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2019 Integrated Resource Plan

Modesto Irrigation District

Final Revision
Submitted: March 5, 2018

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Appendix

I. Executive Summary

1. Overview of MID

Modesto Irrigation District (MID), located in California's Central Valley, provides electricity, irrigation water and treats surface water for drinking. MID is an independent, publicly owned utility. MID transmits and distributes electricity on more than 1,800 miles of power lines throughout its service area, providing power to the communities of Modesto, Waterford, Salida, Mountain House and parts of Ripon, Escalon, Oakdale and Riverbank. MID provides benefits that include community ownership, control by a locally elected Board of Directors, and business operation on a not-for-profit basis. MID is committed to providing reliable service at the lowest cost possible. MID provides reliable electric service to approximately 101,000 residential customers and more than 10,000 commercial customers.

MID's 2019 Integrated Resource Plan presents the utility's plan for reliability planning and budgeting, demonstrates compliance with MID board policy, federal and state laws, and provides a frame of reference for development of new and revised board policy. California Public Utilities Code - PUC Section 9622 empowers the Energy Commission to review publicly-owned utilities (POUs) Integrated Resource Plans (IRPs) to determine consistency with section 9621. The Energy Commission adopted the first IRP Guideline in 2017 which requires POUs to adopt Integrated Resource Plans by January 1, 2019 and to file the plans with the California Energy Commission by April 30, 2019. These integrated resource plans will detail how each utility plans to meet the state's environmental and energy goals. Though in September 2018 SB 100 updated the renewable energy targets from those adopted in SB 350 in 2015, this IRP assumes the SB 350 RPS targets as the utility works to implement the updated targets.

1.1. Planning Horizon

This Integrated Resource Plan encompasses a 12 year horizon, covering the period 2019 through 2030. It details MID's projected electric demand, and future resource portfolio. The plan is divided into several sections as detailed in "Table of Contents".

1.2. 2019 Planning Assumptions

This section of the IRP provides a high level overview of MID's 2019 IRP assumptions. The assumptions and methodology discussed in this chapter describe MID's current understanding of its customers' capacity and energy demand over the planning horizon. Later chapters in this plan present the assumptions in more detail.

1.2.1. Input Assumptions

MID's 2019 IRP utilizes a planning scenario that conforms to greenhouse gas emission reduction targets as well as energy and other policy goals outlined in SB 350.

Table 1-1 below shows a summary of MID's IRP Planning Assumptions.

Table 1-1: Input Assumptions of MID's IRP Analysis

Input	Planning Assumptions
Demand Forecast	MID's 2018 Long Term Demand and Energy Forecast
Planning Reserve	Planning reserve margin is calculated at 15% of the 1-in-10 forecasted peak demand
Natural Gas Prices	Natural gas prices are derived from ICE forward price curves; price increases beyond the price curve range are based on the EIA outlook forecast.
GHG Prices	CEC's Preliminary 2017 IEPR Carbon Price Projections
CO2 Emission Rates	Gas-fired and Import resources based on California Air Resources Board (CARB) 2016 published emission rates.
Power Prices	Power prices are derived from ICE forward price curves; price increases beyond the price curve range are based on the EIA outlook forecast.
Hydro Conditions	Average hydro conditions are assumed; MID's share of generation from the Don Pedro Plant is estimated to be 175 GWh annually.
RPS Portfolio	MID's existing portfolio, plus future resources are expected to achieve 50% RPS by 2030

1.2.2. Demand-Side Forecast

MID established its "Managed Load" forecast for its IRP analysis based on the MID's 2018 Long Term Demand and Energy Forecast (2018 LTDEF). MID derived its hourly net load and peak forecast by incorporating assumptions for demand-side resources including Energy Efficiency, Solar Photovoltaic, and Electric Vehicles. Detailed Demand Forecast assumptions and methodology are described in Chapter 6 of this IRP.

OFT (Out of Territory) load represents a small portion of the MID total demand. Due to lack of historical metered data, the OFT load forecast was derived from 2009-2016 end-of-year billing data for the billed rate classes in these areas.

Greenfield load and load migration is also considered in the forecast at the same growth rate of the entire system. Greenfield load accounts for approximately 2% of MID retail load.

1.2.3. Supply-Side Forecast

MID's supply-side resources are used to meet net demand after adjusting for the demand side resources described above. MID provides a description of its supply-side portfolio within the standardized tables that are part of this IRP submission

1.3. 2019 Planning Sensitivities

Sensitivity study or scenario study is a relative new practice to MID's resource planning. Historically, MID presents a single load forecast and planning scenario in the resource plan. In the 2019 IRP, MID began to incorporate sensitivities and probability estimates in the load forecast and planning scenarios. The 2018 LTDEF incorporates multiple weather scenarios to each year's forecast. Instead of providing one forecast value for each time interval, MID models weather scenarios and provides a range of forecast results covering historical extreme weather conditions. Detailed sensitivity variable utilization is described in more detail in Chapter 6 of this IRP.

1.4. <u>2019 Planning Processes</u>

Figure 1-1 Overview of MID's IRP Process

Step 1

- **<u>Examine Compliance Requirements</u>**
- Identify the current business and regulatory environment.
- Develop a multi-faceted matrix of required targets and consider how plan drivers may change during the planning period.

Step 2

- **<u>Identify Strategic Planning Gaps</u>**
- Identify the existing portfolio and its directional gap to compliance targets.

Step 3

- **<u>Consider Resource Options</u>**
- Evaluate available generation resources including conventional, renewable, and long-term market power purchases to identify the role each will play in meeting customer needs and regulatory and policy goals.

Step 4

- **<u>Assess Demand</u>**
- Develop forecasts of load growth, changing load patterns, existing plant conditions, contract terms, and operational constraints to determine resource needs over the planning period.

Step 5

- **<u>Develop Optimal and Reliable Portfolio</u>**
- Develop feasible and efficient resource portfolio through least cost optimization, followed by a quantitative and qualitative evaluation process for resource adequacy to meet reliability requirements.

Step 6

- **<u>Identify Compliant and Risk Controlled Portfolio</u>**
- Use preliminary optimal resource portfolio to identify short positions to compliance targets, update supply portfolio and repeat step 5 until resource porfolio is fully compliant with compliance targets and the District's risk policy.

Step 7

- **<u>Identify Conforming Plan</u>**
- Identify a "Conforming Plan" expected to reliably serve demand at a reasonable long-term cost while achieving compliance, and allowing for flexibility to respond to future policy changes.

Step 8

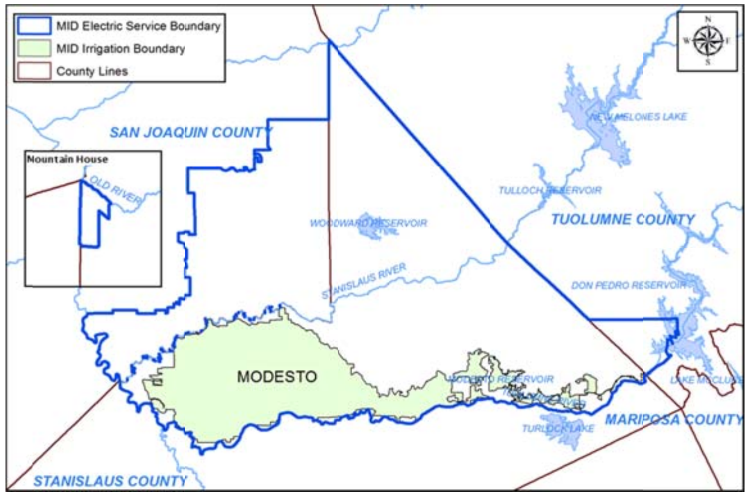
- **<u>Board to approve Conforming Plan</u>**
- Present the identified "Conforming Plan" based on the optimum resource portfolio and prepare the integrated resource plan according to the CEC IRP guideline and present the final plan for approval by the MID Board of Directors.

Step 9

- **<u>Submit the IRP to CEC</u>**
- Submit the board approved IRP to the CEC.

II. MID Electric Service Facts

Modesto Irrigation District (MID), located in California's Central Valley, provides electricity, irrigation water and treats surface water for drinking. MID is an independent, publicly owned utility. MID has been providing electric service to the area since 1923. MID transmits and distributes electricity utilizing more than 1,800 miles of power lines throughout its service area, providing power to the communities of Modesto, Waterford, Salida, Mountain House and parts of Ripon, Escalon, Oakdale and Riverbank.



Electric Service

Electric Accounts*		Electric Revenue	Consumption
Residential	97,935	*$238,963,986*	*1,650,545,405 kWh*
Commercial	12,490		
Other	156	**Average Residential Use**	**Electric Service Area**
Total	***122,734***	850 kWh/month	561 square miles

**as of August 2017*

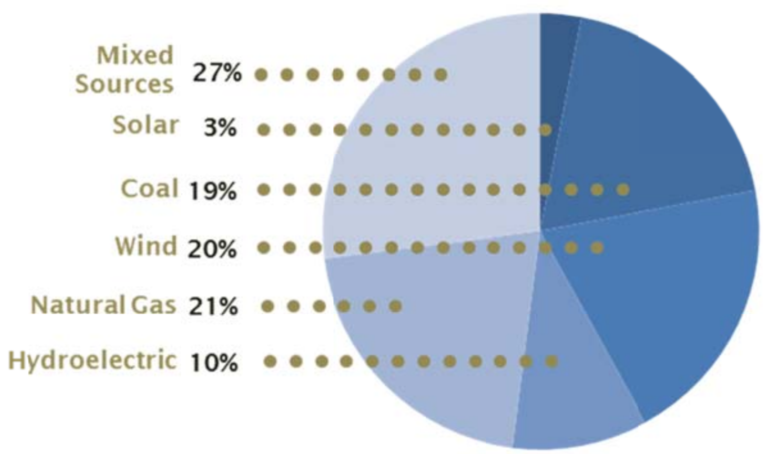
Electric Facilities

Hydropower	Capacity
Don Pedro Powerhouse	*203 MW**
New Hogan Powerhouse	*3.2 MW*

Natual Gas	Capacity
Woodland Generation 1	*49.4 MW*
Woodland Generation 2	*83 MW*
Woodland Generation 3	*49.6 MW*
McClure Generation	*112 MW*
Ripon Generation	*95 MW*

*MID's ownership interest in Don Pedro is 62 MW

Electric Resource Mix



III. Planning Goals

3. MID's Mission

MID will provide electric, irrigation and domestic water services for its customers, delivering the highest value at the lowest cost possible through teamwork, technology, innovation and commitment.

3.1. MID's Transition Ready Electric Supply

MID has taken several actions to align with California's efforts to transition to a cleaner energy portfolio. One major action was divestment of its ownership interest in the San Juan coal plant effective December 31, 2017. As a result of the divesture, MID no longer procures any output from coal burning facilities. MID undertook significant early action in the procurement of renewable resources. This early action ensures that MID will meet its RPS requirements through 2024 with its current portfolio. Though this IRP focuses on renewable energy procurement targets consistent with SB350, MID's Board of Directors has adopted a procurement plan that specifies renewable energy procurement targets of 60% by 2030.

3.2. A Stress Resistant Reliability Plan

Achieving a safe and reliable electric grid is one of MID's most important goals. Electric reliability and resource adequacy are key components in order to achieve these goals. MID prioritizes electric reliability and has achieved a system average interruption duration index (SAIDI) of 30, which it views as a key service differentiator. In this IRP, MID plans to maintain the successful operational initiatives MID has in place to maintain the SAIDI level.

MID relies on the widely-accepted one-day-in-ten-years (1-in-10) loss of load standard to define its resource adequacy needs. The 1-in-10 loss of load event (LOLE) standard requires that MID maintain sufficient generation and demand response resources such that system peak load is likely to exceed available supply only once in any ten-year period. The Planning Reserve Margin (PRM) is then measured as the surplus of the amount of generation capacity available to meet expected net demand in the planning horizon. MID's PRM is set at 15% system wide with some adjustment for certain resources, such as hydro resources and firm import energy.

As discussed in later chapters of this IRP, MID demand experiences a wide range of energy loads during the day, especially during summer. The maximum demand within a day could be twice the lowest demand of the same day. This load pattern largely stresses MID's resource adequacy levels. This pattern is expected to be even more volatile in the near term, mostly due to the fast development of DERs (distributed energy resources). Behind-the-meter solar resources can offset part of the mid-day gross load peak and then quickly ramp down when the sunlight fades in the evening. This pattern can lead to reduced demand during the day, aka, the "duck curve". MID has not experienced the pronounced reduction in net day time demand, which has been observed in other parts of the state.

MID takes several steps to prepare for the evolving stress of potential "capacity shortage." Within the next five years, capacity needs will be met with planned renewable resources and with short term contracts delivered through existing transmission. MID maintains a 5-year capital improvement plan which identifies projects that could maintain system reliability. MID will also analyze how the Western EIM (Energy Imbalance Market) could improve the efficiency of MID's real time resource dispatch.

3.3. Low and Stable Rates

As a publicly owned utility, maintaining low and stable electric rates is a key MID mission considered in the development of this IRP. MID has consistently maintained electric rates that are lower than adjacent investor owned utilities, and MID rates have not been increased since 2012. Total System Average Rate (SAR), defined as a utility's total revenue divided by total kWh sales, is a measurement of the utility's cost to serve. MID's 2018 SAR is 14.37 ¢/kWh. In 2018, SCE's total authorized electric system average rate was 14.61¢/kWh, PG&E's was 16.27 ¢/kWh, and SDG&E's was 22.50 ¢/kWh, based on each IOU's January 1 authorized revenue requirement and forecasted total sales. MID's SAR had an annual increase of 0% for the period of 2013-2017. Over the same period, electric SARs for PG&E, SDG&E and SCE increased annually from 2013 to 2017 by approximately 4%, 8% and 1%, compared to an average annual inflation rate of 1.3% over the same period[1].

This IRP includes details on MID's initiatives to support its mission. The recommended portfolio and improved capital structure are expected to help maintain affordable rates throughout the planning horizon. Going forward, MID must balance between affordable rates on one hand and the prospect of long-term rising capital spending requirements on the other. MID must also continue to control operating and maintenance expenses and manage its energy market risks.

MID's current rate forecast does not show upward rate pressure through 2022, although MID is still in the midst of the 2019 planning cycle. MID has not developed a rate forecast beyond 2022 at this time.

[1] Comparison SARs for Investor Owned Utilities are published in the "2018 Actions to Limit Utility Costs and Rates, CPUC May 2018 Annual Report to the Governor and Legislature," California Public Utilities Commission, May 2018.

IV. Key Policy Drivers

4. Impact of Policy Uncertainty

MID's IRP presents the utility's plan for reliability planning and budgeting, demonstrates compliance with MID board policy, federal and state laws, and provides a frame of reference for development of new and revised board policy. Reducing statewide GHG emissions to 40% below 1990 levels by 2030 is the state's overarching goal. However, many aspects of the policies are not completely finalized or not defined. Policy uncertainty is a class of economic risk where the future path of government policy is uncertain, raising risk premia and leading utilities to delay spending and investment updates. It is generally understood that the level of policy uncertainty in the utility industry is high. MID's mission is to deliver the highest value at the lowest cost possible through teamwork, technology, innovation and commitment. Due to the high level of policy uncertainty, MID conducts resource planning in a conservative and economical way.

This chapter lists some of the policies that impact MID's electric resource planning.

4.1. Planning Beyond 2030

Due to high level of policy uncertainty beyond 2030, this Integrated Resource Plan encompasses a 12 year horizon (covering the period 2019 through 2030) of MID's projected electric demand, resource portfolio and expected costs associated with the demand and supply.

4.2. MID Board Policies and Procedures

The Modesto Irrigation District Board of Directors sets policy for the District. Board members represent geographical divisions within the irrigation district boundary. Registered voters within each division elect a director for a four-year term of office. Below are MID Board policies governing energy procurement.

4.2.1. Long Term Demand Capacity Procurement

Demand Capacity refers to the highest amount of power demand from MID's customers in any hour and is usually quoted as the peak demand for the entire summer period, or the peak demand in any month, expressed in megawatts (MW). The current MID procurement policy is to procure or build supply capacity equal to 115% of the expected peak demand, and to procure 70% of the supply capacity from long-term resources and 30% from short-term resources. Long-term resources are utility owned projects, or contracts with a term of at least 10 years.

4.2.2. Renewable Portfolio Standard (RPS) Procurement

The MID Board of Directors originally adopted an RPS policy through board resolution 2003-245 to meet the mandates of the state's RPS bill (SB1078). This policy set a target that 20% of the statewide energy mix be supplied by renewable resources by 2017. SB1078 was superseded by SBx1-2 which set a renewable energy target of 33% by 2020 for all California utilities. The MID Board of Directors subsequently adopted an RPS procurement plan through resolution 2013-87 to incorporate the state's

33% RPS requirements. SBx1-2 was superseded by SB350, which increased the RPS targets to 50% by 2030. SB100 further increased the RPS targets to 60% by 2030. The MID Board of Directors adopted a revision to the RPS procurement plan, which incorporates the 60% target.

4.2.3. Energy Efficiency (EE) Procurement

The MID Board of Directors originally adopted an EE target through resolution 2010-50 and approved the submittal of targets to the CEC through resolution 2013-18. The MID Board of Directors subsequently adopted the District's 2018-2027 EE targets through resolution 2017-59. The most recent targets are incorporated into this IRP.

4.2.4. Exposure Limits

MID's Risk Management Policy implements a Value-at-Risk (VaR) limit as well as position limits. The VaR is a financial limit expressed in dollar amount and the position limits are energy position limits expressed in hedged percentage or "covered" volume.

4.2.5. Energy Storage Procurement

The MID Board of Directors adopted a policy through resolution 2014-72 stating that mandatory energy storage procurement targets are not appropriate. It was determined that mandatory procurement of energy storage cannot be cost effective without an identified operation or reliability need. Instead, MID will evaluate energy storage on an economic basis as opportunities arise.

4.3. Federal and State Laws

MID complies with federal and state laws. Below are federal and state regulations and laws governing MID energy planning and procurement.

4.3.1. Applicable Federal Law Passed Since 2006

Policy	Description
Greenhouse Gas Reporting (2010)	Mandatory reporting of power plant emissions to U.S. EPA for facilities located in the United States that emit 25,000 tons of CO_2e or greater per year. As of July 2018, Woodland and Ripon generation stations continue to meet the criteria for reporting.
National Ambient Air Quality Standards (2006)	Sets limits for six principal pollutants which are called "criteria" pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particle pollution, sulfur dioxide).
Mercury and Air Toxics Standards (2011)	Limits emissions of toxic air pollutants like mercury, arsenic and metals from coal and oil-fired power plants
EPA New Source Performance Standard (2012)	The Environmental Protection Agency issued a New Source Performance Standard that requires any new baseload fossil-fuel power plant to emit no more than 1,000 pounds of carbon dioxide per megawatt-hour of electricity produced, calculated over a rolling 12-month period. This compares to average coal plant emissions of about 1,800 pounds of CO2 per megawatt-hour and average natural gas plant emissions of 850 pounds of CO2 per megawatt-hour. The proposed rule does not apply to existing plants. The current EPA administration has begun the process of withdrawing this proposal. While it is very unlikely that any of these requirements would be enforced in this presidential term, construction of plants that do not meet the standard would likely carry some long-term risk.

Policy	Description
Proposed Rule for Greenhouse Gas Reductions from Existing Electric Utility Generating Units (2014)	The Environmental Protection Agency proposed a rule for limiting GHG emissions from existing power plants, with the goal of achieving nation-wide electricity sector GHG reductions of 30% below 2005 emissions by 2030. The rule proposes individual emission reduction targets for each state. The 2030 California goal is to achieve a sector-wide emission factor of 537 lbs/MWh. Each state is given the opportunity to propose its own State Implementation Plan (SIP), outlining strategies to reach the identified target. The impacts to MID would not be known until California releases its proposed SIP; however, it does not seem likely that the proposed target will be more stringent than what is already being implemented in the state to achieve post-2020 emission reductions, given that California is targeting 2050 emissions that are 80% below 1990 levels. Additionally, the California Air Resources Board (CARB) estimates that California should meet those targets with the existing state programs (RPS, cap-and-trade, energy efficiency). The current EPA administration has begun the process of withdrawing this proposal. It is very unlikely that any of these requirements would be enforced in this presidential term.

4.3.2. State Law Passed Since 2006

Policy	Description
AB2021 Energy Efficiency (2006)	Requires load-serving entities to procure all cost effective energy efficiency measures with the goal of reducing statewide electrical consumption by 10% over the next 10 years. This resource plan incorporates new energy efficiency reductions sufficient to reduce MID's projected energy consumption by approximately 152 GWh by 2023.
SB1 Solar Energy Net Metering (2006)	Requires MID to have a program that adequately supports the state's efforts to install 3,000 MW of rooftop photovoltaic capacity in California. SB 1 also set the net metering cap 2.5% of peak load. On July 31, 2007 the MID board adopted resolution 2007-138 which authorized the District to begin offering rebate incentives for qualifying PV systems. The District's customers have installed approximately 42MW of behind-the-meter solar capacity, which exceeds the District's net metering obligations, allowing the District to offer a replacement net metering program.
SB1368 Emission Performance Standard (2006)	Limits investments in baseload generation to resources that meet an emission performance standard of 1,100lbs CO_2/MWh. This requirement essentially limits baseload generation options to natural gas given that the average coal plant emits 1,800 lbs CO_2/MWh while combined-cycle natural gas plants typically emit 850 lbs CO_2/MWh.
AB32 Global Warming Solutions Act of 2006	This law targets climate change by establishing a goal of reducing California's greenhouse gas emissions to 1990 levels by 2020, representing a 25% reduction statewide. In accordance with AB32, ARB adopted a cap-and-trade program in 2010 to limit statewide greenhouse gas emissions. The program implements an annual emissions cap starting in 2013 that decreases annually through 2020. The cap applies to utilities, large industrial facilities and to the fuel distribution sector. Utilities receive enough free allowances to cover about 90 percent of overall sector emissions and must buy compliance instruments for any remaining emissions. MID's compliance costs through 2020 are expected to be relatively modest after accounting for free allowances. In 2016, SB32 expanded the statewide GHG emissions reduction goal to 40% below 1990 levels by the year 2030.
AB1613 Waste Heat and Carbon Emissions Reduction Act (2007)	The bill's goal is to advance the efficiency of the state's use of natural gas by capturing unused waste heat and to support and facilitate both customer and utility-owned Combined Heat and Power (CHP) systems. This bill requires electric utilities, including POUs, to establish a program that allows retail customers to utilize heat and power systems and for the utilities to provide a market for the purchase of excess electricity of a CHP system at a just and reasonable rate determined by the governing body of the utility.
AB118 Alternative Fuels and Vehicle Technologies: Funding Programs (2007)	This bill sets up funding for Alternative and Renewable Fuel and Vehicle Technology Programs to be administered by the Energy Commission. It also allows CARB to set up a low carbon fuel standard for transportation fuels that seeks to reduce the carbon intensity of transportation fuels by 10% by 2020.

Policy	Description
AB920 Solar and Wind Net Metering (2009)	AB 920 requires MID to adopt a net metering rate for surplus energy from customer-generators by January 1, 2011. This rate applies to customer installations of solar or wind generators with up to 1 MW capacity. The net metering cap will remain at 2.5% of peak load as established by SB 1. Any surplus energy purchased from a customer-generator will count toward MID's RPS. The MID surplus rate has been set at the calculated annual avoided cost for the energy generated plus the annual green energy adjustment for the renewable attributes. The rate is intended to ensure that all other customers are indifferent to any surplus generation. The current MID surplus rate is $0.0567/kWh for net metering 1.0 customers and $0.076/kWh for net metering 2.0 customers.
SB32 & SB1332 Feed in Tariffs for Renewables (2009) & (2012)	SB 32 and SB 1332 require POUs to adopt standard terms for the purchase of renewable energy from eligible projects. The tariff must be made available to eligible renewable projects with a generating capacity not exceeding 3MW, on a first-come-first-served basis until MID's proportionate share of the 750 MW state cap is reached (approximately 8 MW). A tariff request can be denied only if it is determined that building or interconnection standards are not met or if the proposed installation would adversely impact the distribution system. The MID Board of Directors adopted a feed-in tariff, which became effective on July 1, 2013. The tariff offers a seasonal time-of-delivery rate to renewable projects with a generating capacity greater than 30kW but not exceeding 3MW.
AB510 Utility Net Metering (2010)	Utilities must provide meters that can read and record in both directions, and must accept generation up to a cap of 5% of the total load. MID achieved its 5% obligation in 2016.
AB2514 Energy Storage (2010)	AB 2514 requires the state's publicly owned utilities to open a proceeding to determine appropriate energy storage targets (if any) by March 1, 2012 and to adopt an energy storage procurement target by October 1, 2014. The overall target is to be achieved in two parts; the first target is to be achieved by December 31, 2016 and the second target is to be achieved by December 31, 2021. The MID Board of Directors has adopted a policy stating that energy storage targets are not appropriate for the District at this time, given the lack of reliability and operational drivers.
SBX1-2 Renewable Energy (2011)	This bill requires all California electric utilities, including publicly-owned utilities, to meet a renewable energy target of 33% of retail sales by 2020. It increases the state's previous RPS targets to 20% for 2011-2013, 25% by 2016 and 33% by 2020. MID is currently meeting its RPS obligations, and is on track to meet the 2020 target with the existing resource mix.
SB1275 Charge Ahead California Initiative (2014)	SB 1275 establishes a state goal of 1 million zero-emission and near-zero-emission vehicles in service by January 1, 2023 and to increase access for disadvantaged, low-income, and moderate-income communities and consumers to these vehicles through programs including rebates and vouchers. Indirect impacts of this bill on the electric industry may be an increase in electric vehicle charging load.
SB350 Renewable Energy, Energy Efficiency and Vehicle Electrification (2015)	SB 350 increases the renewable energy target from 33% in 2020 to 50% in 2030. Additionally, the bill requires the CPUC to identify cost-effective electric efficiency savings and to establish efficiency targets for gas corporations. The bill requires programs to be established to achieve a cumulative doubling of statewide energy efficiency savings in electric and natural gas end uses by January 1, 2030. This bill also requires POUs to address transportation electrification in the IRPs adopted and submitted to the Energy Commission.
SB338 integrated Resource Plan: Peak Demand (2017)	This bill requires the commission and the governing boards of local publicly owned electric utilities to consider, as a part of the integrated resource plan process, the role of distributed energy resources and other specified energy- and efficiency-related tools, in helping to ensure that each load-serving entity or local publicly owned electric utility, as applicable, meets energy needs and reliability needs while reducing the need for new electricity generation and new transmission in achieving the state's energy goals at the least cost to ratepayers.

4.4. 2019 Policy Driven Planning Initiatives

MID is currently assessing new planning software capable of modeling energy storage resources. The current planning software is not capable of modeling the bi-directional flows of energy storage resources.

To aid in evaluation of potential energy storage resources, MID plans to request project developers add energy storage options to their project proposals. This will allow MID to understand the optionality of the projects and can help screen projects that are incompatible with energy storage at the initial stage of the energy procurement process.

V. Renewable Energy Procurement Plan

5. MID Renewable Energy Procurement Overview

MID relies on a diverse, balanced power resource mix to meet customer needs. This chapter presents the utility's plan for procuring renewable energy to balance the electric resource portfolio to meet the state's mandates and the utility's reliability needs.

On November 12, 2013, the MID Board of Directors considered and approved the RPS Procurement Plan in accordance with Section 3205(a)(1) of the Enforcement Procedures for the Renewable Portfolio Standard for Local Publicly Owned Utilities. As explained in section 3.1, this IRP focuses on the renewable energy procurement target to meet 50% of its electric retail sales with renewable energy by 2030, though the utility is in the process of implementing the recently adopted 60% by 2030 renewable energy procurement target. A future IRP filing will incorporate the updated RPS renewable energy targets[1]. MID projects that under the 50% RPS by 2030 target, it is well-positioned to meet its RPS compliance requirements for all compliance periods and will not have incremental RPS physical need until at least 2026. MID plans to meet its RPS requirements through 2025 by, applying previous volumes of excess procurement (also known as the use of "banked" renewable energy credits ("RECs")).

This chapter lists the policies, assumptions, and plans that impact MID's renewable resource planning and shall be considered a frame of reference to the renewable procurement plan.

5.1. RPS Targets by 2030

SB350 and SB100 allow POUs to maintain discretion over the mix of resources (eligible renewable energy and other) for purposes of ensuring resource adequacy and reliability, as well as the discretion associated with the reasonableness of costs incurred by the POU for eligible renewable energy resources. This version of the IRP lays out MID's plan to comply with the SB350 RPS targets, as a percentage of retail load as below:

- 33% by December 31, 2020;
- 40% by December 31, 2024;
- 45% by December 31, 2027;
- 50% by December 31, 2030.

The table below provides a brief summary of the requirements through 2020:

[1] Though not used in this submittal of this IRP, SB 100, signed by Governor Brown in September 2018 updated these targets to 44% by by December 31, 2024, 52% by by December 31, 2027, and 60% by by December 31, 2030.

Table 5-1: RPS Buckets

		Compliance Year[2]	**12/31/2013**	**12/31/2016**	**12/31/2020**
		RPS % as a percent of retail energy sales	Average 20%	25%	33%
Commonly Known as Buckets	Portfolio Content Category (PCC) 1	Minimum portion of RPS required to be either: ▪ 1) Physically within CA, or 2) adjacent, or 3) dynamically scheduled into CA.	50%	65%	75%
	PCC 2	Firmed and Shaped	No minimum or maximum	No minimum or maximum	No minimum or maximum
	PCC 3	Tradable Renewable Energy Credits ("TRECs") Maximum- post 6/1/2010	25%	15%	10%
	PCC0	Grand-fathered contract executed before 6/1/10.	Count in Full	Count in Full	Count in Full

Note: the updated SB100 RPS requirements maintain the 2020 level of required PCC1 and PCC3 electric products post the 2020 timeframe.

