Minutes of the Distribution System Code Task Force
13th Meeting - September 29, 1999, 9:30 am – 3:30 pm

Location: Ontario Energy Board Offices

IN ATTENDANCE:

Ken Quesnelle (Chair)	Woodstock PUC
John Alton	Lincoln Hydro
Mike Angemeer	Hydro Mississauga
Stephen Au	Toronto Hydro
Quan Tran	Toronto Hydro
Rene Gatien	Guelph Hydro
Tom Godfrey	Sault Ste Marie PUC
Kevin Henderson	Caledon Hydro
Curtis Cesarin	Caledon Hydro
Lorne Pasche	Welland Hydro
Mary Ellen Richardson (Meeting Secretary)	ECS
Gord Ryckman	OHSC
John Savage	MEST
Darius Vaiciunas	The Collingwood P.U.C.
Ray Powell	The Collingwood P.U.C.
Lisa Brickenden	OEB
Nabih Mikhail	OEB
Kirsten Walli	OEB
Zora Crnojacki	OEB
Mike McLeod	OEB
Neil McKay	OEB
Tanya Bodell	PHB Hagler Bailly
Norm Ryckman (Guest)	Enbridge Consumers Gas
Trent Winston (Guest)	Enbridge Consumers Gas

1. **Opening Remarks**:

Mr. Quesnelle requested that the group keep an open mind with respect to the information that was to be presented at the meeting, and to try to understand how this model might be applied.

Mr. Gatien asked whether a first draft of the DSC could be previewed by the group, so as to provide a better understanding of what the document looks like as well as the 'language' of the code, and to focus the group on outstanding items.

Action Item: **Ms. Bodell** will send out the current DSC draft before the next meeting.
Action Item: **Ms. Walli** will update the DSC work plan for the next DSC meeting (October 13, 1999).
Action Item: **Mr. Quesnelle** will then prepare a 'work-in-progress' chart (October 27, 1999)

2. Review and approve minutes of Meeting #12

Minutes were approved, as presented. Mary Ellen Richardson assigned as Meeting secretary.

3. Suggest additional agenda items

The formation of a sub-committee for Expansions was added under Agenda Item 5.

4. Review Status of action items (Deferred until later in the meeting)

Outstanding Action Item from Meeting #12: Ms. Bodell will provide a copy of the RSC draft to the DSC group as soon as possible.

5. System Expansions:

a) Background and Principles of Regulation of System Expansion – Neil McKay, Manager, Facilities Planning, Licensing Group, OEB (see Appendix 13B, distributed electronically)

Introduction:

This session was intended to give the task force members an overview of the regulatory experience on the natural gas side. The presentation provided an overview of EBO188 Guidelines, developed in consultation with the gas utilities and other stakeholders, specifically:

i) why guidelines of system expansion were required;
ii) the principles of EBO188, specifically the portfolio approach and the feasibility analysis;
iii) contribution policies;
iv) monitoring and reporting, and;
v) implications for electricity projects.

Summary of Comments:

The previous guidelines (EBO134) were replaced in 1998. Previously, the OEB and the utilities relied on discounted cash flow (DCF) analyses. The concern was that there was no consistency of approach between the utilities which became very problematic when evaluating analyses for competitive projects (e.g. competing franchises/customers) in which the utilities had used different parameters in the development of both revenue streams and costs. In addition, there was no consistency in the approach to contribution in aid of construction. There were no rules about how contributions were to be calculated or obtained. It was difficult to assess approval under this regime.

The OEB initiated a two-year process to develop and finalize a new approach (i.e. EBO 188). The process included significant negotiation and discussion, including an ADR processes. The OEB desired a common approach to economic feasibility analysis, a common reporting requirement, and to provide flexibility for the utilities to decide which expansion projects they were going to pursue (developed a portfolio approach for system expansions).

