Intermittency Analysis Project
CPUC Energy Division Staff Comments on PIER Draft Final Report "Intermittency Analysis Project" by GE Energy Consulting

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California Public Utility Commission staff (CPUC staff) believe that the IAP has produced insights that can aid efforts to economically and reliably integrate wind and other intermittent generation into California's energy system. It is important that the final report(s) clearly identify major implications for real world decisions, and we welcome efforts toward this end that GE has made in producing a draft report.

The GE Energy Consulting (GE) portion of the IAP draft final report describes a number of analytic steps representing interdependent and sometimes overlapping real world processes. CPUC staff's comments address various issues and recommendations regarding the report as an integrated whole, since it is the integration and relationship of the parts that supports the major findings. Inevitably this does lead to comments regarding specific aspects of the report. In addition, we anticipate that entities directly involved with the practical operational integration of intermittent renewable generation, such as the California Independent System Operator (CAISO) and the utilities that own transmission and purchase renewable energy, will provide specific comments on various aspects of the IAP report. We hope that such comments along with our own will be factored into the final report and also taken into consideration when moving forward where the report leaves off.

The following comments are intended to aid preparation of the final report, but in some instances may not be able to be addressed in a report that is on the verge of completion. Hopefully they will be useful going forward.

Relation to the DPC Study.

Via narrative and a diagram, the GE report describes the relationship between the DPC and GE portions of the IAP analyses. However, a clearer description of this relationship is desirable. Since the GE study apparently adopted the transmission and generation expansion assumptions from the DPC study, the rationale and implications of those assumptions need to be at least briefly, but clearly provided in the GE report (separate comment below). If, as it appears, there were modest differences between the two studies regarding generation and transmission additions, this should be explained. Beyond this, the GE draft report indicates that DPC power flow results were in some way used by the GE study, at least for the Quasi Steady State (QSS) analyses. This needs to be clarified. Finally, it would be informative to compare the transmission loading/overloading results for the two studies. Even though the DPC study modeled snapshot hourly AC power flows or in some instances a limited series of hours, whereas the GE production cost study modeled 8760 hours per year using DC flow (with the QSS study apparently modeling 3 hours in 5 minute steps using AC flow) - - some illuminating comparison of the different transmission loading and congestion results should be possible.

Report Structure: A More Visible "Framework" Anticipating Key Results.

The report contains separate analytic components (statistical, production cost and QSS analyses) which themselves contain multiple elements that can be quite complex. The study's concrete objectives and key results can provide a logical unifying framework to guide readers through the different components, their roles, and their interrelationship. However, only very broad objectives are established in Section 1, and while both the executive summary and conclusions contain useful concrete results, the reader needs a more structured framework based on key objectives and results to provide context and guidance as the report progresses through the different complex pieces of the analysis.

In essence, there are many trees, and the forest should be more clearly defined at the outset and then occasionally recalled to the reader's attention at appropriate points throughout the report. It would be helpful to clearly establish at the outset the concrete results toward which we are progressing, along with a conceptual framework within which the different analytic elements contribute to the results. This would help the reader asses not only the process, but also the robustness and uncertainties associated with results. Some of the useful results and the questions they address were likely not readily definable at the outset of the study. However, once identified, they become fair game for constructing a useful framework for organizing the report.

Too Many Trees - - Move Some Items to Appendices.

Beyond helping the reader by providing an ongoing analytic framework based on key objectives and results, clarity and focus could be enhanced by reducing the amount of detail in the body of the report, and moving some items, including some tables and figures, to appendices. This especially applies to statistical results in Section 3 and some of the economic and emissions material in Section 4. Analyses and results that are on the critical path to key results should remain, while others could be summarized, with the reader being directed to more detail in the appendices.

Some of the Economic Results in Section 4 Should be Moved to an Appendix and/or Presented Differently

The economic analyses in Section 4 are, as at least partly suggested by the report, off the critical path to the main study objectives, which involve operational issues for integrating large amounts of intermittent generation. (It would appear that the emissions results are also off the critical path.) Furthermore, there are unanswered questions and pitfalls in the economic results. Only those economic analyses that contribute to pursuit of the main integration issues should be retained in Section 4. This might include the simulated spot market prices, with caveats regarding generator viability, fixed cost recovery, and capacity market implications. Information relevant to estimating commitment and scheduling costs (for wind and solar integration) might also be retained, if it is sufficiently supported (which is unclear - - see below).

Some ambiguity appears to arise from the treatment of commitment and scheduling costs. It is unclear if or how such costs, presumably not contained in modeled spot market prices, are included in the results presented from producer and consumer perspectives, such as in Figures 67-70. Other wind integration studies generally appear to find the largest economic costs of integration come from commitment or scheduling, not shorter-term load following and regulation adjustments. Thus, to the extent that the GE study can credibly shed light on commitment and scheduling costs and related operational implications, this is valuable. However, estimation and interrelation of the different integration cost components appears to be elusive, since as pointed out in the report, commitment (and presumably HA scheduling) although stated to lead to adequate load following and regulation capability, could be adjusted (presumably at some cost) to enhance and likely reduce the cost of load following and regulation. Such economic tradeoffs appear to be beyond the scope of the IAP, so perhaps they should be recognized but not addressed.

