Stakeholder Comments on RRO Options

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Options for Enhancing the Design of the Regulated Rate Option (RRO)

Participant and Stakeholder Response

May 19, 2017

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On behalf of the Alberta Federation of Rural Electrification Association (AFREA) Members, thank you for the opportunity to provide input concerning the review of Options for Enhancing the Design of the Regulated Rate Option (RRO). As the RRO is an integral part of the services provided by each Rural Electrification Association (REA) within the AFREA, it is imperative that stakeholder engagement in this process is structured, detailed, and given proper time and consideration as changes to the RRO will impact REAs. As such, the thoughts and views expressed are representative of REA members of the AFREA. This document provides high level responses and input into the RRO review process; however, should additional detail and elaboration be required the AFREA and REA Members are open and available to provide.

Response Outline

Background on AFREA REA Member

The AFREA promotes the economic welfare of its cooperative members by providing strong representation to government and stakeholders. Through its ongoing professional interaction within the electric industry, and the Alberta rural community, the AFREA maintains mutual relationships and supports the "working together" cause of the cooperative business model. An understanding of the government and its processes, financial responsibility and accountability, and a high level vision provide an outline for effective leadership that not only promotes viability within, but supports members and the REA family, as a whole. Twenty-three of the thirty-two REAs in the province today are members of the AFREA.

The AFREA vision of *Innovative & Dynamic REAs* supports the value of REAs as significant contributors to the economy of rural Alberta. Part of our core mission is to create the conditions for REAs to be successful and sustainable – not just within our membership, but for all REAs as part of an ever-changing rural demographic.

Within this section of the response, the following areas will be addressed:

- REA Structure
- Retail Functions / Services

REA Structure

Rural Electrification Associations (REA) operate under the *Rural Utilities Act* (http://www.qp.alberta.ca/documents/Acts/R21.pdf) and the *Rural Utilities Regulation* (http://www.qp.alberta.ca/documents/Regs/2000_151.pdf). The Act establishes the organisation, governance, and makes provisions for the management of business and affairs of rural utilities associations. A rural utility association is an incorporated entity of five or more persons, of which its main purpose is to supply to its members utility services for electricity, gas, and/or water that is used primarily for domestic purposes, and sewage. An REA qualifies as a rural utility association. REAs provide RRO service to members, but it is imperative to clarify that REAs are not retailers and do not have the same structure or motivation as competitive retail entities.

REAs are cooperatives and, as such, are owned by their members. Each REA owns its utility distribution system. Therefore, REA members own the distribution wires through the REA. There are two distinct types of REAs: self-operating REAs own and operate their own utility distribution systems, and operating REAs that own their utility distribution system and contract the operation and maintenance to another party. REAs also provide various levels of energy retail services for their members that includes the provision of RRO service and some also provide a stable rate for members.

As owners of distribution systems, the REAs are under consistent competitive threat from ATCO Electric and FortisAlberta. With few growth prospects in the province of Alberta, Investor Owned Utilities (IOU) such as ATCO Electric and FortisAlberta see the distribution systems owned by the REAs as opportunities for growth, as evidenced by their ongoing acquisitions of REAs.

Retail Functions / Services

The provision of retail services varies across REAs. The spectrum of services offered, and associated comments, by REAs include:

- Provision of Regulated Rate Option
- Energy Retail / Stable Rate
- Price Risk Mitigation
- Billing of Revenue
- Settlement of Supply Expenses

Some REAs provide stable rates, others do not. Within those REAs that provide stable rates the contract durations vary, but it is important to point out that no stable rate operate as month to month products like the RRO, rather they are fixed for annual terms.

Some of the REAs provide the RRO themselves while others source the provision of RRO from other external entities which include, but may not be limited to:

- Direct Energy Regulated Services (DERS) – 10 REAs
- EPCOR Energy Alberta (EEA) – 6 REAs
- Other REAs – 16 REAs (provide their own members or other REAs)

The provision of RRO service by the REAs or by contracted service providers has followed the Regulated Rate Option Regulation *(Alberta Regulation 262/2005).*
http://www.qp.alberta.ca/documents/Regs/2005_262.pdf.
Specifically, some REAs have hedged for future RRO load in alignment with the Act, calculated corresponding RRO rates monthly, submitted those rates to the appropriate Regulatory Authority, which in the case of the REAs is their Board of Directors, and posted the rates appropriately for the REA members.

Other REAs have not engaged in the execution of forward market transactions to mitigate price risk for members on the RRO, but have implemented other means for price risk mitigation. Specifically, one REA has implemented price mitigation structures for RRO exposure that implements a "surplus energy fund" that smooths the effects of commodity pricing across months for RRO consumers. In this specific example when the fund grows beyond a determined amount, members receive refunds either through reduction in energy commodity rates or through an energy rebate payment. Conversely, when the fund declines below a determined value commodity price the RRO will be increased. This structure acts to mitigate price volatility in a manner reflective of a not for profit organization in that over collections when supply prices are low and application of the reserved energy fund during times of high supply cost smooth commodity prices for their RRO rate base.

To summarize, REAs are member-owned, not for profit cooperatives that own distribution systems and some provide retail functions to their members.

Questions Posed by the MSA

The AFREA provides the following feedback on behalf of its members, to the questions posed by the MSA in the 21-Apr-17 Options for RRO Enhancing the Design of the RRO document with the objective of presenting advantages and disadvantages with focus on clarifying the resulting effects on the REAs.

Should there be one RRO rate for all eligible consumers (or customer category) in Alberta:

- Disadvantages
    - This change would create an added cost of administration as this program would require extra settlement and reconciliation management if managed by the individual entities, or result in extra costs being allocated to REAs if this task was centrally managed.
        - Also if the management of this is moved to a centralized agency this would likely result in loss of local jobs within REAs.
    - One RRO rate would not reflect the different consumption profiles and geographic locations associated with different pricing.
    - The incorporation of this option would be convoluted. Incorporation of differing line loss and unaccounted for energy (UFE) across distribution networks will make this impossible under the existing RRO structure, as this would create subsidization across rate bases and RRO providers. Therefore, to make this proposal work the line loss and unaccounted for energy would need to be separated from the Energy Costs and reported uniquely.
    - There would be additional administration that would require changes to existing invoice structures and create added costs for REAs.
    - This will not work without a centralized procurement structure, which is another change to the existing processes. In essence, creation of a single rate involves two changes not one.
    - To implement this fairly from a consumer perspective would require levelling Admin/Customer Care charges across all RRO providers, which currently differ from service area to service area. For instance, the different risk levels that REAs take regarding management of bad debt, termination of service, and other provisions of

RRO service in comparison to larger entities can result in higher non-energy costs due to economies of scale.

        - This would create issues similar to differing UFE and Line Losses that can only be solved through increased regulatory oversight and cost.

- Advantages
    - The creation of a single provincial RRO rate would reduce concerns consumers have regarding the rationale for different rates in different cities, towns, territories.
    - Communication of rates across the RRO consumer base would be simplified.
    - As a single provincial rate could only be established via a move to a form of centralized procurement which, of note, the AFREA is not necessarily in agreement with, the RRO energy procurement for each RRO Provider could be relieved.
        - Moving to central procurement for the RRO presents other advantages and disadvantages as will be discussed in a subsequent section of this response.

Changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement:

Options that Do Not Require Advanced Procurement

This approach would reflect a reintroduction of a "Flow-Through" RRO Rate, as such the RRO Customer would pay the AESO Hourly Pool Price based on their consumption/load profile.

- Disadvantages
    - There may be public backlash to this type of program as consumers are quite concerned with spot market volatility.
    - Traditionally this has been viewed as a high risk to the customer base and is contradictory to the Government of Alberta (GoA) vision of RRO price stability.
    - The flow-through RRO Rate shifts focus to commodity volatility and takes focus away from core RRO cost components.
    - This approach ignores existing REA hedging positions and the competitive disadvantage that will be created if the RRO process is modified.

- Advantages
    - The electricity market in Alberta is based on supply and demand, with options for consumers to buy via contracts that establish a longer-term price. The fluctuation that RRO consumers would likely experience could be avoided through the Stable Rates offered by the REAs.
    - There are potential benefits to this option as currently the Commodity Cost component of the RRO is between 15-25% of the total invoice, and modest month to month fluctuation in pricing due to spot market volatility would not cause dramatic change to monthly bill amounts.

        - The majority of RRO customer costs are within the transmission and distribution portions of the invoice, which are weighted to consumption volumes. Increases in RRO consumer bills are much more closely tied to consumption, which is applied in all categories of the bill than to spot price volatility applicable only to the commodity component.
    - Potentially reduces or maintains current program administration costs that REAs incur.
    - The Alberta Electric System Operator (AESO) has extensive experience with the Alberta market, and is comprehensively meeting expectations of the industry in monitoring consumption and forecasting future need. This combined with the proposed Capacity Market will reduce price fluctuations, so this form of rate will likely be less risky in the near future.
        - Capacity costs will be transferred to customers via transmission rates so any variability in capacity costs will not be felt by customers via the commodity component of the rate.

Centralized Procurement

- Disadvantages
    - It is anticipated that centralized procurement will result in extra administrative cost and burden.
        - To create this effectively, the GoA will have to have all the players at the table, and the Big Three RRO providers have spent a fair degree of time and energy creating these processes; therefore, dismantling them will not come without costs being incurred by the consumer.
        - Rural Alberta will not be well-represented in these discussions, as their combined consumption is a small piece of the market across a very large number of entities, and the allocation of their hedges back via central procurement will be far more costly than existing REA processes.
    - Again this solution does not alleviate the issue of unwinding the existing Hedging Programs that many REAs have created, in alignment with RRO regulation, and manage effectively with minimal administrative overhead.
        - If you reset the market structure without effective remuneration for REAs that have implemented their own hedging strategies, you are creating an uneven playing field by in effect pushing financial harm on the REAs and creating an advantageous playing field for IOUs to acquire the REAs.
    - Many REAs and a number of municipalities already effectively manage electricity purchases for their members in a not for profit manner and don't see any enhancements or gains from centralized procurement. Managing energy purchases for REA members has allowed the REAs to remain competitive with IOUs in the market while minimizing regulatory and administrative costs.

        - As previously cited, one REA has essentially created a surplus energy fund to mitigate risk and fluctuating energy prices. When the fund grows beyond a determined amount, members receive refunds either through an energy rebate or reduction of rates. Conversely when the fund declines below a determined value prices will be increased. This mechanism has enabled stable RRO rates for long periods of time in an extremely cost effective manner for its members.
- Advantages
    - Creates a Standardized Energy Cost across all RRO providers and allows visibility of non-energy cost structures of RRO providers.
    - Many REAs are extremely cost effective service providers and given a standard Energy Rate despite the economies of scale disadvantage would be quite competitive with the DERS and EEA RRO Rates.
    - Long term reduced administrative costs for larger providers, but as previously noted unlikely to help the REAs in this area.
    - If done properly the economies of scale would realize cost effective hedging.

Advanced Procurement for Longer Terms

- Disadvantages
    - Consumers in Alberta currently have existing options available to procure predictable and stable rates for long term electricity. These rates are readily available through REAs and Competitive Retailers. As such, the REAs do not believe this is the role the RRO was intended to or is supposed to play.
    - This is what many of the REAs are currently doing and moving to this strategy would simply be an attempt to reset the strategy at a time when forward prices are perceived as low.
        - This further highlights the fact that existing REA hedging programs would be significantly disadvantaged financially. How the existing hedging programs would be amalgamated into a long term procurement strategy is unknown.
    - This strategy was previously unsuccessful. The RRO structure in which long term hedges were applied ran into issues where RRO providers secured long term hedges at high prices, then as the market dropped the RRO providers lost customers to competitive retail contracts at lower prices and the remaining customer base was forced unfairly to absorb the losses – which led to the implementation of the current structure of the RRO (shorter term pricing windows such as the 45 day window and the current 120 day window).
    - Buying long term guarantees only stability, it does not guarantee the best price (taking a speculative position in the market), nor the lowest price.
    - Procurement of energy in a longer-term product is a hedge against price fluctuation, attracting a risk factor from the generator, again a cost to consumers.

- Long term procurement can create stranded costs due to changes in RRO customer base over the length of the price period.
    - For the RRO provider, volume risk is greater than price risk due to incongruities between RRO contract length (can exit in 30 days or less) and the length of the proposed procurement window (1-5 years). Allowing RRO customers to leave the RRO with 30 days of notice, but mandating RRO providers to hedge 1 to 5 years out into the future will create volumetric position risk.

- Advantages
  - Long term procurement will create a stable rate for the electricity component only and therefore decreased price volatility for RRO consumer; however, the commodity component is the smallest component of the total delivered cost of energy to consumers
  - If procurement occurs during what turns out to be historically low price periods then commodity prices will be locked in at beneficial rates long term for consumers, but this is speculative in nature (it could also be a high time).

Introduction of deferral accounts or changes to bill smoothing:

- Disadvantages
  - Deferral accounts bring with them significant administration and carrying cost.
  - Deferral accounts are currently not allowed for Energy Charges under the existing RRO Regulation, would require a change to legislation for a component that as previously noted only makes up 15-25% of a customer's bill.
  - Almost all providers already currently provide some form of Budget or Balance Billing product.
  - Deferrals can result in unfair treatment of customers - treatment of costs/savings is never applied across the same rate base that accrued the initial rates.
  - Bill smoothing should be managed at the total invoice level not the RRO product level, as many RRO providers bill for multiple services, and therefore need to create a budget amount based on all services not just the RRO Rate.
  - RRO providers are at increased credit risk as the vast majority of consumers' bills are made up of non-commodity costs exposing the RRO provider for recovering Distribution and Transmission costs.
  - Implementation of deferral accounts will increase the regulatory cost and burden on the REAs as this system will require the REAs to complete the Alberta Utility Commission (AUC) approval process due to the complexity and rationalization needed to implement these deferrals.
- Advantages
  - Allows for some form of price consistency; however, may include more hidden costs.
  - Can piggy back on existing (rate rider, budget billing) services that exist for all RRO providers to implement the methodology.

When and how a change to the RRO should occur:

Changes to the RRO were set in motion with the implementation of the RRO Price Cap activation this June. Making changes to the RRO should be made with thoughtfulness and with the member/consumer in mind. Doing this right must be more important than doing this fast. Overall, the AFREA membership feels uncomfortable with the direction of the potential RRO enhancement as currently it appears there are no established deadlines, nor a well-defined plan that will result in a mutually beneficial outcome.

There is a need for further stakeholder engagement beyond the MSA request and proposals for RRO. Change should be presented and vetted by all Stakeholders prior to any recommendations to the GoA. Considering the purchasing options available, changes that are now occurring on the generation side of electricity in Alberta, and the current oversight, there is very limited benefit, if any, to consumers for further interference in the RRO process. The disadvantage to instituting the options the MSA has asked stakeholders to consider far outweigh the advantages from the viewpoint of the AFREA membership.

Changes to the RRO will have the potential to profoundly affect the consumer base and RRO providers. In the current RRO structure of transmission skewed consumer bills, the focus for RRO change should be strategic and consumer centric not simply an attempt to stabilize commodity costs. Before any changes are effected it would be of great benefit for the GoA to present straw dogs for any proposed changes so the market can comment in greater detail than just supplying commentary on the categorical areas provided in this engagement.

REA Concerns and Risks

In consideration of the potential changes to the RRO, there are a number of risks and concerns to REAs. The following section identifies various concerns discovered in discussions with AFREA REA members pertaining to effects of changes to the RRO.

Competitiveness of the REA Structure

REAs are distribution service owners and also provide retail services to REA members. They are competitive with the services of other distribution companies and as it pertains to this feedback they are competitive in terms of the provision of RRO services. If provision of RRO service is no longer under the purview of the REAs they risk losing the customer connection of combined distribution and retail service. By handling the energy aspect of the member service it provides another opportunity for the REA to foster that relationship. Because REA members own the REA, the provision of RRO service to REA member is done effectively in a not for profit manner. REAs currently can and do perform the service of affordable, stable rate provision, while minimizing regulatory and administrative costs. This additional business initiated by the REA stimulates the local economy within the rural area. Removal of this service from the REAs and placement with another RRO provider would result in additional costs to REA members on the RRO. Removing this service aspect may diminish the perceived value of the REA to its members, thus providing IOUs increased opportunity to take over all REA services.

Relatively Small Impact of Commodity Prices on the Delivered Cost of Energy for RRO Consumers

To provide context, the RRO constitutes approximately 10.5% of the entire electricity market in terms of annual electricity consumption. In terms of site composition, 55% of eligible residential sites in Alberta are on the RRO, 43% of eligible small commercial sites (including pumping and irrigation) in Alberta are on the RRO, and roughly 73% of eligible farm sites in Alberta are on the RRO. For those sites on RRO service, the monthly expense, or bill, is comprised of the following components:

- Electricity Commodity
- Distribution
- Transmission
- Rate Riders
- Access Fees
- Administration

In the commodity, distribution, and transmission the dollar value expense is derived from multiplication of a price per unit and the volume of electrical energy consumed. Regardless of what is done with respect to the commodity price, changes in volume of energy consumption impact distribution and transmission components as well. The result, regardless of what restrictions are applied to the energy rate, large swings to the consumer's electricity bill can exceed $30 per month. Consider the scenario in which an REA member with small commercial service is on the RRO, if only a small amount of energy of 0.650 MWh is consumed in the month of June because of cool weather, but a large amount of energy of 1.0 MWh is consumed in the month July because of significant increases in air conditioning load, the bill to the REA consumer on the RRO will increase by roughly $38.15 if energy prices are held constant. The effects of volume consumed on distribution and transmission outweigh the effects on commodity. Under a similar example, holding the volume consumed constant from month to month, but increasing the energy commodity rate from $32.00/MWh to $64.00/MWh (an increase of 100%) only results in a monthly bill difference of $20.80/MWh. There are numerous examples for RRO consumers (irrigators, small commercial, and farms) that show the primary driver of month to month bill volatility is electricity consumption, as opposed to price. And given that changes to the market in terms of structure (i.e. the change to a Capacity Market) are expected to result in muted electricity price volatility, while certainly increasing transmission costs that farm RRO consumers cannot avoid, there is little reason to undertake costly regulation reform for something that does not eliminate month to month bill volatility.

Contrary to the statement "Gone are the days when the average bill could – and did – swing by $30 in a single month," even with reform to the energy commodity price component of the RRO consumers bill, there will still be times when RRO consumer's bills swing more than $30.00 per month simply based on the volume of energy consumed. In short, RRO consumers see limited variance in the total delivered cost of electricity due to commodity price per unit variance.

Removal of Revenue Streams

Without the revenue streams created by the provision of RRO service to members, some REAs would likely be forced to reduce personnel. Payrolls of the REAs are significant in the rural community and without this payroll subsequent spending in the rural communities could be reduced, effectively increasing the rate of commercial erosion in rural communities. Exporting the profits and payroll to a large corporation simply adds numbers to a ledger, but does not add value to the interpersonal connection of a community.

Stranding of Hedge Costs

As previously noted, REAs have followed the Rural Utilities Act and the Regulated Rate Option Regulation, and in doing so have transacted fixed price derivatives for future periods. Similarly, other entities such as municipalities have also undertaken comparable hedging strategies, again in line with regulation, to assure price risk mitigation for RRO consumers. The current position for some of the REAs and municipalities is established, but could be extremely compromised should the RRO regulation be changed. This in effect could be considered changing the rules of the game during play of the game. These entities with hedged positions will be significantly disadvantaged simply because the considered RRO regulation modification is at a time when short term forward market prices are at some of the lowest points in the history of the deregulated electricity market in Alberta. Because of the relatively small size of the REAs, the absorption of losses forced on them by regulation change will cripple some REAs financially. Any losses associated with changes to the RRO regulation or the manner in which the REAs must abide by the regulation could result in financial losses too great for the REAs to bear.

Significant Political Risks in the Market

It is critical to consider the perspective of REAs and their value to rural Alberta, aligning the views on REA sustainability, value, and service necessity. Is critical to the long term sustainability and viability of REAs. A pertinent real time example is the RRO Price Cap. In December 2016, the GoA announced the 6.8 cent per kilowatt hour price cap effective June 1, 2017. With approximately 2 weeks left in the month of May 2017 the REA RRO providers do not have clarity on what they can or cannot do. As such, with respect to the RRO, the REAs hang in limbo with equity eroding, member discontent, and no visibility on whether this status will change anytime in the near future.

Summary Messages

In summary, AFREA believes the proposed changes in the RRO have already detrimentally impacted REAs and, if pursued, will further negatively affect REAs and the overall electricity market in Alberta. REAs that have hedged RRO are experiencing financial losses, and those losses will mount if this moves ahead. The implications to the market, to Albertans, and to our members are complex and a thoughtful, in-depth review is in order to ascertain the advantages, disadvantages, and the potential economic impacts.

RRO Changes are resulting in Financial Losses for REAs

Some REAs are now experiencing financial losses because they hedged RRO exposure with a long term strategy in alignment with current legislation and regulation. The proposed changes in the RRO (price cap) are causing member movement and resulting in stranded hedges that are significantly out of the money due to low market prices. And now the GoA is considering a reset to that position to potentially execute the exact same strategy (take a long term position). It does not make sense to do this now based only on forward pricing that is low.

Other Market Structure Changes Impending Reduce the Impetus for RRO Regulation Overhaul

Implementation of a Capacity Market will reduce spot price variability and the expectation is that commodity pricing will be much closer to the marginal cost of generation. This should have a similar effect on the forward market, bringing forward prices much close to the expected marginal cost in future periods. Further, RRO consumers in Alberta have options available to procure predictable and stable rates for electricity. Considering the available hedging options available to RRO consumers in the competitive market, interference in the RRO markets seems unwise, and modification to the RRO regulation dealing with price risk management is unnecessary.

Need for Further Stakeholder Engagement

When considering changes to something as important and intricately connected as the provision of RRO service, the MSA should follow its standard Stakeholder Consultation Process. Proposals for any change to the RRO regulation should be presented and vetted by all Stakeholders prior to recommendations being submitted to the GoA. For simplicity, presentation of any proposed scenarios will allow the entire market the opportunity to comment in greater detail than just the categorical areas provided in this engagement. The MSA may want to follow the AESO's lead in the Capacity Market implementation in that Stakeholder Working Groups have been created to ensure proper vetting and validation of proposed changes. In short, it is imperative that the GoA does not rush into RRO regulation modification.

ATCO ELECTRICITY
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May 19th, 2017

Mr. Mark Nesbitt
Manager, Retail and Investigations
Alberta Market Surveillance Administrator
Submitted via email

RE: MSA Consultation on Options for Enhancing the Design of the Regulated Rate Option (RRO)

Dear Mark,

Thank you for the opportunity to provide comments on the request from the Minister of Energy to review the RRO. As a retailer and generator, ATCO can offer feedback from both perspectives.

Its ATCO's position that changes to the RRO should be minimized at this time. Several reforms to the electricity industry have recently been announced and are ongoing (RRO cap, capacity market development/implementation, phase-out of coal, carbon pricing, renewable energy programs). Should any changes to the RRO be proposed resulting from this process, ATCO would expect that additional stakeholder consultation would occur to identify any unintended consequences and to understand the Government's position on the continuation of competitive retail.

A competitive retail market provides options for consumers to have long-term, stable and affordable prices.

In response to the specific questions that the MSA has asked, ATCO offers the following responses.

i) whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta;

ATCO understands this question as a proposal for a single commodity price across the RRO (differences in distribution tariffs will still exist, as will varying administrative fees). A single rate has the benefit of simplicity and could simplify customer's ability to compare the RRO to competitive offerings, but here has been less than a 0.5 ¢/kWh range in the monthly RRO since 2016,[1] indicating a strong convergence in RRO already.

ii) changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement;

Changes to procurement within the RRO were previously evaluated in the 2012 Retail Market Review Committee which noted that moving to a longer-term model would create negative impacts on the competitive retail market, specifically:

> *Implementing mandatory, long-term procurement subject to regulatory review, prudential assessment and risk allocation would create a regulated alternative that would compete directly with retailers' core business. Customers might in many respects be*

[1] Based on an analysis of UCA collect RRO prices.

> *better served by a return to full cost-of-service–based regulation than by such a hybrid approach, which would essentially sterilize the retail market.*[2]

ATCO is concerned that changes such as this, would have a deleterious impact on the competitive retail landscape.

In response to the specific questions from the MSA, advanced procurement of longer term products would be in-line with general practices that currently exist in the RRO. This has the benefit of smoothing price and reducing volatility for the RRO, but comes at the risk of locking customers into an over-priced contract. Further, longer term hedges come with a higher risk premium than shorter terms. This would likely increase liquidity for longer term forward market products. With this option, given consumer's choice to switch from the RRO to a competitive contract, there would be further issues with over/under procurement of volumes as customers switch.

With respect to centralized procurement, this could better enable the notion of moving to a single RRO, but questions would abound on who should perform such a function, and if done by a regulated agency, whether they would engage in the market a commercial manner.

Competitive retailers already offer options such as spot-price flow through, which does not necessarily require advanced procurement. Using flow-through pricing for the RRO would leave it exposed to market volatility, which could be mitigated through longer-term averaging, or through deferral accounts to stabilize the prices. Using an ex-poste approach such as this would be detrimental to liquidity in the forward market. An approach such as this would have the same deleterious impact on the competitive retail market, along with negative impacts on the forward market.

iii) introduction of deferral accounts or changes to bill smoothing;

Depending on the timeliness, the use of deferral accounts could create a disconnect for customers who switch from the RRO to competitive contracts between consumption and final deferral account true-up. This would add administrative complexity and costs. If deferral timing was close together, then there would be little smoothing of the volatility in the pricing of the RRO.

iv) when and how a change to the RRO should occur?

The RRO has been reviewed on a regular basis, with the last major review occurring in 2012 (Retail Market Review Committee) which recommended that the RRO should be phased out.[3] Any changes to the RRO should involve a much more substantive stakeholder process than the current MSA options paper. Given changes to the wholesale market design by 2021, there will have to be some alignment with changes to the retail sector. Instead of changing the RRO twice in

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[2] Retail Market Review Committee (https://open.alberta.ca/dataset/c4b279c0-63a5-4a87-87ca-cbd5e4152794/resource/4246f8f0-2572-413f-8cec-d9ec28452fdd/download/RMRCreport.pdf)

[3] Recommendation also included the introduction of a "provider of last resort" to protect vulnerable customers. ATCO believes that that service will always be essential as it provides a safety net for customers that are unattractive to retailers for reasons of creditworthiness or otherwise.

more substantive stakeholder process than the current MSA options paper. Given changes to the wholesale market design by 2021, there will have to be some alignment with changes to the retail sector. Instead of changing the RRO twice in the next five years, ATCO suggests that a prudent outcome would be to align any changes to Alberta's default rate, the RRO, to be in-line with changes to the wholesale market. Until the capacity market structure is finalized and cost allocation is understood, there should be no changes to the RRO.

As mentioned, it is ATCO's position that changes to the RRO should be minimized at this time. If changes are proposed from this process, ATCO would expect that additional stakeholder consultation would occur to identify any unintended consequences and to understand the Government's position on the continuation of competitive retail.

Should you have any further questions, please don't hesitate to contact us.

Sincerely,

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May 19, 2017

Mr. Mark Nesbitt
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Dear Mr. Nesbitt:

Re: Options for Enhancing the Design of the Regulated Rate Option (RRO)

Capital Power provides this letter in response to the Notice to Market Participants and Stakeholders[1] (the "Notice") issued by the MSA on April 21, 2017. The Notice includes a letter from the Minister of Energy requesting that the MSA "conduct an analysis and provide a report with options for enhancing the design of the Regulated Rate Option to provide long-term, stable and affordable prices for Alberta's electricity consumers into the future."[2] Accordingly, the MSA has requested comments from stakeholders identifying options – advantages and disadvantages – for enhancing the design of the Regulated Rate Option ("RRO").

Capital Power believes that the GoA can achieve its objectives by transitioning the RRO to longer term (up to one year), competitive, centralized procurement through the wholesale market. No changes to Alberta's wholesale electricity market are required. Volatility remains integral to providing an effective price signal in the Alberta wholesale market, which is necessary to ensure supply adequacy. In this respect, Capital Power provides the following comments.

<u>Align the Timing of RRO Changes with the Implementation of the Capacity Market</u>

Capital Power understands from the Minster of Energy's letter that "[i]t is the Government of Alberta's intention to protect consumers from price volatility by ensuring Alberta's electricity arrangements are in the long-term interests of consumers."[3] Capital Power notes that on November 22, 2016, the Government of Alberta ("GoA") announced a price cap of 6.8 cents per kilowatt hour to be applied to the RRO.[4] The rate cap will protect Alberta consumers on the RRO from price volatility during the period from June 2017 to June 2021,[5] and limits the need for immediate changes to RRO design or additional measures in the near term.

While it is not clear whether the GoA is considering enacting any RRO changes prior to the expiry of the price cap, Capital Power believes that it would be reasonable to align potential RRO design changes with the implementation of the capacity market, and expiry of the price cap, in 2021. This would provide a reasonable window for the necessary consultation, development, and implementation efforts associated with designing a new RRO and would help to limit further market uncertainty and minimize potential market impacts. In this respect, the GoA should provide clear direction to the market on the nature of any RRO design changes within the next 6-12 months. The GoA must also ensure that any RRO design changes are accompanied with effective customer outreach and education.

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[1] Market Surveillance Administrator, *Notice to Participants and Stakeholders Re: Options for Enhancing the Design of the Regulated Rate Option (RRO)* (April 21, 2017).
[2] Ibid, p. 1.
[3] Ibid, p. 3.
[4] Alberta Government, *News Release: Price cap to protect consumers from volatile electricity prices* (Nov. 22, 2016) https://www.alberta.ca/release.cfm?xID=4487283D35A59-070B-5A1F-76A7FB63D2CA149D
[5] Ibid.

Consider a Uniform Rate for All Albertans

To the extent that it is feasible from a technical perspective, given the various load shapes throughout the province, the GoA should consider a uniform RRO rate for all eligible consumers. Such an approach would improve transparency and regulatory efficiency and may reduce administrative costs compared to the current model. A uniform rate would also help to facilitate longer term, competitive, centralized procurement, described in the next section.

Move to Longer Term, Competitive, Centralized Procurement

To promote more predictable and stable rates that are still fundamentally driven by competitive market forces, the GoA should consider implementing competitive, centralized procurement of RRO volumes through the wholesale market and allowing longer term hedging (up to one year) as opposed to the current 120-day limit. Such an approach would mitigate volatility without unduly impinging on the competitive retail market and would help to retain and improve forward market liquidity which would only further benefit the RRO.

Centralized procurement through the wholesale market will promote higher levels of competition, which would result in more competitive price outcomes. To implement centralized procurement, the GoA could either provide a standardized, default rate energy price setting plan prior to auction, or simply conduct a centralized auction based on lowest cost for the specified term. The current level of transparency and reporting of price and volume should be maintained. Both near and longer term procurement mechanisms must allow participation of as many willing wholesale market participants as possible and any approach must ensure that a level playing field is maintained and not create competitive inequities due to the interaction of regulated and deregulated business entities.

Longer term hedging (up to one year) beyond the current 120-day procurement will create some degree of additional procurement risk and may increase costs over the long term. The increased risk is a reasonable trade-off to achieve the GoA's goal of mitigating volatility for RRO customers. Hedging beyond a one-year term will place greater risks on RRO customers and such risks may not outweigh the reduced volatility. Longer term hedging will also remove any real-time or near to real-time price incentives for customers to adjust their usage based on market fundamentals, such as during peak hours.

Concluding Comments

Capital Power notes that the Minister's request relates specifically to managing price volatility for RRO customers and as such it is neither appropriate, nor necessary to consider measures to mitigate wholesale price volatility within this process. The GoA's objectives can be accomplished through the changes to RRO design proposed above by Capital Power and do not require changes to Alberta's wholesale electricity market. Similar measures to mitigate wholesale price volatility would create additional risks for existing generation investments and may impact their ability to recover costs and earn a fair return. Volatility is integral to providing an effective price signal in the wholesale market, which is necessary to ensure supply adequacy.

Beyond the RRO, there are many options available to consumers to manage price volatility in the market. Residential consumers have access to competitive fixed-price contracts and other flexible-term energy solutions. Likewise, large commercial and industrial consumers are active in hedging and forward contracting and have numerous energy products and services available to them to manage volatility, including the option to self-supply. Efforts should continue to be undertaken to ensure Albertans have access to the products offered by competitive retailers. Many existing retailers offer budget payment or equalized payment plans, where a consumer's energy costs are averaged over 12 months and they are billed an equal amount each month.[6]

Vulnerable Albertans may need support with respect to their electricity bills regardless of the level of price volatility. Programs exist today – outside of the market – that provide such financial assistance for those in need.[7] Additional protection from price volatility, if necessary, should be funded and administered by the Government through its various consumer protection agencies and outside of market pricing mechanisms.

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[6] Utilities Consumer Advocate website, http://www.ucahelps.alberta.ca/payment-options.aspx
[7] Ibid.

Capital Power appreciates the opportunity to provide its comments on this initiative. Please contact me at (780) 392-5294 if there are any questions or if you wish to discuss Capital Power's comments.

Regards,

Grant Berry
Senior Advisor, Regulatory and Environmental Policy

cc: D. Jurijew, Vice-President, Regulatory and Environmental Policy

CITY OF
Lethbridge
Infrastructure Services (Electric)

THE CITY OF
Red Deer
ELECTRIC, LIGHT & POWER DEPARTMENT

May 25, 2017

Mark Nesbitt
Manager, Retail and Investigations
The Alberta Market Surveillance Administrator
500, 400 - 5 Avenue SW
Calgary, AB T2P 0L6

Dear Mr. Nesbitt,

SUBJECT: *Options for Enhancing the Design of the Regulated Rate Option (RRO)*

In response to your April 21st memorandum, the City of Lethbridge and the City of Red Deer offer the following comments regarding your above-mentioned task to the Minister. We appreciate the relatively short turn-around in which you are to complete your report and therefore apologize for the lateness of our response.

We have organized our comments in three main sections related to the general policy objective of a longer-term stable price, a single Alberta RRO rate, and when such changes could be implemented.

Providing a longer-term stable price

The cities agree with the policy objective of providing a longer-term, stable RRO price. The current short term price is a frequently changing price signal that violates a longstanding and generally accepted ratemaking principle of regulated utilities: rates should be simple and easily understood. The unintended consequence of a rate that is not simple and easily understood is that customers unable to make any economic decisions about their electric use.

Changing the method by which the RRO is priced will affect the RRO compares to competitive retail contracts. However, the cities have not included this as either an advantage or disadvantage because no matter what customer preference the RRO satisfies, it can only satisfy **one** type of preference. This will leave competitive retail to satisfy all other customer preferences.

Relevant to this issue, the cities have observed from contact with end-use customers that there seems to be a greater correlation between those who want a stable, long term price and those who do not have interest in competitive retail as it exists today.[1] Similarly, there also seems to be greater correlation between those who appreciate short-term pricing and those who are interested in retail choice. There is also a segment of the population that appreciate having a choice between long and short term prices and are not necessarily concerned about which option is the RRO and which one is a competitive contract.

By current policy, the RRO must provide a short-term price and therefore no customer preferences are particularly well served by the status quo. Even among those who appreciate a choice between long and short term prices are not as well off because the only long term option is a competitive retail contract. The cities opine that competitive retailers are at a disadvantage in this regard because the business risks of offering a long-term product are high. A regulated supplier subject to the traditional regulatory compact[2] can more easily absorb such risks at a lower cost.

For this reason, the cities expect that a stable RRO is more likely to benefit a greater proportion of low-use customers as well as competitive retailers.

Specific advantages and disadvantages of longer-term procurement as well as deferral accounts are as follows

Longer-term procurement

Advantages

- A more diverse portfolio of short and long term products will stabilize procurement costs, which can then be reflected in the RRO price.
- This policy can be implemented with minor changes to RRO regulation. The cities can begin process to implement almost immediately.

Disadvantages

- If the portfolio contains too many long-term products, the risk increases of procuring energy that is not ultimately required. Provided that RRO providers have a more general mandate to use a mix of tools to stabilize the RRO price, this risk should be manageable.

[1] Among customers that have considered and remain uninterested in competitive retail, the feedback that the cities receive is that the energy commodity component is too small of a portion of the total utility bill (and overall household expenses) that is not worthy of time and attention.
[2] i.e. the trade-off of an obligation to serve in return for a reasonable opportunity to recover prudently incurred costs.

Deferral Accounts and Bill Smoothing

Advantages

- Achieves many of the same beneficial outcomes as longer-term procurement without the risk of procuring long-term energy that is not ultimately required.

Disadvantages

- A different business risk in which customers avoid deferral account charges by temporarily switching to competitive retail.
- The existence of the Payment in Lieu of Tax (PILOT) Regulation may increase the variability of deferral account balances insofar as over and under-collections relating to deferral account reconciliations might be reportable as either a profit or loss. Though not directly related to the MSA's current task, the cities remain concerned that PILOT collections on the RRO amount to a wealth transfer from low-use RRO customers to high-use industrial customers.

By way of a concluding remark on this subject, the cities submit that the issues listed above can be situationally dependent and therefore specific actions cannot be prescribed. To accomplish the government's policy goal, the cities strongly recommend that the RRO provider should be given a mandate (with regulatory oversight) to take prudent actions to provide a stable, longer term market price. How the mandate is fulfilled will vary, but in this way, the tools available to RRO providers are not limited and innovation remains possible.

Single Alberta RRO Rate

The cities are not able to identify any practical means to have one Alberta RRO rate unless there is one centralized party that both procures and administers. The alternative would involve subsidies/transfers between the RRO providers and the central agency to levelize the RRO, thus creating an administratively complex system of payments. It would also reduce an RRO provider's accountability to customers because efforts to minimize cost do not accrue to those customers. The cities reject that alternative out of hand because we are unable to identify any benefit associated with having the same RRO rate for all of AB.

Advantages of centralized procurement/administration

- An independent provider should eliminate all (perceived or real) conflict of interest concerns with competitive retail.
- Provided there is an effective governance structure, one provider should theoretically be able to minimize the average admin cost per customer. However, due to what would likely be significant and material transitional costs, this

theoretical cost advantage might only be realized after many years and possibly decades.

Disadvantages of centralized procurement/administration

- A centralized system will represent a loss of local accountability. On a local level, the cities have established some degree of trust and goodwill that would be lost.
- The current decentralized system facilitates a process where RRO providers and regulators discover and innovate best practices through observing/comparing between providers. One centralized provide may lead to fewer innovations.
- It is difficult to develop an effective governance and management structure that will be able to minimize administration cost from the beginning. Either there will be a new government agency without the benefit of institutional knowledge/expertise, or the function is provided by a for-profit contractor that will expect a commensurate return or expect customers to absorb more risks (particularly in the beginning).
- Centralized provision will be the most disruptive option and subject to the risk of unintended consequences. The cities expect this will take a long time to get right.

When and how a change to the RRO should occur

The cities believe that a policy change to mandate longer-term stable pricing can be implemented in relatively short order with minimal disruption. Regulatory lag times differ between regulators, but in Red Deer and Lethbridge, changes to the pricing plan can be implemented as soon as the issue can be added to the Council agenda. This varies depending on the budget cycle, but changes to the pricing plan should generally require less than 6 months.

