Ontario Energy Board

EB-2010-0060

Staff Report to the Board

Distribution Revenue Decoupling

January 18, 2011

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Acronyms Used

AU	Average (energy) use (m3 or kWh) per customer (usually in a rate class)
CDM	conservation and demand management (electricity)
COS	Cost of Service (application for rate rebasing)
DAU	Declining average use (see AU)
DSM	demand side management (gas)
EDx	electricity distributor
GDx	natural gas distributor
IRM	Incentive Rate Mechanism
LRAM	Lost Revenue Adjustment Mechanism
RD	Revenue Decoupling
ROE	Return on equity
SFV	Straight Fixed Variable (rate design)
SM	Smart meter
SSM	Shared Savings Mechanism

Executive Summary

Consultation objective and purpose of this report

The objective of the Board's consultation on Distribution Revenue Decoupling is to confirm whether the revenue adjustment and cost recovery mechanisms now available to electricity (EDx) and natural gas (GDx) distributors in Ontario remain adequate and sufficient to address potential revenue erosion resulting from unforeseen changes in the volume of energy sold.[1]

In a letter issued October 27, 2010 (the October letter), the Board directed that the revenue decoupling consultation would not proceed until the substantial completion of three new priority policy initiatives the output of which will be considered in the Board's future work on this subject. Accordingly, the purpose of this staff Report to the Board is to summarize and evaluate information and views provided in the course of the consultation and offer advice as to appropriate next steps.

Background

A gas or electricity distributor's revenues are said to be 'decoupled' if provisions are in place to relax the link between the recovery of a distributor's revenue requirement and customer use of the distributor's system. Key elements of the regulatory frameworks applicable to Ontario distributors that individually and in concert have this 'revenue decoupling' (RD) effect are listed in the table below. With one notable exception, all are shared by EDx and GDx but there may be variations between the sectors and among distributors within a sector in terms of the degree to which a given element is typically utilized.

Existing RD aspects of Ontario's regulatory framework

Element	Electricity	Natural Gas
LRAM recovers revenue lost due to CDM/DSM programs	√	√
Forward test year (i.e. forecast) rate rebasing	√	√
IRM 'off ramp' (early rebasing)	√	√
Use of substantial fixed charges for low volume customers	√	√
Partial (weather normalized) average use adjustments	-	√

[1] The Board's consultation cover letter (the "cover letter") was issued on March 22, 2010.

Rationales for RD

To evaluate the effectiveness of these mechanisms against selected alternative approaches to RD used elsewhere, Board staff retained Pacific Economics Group Research ("PEG").[2] The impetus for RD, as explained in the PEG report, can come from any or all of three concerns:

- neutralizing a disincentive to distributor participation in CDM/DSM activities, which are intended to reduce customer use of distribution systems;
- managing potential 'earnings erosion' risk related to any or all drivers of reduced customer system use; and
- enhancing regulatory efficiency by avoiding rate cases triggered when revenue recoveries fall short of the approved revenue requirement.

Generic RD Approaches

The PEG report describes how all three RD drivers are addressed in some degree by three generic approaches:

1) lost revenue adjustment mechanisms (LRAMs) which compensate for specific sources of energy volume losses not otherwise predictable by distributors
2) decoupling true-up plans (true-ups) which typically use variance accounts to track and periodically true-up differences between actual revenue recovered and the approved revenue requirement; and
3) straight fixed variable pricing (SFV) which uses fixed charges to recover fixed costs (i.e. the bulk of short run distribution costs) and usage charges to recover costs that vary with system use.

Stakeholder Written Comments

The PEG report appraises the regulatory arrangements for GDx and EDx. For GDx, two changes to existing arrangements were proposed for consideration: eliminate LRAM payments; and calculate AU adjustment for IRM purposes using non-weather

[2] Review of Distribution Revenue Decoupling Mechanisms (the "PEG report") was posted on March 22, 2010.

normalized data (i.e. decouple for weather risk). In PEG's view, these measures would enhance regulatory efficiency; facilitate rate designs that promote DSM goals; and save costs related to operating risk.

For the EDx regulatory framework, the PEG report suggested that either a partial (as currently used by GDx) or full true-up (which removes weather-related risk); or SFV pricing approach be considered to replace LRAM to: a) reduce administrative costs; b) remove disincentives to a wider range of distributor CDM efforts; and c) mitigate potential "earnings erosion" resulting from declining system use per customer.

The Board's consultation cover letter invited written comments from stakeholders framed by the information contained in the PEG report and by seven questions on specific matters of interest to staff. Stakeholder comments (abbreviated here for convenience) are summarized below.

- *Is further revenue decoupling needed?* – Most stakeholders' comments, including industry stakeholders, were to the effect that current arrangements for GDx are adequate and sufficient in relation to all three potential drivers for incremental RD measures. Notably, LRAM as applied to the gas sector was generally accepted as a valuable component of the framework.

  This was not the case for EDx, where while deemed satisfactory in principle, LRAM is seen by some stakeholders as overly cumbersome and costly relative to the potential benefits accruing from an LRAM application, especially for smaller distributors. As to other potential sources of unforeseen changes in system use, some stakeholders noted the exposure of utilities under IRM to potential load reductions between rebasings. Several stakeholders expressed the view, however, that additional information is required before a clear determination could be made as to whether changes are warranted.

- *Considerations for selecting an overall decoupling approach* – Stakeholder comments addressed both the principles and objectives of rate making in their suggestions as to the decision criteria that should apply in this context. Some of these refer to the question as to whether and to what extent revenue recovery risk should be mitigated by regulation; others relate to choosing one or another of the generic RD options or to the detailed design thereof.

- *Impact of Smart Meters (SMs)* – Several stakeholders recognized the potential for smart meters to provide data useful for ratemaking, suggesting among other things that SM enabled demand charges could enhance revenue requirement recovery and clarify cost causality at the individual consumer level within a rate class.
- *Risks to be removed by decoupling* – A variety of stakeholders commented that risks associated with energy conservation should be addressed, some indicating that disincentives to distributor participation in all types of conservation must be neutralized; others noting that such risks are not within a distributor's ability to control. Some industry stakeholders, based on their view that distribution costs vary little with energy volumes, felt that the regulatory framework should neutralize any source of revenue recovery shortfall from forecast. In this context, a number of stakeholders felt that any consideration of using regulation to reduce market risks should include a review of allowed ROE and/or approved capital structure.
- *Alternative Approaches* – A number of stakeholders proffered interesting alternatives to or refinements of the generic approaches to RD. Stakeholders variously noted that the sheer number of electricity distributors in Ontario necessitates casting the net beyond these options; that differing circumstances between the sectors and from one distributor to the next could preclude a 'one size fits all' approach; and that, given the importance of conservation, and the potential for rate design offered by SM data, additional research should be conducted to shed light on the potential for using distribution rates to foster energy efficiency.
- *Preferred Approach* – Given that, for the gas sector most stakeholders expressed general satisfaction with the *status quo*, comments tended to focus on specific modifications, such as decoupling for weather or setting customer charges equal to fixed costs per customer. For the electricity sector, stakeholder preferences ranged from those expressing comfort with the *status quo* to those who favoured the introduction of either true-ups or SFV pricing. Reasons mentioned in support of the true-up approach included the ability to compensate for the impact on revenue recovery of all forms of energy conservation; to maintain essential rate design characteristics; and to facilitate rate design experimentation. Arguments in favour of SFV pricing (including 'designer' variants thereof) included greater bill stability relative to true-ups; consistency with the principle of cost causality; more

transparent conservation incentives; and greater administrative efficiency relative to true-up administration.

- *Inter/Intra Sector Considerations* – Stakeholder comments on SFV pricing and true-up options, considered together, equally suggest that choices about the most suitable approach; design details; and related implementation process are closely related. Moreover, stakeholders are concerned that options be considered in view of the business, policy and regulatory context of each sector, recognizing the potential constraints posed by the number, size and circumstances of companies. Stakeholders variously articulated the view that a common approach may be neither necessary nor practical given differences in: the number of companies and extent of current RD; types of metering data available; sources and magnitudes of revenue risk (including differences in CDM vs. DSM mandates and opportunities); appetites for potential ROE vs. RD trade-offs; and capacity for forecasting sophistication (including weather normalization).

Conclusions & Next Steps

As noted in the introduction, the Board's October letter directs that work on this revenue decoupling initiative should not proceed further until other projects are substantially completed. In view of the foregoing discussion, staff believes that the matters raised by stakeholders as noted in their written comments can be revisited at the appropriate time in one or another ongoing or prospective Board initiative.

