Southwest Import Capacity

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6/12/2014

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1.0 INTRODUCTION

The Northwest Power and Conservation Council asked Energy GPS to examine the potential for exports from California to the Pacific Northwest for October 2018 through September of 2019 for the purpose of reliability planning. Energy GPS developed a model to test available margins for export under different assumptions based on likely resource supply and energy loads in those scenarios. We have attempted to be conservative in our modeling efforts; when deciding on data or assumptions to use in the model we erred on the side of less capacity or more load when given the choice. The Summary of Findings highlights the results of the modeling. The sections following the Summary detail the thinking and assumptions underlying each component of the model.

2.0 SUMMARY OF FINDINGS

Supply MW		**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**
	Demand Response	2,512	2,512	2,512	2,537	2,537	2,537	2,537	2,537	2,537	2,537	2,537	2,537
	Hydro	5,255	3,540	3,244	2,483	2,431	3,208	3,354	4,744	6,043	6,815	6,275	6,081
	Nuclear	1,909	1,793	2,066	2,203	1,933	1,909	1,938	1,645	2,102	2,243	2,129	2,169
	Natural gas	37,399	34,926	37,229	37,098	33,425	33,132	32,098	33,942	36,757	38,136	38,353	38,292
	Biomass, geo, etc	3,518	3,518	3,518	3,525	3,525	3,525	3,525	3,525	3,525	3,525	3,525	3,525
	Wind	385	116	580	443	576	1,134	1,037	3,039	1,359	2,579	2,408	736
	Solar	567	1,226	816	139	194	83	876	1,932	12,270	3,600	5,647	4,360
	Pumped Storage	2,943	2,943	2,943	2,943	2,943	2,943	2,943	2,943	2,943	2,943	2,943	2,943
	Other Storage	719	719	719	719	719	719	719	719	719	719	719	719
	Non-PNW Imports	7,183	7,183	7,183	7,766	7,766	7,766	7,766	7,766	7,766	7,766	7,766	7,766
	Total	62,390	58,475	60,809	59,855	56,049	56,956	56,792	62,790	76,020	70,862	72,302	69,127
Net Availability - in state													
	Demand	(37,918)	(35,778)	(40,136)	(40,538)	(37,533)	(37,107)	(36,618)	(36,847)	(55,545)	(60,479)	(64,343)	(59,576)
	Reserves - hydro	(263)	(177)	(162)	(124)	(122)	(160)	(168)	(237)	(302)	(341)	(314)	(304)
	Reserves - Other	(2,286)	(2,257)	(2,582)	(2,664)	(2,457)	(2,373)	(2,328)	(2,247)	(3,465)	(3,756)	(4,065)	(3,745)
	Supply	62,390	58,475	60,809	59,855	56,049	56,956	56,792	62,790	76,020	70,862	72,302	69,127
	Net Margin	21,923	20,264	17,929	16,529	15,937	17,316	17,678	23,459	16,707	6,285	3,580	5,503
	% Margin	35.1%	34.7%	29.5%	27.6%	28.4%	30.4%	31.1%	37.4%	22.0%	8.9%	5.0%	8.0%
	Historical Avg ATC S>N	3,126	3,726	4,135	4,495	4,259	3,837	3,879	3,852	3,957	4,228	4,270	3,669

During the peak PNW demand hour using conservative assumptions, California has excess supply to more than fill the AC and DC interties, from south to north, during the winter months. For these months, California can reasonably be expected to export MW to the PNW should there be sufficient economic incentive. Only during the summer is there insufficient MW to fill the interties up to historical average ATC. The scenario pictured uses the 25th percentile wind and solar production; California demand is scaled from mid-case (i.e. 1:2) non-coincident peak as projected by the CEC.

