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Docket Number:	16-AFC-01
Project Title:	Stanton Energy Reliability Center
TN #:	222124
Document Title:	Stanton Energy Reliability Center LLC's Supplemental Response to Data Request A10
Description:	N/A
Filer:	Marie Fleming
Organization:	DayZen LLC
Submitter Role:	Applicant Representative
Submission Date:	1/10/2018 11:12:59 AM
Docketed Date:	1/10/2018

Updated CEQA Mitigation Strategy (12/2017)

A10. Please provide the mitigation strategy for all nonattainment criteria pollutants and their precursors to meet the Energy Commission's CEQA mitigation requirements, including NOx, VOC, SOx, PM10 and PM2.5.

Supplemental Response: The following supplements SERC, LLC's original response to Data Request A10. In the original response to Data Request A10, SERC, LLC explained that it is not required, under New Source Review (NSR) Rule 1304 (d)(1)(A), to acquire emission reduction credits to offset project emissions since it will be a minor NSR source for NO_x, PM10, SO_x, VOCs and CO. SERC, LLC did not propose any CEQA Offsets or other types of CEQA Mitigation for its criteria pollutant emissions because a study performed by ZGlobal concluded that the expected dispatch of the SERC EGTs would result in a net reduction of criteria pollutant emissions within the South Coast Basin and the South Coast Air Quality Management District (SCAQMD) would be offsetting the potential emissions of the SERC according to its rules. Since the time of the original response to Data Request A10, ZGlobal refined its analysis to identify operational dispatch changes to specific facilities resulting from the modeled dispatch of the SERC EGTs. The study is attached.

The ZGlobal Study considered predicted dispatches and operations of a whole host of gas-fired generation sources located within the South Coast Air Basin, and serving SCE and/or the CAISO market. The methodology described below considers those sources identified by the ZGlobal Study as impacted by the predicted SERC facility operation, for both with and without SERC conditions, and based on the predicted changes in operation, the emissions from the affected facilities were estimated.

The following is a brief explanation of the methodology used to calculate the potential emissions decreases of the five main criteria pollutants and CO_2 for affected sources in the South Coast Air Basin due to the modeled operation of the SERC facility. The following table is the key to be used when referencing the attached calculation workbooks. The ZGlobal Study report is included in Attachment 1.

Table DRA10-1 Workbook Key

Text ID	Workbook Name	Comments
WKB 1	SERC MIT CALC 1	Basic ZGlobal Study-predicted unit heat rate data by month for 2020
WKB 2	SERC MIT CALC 2	Basic ZGlobal Study-predicted unit heat rate data by month for 2020, with final annual heat rate totals and emissions factors, and emissions estimates
WKB 3	SERC MIT CALC 3	California eGRID data for 2014 (plant and unit data), all non-California data was deleted, and all non-essential CA data was also deleted
WKB 4	SERC MIT CALC 4	Additional facility data (heat rates, emissions, and emissions factors) derived from PTOs, EPA Title V permits, and CEC AFC docs
WKB 5	SERC MIT CALC 5	CA eGRID data with preliminary emissions and emission factor calculations

<u>Summary of Methodology to Predict Emissions Reduction Resulting from Addition of SERC</u>

1. The ZGlobal Study data, as identified for the gas-fired resources located in the South Coast Air Basin, was used to identify the affected sources, and the predicted heat rate changes on a monthly basis for 2020 (the year SERC is to be operational). **WBK 1**
2. The ZGlobal Study data was tallied to show the annual heat rate increases or decreases for each affected source, as well as the difference due to the operation of the SERC facility. **WBK 2**
3. The eGRID data for 2014 for the US was obtained from EPA. All of the non-California data was deleted. All data for non-essential CA sources not required for the mitigation analysis was also deleted. These deletions were done to make the size of the original eGRID file more manageable. The file has two tabs which show the plant and unit heat rate data for 2014 respectively. **WBK 3**
4. Emissions data for the identified affected sources, per the ZGlobal Study, were obtained from either the CARB emissions inventory database, or the SCAQMD FIND database. These emissions values were in units of tons per year (TPY). Emissions for 2014-2015 were used for most sources, although due to the schedule of emissions updates by the various air districts, some of the emissions are most likely for earlier years, i.e., 2012-2013, etc. These facility wide emissions were used in conjunction with the total annual heat rate values from eGRID to calculate estimated emissions factors in terms of lbs/mmbtu. In some cases, actual emissions factors derived from current PTOs, EPA Title V permits, and CEC AFC documents were used. The sole purpose of this exercise was to generate reasonable emissions factors for each affected facility in terms of lbs/mmbtu. **WBK 4 and WBK 5**
5. The resultant emissions factors in terms of lbs/mmbtu were then applied to the annual heat rate differences to estimate the amount of emissions increases and decreases with and without the SERC facility in operation in 2020, based on the ZGlobal Study heat rate predictions. The overall analysis and the final emissions differences are shown on the bottom portion of **WBK 2**.
6. It should be noted that these estimates, i.e., the emissions decreases shown on **WKB 2**, are subject to some variability due to the following:
   a. Heat rates and emissions factors were derived using the period 2012-2015, i.e. the most recent years available for each of the affected sources.
   b. Emissions factors as calculated were based on various combinations of emissions inventory years and 2014 heat rate data.
   c. The emission factors as calculated, based on facility wide heat rate and facility wide emissions may result in an over or under prediction of emissions for some individual units.