A particularly strong statement on page 176 regarding "ignoring state-of-the-art [wind and solar] forecasts," implying the importance of intermittent generation forecasts in general, is the following: "The economic analysis (Section 4.2) showed that the economic penalty, in terms of operational inefficiency, completely swamps any benefits due to the addition of renewables. The penalty is measured in billions of dollars." This stark conclusion requires elaboration and foundation, especially regarding the manner in which it is supported by the economic analyses summarized in Section 4.2. In Section 4.2, using no wind/solar forecast (for commitment) is shown as reducing the simulated spot price, which is stated to pose viability risks for generators and to reduce load payments (as Figure 67 appears to show). However Figure 68 and accompanying text appear to indicate that, paradoxically, <u>use</u> of forecasts reduces "total variable operating costs." Are generator operating costs other than incremental costs, such as start-up, minimum load, or other commitment-related costs, included in "variable operating costs"? What is the nature of the operating costs that are saved by using wind/solar forecasts, and (how) are these cost reductions reflected in depicted "load payments?" These economic issues are directly relevant to the economics of wind/solar integration and also shed light on operational issues, including the tradeoffs among commitment vs. scheduling vs. load following/regulation capabilities and adjustments (and costs). However, as presented in the draft report, there appear to be ambiguities or gaps. Some of these matters may be beyond the IAP scope and the way and place they are presented should not detract from clear, understandable presentation of the main operational issues, methods, and results. Again, moving part of this to an appendix might be useful.

Assumed Transmission and Non-Renewable Generation Additions

Whether the future electric system can accommodate substantial intermittent generation without unacceptable risks of damage or outage (or very high costs) depends on what renewable generation is assumed to be added, which is reasonably well described by the GE report. However, it also depends on what kinds and amounts of other generation are assumed to be added (or retired), and what transmission is assumed to be added. Repeating CPUC staff comments on the DPC draft report, these assumptions should be more fully described. The basis and uncertainty of such additions (such as which of them are in planning or permitting) should be addressed, and the participation and importance of added generation and transmission in providing different kinds of system maneuverability to support wind/solar integration should be more fully and quantitatively revealed. For example, what "economic dispatch" units modeled in the QSS analysis were new generators? What is the breakdown of hydro versus combined cycle vs GT vs. steam, in providing maneuverability in the production cost, and (separately) the QSS analyses, in the different time frames summarized in Conclusions (Section 7)? What part of the maneuverability generation is at risk of retiring? What are the locations of maneuverability provider? Were geothermal or biomass assumed to not provide maneuverability? Did transmission constraints ever limit availability of maneuverability? To what extent was required maneuverability assumed, or determined to be localized, i.e., SP15 or LA Basin?

On a gross level, what is the modeled reserve margin for 2010 and 2020, with and without including intermittent renewables (when included, assigning the appropriate capacity derating)?

The amounts, roles and uncertainty of assumed generation and transmission additions (and retirements) clearly are important for understanding the robustness of conclusions. They are also important for understanding implications for future asset procurement, and for comparison with historical experience.

Relationship and Interaction of the Different System Response Time Frames, Consequences for Needed Maneuverability, and How this is Impacted by Variability vs. Uncertainty - - Should be More Clearly Presented

At the heart of the IAP is the need for electric supply operations to respond to developments and information/uncertainty in different time frames, using the varied capabilities of different assets. This challenge is central to electricity supply in general, and presents a very complex analysis problem for wind/solar integration as addressed by the IAP.

It is also very difficult for the reader to understand and follow the rationale and roles of the different analytic steps, how they fit together to produce concrete useful results, and what the embedded key drivers and uncertainties are. There are also important ambiguities. For example, the selection of discrete time horizons is reasonable, but necessarily partly arbitrary. (If combined cycle generators have a 4 hour startup time, how does this fit within the DA and HA time frames? Also, there are tradeoffs between different maneuverabilities and their costs, and suboptimal commitment and/or scheduling from the hourly perspective may provide worthwhile maneuverability, security and economy at the sub-hourly level.)

Just as comments above recommended a more prominent framework based on overall objectives and key results toward which the analysis is proceeding, conceptual aids would be helpful to clarify the time frame and uncertainty complexities noted in the preceding paragraph. A flowchart or similar diagram, perhaps accompanied by a table, could serve this purpose. Such a "teaching aid" figure/table could be inserted at multiple points in the report to enhance clarity, continuity and context. This should be doable in time for the final report.

