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OMS

Organization of MISO States

COST ALLOCATION AND REGIONAL PLANNING (CARP) MEETING
CARP XV
March 9-10
Minnesota Public Utilities Commission
St. Paul, MN

MINUTES

March 9

On site sign-in sheets and on-phone roster are available from Brian Rybarik.

Negotiators participating by phone: Mike Proctor, Dennis Koepke

EISPC Update

DOE has scheduled conference call between Topic A and B (EIPC and EISPC) recipients to get them on the same page. There are a variety of issues that need to be worked out to help get the transmission study efforts off the ground on the right foot. This conference call will occur in the next couple of weeks.

The kickoff meeting for EISPC is scheduled for March 25-26 in Crystal City (Washington, D.C. area). The agenda for the first day is going to be organizational, bylaws, elections and identification of Topic A steering committee members. Day 2 will be more substantive – engineers will be on hand to discuss an overview of transmission planning, what it entails and how EISPC will fit into Eastern Interconnection studies.

The EIPC repropsal has been filed – it is available from Brian Rybarik or from the Midwest ISO. Midwest ISO is a principal investigator of the EIPC, so they are a good resource on the actions of the EIPC.

NOTE: The UMTDI update was removed for this meeting. It will be added as necessary for future meetings.

RECB Taskforce Update

Early February meeting: RECB looked at the exclusion criteria, including a benefit-cost metric (this was also discussed at the late Feb. meeting.) This would different than the metrics used to move a project from Appendix B to A. It would narrow the # of projects that would be cost-shared under I/W.

NOTE: After the late February meeting, the RECB Taskforce voted to NOT use the cost-benefit metric as part of the exclusion criteria. The vote was 20 in favor and 34 opposed.

At the early February meeting, the Midwest ISO also provided an overview of the differences between HW/BW and I/W. Network upgrades (and how they might fit into a new cost recovery mechanism) were also discussed, specifically, where is the breaking point where a network upgrade is a regional project rather than generation interconnection.

Late February Meeting: The RECB taskforce received a verbal report from LECG regarding concerns about potential market impacts of the I/W design. There was discussion of using compromise negotiations. The feedback from stakeholders was that compromise negotiations may not be fruitful – therefore, they were abandoned. It would have been difficult to identify small groups and difficult to negotiate something that is not concrete yet (i.e., without the actual tariff language), particularly since it would be difficult to find small groups since everyone desires to be involved in the discussions. Also, the various stakeholders were able to identify their issues and potential areas of compromise through their recent hot topic papers.

> IL (Rismiller): Has a deadline been set with respect to when the detailed proposal will be available?
>
> JENNIFER: The goal is to have a detailed proposal available for the late March meeting (prior to the RECB and CARP meetings at the end of March). They are also trying to have more detailed business rules (draft) available at that time as well.

SPP Update (Mike Proctor): The SPP's Market Operations Policy Committee (MOPC) [equivalent to the Advisory Committee at the Midwest ISO]. There were two votes on the agenda, one of which was to approve early submittal of the HW/BW cost allocation in April. They took a telephone vote to determine whether they would recommend the Highway/Byway proposal to the SPP Board to file. It would require a 2/3rds to approve. The proposal received 64% with respect to the specific tariff language – the MOPC never took any second vote, which was more on the policy of Highway/Byway.

The issue appears to be tariff language relating to "unintended consequences." Under the tariff language, there would be a periodic review (at least every 5 years) to ensure that the tariff is working properly. Those who voted against the proposal wanted to bolder this language and include a review of the "benefits" from the HW/BW cost allocation – to determine where the benefits were actually going after some experience with the cost allocation.

The SPP Board is going to have a meeting at the end of this month (after CARP) in Dallas (31st) to discuss among the stakeholders how to fix this issue and keep things moving forward.

Subregional Layer Alternatives

Jennifer Curran, Midwest ISO

The presentation for this section is available here:

http://www.misostates.org/CARP%2015%20%20Sub-Regional%20Layer%20Alternatives%2003-10-10.pdf

Midwest ISO performed a number of runs to identify the impacts of a variety of changes; the changes are as follows:

- Eliminate subregional layer
- New tie line rules
- Filter out loop flows
- Utilize all branches in the engineering analysis
- Utilize two voltage classes

Some of these changes were a reaction to the LECG concerns about distorting dispatch. It is likely that the MWh charges at the subregion will have to be addressed in some way.

