RETAIL ELECTRICITY USE AND IMPLICATIONS OF PROPOSED REGULATORY CHANGES

SUBMISSION TO RETAIL COUNCIL OF CANADA:
FEEDBACK ON ONTARIO ENERGY BOARD CONSULTATION ON A RENEWED REGULATORY FRAMEWORK FOR ELECTRICITY

April 3, 2012

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EXECUTIVE SUMMARY

On December 17, 2010, the Ontario Energy Board (the "Board") initiated a consultation process on several inter-related policy initiatives related to a Renewed Regulatory Framework for Electricity ("RRFE") transmitters and distributors. The Board recognized both the need for significant, long-term investment in the sector and the fact that consumers were increasingly concerned over bill increases.

Parsons Brinckerhoff, Loop Initiatives and Halsall Associates (the "PB Team") were enlisted to assist the Retail Council of Canada ("RCC") and the Board to understand how retailers consume electricity and how policies and reforms proposed in the consultation will affect retail sector ratepayers and electricity consumers. The PB Team's perspectives on the impacts of the RRFE on Ontario retailers were developed by: interviewing retailers; analyzing actual energy consumption data; reviewing the Board's "Straw Man" Model Regulatory Framework for Electricity and staff discussion papers; and completing a literature review.

Electricity represents a significant cost to both large and small retailers. For large general retailers electricity costs are equivalent to approximately 1% of sales; for grocers it is 2%. Electricity and energy management as a whole are becoming areas of competitive advantage for some large retailers because operating costs can be reduced through investment in more energy efficient technologies (particularly those related to refrigeration and lighting). These strategies require a large degree of technical competency and access to capital.

Because of business needs and typical consumption patterns, little opportunity exists for small retailers to respond to TOU pricing through operations and scheduling shifts. Small retailers subject to Time-of-use ("TOU") pricing will not be able to constructively respond to increased peak hour rates and will simply pay more for power; larger retailers may have more opportunity to respond, but some may not be affected because of their bulk power purchasing agreements, not typically subject to TOU rates. Under current electricity contract structures (with both distributors and landlords), many charges do not directly relate to electricity consumption; therefore, retailers do not feel they can control a large share of their cost, which reduces incentive to take action.

The Board acknowledges that the current framework for electricity rate setting and infrastructure investment planning is imperfect; the PB Team believes that improvements are warranted sees improvement to the current framework as a positive sign. The proposed RRFE has both short- and long-term implications on cost and quality of electricity for Ontario retailers including:

- The Board is willing to adapt the system for larger-scale, more integrated and longer-term power planning studies, and proposes to allow review periods to align with key utility project milestones. This will likely yield more cost-efficient decisions and improved system performance, and provide more process clarity and opportunity for dialogue.
- Clear efforts are being made to enhance performance standards and to adopt an effective incentive structure. The PB Team supports proposals to integrate customer service-oriented metrics into assessments of utility performance.
- Using Total Factor Productivity to inform rate setting is valuable. Its use should support focus on efficiency and reliability in proposed infrastructure renewal and expansion, and encourage long-run cost reduction across the system. An issue of concern is how best to incorporate into the RRFE the Green Energy Act renewables – costs related to these smaller, intermittent generators may eventually be factored into distribution and transmission infrastructure parts of customer bills, alongside other wider system costs.
- It is not clear what safeguards will be in place to prevent sudden, large rate increases. Proposed total bill mitigation criteria and thresholds (maximum annual price increases) are not yet clearly defined.

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1. INTRODUCTION

1.1 BACKGROUND

On December 17, 2010, the Ontario Energy Board (the "Board") initiated a consultation process on several inter-related policy initiatives ("staff discussion papers") related to a Renewed Regulatory Framework for Electricity ("RRFE") transmitters and distributors. The Board recognized both the need for significant, long-term investment in the sector and the fact that consumers were increasingly concerned over bill increases.

The five staff discussion papers that are subject to consultation, and addressed in this report, are as follows:

- Distribution Network Investment Planning (EB-2010-0377).
- Approaches to Mitigation for Electricity Transmitters and Distributors (EB-2010-0378).
- Defining and Measuring Performance of Electricity Transmitters and Distributors (EB-2010-0379).
- Establishment, Implementation and Promotion of a Smart Grid in Ontario (EB-2011-0004).
- Regional Planning for Electricity Infrastructure (EB-2011-0043).

1.2 PURPOSE OF THIS REPORT

Parsons Brinckerhoff, Loop Initiatives and Halsall Associates (the "PB Team") were enlisted to assist the Retail Council of Canada ("RCC") and the Board to understand how retailers consume electricity and how policies and reforms proposed in the five staff discussion papers will affect retail sector ratepayers and electricity consumers. This report assists the RCC to identify and understand the proposed changes to Ontario investments in electricity supply infrastructure and pricing.

Reviewing and analysing the material related to the RRFE requires both technical and policy background and expertise. While this report has been written to convey material in an approachable manner, it is expected that readers of this report will have an appropriate level of technical understanding.

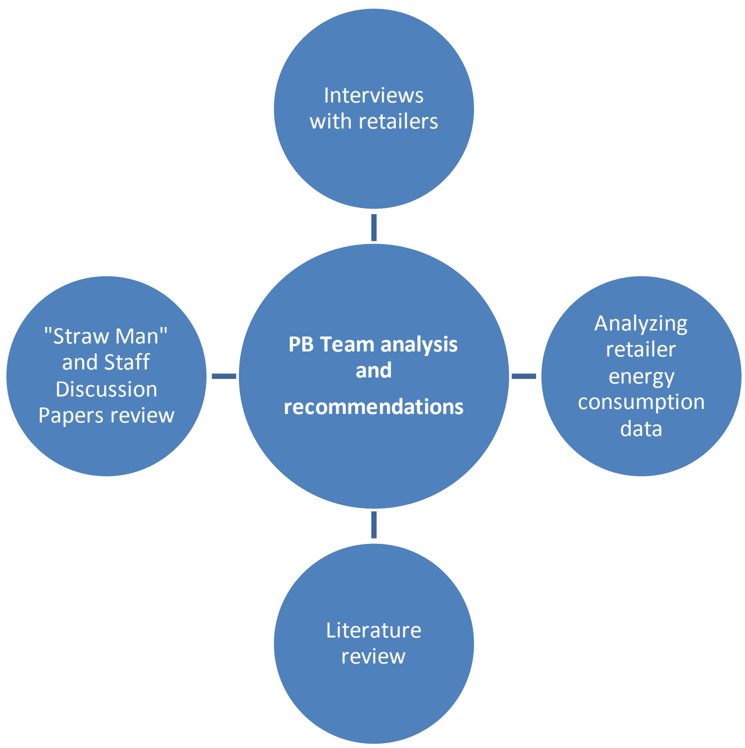
1.3 REPORT BOUNDARY AND SCOPE

The PB Team's analysis focuses on issues affecting the retail sector. The report boundary is retailer electricity use in the Province of Ontario. Interviews were completed with retailers located in Ontario, and some interviewees had both national and international facilities; this provided additional context to the broader electricity-related issues facing retailers. Due a shortage of data availability, the literature review was also expanded to an international scope.

RCC membership consists of international, national, regional and independent retailers. Categories of retail sales/members include general merchandise, apparel, home, electronics, gift, specialty and food. Data collection and interviews were focused on these sectors.

1.4 ANALYSIS APPROACH AND REPORT LIMITATIONS

The PB Team's perspectives on the impacts of the RRFE on Ontario retailers were developed by: interviewing retailers; analyzing actual energy consumption data; reviewing the Board's "Straw Man" Model Regulatory Framework for Electricity and staff discussion papers; and completing a literature review.



1.4.1 INTERVIEWS WITH RETAILERS

Six large retailers with significant presence in Ontario agreed to be interviewed by telephone, subject to anonymity and confidentiality; others declined to participate for confidentiality reasons. Retailers treat electricity use and cost as confidential information due to industry competitiveness and investment in acquiring expertise. The RCC provided access to two small retailers who agreed to interview, again subject to anonymity[1]. One was a sporting good supply store, and the other was a kitchenware supply store. Details are as follows:

[1] Interviews were also attempted with local street-level retailers; however, those small retailers that were approached knew little of their electricity consumption and were unable to provide comment.

Table 1 – Telephone interview participants (Note: interviews were agreed to under promise of confidentiality)

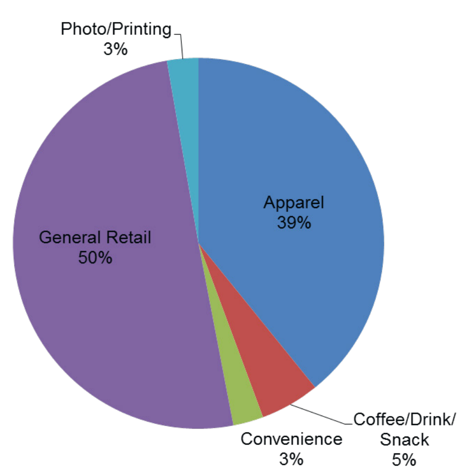
Size	Type of Retailer	Role
Large	Grocer	Director Risk Management
	Grocer	Lead Energy Management
	Big Box Furniture	Country Facilities Manager
	Department Store	Senior Manager Energy
	Chain – Telecom & Media	Energy Manager
	Chain – Specialty Retailer	Manager Energy & Environmental Management
Small	Sporting Goods	General Manager
	Kitchenware Goods	Vice President

Interview questions related to electricity use and costs, electricity management strategies and quality issues. The list of questions asked can be found in Appendix A. Time constraints prevented the completion of a large survey of smaller retailers. The interview findings, published in report *Retail Sector Electricity Insights* (March 20, 2012) and located in Appendix B, can be used to structure a larger survey to RCC membership.

1.4.2 SAMPLE OF RETAILER ENERGY CONSUMPTION DATA

Limited retailer electricity consumption data exists in the public domain. However, using Halsall's Building Performance Database, actual 2011-2012 Time-of-Use ("TOU") data was identified for 34 retailers located in the shopping concourse of a Toronto indoor office complex. Retail shops were of different sizes and types. A breakdown of these 34 retailers by the share of total building area is as follows:

Figure 1 - Retail electricity data analysis (retail category by share of total building area)



General retail members included mobile phone carriers, a toy shop and an office supplies store among others. It is recognized that there could be differences in electricity use between enclosed shopping mall/office tower setup versus street-level retail.

1.4.3 STRAW MAN MODEL REGULATORY FRAMEWORK FOR ELECTRICITY AND STAFF DISCUSSION PAPERS REVIEW

The Straw Man Model Regulatory Framework, issued on February 6, 2012, was reviewed, as were each of the five Board staff discussion papers highlighted in section 1.1 BACKGROUND, along with key reference documents (e.g., Power Advisory LLC *Bill Impact Estimation Model*; Navigant *Transmission and Distribution Rate Mitigation Measures for Ontario*; etc.). As per the Board:

> "the 'Straw Man' model regulatory framework for electricity distributors… is intended to provide a high-level illustration of how the main components and outcomes discussed in the five staff discussion papers might be brought together in a coherent, internally consistent manner that highlights key linkages between outcomes, defined performance, measured performance and potential regulatory mechanisms."

The Straw Man Model and staff discussion papers were assessed for potential impact on retailers, both in terms of cost and power quality implications, based upon the PB Team's expertise in generation, transmission and distribution systems and feedback gathered from retailer interviewers.

1.4.4 LITERATURE REVIEW

Industry association, government, academia and not-for-profit sources were reviewed to provide insight in retail sector energy use. There is very little information available regarding retail energy use and management beyond high-level energy use profiles and typical conservation measures and much information is out-dated; however, the published information was consistent with the information gathered in the retail interviews. Published information does not apply to the current Canada/Ontario scenario. The following sources were identified and assessed:

Table 2 - Literature review sources

Type of Association	Reviewed Association Websites
Government	• ENERGY STAR: U.S. and Canada • Natural Resources Canada (NRCan) • U.S Department of Energy – U.S Energy Information Administration (EIA) – Retail Energy Alliance
Industry	• International Council of Shopping Centers (ICSC) • Food Marketing Institute (FMI) • Professional Retail Store Maintenance Association (PRSM) • Edison Electric Institute (EEI) • International Facility Management (IFMA) • American Council for an Energy-Efficient Economy (ACEEE) • Independent Electricity System Operator (IESO)
Not for Profit	• Alliance to Save Energy, U.S. • Carbon Trust, U.K. • Greening Retail, Canada

1.5 REPORT STRUCTURE

In Section 2, entitled "How Retailers Use Electricity", retailer electricity use is reviewed along with cost analysis and implications. Context is then provided on ongoing retailer efforts to manage electricity consumption and outages.

In Section 3, entitled "Implications of Proposed Regulatory Framework Changes on Retailers", a brief PB Team perspective on the situation facing the Ontario generation, transmission and distribution system is presented. The PB Team then analyzes the proposed RRFE and its implications for retailers following the Straw Man Model categories:

1. Integration of planning
2. Treatment of capital
3. Performance standards and incentives
4. Approach to rate setting
5. Period of COS[2]/IRM[3] review
6. Total bill mitigation
7. Straw Man Model Regulatory Framework for Electricity – Distribution Network Investment Planning

In each subsection, a summary of the Straw Man proposal is presented, followed by a summary and discussion of the issues, implications and opportunities. As noted in the introduction, this section may require technical and policy background and expertise to fully understand all issues and matters that are discussed.