Some highlights of the EBO 188 financial criterion include:

- A fundamental tenet is to ensure that there is no cross subsidization between existing customers and new customers.
- The OEB does not approach individual projects but rather approves a portfolio of projects.
- The utilities have the flexibility to determine when and where expansion will occur. The portfolio approach pools all expansion projects into one portfolio and the utilities develop a profitability index (PI) which is the sum of the DCF for all the expansion projects undertaken, including an allowance for re-inforcement components. The utilities must maintain a portfolio PI of 1.10.
- Common methods of financial feasibility were also developed in terms of the parameters for revenue estimation, specifically: customer attachment horizon (10 years of customer attachment used as input for DCF); customer revenue horizon (40 years); discount rate; allowance for O&M costs; ensure conformity in CCA and other tax treatment in the formulae for DCF.
- With respect to the revenue, the commodity is treated as a ‘pass-through’, so it does not have an impact on the analysis. The regulated revenue is all that is used.
- Future load growth and expansions were to be taken into account.

With respect to contribution policy:

- The utilities would be allowed to continue to collect contributions.
- If, for an individual project, the PI were under 0.8, the OEB would expect that a contribution would be made such that the PI was raised to 0.8.
- The portfolio of projects would essentially balance groups of projects which are very profitable and those which are less profitable.
- There is no cross subsidization within the portfolio between new customers
- All customers are subject to contribution. Industrial and commercial customers would have to pay proportionately. The large customers pay based on peak usage(calculated on a 'design load' basis)
- For Enbridge Consumers' Gas ("ECG"), the contribution is collected through a cash payment or through periodic contribution on monthly bills, over 60 months. If the contribution is collected sooner then expected, any refund would be given to customers who had paid cash initially
- If a project were dominated by one or more large projects, the contribution would be based on the cost associated with the project. That is, a large industrial customer, using 75% of the line, would pay a proportion based on their peak usage.

With respect to monitoring and reporting:

- The utilities file projected portfolio expenditures in rate cases. The future portfolio (i.e. what they expect during the next year ("test" year) and the PI is submitted. This is done for rate review by the OEB for costs associated with the test year.
- In addition, the utilities keep a rolling PI on a 12-month monthly basis, based on actual figures for projects where gas is flowing or the pipe is laid in the ground. This is a backward looking, rolling 12-month average, which is submitted every 3 months to the OEB for review of actual versus forecast. Mr. McKay noted that the actual PI submitted by ECG is well above the 1.1 threshold.
- The OEB retains the right for audit. To date, the OEB has not performed an audited of projects since EBO188 has only been operating for one year.

In response to a *question* regarding re-inforcement and other capital expenditure programs beyond expansions to meet new customer growth:

- In situations where the population density increases over time, and reinforcement is required, the investment must be accounted for within the portfolio. ECG cited the Orangeville re-inforcement project (transmission line looping), in which ECG considered the existing customers as well as the new customers. This was included in the portfolio, but was also subject to individual review by the OEB as to the appropriateness of the spending.
- For ECG, they have had a major expenditure to replace cast iron mains in Toronto. The OEB doesn't review these on an individual basis, but does look at the criterion used, as well as the overall program.

- There is an allowance for re-inforcement.
- For maintenance projects (i.e. related to safety, security of supply), profitability does not enter into the evaluation. Since there are no new customers from whom to collect the money, these would be included as a system cost, under a maintenance program.
- Life cycle replacement, would be included under maintenance programs.
- In the case of hybrid investment (i.e. where there is both a replacement and an expansion to a bigger pipe),only the costs associated with the re-inforcement would be included in the feasibility calculation.

Principles that have potential to be applied to electricity projects:

i) standardized approach to DCF analysis. The DCF analysis is what the OEB has relied upon for 15 years;

ii) common contribution policies, such that there are some rules around how the utility would collect, how much and from whom;

iii) some common filing and reporting requirements on the system and the projects that are being done.

Principles that may not apply to electricity projects:

i) Portfolio approach-assumes utility decides where to serve. The Portfolio was intended to balance high and low profitability projects so as to decide which areas should be served. The electricity provider has an obligation to serve;

ii) Rate case filings and monitoring. Under PBR, there would be some reporting requirements in parallel with this process.

