Ontario Energy Board

Renewed Regulatory Framework
for the
Electricity Distribution and Transmission Sectors

Consolidated Notes from Executive Roundtables with Distributors

February 21 & 22, 2012 & March 5 & 7, 2012

The discussion topics raised with the participants included:

- Approach for the regulatory framework
- Key elements of the Board's approach
- Performance outcomes
- Planning optimization
- Flexibility

Views and comments

Objectives, Vision, Strategy

- The RRFE initiative is timely.
- The focus on outcomes is to be welcomed.
- Time is of the essence – new policy is needed as soon as possible.
- Implementing changes to the regulatory framework will be facilitated if the philosophy behind the objectives of the changes is clear to all stakeholders.
- Some aspects of the regulatory framework are higher priority than others and should be more expeditiously addressed by the Board (e.g. treatment of capital).
- Renewal of the Framework will take several years (process of change). Goal is RRF in place for 2014 rate-setting but certain pieces have greater urgency than others.
- Will the Board explore other models of regulation – such as municipal and co-op oversight in the US – for smaller utilities (especially non-profits)?
- Since starting the RRFE process some key issues have arisen (e.g. the Drummond Report; Gov't interest in leveraging smart grid potential/expertise) is there a potential to incorporate these considerations in the RRFE consultation?
- The Board should be less prescriptive in general.
- It is important to look at future requirements and develop a framework that will work well in the long term. Perhaps it is better to start with a blank page rather than frame discussion around amending the existing framework. Perhaps a fundamental paradigm shift is needed.

- While the OEB appears to recognize that "one size does not fit all" there are benefits to greater simplicity in regulation.
- Board should consider possibility for streamlining the regulatory process for instance establishing bands of reasonableness to recognize LDC's growth, capital spending, performance.
- The framework should recognize that each utility is unique.
- Before implementing any new framework, Board should do modeling with data to see impact of new policy.
- The Ontario distribution sector has had to respond to significant changes in the past ten years or more; greater stability and certainty would be desirable attributes of the renewed framework.
- Private sector investment should be enhanced to meet capital needs.
- Incentives should be focused around innovation and technologies.
- How can we continue to protect consumers but still allow innovation and private/public sector partnerships? e.g. ARC prevents harnessing fully utility staff power to foster innovation.

Regional Planning

- Utilities already do regional planning though perhaps not 'formally' or consistently across the province and already have a process, which feeds into asset planning although the main impact of such planning is on transmission. Electricity distributors do have a history of collaboration where warranted, e.g. CDM.
- What does the Board's new policy mean for utilities? How will it change what utilities do now? What will the Board expect from utilities with respect to regional planning? What is wrong with what utilities are doing now?
- Clarity on cost responsibility and on planning roles is needed.
- All utilities are unique, but Ontario is similar to other jurisdictions.
- Ontario Hydro's method of regional planning was very effective; parties met and explained their respective plans and found the middle ground where needed.
- It is important to respect regional differences and needs. Communities must also be empowered to do what's best for them.
- Existing codes (especially TSC) are too limited in view e.g. there may be additional regional spin off benefits that could justify certain expenditures which would otherwise be considered imprudent.
- A structured approach to getting regional based customer groups involved in planning is needed.

- The main problem with the current situation is that there are too many organizations involved and too little action; there is a lot of activity but triggering implementation is problematic. Analysis is delaying action.
- Focus is on transmission, distribution planning and reliability has little regional impact.
- How will regional planning disputes be arbitrated?
- Whatever the OEB decides to do with regard to regional planning should recognize the need for flexibility.