The outcome of the ZGlobal Study and the subsequent emissions displacement analysis are summarized in Table DRA10-2.

Table DRA10-2 Estimated Potential Emissions Displacement Resulting from SERC Operation (2020)

Parameter	Potential Reduction Value
Potential mmbtu/yr reduced from existing generation sources	1,016,407.9
Potential CO_2 reduced, tpy	54,822
Potential VOC reduced, tpy	0.9
Potential CO reduced, tpy	8.7
Potential NO_x reduced, tpy	8.3

Potential SO_x reduced, tpy	0.8
Potential PM10/2.5 reduced, tpy	4.1

Table DRA10-3 summarizes the SCAQMD Offset Trigger Thresholds, the SERC Facility Potential to Emit (PTE), the calculated mitigation emissions from Table DRA10-2 and the surplus/(deficits) for each pollutant. If SERC's availability to the CAISO market did not provide inherent emissions reductions as discussed above, the amount of mitigation the CEC would normally require would be equal to the SERC PTE.

Table DRA10-3 SCAQMD Emission Bank Credits Required By SERC

Pollutant	**PM10/2.5**	**VOC**	**NO_x**	**SO_x**	**CO**
SCAQMD Offset Trigger Thresholds, tpy	4	4	4	4	29
SERC Facility PTE[1], tpy	2.71	1.74	3.91	0.89	4.57
Displaced Emissions, tpy	4.1	0.9	8.3	0.8	8.7
Surplus/(Deficit), tpy	1.39	(0.84)	4.39	(0.09)	4.13
[1]Mitigation based on the first year of operation (potential to emit)					

As shown in Table DRA10-3, operation of the SERC will lead to emission reduction greater than SERC's PTE for all pollutants except VOCs and SO_x. However, while SO_x is considered a precursor to PM10/2.5 formation, the surplus mitigation of 1.39 tpy for the direct emissions of PM10/2.5 more than covers any CEQA requirements for the potential SO_x deficit of 0.09 tpy. Although a displacement deficit is predicted for VOCs (an ozone precursor), the VOC deficit of 0.84 tpy would be more than covered by the surplus NO_x emissions of 4.39 tpy, which would represent a 5.2:1 ratio of NO_x for VOCs. Therefore, operation of the SERC will not result in any net emissions increase of criteria pollutants within the South Coast Air Basin and would not result in impacts requiring CEQA mitigation.

Use of the SCAQMD Minor Source Bank

Notwithstanding that the SERC will not result in emission increases requiring CEQA mitigation, the SCAQMD will be required to provide emission reduction credits from its Offset Accounts for Nonattainment Air Contaminants as further described here. The SCAQMD is required to track all offset account debits for Federal NSR equivalency which allows the SCAQMD to demonstrate that there is no net increase in non-attainment pollutants. At the same time, the use of Offset Accounts allows the SCAQMD to accommodate for regional economic growth. Therefore, SCAQMD has assumed the responsibility of providing the necessary offsets for exempt sources, i.e. minor NSR sources (see Rule 1315).

The SCAQMD tracks all emission increases that are offset through the Offset Accounts for Federal NSR Equivalency, which includes the minor source bank and Priority Reserve, as well as all increases that are exempt from offset requirements pursuant to SCAQMD Rule 1304 – Exemptions (Minor Source Offset Account). These increases are all debited from SCAQMD's federal offset accounts when they occur at federal major sources. For federal equivalency demonstrations, SCAQMD uses an offset ratio of 1.2-to-1.0 for extreme non-attainment pollutants (ozone and ozone precursors, i.e. VOC and NO_x) and uses 1.0-to-1.0 for all other non-attainment pollutants (non-ozone precursors, i.e. SO_x, CO, and PM10/2.5) to offset any such increases.

SCAQMD's NSR Rules and Regulations are designed to comply with federal and state Clean Air Act requirements and to ensure that emission increases from new and modified sources do not interfere with efforts to attain and maintain the federal and state air quality standards, while not unnecessarily impeding economic growth in the South Coast region. Regulation XIII (NSR) regulates and accounts for all emission changes (both increases and decreases) from the permitting of new, modified, and relocated stationary sources within SCAQMD, excluding NO_x and SO_x sources that are subject to Regulation XX (Regional Clean Air Incentives Market, or RECLAIM).

