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Thursday, May 19, 2011

SAAC notes for February 2, 2011

Schilmoeller opened the meeting by welcoming committee members and visitors. (A copy of the sign in sheets and the GoToMeeting™ meeting attendance log are attached.) The committee reviewed and unanimously adopted the previous meetings minutes. Schilmoeller suggested that another meeting of the SAAC be held in about 2 months, perhaps mid April. [This schedule has been slipped.]

Schilmoeller asked the SAAC an open question about what non-RPM modeling topics this SAAC should address. The question was raised at the last meeting, and Schilmoeller had sent out in a query that listed possible topics. There has been no response, although the PNUCC has offered to have their System Planning Subcommittee consider this question. Schilmoeller invited anyone who would be interested in organizing a task group to focus on other modeling topics to step forward. He would need more help researching and preparing presentations on any additional topics. Schilmoeller mentioned that the Plexos™ model might be a good candidate for studying the economics of ancillary service demand and supply.[1]

A participant asked about the status of a staff paper on Council planning and modeling methods. He suggested that the paper could put the RPM and other modeling work into context. Schilmoeller agreed to send out copies of that paper as it becomes available.[2]

Review of Concepts

Moving on, Schilmoeller began his presentations with a review of topics from the last meeting. Schilmoeller quickly covered the uncertainties that RPM's addresses. He provided a description of how the RPM's approach resembles and differs from more familiar approaches. He mentioned how the Act bears on creating a resource portfolio. Finally he described the general requirements of any computer model designed to address risk.

Modeling regional ratepayer cost and risk, as required of the Council by the Act, introduces a few subtleties. Models that represent the region as part of a larger system, such as the WECC, may not give the needed information. The problem arises in particular when evaluating new resource additions. Many models make resource build decisions by minimizing system-wide cost or to equilibrate electricity prices among connected areas. It is hard to decide what portion of a new resource, however, has been built for any particular utility. Similarly we have no clear picture of which new resources, if any, benefit the region. Of course, the Council's regional resource plan needs to answer just that question. It was mentioned in the meeting that just as WECC RPM results are difficult to interpret vis-à-vis the "region" so also regional RPM results are hard to interpret vis-à-vis a particular utility.

Schilmoeller described the job of the optimizer. OptQuest creates and tests plans to find ones that minimize cost for a given level of risk. The process of searching for these least-cost plans produces the

[1] Subsequent to the meeting, Schilmoeller discovered that the California Energy Commission (CEC) has a license for Plexos and that the Idaho Power Company (IPC) will be using Plexos for their wind integration studies.

[2] The paper is available on the Council's web site: http://www.nwcouncil.org/library/2011/2011-02.pdf

“feasibility space.” The efficient frontier of the feasibility space can be compared to the set of least-cost plans.

The chart that illustrates the feasibility space has risk on the vertical axis and cost on the horizontal axis. A participant pointed out that some audiences, such as those accustomed to financial portfolio analysis, might find this confusing. He pointed out that the axes are typically reversed for financial portfolios.

A member asked, “How is risk measured? Is it a function of not meeting load?” The approach is to test each plan under 750 games or "futures". Risk is the average of the 10% worst NPV cost outcomes. The RPM doesn't explicitly address engineering risk, although plans are assessed afterwards for adequacy and reliability.

A participant asked, what about other measures of risk? Schilmoeller agreed that it is important to consider other measures of risk. He stated that several measures of risk are preserved for each plan. TailVaR_{90} relies on net present value costs of plans under futures. Net present value, however, does not capture year-to-year power cost variations. It also doesn't capture reliability and adequacy directly. Consequently, staff pays special attention to these other risk metrics.

So far, however, the other measures tend to track TailVaR_{90}. Some brief consideration suggests why that might be the case. There are typically more power plants built in low- TailVaR_{90} resource portfolios. These have a tendency to dampen wholesale price variation and provide greater assurance of meeting load.

A committee member likened the efficient frontier to an indifference curve. An indifference curve, however, doesn't tell you what to spend until you overlay a constrained budget, he pointed out. If we knew our marginal willingness to trade risk for expected cost, we would know where to land on the efficient frontier.

