Case Study on Using Analytics to Save Money for Ratepayers

Beyond a Flip of a Coin

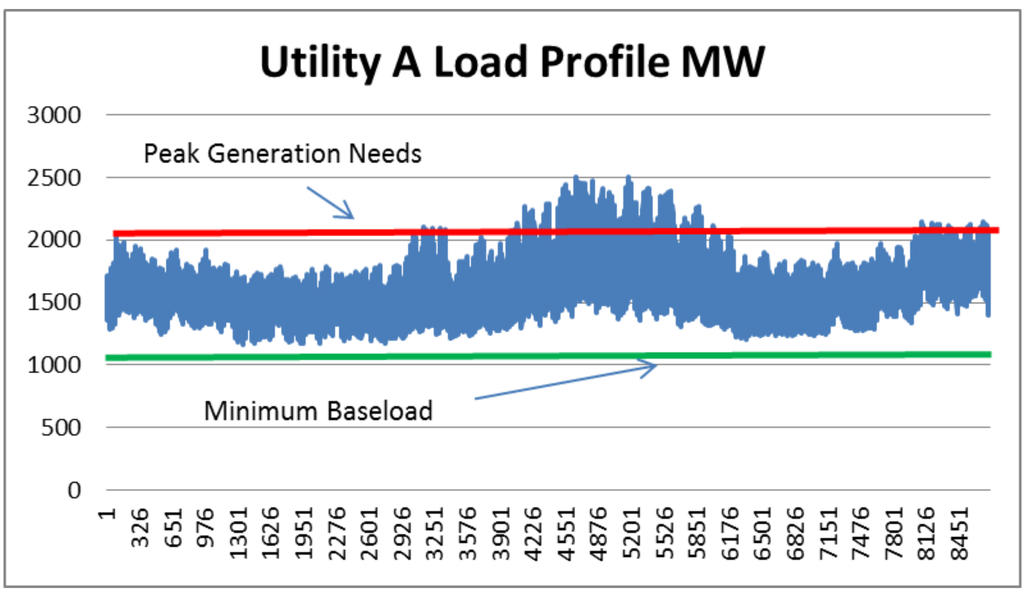
This analysis uses real data to present a case on how analytical data of the market place can be used to save ratepayers from unreasonable market premiums. In addition to saving ratepayers money, this analysis will also save you headache from the Monday morning quarterbacks waiting to say "I would have…you should have…" Making a decision with a choice of "locking in" using futures markets involves more than pure market fundamentals. A market risk calculation is being applied from the counterparty. This market risk changes throughout time as the market carries the emotions of recent events no matter how likely or unlikely these events occur. Being able to quantify this market risk systematically allows effective decision making.

Introduction

In this case study, Utility A is a utility based on cost of service. The objective of the utility is not to generate profits, but to minimize cost for its ratepayer while maintaining a high level of reliability. Utility A is located in the Southwestern region of the United States. Their primary power hub is Palo-Verde with the gas hub being San Juan.

Utility A load is summer peaking – see Figure 1 below.