Natural gas distribution

The need for adjustments or incremental additions to existing regulatory arrangements for GDx is not perceived as urgent. Potential regulatory cost savings from dropping LRAM depend on whether SSM – which shares the same administrative basis as LRAM – is also to be eliminated from the DSM framework. This matter is best considered in the context of the currently ongoing DSM Guidelines for Natural Gas Distributors (EB-2008-0346) consultation.

The question of decoupling for weather in the GDx context, including potential ROE adjustments, is sufficiently complex that it could best be considered for inclusion in the context of the next gas IRM review process.

Electricity distribution

LRAM can compensate EDx for CDM-related lost revenue, thereby removing the disincentive to their participation in CDM programs. Moreover, the SSM incentive to pursue CDM aggressively has been reinforced under the new CDM framework by the potential to earn rewards linked to performance against targets. The corresponding potential for larger claims may enhance the cost-effectiveness of LRAM applications, the cost of which will be lowered by the fact that much of the information needed to file a claim will be produced in the process of tracking, evaluating and reporting on CDM performance.

Given the possibilities for and stakeholder interest in the application of advanced metering information to rate design, this matter could be considered in advance of the Board's next electricity rate design consultation. The Board's next electricity IRM framework review could also be informed by the results of this investigation; experience with the new CDM regime; and the information and stakeholder views garnered in the present consultation..

1 Introduction

1.1 Background, Purpose & Objectives

Ontario electricity (EDx) and natural gas (GDx) distributors use a combination of customer and usage charges to recover their Board-approved forecast costs or ‘revenue requirement’ (see Figure 1) from customers.

Figure 1

Illustration of Distributor Residential Customer & Usage Charges

Natural Gas	Rate	Usage	Charge	Amount
Customer Charge	$18.50/mo	--	18.50	18.50
Usage Charge				
Up to 50 m3	$0.0570/m3	50 m3	$2.85	
next 100 m3	$0.0520/m3	100 m3	$5.20	
over 150 m3	$0.0490/m3	100 m3	$4.90	
Total Usage		250 m3	$12.95	12.95
	Total Distribution Charges			$31.45

Electricity	Rate	Usage	Charge	Amount
Customer Charge	$18.50/mo	--	$18.50	18.50
Usage Charge	$0.0175/kWh	740 kWh	$12.95	12.95
	Total Distribution Charges			$31.45

Note: Charges shown are for illustration only. The 'Delivery Charge' can include transmission charges, rate riders, and other adjustments. Only the distributor's Customer and Usage Charges would be subject to RD.

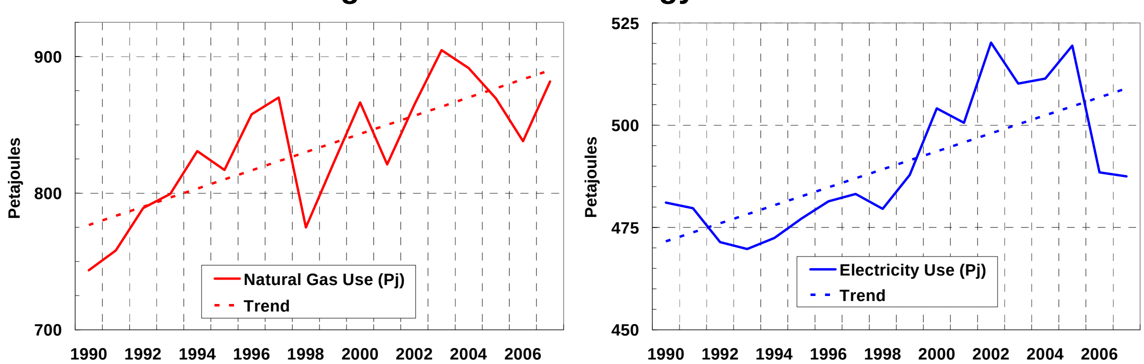
Source: Ontario Energy Board

The revenue requirement includes costs that do not vary with energy ‘throughput’ or volumes sold (“fixed costs”) and those that do (“variable costs”). In theory, variable costs would be recovered through a ‘usage charge’ ($/m^3; $/kW; $/kWh), so that revenue would rise and fall in lock step with incremental costs. Fixed costs would be recovered through the ‘customer charge’ ($/customer or $/connection), so that revenue would adjust with changes in the number of customers. In practice, fixed costs account for a much larger proportion of total costs for GDx and EDx than costs that vary with volumes sold, so distributors' rate designs typically recover a certain amount of fixed costs through usage charges.

In this way a distributor's *actual* revenues are 'coupled' to the number of customers through the customer charge and to energy sales volumes through usage charges. It follows that, depending on the accuracy of the distributor's customer and energy sales forecasts underpinning the revenue requirement and used to calculate rate levels, actual revenues may differ from the revenue requirement.[3]

A distributor's revenues are said to be 'decoupled' if provisions are in place to reduce or eliminate the difference between actual receipts and the revenue requirement. Such provisions are referred to here as revenue decoupling (RD) mechanisms.

Figure 2 - Ontario Energy Use Trends



Source: Natural Resources Canada; Office of Energy Efficiency

As illustrated in Figure 2, while overall total[4] natural gas and electricity use in Ontario have trended generally upward over many years, there are indications that this may be shifting, especially for the electricity sector. Several related factors can, over the long term, exert downward pressure on the quantities consumed through distribution services that, despite the counterbalancing effect of rising customer numbers, can

3 Distributors may respond to revenue shortfalls through some combination of discretionary cost adjustments, applying for new rates based on a revised forecast, or absorbing the loss by lowering shareholder returns.

4 Figure 2 includes gas and electricity purchased through wholesalers and distributors, and self-generation where applicable. Data are not weather normalized.

result in distributor revenue recovery falling short of the approved revenue requirement:[5]

- technological innovation that results in increased end-use equipment efficiency and higher penetration of customer 'own use' generation installations;
- the adoption of increasingly stringent energy efficiency standards in building materials and components; and
- the promotion by all levels of government and non-governmental organizations of energy conservation and end-use efficiency.

In addition to these factors affecting long term trends, short run variations in overall and customer average system use can occur due to changes in weather, the business cycle, or energy commodity prices – factors over which distributors have little or no influence.[6]

Generally, where RD mechanisms are used, the impetus has been either to insure the recovery of distributor fixed costs against observed or prospective declines in AU; and/or to neutralize the disincentive for utility participation in initiatives aiming to encourage the efficient use of energy.

The respective regulatory frameworks under which Ontario EDx and GDx recover their revenue requirement incorporate a number of elements designed to reduce distributor exposure to potential revenue recovery deficits due to unpredicted changes in the volume of energy sold. These include a 'lost revenue adjustment mechanism' (LRAM) and (for gas only) an average use (AU) adjustment and true-up process for smaller volume per customer rate classes.

To evaluate the effectiveness of these mechanisms against selected alternative approaches to RD used elsewhere, Board staff retained Pacific Economics Group Research ("PEG"). PEG's report – Review of Distribution Revenue Decoupling

[5] The PEG report (pp. 11 – 12) explains the concept of average use (AU) and the role it plays in the relationship between rates and unit costs.

[6] Note that some volume-based revenue drivers (e.g. weather) are effectively neutral (with respect to volumes but not necessarily actual dollar amounts) over the longer term, such that losses/gains eventually balance to a large extent. Others (e.g. technology related energy efficiency improvements and new energy uses) may have persistent positive or negative effects.

Mechanisms (the "PEG report") – was posted for written comment on March 22, 2010 along with a Cover Letter (cover letter) announcing the initiation of this consultation on Distribution Revenue Decoupling.

As stated in the cover letter, the objective of the consultation and by extension, of this *Report to the Board* is to "enable the Board to confirm whether these mechanisms remain adequate and sufficient under current conditions." Such current conditions include provisions of the *Green Energy and Green Economy Act, 2009* (GEA), as well as amendments made by the GEA to the *Ontario Energy Board Act, 1998* (the Act) whereby electricity distributors are required to achieve conservation and demand management targets "as part of an overall policy of promoting and expanding energy conservation by all consumers."[7]

This staff report summarizes and evaluates information provided in the PEG report and in written comments received from stakeholders, framed according to a set of questions on matters of interest to staff as provided in the cover letter as follows:

1. In light of developments in metering, CDM and demand side management ("DSM"), among possible others, is the implementation of further or modified revenue decoupling mechanisms for electricity and/or gas distributors warranted at this time and if so, why?
2. What factors should be considered when assessing the suitability of Ontario's current mechanisms and of alternative approaches? Are any of these factors more or less important than others? If so, why?
3. What, if any, are the implications of the wide-spread deployment of smart meters for the Board's approach to revenue decoupling?
4. What scope for further or modified revenue decoupling might be appropriate? For example, should the impact of all variances from forecast in commodity demand be eliminated regardless of the cause (i.e., distributor-provided CDM/DSM programs, other CDM/DSM programs, the economy, weather, customer growth, etc.)? Why or why not?