> IL (Rismiller): Couldn't you just eliminate the charges rather than eliminating the subregion?

> JENNIFER: that is another option – eliminating the subregion was an attempt to solve a variety of concerns identified by stakeholders at the same time.

These changes make the allocation factors approximately 50/50 local to regional. Note, the calculations ultimately recognize some regional differences as identified on Slide 4 of the presentation.

Slide 4 – the numbers in parentheses show what the allocations would have been prior to the rule changes.

> IL (Rismiller): Questioned why the voltage classes were rolled together – there had to have been some reason to do this.

> JENNIFER: One idea was variability – rolling the voltages together will avoid some significant variability (particularly when rolling in some 765kv infrastructure).

The expanded local areas are now called neighborhoods. SLIDE 11 shows the allocation percentage if the neighborhoods are applied.

> MO (Proctor): When you look at the engineering analysis in the west, local percentages were pretty low. With neighborhoods, none of the local is this low. When looking at the allocations in the neighborhood analysis, does the local flow go up because you are expanding the local area?

MATT TACKETT: That is correct – there is more local because you are expanding the local area.

SLIDE 15 provides a comparison between subregions and neighborhoods.

MO (Proctor): when comparing here – you are comparing 3 layer approach (local/subregional/region) to the neighborhoods approach?

JENNIFER (Midwest ISO): No, this is a comparison between two layer analysis (regional/local) and two layer approach with larger local zones.

MO (Proctor): is it possible to compare the neighborhoods approach to the 3 layer approach?

JENNIFER: This analysis will be looked at and should be available by day 2.

[NOTE: the analysis is available here: http://www.misostates.org/CARP%2015%20Sub-Regional%20Comparisons%20of%20Updated%20Allocation%20Factors%2003-10-10%20(2).pdf]

ND (Lein): moving to two voltage classes seems to have a significant impact on the larger transmission projects. Are we really going to charge 35% 765 lines to the local layer?of

JENNIFER: The impact of zones from three layers to two; on some of the voltages, you move more into the local zones.

MO (Proctor): this point is very important; before, 765 allocation was very high in the regional layer.

QUERY: How do the state negotiators feel about the neighborhoods?

ND (Lein): this seems to be pushing more into the local layer yet, combining 765 with 345 seems to move too much to the local layer.

IL (Rismiller): my position hasn't changed either – I worry that removing the subregion will push too much into the regional layer. This appears to be some level of middle ground between the two positions and keeps more in the local zone.

SD (Rislov): we don't have 765 or 345 in the Dakotas. To allocate 35% of the costs to our states would defy common sense. When we attribute significant costs to our load, this is a major problem – there aren't enough ratepayers in South Dakota.

MI (Martinez): I want our discussions to move forward. Let's keep an open mind. We don't really know what the costs are and we don't know what will get built in the end. The goal should be a focus on the policy. Is it the correct policy?

IA (Hanson): Aren't we totally discounting the benefit of having generation in the state? There are benefits to building generation in your state.

SD (Rislov): it is very difficult to see how the benefits of new generation are commensurate with the costs we are seeing here. We will pay for our fair share of the benefits – at this point, I/W doesn't appear to line up. We are more concerned about the costs that will go to the load in our local level. Many of the plans were begun with a significant build out. I don't think the build out needs to be as aggressive as what we are talking about here.

ND (Lein): North Dakota has exported power for a long time – the transmission development has always been through the generation projects that were proposed and built. We have always gotten the local costs covered by the fact that there were agreements in place for the export of the energy.

QUERY: Are people willing to accept the neighborhood concept?

JENNIFER: From my perspective, it is important to hear the discussion from this group. We have different answers to similar problems from RECB Taskforce and CARP and want to hear the reasoning behind these differences.

OH (Choueiki): we already voted to include a subregion – why are we revisiting this issue? He also pointed out that the formula will deal with the issue of small load states; it is not 35% of the project. It is commensurate with the load in the state. We are talking about major generation projects – much of the cost will go to them.