Figure 1 Utility A 8760 Load Profile



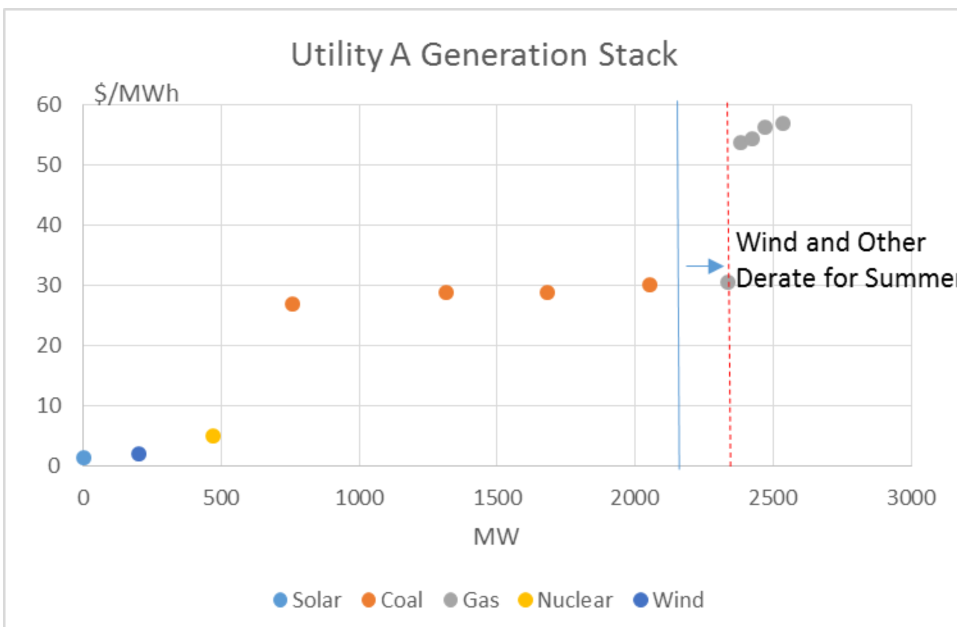
They have a range of assets from Wind, Solar, Nuclear (partial ownership), Coal, and Natural Gas units. The resource planners have done a fine job in making sure their assets are utilized with their load profile. The minimum baseload generation coincides with their minimum load therefore minimizing the need to find off-system sales. The peaking generation needs represents load greater than 2100 MW, which includes derating from their wind assets and seasonal operational derates from nuclear and coal plants. Load greater than 2100

MW represents the times where they may run their peak generating units (gas and oil units with heat rates greater than 10). This event typically occurred during the summer in on-peak hours which put the wind generation at risk. The winter peak events occurred in the off-peak hours and generally the wind variability could supply the needed power.

Running the peaking units come with additional cost beyond the dispatch. Maintenance and deliverability of gas can be suspect as many units are really designed for emergency, use not routine use. If Palo Verde prices were close to dispatch cost, the preference would be to buy from Palo Verde and save the units for emergency runs. Purchasing from the market also avoided environmental issues with several of the units permitted to only run in limited time periods.

A dispatch stack with only Utility A units is presented below. The stack is based on 100% capabilities. The red-dash line shift the stack over due to summer derates leaving the peaking gas units for loads greater than 2100 MW.

