Single Schedule Market – Phase 1, Session 3

June 29, 2017

Minutes of Meeting

Date held: June 29, 2017	**Time held: 9am – 3pm**	**Location held:** Crowne Plaza Toronto Airport
Company	**Name**	**Attendance Status** (A)ttended; Attended via WebEx;
Amp Solar Group Inc.	Luukkonen, Paul	WebEx
Amp Solar Group Inc.	Cibuku, Olta	A
AMPCO	Anderson, Colin	A
AMPCO (behalf of)	Wright-Hilbig, Rhonda	A
Anbaric Development Partners	Duguay, Philip	WebEx
APPrO	Butters, David	A
Brookfield	Wu, Julien	WebEx
Bruce Power	Dalzell, Pat	A
CanSIA	Johnston, Wesley	A
CanWEA	Giannetta, Brandy	WebEx
City of Toronto	Koff, Chaim	WebEx
CRA	Rivard, Brian	WebEx
Enbridge	Chin, Edith	WebEx
Enbridge	Jayaraman, Jay	WebEx
Energy Consultant	Eich, Christopher	A
ENGIE Canada Inc.	Hiltz, Bonnie	A
EPRI	Ela, Erik	WebEx
FTI Consulting	Harvey, Scott	A
FTI Consulting	Pope, Susan	A
Goreway Power Station	Coulbeck, Rob	A
Goreway Power Station	Sutherland, Christopher	A
H2O Power	Medina, Ron	WebEx
Manitoba Hydro	Penner, Audrey	WebEx
Manitoba Hydro	Wells, David	WebEx
Manitoba Hydro	Bertholet, Kelly	WebEx
Nalcor Energy	French, Davin	WebEx
NextEra Energy	Tuck, Jennifer	WebEx
Northland Power Inc.	Samant, Sushil	A
Ontario Energy Association	Hrab, Roy	WebEx
Ontario Energy Association	Brescia, Vince	WebEx
Ontario Power Generation	Wizniak, Lynn	A
Power Advisory LLC	Chee-Aloy, Jason	A
Power Advisory LLC	Robers, Carson	WebEx
Power Advisory LLC	Cumming, Alison	A
Powerful Solutions	Inman, Peter	A

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Company	**Name**	**Attendance Status** (A)ttended; Attended via WebEx;
PwC	Teng, Xiao	WebEx
Resolute Forest Products	Degelman, Cara	WebEx
Rodan Energy Solutions	Holowatsky, Yuri	WebEx
Rodan Energy Solutions	Ingman, Rachel	WebEx
Rodan Energy Solutions	Quassem, Farhad	A
S&P Global	Watson, Mark	WebEx
Samsung Renewable Energy	Anders, David	WebEx
Shell Energy	Kerr, Paul	WebEx
SLGoldbert	Goldberg, Sam	WebEx
Suncor Energy Services Inc.	Scott, Christopher	A
Tembec	Dottori, Paul	A
TransAlta	Nguyen, Thanh	WebEx
TransCanada Energy	Kuntz, Margaret	A
Whisker Labs	King, Robert	WebEx
Workbench Corp.	Jayapalan, Jennifer	A
Workbench Corp.	Sears, Heather	A
IESO	Agavriloai, Ioan	A
IESO	Ellard, Barbara	A
IESO	Bell, Brian	WebEx
IESO	Butler, Joanne	WebEx
IESO	Cary, Timonthy	WebEx
IESO	Diebel, Sarah	WebEx
IESO	King, Ryan	A
IESO	Louw, Brennan	A
IESO	Matsugu, Darren	A
IESO	Murray, Patricia	WebEx
IESO	Sapona,Ingrid	A
IESO	Scratch, Jonathan	A
Scribe: Ingrid Sapona. Please email any corrections, additions or deletions e-mail to the scribe (ingrid.sapona@ieso.ca).		

All meeting material and the recording of the session is available on the IESO web site at: http://www.ieso.ca/en/sector-participants/market-renewal/market-renewal-single-schedule-market

Meeting Started at 9:40 a.m.