Other discussion:

i) There is no evidence that the OEB will be discarding the EBO188 approach under a PBR regime. The OEB would like to see some standards for economic feasibility for individual projects and rules around contribution, which must flow from a common feasibility methodology.

ii) With respect to the minimum 0.8 PI standard, the OEB felt that there was some ‘public interest good’ to be achieved through expansion of the gas system. The 0.8 came from the desire to serve the northern and eastern areas of Ontario (‘hard rock’/high cost country).

iii) EBO188 deals with expansions and re-enforcements (i.e. growth). Maintenance and life cycle replacement due to safety, security of supply and reliability is handled elsewhere. Under the current review system, there are separate categories under operation and maintenance expenditures. There is intense scrutiny now of gas utilities both on the line by line side of capital expenditure as well as envelopes of capital expenditures. For electric utilities, some reliability issues, which are minor, are now deemed O&M. However, some are budgeted as capital items. Section 92 says that if replacing '1 for 1', the expenditure is exempt. For utilities that migrate to the next size up cable, there may be some room under section 95 for exemptions (minor capital). In future, if an electric utility is undertaking both a life-cycle replacement and an upgrade for growth, need to separate these two investment amounts.

iv) The basic concept is that a gas utility can expand as long as can recover under existing rates. The *question* was raised as to what happens if the utility does not recover, and the utility wants a rate increase. For individual projects, there is a three-year review process. The OEB will select a representative sample of projects and evaluate the reported three-year actual figures relative to the forecast. It is expected that the comparison will show the estimates were reasonable. However, if there were not, the utility would be subject to more intense scrutiny and perhaps some future disallowances. There is an incentive for the utility to put forward estimates that are as reasonable as possible, since they do not want to put the OEB in the position to take punitive action.

Mr. McKay agreed to continue to provide support to the working sub-committees as the group went forward.

b) Discussion of Practical Issues of EBO 188 –Enbridge Consumers Gas-Norm Ryckman and Trent Winston

Mr. Ryckman and Mr. Winston responded to a number of questions, as follows:

i) In the situation where there are several coincident development projects within a franchise, ECG has to balance these projects. ECG tries to maintain clear lines of communication between the developer and themselves. Through the capital budgeting process, look at known developments and make a decision on reasonableness of the figures, and the customer attachments associated with them. Feasibility analyses are done as well on individual projects. The utility over time has the ability to switch funds within the capital budget to respond to changes in the market. There is, built into the portfolio approach, some forecasting error that some projects will not go forward. On average, the utility comes out close to budget numbers. When individual projects come to the OEB under a leave to construct, the OEB evaluates the forecast of customer attachments and compare to actual experience. The OEB also looks to evidence from the municipality for new subdivisions so as to test the reasonableness of the utility's forecast of development. ECG relayed that there were some challenges around setting budgets since the budgets are set two years hence, and many factors can change. The budget is struck based on initial project evaluated as greater than 0 (NPV) and PI at 1.0 or greater than 1.0. However, over time, costs of projects can slide between budget periods due to weather and other factors.

ii) In theory, a customer could contribute the whole amount, but ECG would rather that they did not since this takes away from their revenue base (i.e. their rate base). The contributions amounts are kept separate and are not included in the rate base. Since gas is a discretionary service, the utilities would prefer to maximize the number of customer attachments. Therefore, the utilities would prefer to minimize the contribution.

iii) The minimum profitability which is acceptable is .8 at which a customer contribution is required. On rare cases, other contributions are factored in. For example, funding from municipalities, provincial and federal governments would be taken into account so as to increase the PI.

iv) With respect to the portfolio approach, not talking about how to budget capital, but rather how to use this portfolio to evaluate projects revenue and costs. The portfolio approach is a 'management tool' for gas utilities to allow them to make decisions about where they should expand their system.

v) With respect to interaction with the OEB, where a new subdivision might come on, or maintenance program becomes necessary due to reliability results. ECG commented that with respect to new construction developments, they are not in contact with the OEB at this level. ECG would undertake the projects when financially reasonable and there is a customer desire. ECG would be comfortable defending this in the next rate case that they had managed prudently. If there were a large project developing, the OEB would be contacted to increase awareness so as to ensure that progress can be made. Under the traditional rate setting process there are annual reviews, such that if there were mid-year major capital expenditures, they would have to justify these at the annual rate review. How unbudgeted areas are accounted for and adjusted under PBR will likely be different.