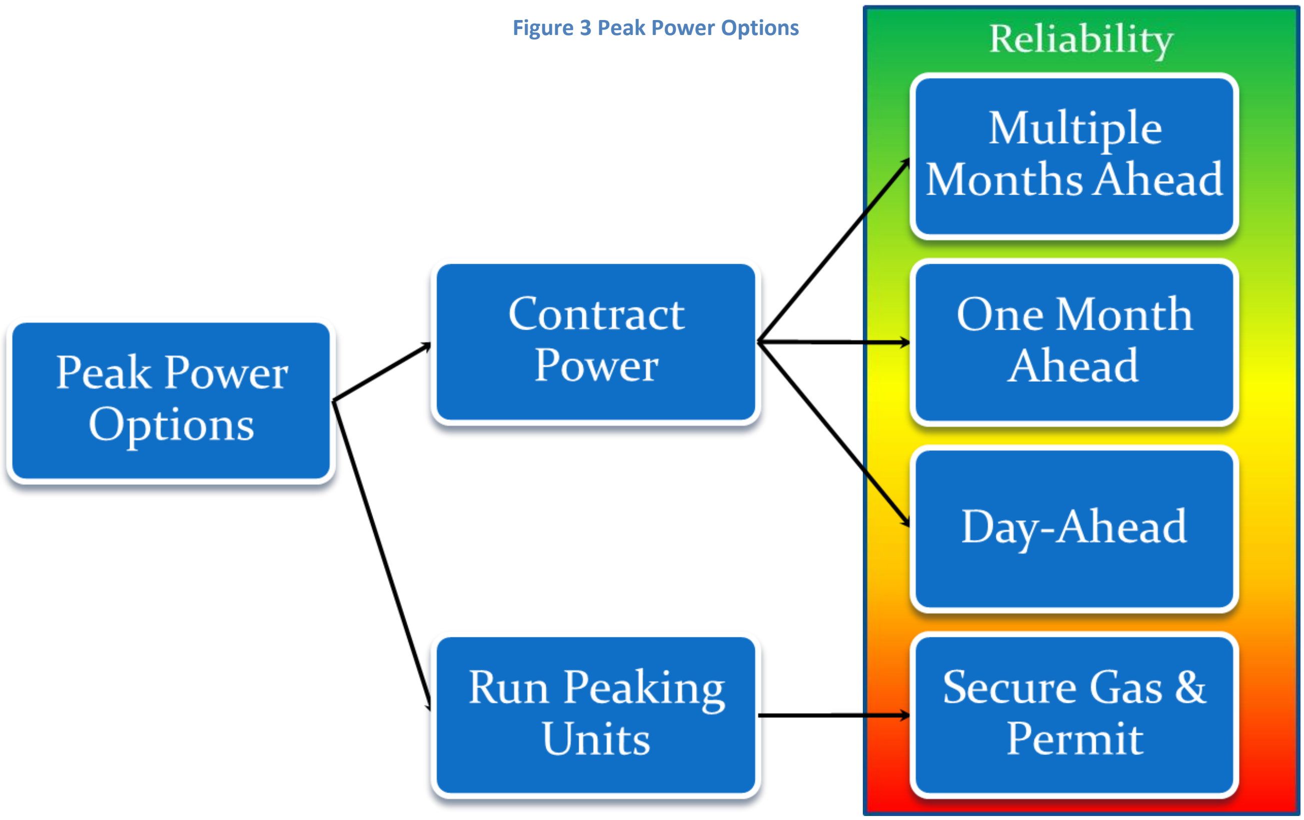
Figure 2 Utility A Supply Stack



Opportunity

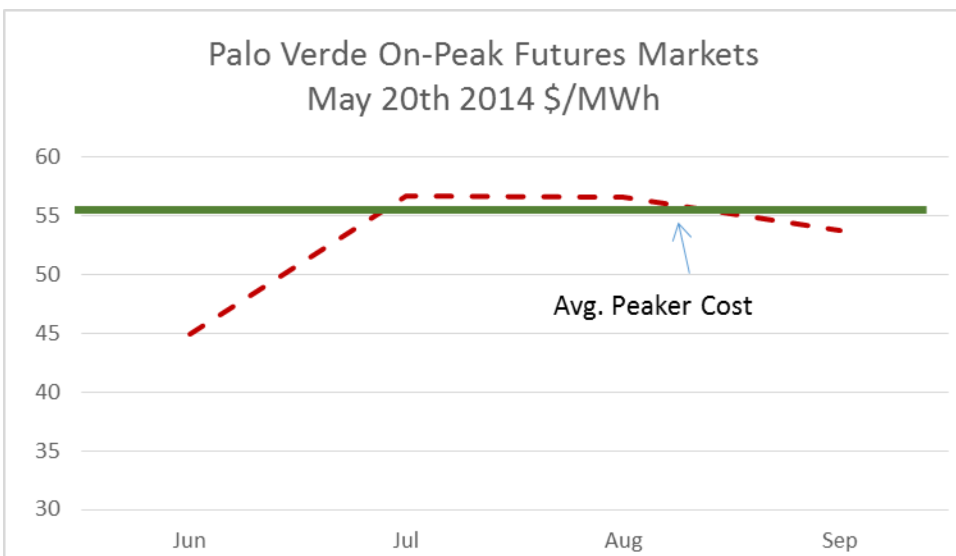
Typically, one states the problem in a case study, but we believe this is an opportunity, not really a problem. Utility A has two options to manage the summer peak loads. The options are to run their peaking units or purchase power from the market. Purchasing power from the market can come in 3 forms. The options are shown below in Figure 3. Buying power way ahead secures availability and counterparty prepardness. Using your peaking assets may potentially leave you without much buffer in the market place.

Figure 3 Peak Power Options



In the first contract power option, on May 20th 2014 the market presented an opportunity to "lock in" power prices for the on-peak time periods for the summer at $45/MWh Jun., $57/MWh Jul. and Aug, and $54/MWh Sep – as seen in the Figure 4.

