Aspen Environmental Group

Independent Review of "Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers"

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This report was prepared by Aspen Environmental Group (Aspen) as an independent, third-party review of the analysis and conclusions developed by EtaGen Inc., estimating savings to investor-owned utility ratepayers from on-site distributed generation. Catherine Elder, director of Aspen's Energy Resource Economics practice, served as the principal analyst and project manager for this review. She was assisted by Ashley Spalding, who performed the quantitative review of the EtaGen model and contributed to drafting Aspen's report.

In reviewing the EtaGen analysis, Aspen relied on its best professional judgment; any opinion rendered is our own. The study was prepared independently, by Aspen, using its best professional judgment and analysis of publicly-available data. Such data is not within the control of Aspen and we are not responsible for its accuracy. Any use of this report constitutes agreement that Aspen accepts no liability for consequences arising from said use.

Independent Review of
"Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers"

Introduction

EtaGen Inc., (EtaGen) asked Aspen Environmental Group (Aspen) to perform an independent, arms-length review of its "Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers" Analysis. The analysis purports to show that from 2010 through 2013, distributed generation (DG) would have provided enough economic benefit to other ratepayers to more than offset the value of "Departing Load Charges" (DLCs). The goal was to have a third party knowledgeable about California energy policy, utility cost allocation, rates and revenue recovery, and generation dispatch economics review EtaGen's methodology and calculations to give an opinion as to the reasonableness of EtaGen's approach and conclusions.

After a preliminary overview of EtaGen's calculations and presentation to assess general plausibility, Aspen agreed to perform this independent review. The review sought to answer three questions: 1) whether EtaGen's spreadsheet analysis functions correctly; 2) whether the methodology is appropriate; and 3) whether the assumptions are conservative. Aspen's approach to conducting the analysis is described in this report. Our finding, made at the conclusion of our review, is that EtaGen's analysis is sound: the spreadsheet calculations function correctly, the methodology is appropriate, and the assumptions are conservative.

Background

EtaGen is the developer of a new and innovative gas engine architecture for DG applications. The architecture features high electrical efficiency and ultra-low NOx emissions. Its deployment fits squarely within the state's goal of deploying 12,000 MW of DG. In discussions with potential customers, however, EtaGen is finding that DLCs are a significant economic barrier to the installation of DG projects. Non-bypassable charges (NBCs) are charges assessed by investor-owned utilities (IOUs) on a per kilowatt-hour basis to electricity purchased from the grid. They are designed to ensure cost recovery for several types of programs such as public purpose programs and nuclear decommissioning. Current regulations require customers who install DG that is not under a Net Energy Metering (NEM) tariff to pay NBCs for the electricity they generate and consume onsite, even though this energy is not provided by the grid. The argument in support of this policy is that it keeps the NBC cost recovery burden from shifting onto remaining ratepayers of the IOU. This is often referred to as the "DLC Cost Shift." A key consequence of DLCs, however, is that they create an economic hurdle that DG must overcome in order to provide customers a viable return on investment. Furthermore, DLCs provide an additional hurdle for developers of new distributed technologies.

In considering the regulatory reasoning behind DLCs, EtaGen hypothesized that DG might provide a greater benefit to all ratepayers than the DLC Cost Shift. EtaGen set out to quantify the potential change that could occur in the wholesale market price of electricity as a result of the deployment of DG. While there a numerous benefits provided by DG, EtaGen focused on quantifying the economic benefits for CAISO market energy prices and avoided Transmission and Distribution (T&D) costs utilizing historical data. EtaGen then compared these cost-savings to the DLC Cost Shift. The end result confirms EtaGen's hypothesis that the reduction in the market prices and the avoided T&D costs provided by DG is more than enough to compensate ratepayers for the DLC Cost Shift.