[7] In accordance with the Directive, the Board is required to amend certain electricity distributors' licences to include a requirement to achieve reductions in electricity consumption and reductions in peak provincial electricity demand by the amounts specified by the Board, through the delivery of CDM programs, over a four year period beginning January 1, 2011.

5. Are there any alternative approaches, beyond those identified in the PEG Report, which better address revenue erosion due to changes in consumption? What are the costs, benefits and implications of implementing the alternative approach?
6. Is there a preferred approach (or elements of an approach) and if so, what are the important implementation matters that must be considered? What are the costs, benefits and implications of implementing the preferred approach or of refraining from doing so?
7. Can or should the preferred approach be the same in both the gas sector and the electricity sector? Why or why not? Would any other form of differentiation based, for example, on a specific distributor characteristic(s) be appropriate? If so, what might be the defining characteristic(s)?

1.2 Role of the Board

In carrying out its responsibilities in the electricity and natural gas sectors, the Board is guided by the objectives that are set out in the Act in sections 1(1) and 2 respectively. The objectives for both sectors include the protection of the interests of consumers[8] and the maintenance of the financial viability of the sector.[9]

The GEA amended the Act by adding new Board objectives for both sectors in relation to the promotion of energy conservation in line with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.[10] A related amendment identifies the Board as responsible for implementing government Directives for the establishment of CDM targets to be met by electricity distributors.[11] A Directive to this effect (the Directive) was issued in March 2010 (after the PEG report was posted and a stakeholder meeting was held to discuss the report's content).[12]

These new additions to the Board's mandate build upon its ongoing role in CDM/DSM activities by distributors through the review and approval of spending

[8] The Act; section 1(1)1 and section 2.2.
[9] The Act; section 1(1)2 and section 2.5.1.
[10] The Act; section 1(1)3 and section 2.5.
[11] And other licensees. The Act, section 27.2.
[12] To the extent that the Directive could affect natural gas consumption through inter-fuel substitution ("fuel switching"), natural gas distributors' volume throughput could be affected (positively) as well.

levels and proposed programs, reporting guidelines, program evaluation, and the review and approval of applications for recovery of the Lost Revenue Adjustment Mechanism ("LRAM") and the Shared Savings Mechanism ("SSM"). In relation to electricity distributors, the Board also reviews and approves claims for LRAM recovery associated with distributor CDM activities that are funded by the Ontario Power Authority (the "OPA").[13]

1.3 Regulatory Principles & Policies

Some of the issues highlighted in the PEG report and/or by stakeholders in their comments either on RD in general, or on the 'SFV pricing' and 'true-up' approaches thereto invoke rate design concepts, principles and policies. A brief review is therefore warranted.

1.3.1 Cost causality & cost allocation

A distributor's expected annual cost of providing service (or 'revenue requirement') must be divided amongst customer classes for the purpose of recovery through rates. The principle of cost causality, which assigns to each customer class a share of the revenue requirement proportionate to the costs incurred by the distributor on behalf of that class, provides the starting point for this analysis.[14]

Where, as is often the case, distributor costs are incurred that benefit more than one class or customers in general, they must be shared. Consequently, cost allocation policies can be used as a guide to implementing the cost causality principle. In this way, the cost of providing service is reasonably allocated among the various customer classes.[15] The appropriate relationship to be achieved between the revenue recovered from a given rate class and the share of total costs allocated to

[13] *Guidelines for Electricity Distributor Conservation and Demand Management*; March 2008 (OEB 2008); p. 1. Analogous Guidelines for GDx are currently the subject of a Board consultation (EB-2008-0346); the Board established rules for DSM programs in its *Decision with Reasons* (EB-2006-0021) August 2006 (OEB 2006).

[14] See *Report of the Board - Application of Cost Allocation for Electricity Distributors* (EB-2007-0667); November 28, 2007 (OEB 2007); p. 2.

[15] The Board's *Filing Requirements for Transmission and Distribution Applications* (Chapter 2; June 28, 2010) provide for the filing of a completed cost allocation study based on updated forecast year data.

that class (the "revenue-to-cost ratio") may be reviewed and revised from time to time.[16]

1.3.2 Rate fairness

Once the respective shares of the revenue requirement to be recovered from each rate class have been determined, distribution rate design seeks to recover this sum from individual customers within each rate class in a 'just and reasonable' manner.[17] This concept can include the notion of 'fairness', which may be gauged in different, perhaps conflicting ways.

Cost causality is one basis for reckoning fairness. It can be used to guide the design of rates so as to recover from individual customers within a rate class the share of costs allocated to that class incurred by the distributor on their behalf. Some costs, like certain metering, billing and collections costs, can be shown to be shared equally among individual customers and therefore amenable to a rate class-wide fixed charge. Others, such as physical capacity related costs, are perhaps best allocated according to proportionate use. However, measurement limitations may result in usage rates that only reasonably approximate individual contributions to collective costs. In assessments of fairness then, a degree of judgement is often required.

1.3.3 Rate stability and gradualism

Stable rates cannot be guaranteed, but stability – in terms of speed and direction of change – is preferred. On this basis, constructing rates in a manner that makes them liable to counter directional changes is to be avoided where possible because this confuses customers, makes energy cost planning difficult and can undermine customer confidence in the rate making process.[18] Moreover, any given rate change should consider the ability of consumers to react to their new costs.[19]

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[16] The results of the most recent review are found in OEB 2007. The commencement of the most recent cost allocation policy review process (EB-2010-0219) was announced in September 2010.

[17] The Act; section 78(3).

[18] OEB 2007; p. 6.

[19] OEB 2007: pp. 6 – 7. For a more detailed discussion of short term rate impacts see *Final Report of the Board* (EBO-188); January 30, 1998; pp. 9 – 16.

The counterpart of rate stability is revenue stability, which is desirable from the distributor's perspective for much the same reasons as rate stability is for customers: unexpected changes can have serious adverse effects.[20]

1.3.4 Risk

Risk is a source of cost the responsibility for which may be borne by distributor shareholders, customers or both. Where assigned under a regulatory framework, the basis of the assignment may be a determination as to which party "causes" the cost (i.e. source of risk) and/or which party is best able to manage it.

Note that if not purposely assigned through rate design, risk related costs default to one or, in some degree both parties. Short run weather risk, for example, is by default shared by customers and shareholders in that both customer bills and shareholder returns can be adversely affected by weather fluctuations.

Since the objective is a rate structure that matches expected costs with expected revenues, the aggregate cost of all risks assigned (including by default) to utility shareholders is reflected in the Board's approved maximum allowed rate of return on equity (ROE), which in turn is incorporated into the revenue requirement and recovered in rates. The methodology the Board uses to set the ROE involves multiple tests rather than aggregating measured exposure to specific sources of risk.[21]

1.4 Outline

Sections 2 and 3 provide, respectively, a brief explanation of what RD is and the purposes for which it is intended; and a summary overview of the elements of Ontario's existing regulatory framework that, as noted above, reduce distributor exposure to unpredicted changes in the volume of energy sold. Section 4 reviews stakeholder written comments and provides staff views on key themes, points of stakeholder consensus and divergence and the issues raised thereby. Section 5 provides a concluding summary and staff suggestions as to next steps.

[20] See Bonbright, J.C. *et al*.; *Principles of Public Utility Rates*; Public Utilities Reports Inc.; 1988; pp. 382 – 389.

[21] See *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084); December 11, 2009; p. 36 and *passim*.

2 Revenue Decoupling Basics

As noted in section 1, Board staff engaged Pacific Economics Group Research (PEG) to prepare a report describing and explaining the different approaches to and jurisdictional experience with various forms of RD. The report was also to compare these approaches to the existing Ontario framework under which distributors establish and recover their revenue requirement with a view to highlighting the relative merits of the alternatives in the Ontario context. This section summarizes and highlights key portions of the PEG report.[22]

2.1 Why Revenue Decoupling?

The PEG report defines RD as regulatory provisions that are expressly designed to relax the link between the recovery of a distributor's non-energy input costs and customer use of the distributor's system.[23] The impetus for RD can come primarily from any or all of three main drivers, each of which is addressed to varying degrees by the three primary approaches to RD (see section 2.2).

Two drivers relate to the exposure of distributor shareholders to potential 'earnings attrition'[24] associated with the accuracy of forecast customer numbers and energy sales volumes that form the basis of the 'test year' revenue requirement included in a cost of service (COS) rate application. The third driver relates to the inherent and practical (context-based) efficiency of the regulatory processes used to set, and where multi-year ratemaking is used, periodically adjust rates.

