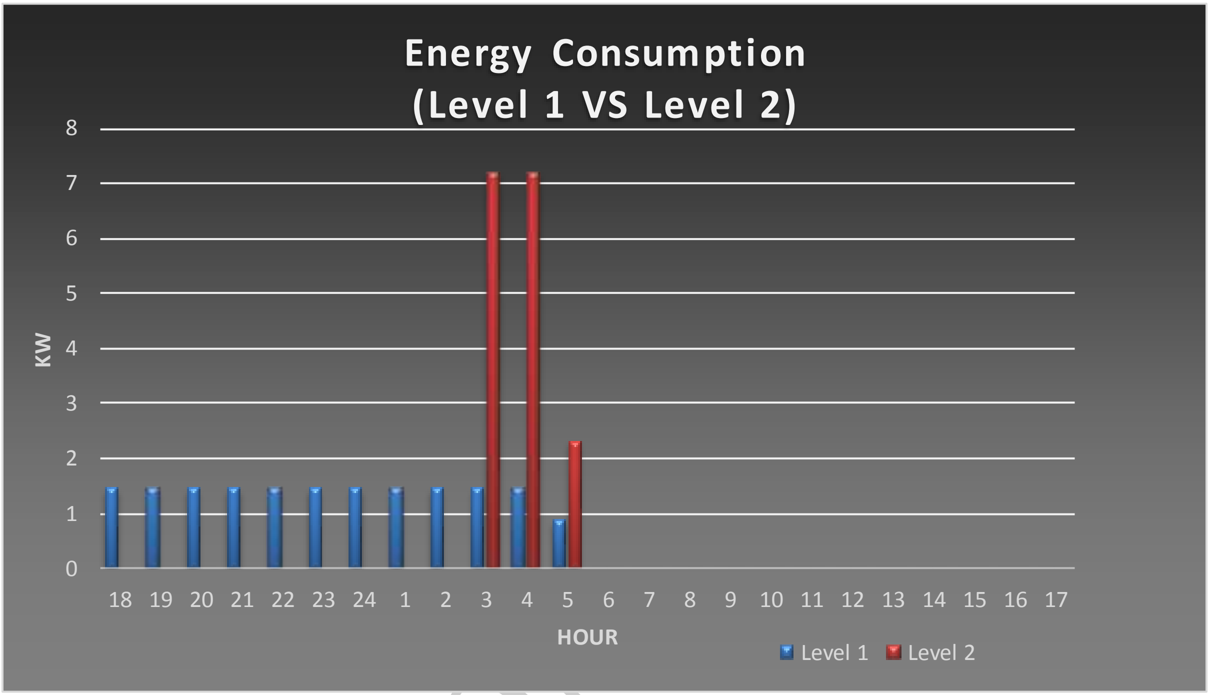
[2] http://www.afdc.energy.gov/laws/10513

[3] https://www.epa.gov/cati/workplace-electric-vehicle-charging-stations-californias-south-coast#incentives-veh-install

Light Duty Electric Vehicle Charging Habits

In the past all analysis/calculation was made assuming how many hours the electric vehicles needed to be 100 percent 233harged, and was taking in consideration that most of electric vehicles charging occurs during night hours (start charging at 7 or 8p.m.). In the last quarter of 2015 when the majority of the new customer change from Level 1 to level 2 we have a different energy consumption shape, c~~ustomer plug in the vehicle~~ the logic of the charger is different. Level 2 devices setup an hour at the one the vehicle need to be 100percent (in most common cases is 6 a.m.). The graph below reflects the energy consumption between level 1 & Level 2 chargers.

Exhibit 96: Energy Consumption of Level 1 & Level 2 Changing Stations



The graph is taking in consideration a single customer that one starts charging the vehicle at 6 p.m., and they need to have 100 percent charged by 5 a.m.

Consumer Light Duty Vehicles Transportation Impact

In the next analysis we calculate the cost per mile for the three categories (gasoline, PHEV and BEV). 40 models light-duty vehicles were analyzed and the table below shows the average. For compare each category was used dollars per mile ($/mi) units.

For the vehicle population and miles traveled per day in the analysis below we got the data from CARB's EMFAC Web Database. The cost is taking in consideration two factors, that are the vehicle cost and the fuel cost. For the vehicle cost we divide the total cost of the vehicle by 120,000 miles. Only for BEV and PHEV tax credit was applied to the total cost of the vehicle, credit depends on the type of vehicle and battery size.

And for the fuel cost all units was analyzed separate and take in consideration the type of vehicle, engine efficiency, battery size, and other variables that can affect the cost per mile. The variables stay constant to all the vehicles analysis was the energy price and the fuel price.

The energy residential rate was the same for all vehicles and was 13.9 cents per kWh, and the same applied to the fuel cost was use 2.79 dlls/gl on along the study.

Exhibit 97: Light Duty PHEV & BEV Characteristics

Vehicle Characteristic	Gasoline	Plug-In Hybrids Vehicles (PHEV)	Battery Electric Vehicle (BEV)
Range (miles)	304-595	270-640	58-335
MPG	24-52	25-46	-
KWh/mile	-	0.44	0.29
Total Annual Energy Use (MWh)-IID Fleet	-	3,500	5,250
Total Annual Energy Use (MWh)-Customer Program (15%)	-	89,813	128,520
Vehicle Cost (dlls/mi)	0.24	0.43	0.24
Fuel Cost (dlls/mi)	0.09	0.06	0.04
Total Cost (dlls/mi)	0.33	0.49	0.28

BEV have the better cost of 0.28 $/mi but we need to considerer that the mile range goes from 58-335 miles per battery 100 percent charged. BEV customers need to charge at home, not too many charging stations are in Imperial Valley so in most of the cases we are taking in consideration a 34-107 miles' radius travel from home. PHEV have a better mile range (270-640) but they have a highest cost of the three categories 0.43 $/mi, one of the factors is that most of the PHEV receive a percentage of the tax credit while BEV can have 100 percent of the tax credit.

Gasoline engines have the highest share in the market, the cost per mile is higher than the BEV, and lower than PHEV. Gas based motors have a minimum loading tank comparing to 100 percent charging time of BEV, also gas stations are available along the Imperial Valley and the US.

In the last year Fuel Cells Vehicles has been introduce to the market, the fuel FCV in a technology that use hydrogen as fuel and is a zero emission unit. FCV cost are higher in comparison to BEV, PHEV and conventional gas engines, in the US there are not too many hydrogen stations and recharge fuel time is very similar to the gas based engines.

Various light duty vehicles observed

Models selected for the study are the ones that represent 90 percent of the nationwide market share. The first part (highlighted in red) are the BEV and the next section (highlighted in blue) is the PHEV portion. We also include an estimation hours of charging time, this section is divided by Level Type and the calculation is based on the battery size of each vehicle. In the table below are the models we analyzed, the

Exhibit 98: BEV and PHEV cost analysis by vehicle models

Company	Model	Classes	Year	Seating	Battery Size (kWh)	Mile Range	Vehicle Cost	Vehicle Cost ($/mi)	Fuel Cost ($/mi)	Total Cost ($/mi)
Nissan	Leaf	Midsize	2018	5	40	151	$29,120	$0.243	$0.041	$0.283
Tesla	Model S 75D	Large	2018	5 + 2kids	75	259	$74,500	$0.621	$0.041	$0.661
Tesla	Model 3	Midsize	2018	Midsize	75	220	$35,000	$0.292	$0.048	$0.339
Fiat	500e	Minicompact	2018	4	24	84	$32,995	$0.275	$0.040	$0.315
Ford	Focus Energi	Compact	2018	5	33.5	115	$29,120	$0.243	$0.041	$0.283
Chevrolet	Spark EV	Subcompact	2016	4	19	82	$25,510	$0.213	$0.032	$0.245
KIA	Soul EV	Small Station Wagon	2018	5	30	111	$33,950	$0.283	$0.038	$0.321
BMW	i3	Subcompact	2018	4	33	114	$44,450	$0.370	$0.041	$0.411
Chevrolet	Volt	Compact	2018	5	18.4	420	$34,095	$0.284	$0.049	$0.333
Ford	C-Max	Large	2018	5	7.6	400	$24,175	$0.201	$0.053	$0.255
Ford	Fusion	Compact	2018	5	7.6	610	$26,100	$0.218	$0.051	$0.268
Toyota	Prius Prime (Plus)	Midsize	2018	4	8.8	640	$27,300	$0.228	$0.049	$0.277
Chrysler	Pacifica Hybrid Touring Plus	Minivan - 2WD	2018	7	16	566	$39,995	$0.333	$0.068	$0.401
Honda	Clarity Plug-In Hybrid	Midsize	2018	5	17	340	$33,400	$0.278	$0.051	$0.329

BEV and PHEV units can receive a Federal tax credit up to $7,500. Tax credit depends on the battery size of the vehicles, with a minimum battery pack of 4kW for $2,500 and $7,500 for a 16kW or more.

PHEV have a less charging time due to the hybrid electric/gas engine. BEV customer charge the units at night, and there are a few charging stations at the workplace. available Mile range is better for PHEV.

Most of the PHEV customer charge automobile once a day and when the battery is discharged the engine switch to gasoline. For the BEV is a different condition because there is no alternate fuel and this affects the customer habits. Three types of scenarios are analyzed under BEV units.

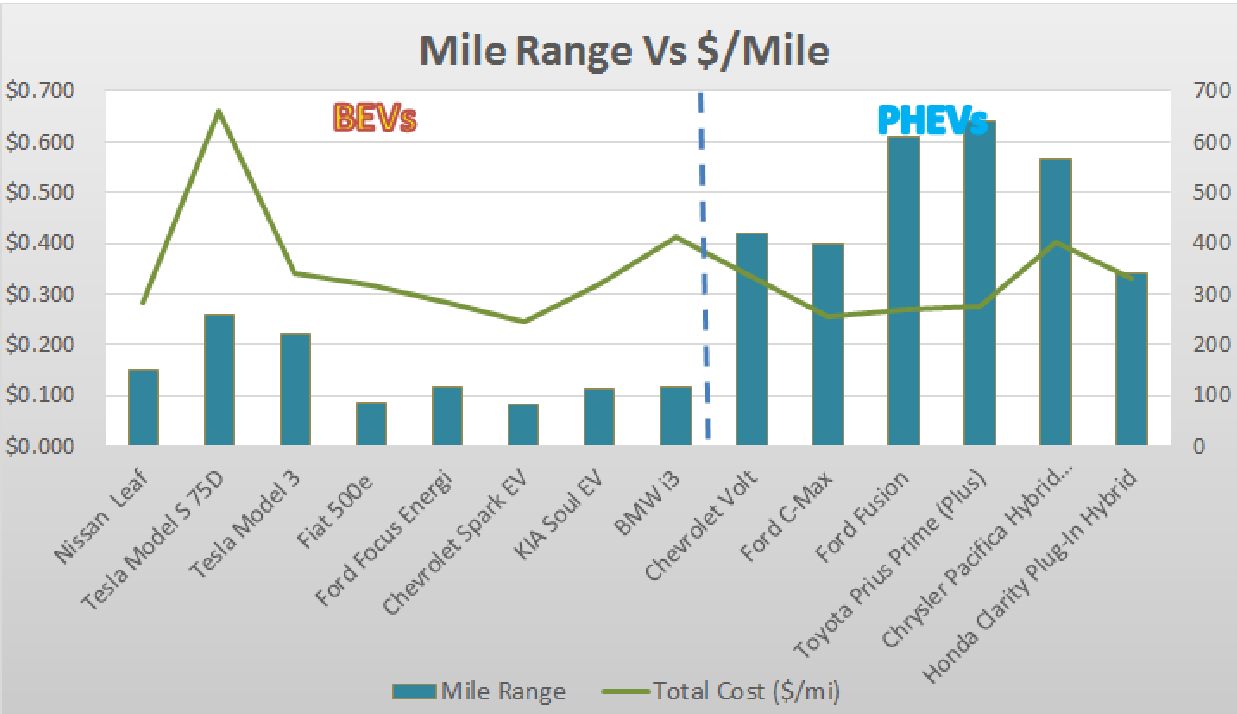
1) One charge per day. Customers need to be plug the vehicle at home and have the unit 100 percent charge for a certain hour in the morning (50 percent of the customers are in this category)
2) Two charges per day. Customers need to be plug the vehicle at home and have the unit 100 percent charge for a certain hour in the morning, and also they charge the vehicle at work (36 percent of the customers).
3) Three charges per day. Customers need to be plug the vehicle at home and have the unit 100 percent charge for a certain hour in the morning, charge the vehicle at work, and another charge at home after work (14 percent of the customers)

When customer need to charge more than once a day and the charging time is a limitation to use the vehicle, customers strongly prefer shorter charging periods. Install a Level 2 charging station cost approximately $1,600, and in some cases double this price due to extra modification to their electric system, this is the main reason customer do not migrate from Level 1 to Level 2. Utilities setup rebate programs for customers that install Level 2 charging stations, this is to incentive residential and commercial customer. In general, as more customers connect to the grid the better benefits because can complement and balance intermittent renewable energy.

Mile range and charging time are very strong variable that customers analyze before moving to vehicle electrification. The next graph we put together all the vehicle and the bars illustrate the total miles per fully charge, the green line represents the cost per mile for each vehicle.

The graph below illustrates mile range and cost per mile between BEV and PHEV.

Exhibit 99: Mile Range and Cost Between BEV and PHEV



Analysis of Potential Programs

Based on the information above, IID observed several program structures and their impact potential. Furthermore, the investment potential and return of revenues through greater loads was used to determine the potential value of a program. The two basic programs studied were as follows:

- Charging station rebate
  For customer Level 1 is a good option, is the lowest cost in most of the cases, no modifications to the existing electric circuit, and charging time is longer (usually charge vehicle at night hours). Level 2 can reduce the charging time in a half but require customer investment. Level 2 minimize intermittent impacts due to renewable resources, more customers interconnect are better to the utility electric system. IID can promote Level 2 installation with a rebate program for residential and commercial customers. Most of the utilities in California offer rebates up to $500 per residential charging stations and $1,000 for commercial applications.
- Charging station based program (describe)
- Customer based program (describe)

The coverage scenarios and the estimated saturation levels for the studies are as follows:

- Total light duty vehicles estimated for all IID customers:
  - *Approximately 286,248*
- Scenarios studied of total saturation of all vehicles in IID area converted to BEV or PHEV and incentivized to charge batteries:
  - *5 percent*
  - *15 percent*
  - *30 percent*
- Each scenario added a certain amount of energy (i.e., revenues) to the IID system that was calculated and attributed to the public program

The results were observed in two forms:

1. A single year return on investment
2. 10 year NPV return on investment

Below are two tables that summarize the two versions:

Single Year

Exhibit 100: BEV & PHEV System Impact and Public Programs Potential (Singer Year)

SYSTEM IMPACT		BEV				PHEV			
		100%	5%	15%	30%	100%	5%	15%	30%
ENERGY (MWH)		1,193,492	59,675	179,024	358,048	1,195,138	59,757	179,271	358,541
PEAK IMPACT (MW)		409	20	61	123	409	20	61	123
ADDED REVENUE		$165,895,373	$8,294,769	$24,884,306	$49,768,612	$166,124,194	$8,306,210	$24,918,629	$49,837,258
SAVINGS AMOUNT		$88,318,400	$4,415,920	$13,247,760	$26,495,520	$88,440,219	$4,422,011	$13,266,033	$26,532,066
70% OF ENERGY TRADEOFF		$61,822,880	$3,091,144	$9,273,432	$18,546,864	$61,908,153	$3,095,408	$9,286,223	$18,572,446
PUBLIC PROGRAM POTENTIAL									
CHARGING STATION BASED PROGRAM	# CHARGING STATIONS 1	103,038	5,152	15,456	30,911	103,180	5,159	15,477	30,954
	# CHARGING STATIONS 2	9,396	470	1,409	2,819	9,409	470	1,411	2,823
	# CHARGING STATIONS 3	2,114	106	317	634	2,117	106	317	635
CUSTOMER BASED PROGRAM	INCENTIVE PER CAR SOLD	$215.98				$216.27			

Exhibit 101: BEV & PHEV System Impact and Public Programs Potential (10 Years)

SYSTEM IMPACT		BEV				PHEV			
		100%	5%	15%	30%	100%	5%	15%	30%
10 YEARS SAVINGS AMT		$883,184,001	$44,159,200	$132,477,600	$264,955,200	$884,402,186	$44,220,109	$132,660,328	$265,320,656
70% OF ENERGY TRADEOFF		$618,228,801	$30,911,440	$92,734,320	$185,468,640	$619,081,530	$30,954,077	$92,862,230	$185,724,459
PUBLIC PROGRAM POTENTIAL									
CHARGING STATION BASED PROGRAM	# CHARGING STATIONS 1	1,030,381	51,519	154,557	309,114	1,031,803	51,590	154,770	309,541
	# CHARGING STATIONS 2	93,956	4,698	14,093	28,187	94,085	4,704	14,113	28,226
	# CHARGING STATIONS 3	21,136	1,057	3,170	6,341	21,165	1,058	3,175	6,350
CUSTOMER BASED PROGRAM	INCENTIVE PER CAR SOLD	$2,160				$2,163			

In addition to the above analysis, IID will also consider the potential programs that allow full vertical integration of electric vehicles. Such programs similar to vehicle-to-grid that provides an all inclusive system that allows EVs to communicate with the grid and even sell demand response services by either returning electricity to the grid or by throttling their charging rate. This type of program can also allow EVs to store and discharge electricity generated from renewable resources that tend to fluctuate based on weather patterns.

Medium-Heavy Duty Vehicles Electrification Impact and Programs Potential

The vehicles electrification analysis above is mainly focus on light-duty vehicles. IID also did some research on medium-heavy duty vehicles electrification impact and programs since medium-heavy duty vehicles also play important role in in California's regulations and incentives to advance its clean transportation goals. Four categories of medium-heavy duty vehicles are considered in IID's medium-heavy duty vehicles research and analysis: public transit buses, school buses, other buses (the buses not owned or operated by transit agencies or school districts, such as hotel/airport shuttle buses, commercial fleets, military transport and etc.) and medium-heavy duty freight trucks. According to EPA's classification, GVWR<8,500 lb is Light Duty Vehicle, GVWR>8501 lb is Medium-Heavy Duty Vehicle. CARB's EMFAC Web Database provides detailed data on the vehicle population and miles traveled per day and per year by the four categories of medium-heavy duty vehicles operated in IID's service area as the below exhibit shows.

	Public Transit Buses			School Buses			All Other Buses			Medium-Heavy Duty Trucks		
Counties	Imperial	Riverside	Total IID	Imperial	Riverside	Total IID	Imperial	Riverside	Total IID	Imperial	Riverside	Total IID
Vehicle Population (#)	35	35	70	234	111	345	237	65	302	6,738	3,080	9,818
Annual miles driven (miles)	1,588,480	1,767,426	3,355,906	2,911,240	1,413,050	4,324,290	4,619,440	1,236,955	5,856,395	295,912,800	122,421,892	418,334,692
Daily Miles Driven per vehicle	127	142	135	35	36	35	55	53	54	123	112	120

We also collected the cost performance information of the mainstream models and manufacturer in the current medium-heavy duty vehicles market such as engine efficiency, battery size, mileage range after full charge and etc. as the below exhibit shows.

Type	Manufacturer	Model	Seating	Weight	Battery (kWh)	kWh/Mile	Nominal Range(miles)
BEV public transit bus	PROTERRA	XR+	40	43,650 lbs	330	1.387	238
	PROTERRA	FC	28	39,500 lbs	94	1.403	67
	BYD	K7M 30' All-Electric Transit Bus	20	29,762 lbs	196	1.452	135
	BYD	C6 23' All-Electric Coach Bus	16	16,424 lbs	128	1.032	124
BEV school bus	Greenpower	SYNAPSE 72 All-Electric School Bus	72	unkown	150	1.364	110
	eLion	All-Electric Type C 4x2 School Bus	54-72	30,000 lbs	256	1.652	155
	Motiv	Starcraft eQuest School Bus on EPIC 6	various	14,500 lbs	106	1.413	75
BEV other buses	Chanje	V8100 Panel Van	-	16,535 lbs	100	0.667	150
	Motiv	EPIC 4 Dearborn on Ford E450 Walk-in Van	-	22,000 lbs	106	1.178	90
	Phoenix Motor Cars	ZEUS 300 Shuttle Bus	20	14,500 lbs	105	0.955	110
	BYD	C6 23' Coach Bus	58	49,604 lbs	394	1.970	200
BEV med-heavy duty trucks	BYD	T5 Class 5 Cab-Forward Delivery Class-5 Truck	-	16,138 lbs	145	0.935	155
	BYD	6F Class 6 Cab-Forward Class-6 Truck	-	26,000 lbs	221	1.782	124
	BYD	8TT All-Electric Tractor Trailer Class-8 Truck	-	105,000 lbs	435	2.605	167

Based on the information above, we used the same approach as that of light duty vehicles to analyze the potential load impact and value of potential public incentive programs. Three scenarios were studied by the different levels of saturation of medium-heavy duty electric vehicles: 5 percent, 15 percent and 30 percent; Each scenario added a certain amount of energy and revenues to the IID system, as the below exhibit shows:

	School Buses			Public Transit Buses			All Other Buses			Medium-Heavy Duty Trucks			Total Vehicles		
Electrification impact	5%	15%	30%	5%	15%	30%	5%	15%	30%	5%	15%	30%	5%	15%	30%
Vehicle Population (#)	17	52	104	3	10	21	15	45	91	491	1,473	2,945	526	1,580	3,161
Annual miles driven (miles)	216,177	648,531	1,297,062	168,413	505,239	1,010,478	292,593	877,778	1,755,556	20,916,059	62,748,178	125,496,356	21,593,242	64,779,726	129,559,452
Energy(MWh)	319	957	1,914	222	666	1,332	349	1,046	2,093	37,105	111,315	222,631	37,995	113,985	227,969
Off peak impact (MW)	0.11	0.33	0.66	0.08	0.23	0.46	0.12	0.36	0.72	12.71	38.12	76.24	13.01	39.04	78.07
Added revenue ($)	$41,480	$124,440	$248,880	$28,856	$86,568	$173,135	$45,340	$136,020	$272,041	$4,823,662	$14,470,985	$28,941,970	$4,939,338	$14,818,013	$29,636,026
Energy cost to serve ($)	$20,740	$62,220	$124,440	$14,428	$43,284	$86,568	$22,670	$68,010	$136,020	$2,411,831	$7,235,492	$14,470,985	$2,469,669	$7,409,007	$14,818,013
Savings amount ($)	$20,740	$62,220	$124,440	$14,428	$43,284	$86,568	$22,670	$68,010	$136,020	$2,411,831	$7,235,492	$14,470,985	$2,469,669	$7,409,007	$14,818,013

From the table above we can see that public transit buses have the smallest impact to IID system load because only 70 public transit buses totally are operated in IID service area and each bus travels around 127 miles per day. So even we assume 30 percent of these 70 public transit buses are replaced by electric buses, the load impact is little, only 1,914 MWh a year; if we assume these buses only charge during off peak, the off peak impact is only 0.66MW. On the other hand, medium-heavy duty freight trucks have the largest load impact to IID system. If we assume that 30 percent of those freight trucks operated in IID service area are replaced by electric trucks and are charged with IID provided electricity, the load impact is 222,631MWh, it could bring IID more than $28 million in revenues per year.

Similar as the assumptions of the potential public programs in the light duty vehicles analysis above, 70 percent of revenues are used for the investment of the public programs to incentivize transportation electrification. Two public programs are designed in the analysis: charging station rebate and customer rebate; the public programs are observed in two forms: single year return on investment; 10 year NPV return on investment. It was noticed that the charging station cost for medium-heavy duty vehicles are much more expensive than the ones used for light duty vehicles ($105,000 for Level 2, $600,000 for Level 3 in the calculations below)

The results are as the below exhibits shows:

Medium-Heavy Duty Vehicles Elctrification Public Program Potential				
Electrification Impact		5%	15%	30%
Program fund from 1 yr 70% saving		$ 1,728,768	$ 5,186,305	$ 10,372,609
Charging station based program	# Charging station level 2 (1 yrs savings)	16	49	99
	# Charging station level 3 (1 yrs savings)	3	9	17
Customer based program	Incentive per vehicle sold ($)(1 yr savings)			3,282
Program fund from 10 yrs 70% saving		$ 17,287,682	$51,863,046	$103,726,091
Charging station based program	# Charging station level 2 (10 yrs savings)	165	494	988
	# Charging station level 3 (10 yrs savings)	29	86	173
Customer based program	Incentive per vehicle sold ($) (10 yrs savings)			32,820

Grid Impact

If the number of electric vehicles increase significantly, additional grid studies require to determine if system upgrade or modifications are need to support the extra energy demand. Several actions plans can put together before start upgrading the electrical system, such as

- Monitor and track the consumptions shapes and try to optimize charging station by start them when energy begins to decrease (as example when air conditioning units are not running).
- Other utilities along the US have two energy prices, utilities offer a lower kWh price during the hours that the energy begins to decrease (usually at night hours).

These are the significant impacts, IID need to track each circuit and monitor the quantity and demand of the electric vehicle charging station.

Chapter 6: IRP Modeling Assumptions

This section reviews some of the input assumptions needed for evaluating the candidate resource options listed in Chapter 5. The evaluation required multiple assumptions including assumptions for the following key variables:

- Challenges facing IID
- Other Risks faced by IID
- Natural gas prices
- Market energy prices
- Cost of capital assumptions
- Escalation rate and discount rate assumptions
- Planning reserve margin
- Modeling approach

Challenges Facing IID

During the process of this IRP, IID has identified three key areas where IID is facing the most critical challenges. These challenges create a situation where decisions made today can be based on a set of assumptions that can be very wrong due to the levels of severity in these challenges. As a result, below is a summary of those challenges that were factored into the resource modeling and risk assessment for this IRP:

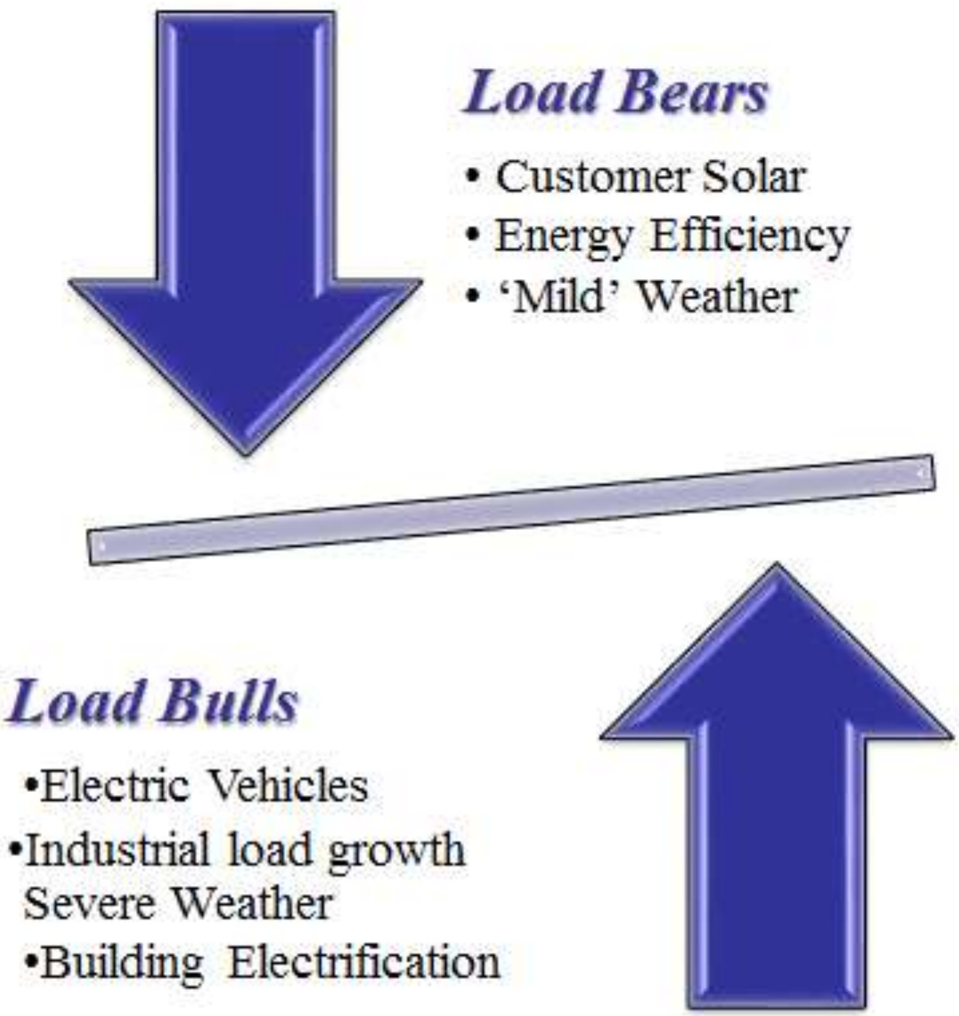
Load:

Load growth is a key piece that all decisions are based upon. If load grows faster than expected, then resource needs increase and IID must be prepared for this. On the other hand, if load does not grow or if load decreases, then any decisions made today based on load growth will result in significant losses. In this type of environment, load forecast accuracy is critical to these decisions. However, there are several aspects about forecasting load that have become more significantly uncertain and greater uncertainty leads to greater volatility in load. The results of the load forecast are discussed in much greater detail earlier in this document, but this uncertainty is a result in the following variables that are under constant change:

- Rooftop solar penetration
- Energy efficiency impact
- Electric vehicles
- Industrial load in the IID system
- Regulatory requirements

Below is an illustration how each of these competing variables cause situations of load growth or of load degradation:

Exhibit 10: Load Bears and Bulls



With these challenges, IID has also identified several areas of opportunity within these challenges including:

- Incentivizing industrial load growth
- Incentivizing electric vehicles
- Invest in total smart meter saturation
- Adjusting customer electric rates to reflect balancing costs more accurately

RESOURCES

Much of IID's resource fleet is quite old so many of the challenges IID faces related to resources, is a result of an aging fleet. Below is a list of the key challenges related to IID's energy resources:

- Forced outage rates (perceived outage rates vs actual outages)

- Unit reliability
- High cost of operations and maintenance
- Flexibility
    - Hourly and Intra-hour
    - Ramping speed
    - Ancillary requirements
    - Over generation and non-flexible resources

However, with these challenges, this IRP has identified areas where opportunities are presented and they are as follows:

- Timing of added resources can match need timeline
- Quick COD of fairly inexpensive energy storage to address current system concerns
- Improving technologies
- Investing in unit capabilities
- Timely GHG allowance sales to absorb some cost impacts
- Neighboring market opportunities of ancillary support
- Resource repositioning
- Market access alternatives in natural gas and energy

TRANSMISSION

IID is located in strategically advantageous area in relation to transmission resources. Some of the challenges IID faces related to transmission also offer opportunity to IID to offer lower cost and more reliable energy service to its customers. IID has a number of market access points to compare to IID's generation fleet of resources on a daily and even hourly basis. Access to CAISO offers opportunities to take advantage of CAISO sporadic negative priced energy markets. However, during times of price spikes and extremely high prices, IID has the option of accessing non-CAISO energy delivery hubs. This market dynamic provides opportunity, but it also presents various challenges due to pricing dynamics being uncertain between various daily profile shapes and the market points and how all of that relates to IID constantly changing load.

As discussed in this document, the concept of "Regionalization" currently being reviewed as a regulatory policy and IID's market access and system balancing activities would greatly be restructured under such a policy. With these uncertainties along with other regulatory uncertainties, IID is faced with the challenge of deciding today for a 20-30 year period that contains a significant range payback potential. IID can address some of these challenges by constantly monitoring seasonal opportunities at various transmission hubs and seek to participate in ancillary markets.

OTHER KEY RISK FACTORS FACED BY THE IID

The natural gas and energy commodity markets are known as the most volatile commodity markets and therefore include volume, budgetary and price risks. This means that every purchase that the IID makes has inherent risks that are constantly varying with potential cost impacts. Each purchase can contain varying levels of risk depending on the structure of the agreed terms. Each term that is outlined in agreements for development of generation facilities, natural gas, energy/capacity, emission allowances and offsets, renewable products and other energy related commodities can be critical (an estimated 60-70 percent of total costs) to the level of risk contained in a given purchase. Some of the key examples of risk that are observed in most or all transactions include the following:

Forecasting Risk: The financial risk associated to volumetric variations of forecasts to actuals due to weather, economic and other uncontrollable forces. The IID makes its long-term natural gas and energy purchases based upon sophisticated forecasts of demand and energy requirements. If the forecast is too high, the IID purchases too much and may have to sell at a loss. If the forecast is too low, the IID may not purchase enough in the forward markets and have to purchase additional energy and/or natural gas in the spot markets at a higher cost.

Regulatory Risk: The risk associated with having to meet new market regulations or changes in regulatory directions. An example of this is the GHG emission restrictions imposed by the state after the IID had made a substantial investment in a coal-fired generation facility.

Market Price Risk: There are risks that forward purchases are made at the wrong time. Energy and natural gas prices fluctuate daily. A purchase made several months (or years) ago may be expensive compared to today’s price. Conversely, a sale of energy or natural gas could be made for more today than when it was made in the past.

Counter-Party Risk: The risk associated with purchases and sales to counter-parties that refuse or are unable to perform. This may result in either a loss due to nonpayment for energy supplies or an inability to provide contracted deliveries resulting in higher costs to purchase replacement supplies.

Supply Risk: The risk associated with a generation unit or transmission line having a forced outage that affects its ability to provide energy. Failure of a generator may result in having to purchase energy at higher prices or even threaten the reliability of the system.

Process Risk: The risk associated with the process of developing or procuring a structured transaction for gas, power or environmental commodities such as RECs or emissions allowances/offsets. The time involved with deciding what type of structure is best, the time it takes to make the decision, the time it takes to evaluate proposals and the time that it takes to actually execute all have an implied amount of risk. If the IID does not consider the importance of processing transaction, then the value of the underlying commodity is at risk of fluctuation and IID could be exposed.

These are just a few examples of the risk that the IID faces in its daily power supply decisions. The IID attempts to minimize the effects of risks in its daily purchases of energy and natural gas but it will never succeed in totally eliminating the financial impact of risk.

PURCHASING NATURAL GAS AND ENERGY

One of the largest expenses of the IID is the cost of natural gas supplies for internal generation.

In the wholesale market, natural gas is traded on a million BTU basis, or MMbtu, (sometimes referred to as a decatherm). Natural gas has approximately 1,000 BTU[20] per cubic foot (cf) of gas. Therefore, approximately 1,000 cf of gas is equivalent to 1,000,000 BTU's. Retail natural gas is sold in therms, which are 100 cf or 100,000 BTU.

National gas prices are quoted for delivery at Henry Hub, a trading point near New Orleans. The Henry Hub gas is the trading point for all future trades on the New York Mercantile Exchange (NYMEX). However, there are regional trading points where trades occur at prices higher or lower than the NYMEX price depending upon local demand. The difference between the Henry Hub price and a specific trading point is called the basis.

The spot price of gas is the current day's price of gas at a specific delivery point. The future (or forward) price of gas is the price of gas delivered at a specific delivery point at some time in the future. Generally, future prices are for a specific amount of gas delivered each day of the month while spot gas can be any quantity of gas.

The IID purchases gas for use in its internal generation at the Southern California Citygate (SoCal Citygate), a virtual trading point created by the CPUC comprised of a number of pipeline delivery points into the Southern California Gas (SoCal Gas) distribution pipelines.

Due to the recent construction of a pipeline that extends the Yuma lateral from Ogilby to Ehrenburg, the Yucca power plant can utilize fuel supplies that can be delivered to the El Paso South Mainline natural gas delivery hub. Previously, the supply hub was the El Paso Permian Basin and the only type of hedging possible for the Yucca gas supply was financial, which came with higher risks and additional trading hub basis differential costs. The new pipeline arrangement allows IID the flexibility to hedge physical natural gas for use at the Yucca generation facility, which was not possible before the pipeline existed. With this ability to hedge, IID can reduce price/cost fluctuation exposure and avoid paying high basis differential fees between delivery to the Yucca plant and the El Paso Permian Basin.

Long-Term Perspective of Gas and Energy Markets

IID's Energy Department is continuously observing the gas and energy markets on an hourly, daily and long-term basis. There are various types of fundamental drivers that drive each of the markets that can help indicate the general price direction of the markets. However, predicting prices or the moment of price direction change is not possible. For this reason, IID keeps a close watch on both the fundamental market drivers and the technical market indicators. Since the energy market and the gas market maintain a fairly

[20] A BTU is the amount of heat necessary to raise one pound of water from 60 degrees to 61 degrees Fahrenheit

robust correlation, the following are some, but not all, of the fundamental market indicators that IID observes:

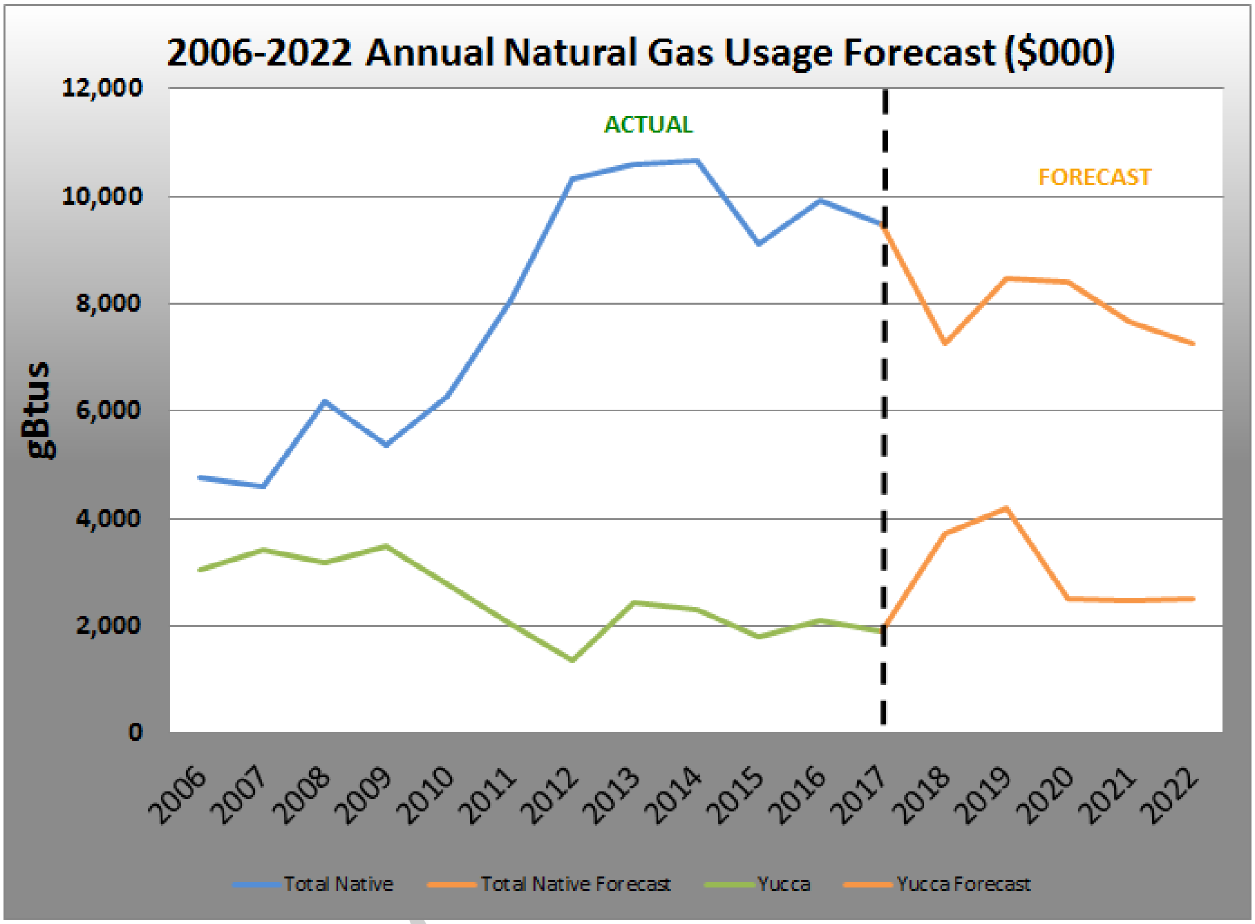
- Natural gas storage
- Regional and national demand trends
- Weather patterns that drive demand
- Natural gas drilling rigs online
- Crude oil pricing trends
- The value of the dollar
- The condition of the economy
- Major outages from various fuel sources
- Market related volatility in the short and long term
- Interest rates that could affect the risk premium paid for futures contracts

The above considerations, along with others, can be helpful to indicate the overall *market* condition, but relative to *IID's natural gas position condition*, the following considerations are constantly observed:

- The impact of a purchase or a lack of a purchase on the fuel and purchased power budget
- The Value at Risk measure of the budget
- Potential transaction structure alternatives
- The purchase price at the time of execution vs. the purchase price assumption in the budget for the month of the year purchasing
- The forecast volume of natural gas/energy/capacity needs
- Scheduled maintenance on internal resources

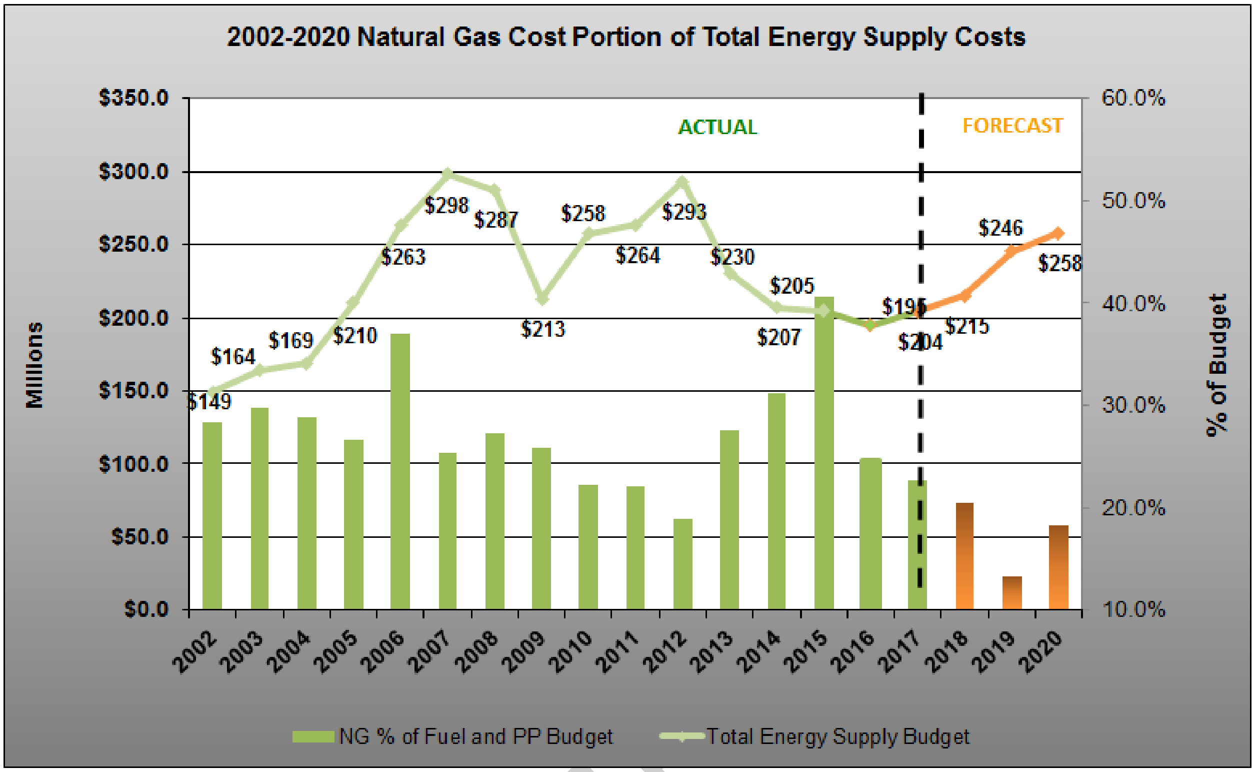
Some of the above considerations are also heavily dependent upon the dynamic of IID's internal decision process. IID is constantly ensuring that the correct decisions are made and will be made in future activities and due to things like weather, forced outages and economic conditions being unsystematic, IID considers many variables as potential outcomes to assure optimal decisions are formulated, since IID's natural gas requirements are significant in volume and significant in potential cost. The following exhibit illustrates the actual annual natural gas usage and the projected usage for both native/internal based facilities and the Yucca plant.

Exhibit 102: Natural Gas Usage and Projected Usage



The following exhibit aggregates all natural gas requirements and displays percentage of the total natural gas cost as a portion of the total fuel and purchased power costs.

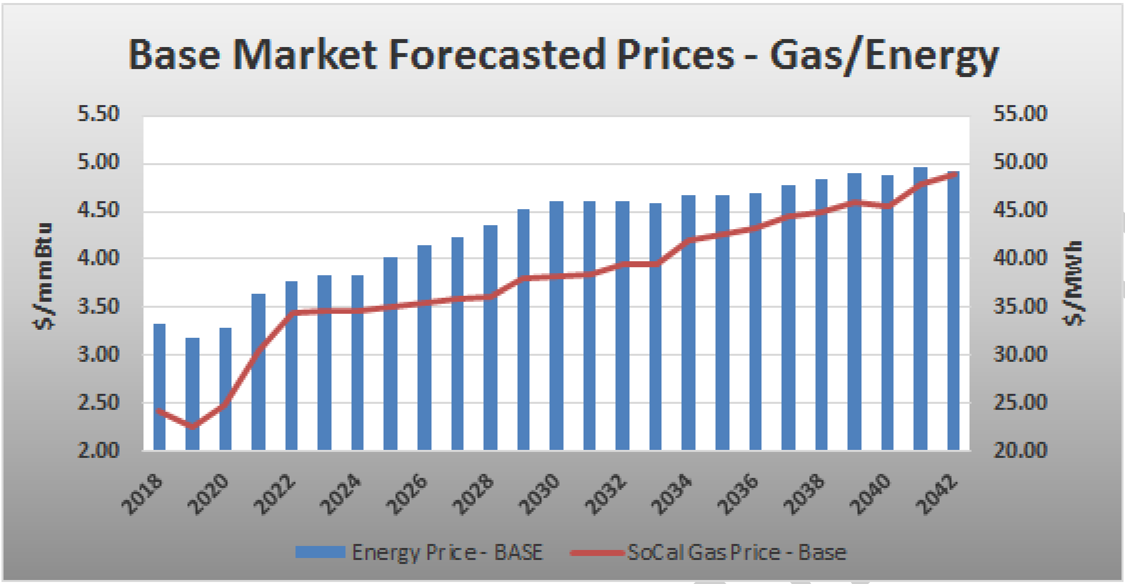
Exhibit 103: Natural Gas Costs as a Portion of the Energy Supply Costs: 2002-2020



IID's budgeting process heavily depends on the long-term expectations of the gas and energy pricing markets, and the procurement program and projected needs heavily depend on the markets as well. The understanding of the impact of the markets on the budget is crucial to the management of the budget and the procurement program. The long-term expectations of the markets can and, most likely, will be different than the expectations that were held at the time of creating and submitting a fuel and purchased power budget for board approval.

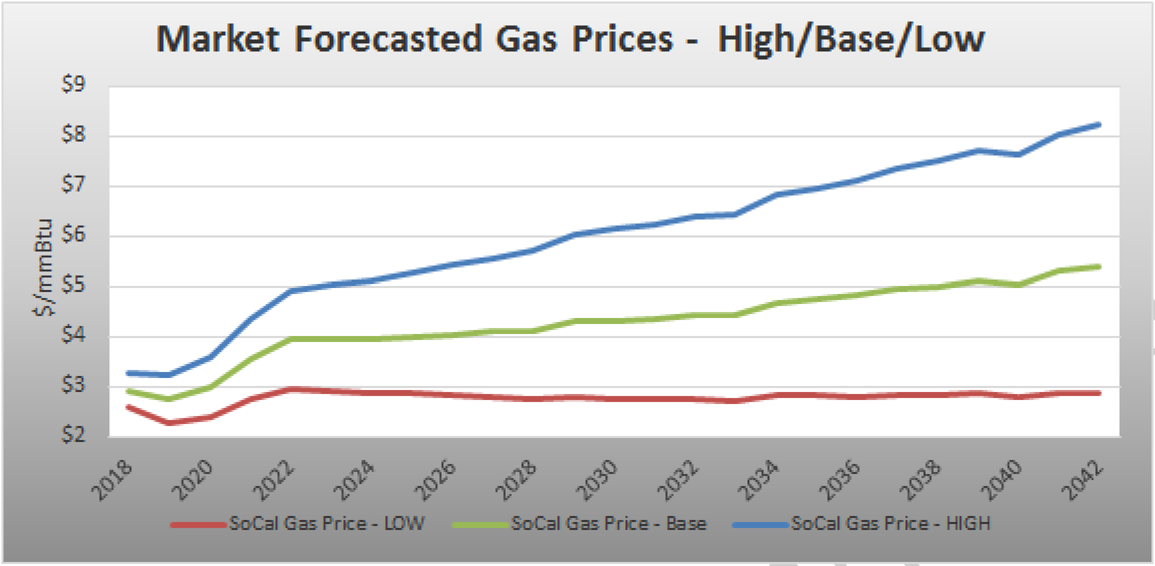
The following exhibit represents a long-term price forecast of energy and natural gas prices at trading hubs that IID uses to bring in supplies of natural gas (SoCal) and energy (Average Energy Price)

Exhibit 104: Long-Term Price Forecast (Base Case)



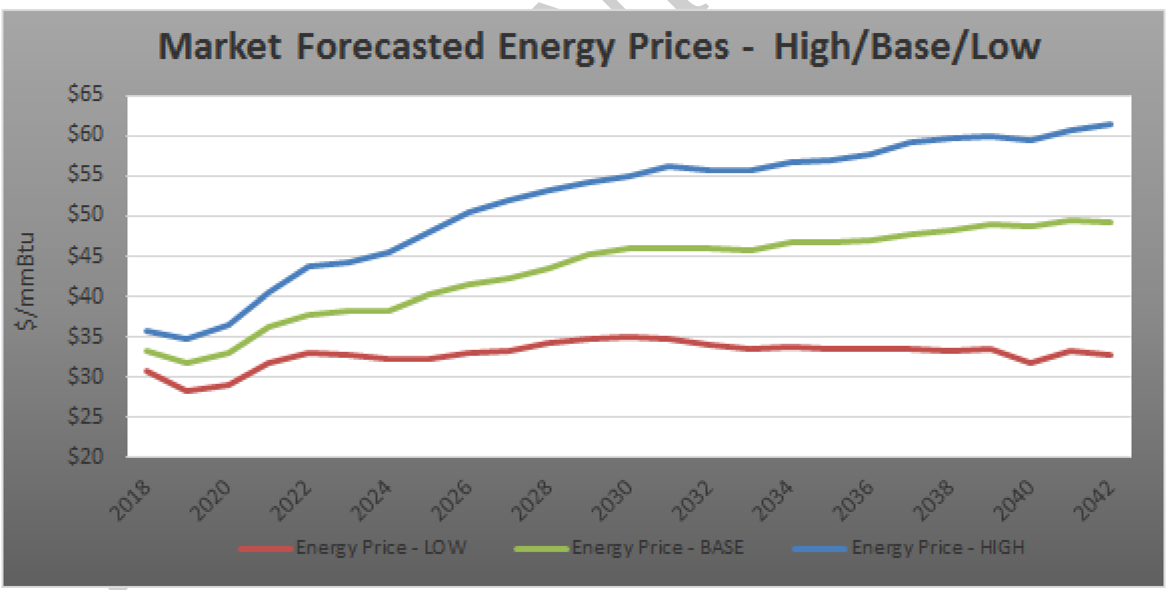
As shown above, the near term (2016-2020) price forecast is showing a major increase in gas and energy prices, and so the IID must maintain a clear strategy in approaching this potential increase so that the rates and revenues can correlate to the costs. Additionally, the gas and energy markets have a tendency to follow each other and the price forecasts used in IID's planning process expect this to occur. However, the day-to-day pricing activity cause the gas and energy market correlation to vary, which could result in varying dispatch decisions. Additionally, the above price forecast shows the base case expected pricing forecast. However, to fully review market conditions and their impact on both operational dispatch decisions and long-term procurement/development decisions, a range of potential outcomes must be observed and studied. The following chart compares the base case forecast with the high and low pricing forecast in gas prices:

Exhibit 105: Long-Term Gas Price Forecast Comparison of Base Case, High and Low Scenarios



As previously discussed, energy prices and gas prices tend to have a fairly strong relationship over the course of a year, so the following exhibit demonstrates the market forecast for energy prices with a similar trend to gas price forecasts.

Exhibit 106: Long-Term Energy Price Forecast Comparison of Different Scenarios

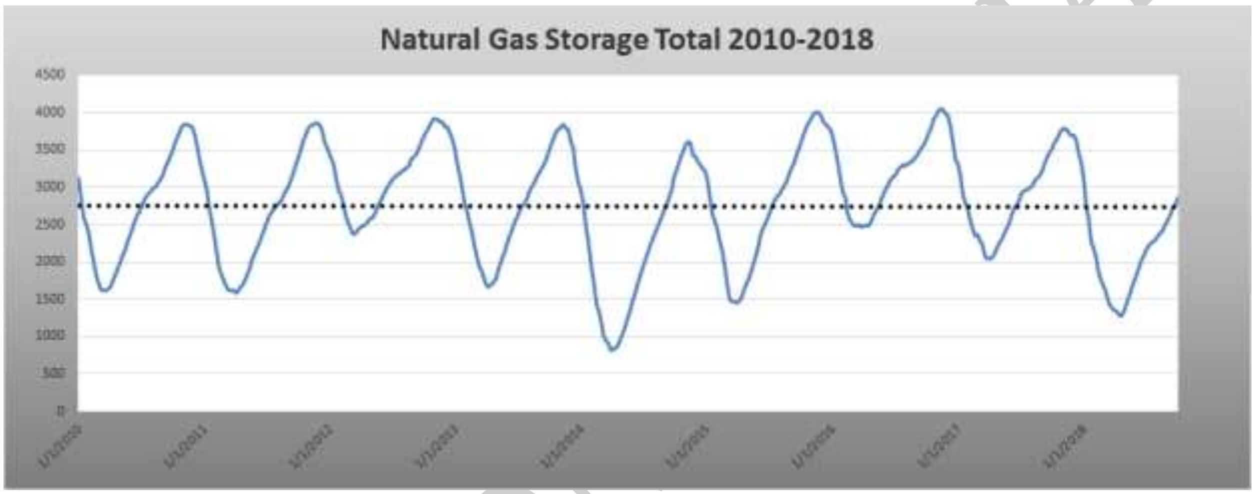


The above pricing scenarios were used as a part of many of the studies performed for this IRP. The variance between each of the scenarios presents an insurmountable capacity for risk. These risks of varying pricing scenarios must be considered in any of IID's decisions.

IMPACT OF SHALE GAS

Many analysts expect that the shale gas production will continue to increase, not only in the U.S. but also in many other countries and the EIA will continue to research how the potential for exporting some of this excess supply will affect the long-term gas and power markets. One impact is a reduction in carbon dioxide emissions. This occurs when the supply of natural gas in the U.S. is in surplus; then lower emitting natural gas-fired generation becomes more economically efficient than other higher carbon dioxide emitting generators such as coal-fired plants. The following chart illustrates the increase of natural gas supplies as reported by the EIA:

Exhibit 107: U.S. Natural Gas Storage History



As observed in the above chart, the supply of natural gas has greatly increased, especially since 2008 where prices spiked all the way to $12-30/MMbtu. Today's market is in the $4 range and much of this reduction in natural gas prices can be attributed to the new influx of supply from the shale extraction process. In 2008, the peak supply in storage was about 3,500 BCF and in 2013, the storage climbed all the way to about 3,800 BCF at the end of the injection season, which is an increase of about 8.5 percent. Should the government place a hefty tax on the developers of shale extraction or if the shale extraction was somehow limited due to environmental reasons, then the impact of the long-term pricing market will be acute.

IMPACT OF CARBON AND RPS INTEGRATION

AB 32's Cap-and-Trade Program along with SBx1 2 RPS law both provide new markets. With new markets come correlations to other markets and the fundamental impact of the other markets. The first carbon auction was held in 2013 and prices did not surge to any unreasonable levels. However, if prices were to spike to higher than normal pricing, then the gas and power markets will be impacted, since the carbon price must be considered in any economic dispatch decision of all carbon emitting resources, be it an import or self-generation. A cost adder should be observed for all generic/unspecified power imported into California, reflecting an average carbon content of .45tons/MWh. If the source is known, then WSPP has created a new schedule for transactions called Schedule Z, which will allow for traders to calculate an exact emissions charge.

SHORT-TERM PERSPECTIVE OF GAS AND ENERGY MARKETS

Like the long-term markets of gas and energy, there are many contributing factors that fundamentally impact the short-term pricing markets. The short-term market is slightly more sensitive to major unit outages and the general market sentiment.

IMPACT OF SONGS NUCLEAR GENERATION OUTAGE

The San Onofre Nuclear Generating Station as down during the summer of 2012 and, during this summer, the daily market was a bit more volatile than the previous couple of years. The unit was offline for the summer of 2013 and will be decommissioned. The market analysts are constantly discussing the impact of the retirement of more than 2000 MW of conventional fuel source generated power. Analysts have estimated the overall financial impact of the SONGS outage anywhere from $250 to $350 million dollars on the electricity pricing market.

Additionally, IID is constantly monitoring the volatility in both of the markets. Volatility is the measure of the variation in price from one point in time to another. The day-to-day volatility is critical to the day of transaction. Some days can be more volatile than others, which can be a good thing or a bad thing depending on the direction of price change.

Exhibit 108: Daily Gas Price Open and Close with Volatility

As illustrated above, as the day-to-day prices contain greater price changes, then the volatility increases. Currently, for the month of November 2018, the volatility has increased recently since the time of expiration is becoming closer and closer to termination.

Transportation Costs

Transportation costs comprise a significant portion of the IID's natural gas costs. Transportation on the SoCal Gas pipeline system is around $0.46/MMbtu, while on the APS gas transportation system (used to supply the Yucca Steam Plant fuel requirements) it is around $0.50/MMbtu (including a 7.0 percent utility-user tax). This cost is around 8-10 percent of the total cost of natural gas to the IID.

However, more recently, the backbone transmission service has significantly increased in volatility ranging from .50c-$10/mmbtu. This recent volatility situation may continue and if this is the case, then IID will more constantly relay on resources that utilize supply from other pipeline delivery systems or other types of resources.

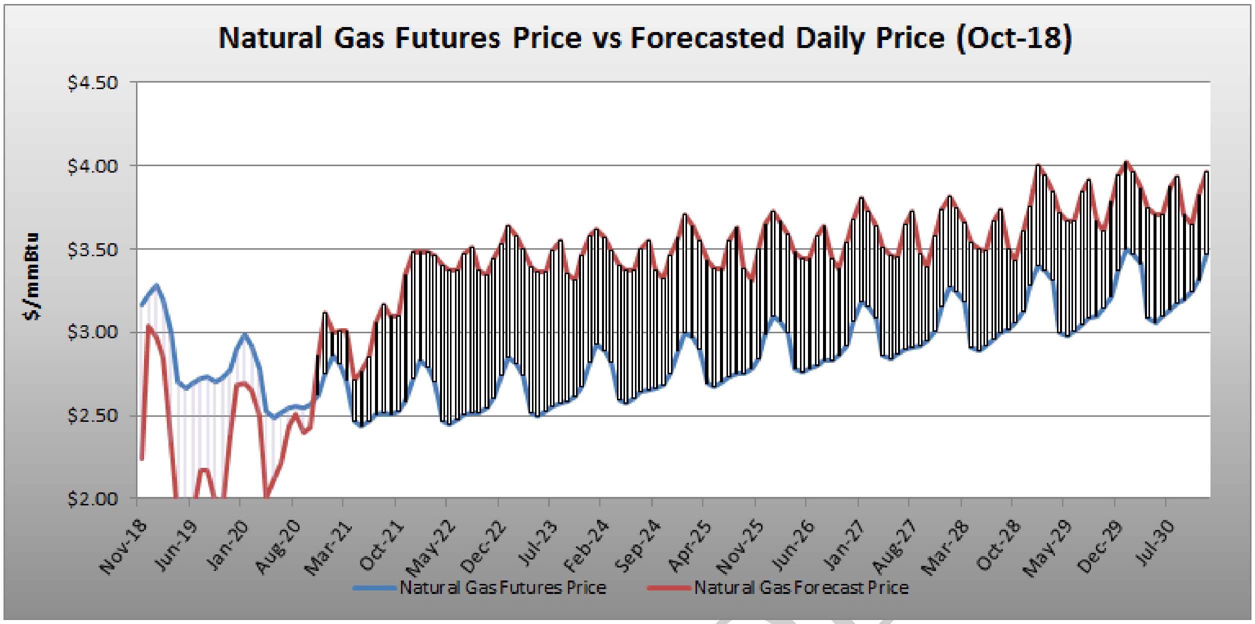
Spot versus Future Prices

The price of natural gas has a temporal, or time, value. Natural gas prices vary by day and season even though the trend of natural gas prices may be up or down at any time.

The spot price of gas is the daily price at a specific delivery point, for example Southern California Citygate or Ehrenberg trading hubs on the western transmission system pipeline.

The forward price curve in the following exhibit shows the future price of natural gas for specific months in the future (for delivery at Henry Hub) compared to the monthly price forecast of the daily spot market**.**

Exhibit 109: Futures Contract Price vs. Forecasted Daily Price



As seen above, the future contract price curve will always contain a premium and thus the distance between the forecasted daily spot price and the futures contract prices is known as the risk premium. IID constantly studies these variances for the procurement program to strategically monitor the underlying meaning in the market and level of risk that the market may imply in the futures contract prices as compared to the daily spot prices.

Forward curves tend to be upward sloping, reflecting the cost of storing gas from month to month and seasonal demands for gas.

An upward sloping forward curve illustrates why it is difficult for the IID to purchase gas years into the future to fix prices. The current forward price for gas delivered in December 2018, for example, is more than double the current spot price of gas. As we move closer to the December 2018 delivery date for gas, the forward price and the spot price will converge. What is not known is whether December 2018 prices will move toward today's spot price or vice versa.

Burner-Tip Prices

There are so many additional costs associated with delivery of gas to a generator that use of a contract or daily price underestimates the cost of producing energy.

Instead of using the spot price as an estimate of gas costs, a better indicator of natural gas costs is the burner-tip price. The burner-tip cost includes the cost of gas, transportation, taxes, scheduling fees and any other cost necessary to deliver gas to the generator.

The burner-tip cost is generally around $.50-$1/MMbtu greater for the IID or around 10 percent greater than the cost of the gas commodity itself.

FIRM PURCHASES

The easiest way to purchase gas is a firm purchase of a specified quantity of natural gas at a specific location. For example, the IID could purchase 5,000 MMbtu/day of natural gas delivered at SoCal Citygate at either a fixed price or the daily spot price of gas (referred to as the index price).

Firm purchases make up the bulk of IID's daily gas purchases. Firm gas means that if the supplier does not deliver the specified quantities of gas, it will be liable for any additional costs incurred by the IID for replacing the contract quantity.

The advantage of a firm purchase is that the quantity, term, price and delivery point are all known. The disadvantage is that prices may decline between the time that the purchase is made and the gas is actually burned.

CALL OPTIONS

The IID uses call options to cap the price it will pay for natural gas.

A call option allows the purchaser to buy the right to purchase a specific quantity of natural gas at a fixed price (called the strike price) regardless of the market price. For example, the IID may purchase a call option for 2,000/MMbtu per day of gas at SoCal Citygate at a price of $7.50/MMbtu. If gas prices are greater than $7.50/MMbtu, then the IID would exercise its right and pay the strike price. If prices were less than $7.50, the IID would not exercise its right and instead purchase in the market at the lower price.

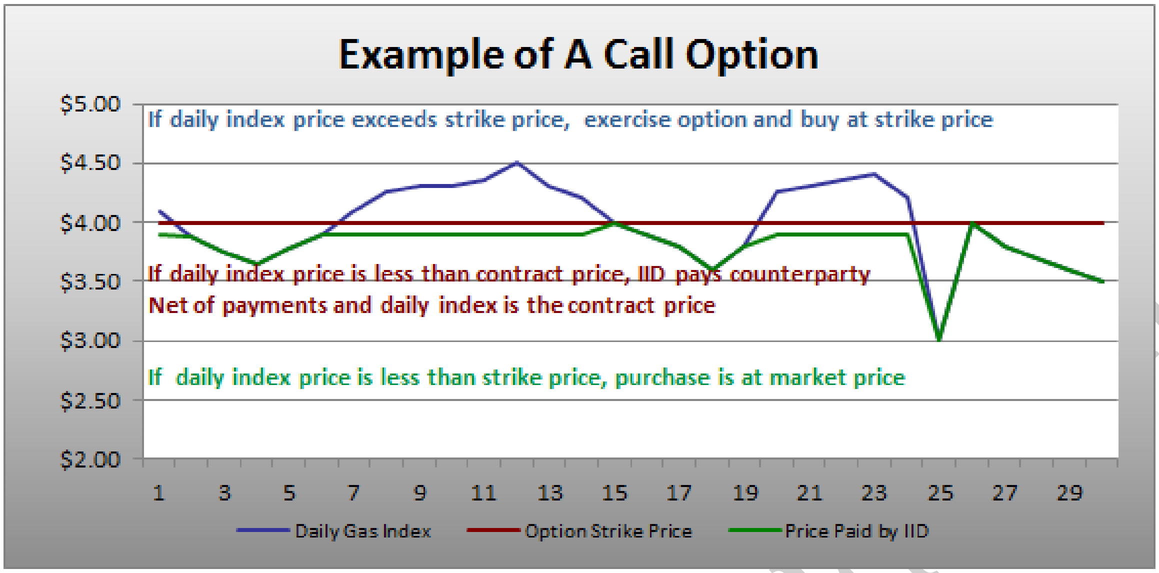
The price that the IID has to pay for call options depends upon the time left to exercise an option and the strike price relative to the market.[21] The lower the strike price, the higher the option premium. Also, the further out in time the option is, the greater the price reflecting uncertainty about the future direction of the market.

The IID has to balance current and forward prices with options. In the best case, any option purchased by the IID would not be exercised, meaning that daily market natural gas prices were less than the strike price and the IID could buy gas less expensively.

Options are used to cap natural gas costs. An option is protection against the financial impact of high gas prices on the IID, but that protection comes with a cost.

Exhibit 110: Example of a Call Option

[21] Option prices have been studied extensively and depend upon the relationship of the price to the strike price, time to maturity, underlying price volatility and the interest rate



Put Options

A put gives the seller the right to sell at a specific price, regardless of the cost of an underlying commodity. For example, the IID might buy a put if it felt natural gas costs were falling and it had surplus gas.

Historically, the IID has not used puts because the IID avoids having surplus natural gas that it must sell in the market.

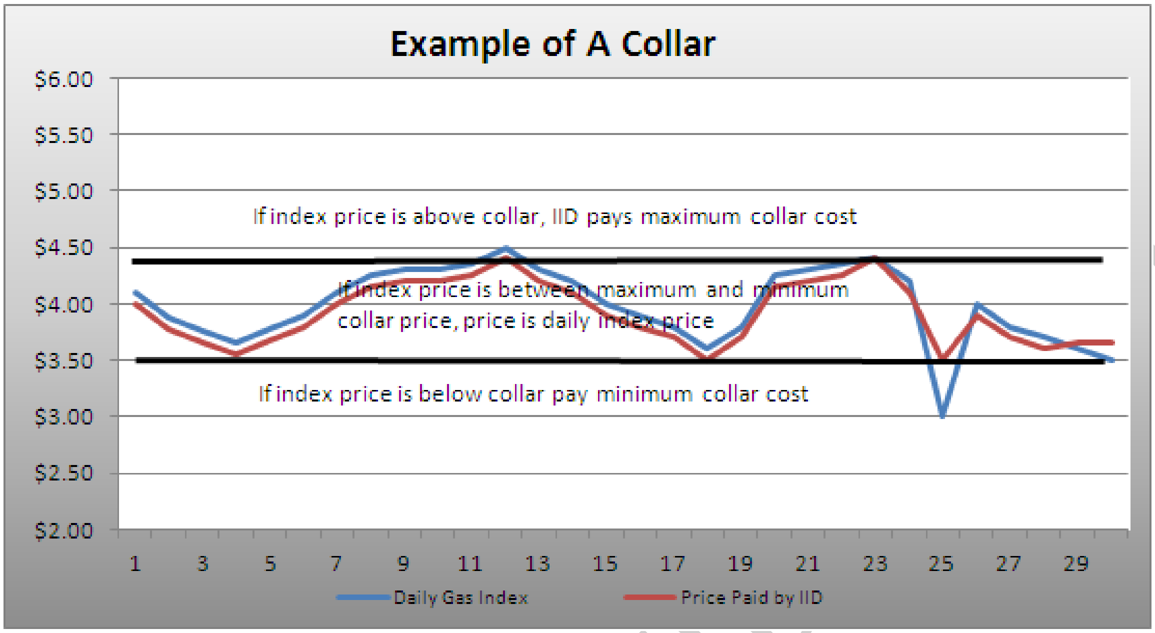
Collars

A way for the IID to avoid paying the high premium cost of options, especially when gas prices are expected to rise, is to use costless collars. With a collar, the range of gas prices is fixed. A collar with a cap of $7.00/MMbtu and floor of $3.50/MMbtu means that the IID will not pay more than $7.00/MMbtu for the gas, regardless of how high the price of gas is during the delivery period. But, the IID would also not pay less than $3.50/MMbtu regardless of how low natural gas prices are.

The advantage of a costless collar is that, unlike a call option, the IID does not have to pay for price protection. The value of the implicit put is used to offset the cost of the collar.

Costless collars are generally asymmetric. If the future gas price is $4.00/Mmbtu, the collar may be from $3.25 to $6.50. If the IID wanted a symmetric collar (for example $3.00 to $5.00) then it would likely have to pay the counterparty.

Exhibit 111: Example of a Collar



Financial Hedges

The IID has historically not made much use of financial hedges, preferring instead to purchase with fixed price and options. However, primarily due to the MRTU market that many counter-parties participate in, financial hedges have become much more common in the California wholesale gas and electric markets and the IID is beginning to use them more often for specific purchases[22]. These types of hedges are also permitted under the IID Risk Policy.

The simplest form of a financial hedge is a contract-for-differences. The two parties agree to a fixed, or strike, price based upon a daily index cost of gas and a specific quantity.[23] On a daily basis, the difference between the spot price and the strike price is due one party. If the price is below the strike price, the IID would owe the counterparty while if the spot price was above the strike price, the counterparty would owe the IID.