5.2. MID Current and Future RPS Mix

MID's RPS portfolio currently includes power purchases from four wind generation projects; the Big Horn I and II Projects purchased through M-S-R Public Power Agency, and two wind projects procured directly by MID: the Star Point Wind Project, and the High Winds Project. The Big Horn I and II projects are located in Klickitat County, Washington; and the Starpoint and Highwinds projects are located respectively in Sherman County, Oregon and Solano County, California. MID's renewable energy mix also includes the New Hogan and Stone Drop small hydro projects, the Fiscalini biomass facility, the Ripon Solar Energy Project, and the McHenry Solar Farm. The District also obtains a small amount of RECs from the Western Area Power Administration for generation from their small hydroelectric units.

In September 2017 MID executed two 20-year power purchase agreements. MID will obtain the energy output, capacity, and associated environmental attributes from two solar photovoltaic projects yet to be constructed: the Mustang II Barbaro and Blythe Solar IV projects. MID will purchase the output from a 50 MW portion of the 150 MW Mustang II Project, which will be located just west of Lemoore, in Kings County, California. This facility is expected to reach commercial operation by December 31, 2020 and is being developed by Recurrent Energy. MID will also purchase the output from a 62.5 MW portion of the

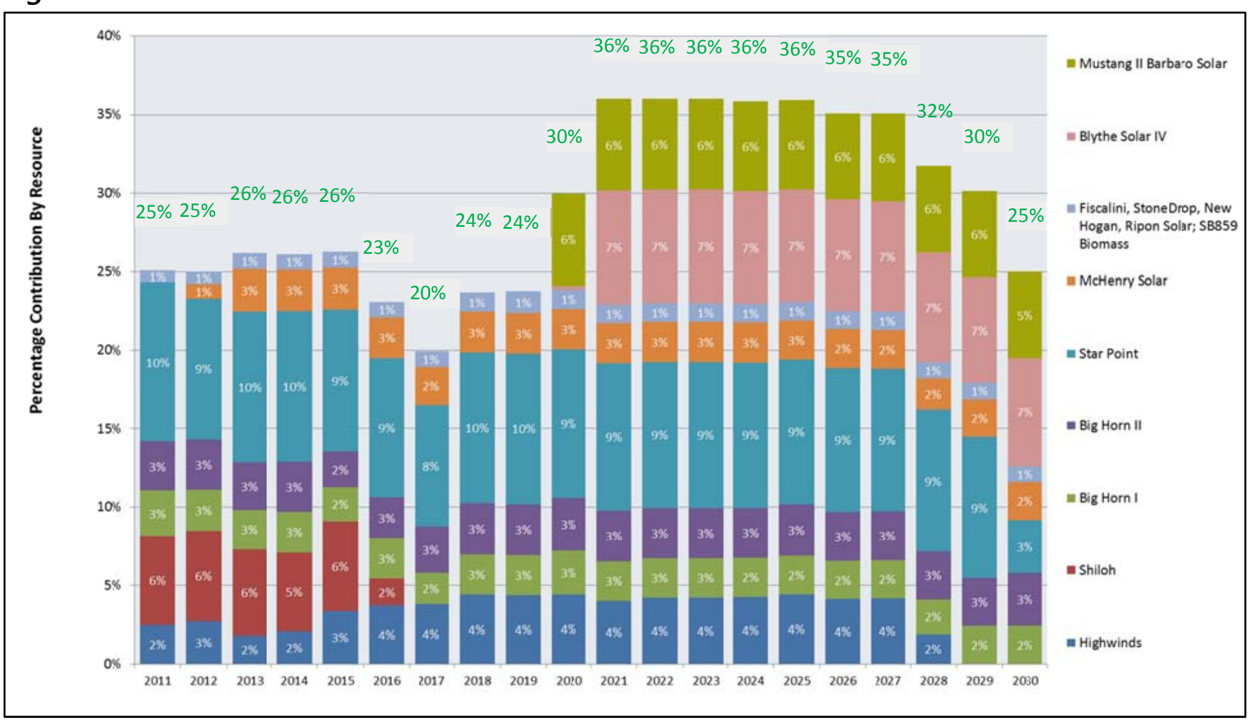
[2] The statute calls out three distinct compliance periods. The first compliance period is between 1/1/11-12/31/13, the second is between 1/1/14-12/31/16, and the third is between 1/1/17-12/31/20.

125 MW Blythe Solar IV Project, which will be located near Blythe, in Riverside County, California. This facility is expected to reach commercial operation by December 1, 2020 and is being developed by NextEra Energy. In addition, pursuant to SB859 the state's electric utilities must acquire their load ratio share of capacity from biomass facilities that burn woody biomass from high hazard fire zones. The law was enacted as an effort to reduce the risk of forest fires. Because the District's share is too small to procure efficiently (about 1½ MWs), MID has been working with a group of POUs to acquire its share of the output through a joint solicitation and procurement process. To date a 0.994 MW portion of the total 1½ MWs has been secured under a 5-year agreement. It is anticipated that the remaining portion of about ½ MW will be obtained in 2019.

MID has taken steps to minimize its renewable energy resource procurement risks by: (i) first procuring renewable energy resources that are located within the state of California, (ii) obtaining assurances that counter parties will meet deliverability requirements for both energy and environmental attributes (and "RECs"); and (iii) examining potential legislative impacts within the regulatory framework in which MID operates. MID has also ensured competitiveness of the purchases made to date by procuring its resources through competitive bidding processes.

Figure 5-1, on the following page, presents a snapshot of MID's procured RPS resources. In 2017, 20% of the energy required to serve MID's retail load was sourced from eligible renewable energy resources. The gap between what is generated and the RPS targets in the third compliance period will be met through the use of banked RECs (Renewable Energy Credits).

Figure 5-1: MID's Procured RPS Resources



5.2.1. Use of REC Banking and TRECs for RPS Compliance

SBX1-2 allows for RECs to be banked for up to 36 months from the date the corresponding energy was generated. In addition, SBX1-2 allows for those contracts that were approved by the governing boards of electric utilities prior to June 1, 2010 to count in full as part of the POU's RPS. Further, the adopted CEC regulation includes an allowance for POUs that took early action by allowing a carryover of the excess generation measured from 2004 through 2010.

With the exception of tradable RECs that must be retired at the end of each compliance period , excess RECs that are not used to meet a measurable goal in a specific year will roll over to a future year and offset the RECs that will be generated in that future year. Again, those RECs generated during that future year will be rolled over to another year and so forth.

MID assumes that the ability to bank in this fashion will remain as the CEC implements regulations for the state POUs to enforce the requirements of SB350 and SB100. By banking excess RECs from existing renewable energy projects, MID can meet the RPS targets through most of 2025 without additional resources, using the SB350 trajectory.

5.2.2. Renewable Portfolio Standard (RPS) Procurement Policy

The MID Board of Directors originally adopted an RPS policy through board resolution 2003-245 to meet the mandates of the state's RPS bill (SB1078). This policy set a target that 20% of the statewide energy mix be supplied by renewable resources by 2017. SB1078 was superseded by SBx1-2 which set a renewable energy target of 33% by 2020 for all California utilities. The MID Board of Directors subsequently adopted an RPS procurement plan through resolution 2013-87 to incorporate the state's 33% RPS requirements. SBx1-2 was superseded by SB350, which increased the RPS targets to 50% by 2030

5.3. Items for Further Consideration

5.3.1. Energy Storage

AB 2514 required the state's publicly owned utilities to open a proceeding to determine appropriate energy storage targets (if any) by March 1, 2012 and to adopt an energy storage procurement target by October 1, 2014. The overall target is to be achieved in two parts; the first target is to be achieved by December 31, 2016 and the second target is to be achieved by December 31, 2021.

MID has conducted an initial assessment of different types of battery systems. Lithium Ion battery systems are found to be the most applicable to MID's system needs. Lithium Ion battery systems may reduce local peak demand and provide ramping support at evening peak; however the costs of a battery system currently outweigh the benefits. The MID Board of Directors adopted a policy in 2014 that energy storage targets are not appropriate for the District in the near-term, given the lack of reliability and operational drivers.

5.3.1.1 RPS Solicitation Energy Storage Component

Although MID did not adopt mandatory energy storage procurement targets, MID plans to encourage developers or merchants to offer stand-alone energy storage systems or hybrid energy storage components in response to future RPS solicitations. In previous solicitations, the proposals offered by developers or merchants generally did not provide the option to include an energy storage system with renewable projects. This option should provide more opportunities to analyze the benefits of energy storage.

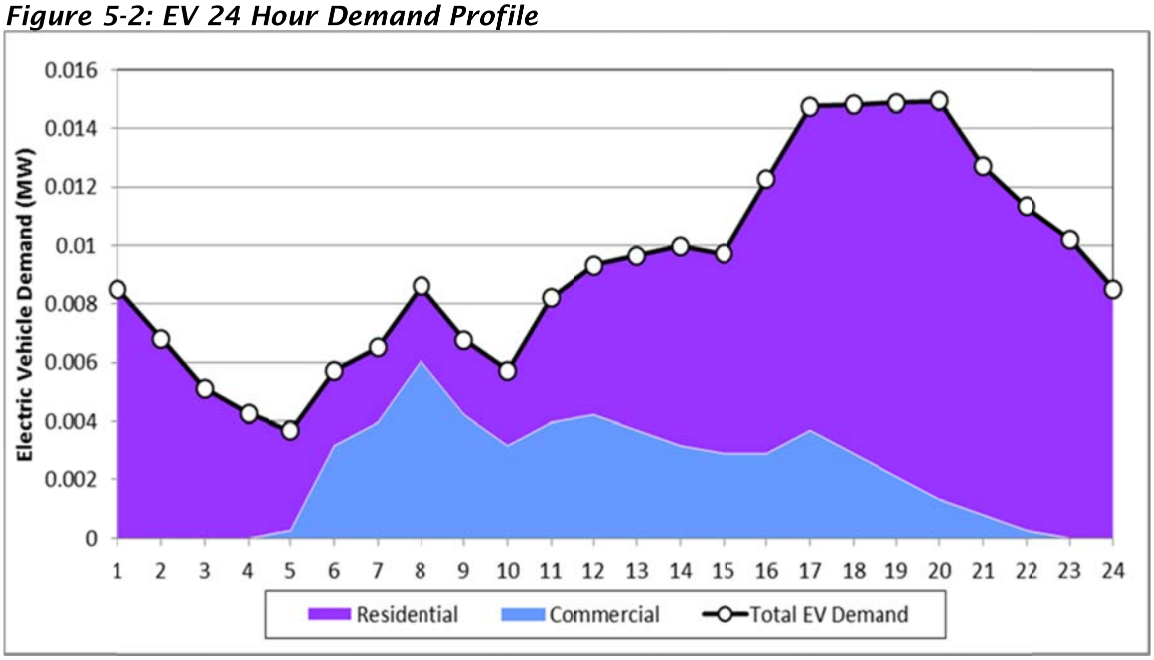
5.3.2. Transportation Electrification

The transportation sector accounts for nearly 40 percent of statewide GHG emissions. POUs are required to address Transportation Electrification in the IRPs adopted and submitted to the Energy Commission pursuant to SB 350. Energy Commission staff has 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 (LD PEV) deployment in their service territories. In the CEC tool, the statewide PEV count is estimated to reach 3 million vehicles by 2030. MID's share of the statewide target is 0.16%, approximately 5,000 PEVs by 2030. MID incorporates the results of this EV forecast in its IRP.

5.3.2.1 Electric Vehicle Charging Profile

According to the California Clean Vehicle Rebate Project (CCVR) website, as of June 2018, there were 628 rebates (0.32% of the state's share of 197,298) paid out in the MID service area. MID relies on the CCVR website for historical PEV statistics. MID develops a unique hourly profile of PEV consumption based on the profile developed by Rocky Mountain Institute in the 2016 article, "Electric Vehicles As Distributed Energy Resources". The estimated typical PEV hourly charging profile on a peak summer day in 2019 is listed in Figure 5-2.

Figure 5-2: EV 24 Hour Demand Profile



Using the Energy Commission "Light_Duty_Plug-In_EV_Energ_and_Emission_Calculator_v_3_5", the projected MID PEV charging demand has a growth rate of 17.7% for 2019-2030. A detailed projection of demand in GWh is listed in Table 5-2.

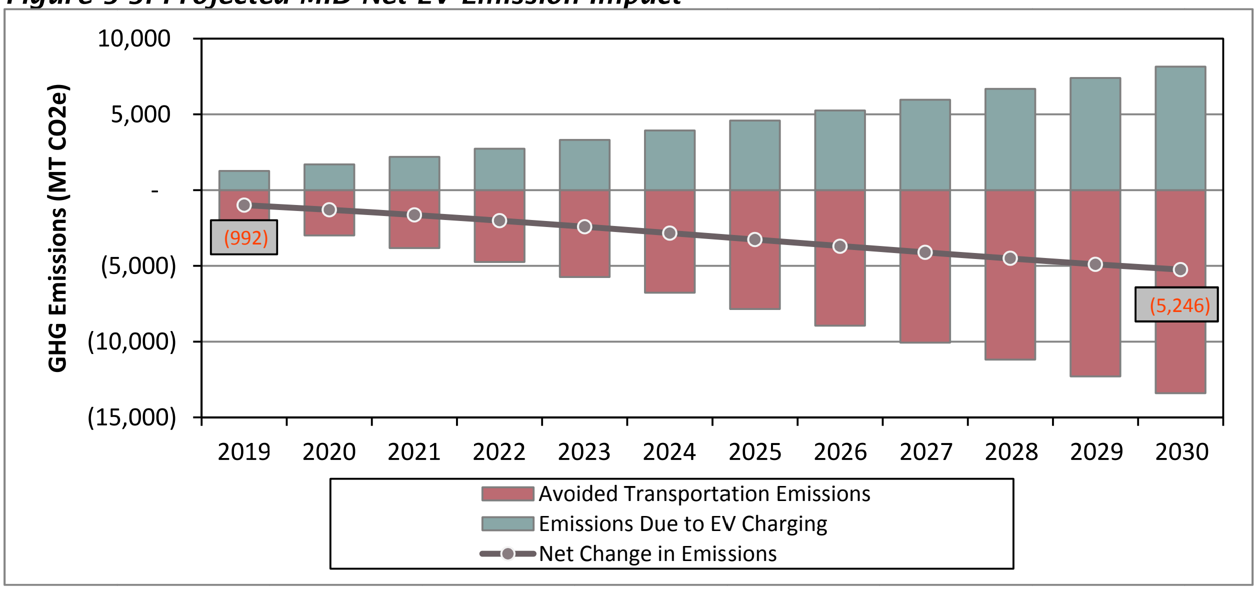
Table 5-2: EV Annual Energy Estimate (GWh)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2018 LTDEF	3.6	4.6	5.8	7	8.4	9.7	11.2	12.6	14.1	15.6	17.1	18.6

5.3.2.2 Transportation Electrification Impacts

Pursuant to the Energy Commission Staff's calculator, MID estimates that PEV charging demand has a relatively small impact to the MID's emission profile. Emission growth and reduction from transportation electrification are estimated and reported on the Standardized IRP Tables. The estimated impact to emissions is shown in below Figure 5-3.

Figure 5-3: Projected MID Net EV Emission Impact



Transportation electrification also impacts system coincident peak. Net peak demand impact (increase) from transportation electrification is estimated as in Table 5-3.

Table 5-3: EV Peak Coincident Capacity (MW)

Year	1-in-2 Peak Conditions	1-in-10 Peak Conditions
2019	0.6	0.6
2020	0.8	0.8
2021	1.0	1.0
2022	1.2	1.2
2023	1.5	1.4
2024	1.7	1.7
2025	1.9	1.9
2026	2.2	2.2
2027	2.4	2.4
2028	2.7	2.7
2029	2.9	2.9
2030	3.2	3.2

5.3.2.3 Transportation Electrification Infrastructure

MID is currently evaluating PEV charging station installation standards for single-family dwellings, multi-family dwellings and workplaces. Due to the low ownership percentage of PEV in the area, MID has no definite infrastructure investment plan or grid plan for EV charging stations at this time. MID currently does not have public transit or heavy-duty vehicle electrification investment plan.

5.3.2.4 Transportation Electrification in Disadvantage Communities

MID does not currently promote special rebate programs to sponsor PEV for disadvantaged communities. MID residents are eligible for CVRP (Clean Vehicle Rebate Project) rebates if their gross annual incomes are below the following thresholds:

- $150,000 for single filers
- $204,000 for head-of-household filers
- $300,000 for joint filers

Low income consumers will benefit from larger rebates dependent upon the number of persons in the household and the total income levels for the households. These levels are explained on the CVRP website: https://cleanvehiclerebate.org/eng.

VI. Energy Demand and Peak Forecasts

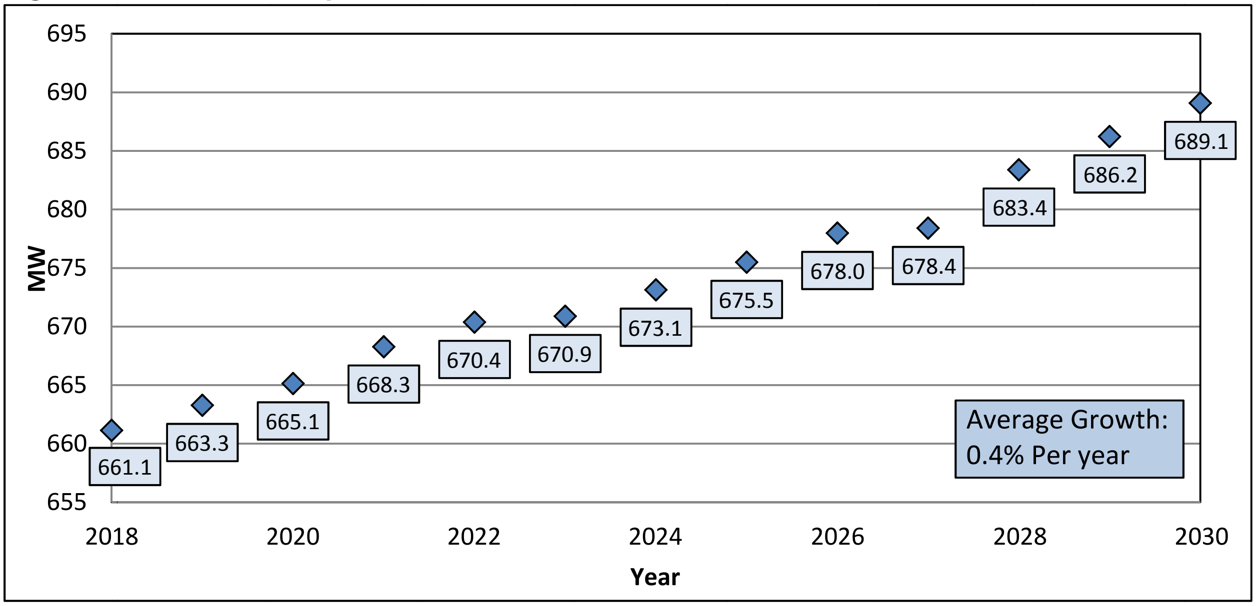
6. Overview of IRP Energy and Peak Forecasts

POUs are required to address Energy Demand and Net Peak Forecasts in the IRPs adopted and submitted to the Energy Commission pursuant to SB 350. MID is the sole load serving entity of the greater Modesto area (north of the Tuolumne River, Waterford and Salida); and has been serving load in the northern expansion area, defined as "a 400 square mile area in Southern San Joaquin County, Northern Stanislaus County, and Western Tuolumne County", often referred as "four-city area" "including Ripon, Escalon, Oakdale and Riverbank", on a competitive basis, since 1996. Additionally, MID has been the sole load serving entity in the community of Mountain House since 2001. MID is also a non-exclusive load serving entity for load migrated to the northern expansion area, referred as "Greenfield load", since 2007. The MID in-house 2018 Long-Term Demand and Energy Forecast (LTDEF) for the MID region and out of MID territory cities (OFT) serves as the input for determining the POU's resource procurement needs. This chapter includes discussion of the methodology, assumptions, and data used to create the Energy Demand and Peak Forecasts. The forecast horizon is from 2018 through 2030.

MID's Energy Demand and Peak Forecasts are based on a set of econometric models describing the hourly load in the region as a function of a number of weather variables (e.g., surface temperature, solar irradiance level), calendar variables (e.g., day of week, holidays), and demographic variables (e.g., labor force data). The LTDEF utilizes regional demographic data obtained from the U.S. Department of Labor. The weather data utilized in the LTDEF is thirty years of historical weather data provided by the Weather Company for two weather stations. This LTDEF also incorporates demand side forecast models, which include projections for customer solar, energy efficiency and electric vehicle charging.

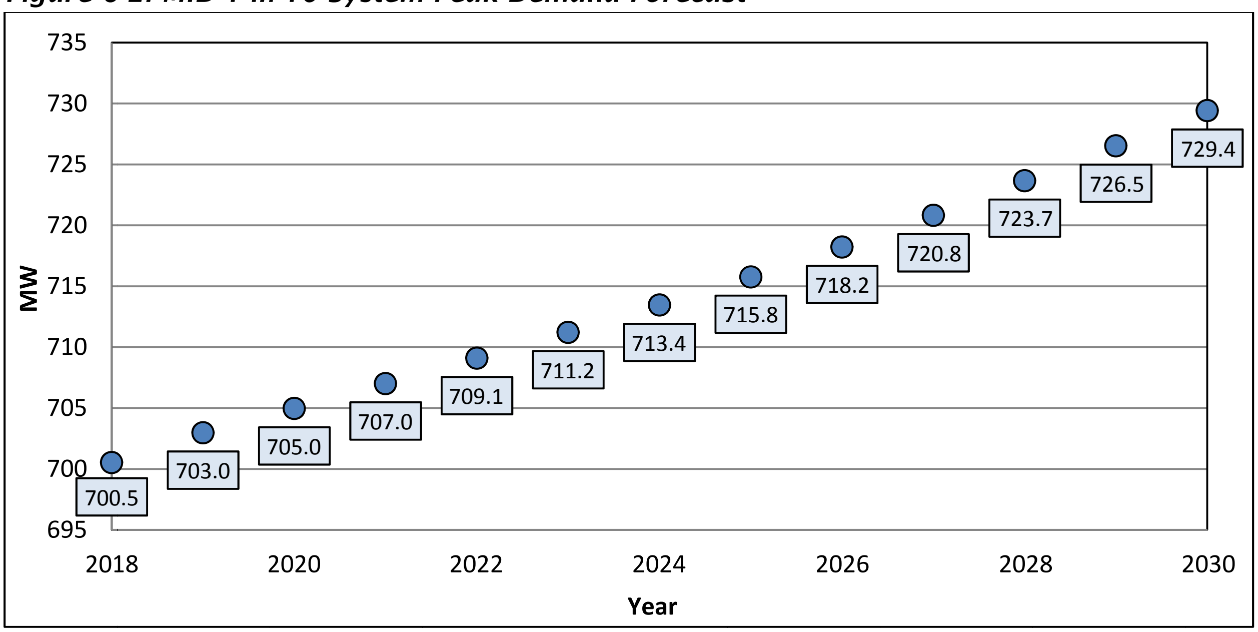
6.1. Overview of Forecast Results

Figure 6-1: MID 1-in-2 System Peak Demand Forecast



As shown in Figure 6-1, the 2018 LTDEF projects a system 1 in 2 non-coincident peak[1] demand growing at an average annual rate of approximately 0.4% from 2018 to 2030. Historically, peak demand annual growth rate was 0.8% from 2008-2017. The slower growth rate from 2018 to 2030 is mostly attributable to a slower annual growth in demographic variables.

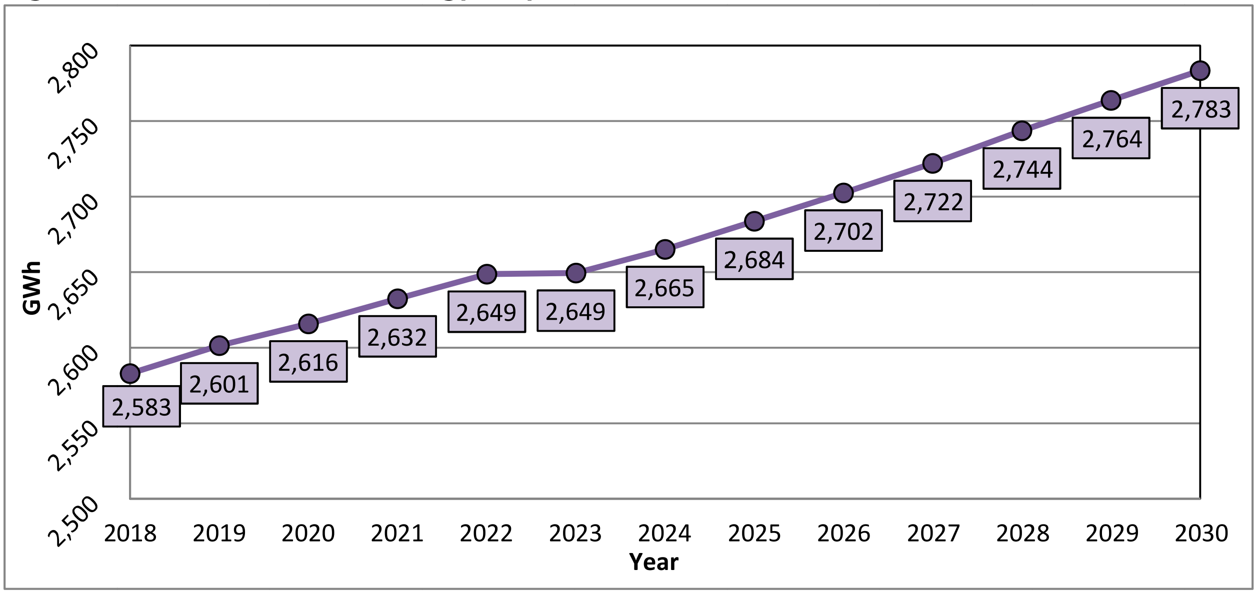
Figure 6-2: MID 1-in-10 System Peak Demand Forecast



[1] Non-coincident Peak: MID regional peak usually does not coincide with statewide peak. MID forecasts its own peak demand irrespective of coincidence to statewide demand.

As shown in Figure 6-2, the 2018 LTDEF projects a system 1 in 10 non-coincident peak demand growing at an average annual rate of approximately 0.3% from 2018 to 2030.

Figure 6-3: MID Forecasted Energy Requirement



As shown in Figure 6-3, the 2018 LTDEF projects system energy growing at an average annual rate of approximately 0.6% from 2018-2030. Historically, the annual energy growth rate was -(0.2)% from 2008-2017. The energy forecast grows at a quicker pace compared to Peak Demand mostly due to the regional economic recovery post 2014 and its impact to energy consumption.

6.2. 2018 LTDEF Methodology and Assumptions

This chapter provides a high level overview of the 2018 LTDEF. The assumptions and methodology discussed in this chapter depict MID's current understanding of the region, the regulations and technology developments and their impacts to energy consumption. Later chapters in this IRP present a comparison of earlier long term energy forecasts and the 2018 LTDEF. This chapter focuses on the 2018 LTDEF.

6.2.1. Modeling Framework

The 2018 LTDEF is a linear regression model. The model accounts for the impacts of weather, economics, demographics and seasonal trends. The 2018 LTDEF also incorporates demand side forecasts including hourly photovoltaic, energy efficiency, and electric vehicle projections. Impacts from existing interruptible and demand response programs to the energy and peak demand forecast are not modelled in the 2018 LTDEF. Those resources are dispatchable and are instead considered part of MID's resource mix.

The MID LTDEF is comprised of load from two geographic regions: MID base territory and MID OFT. Forecasts for both territories share a similar methodology.

The LTDEF model building process consists of four steps:

- Variable selection
- Econometric model building
- Weather scenario building
- Model results adjustments

6.2.1.1. Model Variable Selection

The LTDEF was developed using a combination of the following variables. While each of these variables was considered, the final model was based only on the most statistically relevant variables.

- Weather Variables
    - Surface Temperature
    - Solar Irradiance
    - Rainfall (not used in the final model)
    - Humidity (not used in the final model)
    - Lagged Temperature (1-4 hours)
    - 24 Hour Temperature Moving Average
- Economic and Demographic Variables
    - Labor Force Data
    - Inflation (not used in the final model)
    - Population (not used in the final model)
- Categorical Variables
    - Month
    - Day Type (day of week, holiday)
    - Hour
- Cross-Reference Variables
    - Temperature and Hour
    - Temperature and Month
    - Lagged Temperature and Hour
    - Lagged Temperature and Month
    - 24 Hour Temperature Moving Average and Hour
    - 24 Hour Temperature Moving Average and Month
    - Hour and Day Type
    - Hour and Month

6.2.1.2. Econometric Model Building Process

During the model building process, historical hourly demand, temperature, economic and demographic data from 1/1/2008 – 12/31/2017 were used. All variables were tested and evaluated. Only statistically significant variables were selected to build the econometric model.

The initial stage of building the forecast model was to run a set of regressions using actual data from previous years. This is the "sliding simulation" stage. All variables were regressed with actual values that functioned as either independent variables or cross-related variables (X variables). Year 2013 to 2017 load functioned as the dependent variables (Y variables). These five rolling test result years (2013-2017) were projected using the actual data from the prior four years. By benchmarking the regression's projected Y variable to the actual load of those years (2013-2017), the X variables that had material impact to the resulting projections were identified. Any immaterial X variables were excluded from the model. For example, rainfall data was determined to be an immaterial variable in the econometric model. After multiple sliding simulations and additional testing, a preliminary econometric model was built with the material variables.

During the 2nd stage of building the econometric model, a series of rolling regressions were conducted to determine the best regression period. After benchmarking the results of these rolling regressions to the actual load, it was determined that actual load was best represented (fit) by the econometric model and its coefficients derived from the most recent four-year period. This is consistent with the intuition that the current year's electricity consumption pattern has most similarities to its adjacent historical years.

The table below demonstrates the test result year's relationship to its sliding regression data.

Table 6-1: Simulation Years and Forecast Years

O - Test Result Year		**Econometric Model Simulation Years**								
X - Historical Regression Data		$Year_1$	$Year_2$	$Year_3$	$Year_4$	$Year_5$	$Year_6$	$Year_7$	$Year_8$	$Year_9$
Forecast Model	$Regression_1$	X	X	X	X	O				
	$Regression_2$		X	X	X	X	O			
	$Regression_3$			X	X	X	X	O		
	$Regression_4$				X	X	X	X	O	
	$Regression_5$					X	X	X	X	O

The final econometric regression model is then fitted and adjusted for data abnormalities. For example, this current version of the econometric model does not handle holidays very well. So, manual adjustments on those special occasions would help remove some time related forecast errors.