Capital Planning and Investment

- Difficult to reconcile long-term (as long as 30 years) capital planning with short-term rate & regulatory cycles.
- Need to avoid "sawtooth" costs that are associated with the current 3GIRM regime.
- Prefer long-term capital strategy that unique to the utility's needs & situation. (i.e. 30 years).
- A lifecycle view is needed – match planning cycle with cost recovery cycle.
- Utilities are already using experts to assist in asset management and long term planning, experts vet the plans.
- The Board should really be asking if utilities are spending enough on capital? Are they spending efficiently? In the right areas? The key question should be what is the amount of money needed for sustainment? Then let utility determine where and how to spend it.
- The renewed framework will need to address an accumulated past underfunding of capital investment
- How will the Board assess the efficiency and effectiveness of capital plans? A consistent, independent approach to validating investment plans and planning processes is needed:
    - to evaluate the relationship between the asset management plan and the capital investment plan;
    - to assess plan objectives; and,
    - to measure outcomes against objectives.
- Expert third-party review of plans may be of value. The OEB could consider establishing a roster of such third parties from which the distributors may choose.
- Rates process concerned with short term rates therefore it does not necessarily provide the best value in assessing long term plans. Expertise is needed to undertake such an evaluation; who can the Board turn to for independent advice?
- Utilities are already using experts to assist in asset management and long term planning, experts vet the plans.

- Once plan is approved, utility should be able to maange within the envelope and only address major deviations from the plan. Costs for plan should be built into rates.
- Greater standardization is needed of asset management/planning concepts, investment category definitions and key plan elements (e.g. load forecast methodology) in order to:

  - minimize the need to engage consultants for one-off reviews;
  - reduce stakeholder-related costs; and,
  - create greater regulatory predictability.

- The appropriate timing of investment expenditures and their recovery in rates are central. Considerations include:
  - balancing rate stability against cost recovery certainty over the spending horizon (especially important where private equity/capital markets are accessed);
  - Accommodating the impact of unforeseen events on project priorities or timing within the spending timeframe – trade off between Board scrutiny and acceptance of particular plan with utility flexibility to manage unforeseen events.
  - the higher the proportion of refurbishment/replacement investment relative to growth-related capex, the greater the need for flexibility in rate recovery due to changing requirements over the plan horizon.
- The Incremental Capital Module (ICM) threshold definitions must accommodate the need to transfer between investment categories as and when needed - standardized concepts and definitions will support this.
- It is important to recognize the planning process will be driven at least in part by new requirements for LDCs (e.g. new systems and responsibilities for managing DG and DR).
- How to maintain an appropriate age of infrastructure (stabilize assets at 25 yrs for example)?
- OEB is only one of three authorities to whom distributor managers are responsible for capital planning; the distributor's Board and the municipal council are also involved. Municipal requirements often affect the timing and priorization of capital projects.
- Provincial planning requirements, such as those that fall under *The Places to Grow Act*, also have to be considered.
- Also consider involvement of the ESA in asset management and planning as they are interested from safety aspect.
- Capital structure can also be a barrier to sound investment planning. Utilities need debt & equity to fund capital projects. Debt is relatively easy to get. The problem is

getting equity, and municipalities often view the utility as a source of revenue rather than investing in the utility.

- There may be lessons to be learned from European experience with regard to standards on asset management.
- Different considerations apply to distributors experiencing load growth than to those for whom load is decreasing.
- Multi-year approvals for capital plan envelopes are beneficial but need to accommodate the "lumpiness" of some investments, e.g. addition of a new Transformer Station
- In contrast with the natural gas utilities, electricity distributors are not under the same pressure to maintain assets for safety reasons while natural gas distributors do not have the obligation to serve that electricity distributors have.
- Asset management may be thought of as "documented commonsense".
- Taking a long term approach to capital investment planning will be a challenge for intervenors who tend to be more focused on the short term.

<u>IRM & Rate-Setting</u>

- The sector has evolved. IRM had its place but is not appropriate for stranded assets, a growing rate base or aging infrastructure.
- Recognize the impact of declining consumption (where applicable) on revenue requirement recovery and the implications for the timely recover of capex:
  - options include greater reliance on fixed rates;
  - variance accounts approach must recognize intra-class differentials; and
  - the chosen approach must be consistent.
- IRM works for some utilities, but needs some tweaking to keep up with evolving sector. The industry today is not as it was envisaged 10 years ago. Government keeps changing the rules and it is hard to keep up.
- Incentive regulation as a concept is good, but the problem is how it is implemented.
- Is there a way to incorporate capital into the IRM so as to mitigate fluctuations in rates?
- With respect to ROE, be mindful of risk transfer. Don't transfer risk to the utilities.
- If rate recovery of capex is consistent with a utility's planning cycle, and planning cycles may vary across utilities, cycle term may vary accordingly. Since planning is an ongoing process, the "moving window" nature of investment plans must be accommodated within the cycle by the capital recovery mechanism.
- Utilities should have discretion over the length of the CoS/IRM cycle; alternatively the Board could offer 'buckets' of different cycles for LDCs to choose from to avoid

having 80 different cycles. Criteria/conditions should be established whereby a utility due for a CoS review can request to remain on IRM.