3.0 CAPACITY

There are two inter-related themes that are driving what new capacity will be built. One theme is the build out of intermittent resources in response to state renewable portfolio standards (RPS). By 2019 the RPS target will increase to between 29% (2018) and 31% (2019) of load from today's standard of 20%. This will result in 35,000 MW of new renewables connecting to the grid between now and 2019. The renewable build out has already been felt in the electricity commodity markets in California. Over the last several years prices have been low, and the expectation is they will remain that way for the foreseeable future. A second theme is that capacity additions will be dictated almost entirely by utility procurement – long term power purchase agreements will be required for any capacity to be developed in the next five years, and possibly longer. Because of the build out of the renewable fleet, the expectation is that the market will be over-supplied with energy a significant portion of the time. In today's market, combined cycle natural gas plants earn very little money. As a result, the only new thermal capacity will be developed to meet a need for capacity, not based on expectations of merchant energy profits. This marks a change from the last 15 years where a great deal of new capacity was initially developed and often built on a merchant (or partially merchant) basis. Accordingly, the amount of capacity that will be installed in California in 2019 will be driven by six factors.

1. Existing capacity.
2. Thermal capacity currently under construction.
3. New renewable capacity installed to meet RPS requirements.
4. New thermal and storage capacity installed to address local reliability.
5. Planned retirements.
6. Demand response.

The model developed by Energy GPS addresses each of these factors. The main model drivers are described below.

3.1 Existing Capacity

Existing installed capacity serves as the starting point of the analysis. The California Energy Almanac, published by the CEC, contains all plants larger than 0.1 MW in the state. Energy GPS aggregated the plant-by-plant data into resource categories to develop a bottom-up method estimate of the current California generation capabilities.

Table 1- Current California Installed Capacity MW by Resource Type

Natural Gas	47,084
Wind	6,488
Solar	2,211
Hydro	13,556
MSW	99
Digester Gas	86
Landfill gas	367
Biomass	1,097
Coal	342
Geothermal	2,603
Nuclear	2,323
Total	76,255

3.2 Thermal Capacity Under Development

By statute, the CEC licenses all thermal generation in excess of 50 MW. They publish information related to the status of projects throughout the approval process. They provide a variety of descriptors for projects such as “Under Construction”, “Pre-Construction”, and “On Hold.” The CEC provides information about percentage of completion and expected online date, if known, for these resources. They also provide details for projects that are still under review. Currently, there are 2,714 MW approved and in pre-construction of which we assume 1,281 MW will be available by 2019.

3.3 Additional Renewable Resources

California load serving entities are required to meet the RPS obligations under Senate Bills 1078, 107, and 2. Unlike thermal generation, which is easily tracked through the CEC licensing process, it is more difficult to track the additional renewable resources that will be coming online between now and 2019. Both the investor-owned utilities and publicly-owned utilities have large renewable procurement plans under way. The CPUC provides public data related to IOU renewable procurement. For a variety of reasons, the quality of this data is variable. For example, there is a significant failure rate for projects that have power purchase agreements that have not been constructed. While it would be possible to review the list in an effort to pick winners and losers, such an effort is beyond the scope of this project. The publicly-owned utilities reveal information about RPS procurement through integrated resource plans and public meeting minutes. Again, obtaining high quality information about the resources coming online to serve publicly-owned utility load is also beyond the scope of this project.

Fortunately, there is an effective alternative to a bottom-up approach for the renewable sector. The RPS targets call for 29% of load to be met with renewables in 2018 and 31% in 2019. Energy GPS used a top-down approach for the additional renewable resource category. The following bullets describe this process:

- Assume that entities with an RPS compliance obligation exactly meet that obligation in the appropriate year. Based on the procurement activity observed to date, it appears that utilities will meet or exceed their RPS obligations moving forward.
- Calculate total energy needed to meet RPS standards. This is done by starting with the long term CEC load forecast, grossing the load up for line losses, and subtracting load without a compliance obligation (e.g. Metropolitan Water District).
- Allocate the gross renewable energy demand into renewable resource capacity. Convert the % of load obligations into capacity obligations for each type of renewable resource. The split between the different renewable technologies is based on CPUC data. The major technologies include solar PV, wind, biomass, geothermal and biogas. Due to uncertainty on the viability of solar thermal, we assumed all solar thermal will ultimately be converted to solar PV[1].
- Allocate in-state vs out of state. There is a complex bucket categorization between in-state and external resources, as utilities procurement of non-California capacity is limited going forward. Based on these regulations, we reduced the volume of new generation by 10% to account for resources developed out of state and not directly scheduled to California.