AZAR: the subregion issue is one of the primary differences between CARP and the RECB Taskforce – this has been an issue ever since we took this vote (which was an 8-4 vote). The subregional issue has always been on the table.

OH (Choueiki): Ohio is willing to discuss the neighborhood idea, but it should be noted this would be a compromise for Ohio.

IA (Hanson): The 35% number seems intuitively high to the local zone to me; but we are willing to find some level of compromise.

SD (Rislov): We want development in our state – I will never close the door on these ideas. We have to get something done in this process to meet the FERC deadline.

ND (Lein): if we were just building an overlay – does that change this discussion? We could just charge everything to the regional level…

MI (Martinez): Subregions are important to Michigan. We are always open for discussion, but this is an important part of the design from Michigan's perspective.

Generator Interconnection Projects

Eric Lavery of the Midwest ISO walked through the following presentation:

http://www.misostates.org/CARP15GeneratorInterconnectionProjects03-09-10%20(2).pdf

Free rider issue: this isn't a new issue; it has been around since transmission began. Midwest ISO has looked at a number of individual utility plans on the free rider issue – these haven't been very useful.

Eric walked through a number of examples to show how the GIP process would work and how the "higher of" pricing would work and where the charges (and how much they would be) would be allocated.

Additional Discussion Of Exclusion Criteria

Jennifer Curran, Midwest ISO
CARP Negotiators

Jennifer gave the following presentation:

http://www.misostates.org/CARP15AdditionalDiscussionofExclusionCriteria%2003-09-10%20(2).pdf

Jennifer began by noting that the RECB Taskforce voted against moving forward with a Cost/Benefit criterion as an additional exclusion criterion. The vote was 20 for, 34 against.

The factors that would be applied in the Cost/Benefit were identified, but no specific formula was developed. At some level, this was a vote on whether a Cost/Benefit analysis is logical from a philosophical sense.

The first slides in this presentation show the exclusion criteria that the RECB Taskforce is currently applying.

Current MTEP 10 projects – there would be about $66 million that would get shared under I/W that would not shared today. From MTEP 06 to 09, there is about $390 million that would be subject to I/W that was "other" under the current tariff and not cost shared. This represents mostly two large projects.

> MO (Proctor): This is concerning to me – I thought the idea is to create a system to address the issues that aren't addressed by RECB I and II. He was confused by why we are discussing this on a backward looking basis.
>
> IL (Rismiller): On page 5, how do these projects in the last bullet not get cost shared under RECB, but make it into I/W? We are here because there is a purported failure in RECB I and II – if we developed proper rules for RECB I and II, perhaps these 5 projects get shared. We should address the flaws.

MI (Martinez): Do things that used to qualify for RECB I and II, then they would all make it into I/W, right?

JENNIFER: Yes. Anything that is meeting NERC reliability criteria is going to get built regardless of cost-sharing. The issue here is whether we expand the net of cost sharing.

QUESTIONS

1. **Do we want to narrow the criteria and exclude additional projects to reduce down to current RECB I and RECB II criteria?**

2. **Do we want to incorporate a cost/benefit metric?**

OH (Choueiki): Proposed some level of Cost/Benefit metric be included as a criterion under I/W.

CLAIR MOELLER: to get into Appendix A, you have to meet an economics test…then, at the State Commission, you have another economic analysis to determine the "public interest". A project will have to meet both of these tests in order to actual get cost shared under I/W.

IN (Johnston): The problem is how big is the bucket going to be? This comes back to the planning criteria. We need to start addressing this issue and being active in the development of the planning criteria.

AZAR: The PAC is responsible for this. States need to get involved in this process and have an impact on the PAC.

JENNIFER: This may be why the planning process is so important to address this. A rational planning process will lead to rational cost sharing.

IN (Johnston): There is some concern about relying on the states' public interests tests – it must be noted that some states are going to be more lenient than others.

OH (Choueiki): Is the PAC going to have these criteria completed before I/W is filed?

JENNIFER: That is the goal – but it will not be done before the straw proposal is complete.