A change to implement centralized procurement and/or administration would take the longest and would likely require legislation (as opposed to regulation). There is also a high risk of unintended consequences in transition and setup. Examples of unintended transitional issues would include dropped customers, lost customers, unrecorded payments, uncollected payments. This was observed before in the transition to competitive retail in 2000-2001 and the costs and loss of goodwill were significant, particularly in areas where wires owner handed customers over to third party provider. Centralization would be an even bigger administrative change because all customers are being handed over.

Conclusion

Overall, the cities agree a policy proposal to provide a longer-term, stable RRO price. As with any change to the method of pricing the RRO, there will be impacts on existing competitive retail contracts. For the reasons outlined earlier, however, we believe that a mandate for the RRO to provide a long-term and stable price will provide a more distinct and better-suited product space for competitive retailers to operate.

The cities appreciate the opportunity to provide feedback on this policy discussion and trust that our responses will add value to the process. Should you have any further questions or comments, please feel free to contact Stewart Purkis at (403) 320-4166 or Jim Jorgenson at (403) 342-8341.

Yours truly,

<submitted electronically>

Stewart Purkis, City of Lethbridge Electric Manager
Jim Jorgenson, City of Red Deer Electric Manager

cc. Michael Turner, Chymko Consulting, (403) 781-7691

WACHOWICH & COMPANY
Barristers & Solicitors

Alberta Market Surveillance Administrator
Suite 500, 400 - 5th Avenue SW
Calgary, AB T2P 0L6
stakeholderconsultation@albertamsa.ca
mark.nesbitt@albertamsa.ca

Attn: Mark Nesbitt
Manager, Retail and Investigations

Dear Sir:

RE: MSA Notice Dated Apr21, 2017
Options for Enhancing the Design of the Regulated Rate Option

I refer to the MSA's notice letter dated April 21, 2017 requesting comments from stakeholders respecting the future of the Regulated Rate Option (RRO). The MSA's letter follows a letter from the Minister of Energy requesting the MSA to conduct an analysis and provide a report with options for enhancing the design of the RRO with a view to providing long term, stable and affordable prices for Alberta electricity consumers into the future.

The CCA is pleased to respond to the MSA's request herein.

The Existing RRO Mechanism

The RRO (or Regulated Rate Tariff as previously named) has served as the default supply option since retail deregulation. There are many trade-offs involved in policy making for RRO, including meeting the objectives of affordability, stability and fair competition. Affordability, which is a relative value term, can mean many things depending on the context. In the context of RRO, affordability may be translated to mean the lowest cost of electricity over the long term; the lowest cost of electricity over the long term may in turn be considered to be the average pool price for electricity for one or more years

However, long term affordability does not address the issue of short term affordability where prices may spike up (or down) in certain hours within a month (intra month) or, fluctuate sharply from month to month (inter month). Although over the long term such price spikes may tend to level out and therefore meet the long-term affordability objective, they may still cause short term affordability or rate stability concerns. Hence the existing RRO design includes mechanisms to mitigate price volatility intra month. To the extent hedging mechanisms were put in place to mitigate short term volatility of prices, there were trade-offs against long term affordability. This is because there is a premium to be paid for swapping floating (pool) prices for fixed prices established through hedging mechanisms; as well hedging mechanisms go hand in hand with significant administrative costs and risk management costs, payable to the RRO provider, as well as regulatory costs.

Another feature of the existing default supply mechanism in Alberta is that it must not be anti-competitive in relation to competitive retailers of electricity. In essence, the default supply price becomes the price to beat by competitive retailers.

At the time the existing RRO legislation was put in place there was a desire on the part of policy makers to encourage unregulated retail suppliers with the hope of developing retail competition while addressing short term affordability or volatility of default supply prices. Accordingly, RRO providers were required to provide a fixed price for RRO for each prompt month and they were compensated for procurement of hedge products and for other risk management activities associated with providing a fixed RRO price. The CCA analysis comparing average RRO prices with the weighted average pool prices by month from 2005 to 2014 suggests the average RRO price carried a hedge premium of about 16% from 2005 to 2014, on average; if the commodity risk compensation, hedge administration costs and regulatory costs were added to the hedge premium, the percentage noted above would be even higher. This is attached in excel.

The existing RRO mechanism provides a relatively high price to beat by competitive retailers which means they have greater head room for pricing competitive products. By limiting purchase of hedge products to 120 days ahead of the prompt month, the existing method has the effect of inflating hedge prices, because the hedge products that may be acquired within a 120-day window would not reflect the offsetting effects of pool price changes over a longer period. Further the 120-day procurement window limits the extent, if any, to which inter month price volatility may be mitigated.

Possible Alternative Methods:

Approach 1: This approach contemplates continuance of the existing RRT method but prompt month hedges would be replaced by a mix of longer term hedges (quarterly, annual) for a significant portion of the portfolio. The proportion of annual hedges to quarterly hedges and perhaps some flow through energy, must be designed to balance the risk of customer attrition and/or accretion versus rate stability, for a period of at least one year. Providing price stability beyond a one year period for RRO may be considered as undue encroachment into the unregulated or competitive retailer market which is best able to offer fixed price contracts for periods longer than one year. The CCA position has always been that the components of the regulated rate should not be constrained by the desire to develop an unregulated retail industry.

The advantage of longer term hedges is that they would not only address intra month rate stability but also inter month rate stability over a one year period. There would likely be improvement in the affordability objective relative to the existing approach since longer term hedge products tend to command a lower premium on fixed for floating swaps due to the hedge provider's ability to offset price increases and decreases over longer periods. The commodity risk assumed by the RRO provider may need to recognize any change in risk.

The disadvantage of longer term hedges is that RRO will continue to be relatively expensive (long term affordability). This is as a result of hedge premiums, commodity risk compensation and administrative costs payable to the RRO provider as well as due to significant regulatory effort. Unregulated retailers may perceive the RRO's expansion into mitigating inter month price volatility as unfair competition in terms of their share of this market.

Approach 2: This would be a complete departure from the existing methods in that RRO would cease to offer month ahead fixed prices. Instead, RRO customers would be billed the actual pool price in each month on an equalized billing basis over a one year cycle. Equalized billing essentially is an equal payment plan and may be based on the estimated average cost of hourly electric energy for a given load profile for a period of one year. True ups can occur at year end or tolerances could be built in to adjust equal payments to trend towards a zero balance by year end.

Equalized billing could be adjusted for seasonality so that price is equalized over 12 months but customers pay for higher or lower volumes depending on the month, at average price. This could be a variation of the equalized billing approach.

The advantage of the equalized billing method is that it could achieve both long term affordability as well as short term rate stability. Under equalized billing there is an implicit averaging of prices across hours, months and for the whole year. This means a premium need not be paid for acquisition of hedge products to mitigate short term rate stability issues nor is it necessary to pay a commodity risk premium to the RRO provider for managing commodity risks; further, the administrative costs involved in administering the commodity price of RRO would be minimal and the regulatory burden would be confined primarily to non-energy matters. Adoption of equalized billing may mean higher working capital requirements and potentially, higher bad debt risks, for RRO providers.

In terms of possible disadvantages, an equalized billing approach may be considered a deferral account. Deferral accounts could be considered as inconsistent with earlier policy objectives of competition and economic pricing principles as they would not provide current price signals as consumption occurs. Hence unregulated retail competitors may consider an equalized billing approach as having anti-competitive characteristics. However, retailers could and do offer flow through services for both gas and electricity, and may add more "frills" to their product offerings. As such, the default supply is not necessarily a "price to beat"; but a product that has a different flavor than the "plain Jane" RRO product offering.

RRO Administration Issues:

The MSA raises two issues with respect to administration of RRO. The first deals with whether there should be one RRO rate for all classes and the second deals with centralized procurement of hedge products.

RRO by rate class was initially established to recognize differences in load profiles between different classes of customers. However, at the RRO consumption levels, the load profiles for residential and general service customers tends to be similar and therefore there does not appear to be any reason to have different RRO rates for residential and commercial customers. Street lights on the other hand have a different load profile. However, since street light electricity bills are typically paid for by municipalities, they may not require the same protection afforded to residential and small commercial customers and hence street lights could potentially be excluded from RRO eligibility.

The MSA has also asked if the existing hedged RRO pricing approach were to continue, whether procurement of RRO products could be undertaken through centralized procurement rather than each RRO provider continuing to procure its own requirements. There are advantages and disadvantages to centralized procurement. The advantages may include savings due to procurement of larger quantities each time by presumably an independent entity or person, who could be assessed on performance. Procurement of larger quantities each time through streamlined processes may help reduce the cost of procurement related activities for each RRO provider. However, this needs to be weighed against the cost of establishing and operating a centralized procurer. The main disadvantage of centralized procurement is that prudential requirements applicable to each RRO provider as well as their load profiles may be different and therefore, the centralized entity may still need to procure on behalf of each RRO provider. Under the latter scenario, any advantages of centralized procurement would be largely diminished.

Transition Issues:

The changes to RRO could occur any time after the relevant changes to legislation are made. Following such changes each of the RRO providers may be required to file an amendment application to their existing Energy Price Setting Plans to reflect changes in hedging strategy and the consequent impacts on the commodity risk compensation and administrative costs.

This submission is made based on the state of the Alberta industry as at May 19, 2017 and as there are many ongoing policy initiatives, it is subject to the caveat it is based on a current understanding of the market.

Yours truly,

WACHOWICH & COMPANY

Per:

JAMES A. WACHOWICH, Q.C.
CCA Legal Counsel

:

	Av RRO Price	Av Weighted Pool Price	
01-Jan-05	5.996	5.202	
01-Feb-05	5.996	4.374	
01-Mar-05	5.996	4.601	
01-Apr-05	5.903	5.210	
01-May-05	5.903	5.185	
01-Jun-05	5.903	5.856	
01-Jul-05	6.126	3.991	
01-Aug-05	6.126	9.250	
01-Sep-05	6.126	7.974	
01-Oct-05	6.627	12.750	
01-Nov-05	6.627	13.316	
01-Dec-05	6.627	11.008	
01-Jan-06	7.823	7.616	
01-Feb-06	7.823	5.653	
01-Mar-06	7.823	4.614	
01-Apr-06	5.998	4.527	
01-May-06	5.998	6.019	
01-Jun-06	5.998	6.640	
01-Jul-06	7.348	13.837	
01-Aug-06	7.438	7.767	
01-Sep-06	7.774	8.797	
01-Oct-06	8.724	18.600	
01-Nov-06	8.226	11.184	
01-Dec-06	8.890	7.486	
01-Jan-07	9.551	6.364	
01-Feb-07	8.853	7.553	
01-Mar-07	8.431	5.969	
01-Apr-07	8.237	5.522	
01-May-07	7.795	5.219	
01-Jun-07	8.135	5.351	
01-Jul-07	9.692	17.059	
01-Aug-07	11.086	7.617	
01-Sep-07	11.310	5.172	
01-Oct-07	9.938	6.859	
01-Nov-07	9.949	5.734	
01-Dec-07	10.088	6.973	
01-Jan-08	9.383	8.415	
01-Feb-08	8.985	6.747	
01-Mar-08	8.797	8.867	
01-Apr-08	9.709	14.305	
01-May-08	9.862	11.047	
01-Jun-08	9.716	9.135	
01-Jul-08	11.905	6.900	
01-Aug-08	11.644	8.846	
01-Sep-08	9.842	10.187	
01-Oct-08	10.007	10.751	
01-Nov-08	10.547	10.296	
01-Dec-08	11.963	9.352	
01-Jan-09	10.129	9.721	
01-Feb-09	11.177	5.357	
01-Mar-09	9.161	4.475	
01-Apr-09	7.450	3.293	
01-May-09	7.609	3.349	
01-Jun-09	7.055	3.587	
01-Jul-09	8.625	4.394	
01-Aug-09	8.588	3.676	
01-Sep-09	6.957	8.028	
01-Oct-09	5.577	3.639	
01-Nov-09	6.961	5.298	
01-Dec-09	8.038	5.658	
01-Jan-10	6.793	4.489	
01-Feb-10	6.413	4.502	
01-Mar-10	5.892	3.689	
01-Apr-10	5.622	5.196	
01-May-10	6.400	14.694	
01-Jun-10	7.457	6.165	
01-Jul-10	8.872	4.235	
01-Aug-10	8.483	4.057	
01-Sep-10	6.859	2.947	
01-Oct-10	5.535	3.187	
01-Nov-10	5.697	5.103	
01-Dec-10	6.775	6.277	
01-Jan-11	7.620	8.504	
01-Feb-11	9.095	13.312	
01-Mar-11	7.164	5.121	
01-Apr-11	11.822	5.566	
01-May-11	6.527	3.440	
01-Jun-11	7.008	7.882	
01-Jul-11	9.873	6.660	
01-Aug-11	12.819	13.913	
01-Sep-11	8.195	10.584	
01-Oct-11	12.343	7.559	
01-Nov-11	9.104	11.856	
01-Dec-11	13.320	5.443	
01-Jan-12	15.064	9.121	
01-Feb-12	13.792	4.548	
01-Mar-12	8.124	5.380	
01-Apr-12	7.239	4.457	
01-May-12	6.304	3.182	
01-Jun-12	7.695	5.434	
01-Jul-12	8.942	7.547	
01-Aug-12	11.323	6.162	
01-Sep-12	10.493	12.014	
01-Oct-12	9.959	9.890	
01-Nov-12	7.460	9.408	
01-Dec-12	8.510	6.121	
01-Jan-13	9.027	6.102	
01-Feb-13	7.574	2.963	
01-Mar-13	7.242	11.308	
01-Apr-13	8.273	14.883	
01-May-13	7.110	13.998	
01-Jun-13	7.365	11.444	
01-Jul-13	10.958	6.093	
01-Aug-13	11.217	9.118	
01-Sep-13	10.838	12.331	
01-Oct-13	8.122	6.943	
01-Nov-13	8.053	2.948	
01-Dec-13	7.867	5.553	
01-Jan-14	8.222	4.736	
01-Feb-14	7.316	10.058	
01-Mar-14	7.133	4.483	
01-Apr-14	6.997	3.205	
01-May-14	9.857	5.857	
01-Jun-14	5.720	4.546	
01-Jul-14	7.441	13.451	
01-Aug-14	8.316	4.802	
01-Sep-14	8.449	2.496	
01-Oct-14	8.579	2.782	
01-Nov-14	7.307	3.961	
01-Dec-14	8.153	2.793	
Average	8.369	7.222	116%
STD	1.954021	3.4384287	57%

	Av RRO Price	Av Weighted Pool	STD Dev RRO Price	STD Dev Weighted Pool
2005	6.163	7.393	29.2%	338.3%
2006	7.489	8.561	100.6%	414.2%
2007	9.422	7.116	114.5%	325.0%
2008	10.197	9.571	109.1%	201.3%
2009	8.110	5.040	153.6%	199.9%
2010	6.733	5.378	108.1%	311.2%
2011	9.574	8.320	243.5%	340.2%
2012	9.575	6.939	269.3%	265.7%
2013	8.637	8.640	151.9%	411.7%
2014	7.791	5.264	103.8%	327.3%
STD Dev	1.339449	1.586191		

Comments on “Options for Enhancing the Design of the Regulated Rate Option (RRO)”

David P. Brown and Andrew Eckert

University of Alberta, Department of Economics

1 Introduction

We would like to thank the MSA for the opportunity to provide feedback regarding its review of the RRO. Our comments below will address:

- The economic role of the RRO.
- Existing evidence on the competitiveness of the retail electricity market, and the need for further data and research.
- Retail price volatility, and the role of government intervention.
- Interaction of the RRO and the unregulated arm of the market with other government policies and initiatives.
- Finally, we conclude with comments on the four specific questions raised by the MSA.

2. Economic Role of the RRO

It is difficult to evaluate changes to the RRO without being clear on its intended purpose. Therefore, before discussing adjustments to the RRO, we review its economic role.

When the retail market was established in Alberta, the government instituted a default rate to help facilitate a transition to a competitive retail market. The objective of the RRO was to provide consumers with a default rate to provide time for consumers to gradually switch to unregulated retailers (Alberta Department of Energy, 2005). The use of such default rates is a common method to alleviate market power concerns in the early phases of a retail market (Blumsack and Perekhodtsev, 2007; Kwoka, 2008).

The current purpose of the RRO in Alberta is less clear. As of March 2015, 56% of residential consumers remain enrolled in the RRO. The remaining residential consumers are largely enrolled in fixed-price contracts with the unregulated arms of the utilities that offer the RRO. There is a downward trend in the number of consumers enrolled in the RRO (MSA, 2015).

The level at which this regulated default rate should be set depends on one’s view of its effect on retail competition. On the one hand, it has been suggested by some that the default rate should be set high to encourage switching. This approach was implemented in Texas to facilitate competition (Blumsack and Perekhodtsev, 2007). However, if the market is not deemed sufficiently competitive, lower rates might act as a ceiling that reduces the ability of unregulated competitive retailers to exercise market power (Tschamler, 2006).

There is substantial diversity in the way default service rates are set (see Tschamler (2006) and Tierney and Schatzki (2008) for a detailed review). Blumsack and Perekhodtsev (2009) provide several guidelines for the design and pricing of the regulated default rate option in the presence of retail competition. These guidelines include:

- “Default service prices must not be set at artificially low levels or in such a way as to erect an ad hoc barrier to entry by competitive suppliers” (page 680); and

- “The types of service that default utilities can offer their default customers must be chosen carefully. One option... is to place all default customers on a market-based rate. Risk-averse customers can then choose a fixed price contract option from a different supplier if desired” (page 681).

The use of the default rates such as the RRO are often viewed as temporary measures until the retail market is sufficiently competitive. Tschamler (2006) notes: “To achieve sustainable and robust retail competition, Status Quo Service [e.g., the RRO] should be either eliminated or transformed into a service that is not subject to price regulation. Furthermore, default service policies…should be designed so that few customers purchase the service and those customers that do, do not purchase it for very long.”

3. Existing evidence on retail competition and ongoing data requirements

As suggested above, the ongoing role of a default regulated rate depends on the competitiveness of the deregulated retail market. Unfortunately, the empirical evidence on the performance of retail market competition in Alberta and elsewhere is limited. This is due in part to the lack of detailed retail market data. Morey and Kirsch (2016) provide a review of the existing literature and demonstrate that the evidence on the performance and impact of retail market competition is mixed. While several studies find that retail market competition lowers retail prices, others find limited evidence that retail competition reduces prices. Su (2015) finds that retail competition in the U.S. benefited residential consumers, but had limited impacts on other consumer groups. In contrast, Salies and Waddam Price (2004) and Von der Fehr and Hansen (2010), in studies of the U.K. and Norway, find that firms exploit market power over the segment of consumers who are less informed or less likely to switch suppliers.

McFetridge (2012) and MSA (2014) assessed the competitiveness of Alberta’s retail market. The conclusion of the MSA (2014) was that the retail market is competitive. McFetridge (2012) notes on page 35: “the retail electricity market can be regarded at present as being competitive if not highly competitive. The RRO plays an important role in this. Competitive retailers design their offerings with a view to matching if not beating the RRO.” He goes on to note that “it is reasonable to assume that there would be significant new retail entry in the event that the RRO is eliminated.”

The ongoing and future role of the regulation and the RRO in Alberta’s retail market hinges critically on the competitiveness of Alberta’s retail market. As noted above, if there is a market failure in Alberta’s retail electricity market, then regulatory intervention may be necessary. However, there currently exists limited publicly available data to assess the performance of Alberta’s retail electricity market. The transparency of Alberta’s retail market is limited relative to other jurisdictions with competitive retail electricity markets. For example, the Texas power market provides a large amount of publicly available data (ERCOT, 2017) that allows for a more detailed assessment of the competitiveness of the retail market (PUCT, 2015) and utilizes a transparent interface that allows consumer to more quickly compare competitive retail price offerings (PUCT, 2017).

Because the competitiveness of Alberta's retail market is central to understanding the role of the RRO going forward, we emphasize the need for research that evaluates the performance of Alberta's retail electricity market and highlight the importance of more data in order to assess the ongoing competitiveness of Alberta's retail market. Currently assessing the relationship between the RRO and the unregulated market is difficult because of the quality of available data on ongoing and historical competitive retail prices (including fixed charges), and the absence of brand-level consumption data for the unregulated firms. An analysis of the competitiveness of the retail market would also be facilitated through the public availability of continuous forward pricing data. This data would be required in order to consider particular issues that hinder strong conclusions regarding the competitiveness of the retail market, in particular the effect of co-branding.

3. Price Volatility and Market Signals

The Minister of Energy requested that the MSA conduct an analysis on the role of the RRO to provide long-term stable electricity prices. Therefore, it is important to consider the impact and role for price volatility in residential retail markets. Brown et al. (2017) provide a more detailed discussion of the value of allowing retail rates to reflect underlying market signals. We will briefly summarize the key points here.

The cost of providing electricity to consumers can vary widely month-to-month, day-to-day, and even hour-to-hour. As a result, time-invariant retail prices may dampen important market signals that reflect the underlying cost of providing electricity. There is growing evidence that time-varying retail electricity prices can yield large efficiency gains (e.g., see Faruqui et al., 2012; Borenstein, 2013; Faruqui et al., 2016). A move to push the market towards regulated time-invariant residential retail rates would be a move in the opposite direction from what is being undertaken in numerous jurisdictions worldwide (Faruqui et al., 2016). Further, as Alberta moves towards a portfolio with increased variable generation, additional demand-side price-responsiveness will help facilitate the integration of renewables into the power system (Faruqui et al., 2012).

Despite the potential economic benefits of allowing retail prices to vary over time, it is important to recognize that residential consumers are risk-averse and often have a strong desire to avoid retail price volatility. Currently, the retail market provides consumers with an avenue to avoid price volatility by signing long-term fixed-price retail price contracts. In Alberta's current market design, unregulated retailers offer an array of fixed-price contracts that range from one to five years. Households that are risk-averse can access fixed prices and retailers earn a premium for facing the associated risks of providing price certainty.

Some form of intervention may be desirable if retail price volatility is a result of market power. During the period of market restructuring, retail price controls and regulated default rates have been employed in numerous jurisdictions as temporary measures to alleviate market power concerns in retail electricity markets (Kwoka, 2008). However, Littlechild (2002, pg.5) notes that such “price controls tend to mask the underlying problem rather than cure it. Insofar as there are legitimate concerns about monopoly power, it is generally more appropriate to look at the conditions of new entry.”

In the absence of market power concerns in the wholesale, forward, and retail markets, retail price volatility is expected to reflect changes in the underlying costs of electricity, while unregulated retailers provide risk-hedging services to consumers who prefer retail price stability.

5. Experiences from other jurisdictions

Default service policies and their use in competitive retail markets vary widely across jurisdictions. Tschamler (2006) and Blumsack and Perekhodtsev (2007) provide a detailed summary of the different regulated (default service) pricing methods utilized and their experience in numerous jurisdictions. We will briefly outline these different models as it may provide guidance regarding the future direction of the design of the RRO in Alberta going forward.

In Texas, after the initial phases of retail market competition, regulators set default prices at high levels to entice unregulated competitive suppliers to compete over consumers. These default “price-to-beat” rates eventually expired and the market operates with no regulated default rates (although there are still providers of last resort). Retail competition has been deemed to be a success in Texas because of the high degree of participation by consumers (PUCT, 2015). However, recent research begins to question consumers’ willingness to search for lower price offerings (Hortacsu et al., 2017).

Other jurisdictions have adopted a model of wholesale market price pass-through to set default service rates (Tschamler, 2006). While this can encourage consumers to switch to unregulated retailers who offer fixed-priced products, consumers are highly adverse to such price volatility. This has led to issues as discussed in detail in Littlechild (2003). Alternatively, regulators can potentially utilize bill deferral with rate caps or certain smoothing mechanisms to mitigate price volatility in these wholesale price pass-through default service contracts. However, offering such stable default contracts that internalize the price and volumetric risks of retailing would likely reduce unregulated retailers’ abilities to compete for consumers. Unregulated retailers who offer fixed-price contracts build in a risk premium in their rates for the price and volumetric risk they face for offering fixed-price long-term contracts.

Numerous jurisdictions utilize a model where the default energy rate is set via a competitive auction or via direct bilateral agreements where the default service provider competitively procures supply from generators (procurement can also come in the form of financial contracting via a forward market). Subsequently, for any given level of procurement costs, the default rate is set with different degrees of stability (e.g., monthly, six month fixed-price, annual fixed-price, multi-year fixed prices). This type of procurement arises in Alberta, Massachusetts (EEA, 2017), Rhode Island (RIPUC, 2011), New Jersey (Loxley and Salant, 2004), for example. These models have been supported because of their ability to reflect expected future wholesale power costs, provide stable price offerings to consumers, and acts as a price-ceiling for unregulated retailers (Tschamler, 2006). However, these designs have been criticized because they may act as a barrier to entry for unregulated retailers and impede retail market competition (McFetridge, 2012).

6. Interaction with other government initiatives

a. Broader Market Structure Changes

Alberta's electricity market is currently undergoing a period of substantial transition. It is important to understand the role of the RRO and retail market competition in the broader context of these ongoing market design changes. As noted above, a concern of the government appears to be that the retail market provides stable power prices. It has been suggested that the introduction of a capacity market and the likely addition of bid mitigation in the wholesale power market are expected to reduce price volatility in electricity markets, including in Alberta (Shaffer, 2016). However, this is not obvious; as Alberta increases its penetration of renewable generation, wholesale price volatility may potentially increase, as shown for example in Ketterer (2014). As discussed above, allowing retail prices to reflect prevailing market conditions can facilitate increased demand responsiveness that will help integrate variable renewables into the power system (Faruqui et al., 2012).

Another important issue that needs to be considered when discussing changes to the RRO and the retail market is deciding how we should pass-through capacity market related costs to the retail market. A growing penetration of renewables will likely reduce the level of wholesale market prices (e.g., see Ketterer (2014)), so that thermal resources increase their reliance on the capacity market to recover their fixed costs. This reduces the energy market component of consumers' bills, but not necessarily their aggregate retail charge.

b. Distributed Energy Resources

Numerous jurisdictions (including Alberta) are implementing policies to promote deployment of distributed energy resources (DERs) such as distributed generation (e.g., roof-top solar), demand response, and energy efficiency (e.g., MIT Energy Initiative, 2016; Alberta Government, 2017; AUC, 2017; NRCAN, 2017). In particular, on March 31st 2017, the Alberta Utilities Commission (AUC) announced that it is conducting a formal Distributed Generation Review to explore opportunities for more distributed generation growth (AUC, 2017). The decision to adopt and participate in these DER programs is driven in a large part by the level and volatility (e.g., peak and off-peak price differentials) of retail electricity prices (IEA, 2015). This is particularly true in regions (such as Alberta) that have net metering policies where roof-top solar is compensated at the prevailing retail rate. Retail price volatility and time-varying retail rate options can provide consumers with a strong incentive to adopt and participate in the deployment of DERs (Darghouth et al., 2011; Faruqui et al., 2012; MIT Energy Initiative, 2016). Therefore, a move to further dampen key market signals in retail electricity prices can counter other policy initiatives to motivate the deployment of DERs.

In addition, a move to a fully regulated retail market may potentially impede the deployment of these technologies. Other jurisdictions have recently advocated for the potential value of competitive retail markets in order to broaden consumer choice when it comes to the adoption of DERs. For example, California is considering a move to fully deregulate its retail electricity market (CPUC, 2017). It is believed that a competitive retail market may provide more DER services and choices to consumers who are considering adopting DERs than a fully regulated retail market could provide. Effective retail competition has the potential to accelerate the growth of DERs.

c. Retail Market Price Caps

In addition to the changes to the RRO being considered in the current review, the government has indicated that it intends to introduce a price cap of 6.8 cents/kWH on RRO rates until 2021 (Alberta Government, 2016). Here we touch on the main concerns; see Brown et al (2017) for a more detailed discussion of the potential economic implications of retail price controls. While current wholesale and forward prices are at historical lows, the EIA (2017) forecasts that natural gas prices will increase to levels observed in January 2014 by early 2018. In light of recent policies and generation unit retirements that put upward pressure on power prices, the retail price cap could be a binding constraint. In the case where the retail RRO price cap is binding, this can lead to several market distortions.

Artificial price controls that hold rates at sub-optimal levels may dampen important market price signals and reduce the effectiveness of environmental policies targeted at pricing emissions and motivating consumers to adopt distributed energy resources such as rooftop solar, demand response, and energy efficiency. The reduced price-responsiveness of residential demand can reduce an important avenue of power system management with increased renewable generation.

In addition, retail price controls can distort existing retail market competition if unregulated retailers are facing an RRO provider with a binding retail price cap which is subsidized to true-up the difference between underlying costs of providing power and the capped retail rate. Historical evidence demonstrates that it is often difficult to remove binding retail price controls once they are implemented. Further, the removal of binding retail price controls is often met with sizable price spikes as retail prices adjust to equilibrium levels. This can raise further political and regulatory challenges.

We feel that it is important to discuss the impact of the proposed retail price cap on the RRO and its implications for the retail market and broader energy system.

6. Conclusions

To conclude, we would like to emphasize again that evaluating potential changes to the RRO requires clarity on the role of the RRO alongside unregulated providers, and whether this retail market structure is expected to continue. The intended roles of the RRO and the deregulated arm of the market inform the specific questions identified in your call for comments. Further, we stress that it is important to consider the impacts of changes of the RRO alongside the other ongoing electricity market policy initiatives.

If the existing retail market is viewed as being sufficiently competitive and retailers are offering an adequate number and type of fixed-price retail contracts, then it is not clear why enhancements to the RRO are necessary. In this setting, we believe that it is important to assess the impacts of any changes to the RRO on the nature of competition in the retail market. Alternatively, if there is a market failure in the retail market, regulatory intervention and adjustments to the RRO may be desirable. Currently, the lack of detailed retail market data limits researchers' and regulators' abilities to assess the competitiveness of Alberta's retail electricity market.

If the RRO is intended to provide not only electricity retailing, but also price smoothing, then revisiting the procurement methodology may be useful. However, if it is felt that price stability is appropriately provided through the fixed-price contracts of the unregulated arm, and that encouraging switching from the RRO to unregulated products is still a policy goal, then adjusting the RRO to include longer term procurement and other methods of bill smoothing would seem at odds with these objectives.

The purpose of imposing price uniformity across RRO regions and customer classes is unclear. In general, geographic price dispersion of product can reflect local costs, and provide important signals in the same way as price variation over time. In the current context, however, price differences across RRO providers seem to come from differences in EPSP details, underlying load profiles, and procurement methodologies as opposed to reflecting regional differences such as transmission constraints. Finally, in our view, continuing uncertainty about the product provided by the RRO and how it is priced has the potential to hinder the development of the unregulated arm of the retail market.

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May 19, 2017

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Attention: **Mark Nesbitt**

RE: **MSA Options for Enhancing the Design of the RRO**

Direct Energy Regulated Services ("DERS") is writing in response to the Market Surveillance Administrator's ("MSA") notice dated April 21, 2017 requesting comments from stakeholders regarding options for enhancing the design of the Regulated Rate Option ("RRO"). Contained in this correspondence are the comments of DERS which identify options, advantages and disadvantages of specific changes to the RRO.

As an RRO Provider with over thirteen years of experience, DERS is significantly impacted by any changes that occur in the structure of the RRO Regulation. As such, DERS is grateful to be afforded the opportunity to provide comments on potential changes. DERS is cognizant of the Alberta government's mandate to provide long-term, stable and affordable prices for electricity consumers ("Mandate") and would like to continue to collaborate with the other RRO Providers, the MSA and the provincial government to ensure that relevant expertise and experience is carefully considered when examining possible changes**.**

The MSA has requested that stakeholders consider the following:

i. whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta;
ii. changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement;
iii. introduction of deferral accounts or changes to bill smoothing; and
iv. when and how a change to the RRO should occur.

Given the number of expected changes to the electricity market, DERS remains concerned that RRO customers or the risk profile for RRO Providers will be significantly impacted. These changes include but are not limited to capacity markets, "Green" initiatives, RRO price cap, retirement of coal plants, and PPA impacts. Although a great deal of speculation has occurred, the outcome of these changes is currently unknown. Ultimately, implemented RRO changes must offer RRO Providers the flexibility to mitigate negative impacts to their customers (which may include higher costs and increased volatility). As such, DERS is interested in the development of RRO oversight that allows a rapid and efficient response to market changes without a requirement for a full Energy Price Setting Plan ("EPSP") process. This would minimize the impact to customers, shorten regulatory process timelines and reduce the regulatory and administrative cost burden.

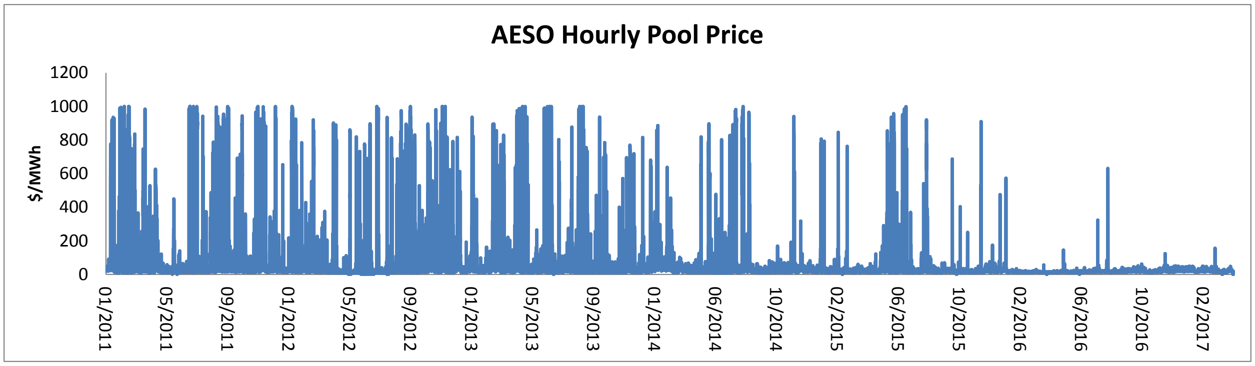
Based on the complexity of this issue, DERS considers that consultation and collaboration between RRO Providers, government, regulators and the MSA will be required to find an effective solution. As a starting point for consideration, DERS envisions replacing today's EPSP mechanisms with a system whereby the overarching outcomes, parameters, and boundary conditions are set through an AUC process that would establish benchmarks, targets, and minimum and/or maximum thresholds, for renewable components, capacity requirements, monthly rate volatility, percentage annual rate changes, and service levels for some reasonable period, say between 4 and 10 years. Each RRO Provider, the entity best positioned to understand their customers, loads, and service territories, would then have the ability to manage their portfolio within the established parameters. Annual reviews by the MSA would test each RRO provider's outcomes against the pre-established benchmarks, targets, limits and adjust risk compensation to reflect market conditions and changes to the portfolios. Similar to today, there would be an ongoing comparison of the RRO Providers which allows for timely intervention in the case of significant divergence of outcomes. Moving to such an outcomes-based model, as opposed to today's prescriptive and administratively determined EPSP model, will allow for rapid reaction to market forces, will ensure RRO Providers "compete" with each other and with the benchmarks, targets, and limits, and will ensure customers receive the government's intended benefits at the lowest possible cost. Nevertheless, DERS reiterates that thorough consultation among all the stakeholders is required before a final solution is determined.

DERS is committed to supporting the transition to a market with a smaller carbon footprint while ensuring that the impacts to customers are reasonable and, most importantly, well managed. Given its background, DERS has the knowledge and experience to manage its RRO portfolio, including new components resulting from a transitioning market, on behalf of its regulated customers.

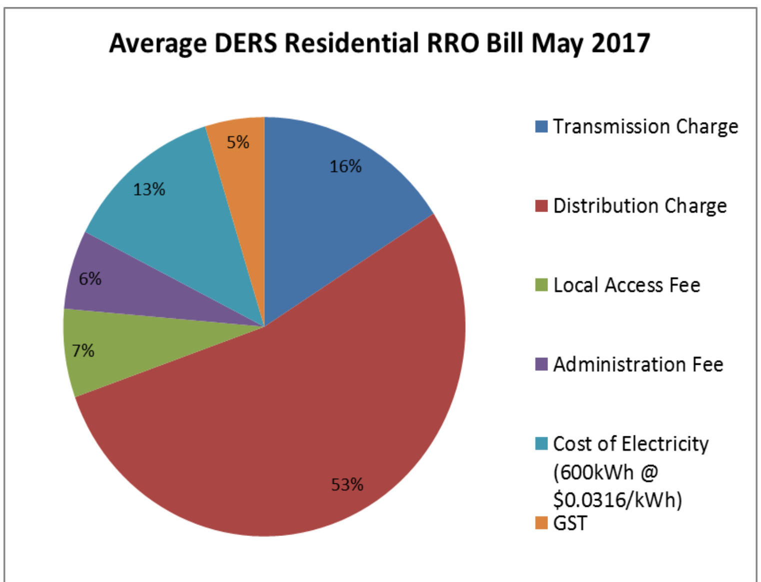
DERS believes the existing RRO is working well, however, small changes could provide the outcomes sought in the government's Mandate. As DERS has outlined in the disadvantages listed below, certain suggested changes such as pool price flow through, deferral accounts and centralized procurement come with significant costs and risks for customers and would go against the goals of the Mandate. In summary, DERS does not consider that significant changes are required at this time.

RRO Volatility and Materiality to Customers

Given the Alberta government's Mandate regarding price stability and affordability, and the incoming $0.068/kWh price cap on the RRO rate, DERS has included historical Alberta power pricing to frame a discussion around the volatility faced by regulated customers. DERS notes that the volatility in the electricity market was a more significant concern from 2011 through 2013. In contrast, electricity prices have displayed remarkable stability since early in 2016, as illustrated in the historical hourly AESO pool prices below:



While Alberta has benefitted from stable electricity pricing as of late, DERS notes that electricity consumption has significant seasonality. Customers use more electricity in the winter, than in the summer, which has the effect of generating variance in month-to-month bill amounts. Even after considering this seasonality, DERS notes that electricity charges are a small portion of the total bill. As highlighted in the table, below, in May 2017 the Transmission and Distribution charges on an average DERS residential bill represented 70% of the charges whereas the commodity was only 13%.



Average DERS Residential RRO Bill May 2017

Bill Item	May 2017	% of Total Bill
Transmission Charge	$ 22.59	16%
Distribution Charge	$ 76.05	53%
Local Access Fee	$ 9.69	7%
Administration Fee	$ 8.66	6%
Cost of Electricity (600kWh @ $0.0316/kWh)	$ 18.10	13%
GST	$ 6.75	5%
Total	$ 141.84	100%

With the cost of electricity being a small portion of a residential bill, the impact of changes to the RRO may only generate minor impacts for regulated customers in terms of what is owed each month. In May 2017, for example, reducing the energy charge by an arbitrary 50% would have resulted in a total bill decrease of only 7%.

DERS' Feedback on Suggested RRO Modifications

DERS has provided below advantages and disadvantages of several alternatives for modifying the RRO. Many of these items are not mutually exclusive, meaning several could be implemented together.

1. Reduce the RRO Limit or Allow Only Residential, Farm, Irrigation and Lighting Customers on the RRO

One alternative that has been suggested is a reduction to the RRO eligibility threshold in order to remove larger commercial and/or industrial customers. Similarly, narrowing RRO eligibility to only the residential, farm, irrigation and lighting rate classes, irrespective of load, would accomplish a similar reduction of the RRO customer base.