vi) With respect to a question of how funding is obtained for projects with very low (0.3) PI ratios, but which are related to safety or aging, ECG responded that these would be deemed maintenance expenditures. Again, if not adding customers, but increasing security of supply, expenditures are not part of the portfolio. If it were a large item, it would be scrutinized during rate making prospectively or retroactively. ECG re-iterated that the EBO 188 approach is related to system expansion for new customer base or reinforcement to serve new customers.

vii) The utilities have to operate to codes with respect to maintenance, and this would be a budgeted item for their rate case. Both maintenance and capital expenditure are evaluated in rate cases.

viii) Current margins are used to evaluate revenue streams from expansion projects. The discount rate varies between the utilities, and is approved by the OEB and reflects the weighted average cost of capital. If the work has a benefit over a lifetime, then the expenditure would be capitalized. There is a split between maintenance expense, and a maintenance capital budget (lifecycle replacement are capitalized when benefits over an extended lifetime).

ix) With respect to why a utility would invest in a project which had a PI= 0.8, ECG indicated that if there was market demand, they wanted to expand their system in a financially responsible manner. ECG indicated that when get into comprehensive PBR framework that includes capital (as opposed to just O&M), they would be thinking 'very hard' about these kind of expenditures. It is possible that at this time the corporate guidelines may be more stringent than the OEB's guidelines.

x) For ECG, the initial impact on rates of a new customer will be negative, since in the short term a new project does not 'turn from red to black ink' until year 13.

c) Expansions and Proposed PBR Handbook-Mike McLeod, Strategic Services, OEB

Mr. McLeod presented a presentation entitled "PBR for Electricity Distributors in Ontario", which outlined the OEB staff PBR proposal (Appendix 13C).

The first generation of PBRRR is a three-year test period. The OEB decided that it would let the gas utilities precede independently of the electricity model.

The scheme will allow the utilities to continue with current cost of service (" COS")/cost allocation assumptions on which the utilities have calculated their current rate structure.

Transition costs will be recognized as one time costs recovered over some time period ("Z" Factor).

It is unclear what will happen at the end of the phase 1. The results of the first term will be filed and monitored over time. Once new COS studies are completed, the OEB will monitor the results so as to see what adjustments may become necessary.

The possibility of a 'g' factor (e.g. growth) will be considered for those utilities for which growth is a significant factor.

It was noted that the deadline for filing evidence for first generation PBR for unbundled rates (i.e. May and August 2000) might slip if the OEB deems it necessary to delay the filing date. It was noted that the utility does not have to be fully incorporated by this deadline, but it needs to be able to clearly define the competitive and regulated sub-components of the utility business. An entity could apply now for unbundled rates, though it would have to go through a full-blown rate case. It was noted that the OEB will make a decision based on the evidence presented to it, and the items that appear on the Issues List so the hearing process is critical to the decision.

The OEB Staff believe that the ‘user should pay’ if causing an addition to the utility’s facilities. If there are system improvements that are of benefit to all users, it is likely to be spread across all users. If a utility needs new capital expenditure, and this is due to customer growth and/or the benefit is not available to all customers then the individual user would have to pay for this.

With respect to connection fees for a facility that lies along the system, the OEB staff is looking for those rules to be recommended by the DSC.

Maintenance type capital expenditure would be assumed to fall under the price cap. If something caused it to go above this expected level (outside of management’s control), this might be considered a ‘z’ factor. Customer contribution only comes into play when there is growth. Whether an expenditure is covered through a ‘z’ factor or through customer contribution, the evaluation would be tied into who is going to benefit from the expenditure. If the whole system is going to benefit (e.g. repair due to a major storm), it might be considered a ‘z’ factor,(if it outside of management’s control). If an individual were benefiting from the expenditure, it would likely be handled through a customer contribution. In a situation where a number of retailers failed and did not pay the distributor, and the amount was beyond what is covered in prudential requirements, this cost might be considered a ‘z factor’.