2.1.1 Neutralizing a disincentive to promoting CDM/DSM

As described in the PEG report, there is a disincentive for utilities to do their part to promote CDM/DSM goals. This is because CDM/DSM initiatives encourage customers to reduce their use of distribution systems, which reduces distributor earnings by slowing AU growth. All three of the generic approaches to RD

[22] The views expressed in this report are those of staff, and unless specifically indicated are not intended to represent the views expressed in the PEG report. The PEG report should be relied upon in the event of any perceived discrepancy between the summary information provided here and the PEG report.

[23] PEG 2010; pp. 3 – 4.

[24] The PEG report defines earnings attrition in context as "attrition in the earnings that utilities use to compensate holders of their debt and equity"; p. 3.

described in section 2.2 can remove this disincentive, but none provide incentives to distributor CDM/DSM promotion.[25]

2.1.2 Managing potential earnings attrition

A distributor's risk of 'earnings attrition' between rate cases stems from two general sources: factors that affect the cost of doing business (e.g. input costs/prices; taxes) and – the focus of RD – market demand factors that affect sales revenues (e.g. energy prices, customer numbers, the quantity and efficiency of energy-using products). According to the PEG report, fluctuations in the latter are difficult to predict accurately (when rebasing in a COS rate case) and can be an important source of earnings risk to the extent that the revenue requirement is recovered through usage charges rather than fixed charges.[26]

Although this rationale for RD applies where AU growth is slowing, the PEG report notes that the need for earnings attrition relief is greatest when AU between rate cases in residential and small commercial rate classes is declining.[27]

2.1.3 Enhancing regulatory efficiency

Regardless of the root cause, where earnings may be undermined through unforeseen declines in revenues or cost increases for that matter, a distributor may seek relief through a COS rate case. The PEG report suggests that especially where a large number of companies are regulated such as in Ontario's EDx sector, RD may reduce the frequency of rebasing by ameliorating deficient revenue recovery between rate cases. Moreover, reducing the importance of load forecasts and of CDM/DSM impact estimates for regulatory purposes may increase the efficiency of regulatory proceedings involving these inputs.[28]

2.2 Generic RD Approaches

Where jurisdictions have approved RD arrangements, they have been adopted by utilities in the gas or electricity sectors, and sometimes both.[29] Three main generic

[25] PEG 2010; p. 14; p. 15 lists ways distributors can promote CDM/DSM goals.
[26] PEG 2010; p. 14.
[27] PEG 2010; p. 17.
[28] PEG 2010; pp. 18 – 19.
[29] PEG 2010: pp. 34 – 36; 41 – 42.

approaches to RD are introduced in the PEG report: lost revenue adjustment mechanisms (LRAMs); decoupling true-up plans (true-ups); and straight fixed variable (SFV) pricing.

2.2.1 Lost revenue adjustment mechanisms

LRAMs are explicitly designed to compensate distributors for 'lost revenue' estimated to result from the distributor's energy efficiency programs.[30] As is the case in Ontario, approved LRAM amounts are typically recovered via a usage-based ($/kWh or $/m3) "rate rider" on customer bills in rate classes targeted by CDM programs. Unforeseen fluctuations in other market demand drivers are not covered by LRAMs. Information in the PEG report suggests that about eight jurisdictions outside Ontario use LRAMs; five of which use them for gas, of which four also use true-up plans (see below).[31]

2.2.2 Decoupling true-up plans[32]

This RD variant has been used at one time or another in about 30 jurisdictions by over 70 utilities, both gas and electric.[33] Under the true-up approach, rates set through a COS rate case are adjusted (up or down) at prescribed intervals if it is determined that actual revenues from distribution charges do not match the approved revenue requirement.[34]

'Full' true-ups include, by definition, all potential sources of market demand variations from forecast (e.g. the effects of CDM/DSM programs; all other causes of conservation; loss of customers; etc.). 'Partial' true-ups, on the other hand, exclude from the true-up and therefore leave distributors exposed to specific factors that influence market demand. For example, the influence of weather on sales volumes

[30] PEG 2010; p. 4. In Ontario, a shared savings mechanism (SSM) provides an incentive by allowing the recovery from customers of an additional 5% of the estimated value of a distributor's lost revenues as the distributor's "share" of customer savings. LRAM is described in section 3.1.

[31] PEG 2010; p. 42.

[32] The description of decoupling true-up plans (hereafter, "true-ups") in the PEG report distinguishes between 'revenue decoupling mechanisms' (the subject of this section 2.2) and revenue adjustment mechanisms (RAMs), which are typically designed to adjust rates for estimated changes in the revenue requirement (i.e. costs) between rebasings. See PEG 2010; p. 4.

[33] PEG 2010; Total excludes national jurisdictions and transmitters. See Table 1; pp. 34 – 36.

[34] PEG 2010; p. 5. It is noted that unlike SFV pricing (described below), the true-up approach does not define, restrict or otherwise require alterations to existing rate designs.

can be excluded from the true-up by tracking revenues on a 'weather normalized' rather than actual basis. True-ups can be applied to rate classes selectively, or on a combined basis.

True-ups usually involve the use of a variance account – similar to those used in Ontario for other purposes – to track differences between actual revenue and the approved revenue requirement. Variance account balances passed on to customers (e.g. through a rate rider) can be 'capped' so as to moderate the rate changes over a given period. A 'soft cap' allows the distributor to defer the recovery of the account balance to a subsequent period; a 'hard cap' does not; a 'dead band' prevents rate adjustments where RD variance account balances are deemed too small.

Rate volatility associated with true-ups has been recognized by regulators as a potential problem.[35] The PEG report mentions jurisdictions where true-up plans were abandoned (in favour of SFV pricing in one case) due at least in part to rate adjustment issues.[36] Data included in the PEG report indicate that not all utilities for which true-ups have been approved in the past still use them today; nor have all utilities currently employing true-ups done so on an uninterrupted basis since first adopting them.[37] The report also notes that of the 27 U.S. jurisdictions that have approved the use of true-up plans for at least one utility, 8 have approved other such plans while 4 have not.[38]

2.2.3 Straight fixed variable pricing

Information provided in the PEG report indicates that SFV pricing was first approved in the U.S. in 1999 and since then has been adopted and used continuously in five states by a total of 10 gas distributors.[39] Under this rate design, non-energy input costs that vary in the short run with system use (i.e. peak demand; volume) are recovered from usage charges; other (fixed) costs are recovered through customer

[35] PEG 2010; p. 28.
[36] See PEG 2010; pp. 33; 37; 57 – 60; 62 – 65.
[37] See PEG 2010; pp. 34 – 36 (Table 1) for details.
[38] PEG 2010; p. 39 and Table 1. PEG notes that some distributor true-up proposals have been rejected; see p. 39 (fn 54).
[39] PEG 2010; Table 2, p. 41. One gas distributor using SFV pricing, Duke Energy Ohio, also distributes electricity under an LRAM framework. See PEG 2010; p. 42.

charges. In practice, the PEG report notes, usage charges are eliminated in favour of customer charges.[40]

As a result, revenue recovery adjusts automatically to the pace of customer growth, and is little affected by declining average use (DAU) due to CDM/DSM or external business conditions. Therefore, like true-up plans, SFV pricing eliminates disincentives to participate in CDM/DSM programs.[41] Relative to LRAMs and true-up plans, SFV pricing has the lowest administrative cost, which PEG notes can be advantageous in jurisdictions with many utilities.[42]

SFV pricing can raise a number of issues.[43] Since customer charges can be the same for all customers in a rate class, rate fairness can be questioned; where rates do not vary with use, customer bills cannot be reduced by consuming less which may have implications for customer incentives to conserve. Moreover, if during the transition to SFV pricing low volume customers are required to absorb a large bill increase over a short period, rate gradualism concerns could arise. The PEG report describes a number of methods whereby these concerns can be ameliorated; including the use of smart meter (SM) enabled demand charges.

[40] PEG 2010; p. 10.
[41] PEG 2010; p. v; and p. 10.
[42] PEG 2010; p. iv.
[43] PEG 2010; p. 28 – 29.

3 Current Regulatory Framework

Section 2 notes that distributor earnings risks fall into two general categories: those that affect costs and those that affect revenue. There are elements in Ontario's respective GDx and EDx regulatory arrangements (including IRM mechanisms) that mitigate distributor risk related to factors affecting *costs* that are either outside utility control or are otherwise unforeseeable (e.g. access to "Z" factor adjustments).

The key elements of the current regulatory arrangements used in Ontario that respond to factors related to *revenues* are listed in Table 1 and discussed in turn below. All of these elements are shared by EDx and GDx with one exception, as noted. There may, however, be variations between the sectors and among distributors within a sector in terms of the degree to which a given element is typically utilized.