SHOULD CARP CONSIDER SOME LEVEL OF BENEFIT COST CRITERIA AS AN EXCLUSION CRITERION FOR I/W COST SHARING?

IA (Hanson): Adding another criteria you run the risk of knocking something off that probably should have been included. I would rather error on the side of inclusion. A qualitative analysis is troubling because it gets too subjective.

IL (Rismiller): Liked the idea of a Cost/Benefit criterion – when you are asking people to share in these costs, you need to make sure that you do it right. SPP apparently is concerned about where the benefits flow based on their recent vote.

MN (White): there is some sort of economic analysis at other levels – right?

JENNIFER: Yes. To get to Appendix A, there is some economic test.

RECB Taskforce Considerations – some of the elements of what was considered as being included in the Cost/Benefit Criterion (NOTE: RECB ultimately voted not to move forward with this)
Lowering LMP
Lowering planning or operating reserves
Relieving constraints
Increase export capability
Decrease loop flows
Lowering production costs
Increasing reliability
Lowering emissions
Lowering entry barriers

DOES CARP WANT TO START DEFINE A COST/BENEFIT CRITERIA TO BE APPLIED AS AN EXCLUSION CRITERIA FOR I/W? THERE WOULD BE A LATER

GREEN: ND, MI, IL, OH, MO (5)
RED: MN, IA, IN (3)
WHITE: MT, SD, WI (3)

MI (Martinez): I am not totally sure what role we have in the decisions at the PAC. If we can't really help to define the way a project gets from B to A, then a cost/benefit criterion here might make more sense to me. This process could really be useful to get information to the folks that do go to the PAC. Our discussion is going to be useful no matter what.

March 10

On site sign-in sheets and on-phone roster are available from Brian Rybarik.

Negotiators participating by phone: Mike Proctor, Don Neumeyer

Commissioner Azar gave a brief reminder of the overall goal of this group – to come up with a logical and reasonable cost allocation for transmission upgrades. We may get caught up in some of the details, but we need to remember this overall goal.

Hybrid Discussion

Mike Proctor gave the following presentation:

http://www.misostates.org/CARP15ModificationstoInjectionWithdrawal.pdf

There appear to be some concerns with the MWh charges in I/W, rate inequality issues with the MISO market, and whether I/W fully solves the Otter tail problem. This proposal seeks to answer these issues.

> MN (White): the LECG report suggests that the MWh charges at the subregion – is that the only issue you address here?
>
> MO (Proctor): No, this deals with other MWh charges as well.
>
> IL (Rismiller): why is rate equality an issue here – related to LECG report?
>
> MO (Proctor): Not necessarily, this is really getting at rate issues identified in the western part of the footprint.

Overview of proposal: modifies I/W by establishing a Highway (regional)/Byway (Local). Highway allocated region-wide to load on 12 CP, byway allocated to load and generation as access charge. The proposal effectively eliminates injection charges at the highway (regional) layer, but keeps them at the byway (local) layer.

> AZAR: engineering analysis would be retained for allocations on the highway layer.

Specific proposal: Could operate under a three or two layer model (Regional/Sub-regional/Local or Regional/Local)

SLIDE 6: there are two ways that usage charges are likely to be paid by load. 1. For regulated utilities, the costs will be included in their MISO charges/costs. 2. In deregulated/open access states, it is unclear whether the charges will be included in the seller's offer price. In the deregulated (open access) case, you have some issues. There may be some delay in load paying these charges.

Under the proposal, there would be a differentiation between loads that regulated versus those that are in competitive markets.

SLIDE 8: under this proposal, load outside MISO may not always pay.

> AZAR: One of the reasons that generators would get charged a usage charge was to ensure that the right load pays. Are we wrong with that objective/goal?
>
> MO (Proctor): Charging a usage charge may not achieve this goal. In a PTP transaction, the generator is not participating in the MISO market, so the usage fee might not get captured.
>
> MN (White): couldn't an export charge be applied to these PTP transactions?

SLIDE 9: Identifies how the proposal could adapt to a 2 or 3 layer design.

SLIDE 10: Rate design:

OH (Choueiki): Are you eliminating the export component?

MO (Proctor): the export component would be contained in the PTP transmission rates.