Advantages	Disadvantages
• Commercial and industrial customers would not be protected by a price cap that is intended for residential and farm customers.	• High cost to implement: ○ Unless the implementation was aligned with DERS' non-energy and energy application cycle, a new DERS administrative rate application would be required, at a cost of approximately $500K per application. ○ Additional costs would result from billing system changes, customer communication requirements and complaint handling. • Fixed costs are allocated over fewer customers, therefore DERS' Administration Fee and monthly RRO rate would increase for the remaining RRO customers (as shown in the table below).

The table below provides an estimation of the impact on DERS' administrative fees based on various thresholds per year for all rate classes and the impact of limiting the RRO Regulation to only certain rate classes (residential, farm, irrigation and lighting).

Estimated RRT Administration Fee Changes with Various Thresholds:

	Threshold Change						Variance from 2018 Rates				
	No Change 2018 Rate	25,000 kWh/year Limit	50,000 kWh/year Limit	75,000 kWh/year Limit	100,000 kWh/year Limit	Farm/Res/Irr/ Lights	25,000 kWh/year Limit	50,000 kWh/year Limit	75,000 kWh/year Limit	100,000 kWh/year Limit	Farm/Res/Irr/ Lights
	$/day	$/day	$/day	$/day	$/day	$/day	%	%	%	%	%
Residential (E1)	0.428	0.450	0.436	0.432	0.431	0.464	5.1%	1.9%	0.9%	0.7%	8.4%
Small General (E2)	0.443	0.425	0.426	0.431	0.435		-4.1%	-3.8%	-2.7%	-1.8%	
Large General (E3)	0.610	0.422	0.420	0.429	0.459		-30.8%	-31.1%	-29.7%	-24.8%	
Oilfield (E4)	0.457	0.416	0.414	0.424	0.432		-9.0%	-9.4%	-7.2%	-5.5%	
Farm (E5)	0.445	0.462	0.453	0.450	0.449	0.485	3.8%	1.8%	1.1%	0.9%	9.0%
Lighting (E6)	0.219	0.228	0.222	0.220	0.220	0.237	4.1%	1.4%	0.5%	0.5%	8.2%
Irrigation (E7)	0.773	0.733	0.769	0.770	0.765	0.851	-5.2%	-0.5%	-0.4%	-1.0%	10.1%

As shown in the table above, residential customers would see an increase of approximately 5% in DERS' Administration Fee if the RRO eligibility threshold was reduced to 25MW. Based on reduced load, RRO prices would increase by approximately 2% due to the spreading of fixed costs over a lower load. DERS would require a full rate application to recalculate its Administration Fee and a reasonable Return Margin based on lower site count and load, a regulatory process that would cost approximately $500,000.

As an alternative to changing the RRO eligibility threshold, a simpler change that achieves the same outcome, while avoiding the disadvantages listed in the table above, would be to limit the 6.8 cent/kWh RRO price cap regulation to only residential, farm, lighting and irrigation customers.

2. One Rate Class for All RRO Customers in DERS' RRO Territory

Another approach to simplifying the RRO rate would be to eliminate rate classes and generate a single rate for the entire customer base in each RRO Provider's territory.

Advantages	Disadvantages
• Less confusing for customers. • Very small difference in rates for different rate classes, with the exception of lighting.	• One blended rate causes cross-subsidization between rate classes due to diverse customer usage between profiles. • Issues with lighting class, which primarily consumes off-peak electricity. • Does not contribute to the goals of the government's Mandate of long term, stable and affordable prices.

3. One Rate Class for All RRO Customers in Alberta

One suggested change to the RRO would be to eliminate rate classes and generate a single RRO rate for the entire province. This is a more complicated change than option 2, described above, as there would be some type of settlement or true-up between the three RRO Providers in order to achieve a single Alberta rate.

Advantages	Disadvantages
• Potentially less confusing for customers. • Less administrative work required from distributors and retailers	• One blended rate relies on the cross-subsidization of rate classes and across different territories, due to the unique load shapes, Unaccounted for Energy rates and line loss rates for each distributor. • Administration costs associated with RRO Providers having to establish and execute on a settlement or true-up process. • Could create additional risk for RRO Providers, as the energy rate they are charging could be quite different from their underlying costs if there is a disparity in the RRO costs between providers. The costs of the risk would be passed on to customers. • Individual RRO Providers have less control and therefore less accountability over the rate that would

	be seen by their customers. • Issues with lighting class, which primarily consumes off-peak electricity.

4. Default All RRO Customers to Equalized Billing or Promote Equalized Billing

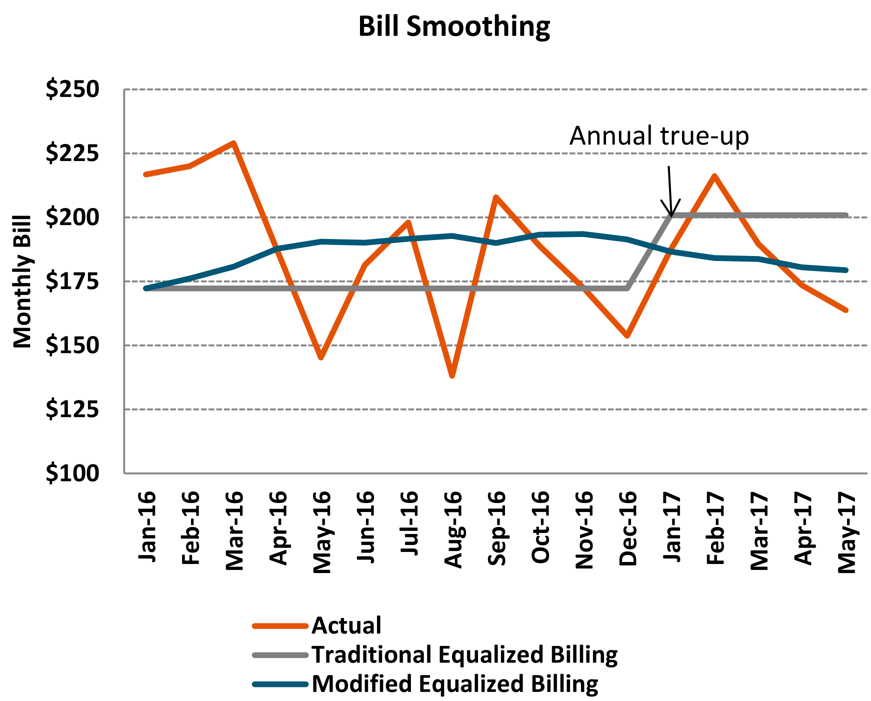
A potential method of reducing monthly volatility in customers' total bills would be to apply a smoothing function such as equalized billing to eliminate seasonality.

Advantages	Disadvantages

• Reduces monthly volatility and seasonality from RRO bills.
• Addresses the total bill, not only the energy costs.
	• Depending on implementation, DERS Working Capital requirement will increase by approximately $200,000, which would be passed on to customers in rates.
	• Some regulated customers may be unhappy with a forced change. Feedback DERS has received from customers includes:
	  ◦ Farms/commercial sites like to match revenue with costs. Revenues are often higher in periods when power use is higher.
	  ◦ Some customers like an immediate cost signal to indicate when prices or their consumption have increased.
	  ◦ Many customers want to pay the exact amount of their bill each month but nothing more.
	• Adjustments to the monthly amount would still be necessary if prices (energy, T&D or other components of the bill) increase beyond a tolerance threshold.
	• Works against the energy efficiency as equal payments removes price signals that may indicate periods of supply constraints.
	• A change to the equalization methodology requires a change to the billing system, which is costly to implement (approximately $500,000 for DERS).
	• Requires a complex set of communications to customers to create awareness and explain the changes which will result in additional costs.
	• Distributor initiated cancel rebills and other billing adjustments are more difficult to present and explain when customers are on an equalized billing plan.

There are two different ways to implement equalized billing, as shown in the graph below. Currently, DERS uses a "traditional" method which estimates a monthly amount at the start of a one-year period, and then any amounts over and above this estimate are carried over and applied at the start of the next billing year, when the new monthly amount is calculated. This results in the customer paying a predictable, stable amount every month, but can generate significant account balances between years. An alternative, or "modified," approach would be to create an equalized payment by recalculating on a monthly basis, based on new usage and rate information. This means that the amount will vary slightly every month, but would eliminate the risk of a large balance at the end of the equalization period. That said, while volatility may be reduced intra-year, this approach would not mitigate any long-term trends in volatility or pricing.

It is important to note that while DERS currently offers this option to customers, the uptake for equalized payments is low (approximately 10% of customers). DERS is uncertain as to whether this low uptake is a result of low awareness or a lack of interest in the billing option. As this option is currently available, DERS suggests that increasing awareness by promoting the equalization billing option would be a simpler remedy than forcing all customers into a billing option that was not requested and may not be desired. If a customer leaves the RRO and is on the equalized billing option, the true up that is required is generally bigger under the traditional option than it would be under the modified option, as seen in the table below.



5. Centralized Procurement Offering

Centralized electricity procurement entails transferring the responsibilities of the RRO Providers to a single entity providing a single procurement methodology for all RRO customers. While this may initially appear to be a straight forward concept, there are significant considerations, including but not limited to:

- How would the centralized entity be selected, and who bears the legal responsibility taken by the entity?

- How would pricing be set for each RRO Provider (discrete allocation of volumes to match each territories load shape or a single rate that subsidizes some customers at the expense of others)?
- Does the centralized entity also carry the commodity risk associated with procurement?
    - If yes, then does the load forecasting function also reside with the centralized entity as a means to better manage its risks?
    - If no, then how will RRO Providers be compensated for assuming a risk profile for which they no longer have oversight or discretion?
- Does the centralized entity fulfill all credit requirements associated with procurement?

Notwithstanding the many facets of centralized procurement, DERS has included generalized advantages and disadvantages of this option.

Advantages	Disadvantages
• Simplify the roles and involvement of the Commission and interveners to possibly allow a more streamlined review processes with respect to procurement. However, as procurement is only one aspect of the overall EPSP, this advantage may be of little benefit. • Administrative cost of the EPSPs could be reduced if a centralized procurement approach were employed such that the roles are consolidated in a central agency.	• Each RRO Provider carries a unique load shape risk and attrition risk based on the pool of customers served. Aggregating procurement would cause subsidization across geographical areas, creating divergence between costs incurred and costs paid by customers. • A single centralized hedging approach, such as an auction, would reduce market liquidity. • Procuring smaller volumes throughout the buying period procurement best reflects the market pricing within the defined buying period. • Significant credit requirements for centralized entity when procuring a large enough volume to satisfy the entire RRO. There is an incremental cost to transact via an NGX auction process, from both a credit and transactional perspective. • Standardized approach would risk foregoing opportunities for efficiencies and cost savings that are unique to a particular RRO Provider or, at the same time, would risk imposing material costs on RRO Providers and their customers by imposing a standardized approach. • No benchmark from other RRO Providers to gauge whether volumes are procured at competitive prices. • Removes the opportunity for innovation that exists with three separate entities procuring differently and sharing best practices.

As mentioned earlier, DERS has the history, knowledge and experience to be able to manage its RRO portfolio on behalf of customers. DERS is of the view that centralized procurement would not alleviate the issues around buying pressure. As previously stated, DERS is of the view that there would be no benefit in a centralized procurement process and, as explained below, significant costs and risks that would be borne by customers..

In Decision 2941-D01-2015, the Commission noted that there is merit in the ability to compare the resulting rates and assess the relative merits of each RRO methodology. By eliminating two parties from the procurement process, the Commission would lose the ability to benchmark the competitiveness of the procurement process. Procurement diversity provides a market check on the three RRO Providers in the concurrent monthly rate setting process. Without this benchmarking, it would be reasonable to expect an increased level of intervention and scrutiny during the centralized entities procurement proceedings, as customer groups and RRO Providers would be fully committed to establishing the proper checks and balances required to protect customers from a monopolistic procurer.

The centralized entity may consider auctions instead of block procurement as a means of avoiding the pitfalls of a single procurer. However, unintended consequences from failed auctions should also be noted as a significant disadvantage of centralized procurement. For example, the EPCOR auction held on April 1, 2014 was cancelled for the May and June flat products (7x24), and June peak product (7x16). This was followed by an increase in prices for May 2014 flat product from $76/MWh on March 31, 2014 to $85/MWh on April 1, 2014. If procurement was performed centrally, unintended price impacts, such as this, could become even more pronounced.

DERS submits that a centralized customer care and billing ("CC&B") provider would result in numerous complex issues for both the RRO Providers and regulated customers. Each existing CC&B system is tailored to the service area that each RRO Provider services and the needs of those customers are unique to each area. A common customer care contact centre would lead to similar issues of stranded costs (which will be significant for ENMAX and DERS, in particular because both have undertaken recent billing system transitions), centralized system build costs, lack of knowledge of the customer base and privacy issues, to name a few. The cost of the system changes alone that would be necessary to accommodate a centralized procurement and billing process would be very high, as discussed below.

The billing system transition undertaken by DERS in 2014 can be used as a proxy for the cost of a billing system transition for a customer base the size of the RRO eligible base in Alberta (approximately 1.5 million customers). The total cost in 2014 for DERS' billing system transition was estimated by Desert Sky Group, the benchmarking firm used by DERS in Proceeding 2957[1], at $123 per customer. Multiplying this per customer cost by 1.5 million RRO eligible customers, the total cost of a billing system transition to support central procurement would be approximately $185 million. This cost estimate is likely conservative given that any billing system change of this magnitude is highly complex and prone to transition-related issues. When considering transitioning all 1.5 million RRO customers in Alberta from three separate RRO Providers' billing systems to a new single billing system, that must accommodate customers from various service areas, additional transition costs and issues must be expected over and above those experienced from the transition for a single RRO Provider. Further, all three RRO Providers achieve economies of scale by servicing other regulated sites and commodities, in the case of DERS, both gas and power customers are served from the same system and other RRO Providers serve municipal water and waste customers. Any synergies gained consolidating RRO billing would be offset by increased costs for gas, and water customers.

[1] Proceeding 2957, Direct Energy DERS 2012-2016 DRT and RRT Application

6. Pool Price Flow Through

Regulatory efficiency may be achieved by eliminating forward procurement altogether, and flowing the pool price of electricity to customers. The problem is that this methodology does not protect regulated customers from price volatility, which is one of the stated goals of the government.

Advantages	Disadvantages
• The lowest price over time for customers that can bear fluctuations in monthly commodity prices (those customers not on fixed or low incomes), as this option eliminates the cost of hedging. • Customers who want stable pricing (and meet credit requirements) still have the option to sign a competitive contract.	• The most volatile alternative, exposing consumers to all price fluctuations. • Difficult for customers to understand in comparison to current month ahead price. • No price signal is received by consumers in advance of consumption. Customers therefore do not have the opportunity to reduce their consumption in response to higher prices. • Due to the potential for large monthly swings, it is a poor alternative for those on low or fixed incomes, who may not have the opportunity to sign a competitive contract due to credit restrictions. • Costly to implement from a retailer perspective, as billing systems are not set up to incorporate pool pricing. DERS estimates a systems change cost of $2 million, including changes to bill presentment.

7. Longer Term Procurement and Rate Setting with Renewable Procurement Standard

Long term volatility could be reduced through procuring a portion of the forecasted load in term volumes of quarterly, semi-annual or annual blocks. A reduction in month-to-month volatility and increased regulatory efficiency may be achieved by setting the RRO rate on a quarterly basis, instead of monthly. DERS is supportive of proactively increasing the procurement of renewable energy in the RRO portfolio, to assist the government in achieving the objective of phasing out coal generation. DERS is proposing the direct contracting of renewable energy by the RRO Providers, which would offset any future charges from the AESO. This gives the RRO Providers flexibility in managing the RRO portfolios, while ensuring a proactively managed, market reflective price for regulated customers.

Advantages	Disadvantages
• More predictable and stable prices for RRO customers. • Quarterly and monthly products are generally available in advance of the start of a quarter making it feasible to offer a quarterly rate without unreasonable risk premiums. • Assist Alberta government in achieving 30% renewable energy by 2030, while mitigating impacts to customers.	• While it mitigates long-term increases in pricing and unplanned for events, hedging often comes at a premium to spot prices. • Term procurement may result in an RRO that diverges from the current market price. • If the RRO Provider is required to buy 100% term power, they may be left at risk of a large loss if higher than expected attrition actualizes.

8: Deferral Accounts

Deferral accounts are more volatile for RRO consumers than the commodity charge itself. Transferring the commodity risk from RRO Providers to consumers is the very thing the government is attempting to avoid. The RRO Provider is in a better position to mitigate the risk associated with commodity price.

Advantages	Disadvantages
• Lower risk margins as customers assume much of the risk.	• Puts commodity price risk on customers instead of RRO Providers that have tools to manage the risk. • Deferral accounts can exaggerate the swings and create greater volatility, which would be a poor solution for those customers with low incomes who rely on a fixed monthly bill. • Creates intergenerational inequity as future customers are left to pay the costs associated with a previous month's consumption.

To illustrate the fact that a deferral account is more volatile than the actual commodity charge that it is meant to resemble, please refer to Attachment 1: DERS Monthly GCFR (Gas Cost Flow-Through Rate) versus AECO Monthly Index. It can be seen that the standard deviation of the GCFR over the last five years was $1.22/GJ while the standard deviation of the AECO Monthly Index price was $0.87/GJ. Please note that this is a large difference on a commodity that averaged a market price of $2.86/GJ over the same time period. This means that the GCFR fluctuates to a greater extent than the market price for natural gas and would translate into greater monthly volatility for regulated electricity customers, if implemented, which the government has stated it would like to avoid.

When and How Changes Should Occur

In order to implement changes that could be effective upon expiration of the current RRO Regulation, which is April 30, 2020, DERS would recommend changes be communicated to the market as soon as possible, but by no later than the first quarter of 2019. It would be difficult for RRO Providers, given the current approval process, to respond with the required changes to their EPSP's within a shorter time frame. Making a change to the RRO Regulation prematurely, without proper consideration of the required implementation period, may cause further disruption and confusion, and create unnecessary risk for limited benefit.

Given the upcoming and significant changes to the electricity market, (capacity market, coal retirements, etc.) it is important that any amendments to the RRO Regulation create a mechanism that allows RRO Providers to quickly and proactively respond on behalf of their regulated customers to manage the costs and the risks and avoid unnecessary expenses. While DERS supports the transition to a market with a smaller carbon footprint, DERS would like to ensure the impacts to customers are reasonable and most importantly, well managed. DERS has the history, knowledge and experience to manage its RRO portfolio on behalf of its regulated customers and is committed to working with the Alberta government to meet its Mandate. DERS also notes that minimal changes to the RRO Regulation may be able to fulfill the government's stated Mandate.

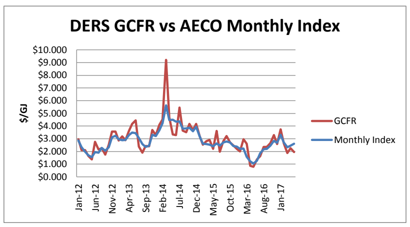
Direct Energy Regulated Services
Comments to MSA on the Design of the RRO
May 19, 2017
Attachment 1: DERS GCFR versus Monthly Index Volatility

Date	North	South	GCFR	MI	GCFR vs MI
Jun-04	$8.257	$8.313	$8.285	$7.0502	$1.235
Jul-04	$5.894	$6.403	$6.149	$6.6132	-$0.465
Aug-04	$6.611	$6.792	$6.702	$6.5278	$0.174
Sep-04	$6.527	$5.927	$6.227	$5.8044	$0.423
Oct-04	$5.106	$5.193	$5.150	$5.3886	-$0.239
Nov-04	$7.909	$8.283	$8.096	$7.5870	$0.509
Dec-04	$7.053	$7.006	$7.030	$7.1717	-$0.142
Jan-05	$7.194	$7.312	$7.253	$6.5874	$0.666
Feb-05	$5.984	$5.997	$5.991	$6.1644	-$0.174
Mar-05	$6.765	$6.057	$6.411	$6.2672	$0.144
Apr-05	$6.253	$6.932	$6.593	$7.0903	-$0.498
May-05	$5.352	$5.790	$5.571	$7.2777	-$1.707
Jun-05	$5.320	$6.825	$6.073	$6.6087	-$0.536
Jul-05	$8.085	$9.042	$8.564	$7.0164	$1.547
Aug-05	$6.199	$7.518	$6.859	$7.1769	-$0.318
Sep-05	$9.636	$9.983	$9.810	$9.0489	$0.761
Oct-05	$11.805	$12.262	$12.034	$10.9373	$1.096
Nov-05	$12.743	$12.182	$12.463	$12.0770	$0.386
Dec-05	$9.217	$8.732	$8.975	$10.2158	-$1.241
Jan-06	$15.037	$15.599	$15.318	$11.4813	$3.837
Feb-06	$6.682	$5.616	$6.149	$8.0225	-$1.874
Mar-06	$6.203	$5.098	$5.651	$6.8651	-$1.215
Apr-06	$7.048	$5.971	$6.510	$6.3089	$0.201
May-06	$6.481	$5.919	$6.200	$6.2260	-$0.026
Jun-06	$3.561	$2.676	$3.119	$5.3007	-$2.182
Jul-06	$5.894	$5.882	$5.888	$5.4923	$0.396
Aug-06	$4.154	$5.304	$4.729	$5.8385	-$1.110
Sep-06	$6.702	$7.828	$7.265	$5.8245	$1.441
Oct-06	$4.102	$3.720	$3.911	$4.2155	-$0.304
Nov-06	$6.947	$6.775	$6.861	$6.3643	$0.497
Dec-06	$8.278	$8.231	$8.255	$7.5189	$0.736
Jan-07	$7.464	$7.376	$7.420	$6.9162	$0.504
Feb-07	$5.893	$6.697	$6.295	$6.8624	-$0.567
Mar-07	$9.149	$9.171	$9.160	$7.4241	$1.736
Apr-07	$7.556	$7.634	$7.595	$7.0207	$0.574
May-07	$4.511	$4.456	$4.484	$7.0875	-$2.604
Jun-07	$6.762	$6.607	$6.685	$6.8557	-$0.171
Jul-07	$5.5500	$4.8970	$5.224	$6.1388	-$0.915
Aug-07	$5.7570	$5.7020	$5.730	$5.0518	$0.678
Sep-07	$4.5650	$4.0500	$4.308	$4.7563	-$0.449
Oct-07	$5.1200	$5.3860	$5.253	$4.9824	$0.271
Nov-07	$5.4490	$5.1810	$5.315	$5.8228	-$0.508
Dec-07	$6.3260	$6.1500	$6.238	$6.2567	-$0.019
Jan-08	$6.6560	$6.5780	$6.617	$6.1011	$0.516
Feb-08	$7.4093	$7.7212	$7.565	$6.8759	$0.689
Mar-08	$9.0437	$9.7074	$9.376	$7.2992	$2.076
Apr-08	$8.5337	$7.7813	$8.158	$8.0905	$0.067
May-08	$7.6219	$9.0092	$8.316	$8.9182	-$0.603
Jun-08	$13.0414	$13.5169	$13.279	$9.5781	$3.701
Jul-08	$10.0081	$6.1168	$8.062	$10.7996	-$2.737
Aug-08	$11.2299	$12.6922	$11.961	$8.4424	$3.519
Sep-08	$5.1236	$7.0550	$6.089	$7.0475	-$0.958
Oct-08	$5.3096	$5.8896	$5.600	$5.9105	-$0.311
Nov-08	$7.1680	$6.8840	$7.026	$6.5568	$0.469
Dec-08	$7.2100	$7.2240	$7.217	$6.8300	$0.387
Jan-09	$6.0920	$5.5840	$5.838	$6.2171	-$0.379
Feb-09	$5.5800	$5.4790	$5.530	$5.3293	$0.200
Mar-09	$4.2350	$4.5260	$4.381	$4.4759	-$0.095
Apr-09	$3.6700	$3.5750	$3.623	$3.8171	-$0.195
May-09	$3.0070	$3.0610	$3.034	$3.2376	-$0.204
Jun-09	$3.2610	$3.5420	$3.402	$3.3495	$0.052
Jul-09	$1.9250	$1.4810	$1.703	$3.1367	-$1.434
Aug-09	$2.9170	$3.1700	$3.044	$2.9012	$0.142
Sep-09	$2.3410	$2.3580	$2.350	$2.5583	-$0.209
Oct-09	$3.3030	$3.4390	$3.371	$2.8729	$0.498
Nov-09	$4.6230	$4.6510	$4.637	$4.6408	-$0.004
Dec-09	$3.9830	$4.0040	$3.994	$4.5276	-$0.534
Jan-10	$5.7340	$5.8410	$5.788	$5.1564	$0.631
Feb-10	$5.8300	$5.8810	$5.856	$5.2343	$0.621
Mar-10	$4.9670	$5.1800	$5.074	$4.8494	$0.224
Apr-10	$3.5940	$3.3770	$3.486	$3.8376	-$0.352
May-10	$2.7000	$3.0620	$2.881	$3.5356	-$0.655
Jun-10	$3.2570	$4.1080	$3.683	$3.6000	$0.083
Jul-10	$4.7450	$4.2210	$4.483	$3.9103	$0.573
Aug-10	$2.4810	$2.3460	$2.414	$3.5073	-$1.094
Sep-10	$3.5840	$3.7300	$3.657	$3.1496	$0.507
Oct-10	$3.6260	$3.3260	$3.476	$3.3770	$0.099
Nov-10	$3.2370	$3.2120	$3.225	$3.1983	$0.026
Dec-10	$4.0450	$3.9000	$3.973	$3.6025	$0.370
Jan-11	$3.9370	$2.8810	$3.409	$3.6712	-$0.262
Feb-11	$3.8500	$4.2110	$4.031	$3.6991	$0.331
Mar-11	$3.0800	$3.0710	$3.076	$3.3622	-$0.287
Apr-11	$4.2840	$3.8500	$4.067	$3.4426	$0.624
May-11	$3.8780	$3.6450	$3.762	$3.5354	$0.226
Jun-11	$4.3460	$3.8960	$4.121	$3.6558	$0.465
Jul-11	$3.3930	$4.0840	$3.739	$3.7166	$0.022
Aug-11	$3.5920	$3.8960	$3.744	$3.4546	$0.289
Sep-11	$3.3430	$3.3230	$3.333	$3.4087	-$0.076
Oct-11	$3.5990	$3.6700	$3.635	$3.4601	$0.174
Nov-11	$3.2990	$3.3110	$3.305	$3.1914	$0.114
Dec-11	$3.2990	$3.3620	$3.331	$3.2062	$0.124
Jan-12	$2.9520	$2.9570	$2.955	$2.8617	$0.093
Feb-12	$2.1470	$2.0640	$2.106	$2.3222	-$0.217
Mar-12	$2.0940	$2.0990	$2.097	$1.9732	$0.123
Apr-12	$1.5940	$1.7000	$1.647	$1.7126	-$0.066
May-12	$1.4480	$1.3310	$1.390	$1.5586	-$0.169
Jun-12	$2.7650	$2.7480	$2.757	$1.9472	$0.809
Jul-12	$2.0970	$2.2100	$2.154	$1.8967	$0.257
Aug-12	$2.3100	$2.1860	$2.248	$2.2794	-$0.031
Sep-12	$1.8320	$1.7010	$1.767	$2.0597	-$0.293
Oct-12	$2.5070	$2.5830	$2.545	$2.3382	$0.207
Nov-12	$3.5410	$3.5730	$3.557	$3.1047	$0.452
Dec-12	$3.5820	$3.5420	$3.562	$3.2483	$0.314
Jan-13	$2.8150	$2.9170	$2.866	$2.9612	-$0.095
Feb-13	$3.1290	$3.2530	$3.191	$2.8797	$0.311
Mar-13	$2.9310	$2.8440	$2.888	$2.9181	-$0.031
Apr-13	$3.7620	$3.4720	$3.617	$3.2837	$0.333
May-13	$4.1880	$4.1460	$4.167	$3.4867	$0.680
Jun-13	$4.5940	$4.2890	$4.442	$3.4442	$0.997
Jul-13	$1.8540	$2.9260	$2.390	$3.0689	-$0.679
Aug-13	$1.7780	$2.0540	$1.916	$2.5924	-$0.676
Sep-13	$2.3220	$2.5470	$2.435	$2.3534	$0.081
Oct-13	$2.4270	$2.3970	$2.412	$2.4527	-$0.041
Nov-13	$3.7210	$3.6850	$3.703	$3.3129	$0.390

GCFR				
Jun04-Present				
Average	$4.642			
Standard Deviation	$2.5391		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 2.1030	$ 7.1812
Jun04-Mar05 - DERS Load Balanced ATCO Pipelines and ATCO Gas				
Average	$6.729			
Standard Deviation	$0.9653		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 5.7639	$ 7.6944
Apr-05 - Sep-08 - DERS Load Balance ATCO Gas only				
Average	$7.379			
Standard Deviation	$2.6018		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 4.7772	$ 9.9808
Oct-08 - Sep-11 - Daily balancing on the ATCO Gas system				
Average	$4.056			
Standard Deviation	$1.2419		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 2.8142	$ 5.2979
Oct-11 - Present - ATCO Nova Integration				
Average	$2.955			
Standard Deviation	$1.1927		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 1.7623	$ 4.1477
3 Years (Jun14-May17)				
Average	$2.741			
Standard Deviation	$0.9400		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 1.8015	$ 3.6815
5 Years (Jun12-May17)				
Average	$3.008			
Standard Deviation	$1.2268		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 1.7812	$ 4.2347
10 Years (Jun07-May17)				
Average	$3.876			
Standard Deviation	$2.0429		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 1.8332	$ 5.9190

Monthly Index				
Jun04-Present				
Average	$4.537			
Standard Deviation	$2.2581		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 2.2787	$ 6.7948
Jun04-Mar05 - DERS Load Balanced ATCO Pipelines and ATCO Gas				
Average	$6.516			
Standard Deviation	$0.6532		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 5.8630	$ 7.1694
Apr-05 - Sep-08 - DERS Load Balance ATCO Gas only				
Average	$7.268			
Standard Deviation	$1.8239		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 5.4436	$ 9.0914
Oct-08 - Sep-11 - Daily balancing on the ATCO Gas system				
Average	$4.035			
Standard Deviation	$1.0719		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 2.9633	$ 5.1071
Oct-11 - Present - ATCO Nova Integration				
Average	$2.825			
Standard Deviation	$0.8559		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 1.9686	$ 3.6805
3 Years (Jun14-May17)				
Average	$2.680			
Standard Deviation	$0.8079		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 1.8718	$ 3.4875
5 Years (Jun12-May17)				
Average	$2.863			
Standard Deviation	$0.8684		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 1.9946	$ 3.7315
10 Years (Jun07-May17)				
Average	$3.753			
Standard Deviation	$1.7648		Lower	Upper
# of St. Deviation	*1*	68.27%	$ 1.9881	$ 5.5177

Delta				
Jun04-Present				
Average	$0.105			
Standard Deviation	$0.8991		Lower	Upper
# of St. Deviation	*1*	68.27%	$ (0.7937)	$ 1.0044
Jun04-Mar05 - DERS Load Balanced ATCO Pipelines and ATCO Gas				
Average	$0.213			
Standard Deviation	$0.5084		Lower	Upper
# of St. Deviation	*1*	68.27%	$ (0.2955)	$ 0.7214
Apr-05 - Sep-08 - DERS Load Balance ATCO Gas only				
Average	$0.112			
Standard Deviation	$1.4833		Lower	Upper
# of St. Deviation	*1*	68.27%	$ (1.3718)	$ 1.5948
Oct-08 - Sep-11 - Daily balancing on the ATCO Gas system				
Average	$0.021			
Standard Deviation	$0.4693		Lower	Upper
# of St. Deviation	*1*	68.27%	$ (0.4484)	$ 0.4902
Oct-11 - Present - ATCO Nova Integration				
Average	$0.130			
Standard Deviation	$0.6063	68.27%	Lower	Upper
# of St. Deviation	*1*		$ (0.4759)	$ 0.7368
3 Years (Jun14-May17)				
Average	$0.062			
Standard Deviation	$0.4524		Lower	Upper
# of St. Deviation	*2*	95.45%	$ (0.8430)	$ 0.9666
5 Years (Jun12-May17)				
Average	**$0.145**			
Standard Deviation	**$0.6427**		**Lower**	**Upper**
# of St. Deviation	**2**	**95.45%**	**$ (1.1404)**	**$ 1.4302**
10 Years (Jun07-May17)				
Average	$0.123			
Standard Deviation	$0.7857		Lower	Upper
# of St. Deviation	*2*	95.45%	$ (1.4482)	$ 1.6946



Dec-13	$3.3010	$3.2940	$3.298	$3.2040	$0.094
Jan-14	$4.0850	$4.1070	$4.096	$3.6599	$0.436
Feb-14	$4.5680	$4.4940	$4.531	$4.2266	$0.304
Mar-14	$9.0240	$9.3880	$9.206	$5.6386	$3.567
Apr-14	$5.1890	$4.2260	$4.708	$4.4675	$0.240
May-14	$2.7480	$3.9150	$3.332	$4.4905	-$1.159
Jun-14	$3.8470	$2.7300	$3.289	$4.3454	-$1.057
Jul-14	$5.7810	$5.1380	$5.460	$4.3751	$1.084
Aug-14	$3.5630	$3.7490	$3.656	$3.7968	-$0.141
Sep-14	$3.3500	$3.7080	$3.529	$3.8310	-$0.302
Oct-14	$4.1490	$4.1800	$4.165	$3.8674	$0.297
Nov-14	$3.6860	$3.6830	$3.685	$3.5913	$0.093
Dec-14	$4.1840	$4.1820	$4.183	$3.9419	$0.241
Jan-15	$3.3350	$3.1060	$3.221	$3.1896	$0.031
Feb-15	$2.4610	$2.6080	$2.535	$2.6044	-$0.070
Mar-15	$2.6800	$2.9700	$2.825	$2.5915	$0.234
Apr-15	$2.9190	$2.9030	$2.911	$2.5435	$0.368
May-15	$2.1860	$2.2270	$2.207	$2.4205	-$0.214
Jun-15	$3.4710	$3.7410	$3.606	$2.6293	$0.977
Jul-15	$1.8220	$2.1330	$1.978	$2.4528	-$0.475
Aug-15	$3.2040	$2.4450	$2.825	$2.7107	$0.114
Sep-15	$3.3580	$3.0710	$3.215	$2.7905	$0.425
Oct-15	$2.6100	$2.8280	$2.719	$2.6994	$0.020
Nov-15	$2.4240	$2.5540	$2.489	$2.4394	$0.050
Dec-15	$2.2000	$2.2000	$2.200	$2.3911	-$0.191
Jan-16	$2.0040	$2.0040	$2.004	$2.1963	-$0.192
Feb-16	$2.9700	$2.9700	$2.970	$2.2284	$0.742
Mar-16	$2.6150	$2.6150	$2.615	$1.5761	$1.039
Apr-16	$0.8620	$0.8620	$0.862	$1.2244	-$0.362
May-16	$0.7950	$0.7950	$0.795	$1.0412	-$0.246
Jun-16	$1.3740	$1.3740	$1.374	$1.2809	$0.093
Jul-16	$1.6310	$1.6310	$1.631	$1.8475	-$0.217
Aug-16	$2.3640	$2.3640	$2.364	$2.1947	$0.169
Sep-16	$2.3510	$2.3510	$2.351	$2.2152	$0.136
Oct-16	$2.6590	$2.6590	$2.659	$2.4676	$0.191
Nov-16	$3.3030	$3.3030	$3.303	$2.8392	$0.464
Dec-16	$2.5790	$2.5790	$2.579	$2.6966	-$0.118
Jan-17	$3.7450	$3.7450	$3.745	$3.3268	$0.418
Feb-17	$2.6420	$2.6420	$2.642	$2.7047	-$0.063
Mar-17	$1.8850	$1.8850	$1.885	$2.3349	-$0.450
Apr-17	$2.2670	$2.2670	$2.267	$2.4646	-$0.198
May-17	$1.9520	$1.9520	$1.952	$2.6168	-$0.665

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May 19, 2017

Market Surveillance Administrator
#500, 400 5 Avenue SW
Calgary, AB T2P 0L6

Attention: Mr. Mark Nesbitt
Manager, Investigations and Retail

Dear Mr. Nesbitt:

Re: Options for Enhancing the Design of the Regulated Rate Option ("RRO")

On April 21, 2017, the Market Surveillance Administrator ("MSA") issued a notice ("Notice") announcing that the Minister of Energy ("Minister") had directed it to "conduct an analysis and provide a report with options for enhancing the design of the Regulated Rate Option to provide long-term, stable and affordable prices for Alberta's electricity consumers into the future."

The Notice seeks comments from stakeholders on four specified topics.

1. Whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta.
2. Changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement.
3. Introduction of deferral accounts or changes to bill smoothing.
4. When and how a change to the RRO should occur.

ENMAX appreciates the opportunity to provide its perspective on these topics. As an RRO provider for the past 13 years and currently providing service to over 175,000 regulated rate customers in the Calgary service territory, ENMAX Energy is materially impacted by any changes to the RRO Regulation.[1]

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[1] Pursuant to the Intercorporate Services Agreement between ENMAX Power Corporation and ENMAX Energy Corporation, effective July 1, 2005, as amended effective January 1, 2006, April 28, 2006, April 30, 2008 and April 13, 2011.

ENMAX notes that term contracts currently available through competitive retailers already align with the Minister's objectives of providing a stable or less volatile electricity price for most Alberta electricity consumers. ENMAX Energy for example, currently offers one-year, three-year and five-year fixed-rate contracts. Competitors also offer these term lengths.

ENMAX remains supportive of the RRO as an option for consumers who do not select a competitive energy retailer. In general, ENMAX believes that minor changes to the RRO Regulation, in conjunction with the announced RRO price cap, are the best way to align the Minister's objectives with the RRO characteristics. As set out in more detail in the comments below, this approach would enable timely and cost-effective implementation, while avoiding the potential pitfalls of major consumer policy changes during a period of significant market transition.

ENMAX's comments are organized as responses to the specific questions in the Notice, followed by additional comments responsive to the more general themes of the Minister's direction.

1. **Whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta.**

ENMAX does not support one RRO rate for all eligible consumers in Alberta or one RRO rate for each particular customer rate category (e.g. residential, small commercial, farm). The primary reason for this is that a single rate approach, whether applied to all Albertans or to each particular customer rate category, results in customers in one area or one category subsidizing customers in another area or category. ENMAX does not believe that changes which result in consumers having less exposure to their actual usage are aligned with the Government's energy efficiency and conservation objectives.

Single Rate for All Eligible Consumers: While a single rate for all eligible customers is easy for customers to understand, the reality is that customer usage patterns and profiles differ across service areas. The rates to supply these individual service areas should reflect the cost to supply the different patterns and profiles, consistent with cost causation and risk management principles. By way of example, the RRO load in Calgary has a higher percentage of peak load, as compared to other RRO service territories in the Province. This cost differential should be reflected in the rates paid by customers in Calgary. In addition, the Unaccounted For Energy ("UFE") and line loss rates vary from geographic area to area; ignoring the differentials of these charges transfers the associated costs (positively or negatively) to a group of customers who do not reside in the affected service area.