For example, suppose that the IID took a three-day hedge for 1,000 MMbtu at $4.00/MMbtu. On day one, the spot price was $4.10, on day two the spot price was $3.75 and on day three the spot price was $3.90.

[22] To avoid having to double-pay in the CAISO settlement process, entities are using financial hedges rather than having to pay both the CAISO and the counter-party and then true-up at the end of the CAISO's settlement period.

[23] The usual index is the Platt's Daily Index of Natural Gas for a specific hub or trading point

The amounts owed by the counterparty to the IID would be calculated as:

*Day 1: (1,000 MMbtu) * ($4.10 - $4.00) = $100.00*
*Day 2: (1,000 MMbtu) * ($3.75 - $4.00) = -$250.00*
*Day 3: (1,000 MMbtu) * ($3.90 - $4.00) = -$100.00*

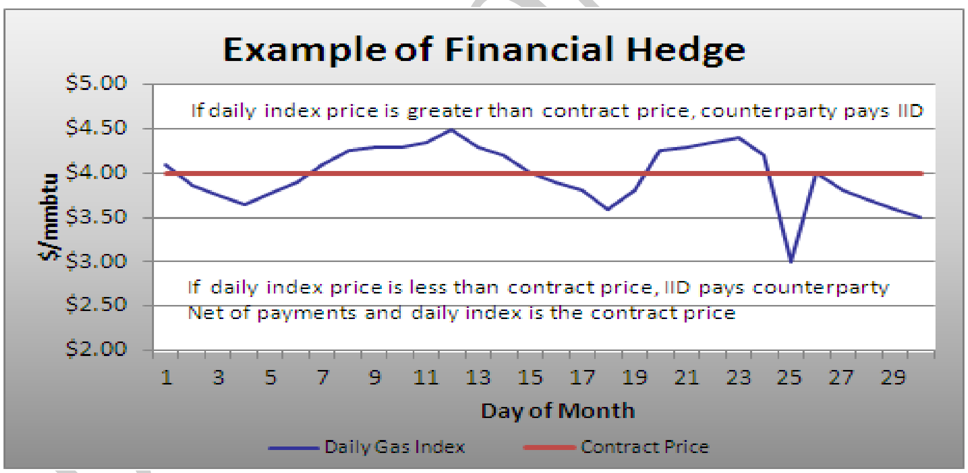
Total Due Counterparty = -$250.00

The IID would pay the spot price to a gas supplier (either the entity that wrote the hedge or any other supplier) $11,750 (the sum of the daily volumes times the spot price) and then $250 to the financial hedge counterparty, resulting in a net cost of $12,000 or $4.00/MMbtu. The exhibit below shows how a financial hedge operates.

The purpose of a financial hedge is to lock in the price regardless of the source of supply. The financial hedge actually works as a fixed price purchase. As shown in the exhibit below, the net of the spot price cost plus amounts owed to, or received from, the financial hedge counterparty will be equal to the strike price.

The advantage of a financial hedge is that it can be done with any financial counterparty so long as an index can be agreed upon. Gas supplies can then be purchased at spot prices from any supplier and the financial hedge used to fix price. This allows entities the opportunity to enter into financial hedges with strong credit counter-parties and buy spot gas from any supplier.

Exhibit 112: Example of a Financial Hedge



The IID does not directly purchase in the CAISO's MRTU energy market and so has not had the need to use financial hedges for energy in the past. However, the IID has found the need to use financial hedges for its Yucca gas purchases, but this is very seldom due to the pipeline development of the Yuma lateral from Ehrenburg. IID now has the capability to physically hedge gas for the Yucca Plant. However, there are only a few counterparties that can physically deliver to the burner tip (El Paso South Mainline) that supplies fuel to the Yucca Plant and, if IID should choose to procure gas from a counterparty that does not have physical delivery capability to the burner tip, then IID would have to financially hedge the gas if IID would like to protect the volatility of the fuel used at Yucca. Additionally, with the recent status upgrade to scheduling coordinator, IID may be looking into this type of protection when dealing with the CAISO.

Yucca gas supplies have traditionally been purchased by APS for the IID, but with the recent construction of the Yuma lateral pipeline, IID now physically purchases gas for this unit. Before the construction of the pipeline, the IID had a large market price risk exposure to gas prices for Yucca.

The IID has five basic ways to buy gas to meet monthly burn requirements; firm purchases, options, puts, collars and spot gas purchases. In addition, it can use financial instruments to fix gas costs. Balancing the mix of firm purchases, options and collars can ensure that the IID's monthly gas costs are capped but allowing for some downward movement in cost requires that the planning group perform sophisticated analysis and market simulations at the lowest possible cost.

The IID does have the ability to meet all of its forecasted monthly requirements using just one method, for example firm purchases or options. But this will almost always result in the IID paying more for natural gas than is necessary.

The IID has traditionally avoided using some of the more esoteric combinations of options and fixed price combinations even though the electric utility industry is becoming more sophisticated and using a wider array of hedging techniques.

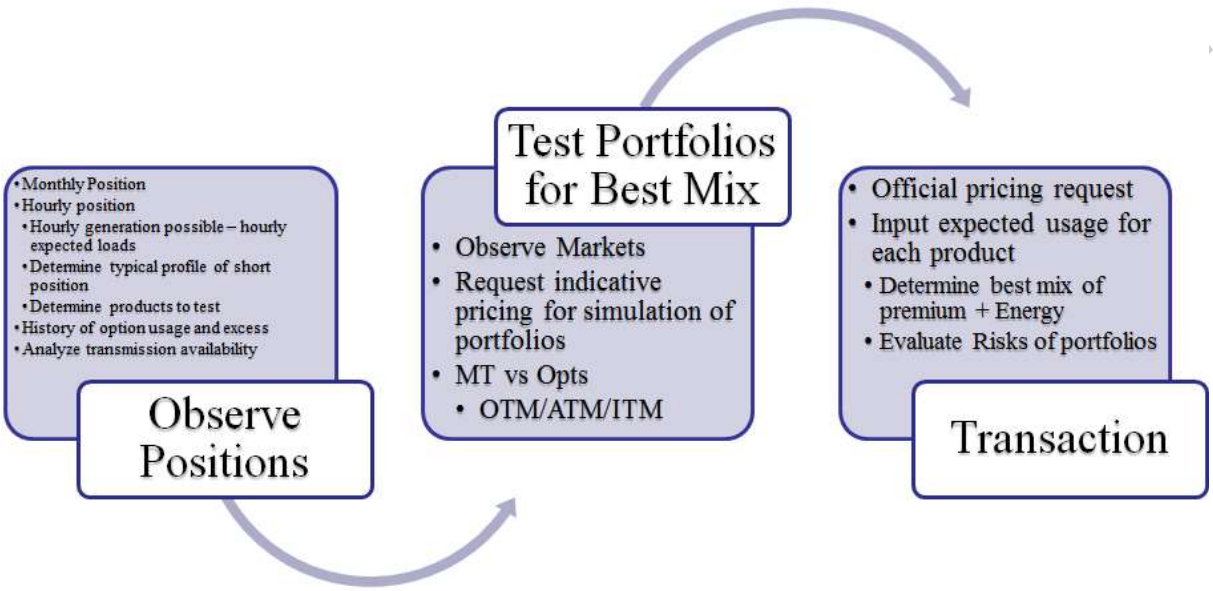
The IID is continuously evaluating prepay purchasing arrangements that could result in significant dollars saved over time; however, the IID must be cognizant of market conditions, the IID's overall debt ratio and the risk.

Additionally, when considering any kind of option (call or put), costless collars and financial hedges, IID is extremely conscientious of how the deal is structured to ensure that the Dodd-Frank requirements are met.

PURCHASING ELECTRICITY

Electricity is a different commodity than gas with many more purchasing options. In particular, while natural gas is bought and sold for daily delivery (except when dealing with interstate pipelines), electricity is bought and sold for different periods of the day, including purchases for less than an hour to meet balancing requirements. The diagram below demonstrates the process of procurement for seasonal energy/capacity needs:

Exhibit 113: Overview of Seasonal Procurement Process



The financial community has attempted to commoditize the energy market, breaking most energy purchases into three separate products:

- On-peak energy: Energy delivered from hour ending (HE) 0700 to 2200, Monday through Saturday;
- Off-peak energy: Energy delivered between HE 2200 to HE 0600 Monday through Saturday and all day Sunday;
- Baseload Energy: Energy delivered for all hours of the day.

In addition, standard products have grown to include super peak, an eight-hour block of energy delivered during the highest use periods of the day.

Generally, only standard products can be purchased in the forward markets. Nonstandard purchases are made in the day-ahead and hour-ahead markets.

Purchasing electricity from outside of the IID system can come with several additional risks. For example, importing electricity may provide ample supply, but does not provide the same type of reliability benefits, such as voltage support and automated generation control (to name a few) that internally produced generation provides. Additionally, excessive amounts of imports leave little room for emergency supply needs. That is, if IID is importing energy/capacity at the full capacity of the line, and the line experiences a forced outage, then IID needs to either ramp up internal generation or import generation from other available transmission capacity. This could present a quandary especially in the high load summer months. If IID is generating internal units to their maximum available capacity and all of the transmission import capability is used and there is an outage on a unit or on a line, then the reserve supplies may need to be called upon. IID does not want to jeopardize reliability in any way with the importation of electricity, so this situation is constantly monitored to ensure compliance with FERC/NERC/WECC reliability compliance measures.

Tolling Agreements

Often, to avoid any market price risk, purchasers prefer that daily gas prices set the purchase price of energy. A tolling agreement (and a heat-rate option) allows a supplier to offer different energy prices based upon the daily price of natural gas and a negotiated heat rate.

Tolling agreements and heat-rate options differ slightly in that a tolling agreement is for firm, must-take energy while a heat-rate option gives the purchaser the right to take the energy depending upon market prices and the terms of the agreement.

With a tolling agreement, the purchaser pays for and reserves the right to call energy at a specific heat rate for some time period. The lower the heat rate, the higher the cost of the option (generally as with any negotiated contract there are exceptions). A tolling agreement with an 8,000 MMbtu/kWh might have a premium of $5.00/kW-month while a 13,000 MMbtu/kWh strike price may have a premium of $2.00/kW-month.

With heat-rate options, the determining factor of how to choose the appropriate heat rate depends upon the forecasted use of the option. If the option is likely to be called on a frequent basis (for example, every weekday afternoon) then the purchaser would likely prefer a low heat rate and a high fixed premium. If however, the option is being used to meet unexpectedly high summer peaks, then the purchaser would want to minimize the fixed premium cost and purchase a high heat rate strike option.

Call Options

Energy call options can be purchased for on, off and super-peak time periods. There are two basic forms – a daily call option or a monthly call option. With a monthly call option, the option must be exercised prior to the beginning of the month and, once exercised, must be taken during the time periods. With a daily call option, the purchaser has the ability to choose to take the energy each day and can choose not to take energy if market prices are below the strike price.

The more flexibility the purchaser has, the greater the price. The premium price is also higher the lower the energy strike price.

Generally, call options are only available for the three standard market products; on-peak, off-peak and super peak.

Dodd-Frank Impact on Strategic Approach

In order to assure compliance, IID is constantly following the ruling and the impact of the law on IID's strategic approach. The various rules and interpretations issued by the CFTC implementing the Dodd-Frank Act have generally provided some measure of relief for end-users like IID. Nevertheless, the procurement group and other divisions of IID follow the CFTC's swap regulations to ensure compliance with any obligations arising under the Dodd-Frank Law. Among the actions taken to ensure compliance with any applicable requirements, IID maintains required records, and keeps track of the justification of each purchase that is made for all commodities including natural gas, energy/capacity, renewable products and carbon products such as allowances and offsets. IID also identifies the right mix of firm purchases, call options and collars, to help ensure that IID will have a mix of resources available to meet load reliably while providing flexibility to take advantage of market opportunities, minimize total power supply costs, and also minimize transactions that may be subject to full-blown swap regulation.

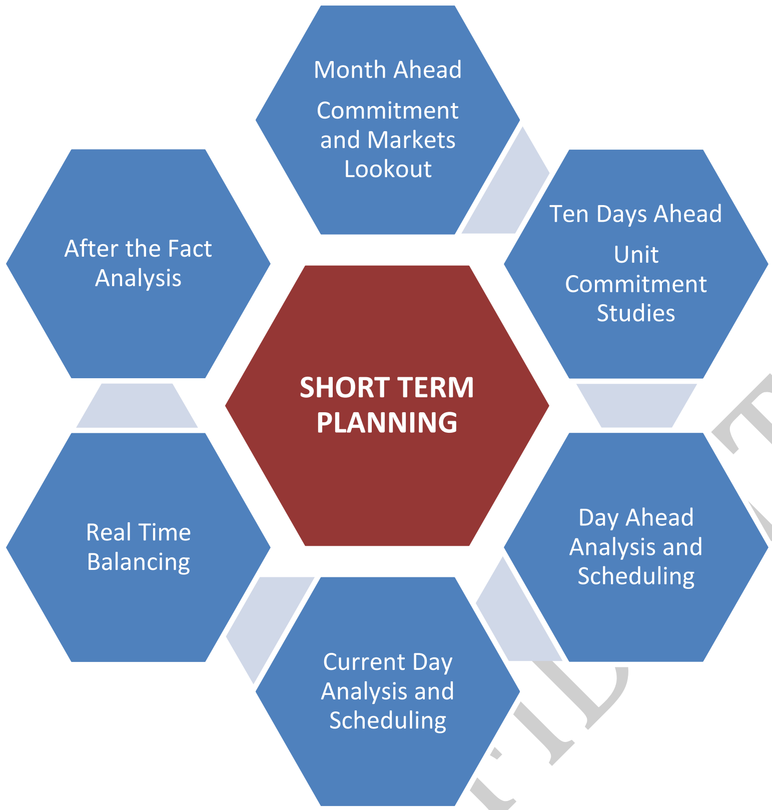
IID must also ensure that it does not have too many heat-rate options in its portfolio. Heat-rate options increase power supply cost volatility as energy prices become perfectly correlated with changes in natural gas prices. Again, like the gas procurement activity, IID is prudent when structuring call options or any kind of deal that may be subject to swap regulation under the Dodd-Frank Law.

Short Term planning and Economic Dispatch

IID's short term planning activates complement its long term planning deliverables including long term contracts and markets transactions.

IID's short term planning process revolves around the outlook horizon of up to a month ahead to real time including after the fact analysis. The following exhibit illustrates the main elements of short term planning activities pertaining to internal generation scheduling and interaction with markets. By design, it is a closed loop process where planning, scheduling and various market activities are supported with their fundamental drivers combined with conclusions from the recent past. On an ongoing basis, various analysis including market trends and units costing are performed at each process stage continually feeding planning and day-to-day operations.

Exhibit 114: Short Term Planning



Short term market transactions can be executed on a balance of the month, day-ahead, hour-ahead, or intra-hour basis. While the main purpose of market activities is to balance IID system, their type, volume and timing can be driven by different factors or their combination and may including certainty of underlying need, risk exposure and economics.

IID economically dispatches its resources to meet changes in load and variable supply while taking into account prevailing market conditions. In the periods when system resource costs are less than the prevailing market price for power, IID can dispatch resources that, in aggregate, exceed customer load obligations, facilitating off-system wholesale market power sales that reduce costs for its customers. Conversely, at times when system resource costs are greater than prevailing market prices, system balancing wholesale market power purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how IID manages net power costs on behalf of its customers.

IID's market activities correlate with commitment and dispatch plans. While most fuel supply for natural gas fired generation is procured as a term deal at a fixed price, IID at all times uses prevailing day-ahead or intraday market prices to price out day-ahead or intraday generation. This practice is consistent with the least cost delivery approach. This coordination between the fuels and power markets is essential to accurately price variable generation costs so that the benefits of market transactions could be properly evaluated. The delivery points for the natural gas include SoCalGas Citygate and El Paso South mainline trading hubs.

IID's baseload generation characterizes with relatively low incremental cost that corresponds with relatively longer start up and minimum runtimes hours and includes more considerable start-up costs and minimum load requirement. Consequently, baseload units' commitment is studied carefully and planned in advance. Typically, commitment studies are performed on a weekly basis and cover a horizon of the next 10 days. This process considers different operating aspects with scenarios and stress testing for forecasted market prices and various system conditions. Final commitment decision is made with consideration of various aspects including study findings. It involves close coordination among various sections for successful execution.

Quickstart generation is a different component of IID resource portfolio and commitment process. Its marginal cost is generally higher than the equivalent baseload cost, but their start up cost and timing is advantageous. Their start up decision may be made as part of load serving economic during the certain number of hours through the day or a reliability consideration.

In short term planning consideration, IID executes transactions in the day ahead and real time markets. In day-ahead markets, the schedules for supply and usage of energy are compiled hours ahead of the beginning of the operating day. The real-time market is used primarily to balance the differences between the day-ahead scheduled amounts of electricity and fuel based on day-ahead forecast and the actual real-time load.

IID schedules most of its natural gas needs in day ahead horizon. Fuel transaction for next day delivery intends to cover planned fuel needs for the flow day. IID also has an option to purchase and sell natural gas on the day of the flow. Those transactions usually come with the premium over the day ahead price. Furthermore, the additional constraints and cost implications may apply in real time on days impacted with pipeline constrains and Operational Flow Orders ("OFOs") declared by SoCal Gas. The price for gas procured in day ahead market is based on the published daily settlement price at the relative hub. It can be estimated based on the open market activity but it is actually know later in the day once the market closes.

IID's bilateral short term deals are executed through direct contact and negotiation with the counterparties and follow WSPP schedule. The deals are commonly packaged in the standard shapes and volumes commonly referenced as on peak or off peak. The liquidity of the bilateral energy market, IID has access to, is the most attractive in the day ahead trading horizon; therefore most bilateral energy deals in short term are executed in day ahead. Generally speaking, energy prices obtained through the bilateral transactions in day ahead horizon are most attractive option for IID to supply its load, especially if coincide with the use of own transmission. It is the general trend as markets dynamics are always shifting so is the tradeoff between the markets. Different drivers including policies impact, characteristics including resource mix and its cost tend to drive their price formation. IID's strategic position and access to multiple markets through different transmission paths help diversify energy sources and optimize their value. The shortfall of bilateral transaction lays in their limited flexibility to customize the volumes and shapes. All the bilateral transactions involving energy imports to California from outside of the state are subject of emissions charge. The value of emissions is monitored and its implication on the value of purchased is always considered during transaction consisting.

While IID has the established history of trading power through bilateral transactions, in recent years IID has been acting as its own scheduling coordinator for CAISO market and currently also transacts for energy with its neighboring RTO.

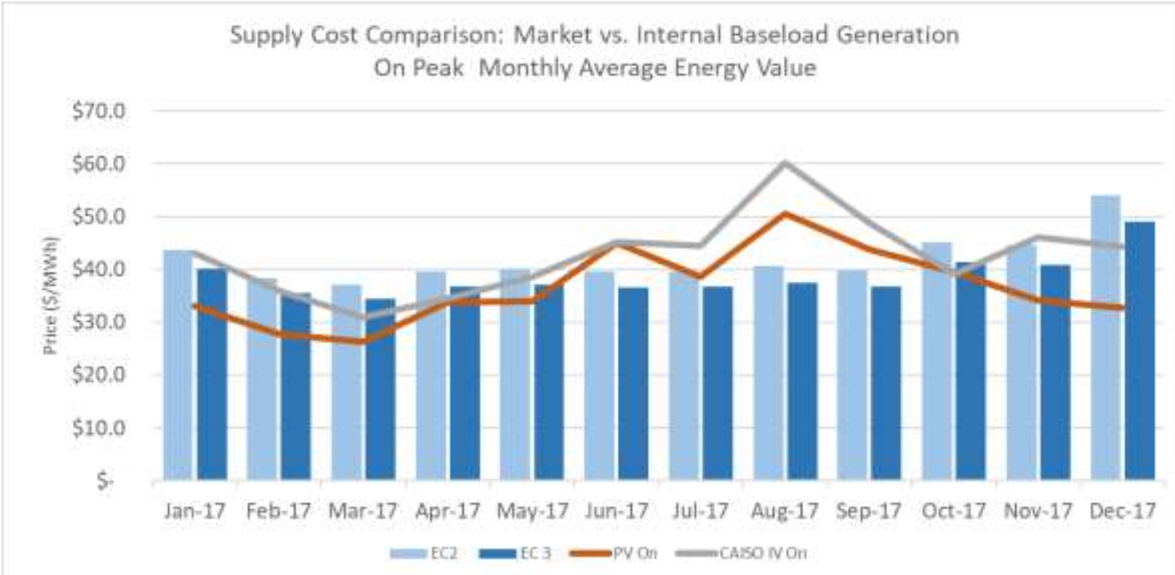
The CAISO markets consist of a day-ahead market and a real-time market. The day-ahead market includes an integrated forward market used to clear supply-and-demand bids for next day energy flow. For its interties, CAISO real-time market comprises the hour ahead bidding process used to arrange transactions for energy flow in 15-minutes intervals.

Aside from transactional fees applicable to transactions with CAISO, energy purchases from this market involve transmission access fee which has a significant impact on the final transaction cost; consequently, it is accounted upfront in form of the transaction adder.

Access to CAISO markets provides IID with the ability to economically bid and transact for different volumes and different hours, which can be considered as a complementary value to bilateral deals aside from an alternative. While IID considers CAISO for reliability and economic transactions in day ahead and real time horizons, CAISO activities currently dominate real time trading as bilateral market liquidity is limited during the day of energy flow. Access to CAISO provides additional opportunity for IID to optimize dispatch and commitment of its assets. Its strategic location with access to both market structures provides an opportunity to optimize its operations from the reliability and economics standpoint generating substantial savings to its ratepayers.

The Following exhibit illustrates the value of internal baseload generation cost in comparison to the day ahead energy prices offered through the two different market structures. For the purpose of the comparison, Palo Verde on peak and CAISO Imperial Valley on peak prices were selected. Ec 2 and EC3 are two baseload units fuels with natural gas from SoCal CityGate.   All market prices and generation cost are illustrated with applicable adders to make them equivalent.

Exhibit 115: Supply Cost Comparison – Market Vs Baseload Generation

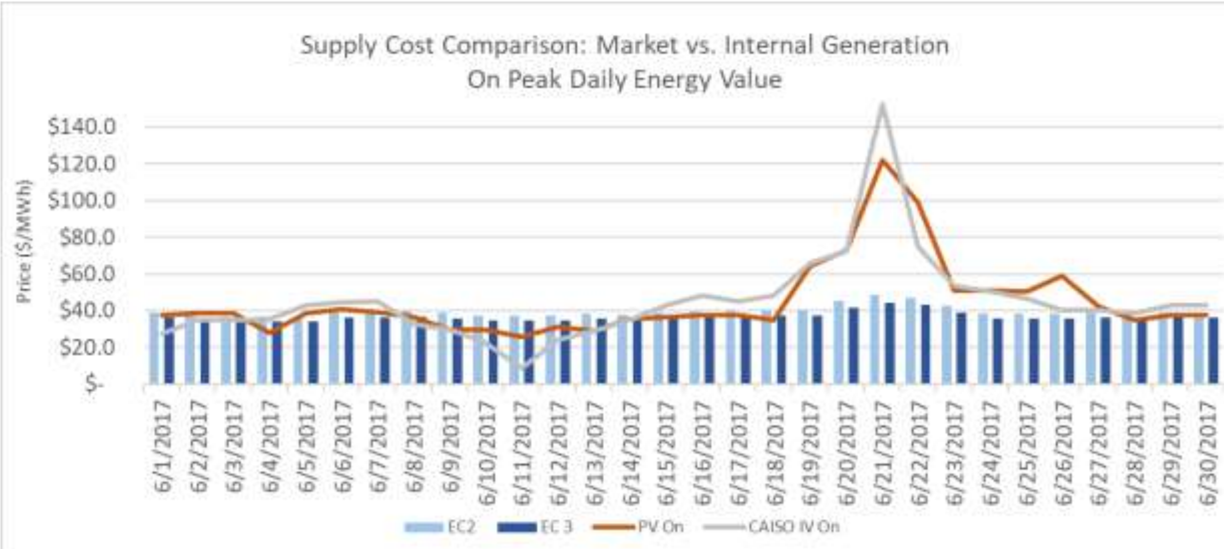


Bilateral markets transparency and price discovery is difficult to capture in bilateral markets as a number of offers and liquidity is limited. CAISO market process and its prices granularity facilitate its analysis and formulation of strategic approaches. In its day-to-day operations, IID make substantial efforts to monitor and analyze trends in CAISO price formation. Example of the studies include the consideration for seasonality of price formation at different IID's nodes during different months and different times of the day.

Figure 1.2 illustrates 2017 months when energy markets were more economical options to serve load rather than its internal generation. In 2017 year it occurred through most of the months in 2017 year including the entire winter. The same graphic also illustrates that more often than so, Palo Verde market is more cost-effective supply option for IID than CAISO. Only in October and July the value of energy from CAISO vs. bilateral was very comparable. It is important to mention that this dynamic may get easily distorted with changes in market dynamics including fuel prices and the implementation of renewables. It is also important to highlight that that daily markets dynamics may vary substantially on a day-by-day basis.

While June 2017 example overall transpired as a month where internal baseload generation was more cost effective over markets, the daily breakdown shows that it has not been a consistent trend during the month. While June had several days where markets were much more expensive than internal baseload generation including the period from June 19 to June 26, there were also market opportunities significantly cheaper than internal generation cost during the period June 8 through June 13. The exhibit below illustrates the value of continues market monitoring and strategic planning on a daily basis. Only that way IID may capitalize on the value of the access to the different energy sources whenever the opportunities present themselves.

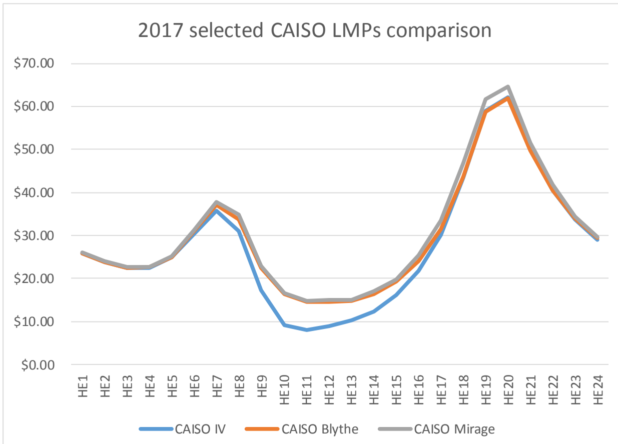
Exhibit 116: Supply Cost Comparison – Market vs Internal Generation



IID has the ability to leverage access to CAISO market through three nodal locations. This is a valuable asset as it provides capability to diversify energy supply. Prices at the three nodes may vary but overall closely align in day ahead horizon. The exceptions are solar hours where the economic value of supply through Imperial Valley node (IV) dominates the remaining two locations. The impact of solar is relevant especially during the months of season transition. During those months, CAISO market at IV has a tendency to reach negative LMP values at certain hours. The occurrence of this trend is closely monitored at IID with consideration for economic displacement when possible.

The charts below illustrate the average of 2017 LMP prices at three IID nodes along with their distribution across different times during the day. Figure 1.5 shows average October 2017 LMPs to demonstrate the seasonality of price variations concerning the annual trend. October is one of the seasons transition months when the occurrence of negative price intensifies during solar generation hours.

Exhibit 117: Annual LMP Pricing Comparison



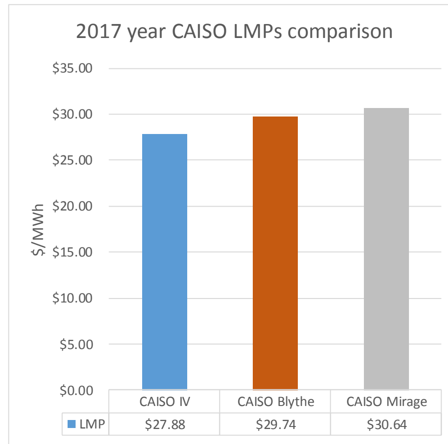
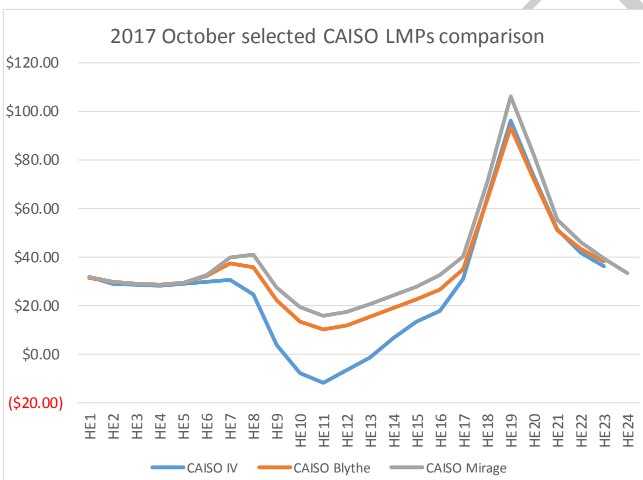
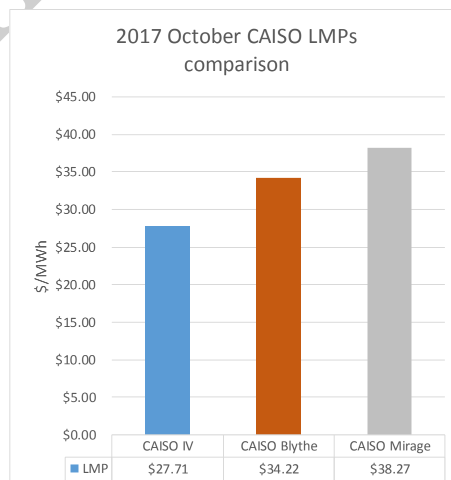


Exhibit 118: Monthly LMP Pricing Comparison





Additional, CAISO monitoring objectives at IID pertain to its performance in different trading horizons. In general, real time market prices are more volatile than day ahead. Certain tendencies and access to flexible generation allow IID to leverage the value of the different prices in these two markets.

Exhibit 119: Day Ahead Market vs Real Time Market

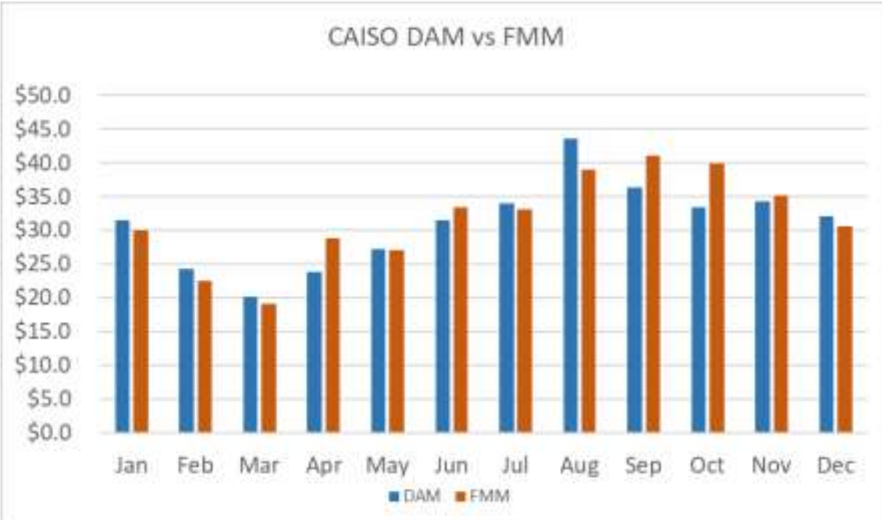
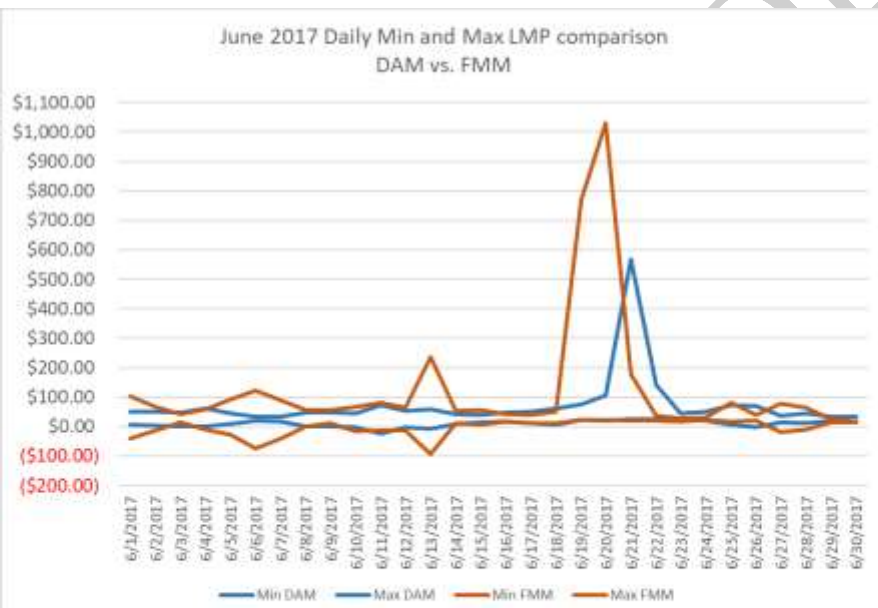


Exhibit 120: CAISO LMP Comparison



Overall the desired market tendency for the day ahead LMP prices is to merge with their LMP counterparts in real time. Currently, the average monthly LMP prices in both horizons settle in close proximity when evaluated in monthly aggregation. Figure 1.6 presents the LMPs comparison based on the 2017 average monthly LMP in day ahead and real time. However, the LMPs value may vary significantly when individual days and hours are considered. The Previous graph illustrates the daily minimum and maximum LMP in June 2017 in DAM and 15-minutes market. As demonstrated on the graph, real time market is more volatile with a tendency to settle at lower minimum daily prices and higher max price in comparison to its day ahead equivalent.

There are specific operational differences that distinct market interaction in the different horizon. In CAISO real time market accessible to interties such as IID, the financially binding awards are made in 15 minutes intervals. The granularity of awards exposes certain operational challenges along with uncertainty when placed economically for the entire hour. This particular characteristic limit IID's ability to interact with CAISO. Over the course of the past few years, CAISO has made substantial changes to its design including implementation of the full 15 and 5 minute energy market in 2014-18 and further implementation of EIM. Currently, CAISO is working on enhancements to its operation and granularity in day ahead horizon. These changes along with other regulatory impacts have substantial implication on LMPs formation and resulting energy value available to IID. IID is actively monitoring those changes along with resulting dynamics and considers their impact on its own operations and load serving economics.

Resource Modeling

As explained in Chapter 6, IID uses a long-term planning simulation model (PCI GenTrader) to estimate short- and long-term power supply costs. The model used is Gen Trader, which uses the forecasted loads, reliability criteria, transmission path characteristics, system constraint information, future natural gas prices and the IID's existing generation resources and power supply contracts to model power supply costs over the planning horizon. By adding (or removing) power supply contracts or new generation resources, the model can estimate long-term power supply costs and compare the value of various resource portfolio combinations.

The simulation model allows the IID to perform statistical studies of the results, including identifying confidence intervals for power supply cost estimates. These studies help IID grasp cost uncertainties and to strategically formulate hedging strategies and resource procurement activities to help reduce the risk of cost variance exposure.

With the impending needs in the near term, the IID needs a solution that meets its planning standards while resulting in a minimal rate impact to IID ratepayers. The modeling approach allows IID to precisely measure the costs and benefits of many varying portfolios.

IID uses a production cost model for projecting and analyzing IID's energy portfolio. The model is a stochastic (or deterministic), two-factor, lognormal mean-reversion model. One factor represents short-run variations that are mean reverting and the other factor represents longer term variations that follow a "random walk". The mean reversion is used to generate a tendency to revert the prices (after a disruption) back to the expected value. The rate of reversion, as well as separate volatility and correlation parameters, are inputs into the model that drive the calculation for uncertainty in weather, load, prices (energy and gas) and outages. Unit operating parameters, market price and availability of energy, transmission capacities, interconnection information and all constraints are also important inputs/factors in the model. The model uses all of this information to determine the most economic use and optimization of resources.

The expected value of a stochastic simulation, or the mean outcome of a simulation, is typically utilized to project total costs, generation output, fuel burn, market purchases/sales, value of the net position and others.

However, a stochastic simulation is also used to produce a variety of potential outcomes within a range of volatility (load, prices and outages) to allow for risk analysis including cash flow at risk, value at risk, varying confidence levels, etc. Generally, a 100 iteration stochastic simulation is administered to provide 100 potential outcomes of any aspect in IID's asset optimization process.

Deterministic simulations are also utilized to project and analyze IID's energy portfolio for the short and long terms. A deterministic simulation uses the same optimization engine and same inputs (except for volatility) as the stochastic simulation, but only provide one average outcome of the desired values. No Monte Carlo techniques are used in these types of simulations. Typically, the deterministic output is very similar to the mean output of a stochastic simulation. For IID's long-term fuel/generation/budget analysis, deterministic results have been utilized for reporting purposes and stochastic results are used for shorter term fuel/generation/budget analysis.

San Juan Ownership

IID's ownership portion of the coal-fired San Juan Generating Station makes up about 20 percent of IID's total annual energy requirements and more than 50 percent of IID's carbon emissions. The debt liability owed through the SCPPA agreement expires in 2020 and the fuel contract for the coal that supplies the entire plant expires in 2017. With this in mind, there are numerous considerations that IID has measured to evaluate the possibility of exiting ownership compared to maintaining ownership of IID's portion of Unit 3 of the coal facility. In mid-2015, the restructuring agreement was finalized and five agreements were finalized:

- Restructuring Agreement
- Decommissioning Agreement
- Amended Mine Reclamation Agreement
- San Juan Project Participation Agreement Restructuring Amendment
- San Juan Project Participation Agreement Exit Date Amendment

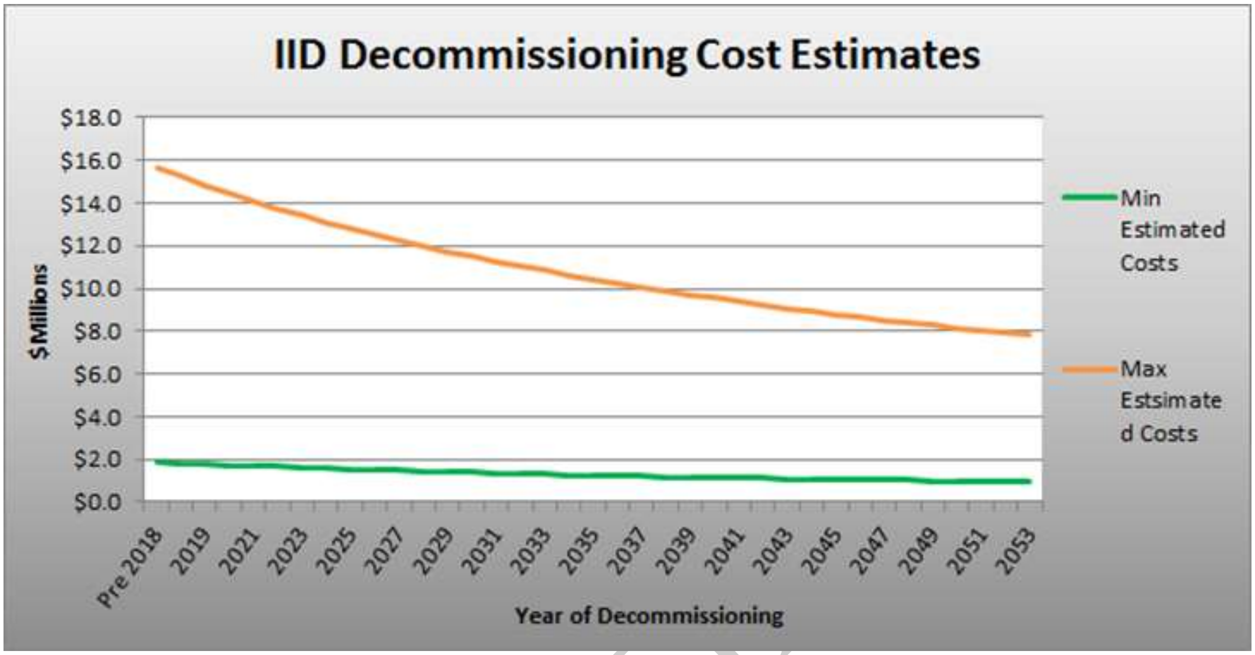
Some of the key points of the restructured agreement are as follows:

- SCPPA and IID would be parties to Participation agreement until June 2022
- Environmental Protection Agency ordered selective catalytic reduction - $1 billion
- SCPPA Share = $130 million + interest
- Public Service Company of New Mexico negotiated two unit shut down in 2017 + selective non-catalytic reductions – Unit 3 will close with or without restructure

Southern California Public Power Authority, M-S-R Public Power Agency, Anaheim, Tri-State Generation & Transmission Association decide to leave

The only major item that will be pending past the exit in 2018, is decommissioning. The restructured agreement allows for a reduction of risk in decommission costs over time. The following exhibit demonstrates SCPPA's and IID's share of decommissioning cost protection that is unknown as of today:

Exhibit 121: Decommissioning Cost Protection



So, depending on a number of various factors, if the plant stays online longer, then decommissioning costs significantly decrease over time. Overall, there were a number of noteworthy benefits of the restructured deal. Below is a comparison of the potential costs with and without the restructured agreement:

Exhibit 122: Benefits of Restructure

Restructured Deal		No Restructured Deal	
Issue	**Negotiated Value**	**Issue**	**Cost Potential**
Demand Charge	($86.8k)	SNCR or SCR	($15 -$66) Million
Eliminate "Take or Pay" ($50/ton coal)	Savings when unit is offline and when coal price > $50/ton	Take or Pay Remains	No savings when unit is offline
Restructuring Fee	($2.036) Million	No Restructured Deal	Great uncertainty in costs of decommissioning, reclamation, & emissions
Payment to SCPPA for Residual Coal	$ 6.578 Million	No Value of Coal	Greater costs in emissions
Decommissioning Trust/Sliding Scale	Provides greater cost certainty	No Decommissioning Agreement	No Certainty of Decommissioning Cost
Funding of Reclamation Trust	Provides greater cost certainty	No Amended Reclamation	Current trust underfunded
Voting on plant decisions	Provides ability to protect SCPPA	Plant Common O&M	($17.815) Cost avoidance
Estimated net benefit of restructuring			**$4.46-83 million**
Note: Estimated net benefits do not include savings from cost protection terms of the agreement.			

The nine owners are still meeting to discuss various aspects of the restructured agreement as well as the fuel agreement and IID will continue to monitor those discussions to ensure that IID's risks are lowered after the exit.

EPA MANDATES

The Federal Environmental Protection Agency and the New Mexico State Environmental Protection Agency both have a series of requirements for air quality standards that affect the San Juan coal-fired generating facility and its owners. There are rules that limit and require a reduction in mercury and air toxins, regional haze as a result of coal-fired generation and, of course, greenhouse gas limitations. All of these limitations and reduction requirements that have been mandated over the years have required upgrades and major maintenance outages to occur causing IID's overall fixed costs for the resource to increase. Over the past several years, IID has invested more than $20 million (six percent of $320 million total) in capital investment for environmental improvements to the plant. Additionally, increased outages have escalated the cost IID incurs to replace the power when the expected baseload 106MW hourly production is not available to IID.

The impact of the EPA mandates continues to be a bit of a mystery to IID. There are a bevy of environmental issues that continue to cloud the SJ3 plant with the risk of more cost inhibitive requirements from both the FEPA and the SEPA. At the current time, the owners of the San Juan Plant and the Public Service Company of New Mexico have been working together with the FEPA representatives to accept the much cheaper alternative requirement that the SEPA has proposed. FEPA initially required the installation of Selective Catalytic Reduction to limit the NOx emissions, which would have a cost of about $50.9 million to IID. The SEPA proposal was to install Selective Noncatalytic Reduction for the same purpose and this alternative would cost IID about $12.9 million. All owners have jointly petitioned the FEPA to allow the SEPA mandate of the SNCRs to be installed as opposed to the SCRs.

As a result of the discussion between all related parties, the state and PNM reached an agreement in February of 2013 to shut down and retire Units 2 and 3 and install SNCRs on Units 1 and 4. This alternative will save the owners of the plants millions, but with the continued environmental constrictions that have trended on coal-fired plants, IID is at risk as an owner for continued increased/fluctuating costs due to the potential of future environmental laws.

SIERRA CLUB

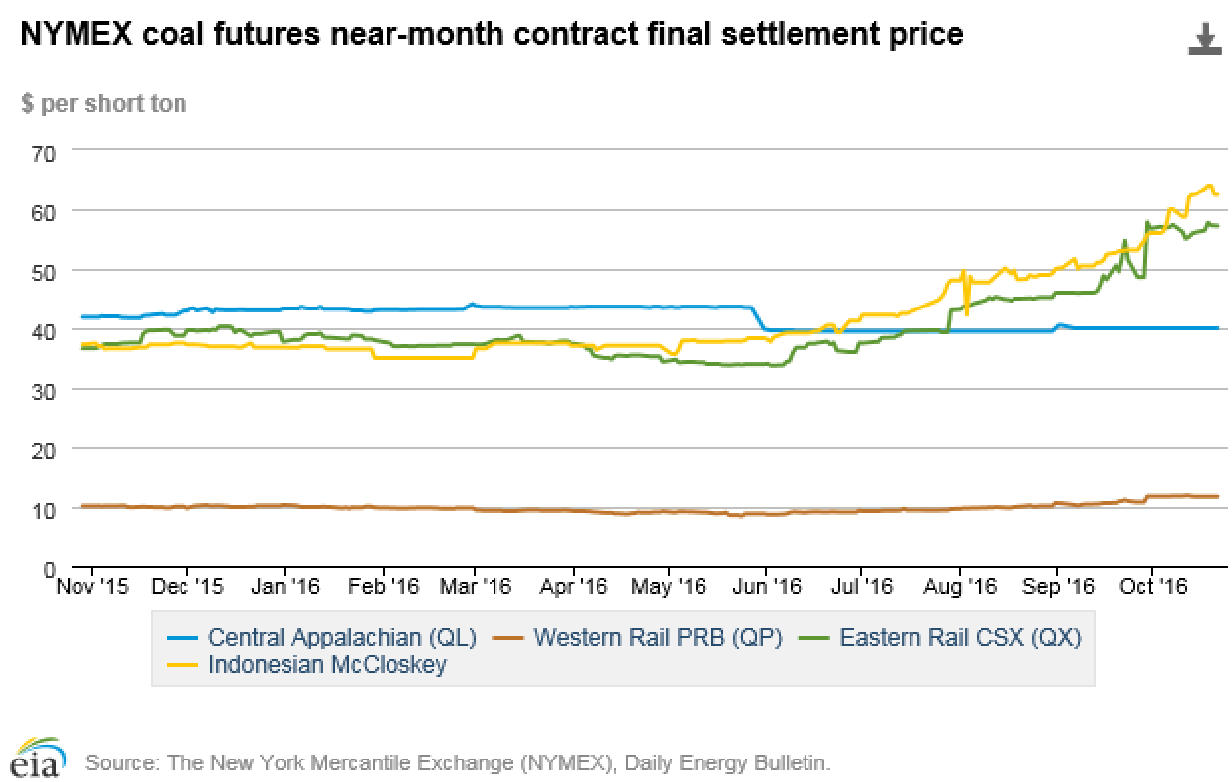
Like the seeming continuity of laws that have steadily affected the costs and requirements of ownership of the San Juan plant, the Sierra Club has constantly coerced litigation to spark action from the San Juan owners. As a result of the Sierra Club activities, PNM, the Joint Utilities Group as well as San Juan owners such as IID, have created a working group to promote the Best Available Retrofit Technology, which is provided in the FEPA mandate. The working group and its participants have spent several years studying numerous alternatives of the best BART approach for all owners in dealing with the new and future environmental requirements.

There is a concern, that the litigation on the San Juan plant imposed by such groups as the Sierra Club could continue and cause additional capital expenditures by the IID. This is a risk that IID would like to avoid where possible.

COAL MINE CONTRACT

All four units of the San Juan Plant are fueled by coal that is supplied by the El Paso Coal Mine. PNM has a contract with the coal mine that expires in 2017, three years prior to the expiration of the debt-service payments from IID. The expiration in 2017 necessitates the need for a new contract to supply the plant. The current contract provides a fairly steady fuel price, but a future contract for coal is a bit of a gamble to predict when IID looks at long-term supply-side costs. The prices of coal have traditionally been fairly flat, but in the past 5-10 years, prices have begun to fluctuate with volatility similar to the gas markets. The following exhibit illustrates this volatility

Exhibit 123: Monthly Coal Prices by Region



As exemplified above, coal prices have a tendency to fluctuate and, with the negotiation of a new long-term coal contract yet to be finalized, IID is at risk of the PNM negotiated price for future years that could be an array of price levels.

OPERATIONS AND MAINTENANCE

As a result of heavy environmental improvement requirements, the operational stability of the plant has been less static in recent years. Additionally, the plant is more than 25 years old and as age takes its toll on the plant, a higher rate of planned maintenance outages and unexpected outages will, most likely, be realized. Since the San Juan generation is considered baseload generation, IID expects the plant to be online and producing and, if not, then IID needs to procure replacement energy for the necessary hours. The cost of this can be above and beyond what is budgeted, which presents a potential financial issue not desired by the IID.

IMPACT OF SJ3 ON IID RPS AND EMISSIONS

As previously discussed, San Juan takes a considerable amount (around 50 percent) of IID's emissions allowances provided by the state for the Cap-and-Trade Program. While the allowances are freely issued by the state, the Cap-and-Trade Program provides the incentivized opportunity for a reduction of emissions via a market-based system that sets a platform for IID to sell excess allowances to the market. The revenues from these excess allowance sales would be greatly increased if IID were to exit the ownership of the San Juan Plant and the revenue recognized would be used towards the acquisition of renewable resources to meet the RPS. The exiting of the ownership is planned to be by the end of 2017 once the unit is closed.

After 2020, the assumption based on CARB' s clarification to the Cap-and-Trade Regulation sections 95812(f) and (g), is that the level of distributed allowances would be about the same looking forward for IID once Unit 3 of the San Juan Generating Station is closed. If the law, in fact, continues in this manner after 2020, then companies like IID are incentivized to consume less coal based generation in their resource supply. The following exhibit estimates the difference of excess allowances IID would possess if San Juan was not a part of the IID resource portfolio

By the end of 2017:

Exhibit 124: Additional Allowances for IID without SJ3 after 2017

Year	Difference in Excess Allowances w/o SJ3	Value of Allowances @ $15/mtco2e
2013	-	$ -
2014	-	$ -
2015	-	$ -
2016	-	$ -
2017	-	$ -
2018	795,983	$ 11,939,747
2019	866,884	$ 13,003,258
2020	727,708	$ 10,915,625

Another aspect regarding the ownership of the San Juan Plant is how this type of baseload resource affects the IID's ability to successfully acquire renewable resources to meet the RPS requirement of 33 percent by

2020. While the coal resource, not including line losses, allowances and transmission, is generally cheaper, it is 106MW all year round. In the winter months when IID's loads are in the 250-300MW range, San Juan is about 35-40 percent of the IID load. In the summer, when loads are 900-1,000MW, San Juan makes up about 10-11 percent. Due to IID's monthly spiking load shape, the challenge is effectively layering in baseload/must-take type of renewable resources. If San Juan was not a part of IID's resource stack, then IID would be able to layer in more baseload renewable resources to meet the RPS. This has an extrinsic benefit to IID that influences the IID's RPS strategy.

Analysis and Strategy

IID spent a great deal of time over the past few years to follow the activities revolving around litigation and environmental improvement requirements for the San Juan Plant. Moreover, several evaluations have been completed to analyze the costs and risks of exiting the ownership as compared to keeping the San Juan ownership as a part of IID's resource supply. The goals of the studies were the following:

- San Juan Unit 3 vs. displacement: Which is the greatest value to IID?
- Will the layoff of SJ3 ownership allow for IID to effectively integrate more renewable resources?
- What are the risks associated with keeping vs. exiting the ownership of San Juan?
    - Emissions allowances
    - IID system flexibility
    - Transmission import capability and investment relativity
    - Current and future Regulatory

The methodology for these studies is as follows:

- Evaluated the key components of San J3 related uncertainties:
    - SCPPA/San Juan Unit 3 Bond Financing of EPA equipment installation requirements of either SCRs or SNCRs
    - Possible residual fuel revenues if IID exits SJ3 ownership
    - Trust fund impact to IID
    - Existing bond financing or refinancing dependent upon ownership
    - Cap-and-trade definition of allocation of allowances
        - Will state keep definition of current allowances, which are based on IID's system resource portfolio, including emissions from SJ3; or
        - Will state redefine the allowances allotted to IID based on a resource portfolio that does not include SJ3 (if IID exits ownership of the plant)
- Used Planning and Risk IID system production cost model, evaluate the costs
    - Created multiple scenarios based on four main cases:
        - Production costs of keeping SJ3 and installing SCRs
        - Production costs of keeping SJ3 and installing SNCRs
        - Production costs of displacing SJ3 with a 50MW geothermal from CalEnergy and summer shaped energy market products

    - Production cost of displacing SJ3 with a 50MW geothermal from CalEnergy and summer shaped energy market products, with the assumption that the state will **revise IID's MTCO2e emissions allowances**
  - Studied a total of 216 iterations of possible market outcomes between gas, energy, emissions, coal and C&T-related regulatory changes

Studying the ownership of San Juan is moderately complex and there are numerous assumptions that need to be considered and, if altered, could vary the entire conclusion of the study. The assumptions used for this study are as follows:

- Market prices
  - **High/Med/Low** forecasts for **Gas/Energy/Coal/Emissions** based on Ventyx WECC long-term reference case and SCPPA SJ3 budget
- Production cost risks in all iterations based on varying combinations of potential market outcomes
- Two key scenarios are applied to the iterations where IID exits ownership of the SJ3 share:
  1. Revenues from full cap-and-trade allowance allocation as currently defined by the state of CA
  2. Revised version of allowance allocation that limits the amount of allowance sales revenues possible for C&T auctions
- There are two trust funds
  1. To cover the reclamation cost of the coal mine; agreement made several years ago and all SJ owners have paid into this fund
  2. To cover the decommissioning and reclamation of the San Juan generators to be shut down. The cost of this is still under negotiation as well as who will cover these costs. The assumption is that this cost will be covered by the residual fuel value at the end of 2017 and the current reserve fund at SCPPA (i.e., no net costs)
- WAPA transmission
  - The costs of the WAPA transmission will continue since there would still be a need for this import capability to import San Juan's replacement either through keeping the WAPA existing transmission capacity or by replacing it with the PV Yuma line
- Fair market value of ownership
  - The fair market value is dependent upon if there are any potential ownership investors. At this point, no serious discussions have taken place.
- Bond financing and/or refinancing
  - In the case of opting out of SJ3 ownership, the assumption is that all SCPPA parties would accelerate the debt-service payments and complete by the end of 2017.
- SJ3 Coal Mine residual fuel worth $30 million to SCPPA (50.98 percent to IID) if SCPPA exits ownership
- SNCR/SCR financing:
  - Two key alternatives are observed:

1. Four unit SCR project where the estimated cost to SCPPA is $100 million (IID 50.98 percent)
2. Two unit SNCR project where Units 1 and 2 are shut down. The estimated cost to SCPPA is $25 million (IID 50.98 percent)

  - 20-year amortization schedule
  - Discount rate of 5.5 percent
  - Owners of plant responsible to pay any of the costs associated with SCRs or SNCRs; not any party who exits ownership
  - Decommission and reclaiming costs are a $0 cost to IID in all scenarios
- Displacement of SJ3 is a 50MW geothermal plant from CalEnergy and summer shaped energy market products
  - 18MW online by 2016
  - 28MW by 2017
  - 50MW (total) by 2019

Four cases were studied 54 times with varying market outcomes for a total of 216 iterations. These four cases are:

1. W/SJ3 plus Four Unit SCR
2. W/SJ3 plus Two Unit SNCR
3. No SJ3 plus 50MW geothermal plus summer products
4. No SJ3 plus 50MW geothermal plus summer products, with revised emissions to reflect the layoff of SJ3

If the allowances that the state has defined stay in similar position for the next 20 years as what they are currently defined, then replacing SJ3 with a 50MW Geothermal Plant (Case 3) is the least expensive of the alternatives studied ***if we assume*** that all pricing scenarios (i.e., Gas, Energy, Emissions and Coal) are the base/mid-range forecast. See below for an illustration of this:

Exhibit 125: Case Comparison of the Mid-Level Price Assumption

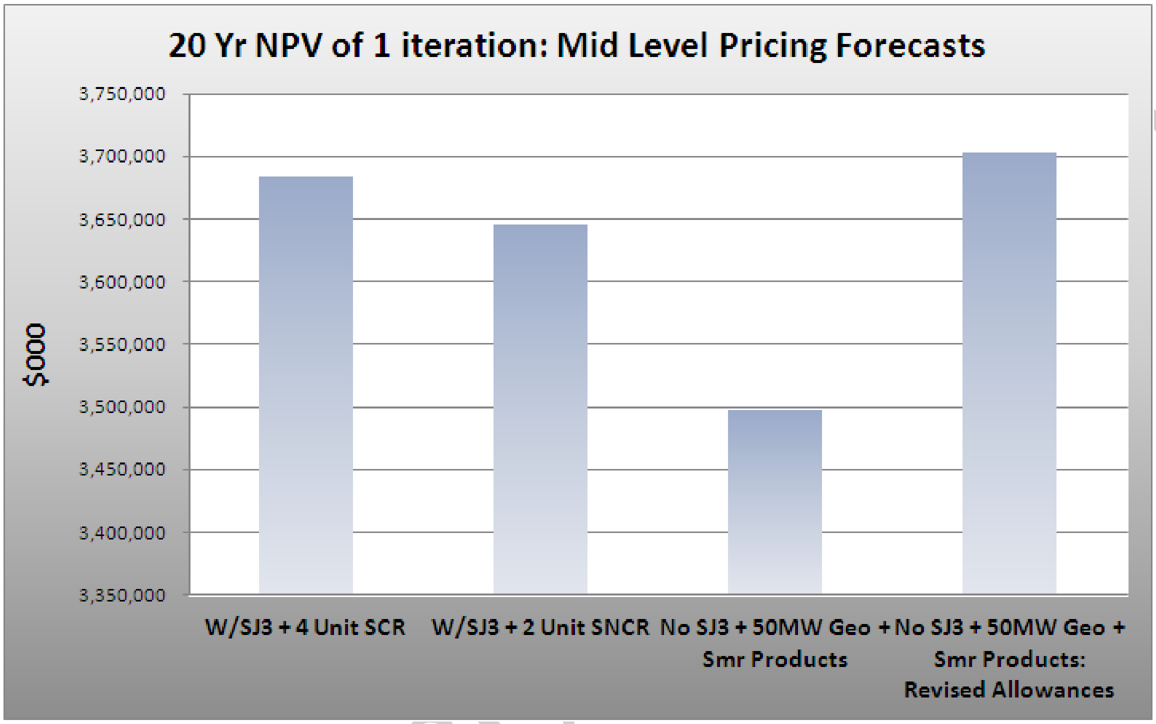
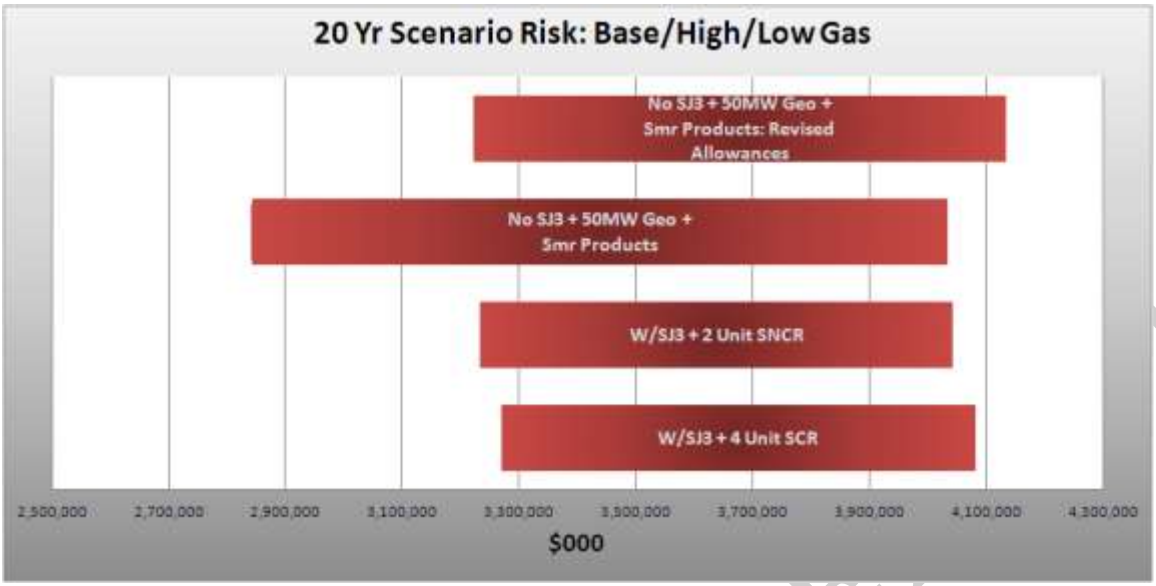


Exhibit 126: Risk Analysis - Range of Potential Costs of SJ Alternatives



The uncertainty in gas prices and emissions allowance prices contain the greatest impact on these results. Market fluctuations and uncertainty are evident in the case where IID exits its ownership. However, there is also great uncertainty in consuming energy from high greenhouse gas emitting resources such as the San Juan coal plant and could result in substantial costs to the IID not accounted for in the analysis. This is a risk the IID is averse to.

When IID exits ownership of the San Juan facility, the IID will be in a better position to layer in renewable resources to meet the RPS targets and will provide a better operating conditions that can be flexible enough to take advantage of market opportunities while avoiding undesirable capacity surplus conditions.

Early SJ3 Exit Analysis

Other SCPPA owners were interested in considering an earlier exit than the agreed 12/31/17 date of exit in the restructuring agreement. Essentially, IID as the majority off-taker performed an analysis that observes the value of the generation in the last year when fixed costs are greatly reduced, making the San Juan energy more attractive during the last year of operations. The total cost analysis is highly dependent upon the production efficiency of the facility. If the production is below the assumed 65 percent, then the costs increase comparatively speaking; if production is above, then costs decrease.

- *65 percent is average CF of 2013-16 YTD*
- *At 65 percent CF, the energy costs about* ***$47/MWh + (allowance value loss when there is no SJ3)***

If all San Juan Costs are still charged after the 2017 shutdown, then it is more expensive to shut down. Essentially, we would be adding the $47/MWh for each MW that is displaced otherwise if all costs are paid; $16/MWh if Fuel is not paid; $2/MWh if fuel and O&M are not paid (all need to subtract next difference of allowance value; it was calculated that **about $7.50/MWh is the net diff in allowance value**).

- Shutdown only becomes valuable to IID if the negotiation results are as follows:
  - *Fuel costs are not charged; or*
  - *Fuel costs & O&M are not charged; or*
  - *The full amount of San Juan costs are not charged in 2018*
- The value of the shutdown becomes greater depending on negotiation goals of what is not charged
- Since San Juan costs are fixed and if all costs are required, then if the market prices increase above $47/MWh, then keeping San Juan is better from a Variable $/MWh perspective

Cost analysis also depends on load and how all resources fit into the daily load curve

These results were shared with the other SCPPA members and SCPPA is in the process of discussing how an early exit proposal would look from PNM.

Chapter 7: Economic Analysis and Results

Chapter 4 indicated that there are needs for additional resources on the IID system beginning in 2019. The need increases to 382 MW by the end of the planning horizon. In this chapter, expansion plans involving the candidate resources from Chapter 6 are developed and evaluated.

Identification of Expansion Plans using Candidate Resources

Numerous Sections within IID conducted studies to determine the combination of resources needed to meet compliance and other requirements. This chapter discusses the evaluations performed within this IRP to determine the best path moving forward meeting all SB 350 requirements.

IID Transmission Assessment

This five-year and 10-year assessment of the IIDs electric system has been performed to ensure the IID has enough generation and transmission resources to serve its load reliably and to ensure grid reliability at all demand levels over a 10 year planning horizon under normal and contingency operating conditions. This is mandated by NERC/WECC planning standards.

While a separate study was performed in December 28, 2017 to comply with NERC/WECC planning standards (specifically TPL-001-4), this study is more comprehensive and addresses potential growth options, increased export capability, new transmission tie lines to neighboring entities, etc.

This study also takes into consideration the following planned projects or modifications that were considered and their projected in-service dates:

NEW FACILITY OR MODIFICATION	**PROJECTED IN-SERVICE DATE**
Path 42 RAS	2020
El Centro SS Bus partitioning	2019
92kV CI-Line (Sha.H-Ave42) upgrade	2019
92kV CN & CL line upgrade	2020
92kV V. Ranch substation	2022
92kV L. Ranch substation	2022
92kV Jasper substation	2022
92kV North Gate substation	2022
92kV Anderson substation	2027

All base cases in the study were updated to reflect the above changes.

Separate assessments are planned or currently underway to evaluate the potential benefits of building or participating in the following:

- The NGIV2 project, which consists of 500kV circuits that interconnect North Gila – Highline – Imperial Valley substations.
- IID has a 20 percent share on the HANG2 line. IID would like to see if building a North Gila - Pilot Knob or North Gila - Highline transmission line is technically and economically feasible to bring up to 240 MW of additional power into the IID system.
- IID is also evaluating opportunities to export power into CFE system. A transmission line through the two systems is being evaluated at different locations.
- To provide additional reliability and operational support in the La Quinta area, IID is considering to add a 50 MW quick-start gas-turbine or battery system at or near La Quinta 92 kV substation. This resource will provide local support to cope with the rapid load growth in La Quinta area.

Study Scope

The scope of IID's five-year (2022) and 10-year (2027) transmission system assessment and expansion plan included:

1. Comprehensive assessment of the IID transmission facilities subject to single and multiple contingency conditions in accordance with NERC/WECC planning standards TPL-001-4 (events P0 through P7).
2. Summer Peak load as well as light winter load conditions to cover a broad spectrum of demand levels.
3. Extreme weather load forecast for the summer peak which was equivalent to about 1,250 F, to stress the system. This would be the worst case scenario.
4. Identification of corrective or improvement plans for criteria violations in the assessment.
5. Preliminary summary report on ongoing studies for economic based projects.

Study Assumptions

Base Case

The study includes a heavy and a light load assessment. Since the IID is a summer peaking utility, the majority of the planning efforts are focused on the heavy load conditions to meet the expected IID demand. The light load assessment identifies the limits of the transmission system for exporting power from resources interconnected within the IID transmission system.

The assessment used the most recent Western Electric Coordination Council power flow (steady state) base cases available in the WECC base case library. WECC full loop representation is used and the IID detailed representation down to the 34.5 kV voltages is modeled in those base cases and assessed.

The following base cases were developed and used in this assessment:

i. System Off-Peak Load for Light Winter 2019
ii. System Peak Load for Summer 2019 (extreme load forecast)
   - Including a mitigation case
iii. System Peak Load for Summer 2022 (extreme weather forecast)
   - Including a mitigation case
iv. System Peak Load for Summer 2027 (extreme weather forecast)

In addition to the above base cases, sensitivity base cases were also developed to further stress the system to identify any weaknesses.

v. 2019 Light Winter Off-Peak load Sensitivity
vi. 2019 Summer Peak load Sensitivity
   - Including a mitigation case
vii. 2019 Summer Peak load with 5 percent increase in load (Reactive Margin)
viii. 2022 Summer Peak load Sensitivity
   - Including a mitigation case
ix. 2022 Summer Peak load with spare equipment strategy Ramon Bank 1
x. 2022 Summer Peak load with spare equipment strategy ECSS Bank 1
xi. 2022 Summer Peak load with spare equipment strategy ECSS Bank 2
xii. 2022 Summer Peak load with spare equipment strategy ECSS Bank 4
xiii. 2022 Summer Peak load with spare equipment strategy CV Bank 4
xiv. 2022 Summer Peak load with spare equipment strategy Ave 58 Bank 4
xv. 2022 Summer Peak load with spare equipment strategy Midway Bank 1
xvi. 2022 Summer Peak load with 5 percent increase in load (Reactive Margin)
xvii. 2027 Summer Peak load with 5 percent increase in load (Reactive Margin

In all, a total of 21 base cases were developed for this assessment.

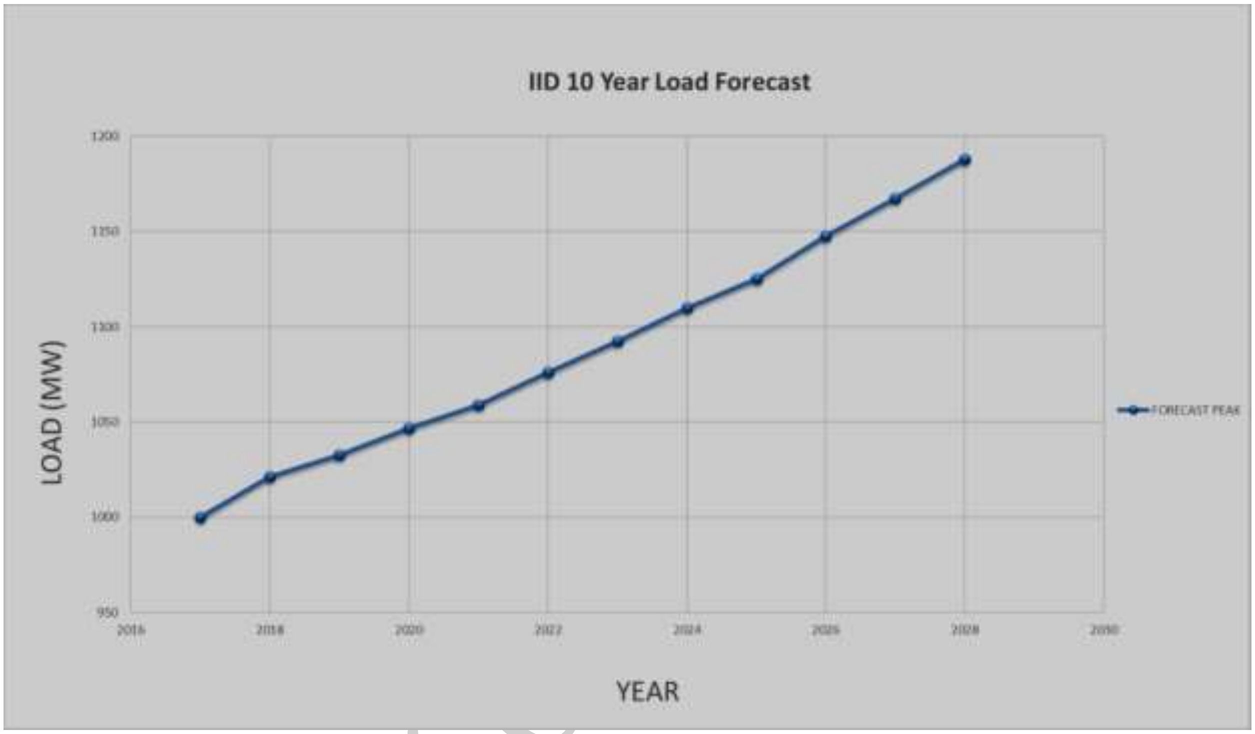
The IID's existing firm transmission commitments that consist of exports of generation resources within the IID control area are modeled in the heavy and light load base cases 24.

