Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416-481-1967
Télécopieur: 416-440-7656
Numéro sans frais: 1-888-632-6273

Ontario

Regional Planning: Cost Responsibility for Optimized Solutions (EB-2011-0043)

Stakeholder Meeting - May 12, 2011

Meeting Notes

Objectives for the project and the meeting

Board staff provided a brief overview of the objective of the meeting which was to allow stakeholders to discuss their views on: (1) problem identification for planning with multiple utilities; and (2) any barriers to optimized solutions in Board codes.

Staff also reminded stakeholders that the consultation is narrowly focused on processes for developing technical solutions and regulatory rules for determining cost responsibility when a localized delivery issue involves a transmitter and one or more distribution service areas. It is not a broad planning exercise, nor a discussion of general regional issues.

Staff then requested feedback on the following objectives in relation to the Board's cost responsibility rules:

- Clarity;
- Consistency; and
- No surprises.

Stakeholders suggested the following two additions:

- Certainty; and
- Timeframe specificity.

Status Check with Utilities

The discussion then turned to the current status of planning across service areas in relation to what is working in the current framework and where is there a need for improvement (e.g., identify barriers).

The most recent Hydro One Networks (HONI) transmission rate case was discussed; specifically, Toronto Hydro's (THESL) short circuit (SC) issues which are generally on the 115 kV system – supply points to downtown area. There are restrictions at Leaside TS and Manby TS and limited capacity when connecting new generation. It was noted that the SC solution provides breathing room but Toronto still has capacity issues. Hydro One (HONI) identified that such SC limitations exist in other areas of Ontario, and it has taken a long time to fix the problem due to the definition of certain facilities, what rate pools they fall into and therefore cost responsibility. For example, there are inconsistencies in definitions of 115 kV lines - some are Connection and some are Network facilities. As a result, they fall into different rate pools and the treatment is different. This makes it difficult to communicate and perform the cost allocation. In regard to such SC issues, it was noted that, while assessments are done on a local level, SC-related upgrades have many beneficiaries across a broader regional area. Also, while new generation increases SC levels for an LDC, upstream Network upgrades by the transmitter can also add to SC levels. It was suggested that there may be an argument to treat these 115 kV Connection facilities as Network facilities since they can have impacts throughout the grid.

An LDC provided a scenario of a potential problem (and a potential solution) with the current strict beneficiary/user pays focus. Assume the "old" Hamilton Hydro needed a transformation station (TS) to serve additional load and a capital contribution to HONI was needed. However, Hamilton Hydro then merges with St. Catharines Hydro. If the TS goes in after the merger, customers in St. Catharines will pay for a TS investment that will not benefit them. Cost allocation is currently done based on corporate configuration and it is difficult to assign users under this system. Could try to trace users of facilities and apportion costs to those users. However, that would cause rate setting issues. A possible solution suggested was to treat the Line Connection pool as part of the Network pool (i.e., everybody pays and no capital contribution is required). The LDC added that there was no equivalent on the distribution side where all customers of an LDC share in the cost of each investment.

OPA noted higher level transmission problems exist where it can become difficult to apply the Board's codes. Discussed the following:

- LDC may not need all the capacity of HONI's standard 230 kV line (accommodates 400-500 MW), however, cannot build "half a line". Example of "lumpy" investments (i.e., not much can be done incrementally).
- Easy to determine who "triggers" need for investment but difficult to determine who "benefits". Therefore, it is difficult to allocate costs to main beneficiaries. LDCs may also not be able to afford the necessary investments on their own.
- 230 kV to 115 kV auto transformer - not really there to serve a single customer. As such, may not be well defined as a Connection asset. Easy to say who triggers investment but harder to identify benefits to all users. Can be fixated with incremental capacity but facilities can also improve voltage level and/or reliability.
- Exemption clause in section 6.3.6 of TSC - not clear "when" it applies. Need to know intention of 6.3.6. Debate on whether 6.3.6 applies also happens at the wrong time - "end" of process. Not an example of "certainty".
- Sometimes there is a standard (e.g., IESO) but facilities require additional features. How do you deal with those additional costs?
- Connection of generation exacerbates these problems
- Raised following questions. What is "long term"? "Whose" lowest cost?
- In old Ontario Hydro (OH) days, just looked for lowest overall NPV to determine most appropriate solution. Could be an LDC (not transmitter) investment. For LDC, may be a big investment while for transmitter could be small; for example, LDC feeder vs. transmission line. What is optimal societal solution?

