Steering Committee EIS Questions/Issues

1. What goals is the EIM supposed to accomplish and can these objectives be achieved without a centralized market?
2. Are we studying anything other than the SPP model for a Western EIM? Does it fit in the Western Interconnection where we have longstanding bilateral agreements? Shouldn't we be asking what we want the EIM (or other alternatives) to achieve and then figure out how to accomplish that?
3. The WECC benefit study does not show clear benefits, and the costs study ranges are too broad to allow a reader to make any conclusion. Because this is such a significant undertaking, will the EIM be restudied and is a restudy prudent based on Question 2 above?
4. SPP utilizes Flow Gates to manage ATC – The West uses contract path... How can EIM be implemented in a contract path scenario?
5. Is there a way for W.C. members to express their opinions and ideas in another forum so they can be heard?
6. What is the incentive for entities with no renewable integration or flow issues to join in an EIM?
7. If a Transmission Provider (TP) doesn't volunteer to participate, and power gets moved across his system by the EIM Market Operator, how is he compensated? What if the compensation rate is less than his existing OATT rate? How would that TP convince his Utility Commission that this is a fair for his ratepayers?
8. If a "winner" is defined as a BA where customer bills are decreased because of the EIM, can an EIM be established with no "losers"?
9. If at the end of all the study work BPA and Western decide not to participate, is the EIM still feasible?
10. Can a detailed explanation of how the proposed (not SPP's) EIM works on a daily basis be provided?
11. How it will be set up?
12. What resources are needed?
13. What governance is necessary?
14. What financial incentives will be used or not?
15. What tariff changes are required?
16. How does each State Commission figures into the mix?
17. How are investors compensated if the EIM makes existing generators uneconomical

The following are questions raised by NVE at the Portland Crossroads and the answers provided. Do you feel that the questions were adequately addressed?

1. Can EIM work in the west if un-consolidated BAs do NOT all convert to flow based transmission? Note* Flow based works ok in the eastern footprint because it is an intermingled system vs. the west's more wagon wheel type system with long stretches of lines between point of receipt and delivery. Yes. The concept of converting to flow-based transmission is associated with Open Access Transmission Tariff calculations of available transmission capability (ATC). *The EIM does not use ATC calculations to provide service.* Hence decisions regarding ATC calculation methodology are independent and moot from the point of view of the EIM. How can an interconnection mix flow based with contract path methodology; especially when the two are not necessarily contiguous?