One part of SCAQMD's NSR program is to offset emission increases in a manner at least equivalent to federal and state statutory NSR requirements. This is accomplished pursuant to Regulation XIII Rule 1315. To demonstrate equivalency, the SCAQMD's NSR program implements the federal and state statutory requirements for NSR and ensures that construction and operation of new, relocated, and modified stationary sources does not interfere with progress towards attainment of the National and State Ambient Air Quality Standards. SCAQMD's computerized emission tracking system is used to demonstrate equivalence with federal and state offset requirements on an aggregate basis.

Two important elements of federal non-attainment NSR requirements are Lowest Achievable Emission Rate (LAER) and emission offsetting for major sources. As set forth in SCAQMD's BACT *Guidelines*, SCAQMD's BACT requirements are at least as stringent as federal LAER for major sources. Furthermore, the NSR emission offset requirements that SCAQMD implements through its permitting process ensures that major sources provide emission reduction credits (ERCs) to offset their emission increases in compliance with federal requirements. As a result, these sources each comply with federal offset requirements by providing their own ERCs.

To support the use of the NSR offset program, Rule 1315, the Federal NSR Tracking System was adopted by the SCAQMD Board on February 4, 2011 to maintain SCAQMD's ability to issue permits to major sources that require offsets, but to also obtain offset credits from sources that are exempt from offsets under SCAQMD Rule 1304.

To support the offset program under Rule 1315, SCAQMD tracks all emission increases that are offset as well as all increases that are exempt from offset requirements pursuant to Rule 1304 – Exemptions. These PTE increases are all debited from SCAQMD's federal offset accounts when they occur at federal major sources.

As stated above, for federal equivalency demonstrations, SCAQMD uses an offset ratio of 1.2-to-1.0 for extreme non-attainment pollutants (ozone and ozone precursors, i.e. VOC and NO_x) and uses 1.0-to-1.0 for all other non-attainment pollutants (non-ozone precursors, i.e. SO_x, CO, and PM10) to offset any such increases from minor sources. That is, for federal sources 1.2 pounds are deducted from SCAQMD's offset accounts for each pound of increase to maximum allowable permitted potential to emit for VOC or NO_x, and 1.0 pound is deducted for each pound of increase to maximum allowable permitted potential to emit for SO_x, CO, or PM10/2.5. A more detailed description of federal debit accounting is provided in the Rule 1315 staff report and Rule 1315(c)(2).

Therefore, notwithstanding that the SERC will not result in emission increases within the basin that would require CEQA mitigation, based on the requirements of Rule 1304 and the offset accounts/tracking requirements under Rule 1315, SERC contends that the use of the SCAQMD offset account for minor NSR projects would fully mitigate the proposed project VOC and SO_x emissions that are in excess of the emission reductions shown in Table DRA10-2. Because SERC will displace higher emitting facilities with emission free spinning reserve, and the SCAQMD Rules require the offsetting by SCAQMD, additional CEQA air quality mitigation is unnecessary.

Attachment 1

ZGlobal Study Report

Assessment of Reduced Natural Gas Consumption due to Implementation of the Stanton Energy Reliability Center

Analysis Summary

Prepared for Stanton Energy Reliability Center LLC

Version 1.0

January 2018

1 Background

Stanton Energy Reliability Center LLC ("SERC") retained ZGlobal to perform an independent assessment and quantification of the gas-burn impacts that result from its proposed Electric Gas Turbine (EGT™) Hybrid System in Southern California. SERC includes two (2) 10 MW/5MWh Battery Energy Storage Systems ("BESS") that are fully integrated with new gas turbines via a supervisory control system. The EGT™ can provide energy and ancillary services to the power grid including supporting system inertia, voltage support requirements, and other commitment constraints as well as capacity for frequency response, regulation, spinning and non-spinning reserve. With the EGT™ incorporated into the supply mix, these grid services can be provided at lower costs and with fewer emissions than traditional thermal resources.

2 Study Methodology and Approach

The objective of this study is to quantify the potential emissions reduction due to the implementation of SERC at the Barre location (City of Stanton) in Southern California. Utilizing PLEXOS Integrated Energy Model for production cost simulation, ZGlobal ran 8760-hour production cost simulations for a 2020 study year to determine the least cost dispatch for the California ISO grid for two scenarios:

- Scenario 1 - without the SERC EGT™, and
- Scenario 2 - - with the SERC EGT™.

The emissions reduction was quantified by calculating the gas-burn difference between the two scenarios for hours when the SERC EGT™ resources were selected for procurement by the PLEXOS model for spinning reserve, recognizing that the EGT™ provides emissions-free spinning reserve via use of the its fully integrated BESS.