Introduction – Ryan King IESO

The IESO announced that formal feedback received from ITC and the IESO's responses are on the Market Renewal – SSM web page (under the May 4, 2017 meeting heading). Also, the tracking document the IESO is developing should be available soon.

IESO Response to Feedback – Barbara Ellard, IESO

The IESO reiterated the scope of Market Renewal and the fact that SSM is one of three projects in the energy workstream. As part of the energy workstream, the IESO will also look at day-ahead market (DAM) and enhanced real-time unit commitment (ERUC). More frequent intertie schedule (MFIS) will fall under the operability workstream. The IESO will go through a similar process around scope and fundamentals for these engagements. The IESO will have broader public education sessions on Market Renewal (MR) in the fall.

SSM is about aligning prices with dispatch. Linear thinkers may find it unusual to start at the end, but the IESO is starting here because it's the enabling change.

A participant asked how the IESO sees it working when another workstream impacts an element of SSM high level design (HLD). For example, under operability, there's always been an issue because the IESO can't accept an outage on dispatchable load. Would the IESO circle back or bring up such issues in the HLD?

The IESO hopes stakeholders raise linkages as soon as possible so it can make sure all such issues are considered and the process is integrated. A core part of the mandate of the Market Renewal Working Group is to deal with seams issues. If the IESO misses linkages, the IESO would have to go back.

Update of Work Plan for SSM Stakeholdering – Jon Scratch

The IESO reiterated the stakeholdering work is still in Phase 1, which is a review of fundamentals. Phase 2 will begin with an interactive discussion of options with the first Phase 2 session on July 27th.

Load Pricing – Module F – Susan Pope, FTI

FTI presented an overview of locational marginal prices (LMP), which is a fundamental element of SSM. It reiterated that in LMP, prices are consistent with the physical dispatch. The IESO produces shadow prices that are basically 'raw' LMPs but they aren't being used for settlement today. To be 'settlement ready', the raw LMPs will need to be processed by a pricing run.

A participant asked whether a separate pricing run is typical for most jurisdictions, rather than taking price out of a constrained schedule.

FIT said yes, because sometimes things need to be cleaned up from the constrained schedule, for example, you may not want penalty prices in the constrained schedule that can be high to flow through into the settlement prices.

A participant asked if one could just use Maximum Market Clearing Price (MMCP) in the constrained schedule.

FTI said yes, that could be done; some reasons other jurisdictions do separate pricing runs might not be any reason to do that in Ontario though – but FTI wants to mention it as an option.

A participant commented that having separate pricing runs gives the IESO flexibility to apply different rules for pricing vs. dispatch, but that can get dangerous – you can start thinking about things, like allowing a three times ramp rate for pricing and you could end up with dispatch instructions out of kilter with your price.

FTI agreed and said that situation would be very rare, but we wanted to mention that a separate pricing run is done in some places. The intention is for the prices to be as consistent as possible with actual dispatch.

Load Pricing – Issue 1: Whether the price charged to loads will include marginal or average cost of losses and congestion

FTI explained load pricing and the principle issues driving the methodologies for pricing load under SSM.

A participant asked whether, at the start of the market, the reason the IESO didn't calculate load at all nodes was because of computing power. Does the IESO think that will be an issue in the future? Do other jurisdictions have difficulties like this? Do they typically make these kinds of simplifications or are they typically making calculations at each node?

FTI indicated that when moving to an SSM, there are a number of software enhancements that need to be done that individually may not look that difficult to do need to be prioritized. A number of ISOs start using their existing software and they put their priorities elsewhere.

A participant commented that they worry that when we say we're relying on this for price, especially when you get into areas like the northwest and northeast and some of the congestion zones, we're just one contingency away from that being a completely inappropriate price, and those are the times when price is most important.

A participant asked whether the effect of distributed or embedded generation is handled in the formula somehow.

FTI said no, anything that is at the distribution level isn't what we're talking about. We're talking about prices calculated at the transmission level – at the level of the grid controlled by the IESO.

A participant asked whether, in terms of flexibility, embedded generation will have an impact on price. If there is high variability of demand, is there a proxy for supply, or a proxy for demand?