Load Forecast

Latest load forecast developed by the IID's Integrated Resource Planning group was used in this study. As is customary, the extreme weather load forecast is used in planning studies to ensure system will perform safely and reliably under the most stressed conditions (worst case scenario). Average load forecast is also shown in the chart below for illustration purposes. The difference between average and extreme load forecast is about 80 MW. The extreme load forecast represents about 125 F in Imperial Valley and surroundings.

The five-year assessment evaluated the impacts of load level of 1,166.38 MW with a Sensitivity of 1,224.7 MW. The 10-year assessment evaluated 1,258.76 MW.

Exhibit 127: IID 10-Year Load Forecast



The winter light load (off-peak load) is less than 30 percent of the summer peak load, which has been modeled in the light winter base cases.

Transmission Path Capacity/Import-Export and System Operation Limits

The IID's transmission inter-tie paths such as the WECC Path 42 were stressed to reasonable level based on historical limits or maximum rated loadings. The exhibit below provides a summary of the IIDs existing and proposed transmission paths maximum scheduling capabilities assumptions used for this assessment.

Exhibit 128: Transmission Path Capacity/Import-Export

ENTITY	TIE-LINE	Capacity
SDG&E	**230 kV S-Line**	**350**
SCE	**230kV Path 42**	**600**

WAPA	**161kV F & D Lines**	**275**
APS	**161kV AX-Line**	**75**

The IID ensures that the System Operating Limits and the subset of SOLs that qualify as Interconnection Reliability Operating Limits found in this analysis are determined based on "IIDs System Operating Limits Methodology for the Planning Horizon." This methodology is developed in accordance with NERC Standard FAC-010.

The study model considered the most recently available WECC approved base case as the seed case for the study time frame and conditions. The IID base cases were developed from the seed case to reflect the IIDs anticipated transmission system configuration, generation dispatch and load level for the study period.

Contingency Files

Contingency files were developed in accordance with the new TPL-001-4 standard which has been effective from January 1, 2016. All events from P0 to P7 in the exhibit of the above TPL standard were reviewed and contingencies categorized accordingly. These events included normal operating conditions, single contingency, double contingency, stuck breaker contingencies, and multiple contingencies.

Some severe contingencies such as stuck breaker, internal breaker faults and bus section outages, required removal of all elements that the protection system and other automatic controls are expected to disconnect for such contingencies without operator intervention.

The contingency list included all major transformer outages, a long lead-time item, to determine if there is any adverse impact on the IID system due to unavailability of this major transmission equipment. The results will help create or modify spare equipment strategy.

The IID also created external contingencies representing its neighboring transmission systems such as Western, SDG&E, SCE, CFE, and APS to determine which contingencies and protection systems have the most severe impacts on the IIDs transmission system. Per applicable standards this was done in coordination with neighboring entities. Contingencies that have been identified earlier to have severe impacts on the IID system such as outages of 500 kV Hassayampa – North Gila with Coachella Valley Bank #4 out, and 500 kV Hoodoo Wash – North Gila were included in these contingencies.

In all, about **2,000** internal and external contingencies (including sub-100 kV) and protection systems were developed and applied in this assessment.

Sensitivity

Sensitivity cases are developed to test the system for extreme conditions, often by increasing the peak load by about 5 percent to stress the transmission system, or by decreasing the light load by about 5 percent to increase exports which also stress selected transmission lines. Sensitivity cases are also developed to comply with sections 2.1.1, 2.1.2, 2.4.1 and 2.4.2 of the NERC Reliability standard TPL-001-4. The purpose of sensitivity cases is to unveil any adverse reliability impacts which are caused by stressed system conditions.

For this study, sensitivity cases were created with an increase in load by 5 percent in both the 2019, 2022, and 2027 Heavy Summer cases.

In addition to the above three sensitivities, the following sensitivities were utilized for the steady state analysis in its Annual Planning Assessment:

WECC SEED CASE	SEASON	SENSITIVITY DESCRIPTION
18LW 2a1	2018-19 Light Winter	• Real and reactive load forecast: Increased load to match 0900 levels • Generation dispatch: Turned on all solar generation • Expected transfers: Increased exports
18HS4a1	2019 Heavy Summer	• Real and reactive load forecast: Increased load 5percent above forecast • Generation dispatch: Set Colgreen to 0MW (no PPA)
22HS1a	2022 Heavy Summer	• Real and reactive load forecast: Increased load 5percent above forecast

All internal and external contingencies (including transfer levels) were applied to test these sensitivity cases and to determine which contingencies have the most severe impacts on the IID system.

Study Criteria and Methodology

Grid Reliability Criteria which incorporates the Western Electricity Coordinating Council ("WECC") and the North American Electric Reliability Corporation ("NERC") planning criteria were used for this study. Key points of these criteria are:

1. Normal overloads are those that exceed 100 percent of normal ratings. The planning criteria require the loading of all transmission system facilities (transmission lines, transformers, generators) be within their normal ratings under normal operating conditions.

2. Emergency overloads are those that exceed 100 percent of emergency ratings. The emergency overloads refer to overloads that occur during single element contingencies (P1 and P2) and multiple element contingencies (P3 through P7). The planning criteria require all transmission facilities to remain within their emergency ratings during single or multiple contingency conditions.

3. Bus voltages should stay within 0.95 and 1.05 per unit under normal operating conditions and within 0.9 and 1.1 per unit under emergency operating conditions. For 500 kV buses, normal bus voltage should not go below 1.0 per unit.
4. Voltage deviation should not exceed 5 percent under single contingencies, and 10 percent under multiple contingencies.
5. Voltage stability is required at 105 percent of load level for single contingencies and 102.5 percent of load level for multiple contingencies. The system must have positive reactive power margin (VAR margin) for single and multiple contingencies at the above load levels respectively.
6. Short circuit duty under single phase to ground fault and three phase fault at any substation should not exceed 100 percent of the fault interrupting rating of the circuit breakers at that substation.
7. Transient stability analysis should demonstrate stable and clearly damped oscillations of generator angle, power, voltage, and frequency under the most severe contingencies.

Steady state, Short Circuit, Transient stability and Post-transient reactive margin analysis were performed on the selected base cases developed for this assessment.

The study assessment considered all of the IID's single and the most severe multiple contingencies and the selected external contingencies that are known (from past studies and experience) to cause the most severe impacts to the IID transmission system. This selection of contingencies applies primarily to steady state assessment. Out of these contingencies, a narrower list with higher steady state impacts was selected to perform transient stability assessments.

The Short Circuit assessment was performed simulating three phase, double line to ground and single line to ground faults on all of the IID BES buses and some non-BES buses modeled in the ASPEN short circuit database.

External contingencies evaluated in this assessment represented the following neighboring utilities transmission systems: A). WAPA Lower Colorado area 161 kV system (South of Parker), B) San Diego Gas and Electric 500 and 230 kV System West of Imperial Valley Substation, C) Comission Federal de Electricidad 230 kV system, from La Rosita Substation to CFE zona costa, D). APS' Yuma area system, and E) SCE System west of Mirage substation.

Corrective or improvement plans were developed for criteria violations and identified in the assessment. All the necessary mitigation schedules for the implementation were included in this document.

NEAR TERM TRANSMISSION ASSESSMENT

Steady State Analysis Results

Steady state analysis provides thermal and voltage performance of the system under normal as well as under emergency (contingency) conditions. This analysis was conducted on the following steady state base cases:

- 2019 Light Winter

- 2022 Heavy Summer
- 2022 Heavy Summer Sensitivity

The stability analysis for the Near Term Planning Horizon in this Annual Planning Assessment is based on the following general assumptions:

- The peak stability analysis was based on the 2022 Heavy Summer Peak Load power flow model as well as the corresponding Sensitivity case. These models are current study cases. The rationale for selecting these cases is that the summer season is historically where the IID system has the poorest stability response. Year 5 was studied to capture the impact of generation and topology changes that are expected to occur during the Near Term Planning Horizon.
- The WECC composite load model "cmpldw" was used to represent the dynamic behavior of the largest loads in the IID system.

The IID developed the contingency list and performed twelve steady state contingencies for extreme events:

- 161kV "L-line" (ECSS-Ave58-CV) and 92kV "K-line" (Mecca-Ave52)
- 161kV "L-line" (ECSS-Ave58) and ECSS 230:92kV Bank #4
- Coachella Switching Station bus fault and Ramon Transformer out
- Coachella Switching Station bus fault and Ave58 Transformer out
- Niland 92kV bus fault and Ramon Transformer out
- Niland 161kV Switching Station bus fault and Ramon Transformer out
- Stuck Breaker at Highline 92 kV bus and Ramon Transformer out
- 230kV "KN-Line" (CV-Mirage) & "KS-Line" (CV-Ramon) contingency with Ramon Transformer out.
- 230kV "KN-Line" (CV-Mirage) & "KS-Line" (CV-Ramon) contingency with "S-Line" (ECSS-Imperial Valley) out of service.
- 230kV "KN-Line" (CV-Mirage) & "KS-Line" (Ramon-Mirage) contingency with "S-Line" (ECSS-Imperial Valley) out of service.
- Hoodoo Wash-North Gila and Hassayampa - North Gila contingency with Coachella Valley Bank #4 out
- El Centro 92kV double bus outage.

Thermal and voltage performance of the system was evaluated for all three base cases under normal (P0), single element outage (P1, P2) and selected multiple element outages (P3-P7). Thermal loadings were reported when a modeled transmission component was loaded above 95 percent of its continuous MVA rating (P0) and above 95 percent of its emergency rating (P1-P7). Generally, the concerns are raised when an element is found loaded above 100 percent of its normal or emergency rating, however, 95 percent was chosen to identify circuits that are also at the edge of an overload. Such circuits need to be closely monitored and can be placed as potential candidates for future upgrades.

Transmission voltage violations for normal (P0) conditions were reported when per unit voltages were less than 0.95 or greater than 1.05. Transmission voltage violations following single or multiple outages were reported when per unit voltages were less than 0.90 or greater than 1.1. Additionally, voltage deviations were recorded whenever these deviations were greater than 5 percent for single contingencies and 10 percent for multiple contingencies.

Voltage Criteria

**Some 500kV buses may have specific requirements*

Voltage Level	Normal Conditions (P0)		Contingency Conditions (P1-P7)		Voltage Deviation	
	Vmin , p.u.	Vmax, p.u.	Vmin , p.u.	Vmax, p.u.	P1-P3	P4-P7
≤ 200 kV	0.95	1.05	0.9	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.9	1.1	≤5%	≤10%
≥ 500 kV	1	1.05*	0.9	1.1	≤5%	≤10%

The steady state study results for each of the above cases are described below:

2019 Light Winter:

Voltage Performance:

No buses in the Heavy Summer base cases experienced voltage deviation exceedances with respect to the voltage criteria table above.

Voltage Deviation:

No buses in the heavy summer base cases experienced voltage deviation exceedances with respect to the voltage criteria table above.

Voltage Phase Angle Violations:

Few voltage angle exceedances occurred in the heavy summer base case under contingency. The exceedances can be mitigated by the curtailment of generation before the line is tested to close. IID is normally limited to 25° closing angles. Since most solar is off-line and the Path 42 RAS consist of mostly solar, addition generation was curtailed on the Collector System to mitigate the violations.

Internal Contingency Closing Angle Violations

LW 2019 Closing Angle Violations

FROM NO.	FROM NAME	FROM KV	TO NO.	TO NAME	TO KV	CK ID	AREA	ZONE	CONTINGENCY IDENTIFIER	CONTINGENCY DESCRIPTION	19LW
21007	CVSUB230	230	24806	MIRAGE	230	1	21	212	TPL_P6_L003	Line CVSUB230 230.0 to MIRAGE 230.0 & RAMON to MIRAGE	37.838
21076	RAMON	230	24806	MIRAGE	230	1	21	212	TPL_P6_L003	Line CVSUB230 230.0 to MIRAGE 230.0 & RAMON to MIRAGE	37.065
21215	C3-S2	34.5	21214	SONORA	0.36	1	21	213	TPL_P6_L003	Line CVSUB230 230.0 to MIRAGE 230.0 & RAMON to MIRAGE	29.319
21988	MDWY1_B2	34.5	21989	MDWY1_G	0.42	1	21	213	TPL_P6_L003	Line CVSUB230 230.0 to MIRAGE 230.0 & RAMON to MIRAGE	29.093
21992	MDWY2_B2	34.5	21993	MDWY2_G	0.42	1	21	213	TPL_P6_L003	Line CVSUB230 230.0 to MIRAGE 230.0 & RAMON to MIRAGE	29.093
21886	IPP-97B2	34.5	21878	IPP-97G	0.39	1	21	213	TPL_P6_L003	Line CVSUB230 230.0 to MIRAGE 230.0 & RAMON to MIRAGE	29.093

Thermal Performance:

No thermal violations occurred.

2022 Heavy Summer:

Voltage Performance:

No buses in the heavy summer base cases experienced voltage deviation exceedances with respect to the voltage criteria table above.

Voltage Deviation:

No buses in the heavy summer base cases experienced voltage deviation exceedances with respect to the voltage criteria table above.

Voltage Phase Angle Violations:

Few voltage angle exceedances occurred in the heavy summer base case under contingency. The exceedances can be mitigated by the curtailment of generation before the line is tested to close. IID is normally limited to 25° closing angles. In order to clear these violations the mitigation to curtail generation at the Anza substation was made.

Internal Contingency Closing Angle Violations

HS 2022 Closing Angle Violations											
FROM NO.	FROM NAME	FROM KV	TO NO.	TO NAME	TO KV	CK ID	AREA	ZONE	CONTINGENCY IDENTIFIER	CONTINGENCY DESCRIPTION	22HS-TPL
21377	RTP3ANZA	92	21378	RTP4SLTN	92	1	21	213	TPL_P2.1_0003	ANZA to SALTON CITY	37.119
21378	RTP4SLTN	92	21379	RTP5DSTS	92	1	21	213	TPL_P2.1_0004	SALTON CITY to DESERT SHORES	34.432
21281	AVE58	92	21380	RTP6OASS	92	1	21	212	SB_P2.3_052	21281 AVE58 (CKTB RSWO) 92.00	28.656
21377	RTP3ANZA	92	21378	RTP4SLTN	92	1	21	213	BF_P2.2_019	21377 RTP3ANZA 92.00	27.585

Thermal Performance:

With a category P6 outage, certain actions are allowed to mitigate it; therefore, no thermal impacts occurred during the heavy summer base cases. In order to clear this violation the mitigation to turn off certain generation was made.

Internal Contingency Thermal Violations

HS 2022 Thermal Violations																
FROM NO.	FROM NAME	FROM KV	TO NO.	TO NAME	TO KV	CK ID	AREA	ZONE	CONTINGENCY IDENTIFIER	CONTINGENCY DESCRIPTION	RATING NUMBER USED	RATING VALUE USED	RATING UNIT	% OVERLOAD USED	22HS-TPL	Delta Flow
21355	NEW_MECCA	92	21457	CLGRNTAP	92	1	21	212	TPL_P6_L451	Line AVE58 161.0 to CV 161.0 & CV BANK 3	2	145	MVA	100	100.8%	-0.131

2022 Heavy Summer Sensitivity:

Voltage Performance:

No buses in the heavy summer sensitivity base case experienced voltage deviation exceedances with respect to the voltage criteria table above.

Voltage Deviation:

No buses in the heavy summer sensitivity base cases experienced voltage deviation exceedances with respect to the voltage criteria table above.

Voltage Phase Angle Violations:

Few voltage angle exceedances occurred in the heavy summer sensitivity base case under contingency. The exceedances can be mitigated by the curtailment of generation before the line is tested to close. IID is normally limited to 25° closing angles.

Internal Contingency Closing Angle Violations

HS 2022 Sensitivity Closing Angle Violations												Mitigation 1
FROM NO.	FROM NAME	FROM KV	TO NO.	TO NAME	TO KV	CKID	AREA	ZONE	CONTINGENCY IDENTIFIER	CONTINGENCY DESCRIPTION	22HS-TPL_SENS	22HS-TPL_SENS_MIT
21377	RTP3ANZA	92	21378	RTP4SLTN	92	1	21	213	TPL_P2.1_C003	ANZA to SALTON CITY	37.099	37.628
21376	RTP4SLTN	92	21379	RTP5DSTS	92	1	21	213	TPL_P2.1_C004	SALTON CITY to DESERT SHORES	34.741	34.787
21281	AVE58	92	21380	RTP6OASS	92	1	21	212	SB_P2.3_052	21281 AVE58 (CKTB RSWO) 92.00	26.538	26.146
21377	RTP3ANZA	92	21378	RTP4SLTN	92	1	21	213	BF_P2.2_019	21377 RTP3ANZA 92.00	27.833	27.76
21387	IPP-73B1	34.5	21386	IPP-73G	0.38	1	21	213	TPL_P6_L003	Line CVSUB230 230.0 to MIRAGE 230.0 & RAMON to MIRAGE	26.553	26.586

Thermal Performance:

With a category P6 outage, certain actions are allowed to mitigate it. In order to clear this violation the mitigation to turn off certain generation was made. For the category P7 outage, the violation would not exist by 2022, because the CI-Line will be re-conducted in 2019.

Internal Contingency Thermal Violations

HS 2022 Sensitivity Thermal Violations																Mitigation 1
FROM NO.	FROM NAME	FROM KV	TO NO.	TO NAME	TO KV	CKID	AREA	ZONE	CONTINGENCY IDENTIFIER	CONTINGENCY DESCRIPTION	RATING NUMBER USED	RATING VALUE USED	RATING UNIT	% OVERLOAD USED	22HS-TPL_SENS	22HS-TPL_SENS_MIT
21309	AVE42	92	21408	SHAHILLS	92	1	21	212	TPL_P6_L558	Line CV 92.0 to NEW JACKSON 92.0 & RAMON BANK 1	2	288	MVA	100	120.22%	69.36%
21309	AVE42	92	21408	SHAHILLS	92	1	21	212	TPL_P7_L021	Line AVE58 92kV to JEFFERSON 92kV & AVE58 92kV to AVE49 92kV	2	288	MVA	100	120.21%	65.96%
21279	CVSUB92	92	21312	COACHELLASW	92	1	21	212	TPL_P6_L538	Line CV 92.0 to CSS 92.0 & CV to NEW JACKSON	2	178	MVA	100	113.51%	112.45%
21279	CVSUB92	92	21312	COACHELLASW	92	2	21	212	TPL_P6_L525	Line CV 92.0 to CSS 92.0 & CV to NEW JACKSON	2	178	MVA	100	113.36%	112.30%
21279	CVSUB92	92	21312	COACHELLASW	92	1	21	212	TPL_P6_L546	Line CV 92.0 to CSS 92.0 & RAMON BANK 1	2	178	MVA	100	107.11%	106.02%
21279	CVSUB92	92	21312	COACHELLASW	92	2	21	212	TPL_P6_L533	Line CV 92.0 to CSS 92.0 & RAMON BANK 1	2	178	MVA	100	106.99%	105.88%
21355	NEW_MECCA	92	21457	CLGRNTAP	92	1	21	212	TPL_P6_L451	Line AVE58 161.0 to CV 161.0 & CV BANK 3	2	145	MVA	100	100.56%	100.39%
21355	NEW_MECCA	92	21457	CLGRNTAP	92	1	21	212	TPL_P6_L524	Line CV 92.0 to CSS 92.0 & CV to CSS	2	145	MVA	100	100.26%	100.19%
21355	NEW_MECCA	92	21457	CLGRNTAP	92	1	21	212	TPL_P7_L020	Line CVSUB92 to COACHELLASW 92kV & CVSUB92 92kV to COACHELLASW 92kV CK1/CK2	2	145	MVA	100	100.28%	100.19%

Transient stability analysis is a time-based simulation that assesses the performance of the power system shortly before, during, and after a contingency. Transient stability studies were performed on the peak summer base cases to verify the stability of the system following a three phase system fault.

Transient stability analysis was performed using General Electric's PSLF software. The results were compared against WECC Disturbance-Performance Criteria for the most severe system contingencies. Transient stability contingencies were simulated for 10 seconds, excluding one second of pre-disturbance data. All simulated faults, unless specified, were assumed to be three-phase with a four cycle breaker clearing time. System damping was viewed in stability plots.

Selected critical contingencies listed below were simulated. These contingencies included the most severe internal as well as external contingencies.

- Ave58 161kV Bus Fault
- Transformer Ave58 and Coachella SS Bus Fault

- El Centro SS 161kV Bus Fault
- Coachella SW 92kV Bus Fault
- Colorado River RAS Bus Fault
- El Centro Bank #4
- Midway 230kV Bus Fault
- Transformer Ramon 92kV to Ramon 230kV Circuit 1
- Transformer Ramon 92kV and Coachella SS Bus Fault
- Transformer Ramon 92kV and Niland Bus Fault
- El Centro Bus 92V Double Bus Fault
- El Centro Bus 92kV Single Bus Fault
- El Centro Steam #2 (ELSTM 2 & REPU 2)
- KNKS and Ramon Bank

Line Faults

- Midway Tap 92kV to Midway 92kV Circuit 1 Line Fault
- El Centro Steam Plant 92kV to Mall 92kV Circuit 1 Line Fault
- Midway to Coachella Valley Substation 230kV “KN” Circuit 1 Line Fault
- KNKS N-2 Line Fault

External Line Faults

- Hassayampa to North Gila 500kV Line Fault (Hang 2)
- Imperial Valley to ECO 500kV Line Fault
- Imperial Valley to North Gila 500kV Line Fault
- ECO to Miguel 500kV Line Fault
- Hassayampa to Hoodoowash 500kV Line Fault
- Colordao River to Redbluff 500kV Line Fault
- Palo Verde to Colorado River 500kV Line Fault

The following are some of the parameters that were plotted on the stability plots:

- Bus Voltage:
  Bus voltage plots provide a means of detecting out-of-step conditions and are useful to assess the magnitude and duration of post disturbance voltage dips and peak-to-peak voltage oscillations. The voltage plots also indicate system damping response and the expected bus voltage following the disturbance.
- Bus Frequency:
  Bus frequency plots provide expected magnitude and duration of post-disturbance frequency swings as well as indicating possible over-frequency or under-frequency conditions.

Six critical buses which provide a representative illustration of the transmission system performance following each of the critical outages studied were monitored. The monitored buses included:

- El Centro SW 230kV
- Ramon 230 kV
- Coachella Valley Substation 230 kV

- Ave58 161kV
- Niland 161 kV
- Yucca 161kV

Voltage Criteria for Steady State, Post-Contingency and Stability

- WECC Criterion TPL-001-WECC-CRT-3.1, WR1 specifies that bus voltages stay within 0.95 and 1.05 per unit under normal operating conditions (P0) and within 0.9 and 1.1 per unit under emergency operating conditions (P1-P7).
- Voltage deviations for all voltage levels should not exceed 5percent under single contingencies, and 10 percent under multiple contingencies.
- Voltage stability is required at 105 percent of load levels for P0 and P1 and 102.5 percent of load level for P2-P7. The system must have positive reactive power margin (VAR margin) for single and multiple contingencies at the above load levels respectively. The minimum reactive power margin at any bus following an N-1 outage is 100MVAr while for N-2 outages any bus must demonstrate a positive margin greater than 50MVAr.

Following fault clearing, the voltage for P1-P7 levels shall recover to 80 percent of the pre-contingency voltage within 20 seconds of the initiating event for BES buses serving load for all P1-P7 events.[6] Following fault clearing and voltage recovery above 80 percent, voltage at each applicable bus serving load shall neither dip below 70 percent of pre-contingency voltage for more than 30 cycles nor remain below 80 percent of pre-contingency voltage for more than two seconds for P1-P7 level.

Instability Criteria

The WECC Criterion TPL-001-WECC-CRT-3.1 requirement WR4 was used to identify system instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. Key indicators are:

- When a post contingency analysis results in steady-state facility loading that is either in excess of a known BES facility trip setting, or exceeds 125 percent of the highest seasonal facility rating for the BES facility studied. If the trip setting is known to be different than the 125 percent threshold, the known setting should be used.
- When either unrestrained successive load loss occurs or unrestrained successive generation loss occurs.

Stability simulations that did not show positive damping within 30-seconds after start of the simulation were deemed unstable.

Results for Events for P1 through P7

The stability studies performed for this Annual Planning assessment included the P1 through P7 events and were analyzed with the contingencies.

The following requirements were used in this study:

- For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.
- For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.
- For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.
- For planning events P1 through P7: An Element where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance.
    - The IID did not identified any element in this Annual Planning Assessment where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance.
    - For planning events P1 through P7: Generation Facilities with Reliability Impact in the planning horizon of more than one year. IID did not identified any IID generation facility in this Annual Planning assessment that can cause adverse reliability impact in the planning horizon of more than one year.

The requirements noted above were met for all stability simulations that were performed. This was verified manually by analyzing plot files representing the simulations and by checking the log files for each simulation. All simulations produced stable, positively damped results and did not result in cascading. No contingencies resulted in non-consequential load loss.

Stability studies were also performed to assess the impact of the extreme events, using the extreme contingencies. All events simulated met the criteria established.

Post-transient stability analysis

The analysis was performed on selected buses in the IID transmission system following selected most severe critical outages. Governor power flow tools were used for the analysis. For each bus assessed, a synchronous condenser was modeled to determine the highest reactive power margin available on that bus.

The following outages were simulated:

- North La Quinta – Ave42 92kV line outage
- Imperial Valley – El Centro SS 230kV line outage
- Ramon – Mirage 230kV line outage
- Coachella Valley – Mirage 230kV line outage
- El Centro Steam Plant Unit 2 outage
- El Centro SS – Mall 92kV line outage
- El Centro SS 230:92 Bank 4 outage
- Ramon 230:92 Bank outage
- Midway – Coachella Valley Circuit 1 outage

- Ave58 – Jefferson & Ave58 – Ave48 outage
- El Centro SS – Ave58 & Ave58 – Coachella Valley outage
- Coachella Valley – Mirage & Coachella Valley Ramon outage
- Imperial Valley – ECO 500kV line outage
- Imperial Valley – Ocotillo 500kV line outage
- Palo Verde – Colorado River 500kV line outage
- Hoodoo Wash – North Gila 500kV line outage
- North Gila – Imperial Valley 500kV line outage
- Devers – Redbluff 500kV line outage
- Colorado River – Redbluff 500kV line outage
- Hassayampa – Hoodoo Wash 500kV line outage
- ECO – Miguel 500kV line outage
- Hassayampa – North Gila 500kV line outage

The monitored buses included:

- El Centro SW 230kV
- Ramon 230kV
- Coachella Valley Substation 230 kV
- Avenue 58 161kV
- Coachella Valley 161 kV
- Niland 92 kV
- Pilot Knob 161kV
- Ave42 92kV
- Midway 92 kV
- Calexico 92 kV
- Coachella Valley Substation 161kV

For post-transient stability, positive reactive margin is desired at all buses. For IID transmission system the post-transient stability analysis criteria are:

Minimum reactive power margin at any bus following N-1 outage is 100 MVAR

Minimum reactive power margin at any bus following N-2 outage is 50 MVAR

The results indicated that IID system has positive reactive power margin and meets the above criteria for all the above outages.

Short Circuit Analysis Results

Short circuit analysis was performed to determine the maximum fault duty on IID substation breakers. The Aspen program was used to conduct the short circuit analysis as described below.

Fault duties were calculated for single phase to ground, double phase to ground, and three phase faults at all IID transmission substations. The total fault current was compared against the circuit breaker's interrupting capability to determine whether or not the fault interrupting capability is exceeded.

The IID annually reviews the previously identified Corrective Action Plans and their timing. This review is performed by performing the short circuit analysis for any of the cases identified for this Annual Planning Assessment where:

- There have been significant changes in the load levels, generation patterns or interchanges relative to the last annual assessment, AND Transient & Post Transient Stability Analysis Results

- Corrective Action Plans were identified or could be identified for those cases due to the changed assumptions.

Due to changes in the methodology used to perform short circuit analysis several circuit breakers have been identified as being potentially over-burdened under fault conditions. Those corresponding circuit breakers will be replaced.

Long Term Transmission Assessment (2027)

Steady State Analysis Results

Steady state analysis for the 10-year assessment was performed exactly in the same manner as for the five-year assessment. All identified system problems were mitigated through the five-year assessment recommendation plan and though some additional recommendations.

Steady state analysis provides thermal and voltage performance of the system under normal as well as under emergency (contingency) conditions. This analysis was conducted on the following 10-year steady state base cases:

2027 Heavy Summer

Thermal and voltage performance of the system was evaluated for all three base cases under normal (P0), single element outage (P1, P2) and selected multiple element outages (P3-P7). Thermal loadings were reported when a modeled transmission component was loaded above 95 percent of its continuous MVA rating (P0) and above 95 percent of its emergency rating (P1-P7). Generally, the concerns are raised when an element is found loaded above 100 percent of its normal or emergency rating, however, 95 percent was chosen to identify circuits that are also at the edge of an overload. Such circuits need to be closely monitored and can be placed as potential candidates for future upgrades.

Transmission voltage violations for normal (P0) conditions were reported when per unit voltages were less than 0.95 or greater than 1.05. Transmission voltage violations following single or multiple outages were reported when per unit voltages were less than 0.90 or greater than 1.1. Additionally, voltage deviations were recorded whenever these deviations were greater than 5 percent for single contingencies and 10 percent for multiple contingencies.

The steady state study results for the case is described below:

2027 Heavy Summer:

Voltage Performance:

No buses in the heavy summer base cases experienced voltage deviation exceedances with respect to the voltage criteria table above.

Voltage Deviation:

No buses in the heavy summer base cases experienced voltage deviation exceedances with respect to the voltage criteria table above.

Voltage Phase Angle Violations:

Few voltage angle exceedances occurred in the heavy summer base case under contingency. The exceedances can be mitigated by the curtailment of generation before the line is tested to close. IID is normally limited to 25° closing angles. In order to clear these violations the mitigation to curtail generation at the Anza substation was made.

Internal Contingency Closing Angle Violations

HS 2027 Closing Angle Violations											
FROM NO.	FROM NAME	FROM KV	TO NO.	TO NAME	TO KV	CK ID	AREA	ZONE	CONTINGENCY IDENTIFIER	CONTINGENCY DESCRIPTION	27HS-TPL
21377	RTP3ANZA	92	21378	RTP4SLTN	92	1	21	213	TPL_P2.1_O003	ANZA to SALTON CITY	37.551
21378	RTP4SLTN	92	21379	RTP5DSTS	92	1	21	213	TPL_P2.1_O004	SALTON CITY to DESERT SHORES	34.93
21281	AVE58	92	21380	RTP6OASS	92	1	21	212	SB_P2.3_052	21281 AVE58 [CKTB RSWO] 92.00	28.219
21377	RTP3ANZA	92	21378	RTP4SLTN	92	1	21	213	BF_P2.2_019	21377 RTP3ANZA 92.00	27.31
21387	IPP-73B1	34.5	21386	IPP-73G	0.38	1	21	213	TPL_P6_L003	Line CVSUB230 230.0 to MIRAGE 230.0 & RAMON to MIRAGE	25.63

Thermal Performance:

With a category P6 outage, certain actions are allowed to mitigate it; therefore, no thermal impacts occurred during the Heavy Summer base cases. In order to clear this violation the mitigation to turn off certain generation was made.

Internal Contingency Thermal Violations

HS 2027 Thermal Violations																
FROM NO.	FROM NAME	FROM KV	TO NO.	TO NAME	TO KV	CK ID	AREA	ZONE	CONTINGENCY IDENTIFIER	CONTINGENCY DESCRIPTION	RATING NUMBER USED	RATING VALUE USED	RATING UNIT	% OVERLOAD USED	27HS-TPL	Delta Flow
21255	NEW_MECC	92	21457	CLSRNTAP	92	1	21	212	TPL_P6_L230	Line ECS 230.0 to IV 230.0 & ECS to AVE58	2	143	MVA	100	101.3%	-0.139
21255	NEW_MECC	92	21457	CLSRNTAP	92	1	21	212	TPL_P6_L229	Line ECS 230.0 to IV 230.0 & NILAND to BLYTHE	2	143	MVA	100	101.2%	-0.138
21255	NEW_MECC	92	21457	CLSRNTAP	92	1	21	212	TPL_P7_L020	Line CVSUB92 to COACHELLASW 92kV & CVSUB92 92kV to COACHELLASW 92kV CK1/CK2	2	143	MVA	100	101.0%	-0.136
21255	NEW_MECC	92	21457	CLSRNTAP	92	1	21	212	TPL_P6_L451	Line AVE58 161.0 to CV 161.0 & CV BANK 3	2	143	MVA	100	100.4%	-0.13

Transient & Post Transient Stability Analysis Results

An operating procedure was already proposed under the five-year plan.

Post-transient stability analysis

The same outages and monitored buses were utilized as in the five-year plan.

For post-transient stability, positive reactive margin is desired at all buses. For IID transmission system the post-transient stability analysis criteria are:

Minimum reactive power margin at any bus following N-1 outage is 100 MVAR

Minimum reactive power margin at any bus following N-2 outage is 50 MVAR

The results indicated that IID system has positive reactive power margin and meets the criteria for all outages.

Summary of Transmission Studies

The study did identify necessary system improvements in order to comply with the established criteria mentioned above which acts as a gauge for system resiliency. This analysis indicated that some of the previously identified system upgrades are still required to meet the applicable criteria based on the current forecasted state of the IID electric grid. A summary of the corrective action plans that will be used to address all issues discovered in the analysis can be found in the following table:

Corrective Action Plans

TIME FRAME	CASE TYPE	EVENT	SYSTEM DEFICIENCY	IMPACTED ELEMENTS	CORR. ACTION PLANS	EXPECT. IN-SERVICE DATE
2018-2019 Light Winter	Sensitivity	P7: CV - Mirage & CV -Ramon	Various Thermal and Voltage Violations	230:92kV Ramon Transformer, 92kV CI-line, CL-line, CA-line and CE-line	Path 42 RAS	2020
2019 Heavy Summer	Base	97: 92kV CD (Ave58 - Jefferson) and CS	Thermal Violation	92kV CI-line (Shadow Hills – Ave42)	Re-conductor CI-line	2019

		(Ave58 – Ave48)				
2019 Heavy Summer	Sensitivity	P1: 92kV CL-line (CV – CSS)	Thermal Violation	92kV CN-line (Coachella Valley – CSS)	Re-conductor CN-line	2021
2019 Heavy Summer	Sensitivity	P1: 92kV CN-line (CV – CSS)	Various Thermal & Voltage Violations	92kV CL-line (Coachella Valley – CSS)	Re-conductor CL-line	2021
2017 Heavy Summer	Base	Extreme: Loss of ECSS 92kV (double breaker substation)	Voltage Collapse	Imperial Valley Substations	Split the North and South bus at ECSS 92kV	2019
2017 Heavy Summer	Base	Short Circuit Simulations	Overburdened Circuit Breakers	Imperial Valley Substations	Breaker Replacement	2022

Future Economic based projects

IID is working with neighboring utilities and companies to explore new transmission projects to increase its exposure, to further strengthen its transmission system through additional tie lines, and to find opportunities to export highly economical renewable energy to neighboring areas.

Path 42 RAS

IID is currently assessing a Remedial Action Scheme (RAS) that is designed to increase the possible flow on Path 42, which consists of the 230kV KN and KS lines between IID (Coachella Valley and Ramon substations) and Southern California Edison (Mirage substation). The RAS is expected to allow export to increase from the currently accepted Path rating of 600 MW to over 1,200 MW. Once the installation of the RAS is complete IID would still have to follow the WECC path rating process to determine a new accepted rating.

Cost estimate: $4.5 Million

Estimated in-service date: 2020

North Gila – Imperial Valley 2 Transmission Line

IID is currently exploring the possibilities of participating in the North Gila – Imperial Valley 2 project. This project would allow IID to take advantage of its 20 percent share on the HANG2 line as well as provide additional reliability benefits. This project would most likely increase the allowable flow on HANG2 from 500,MW to over 1,000 MW which would allow IID to move over 200 MW through HANG2.

Cost estimate: $30 million - $65 million, depending on participation percentage and final construction path

Estimated in-service date: 2021

IID – CFE Transmission line

IID and CFE /CENACE (Mexico) are engaged in exploring various transmission alternatives to interconnect the two systems for import / export opportunities. IID has a tremendous potential for solar, wind and geothermal energy. Studies are currently underway between the IID and CFE staff to select the best transmission option from technical and economical perspective.

Cost estimate: $50 million - $57 million, depending on configuration

Estimated in-service date: 2021

Summary of Distribution System Assessment

The Imperial Irrigation District is geographically situated in both the Imperial Valley area that covers the entire Imperial County as well as the Coachella Valley area that covers parts of Riverside County. Both areas of the IID system contain similar weather patterns but due to the large area of customer location diversity, IID considers how this aspect can factor into its overall distribution plans. As described in the POU IRP submission and Review guidelines under SB 350, below are the required areas that have been addressed in the Distribution related studies:

The IRP must include any discussion of any distribution system reliability concerns and measures to mitigate them over the planning horizon, including the following:

- Upgrades or enhancements to the distribution system, including those intended to reliably integrate distributed generation.
- Upgrades to communications and information technology intended to integrate demand side energy management.

Below are the result of the IID engineering studies that were driven by regular planning activities as well as SB 350

Coachella Valley

The distribution group determined three categories of need:

1. Reliability – Projects that are needed to maintain system reliability
2. Cannabis – Projects that are based on customer interconnections for large industrial producers of cannabis located in the IID system
3. New Development – Projects that depend on load growth

The following are the site specific projects that were identified in these studies:

Ave 52 2nd Bank (2019)

- ***Location.- Avenue 52, City of Coachella***
- ***Description. -*** *Establish new circuit from Avenue 52 Substation (proposed) 2nd Bank*
- ***Driver.-*** *This new circuit will help serve growth in the Coachella Industrial Park.*
- ***Cost.- $4.3*** *million*
- ***92 KV lines in the vicinity.- Avenue 52, "K" Line***

Cannabis #1 (2019)

- ***Location.- In Date Palm Business Park;*** *Along Harrison Street, N/O 49th Avenue, S/O Khadram Way (Parcel 7)*
- ***Description. -*** *(2) 40 MVA Transformer Bank with associated Equipment. Provisions and space for a future third bank. Scope includes construction of the entire substation.*
- ***Driver.-*** *City of Coachella's MW Zone, high-density cultivation load.* Up to 245 MW of electrical load: Date Palm Business Park (58 MW), *Coachella Grow Association (12 MW), Moreles (6 MW), Garcia (6 MW), CTI (5 MW), Del Gro (15 MW), Desert Rock (65MW), Kismet Organics (8 MW), Bejarano (8 MW), De Leon (3 MW), Duran (4 MW), Coachella Grow Corp (15 MW), Green Leaf (40 MW)*
- ***Cost - $9.6*** *million*
- ***92 KV lines in the vicinity.- "CL" Line, New 230 KV Line Required***

Bermuda Dunes (2019)

- ***Location -*** *N/O Fred Waring Drive & Dune Palms Road, W/O Old Harbor Drive, in the Bermuda Dunes Country Club.*
- ***Description -*** *(1) 25 MVA Transformer Bank with associated Equipment. Scope includes construction of the entire substation.*
- ***Driver - third*** *bank will alleviate capacity issues at North La Quinta and Shields substations.*
- ***Cost - $5.6*** *million*
- ***92 KV lines in the vicinity - "CD" Line***

CannaNevada (2019)

- ***Location - Avenue 54 and Polk Street, City of Coachella***
- ***Description*** *– Initial phase: (1) 40 MVA Transformer, with associated equipment.*

- ***Driver** - CannaNevada's request for up to 100 MW of high-density cultivation load.*
- ***Cost - $9.6** million*
- ***92 KV lines in the vicinity - "CW", "K" Lines***

North Gate (2020)

- ***Location.- S/S Indio Boulevard, between Country club Dr. and Burr Street, in the City of Indio***
- ***Description** - Initial phase; (1) 25 MVA Transformer, (4) Distribution Breakers with associated equipment and in/out transmission line arrangement.*
- ***Driver** - An 80-acre shopping center. This project consists of several three phase services that include a hotel, various apartment complexes, a gas station and multiple retail buildings also this new substation will serve undeveloped land in the "Bermuda Dunes" area.*
- ***Cost - $5.6** million*
- ***92 KV lines in the vicinity - "CS" Line***

Marshall 3rd Bank (2020)

- ***Location** - Washington St E/S & 1200' S/O Ave 50*
- ***Description** – third Transformer Bank addition; (1) 25 MVA with associated Equipment. Scope includes new land acquisition and distribution Breakers bay construction.*
- ***Driver** - Marshall Substation is at capacity, alternate feed La Quinta Substation has insufficient capacity to support additional load from Marshall Substation. Adding Bank 3 will reduce capacity constraints at Marshall and La Quinta substations.*
- ***Cost - $5.6** million*
- ***92 KV lines in the vicinity - "CD" Line***

New Dillon (2020)

- ***Location - TBD. Preferable location it is been identified along Dillon road, approximately 2.0 to 3.0 miles N/O Ave. 44. In the Riverside County***
- ***Description** - Initial phase; (1) 25 MVA Transformer, (4) Distribution Breakers with associated equipment and Single Tap transmission line arrangement.*
- ***Driver** - Existing Dillon Substation was built in temporary basis made out of wood and is sat on leased land. It consist of (2) transformers (11,200 and 10,000 KVA) and (2) Distribution breakers. Development in the area has been increased mainly in the rock crushing industry.*
- ***Cost - $5.6** million*
- ***92 KV lines in the vicinity - "CM" line***

Carreon 2nd Bank (2021)

- ***Location - Monroe Street and Dr. Carreon Blvd. in the City of Indio Ca.***
- ***Description -*** *second Transformer Bank addition; (1) 25 MVA with associated Equipment. Scope includes distribution Breakers bay construction.*
- ***Driver -*** *This substation is located in the Central part of the city of Indio, serving a large diversity of load including Hospitals and medical buildings, schools ,retail buildings as well as residential. Neighboring substations are equally loaded and require firm back up support during emergency conditions. Bank #1 is already 60 percent of its capacity*
- ***Cost - $4*** *million*
- ***92 KV lines in the vicinity - "CW" line***

La Entrada West (2021)

- ***Location - (preferred) Approximately 1.25 Mi. S/O I-10, 1.0 Mi. E/O All American Canal between Ave. 50 & Ave. 52 in the City Of Coachella Ca.***
- ***Description -*** *(2) 25 MVA Transformer Bank with associated Equipment. Scope includes construction of the entire substation.*
- ***Driver -*** *A 2,200 Ac. Development with multiple land use including residential of various densities, commercial, education, parks, open space and roadways. This development will require the implementation of a second substation scheduled for year 2022 in the IID 10 year plan*
- ***Cost - $9*** *million*
- ***92 KV lines in the vicinity - Coachella Valley Switching Station 92 KV Bus. New transmission Line(s) required.***

Cannabis #2 (2021)

- ***Location -*** *Along Harrison Street, N/O 48th Avenue (Lot 25)*
- ***Description -*** *(1) 300 MVA 230/92 kV and (2) 40 MVA 92/13.2 kV Transformer with associated Equipment. (10) Distribution Breakers with associated equipment and in/out transmission line arrangement. Provisions and space for a future third 40 MVA Transformer and (5) Distribution breakers. Scope includes construction of the entire substation*
- ***Driver -*** *City of Coachella's MW Zone, high-density cultivation load.* To serve the remainder of the 245MW of Electrical Load requested for the area.
- ***Cost - $10*** *million*
- ***92 KV lines in the vicinity - New 230 KV Line from Coachella Valley Switching Station***

Travertine (2021)

- ***Location - (preferred) at the corner of Avenue 62 and Madison Street alignment.***
- ***Description** - (2) 25 MVA Transformer Bank with associated Equipment. Scope includes construction of the entire substation.*
- ***Driver** - A Development with multiple land use including residential of various densities, commercial, parks, open space and roadways. Requested substation site provided by developer.*
- ***Cost - $9.6** million*
- ***92 KV lines in the vicinity - "R" Line. Closest Transmission line is "L" Line.***

Ave 44 (2022)

- ***Location - (preferred) Along the Transmission corridor S/S of Ave. 44 between Golf Center Parkway and Dillon Rd. in the City Of Coachella.***
- ***Description -** Initial phase; (1) 25 MVA Transformer Bank with associated equipment and in/out transmission line arrangement*
- ***Driver -** Grouped developers including "Fantasy Springs Casino" recently presented to IID plans for future commercial and residential projects in the area. Due to the lack of capacity, IID identified the need of a new substation.*
- ***Cost - $5.6** million*
- ***92 KV lines in the vicinity - "CI", "CM" Lines***

Mecca 2nd Bank (2022)

- ***Location - Ave 68 and Johnson Street in the Community of Mecca Riv. Co.***
- ***Description** - Second Transformer Bank addition; (1) 25 MVA with associated Equipment. Scope includes distribution Breakers bay construction.*
- ***Driver -** Through the years, Mecca area has experienced mainly agricultural load growth and few light industrial (packing Sheds). Presently, circuits are spread out with large exposure. Existing transformer was installed in year 2006 and presently it is close to 60 percent of its capacity.*
- ***Cost - $4** million*
- ***92 KV lines in the vicinity - "K" Line***

Frances Way 2nd Bank (2022)

- ***Location - Washington Street and Frances way in the City of Palm Desert Ca.***
- ***Description*** *- Second Transformer Bank addition; (1) 25 MVA with associated Equipment. Scope includes distribution Breakers bay construction.*
- ***Driver -*** *Through the years, this area has experienced a large addition of light industrial load. Adjacent North View Substation Banks (2-25 MVA) are slightly close to their 80 percent capacity. Addition of this bank will provide back up support to the already loaded circuits in the neighborhood. Existing transformer was installed in the year 1999 and presently it is close to 60 percent of its capacity*
- ***Cost - $4*** *million*
- ***92 KV lines in the vicinity- "CE" line***

(Sec.19) Rancho Mirage (2022)

- ***Location.- TBD. Preferable location has been identified along the Miriam Way alignment, approximately 0.6 miles N/O Dinah Shore Drive. In Riverside County.***
- ***Description -*** *Initial phase; (1) 25 MVA Transformer, (4) Distribution Breakers with associated equipment and Single Tap transmission line arrangement.*
- ***Driver -*** *City planned Section 19 development is estimated as 20 MW in additional peak demand. The area is served by three circuits from Edom Substation with no backups for contingencies. Due to the lack of capacity in the Bob Hope Drive/Gerald Ford Drive/Monterey Avenue corridor, IID identified the need of a new substation*
- ***Cost - $5.6*** *million*
- ***92 KV lines in the vicinity - "CE" line***

Paradise Valley (2022)

- ***Location -*** *N/S of Interstate 10 between Coachella Valley and Chiriaco Summit*
- ***Description -*** *(2) 25 MVA Transformer Bank with associated Equipment. Scope includes construction of the entire substation.*
- ***Driver -*** *Paradise Valley Developers*
- ***Cost -*** *$12 million*
- ***92 KV lines in the vicinity - 92 KV Line extension required from Coachella Valley substation to Paradise Valley development.***

CannaNevada 2nd Bank (2022)

- ***Location - Avenue 54 and Polk Street, City of Coachella***
- ***Description -*** *Establish New circuit from CannaNevada Substation (proposed) 2nd Bank*
- ***Driver.-*** *This new circuit will help serve growth in the Coachella Industrial Park.*
- ***Cost - $10*** *million*
- ***92 KV lines in the vicinity - "CW", "K" Lines***

Jefferson 3rd Bank (2023)

- ***Location -*** *Ave 52 & ¼ mile E/O Jefferson Street*
- ***Description*** *– Third Transformer Bank addition; (1) 25 MVA with associated Equipment. Scope includes new land acquisition and distribution Breakers bay construction.*
- ***Driver -*** *Silver Rock, Beazer Homes,*
- ***Cos - $5.6*** *million*
- ***92 KV lines in the vicinity - "CD" Line***

(Ave.60 dev)Sta. Rosa (2023)

- ***Location.- Ave 58 & Jackson Street, Riv. Co.***
- ***Description. -*** *Initial phase; (1) 25 MVA Transformer, (4) Distribution Breakers with associated equipment and in/out transmission line arrangement.*
- ***Driver -*** *Service requests for several developments in the area adding up to at least 800 residences. IID has identify the need • of approximately 85 MVA to serve undeveloped land for Different use in the area.*
- ***Cost - $5.6*** *million*
- ***92 KV lines in the vicinity - "R" line***

New Oasis (2023)

- ***Location.-*** *Oasis Substation*
- ***Description*** *– Upgrade to (2) 25 MVA Transformers, (8) Distribution Breakers and associated equipment*
- ***Driver -*** *Load Growth*
- ***Cost -*** *$10 million*
- ***92 KV lines in the vicinity - "K" and "R" Lines***

Kohl Ranch (2024)

- ***Location -*** *W/O Avenue 64 and Polk Street*
- ***Description*** *- (1) 300 MVA 161/92 kV and (1) 40 MVA 92/13.2 kV Transformer with associated Equipment. (5) Distribution Breakers with associated equipment and in/out transmission line arrangement. Provisions and space for future second and third 40 MVA Transformers and (10) Distribution breakers. Scope includes construction of the entire substation.*
- ***Driver*** *- Kohl Ranch and Shea Homes Developments, approximately 30,200 homes, alternate Thermal Motorsports power source.*
- ***Cost - $12*** *million*
- ***92 KV lines in the vicinity - "R" Line***

Sky Valley 2nd Bank (2024)

- ***Location - Sky Valley substation***
- ***Description*** *- 2nd Transformer Bank addition; (1) 25 MVA with associated Equipment. Scope includes distribution Breakers bay construction.*
- ***Driver -*** *Load Growth*
- ***Cost*** *- $5.6 million*
- ***92 KV lines in the vicinity - "CM" Line***

New Thermal (2025)

- ***Location -*** *Avenue 56 and Polk Street*
- ***Description*** *– 2-25 MVA to replace the existing Thermal Substation*
- ***Driver -*** *Load growth*
- ***Cost - $7.6*** *million*
- ***92 KV lines in the vicinity - "K" Line***

Ave 54 (2026)

- ***Location -*** *Avenue 54 and Monroe Street*
- ***Description*** *– 2-25 MVA 92/ 13.2 kV with associated equipment.*
- ***Driver -*** *Load Growth*
- ***Cost*** *- $7.6 million*
- ***92 KV lines in the vicinity - "CS" Line***

La Entrada East (2027)

- ***Location - (preferred) Approximately 1.25 Mi. S/O I-10, 1.0 Mi. E/O All American Canal between Ave. 50 & Ave. 52 in the City Of Coachella Ca.***
- ***Description** - (2) 25 MVA Transformer Bank with associated Equipment. Scope includes construction of the entire substation.*
- ***Driver -** A 2,200 Ac. Development with multiple land use including residential of various densities, commercial, education, parks, open space and roadways. This the implementation of the second substation for the La Entrada Development.*
- ***Cost - $9.6** million*
- ***92 KV lines in the vicinity - Coachella Valley Switching Station 92 KV Bus. New transmission Line(s) required.***

N. La Quinta 3rd Bank (2027)

- ***Location -** SW corner of Westward Ho Drive & Adams Street*
- ***Description** - Third Transformer Bank addition; (1) 25 MVA with associated Equipment. Scope includes new land acquisition and distribution Breakers bay construction.*
- ***Driver - Third** Bank *will alleviate capacity issues at North La Quinta and Shields substations; provide additional capacity along Washington Street.*
- ***Cost - $5.6** million*
- ***92 KV lines in the vicinity - "CD" Line***

In summary, the following exhibit shows all projects and the reason for the projects:

Exhibit 129: Distribution Project Breakdown for Coachella Valley Area

Categorized Distribution Projects - Coachella Valley				
Substation / Transformer Bank	**Construction**	**Reason**	**Funding**	**Estimated. Cost**
Ave 52 2nd Bank	2019	Cannabis	CSP	$4.3M
Cannabis #1[1] (2-40 MVA)	2019	Cannabis	CSP	$9.6M
Bermuda Dunes[2] (1-25 MVA)	2019	Reliability	Capital	$5.6M
CannaNevada (1-40 MVA)	2019	Cannabis	CSP	$9.6M
North Gate[3]	2020	Development	CSP	$5.6M
Marshall 3rd Bank	2020	Reliability	Capital	$5.6M
New Dillon	2020	Reliability	Capital	$5.6M
Carreon 2nd Bank	2021	Reliability	Capital	$4.0M
La Entrada West	2021	Development	CSP	$9.0M
Cannabis #2	2021	Cannabis	CSP	$10.0M
Travertine	2021	Development	CSP	$9.6M
Ave 44	2022	Development	CSP	$5.6M
Mecca 2nd Bank	2022	Reliability	Capital	$4.0M
Frances Way 2nd Bank	2022	Reliability	Capital	$4.0M
(Sec.19/Ivey) **Rancho Mirage**	2022	Development	CSP	$5.6M
Paradise Valley #1	2022	Development	CSP	$12.0M
CannaNevada 2nd Bank	2022	Cannabis	CSP	$10.0M
Jefferson 3rd Bank	2023	Reliability	Capital	$5.6M
(Ave.60 Dev) **Santa Rosa**	2023	Development	CSP	$5.6M
New Oasis	2023	Reliability	Capital	$10.0M
Kohl Ranch	2024	Development	CSP	$12.0M
Sky Valley 2nd Bank	2024	Reliability	Capital	$5.6M
New Thermal	2025	Reliability	Capital	$7.6M
Ave 54	2026	Development	CSP	$7.6M
La Entrada East	2027	Development	CSP	$9.6M
N. La Quinta 3rd Bank	2027	Reliability	Capital	$5.6M

Notes:

1. *Cannabis cultivation substations are listed for completeness.*
2. *Bermuda Dunes was a previously active single-bank substation that served the area.*
3. *North Gate Substation will also provide significant reliability improvements for the Bermuda Dunes area.*

4. *Estimated cost does not include cost of land or right of way that may be required.*

IMPERIAL VALLEY

Below is a summary of the site-specific ssset information for the Imperial Valley Area:

New Kloke Distribution Substation (2018-2019)

- ***Location - W/S of Pruett Road at S/S of All American Canal in the City of Calexico***
- ***Description*** - Initial phase 2-25 MVA Substation Transformers with 8 – Distribution Feeders and associated equipment. Also provision for the 3rd Substation Transformer and additional 4 - Distribution Feeders.
- ***Driver -*** La Gran Plaza Complex, New port of entry, Cole road industrial park combined with increased Flexibility of the Distribution Grid at the Western Area of Calexico CA
- ***Cost - $***8.5 million
- ***92 KV lines in the vicinity -*** "ED" line between Pruett substation & Mall substation.

Victoria Ranch Distribution Substation (2019-2020)

- ***Location -*** W/S of Dogwood Road at N/S of Central Drain at Imperial County (future annexation to the City of El Centro).
- ***Description*** - Initial Phase of 1-25 MVA Substation Transformers with 4 – Distribution Feeders and associated equipment. Also Provision for the 2nd Substation Transformer and additional 4 - Distribution Feeders.
- ***Driver*** - *Victoria Ranch, Castlearch and Rancho Imperial projects. This substation will also increase flexibility and reliability to the N/E of El Centro and South of Imperial areas.*
- ***Cost - $***5.6 million
- ***92 KV lines in the vicinity -*** "J" line between ECSS and Rockwood Substation.

Luckey Ranch Distribution Substation (2020-2021)

- ***Location -*** On the W/S of the State Route 111 (SR-111), approximately 700 feet N/O the Intersection of SR-78 & SR-111 at Imperial County (future annexation to the City of Brawley CA).
- ***Description*** - Initial Phase of 1-25 MVA Substation Transformers with 4 – Distribution Feeders and associated equipment. Also Provision for the 2nd Substation Transformer and additional 4 - Distribution Feeders.
- ***Driver*** - Luckey Ranch, La Paloma and Rancho Porter developments combined with increased Flexibility and Reliability on the Distribution Grid on Eastern Area of Brawley CA.
- ***Cost - $***6 million
- ***92 KV lines in the vicinity -*** "J" Line between Brawley substation and Rockwood substation.

Diamante Distribution Substation (2021-2022)

- ***Location -*** On the S/W corner of Intersection Bowker Road & E. Jasper Road at Imperial County (future annexation to the City of Calexico CA).
- ***Description*** - Initial Phase of 1-25 MVA Substation Transformers with 4 – Distribution Feeders and associated equipment. Also Provision for the 2nd Substation Transformer and additional 4 - Distribution Feeders.
- ***Driver*** - Las Palmas, El portal, Santa Fe, and La Jolla Palms developments. This substation will also increase flexibility and reliability to the N/E of Calexico area.
- ***Cost – $***6.2 million
- ***92 KV lines in the vicinity*** - "P" Line between Perry substation and Heber Geothermal substation. Transmission Line Extension of approximately 8,000 feet

Anderson Distribution Substation (2022-2023)

- ***Location -*** In the vicinity of the rectangle comprised of Chick Road on the North, McCabe Road on the South, Pitzer Road on the West and SR-111 on the East. (Future annexation of the City of El Centro CA).
- ***Description*** - Initial Phase of 1-25 MVA Substation Transformers with 4 – Distribution Feeders and associated equipment. Also Provision for the 2nd Substation Transformer and additional 4 - Distribution Feeders.
- ***Driver -*** Waterford, Anderson and Commons Projects. This substation will also increase flexibility and reliability to the S/E of El Centro area.
- ***Cost - $***6 million
- ***92 KV lines in the vicinity -*** Existing "P' Line is installed in a North-South direction along Pitzer Road; this line is interconnected between Heber Geothermal Substation and ECSS

New Euclid Distribution Substation (2023-2024)

- ***Location -*** On the W/S of N. La Brucherie Road, approximately 700 feet N/O the Intersection of W. Adams Avenue & N. La Brucherie Road in the City of El Centro CA.
- ***Description -*** Remove 1-18 MVA and 1-14 MV Substation Transformers with 4 - Distribution Feeders from existing Euclid Substation, Replace with 2-25 MVA Substation Transformers with 8 – Distribution Feeders and associated equipment.
- ***Driver –*** Lerno-Verhaegen, Sky Ranch, La Fuente and West Main Mutual Water Projects. This substation will also increase flexibility and reliability to the West of El Centro area and S/W of Imperial area.
- ***Cost - $***8 million
- ***92 KV lines in the vicinity. -*** Existing "LU" Line connected to Euclid substation

La Paloma Distribution Substation (2024-2025)

- ***Location -*** In the vicinity of the rectangle comprised of Malan Street on the North, Best Canal on the South, Oakley Canal on the West and Old Hwy 111 on the East at Imperial County. (Future annexation of the City of Brawley CA).
- **Description -** Initial Phase of 1-25 MVA Substation Transformers with 4 – Distribution Feeders and associated equipment. Also Provision for the 2nd Substation Transformer and additional 4 - Distribution Feeders.
- **Driver -** La Paloma, Latigo Ranch, Malan Park and Brawley Gateway projects. This substation will also increase flexibility and reliability to the South of Brawley area.

- **Cost -** $6.2 million
- ***92 KV lines in the vicinity*** - Existing "J" Line is installed in a North-South direction along Old Hwy 111; this line is interconnected between Brawley Substation and Beef Plant Substation

Holtville II Distribution Substation (2025-2026)

- ***Location*** **-** In the vicinity of the rectangle comprised of Ash Main Canal on the North, Haven Road on the South, Anderholt Road on the West and Mets Road on the East at Imperial County. (Future annexation of the City of Holtville CA).
- ***Description*** - Initial Phase of 1-25 MVA Substation Transformers with 4 – Distribution Feeders and associated equipment. Also Provision for the 2nd Substation Transformer and additional 4 - Distribution Feeders.
- ***Driver*** **–** Tecolote Ranch I, II,II and Tecolote Ranch commercial shopping Center projects. This substation will also increase flexibility and reliability to the Holtville area.
- ***Cost - $***6.2 million
- ***92 KV lines in the vicinity*** **-** Existing "E" Line is installed on the N/E corner of Ash Main Canal & Mets Road intersection; this line is interconnected between Holtville Substation and ECSS.

Keystone Distribution Substation (2026-2027)

- ***Location*** **-** In the vicinity of the rectangle comprised of Keystone Road on the North, Harris Road on the South, Hwy 86 (N. Imperial Avenue) on the West and Rubber Drain One on the East at Imperial County.
- ***Description*** - Initial Phase of 1-25 MVA Substation Transformers with 4 – Distribution Feeders and associated equipment. Also Provision for the 2nd Substation Transformer and additional 4 - Distribution Feeders.
- ***Driver*** **–** Mesquite Lake, Brookfield and Benson projects. This substation will also increase flexibility and reliability to the North of Imperial and the south of Brawley areas.
- ***Cost*** - ***$***6.2 million
- ***92 KV lines in the vicinity*** **-** Existing "EO" Line is installed in a North-South direction on the E/S of the Railroad; this line is interconnected between Panno Substation and New Imperial Substation.

Barioni Lakes Distribution Substation (2027-2028)

- ***Location*** **-** In the vicinity of the rectangle comprised of Larsen Road on the North, Neckel Road on the South, Austin Road on the West and Hwy 86 on the East at Imperial County. (Future annexation of the City of Imperial CA).
- ***Description*** - Initial Phase of 1-25 MVA Substation Transformers with 4 – Distribution Feeders and associated equipment. Also Provision for the 2nd Substation Transformer and additional 4 - Distribution Feeders.
- ***Driver*** **–** Barioni, McMillan, Morinigstar and Drewery Farms projects. This substation will also increase flexibility and reliability to the North of Imperial area.
- ***Cost*** - ***$***6.2 million
- ***92 KV lines in the vicinity*** **-** Existing "EO" Line is installed in a North-South direction on the E/S of Hwy 86; this line is interconnected between Panno Substation and New Imperial Substation

In summary, the following exhibit shows all projects and the reason for the projects:

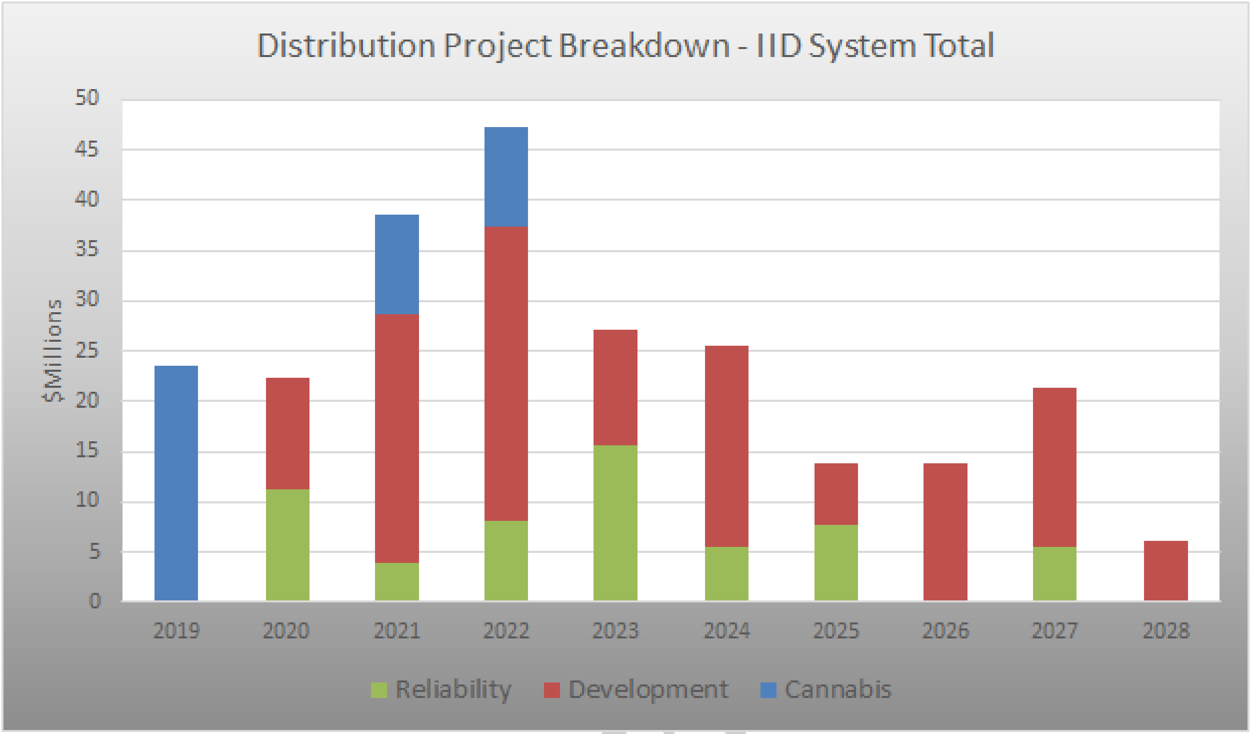
Exhibit 130: Distribution Project Breakdown for Imperial Valley Area

Categorized Distribution Projects - Imperial Valley						
Substation / Transformer Bank	**Budget**	**Year**	**Reason**	**Funding**	**Est. Cost**	**MVA**
Victoria Ranch	2019	2020	Development	CSP	$5.6M	25
Luckey Ranch	2020	2021	Development	CSP	$6.0M	25
Diamante	2021	2022	Development	CSP	$6.2M	25
Anderson	2022	2023	Development	CSP	$6.0M	25
New Euclid	2023	2024	Development	CSP	$8.0M	18
La Paloma	2024	2025	Development	CSP	$6.2M	25
Holtville II	2025	2026	Development	CSP	$6.2M	25
Keystone	2026	2027	Development	CSP	$6.2M	25
Barioni Lakes	2027	2028	Development	CSP	$6.2M	25

Note: Estimated cost does not include cost of land or right of way that may be required.

In summary, the following exhibit shows all projects and the reason for the projects:

Exhibit 131: IID System Area Distribution Project Cost Breakdown



Mitigations to Reliably Integrate Distributed Generation

From our experience with integrating distribution-level generation, mitigations have fallen into four general categories:

1. Minimal System Impact – Line extensions, Distribution Transformer upgrades, etc.
2. Voltage Issues at Customer Site – Adjusting Distribution Transformer taps, Secondary/Service upgrades, Customer Trouble (Lack of requisite demand, customer-side electrical issues).
3. Voltage/Reactive Power Issues on Feeder – Line upgrades, Capacitor Banks, etc.
4. Substation Transformer Bank Voltage Regulation Issues / Reverse Power Flow through Substation Transformer – Regulator Upgrades / Regulator Settings Adjustment.

Distribution Planning captures through studies and assessments, any potential substations or distribution feeders' issues before allowing generation to interconnect. The consistent source of voltage issues occurring after distributed generation is connected are often due to the customer reducing their load significantly below for which their generator was sized to support.

SCADA Deployment

The deployment of SCADA in areas served by non-remote-operable distribution substations will facilitate better data acquisition, service restoration times and system reliability. Distribution Planning has a program to facilitate this deployment.

Distribution Costs to Address Electric Transportation

As most of the electric transportation, being installed is commercial, typical line extension and impact-related upgrades apply. The average cost for service to a commercial charger is $5,600. The potential loading of the service and secondary conductors must be lower than rated capacity for public safety and service reliability.

For planning purposes, IID has conducted numerous studies to evaluate the value of adding and/or retiring generation facilities. The key elements to be discussed in this section for these resource addition studies are as follows:

MODELING RESULTS: ECONOMIC COMPARISON AND ENVIRONMENTAL COMPLIANCE

Below is a discussion on the numerous sets of economic modeling studies performed to determine the most optimal resource expansion plan. In summary below are the key studies performed for this IRP:

1. Retirement and unit addition studies to narrow down resource options:
   a. This study was used to determine several sets of assumptions for the subsequent studies as well as eliminate obvious outliers that are not needed for further studies.
2. RPS and Cap and Trade resource addition studies:
   a. These studies were used to further examine new resources and further eliminate other outliers that do not meet criterion for reliability, economics and regulatory compliance.
3. Reliability assessment of the need for ancillary services offered by energy storage:
   a. This study was used to determine the minimum size of an energy storage project to be compared to some of the remaining conventional generation resources.
4. Additional Studies to Address Resource Needs.
   a. These additional studies addressed additional questions to resource retirements and the current cost of fixed and variable O&M; additional eliminations of alternatives occurred.
5. Black and Veatch/Atonix Energy Storage Study:
   a. This study was used to observe greater details and risks of energy storage projects and how they integrate with RPS/C&T and other resource requirements.
6. Transmission expansion studies:
   a. This study was used to determine the feasibility of various proposed transmission expansion plan and their value to the resource supply stack.
7. IRP Rate Impact Evaluation:
   a. This study was used to determine how the combination of the various energy detertment activities may or may not require rate increases above and beyond the standard inflationary increases.

1. RETIREMENT AND UNIT ADDITION STUDIES

METHODOLOGY AND KEY ASSUMPTIONS

The following are the key assumptions used for this study:

- Evaluated nine alternatives that provide quick responding generation
- Evaluated costs with hourly dispatch simulation Planning and Risk production cost model

- Studied multiple scenarios for each of the nine alternative cases:
  1. No EIM economic market sales
  2. With EIM economic market sales
  3. Shutdown Coachella + Rockwood in 2021 No EIM
  4. Shutdown Coachella + Rockwood in 2021 with EIM
  5. Shutdown Coachella + Rockwood + Yucca in 2021 With EIM
  6. Shutdown Coachella + Rockwood + Yucca in 2021 No EIM
  7. Shutdown Yucca in 2021 With EIM
  8. Shutdown Yucca in 2021 No EIM

A total of 324 iterations were studied of possible market outcomes between gas, energy and emissions in both 25 and 40 year studies.