The gas-burn for the Northern California (PGAE) and Southern California (SCE and SDGE) regions were computed separately based on the hourly dispatch from natural gas-fired resources in each region multiplied by each resource's respective average heat rate. ZGlobal utilized PLEXOS Integrated Energy Model for the production cost simulation to derive hourly generation dispatch, nodal and aggregated load area prices, ancillary services marginal prices, and gas burn subject to transmission and other operational constraints. Input assumptions for ZGlobal's production cost model are provided in Appendix A.

The results of the production cost runs were also used to calculate energy and ancillary services costs impacts to California consumers. ZGlobal ran production cost optimizations for each month for each scenario.

3 Overview of Results

The reduced annual fuel burn impact for the Southern California-LA Basin area was 1,021,741 mmBTU/yr. The study showed that when SERC is operating as a spinning reserve resource it tends to replace Southern California gas-fired resources more significantly than other CAISO system resources.

The addition of SERC EGT™ capability to the supply mix allowed more efficient energy dispatch on a net annual basis. The EGT™s have these general impacts for driving energy or ancillary services cost savings:

1. Lowers overall dispatched HR in the system.
2. Provides for less commitment of higher cost generators for the outlook period.
3. Provision of reserves from the EGT™s displaces reserve provision from other units resulting in those units being more efficiently dispatched for Energy or used for other ancillary services at a lower overall cost to the system.

The production cost analysis also determined that the annual utilization rate for the 2-EGT™ system at SERC is 100% (Table 1). The study showed most of the usage (90.6%) will be to provide spinning reserves to the system. SERC is also selected by the PLEXOS model to deliver energy primarily as a means to also provide regulation service for 7.3% of its total awarded hours. When delivering energy for regulation service, SERC is operating at 50% of its Pmax. Only 3.7% of its awarded hours are used to provide non-spin reserves.

Table 1. SERC Utilization Rates

Hours Awards Received	Energy*	Regulation	Spin	Non-Spin	Total Hrs	Total Hours Awarded
SERC 2-EGT™s						
Annual	641	619	7936	322	**8760**	100.0%
Average/mo.	53	52	661	27	739	100.0%
Percent of Total Usage	*7.3%*	*7.1%*	*90.6%*	*3.7%*		

**Energy hours overlap with Regulation or Spin hours as the unit was at times selected to provide energy plus either regulation or spin in certain hours.*

Appendix A

Production Cost Model Assumptions

The study utilizes a model built in PLEXOS Integrated Energy Model for a 2020 study year. The model is based on the California Independent System Operator (CAISO) full network model and incorporates similar assumptions used by CAISO for their transmission planning studies. The transmission model includes the latest CAISO-approved transmission projects as documented in the 2016-2017 Transmission Plan, dated March 17, 2017[1], and incorporates the assumptions described in this document for (i) demand forecast, (ii) generation including imports, and (iii) fuel price forecast.

Demand Forecast

The load forecast is modeled by utilizing the California Energy Commission (CEC) peak load forecasts as detailed in the "California Energy Demand 2016-2026, Revised Electricity Forecast" report, dated January 2016.[2] for the mid energy demand case. The particular details derived from the report are the electricity deliveries to end users in GWh and the 1-in-2 Net Electricity Peak Demand (in MW) for each Investor-Owned Utility (IOU). These values are used along with historical hourly load profiles for the three largest IOU areas published by CAISO on OASIS to develop demand profiles for all 8760 hours in the relevant study years. The peak load values and resulting demand profiles are purely load and do not include losses or pump load. Table 2 provides the 2020 "1-in-2" peak load and energy assumptions from the CEC report used to create the 8760 hourly demand profiles for the model.

Table 2. 2020 Demand Forecast

1-in-2 Peak Demand MW and Annual GWh			
YEAR	**IOU**	**Peak Demand (MW)**	**Annual GWh**
2020	PG&E	21,345	106,490
	SCE	23,005	110,225
	SDG&E	4,654	21,574

California Pumps

The California aqueduct imposes a significant amount of load on the system. Figure 1 provides a breakdown of the pump dispatch based on seasonal averages.

1 http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf

2 https://www.google.com/url?q=http://www.energy.ca.gov/2015_energypolicy/documents/&sa=U&ved=0ahUKEwj9zaDE74bVAhWLiVQKHbTXB_sQFggEMAA&client=internal-uds-cse&usg=AFQjCNFqAD8X6Ohdd52yMfpjbrgke6AuxA