Schilmoeller discouraged this interpretation. He indicated that he will devote a good portion of some future meeting to discussing interpretation of the efficient frontier. For the time being, he emphasized that the efficient frontier allows us to sidestep the problem of preference and weighting. Each plan that is not on the efficient frontier is “dominated” by a plan that is. Plans on the efficient frontier are at least as good as plans they dominate by every aspect of measurement. (in our case, NPV cost and risk are the aspects of interest). The efficient frontier therefore permits the staff to defer to the Council’s trade-offs rather than prejudging the plans.

This line of questions gave rise to more questions about the selection of the plans on the efficient frontier. If there is no simple rule to recommend a plan, how does the Council make this decision? Again, this is probably better addressed in a meeting devoted to the use of the efficient frontier. Among other considerations, however, are how other risk measures map to the efficient frontier. Staff also examines similarities among the plans along the frontier and how soon commitments are required.

If none of the plans on the efficient frontier require near-term commitments, the least-risk plan may be the best choice. The decision-makers incur no immediate cost. Moreover, the least-risk plan is very likely to have the earliest project milestones. Consequently, adopting the least-risk plan preserves all the plans, in the following sense. If decision-makers re-evaluate resource requirements before the least-risk plan’s earliest commitments, the decision-makers will not have passed the earliest commitments of the remaining plans. That is, the remaining plans are still candidates for implementation.

“How does the optimizer pick the plans? Does the staff provide a set of candidate plans?” The staff does not select candidate plans. Staff can “seed” the optimization with one plan, however, to help the optimizer to look in a particular area. The optimizer’s initial selection of plans is rather random. The optimizer needs to test about 800 plan before the optimizer can figure out how to improve cost and risk. About 3500 evaluations are necessary to construct the efficient frontier, the least-cost plans at each level of risk.

Schilmoeller reviewed the estimate of how many plans potentially exist in the feasibility space. The number is clearly large, when we consider combinations of different technology types, different amounts of addition, and different possible schedules for the construction of power plants. For the Sixth Power Plan, the optimizer had to explore about a dozen values for 54 decision variables. Schilmoeller put his last estimate of the number of potential plans at about 10^{31}.

Because of the relatively continuous relationship of plan attributes to cost and risk, however, Schilmoeller speculated that there are combinations of choices that are of much lower dimension. Designing a more efficient optimizer should be achievable. It would exploit the nature of this particular resource addition problem.

"Was the resource portfolio decision really so hard?" asked a member. "Wasn't the real question in the Six Power Plan just whether to build combined cycle combustion turbines or conservation?"

Schilmoeller responded that if risk were not an issue, the analysis could have been much simpler. It's not that hard to stack up a limited number of resources against a fixed load forecast. Even considering hydrogeneration variability, we could probably manage.

When we consider risk, however, we are talking about carbon penalties of unknown magnitude and timing that will in all likelihood be irreversible. There is the possibility of the permanent loss of 5,000 average megawatts of regional coal-fired generation. The non-regional ownership share of these plants also would make a significant impact on the wholesale market. The regional and non-regional coal plants have a combined nameplate rating of 6,440 megawatts. We are also talking about electricity markets subject to restructuring by legislative or regulatory bodies and about changes due to the introduction of new technologies.

As an example of how risk changes the result, consider the resource portfolio in the Sixth Power Plan. The Plan has 4,000 MW of combined cycle combustion turbines (CCCTs) poised for construction before 2020. After the Sixth Plan was issued in February 2010, questions from around the region focused on those combined cycles, which enter the picture in a large stair step when load growth is almost flat. Such questions arose in the first SAAC meeting. Since the announcement of utility plans to close Boardman and high-level discussion of retirement of Centralia, however, the potential role for those CCCTs is becoming more evident. The Council recently pointed out that its resource plan anticipated these possibilities and probably needs little revision.

"Bear in mind," Schilmoeller said, "that the purpose of the RPM, in contrast with most other models, is ***not*** to forecast." The purpose of the RPM is to explore sources of risk and identify opportunities to minimize that risk. Reliance on forecasts and creation of forecasts are contrary to the RPM's underlying philosophy. The resources strategies in the least-risk plan often serve the purpose of guarding the region against futures that are unlikely, but potentially quite expensive.