3.4 New Thermal and Storage Resources

The CPUC has several new generation procurement proceedings underway. Using input from the CEC and the CAISO, the CPUC has calculated local capacity needs as well as system capacity needs. It is through these proceedings that the investor-owned utilities receive authority to purchase via power purchase agreements or build new resources. In order for a thermal resource to meet an online date of 2018 to 2019, it would have to execute a power purchase agreement by 2014. The only investor-owned utility with active local reliability procurement RFO at this time is Southern California Edison (SCE). SCE is in the middle of its RFO, so it is impossible to say exactly which resources will be built. That said SCE has CPUC approval to procure approximately 1,500 MW of new natural gas capacity. At this time, none of the investor-owned utilities have authority to procure any system capacity. After reviewing the LADWP and SMUD Integrated Resource Plans, it does not appear either has plans for significant new thermal generation by this date.

Pursuant to AB 2514, California investor-owned utilities are required to procure additional energy storage capacity in the coming years. To determine the capacity associated with this requirement, we relied upon

[1] This reflects the additional technological challenges surrounding the deployment of solar thermal resources when compared to solar PV. In conversations with developers the belief was that most of these projects would be retooled as solar PV. The operational difference between the technologies is that solar thermal may have a slightly higher evening peak due to the ability to store energy for a short period.

Rulemaking 10-12-007 which lays out procurement capacity targets by two-year intervals through 2020[2]. This rule making provides utilities with the flexibility to defer the actual completion of storage resources procured. We assumed that utilities will not opt to delay procurement of storage. The storage procurement requirements are broken out between Transmission, Distribution, and Customer for each utility. Only the Transmission and Distribution totals were used for this report as Customer-side storage resources have a higher level of uncertainty. The current SCE RFO includes storage procurement. Once those results are publicly released we will have a better idea of which storage technologies will be selected.

3.5 Planned Retirements

There are two factors driving potential plant retirements. One is the once through cooling (OTC) water quality standard. Older power plants need to be retrofitted to comply with new water quality standards. The timeline for compliance varies by plant but extends well beyond 2020. There are 16,679 MW of capacity currently subject to the OTC regulations, of which 7,074 MW has a compliance deadline before 2018. There is tremendous uncertainty about which plants will retire. Most of these projects are situated in excellent locations on the electricity grid. The challenge is that the fixes are expensive and will require either ratepayers (in the case of the publicly-owned utilities) or a power purchase agreement (in the case of merchant generators) to fund the upgrades. The natural response for the merchant generators is to announce the retirement of the plant due to the high cost of retrofitting. Many of these plants will be retrofitted because they represent the lowest-cost source of incremental power (getting them not to retire) in key load centers. The incremental retirements associated with OTC between now and 2019 we estimate to be 4,734 MW with the remainder repowering. A second driver of plant retirements is purely economic. Some plants are claiming that it is not economically viable for them to continue to operate in today's market without a capacity payment and/or a power purchase agreement. An example of this is the Sutter Energy Center, a combined cycle unit which came online in 2001. After threatening to retire due to poor economics, they secured a power purchase agreement with PG&E, enabling them to continue to operate. Economic retirements will depend on regulator's willingness to allow future reserve margins to shrink and may be delayed as needed.

3.6 Demand Response

There are a variety of sources for demand response information in California. The CPUC and CAISO include a demand response estimate as part of their capacity planning process. The WECC has also published northern and southern California demand response estimates which are reasonably close, in aggregate, to the CPUC/CAISO numbers. We used the WECC estimates for this model. Based on recent history it is reasonable to model demand response activation to allow for power exports. That exact scenario occurred on the February 6th, 2014. During that period the CAISO used demand response resources while simultaneously allowing for exports to the PNW on Paci and Nob.

4.0 DEMAND

Energy GPS used CEC figures for both peak and average demand. The CEC regularly provides forecasts through the Integrated Energy Policy Report (IEPR) which provide a comprehensive examination of expected future energy consumption based on econometric modeling.