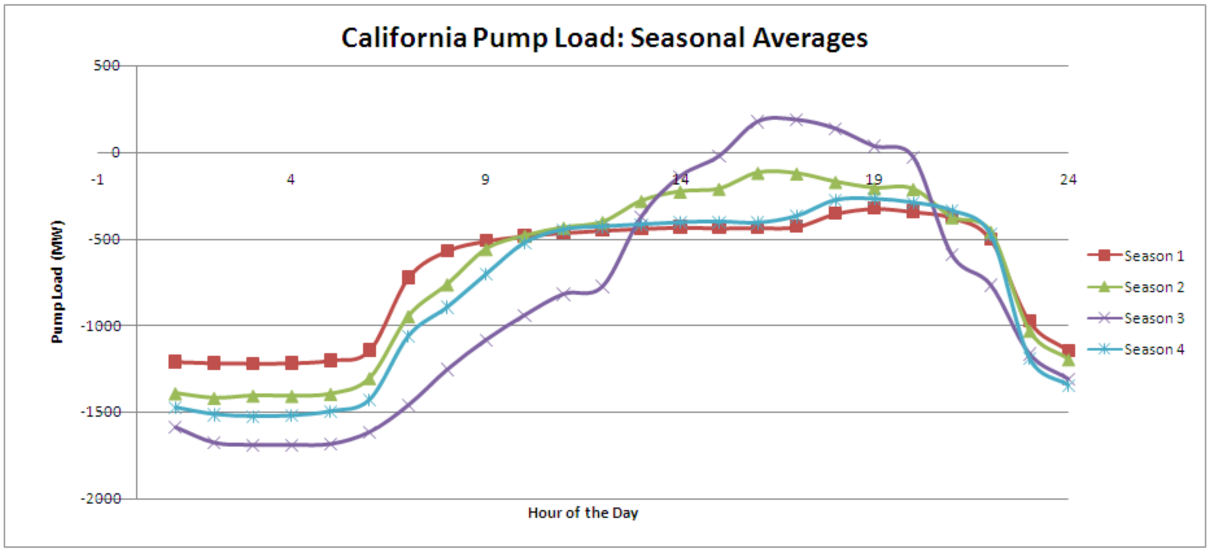

Figure 1. California Pump Load (Seasonal Average)

Generation

The ZGlobal model includes the existing generation modeled in CAISO's 2016-2017 transmission planning base cases per Appendix A of its Unified Planning Assumptions and Study Plan[3], including planned generation projects modeled are listed in its Table A2-1 and the major generation retirements listed in its Table A3-1.

Thermal Generation

Natural gas fired generation represents approximately 33% of the Supply dispatched in the study. Natural gas fired generation resources are modeled using heat rates, start-up costs, minimum load, minimum up/down times, and ramp rates. Heat rates for thermal resources are derived from multiple sources, including:

- Historical bid data analyzed from CAISO data published between 2010 and 2017[4],
- Heat rates and ranges published in the production cost models utilized for the studies performed for the 2016-2017 Transmission Plan, and
- Manufacturer specifications for the specific generator-type.

Table 3 shows sample Incremental Heat Rate curves used in the ZGlobal model for the 3 natural gas fired generator types.

[3] http://www.caiso.com/Documents/Final2016-2017StudyPlan.pdf

[4] CAISO publishes bid data with reference identification numbers for each generator, in order to obscure the actual generator name and its corresponding bids. ZGlobal used known public information about the generation fleet, such as generator size, to match generators to bids to the extent possible. Where not possible, ZGlobal used other means to estimate heat rates. The other means primarily include the copying of bids of known generators to other generators whose actual bids are not known; or using representative general heat rate curves for specific resource types (combined cycle, gas turbine, steam turbine) from publicly available sources scaled to match the appropriate resource size.

Table 3. Heat Rate Curve Examples for 3 Types of Gas Fired Generators

Combined Cycle			
Load Point	245.6	MW	1
Load Point	368.4	MW	2
Load Point	491.2	MW	3
Load Point	603.6	MW	4
Heat Rate	8266.2	BTU/kWh	1
Heat Rate Incr	5690.5	BTU/kWh	2
Heat Rate Incr	5331.1	BTU/kWh	3
Heat Rate Incr	5990	BTU/kWh	4

Combustion Turbine			
Load Point	18.2	MW	1
Load Point	45.42	MW	2
Heat Rate	10808	BTU/kWh	1
Heat Rate Incr	10808	BTU/kWh	2

Thermal			
Load Point	10	MW	1
Load Point	50	MW	2
Load Point	95	MW	3
Load Point	121	MW	4
Load Point	141	MW	5
Load Point	151	MW	6
Load Point	161	MW	7
Load Point	175	MW	8
Heat Rate	7829	BTU/kWh	1
Heat Rate Incr	9747	BTU/kWh	2
Heat Rate Incr	9922	BTU/kWh	3
Heat Rate Incr	10108	BTU/kWh	4
Heat Rate Incr	10268	BTU/kWh	5
Heat Rate Incr	10376	BTU/kWh	6
Heat Rate Incr	10586	BTU/kWh	7
Heat Rate Incr	10586	BTU/kWh	8

Once-Through-Cooled Power Plants

In May 2010, the State Water Resources Control Board (SWRCB) adopted a policy regulating the use of seawater for cooling purposes at power plants in California. At the time of its adoption, 19 power plants in California utilized a Once-through-Cooling (OTC) process and were required by law to comply with the policy or have mitigation plans in place for compliance at a future date. Table 4, lists the OTC units in the CAISO by Local Capacity Area (LCR), along with its SWRCB compliance date and the operational status assumed in ZGlobal's model.