Table 1 - Existing RD elements available to distributors

Element	Electricity	Natural Gas
LRAM recovers revenue lost due to CDM/DSM programs	√	√
Forward test year (i.e. forecast) rate rebasing	√	√
IRM 'off ramp' (early rebasing)	√	√
Use of substantial fixed charges for low volume customers	√	√
Partial (weather normalized) average use adjustments	-	√

Source: OEB

3.1 LRAM[44]

Distributors may make an LRAM application to recover or return the difference between revenues collected and revenues anticipated in rates that result from the CDM/DSM programs they implement.[45] In essence, LRAM is a means of addressing unforeseen declines in sales volumes resulting from the distributor's successful implementation of conservation measures through authorized programs

[44] A companion 'shared savings mechanism' (SSM) provides an *incentive* to participate in CDM/DSM by allowing an additional portion of LRAM losses to be recovered as the distributor's "share" of customer savings.

[45] LRAM was available for GDx and EDx use in 1997 and 2005, respectively.

funded through distributor rates in the case of GDx, or through distribution rates or the OPA in the case of EDx.[46]

EDx can apply for LRAM at any time, while GDx apply once a year.[47] LRAM claim amounts are determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved usage charge for the applicable rate class. Lost revenues are accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, at which time revised sales volumes by customer class are assumed to be incorporated in the load forecast.[48]

The LRAM application process is one element of the overall CDM/DSM structure, which also includes the preparation and submission of a CDM/DSM plan including budget, program evaluation plan and annual reports. Costs specific to the process of applying for LRAM (a 'Shared Savings Mechanism' application is usually made simultaneously) relate to engaging 3rd parties to evaluate OPA-funded programs in the case of EDx; and engaging a 3rd party to review the distributor's own evaluation of rates-funded programs.

3.2 Forward test year

A forward test year is the first year (aka the 'base year') in which a distributor's proposed new rates would be applicable after having been approved by the Board. The use of forward test years can reduce distributor exposure to declining sales volumes (due to CDM/DSM or economic factors) by allowing sales in the test year to be forecast. This typically involves predicting customer numbers and consumption per customer by rate class, and anticipating the effects of business conditions that affect distributor costs.

[46] Section 2.2.1 provides an explanation of how generic LRAMs work. LRAM application requirements for EDx and GDx are detailed in OEB 2008 and OEB 2006, respectively.

[47] The Board has expressed a preference in the EDx context that LRAM/SSM applications be included in COS proceedings (i.e. once in the IRM cycle).

[48] In its September 10, 2010 cover letter announcing the release of its '*Conservation and Demand Management Code for Electricity Distributors*', the Board stated that "The precise mechanism to handle lost revenues incurred by CDM Programs will be developed and communicated to distributors in the future." In the meantime, the approach referred to here applies.

3.3 IRM Off-ramp

To the extent that forecasts of customer numbers and sales volumes (i.e. AU) embedded in forward test years are accurate, the need for RD may be reduced. While this may be true for the test year – the first year of the four (EDx) or five (GDx) year IRM rate-setting cycle – beyond that the accuracy of the forecast may diminish.

If, during the IRM period the gap between revenue recoveries and revenue requirement becomes sufficiently problematic to affect earnings outcomes, distributors can apply for access to the IRM “off-ramp”. The threshold for reviewing of the terms of the distributor’s rate plan with a view to early rebasing is earnings 300 basis points (3%) below the allowed maximum ROE. Note, however, that the off-ramp module can also be triggered at the Board’s discretion if earnings exceed the ROE maximum by the same amount. Thus, the off-ramp is designed to protect both ratepayers and shareholders from respectively, exceptionally high or low earnings outcomes.

3.4 Fixed customer charges

Section 1 noted that a combination of fixed customer charges and variable usage charges are used for billing purposes for both GDx and EDx. While in theory the fixed/variable split reflects their respective category of underlying costs, in practice there is a certain amount of variability across distributors and rate classes in terms of the proportions of total revenue recovered through each type of charge. Generally, the greater the share of the revenue requirement allocated to a given rate class that is recovered using fixed customer charges, the less effect sales volume variability will have on overall revenue recovery for that rate class.

3.5 Average Use adjustments

The IRM mechanisms used by Enbridge and Union both include provisions whereby rates (indirectly in the case of Enbridge) are adjusted to account for changes in average use in general service (i.e. residential and small commercial) rate classes. In each year during the IRM period, Union adjusts the m^3 sales volume number based on the average (weather normalized) use per customer calculated over the preceding three years. Enbridge adjusts both the number of customers and use per customer amounts used to set rates according to an econometric forecast of these values. In addition, both companies track revenue variances resulting from differences between forecast and actual (weather normalized) revenue (Enbridge) or use (Union) per customer in variance accounts. Account balances are cleared through rate adjustments in the following year.

4 Comments

The purpose of this section is to summarize the views provided by stakeholders in written comments and highlight key themes, issues, and points of consensus or divergence. For convenience, this section consists of seven sections, each corresponding to one of the seven questions posed for stakeholder written comment in the cover letter (see section 1.1).[49]

4.1 Is Further Revenue Decoupling Needed?

As noted in section 2.1, the PEG report highlights three main RD drivers: managing revenue recovery risk; neutralizing the disincentive to distributor participation in CDM/DSM; and enhancing regulatory efficiency.[50] The report concludes with an appraisal of each sector as to its respective need for incremental RD. The highlights of these appraisals are presented below for natural gas and electricity in that order, with related stakeholder views organized according to the three RD drivers noted.

4.1.1 Natural gas

As far as the GDx sector is concerned, the PEG report proposed that while "current decoupling arrangements are reasonable" under existing conditions, two "small refinements" could be considered in the context of the next incentive regulation review process:[51]

1) eliminate LRAM payments to enhance regulatory efficiency, albeit modestly since the calculations would still be required for other regulatory purposes; and
2) decouple for weather risk to
    - improve regulatory efficiency by reducing the role of weather normalization calculations in AU accounting;
    - promote DSM goals by facilitating rate designs that emphasize volumetric charges over fixed charges;[52] and

[49] Stakeholder comments are reported under the subheading deemed appropriate.
[50] See PEG 2010; pp. 14 – 20.
[51] PEG 2010; p. 92.
[52] The PEG report explains (in the EDx context) that "Partial true ups reduce but do not fully remove the disincentive for rate design experimentation because distributors would still be vulnerable to weather-related demand fluctuations". See PEG 2010; p. 114.

- create cost savings through operating risk reductions that can be shared with customers.[53]

A. Revenue Risk

Stakeholder comments

Consistent with PEG's overall appraisal, several stakeholders commented that additional RD on the gas side is either not needed or at least not urgently because GDx are already sufficiently decoupled and/or the evidence at this time does not justify it. Some stakeholders added that in any event, the need for and means of incremental RD would be best addressed in detail, either by way of a distributor's COS application, or in the broader context of a review of the gas IRM framework.[54]

GDx indicated that they are relatively sanguine about current arrangements as applied specifically to them, noting that processes are in place whereby revenue risks beyond that posed by persistent declines in AU can be reviewed as and when needed. Union commented that it reserved the right to apply for further decoupling when rebasing in 2013, highlighting concerns about declining volumes more generally, including in rate classes that are not decoupled at present. Enbridge noted that while not needed at this time, changing circumstances such as a decline in space heating demand due to increased use of heat from renewable sources could necessitate a future review of decoupling arrangements.

Some stakeholders expressed agreement that GDx (and EDx if also decoupled) should be relieved of weather risk – that is, for rate classes subject to the AU adjustment – citing rationales that aligned with the potential efficiency or rate design facilitation benefits of decoupling for weather risk mentioned above. Enbridge commented at length in relation to the potential operating cost savings that could result from decoupling for this risk, arguing in part that RD adopted in response to conditions of increased revenue risk will not result in a net reduction in the overall risk profile of a utility.

[53] PEG 2010; p. 93.

[54] Given the different AU methodologies currently in use (see section 3.5), the latter venue should be favoured if harmonizing the two approaches is a priority.

Staff comment

Referring to the consultation objective as indicated in the cover letter, there appears to staff to be a general consensus that existing RD mechanisms for GDx are indeed "adequate and sufficient under current conditions". This view is reinforced by stakeholder comments on LRAM (see 'DSM disincentive' below).

B. DSM disincentive

Stakeholder comments

Some stakeholder comments offered that LRAM does adequately compensate for revenue losses due to DSM. Others, noting that LRAM is not designed to compensate for the effects of broadly defined conservation (i.e. DAU) suggested that combined with an AU tracking account there is no disincentive to the promotion of conservation.