6.2.1.3. Weather Scenarios Building

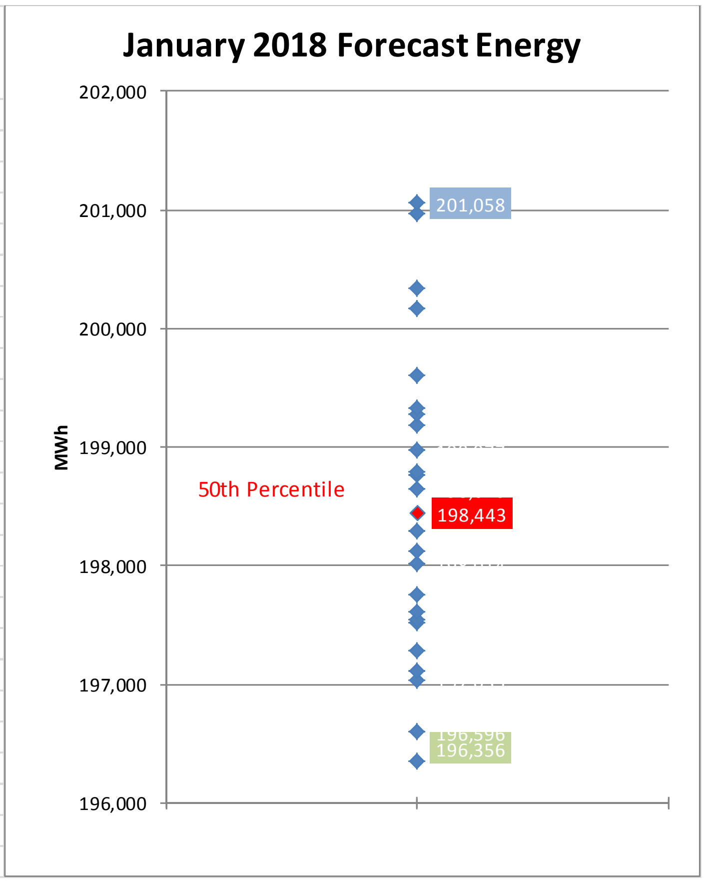
After deriving the final econometric regression model, weather scenarios were used to derive the final energy and peak load forecast. The weather scenarios used in the model are based on 25 years of historical weather data (1/1/1993-12/31/2017). Each year's observed weather pattern is considered an individual weather scenario. For example, the historical weather data from 1997, including solar irradiance, temperature, 24 hour moving average temperature and the other relevant weather variables, is referred to as the "1997 Weather Scenario" in the model.

For each forecast year (2018-2030), those 25 historical weather patterned scenarios were plugged into the econometric regression model to generate approximately 525 sets of load forecasts for 2018-2030. The resulting load forecasts were then fitted and adjusted for special days (holidays), combined with demographic growth, to derive each forecast year's final energy and peak demand projection. Each year's final energy forecast is determined by the result that represents the 50th percentile value of that year's weather patterned model results. Each year's 1 in 2 peak forecast is the 50th percentile value of that year's weather patterned peak model results, and each year's 1 in 10 peak forecast is the 90th percentile value of that year's weather patterned peak model results.

Table 1-2 uses January 2018 as an example to show how the monthly energy forecast was derived. By ranking the forecast results from the 25 weather scenarios from highest to lowest, it was determined that a monthly energy value of 198,443 MWh represents the 50th percentile result, which was derived from weather scenario 1998.

Table 6-2: Energy Forecast Sample

Forecast Year	Month	Weather Scenario	Forecast Energy (MWh)	P 50 (MWh)
2018	1	2014	196356	198443
2018	1	2003	196596.1	
2018	1	2015	197034.7	
2018	1	1994	197116.9	
2018	1	2016	197285.4	
2018	1	1999	197515.3	
2018	1	2010	197542.5	
2018	1	2000	197604.1	
2018	1	2009	197749.3	
2018	1	2012	198013.8	
2018	1	1993	198126.3	
2018	1	2004	198287.7	
2018	1	1998	198443.1	
2018	1	2005	198646.5	
2018	1	2011	198769.6	
2018	1	2007	198788.3	
2018	1	1996	198977.4	
2018	1	2006	199179.9	
2018	1	2001	199274.5	
2018	1	1997	199329.2	
2018	1	1995	199605.9	
2018	1	2002	200171.5	
2018	1	2013	200338.2	
2018	1	2017	200970.3	
2018	1	2008	201058.4	



6.2.1.4. Final Results Adjustments

Due to day of the week impact and leap year influence, the sum of the individual 12 month 50th percentile energy forecast results is slightly different than the 50th percentile result for the entire year. It was determined that the 12-month sum provides a more accurate result than the single annual figure given the inaccuracies in the annual historical data from billing cycle changes and loss factor calculation errors.

6.2.2. Out of Territory (OFT) Load Forecast Scenarios

OFT (Out of Territory) load represents a small portion of the MID total demand. Due to lack of historical metered data, the OFT load forecast was derived from 2009-2016 end-of-year billing data for individual cities and their billed rate classes.

Historically, the northern expansion area represents 6.09% percent of MID's total retail sales and Mountain House represents 1.62% of MID's total retail sales. This ratio to the system total load changes over time, but the difference is considered negligible and is not varied in this forecast.

Greenfield load is also considered in the forecast at the same growth rate of the entire system. It accounts for approximately 2% of MID retail load.

6.2.3. Economic Assumptions and Demographic Data

During the variable testing stage, several economic and demographic variables were tested, including population, employment rate, unemployment rate, seasonal employment and regional population growth. None of these variables was determined to be a good fit to the linear econometric model. The most significant variable was determined to be the regional labor force data published by the U.S. Department of Labor. The monthly labor force data was distributed evenly throughout the entire month and then added to the econometric model. Because a forecast of labor force data is not available, it is assumed that labor force will grow at a rate equal to the average historical growth rate of the past 10 years. This labor force data is then included in the econometric model as an independent variable.

6.2.4. Retail Sales Forecast and Retail Class Forecast

The retail sales forecast is projected by assuming a fixed average transmission loss in the system. After considering the impact of customer solar generation, the average loss factor on the MID system since 2015 is 2.5%. The difference between the system total demand and retail sales is attributed to transmission and distribution losses. Retail class forecasts are derived from historical billing ratios, which are the ratios of historical billed demand in each retail class to the total retail load, and the set of average historical billing ratios was applied to the 2018 LTDEF retail forecast to derive each class' retail forecast respectively. The monthly and annual ratios vary, but overall each retail class maintains a consistent ratio over time.

6.2.5. Forecast for Electric Vehicles, Customer Solar and Energy Efficiency

The 2018 LTDEF incorporates the California Energy Commission electric vehicle forecast and assumptions, which were published in December, 2017 in the "Light-Duty Plug-in Electric Vehicle Energy and Emission Calculator". By the end of 2030, the projected electric vehicle (EV) contribution to MID load is projected to be 19 GWh of energy consumption, with an annual growth rate of 18%.

MID projects that regional customer solar generation grows 4% each year and offsets 126 GWh of system energy consumption by the end of 2030. An hourly profile for customer solar generation was applied to all customer solar projections. The aggregated generation of all the customer solar programs is shaped by this hourly profile. The 8760 hourly profile is the average generation profile derived from two MID customer solar sites, which were determined to be representative samples of typical customer systems. The demand reduction from customer solar programs coincident to the MID system peak is estimated to range from 2 to 10 MW during summer 2018. This model will be updated as more meter data becomes available.

The 2018 LTDEF incorporates the latest energy efficiency targets approved by the MID board. This forecast is consistent to MID's 2017 spring EE forecast submitted to the CEC. MID developed an hourly profile for energy efficiency programs, which is similar to the profiles published in the 2016 CEC staff report CEC-200-2017-007. This hourly profile was used to determine the net hourly consumption.

6.2.6. Forecast Scenarios

The 2018 LTDEF incorporates multiple weather scenarios to each year's forecast. Instead of providing one forecast value for each time interval, MID models weather scenarios and provides a range of forecast results covering historical extreme weather conditions.

Macroeconomic and demographic changes are also significant drivers of MID regional load. Several macroeconomic and demographic variables were studied for significance; however, only the labor force variable was determined to be significant enough to be included in the forecast model. This variable is a composite of many drivers and can also be a dependent variable to other economic and demographic variables. The economic downturn in 2009 created a significant impact to MID electricity demand and also created so much volatility in the economic variables, such as inflation, GDP growth and employment, that their significance to the load forecast was reduced. Due to their reduced significance, these variables were not included in this forecast.

6.3.7 Net Demand Profile

MID's summer and winter net demand profiles have unique characteristics. Situated in the heart of California's central valley, MID's net demand is primarily driven by heating, air conditioning, and seasonal agricultural loads. These factors also drive a large difference between winter peak demand and summer peak demand. MID's winter and summer net peak hour is coincident to the winter and summer gross peak hour, respectively.

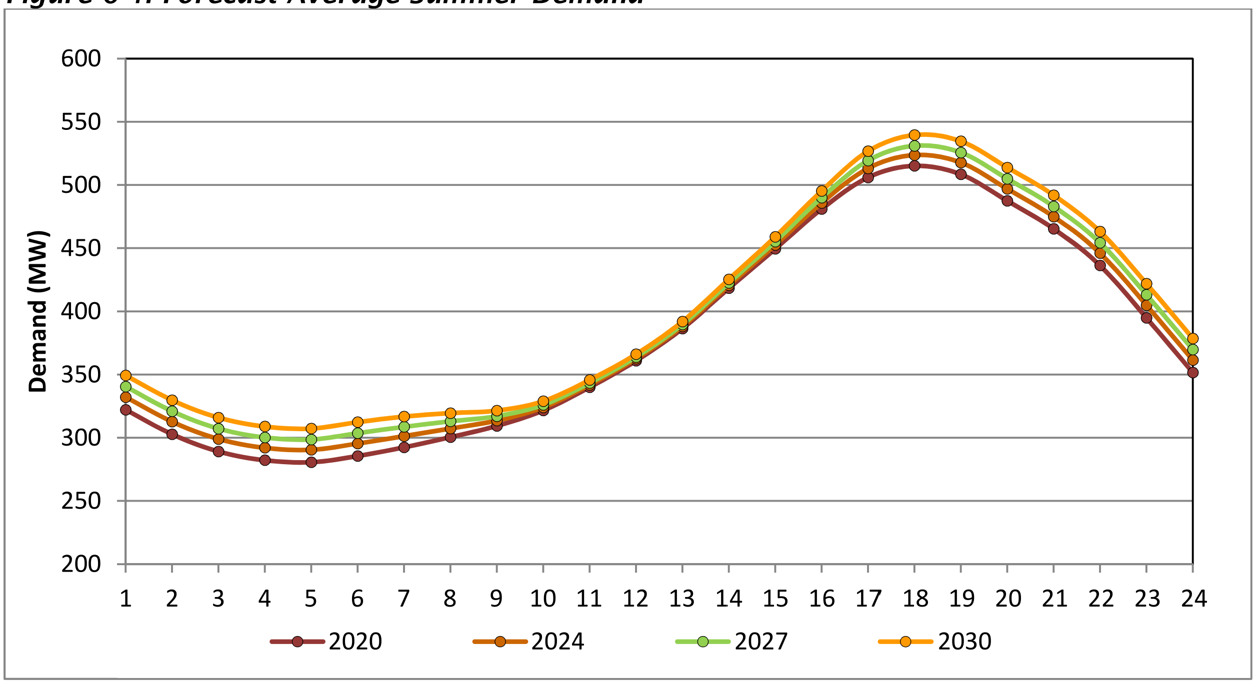
6.3.7.1 Summer Net Demand Profile

MID's summer net demand is largely driven by weather dependent residential load and seasonal agricultural load. It is common for MID to have days when the daily peak demand doubles the daily minimum. Due to the volatility of the summer demand, MID has to maintain flexible energy supplies to maintain reliability.

Summer Profile changes

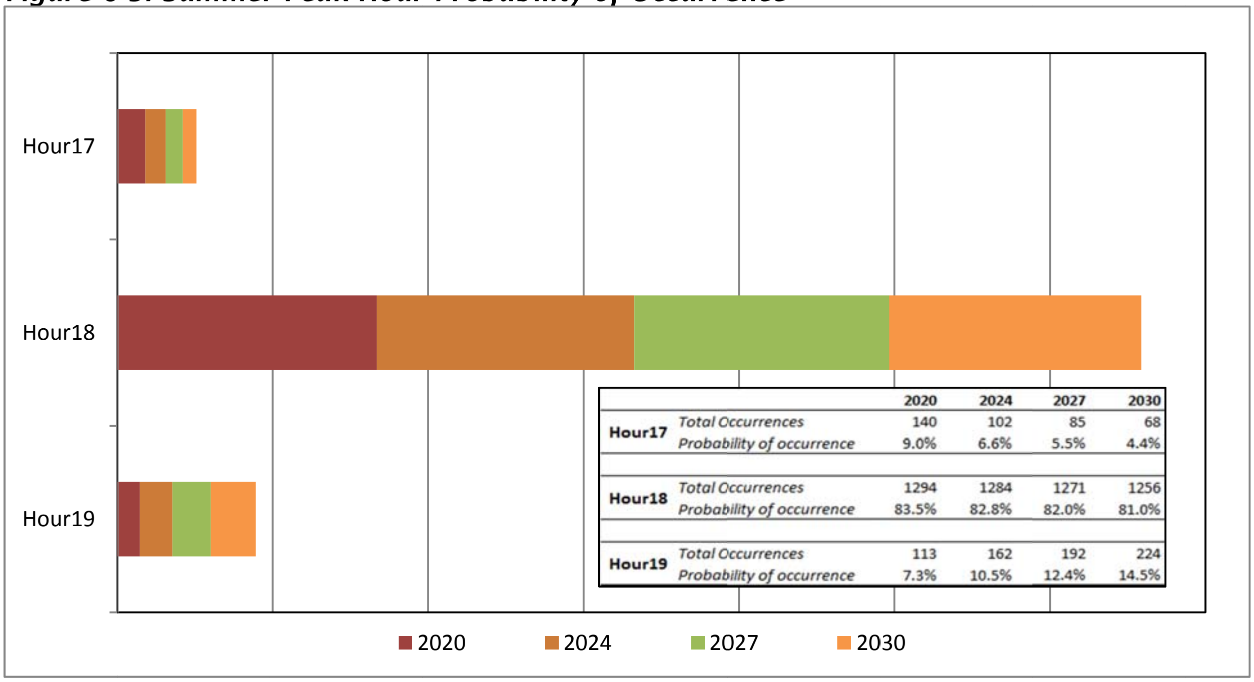
Similar to many utilities in California, MID is experiencing summer load profile changes. In a summer demand profile study from MID's 2018 Long-term Demand and Energy Forecast, a potential pattern change between 2019's summer demand profile and 2030's summer demand profile was noticed.

Figure 6-4: Forecast Average Summer Demand



Twenty-five load scenario simulations were conducted in the study. From the results of these 25 load scenarios, it was concluded that the summer peak might shift to the later evening in the observed planning horizon. The probability of the peak occurring at each hourly interval is calculated by dividing the total count of peak occurring in each hourly interval in all 25 scenarios by the total occurrences of daily peak events in July and August. For example, the total count of daily peaks happening in 2019 in HE (hour-ending) 17 in the 25 load scenarios is 140, and total count of daily peak events in July and August is 1,550 (25scenarios*62 days), so the HE 17 probability of peak occurrence is 9.0%. The results of the study are explained in Figure 6-5.

Figure 6-5: Summer Peak Hour Probability of Occurrence

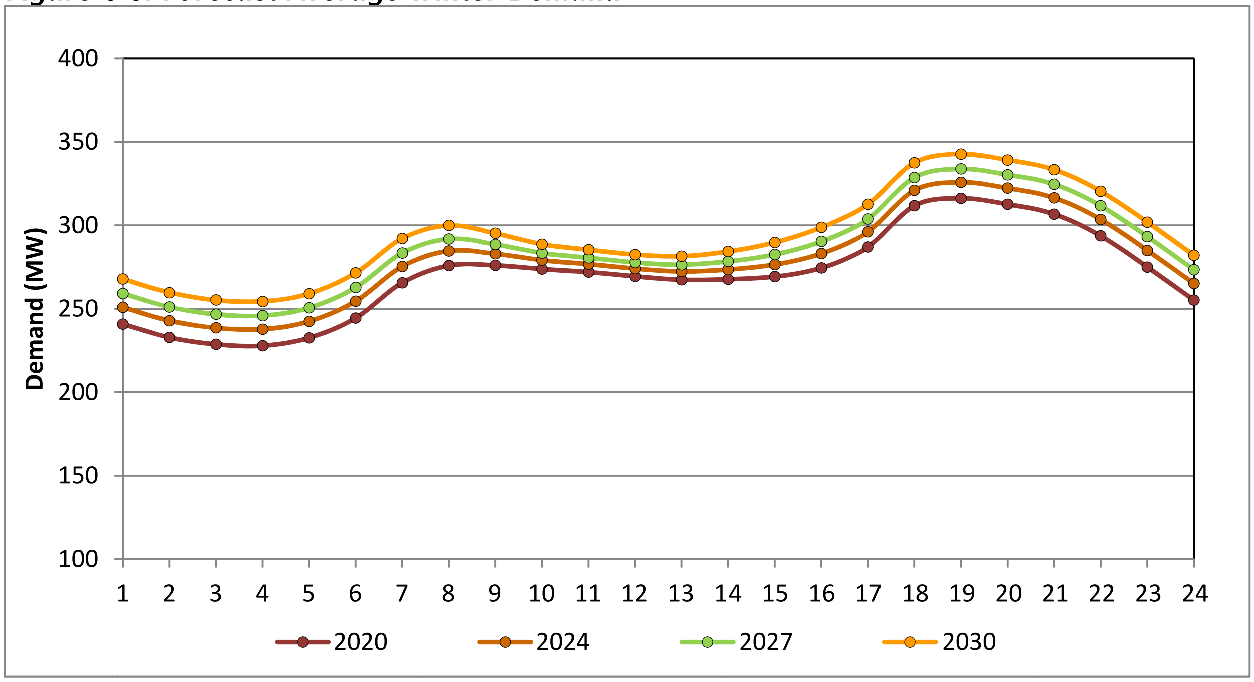


In 2020 there is a 91.5% probability that the peak would occur between HE 17 and HE 18 and 7.3% probability in HE 19. In 2030, the probability the peak would occur between HE 17 and HE 18 reduces to 85.4% and increases to 14.3% in HE 19.

6.3.7.2 Winter Net Demand Profile

MID's winter demand profile remains relativity flat throughout all hours. Unlike summer demand, seasonal loads are not active during the winter months leading to a lower base load. The majority of volatility in the winter pattern is contributed by changes from lighting loads from residential and commercial customers; and a smaller amount is contributed by changes of electric heating load. The shift of peak hours is not observed in the winter load pattern according to the load scenario study.

Figure 6-6: Forecast Average Winter Demand



6.3.8 Distributed Energy Resources (DER's) Impacts to Net Demand

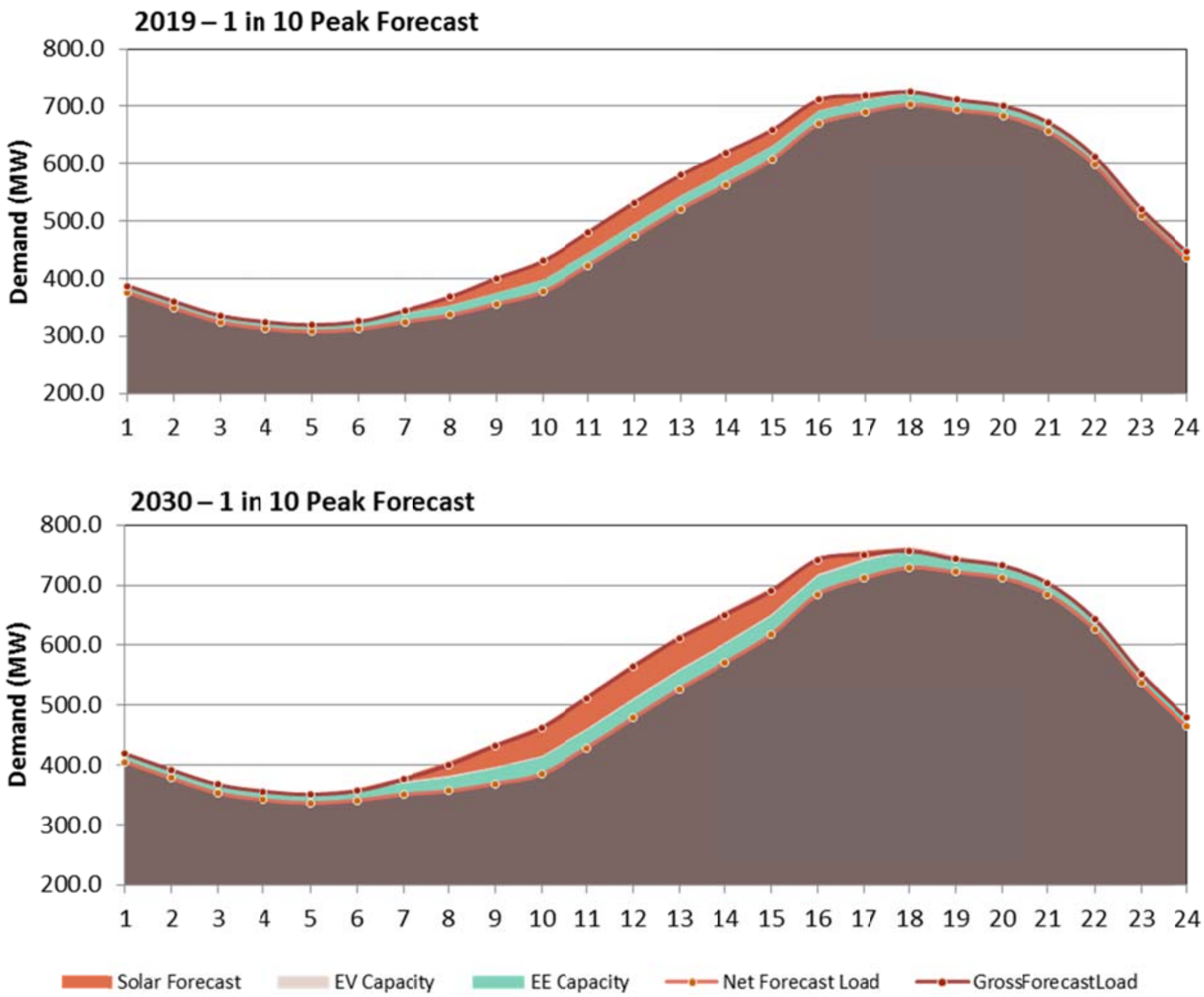
MID currently considers three Distributed Energy Resources (DER's) programs when forecasting net demand; behind-the-meter solar, electric vehicles, and energy efficiency. In addition to these programs, MID manages a demand response program; however this program is considered a supply side resource.

6.3.8.1 DERs Impact to Net Peak

The DER peak shaving contribution coincident to the forecasted net system peak is estimated to be 23.5 MW in 2019 in HE 18. By 2030 DERs are expected to shave an additional 10.4 MW coincidental to the system peak hour for a total of 33.9 MW peak reduction.

The DER peak shaving contribution varies during the day and has different impacts to the net system demand in different hourly intervals. The observed maximum contribution of DERs is expected to occur during HE 12. The DER peak shaving contribution at HE 12 in 2019 is estimated to be 60MW. By 2030, the DER peak shaving contribution is estimated to grow to 91 MW at HE 12. The largest growth in DERs is expected to come from behind-the-meter solar resources, with energy efficiency being the second-largest contributor.

Figure 6-7: DER Impacts



6.3.8.1.1 Electric Vehicle's Impact to Net Peak

MID's Electric Vehicle demand coincident to system peak is expected to be 0.6MW in 2019 at HE 18. This demand is expected to increase to 3.2 MW in 2030 at HE 18.

Table 6-3 shows the forecasted peak coincident demand through 2030.

Table 6-3: Electric Vehicle Peak Coincident Demand

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
EV Peak Coincident Demand (MW)	0.6	0.8	1.0	1.2	1.4	1.7	1.9	2.2	2.4	2.7	2.9	3.2

Energy Efficiency's Impact to Net Peak

Energy Efficiency's (EE) peak shaving contribution coincident to net system peak is estimated to be 21.1 MW in 2019. By 2030, the figure is expected to grow to 28 MW. The maximum demand reduction from energy efficiency is forecast to occur at HE 15, which is before the expected net system peak demand. The EE demand reduction at HE 15 is estimated to be 23.1 MW in 2019 and 31.2 MW in 2030.

Table 6-4 shows the forecasted peak-coincident EE capacity.

Table 6-4: Energy Efficiency Peak Coincident Demand Reduction[2]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
AAEE Peak Coincident Demand Reduction (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE Peak Coincident Demand Reduction (MW)	21.1	22.0	22.9	23.7	24.6	25.4	26.1	26.7	27.2	27.5	27.8	28.0

6.3.8.1.2 Behind-the-Meter Solar 's Impact to Net Peak

Behind-the-meter solar peak shaving contribution coincident to the net system peak for 2019 is estimated at 1.7 MW. By 2030 this figure is expected to grow to 2.6 MW. Behind-the-meter solar has a small impact on MID's net peak demand. The maximum output from behind-the-meter solar occurs during the middle of the day (HE 12), with an estimated maximum output of 37.9 MW in 2019 and 58.3 MW by 2030. As figure 6-7 illustrates, this output declines dramatically by hour-ending 18.

Table 6-5: Behind-the-Meter Solar Peak Coincident Capacity

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Solar Peak Coincident Capacity (MW)	1.7	1.8	1.9	1.9	2.0	2.1	2.2	2.3	2.3	2.4	2.5	2.6

6.3.8.1.3 Demand Response and Interruptible Programs

MID operates a demand response and interruptible program with a total capacity of 28 MW. The demand response (DR) program is a one-way paging system with load controller receivers (LCRs) that temporarily interrupts the operation of enrolled customer's air conditioning units. This program is called Shave the Energy Peak (STEP). The program currently has an estimated enrolled capacity of 30 MW, although STEP is typically dispatched by interrupting one-third of the enrolled devices at a time in order to achieve a continuous demand reduction of 10 MW. The STEP program can be dispatched by MID

[2] No demand reduction estimate for AAEE is included since the nature of those future measures is not yet known.

system operators when needed. Due to its dispatch ability the STEP program is considered a supply resource and is not included in the load forecast.

In addition to the STEP program, MID also has a commercial interruptible program with a capacity of about 18 MW. MID can call on enrolled customers to reduce the demand they've committed to the program when needed. It is also considered a supply side resource.

VII. Portfolio Planning and Evaluation

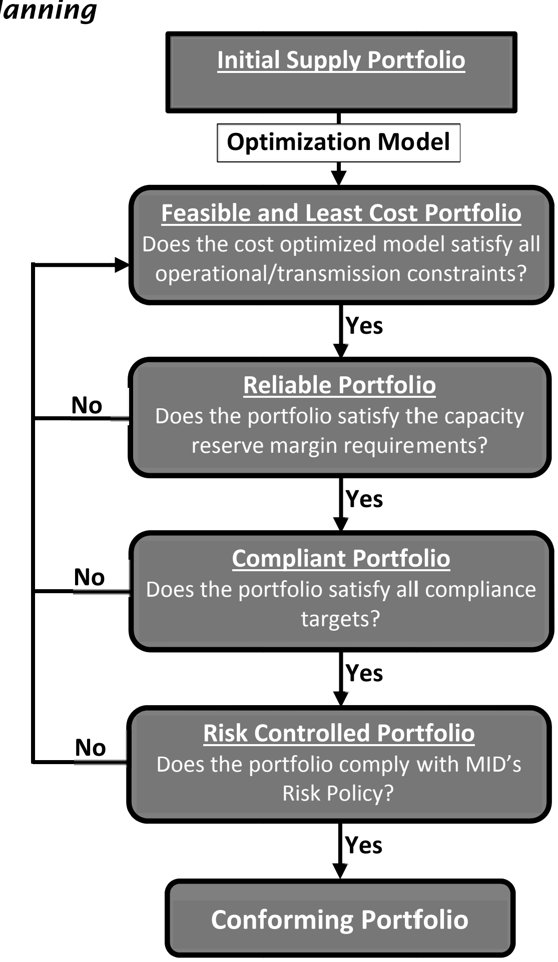
7. Overview of Portfolio Planning and Evaluation

In the IRP process, it is important to build a supply portfolio that satisfies compliance requirements, and operates reliably and economically. This chapter discusses how MID plans a feasible portfolio and examines the economics of the portfolio.

7.1. Portfolio Planning

MID conducts production cost simulations to validate the operational feasibility and performance of different portfolios. Production cost simulation is used to dispatch generation resources at the least cost to meet the demand and ancillary service requirements of the system on an hourly basis, while satisfying all the generator operational constraints, transmission constraints, and other system reliability requirements. The production cost simulation model, which considers detailed generator characteristics, ramping capabilities and balancing load on an hourly basis, is a good tool to assess the operational feasibility of resource portfolios in a power system.

Figure 7-1: Portfolio Planning



7.2. Portfolio Planning Tools

Prosym

MID uses Prosym, a commercial software program with a mixed integer programming optimization engine, to perform production cost simulations and mimic the commitment and dispatch of available generation resources to meet demand and reserve requirements at the least cost, subject to transmission and individual generation resource constraints. MID's Prosym model is a zonal model based on the network configuration of the MID system.

R and RStudio

MID uses R, a programming language and software environment for statistical computing and graphics, to develop the 2018 Long-term Demand and Energy forecast. This is completed with additional assistance from RStudio, an open-source integrated development environment for R.