Single Rate for Each Customer Rate Category: Similarly, while a single rate for each customer rate category would also be easy for customers to understand, the consumption shape among customer rate categories varies. For example, commercial customers have a relatively flat load shape over the course of a day, which requires lower peak supply. Residential customers have a load consumption shape that requires more peak supply. The rates for these customers should reflect that load shape difference. Applying one rate across these categories results in cross-subsidization and is not consistent with cost causation.

Centralized Procurement of RRO: Additionally, ENMAX does not believe that a central procurement model would be of benefit to customers, particularly at this time.[2] The current system of each of the three RRO providers using different procurement approaches, and transacting in the market at different times, has delivered comparable monthly prices over time. The price discovery and natural checks and balances introduced by competitive forces provide assurance that RRO procurement is producing fair and reasonable results. In the absence of the "benchmark" transparency provided by the use of three alternative approaches, customers will not have confidence that the single procurement entity is delivering the best price. Additionally, the incentives and opportunities for innovation resulting from the use of different methodologies will disappear.

Furthermore, having three RRO providers acquiring different volumetric and term supply from the market at different times brings liquidity to the market, which is beneficial to customers in the form of lower pricing. By contrast, having a single procurement entity acquire aggregated volumes results in fewer transactions, of large blocks of supply, at known or predictable times, which is likely to raise prices. In addition, ENMAX notes the opportunity for RRO providers to self-supply at a price lower than market price, which has an obvious and demonstrable economic benefit to customers, would be lost. With respect to credit support associated with procurement, consumers benefit from three RRO providers each providing credit associated with their respective volumes. Consolidating this in a single procurement entity could result in higher costs for consumers.

Centralized RRO Billing & Customer Care: ENMAX does not believe that steps to centralize billing and customer care for the RRO would be of benefit to customers. ENMAX's experience has been that customers strongly support a localized call center and the benefit this provides from a local employment perspective. If the RRO billing and customer care provider becomes centralized, customers (over 350,000 in Calgary alone) will lose services provided within their municipality and will begin to receive up to three utility invoices instead of a single invoice. Related to this, it is important to recognize the cost efficiencies and savings that some larger municipalities are achieving by having billing for municipal services performed by the RRO billing and customer care providers. This approach spreads relatively high fixed cost billing and customer care systems across a larger number of customers and services (e.g. water, gas and municipal services) and achieves economies of scale, while maintaining the benefits of having a localized service provider

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[2] It is difficult to assess the impacts of a significant change, such as centralized procurement, with capacity market auctions and the expected online dates of renewable energy projects approximately aligned with the current expiry of the RRO Regulation. ENMAX believes that policy changes must be evaluated holistically in order to ensure the impacts are fully understood and properly evaluated.

able to respond to questions and concerns. If the RRO service were to be centralized and removed from the shared invoices, the municipalities may need to invest in the capability to provide billing and customer care for the municipal services separately. This will almost certainly increase costs for customers while increasing the potential for billing errors while new billing and customer care systems are developed and rolled-out. Currently, each RRO provider has invested time and resources to improve their customer experience to the benefit of customers and the results can be seen by looking at AUC Rule 003 reporting and the associated performance levels. If there was ever a move to a single RRO provider, the remaining amount of unrecovered investment for an existing provider that was made in good faith to serve customers could be stranded or lost. Consideration would need to be given for recovery of these losses from customers on a go-forward basis.

2. Changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement.

ENMAX believes that minor changes to the RRO Regulation would enable RRO providers to deliver greater predictability and stability to customers and better align the RRO with the Government's broader electricity policy.

However, as noted above, term contracts currently available through competitive retailers already align with the Minister's objectives of providing a stable or less volatile electricity price for most Alberta electricity consumers. ENMAX Energy for example, currently offers one-year, three-year and five-year fixed-rate contracts. Competitors also offer these term lengths.

Enabling Longer-Term Procurement: Enabling longer-term procurement periods would allow RRO providers to create greater stability and predictability for RRO customers. ENMAX supports a maximum procurement term of one year.[3] While a one-year term can introduce added price and supply risks due to reduced liquidity, RRO providers are in the best position to manage these risks and are best able to shield customers from such risks, while providing stable pricing for a longer period of time. Enabling opportunities for RRO providers to innovate has led to the proposal of new procurement approaches, which have reduced costs and provided price stability and lower prices for customers (e.g. NGX RRO Index benchmarking and self-supply).

As part of a longer-term procurement approach, ENMAX suggests returning to the earlier approach of requiring RRO service providers to procure a minimum quantity of quarterly to annual full-load requirement energy products (maximum one year) in the forward market for a portion of forecast RRO customer load. This approach proved to be administratively simple, drove competition between suppliers and removed risks from customers. By way of example, 40% to 60% of the RRO volume is sufficient to establish stable prices and the RRO service provider

[3] With announced market changes, such as capacity market auctions and the expected online dates of renewable energy projects, ENMAX does not believe periods of longer than one year would be advisable at this time.

may choose to bear the volume and shape risks associated with procuring the balance of the forecast load, leading to greater innovation. Having the RRO provider procure only a portion of the full amount of forecast load through full load requirement products will increase the level of competition for a reduced level of volumes, putting downward pressure on prices, relative to attempting to procure the full forecast volumes in a given time period.

Additionally, forward market projections over the next two to three years are currently considerably lower than the Government's 6.8 cent/kWh RRO price cap. This provides an opportunity to encourage greater price stability by, for example, requiring RRO suppliers to procure a minimum quantity of full-load requirement contracts priced below the cap amount and at longer terms.[4] In circumstances where the cap amount is lower than available full-load requirement contract pricing, RRO providers should have an "off ramp" to allow for lower-priced supply to respond to unanticipated market related events, such as procuring a greater percentage of spot market supply or tying rates to the NGX RRO Index.

Finally, extending the procurement period from the current 45 day to 120 day periods[5] to up to one year would decrease the number of procurement and approval cycles, which reduces regulatory and administrative costs. Reducing regulatory and administrative costs was identified by the Minister as an objective of the RRO Review.

Including Renewables in RRO Procurement: One of the goals of the Climate Leadership Plan is to increase the amount of renewable generation in Alberta. However, the Renewable Energy Support Agreements ("RESA") being developed by the Alberta Electric System Operator ("AESO") are only available to new generation projects. The existing 1,491 MW of installed capacity of wind projects will neither have access to the RESA nor to the type of capacity payments available to, for example, natural gas generation. ENMAX invites the MSA and the Government to consider requiring RRO providers to include a component of "green" energy in their procurement so that RRO customers would be supporting continued operation of the existing renewables fleet. Doing so would be complementary to the RESA auction being overseen by the AESO. ENMAX believes that including a mandatory renewable component in the RRO procurement may assist the government climate leadership objectives, including the phase-out of coal generation, and support continued operation of existing renewable generation as well as parallel development of renewable projects. ENMAX is interested in discussing this further; however, one option would be a Renewable Portfolio Standard approach.

[4] Savings related to the procurement of the non-full-load requirement portion at prices below the full-load requirement price would be shared equally between the RRO provider and customers.

[5] Periods currently vary by RRO provider. ENMAX Energy is currently subject to a 45-day procurement period.

3. Introduction of deferral accounts or changes to bill smoothing.

ENMAX does not support the broad introduction of customer deferral accounts for the RRO and notes that the RRO Regulation currently does not allow RRO tariffs to include deferral accounts for energy related costs.[6]

Customer Deferral Accounts: ENMAX does not believe that a move to a more comprehensive set of deferral mechanisms is in the interests of customers. Deferral accounts would shift risks from RRO providers back to customers. The RRO provider should bear the market risk (rather than the RRO customer) as they are in the best position to mitigate the risk. Deferral accounts would also require an added cost of credit to be recoverable by RRO providers. Under conventional deferral account structures, service providers recover less than actual costs in the near term and wait a minimum of several months to recover the balance of the actual costs once the regulator has approved the recovery of such costs. This translates into added costs to consumers.

Bill Smoothing: No changes to the RRO Regulation are required to enable bill smoothing for RRO customers. Smoothing mechanisms are already available to RRO customers through Equalized Payment Plans. Approximately 2% of ENMAX Energy's RRO customers use this option, demonstrating there is not a strong demand for this feature from the existing RRO customer base.

Price Cap Smoothing Mechanism: ENMAX does, however, support a smoothing mechanism to address months in which the energy price exceeds the announced RRO price cap of 6.8 cents/kWh. In this instance, the difference between the actual energy price and the cap should be carried forward to the next month on the customer's bill. The balance of the accumulated price differences, if any, should be cleared on an annual basis by the Government. Given that current energy price forecasts for the next few years appear to be lower than the RRO price cap, this carry-forward approach would likely be self-funding and therefore have no cost impact to Government during this time frame.

4. When and how a change to the RRO should occur.

ENMAX is recommending changes to the procurement length and to the term of the Regulation.

Procurement Length: ENMAX supports immediate changes to the procurement length provisions in the RRO Regulation, followed by a six-month implementation period to ensure orderly transition of billing systems and training of customer care staff. As noted above in response to

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[6] Section 3(1) of the RRO Regulation states: "A proposed regulated rate tariff must not use, provide for or contemplate any deferral accounts, true-ups, rate riders or other similar accounts or devices for energy related costs."

2, ENMAX is suggesting a procurement length of up to one year so that RRO providers can begin to deliver longer-term stability.[7]

RRO Regulation Term Extension: The RRO Regulation is set to expire on April 30, 2020. Whether extended in the near-term or closer to the expiry date, ENMAX proposes that the next term of the RRO Regulation be up to 10 years in length. The longer term will provide policy certainty and stability to support investment and also reflect the desire of Government to retain the RRO as a go-forward product for customers. (This time frame may also allow for clarity regarding impacts of announced and pending market changes, such as the capacity market and the renewable energy program.)

Other Changes to RRO Regulation: To the extent additional changes to the RRO Regulation are contemplated, ENMAX believes that the optimal timing for changes to the RRO would be in connection with expiry/amendment (i.e. April 30, 2020). In addition to working within an existing term and market mechanism, this timeframe is also approximately aligned with the timing of other announced market changes, such as capacity market auctions and the expected online dates of renewable energy projects. If changes to the RRO are anticipated in an earlier timeframe, consistent with its comments above, ENMAX suggests a minimum six-month implementation period after a new RRO Regulation is in place, in order to allow for orderly transition (e.g. modifications to billing systems, training of call centre staff and procurement execution).

5. Additional Comments Responsive to Minister's Direction Letter

The letter of direction from the Minister, attached to the Notice, indicates that the options for reform of the RRO should meet the needs of Albertans by providing for affordability of electricity, predictable and stable rates and minimized regulatory and administrative costs. ENMAX offers the following additional comments relevant to these goals.

Affordability/Assisting Vulnerable Albertans: The RRO serves a large number of vulnerable Albertans. In the context of the RRO Review, ENMAX requests that consideration be given to approaches that may further assist vulnerable Albertan electricity customers, leveraging the existing social agency infrastructure in place to assess and manage eligibility. While there may be several approaches, ENMAX would like to highlight two for consideration at this time. ENMAX is interested in discussing these and other options with Government.

- *Tiered Rate Structure*: For ratepayers qualifying for financial support, a volume tiered rate structure could be used (e.g. lowered rates for the first 600 KWh of actual consumption) to provide lower-cost electricity sufficient for basic needs.

[7] This requires a change to Section 11(2) of the RRO Regulation.

- *Extended Load Limiter Season*: The current load limiter season is six months (weather dependent). Certain social agencies have advised ENMAX that extending this period to could provide additional time to address overdue payments and/or to prevent full disconnections.

RRO Price Cap Administration for Smaller Entities: ENMAX recognizes that it may be administratively difficult for the Rural Electrification Associations and smaller municipalities to implement the RRO price cap protection that the Government has established. ENMAX is willing to work with Government and these entities to extend its RRO services and to help provide RRO procurement services and price cap implementation related services. This will enable the RRO price cap to be extended to customers who receive their electricity from these entities so that all Albertans enjoy the same opportunity to purchase electricity subject to a price cap.

Consistency in Approaches for Regulated Energy: ENMAX recommends that the approach and principles related to both the natural gas commodity and electricity commodity regulated rates be reviewed to ensure consistency in objectives and processes. The regulated rates for these commodities impact consumers in a similar manner and should be managed in a consistent and principled fashion. For example, both RRO and Gas Cost Recovery Rate/Gas Cost Flow-Through Rate prices have demonstrated volatility in the past. Procurement processes and regulations could be changed at the same time to provide clarity and consistency for consumers, providers and the regulators.

Lowered Eligibility for RRO Customers from 250 MWh/yr to 50 MWh/yr: The RRO Regulation defines "eligible customers" to include those having an annual consumption of electricity less than 250 megawatt hours (MWh). Lowering the threshold from 250 MWh per year to 50 MWh per year would focus the benefit of the 6.8 cent price cap on residential and small commercial customers. For context, a typical residential site consumes 7.5 MWh per year and a typical small commercial site[8] consumes 33 MWh per year. Setting the eligible customer threshold at 50 MWh per year would easily capture all households. This reduced threshold will also reduce the administrative burden on RRO providers and the potential draw on Government funds for financial support in excess of the price cap (assuming use of government funds, rather than management of excess charge through electricity rates). Larger users, such as commercial customers, are typically more sophisticated entities that are capable of entering into competitive energy contracts to manage their commodity exposures and budgets.

Lowered Eligibility for Gas Default Customers from 2,500 GJs to 500 GJs: Similar to the RRO comments above, a typical residential gas customer would typically use 120 GJs annually. A

[8] These sites generally have a cumulative energy meter. Examples of customers on this rate include small retail stores (e.g. flower shop, barber shop, coffee house), parking lots, churches, small offices, temporary construction and unmetered services, such as traffic lights. Larger users nearer the 250 MWh per year level may include strip malls, banks and larger restaurants.

proposed 500 GJ threshold would capture all residential consumers and encourage larger users of natural gas to enter into competitive agreements, where they can obtain customizable solutions that reflect their actual usage patterns. Larger users may not only use the natural gas for heating purposes, but may also have commercial processes that use more natural gas outside of the winter timeframe.

* * * * *

ENMAX looks forward to the opportunity to participate further and would be pleased to respond to questions or comments.

Yours truly,

Erica Young
Chief Legal Officer & EVP Regulatory
ENMAX Corporation

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May 19, 2017

Market Surveillance Administrator
#500, 400 5th Avenue SW
Calgary, AB T2P 0L6

Attention: Mr. Mark Nesbitt
Manager, Retail and Investigations

Dear Mr. Nesbitt:

Re: MSA Notice on Options for Enhancing the Design of the Regulated Rate Option

On April 18, 2017, the Market Surveillance Administrator ("MSA") received a letter from the Minister of Energy requesting a report detailing options for enhancing the Regulated Rate Option ("RRO"). Further direction was given to identify options that provide for "affordability of electricity; predictable and stable rates; and minimized regulatory and administrative costs."

Subsequent to this letter, the MSA requested feedback from stakeholders, specifically requesting responses to the following items:

i. Whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta;
ii. Changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement;
iii. Introduction of deferral accounts or changes to bill smoothing; and
iv. When and how a change to the RRO should occur.

In response to the request from the MSA, EPCOR Energy Alberta G.P. ("EEA") submits the attached document. The document details the responses to the questions posed by the MSA, identifying advantages and disadvantages to the enhacenments being considered.

EEA appreciates the opportunity to provide comment to the MSA on potential enhancemenst to the RRO. EEA would be pleased to respond to any questions that may arise respecting the attached submission.

Sincerely,

Jay Baraniecki
Director, Energy Services
EPCOR Energy Alberta GP Inc.

EPCOR Energy Alberta G.P. Inc.

RRO Review Submission to the MSA

May 19, 2017

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1.0 EXECUTIVE SUMMARY

Sixteen years ago, the Government of Alberta ("Government") implemented legislation opening the Alberta electricity market to retail competition and creating the Regulated Rate Option ("RRO") for mass market retail customers. Since then, the Government's efforts to deregulate the retail market have been successful in establishing retail competition in Alberta. Customers have had the right to opt out of the RRO in favor of competitive retail alternatives, and many have done so. The regulated option is available to customers who want it.

Meanwhile, several refinements have been made to the RRO service in Alberta through changes to the RRO Regulation as well as through the negotiation and approval process for the Energy Price Setting Plans ("EPSP") of the RRO providers. The current RRO approach strikes a balance between affordability and stability of RRO rates. Customers with a preference for a more stable rate can either sign up for the equalized payment plan offer by the RRO provider or select fixed rate contracts offered by competitive retailers. Customers with the ability to manage high monthly volatility in energy costs can select pool price flow-through options offered by competitive retailers.

It is EPCOR's view that major fundamental changes are not required to the RRO Regulation in order to achieve the Government's objectives of stability, affordability, predictability and reduced regulatory costs. In this submission, EPCOR recommends two changes to the RRO Regulation to further meet the Government's objectives.

EPCOR is also mindful of the long term practicality of its submission. Over the past 16 years of deregulation in Alberta, there have been periods in which it was necessary for government to intervene in the RRO to protect customers from the volatility of the wholesale market. This has taken the form of changes to the RRO Regulation such as an increase in the procurement window from 45 to 120 days, as well as rate caps mandated by government. EPCOR's recommended changes, while consistent with the objectives of the Government, will provide for a robust RRO framework that will provide fair and predictable rates in times of low commodity risk and wholesale prices and at the same time provide for stable, predictable and affordable rates during periods of higher commodity risk and wholesale prices.

First, EPCOR has recommended that the RRO Regulation be amended to enable the AUC to approve EPSPs that include procurement of monthly, quarterly and annual forward hedges. This has the potential to improve both stability and affordability of RRO rates. Over the last 10 years, the current RRO procurement method would have led to 9 instances of month-over-month price spikes of at least 30%, while EPCOR's example of longer term hedging could have mitigated 8 of these instances. Meanwhile, analysis of the average forward price over the last 10 years indicates that the price is lower on average the further out that it is transacted. On average over that period, the forward price was $8.10/MWh lower when procured 9 months in advance as compared with 1 month in advance of delivery. Thus, long term hedging is a solution that would improve stability in RRO rates without increasing the expected overall cost to consumers or creating the new types of costs and risks that are inherent in other options being explored in the MSA's RRO Review.

Second, EPCOR has recommended a simple solution with the potential to reduce regulatory costs by 50% or more. Longer RRO Regulation extensions would provide the certainty required for the RRO providers to submit, and for the AUC to approve, EPSPs which are 4-5 years in length. Due to near-term expiry dates of the RRO Regulation, the current EPSP is only two years in length. Likewise, the EPSP that EPCOR has applied for with the AUC has the potential to be cut to only two years if it is approved only to the expiry of the current RRO Regulation. EPSPs that are two years in length rather than four years in length will double the regulatory costs associated with their development, defense and approval. Thus, EPCOR recommends that extensions to the RRO Regulation be at least 10 years in length.

2.0 BACKGROUND

The RRO has been reviewed a number of times in the past, by both the Department of Energy and the AUC. The RRO Regulation was amended to enable a longer procurement window in 2013. EPCOR proposed that procurement of longer term forward products be implemented in its submission to the Retail Market Review Committee in 2012. Although the proposal was never rejected or formally opposed by other parties, changes to the RRO Regulation to enable this have not yet been made.

In Proceeding 2941, a generic proceeding to determine the EPSPs of all three RRO providers, the AUC sought input from the three RRO Providers and other interested parties, namely the Utilities Consumer Advocate (UCA), Consumers Coalition of Alberta (CCA) and TransCanada on the following questions:

1) Should there be one central, independent entity responsible for the procurement of energy for all three RRO providers?

2) If forward market hedging is proposed to set the base energy charge, should the approach (e.g., auction process, targeted daily block purchases) be the same for all three RRO providers and should the hedging strategy (e.g., use of flat 7x24 and peak 7x16 products with the amount of each product set to a fixed percentage of the average hourly load forecast) be the same for all three RRO providers?
3) Should the energy procurement methodologies (forward market products) be the same for all three RRO providers?

Decision 2941 did not accept centralized procurement, standardization of procurement, and standardization of other elements of the approach such as the auction process and hedging levels. Section 5 below provides additional evidence on centralized procurement from that proceeding.

Current State

Consumers of electricity in Alberta have benefited from retail competition and are able to choose from a variety of retail products through more than 20 retailers. Retail products range from fixed products ranging in length up to 5 years to pool price flow-through products in which the customer bears price volatility risk. Hedged products lie between fixed rate products and flow-through products on the spectrum of volatility, providing customers with a balance between stability and affordability. Customers who have chosen to sign competitive contracts may switch between a fixed product and a flow-through product based on the current market environment, with flow-through products increasing in take-up in recent years. However, a hedged product such as the RRO remains an important choice for both residential and commercial customers. The competitive retail market also provides other products and services, such as green options, nest thermostats, gift cards and "free energy" in addition to the energy supplied. The RRO providers also offer equalized payment options for customers who request it. Thus, the options being explored by the MSA are already available to electricity customers in Alberta.

Different products will appeal to different customers. For example, for the 3.6% of EPCOR's RRO customers who have selected to be on the equalized payment plan, it can be an important tool to help that subset of customers manage payment of their utility bills. However, for the other 96.4% of EPCOR's customers, that is not an option that brings value. In contrast, the vast majority of EPCOR's customers prefer to pay the full amount owing, and not extra, each month.

2.1.1 Principles

EPCOR supports a review of the RRO regulation which enhances the current system and further protects customers in Alberta. To this end, EPCOR proposes that the following principles be used to guide development of recommendations for the RRO review.

Principle 1: Upholding the Interests of Regulated Customers

The RRO rate has become a permanent feature of Alberta's retail electricity market. To ensure the interests of regulated customers are upheld, a shift in the objectives used to design the RRO should occur. RRO Providers should be provided with the ability to design Energy Price Setting Plans (EPSP) for AUC approval that serve the best interests of the customers. Electricity customers value low and stable prices; restrictions to this should be removed. For example, the restriction on the procurement window for forward hedges and the requirement of *monthly* forward market electricity prices serve as barriers to the objective of stable prices.

Principle 2: Long Term Sustainability

Lack of predictability with respect to the Government of Alberta's long term plans for the RRO harms customer of both competitive retailers and RRO providers. This uncertainty reduces efficiency and affects the long term investments and business planning of RRO providers. The RRO Providers, competitive retailers, suppliers of wholesale products, the AUC and consumer representative groups all require certainty in order to work together to create and maintain a retail market that serves the best interests of Albertans. Extending the RRO Regulation for 10 years would provide a reasonable level of certainty.

Principle 3: Consistency with Concurrent Regulatory Reviews

The Alberta electricity industry is undergoing unprecedented change. Competition across supply and demand fundamentals is lowering emissions, improving efficiency, and creating a more distributed system. In response, policy makers are accelerating the review of the existing market structure to accommodate changes while maintaining reliability. Recognizing that there are fundamental changes occurring in the market, revisions to the RRO should support and complement any concurrent reviews that are being made in policy and regulation.

EPCOR's submission is consistent with the aforementioned principles.

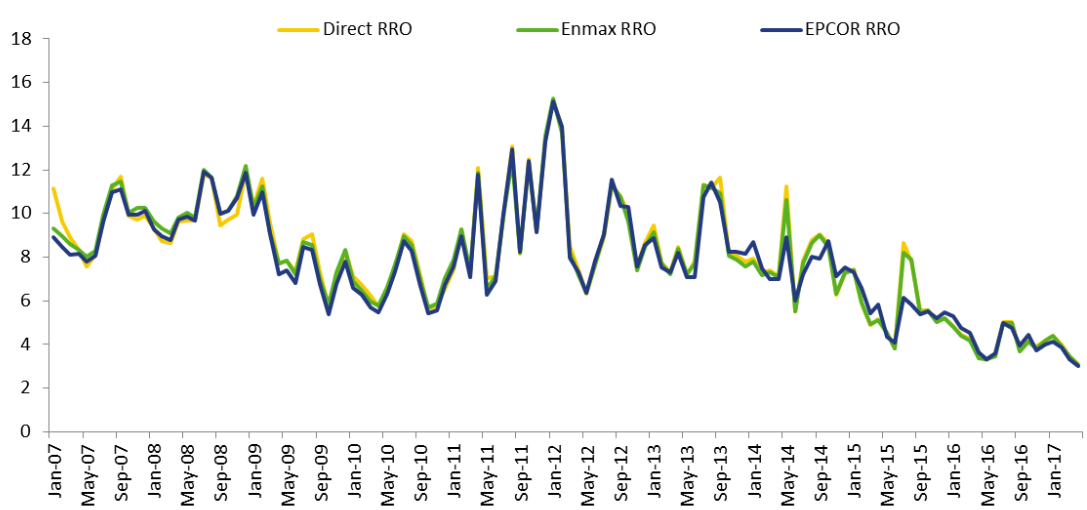
3.0 SINGLE RRO RATE

Through previous regulatory proceedings, a uniform RRO rate among providers and/or rate classes has been considered to reduce the administrative burden of default rates. Despite the benefits that may accrue from a single rate, the concept has been rejected, owing to concerns over cross-subsidization between rate classes; diminished incentives for efficiency and conservation; and administrative risks.

Background

Since 2007, the rates charged to customers under the RRO have exhibited little variation between the three providers. Over this period, the difference in rates charged between RRO providers has averaged 0.4 cent/ kWh s. The strong consistency that has been maintained between providers has occurred despite differences in procurement windows, processes, methodologies, and risk compensation.

Figure 1: Historical RRO Rates (cents per kWh)



The concept of a single RRO rate was explored in 2011 through the Regulated Retail Energy Harmonization Inquiry and again during Proceeding 2941.

Advantages

A single rate for all RRO customers may appear to have the ability to provide simplicity. However, considerable complications with its implementation make this counterproductive as further discussed below.

A single RRO rate for all default customers allows for communication of a single RRO rate to customers across the Province. However, it also eliminates comparability, which can be used to assess the reasonableness of rates.

If RRO rates were able to be calculated by one team of analysts each month, rather than by three separate teams within each of the RRO providers, there would be a reduction in salary costs. However, an RRO provider would still need to validate any RRO rates calculated by a third party. Thus, this is unlikely to reduce administrative costs for the RRO providers, and will add new administrative costs for the third party that is calculating rates for all customers.

The Utilities Consume Advocate raised potential benefits during Proceeding 2941. That position was summarized in Decision 2941 as follows:

> *"The first principle, that the RRO rates within each customer class should not be materially different, is based on the interests of fairness and simplicity for consumers. The ideal outcome of this principle is a single province-wide RRO rate, for each customer class. A single RRO rate for the province is fair to consumers in different regions of the province, drawing on the spirit of postage stamp rates that have a long history in the other Canadian jurisdictions and in Alberta in the 1980's through the Electric Energy Marketing Act 19813. In the present market context, there are also competitive contracts that offer a single price to consumers in nearly all regions of Alberta.*
>
> *For reasons of simplicity and consumer comprehension, a single RRO rate is preferable. Uniformity is most likely achievable through a single rate setting mechanism, which could also reduce future regulatory burdens, possibly lead to cost savings, and facilitate monitoring and assessment of the pricing mechanism process and outcomes."*[1]

[1] Proceeding 2941 Exhibit 139.12 2014-06-04 Rob Spragins UCA Policy Evidence.

However, as demonstrated below, a single RRO rate across the province would violate Principle 3: Fairness of Rates. The UCA claims it is possible that cost savings could be realized, however the source of those savings were not explained. EPCOR is not aware of any costs that would be saved through a single RRO rate, while there are a number of administrative, regulatory and risk-related costs that would increase.

Disadvantages

A uniform retail electricity rate would likely create a number of unintended consequences, listed below.

Increased Costs: RRO providers in Alberta are a unique type of regulated entity that operates in a competitive retail space. As such, the RRO providers have incentive to manage both costs and risks to provide a competitive rate to customers and retain market share. Under uniform pricing, the costs and risks of all three RRO providers would be spread across the entire RRO base in the province, reducing incentive to manage those costs and risks. This topic was explored, and rejected, in the 2011 Regulated Retail Energy Harmonization Inquiry, during which the Independent Advisor for RRO customers discussed the following

> *"Areas that do not have to be the same, according to the independent advisor, include procurement mechanisms, risk and return margins and incentives. He added that these can and do vary by plan to reflect differences in the customers served and the relative risk associated with the respective programs. The independent advisor submitted that the inability to reflect these differences may result in greater risks, hence the need for additional compensation for these risks and therefore higher costs to customers.*
>
> *The independent advisor argued that establishing a standard EPSP for all three RRO providers is not necessary and would result in economic inefficiencies."*[2]

[2] Regulated Retail Energy Harmonization Inquiry, http://www.energy.alberta.ca/Electricity/pdfs/Regulated_Retail_Energy_Harmonization_Inquiry_-_March_25-2011.pdf

Incentives for RRO providers to manage costs and risks are critical. When no such incentives exist, significant resources must be committed by the regulator to minimize the impacts on customers. For example, costs may be benchmarked to similar retail entities and monthly monitoring of operational activities may be required. This increases regulatory costs.

<u>Duplicative Administrative Costs</u>: There would be duplication in administrative tasks, as a third party or central agency would need to calculate the single rate. The RRO providers would then need to validate those calculations to protect against the possibility of billing errors and associated reputational risks. There would also be administrative work involved in providing all required inputs to the third party, as well as auditing and/or validation of those inputs. Thus, although it may seem at first glance that a single RRO rate would reduce administrative costs, the opposite is true.

<u>Cross-subsidization</u>: The load shapes of customers within the same customer category differ by distribution service area. Customers with higher consumption in higher-priced hours should pay more, while customers with lower consumption in higher-priced hours should pay less. A uniform rate across the province would result in cross-subsidization between service areas.

EPCOR conducted an analysis of the redistribution of retail power costs between the two distribution service areas for which it provides RRO service as an indication of the magnitude of the impact. A uniform rate just within EPCOR's customer base (~60% of the RRO load in Alberta) would result in a transfer of approximately $1.5 million each year in energy costs between families in rural Alberta (residential customers in the FortisAlberta service territory - FortisAlberta delivers electricity service to 544,000 residential, farm and business customers across central and southern Alberta.) and families in Edmonton (residential customers in the EDTI service territory - EDTI is the wires service supplier to the City of Edmonton and nearby areas providing electricity to over 350,000 residential and business customers.). Other rate classes within the two distribution service areas are also affected, such that the total transfer from FortisAlberta RRO customers to EDTI is approximately $2 million annually.

If a single RRO rate were to be implemented across the province, the transfer of costs would likely be even higher across the all distribution service areas. Charging a single RRO rate within a distribution service area would not cause significant cross-subsidization for rate classes other than the Lighting rate class. RRO rates are very similar between the residential and small commercial customers, and are in fact identical in many months. However, it is not clear that there would be any benefits to charging the same rate across rate classes.

In its Decision 2941, the AUC considered that a single RRO would be counter to the principle of cost causation and result in cross-subsidization:

> *"The Commission agrees that if customer classes have different load shapes, which means the split between their on-peak energy usage and off-peak energy usage varies, then the resulting BECs should be different. Procuring on-peak forward market hedges is more expensive than procuring off-peak forward market hedges. The Commission considers that the principle of cost causation requires that customers who use energy that is more expensive should pay more than customer who do not."*[3]

<u>Incompatible with Energy Efficiency Initiatives</u>: A single RRO rate exacerbates the current tragedy-of-the-commons issue where consumers are not incentivized to consume efficiently because the actual costs of the individual's consumption are socialized. It would be counter to the Government of Alberta's objective of supporting energy efficiency to further reduce the financial incentives that consumers have to consume energy in the most cost-effective manner.

Recommendation

There are few, if any, tangible benefits to a single RRO rate. A single RRO rate across distribution service areas would result in customers in certain areas of the province cross-subsidizing customers in other areas of the province and would increase the overall cost to customers. For these reasons, the option of a single Provincial RRO rate has been rejected in the past and should continue to be rejected.

The discussion above does not consider RRO rates for the Rural Electrification Associations ("REA"). If there are concerns over inconsistencies in the RRO rates charged by REAs, those concerns should be dealt with separately.

4.0 PROCUREMENT OF LONGER TERM PRODUCTS

Procurement of energy under the current regulation mandates that transactions must occur in the 120 days prior to delivery. This procurement window has proven to be a suboptimal strategy to

[3] Decision 2941-D01-2015RRT and EPSP-Ge_1029.

mitigate risk and volatility for customers. In reviewing the RRO Regulation, it is EPCOR's recommendation that requirements for procurement be amended to permit longer term hedging. This revision would provide customers with added protection when managing their exposure to fluctuating electricity prices.

Background

The current RRO Regulation requires that RRO providers determine monthly Alberta electricity market based prices based on pricing in the 120 days prior to delivery. This requirement makes it difficult for RRO provider to manage rate volatility on behalf of customers through the procurement process.

The RRO Regulation was drafted to disallow longer term hedging for a specific purpose, as stated in the report *Power for the People* by the Retail Market Review Committee:

> *"The resource procurement methodology for a default rate can result in higher volatility and higher rates than are desirable. At the same time, "better" approaches can create huge barriers to entry because any particular procurement methodology may compete head-to-head with competitive offerings."*[4]

Efforts to ensure that the RRO did not hinder the development of a competitive retail market in Alberta have been successful in the five years since that report was released. The competitive retail market has now reached a level of maturity and innovation that such restrictions are no longer required, as per Principle 1: Upholding the Interests of Regulated Customers.

EPCOR provided a submission to the Retail Market Review Committee in 2012. Among the recommendations in that submission was a recommendation to enable longer term hedging for the RRO. That submission first provided the following background information:

> *"Conceptually, a default rate exhibiting a "moderate" level of stability over time will achieve a reasonable and appropriate balance between rate stability and market pricing exposure. As the Government first determined a number of years ago, in the context of the regulated rate option, a*

[4] Power For the People – Retail Market Review Committee, page 152.
http://www.energy.alberta.ca/Electricity/pdfs/RMRC_Ch9_AnalysisDefaultRate.pdf

> *default rate that exposes customers to full pool price volatility is unnecessary and unwarranted. Instead, the Government implemented a transition to full monthly forward contract pricing models which would expose regulated rate option customers to greater price volatility, but fall short of exposing customers to full wholesale market volatility."*[5]

EPCOR went on to make the following recommendation:

> *"Therefore EPCOR considers a blend of 50% monthly forward contracts and 50% long term forward contracts is the optimal portfolio mix for the default rate to meet the objectives of moderate price fluctuations (approximately 23% month-to-month volatility) and facilitating the development of a competitive retail market in Alberta. A 23% level of price volatility would be much more manageable and predictable for customers who choose not to sign a contract and who are attempting to predict and budget for their electricity costs each month."*[6]

Advantages

The current RRO Regulation requires that RRO rates are set on a month-ahead basis in the 120 days prior to delivery. This restricts the ability of RRO Providers to design innovative EPSPs that could lead to lower and more stable prices to customers. It is not necessary for the Government of Alberta to determine the optimal procurement timing or length of hedge product. AUC adjudicated EPSP proceedings are the appropriate forum in which RRO Providers must thoroughly defend procurement proposals, providing evidence that such proposals are feasible, sustainable and in the best interests of the public. The most effective market solution for addressing price volatility would be to allow RRO providers to procure longer-term hedges as part of its RRO energy portfolio than is currently contemplated under the applicable legislation. As outlined below, allowing RRO providers to competitively procure and price its RRO electricity supply using a mixture of monthly, quarterly and calendar year hedge products will provide greater price certainty, predictability and stability for both customers in the coming years.

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[5] Retail Market Review Committee Submission, by EPCOR Energy Alberta Inc. and EPCOR Distribution & Transmission Inc., page 7.

[6] Retail Market Review Committee Submission, by EPCOR Energy Alberta Inc. and EPCOR Distribution & Transmission Inc., page 28.

Stability: By purchasing contracts for electricity supply months in advance of delivery for a portion of its RRO load, an RRO provider can fix the price of that electricity, effectively reducing its overall exposure to events that can cause significant short-term price volatility, such as generator and line outages. RRO prices are generally expected to rise in the coming years as can be seen in both forward curves on the NGX and detailed price estimates developed by experts such as EDC Associates. In addition to reducing customer's exposure to the inherent volatility in the market, long term hedging also allows RRO providers to smooth the impact of rising prices on customers.

EPCOR conducted an analysis to examine the level of price to customers (without margins) and the level of price volatility for three price setting options, including pool price follow through, current monthly procurement, and long term hedging. The analysis backcasts the monthly base energy charge to the RRO customers for the past ten years between January 2007 and December 2016, utilizing historical EPCOR load forecasts, AESO pool prices, and NGX settlement prices of Flat and Peak products.

Specifically, current monthly procurement option sets the price to customers based on EPCOR's 2016-2018 EPSP with six auctions for each product month, 60th percentile peak hedging level and procured within 120 days before the delivery month. Long term hedging option sets the price to customers based on following assumptions:

- Procure 33% of the hedging target with annual products ~6 months in advance of delivery.
- Procure up to 66% of the hedging target with quarterly products ~4 months in advance of delivery, with consideration of the volume of annual hedges that have already been procured.
- Procure up to 100% of the hedging target with monthly product ~2 months in advance of delivery, with consideration of the volume of annual and quarterly hedges that have already been procured.
- Four auctions for each Product Month, including one for calendar product, one for quarterly product, and two for monthly product.
- Procure both Flat and Peak Products in each auction with 60th percentile peak hedging level.

Table 1 demonstrates the results of the analysis. The long term hedging option could result in a slightly lower base energy charge (without margins) on average to RRO customers comparing to the current monthly procurement option.