Table 4. Assumptions for OTC Generation within the CAISO[5]

LCR Area	OTC Units	SWRCB Compliance Date	Assumptions for ZGlobal Model
Humboldt	Humboldt Bay PP (133 MW)	2010	Retired July 2010 and replaced with repowered CTs (163 MW total)
Greater Bay Area	Contra Costa 6 and 7 (340MW Each)	2017	Retired - Replaced in 2013 with Marsh Landing Generation Station (774 MW)
	Pittsburg 5 and 6 (312 and 317 MW respectively)	2017	Assumed off-line
	Potrero 3 (207 MW)	2011	Retired
Los Angeles Basin	Alamitos 1 and 2 (175 Each)	2020	Retired Units 1 through 6 and replaced with 640 MW combined cycle facility.
	Alamitos 3 (320 MW)		
	Alamitos 4 (320 MW)		
	Alamitos 5 and 6 (480 Each)		
	El Segundo 3 and 4 (335MW Each)	2015	Re-powered project Combined Cycle 510 MW (Online 2013)
	Huntington Beach 1 and 2 (226 Each)	2020	Retired Units 1 and 2 and replaced with 644 MW combined cycle facility.
	Huntington Beach 3 and 4 (227 Each)	2020	Retired - Generation facility converted to Synchronous Condensers in 2013
	Redondo Beach 5 (175 MW)	2020	Assumed retired in study.
	Redondo Beach 6 (175 MW)	2020	Assumed retired in study.
	Redondo Beach 7 (480 MW)	2020	Assumed retired in study.

[5] Additional facilities impacted by SWRCB that are outside CAISO include Haynes Generating Station Units 1&2, 5&6 and 8, Scattergood Generating Station Units 1&2 and 3 and Harbor Generating Station.

LCR Area	OTC Units	SWRCB Compliance Date	Assumptions for ZGlobal Model
	Redondo Beach 8 (496 MW)	2020	Assumed retired in study.
	San Onofre (2246 MW)	2022	Retired in June 2013
Big Creek/Ventura	Mandalay 1 and 2 (215MW each)	2020	Assumed retired in study.
	Ormond Beach 1 and 2 (741 and 775 MW respectively	2020	Assumed retired in study.
San Diego	Encina 1 (107MW)	2017	Retire 2017 - Replace with Carlsbad Energy Center
	Encina 2 (104MW)		
	Encina 3 (110MW)		
	Encina 4 (300 MW)	2017	Online
	Encina 5 (300 MW)	2017	Online
	South Bay 1 and 2 (136MW Each)	2012	Retired in 2010-2011
	South Bay 3 (210MW)		
	South Bay 4 (214MW)		
Other in non-LCR Area (Central Coast)	Morro Bay 3 and 4 (300MW Each)	2015	Retired in 2015
	Moss Landing 6 and 7 (754 and 756 MW respectively)	2017	Dynegy plans to cease operation by December 2020, it is assumed offline in this study.
	Moss Landing 1 and 2 (510MW Each)	2017 (replacement needed)	Online – owner has until December 2020 to implement technology changes for compliance
	Diablo Canyon PP (2190 MW)	2024	Online through 2024

Moorpark Sub-Area Local Capacity

As shown in Table 4 this study assumes planned retirement of the Mandalay and Ormond Beach generating facilities. Those retirements coupled with cancelled plans for a replacement generation facility (Puente Project), leaves a capacity deficiency in the CAISO's Moorpark LCR sub-area. The CAISO in coordination with SCE developed and studied three alternative scenarios[6]. This study assumes local capacity requirements are met with Scenario 2 as described in the August 16, 2017 paper which includes the base distributed resource assumptions common to all scenarios of 80 MW of demand responsive behind-the-meter energy storage and 25 MW of hybrid PV solar plus battery storage.

EGT Assumptions

The study assumes the EGT™ system can be modeled as a multi-stage generator in the CAISO's full network model with the following configurations:

- **Configuration 1** – Unit operating range is from 0.0 to 0.01 MW with no start time or commitment cost. In this configuration, the EGT™ is available for 49.9 MW spinning reserve at $0 opportunity cost. Since the resource is not burning fuel, it is providing GHG-free capacity.
- **Configuration 2** – Unit operating range is from 0.01 to 49.9 MW with no transition time from the first configuration. The transition cost was set to be equal to the LM6000's start cost which was derived from data obtained from CAISO's production cost database used in its 2016-2017 Transmission Plan. The EGT™ is able to provide regulation in the operating range between 25 and 49.9 MW.