- Met RPS standard under current law
- 2018 Load Forecast used
- Spring 2018 low/med/high pricing forecast used
- IID financing interest rate: 5 percent
- 100 MW capacity addition in all cases

The next exhibit illustrates the various cases and scenarios studied:

Exhibit 132: Cases and Scenarios of the Resource Addition Studies

Resource Addition Analysis: Simulation of Quick Responding Generation, PPAs and Mkt Sales		
Case	Description	Scenarios ran for each Case
1. Baseline Run -No New Additions	Test the current operations with no new additionts for each scenario	**1.** No EIM economic market sales; **2.** With EIM economic market sales; **3.** Shutdown Coachella + Rockwood in 2021 No EIM; **4.** Shutdown Coachella + Rockwood in 2021 With EIM; **5.** Shutdown Coachella + Rockwood + Yucca in 2021 With EIM; **6.** Shutdown Coachella + Rockwood + Yucca in 2021 No EIM; **7.** Shutdown Yucca in 2021 With EIM; **8.** Shutdown Yucca in 2021 No EIM
2. Alta Power Added	Test the various offers from Alta Power in each scenario	
3. Wartzilla Resource Added	Test an internally owned and operated Wartzilla Engine in each scenario	
4. Recipricating Engines Added	Test an internally owned and operated Reciprocating Engine in each scenario	
5. EC#4 Repowered	Test an internally owned and operated repowered EC#4 in each scenario	
6. Coachella Adjustments	Test how enhancements to Coach would provide value for operations in each scenario	
7. LM6000 Added	Test an internally owned and operated LM6000 in each scenario	
8. LMS100 Added	Test an internally owned and operated LMS100 in each scenario	
9. TEP Gila River PPA	Test an offer received from TEP for a portion of the Gila River Project	

The Exhibit below describes how the varying types of resources can be costly in the initial capital investment and less expensive in operation, whereas others can be less expensive in the initial investment and higher in cost during operations:

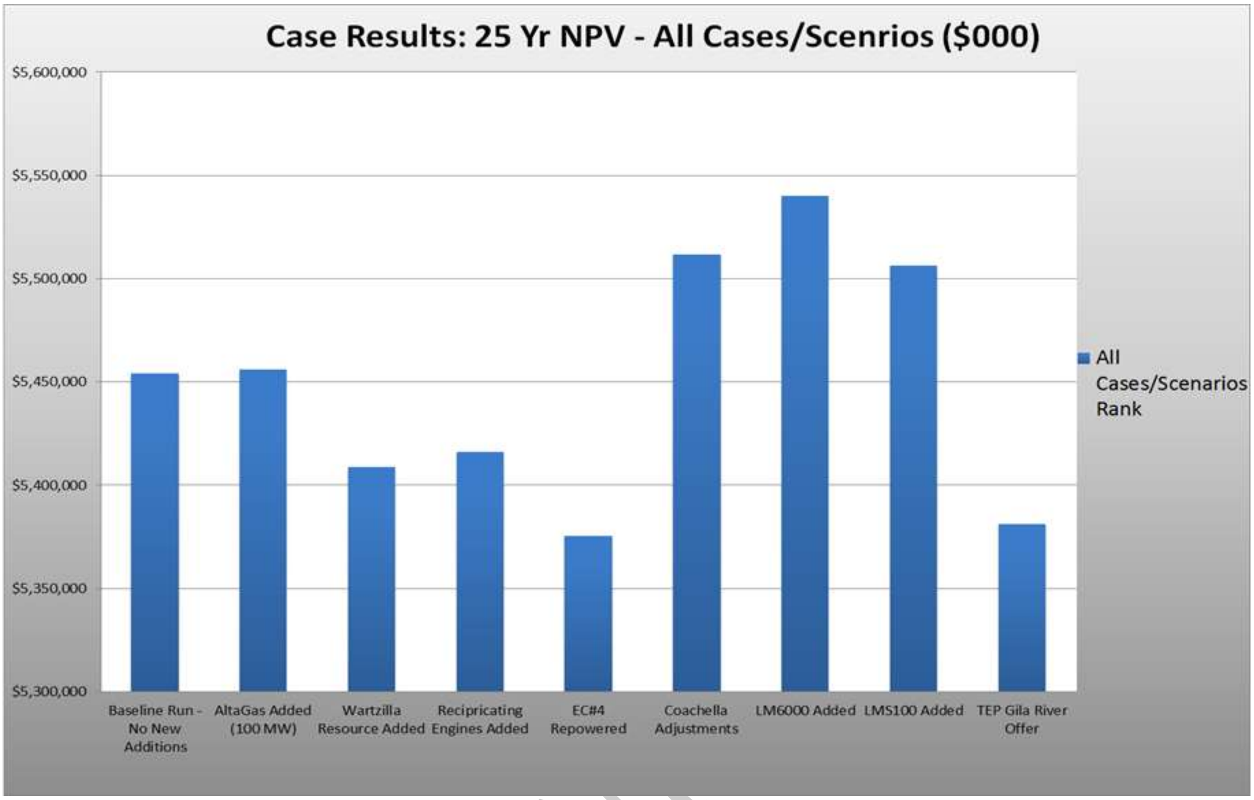
Exhibit 133: Fixed costs vs Variable costs

Fixed Costs Added vs Variable Costs in Tested Resources				
Case #	Case	Annual fixed Costs Added	HHV Heat Rate	$/MWh @ $5 gas price
1	Baseline Run -No New Additions	Current	Current	Current
2	Alta Power Added (100 MW)	$ 18,000,000	6,400	$ 32.00
3	Wartzilla Resource Added	$ 7,840,000	8,400	$ 42.00
4	Recipricating Engines Added	$ 8,200,000	8,241	$ 41.21
5	EC#4 Repowered	$ 13,480,000	7,382	$ 36.91
6	Coachella Adjustments	$ 568,000	12,000	$ 60.00
7	LM6000 Added	$ 12,500,000	9,772	$ 48.86
8	LMS100 Added	$ 11,700,000	9,000	$ 45.00
9	TEP Gila River Offer	$ 11,400,000	7,150	$ 35.75

Essentially, the hourly dispatch model captures the value difference of the high capital cost and low heat rate vs the low capital cost and high heat rate since the degree of dispatch is based on variable economics.

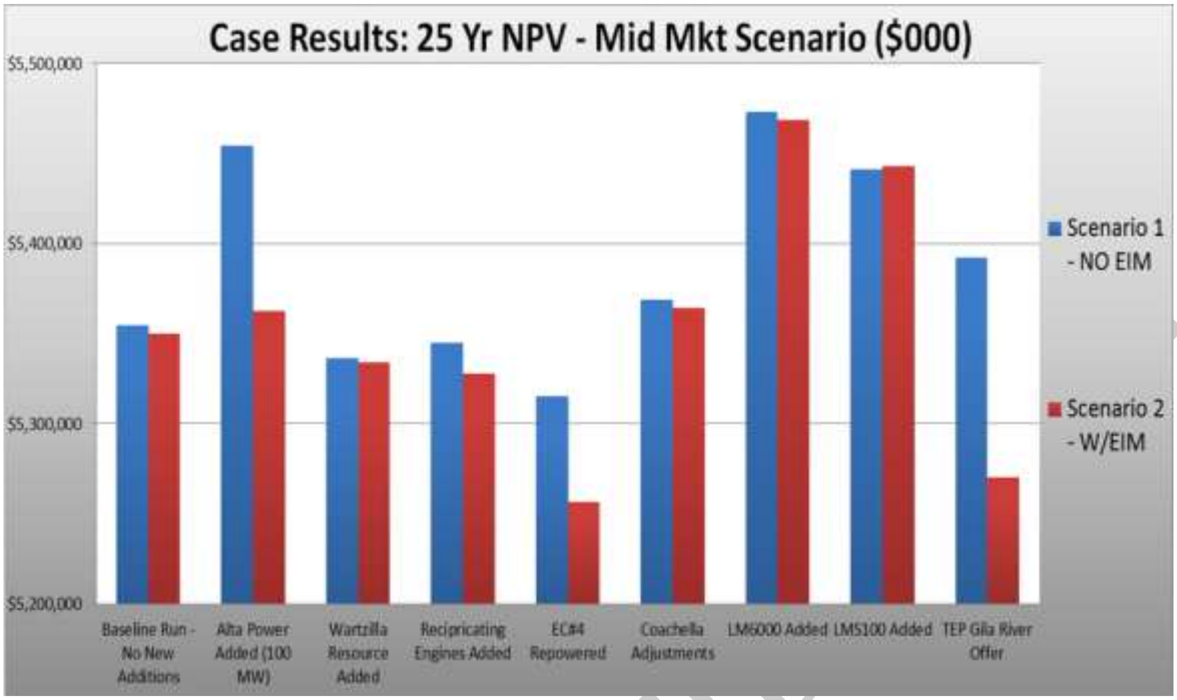
Below are the results in the expected case:

Exhibit 134: Expected Case of Resource Additions



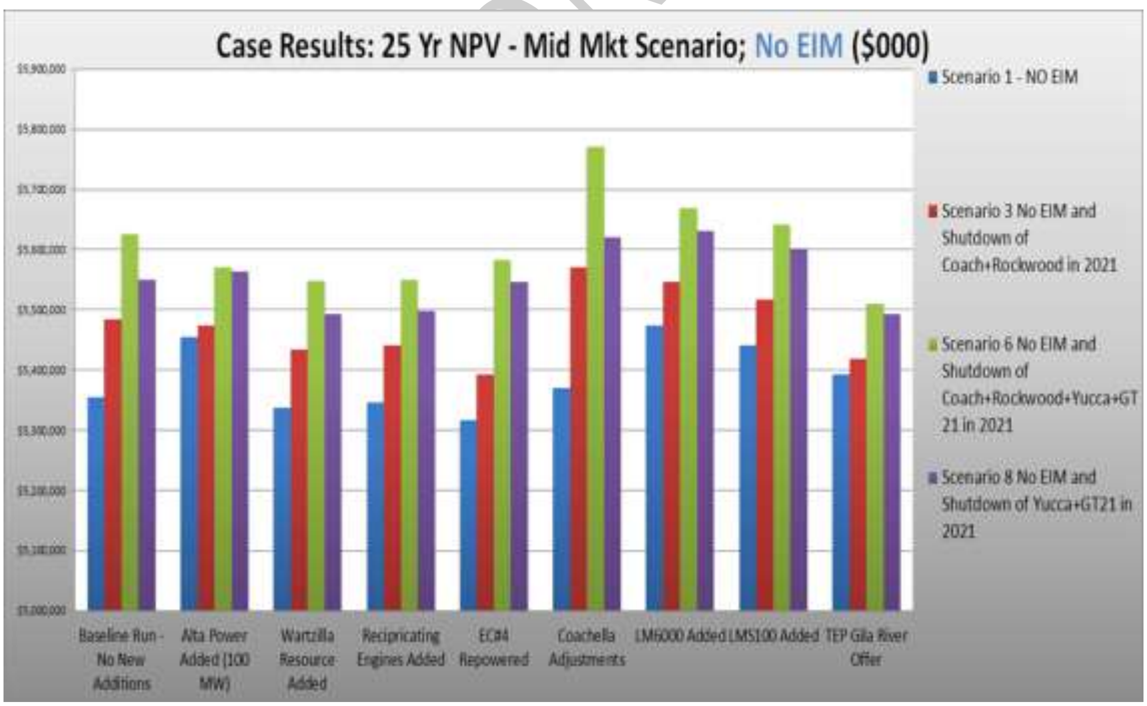
The chart below compares how the EIM market participation can increase the benefits of an added resource that is "in the money" like El Centro No. 4 repower:

Exhibit 135: Market Participation Cases of Resource Additions



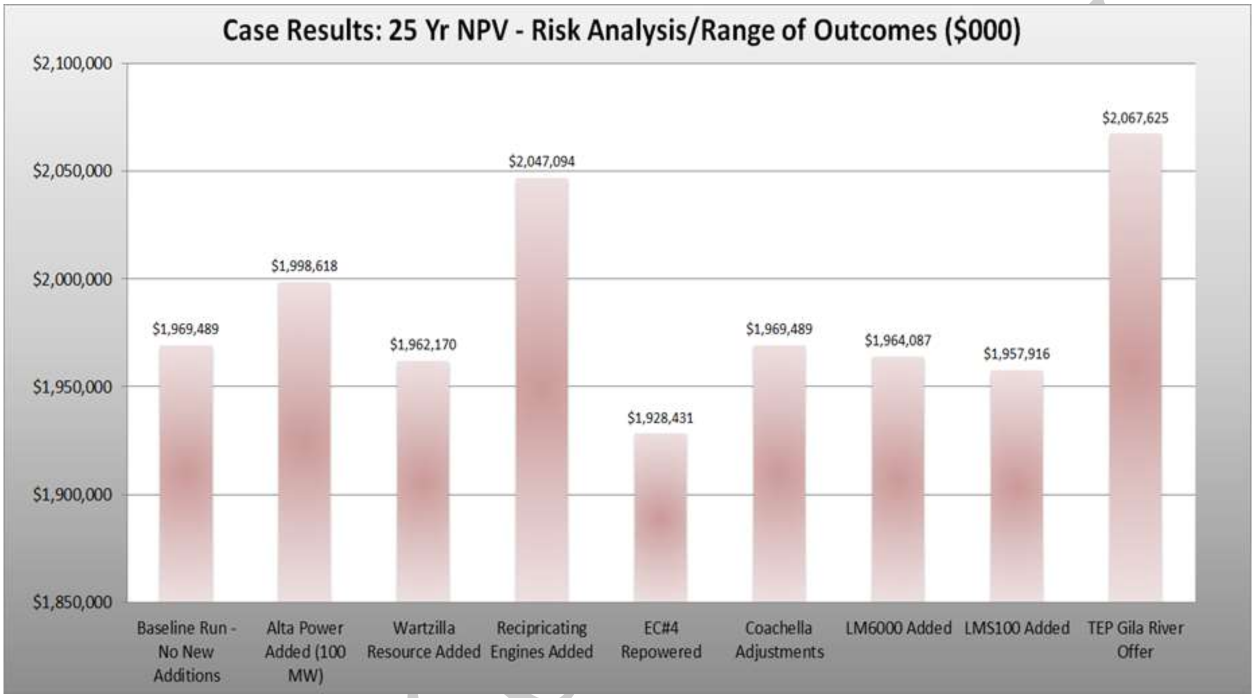
The chart below shows how retirements can be costly, even on old units that are hardly ever used:

Exhibit 136: Market Scenarios of Resource Additions



The various types of resources do not come without risks as there are constant changes in weather driven load, energy prices, gas prices, emission allowance prices and the chart below describes how the risks vary depending on the added resource with EC No. 4 repower being the least risk as well as the least cost tested facility:

Exhibit 137: Risk Analysis of Resource Addition Studies



Based on these studies the following conclusions and recommendations were determined:

- It is apparent that adding certain resources can, in fact, increase economic efficiencies to the IID system in both sales and non-sales environments.
- EC No. 4 Repowered.
- Wartzilla.
- Reciprocating Engines.
- TEP Gila River Contract delivered at PV.
- If units many units are retired (Yucca/GT21/Coach/Rock) at the same time, costs may increase, but adding resources can decrease cost impact.
- System responsiveness and flexibility in added resources is greatest need.
- Doing nothing is not best option when units are retired.
- Retirement of Yucca will be more costly that the retirement of Coachella/Rockwood.
- A resource specific RFP can decrease overall costs and provide a competitive process.
- If IID participates heavily in EIM/Economic Sales markets, lower heat rate alternatives are best.

- We must begin the process of procurement/acquisition of a new resource now in order to complete a 'build' project (if that is the winning offer) by 2021.
- Begin discussing the possibility of financing/issuing bonds with Finance should we decide to build another generation facility.
- Retiring Coachella and Rockwood and doing nothing is not an option.
- Retiring from larger facilities can provide a much lower $/MWh variable cost, but have higher annual fixed costs than other alternatives.
- Negotiating lower annual fixed costs or shorter contract term may be good option during interim of construction of owned facility.
- Higher gas market scenarios improve the economics of lower heat rate alternatives.
- Fixed costs would need to be renewed after 25 year period.
- Building a resource could last 30-50 years, so 40 year perspectives provide greater benefit than purchase cases.
- 50 percent RPS will require greater need for controllable/flexible quick responding resources.

2. Renewable Resources and Cap and Trade

The IID added a number of renewable resources that will come online in 2018-21 both to meet GHG emission reduction standards and renewable portfolio standards as well as achieve greater price stability. While renewable resources are currently more expensive than most fossil-fuel-fired generation, the escalation rate of renewable energy costs is low and known.

Power Supply Simulations

The Resource Planning group tested several portfolios though the economic simulation of the current IID system. Each portfolio maintained the same gas/energy price forecast, load forecast and system characteristics. Different resource sets were simulated over 20 years comparing the various combinations of resources that allow IID to meet the RPS in all compliance periods. IID recognizes that the organization is faced with several challenges that slow the process of procuring renewable resources to meet the state RPS. The major considerations are as follows:

- The RPS compliance is based on retail sales and production of renewable resources; both are uncertain.
- Effectively meeting the RPS and carbon requirements.
- Too much must take eradicates opportunity for dispatch optimization.
- Winter Load vs. Summer Load.
- Availability of seasonally flexible resources within the IID territory and the risk of completion.
- Effectively balancing the system with high amounts of intermittent resources.
- Minimizing the renewable integration cost impact.

With those challenges in mind, the main assumptions for these studies are as follows:

- Current gas/energy pricing forecast from Ventyx.
- Load Forecast.
- IID exits ownership of SJ3 by the end of 2017.
- RPS has been or will be met in all three compliance periods for tested portfolios
    - 20 percent for 2011-13.
    - 25 percent by the end of 2016.
    - 33 percent by the end of 2020.
    - 50 percent by the end of 2030 with a straight line approach in annual increases from 2020-2030 (to be determined by the CEC in mid-2017).

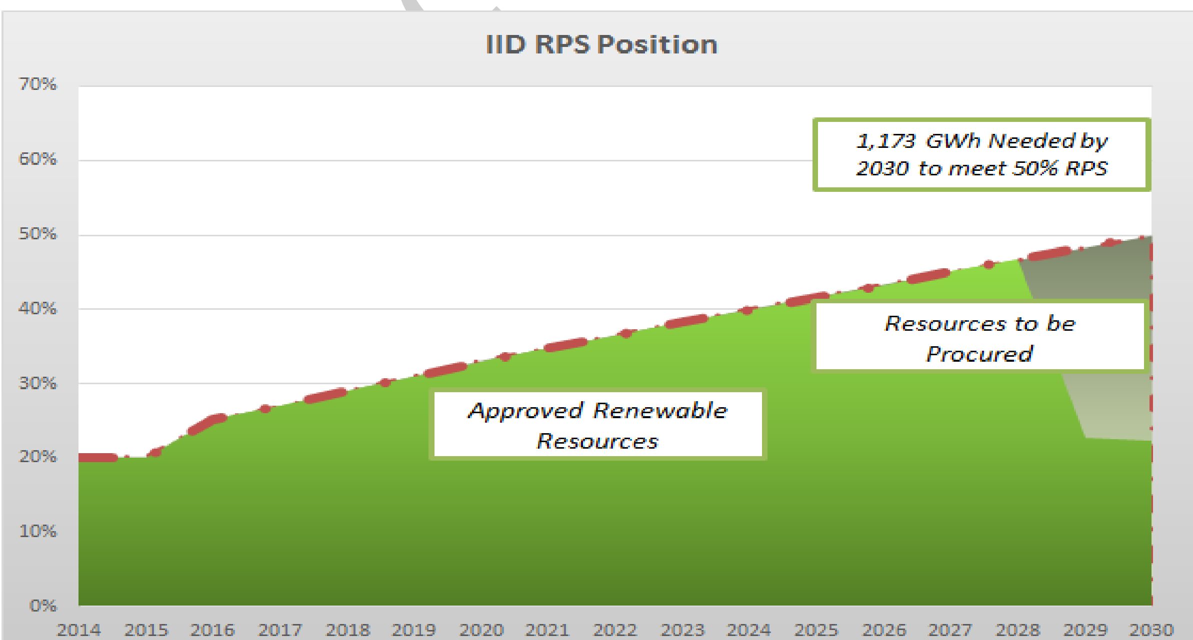
The following exhibits represent IID's current and projected RPS compliance status for the next 20 years. It includes all current and executed renewable contracts to date.

Exhibit 138: 2030 RPS Requirement Forecast under SB 350

RPS Compliance Net Position (GWh)

Resource Type	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Solar (including SDSU)	243.5	352.0	353.8	352.0	350.2	348.3	346.5	344.6	342.9	341.0	339.2	337.4	335.7	333.9	332.1
Biomass	323.0	338.0	326.8	322.4	324.0	292.7	326.8	-	-	-	-	-	-	-	-
Small Hydro	231.4	258.0	274.2	280.8	290.0	294.1	299.4	299.4	299.4	299.4	299.4	299.4	299.4	299.4	299.4
Geothermal	111.7	109.3	146.6	476.0	501.2	503.4	484.6	497.0	479.5	500.3	452.3	445.7	442.3	448.6	418.3
Total Renewable Generation (GWh)	909.6	1,057.3	1,101.4	1,431.2	1,465.3	1,438.4	1,457.2	1,141.1	1,121.7	1,140.7	1,091.0	1,082.6	1,077.5	1,081.9	1,049.8
Requirement % W/50% by 2030	25.00%	27.50%	30.00%	32.50%	35.00%	35.00%	37.00%	39.00%	40.00%	42.00%	43.00%	45.00%	47.00%	48.50%	50.00%
Generation Requirement GWh	817.2	909.2	1,003.5	1,101.0	1,202.0	1,219.4	1,308.7	1,401.2	1,460.8	1,559.9	1,624.9	1,730.4	1,840.8	1,934.0	2,029.9
50% by 2030 Net Position (GWh)	294.7	442.8	540.7	870.9	1,134.2	1,353.3	1,501.8	1,241.7	902.6	483.5	(533.9)	(647.9)	(763.4)	(852.0)	(980.1)

Exhibit 139: 20-Year RPS Requirement Forecast Graph

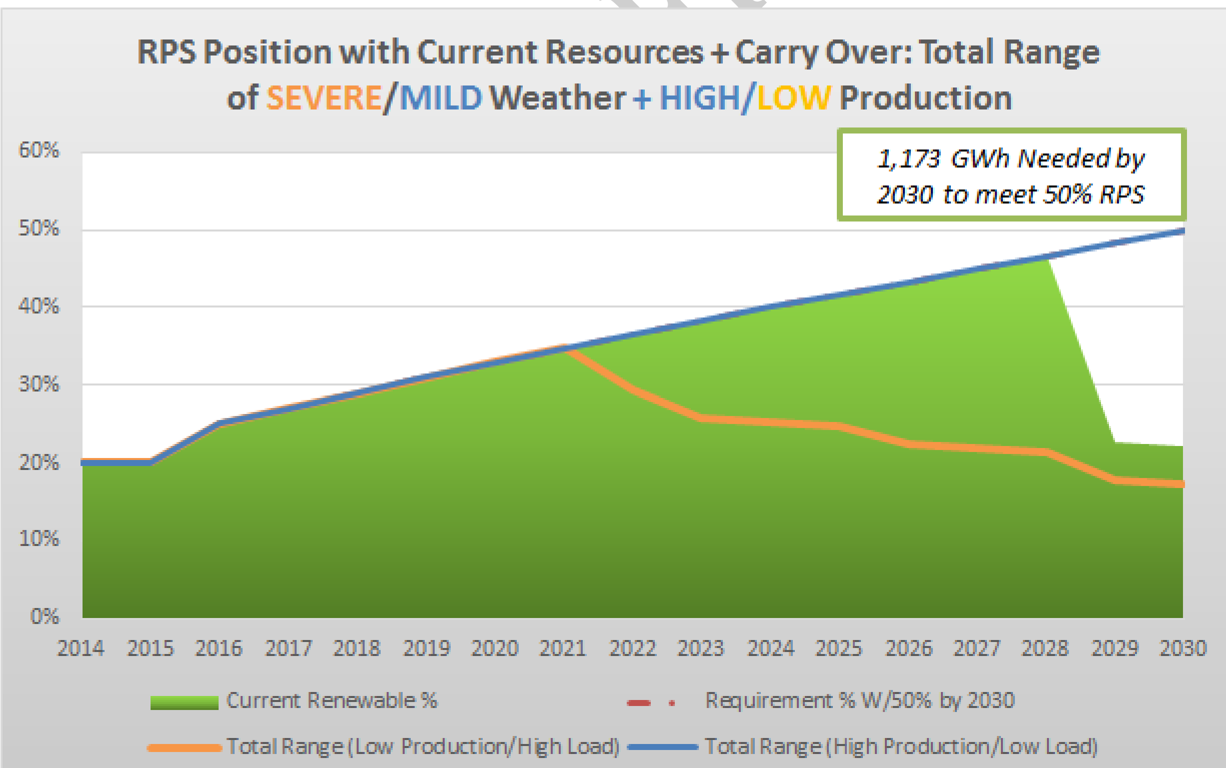


The graph above assumes expected growth and expected renewable production, but a critical concept to understand in RPS planning is the aspects that are involved with compliance or non-compliance. Essentially, RPS compliance is based on two items:

- Total energy sales.
- Total renewable production.

Both of the above, in nature, are unpredictable. So, a ranged forecasted of energy sales was developed in the load forecasting process. This allows IID to observe the risks associated with adding new resources in specific time periods where a given situation of adding a renewable resource too soon where load growth is not distinguishable and could be quite costly. The graph below depicts the extreme when comparing both the lowest possible production per each contract combined with high range of load growth and the highest possible production combined with low or no load growth:

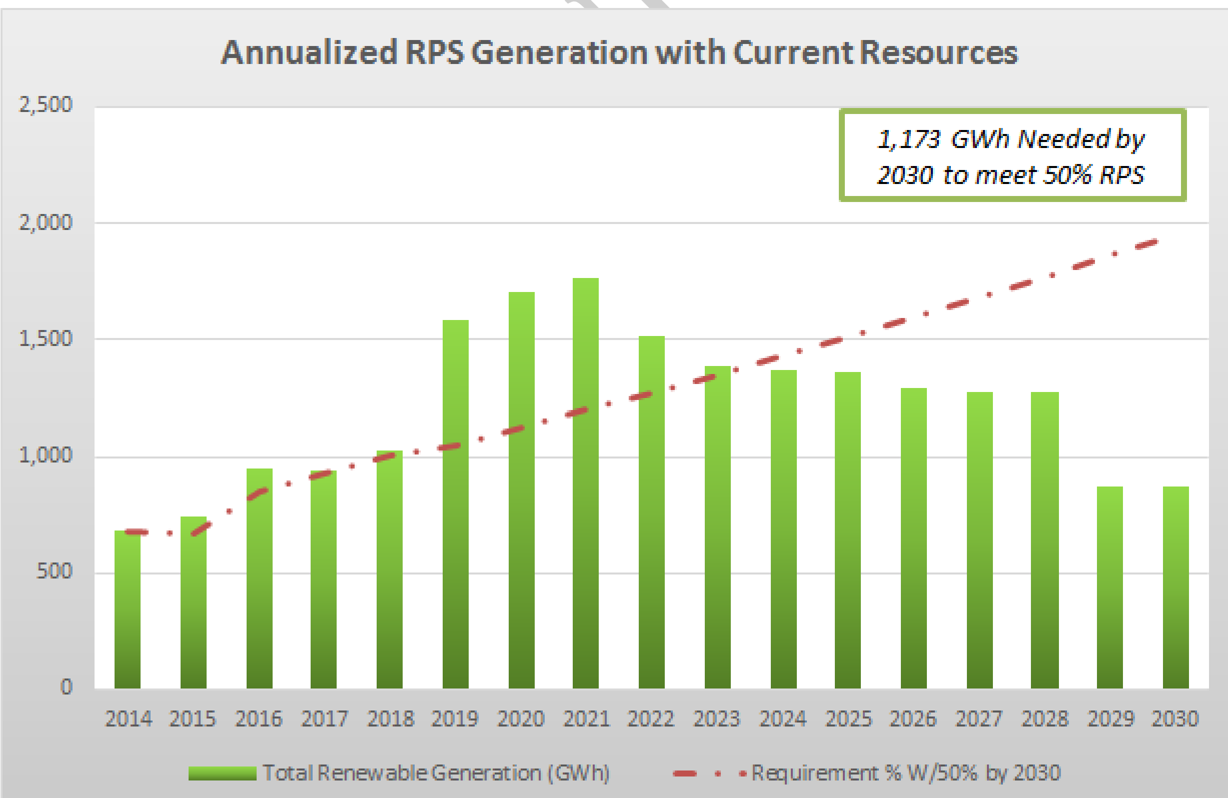
Exhibit 140: Ranged Based RPS Position



This is extremely important for IID to consider in RPS planning. For example, if IID signs and agreement that costs $5 million per year for 75,000 MWh/year with an online date of 2018 and in the case of slow or no load growth, IID will not need the 75,000 MWh/year and there for the net impact from the $5 million gross cost will be a sunk cost.

Furthermore, an important concept to note is that the annual generation does not necessarily represent the annual compliance. RPS law provides various compliance mechanisms and one of them is that excess renewable generation can be carried forward to be applied to future compliance periods. So, if load is lower than expected, the renewable generation that is above the coinciding percent target can be used for the next year or future years that have a short position. The graph above illustrates the renewable generation being applied to each compliance period or future compliance period where there is a need. The graph below illustrates the annualized generation of renewable energy.

Exhibit 141: Annual Renewable Generation



So, from this perspective, it appears that there is a need to procure additional renewable resources by 2023. However, this is *not* the case since the amount of excess annual generation will be applied to the targets for future compliance periods where the space above the red line represents renewable generation that will be applied to future compliance periods.

Additional assumptions for these studies include:

- When RPS goal is achieved, cap-and-trade opportunities expand with additional excess carbon allowances.
- Generation maintenance costs do not vary, even if intermittent resources are greater in various portfolios (needs to be studied).
- Renewable resource output and retail sales are conservative to ensure that RPS targets are met
  - Retail sales two percent growth.
- Current PPAs provide a range of potential output from each plant. The targeted MW capacity was used for these studies (as opposed to the maximum potential capacity)Sol Orchard Community Solar will be fully subscribed.

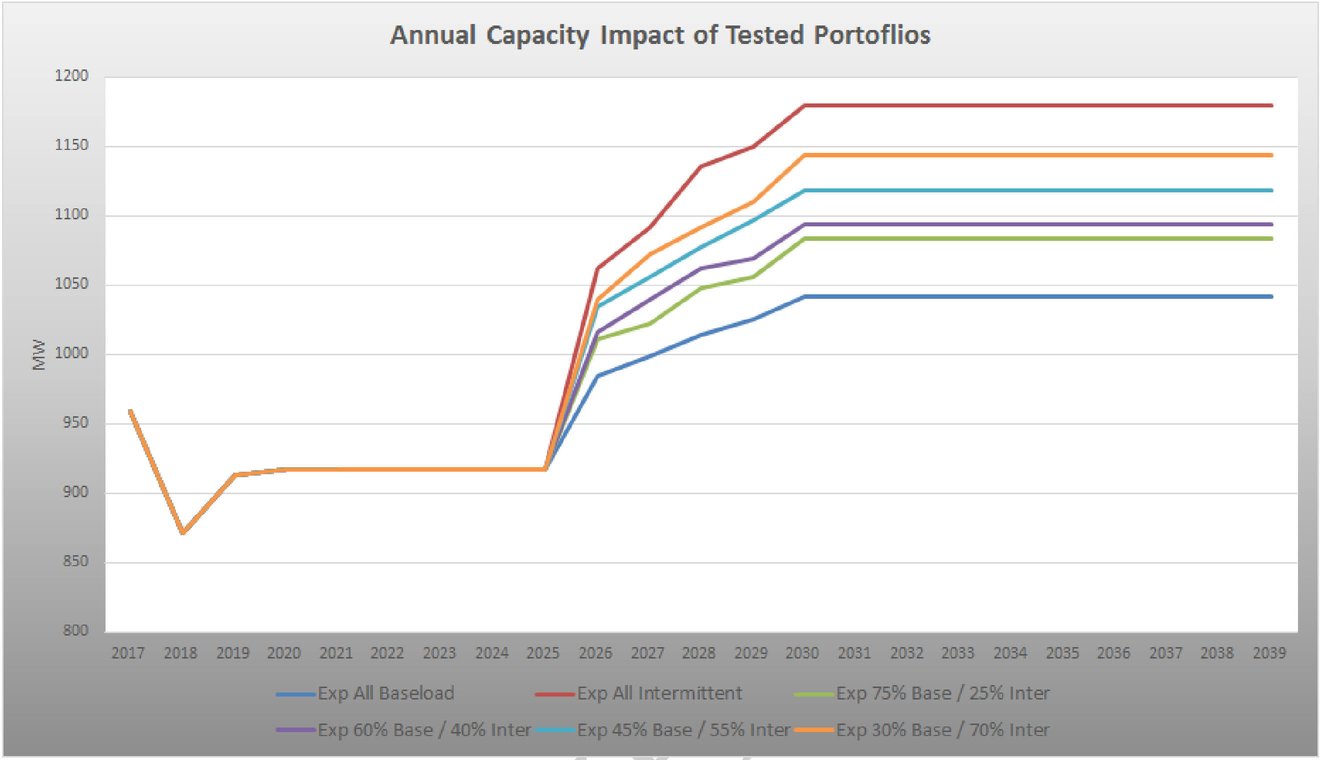
The portfolios tested are included in the exhibit below.

Exhibit 142: Portfolios Tested for RPS Compliance Strategy

IID Energy & Capacity Requirements with 50% RPS: 2030						
Case	Total Needed (MWh)	Possible Mix of Resources Technologies	Geo/Biomass or other Baseload		Solar/Wind or other Intermittent	
			MW	MWh	MW	MWh
Expected Case	**980,108**	100% Base	124	980,108	-	-
		100% Intmt.	-	-	373	980,108
		75% Base, 25% Intmt.	93	735,081	93	245,027
		60% Base, 40% Intmt.	75	588,065	149	392,043
		45% Base, 55% Intmt.	56	441,048	205	539,059
		30% Base, 70% Intmt.	37	294,032	261	686,075
Severe Weather	**1,111,547**	100% Base	141	1,111,547	-	-
		100% Intmt.	-	-	423	1,111,547
		75% Base, 25% Intmt.	106	833,660	106	277,887
		60% Base, 40% Intmt.	85	666,928	169	444,619
		45% Base, 55% Intmt.	63	500,196	233	611,351
		30% Base, 70% Intmt.	42	333,464	296	778,083
Mild Weather	**865,648**	100% Base	110	865,648	-	-
		100% Intmt.	-	-	329	865,648
		75% Base, 25% Intmt.	82	649,236	82	216,412
		60% Base, 40% Intmt.	66	519,389	132	346,259
		45% Base, 55% Intmt.	49	389,542	181	476,107
		30% Base, 70% Intmt.	33	259,694	231	605,954
Zero Net Energy	**744,111**	100% Base	94	744,111	-	-
		100% Intmt.	-	-	283	744,111
		75% Base, 25% Intmt.	71	558,083	71	186,028
		60% Base, 40% Intmt.	57	446,467	113	297,645
		45% Base, 55% Intmt.	42	334,850	156	409,261
		30% Base, 70% Intmt.	28	223,233	198	520,878

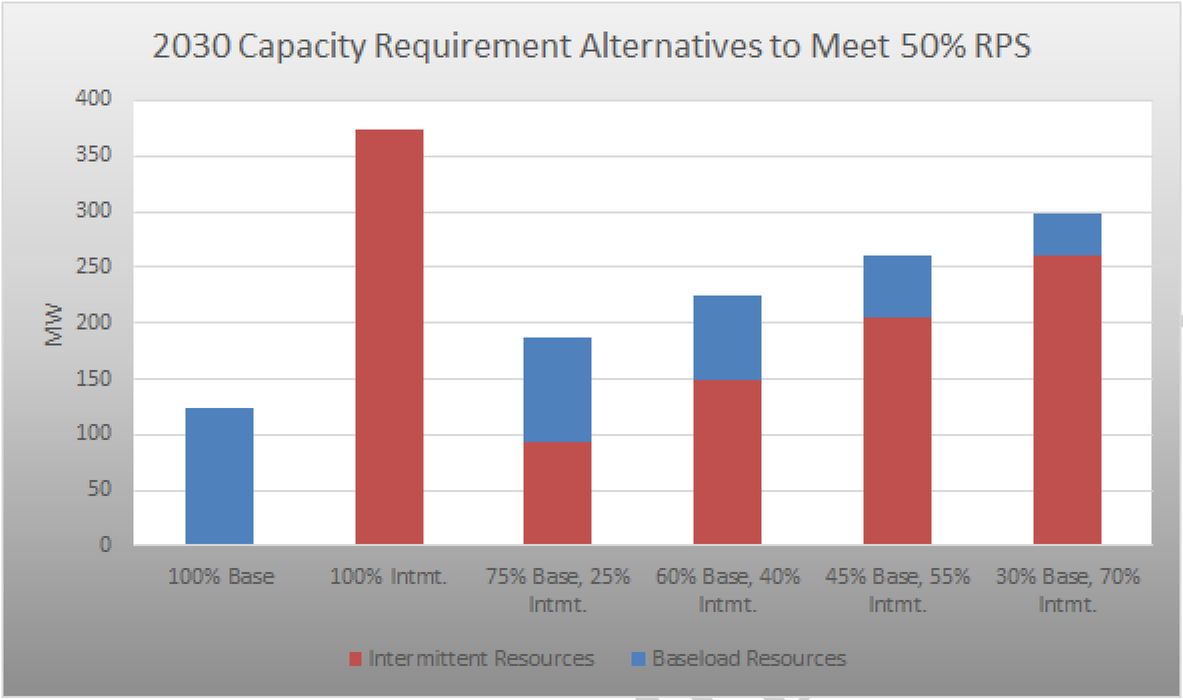
All portfolios sustain varying impacts of added capacity included in the simulated system. This is due to the various types of technologies available to IID and their contrasting annual energy production levels. The following table exhibits the results from these runs.

Exhibit 143: Capacity Position Impact of the Tested Scenarios



As illustrated above, the mix of resources used to meet the 50 percent requirement will impact the capacity positions for future years; however, it is important to note that adding 373 MW of intermittent resources like wind or solar will create a deeper long position that will require repositioning of other resources. Additionally, high levels of intermittent resources will require greater quick responding generation support and the associated costs are considered in these studies. Below is a chart that illustrates the capacity added in the various mix or portfolios tested:

Exhibit 144: Capacity Breakdown of Portfolios Tested



With this in mind, unexpected loads cause varying dispatch results, so a sensitivity of loads was simulated along with emission price sensitivities bringing the iteration total to 48 different iterations for the study to consider the various risks that play a role in the long term hourly dispatch.

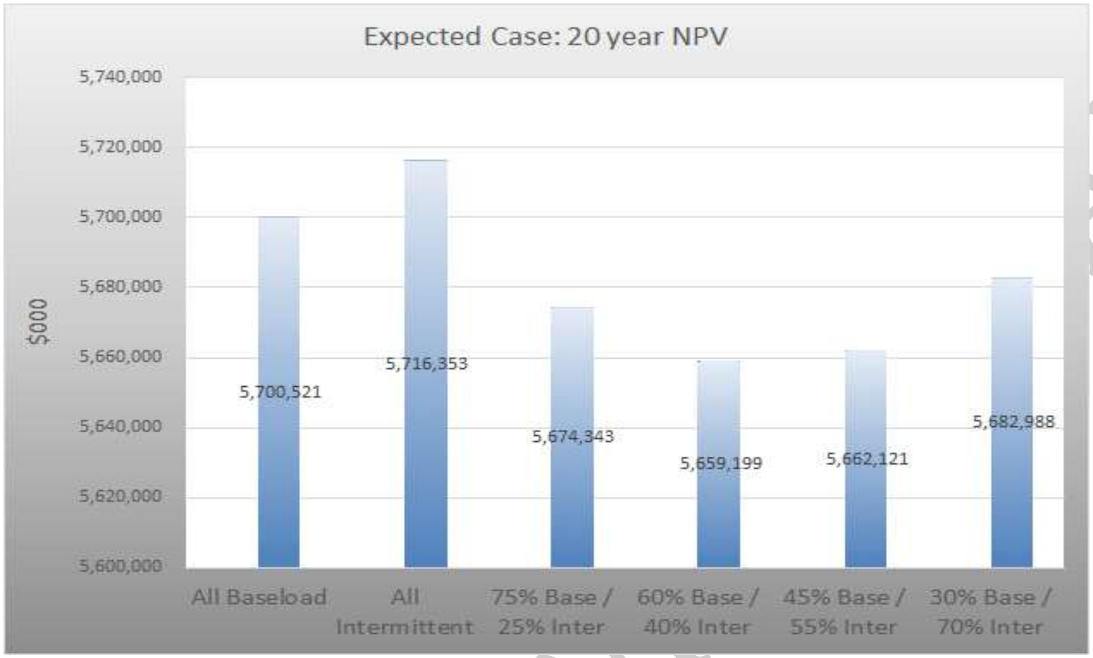
The charts below illustrate the various perspectives of the results:

Exhibit 145: Portfolios Test Results for RPS Compliance Strategy

System Cost			
Scenario	**Portfolio**	**Description**	**Total Cost W/Engy Storage**
Expected	1	All Baseload	$ 5,700,521.37
	2	All Intermittent	$ 5,716,353.41
	3	75% Base / 25% Inter	$ 5,674,343.06
	4	60% Base / 40% Inter	$ 5,659,199.34
	5	45% Base / 55% Inter	$ 5,662,121.21
	6	30% Base / 70% Inter	$ 5,682,987.68
Severe Weather	7	All Baseload	$ 6,127,959.60
	8	All Intermittent	$ 6,137,838.88
	9	75% Base / 25% Inter	$ 6,089,884.93
	10	60% Base / 40% Inter	$ 6,081,790.74
	11	45% Base / 55% Inter	$ 6,095,281.32
	12	30% Base / 70% Inter	$ 6,104,429.56
Mild Weather	13	All Baseload	$ 5,307,833.27
	14	All Intermittent	$ 5,332,918.05
	15	75% Base / 25% Inter	$ 5,291,226.07
	16	60% Base / 40% Inter	$ 5,291,824.14
	17	45% Base / 55% Inter	$ 5,299,108.50
	18	30% Base / 70% Inter	$ 5,316,160.88
ZNE	19	All Baseload	$ 5,024,338.91
	20	All Intermittent	$ 5,064,976.23
	21	75% Base / 25% Inter	$ 5,016,031.95
	22	60% Base / 40% Inter	$ 5,020,801.18
	23	45% Base / 55% Inter	$ 5,030,633.68
	24	30% Base / 70% Inter	$ 5,021,437.73

Below is a summary chart of the expected case:

Exhibit 146: Expected Case Results for RPS Compliance Strategy

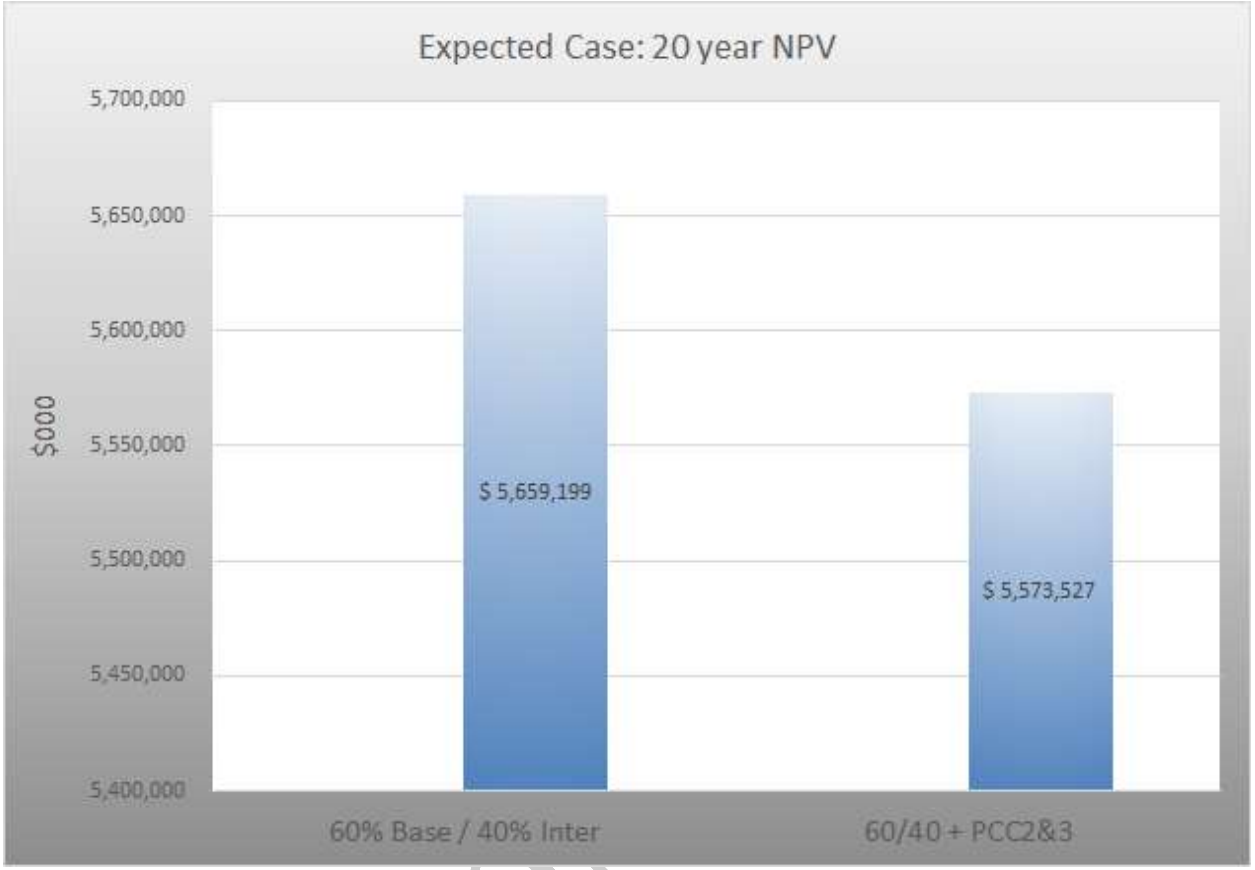


Most of the time, the mix of 60 percent baseload and 40 percent intermittent was the best case and considering the risks, it also is one of the lower risk portfolios. Below is a tornado diagram of the range of cost risk in each of the tested portfolios:

Exhibit 147: Risks of Various RPS Portfolios

Furthermore, it is important to note that the portfolio traits of all of the above tested simulations do not assume the use of several compliance mechanisms that are available to reduce the cost impacts of RPS compliance. IID's current direction is to procure Portfolio Content Category 1 (PCC1) resources directly connected to the IID system. However, if IID were to take advantage of PCC2 or PCC3 or procure PCC1 resources that are not directly connected to the IID system and sink the energy portion to other California Balancing Authorities, then the total cost impacts would be reduced by millions over a 20-year span. As previously mentioned, the specific guidelines for post 2020 RPS compliance requirements will be released in mid-2017. However, assuming the same degree of limitations defined by the pre-2020 SBx-1 law, the following chart summarizes the cost savings potential of an estimated $85.6 million could be realized when RPS compliance mechanisms PCC2&3 are maximized:

Exhibit 148: RPS Compliance Impact with PCC2 & 3 Utilized

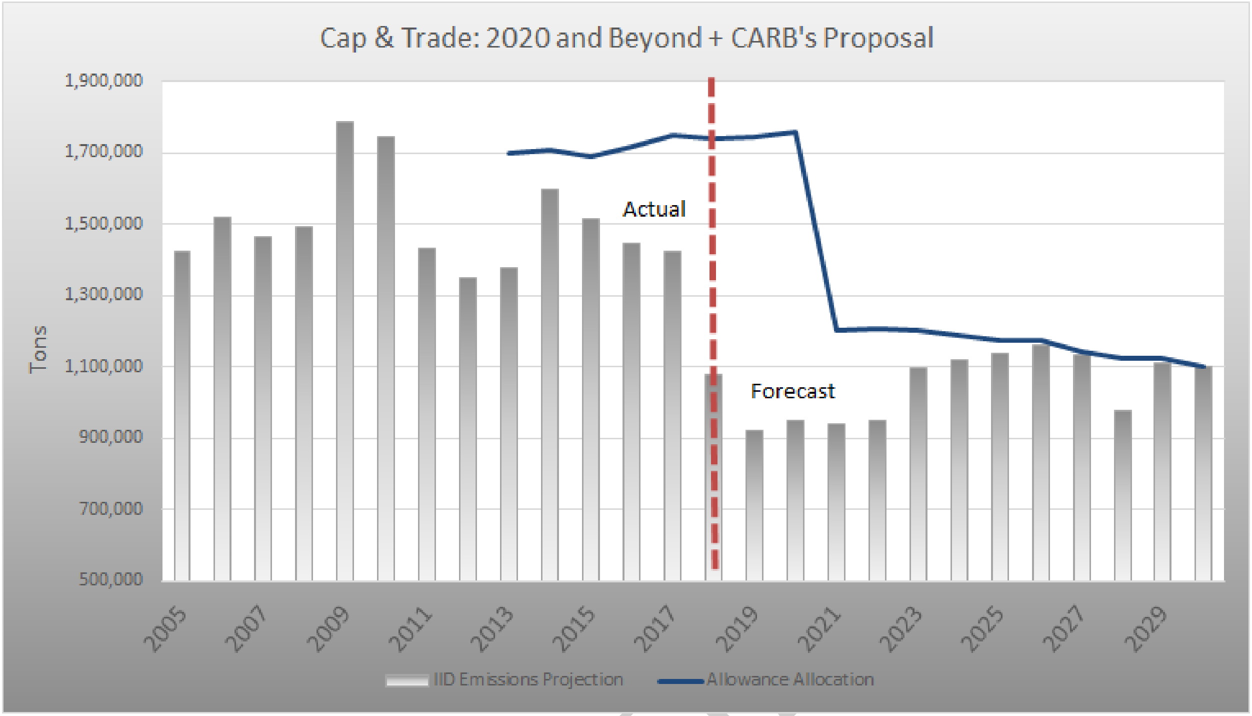


CAP AND TRADE AND THE IRP PREFERRED CASE TO MEET GOALS

The IID has projected its expected allowance levels analyzing different scenarios. Several uncertain factors could greatly impact the depth of the carbon footprint. Factors like operations of the system are tested by observing scenarios of volatility risks of the energy and gas market prices would be one example. Another example of factors effecting IID's carbon footprint is the confirmed divestiture of San Juan facility and the RPS portfolio fulfillment. These scenario analyses are discussed in greater detail in later sections of this plan. IID is in a position to maximize its potential to reduce the cost impact of RPS implementation by making decisions to reduce the MTCO2e emanation to create a "longer" position of marketable, state-allocated emission allowances via the Cap-and-Trade auction (primary market) or the secondary markets outside of the auctions. Since there are still many unknown variables in the Cap-and-Trade market and the external effects of various markets on the emissions trading markets, IID has analyzed the risks and prepared a "'basecase" of emission projections to plan for the Cap-and-Trade market with a set of conservative assumptions.

The following exhibit is a projection of IID's emissions compared to the allowances allocated to it through 2030.

Exhibit 149: Projection of IID's Emissions Compared to Allowances



The Cap-and-Trade Program plays a major role in IID's decision-making process for future renewable resources and impacted its exiting of its ownership in the San Juan coal facility. The above exhibit illustrates IID's forecasted allowance position without participation in San Juan Unit 3.

Consideration for the cap-and-trade market will be a key driver in future generation resource decisions which could result in millions of dollars' worth of savings on emissions.

Beyond 2020, there are still a many unknowns. SB 350 requires the CEC and CARB to work together to determine the rate of decrease beyond 2020. However, IID has monitored the potential outcomes and it appears that currently, IID will meet the targets, even with a 40 percent reduction from 1990 levels. SB 350 added Cal. Pub. Utils. Code Sec. 9621(b)(1) requiring that local publicly-owned electric utility IRPs be developed to achieve GHG emissions reduction targets established by CARB, in coordination with the CPUC and the CEC. The CEC's IRP Guidelines include a GHG Emissions Accounting Table ("GEAT"), which request information regarding "Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB." The CPUC adopted a 42 MMT scenario GHG planning target in its analysis of IRP procurement requirements for CPUC-jurisdictional load-serving entities,[25] though CARB's conclusion will control for purposes of the

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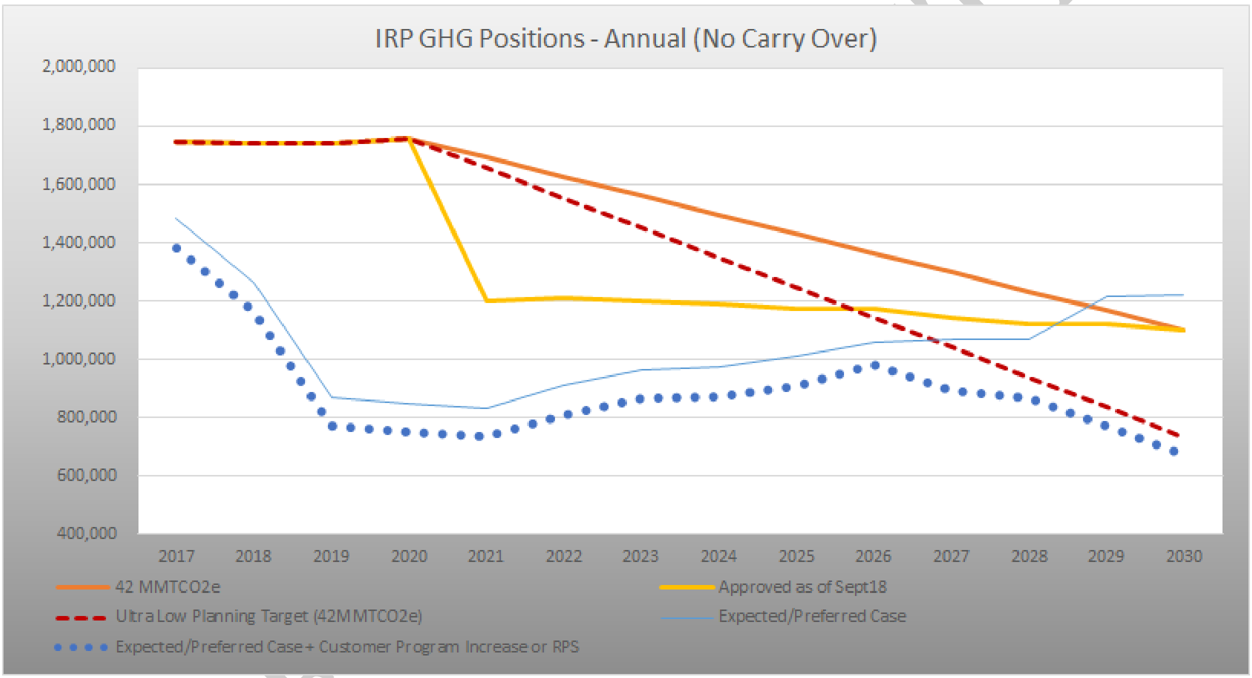
[25] *See* D.18-02-018, *Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning*

CEC's IRP Guidelines pertaining to POUs. On July 26, 2018, CARB approved an overall IRP planning range between 30 and 53 MMTCO2e, as reflected in the 2017 Scoping Plan Update. CARB's proposal also included a range for IID, specifically 524,000 MTCO2e at the low end of the range, and 925,000 MTCO2e range, or 1.745 percent of the electricity sector emissions. Furthermore, the forecast also includes an assumed amount of customer side of the meter programs that may be necessary to fully meet the emissions reductions. Although, the method of counting those programs along with other programs that reduce overall state emissions (i.e., EVs, etc). With this in mind, below is an illustration of IID's future allowance forecast and how the current law of emissions cap may be reduced (this does not represent actual since the guidelines have yet to be released):

Exhibit 150: Projection of IID's Emissions Compared to Allowances



IID assumes that the customer side of the meter programs will provide additional GHG reduction abilities.

However, in October 2016, CARB released their Post-2020 Allocation to Electrical Distribution Utilities Informal Staff Proposal that contains a much different depiction that the regulatory provision of "40 percent below 1990 levels". Below is an illustration of the proposed reduction estimates:

Exhibit 151: Projection of IID's Emissions Compared to Allowances w/CARB's Informal Proposal

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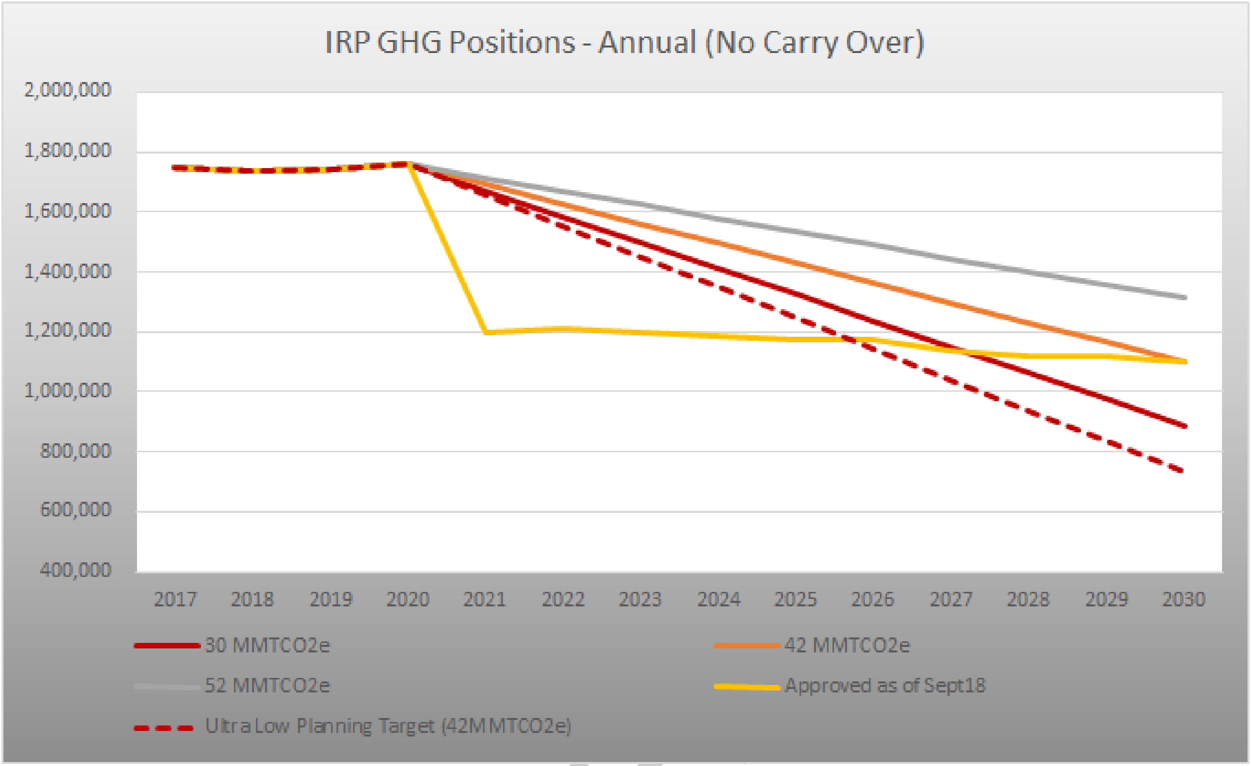
Requirements, Proceeding No. R.16-02-007 (Feb. 13, 2018).



Should this proposal be implemented and enforced, IID will need to look at a bevy of alternatives that allow for this reduction to be possible, some, but not all, areas that may need to be utilized to meet the emissions reductions target are:

- RPS targets
- Operational practices
- Vehicle electrification
- Energy efficiency
  - Collaboration with building standards
  - Rooftop solar and distributed energy resource programs
  - Public programs
  - E-Green programs
- Internal fleet
- Exploration of flexible renewable technologies

In any case, IID is continuously monitoring this activity and compliance highly depends on IID's participation in RPS compliance and energy efficiency programs as described in the SB 350 guidebook.

Repositioning Potential

Furthermore, various situations such as slowed load growth, overproduction, additional procurement will cause the over generation environment to continue to exacerbate and if this occurs, then IID needs to take action to seek opportunities to reposition or lay off/sell resources. While a straight layoff is generally more desirable, if repositioning is possible, then below would be one example of how a layoff may look.

SunPeak Solar is IID's first solar agreement approved in 2011 when the RPS requirements were in the beginning stages. It had a commercial operation date of August 1, 2012 with a "Contract Capacity" of 20 MW at the COD with the ability to produce a maximum of 23 MW. The point of interconnection is the low side of HD-supplied transformer at the IID-owned Niland substation interconnection voltage of 13.2 kV. The agreement has two purchase options at the purchase price of $70 or $80 million:

- ***Purchase Option 1-*** One hundred percent (100 percent) interest in Seller, provided that if IID elects to purchase a one hundred percent (100 percent) interest in Seller, at Closing the only assets owned by Seller shall be Non-Monetary Solar Plant Assets and Seller shall not have any outstanding liabilities ("Interest Purchase Option"); or

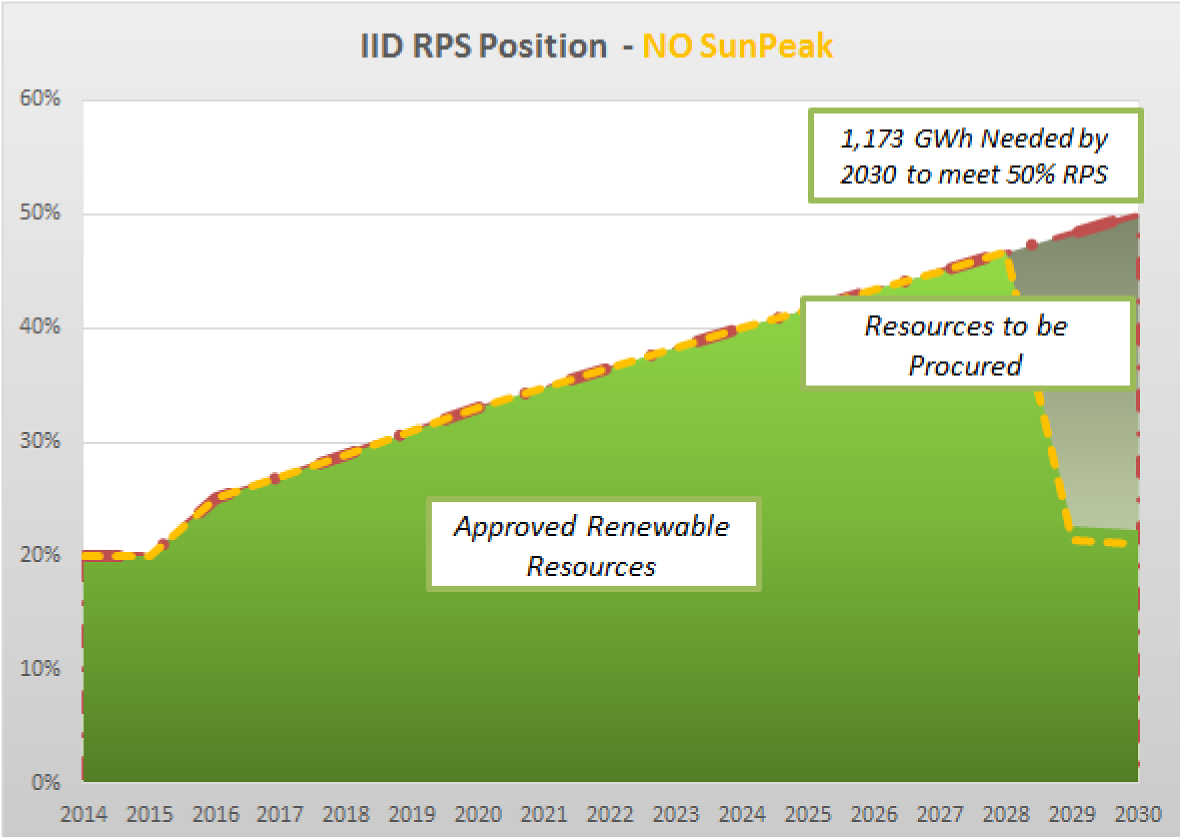
- ***Purchase Option 2-*** *O*ne hundred percent (100 percent) of the Non-Monetary Solar Plant Assets of Seller ("Asset Purchase Option").

IID has until August of 2017 to determine if and which purchasing option it will exercise. An analysis was conduction observing the following:

- 3 amortization scenarios based on 2 fair market value cases were observed:
    - $70 Million fair market value (FMV) buyout
        - 15 year amortization
        - 20 year
        - 30 years
    - 80.5 Million FMV buyout
        - 15 year amortization
        - 20 year
        - 30 years

The impact of the SunPeak facility on the RPS position is minimal as it represents <1 percent of the total requirements. The graph below illustrates the impact of laying off SunPeak:

Exhibit 152: Impact of SunPeak on RPS Position



The Following were the key assumptions used for the analysis:

- *Interest Rate is 4.5 percent/3.9 percent/3 percent for Bond Financing.*
- *Insurance after ownership is .5 percent.*
- *O&M after ownership is $3/MWh.*
- *Purchase price tested at $70 million and $80.5 million based on 23 MW capacity.*
- *Bond finance amortized over cases of 5 years, 10 years, 20 years and 30 years.*
- *Total period observed is 30 years from date of purchase.*
- *Purchase Option occurs on 8/1/18.*
- *Sale of SunPeak is on or before 8/1/18.*
- *Re-buy is for the same amount as the SunPeak PPA; if the re-buy is determined to be less. Than the SunPeak output abilities, then results will vary.*
- *Price escalation is 1.5 percent.*
- *New purchase price is $30/MWh (LCOE).*
- *Depreciation is 8 percent (straight line).*
- *Study period is 30 years from 8/1/2018.*

As a result, the following table exhibits the various perspectives of how the SunPeak resource could bought and sold and the potential pricing point to replace it, if needed:

Exhibit 153: SunPeak Repositioning Summary

Summary of Buyout/Sale/Re-Buy Preliminary Study: 30 Years							
Price Type	Current PPA	Buyout Option ($70 Million)			Buyout Option ($80.5 Million)		
		15 Year Amortization	20 Year Amortization	30 Year Amortization	15 Year Amortization	20 Year Amortization	30 Year Amortization
$/MWh (LCOE)	$ 177.64	$ 102.84	$ 108.43	$ 120.05	$ 102.75	$ 108.34	$ 119.95
Break-even $/MWh (LCOE)	$ 147.64	$ 72.84	$ 78.43	$ 90.05	$ 72.75	$ 78.34	$ 89.95
Re-Buy $/MWh (LCOE)	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00

The following are the key findings from the study:

- *The longer the amortization, the higher the LCOE becomes.*
- *The negotiation of the buyout cost is absolutely critical as it will determine how the sale auction will be benchmarked.*
- *The Re-Buy price will also be a determining factor of how low the sale auction can go.*
- *If the Re-Buy volume can decrease, then the break-even will decrease as well since the total amount spent is lower.*
- *Buyout risks include:*
  - Actual 100 percent sale is not secure.
  - Production is not guaranteed if sale is not achieved.
- *More financial/risk analysis may be needed as several of the assumptions can vary.*

Another example of reposition would be the Biomass facility in the Northern area of the IID system. After some preliminary analysis, it is possible that IID could reposition the facility in a mutually beneficial manner to both the buyer and the seller while meeting the state SB 859 standard; however, the following must be considered in order for this to work properly:

- All laying off (straight sale) alternatives have been exhausted
- We are very long in RPS for the next several years and this is considering some load growth.
- We have excess energy due to fixed MWhs from renewables.
- New resources being brought online are in the $30s-$40s/MWh and prices continue to fall for solar/wind.
- Even if we unload the entire resource (49MW), we still would be covered until 2022. Which I believe the utilities only need about 30MW, so in that case we would be covered until 2024.
- Replacements could be through an RFP that layers RPS energy better over time considering the most updated info.
- Timing – The CEC still has not established when an agreement needs to be in place, but the POUs are moving very quickly.
- GreenLeaf and SCPPA willingness.
- Legal Interpretation of logistics of this type of deal.
- Load growth risks – At this point it looks like load growth continues to be minimal, but if load growth were to be much higher than forecasted, then we would need more RPS.

- IID's Replacements would need to be with both capacity and energy component kept in mind so that excess power is not created again.
-Fuel source of DVP must be specific to meet SB 859 needs. I only found basic language in the agreement on fuel sources.

As illustrated in the exhibits above, the RPS strategy can have a significant impact on IID's overall system costs. The conclusions from the study results are outlined below:

- RPS needs begin in 2025-26
    - *Growth is mainly due to load forecast growth, increases in RPS requirements and contract expiration.*
- To support RPS generation technologies, a new energy storage will be needed and EC#4 repowering will help economics of system dispatch and load following support.
- Seasonal energy market purchases prevent wasted capacity during the winter months and this translates into cost savings.
- RPS products can efficiently cover some of the capacity short position if strategically procured.
- The short position during the summer months can be covered by seasonally procured resources to 2020, unless any units are retired or current units need to be "held back" for reliability purposes.
- The intermittency from the currently contracted 75MW of solar can be covered by the current units, but will cause higher maintenance costs and possibly lower unit reliability on the aging fleet. This is with the assumption that current units will be used more often than today's usage practices.
    - *If more back-up generation is needed for reliability purposes, costs will increase.*
- The addition of any more solar where IID carries reserves will require a new rapid-response unit or site located backup, such as energy storage or small peaking units, installed at the time of the solar COD (2025-2026).
    - *If 75MW of solar was added to the system, a smaller version of the Niland Peaking plant or site located backup resources could be sufficient (42MW LM6000 - $75m capital).*
    - *If 150MW of solar was added to the system, a peaking plant the size of Niland or site located backup resources such as energy storage could be sufficient (86MW LMS100 - $118m capital).*
    - *If facilities are retired or if PPA's are repositioned, then this will impact these recommendations.*
- Procure seasonally shaped resources where possible.
- Strategize the operational activity of the San Juan Unit 3 coal plant ownership from 20162017.
- Discuss or study the reliability/feasibility of operating only one unit (El Centro Unit 3) during the winter as opposed to two units.
- If possible, renegotiate contracts that cause winter season operational constraints.
- Exercise the purchase option of SunPeak1 ($10-15m savings).
- Consider shorter term contracts (3-10 years).
- Explore the option of self-development in solar and geo for 2020 and beyond.
- Monitor the RPS compliance annually.
- Consider cycling the units to allow for greater economic dispatch.

- If IID is going to procure/develop only local resources, then the technologies available are limited. These portfolios are based on the most current information for the technologies available at this time. If we want to further diversify IV-based resources, we need to issue an RFP to see what is available.

In conclusion, resources cannot be evaluated individually. They need to be added to the generation mix and evaluated as a set to identify the way operation of one resource affects other resources.

The simulations performed for this resource plan identify a potential resource expansion plan for the IID for the next five years. Implementing this proposed plan and beginning to identify resources for 2018 and beyond will be addressed appropriately for the IID.