Table 1
Comparison of Monthly

		A	B	C	D	E	F	G	H
		Base Energy Charge (without margins)		**Month-over-month Price Movement (absolute)**		**Number of Month over 20% Price Movement**		**Number of Month over 30% Price Movement**	
	Year	**Current Monthly Procurement**	**Long term Hedging**	**Current Monthly Procurement**	**Long term Hedging**	**Current Monthly Procurement**	**Long term Hedging**	**Current Monthly Procurement**	**Long term Hedging**
1	2007	$ 83.77	$ 78.09	9%	6%	1	0	0	0
2	2008	$ 85.09	$ 87.20	9%	4%	2	1	1	0
3	2009	$ 67.02	$ 76.26	11%	6%	2	0	0	0
4	2010	$ 53.35	$ 55.96	8%	6%	0	1	0	0
5	2011	$ 68.60	$ 61.38	20%	12%	6	2	3	1
6	2012	$ 81.09	$ 75.35	14%	8%	4	1	1	0
7	2013	$ 69.90	$ 68.81	11%	5%	2	0	1	0
8	2014	$ 62.80	$ 59.66	13%	9%	3	1	1	0
9	2015	$ 45.14	$ 48.33	14%	6%	2	1	1	0
10	2016	$ 33.36	$ 38.19	14%	5%	2	0	1	0
11	**Monthly Average**	$ 65.01	$ 64.92	12%	7%	2	1	1	0
12	**Total Month Count**	-	-	-	-	24	7	9	1

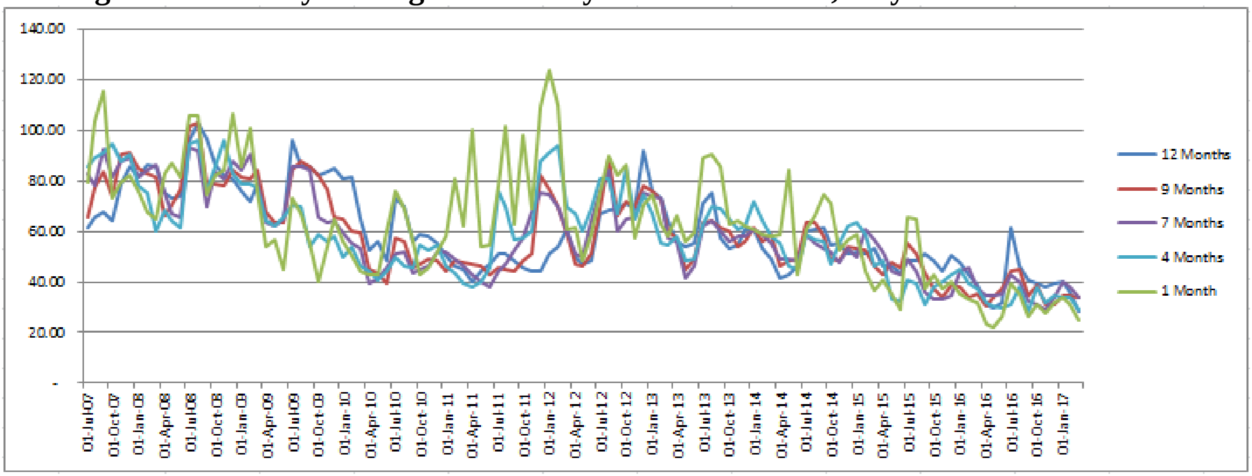
The analysis also provides the estimation of the price volatility in terms of the month-over-month price movement. The average month-over-month price movement (either increase or decrease) for the time period in this analysis is 7% under the long term hedging option, and 12% under the current monthly procurement option. The results indicate that the long term hedging option has lower price volatility than the current monthly procurement option such that it protects RRO customers from the high volatile spot market price (i.e., pool price).

Further, the analysis counts the number of months in the time period that has the month-over-month price movement (either increase or decrease) over a 20% and 30% changes. There are 24 months under the current monthly procurement option that could have a month-over-month price movement over 20%, and 9 months that have a month-over-month price movement over 30% in the sampling time period. In other words, the current price setting option could cause an over 20% monthly price movement in 20% of the time, and 7.5% of chance to cause an over 30% monthly price movement in this analysis.

Conversely, there are 7 months under the long term hedging option could be over the 20% price movement threshold, which is less than 6% of the time in this analysis. Moreover, only 1 month under the long term hedging option that is over the 30% monthly price movement threshold, which is not even 1% of the time in this analysis. Consistently, it is clear that the long term hedging option is a lower volatile price setting option than the current monthly procurement option in this analysis.

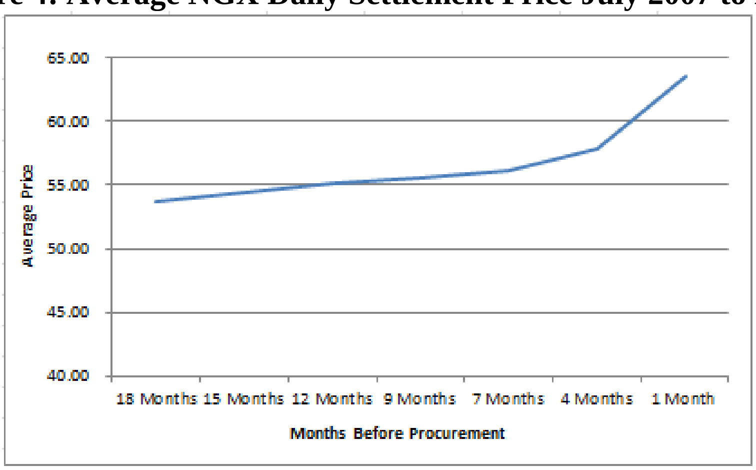
Affordability: In general, a trade-off exists between stability and affordability. In other words, programs to reduce volatility typically come at a cost to the consumer. However, long term hedging is a unique solution in that it has the potential to improve both stability and affordability of RRO rates, as shown below.

Figure 3: Monthly Average NGX Daily Settlement Price, July 2007 to March 2017



The graph above shows market prices for products at certain interval months prior to the month of consumption. The fluctuation in prices is much more drastic when procuring one month out as compared to procuring further in advance.

Figure 4: Average NGX Daily Settlement Price July 2007 to March 2017

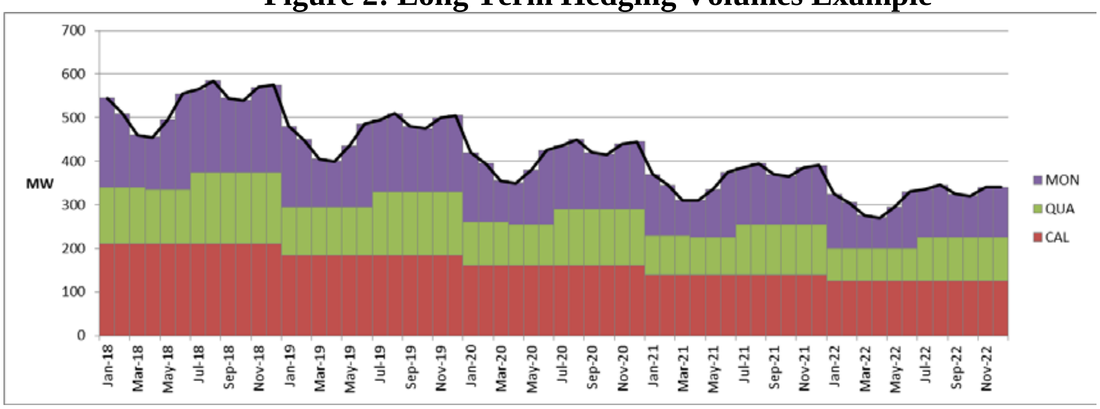


The above graph shows prices from July 2007 to March 2017 averaged over the months prior to consumption. As the graph indicates, prices start to rise as the month of consumption draws closer. On average over the last 10 years, the monthly forward price was $8.10/MWh lower 9 months prior to delivery than 1 month prior to delivery. For any particular month, prices may rise or may fall as the delivery month draws closer, however on average there is the potential for longer term procurement of forward products to lower the procurement price, and thus the final price to customers.

Managing Attrition Risk: One way to implement long-term procurement would be to utilize forward hedges of multiple-term lengths, such as the long term hedging price setting option mentioned above in the analysis. Longer-term hedges could be procured before shorter-term length hedges, so that as the load forecast improves as a delivery period nears, shorter-term hedges can be need to fill the gap.

This method is flexible enough to ensure that even with an assumption of relatively high attrition of customer load over time, the volumes of longer-term hedges would not exceed what was needed in any month. Rather, the volumes of shorter-term hedges that are needed would dynamically reduce to account for any attrition based on updated load forecasts nearer to a particular month. A chart depicting the hedging under such a methodology under an assumption of load attrition over time is shown below.

Figure 2: Long Term Hedging Volumes Example



RRO Rate Cap: Another advantage to long term hedging is that it has the potential to reduce the Government of Alberta's exposure to the RRO rate cap of 6.8 cents/kWh. In addition, long term hedging would help to smooth the rate shock to customers when the rate cap is lifted in July 2021.

Disadvantages

Although longer term hedging has the potential to provide more stable rates to customers overall, it would increase certain components of the RRO rate. The collateral requirements for holding long term hedges are the same as for the corresponding series of monthly products; however, the fact that long term contracts are held for a longer period of time increases the credit costs associated with maintaining the position. In a long term hedging arrangement in which calendar products are procured 179 days prior, quarterly products 119 days prior, and monthly products 59 days prior, the associated incremental credit costs are estimated to be approximately $0.023/MWh for EPCOR's RRO customers. For a typical residential customer with monthly consumption of 600kWh, the increase would be $0.01 on the bill.

Recommendation

Longer term procurement of forward hedges is highly effective in reducing RRO rate spikes from month to month. A backcast analysis indicates that RRO rates would have increased by 30% or more month-over-month only once over the last 10 years, as opposed to 9 times under the current procurement method. Meanwhile, historical forward price trends indicate that procurement prices tend to be lower the further from delivery that they are transacted. Thus, this option provides for *both* stability and affordability of the RRO.

Regulation changes would merely remove the current restrictions that prevent the RRO providers from proposing to the AUC superior procurement plans through the EPSP applications. The details, including an implementation process, would be fully tested through the EPSP process and approved by the AUC.

Changes to the RRO Regulation to enable advance procurement of longer term products should occur by fall 2017. EPCOR has submitted to the AUC an application for its 2018-2021 EPSP. That application contemplates only procurement of month-ahead products, as per the current RRO Regulation. However, EPCOR has carefully tested the main elements in that application, including the auction format and products to be procured, to ensure adaptability to the procurement of longer term products. EPCOR is prepared to submit an alternative EPSP application with only minor changes to incorporate longer term hedging. As wholesale electricity prices in Alberta inevitably rise over the upcoming years, this alternative EPSP would ensure a smoother transition for RRO customers, and would reduce the rate shock in July 2021 when the RRO price cap is lifted.

A copy of an amended RRO Regulation with the changed required to enable longer term hedging is included in Appendix 1.

5.0 CENTRALIZED PROCUREMENT

Centralized procurement is a concept that has been tested through previous regulatory proceedings. While there are tangible benefits that may arise from single-source procurement, it is the opinion of EPCOR that the current form of decentralized procurement will keep rates lower through reduced credit costs and lower energy prices.

Background

In Proceeding 2941, the concept of centralized procurement was thoroughly tested. RRO Providers, consumer representatives and a wholesale energy supplier were provided with the opportunity to present evidence as to whether there should be one central, independent entity responsible for the procurement of energy for all three RRO providers.

Decision 2941 summarizes the evidence as follows:

> *"Other issues raised by parties included: how a centralized procurement agency would be selected, the legal responsibility for the actions of the centralized procurement agency, how procurement would be undertaken, how pricing for each of the RRO providers would be set following centralized procurement, who would bear the commodity risk, and whether the benefits of centralized procurement outweigh the costs."*

Advantages

A larger centralized auction process could present a more attractive opportunity for suppliers, resulting in increased participation. However, a larger volume of forward hedges being procured at once would also create buying pressure that has the potential to place upward pressure on prices. On balance, this is more likely to increase the cost to customers rather than decrease the cost.

Disadvantages

<u>Increase in Cost</u>: Currently the RRO providers bear their own costs and risks, and, operating in a competitive retail environment, have incentive to manage those costs and risks in order to remain competitive. The most efficient and cost-effective approach for one RRO provider may be different than that of another RRO provider due to different organizational structures and capabilities. Centralized procurement would interfere with those incentives and efficiencies,

increasing both risk and cost. Meanwhile, the responsibility for those risks and costs would no longer reside with the RRO providers. Rather, a centralized agency would have to place those risks and costs back on to consumers. EPCOR discussed this problem in Proceeding 2941:

> *"Since the obligation to provide service is on the RRO provider, each RRO provider should be given the discretion to manage and minimize the risks it faces in order to meet its obligation to provide service, having regard for its organizational structures and capabilities. A standardized approach would risk foregoing opportunities for efficiencies and cost savings that are unique to a particular RRO provider or, at the same time, would risk imposing material costs on RRO providers and their customers by imposing a standardized approach that is not appropriate to each RRO provider's circumstances".*[7]

Tripling of credit and trading costs: If the central procurer is a counterparty to the forward contracts, then bi-lateral contractual arrangements would be required between the central procurer (which is holding the forward contracts) and each RRO provider to address the provision of the forward energy to the RRO providers including pricing, collateral requirements, etc. It would be inefficient and costly to have twice as many arrangements. Only credit costs associated with holding the forward contracts would increase, while AESO credit costs would be unaffected. EPCOR's RRO credit costs for the month of May 2017 were 0.021 cents/kWh. The central agency would have had credit costs of 0.021 cents/kWh with the NGX and 0.021 cents/kWh with EPCOR, while EPCOR would have had credit costs of 0.021 cents/kWh with the central agency, thus tripling the cost to customers of holding the contracts to 0.063 cents/kWh. This is an illustrative example, and the actual credit costs of the central agency would depend on that agency's credit rating and the degree of collateralization of the contracts. Centralized procurement would also result in significant legal and administrative costs associated with negotiating terms and conditions, monitoring and validating results and audits.

Financial Viability: As explained by EPCOR in Proceeding 2941, a central procurement agency would require significant financial resources:

> *"Currently, the obligation to procure energy for the RRO is spread among the RRO providers, and the underlying obligation to procure rests with the distribution utility owners. All of these entities are financially capable and*

[7] Proceeding 2941, Exhibit 273.02, EPCOR argument, paragraph 217, PDF page 82.

> *have significant financial resources. By contrast, there are very few entities that would have the financial resources to manage and bear the commodity risks associated with performing the procurement function for all RRO providers in Alberta. The choice of a central procurement agency would likely be limited to government entities, like the Balancing Pool, or one of the three largest RRO providers."*[8]

Higher Risk to Customers: It would be necessary for the risks associated with the central agency providing procurement services to be passed on to customers. Currently, the RRO providers bear commodity and administrative risks on behalf of customers. It is appropriate for the RRO providers to continue to bear risk on behalf of customers, as the RRO providers have the ability to do so. Centralized procurement would thus increase risks to customers. This was also explained by EPCOR in Proceeding 2941:

> *"In addition, a central procurement agency would require significant financial resources. If procurement were centralized through a government entity, commodity risks would likely need to be flowed back through to customers through true-up or deferral accounts or mitigated in some other way as government entities are generally not in the business of managing risk and return, as they are typically nonprofit entities. This would diminish the price signal for customers on the RRO, which does not comport with the purposes of the RRO Regulation."*[9]

Liability: If the RRO providers remain counterparties to the forward contracts, then there would be significant legal issues to be determined, such as liability to the centralized agency that enters into the contract for forward hedges but does not hold said contract. RRO providers would be obligated to honor contracts in which they had no determination, as the RRO providers would presumable have no decision making control over the contracts entered into by the centralized agency. If the centralized agency entered into a contract in error, the liability for that error would need to lie with the agency. These types of risks are not present in the existing procurement arrangements, and would represent new costs for consumers.

Loss of Comparability: Multiple procurement approaches allow for the results to be compared against one another for reasonability. If a single centralized procurement were to take place, there is no such assurance available that the resulting prices are comparable to any other

[8] Proceeding ID 2941, Exhibit 87.01AUC-EEAI-14.
[9] Proceeding ID 2941, Exhibit 87.01AUC-EEAI-14.

procurement method. As an example, although EPCOR is the only RRO provider to use auctions in its EPSP, its resulting RRO rates have generally been comparable to those of EEC and DERS, as stated by EPCOR in Proceeding 2941:

> *"Standardizing procurement approaches would also result in the loss of the ability to compare RRO rates across providers to assess the effectiveness of each RRO provider's rate setting process."*[10]

Regulation Changes

It is not certain how changes to the procurement method to enable centralized procurement would be initiated and decided upon. This would represent a major overhaul to the current EPSP process, in which RRO providers apply for EPSP proposals to be approved by the AUC. For example, negotiated settlements between all three RRO providers, all consumer representative groups and the central agency would present serious barriers to making changes to the procurement process in a timely and efficient manner.

RRO providers have invested in the RRO customer rights. Compensation may be required for any change in law that expropriates those rights.

Recommendation

There is no need to make drastic changes to the current structure to achieve the Minister's stated objectives of "stable, predictable, affordable, long-term rates". The Minister's stated objectives could be achieved much more straightforwardly by removing several of the legislated constraints in the RRO regulation (120 procurement window, monthly rate setting, etc.) that were originally intended to make staying on the RRO punitive to facilitate the competitive retail industry. Without these constraints, RRO providers and the Commission would have the flexibility to design and approve EPSPs that satisfy the Minister's objectives. If the Minister wants to ensure that EPSPs are designed with its stated objectives in mind, then it can add a requirement to the RRO Regulation for the AUC to consider when approving an EPSP.

[10] Proceeding ID 2941, Exhibit 273.02, EPCOR argument, paragraph 224, PDF page 84.

6.0 OPTIONS THAT DO NOT REQUIRE ADVANCE PROCUREMENT

Currently in the Alberta market, customers have ample opportunity to purchase products that allow for a pool price flow-through, exposing them to the current fundamentals of the wholesale market. While these products are suitable for customers who can actively manage their exposure, it presents a significant risk to individuals who are looking for stable and predictable rates. EPCOR is of the opinion that the RRO product should protect customers; this is best achieved through hedged products that allow for long term stability of energy costs.

Background

At the highest level, there are three types of retail electricity products that retailers can offer to customers. A pool price flow-through option simply passes the spot price through to the customers, thus enabling the customer to bear all of the volatility and associated commodity risk. This is the most volatile of the three options. On the other end of the volatility/stability spectrum is a fixed rate contract, in which retail customers can secure a fixed energy rate for terms of up to five years in length. This option is the most stable, and enables customers to transfer all commodity risk to the retailer. The third option is a hedged product, which lies somewhere in the middle of the stability spectrum. This provides a balance between stability and affordability. The RRO falls into the third category.

Advantages

In the current market structure, a pool price flow-through product can be an advantageous option for customers who are able to manage energy consumption and their exposure to pool prices. Through such a product, customers receive a price that is reflective of current market fundamentals, albeit on a lagging basis. The price also has the potential to be lower on average.

As current market fundamentals continue to see the supply surplus diminish, the market structure will create an environment where volatility returns, and pool prices exhibit patterns that are consistent with historical experience. In this environment, pool price flow-through products expose customers to substantially more risk, with significant variability in month-over-month prices. For customers that do not have the wherewithal to manage exposure to volatile power prices, a flow-through product will put customers at risk.

Figure 5: Monthly Pool Price Movement (2007-2016)

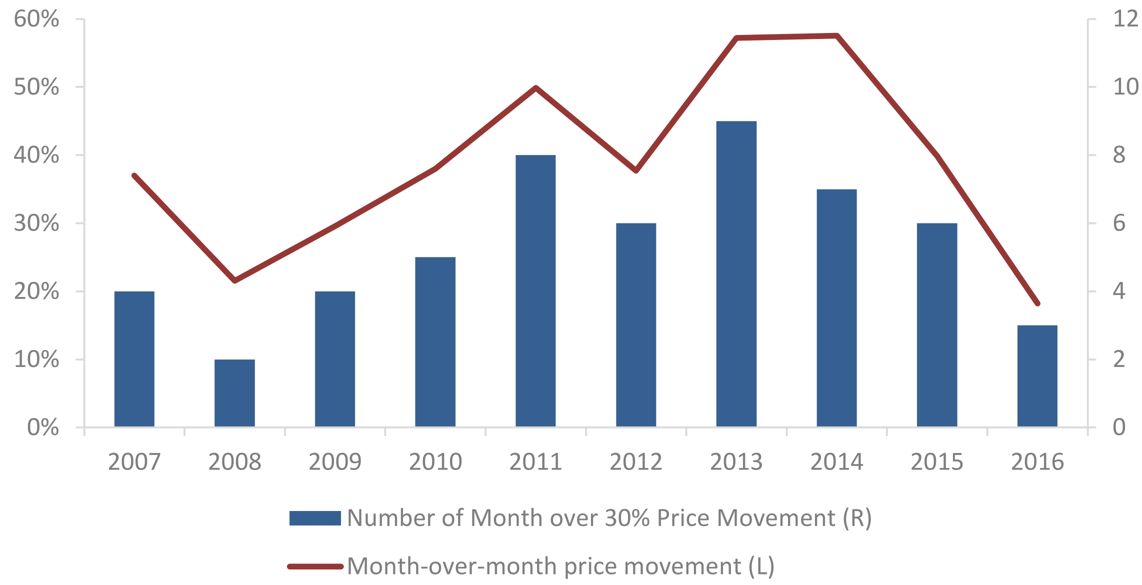


Figure 3 illustrates that there are eight years in the past ten years that have an average monthly pool price movement (either increase or decrease) that is over 30%, while the average monthly price movement over the past ten years is close to 40%. Further, monthly pool price movement is over 30% for 5.8 months each year on average in the past ten years, which is close to 50% of the time. For extreme cases like the year of 2013, the monthly pool price movement was 57% on average, and 9 months had a monthly price movement that was over 30%.[11]

Disadvantages

An RRO rate founded on a pool-price flow-through offers no protection to vulnerable customers from price spikes. This option would also violate the Government's objective of predictability, as the rate cannot be known until after the delivery month; customers would thus have no way of knowing what their energy rates will be until after the month and have already consumed energy for the month. Although it may be tempting to smooth out the impact to customers and announce a backward looking price prior to the consumption month, this only provides the illusion of predictability, at best.

Consider a month in which pool prices were unusually high. A vulnerable customer would have no way of knowing that their electricity consumption will be particularly expensive that month. Had the customer known in advance that their rate for the month was going to be higher than

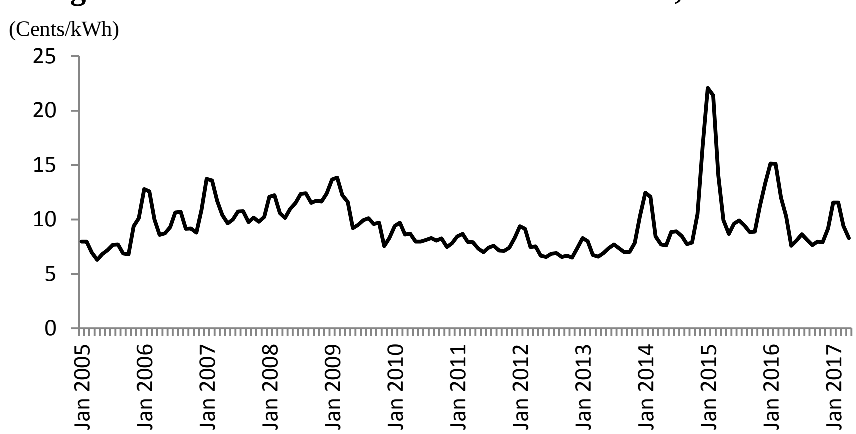
[11] Refer to Table 1 to compare to the current monthly procurement and long term hedging options.

usual, it could have made the extra effort to manage their situation by reducing their consumption (turn the lights off, reduce A/C usage, adjust laundry, etc.)

As a result of the inability of a pool price flow through option to protect customers from volatility and unpredictability, regardless of whether costs are billed shortly after being incurred or deferred to future months, any variation of a pool price flow through will unavoidably be politically unstable.

Capacity Markets: The Government has announced a transition to capacity markets over the next 3-5 years. Although this has the potential to smooth volatility in pool prices, sources of volatility will remain. Changes in weather and the prices of generation inputs, such as natural gas, will continue to be a source of variability. The following chart shows the variable default rate in New England from 2005-2017. Prices stabilized after that market transitioned to a capacity market by 2010. However, volatility returned to rates in the winters of 2015, 2016 and 2017 due to spikes in the price of natural gas. Until the full impact of capacity markets is evident, Alberta should avoid major policy changes based on assumptions of the state of a market that has not yet been implemented.

Figure 6: National Grid Variable Default Rate, 2005-2017[12]



Recommendations

Options that do not required advanced procurement do not meet the objectives of the Government. This option will not provide for stability or predictability, and should thus be rejected.

[12] http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/electric-market-info/electric-industry-overview.html

A hedged RRO rate provides RRO customers with a predictable rate that offers protection from the volatility in spot prices while maintaining affordability. It fluctuates from month to month based on the market's expectation of energy prices in the upcoming month, but does not expose customers to hourly spot market volatility and associated large monthly price spikes. The RRO rate continues to be the most appropriate default rate structure. Because it fluctuates with the market, it provides appropriate price signals to consumers. However, it also protects customers from large, unpredictable swings in the monthly rates. Customers who prefer other products have the ability to choose from competitive retail offerings.

7.0 DEFERRAL ACCOUNTS

Deferral accounts can be applied to retail markets to manage volatility of rates. While it is applied with the intention of protecting consumers, it has drawbacks in the Alberta context that should disqualify it from consideration. The drawbacks include increasing costs through greater financing requirements; reduced incentives for energy conservation; and incenting customer switching in a competitive retail environment.

Background

Deferral accounts are tools that can be used to smooth costs to consumers. The retailer essentially functions as a "financial institution", holding funds belonging to customers and/or effectively lending funds to customers, thus deferring credits and debits to future months. Deferral accounts are typically applied on an aggregate basis rather than at the customer or site level. For example, if a customer leaves the program while the deferral account is positive (i.e.: the retailer is holding funds belonging to the aggregate group of customers), that customer will not receive a credit for the outstanding funds. Rather, those future credits will be applied to the customer remaining in the program in future months. Deferral accounts applied on a customer or site basis are addressed in Section 8.

Advantages

In a retail market without the option for customer switching, deferral accounts can be an effective mechanism to reduce rate volatility. For example, rather than allowing rates to spike from one month to the next, the price to the customer may be capped, with associated revenue shortfalls of the retailers being deferred to future months. However, customers retain the risk, as discussed in the disadvantages section below.

Disadvantages

RRO providers are not in the financial services industry, and financing is not free. Requiring RRO providers to provide financial services to RRO customers would introduce unnecessary financing costs to RRO providers, which would ultimately need to be passed onto RRO customers.

Failure to Protect Consumers: When customers have the option to switch in and out of the default rate freely, deferral accounts provide a free option for savvy customers to switch strategically, moving on to the default rate in months when the deferral account is positive (customer refunds) and moving off the default rate when the deferral account is negative. Further, deferral accounts would be counterproductive for protecting vulnerable customers. In a worst case scenario, a deferral account can compromise the sustainability of the default rate by causing a death spiral. If very large losses ever need to be recovered through the deferral account, this could cause mass exodus from the RRO, leaving those losses to be recovered over fewer and fewer customers.

Price Signals: Deferral accounts lead to higher prices because they remove important price signals. For example, prices should be highest in months such as July and January when demand tends to be the highest in Alberta. A deferral account that spreads higher risk months or periods evenly over all months in the year distorts the incentive to more closely manage energy usage during months with high prices. This will end up costing more in capacity costs as consumers have no signal to reduce consumption in those periods. Deferral accounts also hide the true cost of energy, making consumers less responsive to energy efficiency programs. The ability of consumers to respond to price signals will only increase with time, as smart meters, data availability and end use technologies empower consumers to better manage their consumption. and deferral accounts would lessen the effect of customers responding to any price signals incentivizing responsible energy usage by the end user.

Recommendation

Competitive retailers and RRO providers are in the best position to manage commodity risk on behalf of customers. Deferral accounts would transfer commodity risk from retailers to consumers, who would have no foreknowledge of the risk they are incurring and limited ability to manage the risk. Further, deferral accounts would not protect vulnerable customers. To minimize the cost of capacity markets, encourage efficient use of energy and continue to provide predictability and protection to consumers of electricity in Alberta, deferral accounts should continue be rejected.

8.0 BILL SMOOTHING

A number of mechanism are available to attempt to reduce the volatility that customers can face on their power bills, including deferral accounts, bill smoothing and rate smoothing options. Section 7 discussed the pros and cons of deferral account. Rate smoothing would not be an ideal solution to reduce volatility, and it would result in a complicated payment process requiring multiple rounds of reconciliation, as well as new costs of upgrading the billing system for the rate smoothing. Bill smoothing has the potential to smooth both the rates and the consumptions at the same time. However, all of these still impose risks and create new costs to customers. EPCOR dedicates considerable resources to managing the balances of the small number of RRO customers currently on the equalized payment plan, and those costs would increase if all customers were on a bill smoothing model. To the customer, it would reduce the bill transparency, which EPCOR expects will result in a very high level of customer dissatisfaction.

Background

There are several ways that bill smoothing could be achieved. As mentioned earlier in EPCOR's submission, the RRO Regulation could be amended to allow for the procurement of longer term hedges. Longer term hedges would reduce RRO rate volatility as the portion of the RRO energy charge coming from the longer term hedges would be the same from month to month. EPCOR recommends that permitting the procurement of longer term hedges is by far the least disruptive means of smoothing rates for RRO customers.

Other options would include the use of deferral accounts, rate smoothing or bill smoothing. Deferral accounts are typically applied on an aggregate basis across customers enabling customers to leave the RRO at any time, without any liability, such as a final bill true-up. Bill smoothing could also be achieved by smoothing RRO rates at the site level or smoothing RRO customer bills at the account level (similar to EPCOR's current Equalized Payment Plan ("EPP") program) Smoothing the RRO rate would not address bill volatility due to changes in a customers' consumption over time. Smoothing the bill would address both RRO rate volatility and consumption volatility; however this option would result in a customer having a liability with the RRO provider in the form of a final bill true-up if the customer were to leave the RRO. D&T charges contain both fixed and variable components. Thus, a smoothing to the D&T portion of the bill could not be addressed through rate smoothing. Rather, to smooth D&T charges it would be necessary to smooth the bill (or a portion of the bill).

All of these options would weaken price signals for customers, reduce billing transparency for customers and add significant administrative effort as well as additional costs and risks to the RRO provider, which in turn would increase costs for customers. These disadvantages are discussed further below.

In addition, the minimal uptake of EPCOR's current EPP program suggests that bill smoothing options are not highly sought after by customers. Section 23 of the RRO Regulation requires that RRO providers make available an equalized billing plan to customers meeting specific criteria. EPCOR has elected to make its EPP option available to all of its customers. Only 3.6% of EPCOR's RRO customers have elected to sign up for EPP, which smooths customers' total bill including energy, D&T, gas (if applicable), waste, drainage and water charges. EPCOR monitors its current EPP program closely and makes any periodic bill amount adjustments required to prevent customers from facing large credit or debit settle-up amounts. There is no need to force all RRO customers on to a bill smoothing mechanism as all RRO customers already have access to such programs and those the find this type of program desirable already have the option to sign up for EPP.

Advantages

As discussed above, at a high level, there are two methods of reducing volatility in customers' electricity costs. The first option involves changes to the underlying make-up of the rate itself, such as procurement of longer term hedging products. The second option involves a redistribution of the costs over time through smoothing of either the rate or of the bill, essentially requiring the RRO provider to serve as a "bank account" that customers are required to debit and credit from. At first glance, it may appear that the latter will come at a lower cost to customers. However, as discussed further below, bill smoothing options will result in new costs and risks to customers and RRO providers.

Disadvantages

Outstanding balances: Account-specific deferral accounts are merely creative financial instruments, and do little to help the situation because although the deferral account may smooth the rate over the subsequent months, the fact remains that the customer has consumed the relatively expensive electricity and must pay the price, whether now or later. The use of account-specific deferral accounts could create situations in which customers find themselves in debt to their RRO provider and unable to leave RRO service. For example, suppose a customer owes $480 on an outstanding deferral account. A program could be designed that enables that cost to be smoothed over the upcoming 12, thus adding an additional $40 to each month bill and protecting the customer from a large month-over-month increase in costs. However, if that customer wished to leave the RRO and sign a competitive contract, then the full amount of $480 would be outstanding. There are RRO customers for whom this would present a significant financial hardship. Customers who feel that they are unable to exercise their right to leave the RRO will be very dissatisfied with RRO service.

As stated above, currently 3.6% of customers are on EPCOR's EPP. As at March 2017, the balance of the EPP funds for these 3.6% of customers is holding $61,000. Extrapolating from the current balance outstanding on this 3.6% of customers, a simple calculation shows that if 100% of EPCOR's RRO customers were on EPP, EPCOR would currently be holding approximately $21 million in customers' funds[13]. This is calculated using historical EEP amount and grossed up the amount by applied the percentage of RRO customers that are on EPP and then applied the ratio of the bills that belongs to energy related charges. This is equally likely to go in the opposite direction, and EPCOR could be holding $21 million in debt. In addition EPCOR actively manages customers on EPP to prevent large refunds or balances owing from accumulating. In a situation where EPCOR would be constrained to make such adjustments, the balances owing could easily be 2 or 3 times as large as the grossed-up EPP amount, meaning the balances owing to EPCOR's total RRO customer base could be as large as $100 to $150 million at any time. As mentioned above if 100% of EPCOR's customers were on EPP, EPCOR would function as a financial institution, either holding large amounts of its customer's funds or needing to take on debt to finance the large amounts owing to customers.

<u>Working capital costs</u>: Holding large amounts of customer credits for lengthy periods of time would necessitate consideration of paying interest to customers and additional costs to manage larger volumes of cash, as well as the administrative burden of managing the expanded EPP process. In the case of EPCOR being owed funds from customers, EPCOR would require additional working capital to fund the shortfall, which assuming a range of balances outstanding of $100 to $150 million on a 12 month period smoothing period would add approximately $6 -

[13] $47 million * 45%, $47 million is the grossed-up net balance for EPP customers assuming 100% of RRO customers are on EPP for the last 27 months, 45% is the average percentage of energy and distribution charges on a bill for EPP customers.

$9 million in additional annual costs for any year the shortfall is outstanding[14]. Exact costs would require further review.

Challenges with EPP: EPCOR has struggled with maintaining an appropriate equalized payment amount for EPP customers so that this payment amount does not result in a high debit or credit amount when this amount is annually trued up with customers. With changes in the rates and consumption patterns from time to time, it is difficult to forecast what the future rates should look like and to calculate an appropriate equalized payment amount for the year. EPCOR has been facing this challenge for several years. and has come up with different methodologies to determine the equalized payment and has tried to maintain the year-end true up amount at an appropriate level. However, if the rates are going up higher than forecast, customers will end up with a large amount of true up at of the end of the cycle and vice versa. The improvements made so far to the administration of EPCOR's EPP were made with years of experience and provided flexibility in the payment structure, with a new rate smoothing structure it can be expected that there will be initial inefficiencies in the process, particularly if EPCOR is restricted in making adjustments to payments to manage amounts refundable or owing.

Bill transparency: Where currently a customer's energy charge is calculated only using a rate times volume calculation, introducing a true-up mechanism would add significant complexity to a customer's bill as it would now require details on the calculation of true-ups to be included with current billing. In fact, the true-up may introduce cross-subsidization between current and past customers as the rate that a customer is paying may be the result of the consumption levels and behavior of a prior customer at the site. This increase in complexity and decrease in billing transparency would require a higher level of training for customer service representatives and necessitate more time during interactions to allow for a more detailed explanation of a customer's billing charges, adding customer confusion and additional customer service costs. Additional complexity also increases the likelihood of billing disputes where more factors than historical consumption and price information are used. It is expected the net result will be customer dissatisfaction with the billing process.

Bad debt costs: Billing a customer for true-up consumption at a later time under a rate smoothing mechanism would increase the length of time it takes to recover delinquencies. As a result, EPCOR's potential exposure to bad debt expenses would also increase as customers could owe true-up amounts in addition to current charges owing under the current structure to the retailer at any point in time. As discussed above, this exposure could increase to up to $100 to $150

[14] 6.01% Weighted Average Cost of Capital ("WACC") times by $100 million and $150 million respectively.

million at any time, potentially contributing to the total write-offs of customer accounts occurring as a result of delinquency while this balance is outstanding. In addition, it becomes more difficult to collect amounts owing from customers as the time increases between underlying consumption and billing as the inputs become less familiar and customer may have moved and hence it is more difficult to track down customers to collect from. Exact costs would require further review.

As discussed above, if a site-based approach to the true-up mechanism is adopted, there will be true-ups assessed to new owners for prior owner consumption. This, along with the added bill complexity and length of time between consumption and billing for true-ups, are factors which would reduce customer perception regarding the fairness of the amounts customers are being billed and hence increased likelihood of billing disputes. Additional billing disputes will increase incidences of non-payment and drive attrition from the RRO due to dissatisfaction, concentrating the recovery of existing bad debt risk over a smaller group of customers.

Pending the structure of the true-up mechanism, a potential sudden increase in customer bills as true-ups are applied could harm vulnerable customers on fixed incomes who have planned expenditures based on the smoothed bill amount they have become accustomed to. Additionally, there is less immediate feedback for customer billing based on load consumption so the opportunity to curtail power consumption during high priced periods may pass before a customer incurs a large charge, contributing to a higher risk of non-payment.

Increased Administrative Burden: EPCOR anticipates an increase in operational costs would be required to manage bill smoothing. Currently, 1 FTE is required to support the existing EPP process for 3.6% of EPCOR's RRO customer base. EPCOR anticipates this would increase significantly if all customers were on EPP or a similar rate or bill smoothing methodology. There would also be an increase to the FTEs required to review billing accuracy based on the increased complexity and decreased transparency of bills. This will also impact the number of FTEs required to support customer billing inquiries as more time would be needed to review the bill with customers. As simple extrapolation of the current cost to operate EPP for 3.6% to 100% of customers would be 28 FTEs, representing a significant increase in FTE. This is several times higher than the 3 FTEs required to perform the current RRO load forecast, hedging and procurement functions for EPCOR's RRO customers. Exact costs would require further review. This also assumes that the approved EPSP would allow the RRO providers to exercise this level of discretion to manage the size of outstanding EPP balances with individual customers. If the RRO providers did not have this level of flexibility, then the cost exposure would be far greater than the $100 to 150 million estimated above.

A reconciliation process that involves bill smoothing was experienced in 2002, when RRO customers' bills from 2001 were smoothed and reconciled in the following year. This led to significant customer dissatisfaction, as customers' bills were affected by the usage of previous tenants at the site.

Recommendations

EPCOR supports the Government of Alberta's objectives of stabilizing electricity costs to customers in Alberta. In general, there is a trade-off between volatility and prices, such that options to reduce volatility typically come at a cost to customers. Any rate smoothing option will be no different, as each rate smoothing model contains costs and risks that RRO customers currently do not pay for. On the other hand, advance procurement of longer term products has the potential to stabilize rates without significantly increasing the overall level of electricity costs to customers

9.0 LENGTH OF RRO REGULATION

Amending the RRO Regulation to extend the expiration has become commonplace in Alberta. The constant change in the regulation has inhibited stability that could be achieved through long term planning. Through these constant revisions, customers have born the costs through greater administrative costs associated with EPSP development and procedural hearings. EPCOR is of the opinion that the RRO Regulation should be amended to extend the term of the requirements for a period that would allow for greater stability in EPSP development.

Since its introduction in December 2005, the Government has extended the expiry of the RRO Regulation on five occasions. The last time the Government extended the RRO Regulation was in 2015 when it extended the expiry from April 30, 2018 to April 30 2020. The short expiry period creates uncertainty about the fate of the Regulation in stakeholders' minds. Extension of RRO Regulation with an expiry of 10 Years or longer at a time will reduce uncertainty for potential RRO customers and it will send the signal that with respect to RRO vs. competitive retail options, the Government has no preferences. As long as customers choose to be on it, the RRO option is here to stay.

EPCOR's current EPSP began in August 2016 and is set to end less than two years later, in April 2018. With a current RRO Regulation expiry date of April 2020, the next EPSP may likewise be limited to two years in length. This is in contrast to the 2006-2011 EPSP and the 2011-2016 EPSP which were 4-5 years in length. EPSPs that are negotiated or litigated every 2 years instead of every 4-5 years double the legal, consulting and other regulatory costs that the RRO providers, intervener groups and the AUC must commit, ultimately increasing costs to rate payers and tax payers in Alberta.

The longer expiry will also reduce uncertainty for RRO investors and it will send them a signal that as long as they are competitive, the Government will not arbitrarily discontinue the service they provide. The certainty will help them plan their products and resources with an eye on the long term. Their decisions with respect to strategy, IT & other systems, human resources and finances will be based on a longer term horizon. All this certainty could further benefit customers and help enrich the competitive landscape in the province.