4.1 Maximum Demand

The CEC IEPR forecasts non-coincident expected maximum demand by year. The challenge is to convert this single number to monthly maximum numbers. To do this, we looked at hourly load for each balancing

[2] R 10-12-007, Table 2

authority. We calculate monthly maximum historic demand for each balancing authority using the most recent two years of available historic data. Those single-hour monthly maximums are then aggregated to get a California, non-coincident, monthly maximum demand. We create a monthly scalar for California by dividing each monthly maximum by the overall maximum. With the CEC non-coincident annual maximum and the monthly scalars, we calculate the monthly maximums.

The choice of hour makes a big difference in available capacity. During some months, the Pacific Northwest and California hit maximum demand in the same hour. In other months – especially the winter months – the Pacific Northwest peaks in the morning while California peaks in the evening. To identify the hour with maximum demand in California we rely on CAISO data. To identify the hour with maximum demand in the Pacific Northwest we rely on BPA load data.[3] This allows the model user to evaluate the total California supply and demand picture during either the California or Northwest peak hour.

4.2 Average Demand

The CEC IEPR forecasts total annual energy demand. We take the aggregate annual demand forecast from the CEC and break it into monthly demand numbers using historic data. The monthly allocation of demand is based on two years of load data from the CAISO and FERC 714 for non-CAISO load. Each month's average demand factor is calculated by taking the historic monthly aMW divided by the total annual aMW. These factors are then applied to the CEC forecast for 2018 and 2019.

4.3 Peak Demand

We applied a similar methodology to estimate peak demand as we used for average demand where peak hours are 0700 to 2200 for Monday to Saturday. To develop a monthly Peak scalar we divided aMW for peak hours and divided by aMW for the annual around-the-clock production. These twelve distinct monthly scalars were then applied to the CEC average demand forecast to obtain monthly on peak demand.

5.0 IMPORTS

The WECC forecasts total state available imports for reliability purposes. Unfortunately, this data is aggregated simply into Northern and Southern California rather than by source. We assumed all Northern California imports are sourced from the PNW and did not include them in the total. For 2018 the WECC estimate for reliable imports to Southern California is 9,812 MW. Without further clarification from the composition of these imports, we selected a conservative approach by subtracting a variable quantity of DC intertie capacity from the total depending on user input. At worst this approach leaves at least 6,712 of reliable imports from the Desert Southwest. This would be an area for further discussion with the WECC.

6.0 CAPACITY FACTORS

One of the most important sets of calculations in the model relates to capacity factor. Model results change dramatically depending on capacity factor assumptions. With the build out of the renewable fleet, California will have a diverse set of resources, each with a different capacity factor profile. Energy GPS relied on historical data from a variety of sources for making these assumptions. For solar and wind resources, we generated a 12x24 capacity factor matrix to estimate expected MW for a given hour or group of hours. Other renewables are subject only to a flat derate across all months reflecting outages. Storage and demand response availability is controlled by the model user, by default we assume that storage will be dispatched for peaking purposes. Demand response resources depend on the system operators to call upon them and thus

[3] In our model we treat the non-coincident demand number as a single-hour demand in order to generate a more conservative estimate of future peaking needs then is actually the case.

would most likely only be used to meet a California Single Hour Peak with the default model settings reflecting this fact. We apply a derate factor to thermal resources which varies by month. This derate factor reflects the combined impact of forced and planned outages. Hydro resource availability is based on the historical record to determine low hydro year average generation and then constructed a scalar between average and peak generation.

6.1 Wind

Energy GPS uses California total hourly system wind production provided by the CAISO to model 12x24 wind capacity factors state-wide. To calculate capacity factory you need actual hourly production in the numerator and installed capacity in the denominator. Relying on CAISO data, we use actual hourly CAISO wind in the numerator. Unfortunately, the CAISO doesn't publish the total installed wind capacity for each hour. To estimate total hourly installed capacity we employ a "maximum-up-to" methodology. In any given hour, the total installed wind capacity equals the highest single-hour of production up to that hour in the historical record. This method certainly under-estimates installed capacity since all wind generators in California never hit maximum production at the same time. Accordingly, we adjust this hourly installed capacity so that the resultant capacity factor equals 33% over a one-year period. This estimate of a 33% capacity factor for the system comes from the CPUC. This methodology has some built in distortions, for example if additional capacity is added during a month with low average generation it is likely the maximum will be unaffected. However the average generation will be increased as there is more capacity than the calculated maximum is modeling. In order to reduce such noise, we use averages for the 2012 through 2014 period. Additionally supporting the reasonableness of this methodology is that the 12x24 matrices generated using this methodology typically correlate to a fairly high degree with individual project production profiles provided to Energy GPS in the course of consulting work.