Summary/Snapshot of the EtaGen Calculations

EtaGen performed its calculations in a Microsoft Excel workbook. The essence of their analysis is to measure the change in electricity prices that ratepayers of the IOUs would have experienced as a result of a reduction in demand on the grid caused by other customers installing DG. EtaGen does not attempt to estimate IOU avoided energy cost for a future period (which requires a significant number of assumptions and much more detailed modeling to predict the future resources and loads). Instead, EtaGen utilizes historical CAISO day ahead hourly (DAH) energy price and demand data for 2010 through 2013 to estimate the impact that 500 MW of demand reduction would have had on energy prices assuming 500 MW of DG been added.[1] In estimating this price change, EtaGen includes a conservative adjustment factor to account for the T&D line losses that are avoided by the DG.

After estimating the change in CAISO energy prices, the analysis then relies on publicly available data reported by the IOUs to FERC that details their annual electricity purchases in 2010 through 2013. This data is used to estimate how the changes in market energy prices would have affected IOU energy costs. The analysis quantifies the IOU cost savings by applying the changes in market energy prices to each IOU's purchases directly from the CAISO market and purchases from qualifying facilities (QFs). Lastly, EtaGen accounts for the value of avoided T&D costs by using published values from a 2010 California Public Utilities Commission decision on the cost-effectiveness of demand response activities.

Aspen Analysis and Findings

Aspen reviewed the EtaGen DG benefits calculations, the associated presentation slide deck explaining the calculations and results, and met with EtaGen to ask clarifying questions. The agreed upon scope for this independent review was to confirm the following: 1) does the Excel spreadsheet function correctly; 2) is the methodology appropriate; and 3) are the assumptions conservative.

Model Functions Correctly

Aspen carefully reviewed the Excel workbook and concluded that it functions correctly. We found that the formulas contained in the workbook are correctly implemented. We thoroughly examined the formulas in the workbook and have confirmed that there are no typos or computational errors.

A key portion of EtaGen's calculations rely on a series of regression equations for each month to estimate how energy prices respond to changes in the DAH demand. The calculations used to

[1] As indicated later herein, the quantity of DG assumed installed and associated IOU load reduction is an input the user can change. EtaGen evaluated several different levels of DG but their main presentation focuses on the installation of 500 MW.

determine the regression coefficient estimates are contained in a separate Excel workbook, but Aspen confirmed the energy price regression results via spot checks in which we took the underlying data and were able to independently replicate the regression equation and obtain the same coefficient estimates as in the separate workbook.

EtaGen also uses Excel's "Goal Seek" function to determine the "demand threshold", which is described in the following section. Goal Seek behaves like an Excel macro, in that the calculations are performed without traceable functions. Aspen therefore tested the Goal Seek function by replicating the needed function set-up parameters. Aspen was able to replicate the same results that EtaGen produced and we can confirm that the output is accurate and repeatable.

The CAISO data EtaGen used as the basis for their calculations in the workbook is from publicly available sources on CAISO's OASIS website. We located these sources and confirmed that that data in the Excel workbook matches values reported in the noted sources. The DLCs are taken from PG&E's E-19 tariff, SCE's TOU-8 tariff, and SDG&E's AL-TOU tariff (all in effect in February 2013). These tariffs are no longer available online, so EtaGen provided Aspen with the tariffs, allowing us to confirm that the values in the tariff are those used in the spreadsheet workbook.

Key to the calculations is data on energy purchases made by the IOUs from the CAISO, the dollar value (or cost) of those CAISO energy purchases, and the QF purchases and costs for each IOU and year from FERC Form 1 (FF1) filings. These values are the sum of individual line items in the FF1s. Aspen located the FF1s and EtaGen provided us with an additional workbook in which the FF1 data was aggregated. We confirmed that the reported FF1 values match those used in their calculations and that any changes to the reported FF1 values contained in the workpapers are reasonable. EtaGen's analysis relies on CAISO energy prices (EP) and DAH demand data for each hour in the four-year test period. We confirmed that raw CAISO data included in the analysis matches CAISO Oasis data. Further we used the "trace dependents" function in Excel to trace all inputs through the model and confirmed that they flow through to the results calculations correctly.