FTI indicated that when you have generation, dispatchable load, energy efficiency, etc. anything behind the meter to the IESO will affect the net load on the system. For dispatch, the IESO sees net load at each dispatch location. It doesn't matter if it's less load or more generation, it's how much power is being consumed. So, when we're looking at the forward unit commitment or day-ahead market, one needs to know what those individual resources are, but when one's pricing in real time, one is just observing the net withdrawals or net injections into the system.

A participant asked if load variation is a proxy for whatever embedded effects there may be.

FTI said indicated that's right. They'd be seeing the same price at that location. We're talking about whether generation and dispatchable load are seeing the same price – the LMP price would be the same for all those. How the IESO is actually going to charge them is what we're talking about. LMPs are not being calculated down below the level of the grid the IESO dispatches.

A participant commented they are having a difficult time seeing negative losses and asked if – under this model, with respect to congestion rent that's accumulated – is it the intention to eventually say, "Ok, we need to increase the transmission capability in this area?" Also, for embedded generation or the other side of it – around demand management – where is the price signal or the signal that goes to end users that this is the time to back off on demand, or back off on load? How does this fit into a smart grid kind of an arrangement when you have interactions between both supply and demand?

FTI indicated that congestion prices are an indication of where congestion is repeatedly happening; it's a tool, a piece of information that transmission planners and shareholders can use to explain and quantify the degree of impact of congestion in particular areas on the cost of serving load. It's a tool that informs the process of determining where transmission might be needed and to enable evaluation of transmission alternatives. It's not being proposed as a tool for funding the embedded cost of transmission. Congestion rents could be used as an offset in total against the total pool of transmission costs. In terms of a price signal for embedded generation or embedded load, how to correctly deliver that signal is a challenge which all systems are facing today.

A participant asked whether, when it comes to losses, we are talking about static losses or dynamic losses.

The IESO indicated it is static losses and it noted that one of the issues that might be discussed in the options phase is whether to move to real-time dynamic losses. A question to consider is whether this is a 'Day 1' deliverable, or an evolutionary improvement.

A participant asked whether it is possible to have negative congestion rent. On the idea of having negative losses – it would be helpful to distinguish between negative values we saw in the calculation of LMPs and how that relates to the concept of congestion and losses.

FTI indicated the LMP is going to be produced in the constrained schedule. And the prices coming out of the constrained schedule, the raw amounts, may need to be massaged.

Load Pricing – Issue 2: Whether loads will pay a nodal, zonal, or uniform price

A participant asked what the potential effect of these discussions is on existing load. There's been lots of discussion about where you put load in the future – what about the impact on existing load? A discussion about this would help us understand the pros and cons, given that it seems there will be winners and losers over the status quo. What guidance can you give for that part of the equation?

FTI indicated that what the participant says is true – if you change from the existing uniform system to a more granular system, some customers will see increases in their bills, some will see decreases. How these are addressed during the transition is a relevant question. It's typically addressed through some sort of a payment system like FTRs, which we'll touch on briefly today.

The IESO acknowledged that today's information is a challenge. The IESO is taking the time to talk about "average vs. marginal" to at least highlight that if you start to charge loads different prices, there ends up being some residual left over – either made up of congestion rents or loss residuals.

A participant wondered if, when talking about efficiencies, materiality studies regarding the efficiencies of locational load pricing been observed. Have they been successful in achieving those efficiencies?

FTI indicated that in many regions in the US the load sector hasn't developed as well as they thought it would because how load gets charged is intertwined with different state laws and policies.

A participant asked whether it's fair to say it's a theoretical efficiency that could result in savings.

FTI indicated the fact that the load is responsive has been demonstrated to be true. In Texas, for example, prices are extremely high at peak hours and if loads can consume less during the peak hours, that's really valuable. We know there's load that participates. Lots of load responds to peak prices. They made those changes so they get lots of demand response. The more you aggregate, the less you can do. In the US, it's *at the distribution level – there's been huge growth is companies providing load management behind-the-meter solutions.*

The IESO commented that one of the unique features of Ontario's market is participation from dispatchable load. In talking to other jurisdictions, the IESO has an appreciation for the fact that Ontario has a good foundation for load-side economic participation. The IESO wants to leverage sending better price signals to that part of the market and its advanced consumers.