Table 7-1: Portfolio Planning Tools

Name	Version	Model
PROSYM	Ventex MULTISYM V8.1.00	Production Cost Optimization
R Studio	RStudio Team (2016). RStudio: Integrated Development for R. RStudio, Inc., Boston, MA (1.0.143) R Version 3.4.0 (2017-04-21)	Demand and Peak Forecast

7.3. Input Assumptions

MID's 2019 IRP utilized the planning scenario that conforms greenhouse gas emission reduction targets as well as energy and other policy goals outlined in SB 350.

Table 7-2 below shows a summary of MID's IRP Planning Assumptions.

Table 7-2: Input Assumptions of MID's IRP Analysis

Input	Planning Assumptions
Demand Forecast	MID's 2018 Long Term Demand and Energy Forecast
Planning Reserve	Planning reserve margin is calculated at 15% of the 1-in-10 forecasted peak demand
Natural Gas Prices	Natural gas prices are derived from ICE forward price curves; price increases beyond the price curve range are based on the EIA outlook forecast.
GHG Prices	CEC's Preliminary 2017 IEPR Carbon Price Projections
CO2 Emission Rates	Gas-fired and Import resources based on California Air Resources Board (CARB) 2016 published emission rates.
Power Prices	Power prices are derived from ICE forward price curves; price increases beyond the price curve range are based on the EIA outlook forecast.
Hydro Conditions	Average hydro conditions are assumed; MID's share of generation from the Don Pedro Plant is estimated to be 175 GWh annually.
RPS Portfolio	MID's existing portfolio, plus future resources are expected to achieve 50% RPS by 2030

7.4. Production Cost Model

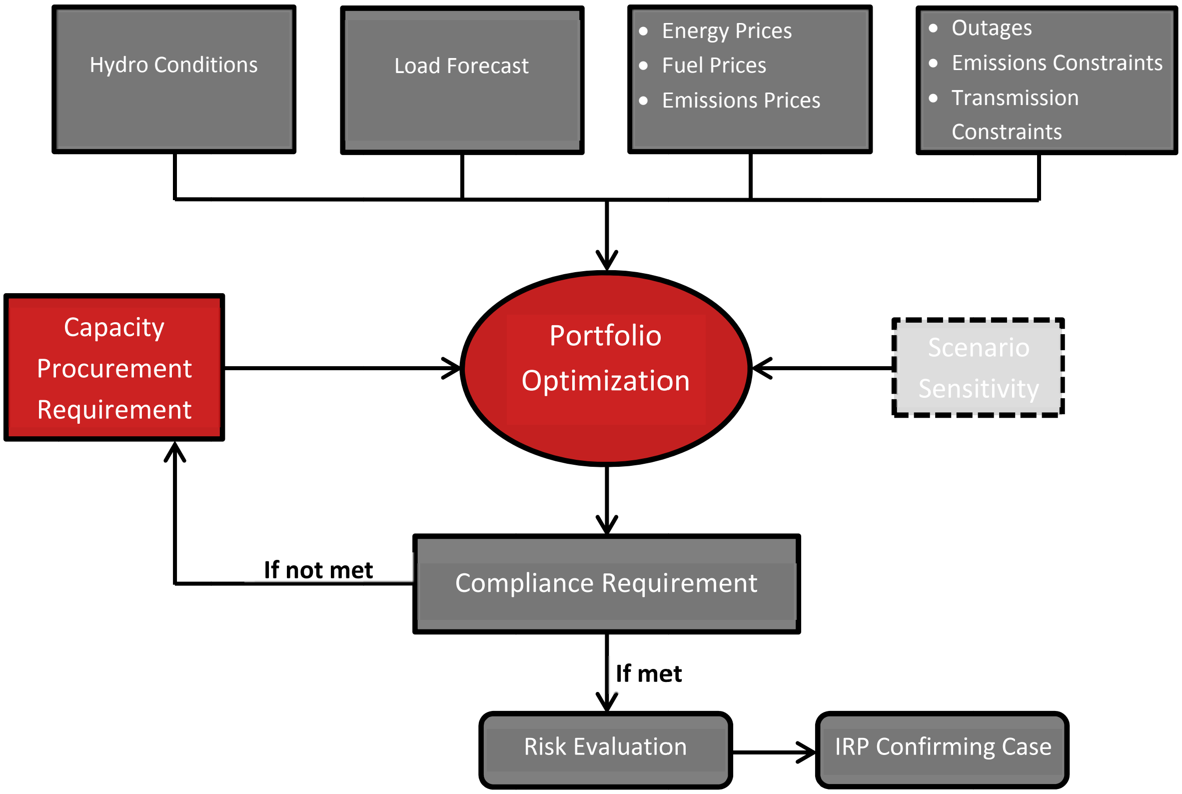
MID established its energy supply planning portfolio based on three major supplies: utility owned generation, renewable portfolio (in state and out of state), and market purchases. MID's production cost model is a simulated planning model that mimics real world "production".

MID builds the production cost model for its utility owned generation portfolio according to the physical characteristics and historical operating patterns of each plant.

The renewable and market portfolio represents procurement from the "market place". Those procurements are either bilateral contracts that have a negotiated pricing scheme or short term purchases either through financial hedges or very short term energy transactions.

The goal of establishing a close to real world portfolio is to simulate the dispatch of all resources under constraints and find the optimal production cost for the portfolio. Below is MID's portfolio optimization process and a flow chart that illustrates MID's process.

Figure 7-2: Production Cost Model Process



7.5. Scenario and Sensitivity Testing

Due to the limitations of the current planning tools, MID's current portfolio optimization process is based on a deterministic simulation model and does not include stochastic scenarios in the simulation process.

MID updated its "Managed Load[1]" forecast model in 2018 and has the capability of providing weather sensitive load and peak demand forecasts to its production cost model. This IRP analysis is based on MID's 2018 Long Term Demand and Energy Forecast (2018 LTDEF) median forecast result.

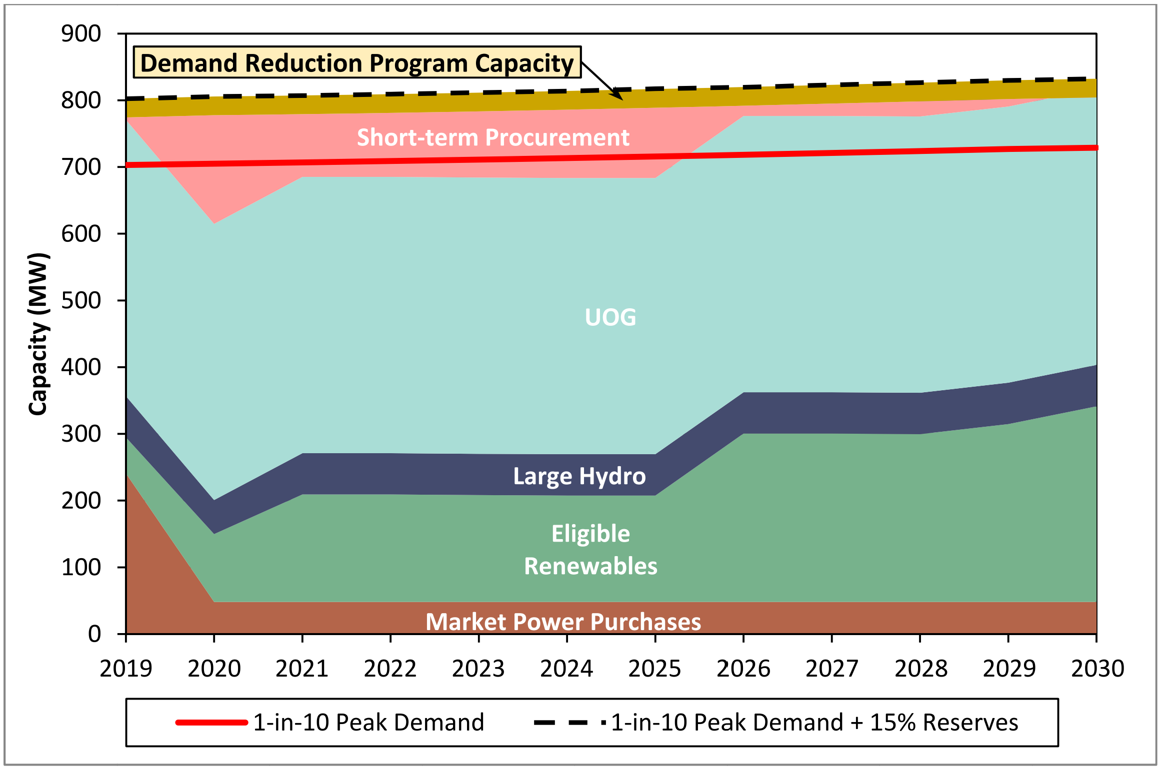
7.6. Capacity Requirement Evaluation

MID's PRM (planning reserve margin) is set at 15% with some adjustment for certain resources, such as hydro resources and firm import energy. The sum of the probability-adjusted 1 in 10 peak demand and the PRM is MID's capacity requirement.

[1] MID has been serving load in the northern expansion area, defined as "a 400 square mile area in Southern San Joaquin County, Northern Stanislaus County, and Western Tuolumne County", often referred as "four-city area" "including Ripon, Escalon, Oakdale and Riverbank", at a competitive basis, since 1996. Additionally, MID has been the sole load serving entity in the city of Mountain House since 2001. MID is also the non-exclusive load serving entity for load migrated to the northern expansion area, referred as "Greenfield load", since 2007. MID's "Managed Load" is the sum of above mentioned serviced load.

By evaluating the initial supply stack derived from the production cost model against the capacity requirement, MID calculates the capacity shortage and adjusts the supply stack until the capacity requirements are met. Once the adjustment process is complete the production cost model is used to check the feasibility of the adjusted supply stack. If the new supply stack passes the feasibility check, the supply stack would meet the feasible, economic and reliable requirements. This is the “Reliable Portfolio” in the evaluation process, and is shown in Figure 7-3. More detailed information is included in the Standardized Tables.

Figure 7-3: Capacity Requirement



7.7. Optimal Portfolio Snapshot

MID’s reliable portfolio meets energy and capacity requirements. It is also a feasible and economic portfolio derived by least cost production cost simulation. MID considers this portfolio an optimal portfolio that satisfies operational constraints, economic constraints and reliability requirements. Figure 7-4 is a snapshot of this optimal portfolio. Detailed supply stack information is listed in the energy balance table. Table 7-3 and Table 7-4 provide an overview of MID’s current supply stack.

Figure 7-4: Energy Requirement & Supply

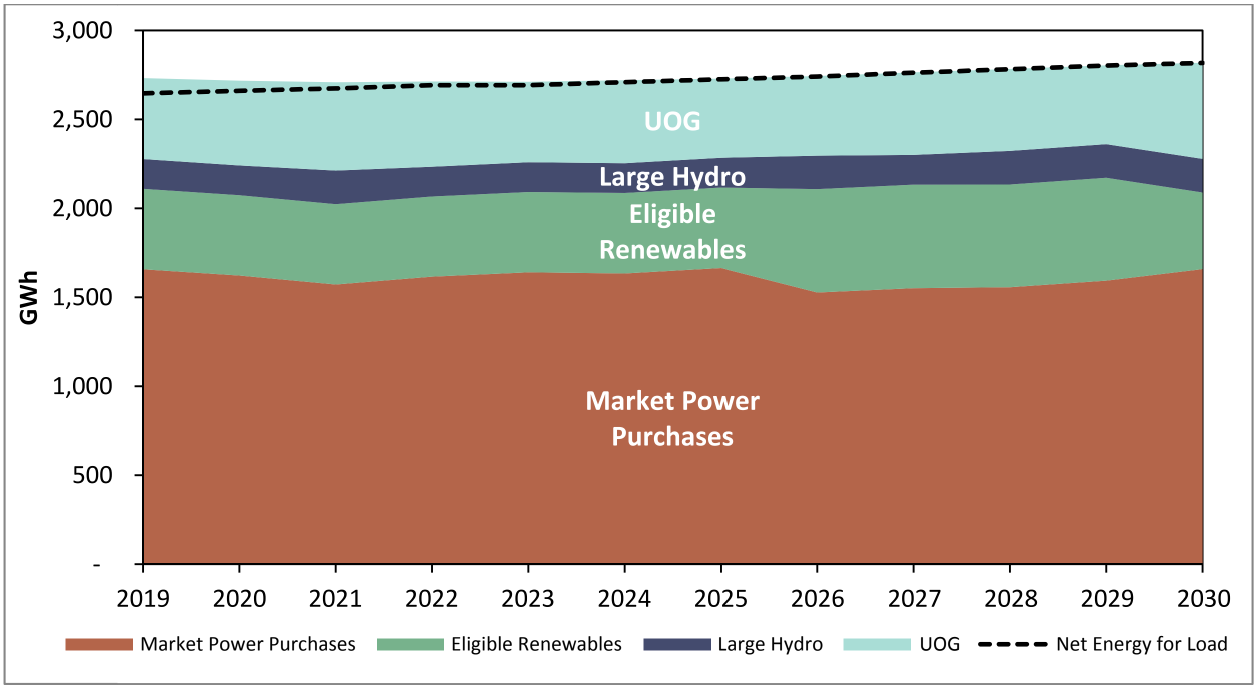


Table 7-3: Utility Owned Generation

Generation Units	Service Start Year	Plant Type	Fuel	Max Capacity-Summer (MW)	Max Capacity-Winter (MW)
Woodland 1	1993	Gas Turbine	Natural Gas	45	45
Woodland 2 (CTG:50 MW) (STC:33 MW)	2003	Combined Cycle Gas Turbine	Natural Gas	83	83
Woodland 3 (6 Units Total)	2011	Reciprocating	Natural Gas	49	49
McClure 1	1980	Gas Turbine	Natural Gas/Diesel	54	54
McClure 2	1981	Gas Turbine	Natural Gas/Diesel	54	54
Ripon 1	2006	Gas Turbine	Natural Gas	50	50
Ripon 2	2006	Gas Turbine	Natural Gas	50	50
Lodi Energy Center	2012	Combined Cycle Gas Turbine	Natural Gas	32	32
Don Pedro	1973	Francis Type	Hydro	53	53
STEP	1984	DR	N/A	10	0
Interruptible	-	DR	N/A	18	0

Table 7-4: Power Purchase Agreements

Contract/Resource	Contract Capacity (MW)	Fuel Type	Start Date	End Date
WAPA	5	Hydro	2005	2024
Big Horn I	25	Wind	10/4/2006	9/30/2031
Big Horn II	33	Wind	11/1/2010	11/31/2035
Star Point	98.7	Wind	6/1/2010	5/31/2030
Fiscallini	0.75	Biomass	4/1/2012	12/31/2027
McHenry Solar	25	Solar	7/1/2012	6/30/2037
Stone Drop	0.26	Hydro	-------	-------
High Winds	50	Wind	6/1/2015	3/30/2028
New Hogan	5	Hydro	5/23/1983	5/23/2033
Mustang2	50	Solar	12/31/2019	12/31/2039
Blythe4	62.5	Solar	12/31/2020	12/31/2040
Future Solar*	150	Solar	2026-2030	-
Future Baseload Renewable*	15	TBD	2029	-
Future Wind*	60	Wind	2028	-
Market Power Purchases	125	Purchase	2019-2021	-
SB859 Biomass*	0.6	Biomass	2019	12/31/2023
Loyalton	1	Biomass	5/1/2018	5/1/2023

*Not yet procured

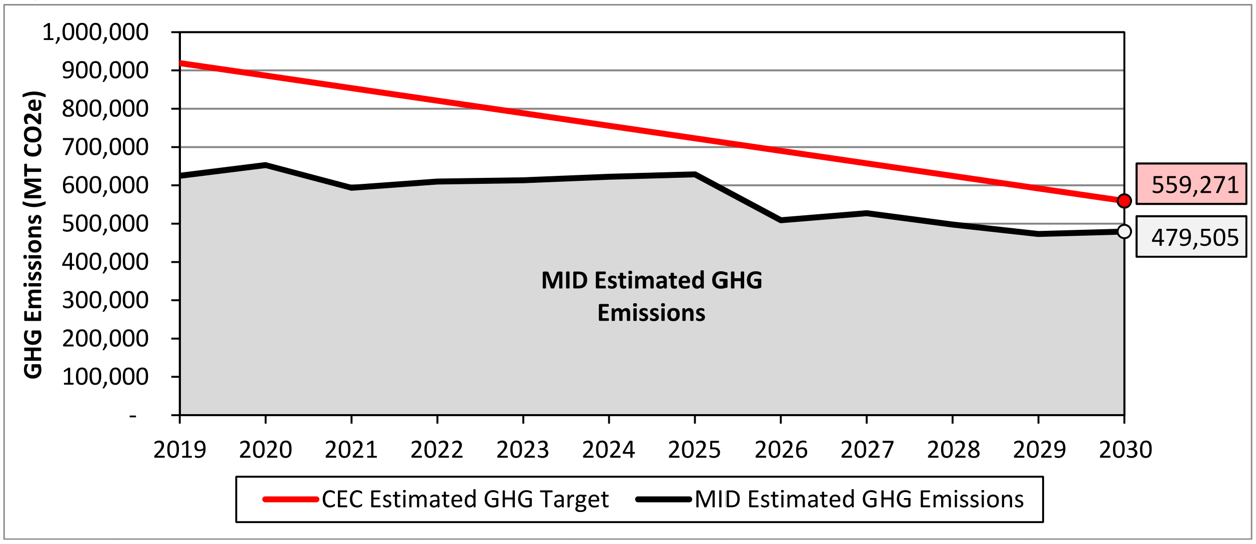
7.8. Compliance Validation

After generating an optimal portfolio, MID conducts a compliance validation process to verify that this portfolio meets all compliance requirements. This step validates the main compliance goals and may involve multiple iterations of portfolio changes until all requirements are met.

7.8.1. GHG Target Compliance

Meeting the GHG reduction target is one of MID's compliance goals. Thanks to the divesture of the San Juan coal plant, MID is in position to meet the GHG reduction target. Below is a graph that shows MID's GHG target compared to the forecasted emissions over the IRP planning horizon.

Figure 7-5: GHG Portfolio Compliance

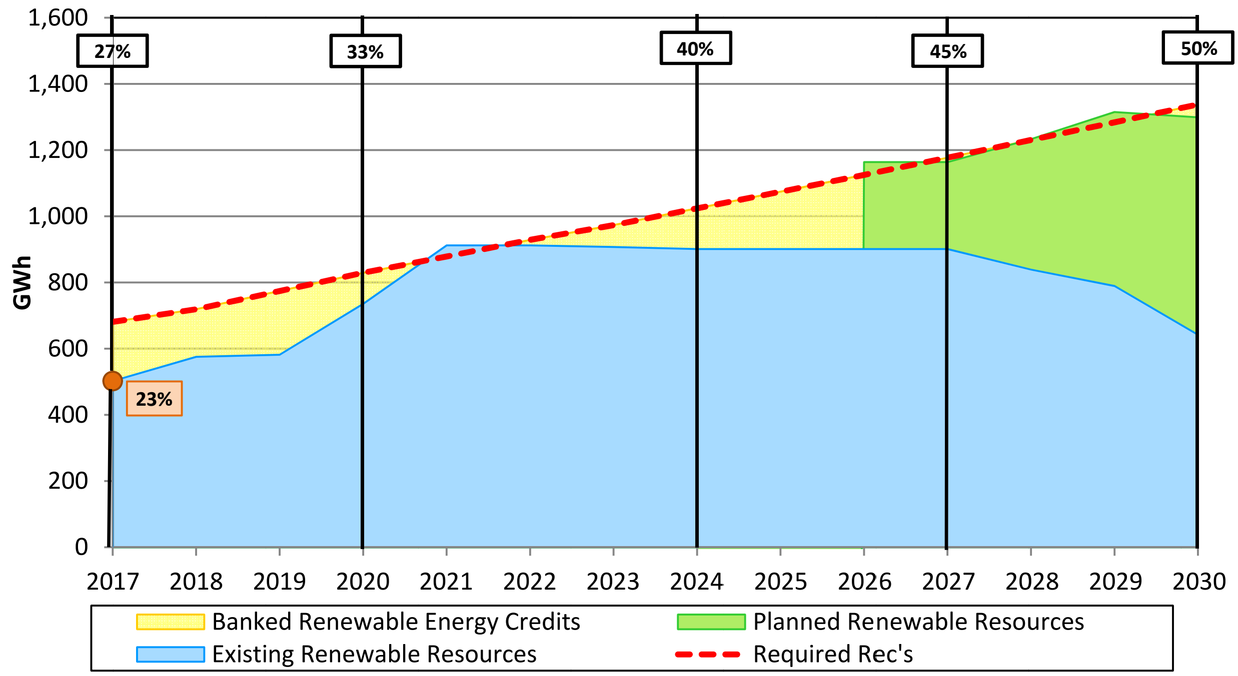


7.8.2. RPS Target Compliance

Meeting RPS compliance goals is also one of MID's IRP goals. As discussed in chapter 5 of this IRP, by banking excess RECs from existing renewable energy projects, MID can meet the RPS targets through most of 2025 using the SB350 trajectory without adding new resources. MID includes generic renewable resources in its planning process in order to account for the future procurement of eligible projects. These generic resources are replaced with specified projects as they are procured.

Figure 7-6 show an illustrative depiction of MID's current RPS compliance trajectory.

Figure 7-6: RPS Trajectory



7.9. Risk Checking

To minimize exposure to market volatility, MID established a risk policy for energy procurement. MID's Risk Management Policy implements a Value-at-Risk (VaR) limit and position limits. The VaR is a financial limit expressed in dollar amount and the position limits are energy position limits expressed in hedged percentage or "covered" volume. This risk policy outlines the position limits that apply to energy and gas procurement. This step includes checking planned procurement results against the risk management policy, which is included in the appendix of this IRP.

7.10. 2019 Conforming Case

A final conforming portfolio is generated after validating its feasibility, economics, reliability, compliance and risk. This conforming plan is the basis for this IRP. All current projections show compliance with state goals.

VIII. Electric T&D System

8. Overview of T&D Facts

MID provides local electrical service to an area of approximately 568 square miles in portions of San Joaquin, Stanislaus and Tuolumne counties. MID is the exclusive provider of electric services within its traditional service area of approximately 160 square miles and within the Mountain House Community Service District in San Joaquin County, which covers approximately 8 square miles. MID may also provide service to customers in a 400-square mile joint electric distribution service area, where MID may compete with PG&E.

Every year, MID performs an evaluation and study of the electric transmission system, to assess its compliance with NERC/WECC Standards and to evaluate its general reliability and operational flexibility.

8.1. Transmission and Distribution System

This section provides an overview of MID's transmission and distribution assets. Each year MID updates its five year plan. The five year plan provides a system assessment for the next five calendar years with the focus being primarily on system peak values. The five year plan includes analysis for both the transmission system (69 kV – 230 kV) and distribution system (6.9 kV – 21 kV).

8.1.1. Bulk Transmission System

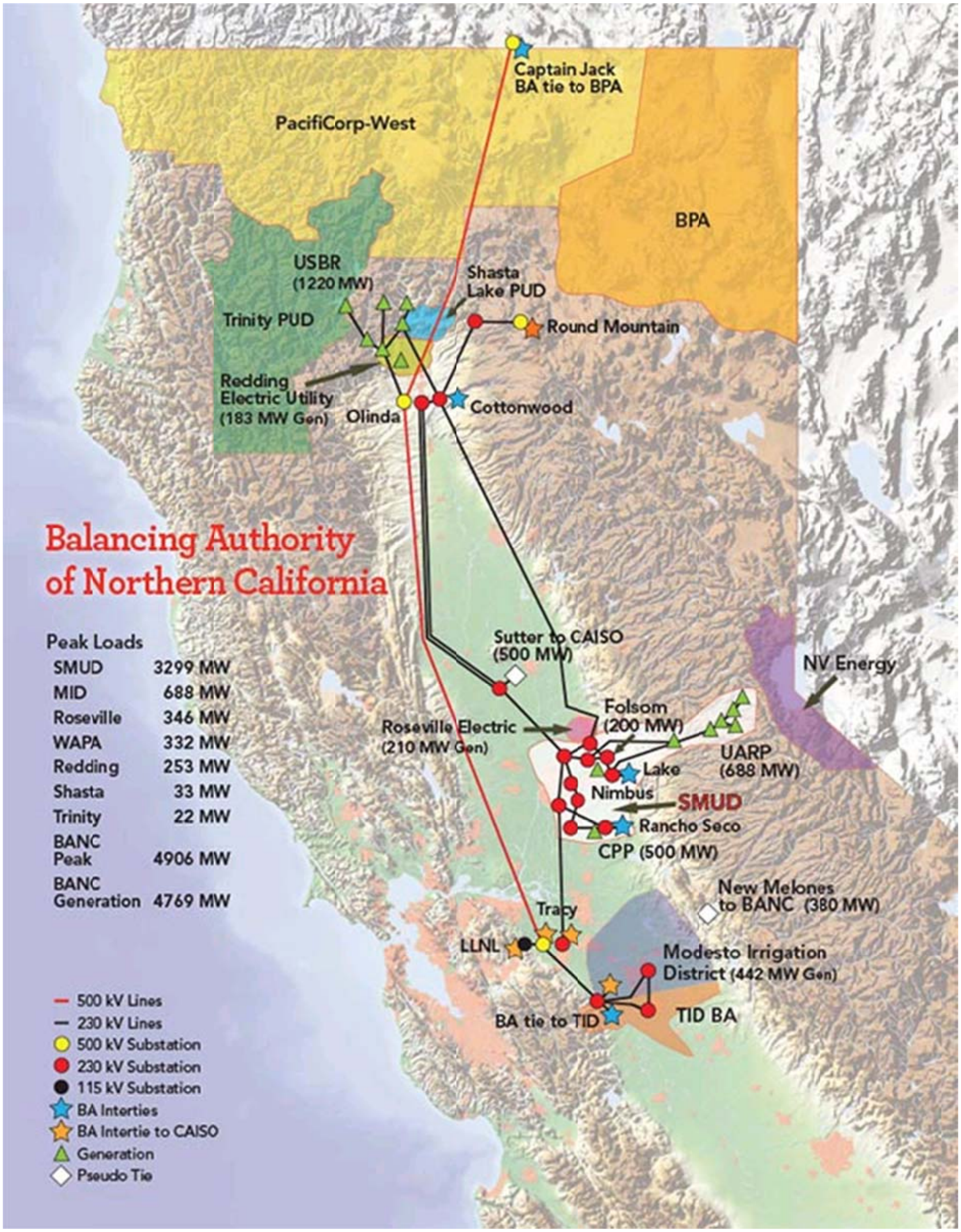
MID, together with other northern California cities and utilities, is a member of a California joint powers agency known as the Transmission Agency of Northern California ("TANC"). TANC, together with The City of Redding, Western Area Power Administration ("WAPA"), two water districts and PG&E own the California-Oregon Transmission Project ("COTP"), a 339-mile long, 1600MW, 500 kV transmission project between southern Oregon and central California. The southern physical terminus of the COTP is near PG&E's Tesla Substation. The COTP is connected to Western's Tracy and Olinda Substations.

PG&E provides TANC and certain of its members with 300MW of firm, bi-directional transmission service on its transmission system from its Midway Substation near Buttonwillow, California (the "Tesla-Midway Service") to those members under a long-term agreement known as the South of Tesla Principles. MID's share of Tesla-Midway Service is 102MW. Table 8-1 lists MID's transmission rights on those bulk transmission systems. MID expects little change to those transmission rights in the next 5 to 10 years. Figure 8-1 depicts how MID is connected to the bulk transmission system.

Table 8-1: Transmission Rights on Bulk System

MID Tramsmission Rights	Paths	Direction	Capacity (MW)	Firmness	Notes
COTP	Captain Jack to Tracy	Southbound	320	Firm	MID COTP rights will step down to 311 MW by end of 2024, and 286 MW by end of 2039
SOT	Westley to Midway	Southbound	102	Firm	
COTP	Tracy to Captain Jack	Northbound	314	Firm	MID COTP rights will step down to 305 MW by end of 2024, and 280 MW by end of 2039
SOT	Midway to Westley	Northbound	102	Firm	

Figure 8-1: Balancing Authority of Northern California



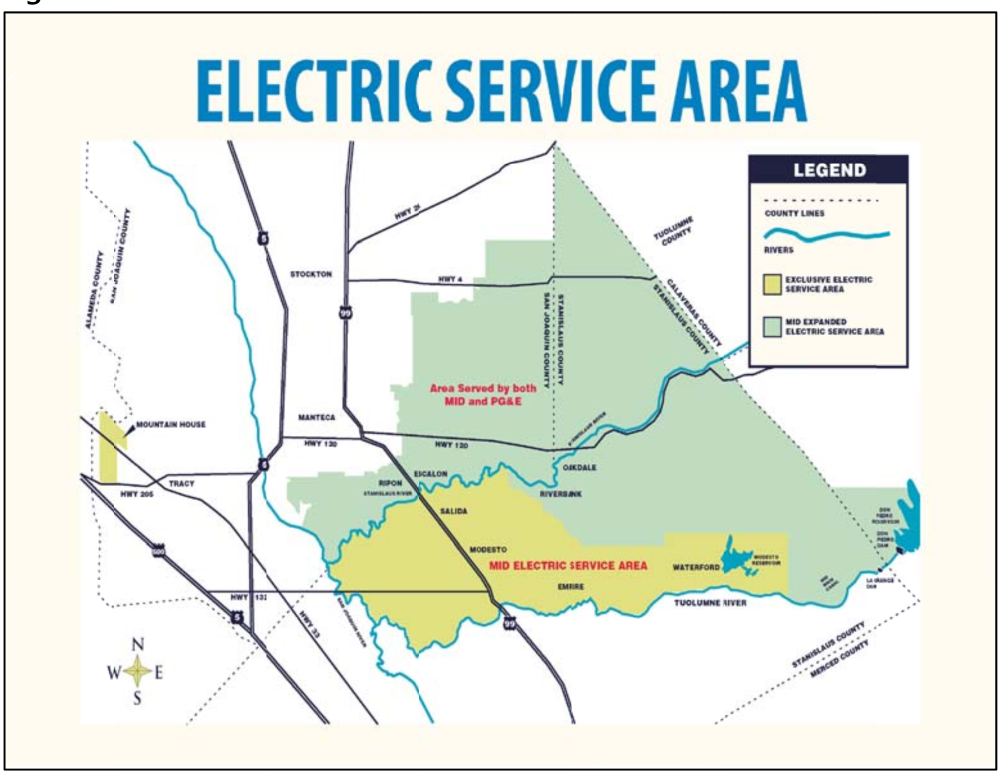
MID's Bulk Electric System (BES) transmission facilities are listed below:

1. Westley Transmission Station – 230 kV Transmission Station jointly owned with TID
2. Rosemore – 230 kV Transmission Substation
3. Parker – 230 kV Transmission Substation
4. Standiford – 115 kV Transmission Substation
5. Santa Cruz – 115 kV Transmission Substation
6. Claus – 115 kV Transmission Substation

8.1.2. Distribution System

MID's distribution system consists of over 1,000 miles of distribution lines and 35 distribution substations over a 160 square mile territory. The traditional 12 kV distribution system currently includes all of Modesto and surrounding communities (Empire, Waterford, and Salida). In addition, MID also serves portions of the cities of Riverbank at 12 kV and Ripon, Escalon, and Oakdale at 17 kV. Further, MID also serves the community of Mountain House at 21 kV. The MID traditional distribution service territory is divided into six (6) planning areas with two (2) additional areas for the Four Cities and Mountain House. The planning areas are defined by electric boundaries, which limit load transfers. The substations within each designated area are adjacent to each other. This means that each substation has the ability to back-up the others defined in the area.