Aspen confirmed that the analysis results are in the right order of magnitude. Aspen did a spot-check of estimated price changes and found that on average, the energy price computed in the workbook decreases by 2 percent in January 2010 as a result of adding 500 MW of DG. The price change and its magnitude relative to the hourly market-clearing price will vary as the price itself varies by month and hour. But generally, we should expect the impact of 500 MW of DG to be small, and the model produces a price change consistent with that expectation. The aggregate savings resulting from this price change are nonetheless substantial because the small price change is applied to a large number of megawatt-hours.

Aspen also confirmed that the results respond appropriately to input changes. Prior versions of the Excel workbook did not account for T&D losses. Aspen tested this by taking the final version of the workbook and setting T&D losses to zero. We were thus able to see that the results with T&D losses set to zero matches those produced by the prior versions of the workbook.

Finally, EtaGen built in sensitivity to allow users to modify the CPUC adopted T&D facility savings. Aspen confirmed that the workbook calculates correctly by reducing the realized savings by 50%. As appropriate, the calculated T&D savings decreased by 50%.

Methodology is Appropriate

The basic approach to EtaGen's analysis is to compare ratepayer system savings from DG to the DLC Cost Shift. The key ratepayer system savings from DG are due to the fact that DG lowers the demand on the grid, which results in lower CAISO market energy prices, lower T&D losses, and avoided T&D facilities costs. In order to compute these savings, the Excel workbook first prepares the raw inputs using the following three steps:

1. *Estimate the change in CAISO energy prices from decreased demand by DG*

The most accurate way to measure the change in electricity price associated with having DG in a given hour would be to rerun the CAISO dispatch algorithm for each hour, with DG added in the proportions assumed for each IOU. Unfortunately, this approach is not feasible. What is feasible, however, is to obtain the data that is publicly-available for the market-clearing price and quantity of megawatts dispatched and sold for every hour, by month, in the four-year historical test period. This data can be used to construct a curve that relates CAISO DAH energy price to DAH system demand (CAISO market-clearing quantity) for all the hours in a given month. This curve then allows one to mathematically calculate the change in price that would occur in any given hour of a month for a given change in system demand in the CAISO market.

In economic terms, the analysis assumes that short-term supply of electricity in the CAISO wholesale market is fixed. The installation of a new DG technology is a change independent of any change in price and reduces demand at every price. Therefore, the analysis treats the installation of DG as a shift in the demand curve. Another way of thinking about this is to realize that a demand change caused by the installation of DG is not a demand changed caused by an exogenous price change, which is treated differently in economic analyses.[2]

EtaGen created monthly curves by fitting fourth-order polynomial regression lines to the raw CAISO DAH energy price and system demand data. The monthly regressions set hourly CAISO energy prices as the dependent variable and DAH CAISO demand as the independent variable. By fitting the equation to monthly data, the approach captures enough data points to serve as a reasonable proxy in lieu of re-dispatching the entire CAISO market. EtaGen used fourth-order polynomial regressions for two reasons: 1) to sufficiently capture the three major inflection points of a typical supply stack in the CAISO market that represent the transitions between resource groups (i.e., renewables/nuclear, natural gas combined cycles, and natural gas peaker plants), and 2) to use a uniform model for all months that had statistically significantly parameters and could accurately estimate the actual annual costs of electricity in the CAISO market.

[2] For further background on these differences please refer to, for example, the Instructor's Manual written by Nora Underwood for Pindyck and Rubenfeld's book, *Microeconomics*, at page 7. A copy of the Manual can be found at http://www.slideshare.net/SaraMishelle/pindyck-microeconomics-6ed-solution.

EtaGen's workbook contains the resulting coefficient estimates for the polynomial regression equation for each month. For every hour in a given month of the 2010 through 2013 period, the analysis calculates the change in price that would have occur in that hour if DG had served load, thereby reducing the CAISO system demand. The workbook does this by applying the coefficient estimates for the corresponding month to historical DAH demand and DAH demand less the DG output to compute the pre-DG price and the post-DG price for every hour in the month resulting from reduced market-clearing demand.