Conservation by customers who are not now subject to an AU true-up mechanism is of concern to several stakeholders. Some expressed a willingness to accept proposals to apply the AU adjustment approach to other customer classes on the presumption (for some, on the condition) that doing so would facilitate further customer conservation. Others were less permissive; one allowing that RD should be extended to other rate classes if and when DAU became a problem.

Staff comment

As noted earlier, these different perspectives highlight the concept of distinguishing, as drivers of RD, between removing obstacles to energy conservation, and assigning all sources of revenue risk to customers. RD using true-ups or SFV pricing adopted to compensate distributors for the effects of customer decisions to conserve will, unless explicitly designed otherwise, also protect against the effects of every other factor that influences revenue recovery.

C. Efficiency gains

Stakeholder comments

Stakeholders who commented on this were generally of the view that the actual regulatory cost savings from eliminating LRAM would be immaterial if the use of SSM – which is an incentive for GDx to participate in DSM programs – is retained. The potential efficiency gains accruing from decoupling for weather risk was another matter: stakeholders commenting on weather risk and weather normalization noted that regulatory proceedings are made more complicated and hence more costly by the complexity of these matters. However, some stakeholders, including distributors offered that since weather normalization is used for a variety of business planning purposes relevant to regulatory processes, efficiency gains from dropping it for AU calculation purposes (only) would be minimal.

Staff comment

Simplifying AU calculations by standardizing or eliminating the normalization step could very well enhance transparency, improve process efficiency and reduce related regulatory costs; simpler calculations are easier to understand and independently verify. Staff accepts, however, that such gains would be limited to the extent that as noted above, data normalization may continue to be used for other regulatory purposes (e.g. rate applications). Against this limited benefit must be weighed the inevitability of increased weather-related rate volatility the effects of which, for decoupled rate classes, would be borne exclusively by customers.

4.1.2 Electricity

The PEG report suggests that average use among residential customers appears to be declining materially and that "changes in Ontario CDM policies are apt to cause these conditions to continue or intensify".[55] While the existing revenue recovery framework for EDx, including LRAM, provides "considerable relief" from the potential impact of DAU, PEG's view is that LRAM could be replaced with a broader form of RD (partial or full true-up; or SFV pricing) that would "make more sense" all things considered.[56] Among the benefits of doing so would be reduced administrative

[55] PEG 2010; p. 110.
[56] PEG 2010; pp. 110 - 111.

costs; the removal of disincentives to a wider range of distributor CDM efforts; and "more complete relief from earnings attrition between rate cases."[57]

A. Revenue Risk

Stakeholder comments

Two consumer group stakeholders commented that, based on the evidence provided in the PEG report, major changes to the regulatory framework were not warranted at this time despite, one observed, recent sector developments like smart meters and the CDM Directive.

Several written comments noted that given the relatively short duration of the sector-wide data sample (2002 – 2008), and the fact that the data were not normalized to remove the influence of weather, conclusions about sector-wide trends in AU are difficult to draw. Others, including some distributor stakeholders, commented that in any event, AU trends for the sector as a whole may not be representative of each electricity distributor's situation, some arguing that for this and other reasons reflecting differences among companies, the need for RD, and/or suitability of specific forms thereof might vary from one company to the next.

Two distributor stakeholders commented to the effect that load forecasts that account for the impact of various demand drivers, including the effects of CDM programs, can reduce the need for RD. Stakeholders also noted the potential exposure of utilities under IRM to load reductions between rebasings, arguing that one or another form of RD (see sections 4.5 and 4.6) could be adopted to address this.

Some stakeholders, including environmental stakeholders shared the view that additional RD is needed since LRAM alone will not provide distributor protection against unforeseen lost revenues due to consumer conservation not related to CDM programs; and that such protection is essential to ensure that electricity distributors are not discouraged from pursuing conservation beyond CDM programs.

[57] PEG 2010: p. 113.

Staff Comment

Stakeholder comments in relation to *timing* are noteworthy in terms of the degree of revenue risk facing distributors in general over the foreseeable future. Over the period to the end of 2014, estimated revenue shortfalls attributed to the effects of CDM participation will be recoverable through an LRAM application. Revenue risk beyond the impact of volumes attributed to CDM programs depends on declines in AU *beyond* the CDM targets to be achieved. Also noted are the PEG report's comments to the effect that, relative to their gas counterparts, electricity distributor revenues may be less affected by market – as distinct from policy-driven – improvements in end-use efficiency; and that gradual recovery from recession may offset efficiency related declines in AU for a period.[58]

These cross sector influences may not, of course, be felt equally by all distributors. Indeed, stakeholders have underlined the issue as to whether – or which form of – RD should be adopted on a sector-wide rather than individual company basis. SFV pricing, since it is a rate design, may only be applicable generically with individual variations among distributors only in terms of rate levels. True-ups may be more amenable to a case-by-case approach, but given the potential for rates to be adjusted in both directions under true-ups, the conditions around a distributor's discretion to opt in or out would have to be clear.

Any action based on the view that distributors should be protected from broadly defined "conservation" related revenue risk must consider that, as noted earlier, some forms of RD do not discriminate between causes of revenue variance. The consequences of say, CDM program success are indistinguishable from those resulting from customers switching from an electric stove to a gas range, or from customers simply reducing consumption in response to higher bill costs, budget constraints or both.

The policy issue raised (and addressed in greater detail in section 4.4) is whether and if so to what extent distributors should be exposed to potential 'earnings attrition' risk associated with the various drivers of market demand.

[58] PEG 2010; pp. 110 - 111.

B. CDM disincentive

Stakeholder comments

Most stakeholders took the view that *in principle* LRAM adequately compensates distributors for revenues lost due to CDM programs. Some – notably distributor stakeholders – emphasized that the current application process is highly complex and therefore not cost effective to use, especially for smaller companies. In short, in contrast to LRAM in the gas context, stakeholder comments suggest some degree of disincentive to CDM participation remains for EDx despite the availability of LRAM.

That said, a number of stakeholders focussed attention on the impact of the CDM Directive on the disincentive to EDx participation. Comments pointed out that the Directive (which was issued after the PEG report was posted) not only obligates EDx CDM participation in OPA and/or their own Board-approved programs; it also provides for performance-based incentives. Some stakeholders suggested that this combination of obligation and incentives effectively neutralizes any disincentive to distributor participation.

Staff comment

Obligating and incenting distributors to undertake OPA and/or their own Board-approved CDM programs should effectively nullify any disincentive to distributor participation in CDM. That said, obligating EDx participation in CDM does not guarantee EDx participation in LRAM.

However, as noted by stakeholders (see below) each utility's performance assessment against its CDM target will require much if not all of the information needed for an LRAM application, so once the former is complete, the incremental cost of applying for the latter should be significantly reduced. In addition, the incentive framework built into the CDM framework may enhance the potential benefit of filing an LRAM application by increasing the size of the volume reduction claimed. Finally, to the extent that CDM targets are integrated into load forecasts in COS applications and the targets are subsequently demonstrated to have been met, the need to seek compensation via LRAM may be reduced.

C. Efficiency gains

Stakeholder comments

As to the impetus for RD provided by the need for greater regulatory efficiency, stakeholders drew attention to the mitigating impact the cost of measuring CDM performance – necessary under the Directive – will have on the potential for efficiency gains by eliminating LRAM.

Responding to the PEG report's suggestion[59] that full decoupling would reduce the importance of volume forecasts used for rate rebasing, several stakeholders variously provided reasons why forecast accuracy would likely remain important even under a true-up approach:

- the less accurate the forecast, the greater the rate instability;
- unless the forecasts (and not just revenue variances) are revisited each true-up period, the disposition of the true-up variance account balances would reflect the original, incorrect forecast; and
- the forecast affects the working capital component of rate base.

Staff comment

The administrative cost savings of dropping LRAM in favour of any form of RD may not be material as long as distributor CDM performance is subject to detailed measurement and evaluation. In addition, as noted in the GDx context, savings might also depend on how the SSM is dealt with. On the practical side, eliminating LRAM in favour of a broader RD option might lower administrative costs, but given the number of EDx, overall changes in regulatory costs would depend on which option is adopted: relatively high cost true-ups or SFV pricing.

[59] PEG 2010; p. 114.

4.2 Considerations for Selecting an Overall Decoupling Approach

Stakeholder comments

Some stakeholders focussed on one or two factors, while others listed a number of issues and considerations to be weighed in the balance when choosing an appropriate approach. While some of the stakeholders who listed a number of factors indicated the ones they felt were most important, most did not. In summary form, the considerations mentioned by stakeholders are listed below.