- Need to optimize solution for society, and make sure cost attribution rules in Codes don't distort achieving that outcome

OEB staff asked the following question. Loads pay for Connection through rates, while generators pay through upfront contributions. Is there a problem with the model for distributing and apportioning costs?

- Generator representative noted there is a group of people that want to be generators and a lot of costs were added after FIT rates were set and contracts were signed. There are also situations where discussions regarding cost attribution take so long that distributor misses a deadline. Some individual generators cannot afford capital contribution. Need to figure out a way to make things more accessible to smaller generators.
- Consumer representative did not see where changing payment from upfront contribution to payment through rates addresses any issues. Problem is assignment to pools.

A large consumer representative discussed two cases that hit on two issues.

- Client whose load is planned to increase annually over next five years to the point where TS capacity is an issue. Also, a lot of asset management issues. When it comes to plans for TS in the future, Transmitter will reply that no plan is in place but will make a plan for a cost (while generators are connecting). Need criteria for when and how transmitter should be "planning" to improve transparency in those situations.
- Other example, new large load (100 MW) connecting to Network. Transmitter should pay under current rules unless "exceptional circumstances" (TSC section 6.3.5). Transmitter's current method is to say it is exceptional circumstances and all costs paid by load. Need more clarity as to what are "exceptional circumstances".
- Also referenced an OEB Compliance Bulletin issued in 2006 that addressed cost attribution involving customer connections *[Note: The following is a link to the Bulletin: www.ontarioenergyboard.ca/documents/cbulletin_200606.pdf]*.

Generator representative suggested loads (e.g., LDCs) should pay for their connection facilities (e.g., THESL customers should pay if third line to service Toronto). Feels user pay approach will drive optimal solution through additional emphasis on increasing energy efficiency and distributed generation. Requiring load to pay would incent THESL to look at those other options.

- OEB staff noted it was primarily generators that created THESL's SC issue and asked whether generators should be exempt from user pay principle?
- Generator representative noted they had only thought this through for load customers.

LDC representative pointed out that "who benefits" may not be the ideal way to apportion costs. A utility may benefit from an upgrade triggered by another utility, but the first utility may not need/want that benefit. Should the first utility pay?

OEB staff asked how optimal planning is done now and whether there should be Local Regional Connection pools across Ontario.

- Kitchener-Wilmot (K-W) Hydro discussed their experience with the OPA's integrated regional planning process in noting there are five LDCs (including HONI Distribution) that share the local transmission network and have developed a Regional Plan which is now with the OPA (and had also done one about 10 years ago). However, some necessary investments go beyond the five LDCs. For example, driven by “Places to Grow” legislation, the load is estimated to double and it is too costly for the five LDCs involved. Identified regional planning works well to determine investment “needs” but not “who” pays.

An LDC suggested, under Ontario Hydro, the system was previously built for the future. However, the shift to a user pay system has held up investment by LDCs, industry and transmitters. Focus has shifted to arguing cost responsibility. Pools operate to select projects that are in the best interests of society.

IESO staff discussed the U.S. RTO “regional needs” approach (i.e., when investments affect multiple states such as a line crossing state boundaries) and suggested the OEB may want to look at that approach as a potential option. It could entail having a standard application for a regional facility. Regardless of the approach, suggested that the OEB might need to do a case study to see how different cost responsibility rules would play out for a particular investment.

OEB staff identified that the recent OPA IPSP document included a discussion of Regional Plans and that, while it does not discuss cost allocation, it did speak to the benefits of providing a strong backbone in an area.

- LDC representative discussed societal benefit versus user pay principle. Noted one reason for pool pricing is that reliable supply is an enabler. If business wants to move to a region, it will decide what they should pay to build and enable them to connect. Some businesses may not come unless investments are already complete. A user funded scenario could drive away business, jobs, etc.
- Large consumer representative noted that, if not user pay, growth in one area drives up costs everywhere. For example, a new line in southern Ontario causes rate increases in Thunder Bay. In other words, banning user pay to attract industry may actually drive industry away.