As indicated previously, Aspen spot-checked the regression equation results. We also agree that use of the fourth-order polynomial regression results is reasonable. To determine whether or not the fourth-order polynomial is the appropriate functional form to use for the regression equations, EtaGen generated third- and fifth-order polynomial regressions for each month in which the absolute value of the t-statistics of the original equations were less than two. The analysis compares the t-statistics and p-values across the three sets of models. The third- and fifth-order polynomials provide a better fit (i.e., the absolute value of t-statistics for the coefficient estimates are greater than two) for several months during the four-year test period. However, the fourth-order polynomial provides the best fit for the majority of months.

EtaGen also provided the R-squared results. The R-squared statistic represents the percentage of change in the dependent variable that is explained by changes in the independent variable, and it is used to assess the "goodness of fit" or explanatory power of regression equations. The R-squared values range from 0.522 in December 2013 to 0.915 in July 2013, with an average R-squared value across all months and years of 0.770. These results indicate that the polynomial fits better in some months than in others, but overall, an average of 77% confirms a reasonably good fit across the test period.

More importantly, the Excel workbook validates the monthly regression estimates by comparing the reported CAISO load cost to the total cost computed using the estimated pre-DG price. The values differ by less than 0.0000002%, demonstrating that the model reasonably estimates annual costs.

2. *Estimate the amount of IOU savings from lower CAISO market prices*

Estimating these savings relies on calculating how much energy was purchased from the CAISO market in each hour by each of the IOUs and at what price. FERC Form 1 reports the total annual cost and quantity of IOU energy purchases, with a break out of the cost and quantity each IOU purchased from the CAISO and from QFs. It does not provide hourly prices, however. The CAISO reports hourly TAC area demand for each IOU and associated locational marginal prices (LMPs) in each hour. An important aspect of EtaGen's analysis is that it relies on matching each IOU's annual total amount and cost of CAISO energy purchases reported to FERC with the hourly market-clearing quantities and prices reported by CAISO.[3] Put differently, the analysis finds the quantity at which all higher demand can be

[3] EtaGen also uses the FERC data to determine the following for each IOU and year: 1) the total purchases for each IOU as a percentage of total purchases in their TAC area; 2) the total CAISO purchases for each IOU as a

deemed to be a purchase from the CAISO, after IOU-owned, bi-laterally contracted, and QF generating resources are exhausted.

This is accomplished as follows. EtaGen first assumes that for every year, the ratio of IOU total annual demand to the TAC area total annual demand is constant over all hours in that year. Using this ratio, the analysis establishes a “demand threshold.” The demand threshold represents the portion of TAC area demand above which purchases are made from CAISO. The workbook computes different demand thresholds for each IOU for each year, and each threshold is held constant for each year.

The analysis uses the Goal-Seek function and applies two different methods to determine each demand threshold: a “match cost” and “match load” method. The match cost method finds the minimum hourly TAC area demand such that the computed annual cost of IOU CAISO purchases (sum of hourly LMP times the hourly IOU demand in excess of the threshold for all hours in the year) is equal to the annual cost of IOU CAISO purchases reported in FERC Form 1.[4] The match load method finds the minimum hourly TAC area demand such that the computed annual IOU CAISO load (sum of hourly purchases in excess of the threshold for all hours in the year) is equal to the annual IOU CAISO load reported on FERC Form 1. The user can select which method to use in the analysis.[5]

3. *Estimate the amount of IOU Energy Losses from T&D*

DG reduces IOU line losses because it is located at its use point as opposed to being transmitted to its use point. EtaGen does not produce its own estimate of line loss. Instead, it compiled a range of line loss percentage estimates from the CPUC, EPA and CEC and selected a value at the low end of this range, 6 percent. The analysis defines the load displaced by DG as the DG output divided by one minus the percentage of T&D losses.