3. *Analysis to Determine Optimal (BESS) Size for Operational Needs*

Overview

The purpose of this section is to provide a high-level assessment of both the growing regulating demands placed on IID's electric grid, IID's real-time capability to respond those regulating demands. This paper also explains how additional Battery Energy Storage System(s) could be operationally utilized to regulate Area Control Error excursions and meet IID's spinning reserve requirements, as well as recommendations regarding the sizing and location such a system.

Regulation is the process of adjusting the power output of generation units connected to the automatic generation control system which provides minute-to-minute system balance (between generation resources and load centers). The process of regulating becomes increasingly more challenging as renewable generation resources tend to be highly volatile with respect to their output levels on a minute-to-minute basis. Throughout the electric utility industry, regulation is typically one of the most expensive ancillary services.

In recent years, with the addition of renewable portfolio standards (SB 2 (1X), SB 350, SB 100) in California which require load serving entities to increase the percentage of renewable energy used to serve native load; IID along with other balancing authorities have procured such renewable resources within its own balancing authority footprint. This increase in renewable resources also increases volatility of generation output while simultaneously reducing the ability of IID as a balancing authority to regulate ACE using conventional methods.

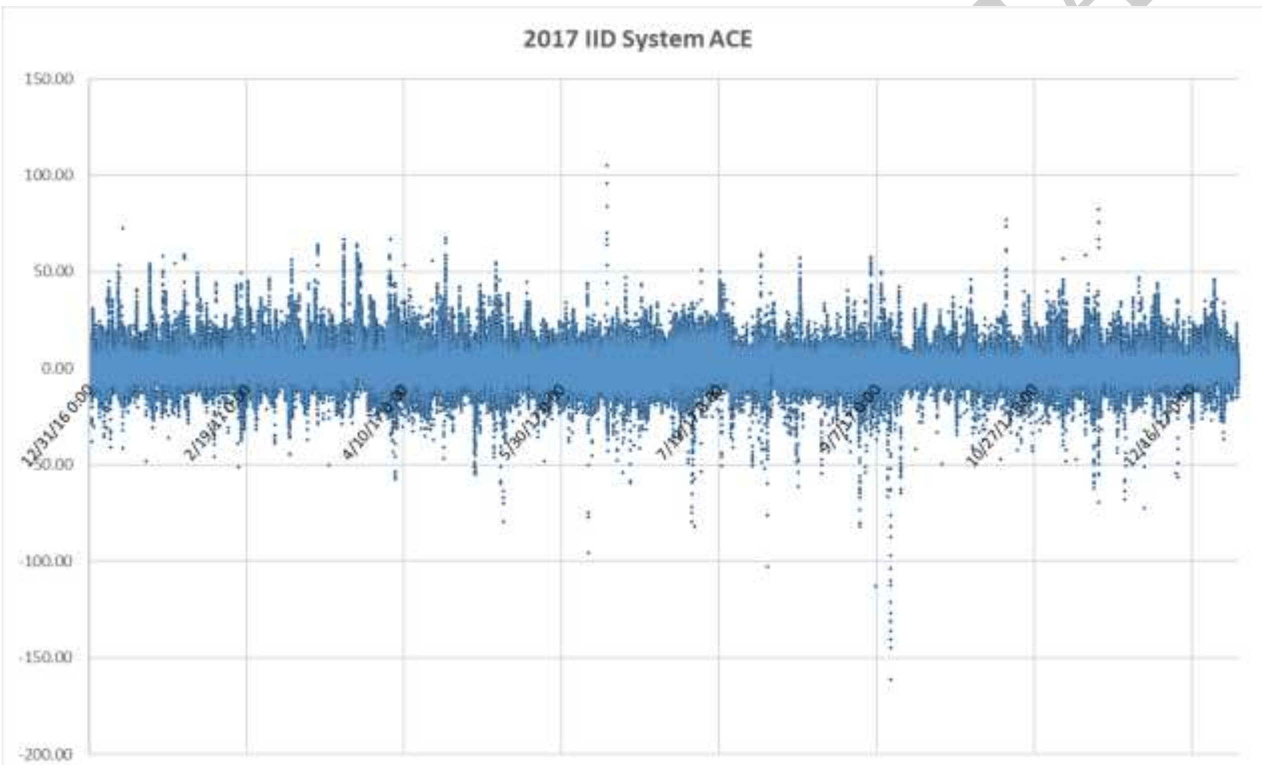
IID System Operations has first-hand experience with the challenges of integrating renewable energy resources within the IID Balancing Authority. Between 2016 and 2017, IID System Operations saw a twenty-six percent increase in solar generation and is projected to experience a fifty-six percent increase in solar generation between 2016 and 2018. This experience highlights deficiencies in spin requirements experienced by the IID's real-time system operators with the increased variability and forecast uncertainties associated with the high penetration levels of renewables such as solar.

Analysis

A statistical analysis of actual historical data was used to assess how the IID system performed in 2017 in terms of regulation control and operational reserves. Large data sets were created by sampling the 2017 calendar year in one minute intervals. Data sets were created for the following: System Frequency, System

Load, Net Actual Interchange, ACE, Total IID Generation, Spinning requirements and Most Severe Single Contingency. Excess spin was derived and validated using the above data sets. The statistical analysis showed that in 2017 there existed many instances where the system was deficient in spinning reserves. The majority of these deficiencies were caused by generation volatility and the rest were caused by the loss of large generation units that serve IID load. **Figure 1** below shows the IID system ACE for the entire year. The large negative deviations were the product of the loss of large generators serving IID load or loss of large energy purchases. The solar variation is represented in the ACE points closer to the Horizontal axis.

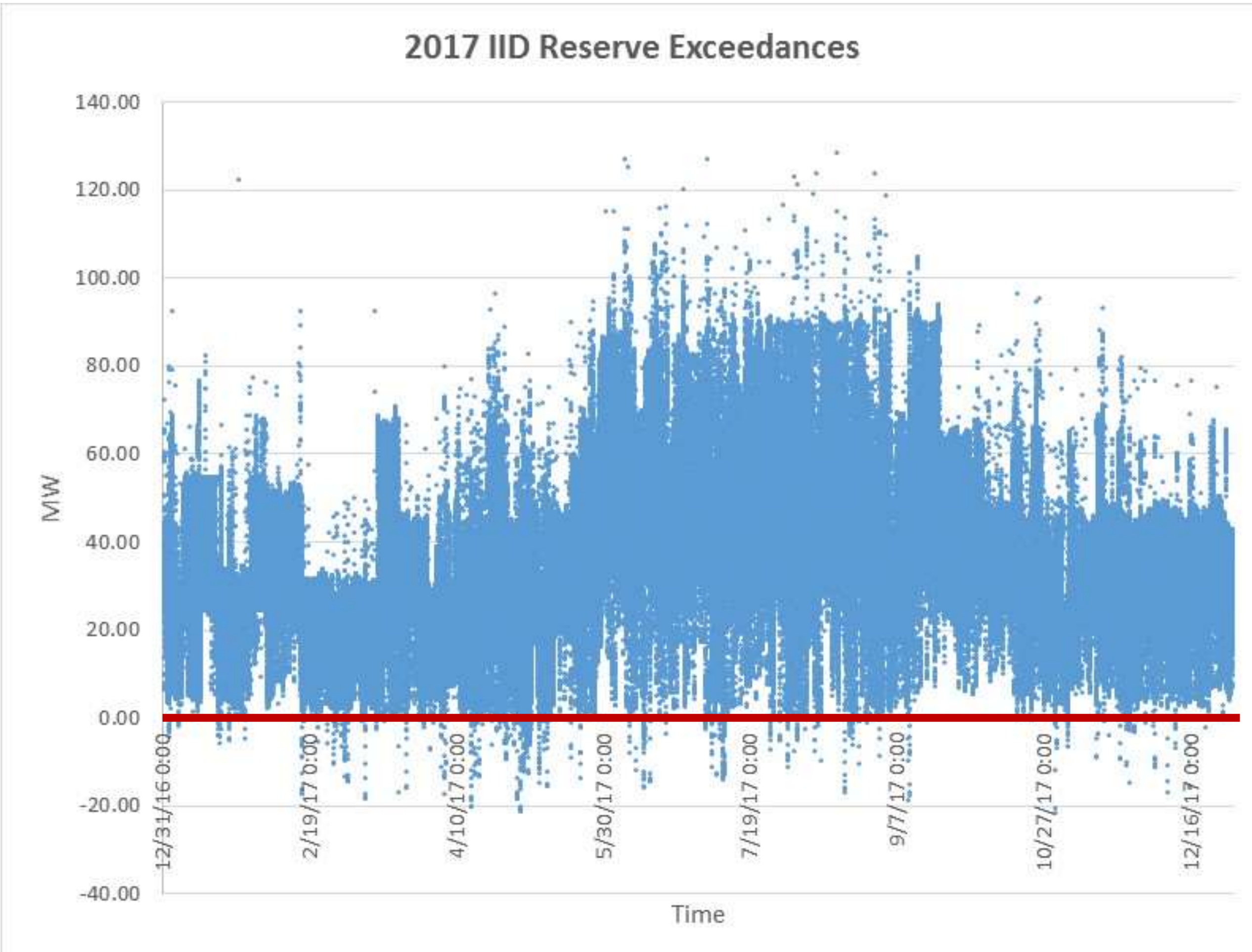
Exhibit 154: IID system ACE for the entire year (minute intervals).



RESULTS

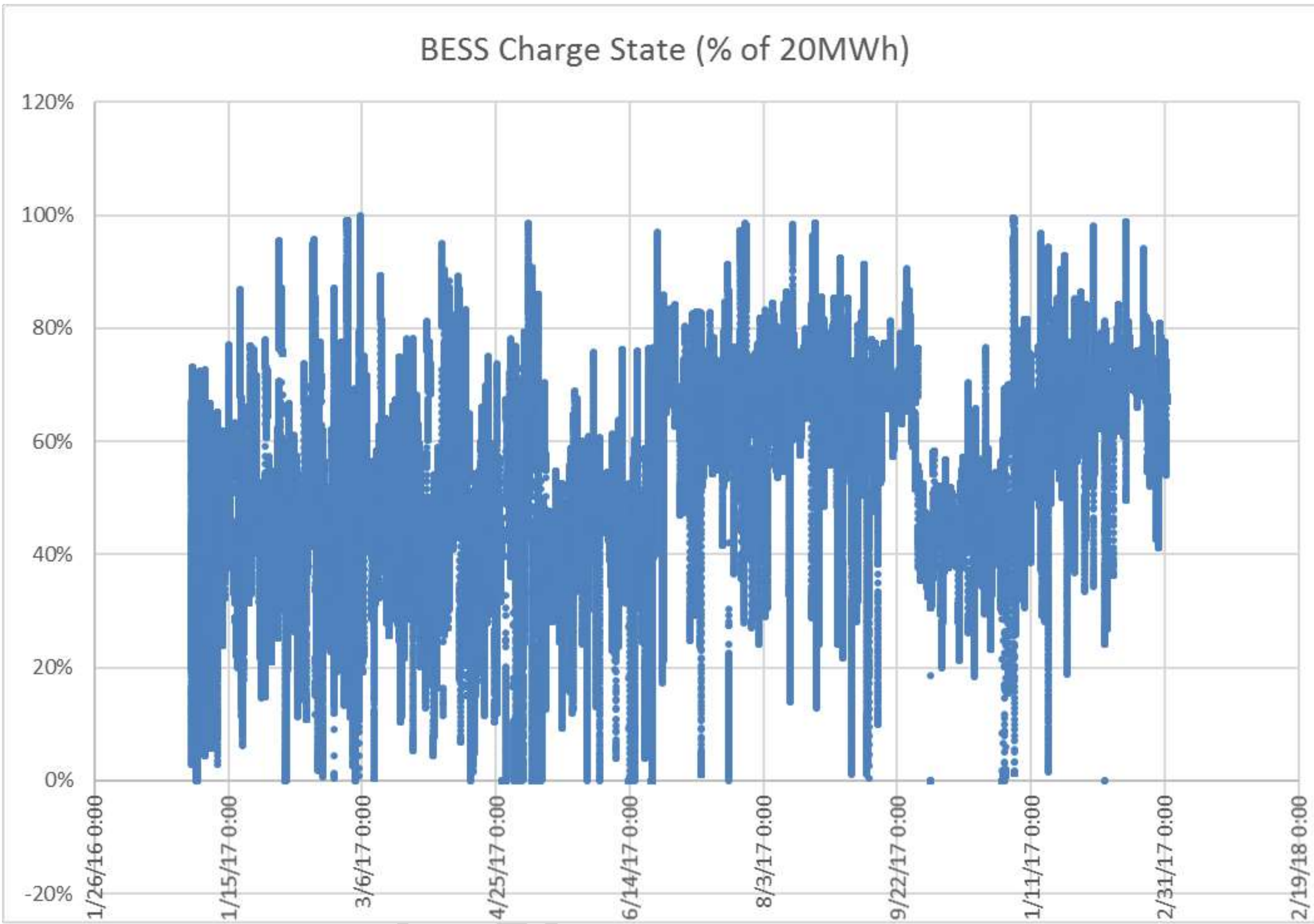
Using the reserve exceedance data (shown in **Figure 2)** it can be noted that the IID system has a surplus of spinning reserves throughout most of the year. However, there were instances where the IID was deficient in spinning reserves. This is shown on **Figure 2** by the points below the zero margin line. These represent operational periods where System Operations would have been incapable of withstanding further loss of generation and would have resulted in forced load shedding. While the duration of the deficiencies were below NERC required durations, it sheds light on the predicament that solar output variation has on the IID electric system. Magnitudes of deficiencies are in the -21 MW range. This means that IID was lacking 21MW of reserve at that moment and an event (such as loss of generation) would have triggered a proportional tripping of customer load in order to maintain its ACE and stay compliant with NERC operating standards.

Exhibit 155: IID Reserve Exceedances (redline indicates zero spin margin)



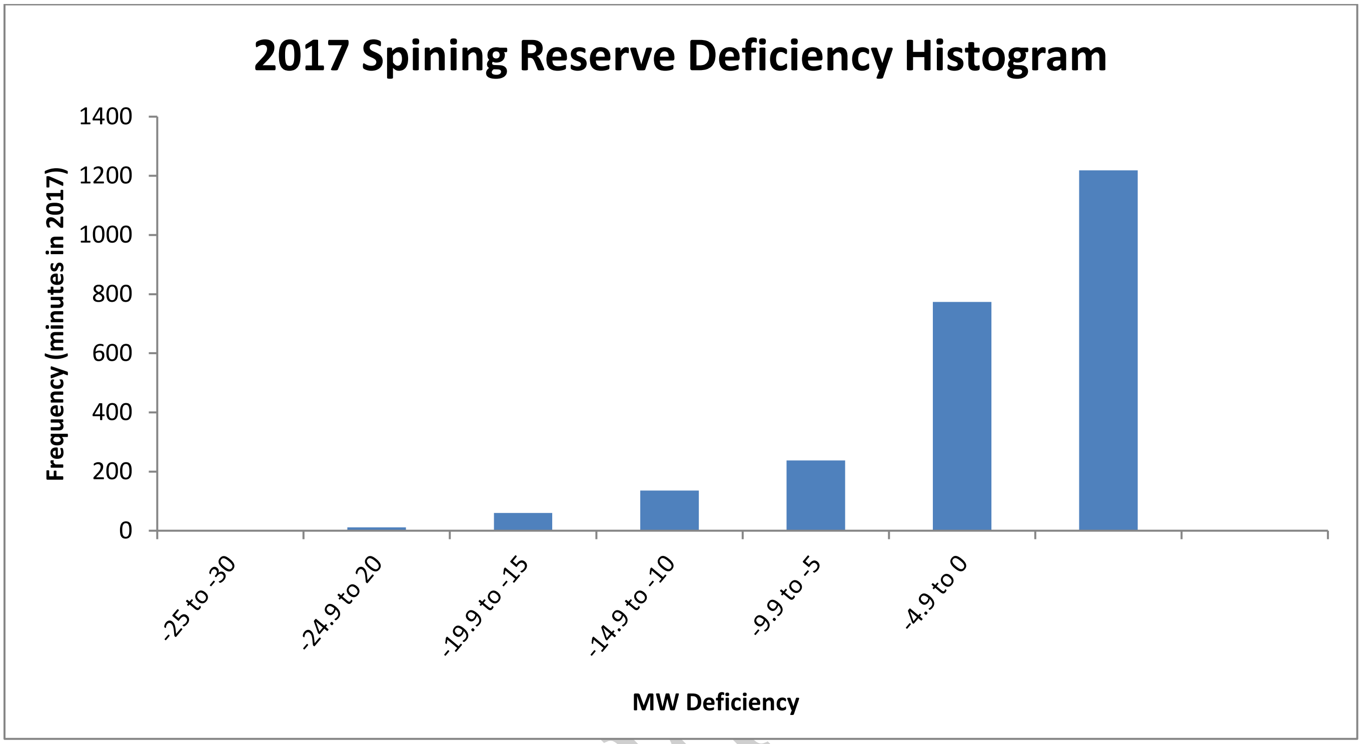
It should be noted that the current BESS (20MWH 33MVA system) has a continual 20 MWH contribution in the current EMS calculation for spinning reserves. This adds a margin of error to the reserve exceedance calculation because it assumes the BESS is always at a 100 percent state of charge. **Figure 3** shows that this is not the case. The average state of charge of the BESS for 2017 was in the 55 percent range. It is recommended by the current BESS battery manufacturer (Samsung Electronics Co.) to keep the charge state of the battery below 80 percent as faster degradation of the batteries occurs during a full charge state. This is an important factor to consider when calculating size for a future BESS.

Exhibit 156: BESS Charge State for the entire year (minute intervals).



Observing the histogram of the 2017 reserve exceedances (above) it can be seen that there were over twelve hundred minutes during which IID was deficient in spinning reserves. The largest magnitude being in the 22MW range. Based on this spinning reserve requirement it can be concluded that if the IID System Operations had an additional 22 MWh battery energy storage system in 2017, IID would not have been at risk of shedding load at any point in the year. However, this assumes that the 22 MWh battery would have been at 100 percent charge state. Based on the battery manufacturer recommendations, stated above, the charge state should not be above 80 percent. Thus the ideal size of an additional BESS should be 20 percent larger than what is operationally required to ensure battery degradation does not occur at an accelerated rate. Therefore, to avoid battery degradation and shorter battery life span, the recommended size of an additional BESS system should be in the 26 MWh range. This value is represents a conservative estimate as it does not include the actual spinning reserve provided by the current BESS (error), nor the 30 MW of solar generation from Citizen Solar, which is scheduled to come online in 2018. Consequently, IID may expect to see a system size for an additional BESS, which is closer to the 30 MWh range.

Exhibit 157: Histogram showing all the instances in 2017 that IID was deficient in spinning reserves



FACTORS IN CONSIDERATION

This statistical analysis is a sound foundation for further analysis into sizing of an additional BESS system or expansion of the current system. The analysis shows that a 26 MWh battery energy system would enhance the reliability of the IID system in terms of minimizing potential load shedding scenarios. Analysis also highlighted that the number can be closer to the 30 MWh range when accounting for the error in the spinning reserve exceedance data and the 20 MW solar plant that is set to come online in 2018. In regards to the location of the BESS, System Operations has conducted several assessments related to voltage stability and has flagged weak performing substation in the Coachella Valley area. Hence, ideal placement for the BESS, given its wide range reactive capability is in the Coachella area. But given future transmission expansion projects assessment is required to determine the optimum sizing and location of a new BESS.

4. Additional studies to address Resource Needs

In addition to the previously mentioned studies, IID performed more in depth studies to address two main areas in question:

(1) Comparison of resources to address current system reliability and stability needs.
(2) Comparison of resources to address the need for RPS and GHG reducing resources in 2028.

Below is a summary of the resources tested along with some of the key preliminary qualitative findings:

Exhibit 158: Resources Tested and Preliminary Findings

Resource Category	Technology	Key Findings from Studies
Combined Cycle	1 x 1GE 7FA	High Capital Cost; Low Flexibility; Low HR
	2 x 1 GE 7FA	High Capital Cost; Low Flexibility; Low HR
	2 x 1 Advanced Class	High Capital Cost; Low Flexibility; Low HR
	EC#4 Repowered	High Capital Cost; Low Flexibility; Low HR
	Yucca Repowered	sSame as EC#4; Out of State Imports; No Local Gen
Combustion Turbine	GE 7 FA	High Emissions; Mid Flexibility; Mid HR
	LM 6000	High Emissions; Mid Flexibility; Mid HR
	LMS 100	High Emissions; Mid Flexibility; Mid HR
	Coachella Adjustments	Low Capital; Mid Flexibility
Wartsila Power Engine	20V34SG(50MW+)	Low Capital; High Flexibility; Permitting Issues
	18V50SG (100 MW+)	Low Capital; High Flexibility; Permitting Issues
Caterpillar Reciprocating Engine	G3520H	Low Capital; High Flexibility; Permitting Issues
	CG260-16	Low Capital; High Flexibility; Permitting Issues
	G20CM34	Low Capital; High Flexibility; Permitting Issues
Purchases	Tolling agreements	Higher Premium; Low HR; Not Local Gen
	Asset Acquisition	Higher Premium; Low HR; Not Local Gen
	Seasonal Options	Low Cost; Not Local
Renewables	Solar (or solar ownership)	No Debt; Low Variable; High Integration
	Solar + Storage	No Debt; Low Variable; High Integration
	Biomass and Geothermal	No Debt; Low Variable; High Integration
	Wind	No Debt; Low Variable; High Integration
	In State Purchases sink to CAISO	No Debt; Low Variable; No Integration
	In State Purchases sink to IID	No Debt; Low Variable; High Integration
	Out of State Purchases sink to CAISO	No Debt; Low Variable; No Integration
	Out of State Purchases sink to IID	No Debt; Low Variable; High Integration
Storage	Additions to Niland to Provide Spin	Low Capital; High flexibility; Mid HR
	Compressed Air storage	Mid Capital; High flexibilty; Low Energy
	Battery Storage (Flow, Lithium, Nickel Cad)	Mid Capital; High flexibilty; Low Energy
	Super Capacitors	Low Capital; Not an energy resource
	Flywheel Energy Storage	Mid Capital; High flexibilty; Low Energy
	Pumped Storage	Mid Capital; High flexibilty; Low Energy
Potential Retirements	Yucca	High O&M; High system need; Mid HR
	Coachella 1-4	High O&M; High system need; High HR/emissions
	Rockwood 1&2	High O&M; High system need; High HR/emissions
	Hydros	High O&M; High system need; Mid HR
	GT21	High O&M; High system need; High HR/emissions

Overall, this study contained there were a much larger portion of factors for these studies, so there were approximately 2,268 different iterations and cases between all studies performed. Since the variables can provide differing results, there were three main cases for all runs to identify how changing variable may change in each case. These three cases were:

(1) High load growth.
(2) Expected load growth.
(3) Low load growth.

Please refer to the chapter with the load forecast details for more details on the above cases.

Below is a table that summarizes all cases and scenarios performed in these additional studies:

Exhibit 159: Cases and Scenarios Overview

2018 IRP: Cases and Scenarios Overview									
Case Study	Load	Gas Prices	Energy Prices	Emissions Prices	Emissions Targets	RPS Targets	Transmission	Retirements (2021)	New Resources (2021)
Base/Expected Case	Base Case	High	High	High/Mid /Low	Mid/Extreme Low	50% by 2030	IV Upgrades	Coachella, Rockwood, Yucca, GT21, Small Hydros	GTs, LMS100, Repowering, Reciprocating Engines, Energy Storage, Solar, Biomass, Geo, Wind, Market Energy
		Mid	Mid			60% by 2030			
		Low	Low			100% by 2040			
High Case	High Case	High	High	High/Mid /Low	Mid/Extreme Low	50% by 2030	IV Upgrades	Coachella, Rockwood, Yucca, GT21, Small Hydros	GTs, LMS100, Repowering, Reciprocating Engines, Energy Storage, Solar, Biomass, Geo, Wind, Market Energy
		Mid	Mid			60% by 2030			
		Low	Low			100% by 2040			
Low Case (Other Observation ZNE case)	Low Case	High	High	High/Mid /Low	Mid/Extreme Low	50% by 2030	IV Upgrades	Coachella, Rockwood, Yucca, GT21, Small Hydros	GTs, LMS100, Repowering, Reciprocating Engines, Energy Storage, Solar, Biomass, Geo, Wind, Market Energy
		Mid	Mid			60% by 2030			
		Low	Low			100% by 2040			

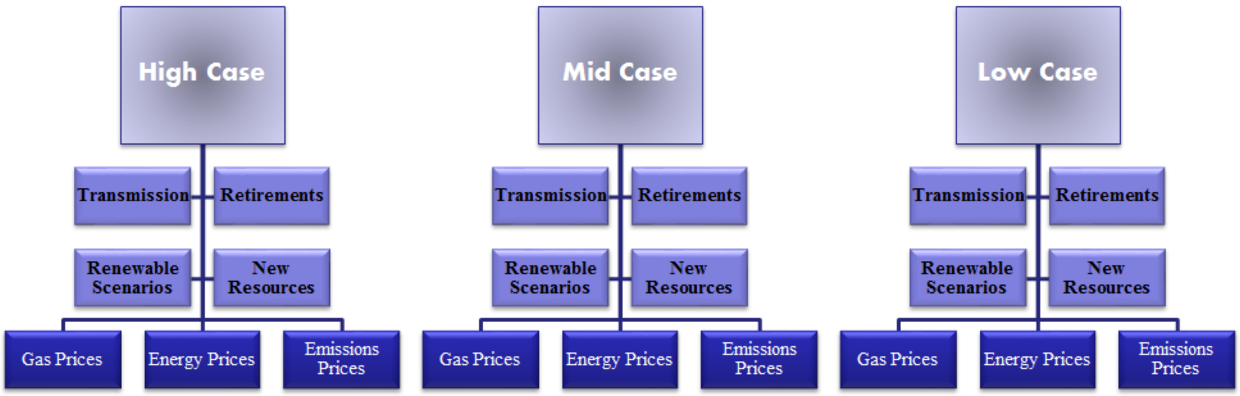
Furthermore, below is a summary of the various resources studied each combined with the various cases:

Exhibit 160: Additional Portfolios Studied

2018 IRP: Portfolios Studied						
Case Study	RPS/GHG Portfolio (Ran in Each Case)	New Unit Additions (Ran for each Case and Portfolio)	Gas Prices	Energy Prices	Emissions Prices	Emissions Targets
Preferred Case (Base Case) High Case Low Case (Other Observation ZNE case)	100% Geo/Biomass; 0% Solar 0% Geo/Biomass; 100% Solar 75% Geo/Biomass; 25% Solar 60% Geo/Biomass; 40% Solar 45% Geo/Biomass; 55% Solar 30% Geo/Biomass; 70% Solar 10% Geo/Biomass; 10% Solar	LMS 100 - 30 MW in 2021 LMS 100 - 60 MW in 2021 LMS 100 - 100 MW in 2021 Reciprocating Engines - 30 MW in 2021 Reciprocating Engines - 60 MW in 2021 Reciprocating Engines - 100 MW in 2021 EC 4 Repower (145 total at EC4; 75 MW new in 2021) Energy Storage - 30 Mw (1Hr) in 2021 Energy Storage - 60 Mw (1Hr) in 2021 Energy Storage - 100 Mw (1Hr) in 2021 Energy Storage - 30 Mw (4Hr) in 2021 Energy Storage - 60 Mw (4Hr) in 2021 Energy Storage - 100 Mw (4Hr) in 2021	High/Mid /Low	High/Mid /Low	High/Mid /Low	Mid/Extreme Low

Furthermore, below is a diagram that provides a high level picture of the scenarios tested:

Exhibit 161: High Level Overview of Scenarios Tested



For RPS purposes, below is a table of the RPS/GHG portfolios and the capacity each portfolio requires to meet the various compliance targets:

Exhibit 162: RPS Portfolios and Capacity/Energy Requirements

IID Energy & Capacity Requirements with 50% RPS: 2030								
Case	Generation Requirements (MWh)	Total Projected Generation (MWh)	Total Needed (MWh)	Possible Mix of Resources Technologies	Geo/Biomass or other Baseload		Solar/Wind or other Intermittent	
					MW	MWh	MW	MWh
Expected Case	**1,953,804**	**779,603**	**1,174,201**	100% Base	149	1,174,201	-	-
				100% Intmt.	-	-	394	1,174,201
				75% Base, 25% Intmt.	112	880,651	99	293,550
				60% Base, 40% Intmt.	89	704,521	158	469,681
				45% Base, 55% Intmt.	67	528,391	217	645,811
				30% Base, 70% Intmt.	45	352,260	276	821,941
				10% base, 90% Intmt.	15	117,420	355	1,056,781
High Case	**2,376,282**	**779,603**	**1,596,679**	100% Base	203	1,596,679	-	-
				100% Intmt.	-	-	536	1,596,679
				75% Base, 25% Intmt.	152	1,197,509	134	399,170
				60% Base, 40% Intmt.	122	958,007	214	638,672
				45% Base, 55% Intmt.	91	718,506	295	878,173
				30% Base, 70% Intmt.	61	479,004	375	1,117,675
				10% base, 90% Intmt.	20	159,668	482	1,437,011
Zero Net Energy	**1,726,765**	**779,603**	**947,162**	100% Base	120	947,162	-	-
				100% Intmt.	-	-	318	947,162
				75% Base, 25% Intmt.	90	710,372	80	236,791
				60% Base, 40% Intmt.	72	568,297	127	378,865
				45% Base, 55% Intmt.	54	426,223	175	520,939
				30% Base, 70% Intmt.	36	284,149	223	663,014
				10% base, 90% Intmt.	12	94,716	286	852,446

Under the three different cases, each case will have various effects on the timing of needs as well as the outcomes. This was a major factor in the IID studies. Below are several graphs that compare the RPS requirements under the three different load growth cases:

Exhibit 163: RPS Scenarios (Expected Case)

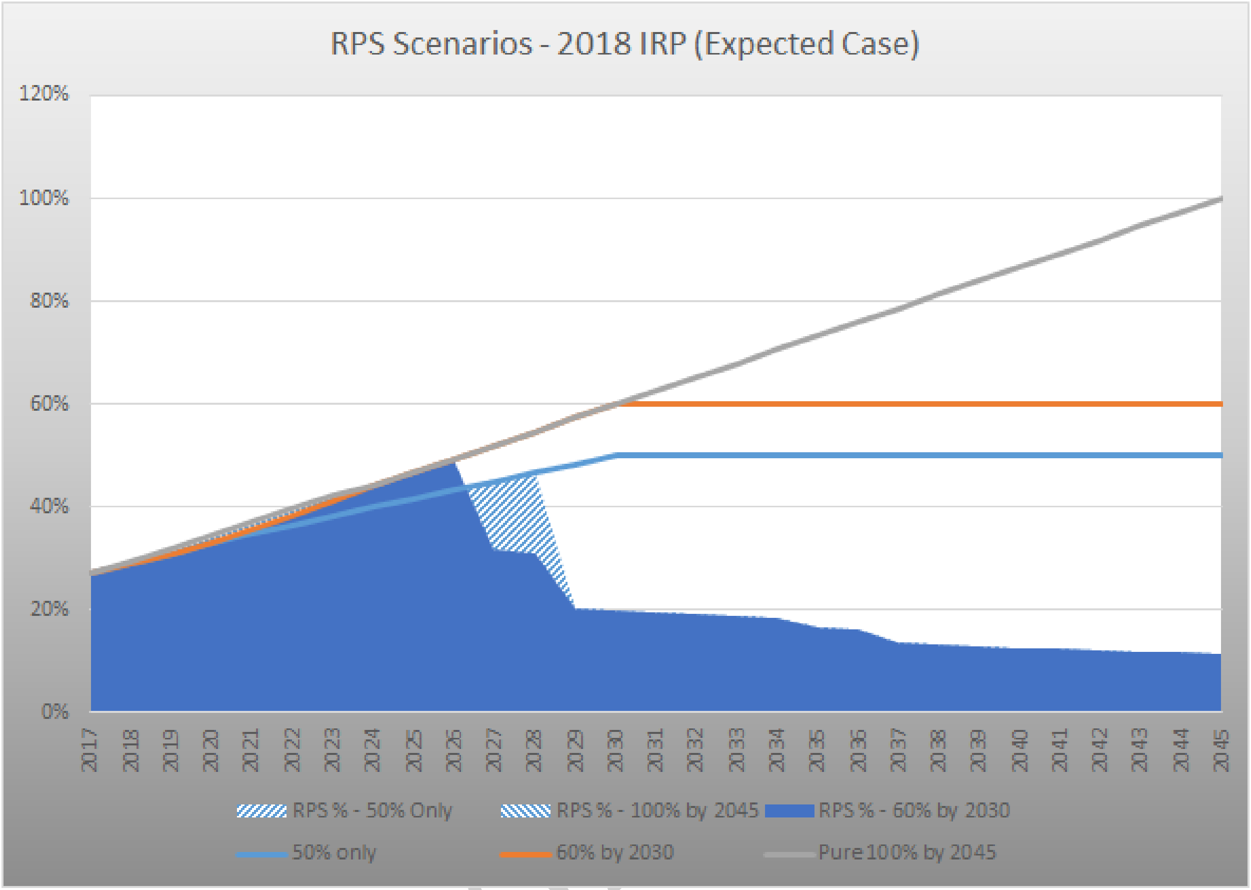


Exhibit 164: RPS Scenarios (High Case)

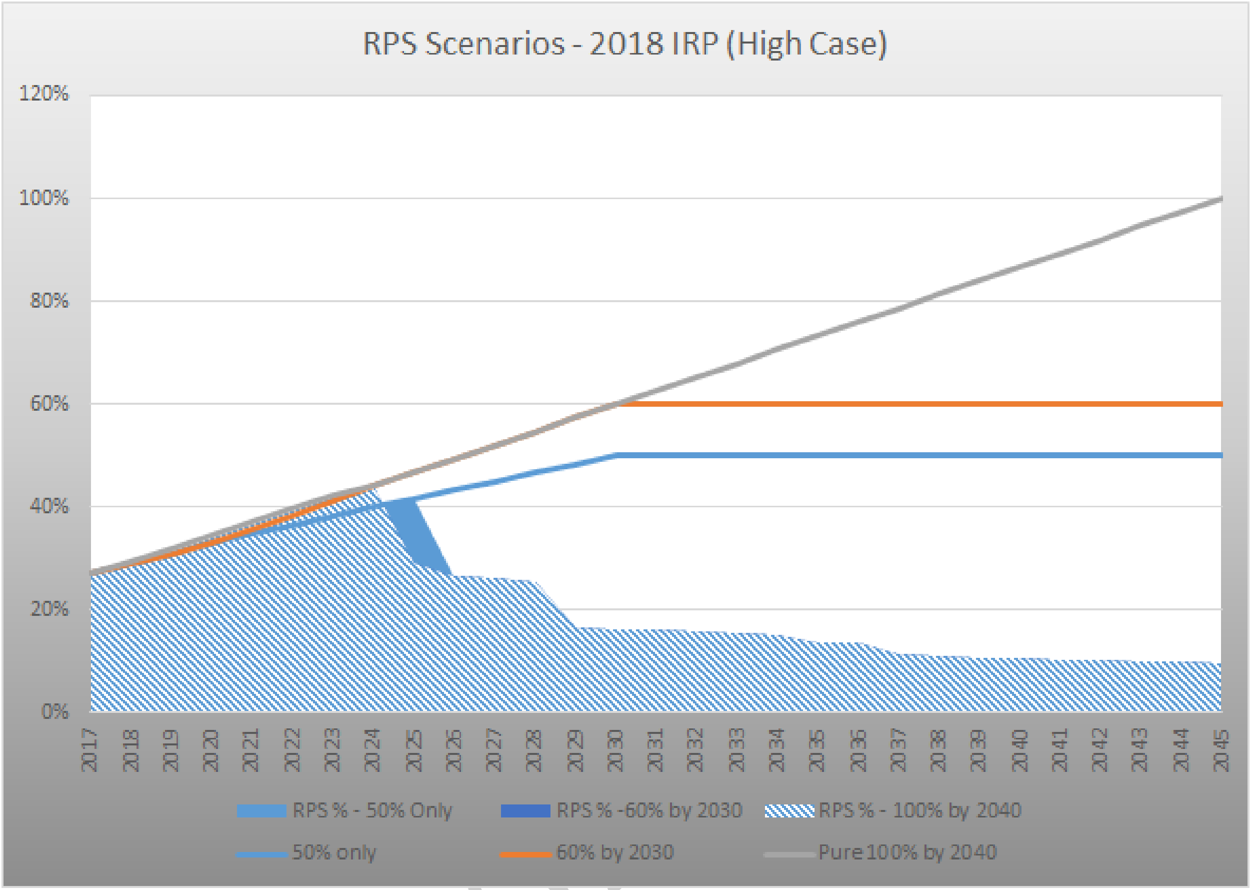
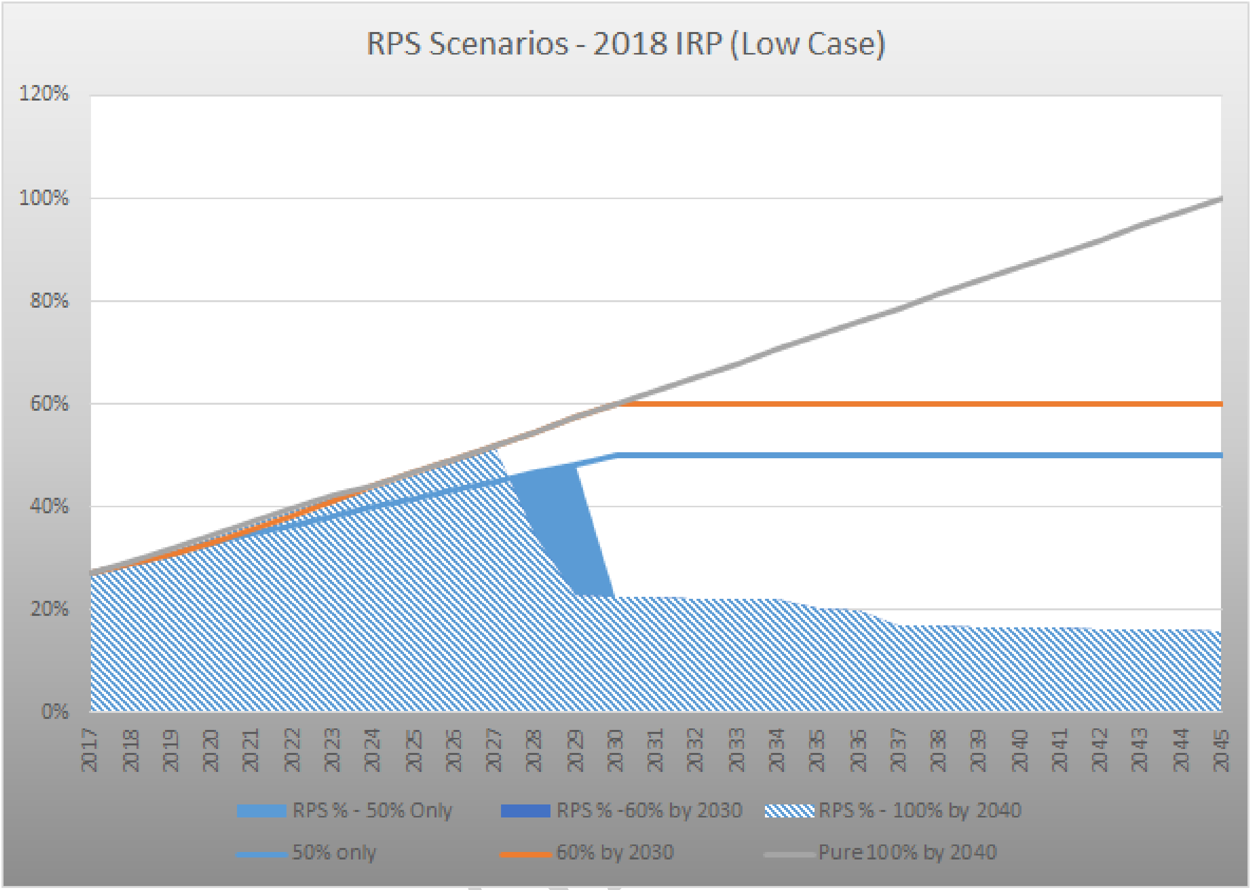


Exhibit 165: RPS Scenarios (Low Case)



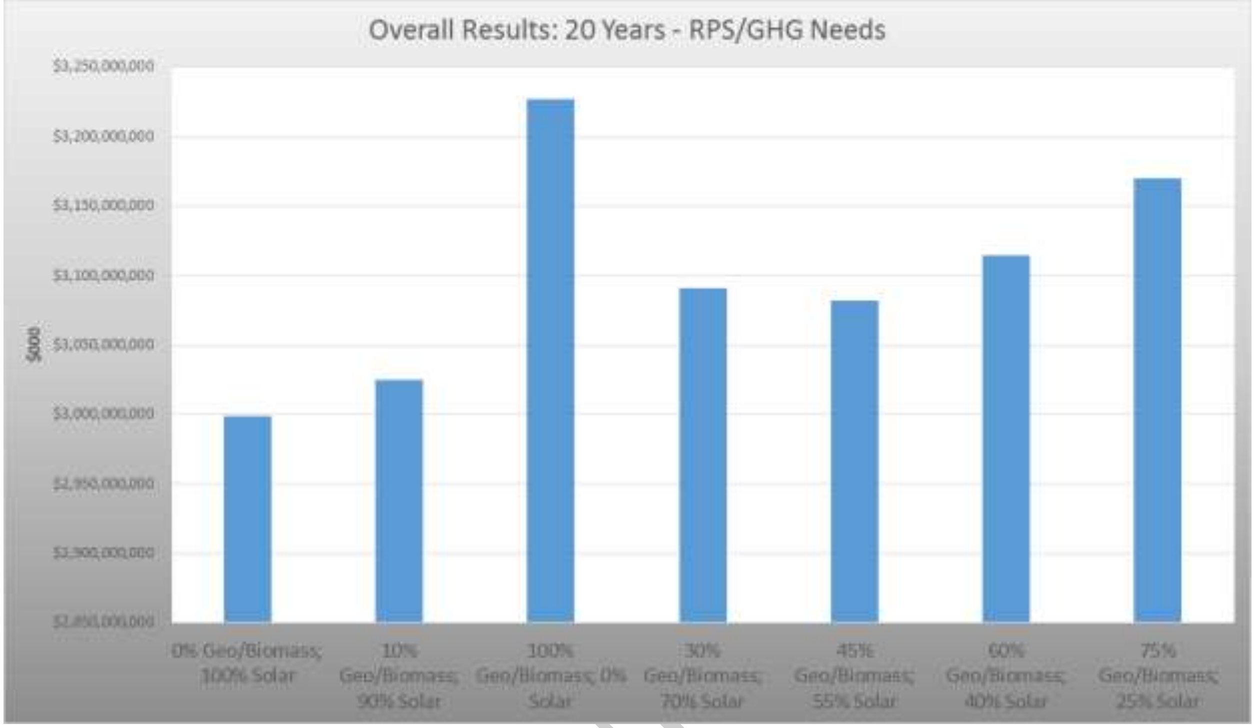
As shown in the graphs above, there are many potential outcomes in how the RPS goals will need to be met, especially with the recently passed SB 100. The guidelines have yet to be released, but the key question is how the guidelines will define "zero net carbon". This is the reason we have three RPS cases analyzed in this IRP:

(1) SB 350 with a goal of 50 percent by 2030
(2) SB 100 with a goal of 60 percent by 2030 and assuming other resources count for the 2045 goal
(3) SB 100 with a goal of 60 percent by 2030 and pure 100 percent by 2045.

Adding these uncertainties to the many uncertainties related to IID's load growth, energy prices, gas prices, emissions prices, resource capabilities and reliability, among others is important to consider as IID makes decisions today for the next 20 years. This IRP does not recommend to bring on all resources today in anticipation of some of these variables as this adds greater risk to the cost stability and system reliability. These studies, results and recommendations reflect these considerations.

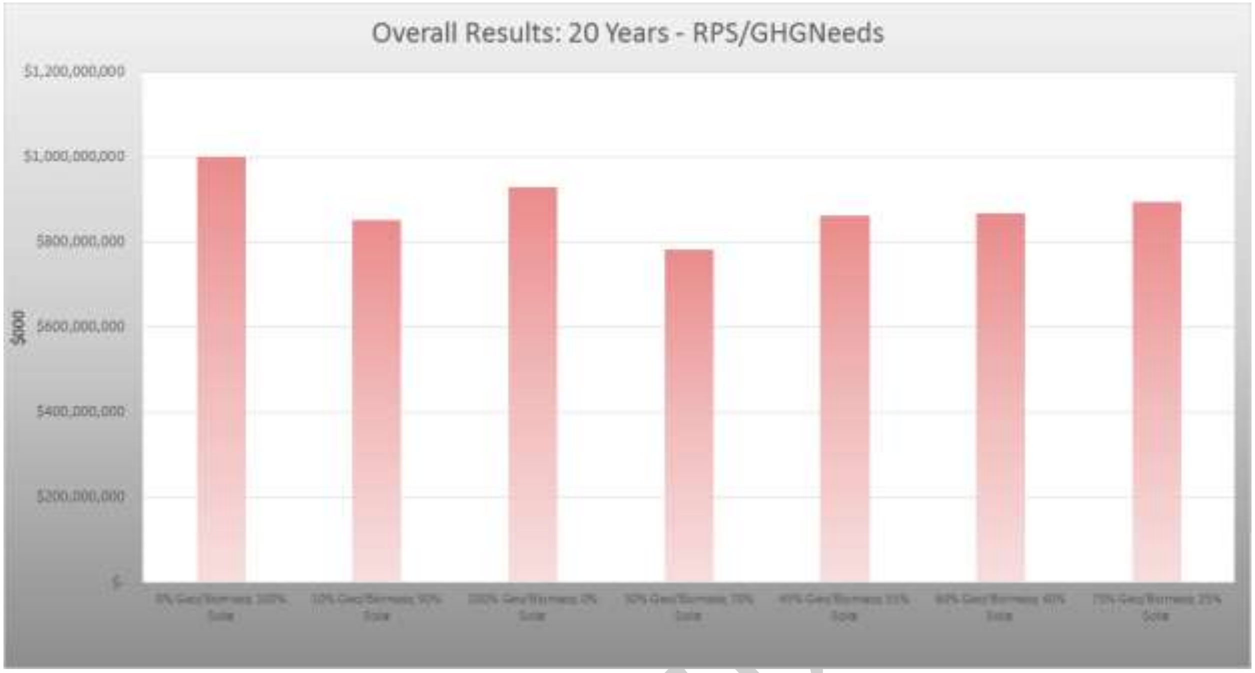
As previously discussed, there are two basic reasons for these additional studies. Below is summary result of all studies addressing the cost of the best mix of RPS/GHG resources in 2028 of the seven different mix cases for all iterations over a 20-year period, assuming the expected load case:

Exhibit 166: Additional Study Results – Overall RPS/GHG Studies



The chart above represents an average of all scenarios studied for these RPS/GHG cases. As displayed in this chart, the ‘all solar’ case is the least cost using the current set of assumptions as previously described. If the amount of influx of solar + storage products causes over generation, then there is a situation where the ‘all solar’ case is not the least expensive and contains reasonable risks in coerced sales into a negatively priced market environment (i.e., paying to dump energy). Furthermore, in a high price low/low load environment, the much higher capacity required for solar facilities would also present a higher risk portfolio. Below is a graph that represents the range of risk of each portfolio:

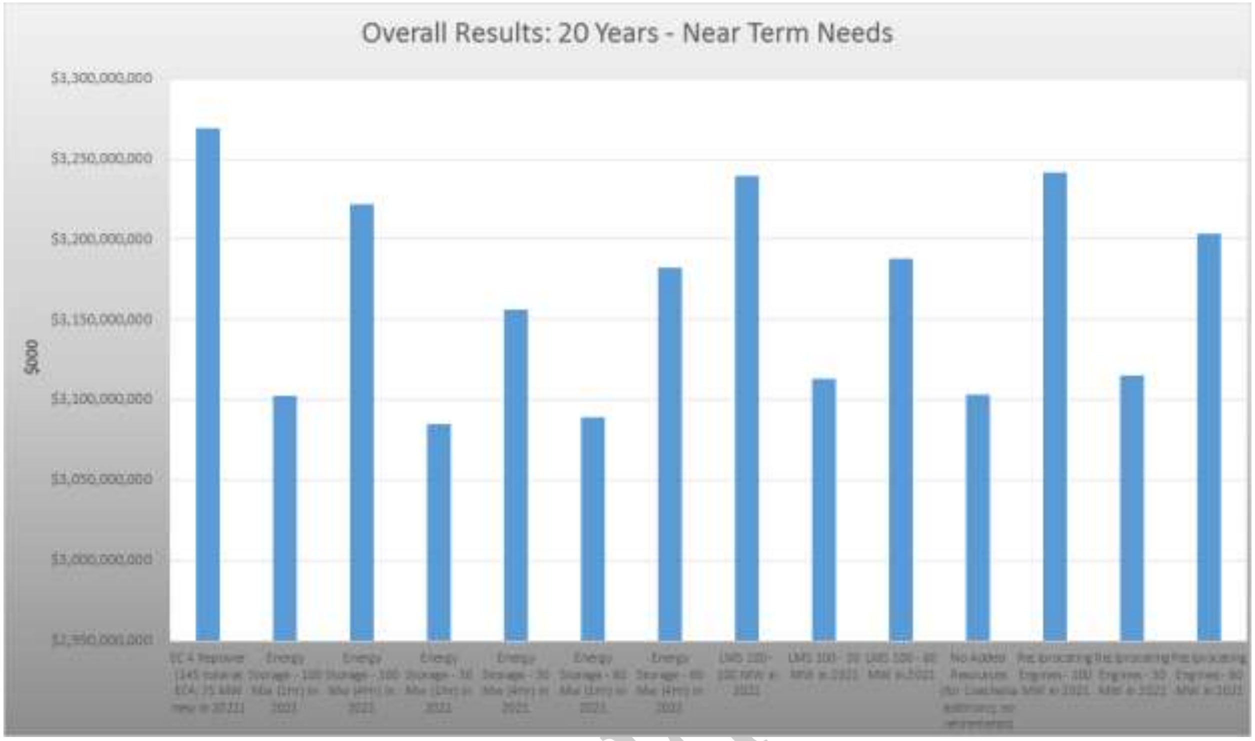
Exhibit 167: RPS/GHG Case Portfolio Range of Risk



As a result, this IRP recommends a mix of resources to meet RPS/GHG needs in the 2028 time frame. Particularly, the preferred case is to mix 90 percent solar with 10 percent baseload resources in 2028.

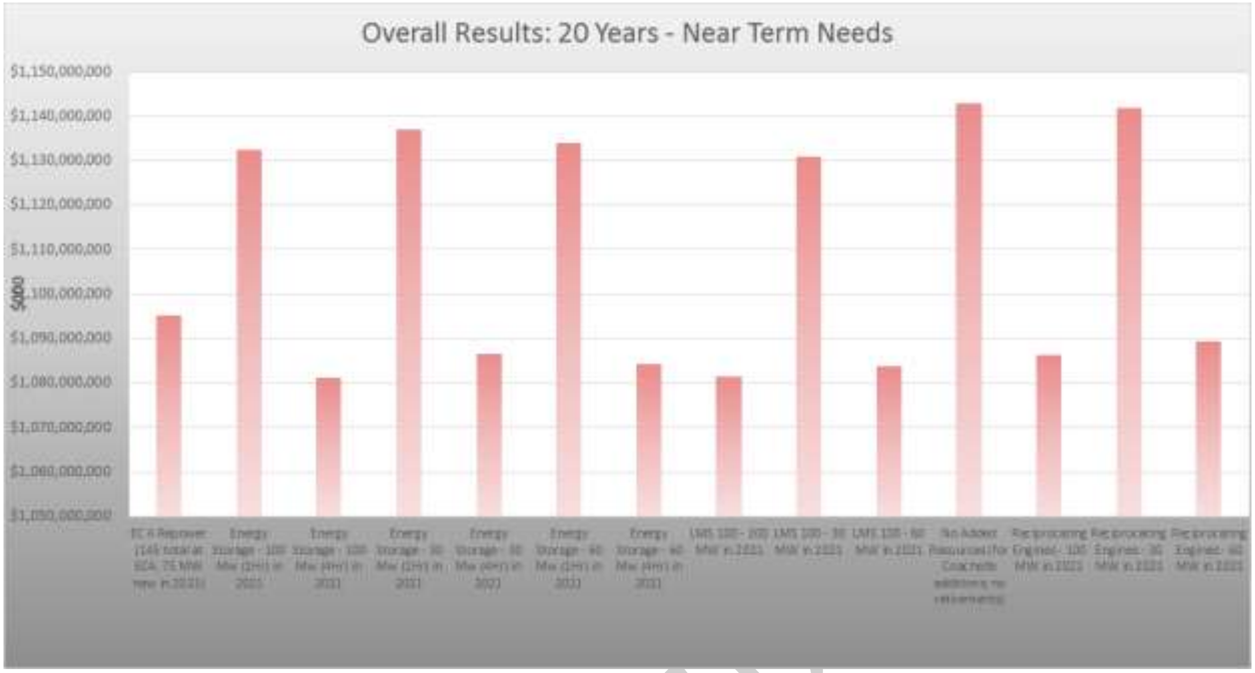
To address the second reason for these studies – IID's near term operational needs – these additional studies also ran a combination of runs with the RPS/GHG based cases. This was described in the previous sections and below are the overall results of all cases for this second aspect of the studies:

Exhibit 168: Additional Study Results – Near Term Needs



As shown in the table above, the 1-hour batteries are very cost competitive. The 30 and 60 1-hour batteries are estimated to actually reduce IID system cost, even when the capital investment is included. This is mainly because of their operating abilities and their relatively low capital costs. The risk assessment also favors the 1-hour batteries. Below are the results of the risk assessment:

Exhibit 169: Additional Study Results – Near Term Need Range of Cost Risks



As shown above, the battery storage systems are very low risk and the least cost providing an excellent platform for recommendation. As discussed previously, the ancillary services are lacking and a 26 MW battery is recommended from a reliability perspective. As a result of these studies, IID staff is recommending to issue a request for proposal for a 30 MW battery located in the Northern area of the IID system.

Key Factors in Consideration of Retirements

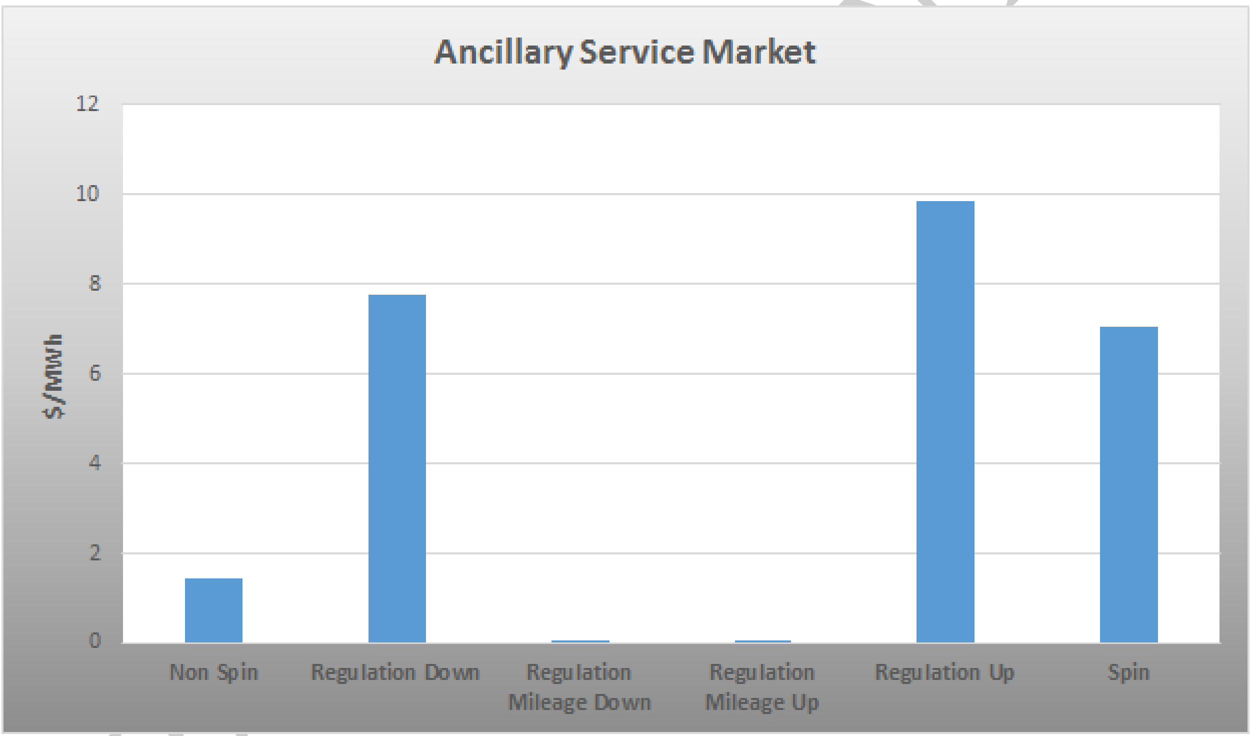
In addition to these studies, unit retirements is a central question at the current moment for IID; however, besides the cost of O&M and energy, there are several other factors that must be considered to properly address this issue. These other factors are not discussed as commonly, but play a very critical role in assessing the value and cost of any resource. In addition to energy and capacity values, below is a list of other considerations in this assessment:

- Spinning reserves
- Non-Spinning reserves
- Regulation up
- Regulation down
- Regulation mileage up
- Regulation mileage down
- Start and stop abilities
- Frequency response and local physical inertia
- O&M costs
- Capital investment
- Dispatch flexibility

- Unit reliability
- RPS/GHG value

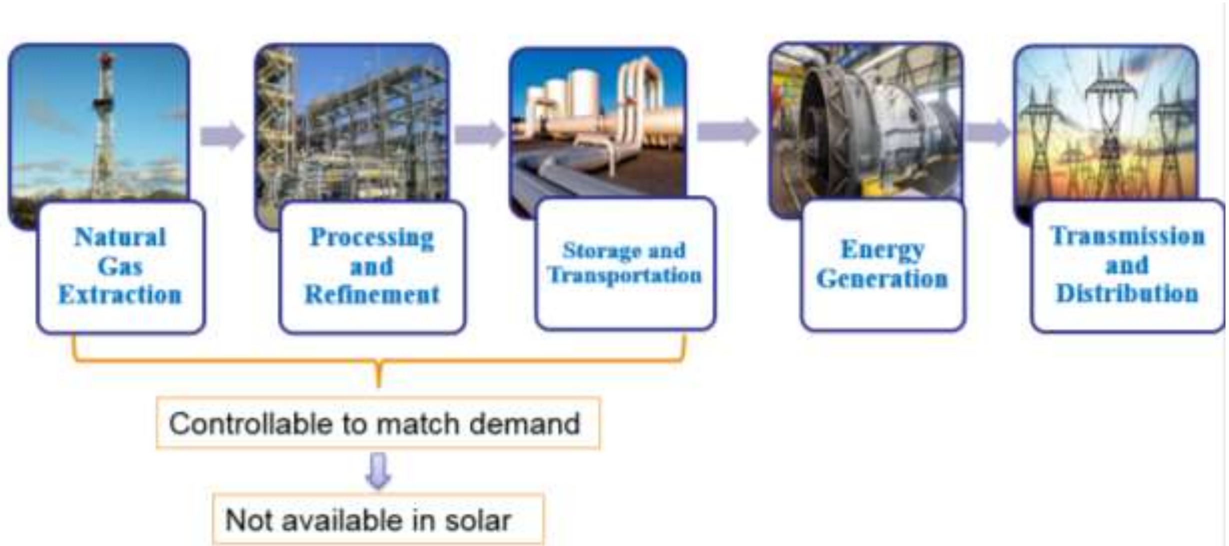
The above list is predominately based on the concept of "flexibility" and how well the resource can respond to common system events such as loss of load, loss of a resource, price fluctuations, etc. When assessing a new resource replacement, these resources must be compared as how all characteristics compare. While energy prices can range from $5-100/MWh (or greater) and capacity (fixed + variable O&M) prices can range from $50-150/kW-year, below is a comparison of some of the other value added components in some resource technologies:

Exhibit 170: Other Ancillary Service Values Considered in Resource Retirments



Some resource technologies do not offer the same as other resource technologies due to the ability to control the fuel source. One example is solar generation vs natural gas fired generation. Below is a table of the supply chain for energy resources that illustrates how the fuel source capability differs between these resources:

Exhibit 171: Generation Supply Chain



As a result of this, the following table compares how new resources compare to existing resources and their value/costs added comparison:

Exhibit 172: Resource Value Added Comparison

Local Units vs Mkt Products or Replacements					
Local Unit		Mkt Product		New Unit	
Value Added	Costs	Value Added	Costs	Value Added	Costs
Capacity value	O&M	Seasonal	Energy	Capacity value	Capital
Reg up	Fuel	Energy	Index Risk	Reg up	O&M
Reg down	Index Risk		Non local	Reg down	Fuel
Spin				Spin	Index Risk
NS				NS	
Energy				Energy	
Other Ancillaries				Other Ancillaries	

So, as shown above, the added value and costs are similar for local units vs. new units and the key aspect is if the lower cost variable and fuel costs can repay the capital investment in a reasonable amount of time. Although, there are some resource technologies that differ in this regard. Below are several summary charts of the last 10 years of IID's generation fleet and how they compare depending on the characteristic observed:

Exhibit 173: Total IID Unit $/MWh

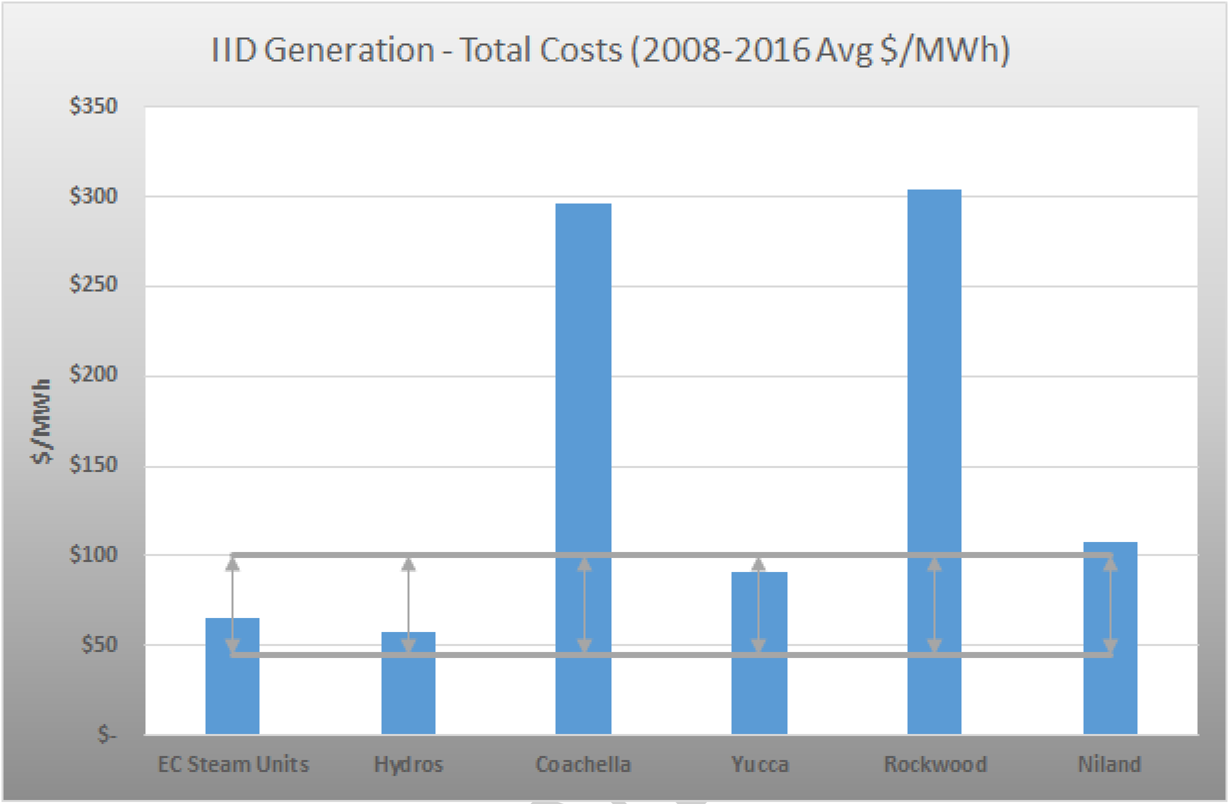


Exhibit 174: IID Unit Fuel $/MWh

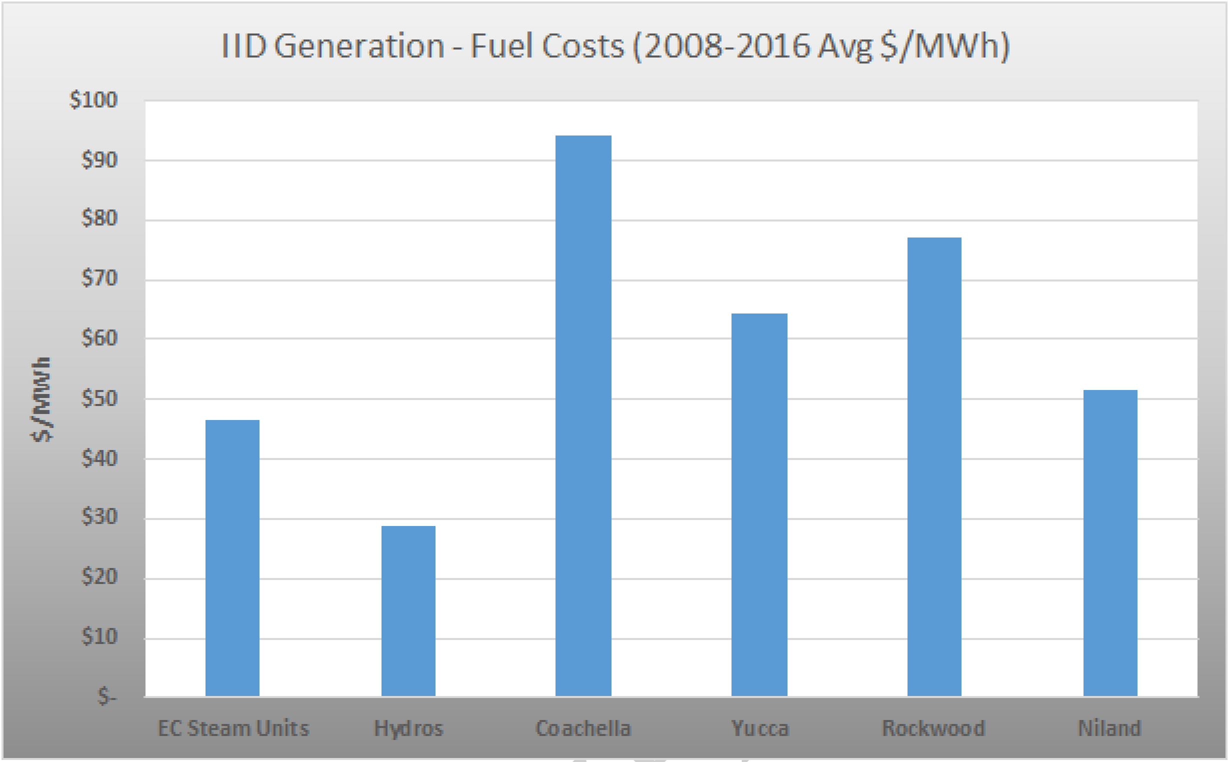
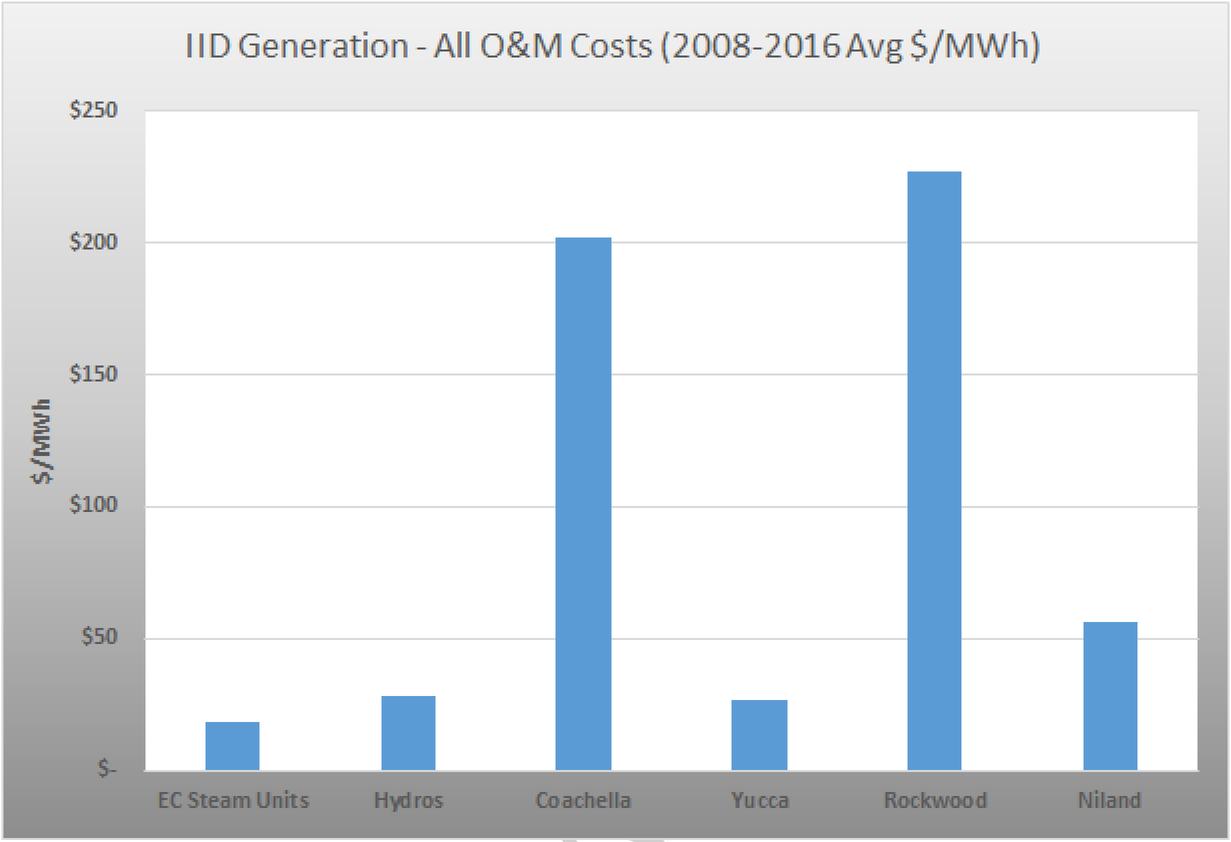
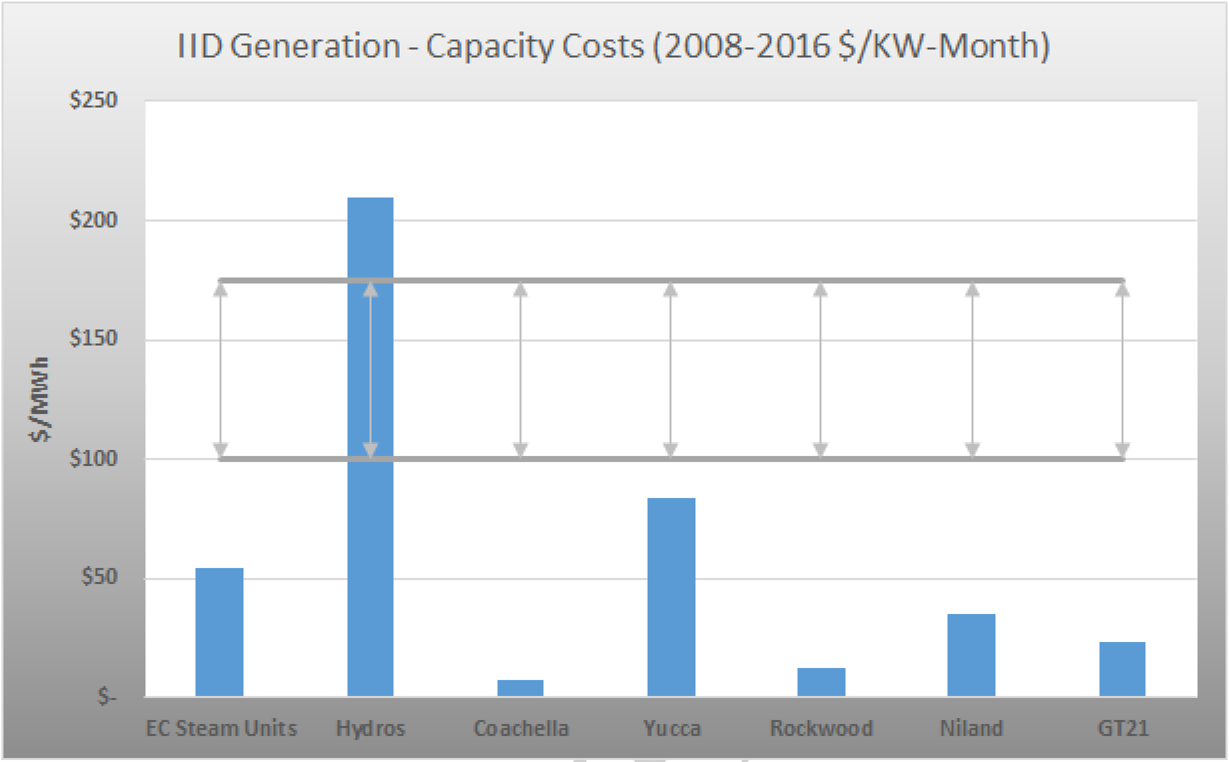


Exhibit 175: IID Unit All O&M $/MWh



Below is a bar graph that shows the average cost in capacity over the last 10 years and how it compares to the market of capacity costs:

Exhibit 176: IID Plant Capacity Cost Comparison



Below is a chart that displays the range of O&M costs for the last 10 years:

Exhibit 177: IID Plant Range of O&M costs for the Past 10 Years

In breaking down the hydro generation facilities, there are some more obvious conclusions:

Exhibit 178: IID Hydro Unit Breakdown $/MWh

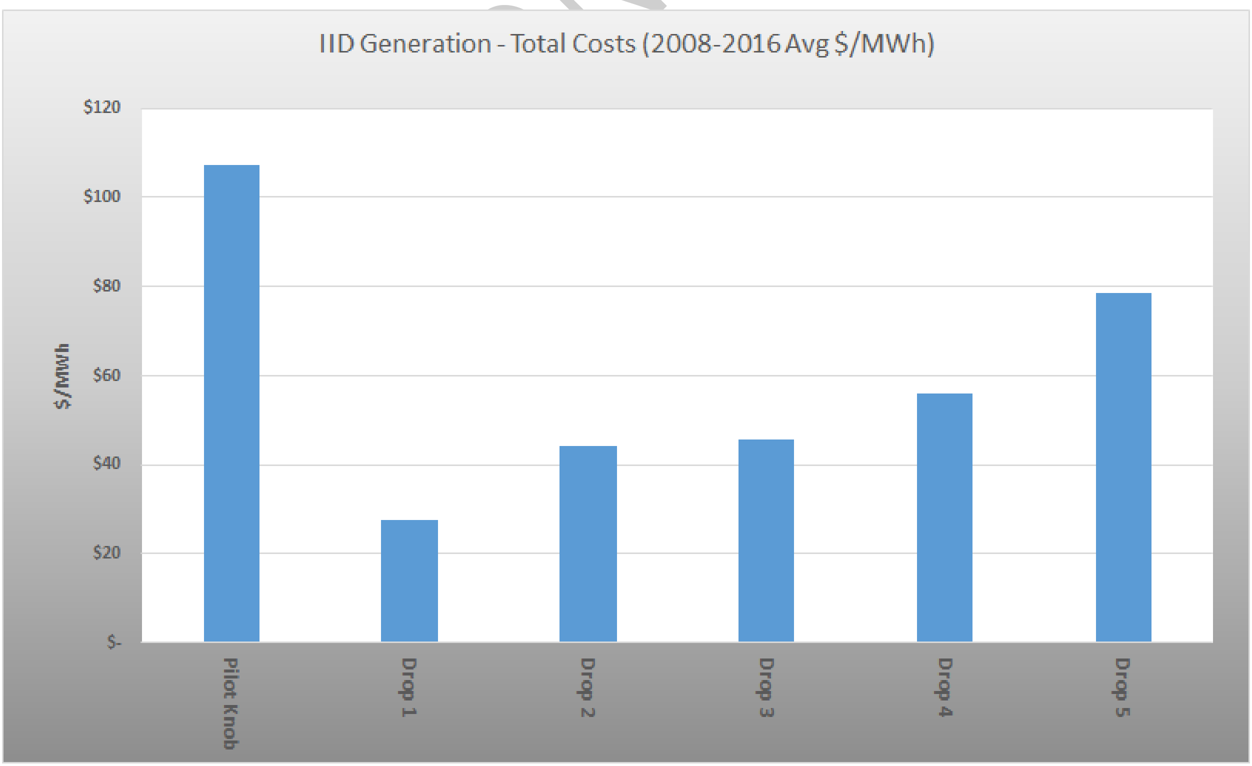
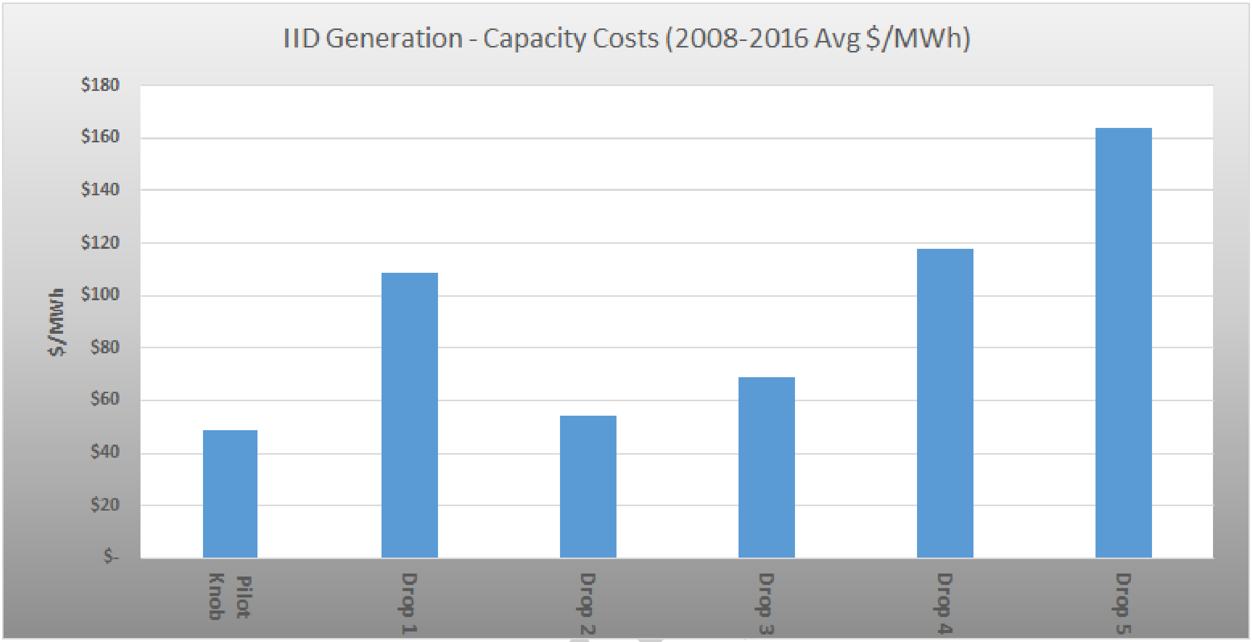


Exhibit 179: IID Hydro Unit Breakdown $/KW-month



When considering retirements for these studies, the evaluation includes all current costs as well as all costs to be incurred with a like kind replacement or replacements that do not offer the same type of generation characteristics (i.e., ancillary services). As a result, it is clear that IID's units are expensive in various areas like O&M and in some cases energy and capacity costs, but with no debt service, many of these units are typically less expensive than a like kind replacement.