Figure 4 Palo Verde On-Peak Futures Price



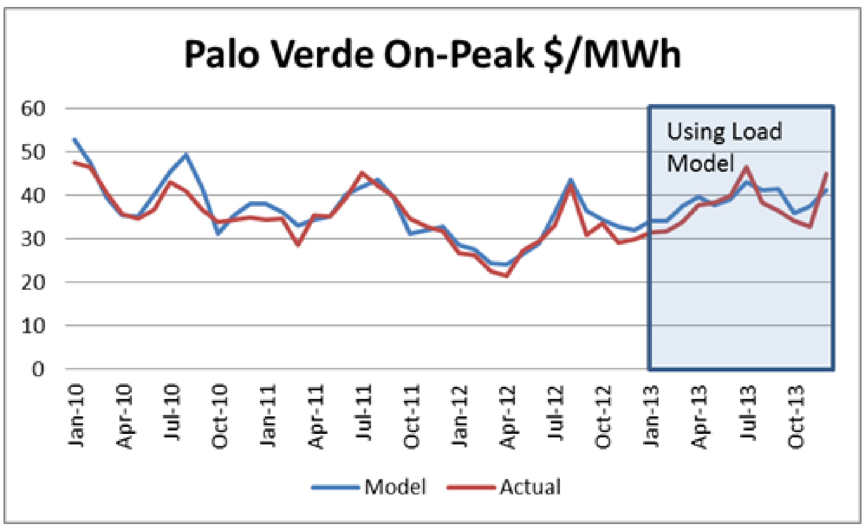
Evaluating the purchase of power from Palo Verde vs. the option to dispatch the peakers, the market offers a more compelling story given the cost and the additional constraints.

The total amount of MWH above the 2100 MW represented 74,000 MWh which computed with the forward curve equals a total of $4.1 Million dollars of power purchase cost. Does Utility A trust the market to quantify risk appropiately and lock in and forget it? What is the downside and upside locking in the forward curve? Are there better options – wait for the day-ahead – or just buy one month out? What will the Monday morning quarterback say if prices collapse? How much can prices collapse? Utility A needs to know more than how their own units operate, but how the market will respond in various situations. A market risk assesment is needed to quantify the market risk premium embedded in the forward curve.

Solution

A key performance criteria is to make sure whatever platform you are using is well calibrated to the market, or your efforts will be futile. PMA-NT is calibrated to the On-Peak Palo Verde markets. Figure 5 shows the on-peak calibrations are good, and PMA-NT can model and quantify risk for this power hub.

Figure 5 Palo Verde On-Peak Power Price Calibrations

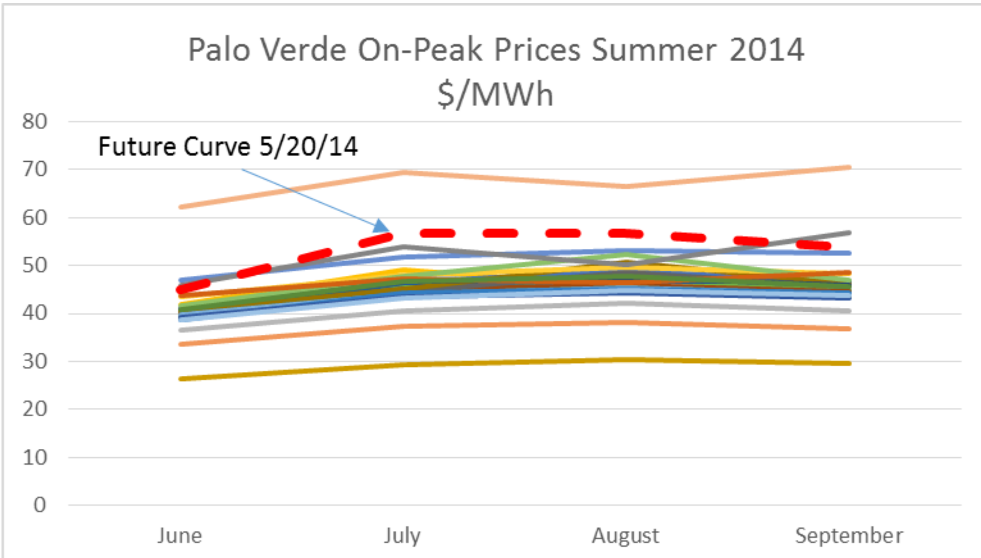


A risk assessment using the PMA-NT analytical platform was applied in the month of May 2014. PMA-NT risk assesments have a typical day turnaround so we offer the speed needed to make effective decisions in a dynamic ever changing futures market. We allow our clients to also incorporate their latest information from outages to retirements to market changes inside the model.