A participant commented that Ontario already has a set of electrical zones. The participant asked if the IESO anticipates re-drafting Ontario's zones.

FTI indicated that's something that could be looked at.

The IESO indicated that's a good question and indicated that will be addressed when it is time to consider potential zones. It'll be important to get into quantitative data: is there a significant price difference within the zones? It'll be important to determine the balance, complexity, and so on. The IESO will flesh out these issues with stakeholders; the IESO has set aside quite a bit of time to discuss the options.

Load Pricing – Issue 3: Whether prices will differ for dispatchable versus non-dispatchable loads

A participant asked whether there is any thought to having a kind of hybrid approach, for example, non-dispatchable getting uniform price and dispatchable getting nodal and whether there are any pitfalls to that.

FTI indicated that's the next topic. One of the problems with using a hybrid system that uses an aggregated price that's different than at the nodes is that it could impact dispatchable loads' willingness to participate.

A participant commented that one shouldn't lose sight of the fact that those loads in lower price area are also helping mitigate local surplus baseload generation during freshet. That's when you want loads to run. You don't want them to take outages – you want to incent them to consume. It may be short-sighted to not look at both sides in terms of the benefits.

FTI noted that it's still efficient to be dispatchable in low price locations. FTI agreed with the participant. It's still efficient to be dispatching them – they can still help the system.

A participant commented that in Ontario this issue of pricing loads is particularly important because of our supply mix.

FTI added that there's another side of this: the non-dispatchable loads in the low price location are just going to choose to say they're dispatchable, but they're not really. In other words, they're going to be *dispatchable to get the low price. Basically, you're setting up a system pushing all non-dispatchable to go to the nodal price and ending up with everybody paying the nodal or zonal price in their location.*

A participant commented that this can be addressed in part by having good market entry requirements.

A participant wondered whether you're basically going to protect loads against paying more than the average price, but that you won't bring loads in lower-priced areas down to their LMP through a side payment.

FTI indicated that loads in lower price locations wouldn't be brought up to the aggregated price.

A participant commented that they are trying to understand whether it's two-sided or one-sided. If one is a load in southern Ontario where the price is presumably higher than average, they will get a side payment to bring them to the average. If they are a load in the northwest, then what?

FTI indicated that whether it's one-sided or two-sided gets into implementation options. This isn't a specific proposal. FTI is describing a pricing mechanism that can be used to address how we might keep loads from defecting and how side payments can be used to do that.

A participant commented that government policies have tried to help loads in lower LMP areas mitigate the cost they pay because of uniform pricing. The participant wondered if it becomes a question of whether those things continue or whether you would try to fix the market?

The IESO noted that the questions being asked are all very good ones and it noted that the group will talk through – and make some first-cut decisions – during the options phase.

Financial Transmission Rights

A participant asked whether Financial Transmission Rights (FTRs) are for loads only, or are they for generation too.

FTI said it depends on what market you're talking about. FTRs can be used to preserve dispatch incentives of dispatchable load if there is uniform or zonal pricing for everybody else and/or to help ameliorate any pricing impacts associated with moving from uniform to zonal pricing for example.

A participant asked if FTRs are independent of 5-minute consumption or 5 or 15-minute interval – what are they based on? Are they based on a difference in congestion costs in certain areas?

FTI indicated yes, FTRs pay the holder the difference between congestion cost between a source and sink for a fixed number of megawatts.

A participant asked how FTRs are funded.

FTI indicated FTRs could be provided by congestion rents –or the marginal loss surplus, or from some sort of separate uplift charge.

A participant asked whether, in other markets, FTRs are largely physical players that transact in those markets or whether, like here on the ties, the players are predominantly people using them as a financial tool.

FTI indicated that when LMP was implemented in the United States, ISOs needed to develop a product that would replace physical transmission rights (physical transmission rights are incompatible with least cost dispatch within an ISO's footprint). FTRs were therefore created to be a financial replacement for physical transmission rights and were originally allocated to physical participants in the market. The allocation mitigated shifts in costs among loads in different locations due to the transition to SSM (which otherwise would have occurred in eliminating physical transmission rights). To support trading (physical and financial) in the energy market, FTR auctions also were introduced. The FTR markets have evolved and FTRs are now financial hedges which are traded in varying ways and support liquid energy trading.