[2] COS: Cost of service application.
[3] IRM: Incentive Regulation Mechanism.

2. HOW RETAILERS USE ELECTRICITY

In this section the PB Team presents its findings regarding electricity use in retail with cost implications, as well as retailers' electricity management efforts.

2.1 ELECTRICITY USE IN RETAIL AND COST IMPLICATIONS

The literature review identified that little published information is available into how retailers use electricity or the costs involved; therefore, first-hand research was required.

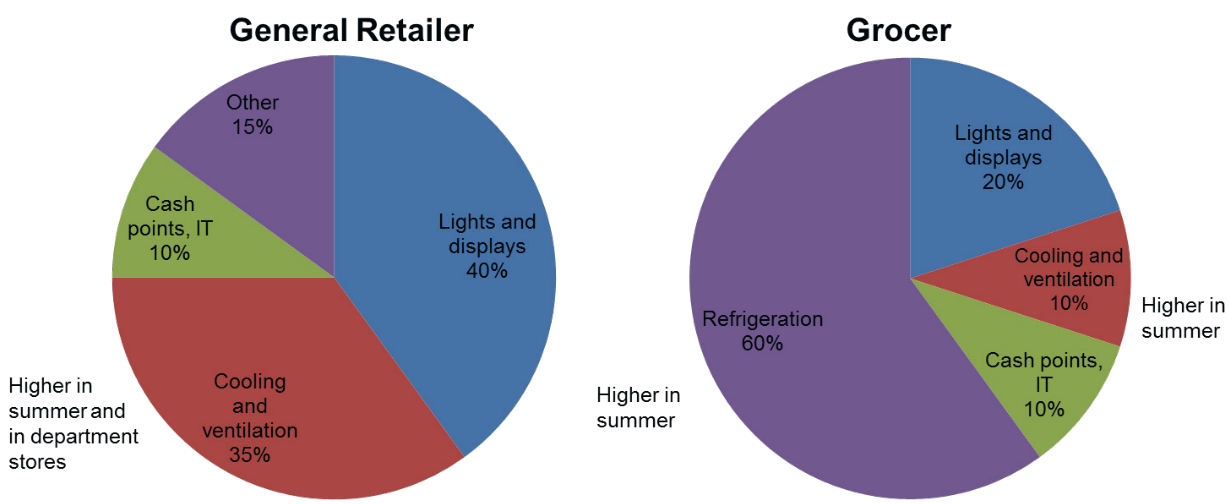
Energy use and cost figures were identified through the analysis of available data in the Halsall Building Performance Database as well as through interviews with large and small retailers.

2.1.1 Energy use breakdown

In the interviews, no retailer was willing to provide detailed data on total energy consumption, use breakdown, or TOU profiles. However, persistent questioning of energy use components, relative impact, and requests for "ranges" enabled good triangulation of results across retailers.

The following charts indicate average electricity consumption in the two distinct profiles, reflecting patterns for both small and large retailers:

Figure 2 - Estimated retailer electricity consumption breakdown by retailer type, by end use



Sources: Loop Initiatives interviews with large retailers. Small retail assumed to be similar (lack of data/analysis).

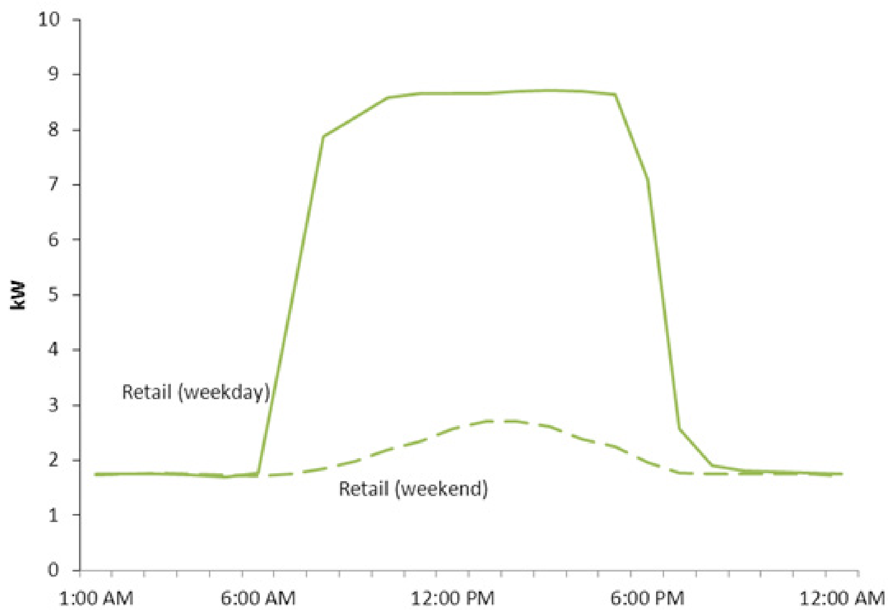
These two charts also correlate with readily available data on office building energy use which increases confidence in results. A key question asked of retailers is, "do you have fridges or freezers, or do you not"? If the answer is "yes" (i.e., grocer), the biggest load is refrigeration, which typically comprises almost two-thirds of electricity use. If the answer is "no", the biggest load is lighting and displays, closely followed by cooling and ventilation.

2.1.2 TOU profiles

While TOU data was not provided by any of the retailer interviewees, retailers communicated that they strive to switch off any unneeded electrical equipment when they are closed; however, during operating hours, they need lights and displays, cooling and ventilation, etc. to be turned on.

Analysis of results of TOU data from the 34 sub-metered retailers in a downtown combined office and retail complex confirms this message, with results as follows:

Figure 3 – Hourly electricity demand in sample of apparel stores



Source: Halsall Building Energy Database.

During weekdays, retail stores are clearly polarized in their daily use of electricity. Retailers consume significant electricity during operating hours and dramatically less when closed. The impact of refrigeration is not included in the above figure; however, it would increase the base load for grocers and drink/snack vendors. Based upon this TOU profile, and relative to larger peers who may have a different contract structure or other consumers with a more steady use profile, any small retailers subject to TOU pricing would be exposed to significant price impact due to demand coinciding with current mid-peak and peak rates. Note that the majority of these retailers, which are located in the shopping concourse of a Toronto indoor office complex, were closed on weekends when the office towers were empty.

Little change opportunity exists for retailers to benefit from operations and scheduling shifts, as will be discussed further in the following subsection.

2.1.3 Cost implications

Electricity represents a significant cost to both large and small retailers. Large general retailer electricity costs are equivalent to 1% of sales, and 2% of sales for grocers. For context, a large chain can spend $30-50 million per year on electricity and a single grocery store may spend $200,000. For a small retailer, electricity cost can in some instances be comparable to carrying an employee. Higher prices would therefore have a measurable impact on retailers. Table 3 presents electricity use and cost, normalized to a 1,500 ft² (small) shop:

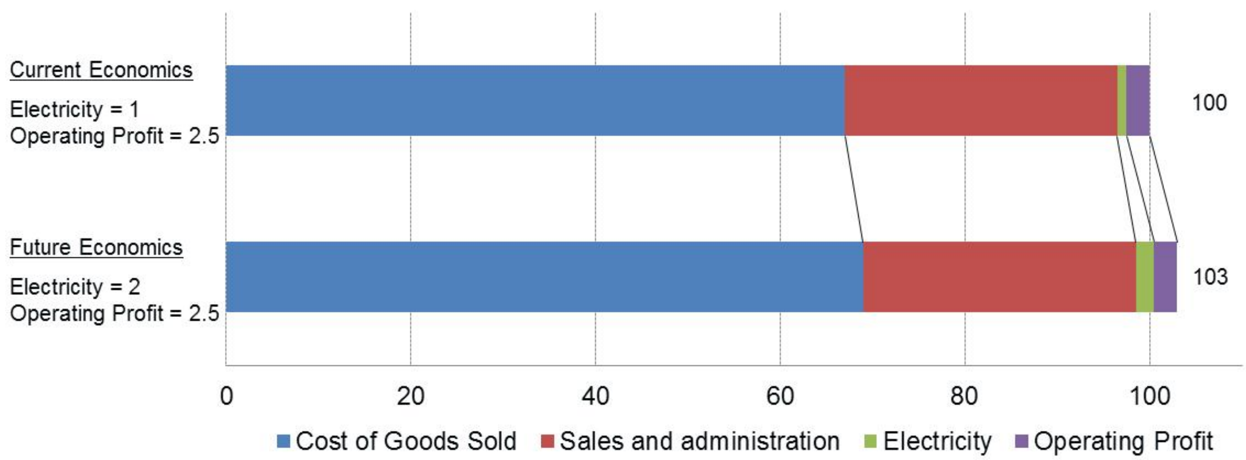
Table 3 - Typical annual electricity use and cost, normalized to a 1,500 ft² shop, by retail category

Retail Category	Annual Electricity Use (kWh)	Estimated Annual Cost ($)	Equivalent FTE Cost
Apparel	35,620	3,562	17%
Coffee/Drink/ Snack	171,596	17,160	83%
Convenience	41,182	4,118	20%
General Retail	34,518	3,452	17%
Photo/Printing	34,896	3,490	17%

The data in Table 3 is based on actual electricity use for the sample of 34 retailers, assuming operations of 65hrs/week at an estimated cost of 10 cents/kWh. Estimated annual salary cost of a full-time equivalent (FTE) employee is $20,700 ($10.25 minimum wage x 37.5 hours/week x 50 weeks/year plus employer EI and CPP contributions).

To illustrate the impact of a doubling of electricity costs on retailers, Figure 4 communicates the corresponding increase in sales that would be required to maintain profitability. The analysis is based on a generic retail industry cost/margin profile and could be applied to any type and size of retail:

Figure 4 - Illustrative effect of 100% increase in electricity cost



Sources: Loop Initiatives interviews with large retailers. Review of retailer financial statements published in annual reports.

2.1.4 Cost mitigation

Two primary strategies exist to mitigate a rise in electricity price: reduce staffing (sales and administration (fixed) costs), or increase sales. A doubling of electricity cost would require either a 3% increase in sales or a 3% decrease in sales and administrative costs to obtain the same profit. Interviews indicated that both alternatives may be difficult as economic pressures have already pushed most retailers to strive to do both.

A third strategy is to reduce consumption by temporarily providing reduced space lighting/conditioning, but this also carries challenges. One sophisticated Department Store retailer revealed that in their well-documented summer study, where air conditioning and lighting levels were reduced during three separate hours to save power, reductions created a knock-on impact of a drop in sales that more than offset any electricity savings generated. "*Who wants to shop in a dark and hot department store when the mall outside is bright and cool?*"

The final strategy is to invest in more energy efficient technology for refrigeration and lighting, and where technically and financially feasible, to pursue renewable energy. However, this strategy requires a large degree of technical competency and access to capital. All large retailers interviewed had completed lighting retrofits and all grocers were upgrading refrigeration. Only one interviewed retailer has invested in renewable energy generation, and did so as more of a risk management than as a cost saving strategy.

For smaller retailers, electricity reduction initiatives beyond "switching off" may be unattainable due to lack of competency and technology (see section 2.2.2), capital availability and contract structures (section 2.2.3).

2.2 ELECTRICITY MANAGEMENT EFFORTS

Electricity and energy management as a whole are becoming areas of competitive advantage for large retailers. Retailers were reluctant to share specific energy consumption and cost data but broader experiences in electricity management were communicated willingly and are summarized below.

2.2.1 Large retailer experiences

Large retailers typically have in-house electricity management skills and experience, and have integrated electricity management into their business processes. Significant investments in know-how and technology have been made to manage risk and opportunities. The following efforts were observed:

- Execute bill audits: check invoices and compare metered consumption and applicable rates.
- Implement utility management system: access to all consumption and cost data in one location and analytical tools.
- Bulk supply (retail) contracts: lock in or hedge electricity costs.

Common strategies implemented to reduce electricity demand are as follows:

Table 4 - Common strategies to reduce electricity demand

Base Load	Peak Demand	Total Consumption

• Just-In-Time scheduling of ventilation, cooling and lights
• Equipment testing and maintenance
• Fridge "curtains"
• Minimum requirements for store cleaning and stocking
	• Systems and protocols for:
	  • Dimming lights
	  • Reducing cooling
	  • System shutdown
	• On-site renewable generation
	• Demand response
		• Light retrofits (e.g., LED)
		• Upgrades of fridges, freezers and chillers
		• Switch to closed fridges and freezers
		• On-site renewable generation

Sources: Loop Initiatives interviews with large retailers.

The challenges identified in executing strategies to manage electricity use are as follows:
- Base load: access to expertise (in some instances).
- Peak demand: negative sales impact.
- Total consumption: significant capital requirements; available technology; and customer mindset.

Interviews found that the ratio between the base load and peak demand (closed and open for business) varies significantly by retailer type:
- Grocer: 1:1.5
- Chain – Speciality Retailer: 1:2
- Big Box Furniture: 1:10

Finally, large retailers welcome even more innovation from equipment suppliers to achieve higher efficiency at affordable cost, and support from industry to accelerate adoption and customer acceptance (e.g. reduced light and covered fridges).