This PMA-NT risk assesment involved over 25 discrete known simulations. The simulations covered the known weather risk, gas prices, and operation concerns (hydro and outages). By running individual sensitivities, understanding of the model functionality and awareness of market variables is obtained. This is not a mathmatical soup calculation. The figure below shows the range of power prices as a result of certain events.

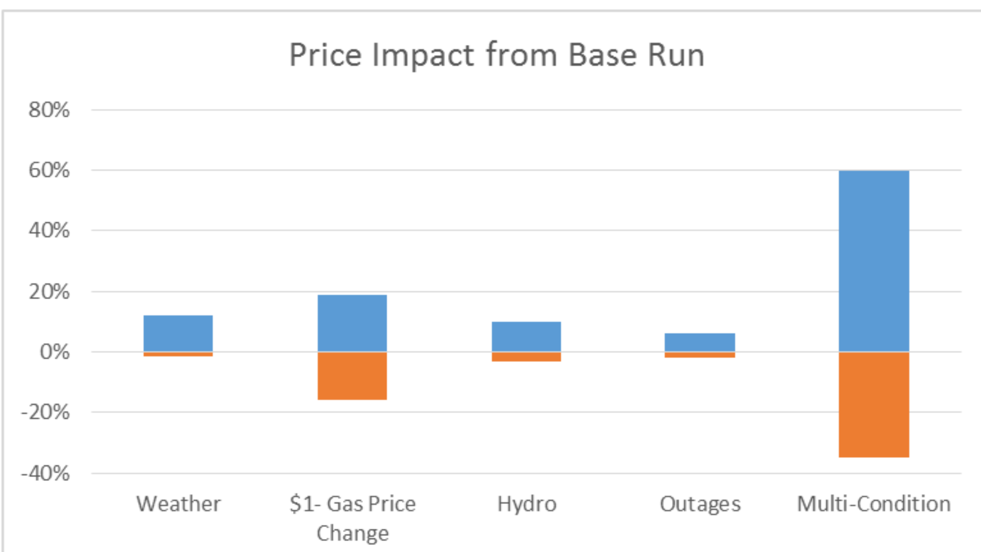
The Base run represented the futures market on May 20th which had an average henry hub price for the summer at $4.4/mmbtu.

Figure 6 Palo-Verde Simulated On-Peak Prices



In addition, a risk assesment for each category was generated – see figure below.

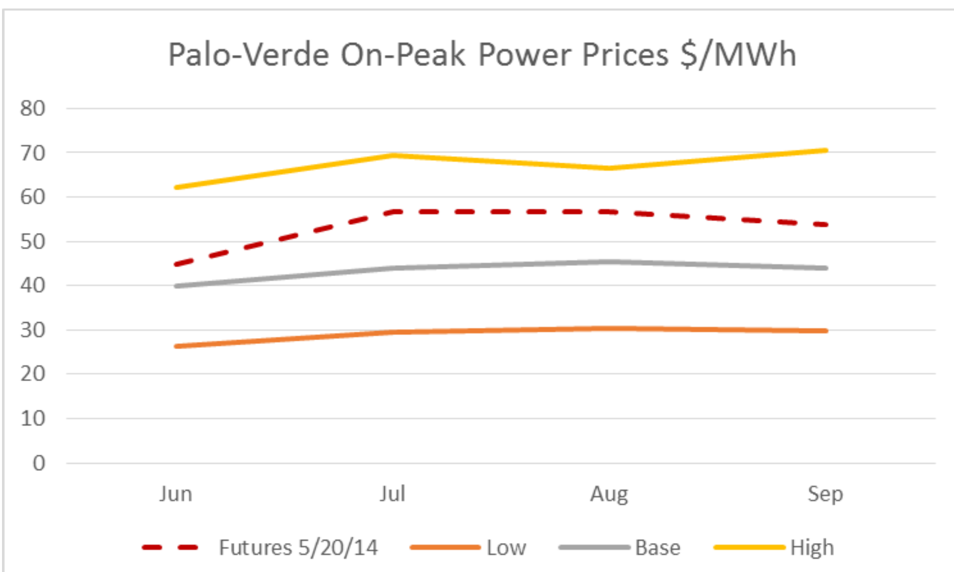
Figure 7 Risk Assessment Impacts to Base Run