How is different cost of capital due to financing by IPPs, IOUs, and PUDs captured? Jeff King has provided real levelized cost information. The cost data assumes average cost of capital across the most likely owners. The Council's Generation Resource Advisory Committee provided or contributed to those assessments.

How is project risk captured? Schilmoeller responded that any cost for project risk is determined endogenously by the RPM. The RPM models construction cost and the uncertainty of economic value explicitly.

"Is it expected that using averaged values for cost of capital provides the same results as using investor-specific values?" No, admitted Schilmoeller. This is a concession to modeling expediency. We should ask, however, whether the results would be *significantly* different, given the levels of uncertainty that the model employs. The Council staff, Ken Corum and Jeff King, are evaluating how alternative assumptions for factors of construction representation affect outcome. Their work may shed like on the question.

"What happens if an IPP builds a plant that is unnecessary? Who takes the bath?" If the IPP must liquidate its ownership and takes a loss in the sale, does the cost fall on the regional ratepayer? Schilmoeller answered no, that the cost of all IPPs – and any other construction in the region not owned by regional utilities – is ignored.

This does not mean, however, that IPP generation additions have no effect on model results. Non-regional generation additions deepen the wholesale electricity market. This greater supply increases the likelihood that generation will be available when utilities need to supplement their generation. In sufficient quantity, it also has the effect of depressing market prices when transmission out of the region is congested. (If transmission out of the region is not congested, however, exports increase but price is unaffected.)

Does the RPM build IPP units? While the model can in principle add IPP units economically whenever markets would suggest they can make money, the Council has chosen not to do so. There are several reasons for this decision. Perhaps the most compelling reason is simplicity of results. The RPM model, however, targets electricity prices that Aurora produces as a median for the RPM electricity price across futures. Aurora is primarily a price-forecasting model. It creates such forecasts by adding any generation that can make risk-adjusted returns in the electricity market. It does so without regard for or knowledge of regional ownership. Consequently, over- or under-construction of non-regional plants does move the median price for electricity in the RPM lower or higher.[3]

Schilmoeller reviewed how he arrived at the value of 750 games in estimating a sample size adequate for Monte Carlo simulation. The decision was driven primarily by a requirement that statistics for risk measure be meaningful. If the total number of games is 750, the risk measure is based on, by definition, only 75 games. TailVaR_{90} is the mean over these observations. In order to say anything meaningful about the accuracy of the mean, one must know the distribution of the mean. Schilmoeller showed the minimum number of samples necessary to give some confidence that the distribution of the mean will be normal is about 75.

Schilmoeller reminded the participants that the uncertainty in the estimate of the mean is large compared to the scale of the efficient frontier. This creates an apparent paradox. How can plans along the efficient frontier be considered distinguishable? Are plans on the frontier the result of mere accident? He assured the participants that he would be resolving the apparent paradox later in the presentation.

A question related to the required number of games is, how many simulations or "plans" are necessary? Staff studies indicate that about 3,500 plans are required before TailVaR_{90} stops improving. The number of decision variables is primary in setting the number of necessary simulations.

The figure of 3500 plans is consistent with the recommendations in the OptQuest User's Manual. There are typically between 50 and 60 decision variables in a simulation. These control such factors as the timing and size of addition for various resources. Choices of values for decision variables in fact define a plan. OptQuest finds better plans by changing the values of the decision variables. The section ***Number of Decision Variables*** on page 141 of the OptQuest™ 2.3 user's manual describes the number of recommended simulations.

How sensitive is the sufficient number of plans to the number of uncertainties? Schilmoeller responded that the number of uncertainties typically has a much smaller effect than the number of decision variables.

One participant inquired about the optimization technique. Schilmoeller described it as a nonlinear, stochastic optimization algorithm that used, among other things, neural networks. References describing

[3] In this context, over- and under-construction is intended with respect to wholesale electric market economics. This might result, for example, from regulatory requirements for capacity or renewable generation.

OptQuest's techniques are available on the internet.[4] Schilmoeller agreed that a genetic algorithm (GA) might be a suitable approach to perfecting the search. Indeed GA techniques are incorporated into an approach that the authors of OptQuest refer to as meta-heuristics.