After additional discussion with the NWPCC on how to capture the uncertainty associated with intermittent, Energy GPS added the option to use percentile based capacity factors. This allows the user to select for example the 25th percentile capacity factor to stress test the supply and demand balance under low wind conditions.

6.2 Solar

We employ the same methodology for estimating solar capacity factors that was used to estimate wind capacity factors, except using solar data.

6.3 Other Renewable Resources

Other renewable resources – principally geothermal, biomass, and biogas are not impacted by the intermittency issues of solar and wind generation. Instead to capture inevitable outages due to maintenance work, unforeseen accidents, and other causes we used a flat 16% outage rate across all months based on average of CPUC expected capacity factors for these resource types.

6.4 Storage and Demand Response Availability

Storage resources were presumed to have 100% availability. For technologies other than pumped storage, there is not current information on likely availability.

6.5 Nuclear

Diablo Canyon is the only remaining operational plant in California. For planning purposes the unit might reasonably be expected to operate at 100% of potential except during periodic refueling outages. This methodology however fails to capture that the unit has experienced unforeseen outages due to for example kelp clogging intake valves, impacting reliability. For example during the early July 2013 extreme heat event across the west, Diablo Canyon unit 1 reported fully offline on the 1st before slowly ramping back up to fully online by the 5th. Energy GPS elected therefore to use average production sourced from EIA Form 923 to determine typical production by month, which reduces capacity to reflect the aforementioned random events as well as spring and fall refueling.

6.6 Natural Gas

There are three drivers of natural gas plant availability and resulting capacity factors. These include forced outages, planned outages, and repowering. Typically, forced outages and planned outages are modeled independently. Unfortunately, there isn't readily available public data that provides this break out. The CAISO publishes a daily outage report (the 1515 report) showing current outages on a plant-level detail. The CAISO splits forced outages from planned outages, although our experience is that this break out is not consistent or reliable. Given the data limitations, we used the CAISO 1515 outage data to estimate aggregate forced and maintenance outages by month, using actual outages as the numerator and installed thermal capacity as the denominator.

We treated the repowering estimates on a high level. Assuming 30% of the thermal resources are subject to OTC repowering and the repowering takes 12 months to complete and with deadline for repowering roughly by 2024 (this deadline will be adjusted based on reliability needs), the result is 3% of thermal capacity, on average, will be subject to OTC repowering in a given year. Accordingly, we reduced available thermal generation by 3% each year due to repowering.

6.7 Hydroelectric

Hydro modeling is a nuanced and complex topic. We relied on historic data provided by the NWPCC to estimate hydro production. After receiving feedback from the Council, we used a critical winter water year based on the lowest average winter production on record.

To estimate maximum hourly deliverable capacity for each month we relied on CAISO data since 2011. We calculated a ratio of maximum, single-hour production to average monthly production for each month using the CAISO data. Since CAISO data only covers a portion of the state, we applied the maximum hour scalar to the state-wide monthly energy volume estimate maximum monthly deliverable hydro capacity.

Another challenge with the hydro data involves the treatment of pumped storage. The CAISO includes pumped storage in its published hydro production data. Naturally, pumped storage has a greater ability to shape generation relative to run-of-river projects and thus its inclusion biases the aggregation. While this bias remains an issue with this methodology, the actual MW difference is likely relatively small.