HONI suggested the timeframe of an investment is an important consideration but is not currently addressed in the TSC. Initially, it will look like a Connection investment. However, looking out over 20 years, what is the function of that investment? The challenge is to look at the function of the investment today vs. the long term, as the function of such assets changes over time. For example, transmission Connection assets could become Network assets in 10 years. HONI also noted:

- Planning is not long term enough. Municipalities do long term planning when new subdivisions are coming (e.g., investments in sewer systems). Where is similar effort for electricity?
- Should thinking match lifespan of asset? Can you foresee switch in use of assets? More often than before, the uses of assets can change over time.

Breakout Sessions

A) Planning Communications

HONI noted the following:
- Current rules are not resulting in appropriate outcomes.
  - If LDC cooperates in planning process, LDC pays
  - If LDC does not cooperate, LDC does not pay
- Sometimes go to municipality (instead of LDC) to obtain all of the information necessary to determine future transmission investment needs
- For the most part, industrial customers are not an issue in planning process; i.e., identify their needs as electricity is only a portion of costs
- Need to look at historic growth and broad provincial planning in determining future investments

LDC representative stated:
- Used to be a lot of available capacity on the system
- No longer the case due to uncertainty associated with cost responsibility rules

OPA noted:
- Do a lot of planning but at a higher regional level and over long term (i.e., 20 years)
- Not involved in lower level planning (e.g., new TS). Only LDC and HONI involved. Who pays is clear (i.e., not a problem) and short-term focused in such cases
- Regional Plans involving more than one LDC should focus on long term
- 5-7 years to build a transmission line – long period of time for LDC when new load customers are continually being added
- Need to pre-plan system
- Look out 20 years because land is disappearing and need to acquire land for corridors
- Should work like municipal planning for highways
  - HONI: Raised a concern that it cannot afford to hold onto land for 10 years as an unused asset under the current conventional regulatory treatment

LDC representative identified:
- Planning disconnect at Transmission and Distribution levels
- Distribution planning – Long term – 5 years
- Transmission Planning – Short term – 5 years (Medium term – 10 years, Long term – 20 years)

LDC representative stated:
- Asset has 80 year life but only focus at OEB is next 5 years
- All current benefits under GEA are based on historical investments

HONI noted:
- OPA, HONI and LDCs already work closely (mentioned Guelph)
- After a few meetings, tend to arrive at agreed upon solution in most cases
- Not a “planning” problem, it’s a “cost responsibility” problem which is an obstacle to arriving at an optimal solution

LDC representative stated:

- Collaboration with HONI and OPA is not a problem
- Meet with HONI monthly
- Problem is once an issue is identified, long period of time to get solution in place
- Transmission projects keep getting delayed and are taking too long. Therefore need to focus on a lot of short term temporary solutions within the distribution system
- Customers sitting on fence until more certainty on cost responsibility
- Should be specific time period given by OEB for LDC and HONI to agree on a solution

HONI noted:

- Need a good set of metrics to determine investment priorities. Help address which region to focus on first
- About 7-8 regions with capacity problems
- Once GEA came in, all capacity used up by generation
- IESO timeframe not very helpful for planning – too short (e.g., 18 months)
- Timeframe is always the problem. Focus is always on next 2 years in rate application, while appropriate planning needs to be over a much longer period of time.

LDC representative stated:

- Need commitment from OEB to approve investments over long term. Cannot keep focusing on short term

OPA suggested:

- Regional plans need to be long enough to determine investment priorities

Fortis highlighted:

- Also need to take into account transmitter–transmitter communications within context of planning. Could become more of an issue with new designation process (i.e., more transmitters)

B) Cost Responsibility

Board staff asked whether concept of Network vs. Connection assets should be maintained or abolished.

- HONI: Determining what is a Connection and what is Network requires a review (i.e., all Network or continue with status quo).
- Some assets are easier to redefine as Network (e.g., auto-transformers, switch-gear) because it is difficult to determine who benefits -- most will benefit many parties and can be difficult to identify trigger and therefore determine how to allocate costs.
- More difficult within context of transmission lines where life is 40-60 years and function can change over time. For example, 115 kV lines that service the Waterloo region would have been defined as Network facilities at one point in time. As the system evolved and built the 230 kV system, it became reasonable to sectionalize system. However, 115 kV lines still provide Network functions. Example is a station rebuild in Burlington. On a long term basis, need to transfer loads from one 115 kV system to another. It therefore provides the capability for the system to grow over

time. 115 kV lines will perform Network functions at some point. However, if the current TSC rules applied 30 years ago, it is likely the 115 kV system would never have been funded.