The data obtained in the above three steps is used to compute the energy price savings and T&D facilities savings for each year and IOU. All costs and savings computed by EtaGen are in nominal dollars. EtaGen defines energy price savings as the sum of CAISO energy price savings and the QF energy price savings. CAISO energy price savings is equal to the difference between the annual cost of purchasing the remaining electricity load on the ISO market at the pre-DG and post-DG energy prices. The Excel workbook computes CAISO energy price savings as follows:

$$\begin{aligned} &CAISO\ Energy\ Price\ Savings \\ &= (Actual\ Demand - Demand\ Threshold - Displaced\ Load)\ X\ (Pre\ DG\ Energy\ Price \\ &\qquad - Post\ DG\ Energy\ Price)\ X\ All\ Hours \end{aligned}$$

percentage of their total purchases; and 3) the total QF purchases for each IOU as a percentage of their total purchases.

[4] The LMPs take into account congestion and other price factors and have to be used here in order to match the computed price times quantity to the annual dollar cost reported in FERC Form 1.

[5] EtaGen uses the match cost method in their main analysis and presentation; however, the difference between the two is less than 5% and does not appreciably alter the analysis results.

Displaced load in each hour is equal to the annual displaced load (i.e. DG capacity adjusted to account for line losses) multiplied by the percentage of capacity assumed to be operating in that hour. The analysis includes five hourly operation cases. The first is the “All Hours” case in which DG operates at 100 percent of capacity in every hour of the day. The “Steady” case assumes DG operates at 100 percent from 8 a.m. to 11 p.m. and 75 percent of capacity from 11 p.m. to 8 a.m. The “Daytime Hours” case assumes DG operates at 100 percent of capacity from 8 a.m. to 7 p.m. and at zero percent of capacity in all other hours. The “Shoulder Hours” case assumes DG operates at 100 percent of capacity from 6 a.m. to 10 a.m. and 5 p.m. to 9 p.m. and at zero percent of capacity in all other hours. The user can select which case to use.[6]

The analysis calculates the QF energy price savings as the product of the amount spent on QF purchases annually, the percent reduction in CAISO energy prices in that year from step 2, the market factor, and the price factors. The workbook defines the market factor as “the fraction of QF contracts of which their energy prices are exposed to market prices (either directly through DAH prices or indexes such as Short Run Avoided Cost that uses forward prices)” and the price factor as “percentage of energy payments QFs exposed to market prices receive out of all payments (not including fixed O&M costs and other potential payments).” The workbook assumes 75% for a market factor and 80% for a price factor.

$$\begin{aligned}&QF\ Energy\ Price\ Savings\\&= (Actual\ Cost\ of\ QFs)\ X\ (\%\ CAISO\ Energy\ Price\ Reduction)\ X\ (Market\ Factor)\ X\ (Price\ Factor)\end{aligned}$$

EtaGen computes the savings from avoided T&D investment costs for each year and IOU by multiplying the T&D avoided cost adopted by the CPUC, the percent realized savings, and the amount of DG capacity.

$$\begin{aligned}&Avoided\ T\&D\ Cost\ Savings\\&\qquad = (CPUC\ Avoided\ T\&D\ Cost)\ X\ (DG\ Capacity)\ X\ (\%\ Realized\ Savings)\end{aligned}$$

The Excel workbook contains a work sheet titled “Main.” This sheet displays key inputs and results of the analysis. We identified the following items as key inputs to the Excel workbook that can be altered by the end user:

- DG installed capacity added to CA grid (MW);
- T&D loss factor (%);
- Method for determining the demand threshold (load or cost match);
- Household consumption (kWh/month);
- DG distribution among the IOUs; and
- DG operating hours

[6] EtaGen uses the “steady hours” case in their main analysis, but varies the cases in its presentation.

Using the user-defined inputs and those supplied by EtaGen, the Excel workbook produces key outputs for each year of the recorded period, which are subsequently averaged to produce the following composite annual estimates:

- Load displaced by DG (MWh);
- CAISO energy price savings ($/MWh);
- QF energy price savings ($);
- T&D avoided costs ($);
- DLC Cost Shift ($); and
- Average household savings ($/month) to put the net benefit in context.