ND (Lein): Eliminating the injection charge on the highway and keeping on the byway would make the possibility of the market to market transactions distorted. If it is on the highway component it won't have the effect of distorting anything since it would apply equally. If there is any injection charge, it should be on the highway.

MO (Proctor): these are MW charges, not MWh charges. They shouldn't distort the offers in the market. If you attempt to add a fixed cost adder in the market, you will likely lose out on the sale because there will be others that will not include the adder.

MI (Martinez): We are hearing many concerns from generators in MI about regional injection charges. They would prefer to keep it at the local levels. Capacity factors for wind in MI is a bit lower than other areas, if they had to incur an additional regional charge, it would further distort the ability to build locally to the load.

MO (Proctor): I agree with those concerns. Wind generation may be on during nighttime hours when it is much harder to put any adder on your bid.

SLIDE 11- provides an identification of various benefits of charging highway (regional) layer on 12 CP.

SLIDE 12: includes an identification of why you might apply a sub-regional layer.

SLIDE 13: identifies benefits of keeping byway injection charges to load and generators.

Mike feels pretty strongly about maintaining some level of injection charges for generation. This is a differentiation between the SPP proposal which does not have such an injection charge.

SLIDE 14: Solving the Otter Tail problem: he believes that this proposal does a better job of solving this problem than would the I/W design currently identified by CARP.

Is this a good compromise? Initial thoughts from CARP negotiators:

MN (White): One of the initial premises of I/W – the load that uses the energy pays for the costs. On a macro basis, this proposal is consistent. On a micro basis, this is less clear. It looks like is spreads the costs over broader areas, not as good on the micro basis.

MI (Martinez): This brings forward some ideas to address issues that we have been hearing. Everyone should keep an open mind.

IL (Rismiller): With respect to the objectives you outline, I don't see the reason to "solve" some of these problems. I don't perceive the issues as problems needing to be solved in the I/W model. Problems that are caused because they don't line up the benefits and costs needs to be solved.

<u>LECG Report on Market Impacts of Injection/Withdrawal Design</u>

The LECG report is available here:

http://www.misostates.org/CARP15LECGEvaluationofMISOInjection-WithdrawalDesign.pdf

LECG Representatives provided the following presentation:

http://www.misostates.org/CARP15FinalReportLECG%20Presentation%2003-10-10.pdf

Scott Harvey and Susan Pope were the presenters.

Context/Goals that LECG started with – 4 principles to achieve. LECG was not evaluating the goals or how the design meets the goals. They were only looking at the potential market impacts of the design.

NOTE: Allocation factors are developed based on prospective engineering analysis; but usage charges are done on actual usage.

SLIDE 6: First substantive slide. Usage charges are presumed to be part of the costs of doing business. When you include in the dispatch cost the "sunk costs" of the transmission, it could have significant impacts on the market. Generation in one region that has a lower cost might lose out because there is a high usage charge for transmission. The transmission expansion may not get fully utilized because of this.

LECG cannot predict the level of congestion that will accrue in the system, so the full impacts of the usage charges cannot be fully known.

SLIDE 7: access charges may have an impact on generator decisions – this would be another cost that would need to be considered in the decision of whether to build or not. Access charges are not the social costs – even if a generator shuts down, the costs will be recovered from others.

SLIDE 8: Energy storage would be significantly impacted – they would probably be paying 3 times. LECG proposes only charging the storage facilities for the losses associated with the storage. They would effectively be charged as "load." This could probably be easily cured.

IL (Rismiller): (Slide 9) Is one concern the difference between the way Module E uses unforced capacity and I/W using installed capacity.

A: We wanted to highlight a difference – it might be appropriate, but the I/W methodology is based on nominal capacity, not the u-cap that Module e uses.

SLIDE 10: Forward contracting could be impacted by megawatt hour charges – if predictability is a goal of I/W, this may need some work.

SLIDE 13: There will likely be significant FTRs created due to transmission expansions. If FTRs are allocated under the current method – some LSEs will get them and others will not. To the extent we have benefits created by I/W, then those benefits should flow to those who fund the transmission expansions.