Figure 8-2: MID Electric Service Area



8.2. Transmission Assessment 2019

MID's most recent transmission assessment demonstrates that MID's transmission system is fully compliant with the NERC/WECC Standards.

The assessment identifies three areas of the system where improvements should be made, as follows (listed in order of priority):

- 230 and 115 kV Relay Protection Coordination Study
- Lapham Claus 69 kV Line Rating Upgrade
- Replace Three 230 kV Circuit Breakers at the Westley Station
- Develop 30 Minute Emergency Ratings for 115 kV Import Lines 7 & 8

MID performs a general evaluation of its transmission system to determine that it will be able to meet the forecasted customer loads in a fully reliable and operationally flexible manner. Although these studies demonstrated the capability of the MID transmission system to meet customer needs and NERC/WECC requirements, the studies also identified some areas where improvements in transmission reliability and operational flexibility could be made, as follows (listed in order of priority):

Table 8-2: MID Proposed Transmission Improvements

		Year
Recommended (A1) and In-Progress (A2) Projects:		
A1	Install 2 PMUs (Phasor Measurement Units) at Parker and Standiford)	2019
A2	*Move Standiford 12 kV Capacitors to the 69 kV Bus (planned, but on hold, and project may be cancelled pending outcome of summer of 2018 evaluation)*	*2018/2019*
A3	Upgrade Standiford-Sylvan and 12th Street-Santa Rosa 69 kV Lines per 2017 LiDAR Study	2018
A4	Lapham-Claus 69 kV Line Upgrade (CT Ratio, EMS/SCADA Scaling)	2018
Potential Projects for Consideration (B):		
B1	Lapham-Claus 69 kV Line Upgrade	2020
B2	Ladd-Kiernan and Kiernan-Standiford 69 kV Line Upgrades	2020
B3	Alternative to Reconductoring: Use of Special Protection Systems	2020
B4	8th Street, Rosemore, and Woodland Station Upgrades	2021
B5	Enslen-Lincoln 69 kV Line Upgrade	2021
B6	Standiford-Sylvan and Enslen-Lincoln 69 kV Line Upgrades	2022
B7	Enslen-Woodland 69 kV Lines Upgrade	Future
Potential Projects Contingent on Negotiations (C):		
C1	Upgrade the Rosemore-8th Street 69 kV Line (with Addition of Oregon Station)	Future
C2	Second Source for the Oakdale (Hershey) Area Load	Future
C3	Automate Switching of the Existing Backup 115 kV Feeder to the Oakdale Area	Future
C4	Redundant Protection System for the Standiford-Warnerville 115 kV Intertie Lines	Future

MID's transmission system meets all the NERC standards for all normal contingencies. However, the most stressed points in the MID transmission system are the Standiford 115/69 kV intertie transformers under certain N-1-1 contingencies. For example, slight overloads occur on these transformers for the simultaneous N-1-1 loss of a Rosemore 230/69 kV transformer and a HHWP (Hetch Hetchy Water & Power) 230/115 kV intertie transformer at Warnerville station, without system adjustments (e.g. , increasing system generation levels).

MID also sees limits imposed on imports during certain BES (Bulk Electric System) N-2 contingencies due to transmission line rating limits on the MID 69 kV transmission system with all MID elements in service. In addition, MID has high loading levels on some 69 kV lines near the Ripon and Woodland generation plants during high generation output, when certain N-1 contingencies occur.

MID also has some limitations on import flows from HHWP due to line ratings on the HHWP 115 kV intertie lines that run from the MID Standiford station to the HHWP Warnerville station, and some potential outage cascading for a delayed clearing fault on those same lines due to the existence of some non-redundant protection system elements.

However, the MID system has very large reactive margins, which helps to maintain critically damped system dynamic stability during all N-2 faults, and for most extreme faulted conditions. This is also evidenced by the study work done in support of compliance with the NERC CIP-014 standard, which demonstrated that the MID system could sustain a catastrophic 3 phase, 20 cycle fault on the MID/TID 230 kV BES Westley station, with delayed clearing from the remote ends of all the connected BES lines, without causing instability, uncontrolled separation, or cascading within the interconnection.

8.3. Distribution Assessment 2019

MID's distribution planning follows a similar, proactive approach. Multiple capital projects are scheduled every year. These projects include constructing new substations, reconductoring underground feeder getaways, and protective relay replacements. A short list of some of the major capital projects scheduled from 2018-2023 are:

- Oregon Substation (aka Santa Cruz 2) (2018/2019/2020)
- Rebuild Reinway Substation (2020/2021)
- Claribel 2nd Transformer (2021)
- Substation Transformer Replacements (2021)
- Langworth Substation (2022)
- Salida Substation (2022)
- Beard Substation (2023)

MID distribution network reliability indices show that MID's distribution network has not experienced material stress caused by DERs. MID gathers data on all outages, and uses this data to calculate reliability indices (statistics). The current statistics show that the top 5 outage causes are not directly correlated to DERs. The analysis of SAIDI[1] shows a reduction in the average duration of outages that result in service interruptions.

8.4. Grid Impact of Load Growth and Renewable Resources

Among the 8 MID distribution areas, two areas are expected to experience the largest load growth for the next five years. Expected commercial and industrial load additions in one of these areas and expected residential load additions in the other contribute most to the projected load growth.

While MID's distribution system has not experienced material adverse impacts from DERs, MID continues to monitor its system for impacts and necessary upgrades.

[1] SAIDI is the system average interruption duration index. This is the amount of time the average customer was out of power in a year. This is calculated by taking all of the customer outage minutes and dividing by the total number of customers

IX. Disadvantaged Communities

9. Overview of MID Facts

Approximately 35%[1] of MID electric service area residents live within disadvantaged communities.

9.1. Barriers to Investment in Energy Efficiency

Studies have shown that the typical low-income household in the United States spends upward of 15 to 20 percent of their total monthly income on energy costs. This expense often competes with other necessities such as groceries, utilities, education, and health care.

Cash flow concerns and a lack of available credit are major barriers that limit the ability of low-income customers to invest in energy efficiency. Most energy efficiency retrofits require available cash or credit upfront. Low-income households that own their home find it challenging to come up with the short-term cash investment even though there is likely a long-term return. Low-income households that rent have limited incentive to make improvements to dwellings that are not their own. Also, low-income households tend to have less available credit for purchases, including those that reduce their utility bills.

Most low-income households are renters. Whether it be a multifamily or single family dwelling, most energy efficiency improvements depend on the willingness of the landlord to make the investments. In the MID service territory, the affordable home inventory is very low and even most affordable multifamily residences have a long waiting list. The minimal supply of affordable housing and high customer demand does not provide any incentives for the landlord to make energy efficiency improvements.

9.2. Barriers to Investment in Transportation Electrification

According to the California Clean Vehicle Rebate Project website, there were 887 approved EV rebates within the MID service territory as of Sep 12th, 2018; less than 0.1 percent of the state total. MID expects its service territory will experience low transportation electrification penetration for the next 5 years.

One of the main reasons for low EV penetration is that the Modesto area experiences a high poverty rate. Approximately 18% of the population in Modesto, CA live below the poverty line, which is higher than the national average of 14%[2]. Another factor is the higher percentage of renters living in the Modesto area. Low-income single-family households are relatively evenly divided between renters and owners, while the majority of multifamily households are renters. Only about a third of low-income homes are owned compared to more than half of all homes. The higher percentage of low-income

[1] The number of residents in disadvantaged communities within MID's service territory was calculated by summing the number of residents living within the disadvantage areas defined by CalEPA methodology(as listed in https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-version-20) and then divided by total residents in the census tracts serviced by the District.

[2] *https://datausa.io/profile/geo/modesto-ca/*

population and the higher percentage of renters both lead to lower investment in electric vehicles and charging facilities. Low income families are more likely to be constrained by their income to afford an electric vehicle; and few renters have the lease rights to approve the installation of charging stations or updating the infrastructure of the home.

Housing ownership rates appear to have a strong correlation with EV charging facility investment. According to Electric Vehicle Charging Station Locations website[3], current charging station locations are close to areas where single family homes make up a higher percentage of all dwellings.

9.3. Energy Efficiency in Disadvantaged Communities

9.3.1. CARES Program

MID offers a discounted rate for qualifying low income customers. The MID CARES (Community Alternative Rate for Electric Service) program reduces the fixed monthly charge from $20.00 to $8.00 and applies a 23% discount on the first 850kWh used each month for a period of up to three years, or as long as the household qualifies.

In 2017 9,728 accounts were enrolled in this program (monthly average) and received rate discounts of approximately $3,377,100 resulting in an average monthly discount of about $28.90 per account. This program comprises a substantial portion of MID's annual public benefits funding allocation.

9.3.2. Weatherization Program

MID's Weatherization Program provides energy efficient measures to rental or owner occupied low-income customer homes. The work may include replacement of broken windows, refrigerator, microwave, swamp coolers and the installation of insulation, sunscreens, weather stripping; and some repairs. Customer eligibility is determined by the same income qualifications as the MID CARES Program and customer demand of the program exceeds the annual amount budgeted. Energy savings from this program are included in the results for the annual SB1037 report to the CEC.

In 2017 MID retained two contractors to perform the actual work. A total of 480 dwelling units were treated at an overall expenditure of $294,680 resulting in an average cost of $614 per dwelling unit. Figure 9-1 shows a "heat map" of the locational distribution of the dwellings served.

MID observes that the locations of the Weatherization Program service points show significant overlap with the location of local disadvantaged communities. A visual comparison of the weatherization projects map (Figure 9-1), and the local disadvantaged communities map (Figure 9-2) confirms this overlap.

[3] https://www.afdc.energy.gov/fuels/electricity_locations.html#/find/nearest?fuel=ELEC&location=Modesto

Figure 9-1: MID Service Area Weatherization Projects

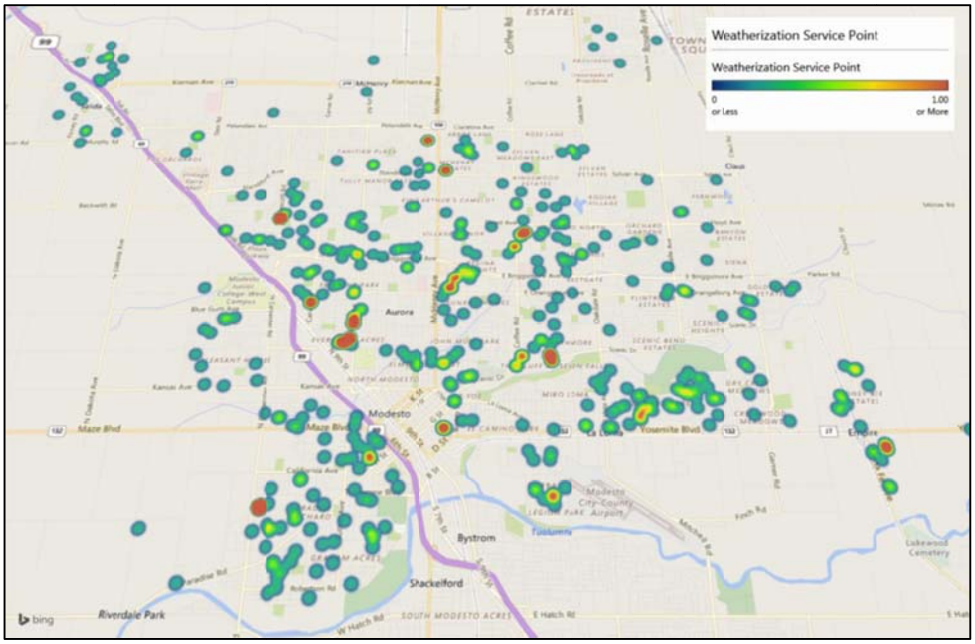
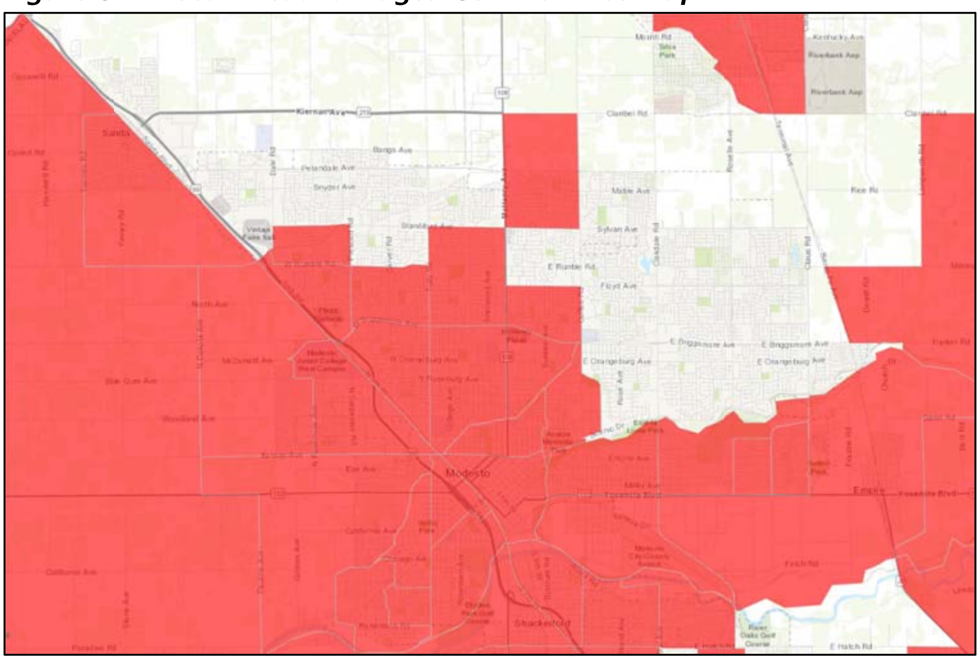


Figure 9-2: Local Disadvantaged Communities Map[4]



9.4. Electric Vehicles in Disadvantaged Communities

MID is in the process of drafting an EV service guide. At this time, MID does not have programs in place to provide incentives to electric customers who purchase an electric vehicle. MID is considering rate

[4] https://oehha.ca.gov/calenviroscreen/sb535

options for qualified electric vehicles, such as time differentiated rates; and is also considering developing incentives, such as rebates for charging equipment and its installation.

As discussed previously, approximately 35% of MID electric service area residents live in disadvantaged areas. Any incentives for EV adoption are expected to provide a benefit for the entire MID service area, including disadvantage communities.

X. Rate Impact Analysis

10. Major Risk Components

As a publicly owned utility, Modesto Irrigation District strives to provide its customers with just and reasonable rates, while achieving its compliance obligations for increased renewables and lower GHG emissions.

Properly managing energy supply costs is key to MID maintaining consistent low retail rates. This section covers MID's major risk components that could affect customer retail rates in the future. The three components that MID identifies are: energy supply costs, capital expenditures and market volatility.

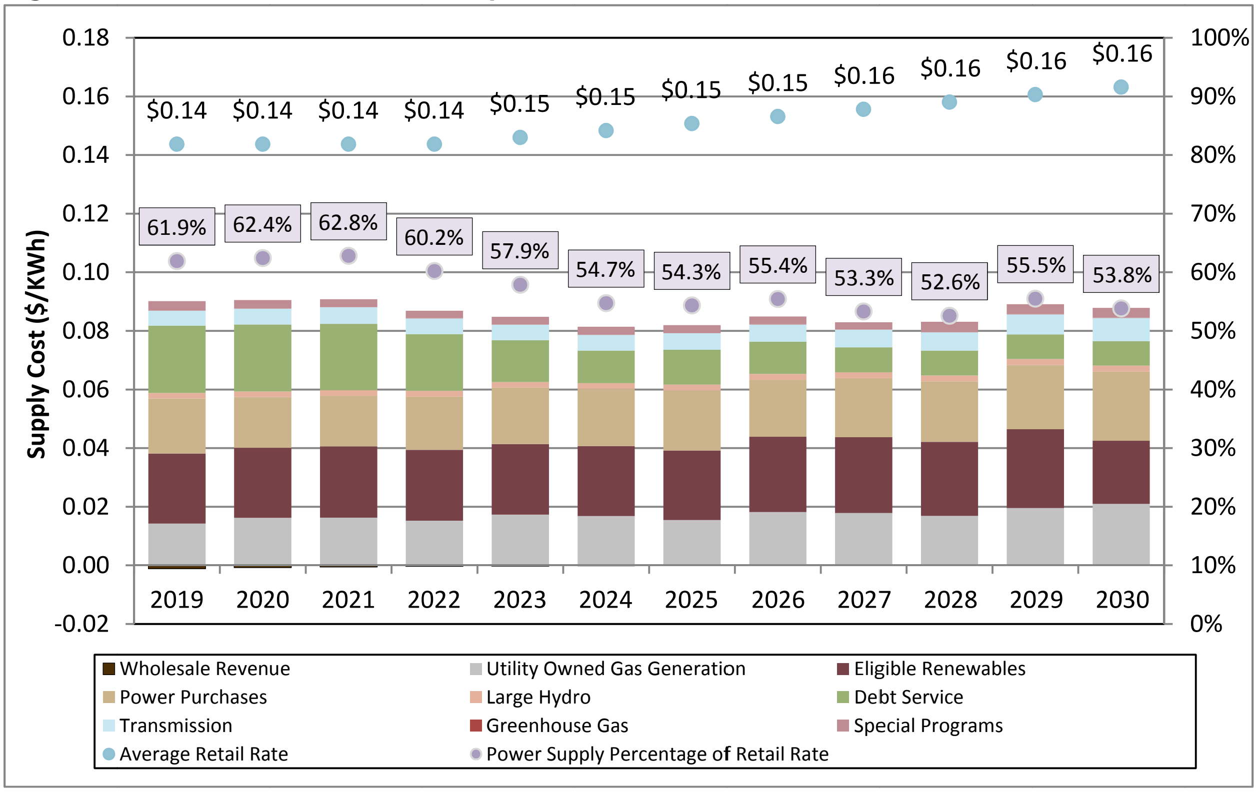
10.1. Energy Supply Costs

Cost related to energy supply make up approximately 50 to 60 percent of MID's electricity retail rates. MID has identified 7 cost components that have the largest impact on energy supply costs:

- Eligible Renewables Procurement
- Debt service
- Power Purchases
- Utility Owned Gas Generation
- Transmission
- Greenhouse Gas
- Special Programs

Under the current policy and portfolio assumptions, MID expects little to no change to overall power supply costs from 2019 to 2030. The estimated energy supply cost for 2019 is $85.34/MWh. By 2030, the supply costs are expected to be nearly identical at $84.66/MWh. However, energy supply costs are subject to volatility and could increase due to the uncertainty of statewide renewable requirements, GHG costs, or changes in market conditions; this IRP presents a snapshot of current projections.

Figure 10-1: MID Estimated Rate Impacts Breakdown



10.1.1. Eligible Renewable Resources

Eligible Renewable Resources are MID's largest supply expense in 2019 with an estimated cost of $61 million. This makes up roughly 17% of MID's retail rates. The current eligible renewables costs do not include potential resources that have not yet been studied in detail. For example, energy storage and additional resources or tools to respond to generation variability are not considered. Eligible renewable resources costs are estimated to be $57 million in 2030 and to make up 13% of retail rates. The decrease is caused by lower cost resources compared to prior procurement.

10.1.2. Power Supply Debt Service

Debt service expenses are the second largest supply-related expense in 2019, at $58 million, accounting for 16% of MID's retail rates. MID has made significant progress in both reducing its electric debt and shortening its debt maturity. As a result of this effort, supply-related debt is expected to decrease to an estimated $23 million, by 2030, reducing its contribution to retail rates to 5%. However, this projection does not account for new financing that may be needed for future resources.

10.1.3. Power Purchases

Costs for power purchases are costs to procure non-renewable power from other parties. It is the third largest supply expense at $48 million in 2019 and makes up 13% of retail rates. Power Purchase costs are expected to be $64 million by 2030, making up 14% of retail rates. The increase in power purchase costs from 2019 – 2030 is mostly attributed to increasing energy market prices, as well as an increase in the volume of energy purchased. The current energy price is relativity low and does not put a lot of upward pressure on this category; however, this cost has significant exposure to market risk.

10.1.4. Utility Owned Gas Generation

MID owns eight gas burning generation plants. They are projected to stay in service throughout the IRP planning horizon. The utility owned generation (UOG) expenses are costs associated with fuel, and operating and maintenance costs. The UOG costs are estimated to be $36 million in 2019, making up 10% of retail rates. Due to increased natural gas transportation rates on the PG&E system, MID expects UOG costs to increase by an average 3.6% annually from 2019 - 2030. As a result, UOG expenses are expect to be $57 million in 2030, making up 13% of retail rates.

10.1.5. Energy Supply Related Transmission Expense

Energy supply related transmission expenses in 2019 make up 4% of retail rates at a total expected cost of $13 million. This category cost is expected to be $22 million in 2030, making up 5% of retail rates. Increased transmission expenses are driven by increasing costs associated with CAISO's Transmission Access Charge.

10.1.6. Greenhouse Gas

Greenhouse gas emission compliance is one of MID's compliance goals. Thanks to MID's divesture of the San Juan coal plant, existing GHG allowances are expected to cover most of MID's GHG compliance obligation throughout the IRP planning horizon. However, this assumption is based on current regulations and allocation schedule and could change if the regulations are revised.

10.1.7. Special Programs

Special programs are programs MID has sponsored to promote renewable energy, energy efficiency or demand response. The programs are mainly customer programs, such as the SB1 solar rebate program, lighting rebate programs, and demand response programs. Those programs are expected to cost $8 million in 2019. Costs associated with existing committed special programs are expected to increase gradually throughout the IRP Planning horizon. In 2030 the total cost of these programs is expect to be 9 million.

10.2. Capital Expenditure Impact to Rate

Electric utilities rank among the most capital intensive of businesses. Thus, cost of capital and access to capital are central concerns of the District as it seeks to maintain affordable rates, while de-carbonizing its generation portfolio and building infrastructure to enable the electrification of economic sectors currently dependent on fossil fuels.

In response to regulatory initiatives and advances in technology, MID has been financially de-levering its electric enterprise. Traditionally, utilities recover costs of supply and costs of capital through retail sales revenues. Developments such as energy efficiency, customer-sited generation, and distributed storage make cost recovery less certain. This creates downward pressure on borrowing capacity and upward pressure on borrowing cost. Besides energy supply costs, the cost of capital will likely be an impactful component to future retail rates.

10.2.1. Past Initiatives

MID has made significant progress in both reducing its electric debt and shortening its debt maturity. Over the five-year period from 2012-17, MID's electric debt dropped from $892 million to $653 million. At the end of 2018, the figure will be less than $600 million. During this 5-year period, MID has held 2040 as the most distant debt maturity. This has reduced the weighted-average duration of MID's debt with the passage of time. Going forward, MID plans to use 20-year bonds (as opposed to traditional 30-year debt) to finance its electric infrastructure. The 20-year bonds will mitigate the risk of stranded debt, although it will mean higher near-term debt servicing costs.

Low natural gas and electric energy prices prevailing during the 2012-17 period allowed MID to reduce debt without raising electric rates. MID has maintained a moderate short position vis-à-vis natural gas and electric energy. In order to maintain this market position at an acceptable level of risk to the enterprise, MID must carry a relatively large cash reserve (on the order of 200 days' worth of operating costs). If MID's cash position were to fall, its bond rating would likely be downgraded, which would increase the cost and decrease the availability of capital. This constrains MID's ability to do pay-go financing: the District has cash reserves, but would face repercussions if it tapped them.

Affordable rates are an imperative for MID given the demographics of its service territory. At the beginning of the 2012-17 period, MID electric rates were above the median for Northern California POUs. That gap has closed considerably as MID has held rates constant over the period. If energy market prices were to increase, MID could choose to cushion the blow with cash reserves, but this would again involve potential repercussions to its credit profile.

10.2.2. Future Expectations

Going forward, MID must balance between affordable rates and the prospect of long-term rising capital spending requirements. MID must also continue to control operating and maintenance expenses and manage its energy market risks. MID projects that near-term capital spending will average 80-100% of its depreciation expense, which is roughly $40 million per year. While the U.S. median capital spend for public power utilities is about 120% of depreciation, MID believes, for reasons explained below, that at the 80-100% level it can maintain its high standard of reliability, grow the distribution system in parallel with the economic growth of its service territory, and ensure the development of electric vehicle charging infrastructure in the area and continued penetration of customer-sited solar. EV infrastructure in particular is becoming a focus area. MID is in discussions with a number of its customers for pilot EV projects, including some large-scale trucking applications.

Reduced spending on generation assets is what's making it possible to hold capital spending below depreciation. California POUs currently spend less on capital than average U.S. public power utilities due to the way that renewable power is incented. As a tax-exempt, customer-owned entity, MID can't capture the available tax incentive credits, so MID plans to continue using PPAs to meet RPS requirements. While this reduces capital spending in the near-term, as the renewable energy percentage grows, electrical capacity – probably in the form of battery storage – will become more important for reliability.

MID maintains a 5-year capital improvement plan. Large-scale battery storage does not currently fall within the 5-year window, but financial plans are being made for investments in the 5-10 year horizon. Also expected in this time frame are large costs associated with relicensing the Don Pedro hydroelectric project, which MID owns together with Turlock Irrigation District. Another reason MID is reducing debt (in addition to de-levering/de-risking) is to create borrowing capacity to fund these costs, which are unknown at this time but expected to be significant.

MID is cautiously optimistic that that it can maintain electrical rates with little or no increases over the first five years forward. However, we expect upward pressure in the 5-10 year period, which could be significant for MID because its hydro relicensing costs appear to coincide with the next wave of electric capacity investments statewide. Risks to the near-term outlook include: higher than expected energy commodity costs, faster than expected labor cost escalation, the potential for major customers to defect to states with lower energy costs, and regulatory uncertainties.

10.2.3. Market Volatility

Energy markets are very active and volatile markets. Energy prices vary by location, and the supply of the energy is constrained by multiple factors including transmission capabilities.

A strong argument can be made that the direction of alternative energy sources (e.g. nuclear, renewables, storage, energy efficiency, and demand response) will have significant impact on regional gas and electricity prices.

To safeguard customers' exposure to market volatility, the MID's Board of Directors maintains a Risk Management Program most recently revised on May 24, 2016, which provides controls for the operational, price and credit risks of MID's power trading and natural gas acquisition operations. The policy document addresses roles and responsibilities, authorized and prohibited transactions, exposure limits, transaction and market data collection procedures, and reporting requirements. Day-to-day risk management activities are carried out by a Risk Management Oversight Committee and a Pricing/Risk Management Administrator. MID uses a number of methods to mitigate market risk and credit risk using short-term and long-term contracts in addition to local generation which provides a long-term hedge against market volatility.

A-A. Acronyms

AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
AB 2021	2006 California Assembly Bill 2021 (set energy efficiency targets)
AB 32	2006 California Assembly Bill 32 (set greenhouse gas reduction targets)
BA	Balancing Authority
BANC	Balancing Area of Northern California
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
COB	California/Oregon Border
COI	California/Oregon Intertie
COTP	California/Oregon Transmission Project
CPUC	California Public Utilities Commission
DER	Distributed Energy Resource
DG	Distributed Generation
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EPA	U.S. Environmental Protection Agency
ETC	Existing Transmission Contract
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GMC	Grid Management Charge
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IRP	Integrated Resource Plan
ISO	Independent System Operator
LEC	Lodi Energy Center
LOLE	1-in-10 Loss of Load Event
LSE	Load Serving Entities
MID	Modesto Irrigation District
MMBtu	One Million British Thermal Units
MRTU	CAISO Market Redesign & Technology Upgrade (implemented in 2009)
MSR	Modesto, Santa Clara, Redding Public Power Agency
MSSC	Most Severe Single Contingency
MTCO2e	Metric Tons of Carbon Dioxide Equivalent

NCPA	Northern California Power Agency
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NP15	North of Path 15 Transmission
OATT	Open Access Transmission Tariff
PB	Public Benefit
PEV	Plug-in Electric Vehicle
PEVC	Plug-in Electric Vehicle Collaborative
PNM	Public Service Company of New Mexico
POU	Publicly Owned Utility
PRM	Planning Reserve Margin
PV	Photovoltaics
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SAIDI	System Average Interruption Duration Index
SAR	System Average Rate
SB1	2006 California Senate Bill 1 (set statewide rooftop solar installation targets)
SBX1-2	2011 California Senate Bill 2 (33% renewable requirement)
SC	Scheduling Coordinator
SCADA	Supervisory Control and Data Acquisition
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SOT	South of Tesla Transmission
SWTP	Southwest Transmission Project
TAC	Transmission Access Charge
TANC	Transmission Agency of Northern California
WALC	WAPA (Lower Colorado Region)
WAPA	Western Area Power Administration
WASN	WAPA (Sierra Nevada Region)
WECC	Western Electricity Coordinating Council
ZEV	Zero Emissions Vehicle
OFT	Out-of-Territory

Standardized Reporting Tables
for Publicly Owned Utility IRP Filing
California Energy Commission
Energy Assessment Division

POUs must submit the following four Standardized Tables to the Energy Commission as part of the IRP Filing. The Energy Commission encourages POUs to submit data for multiple scenarios, though POUs are only required to submit data for one scenario that meets the requirements of PUC Section 9621. Annual data must be reported in the Standardized Tables through the planning horizon.