A participant commented that if FTRs are a means for physical players to hedge their costs and there's a lot of competition for those rights by financial players, it becomes more difficult for internal loads to actually hedge those costs. You have to be careful about what objectives you're setting for the rights at the outset.

FTI noted that if FTRs are something the IESO considers, there are a number of decision points, including whether they're tradable, whether to have an option for them, for example. There can be FTRs without having an option in which financial players can bid for them. The reason FIT thinks FTRs might be a tool in Ontario is that if one thinks about the problem of dispatchable load that gets exposed to a high price, they can be compensated. With an FTR, it's a hedge and dispatchable load only gets the compensation when there's congestion.

A participant commented that when one is talking about zones, he always thought it was because of congestion due to transmission, but it sounds like it originated because of metering.

FTI indicated zones were a reflection of congestion, but where they drew the lines in some places was based on where they could actually meter the withdrawals. It wasn't a perfect measure of congestion.

A participant asked whether FTI is talking about operational telemetry for dividing up the zones.

FTI said yes; this is where, on a 5-minute basis, they could measure the withdrawals on a metering basis.

A participant indicated they were confused between the concept of payment and an FTR, which is a hedge. The participant noted that a hedge can go both ways – it can pay you, or you may have to pay it. The participant wondered whether there is a need to be more specific in terminology when we're talking about system payments.

FTI indicated the term 'payment' is intended to be a little open-ended because one could design these a variety of ways. An FTR can be defined so it entails payments to a party or from a party, it can also be defined as an option where a participant only gets paid, but never has to pay out.

A participant pointed out that there is a difference between a payment and a hedge and indicated they thought it important to be clear when discussing these issues.

FTI agreed.

Market Power Mitigation

A participant asked whether Market Power Mitigation is relevant only to physical traders, or could (potential) bids/offers by virtual traders also be affected?

FTI indicated that with respect to the day-ahead market there's potential for exercise of market power by different kinds of entities and one wouldn't want to have to re-run the day ahead after mitigating offers; there wouldn't be enough time.

A participant asked whether the goal is to do everything *ex ante* instead of *ex post*, as it's being done now.

FTI said yes, that's the key point.

A participant commented that it sounds like this is just being done for energy. They wondered whether it's common to do this for the operating reserve (OR) markets as well.

FTI noted that it is also for OR markets. FTI pointed out that in the Appendix there's a lot more detail about the conduct and impact test in the energy market and reserve markets.

A participant commented that if there's an energy pricing test instead of a CMSC test, there's really no market power on behalf of dispatchable load. The participant sought confirmation that a generator with several generation sites may be incented to set the price high, so other generation sites would get a favourable price. The only manipulation dispatchable load would want is to make the price lower.

FTI indicated that the participant is right. The only complication is when we get into deviations between real time and day-ahead schedules. We don't expect dispatchable load to be exercising market power. There are other participants not expected to have the potential to exercise market power as well.

A participant commented that they understand the US examples. The participant asked FTI to comment on Alberta. He noted that in Alberta there's a long understanding that energy revenues are needed to recover fixed costs and the like. He said that it's now at the point where the Market Surveillance Administrator has worked out a deal with market participants and you see the type of bidding behaviour in that market that allows for some withholding. He indicated there's acknowledgment that that can be an economic activity to make sure you're recovering your costs and some return. He further noted that there's a capacity market being designed in Alberta, but there's still a lot of debate about whether that framework on the energy side needs to change.

FTI indicated that Alberta is different in some respects. Their market wasn't driven by merchant generation – it was driven by co-generation facilities to support oil-sands projects.

Pivotal Supplier Test

A participant asked what happens with the pivotal supplier test if the generators are related. What happens if, say, 70% are owned by one entity?

FTI indicated it doesn't matter if one or all are pivotal, they get mitigated.

A participant asked how these decisions are made, by whom and how complex is the decision-making process? Setting these thresholds must be very challenging and complex.