In order to get a handle on risk for some reasonable tail-ends events, a multi-condition run was developed to produce a high and low power price case. For the high power price case, henry hub prices were set at \$6.5/mmbtu, roughly \$2/mmbtu greater than the market. In reviewing the weather scenarios results, we see 2012 represented the most extreme weather for the region. In addition, we used a 2001 hydro year along with doubling the foreced outage rate. The low power price case henry hub prices were at \$2.5/mmbtu, roughly \$2/mmbtu lower than the market. The weather used in the low case was 2010. In addition, a high hydro profile from 1997 was used along with cutting outages by half. These cases offered a decent tail representative of potential outcomes. The low price outlook at the time included a high hydro year which data would already suggest is not occurring. Balancing the improbable factors in the low price is the assumption in the high case that gas would move to up \$2/mmbtu, which is unlikely given the shale production. However, looking at Figure 7, we see the impact on gas prices for summer is a lot more significant than hydro changes. This would then indicate weighting the high case less likely than the low case. In addition, the upside is also limited as the peaking units can be dispatched.

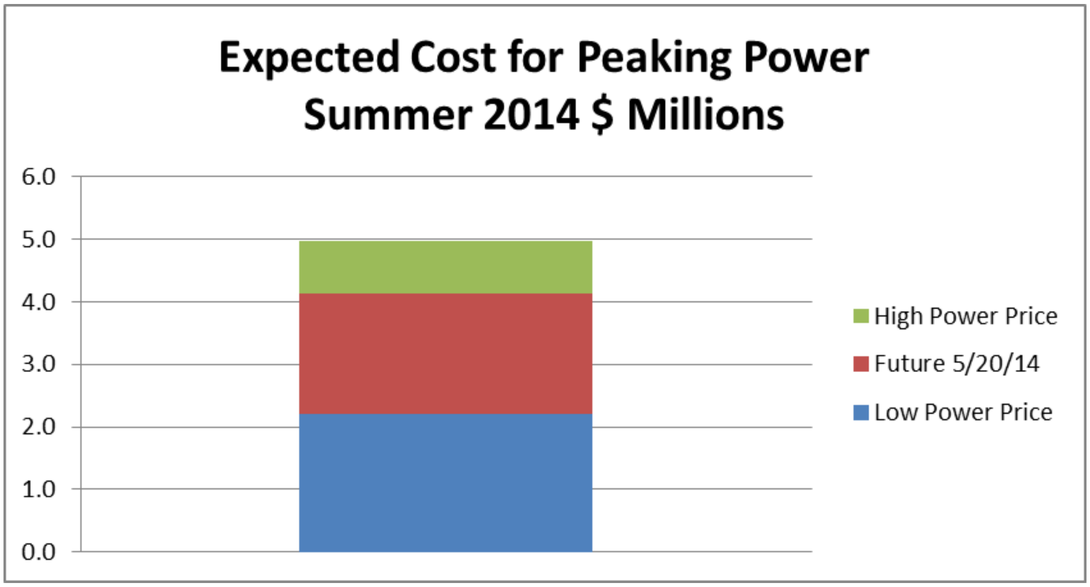
With just the forward price, base, high, and low case presented in the Figure 8 below, this allows us to clearly see the risk for higher prices is limited using the future prices on May 20th 2014. The downside risk is significantly greater whan also accounting for likihood. The futures seems to hold some irrational exuberance in the outer months, probably as a result of the polar vortex observed earlier in the year.

Figure 8 Palo Verde On-Peak Prices



These price assesments ultimately can be converted to dollars at risk – See Figure 9 Below.