7.0 APPENDIX – DATA SOURCES

Existing Capacity:
http://www.energyalmanac.ca.gov/powerplants/Power_Plants.xlsx (warning: links directly to Excel file)

Thermal Capacity Under Development:
http://www.energy.ca.gov/sitingcases/all_projects.html

Additional Renewable Resources:
RPS Targets: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33RPSProcurementRules.htm

CF Assumption: http://www.cpuc.ca.gov/NR/rdonlyres/932CFFAA-0610-474E-905D-30CD1D76C651/0/InputsandAssumptions_UPDATE.pdf

Allocation by Technology: http://www.cpuc.ca.gov/PUC/energy/Renewables/

Total Demand: http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf

New Thermal and Storage:
Storage Procurement: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K912/78912194.PDF
SCE Local Capacity Procurement: https://www.sce.com/wps/wcm/connect/259e4c0f-14a9-4c11-af81-ec3d896843af/D1302015_AuthorizingLongTermProcurementforLocalCapacityRequirements.pdf?MOD=AJPERES

Under Review:
http://www.energy.ca.gov/sitingcases/all_projects.html

Planned Retirements OTC:
https://www.wecc.biz/committees/BOD/TEPPC/TAS/08192010/Lists/Minutes/1/CA_OTCRetirement_TEPPC2020Basecase2010_08_18.pdf

Demand Response WECC Source Files:
http://www.wecc.biz/committees/StandingCommittees/PCC/LRS/Shared%20Documents/Forms/AllItems.aspx?RootFolder=%2Fcommittees%2FStandingCommittees%2FPCC%2FLRS%2FShared%20Documents%2FNERC%20Long%20Term%20Reliability%20Assessment%20%28LTRA%29%20Data%20Sheets%2F2013%20Files&FolderCTID=0x012000FA4FA82A1BFBCC4492413F74844D464B&View={3D8A4591-23BB-4BCD-8C40-2E3B34AA2BBC}

Maximum and Average Demand
CEC Forecasts: http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf

Imports:
CAISO Modeling of Total Import Capacity for System Reliability Purposes:
http://www.cpuc.ca.gov/NR/rdonlyres/C856A74F-1B6A-45A4-8272-98883F909583/0/CAISOOperatingFlexibilityModelingResults.ppt

Capacity and Demand Profiles:
Derived from Energy GPS database using CAISO data and FERC 714

8.0 APPENDIX – NORTHERN INTERTIE

BPA hourly load
Northern Intertie hourly flow
2007 to current

To characterize Northern Intertie availability for reliability purposes, we analyzed flows on the line during high demand periods in the PNW. Figure 1 demonstrates the relationship between the two by showing binned record counts for different load conditions. Each column represents a different BPA load level. The percentages listed in each cell show the percentage of records that correspond to the Northern Intertie flows depicted on the Y-axis. That is, each column sums to 100%. Negative numbers represent exports to BC, and positive numbers represent imports from BC. When demand in the BPA control area is between 9,500-10,500 MW, the flows N>S are almost always below 500 MW as extreme weather events in the PNW likely hit further north as well, limiting flows south from BC.

Figure 1 - Northern Intertie Flows and BPA Demand

	BPA Load by 500 MW Buckets								
	7000	7500	8000	8500	9000	9500	10000	10500	Grand Tot..
-2000	1.83%	1.16%	0.26%						1.27%
-1750	2.59%	1.87%	1.23%	1.17%	0.41%				2.05%
-1500	3.78%	2.93%	2.79%	2.62%	0.41%				3.23%
-1250	5.91%	5.45%	4.22%	4.08%	5.31%				5.36%
-1000	7.53%	6.35%	6.88%	5.54%	10.61%	5.83%	6.45%		7.05%
-750	8.59%	8.09%	7.99%	7.73%	11.84%	9.71%	6.45%	12.50%	8.40%
-500	9.82%	9.12%	10.84%	12.39%	15.92%	18.45%	29.03%	25.00%	10.19%
-250	11.30%	11.28%	10.97%	17.64%	19.59%	20.39%	16.13%		11.89%
0	12.27%	13.41%	15.13%	15.74%	16.33%	32.04%	6.45%	25.00%	13.42%
250	10.26%	14.28%	13.44%	14.14%	12.24%	10.68%	19.35%	25.00%	12.08%
500	9.75%	11.60%	11.75%	9.77%	2.86%	1.94%	12.90%	12.50%	10.31%
750	6.84%	7.64%	9.03%	4.23%	2.86%		3.23%		7.03%
1000	4.13%	3.96%	3.83%	2.48%	1.63%	0.97%			3.85%
1250	2.13%	1.77%	1.23%	2.19%					1.84%
1500	1.24%	0.52%	0.32%	0.29%					0.83%
1750	1.05%	0.39%	0.06%						0.64%
2000	0.76%	0.19%							0.43%
2250	0.21%								0.10%