IL (Rismiller): the way it works now – the costs of transmission upgrades are somewhat socialized, and the FTRs are not provided to those who made the investment.

A: This is a bigger step of socialized costs – the FTR issue needs to be considered more now.

SLIDE 14: Provides a number of recommendations –

1. Energy storage should be charged on net injections
2. Usage charges that vary by region should be avoided.
3. Should attempt to limit unpredictable charges.
4. Value of FTRs should be paired up with investment.

IL (Rismiller): The unpredictability issue also arises with respect to the modifications of the engineering analysis – if the engineering analysis is performed periodically, this will also add some uncertainty.

A: Capacity charges may be a different animal than usage charges – they could be more easily passed through in contracts.

IN (Johnston): Wouldn’t something that caps the top rate on what could flow to a generator, then everything over the top would flow to load.

A: That could one way of resolving this issue.

MN (White): What about some phase-in method? When I read the report, it seemed that if we got rid of the subregion, that would fix much of the dispatch issues, correct?

A: Yes, a phase-in could solve some issues. With respect to subregional issue, removal of the subregion would generally fix the market impact concerns.

IA (Hanson): social costs – do you mean the costs that are created by “generating energy”. You consider transmission a “sunk cost.”

A: The building of the transmission is a real cost. The recovery of the cost is the issue here.

CLARIFICATION: There are really two issues with respect to the usage charges to generators: 1. The differences between the charges in various subregions and 2. The predictability issues.

ND (Lein): this appears to be a qualitative analysis, rather than a quantitative analysis. Are these market impacts so great such that we need to completely rethink what we are looking at here?

LECG: This was not the task at this point; the Midwest ISO may be looking at this.

JENNIFER: we have done some modeling on the potential impacts on the market – they will continue to look at this issue and see what is possible.

LECG: because we don't know how this is going to look 4 years from now, it may be difficult to predict, and you will have to do some sensitivity analysis as well.

MN (White): Always thought that I/W applies when you inject generation onto the system and when you withdrawal from the system. I don't think energy storage fits into either of these and would consider having them taken out of the charges entirely.

IN (Johnston): I always thought that FTRs were for existing owners to compensate them for the use of their lines that were now being used for a different reason or purpose. Why should we continue this trend now that we know what the transmission upgrades are going to be used for?

LECG: One of our main concerns is that we don't have these new transmission upgrades flow into the existing FTR system since these upgrades are different.

<u>WORKING LUNCH – BENEFIT COST EXCLUSION CRITERION</u>

Hisham Choueiki (with the aid of Randy Rismiller) outlined the following elements that could be used as a benefit-cost criterion:

1. Reliability improvements
    a. Quantifiable:
        i. reducing loop flows (MW)
        ii. improvement in transmission availability index (% or $)
    b. Non-quantifiable (YES/NO)
        i. maintaining NERC standards for planning and operations

2. Economic Efficiency
    a. Quantifiable

i. reduction in load-weighted LMPs ($ savings at state or ISO level)
ii. Reduction in APC ($ savings at state or ISO level)
iii. Reduction in required reserves (% or $ savings at state or ISO level)

[(Annual savings)/(Annual rev. requirement) > 1.0 (at state or ISO level)]

This system would allow each state to designate whether they wanted to do this separately or whether this would only be at the ISO level.

b. Non-quantifiable
    i. Reducing barriers to generation and DR entry
    ii. Reducing number of scarcity events

3. Public Policy (public interest)
    a. Quantifiable
        i. emission reduction (tons or $ at state or ISO level)
    b. Non-quantifiable
        i. satisfies a state or federal mandate

OH (Choueiki): Projects would have pass the economic smell test, and a group of non-quantifiable checks (yes or no). Do they all need to be checked? No. Should there be a threshold? Yes. What is the threshold? This isn't fully decided.

MO (Proctor): This could be a two-step process. If a project is proposed to comply with some legal requirement, then it is simply a decision on whether it is cost-effective. If the purpose of the line is something else, then use this test.

DOES CARP WANT TO ADD AN ADDITIONAL EXCLUSION CRITERION THAT IS BASED ON THE ELEMENTS IDENTIFIED ABOVE?