2. Will the EIM be in one footprint? The WECC benefit/cost study will identify benefits for two different size footprints, so that the relative effect of footprint size on benefits and costs can be seen. Most of the Market Operator costs would be incurred regardless of footprint size, and would therefore be higher (per participant or per MWh) for a smaller footprint. Market Participant costs are identified in the WECC study on a per BA basis, and would therefore scale overall with the number of BAs participating. As other markets have shown, the larger the market, the lower to market operation cost per megawatt. To have material benefits there must be a way to allow for dispatch of generation between non-contiguous areas. *There may be a need to address the issue of compensation for use of transmission. However, this issue may need to be addressed regardless of whether markets are contiguous or not*. The question really relates to the matter of whether there can be pockets of EIM mixed in with non-EIM participants. It seems the EIM participants would need to be contiguous or would be required to pay OATT transmission rates to cross non-EIM BAs. Is this correct?
3. Who will administer the EIM? It looks like the proposal is "one administrator" and "one monitor". Do costs for both (staffing/ hardware/ software/ etc) get included in the cost analysis? The cost side of the benefit/cost study is developing a range of cost estimates based on factors, such as whether the market operator function leverages an existing market operator or is a greenfield operation. *The cost analysis will not give cost estimates for specific market operator options, e.g., WECC, SPP or NWPP as the market operator.* At this time it is not known who will be the market operator. The WECC benefit/cost analysis may provide insights into what characteristics make for a more costly and less costly market operator option. Four groups of market operator options have been identified: 1) a new division within WECC; 2) a reconstituted form of one or more of the existing Subregional Entities (e.g., WestConnect, NTTG, ColumbiaGrid, Northwest Power Pool); 3) an existing third-party which operates a market; or 4) a new third-party market operator. The advantages and disadvantages of the options were discussed in a draft paper at http://www.westgov.org/EIMcr/documents/eim-options.pdf.
4. How would the critical mass of BAs be assembled? Would the WECC board take a vote of who's in and who's out? We don't know what will be a critical mass to warrant creation of an EIM. The WECC benefit/cost study may provide insights on what constitutes a critical mass, but will not directly address this question. *An initial indicator of whether a critical mass can be reached will likely be when discussions among BAs result in the commitment of parties to invest in efforts to define a market design and identify a market operator.* A critical mass must show up before making major investments in market implementation. Individual BAs will need to decide whether to establish an EIM. The general drivers for a BA decision are likely to be the costs and benefits of an EIM to the BA. A complicating factor is that individual BA calculations of costs and benefits will be affected by the decisions of which other BAs decide to participate. There is no regulatory requirement that a BA decide to join an EIM or not. Any WECC action related to the EIM will have to be taken by the WECC Board of Directors. At this time, WECC is committed to performing the benefit/cost analysis. WECC staff also intends to do an assessment of risks to WECC (the organization and the membership as a whole) if the EIM is implemented. Some risks will be different if WECC is the market operator than if a third party is the market operator, so these two scenarios will be examined. No decision has been made by WECC to do anything beyond the study.
5. Is it a coincidence that all of the panelists telling us about the benefits of an EIM are all RTOs/ ISOs? An EIM must be justified based on its own merits without any expectation of adding other elements typical of RTOs, such as day-ahead markets, capacity markets, transmission planning, or transmission expansion cost allocation. *There is nothing in the EIM market design that forces the West to later adopt an RTO structure.* In addition, the EIM should not preclude the West

from taking future steps toward more efficient system operation through regional energy markets and coordinated transmission services. The questions relates to the makeup of the panels at the EIM Crossroads. It appears that the panels were slanted to individuals already in RTOs

6. Are there NERC reliability issues? These would be addressed through a Seams Agreement between the Market Operator and the non-market areas (as well as with the California ISO and Alberta Electric System Operator markets). This agreement would be similar to any agreement between to market areas within the interconnection. All reliability standards would have to be complied with on both sides of a seam.
7. SPP utilizes Flow Gates to manage ATC – The West uses contract path... How can EIM be implemented in a contract path scenario? NO ANSWER
8. Who polices and enforces non-compliance in the EIM? The "monitor"? The host BA? NO ANSWER
9. Does EIM implementation assume DSS as part of the scenario? If yes… won't EIS make DSS obsolete? No explicit assumptions are made in the benefit/cost study about the contribution of DSS, which is a tool for the implementation of dynamic schedules.
10. How do "consolidated BAs" differ from an RTO? See #5
11. Who's been the devil's advocate through the cost benefit analysis? Who's bringing up the "downside"? All that has been presented is "the benefits outweigh the costs". NO ANSWER

Utah – Commissioner's Questions/ Comments

1) Do we believe the study? Are our stakeholders engaged? Thus far, WECC has held three stakeholder workshops and multiple stakeholder meetings to explain and secure input on the benefit/cost study. The meetings have included diverse participants. In addition, WECC formed a steering committee and technical review subcommittee for the study, both of which consist of members from a diverse range of entities. Meetings for both committees are open and are well-attended. Both the cost and benefit analyses are likely to present a range of outcomes. *The results of the benefits study, in particular, are sensitive to assumptions that are hard to model specifically.* Potential EIM participants may elect to supplement the WECC benefit/cost study at their individual BA level and by examining the experience with other markets.
2) Do we believe the assumptions? See #1
3) Are we being presented a false dilemma, what are the options to integrate? Presently, individual BAs need to have resources to provide the integration service as a stand-alone operation. Bi-lateral arrangements can be made with parties outside the BA to help the BA balance its loads and resources. While it is always possible to change the rules under which we operate, it is a matter of getting agreement on how to do so. The EIM is one way to do that. *An EIM is not the only tool available to lower the cost of integrating variable generation.* Better wind and solar forecasting, intra-hour scheduling, dynamic scheduling, new storage technologies, and faster bi-lateral markets for transmission and power (e.g., I-TAP) can also lower integration costs. A fast (5 minute dispatch) market that reduces overall variability and uses the lowest cost generation to balance load and generation over a broad footprint has proven effective in lower integration costs in other regions such as MISO, SPP, and the California ISO. However, MISO and CAISO are fully implemented LMP market models that have features beyond what is contemplated with the EIM. It will be important to understand these differences when making comparisons to the EIM proposal for the Western Interconnection.