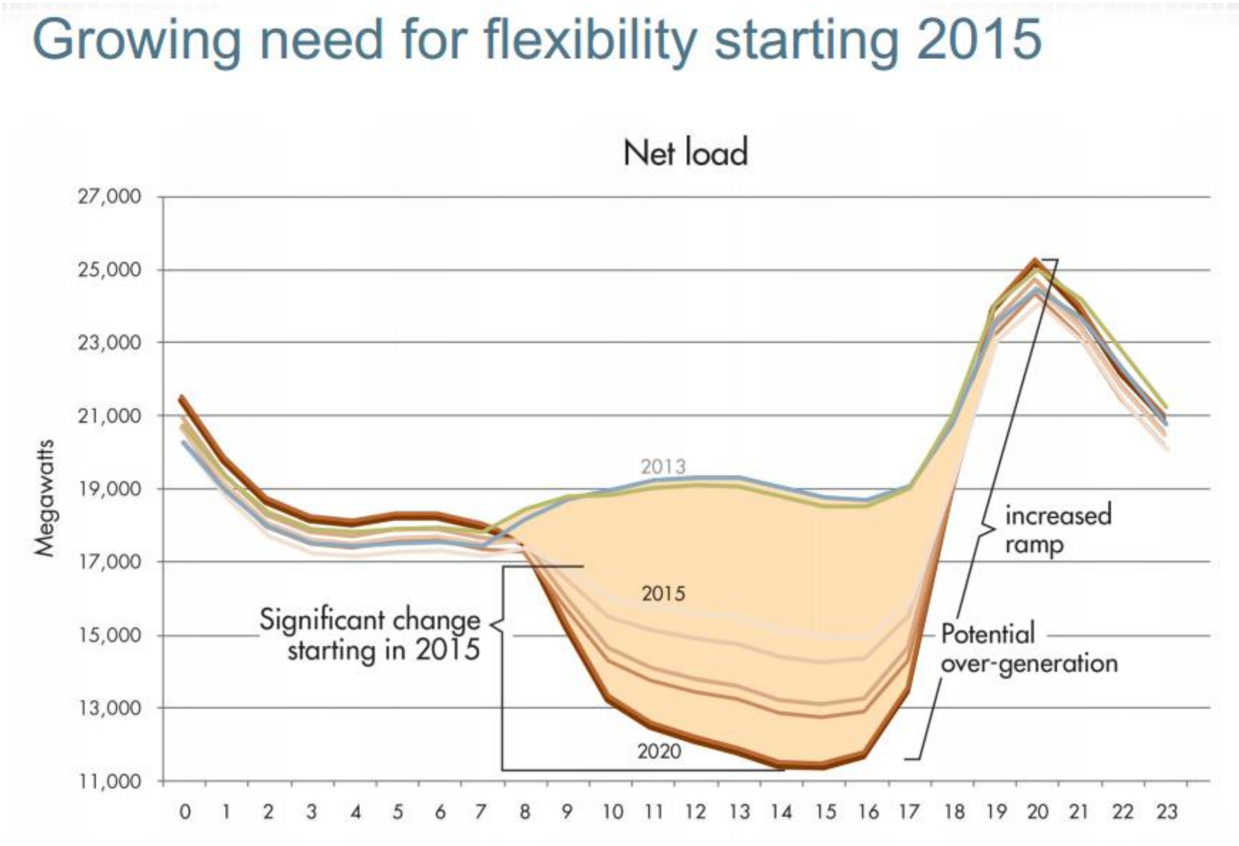
9.0 ADDITIONAL STUDY AREAS

9.1 Wind-load Correlation

Energy GPS' analysis uses a 12x24 matrix to determine average wind production over given intervals. A 12x24 represents an *average* of production over the time period for each month and hour combination. Correlation, either negative or positive between demand and generation is not accounted for. Additional analysis to generate a more granular forecast of likely production during maximum demand hours may impact expected generation levels, especially during the summer.