A longer term RRO Regulation expiry will also be helpful for the Regulator as they could allow RRO providers to come up with EPSP designed for longer durations. Given a busy regulatory schedule, the certainty and resulting longer term plan durations could unburden regulatory schedules which have been very busy for several years now. EPCOR thus recommends that extensions to the RRO Regulation are at least 10 years in length or remove the expiry altogether.

10.0 SUMMARY OF RECOMMENDATIONS AND NEXT STEPS

EPCOR appreciates the opportunity to provide feedback to the MSA in their review of the RRO Regulation. As demonstrated through the discussion above, EPCOR is of the opinion that no major changes are required to achieve the Government's objectives of stability, affordability, predictability and reduced regulatory costs.

While fundamental changes are not necessary, there are enhancements to the current regulation that can be incorporated to further meet the Government's objectives.

First, the Government should amend the regulation to permit RRO providers the ability to procure energy through long term hedges. This should include hedges of quarterly and annual products. As demonstrated through the analysis provided, the benefits of this change will be substantial, leading to more stable and predictable rates for Alberta consumers.

Second, the RRO Regulation should be amended to extend the term of the legislation. By extending the legislation for a period of 10 years, the government will provide the stability necessary for longer term planning. With more certainty in the terms of the regulation, RRO providers will be better equipped to develop and execute Energy Price Setting Plans that greatly reduce the regulatory and administrative costs borne by consumers.

While fundamental changes are not required at this time, EPCOR believes that the aforementioned enhancements to the RRO Regulation will provide the stability that is necessary to ensure consumers receive the protection and value that is expected from their default supplier.

ALBERTA REGULATION 262/2005

Electric Utilities Act

REGULATED RATE OPTION REGULATION

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Definitions

1 In this Regulation,

(a) "Act" means the *Electric Utilities Act*;

(b) repealed AR 264/2007 s2;

(c) "business day" means a day other than Saturday or a holiday as defined in the *Interpretation Act*;

(c.1) "Commission" means the Alberta Utilities Commission established by the *Alberta Utilities Commission Act*;

(d) "eligible customer" means

(i) a rate classification customer, and

(ii) any other customer, if the owner's reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 megawatt hours of electric energy at that site;

(e) "losses" means the energy that is lost through the process of transmitting and distributing electric energy;

(f) "new RRO rate" means the charge to regulated rate customers for the supply of electric energy determined in accordance with sections 10 and 11;

(g) "owner" means

(i) the owner of an electric distribution system, or

(ii) if the owner makes arrangements under which one or more other persons perform any or all of the duties or functions of the owner, the owner and those one or more other persons;

(h) "rate classification customer" means

(i) a residential rate classification customer,

(ii) a farm rate classification customer, or

(iii) an irrigation rate classification customer

as defined in a regulated rate tariff;

(i) "regulated rate" means

(i) repealed AR 11/2013 s2;

(ii) on and after July 1, 2010, a new RRO rate;

(j) "regulated rate customer" means an eligible customer who is not receiving electricity services from a retailer;

(k) "regulatory authority" means the entity that approves an owner's regulated rate tariff under section 103 of the Act;

(l) "risk margin" means the just and reasonable financial compensation that an owner's regulatory authority approves for the owner based on the financial risks

(i) that remain with the owner, and

(ii) that are associated with the supply of electricity services to regulated rate customers;

(m) "site" means a site as defined in accordance with ISO rules for load settlement;

(n) repealed AR 11/2013 s2;

(o) "unaccounted for energy" means the difference between the distribution system total load for an hour and the sum of the allocated hourly loads at the customer meters, plus their allocated losses.

AR 262/2005 s1;264/2007;11/2013

Regulated Rate Tariff

Requirement to provide regulated rate tariff

2 Each owner must make available to eligible customers in the owner's service area the option of being supplied electricity services in accordance with a regulated rate tariff instead of purchasing electricity services from a retailer.

Requirements of regulated rate tariff

3(1) An owner's proposed regulated rate tariff provided to its regulatory authority for approval under section 103 of the Act

(a) must include

(i) repealed AR 11/2013 s3,

(ii) a new RRO rate energy price setting plan,

(iii) the owner's proposed risk margin, and

(iv) the terms and conditions under which the owner proposes to offer electricity services,

and

(b) must show the following information separately, and must indicate how the following information will be shown separately on a regulated rate customer's bills:

(i) the electric energy charge;

(ii) the administrative charge, which may include a billing charge, as a dollar amount for each period specified in the tariff;

(iii) the delivery charge for distribution access service and system access service, separately, as either

(A) a distribution charge and transmission charge, or

(B) a fixed delivery charge and variable delivery charge;

(iv) if applicable, shown under the heading “local access fee”, any amount levied under section 45 of the *Municipal Government Act*, or Schedule 1, section 21 of the *Metis Settlements Act* or by bylaw under the *Indian Act* (Canada).

(2) A proposed regulated rate tariff must not use, provide for or contemplate any deferral accounts, true-ups, rate riders or other similar accounts or devices for energy related costs.

(3) A proposed regulated rate tariff must indicate the period in which the owner intends the tariff to have effect.

AR 262/2005 s3;11/2013

Price setting plans

4(1) The price setting plans referred to in section 3(1)(a) must, with a reasonable degree of transparency, use a fair, efficient and openly competitive acquisition process to ensure that the resulting prices for the supply of electric energy are just, reasonable and electricity market based.

(2) Repealed AR 11/2013 s4.

(3) The price setting plans referred to in section 3(1)(a) must include procurement arrangements for the purpose of

(a) supplying electric energy to regulated rate customers,

(b) managing the financial risk associated with the owner supplying electric energy to regulated rate customers, and

(c) maximizing the stability of RRO rates under the regulated rate tariff.

AR 262/2005 s4;11/2013

Risk margin

5(1) An owner’s regulatory authority must ensure the risk margin is just and reasonable.

(2) The risk margin may only cover risks to which the owner is directly exposed and may not include risks that are borne by a person other than the owner.

(3) Risks covered by the risk margin must include the following:

(a) all volume risk, including attrition and forecast risk;

(b) all price risk;

(c) all credit risk;

(d) all unaccounted for energy and losses.

(4) Risks covered by the risk margin may include other risks associated with energy related costs and non-energy related costs that an owner’s regulatory authority considers reasonable and prudent.

(5) An owner is not entitled to recover from customers any past costs or expenses related to the risks described in subsections (3) and (4) except through the risk margin approved by the owner’s regulatory authority.

(6) The risk margin may be set for a period of months approved by an owner’s regulatory authority.

Approval of Tariff by Regulatory Authority

Matters to be considered when approving tariff

6(1) When considering an application for approval of a regulated rate tariff under section 103 of the Act, a regulatory authority must

(a) have regard for the principle that a regulated rate tariff, including the risk margin described in section 5, must provide the owner with a reasonable opportunity to recover the prudent costs and expenses incurred by the owner,

(b) have regard for the principles that

(i) a regulated rate tariff must allow for a reasonable return for the obligation on the owner to provide electricity services in accordance with section 2, and

(ii) the risk margin described in section 5 must not be considered as a part of that reasonable return,

(c) have regard for the principle that a risk margin approved by it must provide the owner with a just and reasonable financial compensation for the risks described in section 5,

(d) have regard for the principle that a regulated rate tariff must not impede the development of an efficient market for electricity based on fair and open competition in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of any participant,

(e) examine the reasonableness of the owner's billing costs and other costs the owner's regulatory authority considers appropriate in the prevailing circumstances, without regard to any overall increase in costs due to the separation of distribution access service and the provision of electricity services, and

(f) approve the price setting plans referred to in section 3(1)(a) in a manner that ensures that the procurement risk of acquisition remains with the owner.

(2) A regulatory authority must not approve a regulated rate tariff that uses, provides for or contemplates any deferral accounts, true-ups, rate riders or other similar accounts or devices for energy related costs.

Approval of method to determine regulated rates

7(1) A regulatory authority may approve a regulated rate tariff that determines how regulated rates will be established for a period of months.

(2) A regulatory authority may approve a regulated rate tariff under subsection (1) only if the new RRO rate component of the regulated rate tariff is calculated in accordance with section 11.

(3) In an approval under subsection (1), a regulatory authority must select one of the following methods to determine regulated rates:

(a) acknowledgment of each monthly rate calculated by an owner through its price setting plans;

(b) approval of each monthly rate separately.

(4) If a regulatory authority selects the method referred to in subsection (3)(a), the owner must retain records sufficient to enable the regulatory authority to audit any previous monthly rates set by the owner.

(5) If a regulatory authority discovers that an owner has made an incorrect rate calculation resulting in an overcharge of customers, the regulatory authority must require the owner to refund the amount overcharged to the customers as soon as practicable after the error is discovered.

Setting Regulated Rates

8 Repealed AR 11/2013 s5.

9 Repealed AR 11/2013 s6.

Duty to set new RRO rates

10(1) An owner must set a new RRO rate for each calendar month.

(2) Each new RRO rate must be set in accordance with the new RRO rate energy price setting plan referred to in section 3(1)(a) and the calculations referred to in section 11.

Calculation of new RRO rate

11(1) Each new RRO rate

(a) must be based on

(i) regulated rate customer load forecasts made ~~during a relevant price setting period described in subsection (2)~~before the 5th business day preceding the month, and

(ii) ~~monthly~~ forward market electricity prices established ~~in a relevant price setting period,~~before the 5th business day preceding the month.

and

(b) must not be based on prices established ~~before or after a relevant price setting period~~after the 5th business day preceding the month.

~~**(2)** The price setting period for a calendar month is a period beginning on a day that is not more than 120 days preceding the month and ending on the 5th business day preceding the month.~~

AR 262/2005 s11;11/2013

Duty to provide regulated rates to regulatory authority

12 An owner must submit to its regulatory authority, not less than 5 business days prior to the commencement of each calendar month, the regulated rate for that calendar month and the calculations of the regulated rate.

Publication of regulated rates by Commission

13(1) The Commission must post on its internet page the regulated rates from all owners it regulates, on the first day of each calendar month in which the rates are to have effect.

(2) For eligible customers without access to the internet, the Commission must make available on request the regulated rates from all owners it regulates in an alternative format determined by the Commission.

AR 262/2005 s13;264/2007

Publication of regulated rates by owner

14(1) An owner must post its regulated rate for each calendar month on an easily accessible internet page on the first day of the calendar month in which the rate is to have effect.

(2) The owner must ensure

(a) that there is a link on the internet page to a historic file of previous regulated rates for at least the previous 12 months, and

(b) that the address of the internet page is shown on each regulated rate customer's bill, with directions that current and historical regulated rates may be found on the internet page.

(3) The owner may communicate the information described in subsections (1) and (2) using a method other than the internet, but must ensure that

(a) the method used to communicate the information will permit regulated rate customers to access the information easily,

(b) the regulated rates for each calendar month will be available by the first day of the calendar month in which the rates are to have effect,

(c) the regulated rates for the previous 12 months will be available at least once in a calendar month, and

(d) information about the method to be used to communicate the current and historical regulated rates is shown on each regulated rate customer's bill.

Billing

Billing information

15 An owner must include on every bill sent to a regulated rate customer at least the following information, showing separately:

(a) the electric energy charge;

(b) the administrative charge, which may include a billing charge, as a dollar amount for each period specified in the bill;

(c) the delivery charge for distribution access service and system access service separately as either

(i) a distribution charge and transmission charge, or

(ii) a fixed delivery charge and variable delivery charge;

(d) the customer's consumption of electric energy on which the charge referred to in clause (a) is based;

(e) if applicable, shown under the heading "local access fee", any amount levied under section 45 of the *Municipal Government Act*, or Schedule 1, section 21 of the *Metis Settlements Act* or by bylaw under the *Indian Act* (Canada), and the name of the municipality, Metis settlement or band that will receive the levied amount.

AR 262/2005 s15;59/2015

Basis for charges

16 For regulated rate customers,

(a) where any portion of the delivery charge is based on consumption, both the electric energy charge and the delivery charge to customers in a billing period must be based on common consumption data for that billing period, and

(b) at sites where electric energy consumption is metered, at least twice each calendar year, the charge for electric energy for a billing period must be based on an actual meter reading.

Undercharge

17 An owner is not entitled to collect from a regulated rate customer any amount undercharged as a result of an incorrect meter reading, incorrect rate calculation, clerical error or other error of any kind that is made more than 12 months before the date of the bill.

Overcharge

18 If a regulated rate customer is overcharged, the owner must refund the customer the amount overcharged as soon as practicable after the error is discovered.

Miscellaneous Matters

Entry to or exit from regulated rate tariff

19(1) An owner must not, either in its regulated rate tariff or by other means,

(a) collect fees related to the entry to, or exit from, the regulated rate tariff by an eligible customer, or

(b) require notice periods greater than 30 days for entry to, or exit from, the regulated rate tariff.

(2) For the purposes of subsection (1), entry to a regulated rate tariff includes a request by an eligible customer

(a) to purchase electricity services for an existing site, or

(b) to purchase electricity services for a previously unserviced site.

Delegation of duties

20 An arrangement made by an owner under section 104 of the Act under which another person is authorized to perform any or all of the duties or functions of the owner under this Regulation has no effect unless the arrangement is approved by the owner's regulatory authority.

Financial security requirements

21 A rural electrification association is exempt from the requirement to provide financial security, as determined under the ISO rules, in respect of the electric energy acquired by the rural electrification association to meet its obligations under its regulated rate tariff.

Service standards and incentives

22 The Commission may determine or establish service standards and service incentives for providing electricity services under a regulated rate tariff.

AR 262/2005 s22;264/2007

Equalized billing

23(1) An owner may offer an equalized billing plan to regulated rate customers.

(2) The owner must make available an equalized billing plan to equalized billing plan eligible customers.

(3) For the purposes of subsection (2), an equalized billing plan eligible customer is a regulated rate customer who can provide evidence sufficient to satisfy the owner that the customer is currently receiving financial support from

(a) an income support program established under the *Income and Employment Supports Act* or the *Seniors Benefit Act*, or

(b) the Government of Canada under its Indian Northern Affairs Alberta Region First Nation Income Support Program which is administered to on-reserve residents.

Application of this Regulation and Transitional Provisions

Application of this Regulation

24 This Regulation applies in respect of

(a) an owner's application to a regulatory authority for approval of a regulated rate tariff that is intended to have effect on and after July 1, 2006, whether the application to the regulatory authority is made before or after that date, and

(b) a regulated rate tariff that is intended to have effect on and after July 1, 2006.

Rewarding deferrals, true-ups and rate riders

25 Any deferral accounts, true-ups or rate riders or other similar accounts or devices remaining from a regulated rate tariff that was in effect before July 1, 2006 may only be collected by an owner after July 1, 2006 in accordance with an approval from the owner's regulatory authority.

26 Repealed AR 11/2013 s8.

Expiry

27 Repealed AR 11/2013 s9.

Expiry

28 For the purpose of ensuring that this Regulation is reviewed for ongoing relevancy and necessity, with the option that it may be repassed in its present or an amended form following a review, this Regulation expires on ~~April 30, 2020~~December 31, 2027.

AR 262/2005 s28;264/2007;143/2010;224/2012;59/2015

29 Repealed AR 11/2013 s 10.

Robert J. Litzenberger
Director, Customer and
Government Relations

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May 19, 2017

Market Surveillance Administrator
#500, 400 Fifth Avenue S.W.
Calgary, Alberta T2P 0L6

VI**A EMAIL:** ***mark.nesbitt@albertamsa.ca***

Attention: Mark Nesbitt
Manager, Retail and Investigations

Dear Mr. Nesbitt:

Re: Comments Regarding Options for Design of the Regulated Rate Option (RRO)

FortisAlberta Inc. ("FortisAlberta" or the "Company") submits the following in response to your correspondence of April 21, 2017, which provided the Company with an opportunity to provide comments regarding options for the potential redesign of the Regulated Rate Option (RRO). The Company understands that revisions to the existing RRO are being contemplated as a means of ensuring that RRO customers may continue to benefit from stable and affordable rates.

As an owner of an electric distribution system, FortisAlberta has a responsibility to ensure that its customers are provided with the option of receiving service under the RRO if they choose to do so. Section 104(1) of the *Electric Utilities Act* permits the Company to make arrangements with other persons for the provision of RRO services. FortisAlberta does not engage in direct RRO administration as part of its business. Consequently, the Company has contracted with EPCOR for the provision of RRO services to its customers since 2000. The Company has been very satisfied with the manner in which EPCOR has discharged its responsibilities as an RRO provider.

FortisAlberta has had the benefit of reviewing the detailed comments prepared by EPCOR for the consideration of the Market Surveillance Administrator (MSA) in this matter and supports the views that EPCOR has expressed in its submission.

FortisAlberta is pleased to assist the MSA as it works towards completion of the report requested by Minister McQuaig-Boyd. Please do not hesitate to contact me directly should you have any questions regarding the foregoing.

Sincerely,

"Original signed by"

Robert J. Litzenberger
Director, Customer and Government Relations
FortisAlberta Inc.

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T 403.462.4299
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May 18, 2017

Via: stakeholderconsultation@albertamsa.ca

Mr. Mark Nesbitt
Market Surveillance Administrator
#500, 400 5 Avenue SW
Calgary, AB T2P 0L6

Dear Mr. Nesbitt:

RE: Options for Enhancing the Design of the Regulated Rate Option ("RRO")

Thank you for the opportunity to provide input on this matter. Just Energy Alberta L.P. ("Just Energy") is supportive of consumer protection; however, we are not sure what is driving this initiative. Nonetheless, we are offering the following comments to assist the Market Surveillance Administrator ("MSA") in identifying options, advantages and disadvantages to the Regulation Rate Option ("RRO") design options found in the MSA's notice to participants and stakeholders dated April 21, 2017.

Just Energy prides itself on being the trusted advisor for its consumers. Just Energy believes it is in the best interest of consumers, the government and other industry participants to work collaboratively in an effort to ensure that Alberta consumers are well served and protected, while not unduly harming business, innovation and growth in the Province.

ABOUT JUST ENERGY

Just Energy and its affiliates are leading retail energy providers specializing in electricity and natural gas commodities, energy efficiency solutions, and renewable energy options. With offices located across the Canada, the United States and the United Kingdom, the Just Energy companies serve approximately two million residential and commercial consumers providing homes and businesses with a broad range of energy solutions that deliver comfort, convenience and control, including, fixed, variable and flat bill electricity and natural gas products, green energy products, such as renewable energy certificates and carbon offsets, energy management tools, such as the ecobee smart thermostat and LED light bulbs. Just Energy's parent was established in 1997 and is publicly traded on the Toronto and New York Stock Exchanges.

Alberta is an important market for Just Energy, helping to contribute to Alberta's economic success. Just Energy provides reliable and consistent energy and energy management solutions to consumers across the province, offering a choice to consumers to best manage their energy needs and footprint. Beyond being a service provider, Just Energy provides job opportunities to over 80 Albertans on a daily basis, located in 5 offices across the Province.

In addition to being a leader in North American energy marketing services, Just Energy is a conscious corporate citizen. We are committed to pursuing policies and practices that address social and environmental concerns, such as climate change. To this end, Just Energy supports a number of carbon offset and renewable energy certificate projects in Alberta that have a combined approximate value of $5.5 million. Through our green business practices, Just Energy has offset over 400,000 metric tons of carbon emissions and purchased over 730,000 MWh of renewable energy credits.

We also believe in the importance of being an active, contributing and responsible community partner. The Just Energy Foundation focuses on enhancing the livelihood of the communities in which we operate. Through corporate giving, Just Energy strives to help charitable organizations secure the resources required to promote the health and well-being of communities in need throughout Canada and the United States. In the past two years, Just Energy has donated more than $28,000 to Alberta based charities, including a donation to Alberta Fires Appeal and Aspen's Winter Breather campaign which assists individuals struggling to pay their energy bills.

Just Energy is also a partial owner of ecobee Inc., a Canadian manufacturer and distributor of smart thermostats. These thermostats, which are bundled with certain Just Energy solutions and are sold through Apple and in many retail stores, help consumers conserve energy and control their energy usage from anywhere on the planet.

I. CONSIDERATION OF ONE RRO RATE FOR ALL ELIGIBLE CONSUMERS (OR CUSTOMER CATEGORY) IN ALBERTA.

It is Just Energy's position that consumers should be responsible for paying the RRO that is reflective of the cost to service the geographical area within which they reside and/or conduct business. Socializing the cost across the entire province creates an artificially constructed price and will force consumers in lower cost to serve areas to subsidize the cost for consumers living in higher cost to serve areas. In addition, if one RRO for the entire province means the creation of a centralized procurement entity then job loss could also result.

II. CONSIDER CHANGES TO PROCUREMENT, INCLUDING ADVANCED PROCUREMENT OF LONGER TERM PRODUCTS, CENTRALIZED PROCUREMENT OR OPTIONS THAT DO NOT REQUIRE ADVANCED PROCUREMENT

The current RRO procurement design is market reflective and any changes to RRO provider procurement rules should endeavor to maintain said feature. RRO providers should not be providing fixed/long term rate offerings. The competitive retail market is vibrant and stable. It has been that way for years and it is therefore unnecessary for RRO providers to offer what competitive retailers offer. In addition, advanced procurement could lock in high prices which could incentivize consumers to scheme the system. If this occurs, consumers may be enticed to switch back and forth between utility companies and retailers if the RRO is not reflective enough of the market.

If the intent of the MOE is to strive towards price stability then we suggest their efforts be focused on investigating cases of generators exerting market power during high demand periods. This could be done by creating rules for generation offers to ensure that generation units are not being withheld or offered in at unreasonably high prices.

Approximately 50% of residential and small commercial RRO eligible customers in the province are on a retail contract which is a clear indicator that Alberta consumers want choice. Creating a procurement process that allows for the RRO to compete with rates and products offered by retailers may very well result in retailers being forced to leave the market due to unfavorable economics and effectively eliminate consumer choice.

III. CONSIDER INTRODUCTION OF DEFERRAL ACCOUNTS OR CHANGES TO BILL SMOOTHING

In line with the preceding comments, Just Energy's position is that procurement should occur prior to the same month electricity is consumed. RRO providers should be considered experts in what they do and should bear the responsibility of operating efficiently to control costs.

Introducing a deferral account model removes this incentive. Deferral accounts artificially lower prices and push cost recovery to a later date as RRO providers are guaranteed payment through the deferral account. A deferral account takes the focus away from energy efficiency and cost reduction, distorts price signals and creates the ability for companies to shift risk onto consumers. Consumers would ultimately have to pay the cost of deferral account management. This procurement feature removes some of the incentives for RRO providers to be as efficient as they otherwise would have been.

IV. CONSIDER WHEN AND HOW A CHANGE TO THE RRO SHOULD OCCUR

Just Energy is of the view that any change to the RRO is unnecessary; however, submit that any roll out of RRO design changes should be inclusive of industry working sessions and further consultation.

CONCLUSION

Just Energy fully supports consumer protection initiatives; however, there is an unnecessary cost associated with all of the items open for consideration and comment. Electricity prices are and have been stable. We vehemently oppose RRO providers having the ability to offer products that retailers have been offering for years. Just Energy is a leader in innovative energy management solutions and technology solutions and submits that improving consumer protection does not have to mean introducing anticompetitive measures. Just Energy is happy to answer any questions you may have either by phone or in person. Thank you for your consideration of this submission, we look forward to participation in future consultation activities.

Should you have any questions, please do not hesitate to contact Frances Murray or Nola Ruzycki.

Sincerely,

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May 18, 2017

Dr. Matt Ayres
Market Surveillance Administrator
#500, 400 5th Avenue SW
Calgary AB T2P 0L6
matt.ayres@albertamsa.ca

Re: Request from Minister of Energy re Regulated Rate Option

Dear Dr. Ayres,

Maxim Power Corp ("MAXIM") is an owner, developer and operator of innovative and environmentally responsible power plants. We have reviewed the letter from Minister McCuaig-Boyd asking the MSA to develop a report on options for reform of the RRO. Although Maxim is not an energy retailer or distribution company, we believe our hands-on experience in capacity markets provides some insight that may be helpful to the MSA in addressing this request.

In Alberta today, the Regulated Rate Option (RRO) is available to electricity customers who consume less than 250,000 kWh per year. The RRO reflects monthly prices in the wholesale electricity market and consequently is impacted by supply and demand, fuel costs and weather. The Alberta Utilities Commission approves the RRO rate calculation just before the start of each month.

For context, Alberta Energy reports the average household in Alberta used 7,200 kWh of electricity in 2015. Charles River Associates calculate that in 2015, 12% of Alberta Internal Load received the default RRO representing 55% of the total market by customer count (A Case Study in Capacity Market Design and Considerations for Alberta, March 2017).

EPCOR, ENMAX and Direct Energy are the major providers of RRO service to Albertans. Each procures RRO energy through the forward market. Forward contracts are procured by EPCOR through auctions up to 120 days in advance of delivery and by ENMAX and Direct Energy via NGX exchange screens and over-the-counter trades up to 45 days in advance of delivery.

Minister McCuaig-Boyd has asked for options that would provide for:

- Affordable electricity
- Predictable and stable rates: and
- Minimized regulatory and administrative costs

From the outset, we believe it is important to acknowledge that a market model of any kind brings advantages, disadvantages and trade-offs between the two. In addition to the cost of electricity for RRO eligible consumers, important considerations for Alberta in market design include environment and climate change, ensuring adequate and reliable supply, economic development and job creation and potential costs to taxpayers and the Alberta treasury. As we have witnessed in the market restructuring consultation process, each must be carefully considered in developing energy policies for Alberta's future.

In our experience the transition from an energy-only market to a capacity market will impact future electricity prices and rate stability for consumers. Regardless of the mechanism selected to deliver the RRO and the approaches used to acquire RRO energy, implementation of a capacity market will in itself advance two of the three objectives specified by the Minister.

A capacity market is designed to ensure adequate supply at the best overall value for consumers without the need for a volatile energy price signal. Capacity is procured through competitive market auctions held well before the electricity is needed by Albertans. With capacity markets, energy prices reflect the cost of fuel and a small operations and maintenance component. The auction mechanism provides for more stable and predictable rates and competition ensures the best overall deal for consumers. Although not eliminated entirely, volatility is greatly reduced.

Regulatory and administrative costs will be determined by the mechanisms put in place to operate, manage and govern the RRO and Alberta's electricity sector overall. The current system of multiple RRO providers each operating their own separate processes imposes costs on delivering the default rate to eligible Alberta customers.

The purpose and design of the RRO has evolved and changed since the introduction of retail electricity competition in 2002. Going forward an optimal approach will minimize the costs of providing reliable, low carbon electricity to Albertans while recognizing the supply requirements of the future. The capacity market experience of other jurisdictions provides useful lessons learned and points of comparison for Alberta in considering how to achieve this important balance. We recommend careful investigation of the successes and challenges of these jurisdictions to fully inform decisions about the RRO in Alberta.

Maxim Power supports the decision of the Government of Alberta to reform and modernize the province's electricity system. Our team is participating fully with government, regulators, industry and stakeholders in the process to invent Alberta's new electricity future.

Please do not hesitate to contact me if our capacity market experience can be helpful to the MSA and / or Minister McCuaig-Boyd. Thank you for the opportunity to provide our thoughts on this matter.

Sincerely,

Kim Karran

Kim Karran
Corporate Secretary
1210, 715 - 5th Avenue S.W.
Calgary, Alberta, Canada T2P 2X6
Phone: 403-263-3021
kkarran@maximpowercorp.com

Dear Mr. Nesbitt,

Re: Options for Enhancing the Design of the Regulated Rate Option

This letter is in response to the Market Surveillance Administrator's (MSA) notice dated April 21, 2017 regarding Options for Enhancing the Design of the Regulated Rate Option (RRO). The Minister of Energy requested that, as part of its options paper, the MSA "identify options that provide for: 'affordability of electricity; predictable and stable rates; and minimized regulatory and administrative costs.'" These comments specifically pertain to that request.

"affordability of electricity" and "minimized regulatory and administrative costs"

First, it is critical for the Minister to recognize that, over the long-term, maximizing the "affordability of electricity" requires charging RRO customers the actual cost of the electricity they consume. In Alberta, this is the Alberta Electric System Operator "Pool" price, also called the "wholesale market" price. The Pool price is the cost to an RRO provider of the electricity consumed by its customers; by extension, charging any other price without a means of true-up creates the possibility of charging RRO customers more or less than the actual cost of the electricity they consume. Consistently "under-charging" RRO customers is obviously unsustainable in the long-run, whereas consistently "over-charging" them raises questions about the value of such an arrangement.

The RRO is governed by the *Regulated Rate Option Regulation* (RROR). Since 2006, the RROR has required RRO providers to base their monthly energy rates on forward market prices rather than wholesale market prices. For Alberta's three major RRO providers – EPCOR Energy Alberta, ENMAX Energy Corporation, and Direct Energy Regulated Services – this "monthly forward market price setting" is conducted per individual Energy Price Setting Plans that are regulated by the Alberta Utilities Commission.

The monthly forward market price setting mandated by the RROR since 2006 has, to-date, resulted in RRO customers paying significantly more for their electricity than its actual cost. In aggregate, for Alberta's three major RRO providers, I estimate that their customers were charged $452 million (2016 dollars) more than the cost of the electricity they consumed over the decade from July 2006 to June 2016 (inclusive). On average, this works out to $5.01/MWh, or approximately $4 million per month across all three providers.[1]

Second, with respect to "minimized regulatory and administrative costs," it is critical for the Minister to recognize that the Pool price is determined in the wholesale market *for free*. By extension, charging RRO customers any other price necessarily results in some incremental administrative and regulatory burden. To illustrate, basing RRO rates on forward market rather than wholesale market prices (as is the current practice) has the following consequences:

1) Forward market price setting is extremely complex, and this complexity is reflected in each RRO provider's Energy Price Setting Plan. Creating and implementing these plans imposes a significant regulatory burden on both intervenors and the Alberta Utilities Commission.

2) It is costly for the RRO providers to carry-out monthly forward market price setting, and these costs are paid by RRO customers through various adders included in the Energy Price Setting Plans.

[1] Nicolaas Jansen, "A Review of Alberta's Default Rate for Electricity," September 13, 2016: http://prism.ucalgary.ca/handle/1880/51721, page 101 (pdf).

3) Charging RRO customers a price that differs from the actual cost of the electricity they consume exposes each RRO provider to financial risk for which they require compensation; this risk is paid for by RRO customers through various adders included in the Energy Price Setting Plans.

For Alberta's three major RRO providers, I estimate that their customers were charged $570 million (2016 dollars) for these costs over the decade from July 2006 to June 2016 (inclusive). On average, this works out to $6.31/MWh, or approximately $5 million per month across all three providers.[2]

Thus, I estimate that the current rate design cost RRO customers approximately $1.022 billion (2016 dollars) over the decade from July 2006 to June 2016 (inclusive). On average, this works out to $11.33/MWh, or approximately $9 million per month across all three providers.[3] This total value includes both the $452 million over-payment relative to the actual cost of the electricity consumed plus the $570 million worth of administrative costs and risks associated with monthly forward market price setting. In other words, all else being equal, RRO customers could have paid approximately $1 billion less for their electricity over the period in question if, instead of having RRO rates based on forward market prices, wholesale market Pool prices were simply "flowed-through" to RRO customers instead.

"predictable and stable rates"

Over the long-run, basing RRO rates on the actual cost of the electricity consumed (i.e. Pool prices) maximizes the "affordability of electricity" and minimizes regulatory and administrative costs. Doing so, however, would not result in particularly "predictable" or "stable" rates. Therefore, it is critical for the Minister to recognize that there is an inherent trade-off between price level and price "volatility." In other words, there is a cost associated with reducing RRO customers' exposure to Pool price fluctuations.

This is especially true with respect to the current rate design, which was chosen, in part, because the government expected it to provide RRO customers with "appropriate protection" from the inherent volatility of the Pool price.[4] Historical data confirms that, relative to monthly forward market price setting, basing RRO rates on monthly Pool prices would have resulted in greater month-to-month fluctuations and a greater propensity for months with many times the average price and therefore expenditure.[5] However, as demonstrated, this "protection" has come at significant cost.

More generally, this kind of arrangement is consistent with that of insurance: RRO customers effectively pay a premium, on average, to mitigate their exposure to the risk associated with spikes in the monthly cost of their electricity. The critical consideration for the government is whether the benefit of such an arrangement exceeds its cost. It is doubtful that this is the case, both in general and with respect to the current rate design, for the following reasons:

1) Survey results show that preferences with respect to volatility vary significantly, but that most Albertans are unwilling to pay a premium to reduce their exposure to it.[6] Given these survey results and consumers' varying preferences, it is not necessarily nor likely true that RRO customers, either individually or in aggregate, receive a net-benefit from an arrangement whereby they pay a premium for protection against volatility.

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[2] Ibid.
[3] Ibid.
[4] Ibid., page 29 (pdf).
[5] Ibid., pages 103 – 108 (pdf).
[6] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012, pages 91 and 92 (pdf).

2) The insurance offered by the RRO has historically not been very good. That is, the retail market has been able to provide better protection from volatility – in the form of fixed price contracts – at lower prices than the RRO.[7,8] Additionally, for each month from July 2015 to April 2017 (inclusive), each major RRO provider's weighted average Base Energy Charge was higher than the weighted average Pool price. In other words, over nearly the past two years, RRO customers paid a significant premium over the cost of the electricity they consumed, despite there not being any spikes in the Pool price from which they required protection.[9]

It could be argued that those RRO customers unwilling to pay a premium to reduce their exposure to price volatility could simply switch to one of the Pool price flow-through products offered in the retail market. The problem with this argument is that it ignores that there are transaction costs associated with switching that, for the average household, could very well exceed the expected savings of doing so. Acquiring information about flow-through products and how they compare to the RRO (both in terms of price level and volatility) takes time and data, and when combined with the actual effort involved with switching may not justify the expected savings, which are small relative to average incomes.[10] Thus, it is entirely possible for an RRO customer to prefer the lowest price regardless of its volatility and yet remain on the RRO.

To reiterate, the Pool price is the cost of electricity in Alberta. Given consumers' preferences, it is not necessarily nor likely true that RRO customers receive a net-benefit from a rate design whereby they pay a premium to reduce their exposure to Pool price volatility. Ultimately, it is also unnecessary for the government to devise such a rate design, since Alberta has a highly competitive retail electricity market that offers all manner of fixed price products to consumers.[11] Therefore, assuming the government wants to maintain the RRO as an option for consumers, it should focus on reducing barriers to switching rather than protecting RRO customers from Pool price volatility. Doing so would further enable RRO customers to protect themselves should they wish to do so.[12]

Respectfully submitted,

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[7] AUC Exhibit 0139.12.UCA-2941, Utilities Consumer Advocate, "Evidence for AUC proceeding #2941," June 4, 2014, page 17 (pdf).
[8] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012, page 162 (pdf).
[9] In aggregate across the three major RRO providers, the average difference between the monthly weighted average Base Energy Charge and the weighted average Pool price over the period in question was $16.19/MWh. On approximately 14 million MWh of forecast actual usage, this price differential works out to an estimated "over-payment" by RRO customers of almost $227 million.
[10] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012, page 372 (pdf).
[11] Donald McFetridge, "Competition in the Alberta Retail Electric Power Market," May 2012, page 35.
[12] The Retail Market Review Committee identified several switching barriers in its 2012 report and provided recommendations on how the government could mitigate each of them.

THE SCHOOL OF PUBLIC POLICY

UNIVERSITY OF CALGARY

MASTER OF PUBLIC POLICY
CAPSTONE PROJECT

A Review of Alberta's Default Rate for Electricity

Submitted by:
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Approved by Supervisor:
Jeffrey Church, September 13, 2016

Submitted in fulfillment of the requirements of PPOL 623 and completion of the requirements for the Master of Public Policy degree

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Acknowledgements

To my friends and family:

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Capstone Executive Summary

This paper is an analysis of the costs and benefits of the government's chosen rate design for the Regulated Rate Option (RRO) post-2006. The historical performance of the monthly forward market price setting used by Alberta's three major RRO providers is evaluated by way of counter-factual analysis; specifically, its costs and benefits relative to monthly Pool price flow-through price setting are estimated over the course of the "New" RRO. This analysis indicates that the government's chosen rate design resulted in a relative cost of approximately $1 billion, with no relative benefits.

Introduction

Since 2001, each electricity distribution system owner in Alberta has been legally required to make available a "default" rate for electricity to its customers. They are known as such because they are the electricity service that Albertans receive by default if they have not explicitly chosen a retailer from whom to buy electricity. The default rate in Alberta, referred in the singular to mean the retail option generally and not any default rate offered by a specific provider, has been formally called the Regulated Rate Option, or "RRO." The history of the RRO can be divided into two periods: the "Old" RRO that existed pre-2006, and the "New" RRO that came into being with the passing of the *Regulated Rate Option Regulation* in 2006.[1] The passing of the *Regulated Rate Option Regulation* reflected a shift in government policy with respect to the default rate's design, and laid the foundation for the "New" RRO that continues to exist to this day.

This paper is a performance review of the government's choice of rate design for the "New" RRO. This rate design, which I have termed "monthly forward market price setting," has been codified in the *Regulated Rate Option Regulation* and executed by Alberta's three major RRO providers – EPCOR Energy Alberta, ENMAX Energy Corporation, and Direct Energy Regulated Services – through "Energy Price Setting Plans." The historical performance of the monthly forward market price setting used by these Energy Price Setting Plans is evaluated by way of counter-factual analysis; specifically, its costs and benefits relative to monthly Pool price flow-through price setting are estimated over the course of the "New" RRO.

[1] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 43 (pdf).

In section 3, the cost of monthly forward market price setting to RRO customers from July, 2006 to June, 2016 is estimated to have been approximately $1 billion more than monthly Pool Price flow-through price setting. In section 4, I argue that monthly forward market price setting provided no conclusive benefits relative to monthly Pool price flow-through price setting. In other words, the government's choice of rate design for the "New" RRO ended up costing RRO customers approximately $1 billion to date, and arguably nothing was gained over simply "flowing-through" wholesale market (Pool) prices to them on a monthly basis.