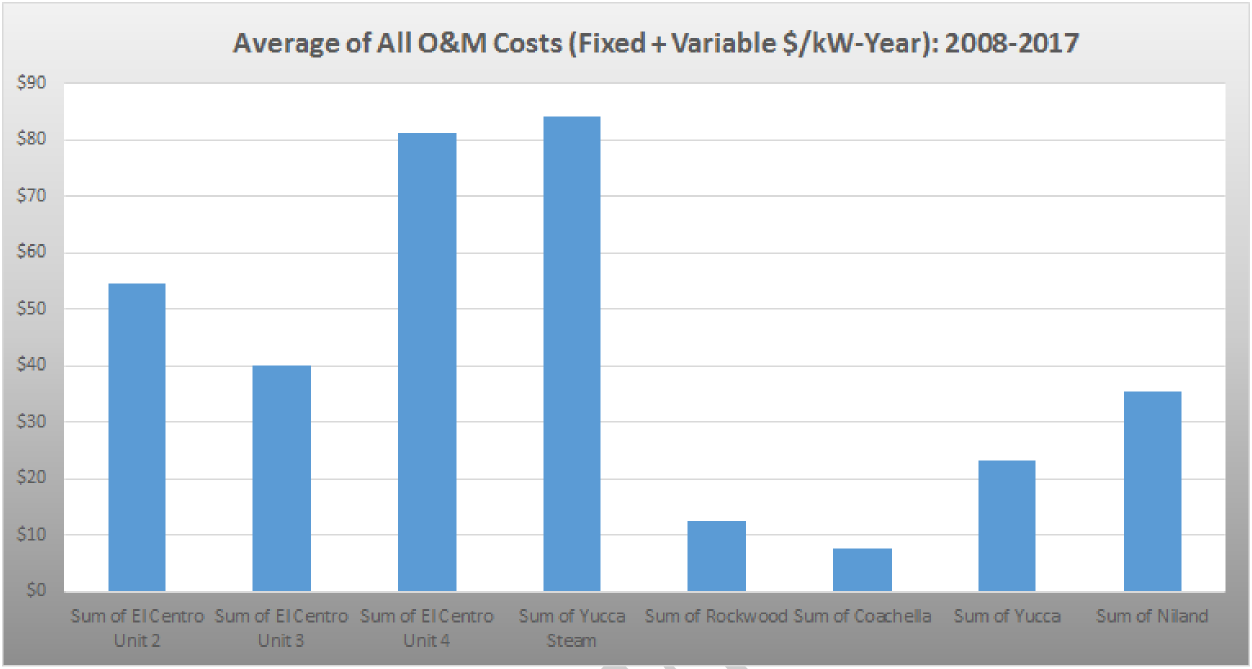
So, when comparing a replacement range of $40-120/MWh and capacity costs of $50-150/KW-month, there are 2 units that stand out as potentially cost-ineffective:

- Pilot Knob
- Drop 5

Both of those facilities have historically costed more than a market replacement. However, depending on the type of replacement, retiring these units is not always a better alternative. Furthermore, if the falling water charge is not included in these calculations, then all costs are essentially cut in half, making them cost effective when producing reliably. IID must closely observe these factors and work with the Water Department to determine how these units should be handled in the very near future.

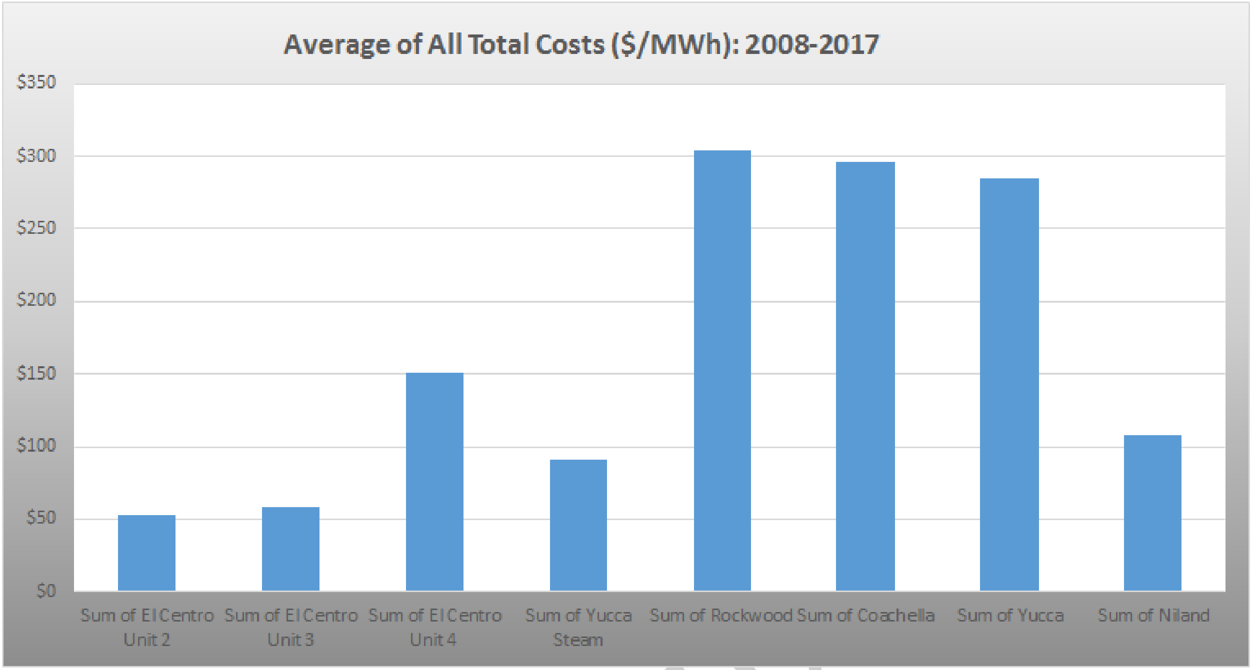
Taking a more specific look at IID's very old gas fired generation fleet, below is a table that compares each unit capacity cost (fixed and variable O&M):

Exhibit 180: IID Gas Fired Unit Capacity Costs



Once again, these units compare to a capacity cost of $50-150/KW-month and it appears that some of the units that are very old are providing a very high cost savings from this perspective. The other units that are slightly higher in cost provide a much lower $/MWh while also adding value in ancillary services helping balance the IID system properly. These units are used much more frequently. Below is a table that compares the $/MWh:

Exhibit 181: IID Gas Fired Unit Energy Costs



So, the facilities that are not used as much (Coachella/Rockwood/Yucca GT21) have a much higher $/MWh, but a much lower $/KW-month compared to the other facilities. So, replacing the older and higher $/MWh is a costly alternative, even with the added cost of capital investment needed for IID's local gas fired facilities. These older and higher $/MWh facilities are used for about 1000-4000 MWhs/year. This compares to IID's total load requirements of more than 3.5 million MWh. However, unit reliability must also be considered. While the internal perception of unit reliability for some of the older facilities is very poor, IID's in depth analysis of the reliability shows otherwise. Below is a table that was compiled and verified through several steps of validation:

Exhibit 182: IID Gas Fired Unit Reliability Statistics (6 years)

Average Annual Unit Statistics								
Unit	Registered Month	Attempted Starts	Actual Starts	Period Hours	Available (AH)	Availability Factor (AF)	Forced (FOH)	Forced Outage Factor (FOF)
ROCKWOOD GT #1	Total	52	49	8,760	7,571.98	86.36	613.01	6.99
ROCKWOOD GT #2	Total	17	15	8,760	8,160.34	93.07	99.98	1.14
COACHELLA GT #1	Total	24	22	8,760	7,980.44	91.02	509.84	5.82
COACHELLA GT #2	Total	26	24	8,760	8,338.27	95.10	106.02	1.21
COACHELLA GT #3	Total	19	18	8,760	8,511.07	97.07	80.81	0.92
COACHELLA GT #4	Total	22	22	8,760	8,573.45	97.78	81.30	0.93
Niland #1	Total	151	150	8,760	8,045.65	91.76	391.63	4.47
Niland #2	Total	135	134	8,760	7,872.55	89.79	521.89	5.96
ECGS U4	Total	2	2	8,760	7,244.27	82.65	279.87	3.20
ECGS Unit 2-1	Total	6	5	8,760	5,249.67	59.89	167.36	1.91
ECGS Unit 2-2	Total	8	7	8,760	5,315.56	60.65	142.41	1.62
ECGS Unit 3-0	Total	4	4	8,760	7,822.94	89.22	25.63	0.29
ECGS Unit 3-1	Total	16	9	8,760	7,526.06	85.84	331.71	3.78
ECGS Unit 3-2	Total	8	4	8,760	7,994.48	91.18	14.80	0.17

A range below 7 percent forced outages could be a concern in a major outage event, but in these situations, IID opts to procure the energy from the energy market, which is typically more expensive. However, this higher cost risk is nowhere near great enough to justify a new facility. However, for reliability purposes, unit investment to allow greater reliability can be a cost effective options over time.

As seen in the charts above, many of the value added characteristics differ from the various perspectives observed. So, after analyzing the data and comparing to offers, the following can be concluded:

- IID hydros are relatively in expensive when combined all together. The cost is cut in half when IID's falling water charge paid to the IID Water Department is no considered. Furthermore, with some capital investment, the units can run at their normal capability and the $/MWh can be greatly decreased when compared to the past year.
- IID retirements of IID's Coachella, Rockwood and Yucca facilities can be costly if they are replaced with facilities that offer the same type of resource characteristics. Furthermore, the CEC has not permitted any new gas fired facilities since 2015 and this is a major process risk.

LOCATION

Based on internal analysis, location is also a very critical factor and how new customer connect to the IID system will impact internal and interonnected flows. Therefore, studies suggest that a heavy influx of new load is possible in the Northern area of the IID system and this influx may require new generation closely located near the load pocket. In this instance, IID must consider quick responding generation and energy storage with low capital costs located near these potential new load pockets. Units such as reciprocating engines and energy storage would be best as described above since they are fairly low cost and contain reasonably low variable costs. The locational aspect may also override the economics of the EC#4 repower since this facility would be located in the Southern part of the IID system.

SYSTEM LOSSES AND PHYSICAL INERTIA

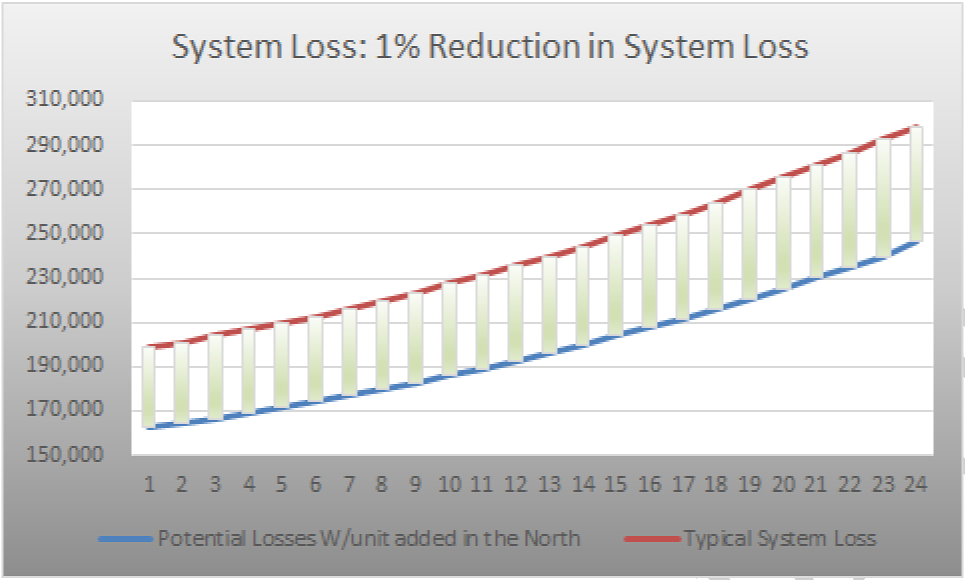
As discussed above, the locational value is significant when system loss savings is considered. In addition to the results shown in the graphs/tables above, IID must consider the value of physical inertia benefits that would be realized regarding enhancing the system service efficiency. In other words, if 60 percent of the IIID load is in the Northern Territory and most of the generation is in the Southern Territory, then more the energy deliveries must travel further to get to the load pocket up North. However, if a useful resource is located closer to the load pocket, it would travel less across the transmission system and therefore contain less losses. The following table illustrates a potential example assuming a 1 percent decrease in system losses indicated the requirement of less energy requirements:

Exhibit 183: System Loss Efficiency Increase Example

Year	Load Forecast (Expected Case)	Savings of 1% reduction in losses (5.5% to 4.5%)	Price Forecast $/MWh	Locational Value @$/MWh
2017	3,616,064	36,161	$ 35.81	$ 1,295,070
2018	3,655,924	36,559	$ 33.89	$ 1,239,036
2019	3,705,854	37,059	$ 36.04	$ 1,335,645
2020	3,759,566	37,596	$ 41.77	$ 1,570,201
2021	3,810,615	38,106	$ 43.87	$ 1,671,831
2022	3,868,314	38,683	$ 43.96	$ 1,700,440
2023	3,929,522	39,295	$ 44.54	$ 1,750,385
2024	3,994,922	39,949	$ 45.42	$ 1,814,417
2025	4,062,922	40,629	$ 47.35	$ 1,923,685
2026	4,133,278	41,333	$ 48.37	$ 1,999,242
2027	4,206,233	42,062	$ 49.17	$ 2,068,071
2028	4,284,380	42,844	$ 49.45	$ 2,118,564
2029	4,362,150	43,621	$ 50.17	$ 2,188,279
2030	4,441,207	44,412	$ 54.05	$ 2,400,642
2031	4,532,628	45,326	$ 54.57	$ 2,473,479
2032	4,617,573	46,176	$ 55.08	$ 2,543,588
2033	4,705,857	47,059	$ 55.58	$ 2,615,621
2034	4,802,727	48,027	$ 56.31	$ 2,704,306
2035	4,905,833	49,058	$ 57.40	$ 2,815,927
2036	5,010,319	50,103	$ 58.04	$ 2,907,767
2037	5,113,747	51,137	$ 58.61	$ 2,996,941
2038	5,216,477	52,165	$ 59.12	$ 3,084,084
2039	5,317,165	53,172	$ 60.18	$ 3,199,854
2040	5,415,712	51,449	$ 60.21	$ 3,097,845

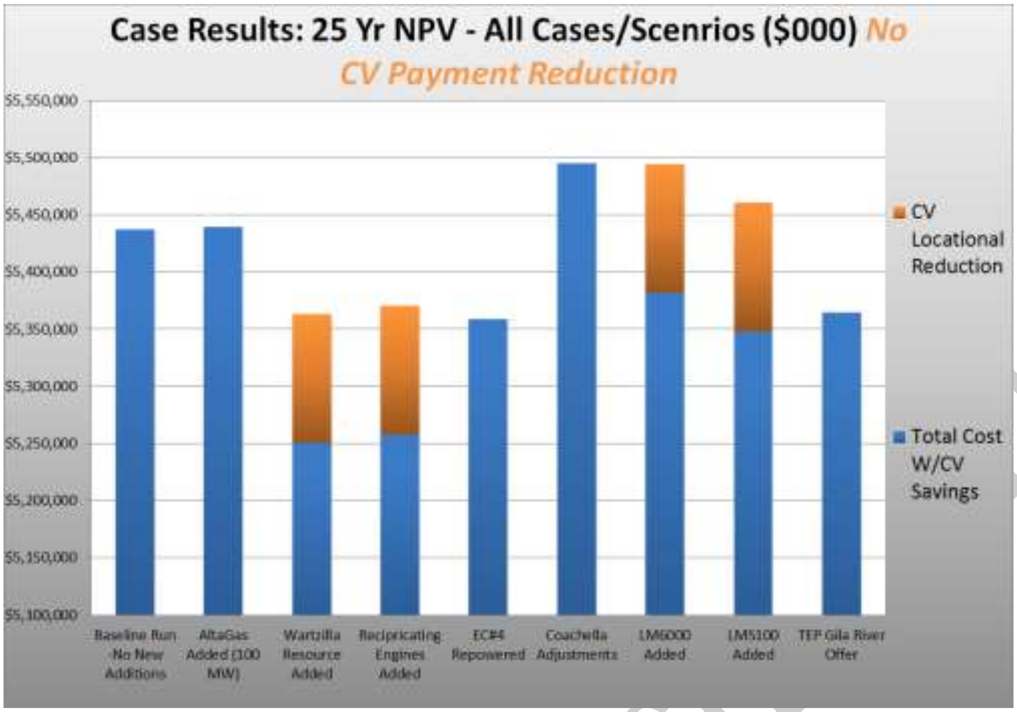
The graph below illustrates the potential/estimated difference from 2017-2040:

Exhibit 184: System Loss Efficiency Increase Example



With the locational factor in mind, the following resulted in the additional study performed to consider the locational needs for IID assuming that IID can obtain a value in savings from paying Coachella Valley $8million/yr as well as an annual value for reducing the IID system loss factor:

Exhibit 185: Locational Value of New Facility

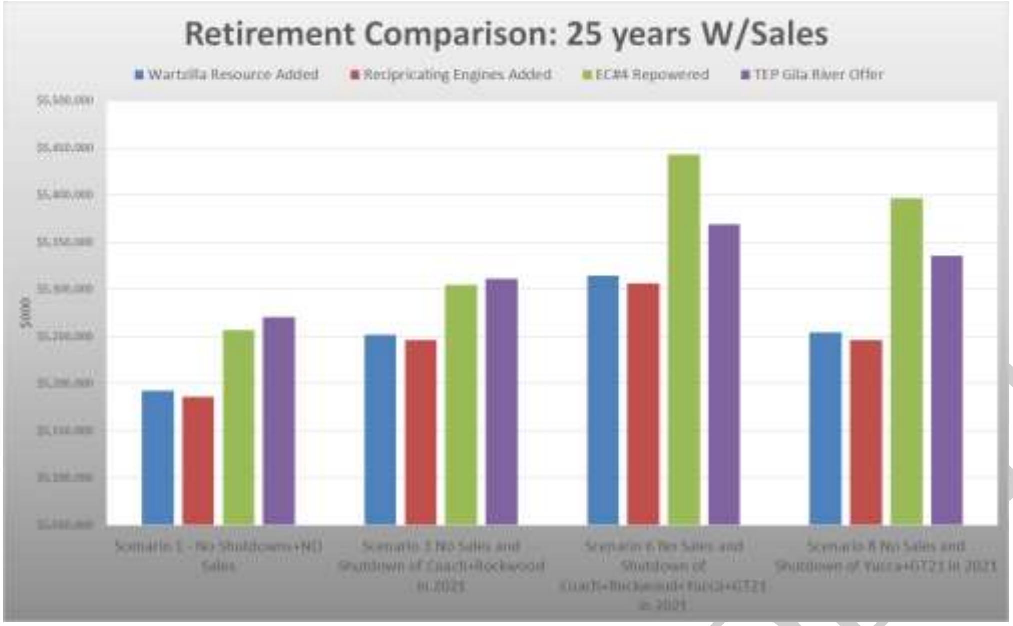


Looking at retirements and assuming:

- IID adds one of the top four above (Wartzilla, Reciprocating engines, EC No. 4, or TEP)
- IID engages in economic dispatch sales,
- Receive full credit from CV savings
-

Then the following is a high level summary of our findings:

Exhibit 186: Retirement Study Results



From these studies, the following is a table that describes how retirements must meet certain conditions in order to be valuable to IID:

Exhibit 187: Ranking of Retirements and Conditional Requirements

Ranking of Retirements of Facilities					
Economic Preference	Retirement Scenario	Conditions that Must be Met in Retirement Scenarios			
		Condition A	Condition B	Condition C	Condition D
1	No Retirements	Adding 30MW (1hr) can reduce costs	Coach/Rock will be used less than 1% CF	More Solar Not Added	Import Capability not limited
2	Retirement of Rockwood or Coach	Adding 30-60 (1hr) can reduce costs and is necessary	Coach will be used less than 1% CF	More Solar Not Added	
Tie 3	Retirement of Coach+Rockwood	Adding 30-100 (1hr) can reduce costs and is necessary		Yucca used more often	
Tie 3	Retirement of Yucca+GT21	Adding 30-100 (1hr) can reduce costs and is necessary	$8 million/yr realized (if not, then EC#4 is better) + $50m from Sale	Coach will be used less than 1% CF	Import Capability not limited
4	Retirement of Yucca+GT2+Coach+Rock	Adding 30-200 (1hr) can reduce costs and is necessary	$8 million/yr realized (if not, then EC#4 is better) + $50m from Sale	Other Resources must be added	Import Capability not limited

Based on these studies, the following conclusions were determined:

- It is apparent that adding certain resources can, in fact, increase economic efficiencies to the IID system in both sales and non-sales environments
  - Wartzilla
  - Reciprocating Engines
  - EC#4 Repowered
  - TEP Gila River Contract delivered at PV
- Retirements can be costly due to loss of capacity value, especially if the correct unit is not added
- If units are retired, IID cannot avoid adding other resources
- The best resource to add appears to be Wartzilla or Reciprocating Engines, but it depends on realizing Northern territorial benefits of:
  - $8m/yr from CV payment savings

    - $50 million in Yucca sale
    - Loss factor decrease by 1 percent making the variance between sales and energy requirements less
- A resource specific RFP can decrease overall costs and provide a competitive process.
- Building a resource could last 30-50 years, so 40 year perspectives provide greater benefit than purchase cases
- If IID meets the 50 percent targets with only PCC1 resources that contain a greater integration cost, then reliable quick responding generation is necessary
- If there is a need for physical flows, then Northern territory resources contain greater value
- We must begin the process of procurement/acquisition of a new resource now in order to complete a ‘build’ project (if that is the winning offer) by 2021
    - Begin discussing the possibility of financing/issuing bonds with Finance should we decide to build another generation facility
- If IID participates heavily in economic sales markets, lower heat rate alternatives contain greater variable cost value

2018 Through 2030 Power Supply Costs

The IID has acquired the necessary resources to meet its 2018 retail energy requirements and has completed most hedging of its 2019 natural gas and energy requirements (up to 85 percent of monthly energy requirements). It has begun the procurement analysis of its 2010-2021 requirements.

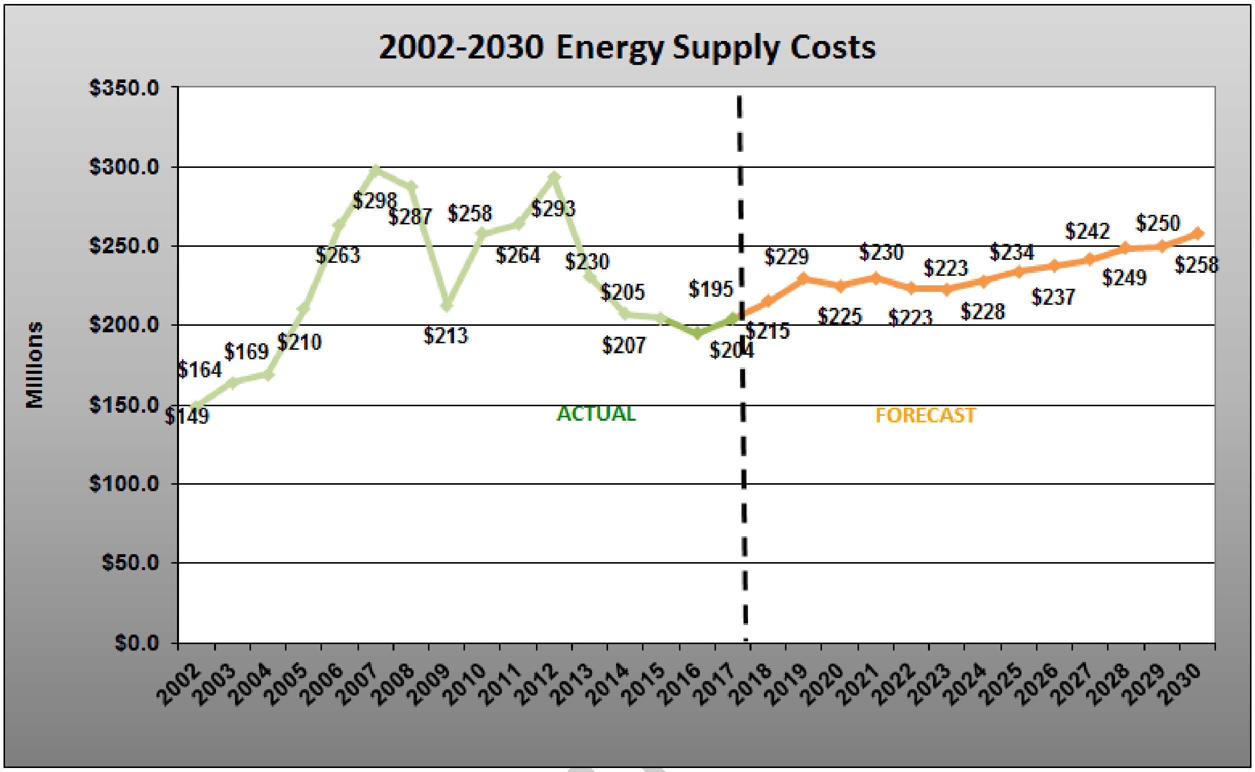
Significant fluctuations of gas/energy market drivers have proved to be fundamental to price direction, and thus cost direction of energy consuming utilities. Market drivers include such items as local/regional/national weather and demand, alternative fuel substitutes (LNG, shales), oil and natural gas storage, coal supply/demand, producing oil rigs, foreign policy, domestic regulation and many other obstinate forces.

Looking forward to 2018-2022, IID’s projected fuel and power supply costs maintain a steady incline mainly due to a growth in load, escalating market prices for energy and natural gas, and renewable energy resource costs. IID’s ongoing hedging program for 2018-22 continues to function as a rate stabilization instrument fixing a portion of natural gas expenses and reducing IID’s exposure to volatility risk.

In 2012, IID completed the repower El Centro No. 3 to Unit No. 3 providing increased fuel burning efficiency and notably decreasing variable costs. Furthermore, as mentioned throughout this document, IID will be obtaining additional resources necessary to meet load requirements while simultaneously complying with regulatory policies such as AB 32 and the state RPS requirements.

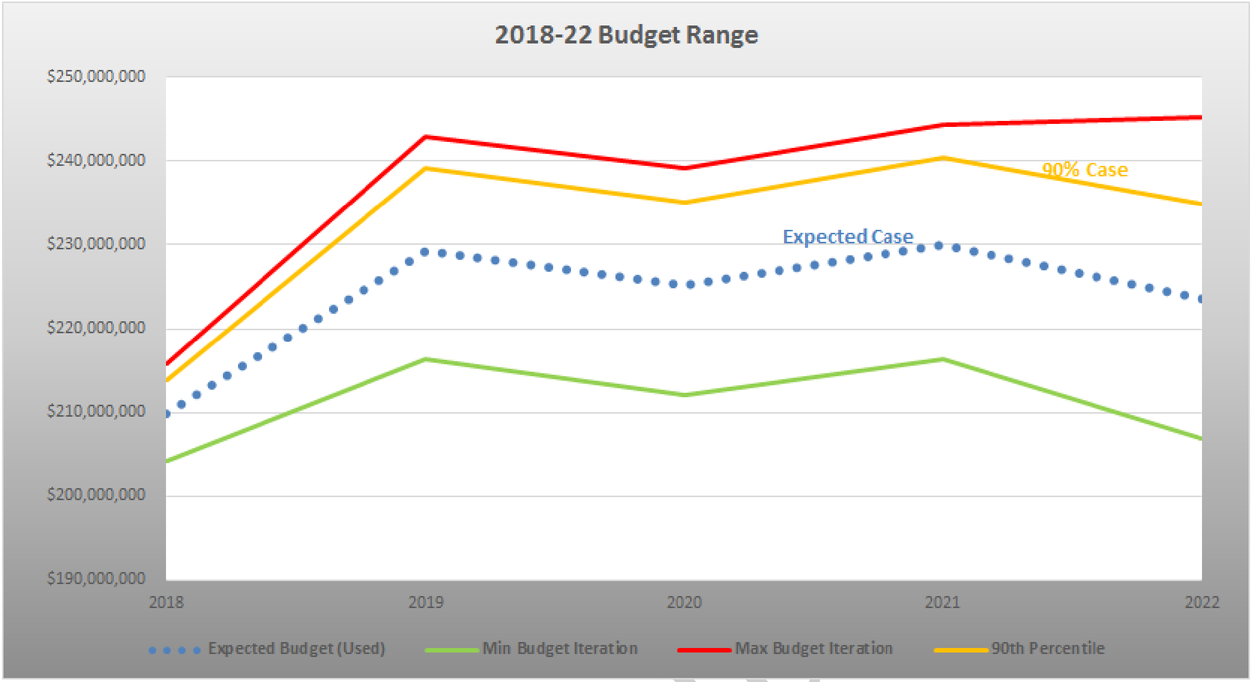
These new resources will allow IID to depend less on the shifting gas/energy market resources while stabilizing costs and reducing volatility in customer energy bills as we proceed to 2017 and beyond.

Exhibit 188: Energy Supply Costs 2002-2030



From a budget risk perspective, below is a chart that illustrates the range of potential costs for the next five years:

Exhibit 189: Budget Risk: 2018-22



2018-23 Budget Risk Management

The 2018-23 forecasted budgets are projected to be approximately $200 to $260 million. These budgeted power supply costs are based upon current forward energy prices that are embedded in the underlying assumptions. The fundamental objective of using risk management instruments is to reduce the uncertainty of price fluctuations and manage the risk of unforeseen budgetary vacillations. The IID has worked to reduce these uncertainties with risk management instruments such as hedging future energy/natural gas short positions and capping costs with call options.

The IID measures its exposure to risk using the Value at Risk (VaR) approach. This method estimates the impact of changes in major underlying variables on expected power supply costs. In order to measure this value at risk, several key aspects critical to budget forecasting must be assumed including:

- Energy prices
- Natural gas prices
- Load forecast
- Supply-side short position (natural gas and energy)
- Market trading hub volatility (based on historical trends)

Even though varying market trends will cause the IID's entire resource stack to optimize differently, a short position of supply resources (natural gas and energy) must be assumed to measure the value at risk in the fuel and purchased power budget. The IID uses a Monte Carlo, stochastic production cost model to project these resource positions based on load. With these assumptions, the IID fuel and purchased power budgetary value at risk can be quantified based on the above assumptions. Below is a table that demonstrates the 2018 value at risk as of Q4 2018:

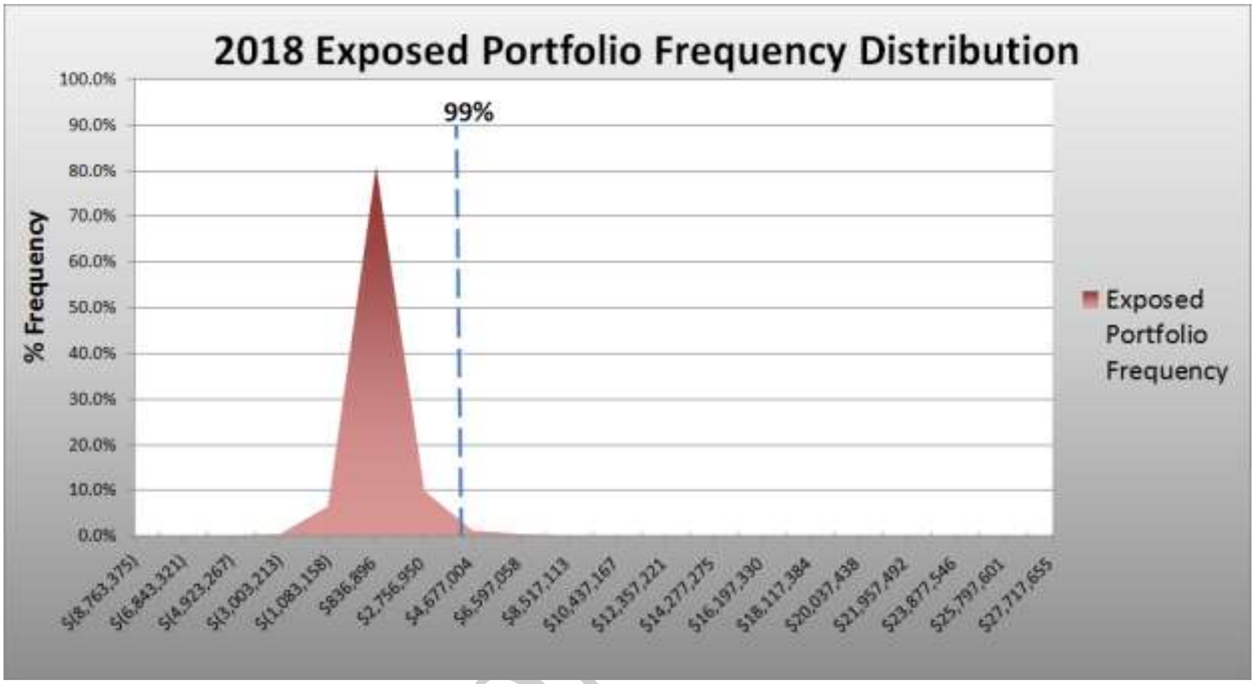
Exhibit 190: 2018 Budgetary Value at Risk

2018 HISTORICALLY BASED VALUE AT RISK						
Confidence Level	99%					
Metric	Native	Yucca	EPE	Spot Mkt Purchases	HR Call Options	Exposed Portfolio (mmBtus)
Exposures (Short	(300,341)	(2,602,172)	-	(255,052)	-	(2,902,513)
Budgeted Prices	$ 3.18	$ 2.94	$ -	$ 26.49	$ 3.18	
Exposures ($)	$ 956,449	$ 7,651,692	$ -	$ 6,755,987	$ -	**$ 15,364,128**
VaR	$ 289,747	$ 1,973,238	$ -	$ 2,524,746	$ -	**$ 3,850,340**
Expected Shortfall	$ 628,791	$ 3,803,524	$ -	$ 4,399,133	$ -	**$ 7,108,114**
* 2018 V@R is heavily based on the assumption that the several renewable projects will be online and operating as expected.						Hedged Exposure
						$ 26,916,261
						52.6%
						% V@R
						1.57%

The above table displays the short position for each budget item of exposure and the corresponding value at risk. Essentially, the VaR for each portfolio item indicates the cost exposures or the probability of exceeding the original budget amount at a 99 percent level of confidence. In this case, if the historical volatility were to continue in 2018 with a similar trend, the IID's budget has $3.85 million value at risk. In other words, if the market were to go up significantly, the fuel and purchased power budget will be $3.85 million higher than the original budget. The expected shortfall is a risk metric IID uses to show if conditions get excessively expensive in the market (such as Hurricane Katrina), then the IID's expected shortfall is the potential value that exceeds the budget. The expected shortfall is an additional statistical function that focuses on the extreme tails of the probability distribution (i.e. the remaining one percent of probability). VaR, on the other hand, illustrates how challenging the environment can be, but focuses on 99 percent of the centered data.

A graphical representation of the above table is shown below.

Exhibit 191: Frequency Distribution of the VaR for 2018



The graph above shows the simulated probability of the budget value at risk. As in the table above, this graph illustrates 99 percent of the probable outcomes below $3.85 million. While the majority of the data is well below $3.85 million, the portfolio has the potential to be $7.1 million over the originally budgeted amount in a worst-case scenario.

Slightly higher risk is evident in 2019 with a total $10.08 million value at risk in fuel and purchased power supply budget in the exhibit below:

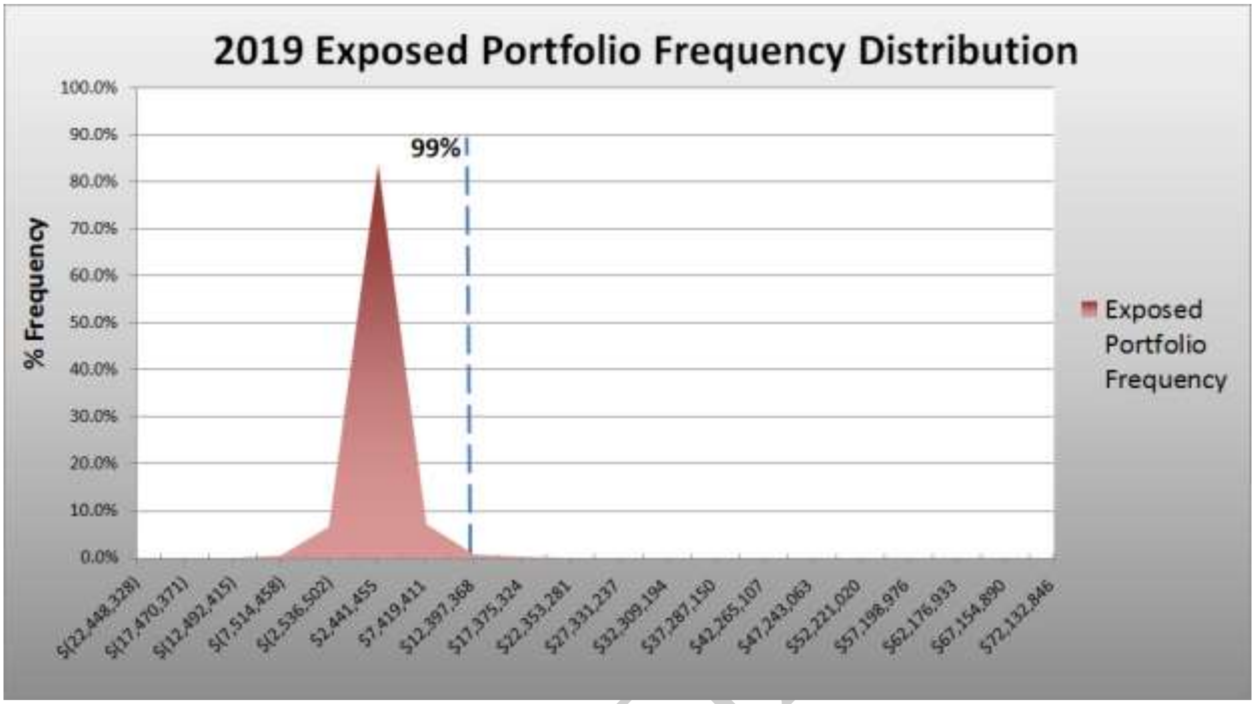
Exhibit 192: 2019 Budgetary Value at Risk

2019 HISTORICALLY BASED VALUE AT RISK						
Confidence Level	99%					
Metric	**Native**	**Yucca**	**EPE**	**Spot Mkt Purchases**	**HR Call Options**	**Exposed Portfolio (mmBtus)**
Volumetric Exposures (Short Position)	(5,353,511)	(2,843,277)	-	(499,534)	-	(8,196,787)
Budgeted Prices	$ 3.09	$ 2.70	$ -	$ 28.02		
Exposures ($)	$ 16,538,689	$ 7,688,434	$ -	$ 13,996,321	$ -	**$ 38,223,444**
VaR	$ 5,010,241	$ 1,982,714	$ -	$ 5,230,495	$ -	**$ 10,079,113**
Expected Shortfall	$ 10,872,908	$ 3,821,788	$ -	$ 9,113,647	$ -	**$ 19,030,190**
* 2018 V@R is heavily based on the assumption that the several renewable projects will be online and operating as expected.						Hedged Exposure
						$ 20,852,947
						40.9%
						% V@R
						4.10%

Less of the 2018 portfolio items are exposed to a potential of more extreme conditions mainly due to lower levels of short positions as a result of more natural gas procurement program compared with 2019 natural gas procurement program. The value at risk for the fuel and purchased power supply budget is $10.08 million at a 99 percent level of confidence. Furthermore, if an event or events were to occur to cause conditions to become extremely detrimental in the market, the expected shortfall (i.e., amount to exceed the budget) is $19.03 million.

The exhibit below shows the frequency distribution of the exposed portfolio for 2019.

Exhibit 193: Frequency Distribution of the VaR for 2019



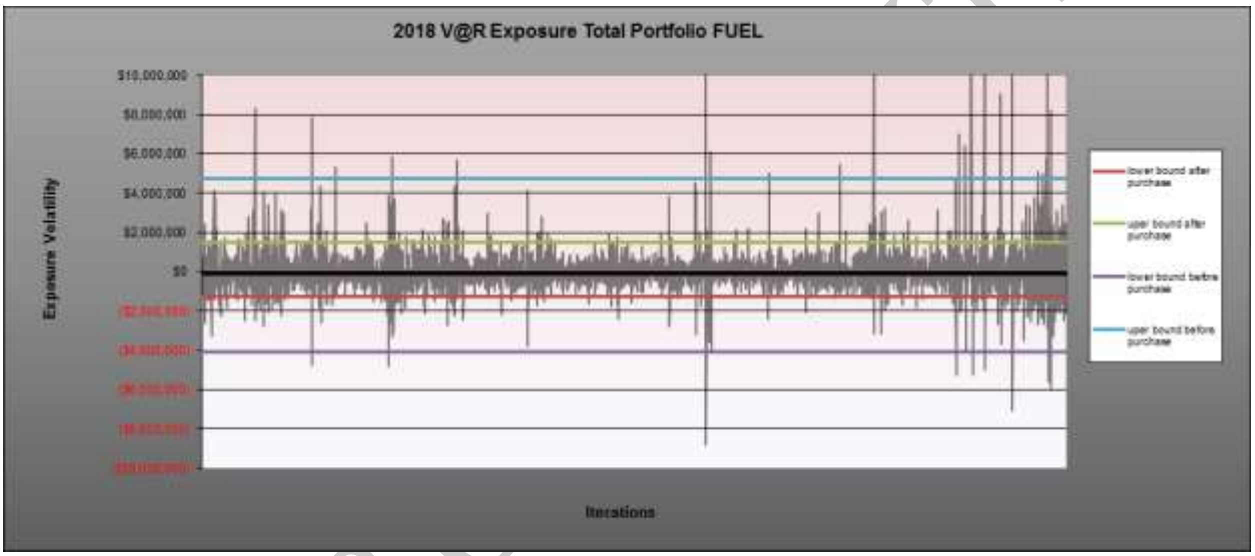
Once again, the above graph shows the value at risk of our budget to be $10.08 million at a 99 percent level of confidence. Compared to the 2018 frequency distribution of the IID exposed portfolio, the 2019 distribution depicts a wider range of potential outcomes (i.e., the budget cost variations show a broader gap between the high and low ranges of probable outcomes in 2019 than in 2018) mainly due to the longer amount of time to maturity and a lesser procured position of exposed sources of the budget.

The method to manage and reduce the budget value at risk is hedging both energy and natural gas used to generate energy internally. Various hedging instruments used include energy strike price call options, heat-rate call options, fixed price energy and gas purchases, costless collar (cap plus floor), financial futures gas purchases, and blending and extending hedges to capture market reductions in price. Fundamentally speaking, the more hedged the greater of a reduction in budget value at risk. Hedging has reduced the 2018 budget at risk more than the 2019 budget at risk and we see the evidence for this in the "Exposed Portfolio Frequency Distribution" graphs above.

Another easy way to view the budget value at risk reduction in 2018-19 is by observing the probability of potential outcomes in a "Top-Down Value at Risk." This perspective provides a glimpse of 3,000 iterations of budget variations based on historical price volatility trends. When observed as a two tail (99 percent and 1 percent) test, the IID's possible ranges of budget variations become very clear. Additionally, the risk reducing impacts of the IID's hedging program are apparent as well. Without a hedging program, the IID's short positions on budget items exposed to market price fluctuations are considerably greater than what they would be without a hedging program. Therefore, as the short position decreases, the IID's budget portfolio achieves an increasingly narrow gap of risk exposure (i.e., lower budget value at risk).

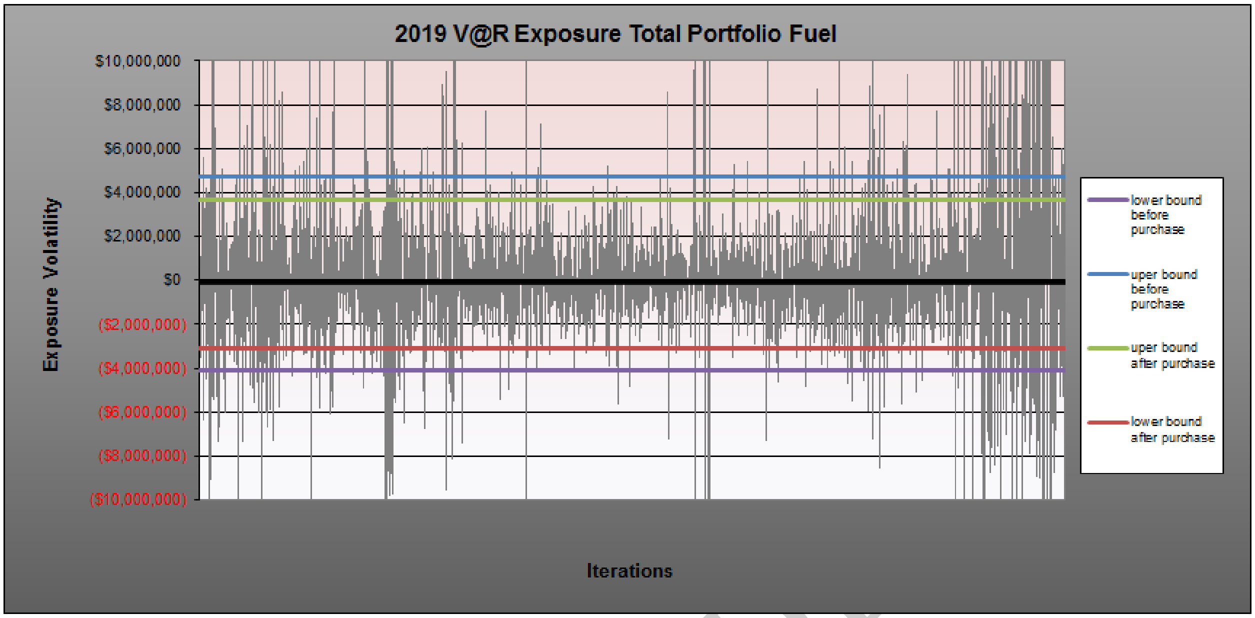
As with the Value at Risk table above, the exposure values are based on historical price volatility. Essentially, the hedging program has reduced the exposure of the fuel and energy supply budget. The **blue** and **purple** lines represent 95 percent confidence that the budget will fall within this range if the hedging program **did not** exist. The **red** and gre**en** lines display the effects of the hedging program representing 95 percent confidence that the budget will fall within the range above. With the hedging program, the budget value at risk is reduced by about plus or minus $3 million. It is important to note that even though the confidence interval is 95 percent (two tails), there is still a probability that the budget could vary outside of the above ranges due to an extreme unforeseen event (e.g., Hurricane Katrina).

Exhibit 194: 2018 V@R Iterations and the Impact of the Fuel Procurement Program



The 2019 value at risk tells a similar story, except the range of after purchasing hedging products is wider due to the fact that there is less hedged in that year leaving a shorter position exposed to the volatile market. This observation is evident in the exhibit below.

Exhibit 195: 2019 V@R Iterations and the Impact of NG Procurement Program



The Resource Planning Section is working toward minimizing the risk of budget deviation through careful planning and prudent decision making with the goal of stabilizing or reducing rates.

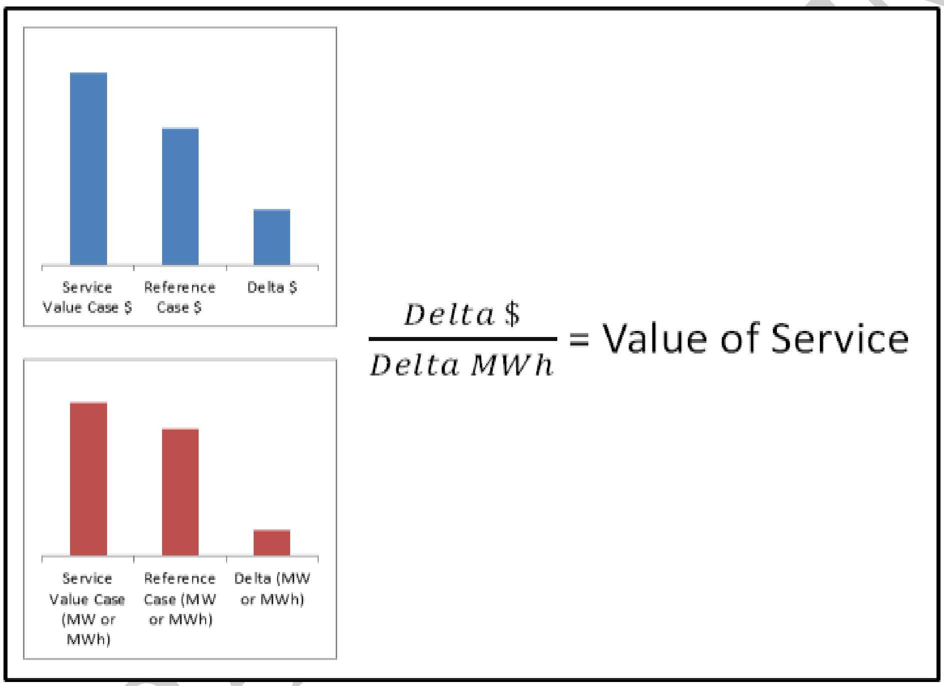
5. Black and Veatch/Atonix In-Depth Study on Energy Storage

As systems evolve to meet renewable energy targets, it is clear that the days of only considering capacity (reserve margin) and electrical energy production are over. Today's planning must also consider other grid services for example:

- Spin
- Non-spin
- Reg up
- Reg down
- Energy arbitrage/load shift
- Balancing
- Frequency regulation
- Quick response/black start

Understanding both the requirement for the various grid services and the value of resources that are able to provide these services gives strategic insights into the resource selection and configuration. The focus of the value of service investigation was to give insight into appropriate configuration and utilization of a battery resource with a specific focus on spin and energy arbitrage. As battery utilization must choose between various grid services to provide, the goal of this investigation was to determine which services will be the most valuable to the IID system. The required grid services are defined and should be valued in a way that is technology agnostic to the degree feasible. It should be noted that, as the system evolves year over year (due to new assets, retired assets, DER, new security requirements, demand, DR, etc.), or as need changes second to second depending on variable resources or fluctuating demand, the value of service will change each second and each year. Similarly, as different plans incorporate different assets with differing ability to meet services, the value of service will be different for each plan. Nevertheless, as long as these limitations are understood, the value of grid services can be evaluated.

Service value was determined from the results of select hourly chronological production cost simulations. In general, a service is valued by removing some portion of assets that provide the service as their primary function, then adding a "service proxy asset" that provides the specific service into the system in incremental steps. The service proxy asset is provided at a level quantity for all hours and at zero cost to the system (no capital or operating cost are associated with the service proxy asset). The difference in generating cost between a run that includes the service proxy and one that does not can be used to calculate the technology-agnostic value attributed to that service. By adding in the service proxy in steps, we can see how the value of the service tracks against the quantity of service added and, as such, at what point the incremental service substantially declines in value.



While valuing of services provides strategic insights, it should be recognized that underlying assets will influence how these services can be delivered and the allocation of specific services to assets (many assets can provide multiple services, but a single asset cannot provide all services at the same time). The value of service methodology described in this document attempts to segregate, to the best degree possible, the value of each independent grid service to the generating system.

This investigation utilized IID's model results rather than replicating the system in another full-scale production simulation environment. As such, results were limited by the same constraints that apply to IID's model. The IID model worked at hourly resolution and did not explicitly consider some of the subhourly services that these batteries could potentially provide. Certain grid services requirements – such as up and down regulation, frequency regulation, and balancing – cannot be adequately evaluated using an hourly time step and deserve some discussion. The additional need for these services is largely driven by the new non-dispatchable renewable energy placed onto the system. At a facility level, these subhourly requirements can be managed in many ways including interconnection requirements or dedicated batteries at each location to manage facility transients. At a system level, quick response batteries can manage both transient increases and decreases in net demand.

However, managing both increases and decreases of system transients does impact battery sizing considerations. If the battery is expected to manage both increases and decreases in demand then it will be kept at a mid-set point allowing it to either charge or discharge which could require a larger battery to provide sufficient capacity in both directions. However, it is during periods of high solar generation that the system most often needs additional management of transients. During high solar generation, an alternative strategy is to dedicate the quick response battery to manage the increases in net demand while curtailment of non-dispatchable renewable resource can manage transient decreases in net demand. This resource utilization strategy is typically the most cost effective. Based on the system state and dynamic forecasts, battery set points can be managed to minimize the use of curtailment for providing grid services. In combination, this strategy can effectively provide the needed subhourly grid services.

The section that follows provides a proxy for the value of services provided by batteries, considering hourly and larger time resolution, and is not intended to capture all variables that must be considered during actual

operation. The subsequent section addresses battery sizing. The methodologies used are described in their respective sections.

Value of Service

30 MW Load Shift Evaluation

Methodology:

Evaluate the plan with and without additional grid service assets.

Reference Run:

Model the system without the 30 MW 1-hour battery selected in the preferred plan.

Service Value Run:

Model the system with a 30 MW 1- hour battery performing just load shifting.

Value of Service Metric:

Avoided Cost per kW per Year.

30 MW Spin Evaluation

Methodology:

Evaluate the plan with and without additional grid service assets.

Reference Run:

Model the system without the 30 MW 1-hour battery selected in the preferred plan.

Service Value Run:

Model the system with a 30 MW 1- hour battery performing just spin.

Value of Service Metric:

Avoided Cost per kW per Year.

30 MW Dual Role Load Shift and Spin Evaluation

Methodology:

Evaluate the plan with and without additional grid service assets.

Reference Run:

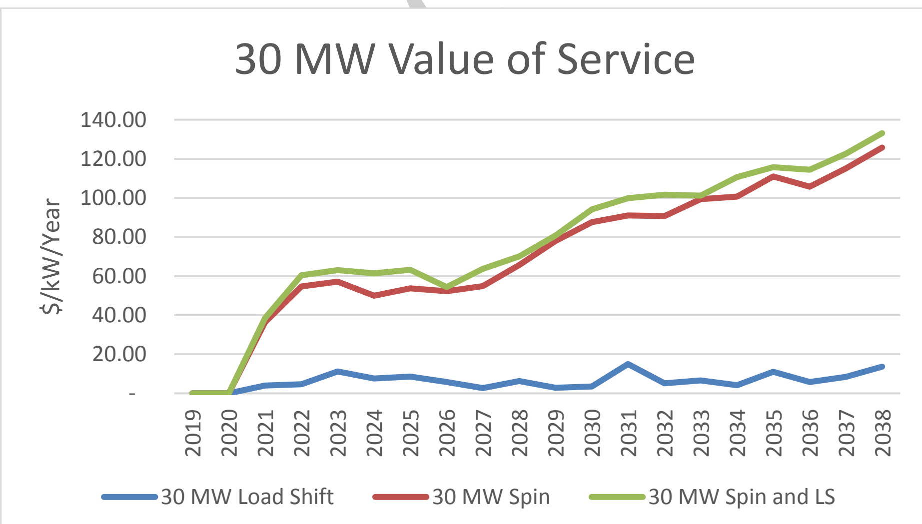
Model the system without the 30 MW 1-hour battery selected in the preferred plan.

Service Value Run:

Model the system with a 30 MW 1- hour battery performing both load shift and spin based on economic value and physical constraints.

Value of Service Metric:

Avoided Cost per kW per Year.



VALUE OF SERVICE $/KW/YEAR			
YEAR	30 MW LOAD SHIFT	30 MW SPIN	30 MW SPIN AND LS
2019	--	--	--
2020	--	--	--
2021	3.93	36.44	38.48
2022	4.60	54.72	60.39
2023	11.12	57.11	63.11
2024	7.65	49.98	61.33
2025	8.54	53.74	63.20
2026	5.84	52.27	54.37
2027	2.66	54.92	63.72
2028	6.35	65.69	70.10
2029	2.90	77.85	80.74
2030	3.54	87.57	94.20
2031	14.98	91.03	99.80
2032	5.17	90.77	101.62
2033	6.58	99.31	101.11
2034	4.12	100.71	110.59
2035	11.06	110.98	115.77
2036	5.80	105.68	114.37
2037	8.41	115.00	122.53
2038	13.61	125.75	133.14

The IID system found clear value for spin and a more marginal value for load shifting. This result makes sense given the generation mix in the preferred plan. The preferred plan opts to keep older units on the system to provide capacity but these units are expensive to run to provide spin. In addition to being less efficient to operate, these older units can struggle with starting up quickly in response to system events and might need to be kept online without this battery providing spin. As a result, the system could reduce generation from these units – specifically EC 2, EC 3, EC 4, and Niliand 2– and instead purchase energy from neighboring grids at lower prices. A battery also has a benefit as compared to conventional generation in that minimum turndown constraints do not apply. This benefit will become increasingly relevant in curtailment management as more and more non-dispatchable generation is added to the system.

The battery serving the dual-purpose of both loading shifting and spin did not provide significantly more value to the system than the same battery performing just spin. It is likely that the value in providing spin through the peak hours of net demand on the system are very comparable to the value of load shifting. This makes sense as there will be tradeoffs between being able to provide spin and discharging the battery on the evening peak while load shifting. For instance, the amount of spin provided on peak by the battery needs to be discounted by the amount of energy being dispatched by the battery. The battery may not be able to provide spin overnight if the battery is drained fully during the evening peak hours.

Further, the system operators may be less comfortable using this new battery in this dual role than they are with the current 20 MW battery on the system. Renewable generation on the system is growing and uncertainty in both the demand and supply side will grow alongside it. The battery will only be able to provide its full potential for spin when it is full of energy. Depending on the average length of a spin event, the battery performing a daily load shifting cycle could run out of energy if the event occurs overnight or during evening peak hours when the battery's energy is being depleted.

The system's need for load shifting is likely being offset by the storage installed alongside the new solar installations in 2029. Prior to this installation, the low value of load shifting found indicates there is not a great need or opportunity for energy arbitrage on the system. The value available in 2029 and beyond is likely captured by the new 4-hour storage batteries installed on the system in that same year.

Battery Sizing

30 MW Battery

Methodology:

Evaluate the plan with and without additional grid service assets.

Reference Run:

Model the system without the 30 MW 1-hour battery selected in the preferred plan.

Service Value Run:

Model the system with a 30 MW 1- hour battery performing both load shift and spin.

Value of Service Metric:

Avoided Cost per kW per Year.

60 MW Battery

Methodology:

Evaluate the plan with and without additional grid service assets.

Reference Run:

Model the system without the 30 MW 1-hour battery selected in the preferred plan.

Service Value Run:

Model the system with a 60 MW 1- hour battery performing both load shift and spin.

Value of Service Metric:

Avoided Cost per kW per Year.

100 MW Battery

Methodology:

Evaluate the plan with and without additional grid service assets.

Reference Run:

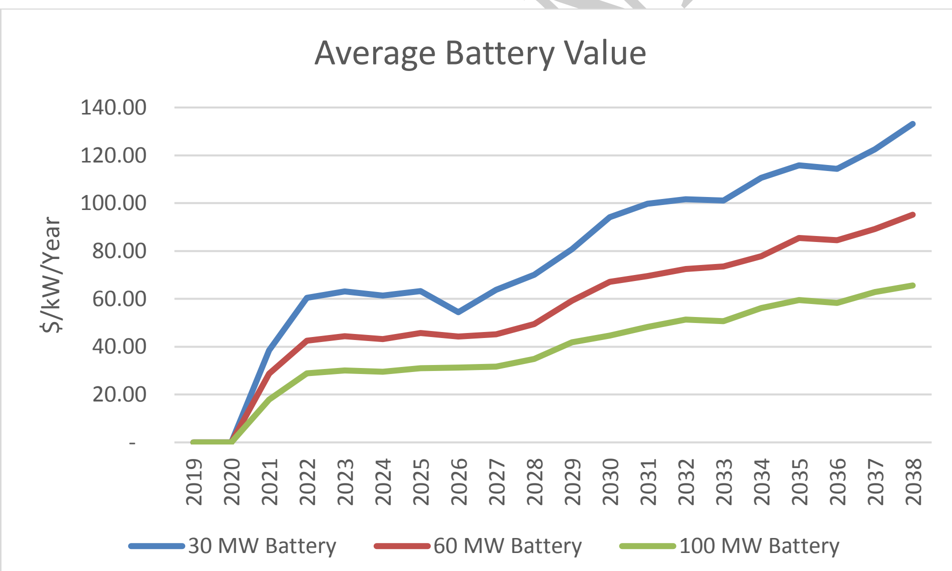
Model the system without the 30 MW 1-hour battery selected in the preferred plan.