Instructions for filling out the tables are in Appendix B Standardized Reporting Tables

Description of Worksheet Tabs

Admin Info: A listing of contact information of the tables' preparer with information for any back-up personnel.

year and the contribution of each energy resource (capacity) in the POU's portfolio to meet that demand.

EBT: Energy Balance Table (EBT): Annual total energy demand and annual estimates for energy supply from various resources.

GEAT: GHG Emissions Accounting Table (GEAT): Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB.

RPT: Resource Procurement Table (RPT): A detailed summary of a POU resource plan to meet the RPS requirements.

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Administrative Information
Form CEC 113 (May 2017)

Name of Publicly Owned Utility ("POU")	POU Name on Admin Tab
Name of Resource Planning Coordinator	Martin Caballero
Name of Scenario	2019 IRP

Persons who prepared Tables	**CRAT**	**Energy Balance Table**	**Emissions Table**	**RPS Table**	**Application for Confidentiality**
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City:	Modesto	Modesto	Modesto	Modesto	Modesto
State:	CA	CA	CA	CA	CA
Zip:	95354	95355	95356	95357	95358
Date Completed:					
Date Updated:					

Back-up / Additional Contact Persons for Questions about these Tables (Optional):					
Name:					
Title:					
E-mail:					
Telephone:					
Address:					
Address 2:					
City:					
State:					
Zip:					

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Capacity Resource Accounting Table
Form CEC 109 (May 2017)

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	723	666	680	682	689	692	690	692	695	698	705	704	707	710
2	[Customer-side solar: nameplate capacity]	43	45	47	49	51	53	56	58	60	62	65	68	70	73
2a	[Customer-side solar: peak hour output]	2	2	8	8	3	3	9	2	2	3	2	3	3	3
3	[Peak load reduction due to thermal energy storage]	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	[Light Duty PEV consumption in peak hour]	1	1	1	1	1	1	1	2	2	2	2	3	3	3
5	Additional Achievable Energy Efficiency Savings on Peak	20	17	17	17	21	22	19	19	20	20	27	21	21	21
6	Demand Response / Interruptible Programs on Peak	6	0	0	0	0	0	0	0	0	0	0	0	0	0
7	**Peak Demand (accounting for demand response and AAEE) (1-5-6)**	**697**	**649**	**663**	**665**	**668**	**670**	**671**	**673**	**675**	**678**	**678**	**683**	**686**	**689**
8	Planning Reserve Margin	99	100	99	100	100	101	101	101	101	102	102	103	103	103
9	Firm Sales Obligations	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total Peak Procurement Requirement (7+8+9)**	**795**	**749**	**762**	**765**	**768**	**771**	**772**	**774**	**776**	**780**	**780**	**786**	**789**	**792**

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	Woodland1	Natural Gas	45	45	45	45	45	45	45	45	45	45	45	45	45	45
11b	Woodland2	Natural Gas	83	83	83	83	83	83	83	83	83	83	83	83	83	83
11c	Woodland3	Natural Gas	49	49	49	49	49	49	49	49	49	49	49	49	49	49
11d	Ripon1	Natural Gas	50	50	50	50	50	50	50	50	50	50	50	50	50	50
11e	Ripon2	Natural Gas	50	50	50	50	50	50	50	50	50	50	50	50	50	50
11f	McClure1	Natural Gas	54	54	54	54	54	54	54	54	54	54	53.5	53.5	53.5	53.5
11g	McClure2	Natural Gas	54	54	54	54	54	54	54	54	54	54	53.5	53.5	53.5	53.5
11h	DON PEDRO	Large Hydroelectric	62	62	62	51	62	62	62	62	62	62	62	62	62	62
11i	San Juan	Coal	72	0	0	0	0	0	0	0	0	0	0	0	0	0
11j	Lodi Energy Center	Natural Gas	30	30	30	30	30	30	30	30	30	30	30	30	30	30
11k																

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**
11l	WAPA CVP	Large Hydroelectric	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11m	CCSF	Large Hydroelectric	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11n	ACS Specified Energy	Unspecified/System Power	0	0	24	0	0	0	0	0	0	0	0	0	0	0
11o	Zero Emission Source Specified Energy	Unspecified/System Power	0	48	48	48	0	0	0	0	0	0	0	0	0	0
11p	Short Term Capacity Contracts	Unspecified/System Power	195	220	271	103	107	109	16	20	24	12	0	0	0	0
11q																
11	**Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a...11q)**		**743**	**744**	**820**	**616**	**583**	**585**	**492**	**496**	**500**	**488**	**476**	**476**	**476**	**476**

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	Stone Drop	Small Hydroelectric	0	0	0	0	0	0	0	0	0	0	0.26	0.26	0.26	0.26
12b																

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**
12c	BigHorn	Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5
12d	BigHornII	Wind	3	3	3	3	3	3	3	3	3	3	3	3	3	3
12e	Fiscalini	Biofuels	1	1	1	1	1	1	1	1	1	1	0.75	0	0	0
12f	McHenry Solar	Solar PV	23	23	23	23	23	23	23	23	23	23	22.6	22.6	22.6	22.6
12g	StarPoint	Wind	21	21	21	21	21	21	21	21	21	21	21	21	21	0
12h	Blythe4	Solar PV	0	0	0	0	59	59	59	59	59	59	59.4	59.4	59.4	59.4
12i	High Winds	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12j	Loyalton	Biofuels	0	2	1	1	1	1	0	0	0	0	0	0	0	0
12k	Mustang2	Solar PV	0	0	0	48	48	48	48	48	48	48	47.6	47.6	47.6	47.6
12l	New Hogan	Small Hydroelectric	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12m	SB859 Biomass	Biofuels	0	0	1	1	1	1	1	0	0	0	0	0	0	0
12n																
12	**Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a...12n)**		**52**	**54**	**54**	**102**	**161**	**161**	**160**	**160**	**160**	**160**	**160**	**159**	**159**	**138**
13	**Total peak dependable capacity of existing and planned supply resources (11+12)**		**795**	**798**	**874**	**718**	**744**	**746**	**652**	**656**	**660**	**648**	**636**	**635**	**635**	**614**

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	Future ACS Specified Resource	Unspecified/System Power	0	0	0	0	24	24	24	24	24	24	24.1	24.1	24.1	24.1
14b	Future Unspecified Resource	Unspecified/System Power	0	0	0	0	24	24	24	24	24	24	24.1	24.1	24.1	24.1
14c																
14	**Total peak dependable capacity of generic supply resources (not RPS-eligible)**		**0**	**0**	**0**	**0**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**

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	Future Solar	Solar PV	0	0	0	0	0	0	0	0	0	93	92.9	92.9	92.9	140.4
15b	Future Base Load Renewable	Biofuels	0	0	0	0	0	0	0	0	0	0	0	0	15	15
15c	Future Wind	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15d																
15	**Total peak dependable capacity of generic RPS-eligible resources**				**0**	**0**	**0**	**0**	**0**	**0**	**0**	**93**	**93**	**93**	**108**	**155**
16	**Total peak dependable capacity of generic supply resources (14+15)**				**0**	**0**	**48**	**48**	**48**	**48**	**48**	**141**	**141**	**141**	**156**	**204**

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)**	**795**	**749**	**762**	**765**	**768**	**771**	**772**	**774**	**776**	**780**	**780**	**786**	**789**	**792**
18	**Total peak dependable capacity of existing and planned supply resources (from line 13)**	**795**	**798**	**874**	**718**	**744**	**746**	**652**	**656**	**660**	**648**	**636**	**635**	**635**	**614**
19	**Current capacity surplus (shortfall) (18-17)**	**0**	**49**	**111**	**(47)**	**(24)**	**(24)**	**(119)**	**(118)**	**(117)**	**(132)**	**(144)**	**(151)**	**(154)**	**(179)**
20	**Total peak dependable capacity of generic supply resources (from line 16)**			**0**	**0**	**48**	**48**	**48**	**48**	**48**	**141**	**141**	**141**	**156**	**204**
21	**Planned capacity surplus/shortfall (shortfalls assumed to be met with short-term capacity purchases) (19+20)**	**0**	**49**	**111**	**(47)**	**24**	**24**	**(71)**	**(70)**	**(69)**	**9**	**(3)**	**(10)**	**2**	**25**

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Energy Balance Table
Form CEC 110 (May 2017)

Scenario Name:

Units = MWh

Yellow fill relates to an application for confidentiality.

Historical Data

NET ENERGY FOR LOAD CALCULATIONS

			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Retail sales to end-use customers		2,561,656	2,485,803	2,537,927	2,687,831	2,709,730	2,731,060	2,736,917	2,756,893	2,779,578	2,801,729	2823727	2846429	2867763	2888734
2	Other loads		0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net energy for load	use scada	2,583,192	2,493,169	2,601,375	2,751,632	2,773,936	2,795,664	2,801,537	2,821,895	2,845,035	2,867,642	2,890,118	2,913,345	2,935,171	2,956,623
4	Retail sales to end-use customers (accounting for AAEE impacts)		2,561,656	2,485,803	2,537,927	2,552,031	2,568,230	2,584,160	2,584,817	2,600,093	2,618,278	2,636,529	2,655,627	2,676,648	2,696,285	2,715,541
5	Net energy for load (accounting for AAEE impacts)		2,583,192	2,493,169	2,601,375	2,615,832	2,632,436	2,648,764	2,649,437	2,665,095	2,683,735	2,702,442	2,722,018	2,743,564	2,763,692	2,783,429
6	Firm Sales Obligations		0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	**Total net energy for load (accounting for AAEE impacts) (5+6)**		**2,583,192**	**2,493,169**	**2,601,375**	**2,615,832**	**2,632,436**	**2,648,764**	**2,649,437**	**2,665,095**	**2,683,735**	**2,702,442**	**2,722,018**	**2,743,564**	**2,763,692**	**2,783,429**
8	[Customer-side solar generation]		73,115	78,685	81,833	85,106	88,510	92,051	95,733	99,562	103,544	107,686	111994	116474	121133	125979
9	[Light Duty PEV electricity consumption/procurement requirement]		1,878	2,642	3,554	4,601	5,762	7,019	8,353	9,745	11,180	12,645	14128	15621	17119	18617
10	[Other transportation electricity consumption/procurement requirement]		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	[Other electrification/fuel substitution; consumption/procurement requirement]		0	0	0	0	0	0	0	0	0	0	0	0	0	0

EXISTING AND PLANNED GENERATION RESOURCES

Utility-Owned Generation Resources (not RPS-eligible):

	[list resource by name]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12a	Woodland1	Natural Gas	152,889	72,745	34,826	109,499	49,574	20,168	109,337	51,800	42,096	102,378	78,077	92,876	98,771	114,371
12b	Woodland2	Natural Gas	200,433	369,909	327,555	279,978	363,106	357,827	272,505	353,970	354,875	276,318	323,777	308,546	246,073	296,069
12c	Woodland3	Natural Gas	65,320	51,229	66,302	65,787	61,523	81,156	56,281	42,594	33,499	48,102	38,193	23,872	22,109	63,701
12d	Ripon1	Natural Gas	52,727	20,737	15,580	12,371	13,139	10,743	7,292	11,404	6,126	10,779	12,575	23,611	48,939	33,933
12e	Ripon2	Natural Gas	36,534	6,869	6,991	4,752	5,136	5,373	2,875	3,355	3,942	5,710	7,413	7,131	23,398	28,052
12f	McClure1	Natural Gas	1,945	1,881	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
12g	McClure2	Natural Gas	2,771	1,872	1,827	1,827	1,827	1,803	1,827	1,827	1,827	1,827	1,827	1,827	1,827	1,827
12h	DON PEDRO	Large Hydroelectric	277,065	104,373	153,809	153,809	175,000	153,809	153,809	153,809	153,809	175,000	153,809	175,000	175,000	175,000
12i	San Juan	Coal	502,212	0	0	0	0	0	0	0	0	0	0	0	0	0
12j	Lodi Energy Center	Natural Gas	77,843	150,700	123,453	115,293	106,348	101,481	87,425	78,749	60,697	48,060	39,760	30,796	14,874	8,892
12k																

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
12l	WAPA CVP	Large Hydroelectric	37,151	13,410	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400	13,400
12m	CCSF	Large Hydroelectric	106,910	0	0	0	0	0	0	0	0	0	0	0	0	0
12n	ACS Specified Energy	Unspecified/System Power	0	0	219,022	0	0	0	0	0	0	0	0	0	0	0
12o	Zero Emission Source Specified Energy	Unspecified/System Power	0	252,788	256,800	256,800	0	0	0	0	0	0	0	0	0	0
12p																
12	**Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a...12p)**		**1,513,801**	**1,046,513**	**1,222,065**	**1,016,016**	**791,553**	**748,260**	**707,251**	**713,408**	**672,770**	**684,072**	**671,330**	**679,559**	**646,891**	**737,745**

Utility-Owned RPS-eligible Generation Resources:

	[list resource by plant or unit]	Fuel type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
13a	Stone Drop	Small Hydroelectric	456	457	700	700	700	700	700	700	700	700	700	700	700	700
13b		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
13c	BigHorn	Wind	58,599	64,091	63,960	63,961	63,960	63,961	63,961	63,961	63,961	63,961	63,961	63,961	63,961	63,960
13d	BigHornII	Wind	73,367	77,129	81,688	81,312	81,521	81,357	81,698	81,384	81,576	81,282	81,562	81,550	81,712	81,250
13e	Fiscalini	Biofuels	877	2,961	2,400	2,400	2,400	2,392	2,400	2,400	2,400	2,400	2,400	0	0	0
13f	McHenry Solar	Solar PV	62,357	63,929	64,746	64,746	64,746	64,746	64,746	64,746	64,746	64,746	64,746	64,746	64,746	64,746
13g	StarPoint	Wind	200,491	229,513	238,313	237,662	237,814	237,142	237,481	238,834	238,807	238,212	238,417	237,217	237,786	90,599
13h	Blythe4	Solar PV	0	0	0	6,618	183,500	183,500	183,500	183,500	183,500	183,500	183,500	183,500	183,500	183,500
13i	High Winds	Wind	95,192	106,588	109,026	109,026	109,026	109,026	109,026	109,026	109,026	109,026	109,026	49,403	0	0
13j	Loyalton	Biofuels	0	2,484	6,970	6,970	6,970	6,970	2,291	0	0	0	0	0	0	0
13k	Mustang2	Solar PV	0	0	0	72,701	146,775	146,775	146,775	146,775	146,775	146,775	146,775	146,775	146,775	146,775
13l	New Hogan	Small Hydroelectric	11,883	6,849	9,674	9,674	9,674	9,674	9,674	9,674	9,674	9,674	9,674	9,674	9,674	9,674
13m	SB859 Biomass	Biofuels	0	0	3,878	3,878	3,878	3,878	3,878	0	0	0	0	0	0	0
13n		0														
13	**Total energy from RPS-eligible resources (sum of 13a...13n)**		**503,221**	**554,001**	**581,356**	**659,648**	**910,965**	**910,120**	**906,130**	**901,000**	**901,165**	**900,275**	**900,760**	**837,526**	**788,854**	**641,205**
13o	**Undelivered RPS energy**		**107,075**	**115,922**	**129,548**	**208,867**	**459,823**	**459,823**	**455,144**	**448,975**	**448,975**	**595,750**	**595,750**	**666,974**	**748,611**	**895,387**
14	**Total energy from existing and planned supply resources (12+13)**		**2,017,022**	**1,600,515**	**1,803,421**	**1,675,664**	**1,702,518**	**1,658,380**	**1,613,382**	**1,614,407**	**1,573,934**	**1,584,348**	**1,572,090**	**1,517,084**	**1,435,745**	**1,378,950**

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
15a	Future ACS Specified Resource	Unspecified/System Power	0	0	0	90,623	219,022	219,023	219,023	219,023	219,023	219,023	219,023	219,023	219,023	219,022
15b	Future Unspecified Resource	Unspecified/System Power	0	0	0	90,623	219,022	219,023	219,023	219,023	219,023	219,023	219,023	219,023	219,023	219,022
15c		0														
15	**Total energy from generic supply resources (not RPS-eligible)**		0	0	**0**	**181,246**	**438,044**	**438,046**	**438,045**	**438,046**	**438,046**	**438,046**	**438,046**	**438,046**	**438,046**	**438,045**

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
16a	Future Solar	Solar PV	0	0	0	0	0	0	0	0	0	276,268	276,268	276,268	276,268	423,043
16b	Future Base Load Renewable	Biofuels	0	0	0	0	0	0	0	0	0	0	0	0	131,040	131,040
16c	Future Wind	Wind	0	0	0	0	0	0	0	0	0	0	0	130,847	130,847	130,847
16d																
16	**Total energy from generic RPS-eligible resources**		0	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**276,268**	**276,268**	**407,115**	**538,155**	**684,930**
17	**Total energy from generic supply resources (15+16)**		0	0	**0**	**181,246**	**438,044**	**438,046**	**438,045**	**438,046**	**438,046**	**714,314**	**714,314**	**845,161**	**976,201**	**1,122,975**
17z	**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
18	**Short term and spot market purchases:**	1,563,922	1,795,749	1,244,019	1,246,802	1,196,679	1,240,335	1,264,581	1,258,202	1,289,010	1,150,999	1,175,914	1,180,952	1,217,699	1,282,544
18a	**Short term and spot market sales:**	767,707	716,232	268,445	230,596	203,379	184,945	168,716	152,942	126,963	112,799	104,331	94,585	78,580	72,167

ENERGY BALANCE SUMMARY

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
19	**Total energy from supply resources (14+17+17z)**	**2,017,022**	**1,600,515**	**1,803,421**	**1,856,910**	**2,140,562**	**2,096,426**	**2,051,427**	**2,052,453**	**2,011,981**	**2,298,662**	**2,286,404**	**2,362,245**	**2,411,946**	**2,501,925**
19a	**Undelivered RPS energy (from 13z)**	**107,075**	**115,922**	**129,548**	**208,867**	**459,823**	**459,823**	**455,144**	**448,975**	**448,975**	**595,750**	**595,750**	**666,974**	**748,611**	**895,387**
20	**Net Short term and spot market purchases (18 - 18a)**	**796,215**	**1,079,517**	**975,574**	**1,016,206**	**993,300**	**1,055,390**	**1,095,865**	**1,105,260**	**1,162,047**	**1,038,200**	**1,071,583**	**1,086,367**	**1,139,119**	**1,210,377**
21	**Total delivered energy (19-19a+20)**	**2,706,162**	**2,564,110**	**2,649,447**	**2,664,249**	**2,674,039**	**2,691,993**	**2,692,148**	**2,708,738**	**2,725,053**	**2,741,112**	**2,762,237**	**2,781,638**	**2,802,454**	**2,816,915**
22	**Total net energy for load (from 7)**	**2,583,192**	**2,493,169**	**2,601,375**	**2,615,832**	**2,632,436**	**2,648,764**	**2,649,437**	**2,665,095**	**2,683,735**	**2,702,442**	**2,722,018**	**2,743,564**	**2,763,692**	**2,783,429**
23	**Surplus/Shortfall (21-22)**	**122,970**	**70,941**	**48,072**	**48,417**	**41,603**	**43,229**	**42,711**	**43,643**	**41,318**	**38,670**	**40,219**	**38,074**	**38,762**	**33,486**

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
GHG Emissions Accounting Table
Form CEC 111 (May 2017)

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	Woodland1	0.488	0.07	0.07	0.017	0.053	0.024	0.010	0.053	0.025	0.021	0.050	0.038	0.045	0.048	0.056
1b	Woodland2	0.457	0.09	0.17	0.150	0.128	0.166	0.164	0.125	0.162	0.162	0.126	0.148	0.141	0.112	0.135
1c	Woodland3	0.445	0.03	0.02	0.030	0.029	0.027	0.036	0.025	0.019	0.015	0.021	0.017	0.011	0.010	0.028
1d	Ripon1	0.562	0.03	0.01	0.009	0.007	0.007	0.006	0.004	0.006	0.003	0.006	0.007	0.013	0.028	0.019
1e	Ripon2	0.562	0.02	0.00	0.004	0.003	0.003	0.003	0.002	0.002	0.002	0.003	0.004	0.004	0.013	0.016
1f	McClure1	1.103	0.00	0.00	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
1g	McClure2	0.804	0.00	0.00	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
1h	San Juan	1.083	0.54	0.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1i	Lodi Energy Center	0.390	0.03	0.06	0.048	0.045	0.041	0.040	0.034	0.031	0.024	0.019	0.016	0.012	0.006	0.003

	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
1j	ACS Specified Energy	0.012	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a…1j)**		**0.824**	**0.344**	**0.216**	**0.225**	**0.232**	**0.223**	**0.213**	**0.219**	**0.208**	**0.211**	**0.219**	**0.218**	**0.215**	**0.259**

	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																

	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
2b																
2	**Total GHG emissions from RPS-eligible resources (sum of 2a…2t)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
3	**Total GHG emissions from existing and planned supply resources (1+2)**		**0.824**	**0.344**	**0.216**	**0.225**	**0.232**	**0.223**	**0.213**	**0.219**	**0.208**	**0.211**	**0.219**	**0.218**	**0.215**	**0.259**

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	Future ACS Specified Resource	0.012	0	0	0.000	0.001	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
4b	Future Unspecified Resource	0.428	0	0	0.000	0.039	0.094	0.094	0.094	0.094	0.094	0.094	0.094	0.094	0.094	0.094
4	**Total GHG emissions from generic supply resources (not RPS-eligible)**		**0.000**	**0.000**	**0.000**	**0.040**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**

	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																
5	**Total GHG emissions from generic RPS-eligible resources**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
6	**Total GHG emissions from generic supply resources (4+5)**		**0.000**	**0.000**	**0.000**	**0.040**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**

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:**	0.428	**0.341**	**0.462**	**0.418**	**0.435**	**0.425**	**0.452**	**0.469**	**0.473**	**0.497**	**0.444**	**0.459**	**0.465**	**0.488**	**0.518**

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)**	**1.165**	**0.806**	**0.633**	**0.699**	**0.754**	**0.771**	**0.778**	**0.788**	**0.801**	**0.752**	**0.774**	**0.780**	**0.799**	**0.873**

EMISSIONS ADJUSTMENTS

8a	**Undelivered RPS energy (MWh from EBT)**	107,075	115,922	129,548	208,867	459,823	459,823	455,144	448,975	448,975	595,750	595,750	666,974	748,611	895,387
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)**	107,075	115,922	129,548	208,867	459,823	459,823	455,144	448,975	448,975	595,750	595,750	666,974	748,611	895,387
8d	**Emissions intensity (portfolio gas/short-term and spot market purchases)**	0.617	0.459	0.437	0.438	0.438	0.436	0.438	0.437	0.437	0.440	0.440	0.441	0.444	0.443
8e	**Emissions adjustment (8Cx8D)**	0.066	0.053	0.057	0.091	0.201	0.201	0.199	0.196	0.196	0.262	0.262	0.294	0.332	0.397

PORTFOLIO GHG EMISSIONS

8f	**Adjusted Portfolio emissions (8-8e)**	1.099	0.753	0.577	0.608	0.552	0.570	0.579	0.592	0.605	0.490	0.512	0.486	0.467	0.476

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**	**0.002**	**0.002**	**0.003**	**0.004**	**0.005**	**0.006**	**0.007**	**0.008**	**0.009**	**0.010**	**0.011**	**0.012**	**0.013**	**0.014**
10	**GHG emissions increase due to LD PEV electricity loads**	**0.001**	**0.001**	**0.002**	**0.002**	**0.002**	**0.003**	**0.004**	**0.004**	**0.005**	**0.005**	**0.006**	**0.007**	**0.007**	**0.008**
11	**GHG emissions reduction due to fuel displacement - other transportation electrification**														
12	**GHG emissions increase due to increased electricity loads - other transportation electrification**														

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
RPS Procurement Table
Form CEC 112 (May 2017)

Scenario Name:

Units = MWh

	RPS ENERGY REQUIREMENT CALCULATIONS	**Beginning balances Start of 2017**	**Compliance Period 3**					**Compliance Period 4**					**Compliance Period 5**				**Compliance Period 6**			
			2017	**2018**	**2019**	**2020**		**2021**	**2022**	**2023**	**2024**		**2025**	**2026**	**2027**		**2028**	**2029**	**2030**	
1	Annual Retail sales to end-use customers (accounting for AAEE impacts) (From EBT)		2,561,656	2,485,803	2,537,927	2,552,031		2,568,230	2,584,160	2,584,817	2,600,093		2,618,278	2,636,529	2,655,627		2,676,648	2,696,285	2,715,541	
2	Green pricing program Exclusion, (may include other exclusions like self generation exclusion)		40,087	36,044	40,087	40,087		40,087	40,087	40,087	40,087		40,087	40,087	40,087		40,087	40,087	40,087	
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		2994526					3804478					3,376,364				3,851,951			
	Category 0, 1 and 2 Resources (bundled with RECs)																			
5	Excess balance at beginning/end of compliance period	1,045,046					348,747					172,484				50,857				96,691
6	RPS-eligible energy procured (copied from EBT)		503,221	554,001	581,356	659,648		910,965	910,120	906,130	901,000		901,165	1,176,543	1,177,028		1,244,641	1,327,009	1,326,135	
6A	Amount of energy applied to procurement obligation		0	0	0	0		0	0	0	0		0	0	0		0	0	0	
7	Net purchases of Category 0, 1 and 2 RECs		0	0	0	0		0	0	0	0		0	0	0		0	0	0	
7A	Excess balance and REC purchases applied to procurement obligation		680,824	710,430	774,330	828,942		878,530	928,587	973,359	1,024,002		1,074,332	1,125,038	1,176,993		1,230,483	1,283,741	1,337,727	
8	Net change in balance/carryover (RECs and RPS-eligible energy) (6+7-6A-7A)		(177,602)	(156,429)	(192,974)	(169,293)		32,435	(18,467)	(67,229)	(123,003)		(173,168)	51,505	35		14,158	43,268	(11,592)	
	Category 3 Resources (unbundled RECs)																			
9	Excess balance at beginning/end of compliance period	13,156					15,921					15,921				15,921				15,921
10	Net purchases of Category 3 RECs		2765	0	0	0		0	0	0	0		0	0	0		0	0	0	
11	Excess balance and REC purchases applied to procurement obligation		0	0	0	0		0	0	0	0		0	0	0		0	0	0	
12	Net change in REC balance		2,765	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)		2,994,526					3,804,478					3,376,364				3,851,951			
14	Over/under procurement for compliance period (13 - 4)		0					0					0				0			

Photograph provided by: Avangrid Renewables

Renewable Portfolio Standard Procurement Plan & Enforcement Program

Photograph provided by: Axium Infrastructure

November 13, 2018
Revision 1

SECTION 1: INTRODUCTION

Senate Bill (SB) X1-2[1], enacted in the 2011-2012 First Extraordinary Session of the Legislature, modified the State's Renewable Portfolio Standard (RPS) program and set forth new RPS requirements applicable to publicly owned utilities (POUs). Among other things, SBX1-2 codified an RPS target for electric service providers of 33 percent of electric retail sales coming from eligible renewable resources by 2020. SBX1-2 also required that the POUs adopt a program of enforcement[2] and also directed the California Energy Commission (CEC), in consultation with the POUs, to adopt regulations to implement an enforcement mechanism for POUs. On June 12, 2013, the CEC adopted the *"Enforcement Procedures for the Renewable Portfolio Standard for Local Publicly-Owned Utilities*" (CEC RPS Regulations).[3] The CEC RPS Regulations became effective on October 1, 2013.

The Clean Energy and Pollution Reduction Act of 2015, SB 350[4], signed by the Governor in October 2015 increased the statewide RPS to 50 percent by December 31, 2030. These targets were recently updated by SB 100[5], the 100 Percent Clean Energy Act of 2018, which was signed into law in September 2018. The new RPS targets require that MID meet the SBX1-2 targets through 2020 and that MID reach 44 percent RPS by the end of 2024, 52 percent RPS by the end of 2027, and finally 60 percent RPS by the end of 2030.

MID has combined the RPS Procurement Plan with its MID RPS Enforcement Program in order to facilitate implementation, administration, and compliance with SBX1-2, SB 100, and the CEC RPS Regulations. As MID had first adopted its MID RPS Enforcement Program outlining specific elements to be included in its RPS Procurement Plan, and the previous version of the RPS Procurement Plan[6] incorporated the critical elements of the MID RPS Enforcement Program, this latest revision combines both the MID RPS Enforcement Program and the MID RPS Procurement Plan into one document. In addition, this latest revision of the MID RPS Procurement Plan and Enforcement Program incorporates the updated RPS targets required by SB 100.

SECTION 2: MID'S RPS PROCUREMENT HISTORY

In accordance with the MID RPS, as it has been updated from time to time, MID made the following renewable energy procurement investments:

Procurement Prior to 2003

- Stone Drop Mini-Hydroelectric Project
  - Located in Waterford, Stanislaus County, CA
  - Built and operated by MID

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1 SBX1-2 (Chapter 1, Statutes of 2011, First Extraordinary Session) amends pertinent provisions in Public Resources Code Sections 25740 through 25751 and amends and/or adds Public Utilities Code Sections 399.11 through 399.31.

2 MID adopted its "*Renewable Energy Resources Enforcement Program*" (MID RPS Enforcement Program) during its regularly scheduled meeting on December 13, 2011 via Board Resolution No. 2011-82.

3 The CEC RPS Regulations are set forth in Title 20, Division 2 of the California Code of Regulations.

4 Senate Bill 350 (De León, Chapter 547, Statutes of 2015). The pertinent provisions of SB 350 are codified in Public Utilities Code Sections 399.15 through 399.30, and added Section 9021 to the Public Utilities Code.