JENNIFER: These are similar to the analyses that we do in the planning process of getting things to Appendix A, but probably not exactly the same recipe as those issues outlined here.

NOTE: The exclusion criteria adopted by the RECB Taskforce is available on pages 2-3 of this presentation:

http://www.misostates.org/CARP15AdditionalDiscussionofExclusionCriteria%2003-09-10%20(2).pdf

OH (Choueiki): It may be true that there is a test to get into Appendix A, but the planning process may not capture everything. This is another test to ensure that cost-shared projects are truly beneficial for a regional system.

IL (Rismiller): This is something that will help us meet the 7th Cir. decision – it will give greater comfort that we are making efforts to address this directive. Having this as part of the package would help us.

SD (Rislov): Are we going to be developing the specifics of the cost-benefit metrics?

AZAR: they would not be developed by CARP – it would be done by the Midwest ISO.

MN (White): I think this is a compromise position that may give Illinois some comfort – I may be willing to bend on this issue. Further, I think this would be good information to consider in the process.

DOES CARP WANT TO ADD AN ADDITIONAL EXCLUSION CRITERION THAT IS BASED ON THE ELEMENTS IDENTIFIED ABOVE?

AZAR: A yes vote would give the Midwest ISO additional guidance that CARP negotiators would like to see an additional criterion applied to project in order to be cost shared under injection-withdrawal.

If there are issues that will change a state's position on I/W as a whole, that would be helpful for the group to know.

GREEN: (Include this as an additional exclusion criteria) - MO, MN, OH, MT, IL, MI, SD, ND (8)
RED: (Do not include this as an additional exclusion criteria) – IN, IA, WI (3)
Not Voting: PA, KY

<u>LECG Recommendations</u>

Energy Storage issue: they could be charged uniquely based on net – i.e., the difference between what they are taking off and what they are putting on.

Pumped storage takes energy off, and puts some back. The idea is that they would be charged based on the difference between what is put in and what is because there is some loss here.

GREEN (modify the design to reflect this issue):
RED (do not modify based on this issue):

No objections were identified on this issue.

<u>USAGE CHARGES ON GENERATORS</u>

A. <u>Subregion/Neighborhood issue</u>

AZAR: if we go to the neighborhood approach, does that resolve the market issue?

JENNIFER: yes.

IL (Rismiller): there was some additional analysis done – it is available here:

http://www.misostates.org/CARP%2015%20Sub-Regional%20Comparisons%20of%20Updated%20Allocation%20Factors%2003-10-10%20(2).pdf
IA (Hanson): do we need to pick an alternative today based on the timing? If we don't have the time to consider this stuff, then we don't have the time.

AZAR: yes – the next meeting will be the roll out of the straw proposal. We would need to take votes on these issue today if we want it to be considered prior to the straw proposal roll out.

JENNIFER: understanding why people are voting and their positions is important to understanding where to go with the straw proposal.

Neighborhoods – we have discussed in a two layer scenario. These are the means by which you set an allocation for a pricing zone, making nine zones for a regional/local allocation. We've ended up at a place with the engineering analysis where the allocations are closer to 50/50 regional to local.

IA (Hanson): if we are trying to allocate the cost of new transmission, why should we figure in the usage of lots of old transmission?

JENNIFER: we used the full system because of variability – if you only use the new transmission, you will have larger swings; and will reflect overtime the entire system that is allocated under I/W.

This is an estimate of what that outcome would look like – the actual analysis is not completed of reviewing all of the shift factors throughout the Midwest ISO footprint.

ND (Lein): When looking at slide 14-15 of the subregional options presentation, these costs are only incremental costs of the build out.

MT (Jergeson): I can't go back to my customers and say that I agreed to a 15.9 dollar increase in their utility rates when someone else got a 3.8 increase.

Identified Options (brainstorming ideas) to fix the subregional charge issue(s):

1. Eliminate Subregion.
2. Eliminate usage charges to generators.
3. Eliminate subregion and replace with neighborhoods.
4. Average the subregional usage charges so that no generator is disadvantaged.
5. Take the lowest of the MWh charges across the footprint and apply that everywhere – then take the increment and apply to MW.
6. Replace MWh subregional charges with MW subregional charges to load.