Figure 9 Expected Cost for Peaking Power 2014



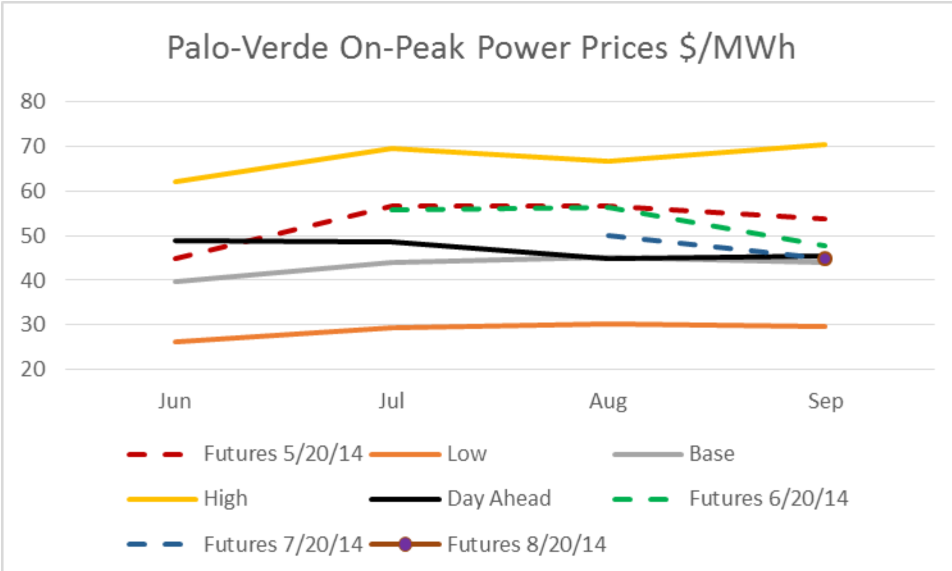
The upside risk is the power prices could move up relative to the forward curve causing an additional cost of $1 million dollars. However, the downside risk is greater with an observed potential of a $2 million dollar swing relative to locking in the futures on 5/20/14. This is an asymmetric risk reward profile suggesting at least holding off on any July, August, and September locks.

After Math Assessment

The baseline cost will be the forward curve option purchased in May for the generation required above 2100 MW which represented $4.1 Million dollars of power purchased. The day-ahead purchase is another baseline clear and transparent to calculate after the fact. The total cost of going and taking the day-ahead prices totaled $3.2 Million. One would think why not go with Day-Ahead prices? Well, that's easier said than done. This summer was relatively mild and gas prices did fall off significantly. However, both of those issues were far from guaranteed in the beginning of summer. The high case simulations resulted in cost exceeding the day-ahead calculations by over $1.7 million. There is a reliability risk that far surpasses any dollar savings to move all peak power purchases in the day-ahead markets.

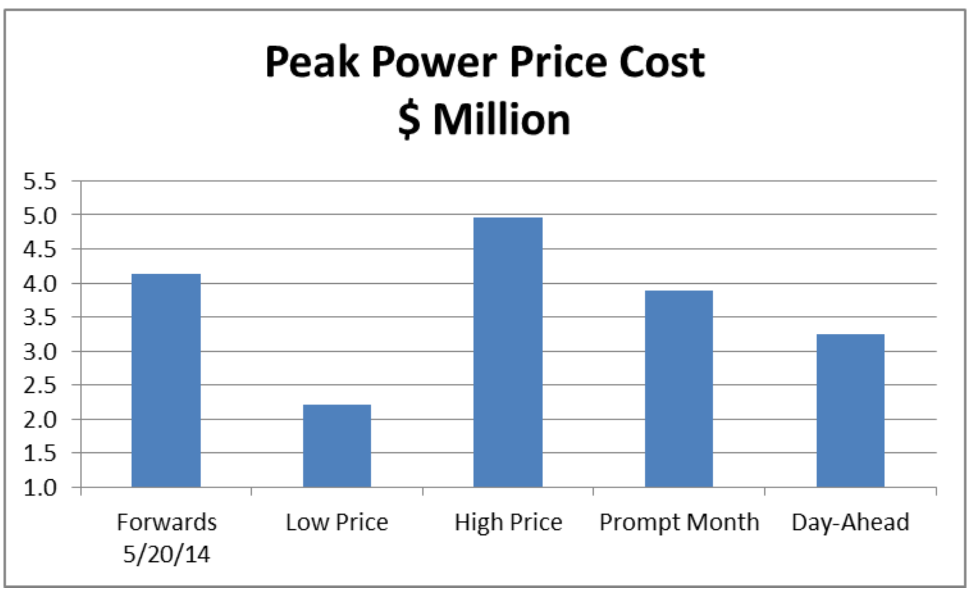
As suggested above, the prudent plan was to go ahead and purchase June in the futures market in May, but leave the decision to July, August, and September for later. If Utility A followed that suggestion and revisited the forward curve a month later, they would have observed the curve coming off – see Figure10 below.