Schilmoeller also felt that an optimizer designed for solving this problem could be much more efficient than a generic optimizer. He said he has some specific ideas for such of program. For example, Schilmoeller mentioned that a technique called "manifold learning" might have some promise. Manifold learning uses statistical techniques to discern low dimensional relationships in a high dimensional space. He hoped to incorporate such ideas in a subsequent version of the model that would be more self-contained.

"How do we know if risk is minimized then?" asked one member. We don't really. Unlike linear programming optimization, explained Schilmoeller, there is never a guarantee of finding the global minimum. Many local pockets may exist. Running over 10,000 plans however suggests that changes after about 3500 plans are … rare.

As the optimizer is approaching its last improvement, is there much change in the actual plan? No, not really, admitted Schilmoeller. Typically, there is a substantial improvement in the first 800 to 1000 plans. Improvements after that are often quite small and there may be long plateaus. In the Fifth Power Plan, however, we saw some introduction of new technologies in the last improvements, and these were important to advocates of those technologies.

One factor that bears on the rate of improvement is the "seed" plan. The OptQuest user can provide the optimizer with a single plan. The optimizer will evaluate this seed plan before the arbitrary set of plans the optimizer uses to orient itself. If the seed plan is the least-risk plan from a base case, the optimizer can be much smarter about its earlier choices. We cannot say that the optimization would improve as rapidly at the beginning had we not provided the optimizer with this information.

"It might be reassuring to see how closely plans around the efficient frontier resemble each other. This could be useful to a couple of reasons. It would lend support to the assertion that the plans on the efficient frontier are not the result of a random accident. It could also shed light on how significantly plans improve with the number of simulations performed." Schilmoeller answered that all of the information that identifies each plan is carried along in the optimization report. That information thus can be provided for any past or future study. He suggested that the SAAC review some of these simulation results in a future meeting.

In summarizing the review portion of the presentation, Schilmoeller asked for volunteers to make presentations on areas in which they are interested or have further questions. He would provide necessary support to prepare the presentation, of course. He felt that the presentations would be more interesting and perhaps more useful if delivered by someone who is not as familiar with the model, as well. There were no immediate offers.

How the RPM Meets the Requirements

Schilmoeller continued his presentation from the previous meeting. The review had described briefly how the RPM worked and how the requirements of the Act bear on the design of the model. It outlined the nature of risk generally and the requirements of any computer risk model. Schilmoeller opened a PowerPoint presentation entitled, ***How the RPM Meets the Requirements for a Risk Model***.

Given the number of 20-year simulations necessary to achieve the desired results – which often numbers in the millions – there are several alternatives that suggest themselves. Schilmoeller discussed these. Schilmoeller explained how the RPM uses statistical distributions to represent the behavior of markets,

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[4]See, for example, http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.127.7194&rep=rep1&type=pdf

loads, and power plant operation over extended periods. He said use of distributions is a reasonable compromise between speed and accuracy. He stepped through how the estimation of cost and value for dispatchable power plant from hourly values of electricity price and fuel price is being calculated. Statistical distributions and correlations represent hourly values over Hydro quarters, on peak and off-peak.

Another feature of the RPM is the use of "standard" months, quarters, and years. Each standard month consists of exactly four weeks. The convention ignores holidays. It permits the calculations to be performed in a uniform manner and makes it easy to convert results to calendar-specific values. While Schilmoeller did not advocate the RPM for rate calculations, rate calculation is an example of a situation where a specific calendar-year's results may be important.

"Wouldn't it make more sense to break the June through August Hydro quarter into two pieces and aggregate the June data with the spring months?" someone inquired. That should not be too difficult, said Schilmoeller, although the input data and the net present value calculation would obviously need to be changed. Before embarking on restructuring the model, however, it would make sense to ask ourselves whether the results would change, in particular from a risk management perspective.

Schilmoeller walked the members through the calculation of costs and value for an energy-constrained dispatchable resource. The Sixth Power Plan used this representation for demand response (DR) projects. Demand response programs may run only 50-100 hours a year.

Schilmoeller pointed out that, although the model shuns predictions over the long term, this algorithm does assume perfect foresight over a three-month period. The formula captures the value of the dispatchable resources over the highest value hours.

A member expressed some concern that high-value hours may not correspond to the times when the system is short of capacity. Schilmoeller reasoned that relatively low market prices for electricity indicates market purchases should be available to meet the capacity requirements. Conversely, high market prices for electricity reflect systemic shortages. Those are precisely the times when the model accesses the demand response energy.