It was clarified that the DSC should be cautious about defining a uniform point of demarcation since the existing rates are based upon the existing demarcation point.

In future, the electricity utility may have to consider the cost to connect versus the expected revenue stream, and charge any unrecovered cost to the individual customer. The electric utility has to make an offer to connect, and have to service even those facilities which are located at the far end of distribution system. In the offer, there are mechanisms to recover the unrecovered costs. Contributed capital is taken out of the rate base. Connection fees may be another revenue source. In the past, these fees have been used to pay for the actual cost of connection from the road allowance into the facility. It will be problematic (i.e. some interveners may take exception to this practice) if these connection fees are also included in the rate base in the future.

d) Open Discussion:

The group discussed the 'learnings' gained from the presentations, as follows:

- There seemed to be two reporting frameworks in the future, the PBR framework and the system expansion framework

- The point was raised that this system might ‘force’ a charge to be applied against customers where historically they did not get charged. It was noted that the utilities do not necessarily have to charge the customers (i.e.

shareholders could assume some of the cost), but they can, and if they do there should be some common evaluation methodology that utilities use to calculate what charges should be.

It was noted that lot of this discussion revolves around the replacement of development charges. It was recognized that what has happened in the past may have meant that existing customers subsidized new customers.

Mr Quesnelle closed by thanking the speakers and by indicating that both the OEB staff and the ECG personnel could be available to the subcommittees.

e) Status of Sub-group

The following individuals volunteered to be part of the Subcommittee on Expansions. Gord Ryckman, Mike Angemeer, Lorne Pasche, Curtis Cesarin, Lisa Brickeden, Nabih Mikhail, Ken Quesnelle, Quan Tran, Mary Ellen Richardson.

Action: **Ms. Walli** will review to see whether there was precedent on the gas side with respect to competing offers to serve a previously serviced territory, or how they had handled a by-pass situation. This might give some background on the situation that existed, the process for approval, the evidence that was presented and the criterion that was considered by the OEB for approval.

Action: **Mr. Quesnelle** will schedule the first subcommittee meeting.

6. Recommendation summaries:

Note: The Definition of Meter prepared by Ms. Bodell was reviewed (Appendix 13A) This final draft 6 was approved by the group, and was accepted unanimously.

a) New Load Transfer Arrangements – Tanya Bodell (Appendix 13D)

The task force engaged in a long discussion relative to whether load transfers should be allowed in the future, and the ownership of the facilities associated with existing load transfer arrangements. Several issues and problems were raised in the context of several scenarios which have arisen in existing load transfers and which may arise in future load transfers. Section 41 was referenced, and the argument made that this would Section could be used to support an argument of no new load transfers.

The following notes attempt to capture some of the discussion held regarding these scenarios:

i) Non-discriminatory access implies that if a developer is close to a distribution utility, which is not licensed to serve the developer (the "non-incumbent distributor"), the developer can request the non-incumbent distributor make a connection. The non-incumbent utility would have to apply to the OEB to revise their license. The OEB would have to publish a notice, and hold a hearing. The OEB might consider any stranded cost that might result by the customer being served by the non-incumbent utility. It was suggested that if the OEB found that the non-incumbent utility, was 'gaming the system', there were no economies and there was stranded costs, the OEB would likely not approve. Conversely, if there are no stranded assets, and some 'societal benefit', it is likely that the OEB would approve.

ii) The point was made that there might be confusion caused by the fact that most of the existing service territories are municipalities which provide road, garbage, water and other services within their territories. In future, the municipality will be responsible for all services within their territory, and possibly electricity within only some of their territory. It was noted that, in the future, the ownership of the utility could change from the municipality.

iii) There will be a set of economic criterion which the neighbouring utility will have to file with the OEB if they wish to expand. There may be two utilities vying for the same customers, presenting competing economic criterion to the OEB, and justifying why they should be serving this customer given the portfolio of current and expected customers which they each serve. The OEB will consider these economic issues and will have to decide which distributor will provide the most economic service and the most "societally beneficial" expansion to serve the customers, such that the system - as a whole - is more efficient.