5 Senate Bill 100 (De León, Chapter 312, Statutes of 2018). The pertinent provisions of SB 100 are codified in Public Utilities Code Sections 399.15, and 399.30, and added Section 454.53 to the Public Utilities Code.

6 The first version of this procurement plan was adopted by the MID Board of Directors on November 12, 2013 via Board Resolution 2013-87.

- 260 kW
- 700 MWhs of renewable energy annually
- Delivery commenced April 1984

2004

- High Winds Wind Project
  - Located in Solano County, CA
  - 10-year contract
  - 25 megawatt (MW) share
  - 65 GWhs of renewable energy annually
  - Delivery commenced June 2004

2005

- Shiloh Wind Project
  - Located in Solano County, CA
  - 10-year contract
  - 50 MW share
  - 140 GWhs of renewable energy annually
  - Delivery commenced June 2006

2006

- Big Horn Wind Project 1
  - Located in Klickitat County, WA
  - Through the Modesto-Santa Clara-Redding Public Power Agency (MSRPPA)
  - 20-year duration and an extension right of 5 years
  - Approximately a 25MW share
  - 65 GWhs of renewable energy annually
  - Delivery commenced October 2006

2009

- Star Point Wind Project
  - Located in Sherman County, OR
  - 20-year contract
  - 99.7 MW
  - 240 GWhs of renewable energy annually
  - Delivery commenced June 2010
- High Winds Project extension and increased share
  - Contract extension of 1 year at the original 25 MW level through May 2015
  - Additional 13 year contract extension starting June, 2015
  - Increased from 25 MW to 50 MW share
  - 110 GWhs of renewable energy annually
- Fiscalini Biodigester
  - Located in Stanislaus County, CA
  - 750 kW
  - 3 GWhs of renewable energy annually
  - Delivery commenced October 2009
  - Contract was extended for 15 years starting April 2012

2010

- McHenry Solar Farm
  - Located in Stanislaus County, CA
  - 25-year contract
  - 25 MW solar photovoltaic power plant
  - 65 GWhs of renewable energy annually
  - Commercial operation was declared in December 2012
- Big Horn Wind Project 2
  - Located in Klickitat County, WA
  - Executed through the MSRPPA
  - 25-year contract
  - 33 MW wind project share
  - 80 GWhs of renewable energy annually
  - Deliveries commenced November 2010
- New Hogan Hydro Electric Project
  - Located in Calaveras County
  - 3.3 MW small hydroelectric project
  - Built and operated by MID
  - 10 GWhs of renewable energy annually
  - Deliveries commenced in 1986
  - Prior to 2010 output was sold to PG&E
  - MID's rights end upon expiration of the FERC license in 2032.

2017

- Mustang II Barbaro Solar Project
  - Located in Kings County, CA
  - 50 MW
  - 20-year contract
  - 150 GWhs of renewable energy annually
  - Deliveries commence December 2020
- Blythe Solar IV Project
  - Located in Riverside County, CA
  - 62.5 MW
  - 20-year contract
  - 185 GWhs of renewable energy annually
  - Deliveries commence December 2020

2018

- Loyalton Biomass Project
  - Located in Sierra County, CA
  - 1 MW
  - 5-year contract
  - 7GWhs of renewable energy annually
  - Delivery commenced April 2018
  - Procured to meet the requirements of SB859; requires that the state's electric utilities acquire their load ratio share of capacity from biomass facilities that burn woody biomass from high hazard fire zones.

SECTION 3: MID'S RPS PROCUREMENT PLAN

In order to comply with Public Utilities Code (PUC) Section 399.30(a) and fulfill its renewable energy resource generation procurement targets, MID adopts and implements this RPS Procurement Plan and Enforcement Program incorporating the specific compliance periods and targets specified in PUC Section 399.30. MID shall procure energy from eligible renewable resources that the CEC has determined meet the definition of an "eligible renewable energy resource" as set forth in Section 399.12(e) of the Public Utilities Code, and including facilities satisfying the criteria of Section 399.12 of the Public Utilities Code, and that have been certified by the CEC as an eligible renewable energy resource. The General Manager shall take all necessary or appropriate actions to implement this MID RPS Procurement Plan and Enforcement Program.

PUC Section 399.30(n) provides that MID shall retain discretion over both of the following:

- The mix of eligible renewable energy resources procured by MID and those additional generation resources procured by MID for purposes of ensuring resource adequacy and reliability.
- The reasonable costs incurred by MID for eligible renewable energy resources owned by MID.

In compliance with SBX1-2, the CEC RPS Regulations, and the requirements of SB 100, including the discretion expressly reserved to MID, MID will endeavor to procure energy from eligible renewable energy resources in a manner that complies with the procurement targets and the portfolio balance percentages for portfolio content categories (PCC). The sections and table below summarize those requirements. The procurement compliance targets listed below are minimum requirements established in SBX1-2, the CEC in the CEC RPS Regulations, and SB 100. ATTACHMENT 1 shows an illustrative summary of MID's plan for compliance with the requirements listed above.

A. **Compliance Periods**

PUC Section 399.30(b) defines compliance periods as follows (*see also* CEC RPS Regulations §3204):

1. Compliance Period 1: January 1, 2011, to December 31, 2013, inclusive.
2. Compliance Period 2: January 1, 2014, to December 31, 2016, inclusive.
3. Compliance Period 3: January 1, 2017, to December 31, 2020, inclusive.
4. Compliance Period 4: January 1, 2021 to December 31, 2024, inclusive.
5. Compliance Period 5: January 1, 2025 to December 31, 2027, inclusive.
6. Compliance Period 6: January 1, 2028 to December 31, 2030, inclusive.

The CEC shall establish multiyear compliance periods in subsequent years (PUC § 399.30(c)(2)).

B. **Procurement Requirements within Each Compliance Period**

1. PUC Section 399.30 (c)(1) and (2) establishes the quantities of energy from eligible renewable energy resources to be procured for each compliance period and calls for reasonable progress toward compliance period targets during intervening years (*see also* CEC RPS Regulations § 3204(a)):

   The following targets are established:

Table 1. RPS Compliance Period Targets

Compliance Periods	Years	RPS Target As a Percentage of Retail Energy Sales
Compliance Period 1	2011 - 2013	Average of 20%
Compliance Period 2	2014	20%
	2015	20%
	2016	25%
Compliance Period 3	2017	27%
	2018	29%
	2019	31%
	2020	33%
Compliance Period 4	2024	44%
Compliance Period 5	2027	52%
Compliance Period 6	2030	60%
Future Compliance Periods	2031 - Onward	60%

2. Unless otherwise updated by the CEC, for the calendar year January 1, 2031 onward the provisions of Section 3(A) in this RPS Procurement Plan and Enforcement Program shall apply.

C. **MID's Interim Compliance Period Targets**
(PUC § 399.30(c)(1) and (2), CEC RPS Regulations § 3204(a)(1))

1. The quantities of eligible renewable energy resources to be procured for Compliance Period 1 have been verified by the CEC and were equal to an average of 20 percent of retail sales.
2. The quantities of eligible renewable energy resources to be procured for all other compliance periods reflect reasonable progress in each of the intervening years sufficient to ensure that the procurement of electricity products from eligible renewable energy resources achieves 25 percent of retail sales by December 31, 2016, 33 percent by December 31, 2020, 44 percent by December 31, 2024, 52 percent by December 31, 2027, and 60 percent by December 31, 2030. MID shall demonstrate that it is making reasonable progress to ensure that it shall meet the 60 percent RPS target by the end of 2030 through its annual RPS compliance filings at the CEC.

D. **Defining Portfolio Content Categories (PCCs)**
PUC Sections 399.30(c)(3) and 399.16 establish PCCs specifying the electricity products that may be procured for RPS compliance during each compliance period (*see also* CEC RPS Regulations § 3203).

The following are general descriptions of each PCC:

1. PCC 1: refer to PUC § 399.16(b)(1), CEC RPS Regulations 3203(a) for a full description of requirements.

Overview

- PCC 1 electricity products must be procured together with associated renewable energy credits (RECs) to be classified as PCC 1.
- The electricity products must be generated by an eligible renewable energy resource that is interconnected to a transmission network within the Western Electricity Coordinating Council (WECC) region.
  - Must have its first point of interconnection within the metered boundaries of a California balancing authority area (CABAA), or
  - Must have its first point of interconnection to an electricity distribution system used to serve end users within the metered boundaries of a CABAA, or
  - Must be scheduled on an hourly or sub-hourly basis into a CABAA without substituting electricity from another source. If there is a difference between the amount of electricity generated within an hour and the amount of electricity scheduled into a CABAA within that same hour, only the lesser of the two amounts shall be classified as PCC 1, or
  - The electricity from the eligible renewable energy resource can be dynamically transferred into the CABAA.

  Maintaining PCC1 Status in a Resale Transaction

  - The original contract for procurement of the electricity products meets one of the criteria above (*see also* CEC RPS Regulations § 3203(a)(1)(A) – (D)). In this case, only the real time transfer of energy and associated RECs to the ultimate buyer that have not been generated prior to the effective date of the resale contract with the ultimate buyer are allowed; or
  - The transaction meets the scheduling condition above while maintaining the original hourly and sub-hourly schedule and the real time transfer of energy and associated RECs to the ultimate buyer that have not been generated prior to the effective date of the resale contract with the ultimate buyer. *See also* CEC RPS Regulations § 3203(a)(2)(d).
- Electricity products originally qualifying in PCC 1 and resold that do not meet the criteria above shall not be counted as PCC 1 electricity products.

2. PCC 2: refer to PUC § 399.16(b)(2), and CEC RPS Regulations 3203(b) for a full description of requirements.

   Overview

   - PCC 2 electricity products (sometime also referred to as "firmed-and-shaped") must be generated by an eligible renewable energy resource that is interconnected to a transmission network within the WECC region, and the electricity must be matched with incremental electricity that is scheduled into a CABAA.
   - The following criteria for bundled PCC2 electricity products must be met:
     - The first point of interconnection in the WECC region for both the eligible renewable energy resource and the resource providing the incremental or firming energy must be located outside the metered boundaries of a CABAA.

- The firming energy used to match the electricity from the eligible renewable energy resource must be incremental to MID[7].
- The contract or ownership agreement for the firming energy is executed at the same time or after the contract or ownership agreement for the electricity products from the eligible renewable energy resource is executed.
- The firming energy must be scheduled into the CABAA within the same calendar year as the electricity from the eligible renewable energy resource is generated.
- The electricity from the eligible renewable energy resource must be available to be procured by the MID and may not be sold back to that resource.

- Electricity products originally qualifying in PCC 2 and resold must meet the following criteria to remain in PCC 2:
    - The original contract for procurement of the electricity products meets the PCC2 criteria above *(see also* CEC RPS Regulations § 3203(b)(2)(A) – (E)).
    - The resale contract transfers only electricity and RECs that have not yet been generated prior to the effective date of the resale contract.
    - The resale contract transfers the original arrangement for firming energy, including the source and quantity for the firming energy.
    - The resale contract retains the scheduling of the firming energy into the CABAA as set out in the original transaction.
    - The transaction provides firming energy for the MID in its claim of the transaction for RPS compliance.
    - The firmed energy is scheduled into the CABAA.
- Electricity products originally qualifying in PCC 2 and resold that do not meet the criteria requirements of either PCC 1 or PCC 2 fall within PCC 3.

3. PCC 3: refer to PUC § 399.16(b)(3), CEC RPS Regulations § 3203(c) for a full description of requirements.
    - All unbundled RECs and other electricity products procured from eligible renewable energy resources located within the WECC region that do not meet the requirements of either PCC1 or PCC2 fall within PCC3.
    - Electricity products that fall under the PCC 3 electricity product category that were procured and under contract prior to June 1, 2010 can be used under the optional compliance measure described in the Optional Compliance Measures, § 3206 (a)(1)(A)(1) of the CEC RPS Regulations, and will be designated by the label "GR3" for MID's internal tracking.
4. PCC 0: refer to PUC § 399.16(d), CEC RPS Regulations § 3202(a)(2) for a full description of requirements.

[7] For purposes of this Section (*see also* CEC RPS Regulations § 3203), "incremental electricity" means electricity that is generated by a resource located outside the metered boundaries of a CABAA and that is not in the portfolio of MID claiming the electricity products for RPS compliance prior to the date the contract or ownership agreement for the electricity products from the eligible renewable energy resource, with which the incremental electricity is being matched, is executed by MID or other authority, as delegated by the MID governing board.

- Contracts or ownership agreements originally executed prior to June 1, 2010, count in full towards the RPS procurement targets set forth in Section 3.B above if the renewable resource met the CEC's RPS eligibility requirements that were in effect when the procurement or ownership agreement was executed by the MID and the associated RECs are retired within 36 months of the date the electricity product is generated. The contracts or ownership agreements will continue to count in full if any contract amendments or modifications that occurred after June 1, 2010, do not increase the nameplate capacity or expected quantities of annual generation, or substitute of a different renewable energy resource to meet the terms of the original agreement. An amendment to increase the duration of the contract beyond its original term is acceptable if the original term was at least 15 years.
- If contract amendments or modifications after June 1, 2010 increase nameplate capacity or expected quantities of annual generation, increase the term of the contract as outlined above, or substitute a different renewable energy resource, only the MWhs or resources procured prior to June 1, 2010, shall count in full toward the RPS procurement targets. The remaining procurement must be classified into PCC 1, 2, or 3, and follow the portfolio balance requirements in accordance with Section 3.E below (*see also* CEC RPS Regulations §3204(c)).
- PCC 0 resources may not be applied to the balancing requirements defined in Section 3(E) below (*see also* CEC RPS Regulations § 3204(c)).

5. Historic Carryover: refer to CEC RPS Regulations § 3206(a)(5) for a full description of requirements.

   - MID procurement generated before January 1, 2011, that met the PCC 0 criteria above (*see also* CEC RPS Regulations § 3202(a)(2)), that was in excess of the sum of the 2004 – 2010 annual procurement targets defined in CEC RPS Regulations Section 3206(a)(5)(D), have been credited to MID by CEC for use in MID's RPS procurement targets during any of the compliance periods.

E. **Portfolio Balancing Requirements- Quantities for PCCs**

Refer to PUC §§ 399.30(c)(3) and 399.16(c), and CEC RPS Regulations § 3204(c) for a for a full description of requirements.

Table 2 provides a summary of the RPS requirements that are applicable to POUs in the CEC RPS Regulations.

Table 2. Portfolio Content Category Requirements

Compliance Periods	Years	Balancing Requirements For Portfolio	
		PCC1	PCC3
Compliance Period 1	2011 - 2013	≥50%	≤25%
Compliance Period 2	2014 - 2016	≥65%	≤15%
Compliance Period 3	2017 - 2020	≥75%	≤10%
Future Compliance Periods	2021 - Onward	≥75%	≤10%

As PCC0 products count in full, they meet the PCC1 requirements. During 2017, MID met its PCC1 requirements with 99 percent PCC0 contracts and 1 percent PCC1 contracts.

SECTION 4: OPTIONAL COMPLIANCE MEASURES

Both PUC § 399.30 and CEC RPS Regulations § 3206 authorize the use of additional flexible measures for compliance. MID incorporates each of optional compliance measures into this RPS Procurement Plan and Enforcement Program as follows:

A. **Banking Mechanism**

   1. MID may apply excess procurement from one compliance period to subsequent compliance periods, including compliance years following 2020, using the criteria outlined in Section 3206(a)(1)(A) of the CEC RPS Regulations. MID may count any excess procurement accrued beginning January 1, 2011. Excess procurement shall be calculated as set forth in the CEC RPS Regulations Section 3206(a)(1)(D).

B. **Deviation from Procurement Content Category Requirements and Timely Compliance**

   1. MID may waive or delay timely compliance with an RPS requirement if MID demonstrates that any of the conditions beyond the control of MID, consistent with those set forth in CEC RPS Regulations Section 3206(a)(2)(A)1-3, exist and MID would have met its RPS procurement requirements but for the cause of delay.

   2. In addition, MID may reduce the portfolio balance requirement for PCC 1 for a specific compliance period. The need to reduce portfolio balance requirements for PCC 1 must have resulted from conditions beyond the control of MID as set forth in CEC RPS Regulations Section 3206(a)(2)(A)1-3, and consistent with PUC Section 399.16(e). If MID reduces its portfolio balance requirements for PCC 1, it must adopt such changes at a publicly noticed meeting (with advance notice to the CEC) and must include this information in the updated RPS Procurement Plan and Enforcement Program submitted to the CEC.

C. **Cost Limitations**
Refer to PUC §§ 399.30(d)(2) and 399.15(c), and CEC RPS Regulations § 3206(a)(3) for a full description of requirements.

1. At the discretion of the MID Board of Directors, the following cost limitation rules may be applied to MID's expenditures for procurement under this RPS Procurement Plan and Enforcement Program, consistent with CEC RPS Regulations Section 3206(a)(3).

   In implementing a cost limitation for procurement expenditures under this RPS Procurement Plan and Enforcement Program, MID will consider the following:

   a. In its efforts to diversify its RPS, MID will examine the cost-effectiveness of new opportunities while taking into consideration the impacts on rates and protecting its customers from an excessive rate increase(s). When compared to the cost to purchase non-renewable energy of comparable volume and delivery profile, if incorporating the annual expenditure of new eligible renewable resources into MID's current RPS Procurement Plan and Enforcement Program would result in rate increases of more than 2 percent per year at any time during the life of the considered RPS procurement, cost limitation may be applied at the discretion of the MID Board of Directors.

D. **MID Authority**
PUC § 399.30, and other relevant laws and regulations.

1. In endeavoring to procure adequate supplies of renewable energy to meet the targets set forth in this RPS Procurement Plan and Enforcement Program, MID shall at all times maintain system reliability and safety. The District retains all authority and flexibility granted under PUC Section 399.30 and other relevant authorities in meeting its obligations under PUC Section 399.30 in accordance with this RPS Procurement Plan and Enforcement Program and retains the ability to modify this document at any time in order to maintain these goals.

SECTION 5: REVIEW, UPDATES, AND ENFORCEMENT

Refer to PUC § 399.30(e). § 399.30(f), CEC RPS Regulations § 3205(a) and § 3205 (b) for a full description of requirements.

This RPS Procurement Plan and Enforcement Program will be updated as appropriate for consistency with RPS requirements, as they may change from time to time.

A. MID will provide the following notice as it pertains to RPS procurement regarding a new or updated RPS Procurement Plan and Enforcement Program:

   1. MID shall post notice in accordance with Chapter 9 (commencing with Section 54950) of Part 1 of Division 2 of Title 5 of the Government Code whenever the Board of Directors will deliberate in public on the RPS Procurement Plan and Enforcement Program.

   2. In addition, MID shall notify the CEC of the date, time, and location of the public meeting to consider the RPS Procurement Plan and Enforcement Program. This requirement will be satisfied if MID provides the CEC with the uniform resource locator (URL) that directly links to the notice for the public meeting. Alternatively, an e-mail with information on the public meeting in Portable Document Format (PDF) may also be provided to the CEC.

3. MID will notify the CEC if any URL provided by MID no longer contains the correct link, and MID will send the CEC a corrected URL that links to the information or a PDF containing the information as soon as it becomes available.

4. If MID distributes information to its Board of Directors related to its renewable energy resource procurement status or future procurement plans in light of its enforcement program, for the MID Board of Directors' consideration at a public meeting, MID shall make all that information available to the public at the same time that it is distributed to the Board of Directors and shall provide an electronic copy of that information to the CEC for posting on the CEC website.

   a. This requirement is satisfied if MID provides to the CEC the URL that directly links to the documents or information regarding other manners of access to the documents. Alternatively, an e-mail with the information in PDF may also be provided to the CEC.

   b. MID will notify the CEC if any URL provided by MID no longer contains the correct link, and MID will send the CEC a corrected URL that links to the information or a PDF containing the information as soon as it becomes available.

B. MID will provide the following notice when there are substantial changes to the areas of enforcement in this RPS Procurement Plan and Enforcement Program:

   a. If the enforcement program is modified or amended, no less than 10 calendar days notice shall be given to the public before any meeting is held to make a substantive change to the enforcement program.

   b. MID will provide the CEC notice and information as described in A(2) and A(3) above.

C. Other enforcement actions by the MID that will assist MID's efforts in in the RPS procurement process as part of this RPS Procurement Plan and Enforcement Program:

   1. Staff shall inform the Board of Directors in the event that MID will not meet the renewable energy resource procurement requirements set forth in MID's RPS Procurement Plan and Enforcement Program.

   2. As soon as reasonably practicable following informing the Board of Directors of a noncompliance issue, staff shall develop and present to the Board a plan to bring the District into compliance.

ATTACHMENT 1

1. EXISTING ELIGIBLE RENEWABLE ENERGY RESOURCES

MID currently has the following energy resources under contract and/or ownership that meet the eligible renewable energy requirements set forth in PUC Section 399.11, *et seq.* and the CEC RPS Regulations:

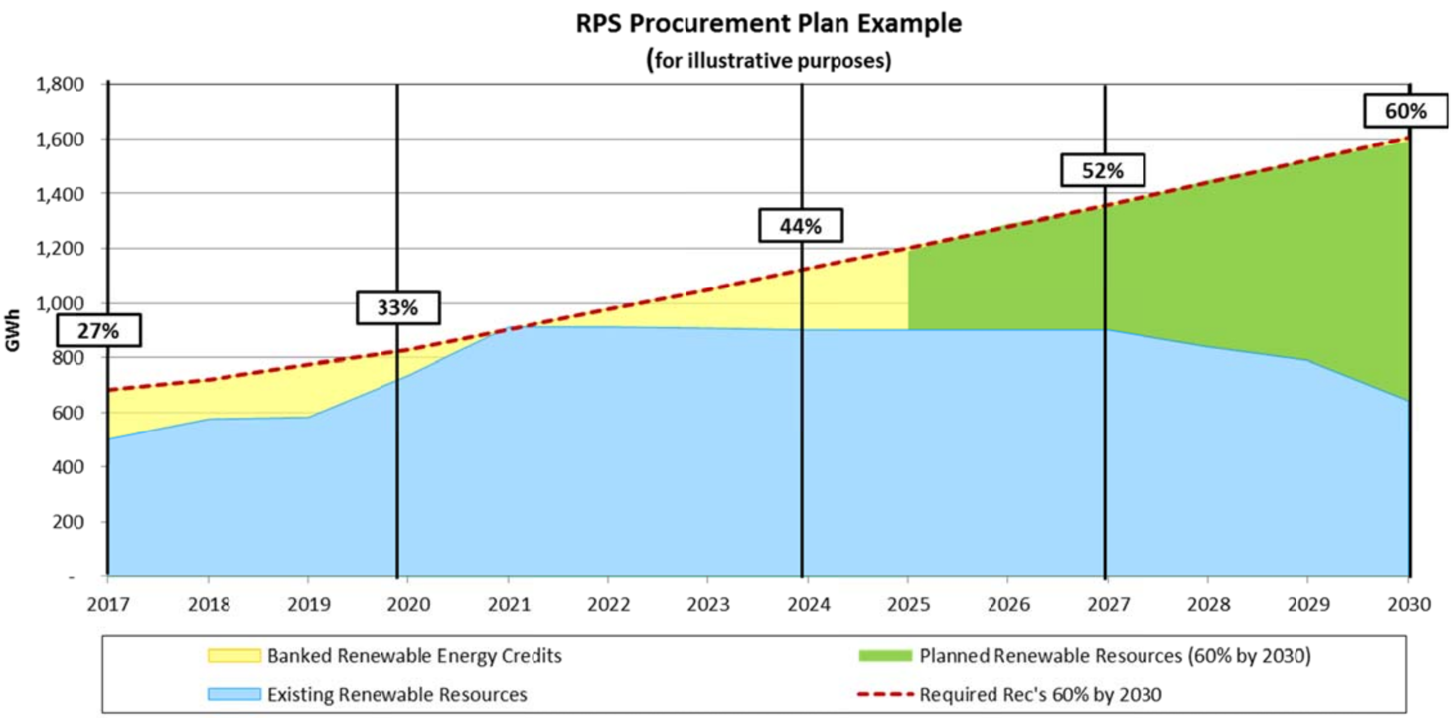
Table 1: MID Current Eligible Renewable Energy Resources

Technology/Projects	PCC Category	MW	Annual GWh
Small Hydroelectric			
• Stone Drop Mini Hydro	PCC0	0.260	1
• New Hogan	PCC0	3.3	10
		-	
Wind			
• High Winds Wind Project	PCC0	50	109
• Big Horn Wind Project 1	PCC0	25	64
• Big Horn Wind Project 2	PCC0	32.5	82
• Star Point Wind Project	PCC0	99.7	238
Digester Gas			
• Fiscalini Farms	PCC1	0.750	2
Biomass			
• ARP-Loyalton	PCC1	1	7
Solar			
• McHenry Solar Farm	PCC0	25	65
• Small Solar Photovoltaic Systems	GR3/PCC3	10	17
Procured			
• Solar: Mustang II Barbaro	PCC1	50	150
• Solar: Blythe IV	PCC1	62.5	185

2. PROCUREMENT PLAN FOR FUTURE RENEWABLE ENERGY RESOURCES

In order to meet the requirements of SB 100 and the CEC RPS Regulations, MID plans to carry forward excess procurement from one compliance period to the next whenever possible. As existing contracts near expiration, MID will negotiate an extension or replace those resources with other eligible renewable energy resources as necessary to maintain RPS compliance. MID will also use its available historic carryover and prior excess procurement in years where there may otherwise be a shortfall through the banking mechanism described in Section 4A of this RPS Procurement Plan and Enforcement Program.

The following example illustrates the banking approach described in Section 4A of this RPS Procurement Plan and Enforcement Program.



3. REVISION HISTORY

Revision Number	Revision Date	Summary of Changes
1	November 13, 2018	Updated title to combine the MID Renewable Energy Resources Enforcement Program with the RPS Procurement Plan, cleanup, and implementation of updates associated with SB 100.

5316

Modesto Irrigation District

Risk Management Policy

Version 5.0, Approved

May 24, 2016

Table of Contents

I. Organizational Structure and Responsibilities

A. Firm-Wide Responsibilities

All personnel involved in procurement, trading, marketing, and risk management activities for energy and related attributes shall conduct business in accordance with all applicable laws, regulations, tariffs and rules. These include MID policies regarding ethics and conflicts of interest. Personnel shall deal honestly and in good faith.

B. Management Responsibilities

1. Board of Directors

The Board has oversight responsibility for the organization including business strategies and the risks involved. The Board:

- Approves and oversees business objectives, plans, strategies and policies.
- Defines the risk tolerance of the organization and the goals, scope and time horizon of the Risk Management Program.
- Designates Qualified Independent Representative(s) (see below, QIR) pursuant to the rules of the Commodity Futures Trading Commission (CFTC), and obligates such QIR(s) to comply with section 23.450(b) (1) of the CFTC rules. The Board will designate each QIR by special purpose resolution after a case-by-case evaluation of a candidate's satisfaction of the CFTC requirements.
- Through the adoption of the Risk Management Policy:
    - Establishes risk exposure limits.
    - Grants authority to Operations to enter into transactions of the types, within the terms, and for the purposes that are explicitly listed as approved in this document.
    - Installs a reporting structure that communicates the risks assumed by MID and shows the results of risk management activities.
    - Grants authority to the Risk Oversight Committee (ROC) to set and approve procedures to enhance the management and control of risk within the constraints of this Policy.

2. Risk Oversight Committee

The ROCshall ensure the implementation and serve as the policy interpretation authority of this policy. Within the constraints of the Board-adopted *policies* herein, the ROC may adopt *procedures* it deems necessary to further define and enhance the risk management and control environment. The ROC includes the Assistant General Manager of Finance, Assistant General Manager Transmission and Distribution, and Assistant General Manager Electric Resources, and such others as the General Manager may designate This body will:

- Implement the Risk Management Policy and ensure the adequacy and functioning of the system of controls over market, credit and operational risks.
- Communicate the results of risk management activities to the Board.
- Adopt procedures to ensure that each Qualified Independent Representative (see below, QIR) meets the requirements of CFTC Regulation 23.450, procedures to monitor QIRs, procedures for QIRs to use in evaluating swaps, and such other procedures necessary to enhance the risk management and control environment.
- Provide adequate staffing and resources (e.g., number, level and experience of staff; computer support; etc.) for risk management activities.
- Approve counterparties and counterparty credit limits.
- Determine business level strategies and their effect on the risk position of MID.
- Propose changes to risk tolerance for approval by the Board based on strategic direction and business opportunities.
- Establish a standard for effective communications among management and staff to maintain timely information on the risks faced by the firm.
- Meet on a regular basis to monitor compliance with policy and procedures and the performance of risk management activities.
- Monitor the performance of risk management personnel.
- Monitor each QIR for performance and for ongoing satisfaction of the requirements of CFTC Regulation 23.450.
- Consider and recommend appropriate risk management actions and/or practices to incorporate into the Risk Management Policy and/or Procedures.

- Monitor for breakdowns in segregation of duties especially in light of potential changes in personnel, organizational structure and information systems.
- Ensure that appropriate action is taken if risk limits are exceeded.

3. Operations

In general, execution of risk management activities (i.e., trading and hedging) will be performed by operating personnel (traders, schedulers, analysts, etc.) who are responsible to:

- Develop physical and financial transaction trading expertise.
- Execute trades (physical or financial) within the limits specified herein.
- Use only recorded lines when transacting by telephone.
- Report all trades to Risk Management and provide copies of deal confirmations.
- Identify areas where the financial markets and/or risk management expertise can be used to increase business opportunities.
- Provide a first line of defense against credit risk by helping to identify and avoid counterparties which are not creditworthy or which lack integrity.
- Provide notice to Risk Management (RM) of concerns regarding conduct of counterparties that may be inconsistent with market rules.
- Maintain communications with the ROC as to the status of all risk taking and risk management activities.
- The Assistant General Manager for Electric Resources will approve a list of authorized traders.

4. Risk Management

To maintain segregation of duties, Risk Management (RM) will be functionally and organizationally independent from the line management of Divisions that execute energy transactions. Risk Management will be responsible to:

- Organize and conduct meetings of the ROC, engaging the ROC in discussions regarding developments in energy markets that could expose MID to losses.
- Measure and communicate the financial exposure of MID's energy portfolio by applying accepted risk measurement and valuation standards.