FTI indicated there are conduct and impact thresholds set out in the Appendix. FTI did not that there is some art to this process. There is a need discern what is reasonable and some negotiation. These are all thresholds set by the ISOs.

A participant asked whether the thresholds are filed as part of the ISO's tariff. The participant noted that there's a governance issue here; somebody gets to adjudicate these if they can't be sorted out within the ISO process.

FTI indicated yes, the thresholds have to be approved. FTI noted that they're all in the market power mitigation section of the tariff, not manuals.

Impact Test

A participant asked who gets mitigated if the impact test is failed.

FTI indicated that everyone that failed the conduct test is mitigated. This includes potentially even a small supplier that failed because of a high opportunity cost on their resource that isn't taken account of by the ISO's modelling.

A participant asked whether market power mitigation is restricted only to suppliers. If so, why?

FTI indicated that in the context of an energy market, it is only suppliers. There's not a lot load can do to impact the outcome in the energy market. In a capacity auction, it's different.

A participant asked what happens in the conduct and impact test if three generators fail the conduct test but only one of them triggered the impact threshold?

FTI indicated in that situation, all three will have their offers mitigated. If the price rises, the price rises – we don't know whose offer caused it to rise – that's the collective guilt problem, and we can't realistically-run the software more than once.

A participant asked whether the whole stack is penalized or just the ones that failed the conduct test.

FTI indicated that just those that failed the conduct test are penalized.

The IESO noted that Module H will be taken up in the next session.

Timing of the Mitigation Test and Reference Pricing

A participant asked how gas is procured, is it just a commodity? The participant noted that with the way gas flows in the pipeline, it can be interruptible or firm, depending how one buys it. Are those parameters considered too?

FTI indicated that usually one's buying the firm pipe space and mitigation is based on the spot gas price being re-sold by someone who had firm space and might be re-selling it.

A participant asked how one would mitigate a hydro-electric resource that is ponding water and offering their opportunity costs of that water to the market?

FTI indicated there has to be some kind of negotiated rule for the opportunity cost. Pacific Gas and Electric in California has a complicated system hydro model which it shares with the California ISO for mitigation purposes. Other ISOs have flexibility rules about how they came up with opportunity costs.

A participant asked whether there's a test and they remove an offer or adjust the price. The participant asked what happens in this instance.

FTI indicated that instead of selling at a high price for an inflated bid, their bid gets mitigated down.

A participant asked whether the bid gets adjusted and lowered down.

FTI said yes, though there is an exception and there are some fallbacks because market monitors do make mistakes. Some ISOs have rules that say that if, because they applied market mitigation ex ante, they got it wrong, they won't review the market, but they will make you whole.

Questions and Comments from WebEx Participants that Were Not Addressed:
The following questions and comments were submitted from participants via the WebEx. Due to time constraints, these were not addressed during the session:

A participant comment that the issue with zones seems to be that aggregators of Distributed Energy Resources (DERs) or Demand Response (DR) would have to register and manage load-side resources by zone, which complicates things, reduces the value of aggregations, and increases the barrier if there is a minimum scale per zone associated with design.

The IESO indicated that Demand Response resources already have to offer into the DR capacity auction by zone. Any analysis of potential zonal options for Load Pricing through SSM will take into consideration the zones used in the DR (and, in future, Incremental Capacity) auctions.

A participant indicated they keep hearing the phrase "wealth transfer". The participant noted that from today's presentation they heard some opportunities for load customers benefitting from wealth transfer, they wonder who is at the losing end and who wins?

The IESO indicated that in a uniform pricing regime, consumers in relatively low cost locations pay the same price as consumers in relatively high price locations. Therefore, a uniform price can result in consumers in relatively low cost locations subsidizing those in relatively high cost locations. Jurisdictions that have more than one load pricing zone (or nodal pricing) have marginal prices that more closely reflect the marginal cost of providing power at a given location. As such, price subsidization tends to dissipate with increasing levels of load pricing granularity (uniform->zonal->nodal).

Conclusion

The IESO reiterated that it would like to hear what participants like and what they don't like. Please send feedback to: engagement@ieso.ca.

Meeting Adjourned at 3:10 p.m.

Next SSM Meeting is July 27, 2017.