2.2.2 Small retailer experiences

Smaller retailers are more exposed to increases in costs versus larger peers. Several small retailer disadvantages exist according to perspectives provided through interviews with both small and larger retailers:
- Electricity management is not a core competency - difficult to access, interpret and take action on electricity data.
  - "*No one in the company would know our % breakdown of electricity use*" (General Manager, small retailer).
- Not affordable to hire specialized staff or outsource to third-party providers.
- Often covered by TOU rates (where smart meters have been installed).
- Typically unaware of changes to rates until after the fact.
  - "*It just showed up on our bill*" (Energy Manager, chain of smaller outlets).
- Sense that they have no power.
  - "*We have tried to get the data from our distributor for more than two years and we are still trying*" (Energy Manager, chain of smaller outlets).
- Unaware of options to reduce electricity use.
  - "*We need lights and computers to run the business*" (Vice President, small retailer).

Furthermore, anecdotal evidence suggests that small retailers use electric heating more frequently than large retailers, which would further compound the impact of TOU pricing because of an inability to shift heating needs away from mid-peak and peak rate periods.

2.2.3 Contract structure implications

Under current contract structure with electricity distributors, retailers do not feel they can control a large share of their cost, reducing incentives to take action. Retailers expressed confusion over the variety and the unpredictability of charges (particularly the Global Adjustment charge). The following bill components and charges were on retailer electricity bills:

Table 5 – Retailer electricity bill charge types

Type of Charge	Observed Charges
Consumption charge	• Global Adjustment • Wholesale operation charge • Special purpose fee
Demand charge	• Distribution charge • Lost revenue adjustment • Transformer allowance • Shared savings charge • Transmission charge
Fixed charge	• Local access fee • Customer charge • Basic charge • Electric energy charge • Administration charge • Delivery charge

Sources: Energy industry research. Loop Initiatives interviews with large retailers.

With many charges not directly related to consumption levels, present contract structures dis-incentivise retailers to manage electricity. This is particularly applicable for retailers who lease shopping centre space and are billed by a fixed rate.

Table 6 - High-level overview of contract structures

Contract Structure	Applicable Retail	Subject to TOU	Ability to Influence		
			Consumption Charge	Demand Charge	Fixed Charge
Retail contracts with wholesalers	Large chains; Very large stores		✓	✓	
TOU pricing with local retail distributor	Small stores; Street location (non-mall)	✓	✓		
Billed directly by local retail distributor	Small stores; Street location (non-mall)		✓	✓	
Billed via landlord based on fixed/ leased area rate	Shared building; Shopping centre location	LACK OF INCENTIVE TO TAKE ACTION			LACK OF INCENTIVE TO TAKE ACTION
Billed via landlord based on sub-meter	Shopping centre location	✓	✓		

Source: Loop Initiatives analysis. Legend: ✓ = Present; [shaded] = Not present, lack of incentive to address

2.2.4 Backup power

All retailers interviewed indicated that electricity system reliability is very important, as outages have an immediate effect on sales, employee/customer safety and security/theft. Because of the historically low frequency and duration of outages in most Ontario regions, retailers are not generally concerned about blackouts. Most supply disruption appears to be managed by battery backup power provided by landlords, rented or own capacity. However, electronic transactions (e.g. Interac, Visa) may not be feasible during a large-scale blackout due to potential offsite disruption to the transaction system providers.

Table 7 - Factors driving backup capacity

	Electricity Draw	Code Requirement	Health & Safety	Insurance Requirement	Internal Decision
Battery Power to Enable Max 6 hours of Critical Operations	Emergency Lighting	✓	✓	✓	
	Security System	✓		✓	✓
	Point of Sale System				✓
Generators to Enable Business Operations	Refrigeration				✓
	Lights				✓
	Building System				✓

Source: Loop Initiatives interviews with large and small retailers.

Electricity backup decisions appear to be related to general risk management and emergency response strategy, as opposed to energy management. Most large retailers communicated that their backup systems can run for up to six hours.

Risk-averse retailers are more likely to invest in own generator capacity. One large retailer indicated that they spend an additional 20% in capital for building mechanical systems to have electricity backup/redundancy.

Grocers with a large portion of fresh/refrigerated foods are most at risk. If an interruption lasts for longer than the backup power system can deliver electricity, food spoilage can be a significant cost for a grocer without backup generation as spoiled food needs to be discarded and is not covered by insurance policies.

In response, grocers have established operating procedures for periods where electricity supply is disrupted:

- Cover fridges and freezers.
- Close doors (if summer).
- Control customer access to cold areas.
- Shut off ovens or stoves.
- Transport backup generators from centralized storage or rental suppliers.

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3. IMPLICATIONS OF PROPOSED REGULATORY FRAMEWORK CHANGES ON RETAILERS

Section 3 analyzes the proposed RRFE and its implications for retailers following the Straw Man Model categories; while it draws upon findings from section 2, it can be read as a standalone section. Please review section 1.5 REPORT STRUCTURE on page 5 for context before proceeding.

The Board acknowledges that the current framework for electricity rate setting and infrastructure investment planning is imperfect; the PB Team believes that improvements are warranted sees improvement to the current framework as a positive sign. The proposed RRFE has both short- and long-term implications on cost and quality of electricity for Ontario retailers. A high-level summary of Section 3 findings is presented below, with detailed analysis provided in sections 3.2 to 3.8.

- The Board is willing to adapt the system for larger-scale, more integrated and longer-term power planning studies, and proposes to allow review periods to align with key utility project milestones. This will likely yield more cost-efficient decisions and improved system performance, and provide more process clarity and opportunity for dialogue.
- Clear efforts are being made to enhance performance standards and to adopt an effective incentive structure. The PB Team supports proposals to integrate customer service-oriented metrics into assessments of utility performance.
- Using Total Factor Productivity to inform rate setting is valuable. Its use should support focus on efficiency and reliability in proposed infrastructure renewal and expansion, and encourage long-run cost reduction across the system. An issue of concern is how best to incorporate into the RRFE the Green Energy Act renewables – costs related to these smaller, intermittent generators may eventually be factored into distribution and transmission infrastructure parts of customer bills, alongside other wider system costs.
- It is not clear what safeguards will be in place to prevent sudden, large rate increases. Proposed total bill mitigation criteria and thresholds (maximum annual price increases) are not yet clearly defined.

3.1 PERSPECTIVES ON THE GENERATION, TRANSMISSION, AND DISTRIBUTION SYSTEM

The following PB Team perspectives on the generation, transmission and distribution system are presented to the RCC to provide context to the comments that follow in sections 3.2 to 3.8 concerning the RRFE's impact on Ontario retailers.

3.1.1 Generation

Most of the electricity consumed in Ontario is generated in large power plants[4], where power output is constantly adjusted in a highly automated and centralized fashion to match consumption and losses throughout the grid. The "grid" (Network loop and radial lines, at both transmission and distribution levels) power flow and other electrical parameters are also continuously monitored and adjusted. The availability of spare generation capacity and the patterns of power flow through the power grid are constantly monitored since these are critical to determining and maintaining the health of the grid.

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[4] Independent Electricity System Operator 2012, *Supply Overview*, http://www.ieso.ca/imoweb/media/md_supply.asp, accessed 21 March 2012.

3.1.2 Transmission

There are more than 30,000 kilometres of transmission lines across Ontario to carry electricity from generators to large-volume customers and utilities for distribution[5]. In the large Ontario system, comprised of five transmitters and 91 distributors[6], efficient planning and system stability can become serious issues, particularly when the power grid is experiencing rapid growth. Power grid operations, particularly at the transmission level, involve a vast array of sensors and automated systems capable of monitoring and quickly addressing any faults. Sound planning decisions are key to maintaining a healthy, efficient transmission system and ensuring reliable electricity power delivery and service to the end customer.

Investment in transmission infrastructure is typically driven by:

- Network strength/stability – the need to increase the capacity of the grid to handle unexpected failures without affecting inter-connected transmitters, distributors and large generators, and ultimately end users.
- Capacity – the need to add infrastructure that is capable of handling the load from additional customers.

3.1.3 Distribution and the "Smart Grid"

The distribution system has been traditionally used to deliver power to the end user, as opposed to generate power to the wider system. The distribution system will likely be most affected by modernization (smart grid) and the renewable energy producers. Typically, "smart" grid refers to the ability to collect and transmit electrical data through digital communication means (power lines, wireless, data networks, etc.), and is applied at the distribution level. The challenge brought about by the GEA and the widespread introduction of renewable energy generation is to incorporate the smaller, intermittent and less reliable producers (e.g., wind, solar), on the distribution side of the grid, without excessive distribution infrastructure investment, i.e., additional generation connection costs and grid upgrades. Reconfiguring the distribution system using smart grid technology will help to limit the amount of power infrastructure (substations, power lines, transformers, etc.) that is needed to adapt to more "transmission"-type functions. The advancement of smart digital technology now makes it possible and increasingly cost-effective to implement higher-level "smart" grid control and monitoring features down to the end-customer level. While smart grid technology should improve power delivery reliability and efficiency, there may also be challenges with new technology integration that will require careful management.

3.2 INTEGRATION OF PLANNING

For each of section 3.2 to 3.8, the PB Team analysis is structured in two subsections:

- "Board proposal summary": an exact summary of the material presented in the Straw Man Model, followed by a list and brief summary of any related staff discussion papers.
- "Issues, implications and opportunities for improvement": analysis of the Straw Man Model and related staff discussion papers.

[5] Independent Electricity System Operator 2012, *The Power System*, http://www.ieso.ca/imoweb/siteShared/power_system.asp?sid=md, viewed 21 March 2012.
[6] See previous footnote.

3.2.1 Board proposal summary

The following “Integration of Planning” Board proposal summary was presented for discussion in the Straw Man Model Regulatory Framework for Electricity:

Model Framework	Current Framework	Change	Gas Framework
Plans include sustainment and expansion requirements, smart grid, generation connection and regional considerations. [See page iv of the “Straw Man” model regulatory framework for depiction.] Planning expectations developed to enhance predictability of reviews. Focus on outcomes.	Limited experience. No regional planning requirements. No tying to outcomes.	Longer planning/rate setting horizon. Coordination and integration facilitates optimal investments and cost savings. Performance affects distributor compensation/customer benefit symmetry.	EBO 188 deals with hydrocarbon pipeline investment, etc.

The following staff discussion papers expand upon the summary presented above from the Straw Man Model. The creation a more transparent, performance-oriented framework for the planning process of large infrastructure investments, to ensure cost-effective and efficient power grid growth and reliability, is the principal objective of these related consultations:

- *Distribution Network Investment Planning* (EB-2010-0377)
    - Proposes ideas on how the Board’s framework and approach to regulatory assessments of network plans can be enhanced.
- *Establishment, Implementation and Promotion of Smart Grid in Ontario* (EB-2011-0004)
    - Examines how/what to provide as guidance to regulated entities to establish, implement and promote the smart grid.
- *Regional Planning for Electricity Infrastructure* (EB-2011-0043)
    - Discusses improving planning of transmission network investments (specifically line connections and reclassification of categories and investment plans based on usage: network, line connection, dual use, etc.).

3.2.2 Issues, implications and opportunities for improvement

The Board acknowledges the need for improved and expanded planning and coordination among the various players in the integrated power grid. Maintaining a healthy and growing power grid requires large, long-term infrastructure investments at all levels. The PB Team agrees with the Board that it is important that grid investments (both infrastructure renewal and expansion) are carefully considered to ensure that decisions are made in an objective manner with minimum impact on electricity rates. Large-scale, more integrated and longer-term planning approaches are part of the Board recommendations that should benefit all customers in the long and short term.

Summary of key points for retailers:

- **Power Advisory LLC Bill Estimation Model:** it is not clear if or how the model factors in potential demand-side reductions. There is a need to guard against overestimation of demand. The model lacks certain specifics on the impacts of renewable electricity generation and related electrical improvements which may impact costs and electricity pricing.
- **Smart grid and the Green Energy Act**: there are uncertainties as to who shall bear any GEA-related costs, be it the direct beneficiary or the wider network ("beneficiary pays" vs. "cost causality").
- **Smart meters vs. Behind-the-Meter technologies**: Behind-the-Meter ("BTM") systems are not constrained by the testing/analysis time required to deploy smart meters and will be consequently more advanced. Retailers could benefit from adopting BTM systems.
- **Privacy/security risks with smart meters**: staff discussion papers define smart meters to present a low level of risk to data privacy/security.
- **Regional planning considerations**: the proposed longer-term, regional approach to planning makes sense. Openness between utilities in sharing load growth forecast data and analysis could improve collective forecasting abilities and mitigate over-investment. Regions with significant concentrations of or growth in renewable energy generation could be subject to larger relative cost impacts.
- More detailed analysis is presented below.

Power Advisory LLC Bill Estimation Model

The PB Team's research indicates that it is important to retailers that a reliable, quality supply of electricity is available at affordable and predictable costs. Retailers are less concerned about individual bill components and more concerned with the ability to predict total cost over a number of years. Integrated network planning therefore needs to explicitly include a consideration of costs to end consumers for all new network investment.

The PB Team suggests that it is important, when evaluating the efficiency of new investments, that alternatives based on meaningful investments in CDM are considered with cost comparisons. It is not clear if or how this model factors in potential demand-side reductions from programs such as the Ontario Power Authority's "saveONenergy Retrofit Program," which provides financial incentives to replace low-efficiency existing equipment and install new systems to improve reduce demand[7] . For instance, does Category 4 titled "Meet Load Growth" (on tab 4. Project Assumptions) implicitly factor in CDM activities that reduce load growth, or are these not considered?