It should be noted that this paper is only focused on the historical operation and performance of the Energy Price Setting Plans that have determined the "energy" component of each of the three major RRO providers' monthly RRO rates since 2006. It does not discuss the "non-energy" component their RRO rates, which covers all of the functions and costs unrelated to the electricity commodity.[2]

1 The Context

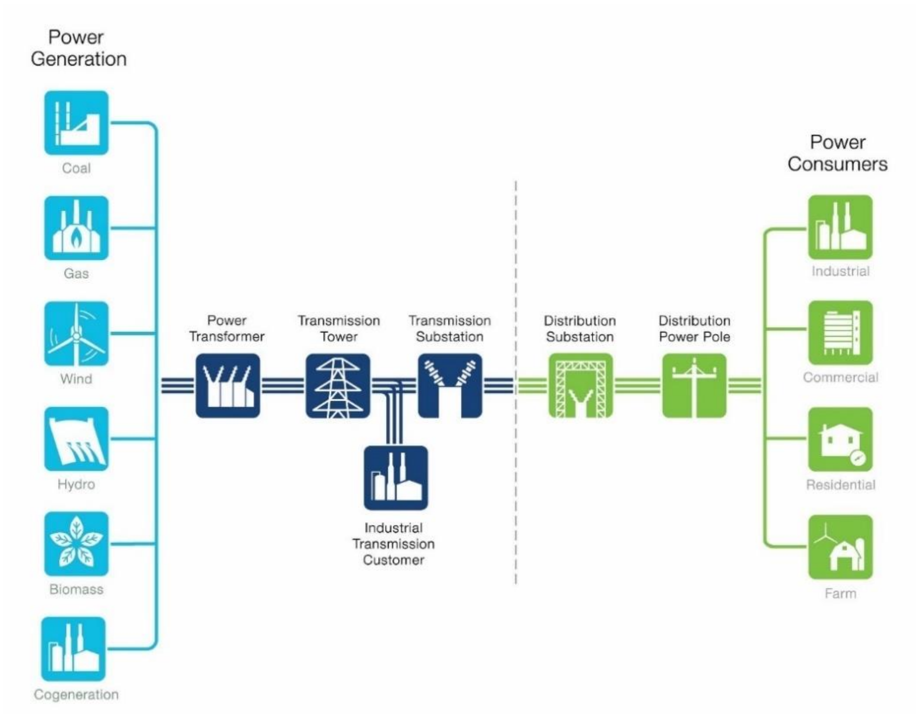
Before the history, operation and performance of the RRO can be examined, a basic understanding of the physical and financial aspects of the exchange of electricity in Alberta is required. This section goes through some basic terminology and concepts that serve as the foundation for the discussion and analysis that follow. It is provided for convenience; if you are already familiar with both the physical flow of electricity and the operation of Alberta's electricity markets, you may safely skip this section and proceed directly to section 2.

[2] Ibid., page 78 (pdf).

1.1 The Physical Exchange of Electricity in Alberta

Most of the electricity produced in Alberta comes from large generating facilities, called "generators" for short. They burn gas or coal to convert water into steam, which drives large turbines that generate electricity. The electricity then travels over long distances on high voltage transmission lines toward end users. Most of this electricity is then transformed to a lower voltage and carried on local distribution systems to homes and businesses for end use.[3,4] Taken together, all of the transmission facilities and distribution systems across Alberta constitute the "Alberta Interconnected Electric System" (AIES), informally known as the "grid."[5] The AIES can be visualized as follows:[6]

Figure 1: The AIES



[3] Ibid., page 27 (pdf).
[4] Some of the electricity is delivered to "direct connect consumers," who draw electricity directly from the transmission system at transmission voltage.
[5] Not including facilities or systems located within the service area of the City of Medicine Hat. See section 1(1)(z) of the Electric Utilities Act: http://www.qp.alberta.ca/documents/Acts/E05P1.pdf.
[6] Image courtesy of the Alberta Electric System Operator.

Upon delivery, electricity usage is measured by the local distribution companies.[7] They are responsible for calculating the hourly consumption of electricity by each of their customers, a process known as "load settlement."[8] At the household and small commercial level electricity consumption is generally measured in kilowatt-hours, or thousands of watt-hours. A watt-hour is a measure of energy usage or production based on the watt, which is a measure of the rate at which something uses or produces electricity.

To illustrate, consider a typical 100-watt household lightbulb. Its 100-watt rating signifies the rate at which it uses electricity. If left on for one hour, this lightbulb would use 100 watt-hours of electricity (100 watts times one hour). Therefore, it is intuitive to understand the watt as measure of capacity – how much electricity something could consume or produce if turned on – and a watt-hour as a measurement of usage or production. When considering large scale electricity production and consumption, it is common to conduct these measurements using more manageable units, such as kilowatts (kW) and megawatts (MW) for measuring capacity, and kilowatt-hours (kWh) and megawatt-hours (MWh) for measuring usage and production. The prefix kilo, like in kilogram, simply means thousand, whereas the prefix mega, like in megabyte, simply means million.

The quantity of electricity demanded in any given moment is known as "load."[9] For example, the lightbulb in the previous example constitutes a load of 100 watts, with an hourly usage of 100 watt-hours. The most commonly used measure of aggregate electricity

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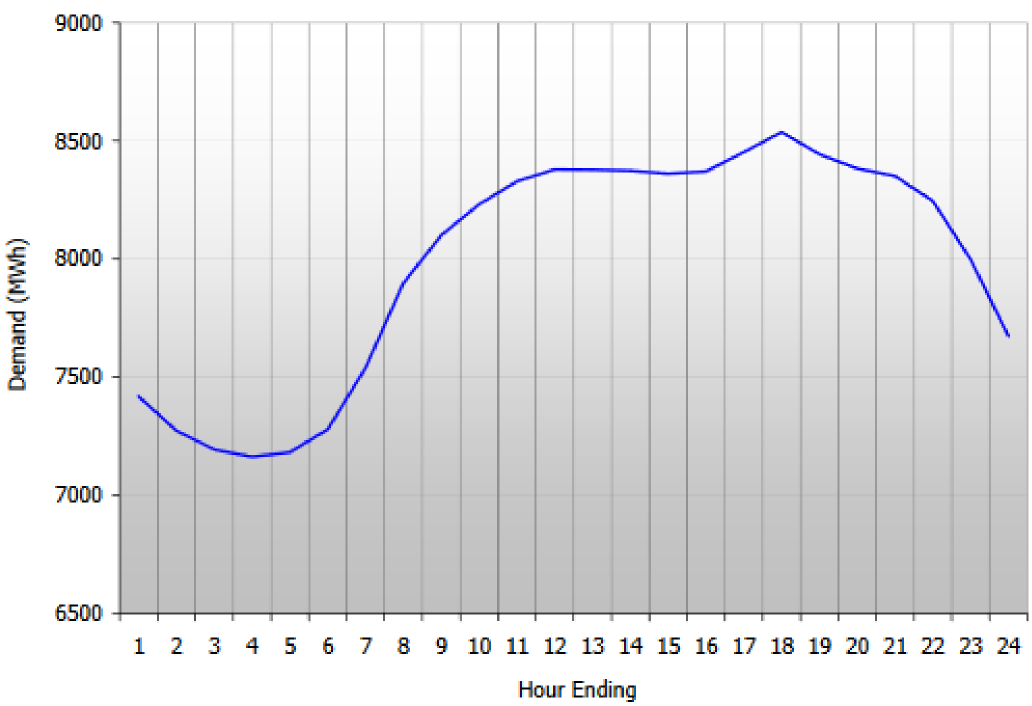
[7] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 30 (pdf).
[8] Ibid., page 55 (pdf).
[9] Ibid., page 186 (pdf).

demand in the province is the "Alberta Internal Load" (AIL).[10] It represents "system load plus load served by on-site generating units."[11] A central feature of this aggregate load is that it fluctuates over time. It is easy to imagine that electricity use throughout the day is not constant; at night people go to bed and electricity use decreases, whereas in the mornings and evenings people are cooking, using appliances, and so on. As a result, Alberta's "load shape" can be visualized with peaks and valleys over the course of a day:[12]

Figure 2: The AIL



In order to maintain grid reliability – e.g. ensure that there are no blackouts or damage to electrical equipment – this aggregate load must be continuously met by

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[10] Alberta Market Surveillance Administrator, "Alberta Wholesale Market: A description of basic structural features undertaken as part of the 2012 State of the Market Report," August 30, 2012: http://albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20Basic%20Structure%20083012.pdf, page 16 (pdf).
[11] Ibid.
[12] Alberta Market Surveillance Administrator, "Alberta Wholesale Electricity Market," September 29, 2010: http://albertamsa.ca/uploads/pdf/Reports/Reports/Alberta%20Wholesale%20Electricity%20Market%20Report%20092910.pdf, page 14 (pdf).

generation.[13,14] In other words, electricity demand must exactly and continuously equal supply. Maintaining this supply-demand balance is the job of the Alberta Electric System Operator (AESO), a not-for-profit, government created, independent system operator. The AESO balances demand and supply in real-time by directing generators to provide or remove a specific amount of electricity from the grid, a process known as "dispatch."[15]

1.2 The Financial Exchange of Electricity in Alberta

The previous section covers basic concepts and terminology pertaining to the *physical* exchange of electricity in Alberta. This section covers the *financial* exchange of electricity in Alberta: who pays, how much, and to whom. There are several markets in which electricity related transactions are organized; for this paper the relevant ones are the "wholesale," "retail," and "forward" markets. This section provides a brief, high-level discussion of each of these markets individually.

1.2.1 The Wholesale Market

All of the electricity dispatched by the AESO to meet the AIL is transacted through the wholesale market, formally known as the AESO "Power Pool," or just "Pool" for short.[16] Generators over a certain size are legally obligated to offer their capacity to the AESO for

[13] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 35 (pdf).

[14] The physics behind this balancing act are excellently explained here: Grant Kent Freudenthaler, "The Implications of Uniform Pricing in Restructured Electricity Wholesale Markets: Evidence from Alberta," April, 2016: http://theses.ucalgary.ca/bitstream/11023/2921/1/ucalgary_2016_freudenthaler_grant.pdf, page 22 (pdf).

[15] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 185 (pdf).

[16] Alberta Market Surveillance Administrator, "Alberta Wholesale Electricity Market," September 29, 2010: http://albertamsa.ca/uploads/pdf/Reports/Reports/Alberta%20Wholesale%20Electricity%20Market%20Report%20092910.pdf, page 5 (pdf).

dispatch through the Pool.[17] They offer their capacity in "blocks" of generation that may be priced anywhere between $0/MWh and $999.99/MWh.[18] The AESO then dispatches generation based on its economic merit; meaning that it dispatches generation from lowest to highest offer until supply-demand balance is achieved. The price of the last block of generation that is dispatched to meet demand sets the "System Marginal Price," (SMP) which "will change through the hour as dispatches are required to changes in the supply demand balance."[19]

To illustrate, imagine a generator with a capacity of 320 MW. It may want to avoid being dispatched off entirely to avoid the costs of having start back up, so it offers half of its capacity at $0/MWh to ensure that it at least continues to stably operate. It then offers one block of 150 MW for $10/MWh, and a second block of the remaining 20 MW for $300/MWh, as follows:[20]

Table 1: Offer Blocks from a Hypothetical Generator

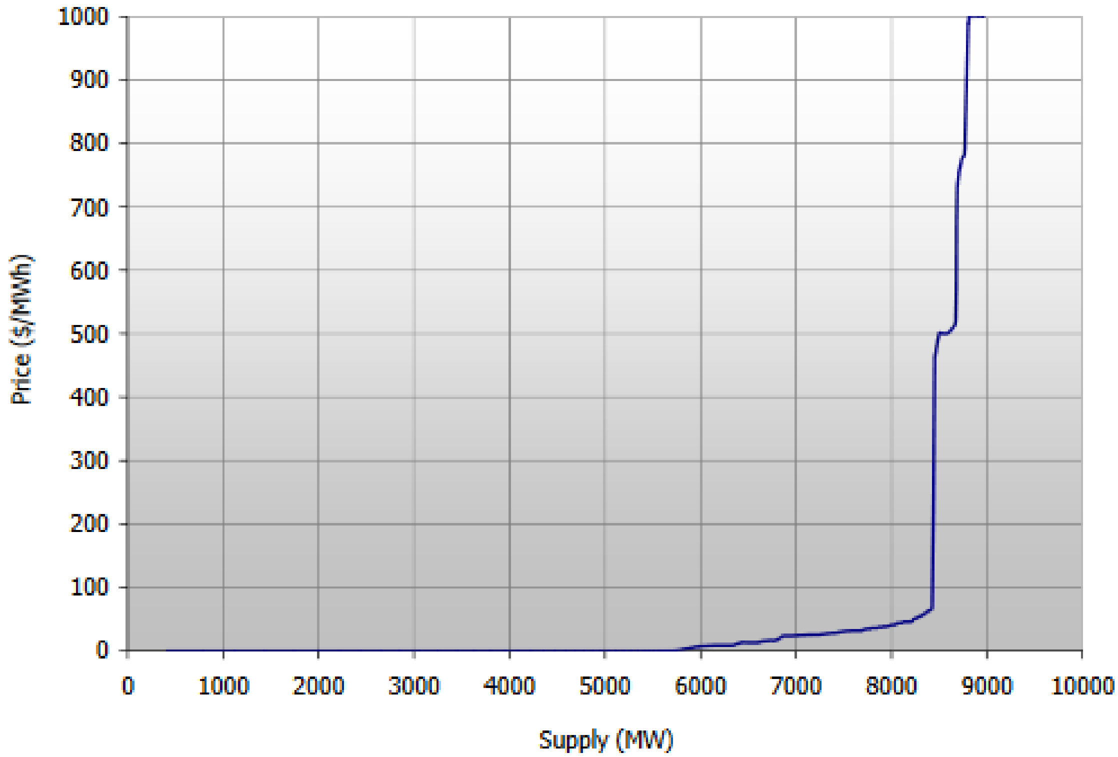
Block	Capacity (MW)	Price ($/MWh)
0	150	0
1	150	10
2	20	300

If this was the only generator in the market and demand was 300 MW or greater, the SMP would be $300/MWh; if demand was between 150 and 300 MW the SMP would be $10/MWh, and if demand was between 0 and 150 MW the SMP would be $0/MWh. There is, however, more than just one generator in the Alberta wholesale market. As of 2015, there are 45 companies owning generation that are in competition with each other to

[17] Ibid., page 9 (pdf).
[18] Ibid., page 10 (pdf).
[19] Ibid., page 11 (pdf).
[20] Ibid., page 10 (pdf).

provide electricity to the AESO.[21] Their offers, when aggregated, constitute the wholesale market supply curve, also known as the "merit order." It contains all of the available offers from lowest to highest price, and typically appears as follows:[22]

Figure 3: The Merit Order



As can be seen, the merit order typically has a sharp upwards kink after most of the available capacity has been dispatched. For example, with the above merit order, a demand of 8,500 MW would result in a SMP of roughly $500/MWh, whereas a demand of just 500 MW less than that would result in a SMP of only between $50 and $100/MWh. A discussion of this this phenomenon and its causes is strictly outside the scope of this paper; however,

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[21] Alberta Market Surveillance Administrator, "Market Share Offer Control 2015," June 30, 2015: http://albertamsa.ca/uploads/pdf/Archive/000-2015/2015-06-30%20Market%20Share%20Offer%20Control%202015.pdf, pages 4 and 5 (pdf).

[22] Alberta Market Surveillance Administrator, "Alberta Wholesale Electricity Market," September 29, 2010: http://albertamsa.ca/uploads/pdf/Reports/Reports/Alberta%20Wholesale%20Electricity%20Market%20Report%20092910.pdf, page 19 (pdf).

the Alberta Market Surveillance Administrator (MSA) has published numerous resources that discuss generator offer behavior.

The AESO "Pool price" is the time weighted average SMP for each hour.[23] It is the "wholesale settlement price," and therefore the cost of consuming electricity in any given hour is the prevailing Pool price (in $/MWh) multiplied by the amount of electricity consumed in that hour (in MWh).[24] In other words, the wholesale market "settles" hourly, such that consumption in any given hour is billed at the Pool price in that hour. These payments from load to the AESO are then forwarded to generators to compensate them for their production.[25]

1.2.2 The Retail Market

With the exception of large industrial and commercial consumers, most Albertans buy electricity in the retail market.[26] As of 2016, this market has 33 retailers that compete to sell electricity to customers.[27] This competition allows people to choose which retailer they buy electricity from, and thereby provides some freedom of choice over price, terms and other services they may wish to receive.[28] When thinking about the retail electricity

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[23] Alberta Market Surveillance Administrator, "Alberta Wholesale Market: A description of basic structural features undertaken as part of the 2012 State of the Market Report," August 30, 2012: http://albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20Basic%20Structure%20083012.pdf, page 9 (pdf).

[24] Alberta Market Surveillance Administrator, "Alberta Wholesale Electricity Market," September 29, 2010: http://albertamsa.ca/uploads/pdf/Reports/Reports/Alberta%20Wholesale%20Electricity%20Market%20Report%20092910.pdf, page 11 (pdf).

[25] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 56 (pdf).

[26] Ibid., page 17 (pdf).

[27] Utilities Consumer Advocate, http://ucahelps.alberta.ca/retailers.aspx.

[28] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 22 (pdf).

market, it is helpful to think of it like the cellphone market. As explained by the Retail Market Review Committee (RMRC):[29]

> Since 2001, Albertans have had the power to choose the company they'll buy their power from. The place they buy it—whether they are aware—is the retail market. It's not a market with stalls and stores and products that people can smell and touch. It's more like the cellphone market, where consumers need to check out their options, do their research and sign up. When Albertans choose an electricity retailer, power still comes to them in the same way. It's still as safe and reliable as before… And if they don't like the choice they've made, they can change companies and find themselves a better deal.

The retail market is known as such because it involves retailers buying electricity at wholesale – from the AESO at prevailing Pool prices – and reselling it at their choice of price, along with whatever other value added services they may wish to offer.[30] As explained by the RMRC in the provided quote, a customer's choice of who to buy electricity from in no way changes its physical delivery over the AIES; every electron is still generated by the same generators and travels over the same wires. It also does not change the cost of the actual electricity itself, which is always the Pool price.

Therefore, retailers really sell a financial *service*, in so far as they buy the electricity their customers need from the AESO at prevailing Pool prices, coordinate load settlement data with distribution companies for the purposes of monthly billing, and ultimately collect

[29] Ibid., page 17 (pdf).

[30] Keep in mind, of course, that retailers "buy" electricity from the AESO in the sense that the electricity flows to their customers over the AIES instantaneously and on demand, and the cost of that electricity is owed by retailers to the AESO. Similarly, the retailers "resell" the electricity in the sense that they arrange for and collect payment from customers for it at a contracted price.

payment.[31] They also provide supplementary customer services, such as flexible payment dates, long-term fixed prices, and discounted bundles for electricity and natural gas.[32]

Every month, retailers receive two invoices on behalf of their customers for which they must collect payment: one from the AESO and one from the local distribution company.[33] The load settlement data collected by the distribution company and forwarded to the AESO is used to calculate the cost of the electricity used by retail customers (remember, this is their usage at prevailing Pool prices). This amount is owed by the retailer to the AESO for the actual electricity that was consumed.[34] As previously explained, the AESO then forwards this money to generators to pay them for their production.

The distribution system owner invoices the retailer for their customer-specific transmission and distribution system costs. The distribution system costs are owed by the retailer to the distribution company, whereas the transmissions costs are ultimately owed to the AESO. Upon payment from retailers, the distribution company forwards the payment for transmission costs to the AESO, and the AESO then forwards this money to the transmission facility owners to pay them for their transmission facilities.[35]

1.2.3 The Forward Market

The forward financial market, or just the "forward market" for short, involves transactions that are "Contracts for Difference" (CFDs), informally known as "hedges,"

[31] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 53 (pdf).
[32] Ibid., page 50 (pdf).
[33] Ibid., page 56 (pdf).
[34] Ibid.
[35] Ibid.

"swaps," or "forwards."[36] These CFDs specify a "volume," usually in MW, for which the "seller" agrees to pay the "buyer" the hourly Pool price over the time period specified in the contract. In exchange, the "buyer" agrees to pay the fixed price specified in the contract for the same time period.[37] To be clear, there is absolutely no physical delivery (i.e. consumption or production) of actual electricity involved in the contract; it is strictly a financial arrangement whose underlying commodity is Alberta electricity.

To illustrate, imagine Jane and Bob, who decide to enter into a CFD with each other where Jane is the seller and Bob is the buyer. Their particular CFD has a contract price of $50/MWh and a volume of 10 MW, with a term of one hour. Suppose the Pool price for the hour in question materializes as $60/MWh. In this case, Jane must pay Bob $60/MWh over 10 MWh, which equates to $600. Bob, on the other hand, must pay Jane $50/MWh over 10 MWh, which equates to $500. As a result of the CFD Bob earns a profit $100. One caveat to this example is that standard CFDs that are readily available in the forward market are not solely for one hour; they typically have longer "terms" of a month or several months (this is discussed later on). This increased length of time does not change the basic math – the CFDs, just like the wholesale market, still settle every hour – so calculating who owes who what just requires summing up the results from each individual hour.

Again, note that Bob neither actually buys any electricity nor does Jane actually sell him any; they just made a financial arrangement – which in this case really just means a bet – on what the Pool price was going to be for the hour specified in their contract. In this case, Bob won the bet because he is the buyer; in trader jargon he took a "long position" (or

[36] Alberta Market Surveillance Administrator, "An Introduction to Alberta's Financial Electricity Market," April 9, 2011: http://www.albertamsa.ca/files/Financial_Electricity_Market.pdf, page 6 (pdf).
[37] Ibid.

simply “went long”) and benefited from the Pool price ending up higher than the contract price. Jane, as the seller, took a “short position” (or simply “went short”) and lost because the Pool price ended up higher than the contract price.

In the real material world this example is extremely intuitive: if you buy a house you have effectively gone “long” on real-estate. If you pay $250,000 for that house and then sell it a year later for $300,000 you will have made a profit of $50,000. Because you are long real-estate, you benefit when the price of real-estate increases. Conversely, if you own real-estate and you sell it for less than you paid for it, you suffer a loss. To simplify even further, “going long” can be thought of as “betting for” something, whereas “going short” can be thought of as “betting against” something.

In Bob’s case, the CFD makes it as if he had bought the electricity from Jane for $50/MWh and was re-selling it for $60/MWh, resulting in a profit of $10/MWh. Of course, he never actually bought nor sold any electricity, the CFD is just a financial arrangement that makes it as if he had. The opposite is true for Jane; the CFD makes it as if she was selling the electricity to Bob for $50/MWh, despite having paid $60/MWh for it, thereby resulting in a loss of $10/MWh. Of course, Bob and Jane’s fortunes could easily be reversed if the Pool price was less than $50/MWh.

In the example of Jane and Bob, it was assumed that neither party had an underlying “volumetric positon.” That is to say that neither of them had generation or load that would make them inherently long or short, respectively. For example, a generation owner is inherently long to the Pool price, since they benefit when it increases, all else being equal, because they get paid more by the AESO for each MWh they produce. A retailer or load owner, on the other hand, is inherently short to the Pool price, since they benefit when it decreases, all else being equal, because they pay less to the AESO for each MWh they consume.

When parties do not have an underlying volumetric positon, they are necessarily "speculating" on the Pool price by entering into a CFD. This is because they are taking on a volumetric position, either long or short, and therefore are effectively speculating that future Pool prices will make it profitable.[38] As illustrated, the outcome for each party when speculating entirely depends on whether the Pool price ends up being higher or lower than the contract price. For convenience, these potential outcomes are summarized as follows:[39]

Table 2: Volumetric Position Outcomes

	Outcome	
Volumetric Position	**Pool price is HIGHER than the contract price**	**Pool price is LOWER than the contract price**
Long	Profit	Loss
Short	Loss	Profit

However, when parties do have an underlying volumetric position and they enter into a CFD that reduces it (i.e. the extent to which they are either long or short) then they are no longer speculating, but instead "hedging." For example, imagine a generator that produces quantity "q" in any given hour, for which it is naturally paid the Pool price. Now suppose the generator sells a CFD with the same volume, for which it receives a fixed price from the buyer in exchange for paying the buyer Pool price. The net effect is that the generator is simply left receiving the contract price for quantity "q;" an arrangement from which it profits so long as the Pool price is less than the contract price. In other words,

[38] Ibid., page 8 (pdf).
[39] This table is adapted from: AUC Exhibit 0277.02.UCA-2941, Utilities Consumer Advocate, "Argument," November 17, 2014, para. 20, page 6 (pdf).

selling a CFD causes the generator to lock in a certain amount of volume at a predetermined price, and therefore protects revenue and increases the certainty of cash flows.[40]

In the same way that CFDs allow generators to lock in revenue, they also allow loads to lock in costs. Remember, loads must purchase electricity from the AESO at prevailing Pool prices, which makes them inherently short. For example, consider an industrial load that buys electricity as an input in its production. As the Pool price increases, its profits decrease, all else being equal. Buying a CFD serves to "lengthen" the load's overall volumetric position – and just like with the generator – locks in a certain amount of volume at a predetermined price. This reduces the risk posed by spikes in the Pool price and provides a level of cost certainty. For example, imagine a factory that consumes quantity "q" in any given hour, for which it naturally pays the Pool price. Now suppose the factory buys a CFD with the same volume, for which it receives Pool price from the seller in exchange for paying the seller the fixed contract price. The net effect is that the factory is simply left paying the contract price for quantity "q;" an arrangement from which it profits so long as the Pool price is greater than the contract price.[41]

The point is that speculating is distinguished from hedging based on the effective outcome of engaging in the CFD: speculating creates a volumetric position that is "exposed" to the Pool price, whereas hedging reduces an existing volumetric position that is exposed to the Pool price. Because CFDs do not involve the actual delivery of electricity, participation in the forward market is not limited to just consumers and producers. In

[40] Alberta Market Surveillance Administrator, "An Introduction to Alberta's Financial Electricity Market," April 9, 2011: http://www.albertamsa.ca/files/Financial_Electricity_Market.pdf, page 9 (pdf).
[41] Ibid., page 14 (pdf).

addition to generators and loads, there are also power marketers (e.g. retailers) and proprietary traders (e.g. banks, hedge funds, and other financial institutions) that buy and sell CFDs in the forward market.[42] There are two ways in which these forward market participants transact CFDs: on the Natural Gas Exchange (NGX) and Over-the-Counter (OTC).[43]

The NGX is an "electronic trading platform that also provides central counterparty clearing and data services to the North American natural gas and electricity markets."[44] Trading on the NGX is done anonymously and transparently, but requires sufficient collateral (i.e. credit) to be posted to cover the value of a participant's volumetric positon.[45] When transacting on the NGX, participants will post bids if they wish to buy and offers if they wish to sell, with transacted contract prices being determined by market forces on the exchange. Transacting OTC, on the other hand, simply means having buyers and sellers transacting with each other directly or doing so through a broker. This could be potentially risky if the parties do not provide any collateral and default on the contract, or if they simply decide to renege on the contract in the event Pool prices do not turn out in their favor.[46]

CFDs traded on the NGX and OTC vary by both "term" and "type." The "term" of a contract simply refers to the time period for which it applies (i.e. over which the buyer and seller agree to pay each other).[47] For example, a CFD can be for a specific day, month, quarter, or even year. The "type" of a CFD refers to the specific hours over the "term" to

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[42] Ibid., pages 15 and 16 (pdf).
[43] Ibid., page 9 (pdf).
[44] Ibid.
[45] Ibid.
[46] Ibid., page 10 (pdf).
[47] Ibid., page 24 (pdf).

which the CFD applies.[48] For example, a CFD can apply to every hour of every day (known as a "Flat" contract); or, it can only apply to certain hours of certain days. For example, a "Peak" CFD only applies for the hours of 8:00 through 23:00, Monday through Saturday, excluding Sundays and holidays.

The three factors that generally influence the price of a CFD (i.e. the fixed $/MWh stipulated by the contract) are its type, term and when it is transacted prior to the term. Different types of CFDs provide volumetric positions for different times of the day over different days of the week, and are therefore priced differently on that basis. For example, because of their difference in coverage, Peak CFDs necessarily have higher prices than Flat CFDs for the same term.[49]

With respect to term, CFD prices depend on expected wholesale prices.[50] Wholesale prices, in turn, are driven by a number of factors, including supply and demand conditions that depend on the weather, population, planned generator outages, and transmission constraints.[51] These factors are variable over time and can be term specific; for example, the weather for July is typically very different from the weather in March. Therefore, the prices of CFDs with different terms will generally reflect the different expectations of wholesale market conditions and therefore Pool prices upon which they are based.

Finally, two CFDs of the same type for the same term can also have different prices depending on when they are transacted, since prices generally adjust as new information

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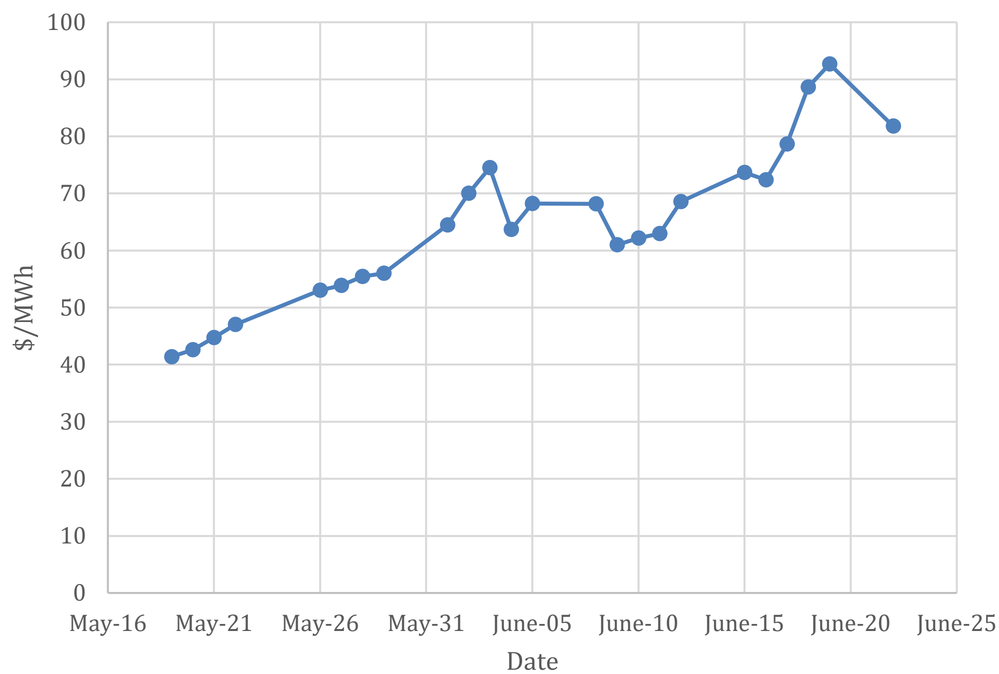
[48] Ibid., page 28 (pdf).
[49] AUC Exhibit 0139.02.UCA-2941, Utilities Consumer Advocate, "Evidence of Jason Beblow," June 4, 2014, page 24 (pdf).
[50] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 83 (pdf).
[51] Ibid.

pertaining to wholesale market conditions for the term in question becomes available to forward market participants.[52] To illustrate, the following graph shows the prices of Flat CFDs traded on NGX for the month of July, 2015:[53]

Figure 4: CFD Prices in Advance of Month



As can be seen, the prices for Flat CFDs fluctuated significantly in the two months preceding July, 2015. They started around $40/MWh in mid-May and roughly doubled in price by the end of June. Price fluctuations like this in advance of the term in question are normal; buyers and sellers adjust their expectations as the term draws more near and more information about wholesale market conditions becomes available.[54]

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[52] AUC Exhibit 0277.02.UCA-2941, Utilities Consumer Advocate, "Argument," November 17, 2014, para. 232, page 67 (pdf).

[53] This graph actually shows the NGX Alberta Flat Electricity RRO Index for the month of July, 2015. Technically, it does not show the "prices" of transacted Flat CFDs *per se*, but is rather a complex weighted average of trading activity for that product on the NGX, including bid and offer activity. It is shown here for illustrative, indicative purposes only. For a complete explanation of how it is calculated, please see: http://www.ngx.com/pdf/NGX%20Index%20Methodology.pdf.

[54] AUC Exhibit 0277.02.UCA-2941, Utilities Consumer Advocate, "Argument," November 17, 2014, para. 232, page 67 (pdf).

For example, it could have been possible that in mid-May, 2015, there were no generator outages scheduled for the month of July, thereby leading to expectations of surplus supply and low Pool prices. However, perhaps by mid-June the AESO had posted several generator outages, thereby leading to revised expectations of low supply and high Pool prices. Ultimately, the forward market is one big guessing game, where participants' guesses are only as good as the information they have at their disposal.

This discussion of the Alberta forward electricity market has admittedly been complicated, so for convenience here is a recap of the important points:

- The forward market essentially involves parties betting on what Pool prices are going to be in the future.
- These parties – which include retailers, generators, hedge funds, etc. – engage in these bets by exchanging financial instruments called Contracts for Difference (CFDs), also informally knowns as "swaps," "hedges" or "forwards." These bets are made for two reasons: either to "hedge" a pre-existing position or to "speculate" by creating a position.
- There are two common means by which parties transact CFDs in the Alberta forward electricity market: either over the Natural Gas Exchange (NGX) trading platform or Over-the-Counter (OTC).
- The CFDs transacted in the forward market vary by their "term" and "type." All else being equal, two CFDs of a given type will likely have different prices depending on their term; likewise, two CFDs of a given term will likely have different prices depending on their type.

- CFDs of a given term and type generally fluctuate in price in advance of the term in question in response to changing expectations of wholesale market conditions.

2 Alberta's Default Rate for Electricity

As explained in section 1.1, electric distribution systems transform the power from transmission lines to lower voltages and carry it to end users. Section 103(1) of the *Electric Utilities Act* (EUA), SA 2003, c E-5.1, mandates that each owner of an electric distribution system, of which there are many throughout Alberta, must make available a "default rate" for electricity to its customers.[55,56] In Alberta, these default rates are interchangeably called the Regulated Rate Tariff (RRT) or Regulated Rate Option (RRO). They are known as "default rates" because they are the electricity service Albertans receive by default if they have not explicitly chosen a retailer from whom to buy electricity.[57]

The default rate in Alberta, referred in the singular to mean the retail option generally and not any default rate offered by a specific provider, originated in 2001 with the creation of the retail electricity market. Since then, its history can be divided into two periods: the "Old" RRO that existed pre-2006, and the "New" RRO that came into being with the passing of the *Regulated Rate Option Regulation* in 2006. The passing of the *Regulated Rate Option Regulation* reflected a major shift in government policy with respect to the default rate's design, and laid the foundation for the "New" RRO rate that continues to exist to this day. Section 2.1 discusses the "Old" RRO that existed pre-2006; it is essentially a

[55] Electric Utilities Act, SA 2003, c E-5.1, < http://canlii.ca/t/827s> retrieved on 2015-11-17.
[56] Section 103(1): "Each owner of an electric distribution system must prepare a regulated rate tariff for the purpose of recovering the prudent costs of providing electricity services to eligible customers."
[57] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 7 (pdf).

brief and broad history lesson. Section 2.2 then specifically focuses on the post-2006 default rates of Alberta's three major RRO providers: EPCOR Energy Alberta, ENMAX Energy Corporation, and Direct Energy Regulated Services.

2.1 Pre-2006: The "Old" RRO

In 1998, the *Electric Utilities Act* (EUA) was amended to allow electricity customers the right to choose who to buy their electricity from, thereby leading to the creation of the retail electricity market in 2001.[58] After the retail market was created, the government deemed it necessary to provide both customers and retailers with a "transitional period," which would allow customers time to gradually switch to new retailers and in turn provide retailers time to "implement internal systems, marketing plans, and create new products and services."[59] To facilitate this transitional period the government included provisions in the 1998 EUA amendment mandating that local distribution companies provide their customers with a temporary regulated default rate.[60,61] Customers who consumed less than 250,000 KWh were to be allowed to stay on the default rate for up to five years, until the end of 2005, whereas customers who consumed more than that amount were only to be allowed to stay on the default rate for up to three years, until the end of 2003.[62]

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[58] Ibid., page 22 (pdf).

[59] Alberta Department of Energy, "Retail Market Review: An Update and Review of Market Metrics," April 15, 2010: http://www.energy.alberta.ca/electricity/pdfs/retailmarketreview.pdf, page 6 (pdf).

[60] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 22 (pdf).

[61] A "rate" in this case has two meanings, one being "an option for customers in the retail market," and the second being "the price paid for electricity." Therefore, "default rate" can be interpreted as both "the default price for electricity" and "the default option for customers in the retail market." In this case it is really a distinction without a difference, since the "price" essentially is the "option."

[62] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 43 (pdf).

The government's rationale for mandating the creation of the default rate was that it would allow customers to remain with their existing electricity provider at a regulated price without any forced changed in service. According to the government, the default rate was "intended to be a last resort rate and was necessary to provide time for market participants to make decisions and to ensure that all Albertans would receive electricity during the transition period."[63] However, it quickly became apparent that customers were switching off of the default rate to competitive retailers to a lesser extent than anticipated. This was largely due to the fact that, prior to 2006, the default rate was based on long-term forward market prices, and only changed on a quarterly basis. Given the stability of the default rate and the state of the retail market at the time, the default rate became the "preferred option for most customers."[64]

The government subsequently came to understand two things, the first being that, given the extreme lack of switching that had occurred up to that point, it could not simply discontinue the default rate come 2006 without reprisal from consumers (who are also voters); the second being that, in order to incent people to switch to competitive retailers, it would have to redesign the default rate. These two realizations led the government to extend and redesign the default rate by passing the *Regulated Default Supply* (RDS) *Regulation* in 2003.[65] This regulation mandated that starting July 1, 2006, the default rate would be based on the Pool price instead of forward market hedges, which was deemed a "simple to implement" and "pure market" approach.[66] However, the government quickly

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[63] Ibid.
[64] Alberta Department of Energy, "Retail Market Review: An Update and Review of Market Metrics," April 15, 2010: http://www.energy.alberta.ca/electricity/pdfs/retailmarketreview.pdf, page 6 (pdf).
[65] Ibid., page 7 (pdf).
[66] Ibid.

repealed the RDS Regulation before it could take effect over concerns that a) basing the default rate on Pool price would be too "volatile," and b) it would be impossible for customers to know the price of electricity before the month in which they consumed it.[67,68,69]

Subsequent to the failure of the RDS Regulation, the government began working with stakeholders in 2004 to develop a default rate that would "allow customers to know and respond to market prices for electricity."[70] The government's 2005 Electricity Policy Framework paper (the "Framework paper," for short) subsequently laid out its vision for the future of the default rate in Alberta. The "New" default rate would be called the "Regulated Rate Option," and its design would be governed by "two overriding objectives:"[71]

1) Appropriate protection; and,
2) Retail market development

With respect to the first objective, the government laid out "five key dimensions" that it thought necessary to ensure "appropriate consumer protection," three of which related to rate design:[72]

- "Moderation of Price Fluctuations;"
- "Gradual Introduction of a New RRO; and,"

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[67] Ibid.
[68] Ibid., page 21 (pdf).
[69] Alberta Department of Energy, "Alberta's Electricity Policy Framework," June 6, 2005: http://www.energy.alberta.ca/Electricity/pdfs/AlbertaElecFrameworkPaperJune.pdf, page 54 (pdf).
[70] Alberta Department of Energy, "Retail Market Review: An Update and Review of Market Metrics," April 15, 2010: http://www.energy.alberta.ca/electricity/pdfs/retailmarketreview.pdf, page 7 (pdf).
[71] Ibid, page 29 (pdf).
[72] Alberta Department of Energy, "Alberta's Electricity Policy Framework," June 6, 2005: http://www.energy.alberta.ca/Electricity/pdfs/AlbertaElecFrameworkPaperJune.pdf, page 18 (pdf).

- "No Unacceptable Economic Impact in Moving from One Regulated Rate Design to Another."

The second objective, retail market development, related to having an RRO that facilitated the entry of unregulated (called "competitive") retailers into the retail market, and having RRO customers switch to those retailers.