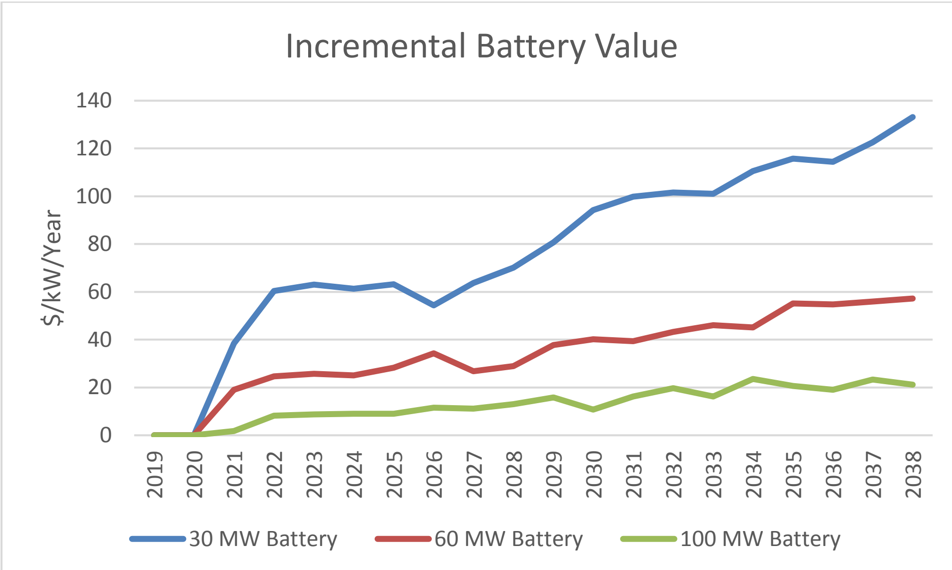
Service Value Run:

Model the system with a 100 MW 1- hour battery performing both load shift and spin.

Value of Service Metric:

Avoided Cost per kW per Year.




Incremental Battery Value
$/kW/Year
140
120
100
80
60
40
20
0
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
30 MW Battery
60 MW Battery
100 MW Battery

VALUE OF BATTERIES $/KW/YEAR						
YEAR	AVERAGE			INCREMENTAL		
	30 MW	60 MW	100 MW	30 MW	60 MW	100 MW
2019	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00
2021	38.48	28.78	17.96	38.48	19.07	1.72
2022	60.39	42.51	28.80	60.39	24.63	8.24
2023	63.11	44.44	30.13	63.11	25.77	8.68
2024	61.33	43.17	29.50	61.33	25.02	8.98
2025	63.20	45.76	31.05	63.20	28.31	8.98
2026	54.37	44.32	31.23	54.37	34.27	11.59
2027	63.72	45.24	31.62	63.72	26.75	11.20
2028	70.10	49.50	34.89	70.10	28.90	12.98
2029	80.74	59.23	41.86	80.74	37.71	15.82
2030	94.20	67.18	44.61	94.20	40.16	10.76
2031	99.80	69.58	48.23	99.80	39.35	16.22
2032	101.62	72.47	51.39	101.62	43.32	19.76
2033	101.11	73.56	50.62	101.11	46.02	16.20
2034	110.59	77.84	56.13	110.59	45.10	23.57
2035	115.77	85.43	59.49	115.77	55.10	20.58
2036	114.37	84.54	58.32	114.37	54.72	18.99
2037	122.53	89.23	62.87	122.53	55.93	23.34
2038	133.14	95.18	65.60	133.14	57.22	21.22

When evaluating the proper battery size, it can be informative to look at both the average and incremental value. Generally, incremental value is used to appropriately size a battery installation and average value is used to compensate service providers based on the size selected. The average value refers to the total savings -compared to the no battery case- divided by the size of the battery evaluated. The incremental value refers to the differential savings between the different sized battery cases divided by the differential size of the battery. For example, the 60 MW battery incremental battery value is determined by subtracting the cost of the 30 MW battery run from the cost of the 60 MW battery run and dividing by the incremental 30 MW.

The average value is informative when trying to determine how to equitably compensate service providers. Often, the first MWs of a service provide a disproportionate amount of the value to the system. If the early installers are compensated at higher rates than later adoptions, this can have the effect of picking winners and losers, potentially chilling later investment. For instance, early adopters of solar generation in Net Energy Metering have been compensated at avoided cost rates and late adopters are getting compensated at much lower rates. This can lead to social equity issues as often these late adopters are in a lower socioeconomic class. While IID is currently contemplating owning this battery itself, the principles of using average value could be applied to any service provided by a third party such as solar energy or any other grid level service.

Incremental value is useful for informing the right level of battery investment. This is because often the most value is found in the first tranche of service provided. Average value can make a larger battery installation look more attractive than it really is because the average includes the value captured in the first tranche as well as the second.

This is evident in the results found for IID. The 30 MW battery is worth roughly $60/kW/year in 2024 and on average the 60 MW battery is worth about $43/kW/year but remember this is the average of the first and the second tranche of 30 MW. The incremental results for this year show that the difference in the value of the first 30 MW and the second 30 MW is quite large. The incremental value of the second 30 MW is worth just $25/kW/year. If the levelized cost for the battery was less than $25/kW/year then this could still be a good investment. However, if only the average value was evaluated, investing in a battery that costs far more than the incremental value beyond the initial 30 MW could be detrimental.

Our analysis shows that the investment in the 30 MW 1-hour battery has a strong basis for the 2021 timeframe. The battery will provide necessary spin to deal with the growing renewables found on the system. The company could invest in additional storage later during the study period should battery costs continue to fall. The incremental value of the 60 MW battery does continue to grow over the study so it is likely there will come a time when it is cost effective to invest further.

Separate system studies determined the need for approximately 30 MW of quick response to address the growing challenges of managing the increase in non-dispatchable resource on the system. This further confirms the selection of 30 MW 1-hour battery as the appropriate choice when considering the multitude of grid service requirements.

Designed/Planned Operations vs Actual Operational Risks

While these studies clearly show that the battery can be a cost competitive addition to the IID system fulfilling much needed ancillary and operating reserve needs, there are various risks that must be observed and mitigated as a resource is procured and integrated. IID performed and analysis testing the risk of operational performance variance from the planned operational performance and its capabilities. This is an important test as the current battery system in IID's resource stack was planned and designed to provide 20

MW of spin, other ancillaries and energy value. However, after about 2-3 years of operations, it was decided to count the battery value as half of the designed quantity. So, the ancillary and energy value is actually only 10 MW, instead of the full 20 MW. The residual 10 MW is deemed un reliable to count at this current time.

The study performed evaluated this situation if a new battery were to be procured and implemented. Using the same assumptions as described previously, three scenarios were created:

(1) 30 MW 1 hour battery with operational efficiency half of the design
(2) 60 MW 1 hour battery with operational efficiency half of the design
(3) 100 MW 1 hour battery with operational efficiency half of the design

Below is a table that compares the cost value lost when the battery efficiency is cut in half:

Exhibit 196: Design vs Actual Operational Value Loss

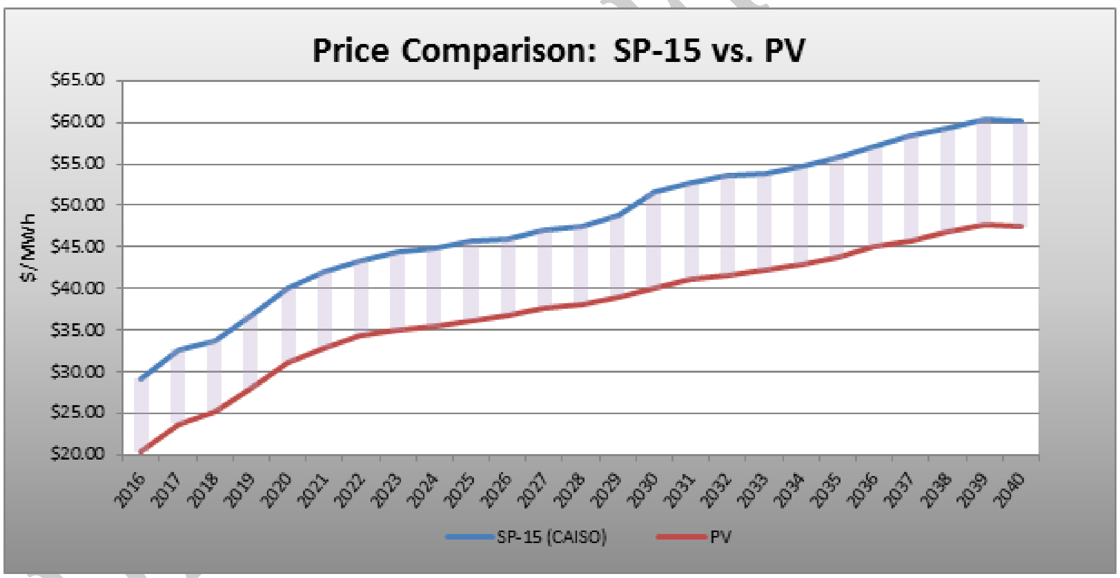
Battery Efficiency Value Loss			
Year	100 MW efficiency cost difference	60 MW efficiency cost difference	30 MW efficiency cost difference
2019	-	-	-
2020	-	-	-
2021	68,896	413,632	492,272
2022	261,008	515,200	698,864
2023	294,096	559,408	733,952
2024	318,576	590,624	806,512
2025	322,656	631,008	865,520
2026	437,808	706,928	682,048
2027	453,856	536,496	915,024
2028	555,392	488,816	1,132,064
2029	697,296	921,920	1,038,080
2030	565,888	831,744	1,218,048
2031	806,608	773,408	1,312,144
2032	992,672	1,092,096	1,298,752
2033	887,856	1,109,648	1,437,120
2034	1,208,784	1,072,976	1,461,280
2035	1,112,336	1,292,528	1,478,528
2036	1,063,024	1,243,472	1,644,736
2037	1,254,560	1,309,600	1,754,880
2038	1,191,936	1,315,360	1,849,952
Grand Total	**12,493,248**	**15,404,864**	**20,819,776**

So, as shown in the table above, there can be significant losses over a 20 year period if the design capabilities are not implemented into the IID system. This aspect must be considered in the IID procurement process to ensure operational guarantees and longevity of the facility.

6. Transmission Expansion Studies

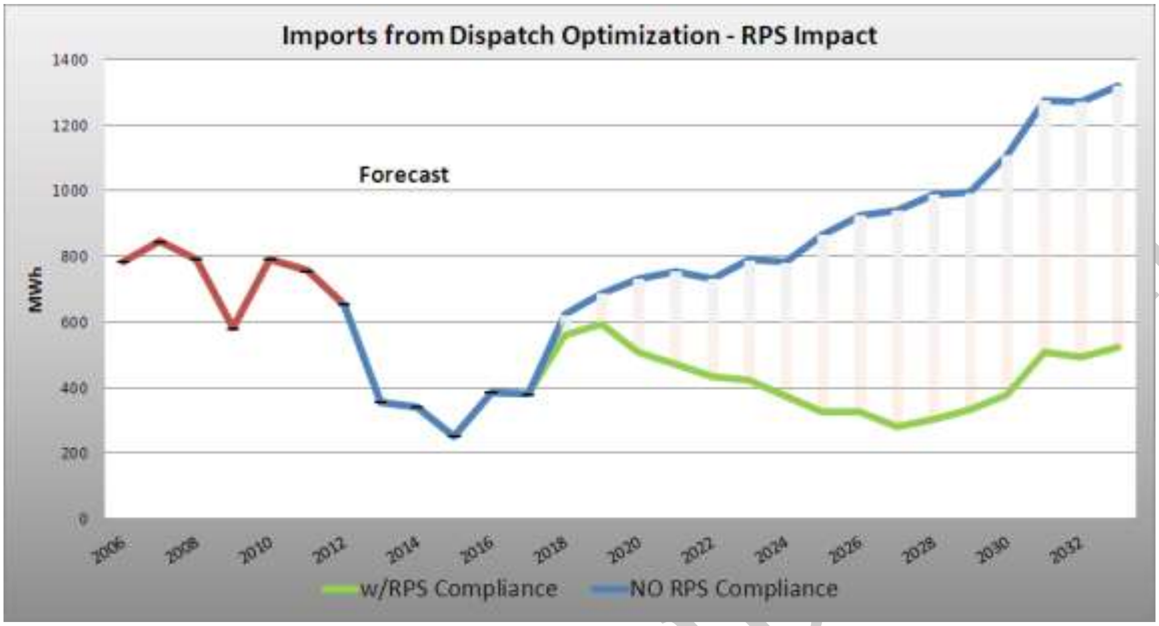
As discussed in Chapter 9, IID is actively exploring various options to expand the IID transmission infrastructure. The need for imports and the demand for exports are key to understanding the value of increasing the IID's transmission infrastructure and as IID embarks upon the new world of RPS compliance and emissions reduction standards, the import/export dynamic is an ever changing and evolving concept. While the need for renewable resources increases in the coming years and with the availability of IID's bevy of renewable resources potential, the opportunity to import energy will be displaced with must-take renewable generation that cannot be dispatched. While the risk of importing energy from various markets such as the CAISO vs. the markets to the east is quantifiably divergent, IID must recognize that the return on transmission investment may not be justifiable by simply looking at the value of accessing a less risky market. The following illustrates the variance in energy prices of the CAISO market (SP-15 trading hub) and the market at Palo Verde:

Exhibit 197: Forecast of Price Variance of SP-15 and PV



Clearly, there is a fairly wide gap in the forecast of prices between the CAISO and Palo Verde, and IID has access to both. Even though the access to the PV market can be constrained due to a lower level of owned transmission rights than SP-15, the benefit of investing in transmission lines to the east to gain a greater access to the PV market is greater if there are more import needs. However, the forecast of import needs is gradually declining. The following exhibit exemplifies the historical trend as IID has increased renewables in 2012-13 along with the forecast of import needs in the next 20 years as local renewable projects come online:

Exhibit 198: Impact of RPS on the Need to Import



As the need to import decreases, the value return of investing in transmission projects must come from other sources. IID performed many studies to analyze the potential value additions with transmission structure investment. The studies focused on five projects that combine several projects discussed in Chapter 9 and they are as follows:

- *Projects to be completed in 2017*
    - Entire CI line
    - Portion of the R line (Ave 58 to Coachella 92 kV)
    - CN line
    - CL line
    - Third transformer at Midway (currently under review for alternatives)
    - Bigger size transformer at Niland
- *Recommended projects in the next 5 years*
    - Remove Current Transformer limitation or adjustment in switching arrangement at no cost to IID
    - Install 75 MVARs capacitor bank at Coachella Valley substation
    - Install about 15 MVARs capacitor banks at identified 92 kV substations
    - Install of a microprocessor based monitoring system, respectively
- *Recommended projects in the next 10 years*
    - Upgrade to a high capacitor conductor at Jefferson-Marshal and La Quinta-N. La Quinta
- *Other Potential Projects*
    - North Gila-Pilot Knob (HANG2)
    - DFE Tie Line

The assumptions were determined during the IRP development process and a change in any of the assumptions can drastically alter the results of the studies. For all intents and purposes of this IRP, the following assumptions were used:

- IID exits ownership of SJ3 by the end of 2017
- RPS will be met in all three compliance periods for tested portfolios
- RPS is met through 20-year study period
- SRSG value given to projects to the east (PV-Yuma)
- Subscription scenarios of 100 percent, 75 percent, 50 percent, 25 percent and 0 percent were considered
- New geothermal exports are 35 percent of total exports and new solar are 65 percent of total exports
- Renewable resource output and retail sales are conservative to ensure that RPS targets are met
- Retail sales two percent growth
- Current PPAs provide a range of potential output from each plant. The targeted MW capacity was used for these studies (as opposed to the maximum potential capacity)
- The SRSG requires delivery availability to Arizona
- Currently, IID delivers to Yucca or Pilot Knob when supported with IID system or uses SJ3 energy to deliver to AZ
- When IID exits SJ3 ownership, SRSG membership for IID is at stake
- Value/savings of SRSG is assumed to be around $3.84 million/yr.
- This savings is applied to analysis of new transmission projects to the east (PV-Yuma)
- Many challenges were considered to fully examine all potential risks of the observed projects. Some of the main considerations are as follows:
- As RPS requirement grows, the resource portfolio shifts
- Too much must take eradicates opportunity for dispatch optimization
- Contracted power does not necessarily mean transmission capacity is used all hours of all year
- Winter Load vs. Summer Load
- Could present an opportunity during the winter months to market energy and ancillary services
- FERC Order 1000
- With new transmission and new external markets seeking IID renewables, IID could benefit by taking a chunk of a larger project with better economics

When the IID is capable of economically selling energy and/or ancillary services to other external markets, the projects have a greater potential for a higher payback.

After in depth studies were performed, a good perspective of the range of risks and rewards were provided and as a result, the following conclusions were determined:

- Each project was looked at separately to provide the net effect of that project
- A return on transmission project investment is heavily dependent on developers obtaining PPAs with external markets.

- Project payback depends on:
- The total capital cost of the project
- Total import/export capability
- High/Low gas market
- The use of IID internal generation for system economic sales
- The possibility of bringing on new units (like EC No.3 or Niland) that can be "in the money" in other external markets

Minimizing the renewable integration cost impact and transmission expansion cost impact will require an organizational shift of business practices

- Marketing energy sales
- Energy Imbalance Market (EIM)
- Ancillary service sales
- Market developers to IV by promoting new transmission projects
- With new transmission and new external markets seeking IID renewables, IID could benefit by taking a chunk of a larger project with better economics.
- The potential for a positive return on investment may require more investment (depending on the project)
- Seasonally shaped resources help create opportunities of market sales and ancillary service sales
- If possible, renegotiate contracts that cause winter season operational constraints

NG-IV2 Impact on Supply Resources

IID has a share of the Hassayampa – North Gila 500 kV line #2 (HANG2) in Arizona which terminates at North Gila (N.Gila) substation. This share can provide access to the Palo Verde market, but IID needs to finish the project to fully grant that access for IID use in daily dispatch of the IID system. Finishing the project requires one or both of the following:

1. A 61 mile transmission line from North Gila to the Highline substation
2. 61 mile transmission line from North Gila to the Highline substation + a 36 mile transmission line from the Highline substation to the Imperial Valley Substation

At this current time, the only cost estimates available are for the configuration described in #2 above. Therefore, the capital investment assumption is based on #2. However, we have completed sensitivities to address the potential for a lower cost alternative such as #1. In order to properly assess the risk of the investment, several variables must be observed including:

- Energy/gas prices
- IID load
- Capital investment

Additionally, there are several other factors that the value will depend on:

- Wheeling subscriptions
- SRSG Value
- Market participation under SB 100

Various combinations of these variables were tested within the production cost model with and without the NG-IV2 project to answer the question of how might the additional transmission line add value to IID's load serving activities.

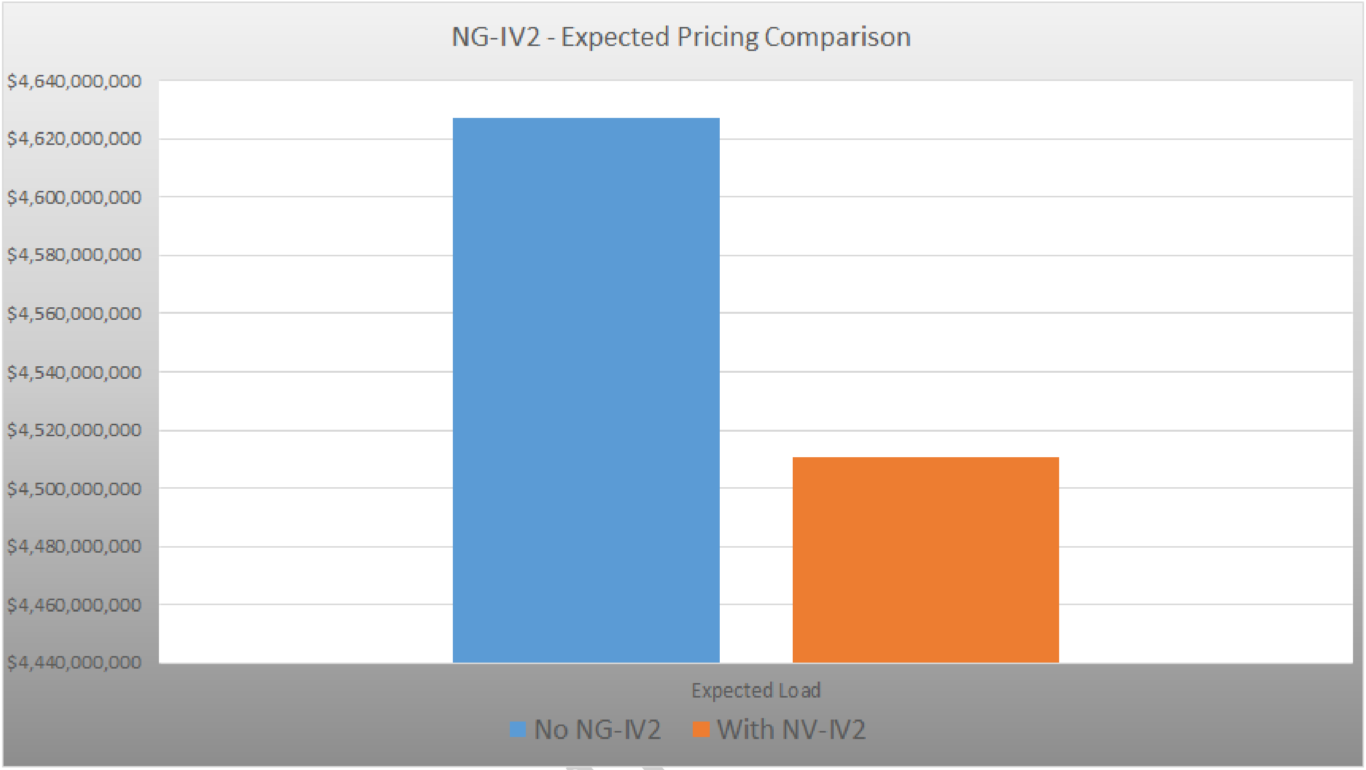
In total, there were 189 iterations for this study and the following is a summary of the sensitivities that were studied:

NG-IV2 Study Sensitivities					
Transmission Assumption	Capital Cost Sensitivities	Wheeling Subsciptions	Expected Price	High Price	Low Price
No NG-IV2	$60 m $50 m $40 m $30 m	100% 75% 50% 25% 0%	Expected Load	Expected Load	Expected Load
			High Load	High Load	High Load
			Low Load	Low Load	Low Load
With NG-IV2			Expected Load	Expected Load	Expected Load
			High Load	High Load	High Load
			Low Load	Low Load	Low Load

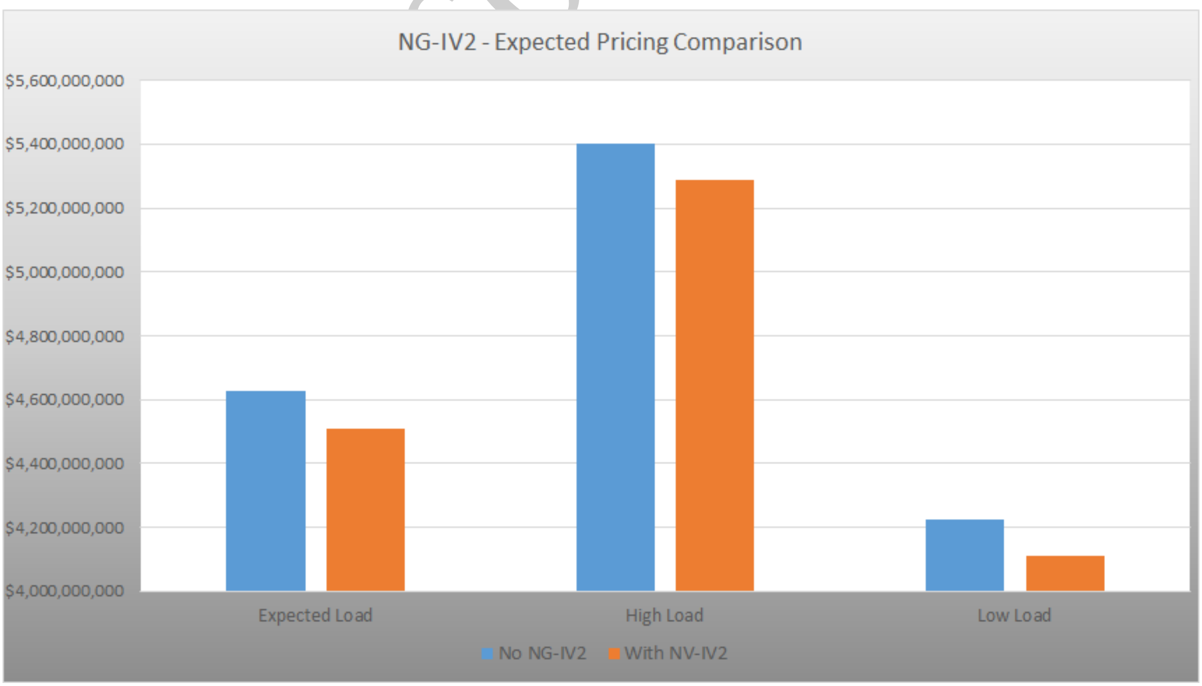
These sensitivity studies provide a range of potential outcomes to the investment. In addition to this study structure, the following is a list of key assumptions used for this study:

- 2018 load forecast used for expected/high/low cases
- Aug 2018 Price forecast used for expected/high/low cases
- SRSG value = $1.25m
- Solar to baseload breakdown = 65 percent solar; 35 percent baseload
- Transmission rate baseload = $1.92/KW-month
- Solar transmission rate = $3.94/MWh
- Capacity factor of baseload -= 92 percent
- Capacity factor of solar = 34 percent
- IID meets RPS and emissions targets
- 2018 IRP recommendations implemented successfully
- Online date of NG-IV2 = 2021
- NG-IV2 adds 200 MW of bi-directional ATC
- NG-IV2 allows access to non-CAISO market at PV

Below is a summary of the results assuming the expected prices and loads assuming the $40 million case:



Furthermore, if expected price is assumed and load variations are tested, similar results were found:



In terms of risk, there are number of factors that can determine the value of the project including:

- Load growth/slow
- Energy/gas Prices and implied market heat rate
- Emissions prices
- Cost of local resources
- Imports vs Local Generation balance
- Wheeling subscription value vs market access/economic displacement value

The simulation results are as follows:

As a result of these study results, several conclusions can be determined:

- Aside from reliability, overall value depends on the usage of the line as a wheeling resource and a market access resource
- NG-IV2 provides greater system reliability at an economic cost in the expected cases
- If load does not grow or if market heat rate implication (based on gas and energy prices) greatly changes, then the value of the project can vary
- The post 2030 SB 100 rule of "Carbon Neutrality" definition can impact the overall value of the project
- The project payback rate depends on the overall level of investment required (i.e., $30-60m). The project will take longer to pay back, if the total cost is higher
- The cost of the project is assumed at this point and needs to be finalized

CHAPTER 8: CONCLUSIONS AND RECOMMENDATIONS

In the prior chapter, power supply cost simulations were performed to identify potential least-cost resources to be added to IID's current resource mix. This chapter examines unresolved issues that impact power supply costs, the impact on regulatory requirements of the preferred resource set and implications for long-term cost stability.

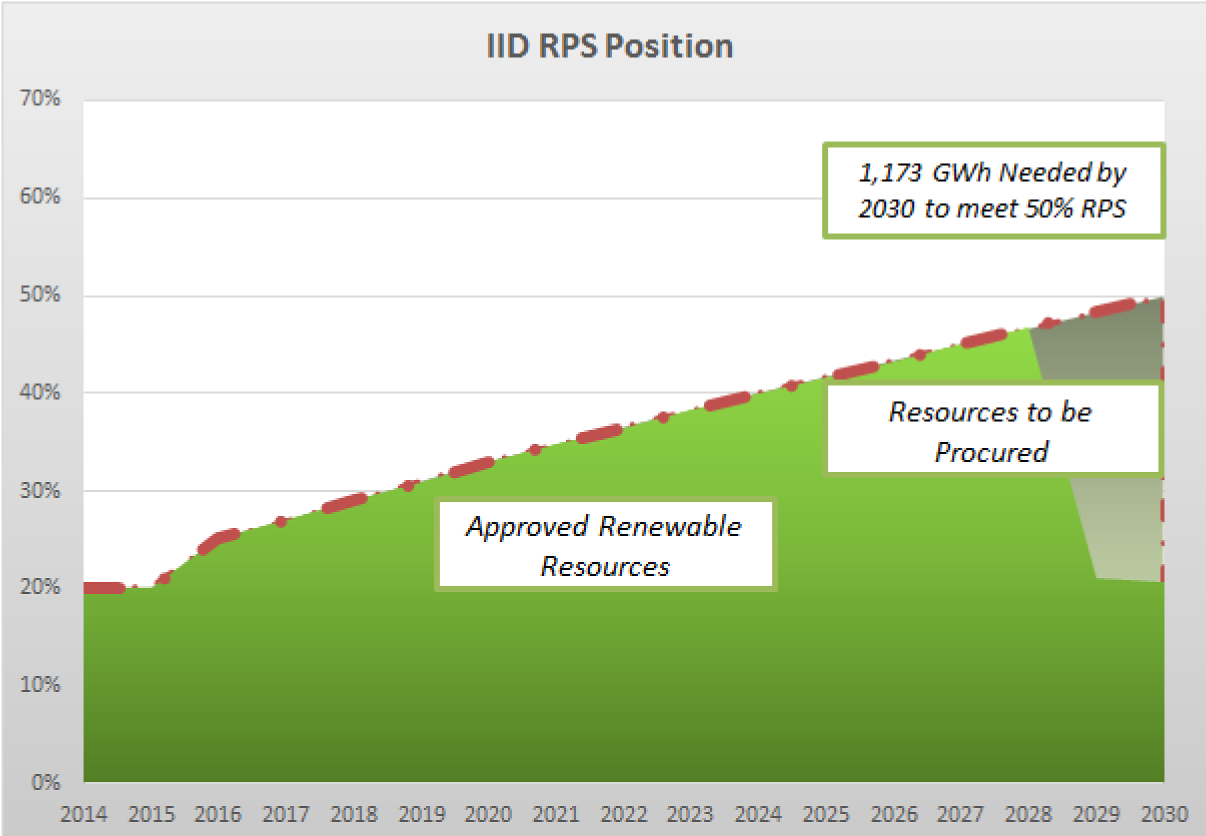
The preferred resource mix, which includes the possibility of repowering of EC4 in 2023-2025 or the addition of local peaking plants and potentially adding economically priced energy storage throughout the next 10 years . Power purchase agreements will be used to meet any remaining monthly capacity or energy deficits. The IID will continue taking advantage of opportunities to stabilize future power supply costs, such as hedging natural gas costs.

RENEWABLES PORTFOLIO STANDARDS

As discussed in prior sections, the IID is required to meet renewable portfolio standards (RPS) of 20 percent of retail load met by renewable resources for 2011-2013, increasing to 25 percent by the end of 2016 and 33 percent by the end of 2020. Currently, the IID has roughly 20.5 percent of load met by renewable resources and is likely to meet the 25 percent obligation in 2016 as well. Meeting the third compliance period is still a work in progress for 2029 and 2030, but IID has studied the abundant amount of options available to the IID since IID's geographical location of its service territory is advantageously located in an epicenter or renewable-resource potential.

With the renewable resources anticipated by the IID, the percentage of load met by renewable resources increases significantly that began in 2014, as shown by the following exhibit.

Exhibit 199: Renewable-Resource Percentage: 2014-2030



Yet, even with the contracted renewable resources coming online within the next five years, the IID is still short resources necessary to meet the 2030 RPS.

The IID's contracted renewable purchases in 2014 through 2017 result in approximately 30-40 percent of total retail energy sales being met by renewable resources for future years. However, the IID must still acquire another 8 percent of renewable generation (or approximately 980,000 MWh) of renewable energy by 2030. This is equivalent to 50-75 MW of baseload energy and around 100-150MW of solar generation or some other intermittent resource such as wind with an annual capacity factor around 30 percent. It is critical to note, however, that these resource must be scheduled properly to deliver to IID at the time of need. Any variance will result in a surplus or deficit, which are both costly.

IID has also analyzed the financial impacts of the RPS requirements on its rates. IID has calculated both the gross and net impacts of being compliant with the State's RPS. The net financial impact is computed by taking the difference of IID meeting its load requirements with conventional energy versus renewable energy resources to meet the RPS requirements. The following exhibit shows the estimated annual net financial impact of the RPS program on the Energy Cost Adjustment rate for 2016-2021:

Exhibit 200: Overall Estimated Net Impact of RPS 2018-2022

Summary of Net Financial Impact of RPS: 2019-22							
Year	Total Fuel and PP Costs ($000)	Net Impact of Green ($000)	Budget with NO GREEN ($000)	Capacity and Premiums ($000)	Projected Retail Sales (GWh)	Estimated ECA RATE (c/kWh)	Net Impact of GREEN on ECA (cents)
2018	$ 209,834.1	$ 20,646.9	$ 189,187.2	$ 8,528.1	3,344.96	0.0602	$ 0.00617
2019	$ 229,265.9	$ 76,042.1	$ 153,223.8	$ 18,339.9	3,381.91	0.0624	$ 0.02248
2020	$ 225,137.3	$ 78,667.8	$ 146,469.6	$ 19,968.3	3,412.32	0.0601	$ 0.02305
2021	$ 229,974.4	$ 79,067.5	$ 150,906.8	$ 20,167.5	3,448.33	0.0608	$ 0.02293
2022	$ 223,495.6	$ 61,542.8	$ 161,952.8	$ 20,389.2	3,489.37	0.0582	$ 0.01764

The following exhibit is an analysis of various renewable portfolios studied and the cost impact of the RPS that each portfolio contains. The financial impact is greatly influenced by factors such as load forecast, technologies selected in future years, price forecasts of natural gas, conventional and renewable energy.

Exhibit 201: Portfolio Comparison of RPS Impact

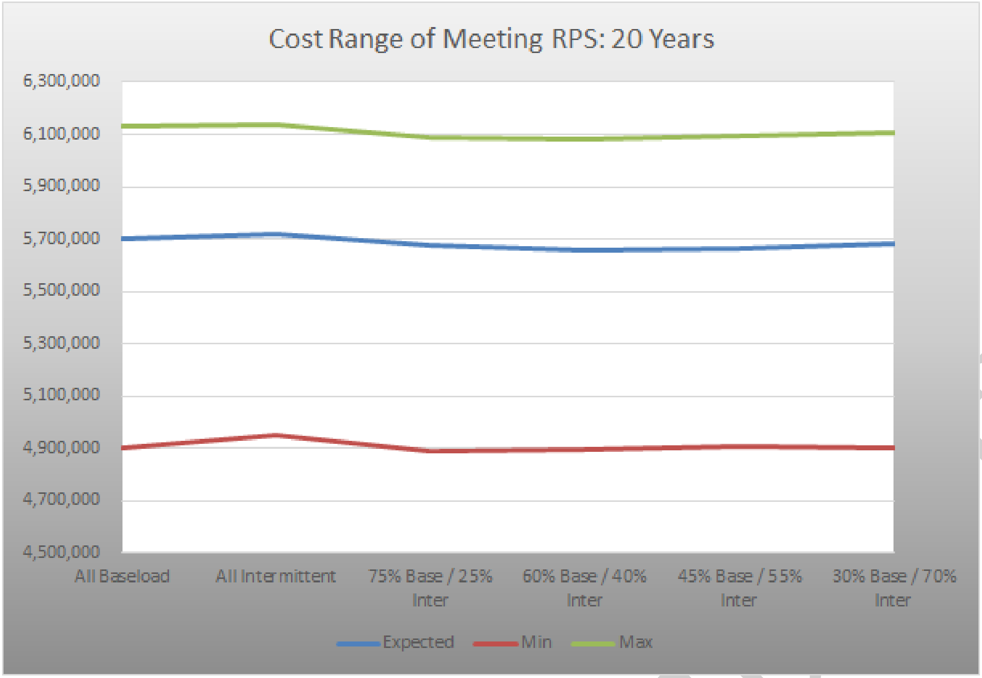


Exhibit 202: RPS Portfolio Scenario Comparison and Range of Risk

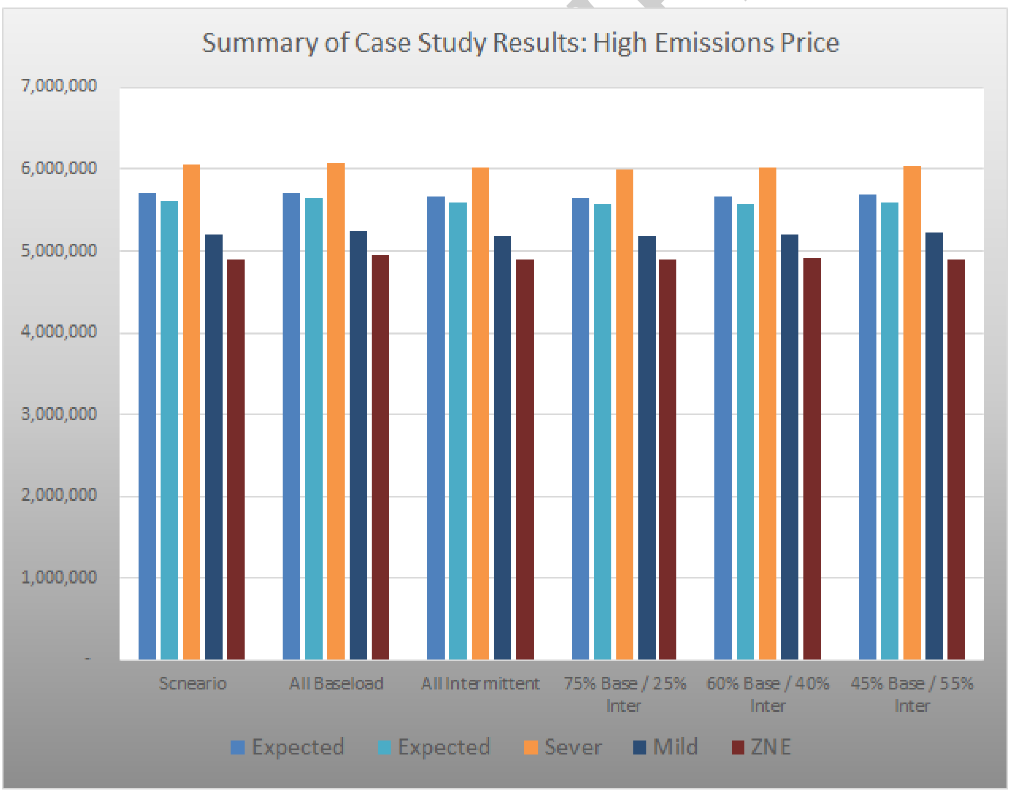
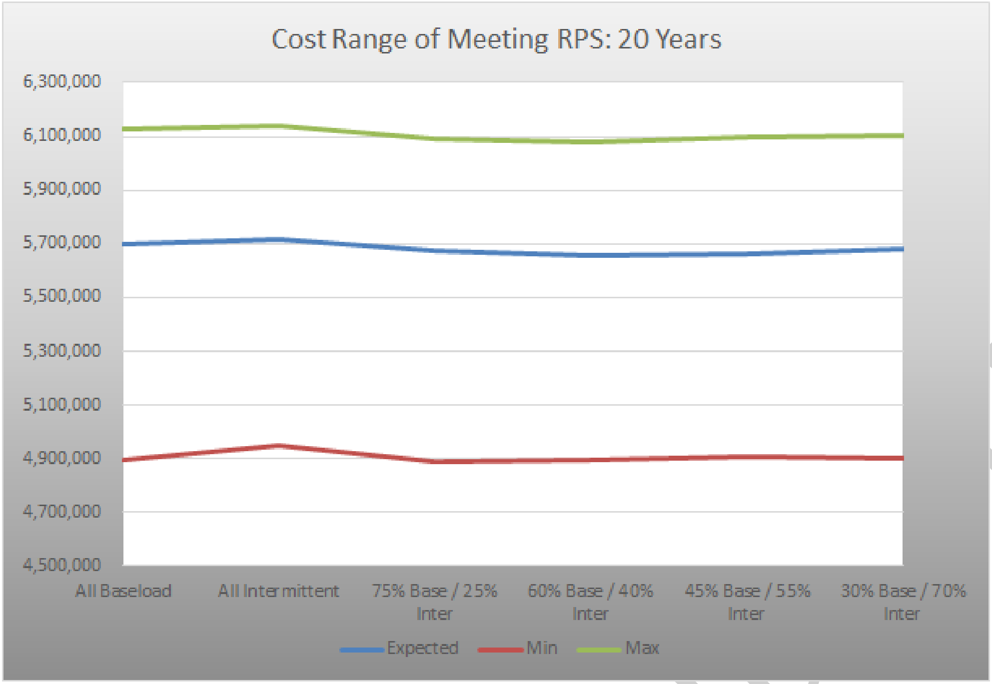


Exhibit 203: High/Low Range Impact of RPS: 20 Years



Typical load growth for the IID is around 1percent MW per year. So, the IID can anticipate purchasing 15–20 MW of renewable resources every other year, or roughly one-half of its annual purchases, to meet renewable requirements.

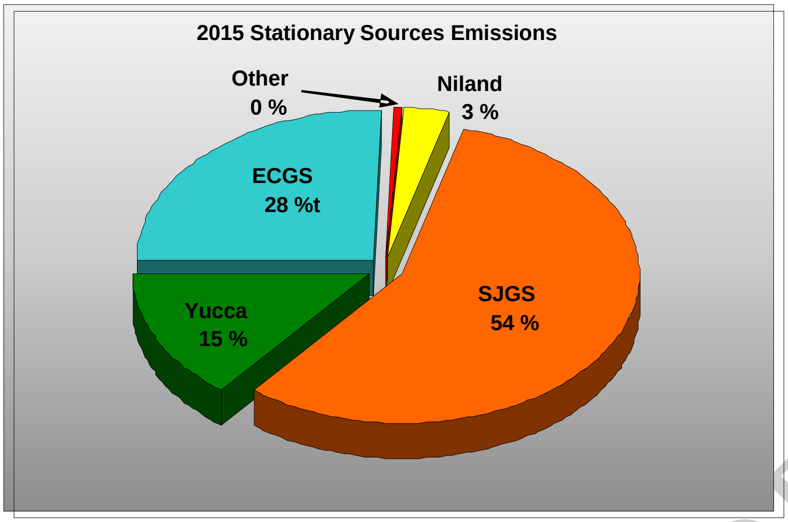
Greenhouse Gas Emission Standards (AB 32)

Determining the possible impact of existing state and proposed federal GHG emission reduction legislation on future power supply costs is a continuous activity. The IID has used a model developed by LADWP and IID's own internal models to estimate the financial impacts of GHG emission restrictions. But, like much of the analysis currently being done, the analysis is heavily dependent upon assumptions about the way regulations will ultimately evolve. It is also heavily dependent upon the overall direction IID takes on the acquisition of renewable resources, which reduce the "carbon footprint".

The final rules governing California's GHG reduction efforts (AB 32) are still under discussion, although a final report indicating how the California Air Resources Board intends to implement AB 32 was released several years ago. The Cap-and-Trade portion of the AB 32 law has the potential to have the largest impact on IID and IID is currently recording, reporting, monitoring and managing a portfolio of greenhouse gas emission resources that result from the manner of optimization of the generation and transmission facilities at IID.

The primary reason that the IID could possibly exceed annual GHG emission standards is its ownership in San Juan Generating Station, Unit 4. This is a coal-fired plant in New Mexico that has relatively high GHG per MWh of generation, approximately 2,400 lbs. per 1MWh compared to the legislated standard of 1,100 lbs./MWh.

Exhibit 204: 2016 Emission Sources



Another issue that is being addressed by Southern California utilities is ownership of coal-fired generation. For a variety of reasons in the 1980s and 1990s, Southern California utilities began acquiring out-of-state coal resources as the least-cost resource alternative. The IID acquired SJGS during this time period.

The IID financed its purchase of SJGS through SCPPA. In 2020, the SCPPA bonds will be retired and the IID's cost of ownership has declined by some $9 million annually. SCPPA is looking at paying off some of the bonds early and restructuring any outstanding bonds. At current borrowing rates, savings could be recognized with a restructure. SCPPA's goal is not to owe any of the San Juan bonds at the retirement of San Juan's Unit 3 on December 31, 2017.

IID's requirement to acquire additional renewable resources and efficient natural-gas-fired generation in order to meet its greenhouse gas requirements have made the retirement of the San Juan Unit 3 a priority.

Because the IID is forced to reduce GHG emissions to 1,100 lbs./MWh on average, new renewable generation and high-efficiency gas-fired generation can be used to reduce the IID's GHG emissions to (or below) 1,100 lbs./MWh. If the IID was to continue purchasing energy from the San Juan Generating Station and run inefficient resources with high GHG emissions, it would have to purchase emission allowances at a cost of around $15/MWh.[26]

A significant unknown at this time is the way that the state or federal rules will deal with power purchases/imports and allowances after 2020. It is still unclear which entity, the generator or purchaser, will be responsible for GHG emissions and any associated penalties.

[26] Based upon $50/ton and SJGS emissions of 2,400 lbs./MWh

From a cost viewpoint, it may not matter as the cost of GHG emission allowances are likely to be included in the total cost of energy, controlling the level of GHG emissions will be easier for the IID rather than relying on power purchase agreements.

IID should not plan on relying heavily on power purchases in the future as energy costs will likely escalate as wholesale sellers begin including GHG costs in the price of power. Over reliance on wholesale purchases will likely result in higher costs to the IID as opposed to generation from high efficiency and renewable resources that do not have carbon penalties associated with them.

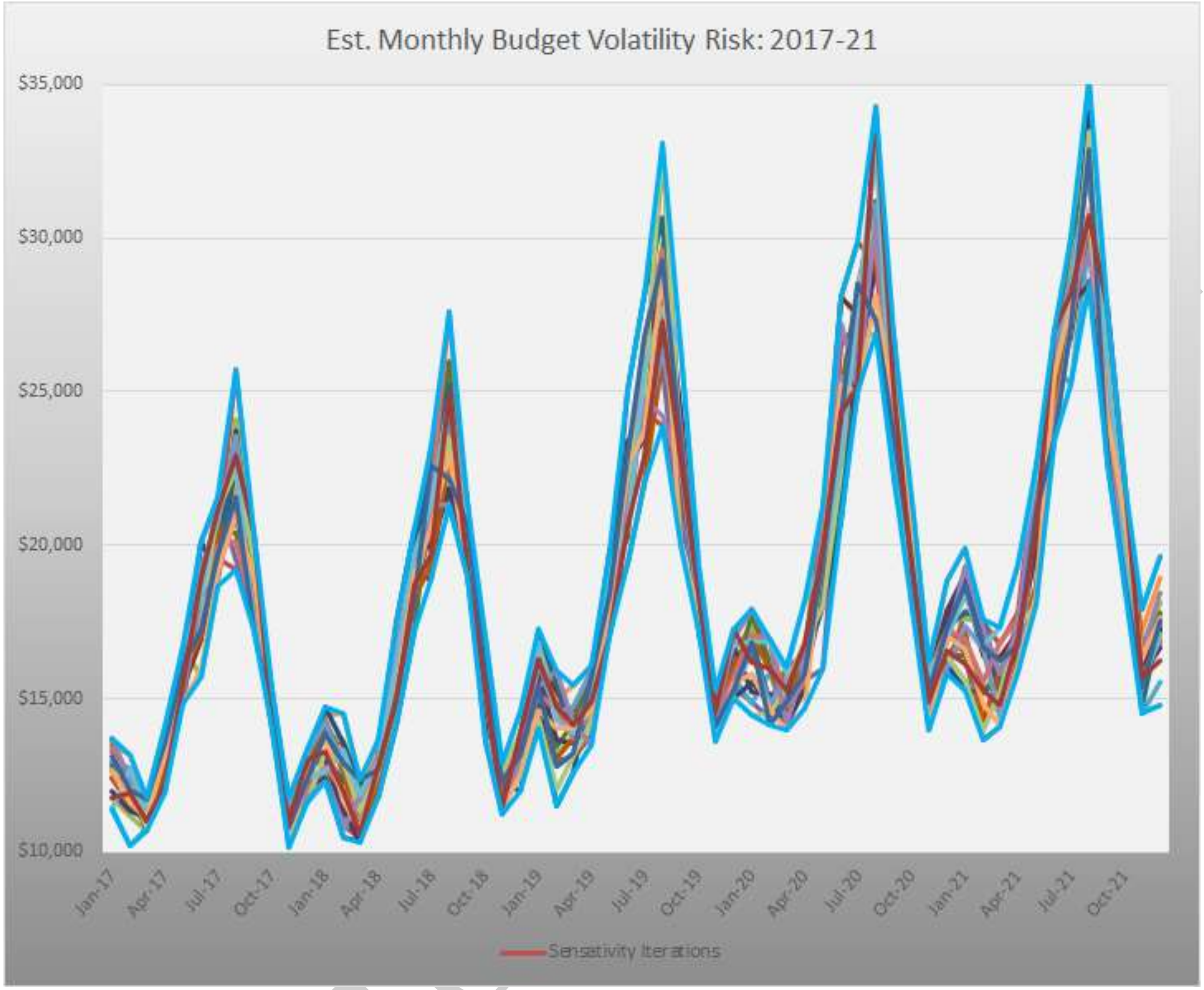
Long-Term Power Supply Cost Volatility

The IID's Risk Management Plan requires that sufficient energy and natural gas supplies be hedged to ensure that power costs do not increase by more than 10 percent in the prompt year (the next planning year), 20 percent prior to the beginning of the second planning year and 30 percent prior to the beginning of the third planning year based upon a $2.00/MMbtu increase in natural gas costs.

Changes in natural gas costs affect not only the cost of energy from the IID's internal generation but also the cost of purchased power, especially tolling agreements.

The following exhibit shows the IID's expected range of power supply costs for 2017 through 2021 and the monthly volatility of total power supply costs.

Exhibit 205: Monthly Volatility of Fuel and Purchased Power Costs 2017-21



As the exhibit shows, in 2017-21 total power supply costs can vary by up to $9.1 million on a monthly basis ($9.1 million above or below the expected cost) based upon underlying factors such as gas costs, forecast errors and other variations in the future energy environment.

As the IID is acquiring new renewable resources to its generation mix, the volatility of power supply costs has begun to decline. Renewable resources may be expensive in comparison to prices today but in the long run renewable caps both power supply costs and overall volatility.

IID Energy Rates

As an integral part of all Energy Department activities, the consideration of energy rates the customers pay for IID's services is a key factor in the decision making process. IID focuses on maintaining competitive rates in the region, state and the country and as mentioned in previous chapters, sustaining low cost rates for the IID ratepayer is a key driver in the Integrated Resource Planning process. IID has not changed its rates for more than 20 years, until a recent change in 2015 and is constantly monitoring the need of future rate adjustments in order to support the inevitable inflation of costs in IID's typical business activities. The

IID webpage contains more details on the topic of energy rates as well as a breakdown of all customer class rate schedules. The webpage can be found at:

http://www.iid.com/index.aspx?page=309

NEXT STEPS IN IRP DEVELOPMENT

Senate Bill 350, the Clean Energy and Pollution Reduction Act, passed in the 2015 California Legislative Session has several new key objectives for public owned utilizes such as the Imperial Irrigation District. These are:

- Increase renewable portfolio standard to 50 percent by 2030 (from 33 percent)
- Increase energy efficiency achievement in buildings by 50 percent by 2030 (from
- Additional focus on low-income communities, removing barriers to participation

Historically IID staff has completed the IRP including the detailed modeling and analysis using internal (IID only) review, comment and support. IRP documents have been completed in 2010, 2014 and 2016 and now in 2018. IID's board has reviewed and approved these plans as well as this document.

SB 100 is a much different process requiring public comment. Experience with other utilities that have a "public comment" requirement suggests that engaging the public and other key stakeholders early and often is key to maximizing public support during the public comment period. Even stake holders that are not totally pleased with the outcome and recommendations of the IRP action plan, often temper their comments if they were part of the review and input process.

IID needs to follow the discussions on the SB 100 rules on:

- RPS guidelines
- Post 2030 allowance allocations
- Energy efficiency requirements
- Vehicle electrification requirements
- IRP development standards

All of the above items and their specific guidelines are expected be released in mid-2017 and have a undeniable impact on all IID plans. This IRP can be used as a good starting point in order to discuss and begin to evaluate new studies using new assumptions per the CEC. Additionally, IID has an RFP underway for assistance with this task as well as how to involve the various stakeholders involved in the IRP process.

The standardized reporting tables are enclosed in a separate file and were prepared to meet the submission guidelines under SB350. IID took the recommendation of the POU IRP Submission and Review Guidelines of running numerous study cases and scenarios. Please see Chapter 7 for more details related to the production cost studies and the various scenarios performed for this IRP. While IID's study results yield many iterations that allow for a better understand of future risk in load, pricing, portfolio mix, etc., IID chose 3 main cases to focus on. The three main scenarios that are reported within the tables are as follows:

1. High Load Case – Expected pricing; Preferred portfolio
2. Expected Load Case – Expected pricing; Preferred portfolio
3. Low Load Case – Expected pricing; Preferred portfolio

Please note: There are some pieces of data for 2017-18 are still not yet available as of the submission date. Each of these cases and their results are subject to change due to many uncertain factors that may arise.

APPENDIX A: CEC IRP STANDARDIZED REPORTING TABLES

The required tables of data are included in this appendix.

EBT:

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Energy Balance Table
[illegible]

Scenario Name: Units = MWh

Historical Data

[illegible]

NET ENERGY FOR LOAD CALCULATIONS

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Retail sales to end use customers	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Other loads														
Net energy for load	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Retail sales to end-use customers (accounting for AAEE impacts)														
Net energy for load (accounting for AAEE impacts)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Firm Sales Obligations														
Total net energy for load (accounting for AAEE impacts) (5+6)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[Customer-side solar generation]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[Light Duty PEV electricity consumption/procurement requirement]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[Other transportation electricity consumption/procurement requirement]														
[Other electrification/fuel substitution consumption/procurement requirement]														

EXISTING AND PLANNED GENERATION RESOURCES

Utility-Owned Generation Resources (not RPS-eligible)

[list resources by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coachella 1	Natural Gas	[illegible]												[illegible]	[illegible]
Coachella 2	Natural Gas	[illegible]		[illegible]											
Coachella 3	Natural Gas	[illegible]												[illegible]	[illegible]
Coachella 4	Natural Gas	[illegible]												[illegible]	[illegible]
El Centro #2	Natural Gas	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
El Centro #3	Natural Gas	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
El Centro #4	Natural Gas	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Yucca GT 21	Oil														
Niland 1	Natural Gas	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Niland 2	Natural Gas	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rockwood 1	Natural Gas			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Yucca Steam	Natural Gas			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rockwood 2	Oil														

Long-Term Contracts (not RPS-eligible)

[list contracts by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Aggreko	Solar			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
BCP Hoover+Tabor	Large Hydro			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Parker_Davis	Large Hydro			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SCAPPA Nuclear	Nuclear			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	0														
	0														
Total energy from existing and planned supply resources (not RPS-eligible) (sum of 22a...22n)		[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Utility-Owned RPS-eligible Generation Resources:

[list resources by plant or unit]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
DRSPS	Small Hydro			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ITSC1	Solar			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														

Long-Term Contracts (RPS-eligible)

[list contracts by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
3 Flo Energy	Solar			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Biomass SEMP	Biomass			[illegible]	[illegible]	[illegible]	[illegible]								
Desert View Colmac	Biomass			[illegible]	[illegible]	[illegible]	[illegible]								
BCPV	Solar			[illegible]	[illegible]	[illegible]	[illegible]								
Feed-in-Tariff Program	Solar			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Heber Solar	Solar			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Ormat Geo	Geothermal			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
Ormat Ormesa Geo	Geothermal			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
BSC YUWUA	Small Hydro			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Regenerate	Solar			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SDEL PV	Solar			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SunPeak 1	Solar			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cal Energy	Geothermal			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
Citizens 20MW	Solar			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
GeoEnerGo	Geothermal				[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total energy from RPS-eligible resources (sum of 24a...24i, and 24k)		0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Undelivered RPS energy															
Total energy from existing and planned supply resources (22+23)		[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

[list resource by name or description]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
Total energy from generic supply resources (non RPS-eligible)				0	0	0	0	0	0	0	0	0	0	0	0

RPS-ELIGIBLE RESOURCES:

[list resource by name or description]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Baseload RPS-eligible resources	Geo, Biomass													[illegible]	[illegible]
Intermittent RPS eligible resources	Solar, Wind													[illegible]	[illegible]
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
	0														
Total energy from generic RPS-eligible resources				0	0	0	0	0	0	0	0	0	0	[illegible]	[illegible]
Total energy from generic supply resources (19+16)				0	0	0	0	0	0	0	0	0	0	[illegible]	[illegible]
Total energy from RPS-eligible short-term contracts															

ENERGY FROM SHORT-TERM PURCHASES

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Short-term and spot market purchases			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Short-term and spot market sales (only report sales of energy from resources already included in the EBT)			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

ENERGY BALANCE SUMMARY

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total energy from supply resources (14+17+21a)	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Undelivered RPS energy (from 19a)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Short-term and spot market purchases (18 - 18a)	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total delivered energy (19-19a+20)	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total net energy for load (from 7)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Surplus/(Shortfall) (21-22)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CRAT

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Capacity Resource Accounting Table
Form CEC [illegible]

Scenario Name:

Yellow fill relates to an application for confidentiality.
Data input by User are in dark green font.

Units = MW

	PEAK LOAD CALCULATIONS	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Forecast Total Peak-Hour 1-in-2 Demand	1,079	1,052	1,061	1,068	1,080	1,092	1,108	1,119	1,138	1,155	1,171	1,186	1,206	1,224
2	[Customer-side solar: nameplate capacity]	64	75	87	96	101	105	109	109	110	110	110	110	110	110
2a	[Customer-side solar: peak hour output]	19	22	27	30	31	32	33	34	34	34	34	33	33	33
3	[Peak load reduction due to thermal energy storage]														
4	[Light Duty PEV consumption in peak hour]		1.35	2.30	2.64	3.16	3.68	4.20	4.70	5.21	5.73	6.24	6.73	7.24	7.74
5	Additional Achievable Energy Efficiency Savings on Peak														
6	Demand Response / Interruptible Programs on Peak														
7	**Peak Demand (accounting for demand response and AAEE) (1-5-6)**	1,079	1,052	1,061	1,068	1,080	1,092	1,108	1,119	1,138	1,155	1,171	1,186	1,206	1,224
8	Planning Reserve Margin														
9	Firm Sales Obligations														
10	**Total Peak Procurement Requirement (7+8+9)**	1,079	1,052	1,061	1,068	1,080	1,092	1,108	1,119	1,138	1,155	1,171	1,186	1,206	1,224

EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES

Utility-Owned Generation and Storage (not RPS-eligible):

For fuel type, choose from list or enter value

	[list resource by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
11a																
11b																
11c																
11d																
11e																
11f																
11g																

Long-Term Contracts (not RPS-eligible):

	[list contracts by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
11h																
11i																
11j																
11k																
11l																
11m																
11n																
11	**Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a...11n)**		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Utility-Owned RPS-eligible Resources:

	[list resource by plant or unit]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12a																
12b																
12c																
12d																
12e																
12f																
12g																
12h																
12i																
12j																
12k																
12l																
12m																
12n																

Page 1

Long-Term Contracts (RPS-eligible):

	[list contracts by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12o																
12p																
12q																
12r																
12s																
12t																
12	**Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a...12t)**		0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	**Total peak dependable capacity of existing and planned supply resources (11+12)**		0	0	0	0	0	0	0	0	0	0	0	0	0	0

GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

	[list resource by name or description]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
14a																
14b																
14c																
14d																
14e																
14f																
14g																
14h																
14i																
14j																
14k																
14l																
14m																
14n																
14	**Total peak dependable capacity of generic supply resources (not RPS-eligible)**		0	0	0	0	0	0	0	0	0	0	0	0	0	0

RPS-ELIGIBLE RESOURCES:

	[list resource by name or description]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
15a																
15b																
15c																
15d																
15e																
15f																
15g																
15h																
15i																
15j																
15k																
15l																
15m																
15n																
15	**Total peak dependable capacity of generic RPS-eligible resources**				0	0	0	0	0	0	0	0	0	0	0	0
16	**Total peak dependable capacity of generic supply resources (14+15)**				0	0	0	0	0	0	0	0	0	0	0	0

CAPACITY BALANCE SUMMARY

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
17	**Total peak procurement requirement (from line 10)**	1,079	1,052	1,061	1,068	1,080	1,092	1,108	1,119	1,138	1,155	1,171	1,186	1,206	1,224
18	**Total peak dependable capacity of existing and planned supply resources (from line 13)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	**Current capacity surplus (shortfall) (18-17)**	(1,079)	(1,052)	(1,061)	(1,068)	(1,080)	(1,092)	(1,108)	(1,119)	(1,138)	(1,155)	(1,171)	(1,186)	(1,206)	(1,224)
20	**Total peak dependable capacity of generic supply resources (from line 16)**			0	0	0	0	0	0	0	0	0	0	0	0
21	**Planned capacity surplus/shortfall (shortfalls assumed to be met with short-term capacity purchases) (19+20)**	(1,079)	(1,052)	(1,061)	(1,068)	(1,080)	(1,092)	(1,108)	(1,119)	(1,138)	(1,155)	(1,171)	(1,186)	(1,206)	(1,224)

GEAT:

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
GHG Emissions Accounting Table
Form IRP [illegible]

Scenario Name:

Yellow fill relates to an application for confidentiality.

Emissions Intensity Units = mt CO2e/MWh
Yearly Emissions Total Units = Mmt CO2e

GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY

Utility-Owned Generation (not RPS-eligible):

	[list resource by name]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1a																
1b																
1c																
1d																
1e																
1f																
1g																

Long-Term Contracts (not RPS-eligible):

	[list contracts by name]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1h																
1i																
1j																
1k																
1l																
1m																
1n																
1	Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a...1n)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Utility-Owned RPS-eligible Generation Resources:

	[list resource by plant or unit]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2a																
2b																
2c																
2d																
2e																
2f																
2g																
2h																
2i																
2j																
2k																
2l																
2m																
2n																

Long-Term Contracts (RPS-eligible):

	[list contracts by name]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2o																
2p																
2q																
2r																
2s																
2t																
2	Total GHG emissions from RPS-eligible resources (sum of 2a...2t)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Total GHG emissions from existing and planned supply resources (1+2)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

EMISSIONS FROM GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

	[list resource by name or description]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
4a																
4b																
4c																
4d																
4e																
4f																
4g																
4h																
4i																
4j																
4k																
4l																
4m																
4n																
4	Total GHG emissions from generic supply resources (not RPS-eligible)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

RPS-ELIGIBLE RESOURCES:

	[list resource by name or description]	Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
5a																
5b																
5c																
5d																
5e																
5f																
5g																
5h																
5i																
5j																
5k																
5l																
5m																
5n																
5	Total GHG emissions from generic RPS-eligible resources		0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total GHG emissions from generic supply resources (4+5)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

GHG EMISSIONS OF SHORT TERM PURCHASES

		Emissions Intensity	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
7	Net spot market/short-term purchases	[illegible]	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TOTAL GHG EMISSIONS

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
8	Total GHG emissions to meet net energy for load (3+6+7)	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

EMISSIONS ADJUSTMENTS

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
8a	Undelivered RPS energy (MWh from EBT)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8b	Firm Sales Obligations (MWh from EBT)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8c	Total energy for emissions adjustment (8a+8b)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8d	Emissions intensity (portfolio gas/short-term and spot market purchases)														
8e	Emissions adjustment (8Cx8D)	0	0	0	0	0	0	0	0	0	0	0	0	0	0

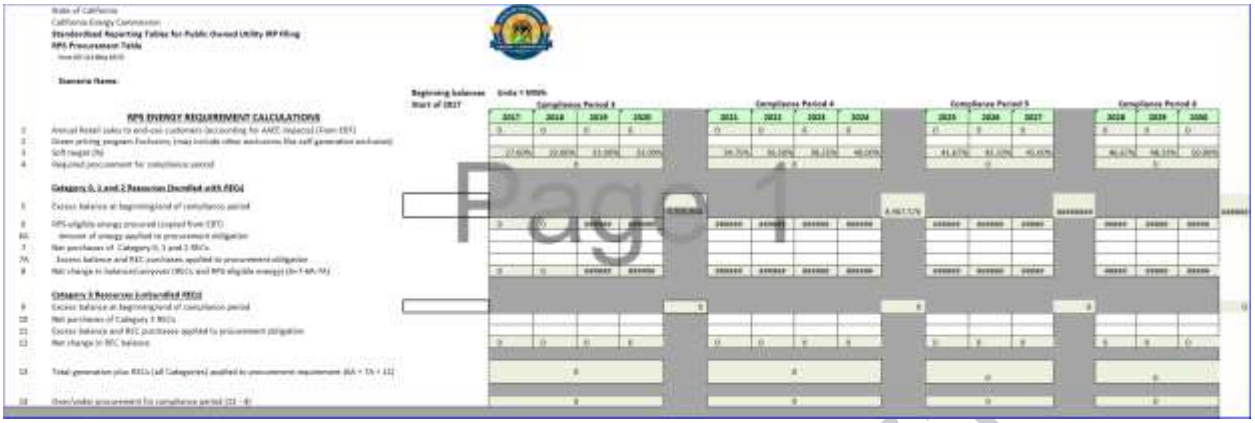
PORTFOLIO GHG EMISSIONS

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
8f	Adjusted Portfolio emissions (8-8e)	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

GHG EMISSIONS IMPACT OF TRANSPORTATION ELECTRIFICATION

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
9	GHG emissions reduction due to gasoline vehicle displacement by LD PEVs														
10	GHG emissions increase due to LD PEV electricity loads														
11	GHG emissions reduction due to fuel displacement - other transportation electrification														
12	GHG emissions increase due to increased electricity loads - other transportation electrification														

RPT:



State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
RPS Procurement Table

Scenario Name:

Beginning balances Start of 2017 | Units = MWh

	RPS ENERGY REQUIREMENT CALCULATIONS	Compliance Period 3: 2017	2018	2019	2020		Compliance Period 4: 2021	2022	2023	2024		Compliance Period 5: 2025	2026	2027		Compliance Period 6: 2028	2029	2030
1	Annual Retail sales to end-use customers (accounting for AAEE impacts) (From EBT)	0	0	0	0		0	0	0	0		0	0	0		0	0	0
2	Green pricing program Exclusions (may include other exclusions like self generation exclusion)																	
3	Soft target (%)	27.00%	29.00%	31.00%	33.00%		34.75%	36.50%	38.25%	40.00%		41.67%	43.33%	45.00%		46.67%	48.33%	50.00%
4	Required procurement for compliance period	0					0					0				0		
	Category 0, 1 and 2 Resources (bundled with RECs)																	
5	Excess balance at beginning/end of compliance period					[illegible]					4,467,576				#######			#######
6	RPS-eligible energy procured (copied from EBT)	0	0	######	######		######	######	######	######		######	######	######		######	######	######
6A	Amount of energy applied to procurement obligation																	
7	Net purchases of Category 0, 1 and 2 RECs																	
7A	Excess balance and REC purchases applied to procurement obligation																	
8	Net change in balance/carryover (RECs and RPS eligible energy) (6+7-6A-7A)	0	0	######	######		######	######	######	######		######	######	######		######	######	######
	Category 3 Resources (unbundled RECs)																	
9	Excess balance at beginning/end of compliance period					0					0				0			0
10	Net purchases of Category 3 RECs																	
11	Excess balance and REC purchases applied to procurement obligation																	
12	Net change in REC balance	0	0	0	0		0	0	0	0		0	0	0		0	0	0
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)	0					0					0				0		
14	Over/under procurement for compliance period (13 - 4)	0					0					0				0		

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APPENDIX B: LIST OF EXHIBITS

APPENDIX C: CAP AND TRADE DISCUSSION

GHG EMISSIONS REDUCTIONS – AB 32

The Global Warming Solutions Act (AB 32) mandates POUs (like the IID), to reduce total company wide emissions to 1990 levels by 2020 and an 80 percent of 1990 levels reduction by 2050 – a state reduction of about 30 percent and a reduction of about 7-10 percent for IID. Due to the nature of the law, IID adjusted its approach to resource planning to meet the emission reduction standard. It is believed by lawmakers, scientists and many energy industry representatives that these reductions in greenhouse gas will decrease overall emissions of harmful gases. California's major initiative for reducing climate change or GHG emissions that will affect IID the most is outlined in Assembly Bill 32 (signed into law in 2006 by former Governor Schwarzenegger). The main strategies for making these reductions are highlighted in the AB 32 Scoping Plan, which has been updated twice. Further, Governor Brown's Executive Order B-30-15, issued on April 29, 2015, established a California greenhouse gas reduction target of 40 percent below 1990 levels by 2030. In 2016, the Legislature passed SB 32, which formalized the 2030 GHG emissions reduction target of 40 percent below 1990 levels set forth in Executive Order B-30-15. In conjunction with SB 32, the Legislature passed AB 197 to provide the California Air Resources Board with further guidance in preparing an update to the Scoping Plan. On December 14, 2017, CARB approved the second update to the Scoping Plan to reflect the targets set forth in Executive Order B-30-15 and SB 32. The Legislature affirmed the extension of the Cap-and-Trade program through 2030 through the passage of AB 398. In order to meet these stringent goals, several steps must be taken in strategic Integrated Resource Planning.

On September 27, 2006, the Global Warming Solutions Act of 2006, known as AB 32, was signed into law. AB 32 required the CARB to adopt a statewide greenhouse gas[27] emissions limit equivalent to the statewide greenhouse gas emission levels in 1990 by 2020. This mandate amount seeks to reduce California's current per person average of 14 tons of carbon dioxide a year to 10 tons per person a year. In December 2007, CARB calculated that, without any changes, California would emit 596 million metric tons (MMT) of carbon dioxide equivalent[28] in 2020. CARB established the 1990 emissions level as 422 MMT. AB 32 required CARB to adopt rules and regulations to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions to achieve the 1990 level.

CARB adopted a plan to reach the 1990 levels through regulations including establishing market- based mechanisms, which have the following components:

7) Expand energy efficiency programs;
8) Achieve a statewide renewable energy mix of 33 percent;
9) Develop a Cap-and-Trade Program that links to the Western Climate Initiative partner programs to create a regional market system;
10) Establish targets for transportation related GHG emissions for regions throughout California;
11) Adopt and implement California's clean car standards, goods movement measures and the Low Carbon Fuel Standard; and
12) Create targeted fees, including public goods charges on water use fees on high global warming potential gases, and a fee to fund the administrative costs of the state's long-term commitment to AB 32.

The Cap-and-Trade Program establishes a declining annual aggregate emissions limit for regulated sources and provides rules for the sale of emission allowances[29]. The first sectors to be regulated under the cap are

[27] Greenhouse gas includes all of the following gases: carbon dioxide, methane, nitrous oxide, hydroflourocarbons, perfluorocarbons, and sulfur hexafluoride.

[28] Carbon dioxide equivalent means the amount of carbon dioxide by weight that would produce the same global warming impact as a given weight of another greenhouse gas.