[6] http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf

Heat rate for each of the LM6000's is modeled with a heat rate of 11,700 Btu/kWh when operating at its regulation minimum of 25 MW and with incremental heat rate 9,600 Btu/kWh from minimum to 49.9 MW. Since the primary purpose of the study was to quantify fuel burn impact, the battery charging load was not modeled. Locations of all the EGT systems used in the study are listed in Table 5.

Table 5. Location for the EGT systems modelled in the Study

Scenario(s)	Resource(s)	IOU Area
Base SERC EGT	ETIWND_6_GRPLND_EGT	SCE
Base SERC EGT	CENTER_6_PEAKER_EGT	SCE
SERC EGT	SERC_6_1_EGT	SCE
SERC EGT	SERC_6_2_EGT	SCE

Hydro Generation

An average hydro generation profile is used for the study. Hydro capacity factors were derived using CAISO historical hourly generation output from 2010 through 2015. The hourly capacity factors were applied uniformly to all hydro generating resources in the model and the total hydro production by season is provided in Table 6. Hydro represents approximately 11.4% of total Supply for the study year.

- Spring: Mar 1 through June 30
- Summer: July 1 through September 30
- Fall/Winter: October 1 through Feb 28

Table 6. Hydro Generation Output

Hydro Generation (GWh)	Spring	Summer	Fall/Winter	Total
2020 Study Year	11,850	8,251	8,775	28,876

Renewable Energy Generation Summary

The ZGlobal model, as a basis, incorporates renewable capacity to achieve 33% of electricity sales by 2020. ZGlobal referenced CEC and CPUC's recommended study portfolios for CAISO's 2015-2016 planning process to determine the installed capacity to be modeled for each CREZ[7]. Generation is modeled either specific to a queued position or by way of a proxy generator to meet the recommended capacity for each CREZ. Total dispatch from renewable resources represented approximately 19.1% of the total Supply, factoring in curtailments.

Wind Generation

Wind generation resources are modeled using an approach similar to that of hydroelectric resource modeling. ZGlobal uses monthly capacity factors based on observed hourly wind generation patterns as reported by the CAISO to apply to individual wind resources. On average, wind resources generally

[7] Refer to Table 4.1-1 in the 2015-2016 CAISO Transmission Plan for a listing of target installed MW values per CREZ. Per letter dated June 13, 2016, CPUC and CEC directed CAISO to use same RPS portfolio as the 2015-2016 planning process in the 2016-2017 Transmission Planning studies.

produce the most power in the early morning (off-peak) and less during the mid-day hours. Figure 2 illustrates the average hourly wind generation profile curve. The annual capacity factor of the modeled wind resources is 24%. Wind production from CAISO resources in the study year was 11.99 GWh, or 4.7% of total Supply.

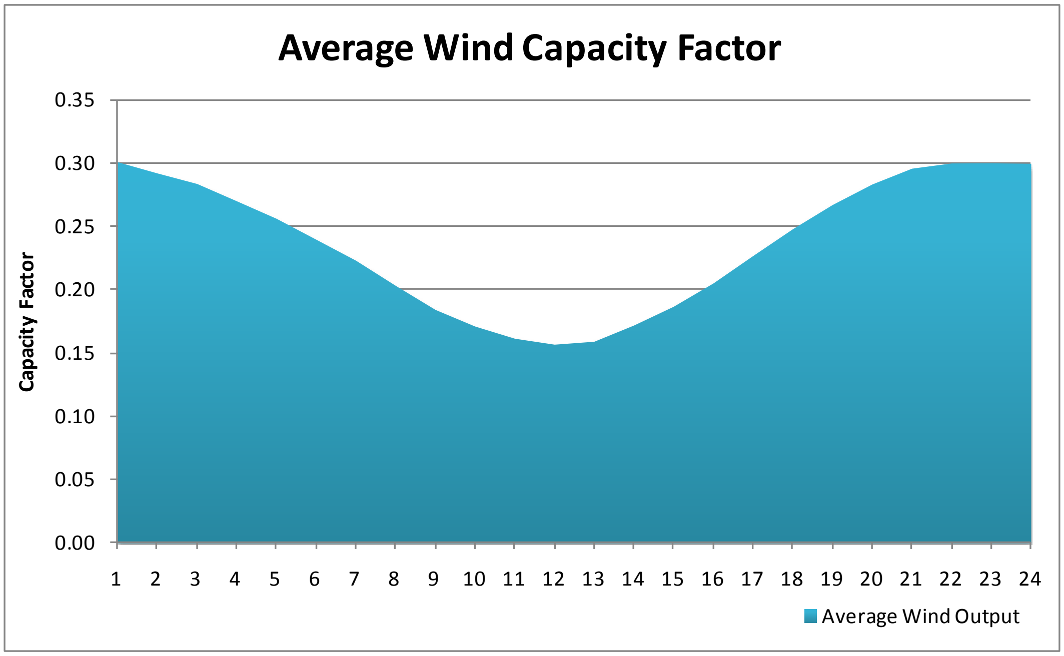

Figure 2. Average Hourly Wind Capacity Factor (Annual)

Solar Generation

An approach similar to that used for wind is used to develop solar production curves. Production by solar generation plants is assumed to peak in the summer months. Figure 3 shows average hourly capacity factor for solar units. Solar production from CAISO resources in the study year was 18.28 GWh, or 7.2% of total Supply.