It was argued that competition implies a market where there are multiple participants and the incentive is to drive prices down to cover marginal costs as efficiently as possible. The wires side are considered a natural monopoly, and don't want multiple participants having access to the same customers. However, as such, there is also not the pressure of market forces to drive the market participants towards efficiency.

PBR is an attempt to mimic market forces in a regulated segment. The wires are a monopoly, but what is not a monopoly is a franchise set by municipal borders. Therefore, an expansion needs OEB approval. It was noted that without a centralized planning agency, there needs to be some other process by which it is determined that expansions do not lead to stranded costs. Historically, the industry has had exclusive territories and load transfers. In the future, there will not be exclusive distribution territories, and some body will determine what is the most economically efficient approach. If two entities want to service a customer(s), then one utility has an obligation to make an offer to connect, and the other utility has the option to make an offer. Both of the entities would have to come before the regulator to determine what the most economically efficient solution is.

It was recognized that it is not desirable to have a system which encourages in-fighting, inefficient assets, or which propagates OEB hearings.

iv) A scenario was discussed of a Transformer Station ("TS") expansion. In this situation, two utilities could individually build their own TS equipment, or they could share one TS. In this situation, the OEB needs to scrutinize capital expenditure since both companies might have a Section 92 application prepared, fully costed out, and interveners would question why a shared TS was not being built. This situation supports the need for a standardized economic feasibility test.

v) In a situation where two distributors make competing offers for the same customer, it was recognized that a shareholder (municipality) might wish to make a contribution towards the connection (or some representation about future distribution tariff) so as to 'keep' the customer. It was unclear whether this subsidy would be allowed. The situation of a municipality making an equity contribution, and a driving "the utility to the ground" because it is recovering enough in property taxes to recover the costs was discussed. At the same time, the Board of Directors would have a fiduciary responsibility to ensure that the best interests of the corporation are protected It was recognized that this is a political reality which this task force should examine. It was felt that this was an issue to be further considered by the sub-committee.

vi) With respect to the offer of a steady rate to a new customer for economic development purposes, the municipality could also offer superior reliability. It was recognized that this kind of competitive offer should be encouraged, though getting into territorial wars over load transfers should not be encouraged.

vii) The question as to whether the OEB would allow a utility could offer a different rate to a boundary customer was raised. While it was recognized that the current approach for some utilities was to differentiate rates based on density, there would still be an issue of equity that would be raised at the

OEB. Again, there was an issue of cross-subsidization that would have to be considered in this argument. In the past, the utilities have been exclusive, but in the future will have to consider these possibilities. The precedent was cited from the gas industry with bypass rates.

viii) The possibility of including a prescriptive valuation methodology was discussed in the case of two distributors evaluating the purchase of facilities. There is currently a requirement for the OEB to evaluate the asset disposition only if the utility is selling a substantial asset or the entire asset. However, in cases where it is difficult for the two parties to agree on a 'market price', might want to consider

Action Item: (Ms. Walli) With respect to whether a municipality, as the shareholder, can invest in the distribution system, and would this be acceptable to the OEB, Ms. Walli will check to see what the municipality can and cannot do with respect to a third party contribution to an LDC's cost. (That is, can they forego dividends in anticipation of anticipated tax revenue.)

Action Item: (Ms. Bodell) It was discussed in the Load transfer Agreements document needs to be revised with respect to new load transfers to include a discussion of the negative situations that might arise if there are non-exclusive franchise territories, and no load transfer agreements. It should also define how these things might be addressed (e.g. OEB hearings, criterion). The document should also address the situations where a load transfer might be necessary and might have merit, and the criterion against which the load transfers should be evaluated, and approved. Ms. Bodell will append this discussion to the document. The existing load transfers will be addressed as far as they highlight the 'worst case scenarios' of what the continuation of load transfers arrangements might engender.