Load forecasts can be subjective and there is a need to guard against overestimations of demand. For instance, when assessing an area in the system, load forecasts are based on load trends, economic indicators, electrical billing and metering data. Sometimes the temptation is to tilt the forecast data towards a desired outcome; in high-growth economic times, load forecasts tend to be more optimistic since nobody can predict the true nature of a cyclical economy.

[7] Ontario Power Authority 2012, *saveONenergy Retrofit Program*, https://saveonenergy.ca/Business/Program-Overviews/Retrofit-for-Commercial.aspx, accessed 20 March, 2012.

The model lacks certain specifics on the impact of renewable electricity generation and related electrical improvements:

- Factual data on parameter assumptions is not included and there is a risk that assumptions could be based on scarce or unproven data, e.g., the "direct benefit" factor, renewables "capacity and diversity" factors, etc. For transparency, parameters should be based on actual measurements/historical data for each specific renewable electricity source profile.
- For larger renewable electricity producers, it may be better to approach on a case-by-case basis that would compare renewables against traditional power generation, i.e., true "anytime" megawatt capacity vs. peak capacity availability in a 24-hour period or seasonal; reliability in mean time between failure ("MTBF"), or system average interruption duration index ("SAIDI", in minutes/year/customer); the customer average interruption duration index ("CAIDI"), etc..
    - An issue with reliability metrics is the need for a uniform statistical definition, since utilities adjust measurements based on internal guidelines. The Institute for Electrical and Electronics Engineers ("IEEE") Standard 1366 addresses many (though not all) reliability metrics issues, is widely recognized and has been adopted by an increasing number of utilities.

Smart grid and the Green Energy Act

A recurring theme re-iterated by the Board is the potential of smart grid technologies to change the electricity delivery business and improve efficiency.

Two definitions of the smart grid were proposed. Definition A: "smart grid as the evolving modernization of the grid"[8] is the preferable definition as per the PB Team in that it conveys that the smart grid is not something special but rather reflects an evolution in the utility business. The Board does not define the "smart" grid beyond "smart" metering systems collecting and sharing customer information data. However, connecting generation to a "smart" grid would require more than smarter monitoring electronics or communication systems. A grid with both generation and consumption at multiple nodes also requires automatic control and switchgear/substation investments, even additional lines and distribution networks, which adds up as a significant need for investment beyond just the electronics or supervisory, control and data acquisition system ("SCADA") necessary to accommodate generators. The Board does not define the "smart" grid in these terms, although it acknowledges this need for connecting the new renewable, smaller generators to the grid.

The Minister's Directive to the Board states that a principle policy objective is customer value: "The smart grid should provide benefits to electricity consumers."[9] In deploying widespread utility metering upgrades to improve grid "intelligence", it is not clear if utilities are passing on to customers knock-on benefits, e.g., smart meters require less administration to read and maintain.

The PB Team suggests that it is important to know if investments are being made because they will increase reliability and decrease long-term costs to consumers, or if they are being triggered by other factors, e.g., GEA-related connections and certain smart grid improvements. Based on the current regulatory framework, two fundamental principles apply when assigning infrastructure investment burden: "cost causality" versus "beneficiary pays". Under the former, costs are spread widely through the network; under the latter, the generator (beneficiary) is responsible for paying any incremental

[8] *EB-2011-0004 Establishment, Implementation and Promotion of Smart Grid*, section 4.2.1.
[9] *EB-2011-0004 Establishment, Implementation and Promotion of Smart Grid*, Minister's Directive.

costs for upgrades to the distribution network. It is not entirely clear how GEA generators will impact the grid and there are uncertainties about who shall bear the cost burden. In consequence, there are some potential equity questions about the need to push out GEA-related costs. There is a risk that customers could see large cost impacts for transmission and distribution improvements in regions with significant green energy projects, and it may not be appropriate for ratepayers to pay some or all of these costs. The impact on customer electricity prices may therefore be uneven. Further research and clarity is required in this area.

There are clear challenges in adapting existing distribution systems to receive and transmit renewable energy. This first GEA period may result in a trial and error series of wasteful investments. Small generators interconnected also require even more complex SCADA with more complex protective control systems than the larger conventional producers would need. The new bi-directional flow of power in the distribution grid would also require more sophisticated “smart” switchgear and controls.

Not all renewables are created equally. Historical data for reliability, availability, reliability, true capacity and grid connection costs is often lacking and location-specific. The PB Team suggests that it is important to better differentiate between various types of sources of renewable energy and the true impact of each on overall cost and reliability.

- Some of green energy sources may end up being dropped if they cause grid reliability problems or are proven to be insufficiently economic, leaving behind unrecoverable infrastructure investments.
- Intermittent or unreliable renewable energy requires conventional generation power capacity to be available, but to generate at reduced levels/not generate.
- Standby transmission capacity is required, but loaded less on average.
- All of these would result in additional costs.

The rules around capital contributions, based on old organic growth of demand, do not necessarily make sense in the context of this new GEA demand. However, the more the renewable energy generator capacity and availability are like the conventional power generation, i.e., can be adjusted based on grid load, capacity and production and not be dependent on outside uncontrollable “natural” factors, the higher the overall benefit. A breakthrough in energy storage technology, e.g., improved, larger and more cost-effective batteries, could significantly shift the prospects and cost-effectiveness of renewable energy sources by “level-loading” the grid, i.e. storing and releasing energy to compensate for generation fluctuations. Finally, if the renewable energy generator can be kept “off-grid” (not synchronized to the grid 60Hz) for production, the impact on the grid infrastructure would be significantly smaller.

On the positive side, renewable energy can provide some local benefit:

- It may serve as small, additional “peak” generation to complement base generation and meet peak demand.
- Renewables can defer costly transmission/generation upgrades to bring distantly located conventional power to the local distribution grid.
- Additional transmission capacity is not needed for area load growth; however, the key is renewable energy availability, as there is not much saved if generation is intermittent.

Smart meters vs. Behind-The-Meter technologies

Utilities require many tests/analysis, approvals etc. to deploy a uniform smart metering system. The most important features of a utility meter are its reliability, ruggedness, accuracy, and compatibility with other utility meter reading systems. By the time they are deployed, while these smart meters may be highly dependable, the testing/analysis lag will mean that they are not the "smartest" that money can buy and their relative value will have diminished.

The BTM systems do not have the same constraints and such systems are already used to reduce demand and save energy by retailers and other customers. The BTM would be cheaper and more advanced than utility systems since they are not restricted by the same regulatory and scale conditions as the smart grid metering. A retailer could buy a smart BTM metering system which will almost be guaranteed to use more advanced hardware and software than the utility smart meter.

As a long-term strategy, ensuring that fast-improving BTM systems are compatible with and have the capacity to complement wider smart grid efforts (meters, etc.) would be of benefit.

Privacy/security risks with smart meters

As defined by the staff discussion papers, there is not much risk to privacy/security. From the PB Team's perspective, tampering with meter and wireless data collection via electronic means could be a risk and concern for some. This could become even more of an issue if "smart" meters are able to collect too much data or can be easily tampered with. If a utility's central billing data storage system is hacked, that could compromise customer privacy and access sensitive utility data. Given confidentiality over electricity data exhibited in interviews, large retailers would likely find smart meter security to be of greater concern than small retailers, who presently place less emphasis on energy management as a source of competitive advantage. While the PB Team's retailer interviews did not ask if smart meter security was a concern, none volunteered it as a concern.

Regional planning considerations

The definition of what comprises a region matters from a cost perspective, as the existing assets and the type of generation pool within the region can determine the electricity rate. If the region has existing or planned renewable electricity generation, especially intermittent small producers, the cost impact could be substantial. The GEA introduces a level of uncertainty to traditional power planning and system growth.

Current short-term planning is problematic and can result in inefficient investment, and there is presently no clear requirement for coordination and collaboration among various utilities that comprise the grid. The proposed longer-term, regional approach to planning makes sense per the PB Team, and may also improve long-term price predictability for consumers, particularly for transmission and distribution bill components.

The larger the planning study, the more accurate is the load growth forecast, and consequently the better the decision making. Load forecasts are typically based on a large amount of electricity, economic, etc. data to predict load in one-, five-, 10-, and 20-year horizons, etc. This is the critical element in any power planning study no matter how sound technically. The kW and kWh technical study results, reliability figures, etc. are then used in planning studies to determine the project economics. Studies that show positive cost-benefit in less than five years, and positive net present value over 10-20 years should be prioritized. The historical complaint that longer-term data for planning purposes may be too unreliable to yield valid results should be less of a problem with the advancement of the smart grid data collecting metering systems and SCADA. Better data sharing for a larger area planning study, and the more coordinated planning effort presented by the RRFE, should also resolve many of these issues. An increased effort from Board to foster openness between players in sharing load growth forecast data and analysis could also improve collective forecasting abilities.

SCADA systems have always been part of the utility business, but not at the retail customer level due to historically high costs and maintenance requirements; this is now changing, and data volumes are rapidly growing. Integrating various utilities to share more grid information can be challenging since they are both collaborators and competitors; however, efforts to encourage regional consistency, coordinated response, and interoperability through standards and guidelines are encouraged by the PB Team. With more accurate input load data, more reliable long range forecasts can be used in power planning studies for better long-term decisions that will benefit all stakeholders. Opportunities exist with the RRFE to align interests, improve cooperation between local distributors and transmitters, and share more sensitive planning information for mutual advantage.

The “first come first served” rule should be abolished. Transmission investments are “lumpy” by nature and smoothing out this investment “lumpiness” is important for rate predictability and equity purposes. Current arrangements are biased toward the first customer that makes the transmission asset request; in many cases, late-coming customers have better arrangements without the first customer being compensated. This creates a disincentive to be the “trigger” and therefore leads to less-efficient planning. Eliminating “first come first served” will encourage customers to propose truly beneficial projects that may have otherwise been disregarded due to the financial concern of being the investment trigger.

Network pooling, as proposed in *EB-2011-0043 Regional Planning for Electricity Infrastructure*, is not necessarily going to lead to over-build and over-reliance on transmission solutions, or unnecessarily increase costs to customers across the province. Pooling at higher voltages (115kV or up) is actually more efficient and covers larger areas. Large capital costs would have less local rate impact when shared by the “Network” pool to spread risks and costs. The network is beneficial for power system stability and strength, even when used as “Line Connections”.

Pooling decisions are made using complex technical and analytical tools which are not particularly “accessible” to the paying consumers. Besides “hard” grid electrical data, study recommendations are dependent on load forecasts (which include broader economic trends) and detailed economic studies (take all electrical data, proposed infrastructure, schedules, etc. and translate/process into investment analysis within a time horizon). The key in the decision making process is a good, reliable load forecast and proven short-term and long term benefits of the proposed investment.

One financial risk of network pooling is spending funds to strengthen the wrong part of the network based on inaccurate predictions and contingency plans, while neglecting real needs. These high-level “Network” infrastructure investments could end up being subject to hidden biases or even political pressures instead of being purely technically driven decisions. For instance, since transmitters’ principal concerns are outages and incidents, they always look for opportunities to strengthen their network and sell to new markets; however, a more “dense” grid could increase available fault currents throughout the network neighbourhood and could lead to costly, switchgear upgrades for other network pool members that are not sharing full benefits.

The hybrid approach to establishing regions proposed by staff is the middle ground between the full pooling option and the status quo option. Since it limits distributors' contributions, it creates the incentive for the distributor to still request the asset without being unfairly penalized financially for a proposed effective solution. Secondly, it eliminates the five-year capital cost contribution/rebate as too short for efficient transmission planning; however, the long-term planning horizon was not defined. Finally, a rebate, with details yet to be defined, would be issued to the initial customers regardless of the timeframe within which the transmitter assigns capacity to another customer.

The proposal to reclassify connection assets to account for additional functional usage with network benefits, therefore becoming subject to network pool classification rules, makes sense to the PB Team; this would allow costs to be spread more evenly and fairly between all customers. Such activities could impact rates since the "Network" is shared by many distributors and "Line Connection" is by one or only a few distributors. While some customers may see a slight increase in transmission rates, no customer should see too large of an impact.

3.3 TREATMENT OF CAPITAL

3.3.1 Board proposal summary

The following "Treatment of Capital" Board proposal summary was presented for discussion in the Straw Man Model Regulatory Framework for Electricity:

Model Framework	Current Framework	Change	Gas Framework
Multi-year approval of capital to match from approved multi-year investment plans throughout term. Outcome-driven planning and focus on reliability.	Full review during COS; may be adjusted during IRM via the incremental capital module.	Pre-approval of multi-year capital plans. Focus on reliability.	Full review during COS.

The following staff discussion papers expand upon the summary presented above from the Straw Man Model:

- *Distribution Network Investment Planning* (EB-2010-0377)
    - Proposes ideas on how the Board's framework and approach to regulatory assessments of network plans can be enhanced.
- *Approaches to Mitigation for Electricity Transmitters and Distributors* (EB-2010-0378)
    - Examines how costs related to asset investments can be smoothed to mitigate any negative impacts of these investments on consumers.

3.3.2 Issues, implications and opportunities for improvement

Summary of key points for retailers:

- Proposed investments should improve overall cost and reliability performance.
- Finding process efficiencies and prioritizing investments to achieve results more quickly is important.
- Alternative cost-recovery models will likely spread out rather than reduce price increases.
- More detailed analysis is presented below.

As evidenced through retailer interview findings presented in section 2.1.3, price certainty for electricity is critical given its ability to affect overall profitability and capital planning. Retailers also communicated that reliability is important, as outages can have an immediate effect on sales, safety and security, with outages leading to food spoilage in grocers without backup generators. The changes that are being proposed should improve overall cost and reliability performance.