- Recommend portfolio hedging strategies.
- Deliver risk reports per Sections IV and V below.
- Monitor for violations of Risk Management Policies and Procedures and report such to the ROC.
- Review the adequacy of risk management activities, controls, reports, and policies; and recommend updates and improvements,
- Review and evaluate proposed energy market activities and transactions to ensure that adequate analysis and risk assessment has been performed.
- Recommend counterparties and credit limits for ROC approval.
- Monitor credit exposures compared to limits, prepare and issue credit risk management reports, and analyze the credit exposure impact of new transactions.
- Accept credit enhancement (e.g., guarantees) from trading counterparties.
- Provide back-up of risk books and records and plan for business continuity (in conjunction with Information Technology).
- Immediately notify ROC of any breakdown in risk management functionality (e.g., risk management software systems).

5. Qualified Independent Representative

The implementing regulations of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Act) require MID to have a Qualified Independent Representative (QIR) in order to trade products the Act defines as "swaps" with entities defined as "swap dealers." Many of the products approved herein for trading meet the definition of "swaps" and many of MID's counterparties are "swap dealers." Note: this Policy uses the term QIR to be consistent with the Act. The Act defines the QIR to be independent of the swap dealer, not MID. MID may have more than one QIR and each QIR can be an MID employee or a consultant. Each QIR will:

- Demonstrate knowledge of the laws and regulations applicable to QIRs.
- Advise MID with respect to swaps, swap transactions and trading strategies involving swaps.
- Meet the requirements of CFTC Regulation 23.450(b) (1) and such additional requirements as the ROC may specify.

6. Risk Management Responsibilities of Other Functional Areas

These responsibilities shall be carried out by individuals within MID to assure corporate policies are followed.

a. Accounting and Controller

- Develop and apply accounting policies to financial transactions.
- Participate in the settlement of transactions (including accounts payable/receivable).
- Follow accounting standards for energy transactions.
- Prepare financial statement disclosures.

b. Finance

- Provide proper types and levels of capital to fund the operation.
- Maintain controls over cash or other assets in custody (including investment decisions on funds in trading and broker accounts).
- Evaluate cash flow implications of stress testing scenarios.

c. Legal

- Review Board-level policies.
- Review trading agreements with counterparties.
- Assess legal enforceability of contracts with applicable laws and regulations.

d. Information Technology

- Specify, develop, manage, and maintain risk management computer systems.
- Data archival, back-up, and recovery planning.

II. Authorized and Prohibited Transactions

This section describes the ethical standards, purposes, parameters, and types of transactions that may be executed by authorized traders under the authority granted via this Risk Management Policy. Traders may execute only those transactions that meet the tests of ethics and purpose, are within allowed parameters, and are of a type explicitly listed as approved. For the sake of clarity and comparison, this section also contains examples of prohibited transactions that shall not be executed. In addition, the Federal Energy Regulatory Commission has characterized certain activities as "gaming" and/or "anomalous market behavior". Traders shall not engage in gaming or anomalous behavior. Potential transactions must affirmatively meet all criteria (ethics, purpose, parameter, and type) before being executed: actions not specifically prohibited are not necessarily allowed.

A. Ethical Standards

- MID will deal honestly and in good faith.
- Trading and risk management personnel have a duty to know and comply with the laws, rules, regulations, and tariffs of the markets in which they participate.
- Trading and risk management personnel shall not engage in fraudulent behavior or make false representations.
- MID will honor the terms and conditions of its contracts.
- Trading and risk management personnel shall not collude with other companies to affect the price or supply of power, allocate markets, "blackball" counterparties, or otherwise restrain competition. (In addition to being unethical, such behavior could subject individuals to civil and criminal penalties.)

B. Purpose of Transactions

1. Approved Purposes

- Transactions must have a legitimate business purpose. Legitimate purposes include generating revenues, managing risks, balancing loads and resources, providing for reliability. Legitimate purposes also include ensuring that MID holds sufficient energy-related attributes (e.g., emission allowances, renewable energy credits) to meet regulatory/legislative mandates and progress towards environmental goals.
- Customer supply activities are allowed. These activities seek to ensure reliable supplies to meet MID's obligations to its customers at low and stable rates.

- Sales of surplus capacity, energy, fuel, and environmental attributes are allowed. Such sales can occur in spot or forward markets.

- Spread and Arbitrage trading activities are allowed. These activities seek to generate revenue or reduce costs by capturing pricing inconsistencies or capitalizing on non-random trends. Spreads may be locational (e.g., California-Oregon Border versus Palo Verde), temporal (e.g., spot or next-day markets versus forward markets), or cross-commodity (e.g., capacity versus energy or gas versus power). "Convergence bidding" in California Independent System Operator (CASIO) markets is allowed.

- Portfolio positioning activities are allowed. MID's portfolio of energy and associated attributes may be positioned long or short within the limits of this policy for the purpose of attempting to reduce net purchased power costs.

2. Prohibited Purposes

- Dealing/Market making is not allowed. This involves (large numbers of) transactions to try and capture the (small) bid/ask spread for a commodity. A market maker stands ready to both buy and sell a commodity at market price. MID will be either a buyer or seller depending on its needs.

- Positioning the portfolio to be long or short outside the exposure limits of this Policy is prohibited.

- Wash trades are prohibited. Wash trading is simultaneous or near-simultaneous trades and offsetting trades done to affect reported trading volumes, revenues or prices.

- Sale of fictitious reliability services or congestion relief. MID shall not offer to sell services that it has no way of providing.

- False scheduling is prohibited. MID shall not falsely represent its projected loads and resources to a scheduling authority.

C. Parameters of Allowed Transactions

1. Commodity

Only transactions involving electrical energy, natural gas, and fuel oil are allowed. Transactions involving attributes associated with electrical energy are also allowed. These associated attributes include, but are not limited to: capacity, resource adequacy, emission allowances, and renewable energy credits. Trading in other commodities (e.g., corn, crude oil, etc.) are prohibited. The delegations of authority to transact contained in this policy do not extend to weather derivatives, credit derivatives, and coal; any transactions involving these products must go to the Board for approval.

2. Term and Tenure

For the purposes of this Policy, "term" means the duration of a transaction; "tenure" means the maximum time into the future that deliveries extend. The maximum allowed term of transactions is four years. For example, a transaction for deliveries starting on 1/1/2013 and ending on 12/31/2016 would have an allowable term. The maximum allowed tenure is the end of the fourth calendar year forward. For example, on March 1, 2013 a purchase of power for the summer of 2017 would have an allowable tenure because deliveries conclude before the end of calendar year 2017 (2013 + 4).

3. Location

Power and natural gas shall be transacted only at delivery points and index locations where MID controls assets or has price exposure. Power is confined to the Western Electricity Coordinating Council (WECC) region. MID has commodity gas exposure at Henry Hub and gas basis exposure at PG&E citygate. To the extent that the Board makes special authorization (outside this Policy) for gas pipeline capacity or purchase power contracts indexed to, for example, Alberta gas, the applicable locations are allowable. Locations unrelated to MID assets and/or prices exposures (e.g., Pennsylvania-Jersey-Maryland power or Chicago citygate gas) are prohibited.

D. Transaction Types

To execute a transaction, traders agree on the commodity, the term, the location, the quantity, the price, the contract type, and any clarifying terms. This section has addressed which commodities, terms, and locations are allowed. Quantities are controlled by Section IV, Exposure Limits. Below are the allowed and prohibited pricing structures, contract types, and clarifications.

1. Pricing Structure

a. Approved

- Both fixed and indexed pricing are allowable within the following limits. Index pricing can reference production costs or a price publication. Any published price used for indexing shall be from a reputable organization for a liquid trading hub. Questions on the suitability of indexes shall be resolved by Risk Management.

b. Prohibited

- Index pricing where an index from a disreputable publisher or illiquid trading hub is employed.

2. Settlement (physical versus financial)

a. Approved

- Both physical and financial settlements are allowable within the following limits. Physical transactions involve the delivery of actual electrical energy/capacity or gas molecules. Financial transactions are settled in cash instead of via physical delivery. Transactions must be specific as to whether they are physical or financial and the conditions for alternative settlement (e.g., financial settlement when physical settlement is impossible).

b. Prohibited

- Traders are not allowed to agree to transaction terms that alter the settlement features of master trading contracts (e.g., Western Systems Power Pool, Edison Electric Institute, International Swap Dealers Association, and North American Energy Standards Board). Examples of prohibited behavior would include altering liquidated damages clauses or giving the counterparty additional discretion to dictate financial versus physical settlement.

3. Contract Type

a. Approved

- Forward contracts
- Futures contracts
- "Simple" put and call options ("simple" as opposed to complex and multiplier structures, see prohibited list).
- "Plain vanilla" swaps ("plain vanilla" refers to fixed-floating and floating-fixed swaps with a pre-determined and constant notional quantity).
- Basis swaps where both indices float, but where a fixed differential is established (e.g., a transaction locking in the PG&E citygate index at 30 cents above the NYMEX settlement).

- First-order combinations of approved types including options-on-futures and swaptions.

- Gas tolling and gas tolling options where one party supplies (physically or financially) natural gas and receives from the other party a quantity of electricity based on a contractual heat rate.

b. Prohibited

- Uncovered written options (i.e., a written option with no physical resource or existing portfolio resources to offset the risk).

- Complex options (e.g., an option on an option).

- Options with a multiplier structure (e.g., option contracts with a variable quantity tied to an index with a multiplier – a put option with a strike price of $20/MWh and a quantity equal to 1,000 MWh multiplied by the COB index divided by the strike price).

- Swaps where the notional amount is not a pre-determined quantity .

- Higher-order combinations of approved types such as extendable swaps.

4. Other Terms

a. Approved

- With respect to regulatory reporting requirements (e.g., of the Dodd-Frank Act), traders are authorized to specify which party will report transactions.

- Traders are authorized to represent that MID is hedging and to specify regulatory categories that MID falls into (e.g., special entity and end user).

- Traders may sign transaction confirmations that repeat terms found in approved enabling agreements.

b. Prohibited

- Long form confirmations in lieu of a valid enabling agreement.

- Granting more credit than is done via the enabling agreement with a party (e.g., waiving a requirement that the counterparty post collateral).

E. Practices Discussed in FERC Market Behavior Documents

Investigations of trading activities in California's Power Exchange (PX) and Independent System Operator (CAISO) markets resulted in a list of activities that the Federal Energy Regulatory Commission (FERC) considers "gaming" or "anomalous market behavior". All of these activities are banned under this Policy. Note that there are also certain activities that FERC does not prosecute, but that are still prohibited at MID.

1. Activities Prohibited by FERC Market Rules

- **False import, also known as Ricochet or Megawatt Laundering**. This is described by FERC as a "fictional export-import parking transaction" where no power actually leaves the state of California. This Policy prohibits false representations and false scheduling, therefore false import schemes are prohibited by MID.

- **Cutting non-firm exports**. In this practice, a market participant schedules a non-firm counter flow on a congested transmission path. Then, after collecting a congestion payment, the schedule is cut. This Policy prohibits transactions that MID cannot perform on or does not intend to perform on.

- **Death Star**. This was a scheme to collect congestion payments without doing anything to relieve congestion. A congestion counter flow would be scheduled along with a series of imports/exports and a transaction with another control area to effectively send the same amount of power back to the point of origin, but no congestion relief would occur. The schedules would book out, but the CAISO still paid for congestion relief. This Policy prohibits the sale of false congestion relief.

- **Scheduling counter flows on out-of-service transmission**. Scheduling counter flows on out-of-service transmission is prohibited at MID. This Policy prohibits transactions that MID cannot perform on or does not intend to perform on.

- **Load Shift**. This is another form of false scheduling to create congestion and get paid to relieve it. The participant overschedules load in one zone and under schedules in another, thus creating apparent congestion in the direction of the overscheduled zone. The participant later adjusts schedules and receives a congestion payment. This Policy prohibits false representations and false scheduling.

- **Paper trading of ancillary services**. In this practice, a participant trades ancillary services even though they do not have the resources to provide the services they sell. This Policy prohibits the sale of fictitious reliability services and sales of ancillary services beyond what the District, in good faith, believes it can provide at the time when the sale is made. This Policy allows legitimate arbitrage of ancillary services markets as described in the following section.

- **Double selling of ancillary services**. This involves selling a resource as reserves in one market and selling it as energy in another. Again, this Policy prohibits transactions that MID cannot perform on or does not intend to perform on.

- **Selling non-firm energy as firm**. Firm energy requires operating reserves; non-firm does not. If a market participant acquires non-firm energy and sells it as firm, an unjust profit can be made because the participant avoids the expense of buying reserves. This is a false representation and is prohibited under this Policy.

2. **Activities not Prosecuted by FERC**

- **Under scheduling of load**. Utilities may attempt to influence market prices by altering load schedules. Although FERC did not prosecute this behavior, it involves false representations and is prohibited by this Policy.

- **Export of California power**. This issue was debated when California was attempting to cap power prices at a lower level than surrounding states. However, selling power that is produced in California and actually exported (unlike the false practices discussed above) is not illegal, does not violate rules or tariffs, and is not prosecutable by FERC. MID relies on purchases from out-of-state when it needs power and this Policy allows out-of-state sales when MID is surplus (in the absence of any legitimate emergency orders or superseding MID policies to the contrary). When selling power, operating personnel shall seek to maximize value for MID's customer-owners.

- **Ancillary services arbitrage**. Unlike the false paper trading of ancillary services discussed above, FERC has found that ancillary services markets can be legitimately arbitraged provided the market participant is buying and selling real, not fictitious, services. For example, reserves can be sold in a day-ahead market and bought back in an hour-ahead market to take advantage of systematic price discrepancies to the extent that the market participant has bona fide reserves available to make good on the transactions. This Policy allows the arbitrage of ancillary services markets to the extent that operating personnel have bone fide resources to cover the transactions and provided that applicable tariff provisions are followed (e.g., CAISO protocols for Convergence Bidding).

III. Exposure Limits

Exposure limits guide hedging activities so that energy price risk remains within MID's tolerance. MID's limit structure includes a Value-at-Risk (VaR) limit and position limits.

A. Value-at-Risk (VaR)

VaR measures risk across commodities, markets, and time frames. Total portfolio risk is rolled up into a single number, making it simple to monitor.

MID's VaR limit is as follows:

- VaR limit = $3,330,000 * Adjustor. The Adjustor is 1.0 as of 5/10/16 and thereafter changes with the year-on-year change in budgeted retail revenue with the adjustment becoming effective on the date that a new budget is adopted.
- 10-day holding period
- 95% one-tailed confidence interval
- (This specification means that one can say with a confidence level of 95% that, over the next 10 days, MID's energy portfolio will not experience a loss in value in excess of the VaR amount.)

VaR is based on *value* rather than *cash*. VaR encompasses gains and losses on positions for future time periods; those gains and losses may or may not be realized. Neither does VaR indicate the maximum amount that could be lost. VaR also requires a computer model for calculation. To mitigate these disadvantages, MID includes cash-based stress testing as part of its risk management program, which highlights extreme loss possibilities, and position limits, which are simpler to calculate.

B. Position Limits

Position limits are straightforward to understand and calculate, and also provide a bridge to long-term resource planning. MID's position limits are specified in terms of "percent covered". Percent covered is on a forecast energy-volume basis. Thus, if the resource plan projects that MID will have an energy need (wholesale and retail obligations) of 200,000 MWh for a given month and MID has 180,000 MWh covered for that month, the coverage would be 90%. Covered means that MID has locked in the pricing for a volume of energy. Fixed-price forward contracts or futures contracts are ways of covering. Projected energy volumes from MID's long-term contracts with Hetch Hetchy, MSR/San Juan, and Western Area Power Administration, while not perfectly fixed in price, are deemed covered for the purposes of the position limits. Resource planning assumed energy volumes from hydro and renewable resources are also deemed covered (MID's stress testing model captures the variability of these resources).

Gas tolling purchases (where MID receives power, but pays based on a gas price) are considered to provide coverage for the power volume, but create a corresponding amount of natural gas need. Call options are considered to provide coverage at 100% of the contract quantity if the option strike price is within 50% of the underlying market price at the time of the transaction.

When MID financially hedges its natural gas exposure, the New York Mercantile Exchange (NYMEX) component is considered to provide coverage at 75% of the contract quantity, while a corresponding basis swap provides coverage at 25%. Buy/re-sells or "one-to-ones" do not count in the percent covered calculations. For example, in the above 180,000/200,000 = 90% covered case, if MID contracted to buy 10,000 MWh at COB and sell 10,000 MWh at Palo Verde, the 10,000 would not be included in either the numerator or the denominator.

Wind resources are intermittent. Historically, there has been negative correlation between wind production and market price (i.e., when prices are high, there tends to be less production). To account for this effect, wind energy will provide coverage at 95% of projected volume.

The table below gives MID's acceptable coverage ranges (these levels must be achieved by the end of January each year and progress must continue throughout the year). No more than 15% of the coverage may be supplied with options.

	Power		Natural Gas	
	Year	Any Month	Year	Any Month
Current Calendar Year (CCY)	-	70%-105%	-	50%-105%
Next Calendar Year (CCY + 1)	75%-100%	60%-100%	40%-80%	30%-90%
Current Year plus Two (CCY + 2)	65%-95%	-	20%-60%	-
Current Year plus Three (CCY + 3)	-	-	0%-40%	-
Current Year plus Four (CCY + 4)	-	-	0%-20%	-

C. Exceeding Limits

If a limit has been exceeded, Risk Management will notify the Risk Oversight Committee and the personnel responsible for the area in which the limit has been exceeded. Such notification shall take place as soon as practicable after the limit violation is detected. In addition, Risk Management shall prepare a recommendation regarding hedging or liquidation possibilities. The Risk Oversight Team will determine a response.

IV. Transaction and Market Data Collection

Trading and risk management are data-intensive activities. Market data are used to evaluate deals, value transactions and estimate risks. A key feature of this Policy is the requirement that MID's energy portfolio be marked-to-market as part of VaR. Mark-to-market is not generally required for financial reporting purposes; rather, it is used to create a disciplined environment where losing transactions are recognized immediately. This section lists the data requirements for the risk management program.

A. Market Data Responsibilities

Risk Management is responsible for gathering market price, yield curve, volatility, and correlation data. This data must come directly from market sources, not MID's traders.

B. Data Sources

Whenever possible, the publicly available sources listed below shall be used. If such data is not publicly available, Risk Management will attempt to obtain bona fide dealer quotes.

Product	Source
Spot Power	Bloomberg, InterContinental Exchange (ICE), Dow Jones Indices, CAISO
Forward Power	Bloomberg, ICE, NYMEX
Spot Gas	Bloomberg, ICE, Gas Daily
Forward Gas	Bloomberg, ICE, NYMEX

C. Forward Curves

The forward curve is the term structure of forward prices. These are prices that could be locked in today for delivery during various periods in the future. Although the prices may be quoted with a bid/ask spread, risk analysis will generally use "mid" curves, which average the bid and ask prices.

A variety of forward curves are needed to value MID's energy portfolio. MID has exposure to power and gas prices in several locations. In addition, there are both on-peak and off-peak products in the power market. A forward curve must be produced for each product-location combination. Risk Management and IT shall develop and maintain software applications for processing data, generating the forward curves, and transferring the forward curves into the risk management system database.

D. Transaction Data Responsibilities

All energy transactions must be accounted for by Risk Management. The data capture requirements for each contract type are shown in the table below. It shall be the responsibility of Operations to provide this data to Risk Management.

Transaction Data Requirements		
Products	**Contract Types**	**Data Requirements**
All		• Settlement (Physical or financial) • Trade date • Delivery term • Counterparty • Buyer and seller • Product/underlying • Quantity (MWh, etc.) • Contract pricing • Broker and fee (if applicable) • Location • Enabling agreement (e.g., WSPP, NAESB)
Additional Data for Swaps	• Fixed/floating • Basis	• Principal or Notional amount • Rates (fixed, floating) • Day-count convention (if applicable)
Additional Data for Options	• Calls, puts • Physical/real asset	• Option type (call/put) • Strike price ($) • Strike date(s) • Exercise Type (American/European) • Premium amount ($)

E. Data Required for Value-at-Risk Analysis

Volatilities, correlations, and yield curves are also required to calculate VaR.

1. Volatility

Volatility is the annualized standard deviation of price changes. This parameter is used to model how far prices can move from their current levels. There are two methods for estimating volatility:

- Historical. Statistical calculations are applied to a time series of historical data (e.g., daily gas prices).
- Implied. Option prices are observed in the market, plugged into an option pricing model, and used to back-solve for volatility (volatility being a determinate of the option price).

Implied volatility is considered to be a purer market measure. However, there is currently not enough trading in electricity options to get representative figures using the implied method. Thus, Risk Management shall calculate volatilities using the historical technique. Risk Management shall use high quality, consistent data and shall consider tenure (near-by months will be more volatile than far-away months) in these calculations. If MID's risk system uses price models that incorporate additional parameters for price modeling (e.g., mean reversion coefficients), then Risk Management shall calculate those as well.

2. Correlations

Correlation measures the tendency of two prices to move together. For example, when natural gas prices rise, there is a strong tendency for power prices to rise. Correlations are used in risk management to quantify the value of diversification.

Calculating correlations presents some challenges. The source data must be gathered contemporaneously. If gas prices were sampled at 8 a.m. and power prices were sampled at 10 a.m., the correlations would be invalid. There is also a large amount of data involved. MID's portfolio encompasses several gas and power locations; on-peak and off-peak products; and the trading authorizations herein extend many months into the future. A correlation coefficient is needed for every combination of location, product, and month. There are well over 10,000 combinations in MID's case. MID shall use high quality, contemporaneous data to calculate correlations.

3. Yield curves

Yield curves are required for present value calculations and valuing swap transactions. The zero coupon yield curve shall be used for these purposes. Developing the zero coupon yield curve is an involved process involving bootstrapping and interpolation. However, it is part of the Bloomberg Professional Service to which MID subscribes. Risk Management shall use the zero curves from Bloomberg. In the event that Bloomberg becomes unavailable, Risk Management shall perform these calculations or determine a replacement data source.

V. Management Reporting

A. Objective

The objectives of risk management reporting are to communicate the market and credit risks assumed by MID and to show the results of trading and risk management activities.

B. Reporting Requirements

The following reports will be prepared by Risk Management:

1. Market Price Reports

a. Energy Market Updates

Energy Market Updates consist of general pricing information and market commentary from a non-technical perspective. These updates are prepared at the discretion of the General Manager.

b. Price Data

Pricing information, consisting of tabular data in electronic form, shall be collected on a regular basis. The data shall cover electricity and natural gas products at locations where MID has market positions. Prices from spot and forward markets are included. The data shall be maintained so that price reports can be produced as needed.

2. Position and Risk Reports

a. Portfolio Analysis Report

The analytic package in MID's Contango risk management system is called the Portfolio Analysis Module (PAM). The output results of PAM include the size of MID's market positions (reported in terms of "delta", the first derivative of value with respect to price), the mark-to-market value, and the value-at-risk.

b. Limit Tracking Report

The Limit Tracking Report is a comparison of actual positions and value-at-risk versus limits. This report shall be presented in graphical or tabular format.

3. Credit Reports

a. Credit Exposure by Rating Report

This report details credit exposure (the potential realized and unrealized losses that could be incurred by MID if a counterparty defaults in payment and/or delivery). Exposures are sorted by counterparty rating.

b. Credit Limit and Concentration Report

The Credit Limit and Concentration Report show credit exposure by counterparty. The percentage of MID's total credit exposure is also shown for each counterparty.

4. Stress Testing Report

MID's stress testing uses Monte Carlo simulation. Energy prices are modeled as stochastic processes where prices evolve randomly over time. The randomness is described mathematically and calibrated to observed market parameters. MID's portfolio is also modeled including statistical uncertainties in load, hydro and wind conditions. A simulation engine runs the model many times, each time sampling the probability distributions that describe MID's market positions and the market prices. Cash flow results are captured for each run. The results are presented in the form of a probability distribution for cash flow, which directly yields the risk at various levels of statistical confidence.

5. Operational Reports

a. Violations/Exceptions

Violations of and exceptions to these Policies shall be reported to the Risk Oversight Team as soon as practical. The Risk Oversight Team shall determine the appropriate course of action.

b. Collateral and Margin

Risk Management shall track collateral and margin outlays. Information shall be reported to Finance & Accounting as required.

c. Energy Derivative Assessment Report

Accounting standards require that certain derivative transactions be reported on MID's financial statements using fair value accounting, rather than accrual accounting. Transactions pursuant to this Policy must be evaluated for applicability and their fair values determined as of the end of the fiscal year. Risk Management shall produce a report for Finance & Accounting and MID's auditors for this purpose.

6. Hedge Performance Report

Hedge performance is benchmarked against the daily price indices for North Path 15 (power) and PG&E citygate (gas). The Hedge Performance Report is a comparison of the costs with and without risk management transactions. The cost with the transactions is the actual cost realized over a period. The cost without the transactions pulls out all the energy and costs of the risk management transactions and assumes the energy was bought at the index price. This is known as a "ratable" comparison.

C. Reporting Requirement Summary

The table below summarizes the reports including the intended audience, the frequency, and the contents.

Risk Reports

Report	Frequency	User	Details
		Risk Oversight Committee	•
Price Report	Weekly	Operations	• Power and gas prices • Spot and forward markets
Portfolio Analysis Report	Weekly	Operations	• Position delta values • Portfolio mark-to-market • Value-at-Risk
Limit Tracking Report	Bi-Monthly	Risk Oversight Committee	• Graph of VaR and position size versus limits
Credit Exposure by Rating	Quarterly	Risk Oversight Committee	• Graph of credit exposures by credit rating categories
Credit Limit and Concentration Report	Quarterly	Risk Oversight Committee	• Credit exposures versus limits for each counterparty • Percentage concentration
Stress Testing Report	Annual	Board of Directors Risk Oversight Committee Finance & Accounting	• Results of stress testing • Simulation and scenario analysis
Violation/Exception	As Needed	Risk Oversight Committee	• Violations of and exceptions to Policies
Collateral and Margin	As Needed	Finance & Accounting	• Cash flows into and out of collateral and margin accounts
GASB #53 Derivative Assessment	Annual	Finance & Accounting	• Fair values and GASB #53 applicability for energy deals
Hedge Performance Report	Annual	Risk Oversight Committee	• P&L, compare hedging to buying spot market energy

VI. Appendix: Board Resolutions Approving Risk Management Policy

Version 2.0 approved June 21, 2005

Version 2.1 approved December 12, 2006

Version 2.2 approved January 22, 2008

Version 3.0 approved January 26, 2010

Version 4.0 approved April 23, 2013

Version 5.0 approved May 10, 2016

RESOLUTION 2016-58
APPROVING REVISIONS TO THE MODESTO IRRIGATION DISTRICT
RISK MANAGEMENT POLICY

WHEREAS, the Board of Directors of the Modesto Irrigation District adopted a Risk Management Policy on May 26, 1998 and has amended the Policy several times, most recently on April 22, 2013; and

WHEREAS, in order to enhance this program, the District has identified certain improvements and updates to the Risk Management Policy.

BE IT RESOLVED, That the Board of Directors of the Modesto Irrigation District hereby adopts Version 5.0 of the Risk Management Policy document.

Moved by Director Blom, seconded by Director Wenger, that the foregoing resolution be adopted.

The following vote was had:

Ayes:	Directors Blom, Byrd, Campbell, Mensinger and Wenger
Noes:	Director None
Absent:	Director None

The President declared the resolution adopted.

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I, Angela Cartisano, Secretary of the Board of Directors of the Modesto Irrigation District, do hereby CERTIFY that the foregoing is a full, true and correct copy of a resolution duly adopted at a special meeting of said Board of Directors held the twenty-fourth day of May 2016.

Secretary of the Board of Directors
of the Modesto Irrigation District

MID Modesto Irrigation District — Water and Power

BOARD AGENDA REPORT

Complete all fields including resolution, if applicable. **Meeting Date:** May 24, 2016

Subject:	Risk Management Policy
Recommended Action:	Adopt resolution approving version 5.0 of the Risk Management Policy.
Background and Discussion:	MID's Power and Natural Gas Hedging Program operates within the limitations set by the MID Board in the Risk Management Policy ("Policy"). The Policy was adopted in 1998 and has been updated several times to reflect changes in energy markets, changes in the District's supply mix and to incorporate industry best practices. The Policy provides staff the authority to execute short-term hedging transactions in accordance with the goals set forth within the Policy, namely reducing volatility and providing price certainty in energy rates. Staff operates within the limits set forth in the Policy, specifically, position and value-at-risk limits. The last change to the Policy was in April 2013. Staff is now proposing further revisions to the document that are routine in nature, mainly refining the document to reflect updated procedures. The proposed changes are summarized below: • Update the value at risk limit to the current rate ($3.4M) and reset the adjustor to 1.0. • Change the name of the group that has authority for setting and approving procedures of the Policy from Oversight Committee to Risk Oversight Committee. • Set the frequency of reports from monthly to bi-monthly and consolidate reporting from the Oversight and Management Team to the Risk Oversight Committee.
Alternatives, Pros and Cons of Each Alternative:	1. Do not accept changes to the policy Pros: Existing policy that has worked well remains in place, no additional work to update document. Cons: Document does not reflect latest procedures and current reporting practices. 2. Accept changes to the policy Pros: The document is updated and reflects current practices . Cons: None.
Concurrence:	Electric Resources, Transmission & Distribution, Finance, Risk Oversight Committee.
Fiscal Impact:	The proposed changes to the Risk Management Policy do not have a fiscal impact.
Recommendation:	Adopt the proposed resolution approving revisions to the Risk Management Policy
Attachments:	Supporting documents attached:

Modesto Irrigation District
Water and Power

BOARD AGENDA REPORT

☒ Presentation ☒ Other supporting docs ☐ None attached

Note: Original contracts and agreements are housed in the Board Secretary's Office, phone (209) 526-7360.

Details listed above are accurate and complete to the best of my knowledge.

Presenter	Asst. General Manager	Interim General Manager
Jimi Netniss	Scott Van Vuren	Greg Salyer
5/6/16	5/6/2016	5/16/16
Date Signed	Date Signed	Date Signed