Action Item: (All) To provide Ms. Bodell with examples of 'worse case scenarios'

b) Others for Discussion –None reviewed

7. Status of Sub-Groups

a) Operations and Maintenance Guidelines – Lorne Pasche

It was relayed that the group is struggling with the time intervals that should be included in the table circulated for inspection cycles. The sub-committee is going to continue with this approach, but it is concerned that if it doesn't receive enough feedback now, it may lead to further discussion at subsequent task force meetings, and not complete the task on schedule. Mr. Pasche relayed that the sub-committee had also addressed the subject of efficiency, and responsibility for customer property.

It was suggested that the group look at the possibility of introducing a system in a phased way, to mirror the PBR framework. The possibility of directing utilities to begin to record data on a circuit-by-circuit basis was also discussed. In this way, the utilities would begin to collect data in a way that moves the utilities towards a more detailed PBR approach, post first generation PBR.

The question of whether the costs associated with more frequent inspection might be deemed a legitimate 'z' factor was raised. The issue of how a utility would prove that they were not doing this in the past and thus justify the transition cost was discussed.

A question was raised as to whether the utilities could come forward with their inspection schedules, rather than prescribe the figures since very few keep to such a rigourous schedule. In this way, the OEB could identify those utilities that are not conforming to this schedule.

The issue of these schedules not being reflective of individual utility conditions, capital used, age of capital, technology, etc. was discussed. In some cases, the inspection requirements may drive costs up, and may also demand some recording which is not necessary.

It was discussed that the reliability statistics should be used to determine whether a utility is performing and, if not, the utility should be required to take corrective action. It was argued that the PBR framework could be used to drive this. The next generation of PBR will be more detailed. Again, if only focus on satisfying the inspection feedback, may be hitting the wrong action item.

Conversely, want to avoid a party 'gaming' the system by saying that they can meet the PBR standards, not do any maintenance, and walk away with a lot of money. Thus, it was argued that there is some minimum requirement to inspect, while not defining what maintenance is.

It was argued that should consider a phased approach to mirror the PBR.

Action Item: Kirsten Walli: Kirsten will check with OEB staff to see whether this

could be considered a legitimate 'z' factor.

Action: **Mary Ellen Richardson: To request Shela Chan to distribute the latest electronic version of the document to all of the task force members.**

Action: **All: To provide feedback to the sub-committee with respect to the inspection cycles included in this table. Specifically, members were asked to provide details of what they currently were doing, the cycle, and any additions or revisions or deletions that should be made to this table. Also, the group was asked to provide feedback with respect to the proposed recording/reporting framework. Members should comment generally on the approach and whether or not they consider it overly prescriptive. Members should strive to give feedback to the sub-committee, via Shela Chan, by October 6, in terms of looking at the template and filling out the numbers.**

b) Relationships between Distributors – Gord Ryckman

The group has received feedback on the structure of the recommendation with respect to the LV lines, and some changes have been made.

Action: **Gord Ryckman to send out the revised Summary of Recommendation documents to the task force for review.**

Action: **(All): Provide feedback to the relevant sub-committees on documents received to date. If any members have themselves or have a neighbouring utility that supply customers greater than 50 Kv, please give a brief description of what the situation is to either Rene Gatien or to Shela Chan, optimally by October 5. The group is looking for several scenarios so as to consider the alternatives.**

c) Embedded Generation – Ron LaPier/Jane Scott (as presented by Kirsten Walli)

This sub-committee now includes representatives from OPGI and OHSC. The discussion has revolved around the conditions of connection with the generator, and the need for such a document for all utilities. One of the goals of restructuring is to encourage new generation, so most utilities will likely be approached in future to connect new generation facilities. It is anticipated that it will be a greater concern in the future then it has been in the past. The issue of gross versus net billing will not be addressed in this sub-committee but rather in the OHSC Transmission and Distribution Hearing.

8. Set draft agenda. Adjourn.

The group agreed that the agenda continue as it was for this meeting, with each sub-committee providing feedback to the full task force on progress made.

Next Meeting: The next meeting of the full task force is scheduled for October 13, 1999 at 9:30 to 3:30 at the Ontario Energy Board.