Staff requested feedback on examples of facilities that would still fit in Connection pool.

- HONI: Perhaps 115 kV lines that link two 115 kV areas (e.g., Niagara and Burlington). Those are long lines that evolved over time. In contrast, where it is just load supplied radially by 115 kV, it could continue to fall into the line Connection pool.
- LDC: Could be good reasons from cost allocation perspective to maintain distinction between Network and Connection assets. Analogy on distribution side is distinguishing customers on primary vs. secondary system. There is no reason to believe the “electrical structure” of Ontario is going to match with “municipal/LDC boundaries”. It may be reasonable to break up province into distinct regions along electrical functionality, especially if they have distinct problems. However, that would affect who pays and raises the difficult issue of rationalizing fairness. Should maintain pools and abandon capital contributions. There could be arguments in favour of maintaining capital contributions but the problems outweigh the benefits.
- Small consumer representative: Noted there may be a need to revisit the principles to identify Network/Connection assets before redefining. Also raised the question, if the transmitter has an obligation to connect, is the pool willing to connect any customer regardless of location in province?
- First Nations representative: Suggested a functional test with an assessment of the purpose of the facility. For example, if it has benefits in terms of reliability and integrity of the system, then no capital contribution.

Staff requested feedback on potential problems associated with uneconomic Connections to the transmission system if OEB were to move away from user pay to more Network assets.

- Generator representative: Defended user pays and reiterated previous statement made amongst broader group which is beyond the scope of this proceeding as it delves into integrated plans (wires vs. energy efficiency vs. CHP plants).
- LDC: Raised a concern that customers will we be paying a premium if rely only on transmitter to install assets.
- Large consumer representative: For line and transformation connection pools, in theory, connecting party has options. Customers can provide their own business case (i.e., not rely on transmitter). Discussed example of a mine customer which has a short life span and noted transmitter would not have recovered costs of assets over time through rates (i.e., capital contribution is required to make up the difference). Supported an economic test.[1] Suggested the functional roles of parts of the system change over time and definition of Network assets may be unduly conservative.
- LDC: Suggested it may be worth distinguishing types of Connections between load and generation.
- LDC: Noted that a test of economic connections implies a choice with control over the amount of consumption, location, etc. This may be applicable within context of industrial customers, however, LDCs are different with control over neither.

[1] Also observed that in reviewing certain cases, the existing criteria for revenue horizon of 5-10-15 years may be too conservative and suggested a retrospective review to determine if some types of customers are over- or under-paying.

- Small consumer representative: Noted uneconomic load can be an issue but uneconomic connection of generation is just as valid.
- OPA: Identified the need to distinguish between FIT and other generation. Economic Connection Test (ECT) only applies to FIT - not other generation. Identified through IPSP and transmission would be factored in. ECT was developed to consider interest to participate and identify what transmission expansions would be necessary to facilitate interest. ECT was envisioned to be test of ratepayer portion of costs. Never did include connection costs, as viewed as generator's costs.

Staff noted section 6.3.6 of TSC addresses where customer does not pay at all when facilities are "otherwise planned" by the transmitter (except for advancement costs) and requested examples of it being applied or not applied.

- HONI: Noted some investments have been approved as Network even though there was a Connection aspect. Highlighted that crux of confusion is what constitutes "a plan" under section 6.3.6. For example, is a plan a rate filing, a joint-regional study led by OPA, Hydro One's internal planning, etc.?
- OPA: Supported the need for clarity on what a plan is. Also referenced an example of a Board decision which identified that plans cannot be last minute to meet the needs of LDCs.

Meeting Conclusion

Following the break-out sessions, Board staff thanked the stakeholders for attending and providing their input. Staff also noted:

- Meeting notes would be posted on the Board's website
- Stakeholders could provide further written comments
- The next step would be the issuance of a Staff Discussion Paper for comment

If you have any questions, please contact Chris Cincar at 416-440-7696 or chris.cincar@ontarioenergyboard.ca.