It turns out that the accuracy of the RPM representation of DR is somewhat moot. The RPM failed to choose discretionary DR in plans along the efficient frontier. "That seems to be contrary to utility behavior," remarked a participant. "There are utilities out there acquiring demand response projects." The reasons why the RPM never chose demand response have not yet been settled. The fixed price for demand response in the Six Power Plan, however, is much higher than it was in the Fifth Power Plan, Schilmoeller offered.

Schilmoeller next described Valuation Costing. Valuation Costing is another trick but the RPM uses to simplify hourly cost calculations using statistical distributions. A problem arises when both the price and quantity required of a commodity like fuel vary hourly. Their product (value or cost) is no longer the simple product of average price and average quantity. Correlation of price and quantity enters the picture. Valuation Costing decouples the partial correlations that exist among fuel price, electricity price, hydrogeneration, loads, and so forth.

The price distributions that you've described are those for price takers, asserted one member. Those prices are static and do not reflect the effect that resource addition has on electricity prices. Schilmoeller explained that more than one calculation typically needs to be performed in order to reflect the impact of additional energy on price. Price changes can and do take place to maintain an energy balance between the resources in the region and regional loads. Schilmoeller explained he would return to this discussion later in the afternoon.

Have there been sensitivity studies looking at the effect of uncertainties such as carbon price? Appendix J. of the sixth power plan includes a regression analysis that identifies, among several other variables, carbon price as a key predictor of total cost, explain Schilmoeller.

Schilmoeller showed a feasibility space graph that showed the RPM could resolve very small differences in cost and risk. Figure 1 shows plans produced by varying the levels of conservation premium only. The efficient frontier consists of four or five strands of closely matched plans, like pearls in necklaces. The distinct strands differ only by lost opportunity conservation market adders, which vary from $20/MWh to $60/MWh, in $10/MWh steps. (The short string at the bottom has two points using $50/MWh and two points using $60/MWh.). The pearls in each necklace correspond to discretionary conservation market adders from $30/MWh to $190/MWh, also in $10/MWh steps. Not all necklaces have pearls corresponding to this entire range.

The cost difference between two adjacent pearls is typically about $15 million NPV, but differences of as little as $5 million are discernable. These differences arise from changes of cost and value entirely due to roughly 50 MWa increments of conservation energy by the end of the study.

Schilmoeller explained that these results are not inconsistent with the earlier observation that the accuracy in the estimate of TailVar_{90} is about $3.3 billion[5]. About 70 of the riskiest 75 futures happen to be common to all plans along and near the efficient frontier. Consequently, random variation actually plays a small roll. The model turns out to be performing sensitivity analysis using these futures. The model is evidently quite sensitive to even very small changes in energy. It is also important to note that the uncertainty of the absolute value of TailVar_{90} is of little consequence. Construction of the efficient frontier depends on relative values of cost and of risk, not their absolute values.

Open-System Models

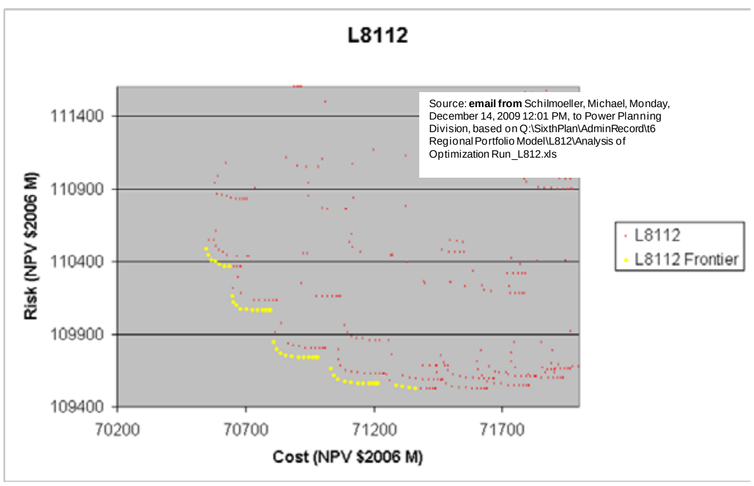

Figure 1: String of Pearls

Schilmoeller went on to discuss open-system models. While most production cost models we are familiar with a closed system models, with respect to electricity, the RPM is an open system model. It effectively treats the region as an island, with imports and exports of energy up to the constraints imposed by transmission.