9.2 CAISO Flexible Resource Procurement and Retirements

Higher renewable penetration levels are driving an increased focus on the need for flexible capacity to balance ramps for the CAISO. One oft cited example is the so called "duck graph[4]" showing up in many planning documents with the figure replicated below:



There appears to be disagreement about the true need for additional capacity with some modeling efforts suggesting no ramping problems in the intermediate future[5] while on the other hand the CAISO attempted to create a Local Reliability Resource Retention mechanism[6] to keep flexible units such as Sutter Energy Center online to meet perceived need in the 2018 onward period. How capacity needs are met will depend on several variables including how much once-through-cooling generating capacity retires. Reviewing unit compliance filings suggest that several units (Contra Costa and Pittsburg) could retire rather than undergo expensive retrofitting without certainty of cost recovery. Accordingly, the model currently assumes these units will go offline by 2018. However if there is a perceived need for the units in the intermediate future the capacity could possibly remain online through a waiver or short-term exemption from OTC regulations. Forecasting accurately how such events will unfold five or more years in the future is difficult. Additional research as events progress will shed light on this issue.

[4] http://www.caiso.com/Documents/Presentation-Mark_Rothleder_CaliforniaISO.pdf
[5] http://www.cpuc.ca.gov/NR/rdonlyres/8A04F5B8-4990-4089-9E40-B7A064387C67/0/CPUC_ED_SCE_Workshop_StochasticModeling.pdf, slide 34
[6] The CAISO was overruled in this attempt by the FERC in Docket ER13-550-000

9.3 Areas for Improvement and Follow Up

Variable	Potential Improvements and Follow Up
Existing Capacity	This data is complete and reliable in this report. When updating the report it will be necessary to update this data using the same source (CEC spreadsheet) cited in the spreadsheet model.
Thermal Capacity Under Development	This category closely relates to the "New Thermal and Storage Resources" category. This category captures potential new resources outside of the currently-active SCE and SDG&E RFO procurement processes. The total capacity under development from the CEC is reliable in this report. Handicapping the probability of success for new capacity can be subjective and is based largely on talking with people in the industry. When updating the report it will be necessary to update both the universe of projects under development (from CEC) and the handicapping of the viability.
Additional Renewable Resources	This should be updated as long term load forecasts or RPS legislation changes.
New Thermal and Storage Resources	This category closely relates to the "Thermal Capacity Under Development" category. This category focuses on the SCE and SDG&E procurement RFO's. Accordingly, this will have to be updated as utilities execute more contracts through the RFO process overseen by the CPUC.
Planned Retirements	This is difficult to quantify. Projects retire for a variety of reasons – most notably because of changing once-through-cooling regulations. Ultimately, they retire because they are no longer economically viable (or the mitigation measures are not economically viable). This is a category that will have to be tracked and updated.
Maximum Demand	Update based on biannual CEC IEPR or through additional communication with CEC on methodology.
Average Demand	Update based on biannual CEC IEPR or through additional communication with CEC on methodology.
Peak Demand	Update as additional data becomes available.
Imports	This section relies on WECC data. This is an area where more research could yield a more accurate estimate for imports into California excluding those from the Pacific Northwest. We would recommend working with the CEC, the CAISO, or WECC to continue to refine these estimates.
Wind Capacity Factors	The wind capacity factors are driven by user inputs. Deciding upon the right exceedance level for future wind output may be informed by further study of the correlation between wind and demand.
Solar Capacity Factors	The solar capacity factors are driven by user inputs. Deciding upon the right exceedance level for future solar output may be informed by further study of the correlation between solar and demand. Further, as a longer solar time series becomes available it will be possible to perform more robust analysis on the larger data set.
Other Renewable Resources	Update as additional data becomes available.
Storage and Demand Response Availability	Coordinate with WECC, California entities for availability of demand response resources. Otherwise update as additional data becomes available.
Nuclear Availability	Update as additional outage data becomes available or if material change to license status.
Natural Gas Availability	Update as additional data becomes available. Determine if responsible California agencies have additional data on Once Through Cooling compliance.
Hydroelectric	Update with new critical water year as necessary. Additional research on appropriate scalars to determine ability of generation to shape into midday peak