Generation, transmission and many distribution investments are generally front-end loaded while benefits are realized only after electricity can be distributed to the grid. Finding process efficiencies and prioritizing investments to “get to market” more quickly is of importance. The proposed harmonization of reviews (e.g. five-year GEA plans and three-year Cost of Service (“COS”) applications) and efforts to improve transparency of plans and applications may help in this regard.

The alternative cost recovery models proposed in EB-2010-0378 will likely spread out/smooth price increases rather than reduce price increases. This would result in higher pre-construction rate increases and lower post-construction rate increases relative to normal cost recovery methods. Increased capital costs would increase price in the short term for long-term benefit – usually to replace plants or increase reliability.

3.4 PERFORMANCE STANDARDS AND INCENTIVES

3.4.1 Board proposal summary

The following "Performance Standards and Incentives" Board proposal summary was presented for discussion in the Straw Man Model Regulatory Framework for Electricity:

Model Framework	Current Framework	Change	Gas Framework
Desired outcomes established for the utilities in addition to existing core performance standards: • Enhanced customer standards used to set outcomes. • Reliability standards developed. • Experts retained to assess utility plans and audit utility planning processes to assess the utility's effectiveness in prioritizing and pacing network investments with regards to bill increases to consumers. • Achievement of investment plan objectives will be encouraged through the use of specific incentives (i.e., financial, reputational, and proportionate processes).	Core performance standards currently in Codes and subject to compliance action. External benchmarks used to adjust rates. A financial incentive is built into the current incentive regulation plan formula for electricity distributors: when distributors "beat the X-factor bar" they are allowed to retain any achieved savings. SSM for CDM.	New performance expectations associated with investment planning and reliability. Potential for expedited review based on utility's effectiveness in prioritizing and pacing network investment with regards to bill increases to consumers. Financial consequences potentially tied to achievement of investment plan objectives.	Core performance standards currently in Rules and/or settlement agreements. External benchmarks used to adjust rates. Earnings Sharing Mechanism is built into share above target earnings with consumers. SSM for DSM[10].

The following staff discussion paper expands upon the summary presented above from the Straw Man Model:

- *Defining and Measuring Performance of Electricity Transmitters and Distributors* (EB-2010-0379)
  - Examines using performance measures and the current and potential role of such measures in the Board's setting of rates to ensure reliable and cost-effective power provision.

[10] Demand and supply management

3.4.2 Issues, implications and opportunities for improvement

Summary of key points for retailers:

- **Appropriate metrics:** there is a need to identify the best metrics and reorient towards customer needs and incentives, and there is an opportunity to improve the accuracy/reliability of critical load forecasts and therefore planning.
- **Balanced risk and reward:** effective incentives and penalties are both required to optimize utility performance.
- **Reliability, capacity and planning horizon issues:** larger-scale, longer-term studies would likely be fairer and yield more cost-effective decisions.
- **Ofgem model commentary:** includes customer satisfaction and social benefit outcomes; a blend of both the current Ontario system and the Ofgem model may offer the best future outcomes for customers.
- More detailed analysis is presented below.

Appropriate metrics

Clear efforts are being made to enhance performance standards and to adopt an effective incentive structure.

To ensure high levels of system performance and to improve the planning process and evaluation of proposals, the right data must be measured. In selecting metrics it is important to consider the following:

- The purpose of measurement must be clear so as to not create additional "data collection" departments and unnecessary administrative burdens.
- There is a need to reorient metrics towards customer needs and incentives.
- Further emphasis should be placed on keeping costs down, ensuring efficient maintenance and capital expenditures, reducing waste/excess redundancy, and discouraging poor performance.
- Objective data should underlie the metrics wherever possible.
- There exists an opportunity to improve the accuracy/reliability of critical load forecasts and therefore planning. Critical load forecasts use a large amount of metering data; utilities already have SCADA and other log systems and some of this is already collected automatically for internal purposes.
- Adopting standardized metrics in measuring utility reliability performance, such as the IEEE Standard 1366 electric power distribution reliability indices, can help compare Ontario distributor performance to other jurisdictions.

During interviews with retailers, some expressed frustration with utility customer service levels. In Table 7 of *EB-2010-0379 Defining and Measuring Performance of Electricity Transmitters & Distributors*, the Ofgem framework for customer service incentives is introduced. While the staff discussion paper acknowledges that further work is needed to develop some of these incentives, the idea of focusing on areas of customer satisfaction, complaints, and stakeholder engagement is sound.

A detailed summary of utility performance measures is presented in Table 4 of the same consultation. Of particular interest to retailers would be inclusion in any utility performance assessment of metrics related to the following areas:

- Service reliability – particularly if a retailer does not have local backup.
- Power quality (voltage surges/sags, "dirty" power) – lighting may suffer with bad voltage.

The current framework CDM targets and incentives should be maintained[11]. Tracking of customer demand-side metrics would help to communicate a more integrated perspective on distribution system and customer satisfaction.

In supporting ongoing measurement of performance, this may highlight and encourage further capital cost investments to achieve required performance by the utility. Big industrial and infrastructure-type customers often require services with much higher reliability (backup feeders, substations, etc.) than the typical smaller retail customer. The higher reliability service also comes with higher installed infrastructure costs, by either the utility or the customer.

Balanced risk and reward

Effective incentives and penalties are both required to optimize utility performance.

It is important to ensure that incentives are not provided for actions that are required by statute/code or the Board's rules. In *EB-2010-0377 Distribution Network Investment Planning*, it was asked whether an incentive-based approach to information filings would help to achieve a requisite degree of quality. It could be countered that the Board should simply set the performance standards and penalize failure to provide/perform.

Financial incentives may be too easily taken for granted by utilities; they can result in raised rates without any tangible infrastructure benefit or improved service quality. Financial incentives for utilities are not mentioned anymore in the Model framework, but it is not clear that they are eliminated. Non-financial incentives, such as simplifying and expediting utility application processes and simplifying electricity rate-setting processes could be more effective, as economically beneficial projects are occasionally caught in the regulatory process to the frustration and expense of both the utility and customers. Expediting applications could be mutually beneficial by accelerating a cost-effective project and avoiding costly delays. The incentive proposed in the staff discussion paper of an expedited review for high performers is viewed positively.

Ex-post incentives could be helpful in terms of ensuring that planning is accurate and/or investments are appropriately implemented. This would help to prevent potential "bait and switch" situations and encourage timely completion of projects where actual performance meets or exceeds design specifications.

Adoption of a built-in "loss of service insurance" component on the bill to compensate for service loss/interruption or other service quality issues (momentary interruptions, sags/surges, "dirty" power etc.) was not considered in the staff discussion papers. Doing so would exhibit a more balanced risk and reward between the utilities and consumers, and this has been discussed and variously applied

[11] *EB-2010-0379 Defining and Measuring Performance of Electricity Transmitters & Distributors*, section 3.3.1.

in New York City and Chicago following major outage incidents. However, this type of loss of service compensation may only be possible for small-scale outages without significantly increasing rates.

Reliability, capacity and planning horizon issues

Utility reliability performance is usually event-based (e.g., outage/service interruption per customer per year, etc.) and driven by expansion (more customers, more load, generation, and therefore more generated income). Improving reliability can be done either by improving operations and maintenance with gradual effects, or by adding or upgrading infrastructure (e.g., doubling a line, creating a Network Loop or adding a larger transformer or new generation).

While operational efficiency plays a significant role in keeping costs under control, the grid capacity limit is a key factor that is difficult to change without significant investment in existing infrastructure (power lines, substations and sometimes generation). Once the grid capacity threshold is reached, grid reliability can be catastrophically impacted.

Grid infrastructure investment has an impact on both reliability and capacity, and therefore it may be tempting for an investor to shift costs between “reliability” and “capacity”, “network”, and other grid definitions to fit a more lucrative financial deal for the typical utility rate increase application. A larger-scale, longer-term study would likely be fairer and yield more cost-effective investment decisions. For example, experience is positive with the Comprehensive Reliability Planning Process (part of the New York Independent System Operator’s Comprehensive System Planning Process), a long-range assessment of both resource adequacy and transmission reliability of the New York bulk power system conducted over five- and ten-year planning horizons[12]. That the Board is willing to look at lengthening the planning time horizon to longer than the current very limited five-year period for both the transmission and distribution level is viewed positively by the PB Team; however, one challenge is the limited amount of historical data available to evaluate renewable energy performance.

Ofgem model commentary

The following key features separate the Ofgem model from the current Ontario system:

- Ofgem scorecard has entries for social benefit outcomes that are hard to measure financially, e.g., “environmental impact”, “social obligations”.
- Ofgem “customer satisfaction” can be relative, but may help to mitigate a sudden, unexpected rate increase.
- Ofgem model appears to offer more price stability (set outcome) but reduced cost transparency.

A blend of both the current Ontario system and the Ofgem model may offer the best future outcomes for customers.

[12] Long Island Power Authority 2012, *Local Transmission Owner Planning Process*, http://www.lipower.org/company/papers/ltpp.html, viewed 22 March 2012.

3.5 APPROACH TO RATE SETTING

3.5.1 Board proposal summary

The following "Approach to Rate Setting" Board proposal summary was presented for discussion in the Straw Man Model Regulatory Framework for Electricity:

Model Framework	Current Framework	Change	Gas Framework
Partial PBR: • OM&A[13] is indexed to performance outcomes and a productivity measure; capital based on approved plan is a pass-through. • Total cost benchmarking of distributors implemented to encourage effective cost containment and help the Board to determine appropriate cost levels associated with investment plans. • Total factor productivity will inform, and total distribution cost benchmarking will be used to support an envelope approach to ratemaking.	Comprehensive Price Cap Plan with empirically-based rate adjustment mechanism.	Sever treatment of OM&A and capital to increase pursuit of operating efficiencies and recognize significant need for capital investment. Measures will be developed to ensure allocative efficiency.	Negotiated Comprehensive Price Cap and Revenue Cap Plans.

The following staff discussion paper expands upon the summary presented above from the Straw Man Model:

- *Defining and Measuring Performance of Electricity Transmitters and Distributors* (EB-2010-0379)
  - Examines using performance measures and the current and potential role of such measures in the Board's setting of rates.

[13] Operations, maintenance and administrative.

3.5.2 Issues, implications and opportunities for improvement

Summary of key points for retailers:

- Using Total Factor Productivity (TFP) to inform rate setting is valuable and its use should support focus on efficiency, reliability, and long-run cost reduction.
- It is not clear what safeguards will be in place to prevent sudden, large rate increases.
- GEA-related infrastructure spending could be a hidden cost driver, especially at the distribution level.
- More detailed analysis is presented below.

The Board recognizes the need to invest in infrastructure and to make the rate setting process more transparent.

Total Factor Productivity (TFP) is proposed to inform rate setting. A system that includes TFP is valuable from the PB Team's perspective, as utilities respond to incentives to modernize and increase efficiency and reliability, in turn reducing long-run costs. Depending on its implementation, TFP can be effective for transmission-related assessment despite the "lumpiness" of investment if it is based on long-term planning with proven short-term payback. Social and environmental benefits (like in the Ofgem model) are hard to justify in a TFP-cost basis.

However, while some performance factors such as the "total factor productivity" and "total cost benchmarking" may have "attractive" names, they could also hide derived factors that are themselves based on infrastructure and other complex assumptions that do not fully consider the actual service performance of the utility. Depending on how TFP is administered, hidden costs could grow; for instance, utilities have traditionally archived a large amount of data grouped by department, and calculation of TFP can be quite labour-intensive. Technology could mitigate some of the administration costs associated with this switch.

While TFP can be helpful for assessing some elements of performance, there is a concern that TFP may under-reward distributors in situations where they have inferior existing capital and a metric is tied to/dependant on existing capital (e.g., existing transmission and distribution facilities). If performance relates to existing facilities, a better comparator may be improvement over time measured relative to baseline performance.

Where retailers are located in markets with small distributors who may have aged/obsolete systems and weaker OM&A departments they may be exposed to additional price risk. Typically, distributors who under-invest in capital can offer cheaper rates in the short-term; however, a serious incident may force a sudden investment in infrastructure due to political pressure. Documents would not necessarily communicate this level of information or risk.

Under the Model framework, it is not clear what safeguards will be in place to prevent sudden, large increases in electricity prices. There is a need for further clarity in this area to improve electricity rate predictability. There is also a need to better understand how the proposed approach to rate setting will ensure the desired allocative efficiency and manage the final price impact.

GEA-related infrastructure spending is not mentioned as a separate entity, but it could be a hidden cost driver to the infrastructure, especially at the distribution level.

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3.6 PERIOD OF COS/IRM REVIEW

3.6.1 Board proposal summary

The following "Period of COS/IRM Review" Board proposal summary was presented for discussion in the Straw Man Model Regulatory Framework for Electricity:

Model Framework	Current Framework	Change	Gas Framework
Term is based on the utility's plan, as approved. Off-ramps determined by performance against plan.	COS every four years; IR in between (3rd Gen IR). Off-ramps determined by financial criteria.	Period between COS reviews more flexible. Off-ramps more strict.	COS every six years; IR in-between.