- Rate stability must be balanced against cost clarity (e.g. clear variance accounts annually).
- Rate design should clearly indicate to consumers how best to maximize savings from conservation.
- IRM for gas and electricity are distinct: gas was successful under IRM due to diversity of portfolio (i.e. large system/service area with a wide variety of asset characteristics and demographics across different communities); whereas electricity/LDC (except HONI) systems are more homogenous in terms of age and characteristics of assets and systems are closely tied to municipal economy therefore investments tend to happen in ‘waves’.
- For electricity there needs to be more flexibility with regard to when and how often LDCs rebase to better reflect each LDC’s asset characteristics (perhaps a variety of ‘planning windows’ could be offered). Especially for small utilities a 5-8 yr window might be best because the COS review is onerous and expensive. The trade off for this is potentially increased regulatory oversight.
- The details if IRM needs a review, e.g.:
  - The index (national index derived from GDP) is wrong; it needs to reflect Ontario utility’s issues (e.g. 60% of costs are labour related, large number of Gov’t imposed programs such as smart meter/TOU implementation). It needs to be homegrown.
  - Trending data (based on US utilities) also needs to be addressed; Ontario is not a stable environment (changing policies, cost increases) which means its very difficult to define baseline
  - The stretch factor seems to be an awkward addition. One possible alternative is earnings sharing instead of a stretch factor.
  - ICM must be improved to create smoother ‘capital steps’ under IRM framework. Utilities Might not need to rebase every year with an improved ICM model but the tradeoff is increased annual monitoring.
  - The off ramp provision needs revision. The level of pressure that the current provision creates (i.e. letting a situation deteriorate to the point when the off ramp is triggered) is too high. Its not in public interest to see utility in financial distress, the system must be able to respond to more (and more quickly) than it currently does. Plus or minus 300 is too big a range:
    - does the range need to be symmetrical?
    - Does it need to be the same for all utilities?
    - Is a financial test alone sufficient?
    - What other factors could be considered in an off ramp? Reliability?
- Providing targeted incentives may lead to “gaming”.

- The current IRM-CoS regime does not take into account sufficiently the real differences among distributors of different sizes, different customer and load growth,
- "Less is more" and simplicity are important principles for rate-making.
- Compared to natural gas utilities electricity distributors have not have a lengthy period of relative stability since restructuring in which to come to some sort of "equilibrium" efficiency.
- Revenue decoupling is worth exploring further.
- Earnings-sharing mechanisms may be of benefit.

Standards & Benchmarking

- Caution against incentives tied to reliability standards because every utility is at a different starting point. The issue is how to properly structure incentives & how to benchmark.
- The best benchmarking is to compare utilities against themselves, and not each other.
- Rather than minimum standards, may be better to have minimum and maximum (i.e. banding).
- To facilitate the use of performance standards, possibly in conjunction with incentives, definitions must be clear, e.g.
    - the use of 'bands' as distinct from 'thresholds' should be considered as a means of accommodating different utility characteristics
    - the use of metrics vs. outcomes: metrics based on uniformly applied absolute measures (call pick up time) may be inconsistent with utility specific 'outcomes' (satisfaction with customer service response)
    - potential impact of compliance with a standard on OM&A and/or capex should be considered (i.e. rate impact)
    - for investment planning/implementation performance & incentives the following were recommended:
        - use meaningful industry benchmarks; e.g. customer/investor "value indicators"; capex efficiency-linked incentives
        - use incentives for achieving outcomes related to meeting 'growth' and 'sustainment' objectives, perhaps consider a 'regulatory cost efficiency' incentive.
- Measurement consistency is important when utilities are being compared:
    - measurement methods must be consistently applied;
    - methodologies must account for different characteristics;
        - size is a factor in some but not all metrics/standards, and
        - utility 'best practices' should be reflected.