EtaGen developed two methods to distribute DG capacity across the IOUs: one is based on market-price exposure and the other is demand exposure. As the name implies, the former relies only on the IOU purchases exposed to CAISO market prices. It serves as a continuation of the methodology used in the workbook calculations, which revolve around the portion of IOU purchases exposed to market prices. The Excel workbook computes market price exposure as the four-year average of each utilities' annual ISO and QF purchases divided by the sum of annual QF and ISO purchases across the IOUs.

The demand exposure method simply assumes that customer installation of DG will occur in proportion to IOU demand. Using this logic, the largest IOU would have the most DG because it serves more customers, supplies more energy, and, therefore, is likely to face greater demand for DG technologies. Demand exposure for each IOU is equal to the four-year average of annual IOU total purchases divided by the combined annual IOU total purchases across the IOUs. The two methods set possible bounds for the allocation of DG and allow the end-user to contrast two ways of capturing the impacts of DG on each IOU. The following table summarizes the locational breakdown for two distribution models:

Exposure Model	PG&E	SCE	SDG&E
Market-Price	38%	56%	6%
Demand	48%	43%	9%

Lastly, it is important to note that EtaGen is not attempting in this analysis to replicate or present a full cost-effectiveness test. Instead, EtaGen is trying to address the narrower issue of whether there are financial benefits to IOU ratepayers sufficient to offset the DLC Cost Shift associated with the addition of DG. Furthermore, EtaGen's analysis uses historical data and performs a retrospective cost analysis rather than forward-looking cost analysis. EtaGen is not trying to calculate full avoided cost but instead simply capture the change in market prices that would occur by virtue of DG lowering demand on the grid and in the CAISO market.

Assumptions are Conservative

EtaGen's calculations rely on a number of assumptions but substantially less than the number of assumptions that would have been required to calculate a forward-looking avoided cost or run a production cost model. Aspen examined each of the assumptions and, where possible, their sources, and can concur that they are conservative.

The Excel workbook allows for two reasonable options for allocating the 500 MW of DG across the IOUs. This prevents the incremental DG from being concentrated in the most favorable IOU.

The analysis adjusts TAC purchases down to the IOU level. The workbook computes the ratio of annual IOU purchases to TAC purchases for each IOU and year. The analysis assumes this ratio is constant across every hour of the year, and uses these ratios to adjust TAC purchases downward in every hour to IOU level purchases for each IOU and study year. This assumption may or may not be strictly correct, but in the absence of publicly available information to the contrary we find it reasonable.

Instead of assuming that all IOU sales are exposed to CAISO market prices, the analysis takes care to assess which portion of IOU sales would be exposed to CAISO market prices and applies the lower CAISO price only to that portion. EtaGen assumes that only the portions of sales in each hour that are greater than the computed demand threshold are purchased on the CAISO market. Further, the analysis assumes that only 75 percent of QF purchases are exposed to market prices and that only 80 percent of the cost of QF purchases is energy cost. This helps to ensure that the resulting savings estimates are not exaggerated. Aspen believes these are reasonable based on the fact that 1) some QFs are still paid a fixed avoided cost rather than a market-based price and 2) payments to QFs historically have also included non-energy components to cover operations and maintenance expense as well as capacity payments. Moreover, these assumptions are changeable by the user.

The analysis is careful not to overestimate T&D line losses. EtaGen compiled a range of reported line loss percentage estimates made by the CPUC, EPA and CEC that have all been, and continue to be, used for policy-making decisions. From those, it selected a value at the low end of this range, 6 percent, to use in the calculations.

Similarly, EtaGen relies on CPUC-adopted figures for T&D avoided investment costs. These were adopted by the CPUC in Decision 10-12-024 ("Decision Adopting a Method for Estimating the Cost-Effectiveness of Demand Response Activities"). These estimated savings continue to be used by the IOUs and the CPUC today. As a conservative measure, the EtaGen workbook allows the user to discount the CPUC-adopted T&D avoided investment costs by changing the value for "% Realized Savings." Thus, the workbook accommodates the idea that there may be situations in which T&D investments may not be avoided.

EtaGen's analysis is in nominal dollars. Aspen deflated the costs and savings for each year using a producer price index that was readily available. The net savings averaged over the four year historical test period does not change by more than 3%. We conclude that this does not appreciably affect the magnitude of EtaGen's results.