The following staff discussion papers expand upon the summary presented above from the Straw Man Model:

- *Approaches to Mitigation for Electricity Transmitters and Distributors* (EB-2010-0378)
    - Examines how costs related to asset investments can be smoothed to mitigate any negative impacts of these investments on consumers.
- *Establishment, Implementation and Promotion of Smart Grid in Ontario* (EB-2011-0004)
    - Examines how/what to provide as guidance to regulated entities to establish, implement and promote the smart grid.
- *Regional Planning for Electricity Infrastructure* (EB-2011-0043)
    - Discusses improving planning of transmission network investments (specifically line connections and reclassification of categories and investment plans based on usage: network, line connection, dual use, etc.).

3.6.2 Issues, implications and opportunities for improvement

Summary of key points for retailers:

- Structuring COS reviews to match the utility's plan should better match reviews with key milestones; however, this may reduce price certainty/predictability.
- Stricter off-ramps to allow rate rebasing should reduce rate risk exposure, or at very least ensure than any rate rebasing is merited and justified.
- More detailed analysis is presented below.

Under the current framework, "The current rate regulation regime for distributors is known as Incentive Regulation Mechanism ("IRM"). With this mechanism, a distributor has its rates rebased through examining its costs and revenues in a COS application every four years. During the intervening three years, through an IRM formula, a distributor has its rates adjusted for inflation, and a productivity stretch factor"[14].

Under the Model framework, structuring COS reviews to match the utility's plan, as opposed to completing them on a fixed four-year timeline, is a shift that should improve alignment between

[14] *EB-2011-0004 Establishment, Implementation and Promotion of a Smart Grid in Ontario.* section 4.1.

reviews and key milestones. This more flexible schedule tied to performance, should better match infrastructure improvement plans to rates. It would also encourage modernizing and improving OM&A performance by tying results more directly to the COS application. This more flexible schedule may, however, reduce price certainty/predictability.

There is merit to tying rate rebasing to broader performance versus plan, as compared to solely financial criteria as under the current framework. Stricter off-ramps to allow rate rebasing should reduce rate risk exposure, or at very least ensure that any rate rebasing is merited and justified.

3.7 TOTAL BILL MITIGATION

3.7.1 Board proposal summary

The following "Total Bill Mitigation" Board proposal summary was presented for discussion in the Straw Man Model Regulatory Framework for Electricity:

Model Framework	Current Framework	Change	Gas Framework
Ex-ante and ex-post.	*Ex-post* only.	*Ex-ante* added.	No requirements.
Total bill considered.	Only distribution charges considered.	Changes in all charges considered.	
Threshold based on empirical data.	10% threshold.	Threshold set empirically.	
Conventional and alternative mechanisms considered.	Conventional mechanisms only.	Alternative mechanisms.	

The following staff discussion paper expands upon the summary presented above from the Straw Man Model.

- *Approaches to Mitigation for Electricity Transmitters and Distributors* (EB-2010-0378)
  - Examines how costs related to asset investments can be smoothed to mitigate any negative impacts of these investments on consumers.

3.7.2 Issues, implications and opportunities for improvement

Summary of key points for retailers:

- **RCC retailer rate classification:** five rate classes exist, each of which are divided into three levels. Retailers should generally fit in the second and third classes.
- **Bill mitigation threshold:** More work is required to formalize the Total Bill Mitigation criteria. Board now looking at total bill, not just the distribution component. There is no fixed cap on maximum price increases.
- **Additional mitigation possibilities:** use of smart meter data may allow targeted mitigation for customers who cannot shift demand from peak or mid-peak TOU rates.
- **Bill communication:** A communication opportunity exists to help retailers better understand bills and to mitigate costs through information about electricity management.
- More detailed analysis is presented below.

RCC retailer rate classification

As per the Power Advisory LLC *Bill Impact Estimation Model*, Ontario electricity customers are divided into five classes based on the monthly average energy consumption and peak demand; for simplicity, the PB Team has grouped together Large Users 1 and 2 below. In general, once a customer reaches a certain size, a "demand" charge is applied to that customer to account for the installed generating capacity costs as separate from the actual electricity generation costs, as shown in the following list:

1. Residential (up to 1,500kWh electricity consumption).
2. Small GS (less than 50kW; between 2,000kWh and 10,000kWh electricity consumption).
3. Large GS (50kW to 1,500kW demand; no consideration of kWh electricity consumption).
4. Large Users 1 and 2 (1,500kW and up; no consideration of kWh electricity consumption).

Each class is further subdivided into three levels. The Large GS and up customer classes would qualify for both demand-based and consumption-related rates.

Based upon feedback from interviews and retailer energy analysis in section 2.1.3, Ontario retailers will generally fall into the second and third rate classes.

Bill mitigation thresholds

More work is required to formalize the Total Bill Mitigation criteria.

Under the Current framework, there is a maximum 10% increase threshold on distribution charges. Historically, "The Board has generally not required mitigation to address impacts stemming from non-delivery charges, but has expressed an awareness of the impacts of these other charges on consumers."[15] Under the Model framework, while the total bill is now considered, the threshold is based upon historical data and both conventional and alternative mechanisms are considered.

Rate mitigation issues are left somewhat open-ended; the previous 10% mitigation threshold is not included in the Model framework and the alternative mitigation mechanisms do not establish a clear mitigation cap. Without a predefined threshold percentage (either in relative or absolute terms), electricity rates could increase unexpectedly. It is also not clear what if any impact "alternative" mechanisms will have on pricing, which Board staff suggested "may be more appropriately characterized as financing tools."[16] For effective mitigation, it is of fundamental importance to ensure that long-term distribution planning is based on realistic load growth estimates for predictable electrical rates. In addition, GEA-related impacts including grid upgrade costs should be captured in the threshold.

The Navigant report and Straw Man framework suggest that mitigation should consider both Ex-post and Ex-ante. A main Board concern is to avoid rate shock and smooth out any rate increases without affecting rate of return for utilities so as to not play catch up in the future. Board defines as "lumpiness" the fact that a long-term infrastructure investment does not gradually benefit the grid during the investment period, but only at the end (i.e., when transmission line, or power plant is turned on)[17]. From a retailer's point of view, smoothing out rates (or "phasing-in") abrupt rate

[15] *EB-2010-0378 Approaches to Mitigation for Electricity Transmitters & Distributors*, section 2.2.5.
[16] *EB-2010-0378 Approaches to Mitigation for Electricity Transmitters & Distributors*, section 4.2.
[17] EB-2011-0043 *Regional Planning for Electricity Infrastructure*, section 2.1.1.

increases has the benefit of predictability to maintain profit margin in the competitive retail pricing environment without excessively increasing prices. An electricity rate shock could translate into a customer "sticker" shock if immediately passed to the product price.

Many customers, not simply retailers, appreciate structure and consistency in pricing. They prefer long-term visibility to prepare for and mitigate pricing impacts. In planning, short-term is typically defined as a five-year or less horizon, with the long term being at least 10 years (and perhaps as high as 30 years). The Board is reluctant to provide a number on "long term" because past history has shown long-term data to not be truly accurate. The reason for unreliable data is not given (economic assumptions; lack of "smart" data collection?; etc.); however, having at least a ten-year rate planning horizon for key components of the bill and with clear pricing ranges and maximum caps, would be helpful from the consumers' perspective. It remains to be seen if mitigation levels will be consistent across the Board or differ between rate classes, resulting in some groups being more affected than others.

Additional mitigation and incentive possibilities

Using smart meter data, it may be possible to facilitate targeted rate mitigation for low-consumption utility customers who are unable to shift demand from peak rate periods owing to business considerations. For equitable mitigation, it is important to recognize the inability of some customers to shift demand patterns. As noted in section 2.1.2, retail energy consumption trends almost exactly match peak and mid-peak rates in Ontario.

Finally, rebates may be appropriate for "good" customers, e.g., those who participate in CDM activities or demand-response events.

Cost mitigation with Behind-the-Meter systems

In theory, cost reduction opportunities exist for retailers through their management of demand and energy consumption with BTM systems. Many large retailers have already invested in BTM and small retailers will not likely use the data because they do not know what it means. Due to the standard retail load profile presented in Figure 3 that largely matches TOU pricing as well as general business requirements, the BTM approach may not offer significant benefit for most Ontario retailers.

Bill communication

In addition to total cost concerns, during interviews, retailers professed a lack of understanding around electricity bills. An opportunity exists to better "decode" bills to improve comprehension and ability to mitigate costs through information about electricity management. The Global Adjustment Rate was particularly confusing to some retailers; better explanation of what the Global Adjustment Rate is would be welcome.

3.8 'STRAW MAN' MODEL REGULATORY FRAMEWORK FOR ELECTRICITY – DISTRIBUTION NETWORK INVESTMENT PLANNING

3.8.1 Board proposal summary

Please see page iv of the Straw Man Model Regulatory Framework (Appendix C) for full details.

The regulations and guidelines provided by the Board have stated the following goals:

- Regional-level optimization of power grid planning and integration.
- Renewable energy generation through "smart" grid approach.
- Expectations for performance and outcomes.

The end results of the improved regulatory framework include:

- Better integration of renewable energy projects.
- "Smart" grid improvement projects.
- Projects to accommodate demand growth.
- Projects to maintain and improve the grid operations.

3.8.2 Issues, implications and opportunities for improvement

Summary of key points:

- The Board expects that high-level regional planning at with longer-term approach will result in an improved, more transparent rate application process.
- Retail customers expect price predictability and control; avoidance of overbuild; system reliability; and improved communication about price increases and CDM opportunities.

The Straw Man graphical presentation provided in Appendix C divides the stakeholders into three groups: Ontario Energy Board; Distributor; and Customers.

Based on the chart, the Board's expectations are that the higher-level regional planning, multi-year investment horizon (versus the current short-term approach) will result in an improved, more transparent rate application process based on customer input.

The load and generation connection applications are treated somewhat separately from the other framework components and are shown as contributors equal to customers in the network investment planning process.

While not defined in the Straw Man Model, customer expectations based upon feedback from retailer interviews include:

- Price predictability and control (for that which can be controlled).
- Avoidance of overbuild.
- System reliability.
- Improved communication from the Board and distributors overall, particularly about price increases and opportunities to participate in CDM.
    - Understanding the trajectory of anticipated price increases will help retailers build in measures for electricity management in their capital planning process and acquire expertise.

- Many retailers are confused about new programs, struggle to derive benefits and require further education.
- Information written in accessible, retailer-oriented language that provides clear, concise and easy-to-action directions would be appreciated.

While CDM programs were not tied into this framework, their inclusion should be considered from an integrated planning perspective. The most cost-effective, reliable system is the desired outcome for retailers and customers in general, and CDM measures may be even more “green” and economical than large-scale GEA investments or investments in traditional electricity generation sources.

APPENDIX A –RETAILER INTERVIEW QUESTIONS

1. Ongoing electricity use and costs

i. What consumes electricity? ventilation, cooling, lighting, IT, cash registers, refrigeration (breakdown by percentage)
ii. What is the share of electricity cost in relation to overall operating cost? In relation to facility cost?
iii. Is the use consistent over business operating hours? How much when store is closed?
iv. Do you know what the total consumption is for an average store over the year (total, peak and TOU data?
v. What types of strategies do you use to manage costs? (i.e., bill audits, utility management systems, demand response, own generator, etc.)
vi. Which rate structures are applicable? Do you know? (retail contract with wholesalers, TOU pricing with local retail distributor, billed via landlord based on fixed/leased area rate, billed vial landlord based on sub-meter, other)
vii. Have you been affected by TOU rates? Explain.

2. Quality issues and costs

viii. What is your experience of supply disruptions? Are they becoming more frequent? How many hours per year?
ix. What type of power backup power requirements do you need to have?
x. How much of your regular demand has to be covered by backup capacity?
xi. If leasing store space, what do you demand from landlords – what is the input into retail facility specifications/leases?
xii. What do your insurance companies demand?
xiii. What are the extra operating costs associated with disruptions in power supply?

APPENDIX B –RETAIL SECTOR ELECTRICITY INSIGHTS PRESENTATION

Retail Sector Electricity Insights

Retail Council of Canada
March 20, 2012

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Contents

- Research methodology
- Electricity use in retail and cost implications
- Electricity management

Research methodology

Data on electricity use in the retail industry is lacking

- Literature review revealed no information beyond high-level energy use profiles and typical conservation measures
- Published information does not apply to current Canada/Ontario scenario
- Retailers treat electricity use and cost as confidential information due to industry competitiveness and investment in acquiring expertise
- New information required to inform RCC consultation response

Industry associations and government sources were reviewed (limited use)

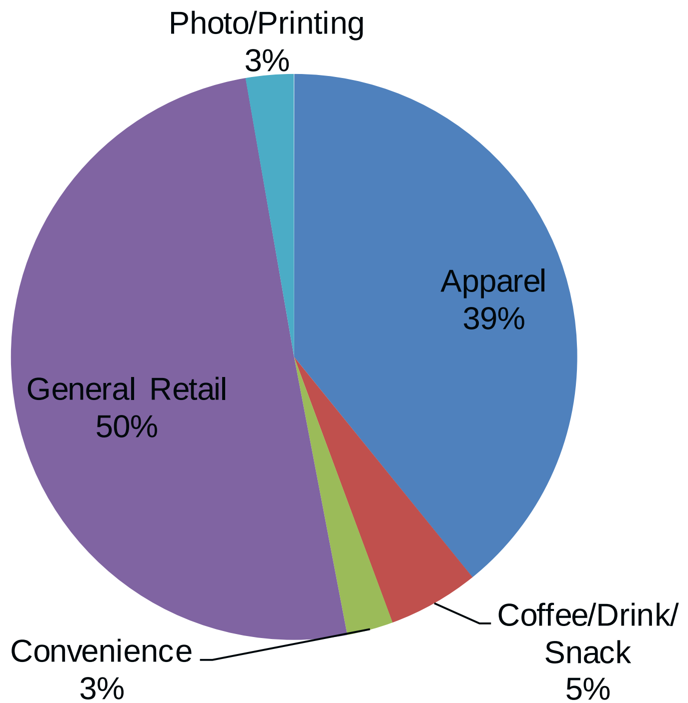
Type of Association	Reviewed Association Websites

Government	• ENERGY STAR U.S. and Canada
	• Natural Resources Canada (NRCan)
	• U.S Department of Energy –
	    • U.S Energy Information Administration (EIA)
	    • Retail Energy Alliance

Industry	• International Council of Shopping Centers (ICSC) • Food Marketing Institute (FMI) • Professional Retail Store Maintenance Association (PRSM) • Edison Electric Institute (EEI) • International Facility Management (IFMA) • American Council for an Energy-Efficient Economy (ACEEE) • Independent Electricity System Operator (IESO)
Not for Profit	• Alliance to Save Energy, U.S. • Carbon Trust, U.K. • Greening Retail, Canada

We analysed 12 months of sub-metered TOU data from 34 small retailers to determine use profiles

Retail Electricity Data Analysis
(Retail Category by Share of Total Building Area)



Source: Halsall Building Energy Database; Actual 2011-2012 data from 34 retailers located in shopping concourse of Toronto indoor office complex.