- Implementation-transitioning from old metrics/standards to new must consider management of transition costs,

  - cognizance of burden created by new reporting requirements is important e.g. purge existing, ineffective metrics to accommodate new, improved ones.

- How to decide what is 'appropriate' in relation to productivity improvements etc.? Productivity improvement incentives may not be sustainable because at some point there is declining return. Caution that productivity improvements should not come at expense of maintenance.
- Utilities, their boards and shareholders focus on rate comparison, ROE achievement and reliability, i.e. how many momentary outages.
- Efficiency standards (among cohorts of similar LDCs) could help simplify process. Must meet a certain threshold unless good reason why its not possible (i.e. massive load growth, decline or very unique service area circumstances). Board has utility data to determine averages etc. (RRR filings). Realistic benchmarks are key.
- IFRS will help to put all LDCs on even footing for OM&A and benchmarking.
- Benchmarking has proved difficult even in the natural gas industry in which there are only two major utilities in Ontario and is unlikely to work for electricity.
- Data quality is a significant problem for setting standards and benchmarks
- If the existing data is properly understood, there may be very little difference among Ontario's distributors with regard to most measures of efficiency.
- In the natural gas sector providing consumer value is regarded as the key standard of performance and in this regard the value of rate stability cannot be overestimated.
- The apparently prevalent notion that the Ontario electricity distribution sector in inefficient may be challenged.

<u>Process</u>

- Primary objective should be the customer and utilities shouldn't be distracted by the burden of process.
- Customers are already well protected by utilities and shareholders. Regulation increases the costs for customers, so Board needs to consider the cost of regulation and compliance with the rules. There should be an opportunity for utilities to tell the Board about areas of regulation that could result in cost savings/reductions. e.g. compliance with the Affiliate Relationships Code.
- Interveners are focused on issues relating to their own constituents (i.e. certain 'types' of customers) not necessarily the consumer community at large nor the consumers of the service area in question.

- The burden of the rate-making and reporting processes takes away valuable resources from the running of the distribution business.

- There should be some onus on intervenor groups to show that the groups that they represent have the types of concerns that they raise in rate cases.
- The Interrogatory process is ineffective and inefficient; it could be improved by coordination among intervenors.
- For capital plan review the adjudicative process may be a blunt instrument: electricity distributors could learn from the natural gas industry which has made good use of Alternative Dispute Resolution methods.

<u>Bills and Mitigation</u>

- Approaches need to address affordable rates & there needs to be a discussion about what affordable means? What constitutes rate shock? What is an acceptable increase? What is an acceptable pace?
- There needs to be recognition of the components of the total bill that are not susceptible to control by the OEB's regulatory framework.
- Proposal that threshold for increase be set at 10% per line item per year. Anything greater than 10% would be politically difficult to justify.
- Insufficient information on bill elements not directly affected by the application will limit certainty of total bill impact estimates; what are the implications of second best approaches; e.g. assuming some bill elements remain constant?
- The Board should consider revenue decoupling.
- Efforts to take a "total bill" approach to rate impacts must be cognizant of the relatively poor understanding of the bill components on the part of consumers.
- There needs to be a better effort towards increasing consumer understanding.

<u>Consumer Input</u>

- Ways and means of enhancing local customer participation in a utility's planning processes should be sought.
- LDCs could engage intervener community in advance (in planning stage) to smooth regulatory review process. Cost is a drawback because interveners will be paid for all these activities. Therefore, this might only make sense for large projects or regional plans.
- Research on what customers value should be incorporated into planning. Leverage survey information etc.

- Townhall type meetings will likely not achieve the results sought because they will primarily draw a certain ‘type’ of consumer limiting the usefulness of feedback. However, for small distributors these may be the most efficient approach.
- Consumer views might change from one year to the next depending on circumstances which hinders needed stability for long term planning.
- Where surveys are used to gauge consumer views it is essential that such activities are accompanied by appropriate education.