Figure 10 Palo Verde On-Peak Prices Over Time



If Utility A transacted using the prompt month strategy, they would have produced a net cost of $3.9 million dollars. This decision saves nearly $250K versus locking in the forward curve markets in May. This strategy was identified by analysis. Following a prompt month strategy without knowing the forward curve was already higher than expected, could have resulted in greater cost than purchasing the forward contract at the beginning of summer. The analysis justified the decision. A summary of cost can be seen in Figure 11.

Figure 11 Peak Power Cost



PMA-NT risk assessment does not foretell the future, but allows an assessment of the risk/reward profile. Monday morning quarterbacks can quickly be silenced by presenting the documented upside/downside risk of your decision. Knowledge increases the capabilities to make effective decisions and also give support to when the future unfolds unexpectedly.

The prudent plan of purchasing a PMA Risk assessment resulted in identifying the over exuberance of the forward markets in May of 2014, in particular the months of August and September producing a savings of nearly $250K over the simple choice of locking in power in the beginning. If the market had moved the other way, your plan can be justified given the analysis done, and you would have the backing of All Energy Consulting.

Improvements & On-going Concerns

Further analysis could have been done to incorporate Utility A load with the varying load from weather, thereby quantifying the volume impact on market price and utility load responses. Collaboration with All Energy Consulting market expertise and your expertise for your system adds another layer of sophistication. In addition, a narrower tail-end event could have been done to reflect the latest knowledge such as not as high hydro generation for the low case and not as high gas prices for the high case. Our models are designed for user input allowing custom scenarios. We will run what you want, but we will be proactive and note our concerns in your scenario choices.

Utility A is going through a transformation as many other utilities are. Utility A will likely be retiring half of their coal generation capability and placing the burden on off-system and/or a mix of gas and renewable generation. This will likely exacerbate the amount of “insurance” requirement from the above analysis. Increasing renewable, particularly wind, will push the need to manage off-system sales in order for baseload and intermediate units to be available during the on-peak hours. PMA-NT off-peak risk assessment will likely be needed to secure power selling price thereby minimizing ratepayer cost.

Risk assessment for Utility A will be growing in value as more interaction with the markets will be made. In addition, assessment of fuel purchase for both gas and coal assets can be done to help the fuel procurement group enhance their decision making process. This will be more important in the future as the portfolio moves more into intermediate resources (natural gas units) than baseload resources (coal).

Given the pricing of power is based on the marginal power plant, it is highly recommended to run these assessments each year as changes in retirement, new builds, and load can significantly change the power price dynamics.

Conclusion

All Energy Consulting power modeling platform Power Market Analysis (PMA) was designed for the high requirements world of power trading. We have brought this platform to the masses in hopes of assisting utilities, end-users, and ratepayers. A summer risk assessment like this for **new clients will be only $5K,** a significant savings vs. our standard rates and essentially free given the returns it can bring to the ratepayer. This case study clearly shows the value from not only a ratepayer perspective, but also from an operations person dealing with the political aftermath when the market does what it does.

With today's computer processing power, software choices, power markets, and consulting services, if you don't come up with a more rigorous ways of making these fundamental choices, you may be threatened with disallowance or at the very least receive a large headache and stress as the Monday morning quarterbacks will question and knit pick your decisions. Large utilities typically have the software and services to perform this type of risk assessment. However we know there are several utilities not able to reach that scale. In addition, a third-party opinion does offer significant reduction of stress from within and outside parties. With that in mind, we opened our platform for you. Many people understand there is much uncertainty in future events; however one should not leave decisions to chance or just assume futures markets represent reality – we can do better than a flip of a coin.

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Background David Bellman was the former Managing Director Strategic Planning at American Electric Power (AEP). He also worked as a consultant in Deloitte Consulting and Purvin & Gertz – now part of IHS. All Energy Consulting was formed in 2011 focused on energy analytics in order to add insights to the energy markets.