We also interviewed 6 large and 2 small retailers with Ontario presence

Telephone Interview Participants

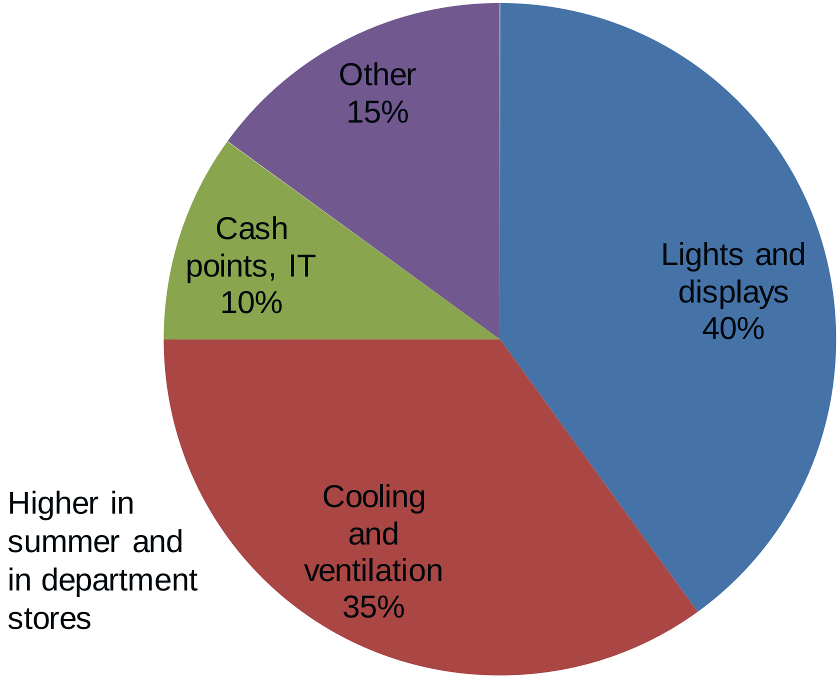
Size	Type of Retailer	Role
Large	Grocer	Director Risk Management
	Grocer	Lead Energy Management
	Big Box Furniture	Country Facilities Manager
	Department Store	Senior Manager Energy
	Chain – Telecom & Media	Energy Manager
	Chain – Specialty Retailer	Manager Energy & Environmental Management
Small	Sporting Goods	General Manager
	Kitchenware Goods	Vice President

Note: Interviews were agreed to under the promise of confidentiality.

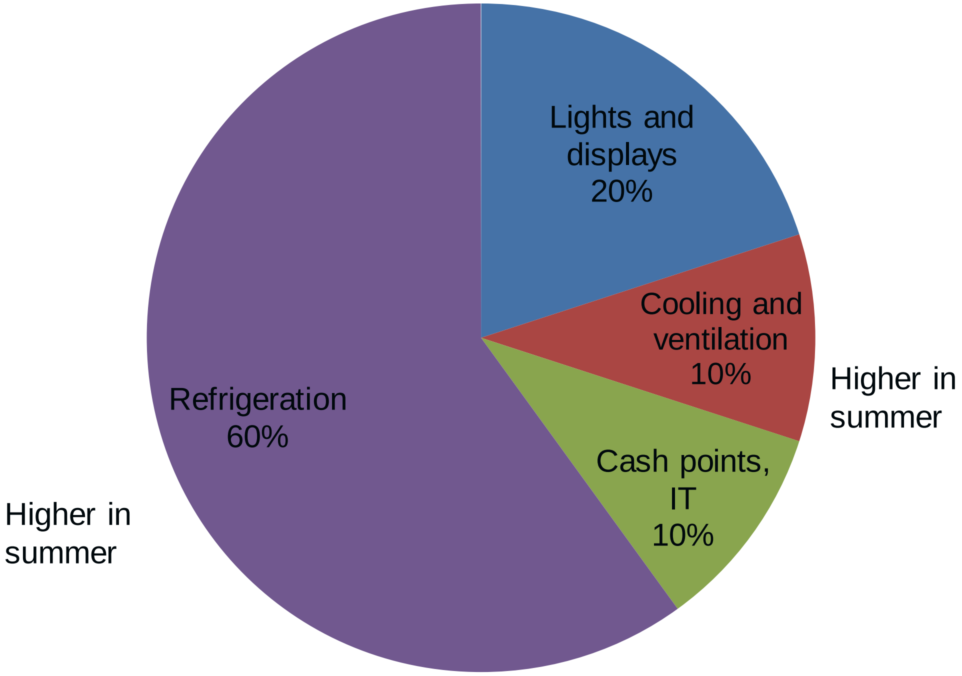
Electricity use and cost implications

Lighting and refrigeration consume most electricity in stores

General Retailer



Grocer

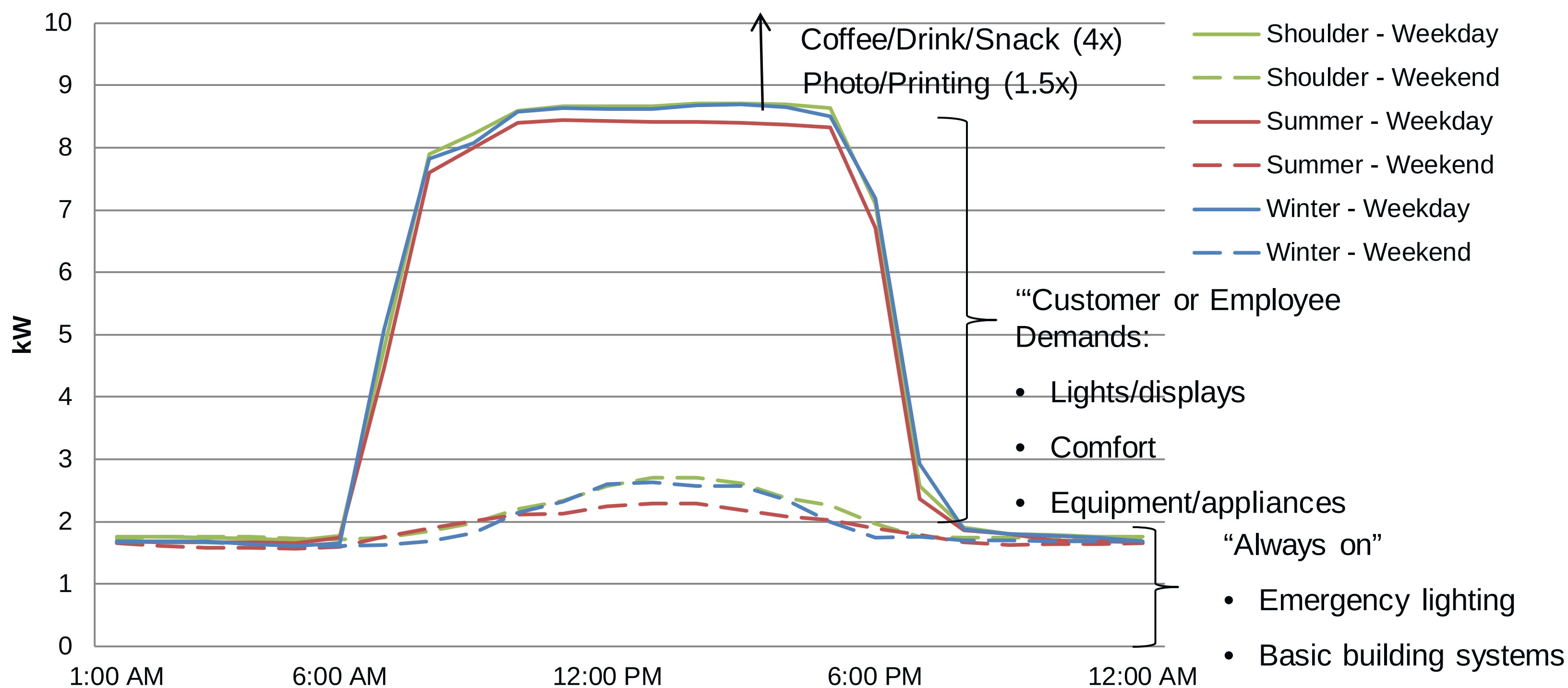


Sources: Loop Initiatives interviews with large retailers. Small retail assumed to be similar (lack of data/analysis).

Sustainably motivated • Business minded

Retail electricity consumption is a function of opening hours

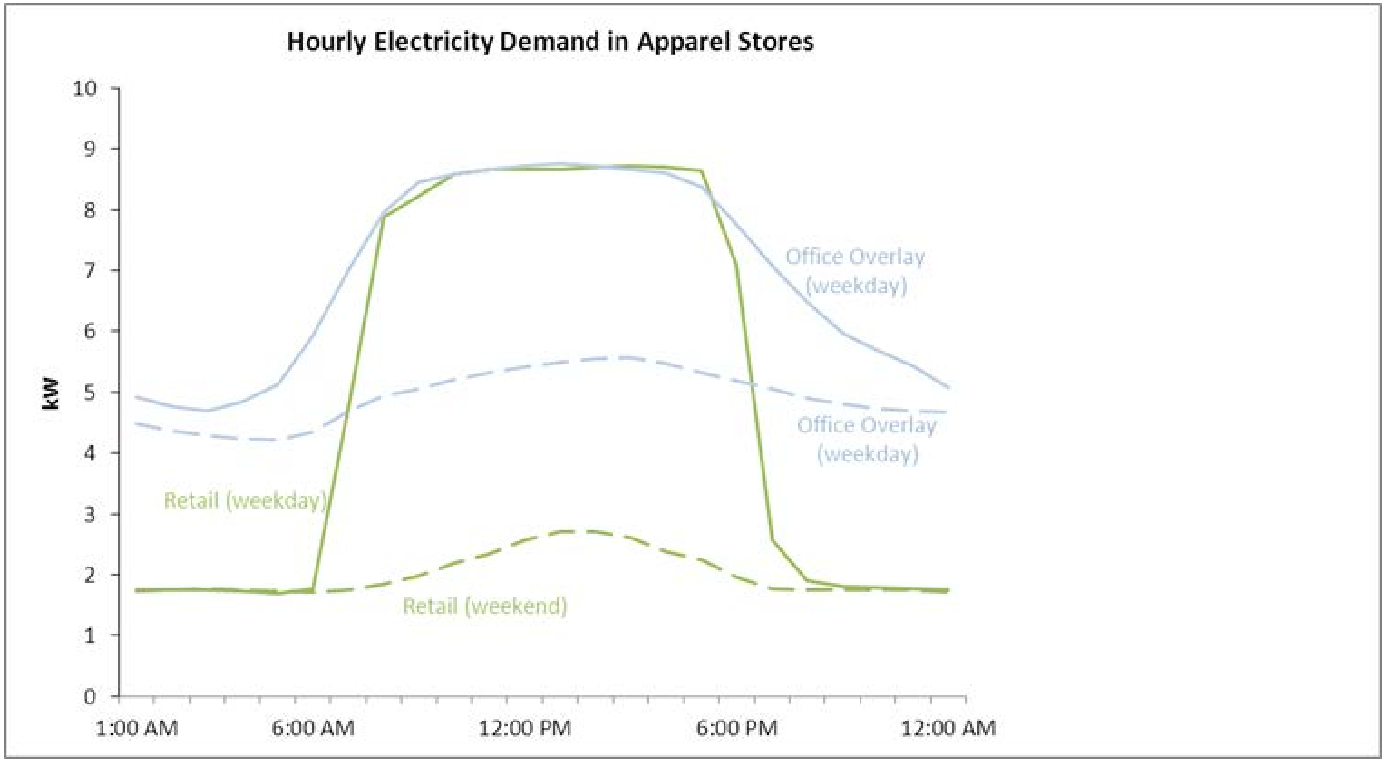
Average Daily Electricity Usage
Apparel, Convenience and General Retail



Source: Halsall Building Energy Database; Actual 2012 data from 34 retailers located in Toronto indoor office complex mall.