Schilmoeller stated that there are several reasons for modeling the region as an open system. One factor is the need to represent the cost and risk to regional ratepayers as separate from the rest of the Western system. This is the issue raised in the discussion of the Act. There must be clear definition of region’s need for new resources, as opposed to that of the interconnected system.

The more fundamental factor, however, is that any model that deals with uncertainty must be an open system model. Schilmoeller illustrated how limitations on the degrees of freedom among variables determining electricity price will force a perfect correlation among them. For example, utility analysts might attempt to capture electricity price uncertainty by varying natural gas fuel price. Unless there is another source of uncertainty or a "free variable" to compensate, however, the annual average market heat rate must remain constant in the long run. This means combined cycle combustion turbines will always appear to be marginally viable. We know, however, that if there is a substantial change in the market, electricity prices and natural gas prices could decouple. Gas plants could become expensive if

[5] This is the accuracy at about 95 percent confidence or ±2σ.

new technologies reduce the market price of electricity and environmental concerns drive up the price of natural gas. The utility analyst's studies will miss the source of risk.

Market prices for electricity reflect our transmission-constrained ties to the Western interconnect, continued Schilmoeller. But shouldn't electricity prices reflect the regional situation? They do, responded Schilmoeller. In fact, the regional price is the only price that matters. The RPM recognizes that the two prices are very close when transmission is not constrained. However, the regional electricity price changes when imports or exports approach transmission limits. This price then reflects an energy balance requirement within the region.

"But shouldn't there be a strong correlation to electricity price and natural gas price?" asked one participant. We have seen market heat rates maintain a consistent pattern in the past.

Answered Schilmoeller, "this relationship depends again on the stability of these markets and on the regulatory environment." New technologies, regulatory and legislative initiatives, and even the economics of existing technology and fuel prices can change this relationship dramatically. The exposure to circumstances that would present a risk to the region is precisely is the potential that the RPM helps us explore.

Schilmoeller introduced the concept of aggregating power plants with similar fuels, heat rates, and variable operation and maintenance costs. He gave examples of how cluster analysis could reduce the region's 54 natural-gas fired turbines to a dozen aggregate units.

Schilmoeller described how the RPM searches for electricity price that establishes a balance of load requirements, generation, and imports or exports. The resulting electricity price is only is feasible in the sense that this energy balance is maintained.

Choice of Platform

Finally, Schilmoeller mentioned that the choice of platforms, that is, an Excel model, stems from a desire to make the model as transparent and accessible as possible. Detailed instructions for tracing through the logic in the RPM appear in the Fifth Power Plan's technical appendices.

A second, more technical reason for adopting Excel was the possibility for a meta-model to write VBA code at run time, including functions and complex objects. Here the term "meta-models" refers to models that write other models. Olivia, the meta-model that wrote the RPM (actually its predecessor), wrote models from scratch based on the user's description. This permitted Olivia to write a workbook model that was as efficient and fast as possible. Olivia included only those features and that code that the user needed.

The VBA, once compiled, can run as fast as other compiled languages. Code performance suffers primarily with COM+ inter-process communication, including calls to user-defined worksheet functions (UDFs) written in VBA. These can be avoided by using the Excel C language interface.

Overbuilt Systems

Approaching the end of the presentation, questions returned to the future discussed at prior meetings. This is future number 750 from the spinner graph of the least-risk plan in the final Council carbon risk study. The question was about overbuilding in that future. Why does the cost of the overbuilt system in this future lie below the cost on average across all futures?

There are several things going on here, responded Schilmoeller. First, the future 1 has the low average requirements. Simply by virtue of the fact that less electricity needs to be generated, we would expect the cost of that future to be lower. This does raise the issue of metric, however. If we use a metric that is normalized by demand, that is, a net present value dollar per megawatt hour of load, we could neutralize this effect somewhat. Second, the appropriate comparison is not with the average across futures. To evaluate the cost of overbuilding in this future, look at a case ***with the same future*** where the combined cycle combustion turbines were not built.