1. Impact in relation to reflecting the principles (e.g. cost causality) and policies (e.g. cost allocation) of ratemaking
2. Impact on regulatory efficiency
3. Impact on consumers in general and rate stability in particular
4. Consistency with other elements (e.g. CDM/DSM; IRM) of the regulatory framework
5. Demonstrated need (e.g. neutralizing effects of CDM/DSM or other/all sources of DAU)
6. Impact on shareholder returns
7. Consistency with Board policy on the assignment of market risk
8. Cost effectiveness
9. Impact on obstacles to increased distributor-based conservation offerings
10. Impact on customer incentive to conserve

Staff comment

Some of the considerations listed above (5 – 7) apply more generally to the issues as to whether and to what extent revenue recovery risk should be mitigated. The other considerations are relevant to assessing the relative merits of the generic RD options and the detailed design thereof. Certain of these concerns, recast as ‘decision criteria’, may be fundamental. That is, an option (or element thereof) would be discarded if it cannot be configured so as to satisfy, or is inferior to other options in relation to the criterion. In sum, the number and variety of considerations stakeholders feel need to be addressed suggests that a multi-layered needs and options analysis process may be warranted.

4.3 Impact of Smart Meters

Stakeholder comments

Many written comments responded to this question in detail (see also section 4.5). Some stakeholders ventured that SMs could provide data useful for assessing the performance of CDM programs, including the impact of RD on customer behaviour.

Several stakeholders recognized the potential for smart meters (SMs) to provide data useful for rate classification and design by way of clarifying cost causality and cost allocation. LPMA, for example, commented that SM enabled demand charges would clarify cost causality at the individual consumer level within a rate class; while CME suggested that the use of SMs would allow for some level of decoupling by using rates linked to peak period usage. As outlined in section 4.5, two stakeholders suggested innovative approaches to RD based on SM functionality.

Several stakeholders warned that SM investments might be undercut by SFV-based RD, to the extent that the role of volumetric rates (which require metering) is diminished in favour of fixed rates. Several other written comments allowed that data collection and analysis over a period of years might be required before SM functionality could be used for ratemaking.

Staff comment

The Board has acknowledged the potential future role of smart meters in allocating costs for rate setting purposes.[60] This role needs to be fully understood in the context of Ontario's rapidly materializing 'smart grid' and may have important implications in relation to the need for and preferred manner of altering existing regulatory arrangements for EDx.

[60] See OEB 2007; p. 5.

4.4 Risks to be removed by decoupling

Stakeholder comments

Some stakeholders commented to the effect that the assignment of specific risks between ratepayers and distributor shareholders should be on the basis of which party is best able to manage the risk, or its consequences. One suggested, for example, that risks related to market factors should be borne by shareholders.

Some stakeholders from every quarter, however, commented that any risk associated with energy conservation should be addressed, but for different reasons. For example, some argued that disincentives to distributor involvement in conservation of any kind must be neutralized; while others – as noted above – felt that such risks are not within a distributor's ability to control.

A number of industry stakeholders from both sectors aligned on the view that since distribution costs vary little by volume sold, RD relief could conceivably be sought to neutralize any source of revenue recovery variation from forecast. However, as discussed in section 4.6, stakeholders differed as to the type of RD deemed best suited to achieving this objective.

Several stakeholders commented to the effect that extending the range of market risks covered by RD should precipitate a reconsideration of the allowed ROE and/or approved capital structure. Specific comments taking the customer perspective were also offered, identifying pros (e.g. ROE reduction) and cons (increased bill or rate volatility) associated with the inclusion of market demand drivers like weather and economic conditions in the RD mechanism.

Staff comment

The issue of 'risk assignment' is indeed fundamental: should the recovery of a distributor's revenue requirement be guaranteed? Judging from stakeholder comments, there seems to be some consensus that protection against the effect of conservation is warranted, but whether stakeholders share the same definition of "conservation" is not clear. As noted earlier, AU is a measure that includes the effects on customer numbers and volumes of such purely economic drivers as energy prices, or customer migration among service territories to take advantage of economic opportunities. Some of the innovative approaches suggested by stakeholders (summarized below) explicitly or implicitly account for this distinction.

4.5 Alternative Approaches

Stakeholder comments

While some stakeholders commented on particular aspects of one or more RD approaches, a number of stakeholders offered innovative approaches to achieving the goals otherwise addressed by the RD options described in the PEG report.[61] Stakeholders variously noted that the sheer number of electricity distributors in Ontario necessitates casting the net beyond these options; that differing circumstances between the sectors and from one distributor to the next could preclude a ‘one size fits all’ approach; and that, given the importance of conservation, and the potential for rate design offered by SM data, additional research should be conducted to shed light on the ways and benefits of manipulating distribution rates to foster energy efficiency.

Coalition of Large Distributors (CLD): For EDx, CLD suggests that customer, demand or capacity-related and variable costs be recovered, respectively, through a customer charge, SM-enabled demand charge, and volumetric charge. This variant on SFV would, in CLD’s view, not violate the cost causality principle and would materially reduce a distributor’s exposure to revenue erosion due to declining average use. SM data would be needed set the appropriate levels; and CLD cautions that the collection and interpretation of data in sufficient quantities to confirm an appropriate design for this purpose could take three to five years.

Hydro One (HO): For EDx under multi-year IRM plans, HO suggests that the IRM price cap formula could be modified to address the issue of revenue erosion related to CDM by redesigning the current price cap index to include a conservation factor that takes into account the CDM target for the forecast year and prior year actual experience.

[61] Including the three generic approaches outlined in section 2.2 and the AU adjustment approach currently used for GDx. For details, please see individual stakeholder written comments.

Low-Income Energy Network (LIEN): To the existing GDx and prospective EDx framework, LIEN suggests the addition of an RD mechanism that tracks variances between forecast and actual customer numbers by rate class. In their view, this would allow revenue losses or gains to be calculated for each class and overall, and eliminate the incentive to underestimate customer numbers in a forecast year. LIEN also suggests that an ROE stabilization mechanism be considered so as to guarantee the approved ROE by providing protection against both revenue and cost variances from forecast. Implementation, they suggest, would require cost benchmarking to prevent inefficiencies.

London Property Management Association (LPMA): LPMA suggests that an SFV/true-up hybrid (SM-enabled for EDx) be devised using demand and energy charges for EDx and higher fixed charges for GDx. In LPMA's view, this approach will allow and encourage customers to manage their bills by adjusting their consumption behaviour while adhering to the cost causality principle.

Power Workers' Union (PWU): PWU suggests the creation of criteria and adjustment parameters whereby utilities could shift revenue recovery from volumetric to fixed customer charges in proportion to their exposure to volume related revenue risk.

School Energy Coalition (SEC): For EDx, SEC suggests a true-up approach be considered in which revenue variances due to conservation and weather (only) of all distributors for each rate class cumulate in a province-wide variance account, with a true-up affected through a common charge paid by all Ontario customers in each decoupled rate class. This approach would, in SEC's view, socialize the impact of specific influences on distributor revenues in a manner analogous to that used to recover the cost of EDx investment related to renewable energy generation connections.

<u>Staff comment</u>

Perhaps not surprisingly given the differences in RD framework and in stakeholder views on the need for further RD between the respective sectors, stakeholder suggestions focus on electricity. This raises the issue as to the extent which RD regulatory arrangements for the gas and electricity sectors can or should differ while still conforming to the considerations listed in section 4.2. Note that this matter is also implicit in the questions addressed in sections 4.6 and 4.7 below.

Interest in approaches based on rate design includes industry and customer stakeholders alike. Two suggestions (CLD; LPMA) leverage SMs to extend demand charges to rate classes now restricted to energy-based rates. PWU recommends, subject to certain constraints, a customer charge that recovers the bulk of a distributor's fixed costs. SEC's proposal, while nominally a mechanism to recover variance account balances, invokes rate design concepts as outlined in section 1.3.

The two remaining approaches essentially involve the *status quo* in terms of rate design, focussing instead on the IRM mechanism. One (HO) involves adding a conservation-based adjustment to the IRM framework; while the other (LIEN) modifies the GDx-style AU adjustment design to account for changes in revenue from customer charges.

The latter two approaches might best be examined in the context of IRM reviews for gas and electricity, respectively. SEC's construct, given that a true-up is at its root, could also be assessed in the context of an IRM review process. SFV pricing approaches, including those incorporating SM functionality, would more squarely fit into a rate design consultation process.

4.6 Preferred Approach

Stakeholder comments

For gas, most stakeholders (including GDx) expressed some level of satisfaction with the *status quo* (see section 4.1). Among these, some commented that specific modifications, such as decoupling GDx for weather or setting customer charges equal to fixed costs per customer should be either considered or adopted outright.

For the electricity sector, stakeholder preferences are markedly more diverse. Some are comfortable with the *status quo* either because the evidence does not clearly demonstrate need or because better evidence and analysis must be marshalled in order to make a determination. Others, although less comfortable with current arrangements, warned that it may be premature to adopt sweeping changes at this time. Again, more information and analysis was thought to be needed.