Retailers are relatively more exposed to TOU than consumers with a larger share of steady use

Retail vs. Office Electricity Consumption Profile



Source: Halsall Building Energy Database.

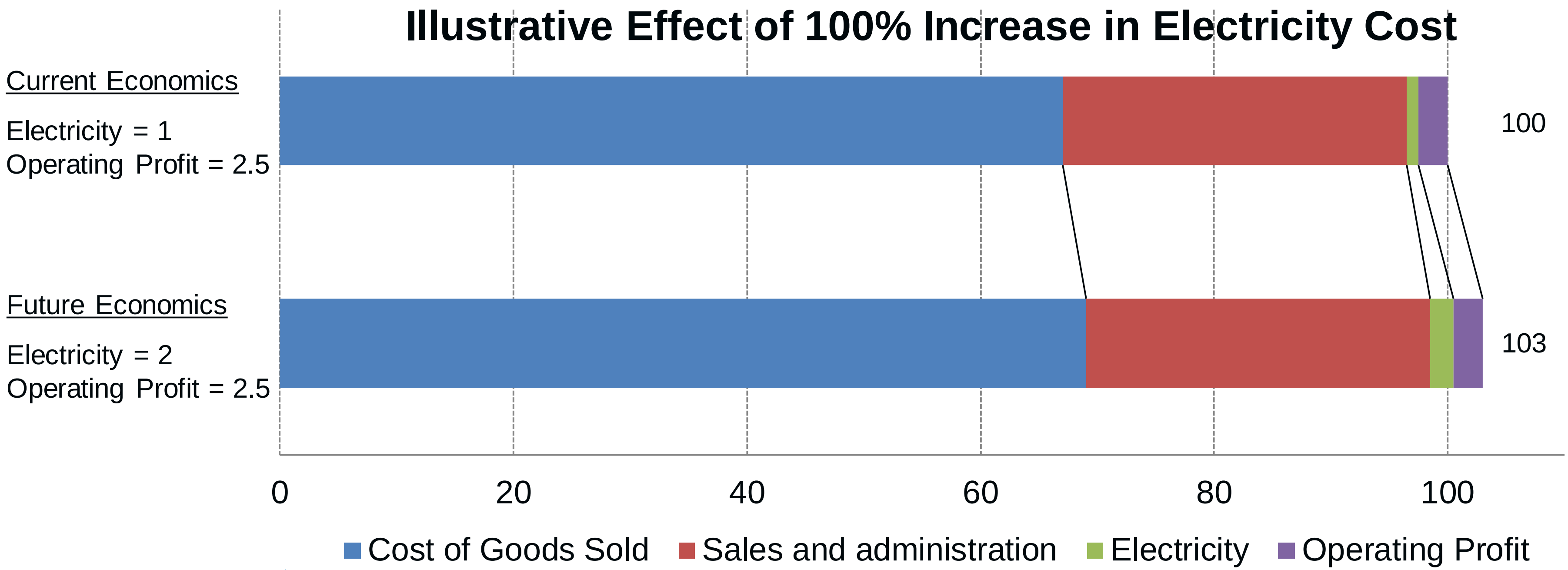
Electricity can represent a significant cash cost for a small retailer

Typical Daily Electricity Use for a 1,500 ft^2 Shop

Retail Category	Annual Electricity Use (kWh)	Estimated Annual Cost ($)	Equivalent FTE Cost
Apparel	35,620	3,562	17%
Coffee/Drink/ Snack	171,596	17,160	83%
Convenience	41,182	4,118	20%
General Retail	34,518	3,452	17%
Photo/Printing	34,896	3,490	17%

Notes: Actual electricity use for sample of 34 retailers operating 65hrs/wk; estimated cost of 10 cents/kWh; estimated annual salary cost of $20,700 (min. wage, CPP, EI).

A doubling of electricity cost requires a 3% increase in sales to obtain same profit



Two Strategies to Mitigate Electricity Price Increase: Increase sales with 3% OR decrease fixed costs with 3%

Sources: Loop Initiatives interviews with large retailers. Review of retailer financial statements published in annual reports.

Electricity Management

Sustainably motivated • Business minded

For large retailers electricity management is a key competitiveness factor

Observed Management Strategies at Large Retailers

- Execute bill audits: check invoices and compare metered consumption and applicable rates
- Implement utility management system: access to all consumption and cost data in one location and analytical tools
- Invest in energy efficiency where positive ROI
- Bulk supply (retail) contracts: lock in or hedge electricity costs
- Demand response: obtain advance warnings of blackouts and obtain compensation for shut down
- Own generation: avoid peak rates; sell electricity to distributors at premium rates

Significant investments in know-how and technology are required to manage risk and opportunity

Sources: Loop Initiatives interviews with large retailers.

Due to lack of expertise, small retailers are more exposed to price increases

Small Retail Disadvantages

- Electricity management is not a core competency - difficult to access, interpret and take action on electricity data – *"No one in the company would know % breakdown of electricity use"* [general manager, small retailer]
- Unaware of options to reduce electricity use *"We need lights and computers to run the business"* [vice president, small retailer]
- Not affordable to hire specialized staff or outsource to third party providers
- Often covered by TOU rates (where SMART meters have been installed)
- Typically unaware of changes to rates until after the fact - "*It just showed up on our bill*" [energy manager, chain of smaller outlets]
- Sense that they have no power - "*We have tried to get the data for more than two years and we are still trying*" [energy manager, chain of smaller outlets]

Support programs needed to enable level playing field

Sources: Loop Initiatives interviews with large and small retailers.

Large retailer management experience shows potential, but execution barriers exist

Common Strategies to Reduce Electricity Demand

Base Load	Peak Demand	Total Consumption

• Just-In-Time scheduling of ventilation, cooling and lights
• Equipment testing and maintenance
• Fridge “curtains”
• Minimum requirements for store cleaning and stocking
	• Systems and protocols for:
	  • Dimming lights
	  • Reducing cooling
	  • System shutdown
	• On-site renewable generation
	• Demand response
		• Light retrofits (e.g. LED)
		• Upgrades of fridges, freezers and chillers
		• Switch to closed fridges and freezers
		• On-site renewable generation

Issues to Execute Strategies:

- **Access to expertise**

- **Negative sales impact**

- **Significant capital requirements**
- **Available technology**
- **Customer mindset**

Sources: Loop Initiatives interviews with large retailers.

Large retailers do not feel they can control a large share of their cost, reducing incentives to take action

Potential Components of Electricity Bills

Type of Charge	Observed Charges
Consumption Charge	• Global adjustment • Wholesale operation charge • Special purpose fee
Demand Charge	• Distribution charge • Lost revenue adjustment • Transformer allowance • Shared savings charge • Transmission charge
Fixed Charge	• Local access fee • Customer charge • Basic charge • Electric energy charge • Administration charge • Delivery charge

Sources: Energy industry research. Loop Initiatives nterviews with large retailers.

Present contract structures dis-incentivize retailers to manage electricity

High-level Overview of Contract Structures

Contract Structure	Applicable Retail	Subject to TOU	Ability to Influence		
			Consumption Charge	Demand Charge	Fixed Charge
Retail contracts with wholesalers	Large chains; Very large stores		✓	✓	
TOU pricing with local retail distributor	Small stores; Street location (non-mall)	✓	✓		
Billed directly by local retail distributor	Small stores; Street location (non-mall)		✓	✓	
Billed via landlord based on fixed/ leased area rate	Shared building; Shopping centre location	LACK OF INCENTIVE TO TAKE ACTION			
Billed via landlord based on sub-meter	Shopping centre location	✓	✓		

LACK OF INCENTIVE TO TAKE ACTION

Source: Loop Initiatives analysis.

Legend: ✓ = Present; shaded = Not present, lack of incentive to address

At present, retailers do not appear to be significantly concerned about blackouts

System Reliability – Interview Synthesis

- Electricity system reliability is very important due to impact on sales, employee/customer safety and security/theft
- In interviews, retailers did not indicate that blackouts are a major concern at current service levels, especially when compared with large and/or unpredictable price increases
- Most supply disruption is managed by battery back-up power provided by landlord, rented or own generator capacity
- Large scale disruption is most critical as electronic transactions (e.g. Interac, Visa) are not feasible

Source: Loop Initiatives interviews with large and small retailers.

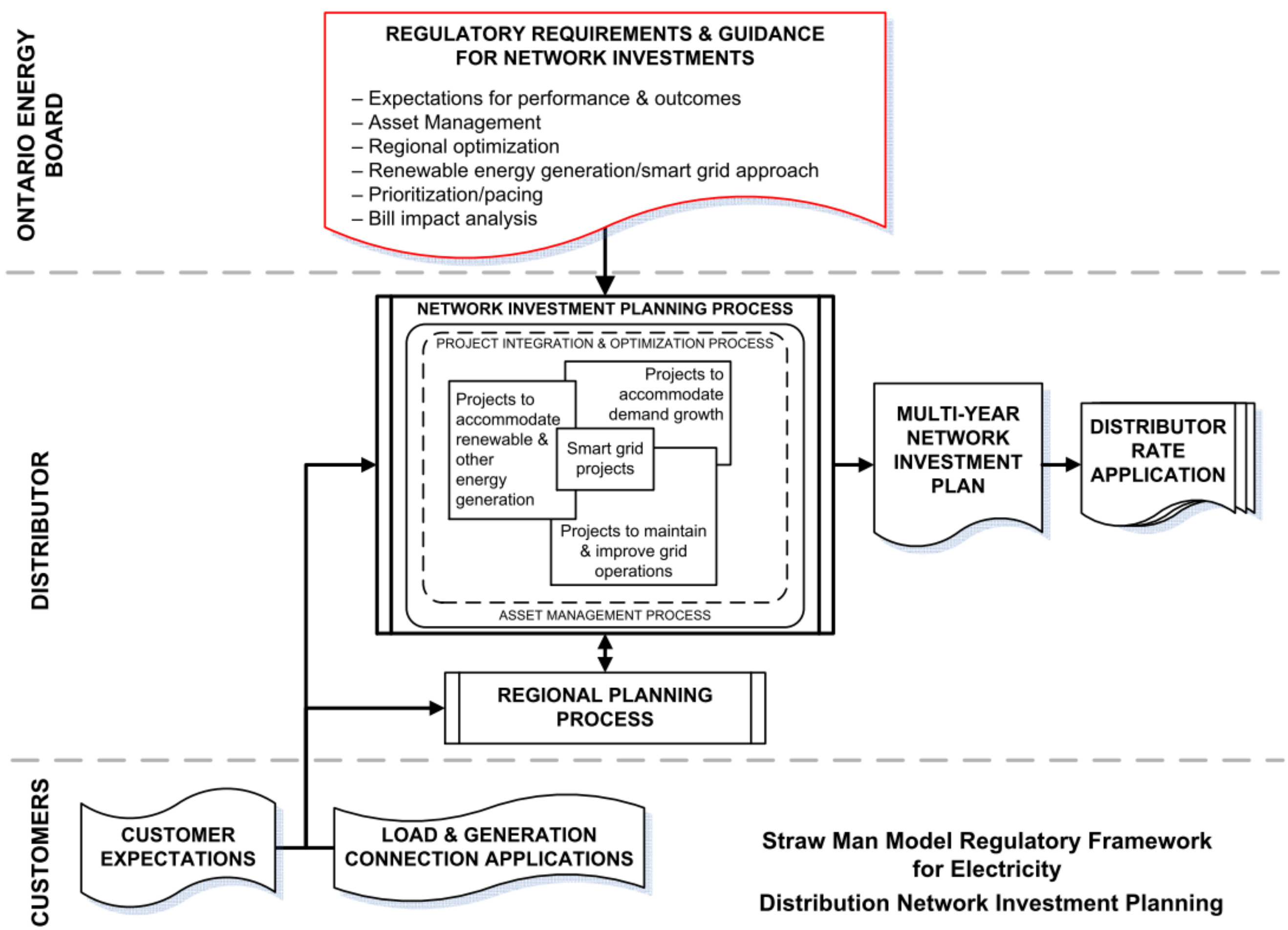
Battery power is typically used during periods of shorter blackouts; presence of generators varies

Factors Driving Backup Capacity

	Electricity Draw	Code Requirement	Health & Safety	Insurance Requirement	Internal Decision
Battery Power to Enable Max 6 hours of Critical Operations	Emergency Lighting	✓	✓	✓	
	Security System	✓		✓	✓
	Point of Sale System				✓
Generators to Enable Business Operations	Refrigeration				✓
	Lights				✓
	Building System				✓

Source: Loop Initiatives interviews with large and small retailers.

APPENDIX C – STRAW MAN MODEL REGULATORY FRAMEWORK FOR ELECTRICITY – DISTRIBUTION NETWORK INVESTMENT PLANNING



APPENDIX D – ACRONYMS

BTM: Behind-the-Meter
CAIDI: Customer average interruption duration index
CDM: Conservation and demand management
COS: Cost of service application
DSM: Demand and supply management
GEA: Green Energy Act
GS: General Service
IEEE: Institute of Electrical and Electronics Engineers
IRM: Incentive Regulation Mechanism
MTBF: Mean time between failure
OM&A: Operating, maintenance and administrative
RCC: Retail Council of Canada
RRFE: Renewed Regulatory Framework for Electricity
SAIDI: System average interruption duration index
SCADA: Supervisory, control and data acquisition system
TOU: Time-of-use