Hydro Issues

Since the last workshop presentations, GE has added a comparison of system-wide historical versus simulated hydro operation and a sensitivity analysis with constrained hydro maneuverability. These additions provide added robustness to results. The GE draft report also includes among identified needs an inventory of actual hydro maneuverability plus ways that it might be increased. It would be helpful for the report to further note that hydro constraints are facility or watershed specific (such as regarding cascading MW and timing constraints over a watershed, and such as forbidden operating zones in terms of reservoir and flows levels), so that future assessment of hydro maneuverability should be at this level. Furthermore, it would be useful to compare simulated versus historical hydro operation at the facility or watershed level, and to consider a dry hydro year west-wide. If not already clear, it should be made clear how the simulated load and hydro years are linked (e.g., did simulated 2004 represent a California and west-wide 2004 load year and 2004 hydro year?).

The draft report notes that hydro was scheduled according to local load profiles, such as PG&E vs. SCE. What about net load profiles? How was system-wide wind netted against PG&E or SCE loads, in order to schedule PG&E vs. SCE (or other) hydro? Apparently pumped storage was dynamically optimized in 8760 hours-per-year GE MAPS simulations, but was removed from supply and treated as part of an input load profile in the 5-minute (3-hours total) QSS simulations - - this should be verified if true. The draft report states that 2-day ahead wind/solar forecasts were used to commit thermal (presumably fossil only) generation and to schedule hydro. How did hydro scheduling work? What was the assumed lead time for making hydro maneuverability available? To what extent did DA scheduling constrain hourly hydro maneuverability, and were any scheduling constraints imposed on a plant or watershed basis? Is a major reason that hydro shifting in response to wind/solar variability was limited to usually < 500 MW/hour and almost always <1500 MW/hour the fact that hydro is generally operated mainly on-peak and wind usually is strongest off-peak?

Transmission Constraints

The draft report states that transmission constraints were simulated using WECC path ratings. (How) were more detailed constraints applied within California? Were commitment and scheduling in the GE MAPS runs driven by N-1 security constraints, or N-0 (assuming no outages)? What was the extent and location of simulated transmission congestion in the GE MAPS and PSLF (for QSS analyses) simulations? Did congestion result in substantial decoupling of some renewables and/or maneuverable generation from the rest of the system, so that integration requirements and potential need for future assets were localized, not state-wide? What were such locations?

Changes in Operating Procedures and Contracts

The draft report states that changes in operating procedures and historical arrangements or contracts would be needed to support the most effective integration of intermittent generation, and indicates that at least some of these required changes (such as regarding contracts) were effectively assumed to already be in place, for purposes of the analysis. Could the report be more specific regarding those consequential changes that were modeled as having occurred but which are not yet in place or committed, and the implications for interpreting the study's results?

Dispatch Semantics

The term "dispatch" is sometimes used to refer to hour by hour changes in generator operation as simulated in GE MAPS production cost modeling, and is sometimes used to refer to 5-minute load-following changes. There needs to be consistency. It appears that what is intended for purposes of this report is for dispatch to refer to 5-minute load following changes, not hourly "scheduling" changes as simulated in GE MAPS.

Wind Forecasts

If not already enumerated, how many individual wind data sites (and where) were used to develop wind forecasts? At what heights, and what is the consequence of these heights? Are these locations and their use in the study judged to over- or underestimate the variability and predictably of wind generation? Were these locations applicable only to the 2-day forecasts used for commitment, or were there also shorter term forecasts and did they use the same monitoring locations? (How) were shorter term forecasts used in simulations and analyses, and are they reflected in any of the conclusions? The draft report cites wind forecasts having only positive error (actual wind sometimes stronger, never weaker). (How) was this converted to unbiased forecasts, and what are the implications for the analysis? Why were 2-day and not 1-day forecasts used for commitment?

2010X Simulations

The 2010X simulations are used extensively to provide a level of conservatism and to more starkly illustrate certain points, such as the value of incorporating wind/solar forecasts into commitment. However, 2010X does not represent part of a rational trajectory of projected developments over time, as do the 2010T and 2020 simulations. It would thus be helpful if the 2010X simulations and analyses were not simply inserted into a 2010-2020 sequence and its analysis, but rather were more clearly treated as a separate, albeit informative and highly emphasized, sensitivity case.

Wind/Solar Versus Biomass/Geothermal Impacts

In several places in Section 4 the impacts of wind and solar additions are distinguished from the impacts of biomass and geothermal additions. For example, wind/solar are shown to have a lower per-MWh value due to their intermittency. The methodology for developing these results appears to have been to first add the biomass and geothermal to derive their impacts, and then to incrementally add the wind and solar to derive their incremental impacts. If so, this could understate the impact or value of wind/solar, since the prior biomass/geothermal additions would likely have already depressed spot market prices and variable operating costs that were then further impacted by wind/solar additions. Reversing this arbitrary order by adding wind/solar first would likely change the results somewhat. If not analyzed, this effect should at least be recognized.

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