INITIAL REACTIONS:

MT (Jergeson): one of the purposes of Mike Proctor's proposal was to equalize the rate impacts. Do these proposals do that?

IA (Hanson): the change in the engineering analysis appears to have largely alleviated the heartburn. He didn't have enough time to fully understand the other options to know if they are good. He would prefer to simply eliminate the subregion.

IL (Rismiller): My heartburn is not gone. In the western region, we are regionalizing a large percentage (65%) of the costs. This is still a big issue for Illinois.

CARP did not make any conclusions about these options.

UNCERTAINTY ISSUES

One proposal – delay the true-ups of usage charges to have predictability and to give a better identification of how charges will change over time. This concern is limited to standardized forward-looking contracts. These contracts are generally used as hedges. If the usage charge is going to be variable; then the contract prices are going to be difficult to nail down.

IA (Bittner): assume there is a 3 year standard contract- if we ran the engineering analysis today and decided to apply it 4 years from now – can we build some delay of the engineering analysis into the system?

IL (Rismiller): we have always heard that one of the beneficial aspects of the I/W is its dynamic nature – this is an unintended consequence of this aspect. Now we are trying to mitigate this aspect. Do we want to reconsider the whole premise of a dynamic cost allocation strategy?

IN (Johnston): There is uncertainty for generators today – for example, what is going to happen with CO2 regulation? This would be an uncertainty in forward-looking contracts, yet they still enter into them. He recognized that this is something they have control over, unlike other uncertainty.

MI (Butcher): Couldn't there be something to hedge this price with?

LEGC: It is unclear how this usage charge could be hedged.

OPTIONS/IDEAS

1. Increasing price certainty for the first 3-4 years would be helpful.
2. Set generators usage allocation factors for future years to a defined level (/MWh charges) and true-up differences with load usage charge.
3. Just don't charge generators a MWh usage charge.

IN (Johnston): I don't think we know enough to take a vote on this, but I trust that the Midwest ISO will take the appropriate action.

IL (Rismiller): I heard two others: 1. Not having an element in the allocation that updates periodically; 2. Maybe this isn't a problem – it's just one more uncertainty.

MONETIZING FTRS

There was a discussion on how FTR or other transmission rights could be allocated to line up with the investments that are associated with any transmission build out.

SHORT TERM DISPATCH ISSUES

Price signal issues may be a good outcome – but there will be an effect on generation location decisions and it may create some distortions. It may not be major.

> OH (Choueiki): The PJM market monitor identified this as a concern as well.
>
> IA (Bittner): even though we haven't built it yet – you are telling me to think of the overlay as a sunk cost. This is unsettling to me.
>
> MO (Proctor): It seems to me, like in SPP, there could be a mechanism in the tariff to deal with unintended consequences, i.e., some way to undo major problems.

CONSUMER IMPACTS

> LECG: on the one hand, charges allocated to the local load – if they do not reflect the benefits to that local load; you may have location decisions for load affected by the cost allocation. This isn't unlike what we have to deal with today.
>
> IL (Rismiller): it is important to remember what this report didn't cover – the relationship between benefits and payment was not a focus of the report. This is still an issue for the group to consider. What we do about this, I don't know yet.

NEXT STEPS

Late March meeting: the goal is to have the Midwest ISO straw proposal.

> IA (Hanson): I vaguely understand the amount of work here – is it possible to get this information to allow for time to have a stakeholder meeting at home.
>
> AZAR: there won't be a vote at the March meeting – the April meeting will be the vote on the straw proposal.
>
> JENNIFER: The goal is to have the unveiling at the March 22-23 RECB meeting.
>
> AZAR: we will likely cancel the May meeting of CARP, but keep the June meeting for final clean up (if necessary).

At the conclusion of the meeting Commissioner Azar identified that she had learned about an alternative cost allocation/cost recovery proposal from the Transmission Owners. The proposal apparently had been shared to a number of CARP negotiators, but not the full group. This may not be helpful to the process – since the goal here is to have an open and transparent process. To the extent anyone has ideas, they should bring them to the table to discuss and maintain our open and transparent approach.