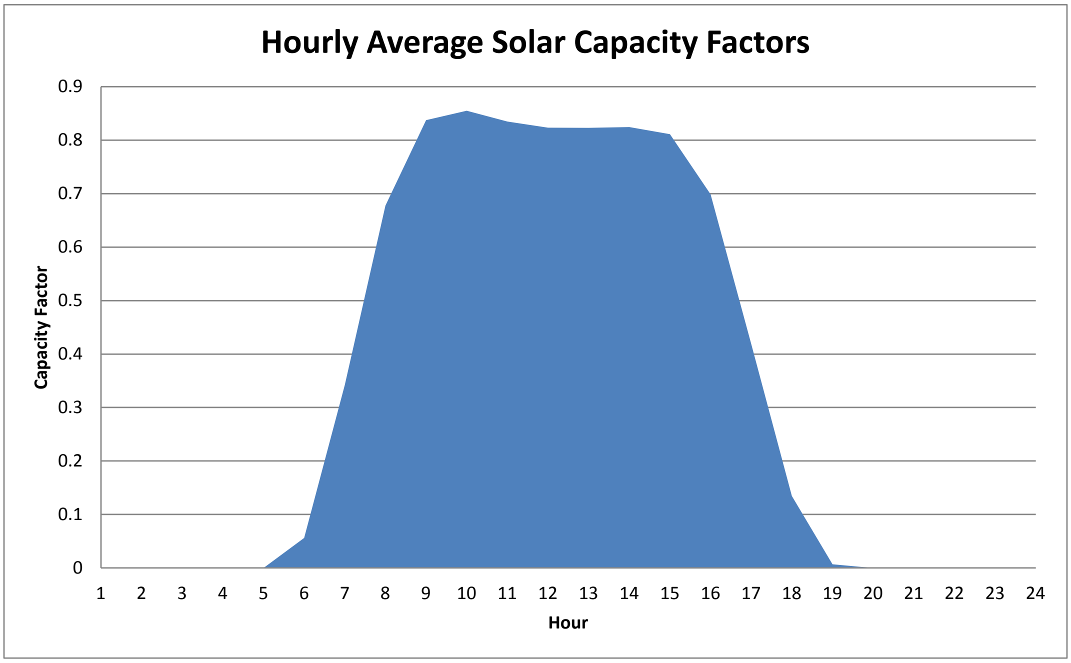

Figure 3. Average Hourly Solar Capacity Factor (Annual)

Biomass Generation

The production profile of Biomass generation is assumed to be constant throughout the day and fluctuate slightly by season. The assumption for the daily peak annual profile dispatch ranges between .80 to 1.0 capacity factor for summer and winter respectively. Total production from Biomass generation was 5.9 GWh, or 2.3% of all Supply.

Geothermal Generation

The production profile of Geothermal generation is assumed to be at full load during peak hours and 95% of full during the off peak hours. During the summer months however, there is a slight de-rate associated with the higher temperatures. The profile is assumed 95% of full load on and off peak during the summer months. Total production from Geothermal generation was 12.1 GWh, or 4.8% of all Supply.

Imports

Each import is designated as one of two types: Base Loaded and Mixture. Base Loaded imports are modeled as pre-defined hourly dispatches at the relevant import location using historical flows. Import locations designated as "Mixture" are modeled with a Heat Rate curve to represent a range of generation imported from outside the CAISO. The Heat Rate in Table 7 is an example such a curve that is used in the model and is derived from historical public bid data. Annual Imports represented 25.6% of the total Supply for a total of 64.6 GWh.

Table 7. Import Curve

Load Point	Heat Rate
200	1000
600	4781

Load Point	Heat Rate
1000	7700
1200	8192
1400	8684
1600	9176
1800	9668

Fuel Forecast

Fuel prices ($/MMBtu) are based on ICE (Inter-Continental Exchange) end-of-day reports (Table 8).

Table 8. 2020 Fuel Price Forecast

2020 ($/MMBtu)			
Month	PG&E	SCE/SDG&E	IMPORT
Jan	3.249	3.189	2.689
Feb	3.224	3.1465	2.6715
Mar	3.1825	3.1275	2.605
Apr	2.845	2.405	2.2775
May	2.822	2.482	2.252
Jun	2.8545	2.527	2.287
Jul	2.9365	2.7165	2.319
Aug	2.955	2.7275	2.3725
Sep	2.949	2.5415	2.3515
Oct	2.9335	2.4835	2.356
Nov	3.092	2.927	2.5445
Dec	3.2065	3.1115	2.734