These stakeholders notwithstanding, and excluding those advocating the pursuit of one or another innovative approach as described in the preceding section, true-ups for EDx were favoured either outright or in principle in half a dozen sets of written comments. Rationales varied, but most mentioned that true-ups provide compensation for all forms of energy conservation while, unlike SFV pricing, rate design fairness need not be compromised. Others commented that true-ups allow for rate design experimentation without undermining RD effectiveness.

The SFV approach was popular among industry-based EDx stakeholders, albeit as described in section 4.5, the SM-enabled concepts espoused were in varying degrees more elaborate than the simple designs apparently in use elsewhere.[62] Rationales provided in support of 'designer' SFV pricing included greater bill stability relative to variance account-based true-ups; consistency with cost causality; more transparent conservation incentives; and greater administrative efficiency relative to true-up administration.

Implementation practicality and complexities were considered by several stakeholders in determining their preferences. For example, those inclined toward SFV pricing tended also to favour the use of SMs for that purpose, but advised that some time would be required to investigate, design and implement a new SM-enabled regime. Some advised that any changes adopted by the Board be implemented on a 'case by case' basis for a number of reasons, including wide variations in important distributor circumstances and characteristics (for more on this issue see section 4.7). Finally, several stakeholders – including some favouring adjustments to the existing frameworks – cautioned that a number of related issues that affect the level and distribution of costs and benefits need to be examined before any determination could be made as to the best approach.

[62] See section 2.2.3 above.

Staff comment

Stakeholder comments as to their preferred approach for gas are generally consistent with views noted in section 4.1 as to whether additional RD measures for gas are warranted. Although not generally noted in the context of describing their preferred approach (see section 4.7), some stakeholders mentioned that current gas RD arrangements, included as they are in a new IRM framework, are subject to future review and evaluation.

This assessment process in the GDx context may provide useful guidance for charting the way forward for electricity. In any event, the articulation of a clear direction for electricity will require certain specialized information including but not limited to:

- whether and how the capabilities of SMs now deployed in Ontario can be leveraged to refine distribution rate-making in order to optimize the achievement of regulatory objectives; and
- whether institutional or administrative realities or obstacles exist that would affect the practical implementation of an RD option or design element.

By way of segue to the section that follows, broad agreement on the regulatory concepts and decision criteria to be applied in the determination of a preferred approach may not necessitate the creation of exactly the same regulatory construct for both sectors.

4.7 Inter/Intra Sector Considerations

There are differences between sectors and variations from one distributor to the next within each sector that condition perspectives on the need for and consequences of adopting one or another approach. The distinctions between the two distribution sectors in terms of the main drivers of RD were highlighted in section 4.1. Highlighted in this section are the differences between sectors and among companies in the same sector that, if existing arrangements are deemed inadequate, will factor into determining the nature of the changes required.

Stakeholder comments

As noted in section 4.1, several stakeholders commented to the effect that LRAM works best for larger companies where materiality is therefore potentially high (e.g. GDx) and less well where the opposite holds (the majority of EDx). Stakeholder comments on SFV pricing and true-up RD options, considered together, equally suggest that choices about the most suitable approach; design details; and related implementation process are closely related. Moreover, stakeholders are concerned that options be considered in view of the business, policy and regulatory context of each sector, recognizing the potential constraints posed by the number, size and circumstances of companies.

Several stakeholders articulated the view that a common approach may be neither necessary nor practical given differences in: the number of companies and extent of current RD; types of metering data available; sources and magnitudes of revenue risk (including differences in CDM vs. DSM mandates and opportunities); appetites for potential ROE vs. RD trade-offs; and capacity for forecasting sophistication (including weather normalization).

As to whether there *should* be variations in approach across distributors in each sector, there was no clear consensus among stakeholders: some felt that all distributors in a sector could and should have essentially the same mechanisms available to them, while a number of others – including but not exclusively some industry stakeholders – preferred customized solutions (including SFV pricing[63]).

Some stakeholders pointed out the differences between sectors that would have a significant bearing on implementation design, timing or both. For example, regarding design one stakeholder felt that a generic ‘partial’ (weather adjusted) true-up option may be precluded for electricity distributors by the fact that most do not use weather normalization for COS rebasing.

In terms of timing, stakeholders also advised that the list of RD choices as described above could best be examined for electricity in the context of a generic consultation (e.g. IRM or rate design review consultation), while the small number of GDx allows for such deliberations in the context of either a generic proceeding or an individual

[63] Each distributor’s SFV-based rate levels would be subject to Board approval.

rate hearing. Several stakeholders were of the view that the current provisions of the gas IRM framework, of which the RD and LRAM mechanisms are a part, should be allowed to run their course before assessing whether adjustments are warranted.

Some stakeholders cautioned that, regardless of approach, more information, research and analysis are needed as to costs, benefits and practical consequences before an appropriate course of action can be identified for either sector. Several comments addressed the type of proceeding best suited to vetting the various options in detail.

Finally, a number of stakeholders (including non-industry stakeholders) submitted that in any event, changes in the regulatory framework could be configured so as to apply on a ‘case by case’ basis at the discretion of the distributor, including ‘opting’ out of an otherwise generically applicable framework. Others, however, preferred a generic approach whereby provisions would be adopted and applied uniformly to all distributors.

Staff comment

It was noted in section 2 that few jurisdictions have approved generic forms of RD for utilities in both gas and electricity sectors. This suggests the situations faced by utilities in the different sectors vary in important ways that affect the degree to which RD is warranted.

Similarly, the fact that gas and electricity distributors in Ontario share elements of their respective regulatory frameworks – including LRAM – that mitigate revenue recovery risk does not imply that these arrangements must be identical. Indeed, as stakeholders have expressed in their comments, there are any number of reasons why such arrangements should differ. Among these, certainly the sheer number of EDx compared to GDx virtually guarantees a potential regulatory cost burden (however efficient the related processes are) that would weigh heavily against the adoption of any approach requiring regular, detailed regulatory scrutiny. Furthermore, the wide variation in EDx size would similarly disqualify the universal application of an overly complex or otherwise resource intensive approach.

5 Conclusions & Next Steps

The Board's October letter outlines the impetus for and underpinnings of a renewed regulatory framework for electricity. Among other things, the letter indicates that the present consultation would not proceed further until the substantial completion of policy initiatives the output of which will inform future work on the matters considered here. As explained below, it is staff's view that at the appropriate time, these matters can be revisited in one or another ongoing or prospective Board initiative.

5.1 Natural Gas Distribution

As noted in section 4 above, the need for adjustments or incremental additions to existing regulatory arrangements is not generally perceived by stakeholders as urgent. Eliminating LRAM will have little or no impact on the *level* of RD currently enjoyed by GDx, so the decision as to whether to do so becomes a matter of potential administrative cost savings the magnitude of which depends on whether SSM – which shares the same administrative basis as LRAM – is also to be eliminated from the DSM framework. This matter is, therefore, best considered the context of the currently ongoing DSM Guidelines for Natural Gas Distributors (EB-2008-0346) consultation.

The matter of decoupling for weather in the GDx context touches upon the suitability of true-up mechanisms (GDx-style AU adjustments or otherwise) for EDx. The question, including potential ROE adjustments, is sufficiently complex that it could be considered for inclusion in the context of the Board's next gas IRM review initiative.

Both of the gas distributors using AU adjustments are expected to rebase in 2012. A review of the performance of the two AU adjustment methodologies currently in use could form part and parcel of the gas IRM review expected to be conducted around that time. The information provided and policy direction arising from that proceeding will help inform future discourse as to options for the electricity sector.

5.2 Electricity Distribution

LRAM can compensate EDx for CDM-related lost revenue, thereby removing the disincentive to their participation in CDM programs. Moreover, the SSM incentive to pursue CDM aggressively has been reinforced under the new CDM framework by the potential to earn rewards linked to performance against targets. As for the cost of LRAM applications, each utility's performance assessment against its CDM target will require much if not all of the information needed for an LRAM application, so once the former is complete, the incremental cost of applying for the latter should be significantly reduced.

Given the possibilities for and increased stakeholder interest in the application of advanced metering information to rate design, this issue could be considered in anticipation of the Board's next rate design initiative. While staff recognizes (as some stakeholders suggest) that several years of data collection may be needed before rates can be set on the basis of advanced metering data, the conceptual possibilities and technical issues potentially raised by them can be explored in advance, with early findings available to condition the manner in which SM data is collected and/or processed when smart metering is fully implemented. The results of this investigation and experience with the new CDM regime, together with the information and stakeholder views garnered in the present consultation could then inform the Board's next electricity IRM framework review

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