Schilmoeller promised to present some analysis of this future for the next SAAC committee. Of particular interest are the nature of costs due to overbuilding and metrics for evaluating cost.

The Relevance of Regional Plans

Several participants asked about the relevance of a plan that addresses the region as a whole. What is there is it is useful to an individual utility? A regional plan doesn't fit everyone. What with the Council's plan look like if the Council actually planned for specific types of utilities?

The different objectives and motivations of utilities within the region could lead to significantly different behavior than that which we anticipate, remarked a member. There may be significant unintended consequences if we do not understand this variety of positions.

One participant responded that the regional plan is important for several reasons, including its value to utilities in support of utilities IRPs. Later that day, the participant expanded on his thoughts in an email. The email note emphasized the value of setting the standards for good resource planning. He pointed to the Council’s use of imperfect foresight, the use of radical uncertainty, and the consideration of construction risk and optioning. He asserted that both utilities and regulators would benefit from broader adoption of such principles and techniques. He thinks, however, the Council needs to do a much better job of communicating to the region why the techniques in the RPM are important. He observed that utilities currently only superficially adopt the RPM concepts. For example, it is typical for an IOU to say that their stochastic risk analysis is similar to the Council’s when in fact the variation is constrained to historical experience.

Schilmoeller added that the Council's plan provides a perspective that would not exist otherwise. For example, in the Fifth Power Plan, the Council pointed out the relative availability of capacity from independent power producers. Without building any more resources in the region, utilities could reduce their exposure to the market by taking an ownership share or contracting for the output of these existing units. Risk could be reduced without adding to the carbon footprint of the region. While acquiring the output of IPPs does not work for every utility, this did raise a question that utilities needed to respond to.

A regional plan reveals impacts of combined utility behavior that would not be evident to an individual utility. For example, utilities individually are price takers for wholesale electric power. A regional plan, however, can reveal how large-scale supply and demand can affect market prices and transform markets. The Council’s plans have identified significant cost reductions attributable to reduction in electricity price due to load reduction. Market transformation through region-wide adoption of energy efficiency codes and standards is another example.

The Council's regional plan is not a substitute for individual utility plans anymore so then summing utility plans can be considered a regional plan. The Council could do a better job of explaining how their work is applicable to individual utilities and other constituents, to be sure. The SAAC is one opportunity for providing that linkage.

The meeting concluded at 3:30PM.

Agenda for the
System Analysis Advisory Committee
February 2, 2011

Preamble

- Introductions and accommodations
- Recusal: The Ultimate Defense
- Orientation and objectives
- **Plan for the day**
- Selection of the next meeting date
- Adoption of minutes

Plan for the day

- Review and consolidation (9:00AM-10:30AM: 90 minutes)
    - Progress on general issues
    - Overview of last meeting's presentation
    - Reactions and thoughts of the Committee
    - Roles and participation
- *Break (10:30AM-10:45AM: 15 minutes)*
- Design of the Council's RPM Part I (10:45AM-11:45 AM: 60 minutes)
    - Techniques for better performance
    - Open-system models
- *Break for lunch—on your own (11:45 AM -1:00 PM: 75 minutes)*
- Design of the Council's RPM Part II (1:00 PM -1:45 PM: 45 minutes)
    - Unit aggregation
    - Speed and accuracy
- The choice of platform (1:45 PM-2:30 PM: 45 minutes)
    - Microsoft Excel®
    - Decisioneering (now Oracle) Crystal Ball®, CB Turbo®, OptQuest®
    - Olivia
    - Efficient frontiers
- *Break (2:30 PM-2:45PM: 15 minutes)*
- Issues, questions, next steps (2:45PM – 3:30PM: 45 minutes)

Adjourn at 3:30pm

System Analysis Advisory Committee Mtg. - May 19, 2011

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Eric Hiaasen	eric.hiaasen@eweb.org	9:16 AM - 3:45 PM
Sibyl Geiselman	Sibyl.Geiselman@eweb.org	10:17 AM - 3:30 PM
Silvia Melchiorri	silvia.melchiorri@pgn.com	1:09 PM - 3:43 PM
Massoud Jourabchi	mjourabchi@nwcouncil.org	2:46 PM - 3:16 PM