The analysis excludes many of the benefits of DG that could be included in a full cost-benefits test. These benefits include, but are not limited to: reduced need for capacity, GHG reduction, job creation, grid security, inertia, blackstart, voltage regulation, reduced congestion prices, reduced CAISO prices to non-IOU participants in CAISO market, and the associated reduction in RPS compliance cost due to lower

IOU sales. The analysis' estimate of savings to utility ratepayers would increase if the excluded quantifiable benefits were included in the workbook.

EtaGen includes five different scenarios for DG operating hours. These scenarios determine the percent of capacity at which DG is operating for each hour of the day. Aspen agrees that the range captured by the operating hours scenarios is reasonable.

The Excel workbook spreads QF purchases and DG output over all hours. This is reasonable because both QF purchases and DG output occur over all hours and many operate on a baseload basis. EtaGen did not, in other words, assume that DG operates solely in the highest-priced hours; thus, the resulting savings to utility ratepayers are spread evenly among high-priced and low-priced hours within a month.

Finally, EtaGen performs sensitivity analysis on the quantity of DG, how the DG is allocated and operates across the IOUs, and in which hours the market purchases might occur. As a result, EtaGen is aware of how changes in the assumptions and the inputs to the workbook alter the results.

Selected Results

The "Main" sheet in the workbook contains a number of tables that display inputs to and output from the analysis. Outputs for each IOU and each year are displayed where available and appropriate. Additionally, the four-year annually averaged outputs for each IOU is included. EtaGen uses the four-year annually averaged outputs for its reported results. The following table is included in the "Main" sheet and displays, among other things, the four-year annually averaged net savings for each IOU when 500 MW of DG are added and distributed amongst the IOUs using the "market-price exposure" method, and when the demand threshold is determined using the "cost-match" method. Net savings is the key output produced by the analysis and is reported in dollars per year. A positive net savings value indicates that the savings measured by the analysis outweigh the DLC Cost Shift. Further, to put the savings in context, annual net savings are converted to average household savings ($/month) at the bottom of the table.

EtaGen Summary of Ratepayer Savings 500 MW Case

Average Annual Results Steady Hours Case	PG&E 4 yr avg	SCE 4 yr avg	SDG&E 4 yr avg
DG Capacity (MW)	190	282	28
DG Load (MWh)	1,474,581	2,188,900	217,301
Displaced Load (MWh)	1,568,703	2,328,617	231,171
FERC Form 1 Energy Data (MWh)			
CAISO TAC Area Total Purchases	105,114,961	105,395,970	21,170,700
IOU Total Purchases	85,899,069	76,022,598	16,472,276
% of CAISO Area Purchases	*82%*	*72%*	*78%*
IOU CAISO Total Purchases	15,673,120	17,112,544	3,039,913
% of IOU Total Purchases	*18%*	*21%*	*19%*
IOU QF Purhcases	12,346,915	24,481,005	1,089,245
% of IOU Total Purchases	*14%*	*33%*	*7%*
Impact of DG ($)			
Savings			
CAISO Energy Price Savings	*$16,614,846*	*$22,327,761*	*$3,281,276*
QF Energy Price Savings	*$11,050,586*	*$25,328,585*	*$1,034,997*
T&D Avoided Cost Savings	*$14,554,754*	*$15,386,898*	*$2,093,619*
Total Savings	$42,220,186	$63,043,244	$6,409,892
Costs			
DLC Cost Shift	$27,618,897	$34,037,390	$2,394,655
Net Savings	**$14,601,289**	**$29,005,853**	**$4,015,237**
Avg Household Savings ($/month)			
at 500 kW/mohth	**$0.087**	**$0.191**	**$0.124**

Source: EtaGen Excel Workbook

Conclusion

Aspen reviewed the methodology, the workbook calculations, and the assumptions EtaGen used in its analysis. We conclude that the methodology is sound. We find the workbook calculations to be implemented correctly (i.e., that the workbook functions as intended) and the assumptions EtaGen used to be conservative.