Current status of Joint Initiatives:

- Intra-hour scheduling – On track for implementing 30 minute scheduling on July, 2011 subject to the availability of automated scheduling tools.
- ITAP – In a product development phase. The product should be available later this year.
- DSS – The DSS Operating Committee has declared the DSS system as operational and established March 11th as the official "Implementation Date".

There are presently no plans for a systematic evaluation of the benefits of the Joint Initiatives. The Joint Initiatives decision to move ahead was based on "back of the envelope" calculations that showed benefits exceeded the relatively small cost of the initiatives. *There are presently no plans to track usage of the Joint Initiatives to enable an after-the-fact systemic analysis of implementation costs or benefits received.* The problem being addressed by the EIM is two-fold. *First, the EIM addresses the issue of economic efficiency and use of the existing grid. Second, the EIM addresses the issue, present and future, of integrating potentially large amounts of variable generation.* There are efforts underway at the Joint Initiatives to promote intra-hour scheduling, dynamic scheduling and a fast bi-lateral market for transmission and generation. No analysis has been done of the impact of the Joint Initiatives on economic efficiency, grid utilization or integration of variable generation. *Although it is too early to determine the impact of an EIM versus the impact of the initiatives already underway, it is believed that current initiatives will have a lower impact than an EIM.* The opportunities for widespread dynamic scheduling are limited at present, but significant work is underway to address the limitations, which may allow for great penetration of dynamic scheduling in the future. For example, the EIM relies upon the use of dynamic schedules in order to implement the regional security-constrained economic dispatch.

4) How do EIM cost overruns get dealt with? A robust market design is perhaps the best way to control start-up costs. The more design decisions that can be made up front and not changed throughout the development process, the lower the potential for runaway costs in the implementation process. Putting together a project management plan will help reduce the risk of runaway costs. Additionally, a test period where the EIM is operated in parallel with traditional balancing procedures has been shown to be important in the successful implementation of new market systems. The cost analysis of the WECC benefit/cost analysis is expected to show lower implementation costs when building on existing operations compared to a greenfield start-up. The WECC cost analysis will also identify some of the risk factors for runaway costs and some suggestions for mitigation efforts.
5) Are cost allocation methods fair and equitable? The answer depends upon how the market is structured. One means currently being discussed would be to have a per unit charge on energy cleared through the market. Other options, such as an allocation to BA participants have also been discussed. The allocation of costs would be determined based upon the market structure. *At this time, it is expected that the cost of the market would be paid through a usage fee paid by market participants. Whether that cost would be passed on to the ratepayers served by those entities would depend upon the pricing process for any individual market participant.*
6) How will utilities minimize their rate recovery risk? NO ANSWER
7) How are risks handled? (is the fox watching the hen house?) NO ANSWER
8) Will this morph into an RTO? See #5 in previous section
9) What is the critical mass required to make EIS happen? How will it show up? Who's in charge? How voluntary will it be? Do generators think it is voluntary? *A BA's decision on whether to join an EIM will be voluntary.* Once a BA joins, generators within that BA will have the option each hour whether to offer units into the EIM. However, hourly settlements within a BA will not be voluntary. Such settlements will be determined by the EIM. It is not clear if generators outside

of a participating BA or BAs which are not contiguous to participating BAs will be able to participate in the EIM.

10) How will this affect reliability? See #6 in previous section