[29] Allowance is the authorization to emit, during a specified year, up to one ton of carbon dioxide equivalent.

the electricity sector and large[30] industrial[31] sources of GHG. Other sectors, including distributors of transportation fuels, natural gas and other fuels, were to have been started to be regulated starting in 2015; the cap starts at 165.8 MMT in 2012. Due to the economic downturn, this amount will achieve virtually 100 percent of emissions for the regulated sector for that year.

The Cap-and-Trade regulations provide for a distribution of allowances through direct allocation and an auction system. The electricity sector has agreed that allocation of allowances within the electricity sector for 2012 should be based roughly on historical emissions[32]. The cap declines approximately two percent per year in the initial period (2012-2014). In 2015 the cap increase to 394.5 million allowances to account for the expansion in program scope to the other sectors. The cap then declines three percent per year between 2015 and 2020. The 2020 cap is set at 334.2 million allowances. The allowances to the publicly-owned utilities have been directly allocated. Investor owned utilities are required to consign all allocated allowances to auction. The IOU use of the auction revenues is still under review at the CPUC, which could indicate the direction of POU related law. CARB has approved regulations that will extend the Cap-and-Trade Program to 2030, with imposing increasing emissions cuts.

To reach the 1990 level of 422 MMT, CARB envisions reductions coming from the above regulatory efforts, including the capped and uncapped sources. The plan anticipates it will receive 60.2 MMT of reductions in the transportation sector from the following programs and requirements:

- Pavley Standards[33] (31.7 MMT)
- Low Carbon Fuel Standard (15.0 MMT)
- Regional transportation reduction targets through reduction of vehicle miles travelled[34] (5.0 MMT)
- Vehicle efficiency (4.5 MMT)
- High Speed Rail (1.0 MMT)

[30] Greater than 25,000 metric tons of carbon dioxide per year.

[31] The 800 largest GHG emission sources, including cement and refineries, are covered in this first cap.

[32] The CARB used the utilities' emissions as reported on the 2007 CEC S-2 forms to reach the 165 MMT number. After CARB calculated the number it became apparent that the water agencies emissions were not included in that calculation but they are to share in the utility sector allocation. Additionally, IID and several other SCPPA utilities have since updated the 2007 S-2 numbers for renewable energy in its portfolio from 2012-2020. It is expected that CARB will re-compute the individual and sector allowance allocation.

[33] Requirement on automobile manufacturers to reduce the amount of GHG emissions in vehicles by 30percent by the year 2016.

[34] SB 375 requires regional planning entities to include reduction of VMTs in planning efforts for new construction and development of regional transportation plans.

- Goods Movement (3.7 MMT).

Additional reductions beyond the cap-and-trade program in the electricity sector are expected from the following programs:

- Energy Efficiency (26.3 MMT);
- 33 percent Renewable Portfolio Standard (21.3 MMT); and
- Million Solar Roofs (2.1 MMT).

The CARB Scoping Plan also expects to have 0.3 MMT of reduction from industrial sources and a 26.0 MMT reduction in GHG from new requirements for Green Building Standards. CARB was tasked in AB 32 with establishing fees to be paid by regulated sources for all GHG emissions as well as penalties for failing to meet the GHG limit during a reporting period for each regulated source. The administrative fee was to cover the costs of running the GHG programs and encourage further reductions. The regulatory penalties for noncompliance are based on CARB's authority under the California Health and Safety Code. The Code allows for penalties to be assessed per day per MW of emissions. CARB approved this Scoping Plan Update on December 14, 2017.

Modifications to the Cap-and-Trade program to reflect the 2030 targets were adopted on July 27, 2017. Further amendments have been proposed to clarify provisions related to changes of ownership and successor liability for emissions compliance obligations and the calculation of the Auction Reserve Price to take into account California's linkage to Ontario's Cap-and-Trade Program (though Ontario since has signaled that it is de-linking from the California program). These amendments were adopted by CARB on March 22, 2018. CARB also has been developing potential regulations to implement AB 398, which approved continued use of the Cap-and-Trade program through 2030, including establishing a price ceiling and two price containment points, and addressing concerns as to overallocation of allowances, among other changes. Proposed formal, 45-day language is expected to be issued this fall for CARB approval in December 2018. In addition, on July 26, 2018, CARB approved an overall IRP planning range between 30 and 53 MMTCO2e, as reflected in the 2017 Scoping Plan Update. CARB's proposal also included a range for IID, specifically 524,000 MTCO2e at the low end of the range, and 925,000 MTCO2e range, or 1.745 percent of the electricity sector emissions.

The GHG rules and the Cap-and-Trade Program adopted by CARB are in effect, and were upheld through appellate review[35] and subsequent denial of review by the California Supreme Court, against legal challenge

[35] *See Calif. Chamber of Commerce v. State Air Resources Bd.*, 10 Cal.App.5th 604 216 Cal.Rptr.3d 694, Case No. C075930 (3rd. App. Dist. 2017), *rev. denied* June 28, 2017.

to halt the implementation of the Cap-and-Trade Program, on the basis that the Program functions like a tax, and must be subject to two-thirds approval by the Legislature.[36]

CAP-AND-TRADE PROGRAM

Cap-and-Trade is a regulatory system that sets a government limit on overall emissions of pollutants like the heat-trapping gases scientists have linked to global warming -- the "cap." It then allows utilities, manufacturers and other emitters to "trade" pollution permits, or allowances, among themselves. The idea is to limit that which is capped through market forces. Those who are familiar with energy and emissions markets consider Cap-and-Trade the equivalent of a tax, rather than direct regulation. Cap-and-Trade is still the most effective means of achieving a significant portion of the emissions reductions called for in AB 32 and SB 32, according to a second, revised Scoping Plan analysis adopted by CARB in December 2017. As described by CARB, the design elements of the Cap-and-Trade Program include:

- Rulemaking
- Market Operations and Oversight
- Caps, Allowances and Revenue Use
- Offsets and Cost Containment
- Reporting
- Public Health and Environmental Justice.

Each large-scale emitter, or a utility like IID, will have a limit on the amount of greenhouse gas that it can emit. IID must have an "emissions permit" for every ton of carbon dioxide it releases into the atmosphere. These permits, also known as "emissions allowances" set an enforceable limit, or cap, on the amount of greenhouse gas pollution that the company is allowed to emit (discussed more in depth below). Over time, the limits become stricter, allowing less and less pollution, until the ultimate reduction goal is met. Further:

It will be relatively cheaper or easier for some companies to reduce their emissions below their required limit than others. These more efficient companies, who emit less than their allowance, can sell their extra allowances to companies that are not able to make reductions as easily. This creates a system that guarantees a set level of overall reductions, while rewarding the most efficient companies and ensuring that the cap can be met at the lowest possible cost to the economy.[37]

In the case of IID, a large scale emitter with inefficient stationary emitters that are key elements of the energy resource stack, a reduction is necessary. Specifically, a 7-10 percent reduction depending upon the amount of allowances distributed to IID.

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[36] http://www.latimes.com/politics/essential/la-pol-ca-essential-politics-updates-cap-and-trade-supreme-1498684764-htmlstory.html

[37] https://cdn.americanprogress.org/wp-content/uploads/issues/2008/01/pdf/capandtrade101.pdf

In the Cap-and-Trade regulation system, there are compliance periods and enforcement periods that have been under debate for some time. As originally proposed in October 2010, the Cap-and-Trade regulation required the program to start in 2012. This included allocation distribution, enforcement, credit, trading and tracking, auctions and all the other pieces that go along with a full-blown market program. Within the details was a requirement that each year within a three-year compliance period an entity subject to the regulation would be required to turn in (surrender) greenhouse gas emissions[38]. A successful Cap-and-Trade Program will maintain the goal of limiting a rise in global temperature by 3.6 degrees Fahrenheit by 2050 by reducing the aforementioned carbon dioxide and other emissions to curb global warming. According to emissions allowance reports, CARB has focused on steadily tightening the cap until emissions levels are reduced to 80 percent below 1990 levels by 2050.

In the case of IID, the reduction of overall organizational emissions will be mainly rendered through a rigorous renewable portfolio program already in progress by the IID Energy Resource Planning Unit. As discussed later, a strategically implemented renewable energy resource program will not only allow for a reduction in emitted harmful greenhouse gases, but will also simultaneously provide compliance with the state RPS program in a cost-effective manner.

As noted above, further amendments to the Cap-and-Trade program to implement AB 398 are being discussed, and it is anticipated that 45-day formal regulatory language will issue this fall for consideration for approval by CARB this December.

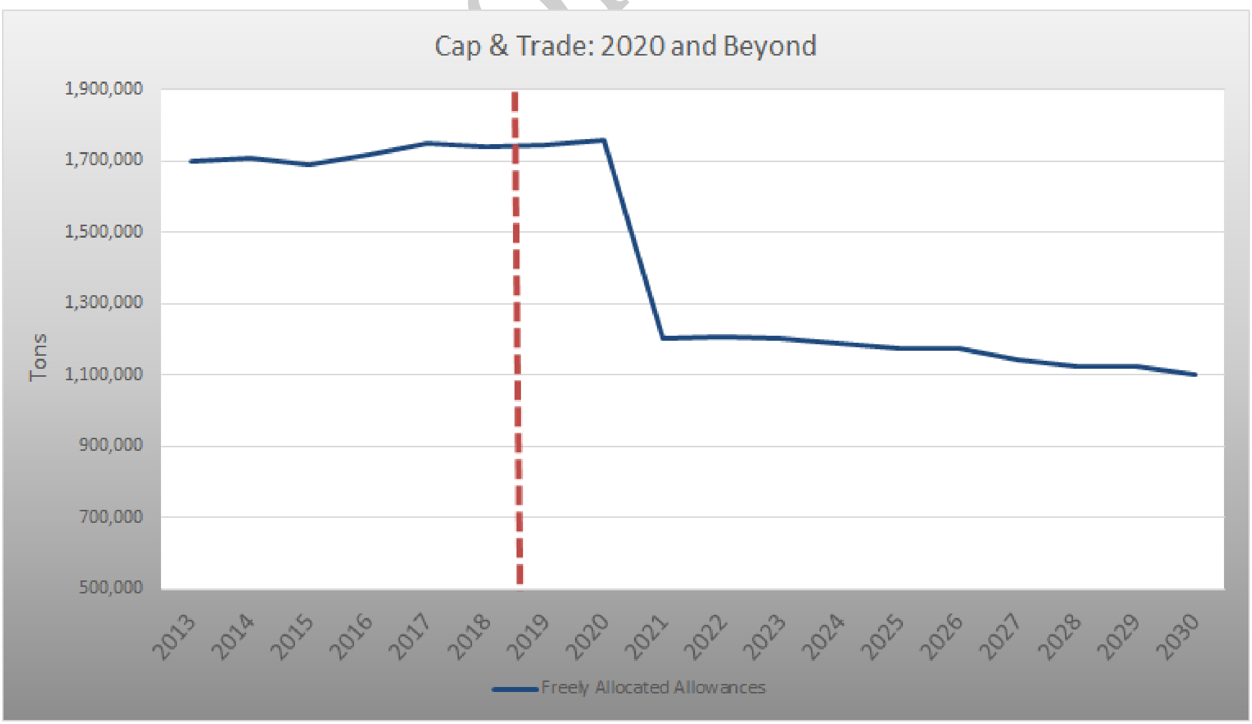
Emission Allowances Granted to IID

Assembly Bill 32, specifies the amount of Metric Tons of Carbon Dioxide Equivalent (MTCO2e) that can be released by each emitting sector. The amounts that are expected to be emitted are called allowances and they will be the means to the end of reducing overall California emissions as per the Cap-and-Trade Program. In order to reduce overall emissions in California, CARB has determined that between 2013 and 2020, all utilities serving load in the state will be allocated--or “limited” to--715,947 metric tons of CO2 equivalent (MTCO2e) or an annual average of 89,493 MMCO2e. AB 32 has designated CARB to determine a methodology and the calculation of the distribution of the above limitations of permitted greenhouse gas emission allowances. CARB has allowed the Southern California Public Power Authority to develop a calculated allocation methodology of distributing allowances to each of the SCPPA members based on a previously reported California Energy Commission energy requirement forecast form “S-2”. In IID’s case, this form is a 10-year projection of total annual load and the resources utilized to meet that load. IID’s forecast, at the time, included renewable resources that will reduce IID’s overall carbon footprint; however, some of these projected resources are not yet contracted and, therefore, the actual amount of reduction in greenhouse gases is not yet certain.

[38] *See generally* http://www.arb.ca.gov/cc/capandtrade/guidance/chapter1.pdf.

Currently the state and the utilities have agreed to an approach that distributes the allowances to each individual utility in a reasonable manner considering numerous factors, such as load growth, resource portfolio, future resource portfolio plans, etc. The following exhibit displays the amount of emissions that have been allotted to IID.

Exhibit 206: State Allocated Emission Allowances to IID 2013-2030



As displayed above, IID's amount of allowed emissions is not decreasing until 2020. This is mainly due to the methodology that was used by the state and SCPPA members. The distribution of allowances factors in growth and utility resource portfolio trends. Therefore, IID's allowances are fairly flat and this is mainly due to IID's higher than normal forecasted load growth rate and the associated resources that are in place to supply the energy for that growth.

In the past, there were some interpretation questions in regards to the Cap-and-Trade Regulation sections §95812 (f) and (g). The provision pertaining to the retirement of allowances allocated to covered entities in the event of a facility shut down was unclear. In October of 2013, the California Air Resource Board made clear that the allowances allocated under the provisions in sections 95812(f) and (g) apply to industrial covered facilities, and does not intend to require the return of allowances in the case that an electric distribution utility shuts down an electricity generation facility. CARB also made it clear their intent to support EDUs to ensure that their efforts to incentivize greenhouse gas reductions in the electricity generation sector are effectively carried out consistent with the State of California goals. This is important when considering the closure of San Juan Unit 3 coal facility, which occurred December 31, 2017. The San Juan Coal plant was close to half of IID's emissions and once Unit 3 closed and now that IID has exited ownership of the plant, then IID should be able to use the revenues recognized from the sales of the allowances for a renewable base load generation plant. This would allow IID to meet its compliance period three target of 33 percent by 2020 while avoiding additional integration costs of intermittent renewable resources and reduce IID's carbon footprint.

IID Emissions Trends and Projections

Distributed allowances are supplied in the form of Metric Tons of Carbon Dioxide Equivalent (MTCO2e), but there are actually numerous greenhouse gases that IID emits which are converted to this measure. A broad understanding of these greenhouse gases is necessary to fully grasp the meaning of IID's distributed allowance from CARB. Below are some critical definitions and information relative to greenhouse gases provided by the Generation Group.

> *Greenhouse gases* (GHG) are the six internationally recognized gases identified in the Kyoto Protocol (an international agreement linked to the United Nations Framework Convention on Climate Change):
>
> - Carbon dioxide (CO_2)
> - Nitrous oxide (N_2O)
> - Methane (CH_4)
> - Hydrofluorocarbons (HFCs)
> - Perfluorocarbons (PFCs)
> - Sulfur hexafluoride (SF6)

Global Warming Potential - The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of carbon dioxide (CO2).

CO2 Equivalent - The universal unit for comparing emissions of different GHGs expressed in terms of the GWP of one unit of carbon dioxide.

Mobile Combustion Sources - Mobile combustion sources include both on-road and non-road vehicles such as automobiles, trucks, buses, trains, ships and other marine vessels, airplanes, tractors and construction equipment.

Stationary Combustion - These are emissions from the production of electricity at facilities owned or controlled by an organization (referring only to the electricity sector).

Process Emissions - These are emissions from acid-gas/SO2 scrubbers (process to remove pollutants), geothermal facilities and other small sources associated with electric power generation.

Fugitive Emissions - These are the emissions of: (a) SF6 from high voltage equipment used in electricity transmission and distribution systems, (b) HFCs from power generation air intake chillers, and (c) CH4 emissions from coal piles. Also includes releases during the use of refrigeration and air-conditioning equipment, process equipment leaks, etc.

Indirect Emissions Associated with T&D System Losses and Consumed - These are the emissions associated with the portion of purchased electricity that is consumed (i.e., lost) in the T&D system or at the entity facilities. T&D system losses are a result of electricity consumption as it moves from one point to another in the T&D system. These losses occur in wires, transformers and other electricity systems.

Currently, the Generation Group is responsible for the compliance of the mandatory reporting as per the Global Warming Solutions Act. IID reports all carbon emissions data to CARB as required and voluntarily reports to the California Climate Action Reserve (CCAR), all reported in MtCO2e. Between the two reports, IID's reporting requirements are broken down into five different categories:

- *Mobile Combustion* -- CO2, CH4, N20 from IID's vehicle fleet converted to MTCO2e;
- *Stationary Emissions* -- CO2, CH4, N20 from IID's load serving generation (internally and externally owned) converted to MTCO2e;
- *Process Emissions* -- CO2 from IID's owned San Juan Coal generation facility (IID's participation scheduled to cease December 31, 2017 upon the closure of San Juan Unit 3);
- *Fugitive Emissions* -- CO2, CH4, HFCs, SF6 from facility (internal and externally owned) refrigerants, cylinders, and coal storage, all converted to MtCO2e;
- *Indirect Emissions* -- CO2, CH4, N20 from IID's external purchases transmitted to the IID system or wheeled energy transmitted from IID's service territory to the sink destination, all converted to MtCO2e.

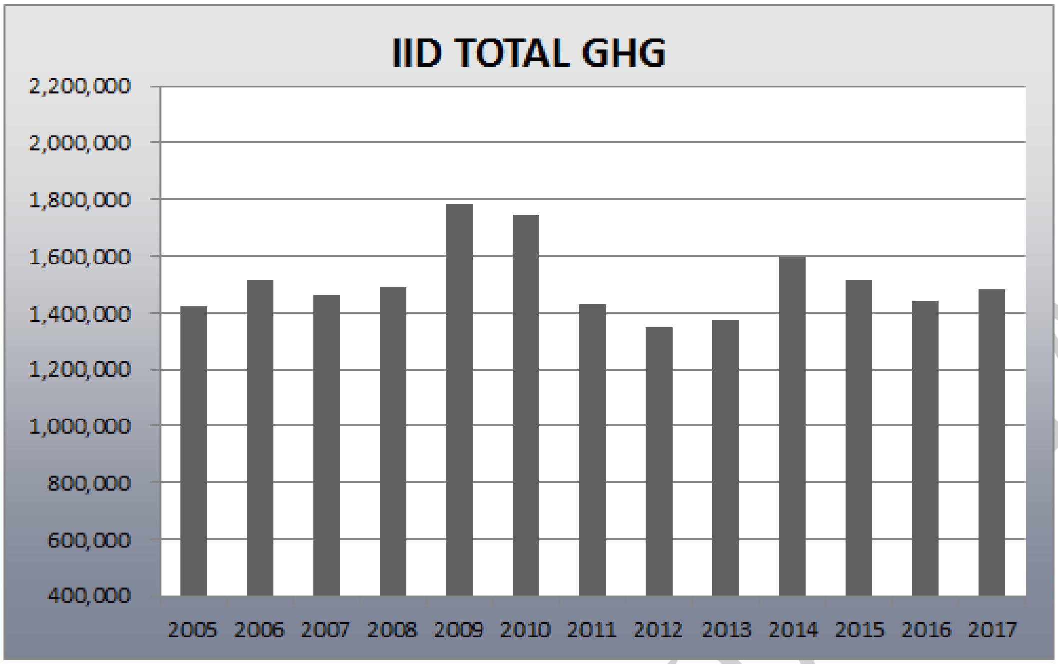
For purposes of Cap-and-Trade auction activity, there are three main categories for IID's primary emitters. There are internal emissions such as the El Centro Steam Plant, Niland, etc., specified imports such as San Juan and the Yucca Plant as well as unspecified imports such as market-based power purchased on the open market. The following exhibit shows the historical emission rates for IID's primary emitters reported to CARB:

Exhibit 207: Average Emission Rates for IID's Primary Emitters

EMISSION RATES FOR PRIMARY EMITTERS			
Cap and Trade Category	Station	Weighted Avg MTCO2e/MWh	Weighted Avg LBs/MWh (CO2e)
Internal Emissions	ECGS	0.561	1,236.68
	Rockwood	0.807	1,778.12
	Coachella	0.873	1,924.99
	Niland	0.503	1,109.61
Specified Imports	SJGS	1.030	2,355.43
	Yucca	0.587	1,293.32
Unspecified Imports	Unspecified Imports	0.435	958.92
Specified Imports	Specified Imports (SJ, Yucca, Wapa, PV)	0.698	1,539.80
Internal Emissions	EC#3 rpwr	0.180	397.72
	ECGS w/EC#3 rpwr (Projected)	0.298	657.69
Renewable Resources	Geothermal (binary-Closed Loop)	0	0
	Geothermal (Flash)	0.0000748	0.165
	Solar	0	0
	Biogas	0.180	397.72
	Small Hydro	0	0
	Biomass	0	0

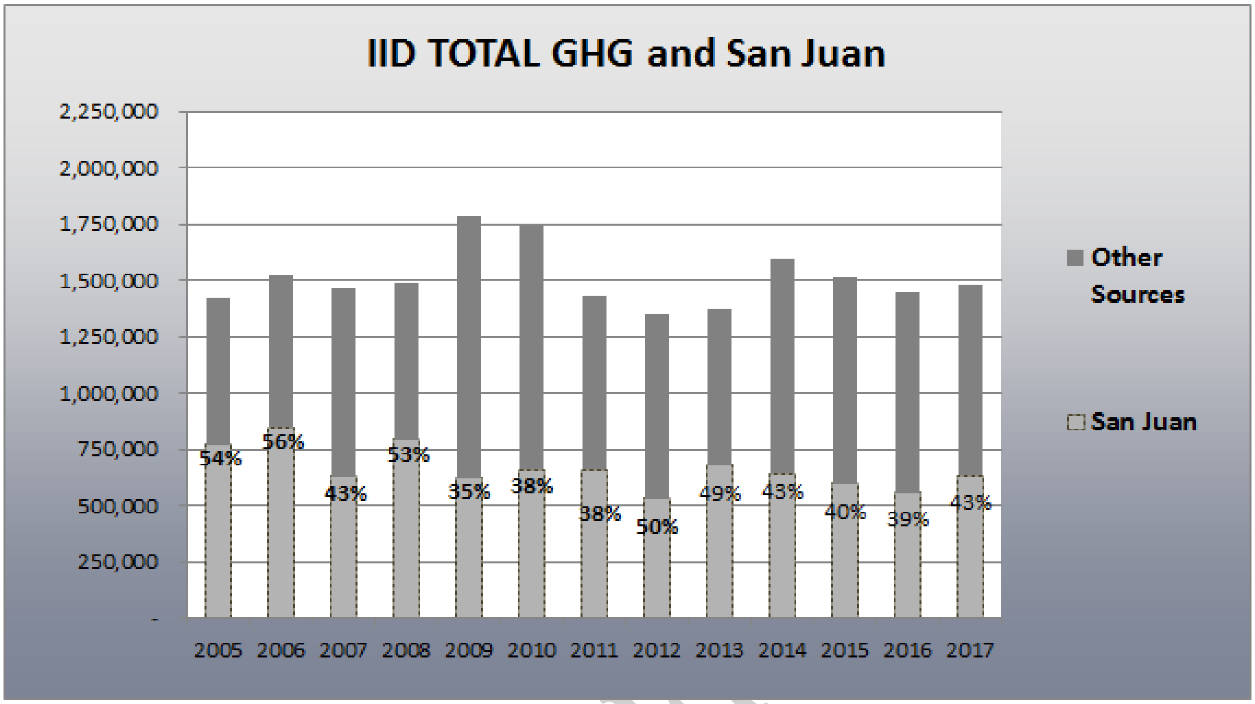
The exhibit shows the reported GHG emissions from all emission sources from 2006-12:

Exhibit 208: Summary of IID's Total Reported Greenhouse Gas Emissions



As shown above, IID's emissions levels have been fairly flat except in years 2010-11 and 2014 which is attributable to specified import emission unit outages and, therefore, an increase in internal generation-based emissions. The San Juan Unit 3 facility is considered a specified import and, as a result, contained its own emissions rate as per the Mandatory Report Regulation. The chart below shows the amount of emissions from San Juan in comparison to IID's total emissions.

Exhibit 209: Summary of IID's Total Emissions and San Juan

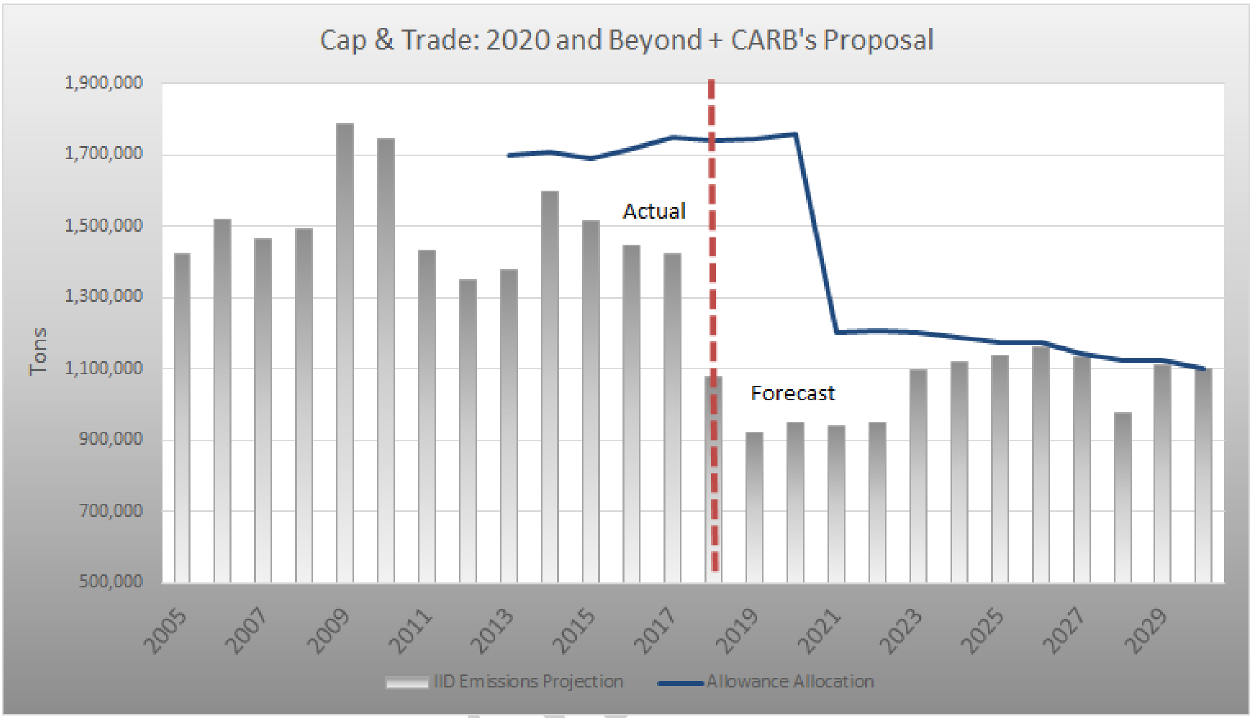


As seen above, a large quantity of IID's emissions came from its ownership in Unit No. 3 of the San Juan Generating Station. The variance from year to year depends on the operation and generation of energy from the San Juan plant. Total customer energy requirements have a direct impact on emissions variance, but it is also due to a higher emission rate charge for internally and externally owned generation (unit specific) than the emissions charge for purchased power from an unspecified source. Also, IID's optimized generation dispatch is most efficient when ramping dispatchable generation up and down for reliability/ancillary service purposes.

The IID has projected its expected allowance levels analyzing different scenarios. Several uncertain factors could greatly impact the depth of the carbon footprint. Factors like operations of the system are tested by observing scenarios of volatility risks of the energy and gas market prices would be one example. Another example of factors effecting IID's carbon footprint is the confirmed divestiture of San Juan facility and the RPS portfolio fulfillment. These scenario analyses are discussed in greater detail in later sections of this plan. IID is in a position to maximize its potential to reduce the cost impact of RPS implementation by making decisions to reduce the MTCO2e emanation to create a "longer" position of marketable, state-allocated emission allowances via the cap-and-trade auction (primary market) or the secondary markets outside of the auctions. Since there are still many unknown variables in the Cap-and-Trade market and the external effects of various markets on the emissions trading markets, IID has analyzed the risks and prepared a "'basecase" of emission projections to plan for the cap-and-trade market with a set of conservative assumptions.

The following exhibit is a projection of IID's emissions compared to the allowances allocated to it through 2030.

Exhibit 210: Projection of IID's Emissions Compared to Allowances

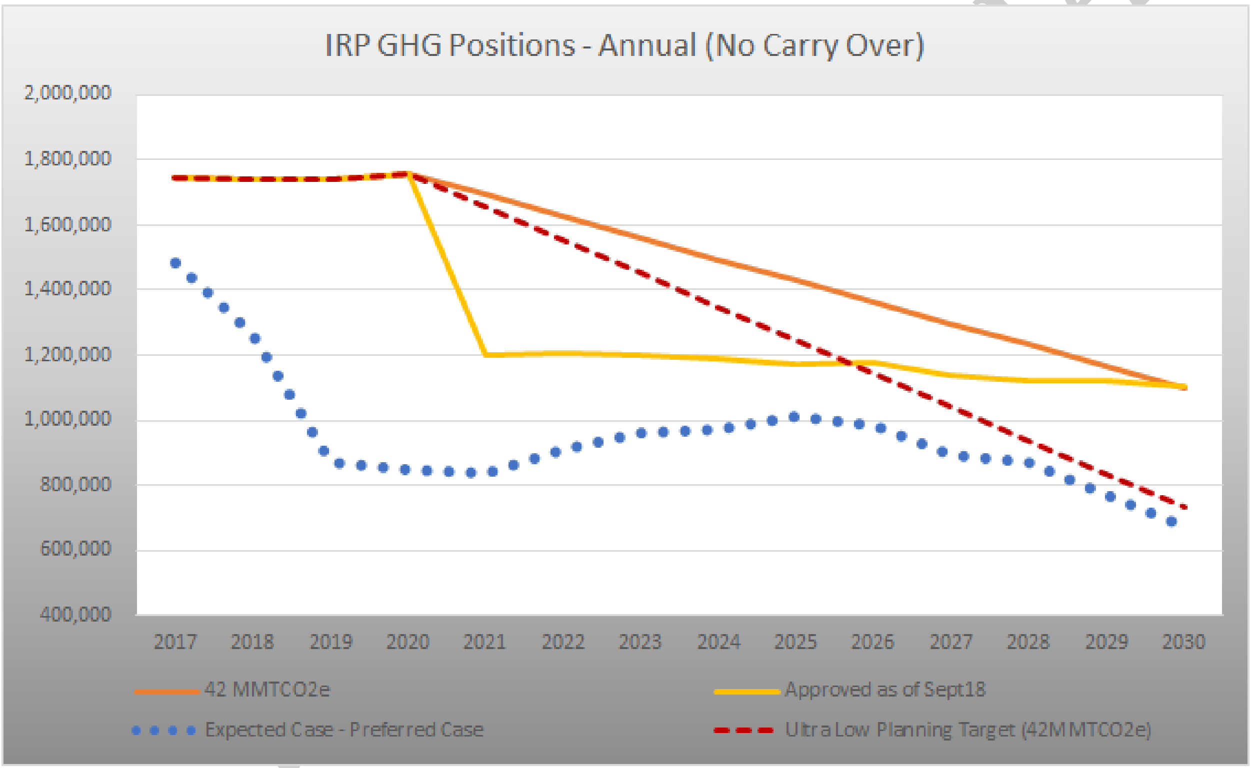


The Cap-and-Trade Program plays a major role in IID's decision-making process for future renewable resources and impacted its exiting of its ownership in the San Juan coal facility. The above exhibit illustrates IID's forecasted allowance position without participation in San Juan Unit 3.

Consideration for the Cap-and-Trade market will be a key driver in future generation resource decisions which could result in millions of dollars' worth of savings on emissions.

Beyond 2020, there are still a many unknowns. SB 350 requires the CEC and CARB to work together to determine the rate of decrease beyond 2020. However, IID has monitored the potential outcomes and it appears that currently, IID will meet the targets, even with a 40 percent reduction from 1990 levels. SB 350 added Cal. Pub. Utils. Code Sec. 9621(b)(1) requiring that local publicly-owned electric utility IRPs be developed to achieve GHG emissions reduction targets established by CARB, in coordination with the CPUC and the CEC. The CEC's IRP Guidelines include a GHG Emissions Accounting Table ("GEAT"), which request information regarding "Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB." The CPUC adopted a 42 MMT scenario GHG planning target in its analysis of IRP procurement requirements for CPUC-jurisdictional load-serving entities,[39] though CARB's conclusion will control for purposes of the CEC's IRP Guidelines pertaining to POUs. On July 26, 2018, CARB approved an overall IRP planning range between 30 and 53 MMTCO2e, as reflected in the 2017 Scoping Plan Update. CARB's proposal also included a range for IID, specifically 524,000 MTCO2e at the low end of the range, and 925,000 MTCO2e range, or 1.745 percent of the electricity sector emissions. With this in mind, below is an illustration of IID's future allowance forecast and how the current law of emissions cap may be reduced (this does not represent actual since the guidelines have yet to be released):

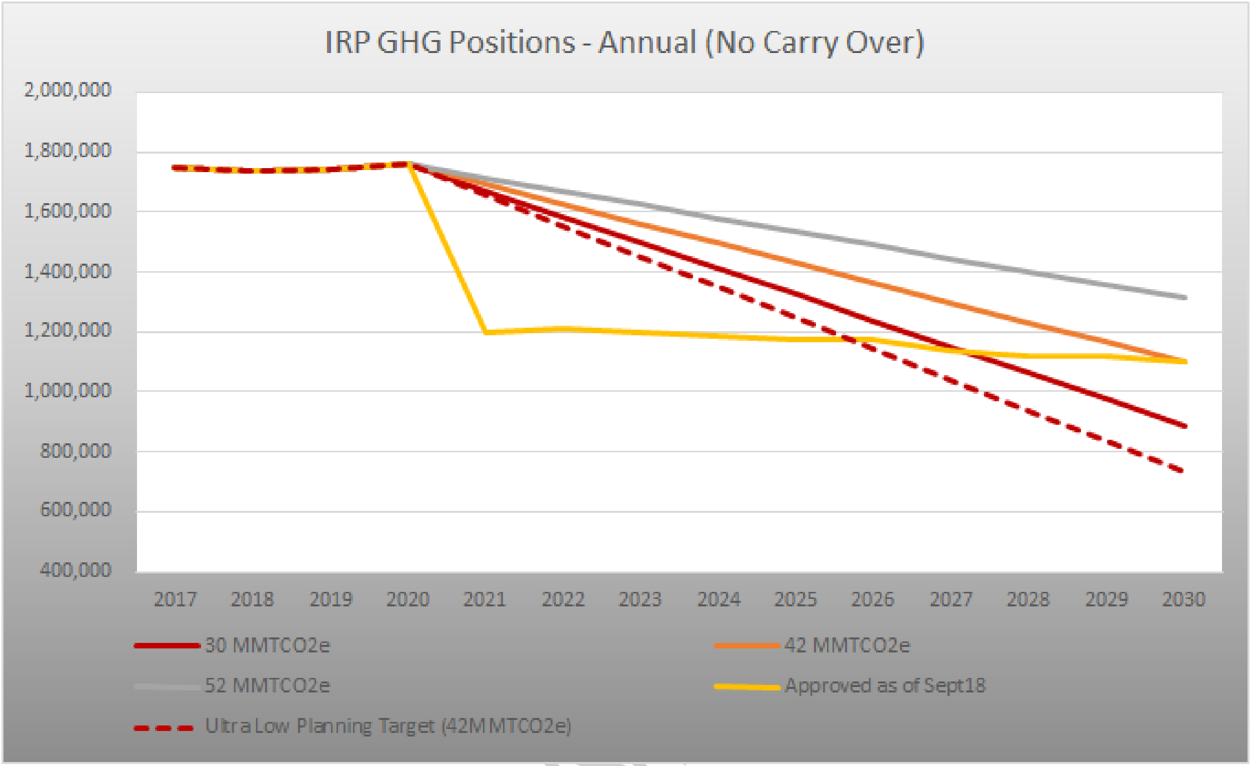
Exhibit 211: Projection of IID's Emissions Compared to Allowances



However, in October 2016, CARB released their Post-2020 Allocation to Electrical Distribution Utilities Informal Staff Proposal that contains a much different depiction that the regulatory provision of "40 percent below 1990 levels". Below is an illustration of the proposed reduction estimates:

[39] *See* D.18-02-018, *Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements*, Proceeding No. R.16-02-007 (Feb. 13, 2018).

Exhibit 212: Projection of IID's Emissions Compared to Allowances w/CARB's Informal Proposal



Should this proposal be implemented and enforced, IID will need to look at a bevy of alternatives that allow for this reduction to be possible, some, but not all, areas that may need to be utilized to meet the emissions reductions target are:

- RPS targets
- Operational practices
- Vehicle electrification
- Energy efficiency
  - Collaboration with building standards
  - Rooftop solar and distributed energy resource programs
  - Public programs
  - E-Green programs
- Internal fleet
- Exploration of flexible renewable technologies

In any case, IID is continuously monitoring this activity and compliance highly depends on IID's participation in RPS compliance and energy efficiency programs as described in the SB 350 guidebook.

RISK MANAGEMENT, ACCOUNTING AND CAP-AND-TRADE

IID's Risk Management and Accounting groups have also been directly affected by the AB 32, SB 32 and the SB 350 legislation. IID's need to purchase products to meet renewable portfolio standards and greenhouse gas emission have not been traded in prior years and, therefore, the need for these products has been recently further defined in IID's Risk Management Policy. The Energy Risk Management Group and the IID Board of Directors have approved the amended Energy Risk Policy that defines these new types of products to be traded. The Energy Department has begun trading some of the following products:

- Allowances – If IID is short of allowances, then a purchase of allowances will be required.
- Offsets – Utilities are allowed up to 8 percent displacement of allowances for offsets. Offsets that have been approved by CARB are less expensive than allowances.
- RECs – Renewable Energy Certificates.
- Biogas – Pipeline quality biogas to burn at IID's internal generation facilities as renewable energy.
- Renewable Energy – A product that will be traded at a given index price plus a premium for renewable energy.

As a result of these new trading activities needed to comply with state laws AB 32, SB 32 and SB 350, IID's Energy Accounting Group has had to begin gaining a working understanding of the terminology and the various types of products that will be traded in order to properly account for the transaction of these products. Additionally, Energy Accounting will be responsible for some data gathering of various types of historical reports that may be useful for compliance reporting.

Tracking Systems

The California Air Resource Board has established that there should be a tracking system for compliance instruments of the Cap-and-Trade Program. In coordination with CARB, the Western Climate Initiative (WCI) has developed a system that supports the implementation of the GHG Cap-and-Trade Program in California. This system is called the Compliance Instrument Tracking System Service, administered by the WCI and is intended to simplify the participation in the Cap-and-Trade Program to all related participants. The CITSS is currently used for the following purposes:

- Register entities participating in the California Cap-and-Trade Program.
- Track the ownership of the compliance instruments.
- Enable and record compliance instrument transfers.
- Facilitate emissions compliance.
- Support market oversight.

With the administration of the activities being carried out by knowledgeable market professionals that have been approved by the Cap-and-Trade governing agencies, IID can take advantage of this free and fairly simple method of tracking emissions and allowance usage. IID has taken the reasonable steps to ensure that the use of this software is understood and will allow IID to maximize the benefits of the Cap-and-Trade Program.

TRADE AUCTIONS

Under the Cap-and-Trade Program, CARB will hold allowance auctions once per quarter (four times per year) to allow market participants and jurisdictional entities to sell or acquire allowances directly from ARB. These actions are held on a web-based platform administered by the WCI as well. The allowance auctions follow a sealed bid, single round, uniform price (lowest winning bid) format and each bidder may submit multiple bids and bid schedules for current or future vintage allowances. For each quarterly allowance auction, there is a pre-determined price floor that is based on the information from the previous auction and the market at that time. The California market has been linked with Québec, Canada, and CARB is proposing to further link the allowance auctions with Ontario, Canada.

Besides the auction, California GHG allowances are available for purchase in secondary markets, including exchanges such as the CME Group Incorporated and Intercontinental Exchange or through Over-the-Counter or bi-lateral transactions between buyers and sellers. IID is actively monitoring both the allowance auctions and the secondary markets to ensure that the activities IID participates in will be of the utmost value to IID.

ENVIRONMENTAL MARKETS

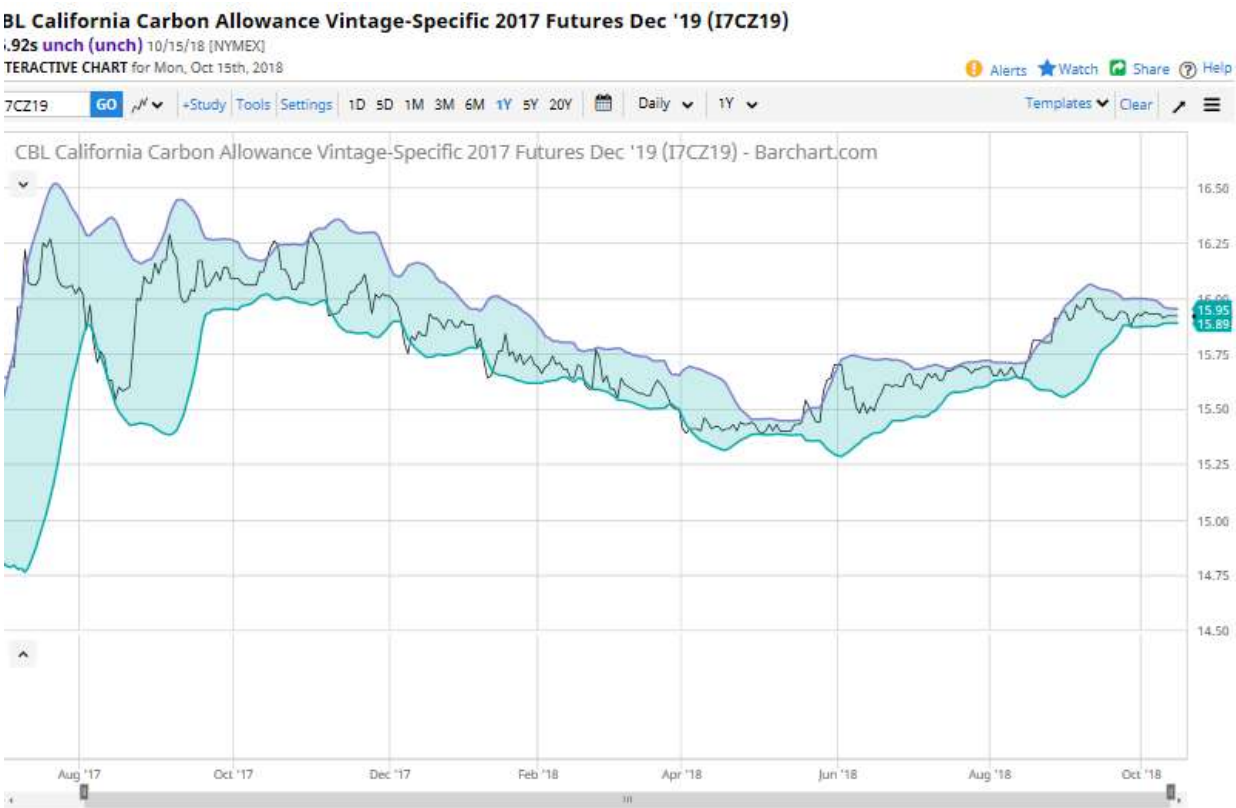
The environmental commodities market is an emerging market with the same associated economic and investing principles as any other established market in the United States, such as the gas and energy markets. The environmental commodities market includes products that are traded on a short- and long-term basis and the product scope ranges from emission allowances needed to fulfill compliance to derivative products that can be physical or financial. This wide ranging market structure, similar to other electricity related markets, will impact other markets and will be volatile. IID is an organization that focuses on budgetary certainty and rate stability and, thus, IID will strategize to detract volatility in the environmental markets and ensure that the compliance requirements are met in a responsible and prudent manner.

The first California Compliance Allowance auction was conducted by the ARB on November 14, 2012. The ARB offered 23.1 million vintage 2013 CCAs that cleared at $10.09/MTCO2e and only 5.6 million vintage 2015 CCAs cleared at $10/MTCO2e (or the auction floor price). A second auction was administered on February 19, 2013, where 12.9 million allowances were sold at an average settlement price of $13.62/MTCO2e and 9.6 million vintage allowances were offered for 2017 at an average settlement price of $13.69/MTCO2e for 2017 vintage. Auction activity is considered the primary market and it is clear that these auctions have an eminent impact on the secondary markets as well as the gas/energy markets.

The supply of allowances available at the auctions has overwhelmed market suppliers, therefore affecting price. Additionally, the Cap-and-Trade Program and the markets involved are in development mode and most covered entities are not yet comfortable with participating in auction activity since there is a lack of historical data and pricing trends. However, there is some data from the secondary environmental commodity markets that provide a depiction of the market since inception.

The characteristics of the environmental markets, like other commodity markets, contain the unfortunate reality of being unpredictably volatile. While there is an obvious shortage of ample data available, the following Bollinger Band chart from Barchart.com demonstrates the capricious nature of the environmental markets, particularly the California Carbon Allowance on the secondary market.

Exhibit 213: One Year Price History of Secondary Market CCAs



Currently, IID is actively monitoring market activity, pricing trends and indicative pricing from environmental market suppliers and merchants. The May 2018 market indicated uncertainty in the market, where only 11 percent of the permits auctioned for sale were purchased.[40] The following exhibit is an example of the spread between the seller bid and the buyer ask prices that are currently being reported/offered by Evolution Markets:

Exhibit 214: Current Indicative Vintage Prices for CCAs

[40] http://www.latimes.com/politics/la-pol-sac-climate-change-challenges-20160614-snap-story.html

Carbon Allowance Pricing

CCA ICE Futures				
PRODUCT	TERM	BID PRICE	ASK PRICE	TRADED VOLUME
California Carbon Allowance - ICE	V18 Oct 18	$15.40	$15.45	0
California Carbon Allowance - ICE	V18 Dec 18	$15.50	$15.53	50,000
California Carbon Allowance - ICE	V18 Dec 19	$16.42	$16.45	50,000
California Carbon Allowance - ICE	V19 Dec 18	$15.47	$15.52	50,000
California Carbon Allowance - ICE	V19 Dec 19	$16.40	$16.45	50,000

Additionally, as mentioned throughout the "Cap-and-Trade" section of this report, the regulation provides that a covered entity can displace up to 8 percent of its allowance portfolio with CARB approved offsets. As a result of the obvious basis differential between the currently offered allowance prices (CCAs) and the prices to California Carbon Offsets, IID is actively observing the pricing trends of the carbon offsets markets. The following table demonstrates the current indicative prices on the market for California Carbon Offsets from Evolution Markets:

Exhibit 215: Current Indicative Vintage Prices for CCOs

California Carbon Offsets (CCO)		
PRODUCT	BID PRICE	ASK PRICE
Oct'18 CCO (8)[1]	$14.20	$14.40
Oct'18 CCO (3)[2]	$14.25	$14.50
Oct'18 Golden CCO[3]	$14.60	$15.00
CCO: compliance offsets from ARB-adopted protocols (US ODS, Livestock Methane, Forestry, Urban Forestry, Mine Methane Capture)		

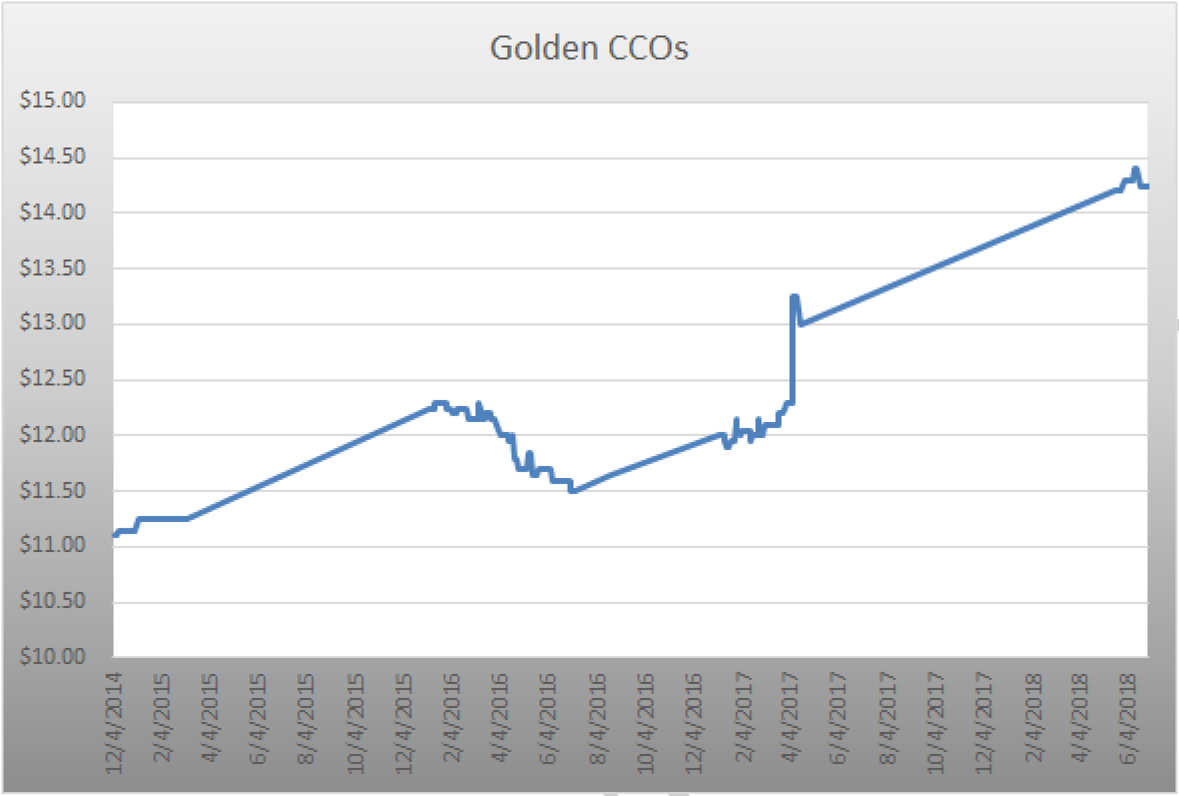
[1] Firm Delivery, invalidation risk is limited to 8 years from issuance pursuant to AB32 regulations.

[2] Firm Delivery, invalidation risk is limited to 3 years from issuance pursuant to AB32 regulations.

[3] Firm Delivery, seller replaces any invalidated CCOs.

Over time, the Golden CCOs have also trended upwards along with the secondary markets as well as the auction settlement prices. Below is a chart that shows the trend of several vintages of CCOs over the last several years:

Exhibit 216: Golden CCO Pricing Trend



As displayed in the previous exhibits, the spread between the CCOs and the CCAs presents a strategic opportunity for IID to enhance the allowance portfolio with the displacement of up to eight percent of the state distributed allowances to IID with CARB approved offsets. This is explored in the section below.

CURRENT CAP-AND-TRADE STRATEGY

Complying with the environmentally related requirements is an important objective for IID. Portfolio development focuses on meeting standards for the state RPS, while simultaneously reducing the MTCO2e emissions associated with IID activities. Due to continuing unknowns of the cap-and-trade market that is currently under examination through market activity testing and demonstration, planning and strategizing can be a challenge. However, the IID Energy Department is prepared to face the stringent requirements of AB 32 and the respective Cap-and-Trade Program. As indicated below, there are three main aspects that guide IID's strategy for meeting the emissions reduction requirements and benefiting from the cap-and-trade market and they are as follows:

1. Coordinated/integrated compliance with RPS goals will allow IID to maximize the benefits from the state allocated allowances;
2. Match the revenue/income dollars from selling excess allowances with the years that have the largest RPS impact;
3. All operational and strategic resource decisions should consider the impact of emissions.

In consideration of the above points, an embryonic and volatile carbon market along with the consideration of the cap-and-trade regulation guidelines regarding auctions and the carbon markets, IID has observed three strategies for 2019 as seen in the exhibit below.

Exhibit 217: 2017 Auction Strategies and Potential Revenues

Potential 2019 Auction Strategy (Price Range Scenarios)					
$/MTCO2e Floor (CCA)	$ 15.26	$ 15.26	$ 15.26	$ 15.26	$ 15.26
$/MTCO2e Ceiling Pricing (CCA)	$ 65.07	$ 65.07	$ 65.07	$ 65.07	$ 65.07
Revenues if ALL LUH Acct. was Sold (Floor Pricing)	**$ 1,907,500**	**$ 1,907,500**	**$ 1,907,500**	**$ 1,907,500**	**$ 7,630,000**
Revenues if ALL LUH Acct. was Sold (High Pricing)	**$ 8,133,750**	**$ 8,133,750**	**$ 8,133,750**	**$ 8,133,750**	**$ 32,535,000**

Another important point is the legislatively defined cost mitigation strategy of utilizing eight percent offsets to displace more expensive allowances. Currently, there is a two to three dollar spread between the price of allowances and the price of offsets and the cap-and-trade regulation provides public utilities such as IID the opportunity to displace allowances, which are allocated, with CARB approved offsets available on the market. These approved products include offsets from the following type of projects:

- U.S. Forest Projects
- Livestock Projects
- Ozone Depleting Substances Projects
- Urban Forestry Projects.
- Mine Methane Capture Projects
- Rice Cultivation Projects

When offsets are a part of the cap-and-trade strategy, then an additional significant amount of strategically determined revenue can benefit IID and its ratepayers. The following exhibit demonstrates the potential benefit.

Exhibit 218: 2017 Auction Strategies and Potential Revenues with Offsets

Below is a summary of the total proceeds from the auctions that have occurred since 2012:

Exhibit 219: Summary of Auction Proceeds

Total California Auction Proceeds to Date		
Auction Quarter of Fiscal Year	Total Proceeds for Current and Advance Auctions in GGRF (USD)	
Q2 2017 (May)	$	511,052,646
Q1 2017 (February)	$	8,163,884
Q4 2016 (November)	$	364,310,763
Q3 2016 (August)	$	8,387,910
FY 2015-2016	$	1,829,134,503
FY 2014-2015	$	1,490,776,417
FY 2013-2014	$	477,140,441
FY 2012-2013	$	257,264,032
TOTAL	$	4,946,230,595

With the IID utility-wide support and effort within the organization, IID will become a leader in the public utility industry and prove to be a cost-effective, proactive and efficient utility in the newly developing cap-and-trade market.

Proposed Amendments to the Cap-and-Trade Regulation were posted on August 2, 2018 which were ultimately approved at a CARBpublic Board meeting on July 27, 2017. These amendments would extend the Cap-and-Trade Regulation to extend beyond 2020, broaden the Cap-and-Trade program through linkages with Ontario, Canada (which has since indicated intent to withdraw) and extend linkages with Québec, comply with the federal Clean Power Plan, and generally enhance CARB's ability to oversee and implement the Regulation. Specifically, the amendments as approved:

- Extend the Program beyond 2020 by establishing new emissions caps, enabling future auction and allocation of allowances, and continuing all other provisions needed to implement the Program after 2020;
- Continue Program linkage with Québec, Canada beyond 2020;
- Continue to prevent emissions leakage in the most cost-effective manner through appropriate allowance allocation for a post-2020 program;
- Ensure that quantifiable and verifiable greenhouse gas emissions are captured by the program;
- Continue the allocation of allowances to the utilities on behalf of rate-payers;
- Provide for California compliance with the federal Clean Power Plan;
- Clarify compliance obligations for certain sectors;
- Simplify participation in the Cap-and-Trade Program by streamlining registration, auction participation, information management, and issuance of offset credits; and - -

Ensure accounting of imported emissions resulting from use of the CAISO's Energy Imbalance Market (EIM).

The allocation of allowances to utilities has changed to rely on an RPS factor rather than a cap adjustment factor and excludes allowances allocated to industrial-covered entities served by a utility. In addition, CARB is proposing formal regulations to implement AB 398, which permits CARB to extend the Cap-and-Trade program through 2030. Changes to be discussed or implemented include a price ceiling and price containment points below the price ceiling for certain non-tradable allowances.[41] Also, as noted above, CARB approved further amendments to clarify provisions related to changes of ownership and successor liability for emissions compliance obligations and the calculation of the Auction Reserve Price to take into account California's linkage to Ontario's Cap-and-Trade Program.

Clean Power Plan

In order to provide data applicable to IID's emissions reduction requirements, Resource Planning & Acquisition has been studied the Clean Power Plan policy to ensure (pending replacement) that the impact in terms of the cost of emissions reductions requirements is less than the impact that is currently enforced by the State under the Cap-and-Trade/AB32 program. In short, the answer is yes, but to avoid any doubt and to provide an overview of our interpretation of the law as it is currently written, below is some information/graphs that you may find helpful

First, the Clean Power Plan (CPP) has several key differences from the state Cap-and-Trade (C&T) Program. Below is a table that contains these key distinctions:

Exhibit 220: Key Difference Between Clean Power Plan and California's Cap-and-Trade Program

[41] *See* CARB Workshop Presentation, Oct. 12, 2017: https://www.arb.ca.gov/cc/capandtrade/meetings/20171012/ct_presentation_11oct2017.pdf; announcement of CARB March 2, 2018 workshop to discuss potential amendments to the Cap-and-Trade Regulation, including as a result of AB 398, https://content.govdelivery.com/accounts/CARB/bulletins/1da9387

Key Differences between Clean Power Plan and California's Cap and Trade Program			
Category	**Clean Power Plan (CPP)**	**Cap and Trade (C&T)**	**Significance/Other notes**
Units of Measure	Short Tons of CO2 (STCO2)	Metric Tons of CO2 *equivalent* (MTCO2e)	Short tons of CO2 under CPP, and C&T uses CO2e which includes a conversion of several other emitters
Mass vs Rate	States can choose target methodology	Mass (volume) based target	Each program contains their own separate target metrics, so comparisons are not easy since IID's generation doesn't change for each program, but the emissions accounting for each program does.
Emissions Accounting	Emissions counted from State of California only	State emissions counted + specific/unspecific imports from other states	States (utilities within states) will need to agree how owned generation will be repaid by generating utility. IID will be a stakeholder in AZ CPP plan as a result of Yucca
Renewable Energy	Counted in the target	no credit given in target, but the more renewables, the closer to target	CPP targets and the method of matching IID emissions to these targets includes the benefit of renewable energy within the calculation
Emissions Trading	ERCs (emission rate credit)	MTCO2e Allowances/Offsets	CPP creates generation-based carbon markets, not consumption based markets for renewable energy. Markets will need to be coordinated
Timeline of Commencement	Program begins in 2022 with plans due 9-6-16 and final by 9-6-18	Program began in 2013 with key targets in 2020	Scheduling of targets differ, so as long as Cap an Trade is more stringent, then investments for compliance will not need to be staggered
Overall Target of Program	32% below 2005 levels nationwide	Reduction to 1990 levels by 2020; and 80% reduction by 2050	While observing targets in terms of % and year benchmarks is important, the metrics are much different, so comparisons must be translated for each program.
Approximate Targets	828 lbs/MWh in rate based plan by 2030; 52.8 Million STCO2/yr by 2030	76.05 million MTCO2e for the state by 2020 ; 1.7 million MTCO2e for IID by 2020	Under the CPP mass based plan (if adopted), we estimate IID's target to be 1.49 million STCO2

Originally, the goal was to draw a direct comparison between the CPP and the state C&T program, but after looking at the numbers and the overall intention of each of the programs, it was determine that, while we can compare after converting units and forecasts to the respective program, it is better to keep them separate for comparison side by side as opposed to an 'overlay' type of comparison. This is mainly due to the following:

- The units of measure require a specific method of counting that is unique to each program.

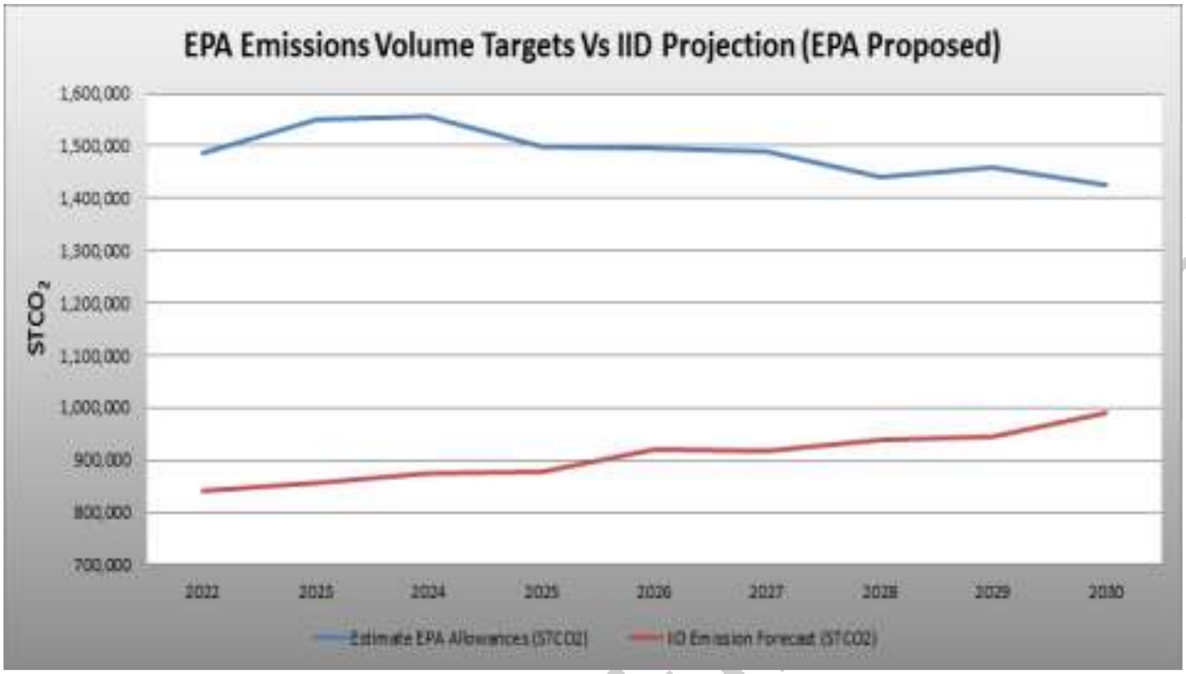
- The federal plan focuses on inter-state emissions whereas C&T accounts for all emissions from resources that provide any energy for the consumption of the utility.

- The federal plan embeds the credit of consuming renewable energy within the rate and mass targets, where the C&T program provides the credit in the difference between the freely allocated allowances and reported total emissions.

As a result of the above notes/table and the main assumptions that result from these notes, below are several graphical representations of IID's position for each of the aforementioned programs:

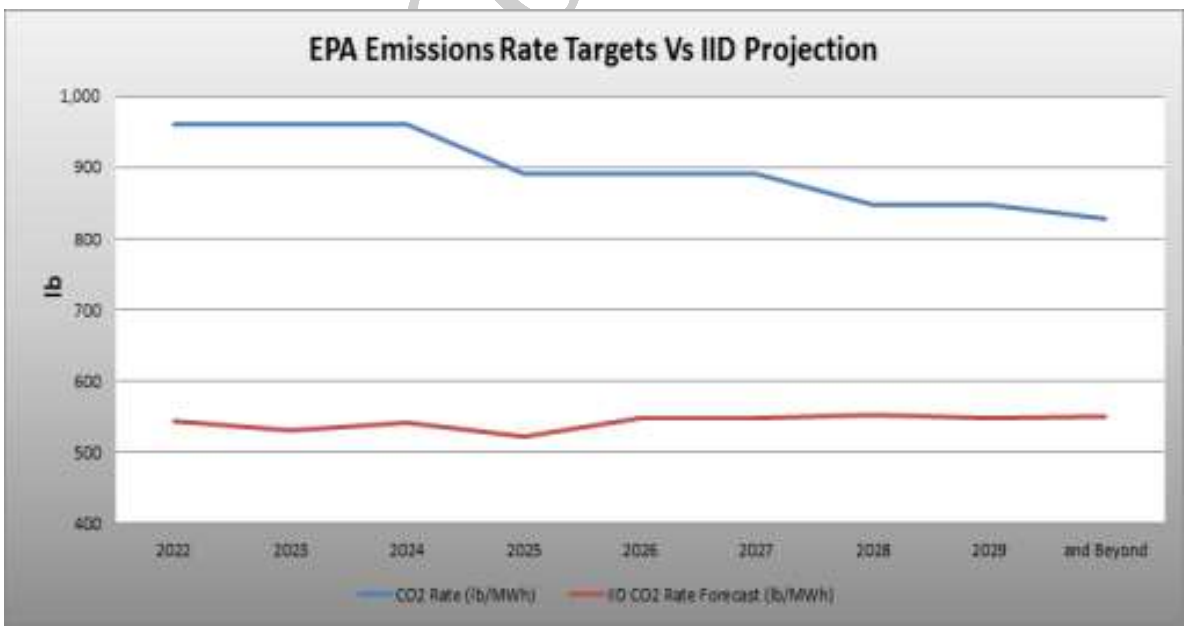
- Est. Comparison of EPA's MASS based plan should California adopt a rate based plan and the allowances are assumed to be distributed similarly as the state's Cap-and-Trade program
- Comparison of EPAs Rate based plan should California adopt a rate based plan

Exhibit 221: EPA Emissions Volume Targets vs IID Projection (EPA Proposed)



Note: The metric above is STCO2 and not MTCO2e as used in CARB's C&T, so the projection is based on this as well as the in-state emissions that are currently counted in the CPP. So, the number is much lower, even if it was to be converted to MTCO2e.

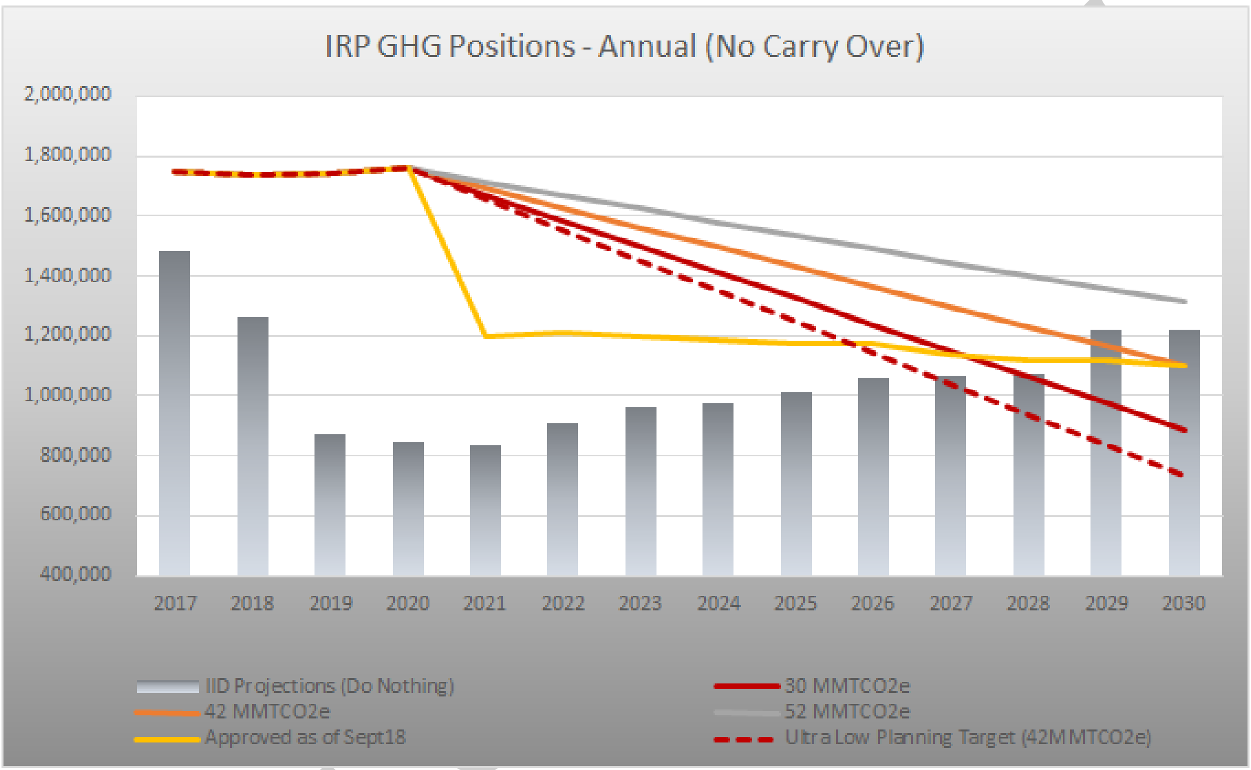
Exhibit 222: EPA Emissions Rate Targets vs IID Projection



Note: The IID forecast is essentially based on the instate emissions divided by the total generation. This provides the credit of consuming renewables since total generation includes renewable generation.

- Comparison of IID's position based on AB32's C&T program:

Exhibit 223: CARB Emissions Volume Targets vs IID Projection



Note: The metric here is MTCO2e and the 80 percent case is still TBD, but assuming a linear regressed reduction to 80 percent of 1990 levels by 2050, then the graph above depicts our position in 2030. Also, we will see further reduction of the red line as we bring more renewables online.

As seen above, for the time being, IID is covered in emissions position from both perspectives and assuming the EPA's CPP is similar to the state C&T, then there may be a potential for additional revenues from the federal emissions market since we are forecasting to be long. Essentially, the how the state deals with freely allocated emissions and emissions targets post 2020 is the main concern. Of course, this assumes that the state's proposal to comply with the CPP, is less stringent than or equal to the current C&T plan. We have an estimate of emissions revenues that we are expecting under the C&T law, so please let me know if there is interest in seeing that as well.

Overall, the main point is that in order to compare C&T to CPP, IID must make some vaulting assumptions to convert one program metric to the other while comparing to the forecasted compliance position for IID. The above graphs and explanation can, hopefully, put a clearer perspective on the relationship (or lack thereof) between IID's emissions under the applicable program and the current view on IID's compliance with state emissions standards. Basically, it is not apples to apples, unless the state proposal is C&T.

While CARB approved regulations to comply with the CPP, at least two events have slowed implementation of the CPP. First the U.S. Supreme Court issued a stay of the CPP, pending review by the U.S. Court of Appeals for the D.C. Circuit of the CPP. Second, the U.S. EPA has announced intent to repeal the CPP. Given that the state's C&T program would comply with the CPP, to the extent that CARB and the state maintain CPP-related regulations, IID's compliance with the C&T program will allow it to maintain compliance with any state-directed compliance measures as to the CPP.