Intuitively, it is clear that these two objectives are naturally in competition with each other. Designing a default rate that provides RRO customers with too much "protection" will not give them much reason to switch to a competitive retailer. This is an observation that the MSA has made in the past:

> The combination of low energy costs and the presence of a competitively priced RRO/DRT may leave very little incentive for customers to switch, especially if they are exposed to relatively low volatility.[73]

Seemingly understanding this inherent trade-off in achieving its objectives, the government explained in its Framework paper that the "New" RRO would have to "give consumers a practical understanding of the <u>appropriate</u> price of electricity,"[74] provide small consumers with "<u>some</u> degree of price protection,"[75] and "protect consumers from <u>too much</u> exposure to spot price variability"[76] [emphasis added]. Given such statements, it appears as though the government was pursuing a "Goldilocks" approach to rate design, whereby it believed that the default rate would need to be sufficiently "volatile" to incent customers to switch but not so "volatile" as to upset them. According to the Alberta Utilities

[73] Alberta Utilities Commission, "Regulated Retail Energy Harmonization Inquiry," March 25, 2011, Proceeding #567, page 84 (pdf).
[74] Alberta Department of Energy, "Alberta's Electricity Policy Framework," June 6, 2005: http://www.energy.alberta.ca/Electricity/pdfs/AlbertaElecFrameworkPaperJune.pdf, page 15 (pdf).
[75] Ibid., page 17 (pdf).
[76] Ibid., page 18 (pdf).

Consumer Advocate (UCA), it was through “the introduction of price volatility” that the government intended to facilitate retail market development.[77]

After comparing six different rate design options, including Pool price flow-through price setting, the government concluded that having the “New” RRO transition to being based on “monthly forward market prices” would be the most conducive to meeting its two objectives.[78] In its own words:

> Having considered a range of options and experiences elsewhere, and given the fundamental objectives set out in Section 3.3 above, the Department recommends that the small consumer market have the benefit of a transitional RRO rate design under which such consumers are gradually transitioned to a New RRO based on a monthly forward hedge during the 2005 to 2010 period.[79]

Additionally, the government also cited the following “advantages” of this method of price setting:

- It would allow customers to “see prices in advance of their consumption,”[80] thereby allowing them “to some extent, adjust their energy consumption and purchasing patterns;”[81] and,
- Basing the price of the RRO on monthly forward market prices, the same methodology used to price the default gas rate, would “make it easier for

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[77] AUC Exhibit 0277.02.UCA-2941, Utilities Consumer Advocate, “Argument,” November 17, 2014, para. 354, page 169 (pdf).
[78] Alberta Department of Energy, “Alberta’s Electricity Policy Framework,” June 6, 2005: http://www.energy.alberta.ca/Electricity/pdfs/AlbertaElecFrameworkPaperJune.pdf, page 54 (pdf).
[79] Ibid., page 15 (pdf).
[80] Ibid., page 17 (pdf).
[81] Ibid.

> consumers to understand and compare natural gas and electricity bills, and for retailers to explain, market and sell bundled energy products."[82]

The government's policy for the "New" RRO was enacted with the 2005 *Regulated Rate Option Regulation* (RROR), which came into effect on July 1, 2006.[83]

2.2 Post-2006: The "New" RRO

The passing of the RROR codified the government's new legal framework for "monthly forward market price setting" – how the monthly RRO Energy Charge paid by customers is determined based on month-to-month forward market prices – that for the most part continues to exist to do this day. As explained in the previous section, this framework was created by the government so that RRO rates would change every month and be based on monthly forward market prices, rather than only changing quarterly and being based on long-term forward market prices. However, the RROR has never been specific to the level of actually prescribing a methodology for *how* monthly forward market price setting should be conducted, and has rather left the details to be proposed by each distribution system owner in an Energy Price Setting Plan (EPSP). It has then been up to each owner's regulatory authority to decide whether the EPSP submitted to it for approval is formulated such that it sets monthly RRO Energy Charges in accordance with the provisions of the RROR.

Regulatory authority for approving RRO rates has resided with the Alberta Utilities Commission (AUC), and prior to 2008, with its predecessor the Alberta Energy and Utilities

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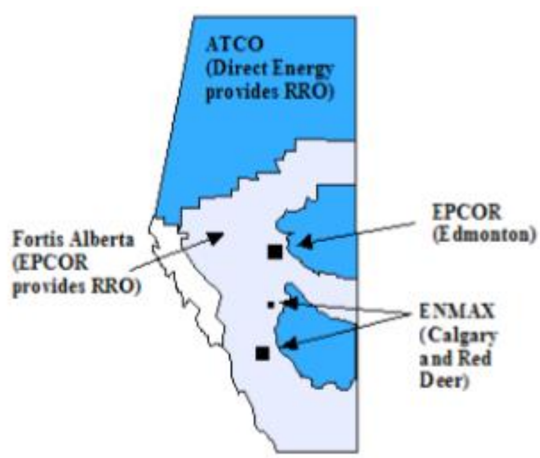
[82] Ibid.

[83] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 43 (pdf).

Board (AEUB). However, municipalities and rural electrification associations that offer an RRO and do not have an affiliate retailer operating outside of their service areas may essentially self-regulate. That is, instead of being approved by the AUC/AEUB, their RRO rates have been approved by their city councils and boards of directors, respectively.[84] As a result, only three RRO providers have had EPSPs regulated by the AUC/AEUB under the RROR: EPCOR Energy Alberta (EEA), ENMAX Energy Corporation (EEC), and Direct Energy Regulated Services (DERS).[85]

EEA is a subsidiary of Edmonton owned EPCOR Utilities Inc., EEC is a subsidiary of Calgary owned ENMAX Corp., and DERS is a subsidiary of investor owned Direct Energy Marketing Ltd. EEA's RRO is offered in the City of Edmonton and FortisAlberta service areas, EEC's RRO is offered in the City of Calgary and surrounding area, and DERS' RRO is offered in the Atco service area.[86] The following map provides some sense of their service areas:[87]

Figure 5: RRO Provider Service Areas



[84] Ibid.
[85] Ibid.
[86] Ibid.
[87] Alberta Department of Energy, "Regulated Rate Option Fact Sheet," June 2010: http://www.energy.alberta.ca/Electricity/pdfs/FactSheet_Electricity_RRO.pdf, page 2 (pdf).

As can be seen, these three RRO providers (herewith referred to as “the” RRO providers) serve most of Alberta in terms of geography. For the year of 2014, a summary of their vital statistics is as follows:[88]

Table 3: RRO Provider Summary Statistics

	EEA	EEC	DERS	Total
Sites - average (RRT Total)[89]	575,245	195,113	134,476	904,834
Energy sales (MWh)	5,085,308	1,584,095	1,332,252	8,001,655
Sites as proportion of total (RRO only)[90]	60%	20%	14%	95%
Sites as proportion of total (province)[91]	34%	12%	8%	54%
Energy as proportion of total[92]	9%	3%	2%	14%

Together, they serve roughly 95% of total RRO sites in the province (a “site” generally referring to a customer with a meter installation), with EEA alone serving roughly 60%; three times as much as EEC and four times as much as DERS. Because EEA, EEC and DERS serve the vast majority of the RRO in the province, and because they have had EPSPs publicly regulated by the AUC/AEUB, the discussion of the “New” RRO that follows strictly focuses on them, and does not discuss any of the other RRO rates in the province.

Since 2006, each RRO provider has had two EPSPs. The first set began on July 1, 2006, along with the original RROR, and concluded on June 30, 2011. The second set began on July 1, 2011 and were supposed to conclude on June 30, 2014, but have been allowed by

[88] Sites and sales data is from each provider’s 2014 AUC Rule 005 filing.
[89] Number of sites based on monthly average for the calendar year.
[90] The denominator used is 955,991, and is calculated from the Market Surveillance Administrator’s Retail Statistics workbook, found here: http://www.albertamsa.ca/uploads/pdf/Archive/0000-2016/2016-04-08-Retail-statistics.xlsx.
[91] The denominator used is 1,687,429, and is also calculated from the Market Surveillance Administrator’s Retail Statistics workbook.
[92] The denominator used is 55,379 GWh, and is the AUC’s total customer usage estimate for 2014, found here: http://www.energy.alberta.ca/electricity/682.asp

the AUC to continue until the implementation of each provider's new EPSP can be completed.[93] Remember from section 2.1 that the RRO was originally supposed to be a "transitional" rate, and as of 2012 the RROR was set to expire on June 30, 2014.[94] Advising the government on "what to do with the default rate" after the expiry of the RROR was one of the RMRC's key assignments.[95]

Perhaps surprisingly, the RMRC unequivocally recommended that the current RRO be phased out.[96] Its reasons for doing so were extensive and varied, and are not reproduced here; however, what underpinned its recommendation was the belief that the "usefulness of the current default rate has passed."[97] The government, in December 2014, rejected that recommendation. Its official explanation for doing so was:

> Nearly two-third of Albertans currently use [the RRO], and the Government of Alberta respects this choice. There is no interest in forcing Albertans to sign contracts for their electricity.[98]

As a result of the government's decision, the RROR was extended, and is now set to expire in 2020.[99] The new set of EPSPs were proposed by the RRO providers in AUC proceeding

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[93] This is the case as of June, 2016. See the monthly approval letters for EEA, EEC, and DERS on the AUC's website: http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx.
[94] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 43 (pdf).
[95] Ibid., page 19 (pdf).
[96] Ibid., page 162 (pdf).
[97] Ibid., page 168 (pdf).
[98] Alberta Department of Energy, "Improving electricity market for Albertans Questions and Answers December 18, 2014: Why were six RMRC recommendations rejected?" http://www.energy.alberta.ca/Electricity/3856.asp.
[99] Regulated Rate Option Regulation, Alta Reg 262/2005, <http://canlii.ca/t/52f2x> retrieved on 2016-07-19

#2941, which concluded in early 2015. They will take effect as soon as their respective implementation periods are complete.[100]

Despite all operating under the same regulation, no two EPSPs have ever been exactly the same, even for a single provider. Both sets of EPSPs were the result of negotiated settlements between each individual provider and consumer groups; they were all approved by the AUC separately, and were each subject to the "gives and takes" of their individual negotiations.[101,102] Furthermore, the EPSPs have been subject to amendment by the AUC; for example, EEA's 2011 – 2014 has been amended no less than five times.[103]

Although they have all been technically different, the EPSPs have all shared a common purpose: to delineate a formula that calculates the "energy" component of the RRO rate customers pay each month.[104] Each EPSP breaks down its formula, explaining and justifying its components, including their purpose, how they have been determined and their quanta. For the purposes of this paper, a comprehensive explanation of each EPSP and the various components of its formula is unnecessary (and would likely require hundreds of mind-numbing pages); instead, the basic structure of the EPSPs is discussed and common elements are summarized.

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[100] Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para 1658, page 306 (pdf).

[101] AUC Exhibit 0284.02.UCA-2941, Utilities Consumer Advocate, "Reply Argument," December 9, 2014, para. 108, page 33 (pdf).

[102] Reaching a "negotiated settlement" involves the applicant and interested parties developing an application together that is then jointly submitted to the regulator for approval, as opposed to the applicant filing its application to the regulator on its own and then having it tested through an adversarial process by the interested parties.

[103] See recent EEA monthly filings, for example: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/21633-D01-2016.pdf

[104] Remember, the RRO rate is the sum of the "energy charge" and the "non-energy" charge. This paper is only concerned with the "energy charge."

2.2.1 The Energy Price Setting Plans

As previously explained, the RROR has historically set the legal framework for price setting and it has then been up to the RRO providers to create an actual price setting methodology that meets the requirements of that legal framework. The EPSPs delineate this methodology, which distills into a single formula that calculates the monthly "Energy Charge" paid by customers for the electricity they consume. It can be summarized as follows:

$$Energy\ Charge = BEC + [RM + F\&C + ERM] \qquad (1)$$

Where:

$BEC = Base\ Energy\ Charge$

$RM = Risk\ Margin$

$F\&C = Fees\ and\ Costs$

$ERM = Energy\ Return\ Margin$

As can be seen, the monthly Energy Charge is the sum of the terms listed above, some of which are variable month to month and some of which are fixed in the EPSP (each term is expressed in $/MWh). It is important to note that DERS and EEA's EPSPs have calculated separate Energy Charges for each of their customer groups, formally known as "rate classes." They have done so to ensure that different groups of customers with markedly different consumption patterns do not cross-subsidize other customer groups; in other words, that each customer group pays according to its actual cost. This practice, however, does not change the fundamental composition of the Energy Charge formula, whose components are individually explained as follows:

2.2.1.1 Base Energy Charge

For each rate class, the Base Energy Charge (BEC) is the forward market based price to which all other adders are applied to achieve the monthly Energy Charge.[105] In other words, all of the terms in the square brackets in the Energy Charge equation are considered "adders" to the BEC, such that it can be considered the "underlying" price charged for electricity. It should be noted from the outset that, historically, this "underlying" price has not always been called the BEC, and in the first set of EPSPs it was not even calculated as one number. For the purposes of understanding how the EPSPs have determined the Energy Charge, however, these details are unimportant. The important thing to keep in mind is that the concept of the BEC provided in the first sentence of this paragraph is really an abstraction for the purposes of illustration.

As previously explained, the government's intention for the original RROR was to have the RRO transition from being set using "long-term forward market prices" to being set using "monthly forward market prices." What this really meant was that instead of being based on the prices of hedges with terms of greater than a month, the RRO would transition to being based on the prices of hedges for just the month in question (i.e. with a term equal to the month for which the Energy Charge is being set). Again, this was done with the intention of designing a rate that "varied to reflect changes in monthly pool prices" but would also protect consumers from the full extent of their variability.[106,107]

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[105] AUC Exhibit 0139.02.UCA-2941, Utilities Consumer Advocate, "Evidence of Jason Beblow," June 4, 2014, para. 26, page 17 (pdf).
[106] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 81 (pdf).
[107] Alberta Department of Energy, "Retail Market Review: An Update and Review of Market Metrics," April 15, 2010: http://www.energy.alberta.ca/electricity/pdfs/retailmarketreview.pdf, page 13 (pdf).

Over the course of the 2006 – 2011 EPSPs, this policy shift was enacted through Section 9 of the RROR, which resulted in the BEC becoming increasingly based on the prices of hedges for the month in question, or just “monthly hedges” for short. Specifically, the minimum extent to which the BEC was weighted by the prices of monthly hedges increased by 20% per year, starting at 20% in 2006 and ending at 100% in 2011. Section 9 mandated that the increasing portion of the BEC based on monthly hedges be calculated in accordance with Section 11, subsection (1) of which has always read as follows:[108]

> **Calculation of new RRO rate**
>
> **11(1)** Each new RRO rate
>
> (a) must be based on
>
> (i) regulated rate customer load forecasts made during the relevant price setting period described in subsection (2), and
>
> (ii) monthly forward market electricity prices established in the relevant price setting period,
>
> and
>
> (b) must not be based on prices established before or after the relevant price setting period.

From 2006 to 2011, Sections 9 and 11 of the RROR effectively resulted in the EPSPs calculating their monthly BEC in two separate parts: an “old” part, which was based on the prices of long-term hedges, and a “new” part, which was based on the prices of monthly hedges.[109] After the transition completed in 2011, Section 9 of the RROR was repealed and, since then, each EPSP has calculated a singular BEC based on just the prices of monthly hedges in accordance with Section 11. Despite the added complexity of this transition, both sets of EPSPs have essentially satisfied the price setting requirements of the RROR by determining the BEC as follows:

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[108] Regulated Rate Option Regulation, Alta Reg 262/2005, <http://canlii.ca/t/52f2x> retrieved 2016-06-22

[109] For example, in DERS’ 2006 – 2011 EPSP, the BEC (as defined by this paper) was calculated as a combination of the “Term Volume Energy Charge” and the “45-Day Volume Energy Charge.” For EEA, it was calculated as a combination of the “Transition Full Load Portfolio” and the “Month Ahead Portfolio Price.”

1) The RRO provider prepares its load forecast. This forecast represents the provider's expectation of how much electricity its customers will consume during the month in question.
2) The forecast load is actually hedged or deemed to have been hedged using the types of hedges delineated in the EPSP.[110,111]
3) The BEC is calculated as the forecast load weighted average hedge price.

In other words, the RRO providers actually hedge, or act as if they have hedged, their forecast load using the types of hedges stipulated by their EPSPs. They then charge the weighted average price of those hedges to their customers as the BEC. During the 2006 – 2011 EPSPs, Section 9 of the RROR specified that the minimum amount of forecast load for a given month either actually hedged or deemed to have been hedged using monthly hedges increase by 20% per year.[112] Once the transition to 100% monthly hedging was complete by 2011, Section 9 was repealed and just section 11 remained to mandate that the Energy Charge only be based on the prices of hedges for the month in question, determined over the course of the price setting period preceding the month.

It is clear from the discussion in section 1.2.3 around how the Alberta forward electricity market actually works that Section 11 of the RROR is quite vague with respect to *how* monthly forward market price setting is to be actually conducted. Ultimately, the RROR has left it up to the RRO providers to propose a load forecasting methodology, which types of hedges' prices in which portion of the price setting period factor into the

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[110] "Deemed" hedging just means that, for the purposes of calculating the BEC, it is as if the RRO provider actually purchased the hedges in question despite not actually doing so.

[111] Prior to 2013 the price setting window began on the 45th day preceding the month and ended on the 5th business day preceding the month; as of 2013 the price setting window has begun on the 120th day preceding the month and ended on the 5th business day preceding the month.

[112] Regulated Rate Option Regulation, Alta Reg 262/2005, <http://canlii.ca/t/jbdv> retrieved on 2016-06-24

calculation of the BEC, and how those prices are weighted using their forecast load, all of which significantly impact how the BEC is determined. This being the case, the regulatory process is designed to afford all affected parties due process, and any price setting methodology proposed in an EPSP must be approved by the AUC. All of the EPSPs to date were approved on the grounds that they were/are in the public interest.[113]

As a result, it is not as if the RRO providers just get to choose the price setting methodology that suites them best; they have to justify it to the AUC. This leeway in price setting afforded by the RROR has, however, resulted in more than one style of price setting having been used since 2006. Despite their technical differences, however, they have all essentially conformed to the simplified process outlined above, which is an adequate description of price setting for the purposes of this paper (describing each of the actual methodologies used in each EPSP by each RRO provider would be both unnecessary and, for lack of a better word, cruel.) Ultimately, the important points to take away from this discussion are as follow:

- By law the Energy Charge must be calculated using the forecast customer load and forward market prices.
- Those forward market prices are reflected in the BEC according to the price setting methodology contained in the EPSP.

[113] There are also various sections of the RROR that have required the price setting methodology used in the EPSP to have certain characteristics; for instance, section 4(1) has mandated that "[t]he price setting plans referred to in section 3(1)(a) must, with a reasonable degree of transparency, use a fair, efficient and openly competitive acquisition process to ensure that the resulting prices for the supply of electric energy are just, reasonable and electricity market based." In addition, section 6(1)(d) has mandated that, when approving the EPSP, the regulatory authority must "have regard for the principle that a regulated rate tariff must not impede the development of an efficient market for electricity based on fair and open competition in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of any participant."

- It is ultimately up to the RRO provider to devise the price setting methodology contained in its EPSP and have it approved by the AUC as being in the public interest.
- Due to the law's vagueness, there have been numerous different price setting methodologies used in the EPSPs since 2006.
- Despite the numerous different styles of monthly forward market price setting over the years, the BEC has essentially been calculated as the weighted average price of forward market hedges purchased or deemed to have been purchased in order to hedge the RRO provider's forecast load for the month in question.

2.2.1.2 Risk Margin

Since the beginning of the RROR, Section 3(1)(iii) has stipulated that each RRO rate must include the distribution owner's proposed "risk margin." Section 1(l) of the RROR has defined "risk margin" as "the just and reasonable financial compensation that an owner's regulatory authority approves for the owner based on financial risks that (i) remain with the owner, and (ii) that are associated with the supply of electricity services to regulated rate customers."[114] Section 5 of the RROR, in turn, has delineated the legal requirements for this risk margin, including what risks the owner may and must be compensated for by the risk margin. According to subsection 5(3), the risk margin *must* "cover" all "volume risk," "price risk," "credit risk" and "unaccounted for energy and losses," and according to subsection 5(4) it *may* cover "other risks associated with energy related costs and non-

[114] Regulated Rate Option Regulation, Alta Reg 262/2005, <http://canlii.ca/t/52f2x> retrieved on 2016-06-22

energy related costs that an owner's regulatory authority considers reasonable and prudent."[115]

In the context of the energy portion of the RRO, "risk" is the possibility that revenues do not cover costs and the RRO provider therefore incurs a loss. The risk margin is intended to compensate the RRO providers for this possibility.[116] As explained by the AUC:

> Broadly speaking, RRO providers are required to make decisions under uncertainty and, as a result, they face a variety of financial risks. The Regulated Rate Option Regulation requires the RRO providers to be compensated for certain financial risks associated with making decisions under uncertainty.[117]

The various financial risks alluded to by the AUC have been organized into two types: commodity risk and non-commodity risk (also called "other" or "administrative" risk). Despite the RROR's reference to a singular "risk margin," the RRO providers have always been compensated for these two types of risks through various "risk margins" included in their EPSPs, which are added to the BEC and form part of the monthly Energy Charge. These risk margins have been approved by the AUC using the standard set out in Section 6(1) of the RROR, which has mandated that the AUC "have regard for the principle that a regulated rate tariff, including the risk margin described in section 5, must provide the owner with a reasonable opportunity to recover the prudent costs and expenses incurred by the owner."[118]

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[115] Ibid.
[116] Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para 1080, page 205 (pdf).
[117] Ibid.
[118] Ibid., para 1033, page 197 (pdf).

You may be wondering why, instead of using risk margins, the RRO providers' gains and losses are not just trued-up (i.e. made even *ex-post).* The reason is, since the beginning of the RROR, both Sections 3(2) and 6(2) have expressly forbidden the use of "deferral accounts, true-ups, rate riders or other similar account or devices for energy related costs."[119] As a result, the energy related risks faced by the RRO providers can only be compensated for on a prospective basis through AUC approved risk margins.[120]

It is important to note that, like with the BEC, these risk margins have had various names over the years and have been calculated using various methodologies. As a result, the simplified discussion here, once again, is an abstraction for the purposes of illustration, and both types of risk are individually discussed as follows:

2.2.1.2.1 Commodity Risk

As explained in section 1.2.1, the price of all electricity consumed is the AESO Pool price. Therefore, the total cost of the electricity consumed by RRO customers in each hour is equal to the quantity consumed (in MWh) multiplied by the Pool price. The RRO provider then owes this money to the AESO. However, the underlying price for electricity the RRO provider charges its customers is not the Pool price, but rather the BEC. As a result, it is possible (and likely) that, for each hour, the RRO provider's revenue does not equal its cost, which means the RRO provider could experience either a profit or a loss.

Because it is possible for the RRO provider to experience a loss as a result of this potential mismatch between its revenue and costs "on commodity" – which is just a shorter

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[119] Regulated Rate Option Regulation, Alta Reg 262/2005, <http://canlii.ca/t/51zp1> retrieved on 2016-06-26

[120] Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para 1213, page 227 (pdf).

way of saying "on the electricity it sells its customers" – it by definition faces "commodity" related risk. As explained by the UCA:

> The price of all electricity consumed in Alberta is the AESO Pool price or spot price. This is the price that is set every hour by the intersection of generation supply and load demand in the province. As the RRO Regulation mandates the RRO rate be based on a price derived from the forward market, as opposed to the AESO Pool price, being the price actually paid for electric energy, there is risk imposed on a [RRO provider] in every hour of every day that the price it receives for the electricity its customers consume is different than the price it pays to the AESO for that electricity (e.g. its revenue is not equal to its cost).[121]

Given the commodity risk borne by the RRO providers as a result of the monthly forward market price setting mandated by the RROR, each EPSP has included some form of commodity risk compensation through a risk margin. Although the fundamental cause of the commodity risk borne by the RRO providers is the fact that they do not charge their customers the Pool price for the electricity they consume, the amount of commodity risk they have borne has been influenced by their respective price setting methodologies.

For example, the current EPSPs have involved each of the RRO providers actually buying hedges for the purposes of determining the BEC, a process formally known as "procurement." As a result, in the process of price setting the RRO providers are simultaneously reducing their commodity risk because they are reducing their inherently short volumetric positions. This does not, however, mean that the commodity risk they face

[121] AUC Exhibit 0277.02.UCA-2941, Utilities Consumer Advocate, "Argument," November 17, 2014, para. 354, page 100 (pdf).

is completely eliminated: it is still possible (and likely) for the RRO providers to incur commodity losses as a result of any remaining volumetric positions.

To illustrate, imagine an RRO provider that is only in business for a single hour. This is, of course, not realistic, but it greatly simplifies the math involved without changing the underlying logic. Assume that the RRO provider forecasts its load for the hour and then hedges it exactly by purchasing a single hedge. Remember that, with the hedge, the RRO provider is paid the Pool price on the hedge volume in exchange for paying the seller the hedge price on the same volume. With respect to the sale of the physical electricity to its customers, the RRO provider pays the AESO the Pool price, and charges its customers the BEC, which in this simplified case is equal to the price of the single hedge. The RRO provider's profit function can therefore be expressed as:

$$Profit = (BEC * Q) - (P^P * Q) + (P^P * V) - (BEC * V) \qquad (2)$$

Where:

$BEC = Base\ Energy\ Charge\ (in\ this\ case, the\ hedge\ price)$

$Q = Consumption$

$P^P = Pool\ Price$

$V = Contract\ (hedge)\ Volume$

This formula simplifies to the following:

$$Profit = (BEC - P^P) * (Q - V) \qquad (3)$$

As can be seen, the RRO provider's commodity profit is a function of the differential between 1) the BEC and the Pool price, and 2) the quantity consumed and the quantity hedged:

- If the hedge volume (V) is zero, then the RRO provider's entire load is "exposed" to Pool price (i.e. its volumetric position is simply equal to Q) and its commodity profit is thus equal to its revenue from the BEC minus its cost from the Pool price.
- If the hedge volume (V) is exactly equal to consumption (Q), then the second term is zero and the RRO provider has no volumetric position. Thus, regardless of the differential between the BEC and the Pool price, its commodity profit is also zero.
- If the hedge volume (V) is positive but not equal to consumption (Q), then the RRO provider's commodity profit could be positive or negative depending on the size and direction of its volumetric position (i.e. whether the second term is positive or negative and to what extent) and whether the Pool price ends up being higher or lower than the BEC, and to what extent. The potential outcomes are the same as those identified in Table 2.

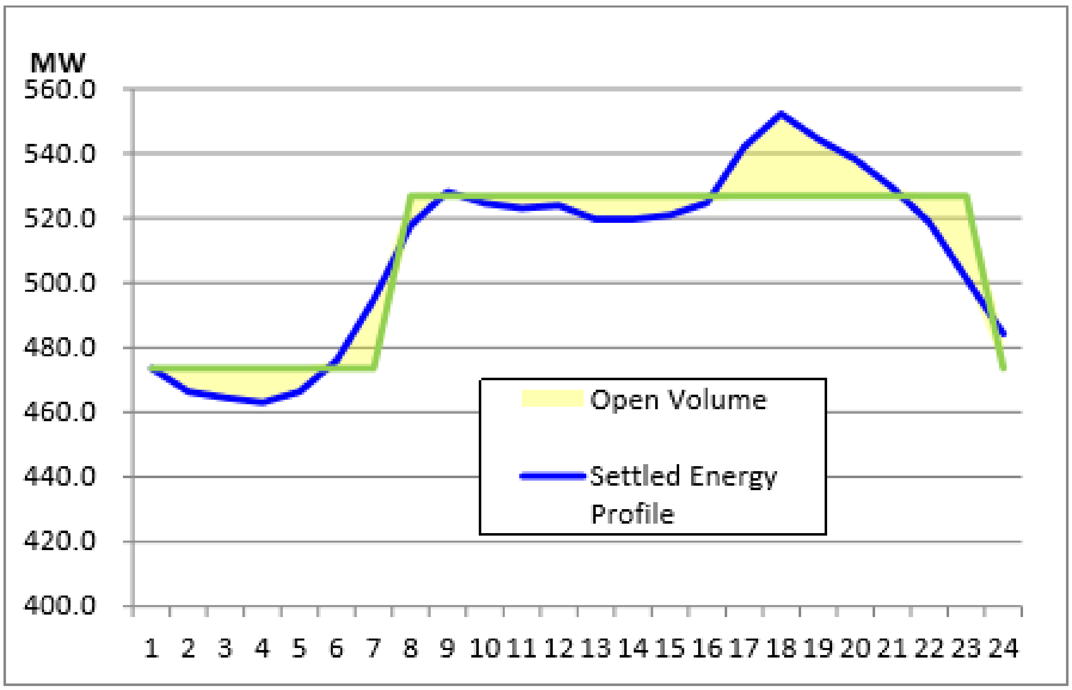
The point of this example is to illustrate that the profitability of any volumetric position is a function of the Pool price. As a result, an RRO provider bears commodity risk if its load is not perfectly hedged. Because the current EPSPs require the RRO providers to hedge their forecast load with standard Flat and Peak hedges, volumetric positions inevitably materialize throughout the day. This is because these are "block" hedges, which provide a constant volumetric position over certain hours.[122] The RRO providers' individual load shapes, however, are not constant throughout the day, but instead vary

[122] AUC Exhibit 0001.01.AUC-2941, Alberta Utilities Commission, "Notice re: Commission-initiated generic proceeding on the regulated rate tariff," November 22, 2013, page 3 (pdf).

from hour to hour, just like the AIL. As a result, even with a perfect load forecast, the RRO providers' actual load will inevitably be imperfectly hedged throughout the day.

Put another way, hedging under current procurement processes is like trying to fit a square peg into a round hole; the "square" hedges do not fit perfectly into the RRO providers' "round" load shape (called the "settled energy profile" in the following figure), thereby leaving volumetric positions (called "open volume" in the following figure):[123]

Figure 6: Illustrative Hedging Outcomes



In the provided figure, the green line represents the hedged volume and the blue line represents the RRO provider's load. The yellow shaded areas are equal to the difference between the blue line and the green line, and illustrate the various volumetric positions (long and short) that could materialize over the course of a day. As shown in the

[123] AUC Exhibit 0139.02.UCA-2941, Utilities Consumer Advocate, "Evidence of Jason Beblow," June 4, 2014, para. 31, page 21 (pdf).

preceding example, the profitability of these volumetric positions is a function of the Pool price. Therefore, at least in the case of the current EPSPs, the commodity risk compensation has effectively placed a valuation not on the risk of the entire load being exposed to Pool price, but rather only the smaller volumetric positions that regularly occur as a result of the RRO providers' inevitably inaccurate procurement (hedging).[124]

2.2.1.2.2 Non-Commodity Risk

In addition to compensation for commodity risk, all of the EPSPs to date have included compensation for energy related non-commodity risk, which has also been known as "administrative" or "other" risk. Like with the other adders in the RRO Energy Charge formula, the non-commodity risk margin has taken many names since 2006 and has been calculated in a variety of ways. It has been intended to compensate for a series of risks, all of which have likewise had varying names. The following list highlights some of these non-commodity risks that have been compensated for by the EPSPs:

- Counterparty credit risk: This is the risk that the seller from whom the RRO provider purchases its hedges "defaults or goes bankrupt and can no longer supply a contracted hedge…" This poses a risk to the RRO provider because it would result in it carrying a larger unhedged position into the month in question, which could result in commodity losses.[125]
- Recurring cost forecasting risk: The RRO providers have recovered certain costs – such as credit costs, AESO collateral costs, system fees and plan

[124] AUC Exhibit 0277.02.UCA-2941, Utilities Consumer Advocate, "Argument," November 17, 2014, para. 355, page 100 (pdf).
[125] AUC Exhibit 0001.01.AUC-2941, Alberta Utilities Commission, "Notice re: Commission-initiated generic proceeding on the regulated rate tariff," November 22, 2013, page 8 (pdf).

implementation costs – on a forecast basis (these are explained in more detail in the next section).[126] This means that they forecast what these costs will be and charge them to their customers as an adder. The risk is that their forecast could be wrong, in which case the RRO providers may under or over-collect depending on what the actual costs materialize as during the month in question.[127]

- Administrative and operational risk: The possibility of the RRO provider incurring a loss as a result of fluctuations in certain costs of business, such as "salaries, other staffing costs, training and software licensing."[128]
- Billing error risk: As a result of Section 17 of the RROR, RRO providers have not been allowed to "collect from a regulated rate customer any amount undercharged as a result of an incorrect meter reading, incorrect rate calculation, clerical error or other error of any kind that is made more than 12 months before the date of the bill." In other words, the "RRO provider is at risk for any billing and/or energy calculation error that results in an undercharge that is not discovered within 12 months."[129]

2.2.1.3 Fees and Costs

As a part of serving their customers, the RRO providers incur certain energy related fees and costs. The EPSPs have included adders designed to recover them from RRO

[126] Ibid.
[127] Ibid.
[128] Alberta Utilities Commission, "Decision 2011-486," December 13, 2011, para. 79, page 21 (pdf).
[129] AUC Exhibit 0001.01.AUC-2941, Alberta Utilities Commission, "Notice re: Commission-initiated generic proceeding on the regulated rate tariff," November 22, 2013, page 8 (pdf).

customers. The following list highlights some of the fees and costs that have been compensated for by the EPSPs:[130]

- Credit costs, which include NGX collateral costs, AESO collateral costs, and counterparty collateral costs: The financial security (e.g. credit or collateral) that the RRO provider must provide to those parties with whom it trades physical electricity and hedges. Credit, is of course, not free, and the RRO providers incur carrying costs as a result of having to post it with these different parties.[131]
- NGX and AESO trading charges: The NGX charges a transaction fee to the RRO providers for hedges they purchase on the NGX trading platform, and the AESO universally charges its "Pool Trading Charge" to all load to recover its own costs, as well as those of the AUC and the MSA.[132]
- Retail Adjustment to Market (RAM): These are charges that occur as a result of retailers correcting for errors that they discover in the final calculation of their load.[133]
- AESO Uplift Charges: These are charges that are a result of "the AESO resolving the issue of the mismatch of dispatch prices and the settlement price." More specifically, "[t]hese payments compensate generators that are dispatched intra-hour (i.e., for less than a full hour) when the hourly pool price is lower than that generator's offer price." They are universally charged to load by the AESO.[134]

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[130] Ibid., pages 5 and 6 (pdf).
[131] Ibid.
[132] Ibid.
[133] Ibid.
[134] Ibid.

- Plan Implementation costs: These are costs associated with the ongoing implementation of an EPSP, including regulatory costs.[135]
- Plan Administration costs: These are costs associated with any supplementary load forecasting, energy procurement, financial reporting, hedge calculation and price setting.[136]

2.2.1.4 Energy Return Margin

Section 6(1)(b)(i) of the RROR has always required that "a regulated rate tariff must allow for a reasonable return for the obligation on the owner to provide electricity services…"[137] As a result of this Section of the RROR, "the RRO providers are permitted to charge customers an amount for a reasonable return for the obligation on the RRO provider to provide electricity services."[138] This "reasonable return" amount contemplated by the RROR has generally been paid to the RRO providers through two margins: an energy and non-energy return margin. The non-energy return margins have been included as part of the RRO providers' non-energy revenue requirement, and has been collected as part of their $/site "non-energy" or "administrative" charge.[139] The energy return margins have been included in the EPSPs and collected as part of the RRO providers' $/MWh Energy Charge.

In addition to mandating that the RRO providers be allowed to earn a reasonable return, the RROR has always mandated through Section 6(1)(b)(ii) that "the risk margin

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135 Alberta Utilities Commission, "Decision 2011-123," March 31, 2011, para. 41, page 13 (pdf).
136 Ibid.
137 Regulated Rate Option Regulation, Alta Reg 262/2005, <http://canlii.ca/t/52f2x> retrieved on 2016-06-28
138 Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para 148, page 36 (pdf).
139 For example, see EEA's monthly rate filings.

described in section 5 must not be considered as a part of that reasonable return." The effect of this Section has been to parcel out compensation for the risks falling under Section 5 into standalone risk margins – i.e. the commodity and non-commodity risk margins explained previously – that cannot be considered part of the RRO providers' "reasonable return." This has been widely regarded as an "unusual" practice that is unique to the regulation of the RRO.[140] The reason why this separation of the risk and return compensation for the RRO is considered unusual is because, in traditional utility regulation, the concepts of risk and return are inextricably linked, such that the "return" paid to the utility *is* its risk compensation.

To elaborate, the concept of providing the utility a "return" traditionally relates to paying its shareholders for the capital they invest, formally known as their "equity." The "return on equity" is calculated with the goal of trying to "reward investors with a return equivalent to what they would have earned on alternative investments of similar *risk*" [emphasis in original].[141] In the parlance of economics, the return investors could earn from investing in a business of similar risk is known as their "opportunity cost," and therefore to incent them to invest in the utility their return on equity needs to at least equal that opportunity cost. Naturally, there is a positive relationship between the level risk faced by a utility and its approved return on equity. As explained by Dr. Sean Cleary, noted

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[140] Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, paras 170 – 178, pages 42 – 43 (pdf).
[141] Jeffery Church and Roger Ware, *Industrial Organization: A Strategic Approach* (Irwin-McGraw Hill, 2000), http://works.bepress.com/cgi/viewcontent.cgi?article=1022&context=jeffrey_church, page 878 (pdf).

finance professor at Queen's University and expert witness for the UCA, "one of the underlying principles of finance is that higher risk, you generate higher return."[142]

Despite the unique separation of risk and return compensation as a result of Section 6(1)(b)(ii), the AUC's interpretation of the purpose of the "reasonable return" contemplated by the RROR is consistent with the concept of "opportunity cost" used to justify the return on equity provided to other utilities. In its own words, the AUC explains that section 6(1)(b)(i) of the RROR can "be thought of as ensuring that the firm is covering all opportunity costs, including a return on resources invested by the firm and skills provided by the owner."[143]

With respect to approving the "reasonable return" paid to each RRO provider, both the AEUB and the AUC have taken into account Section 6(1)(d) of the RROR, which has always stated that the regulatory authority must:

> have regard for the principle that a regulated rate tariff must not impede the development of an efficient market for electricity based on fair and open competition in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of any participant.[144]

In the very early days of the new RRO, the AEUB interpreted Section 6(1)(d) to require it to "strive to set the reasonable return at an amount that is 'just right'."[145] Specifically, the AEUB considered that:

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[142] Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para. 175, page 43 (pdf).
[143] Ibid., para. 238, page 55 (pdf).
[144] Regulated Rate Option Regulation, Alta Reg 262/2005, <http://canlii.ca/t/52f2x> retrieved on 2016-07-01
[145] Alberta Energy and Utilities Board, "Decision 2006-108," November 1, 2006, page 12 (pdf).

> the reasonable return based on the requirements of the legislation has both a lower and an upper limit. The return must be set high enough to allow existing competitors to remain in the market and to attract new competitors. A return that is set higher than is necessary for this purpose however, would allow retail competitors to raise their own returns higher than would be required to remain in the marketplace thus harming consumers and would potentially provide retailers with an opportunity to undercut the RRT provider thus disadvantaging RRT providers.[146]

More recently, the AUC has viewed Section 6(1)(d) through the lens of economics, stating that it should be taken into account "by ensuring that the regulated rate is set so that RRO providers earn a return that reflects the return earned by competitive retailers or, equivalently, RRO providers earn an economic profit that reflects the economic profit earned by competitive retailers."[147] In other words, all of the constituent parts of the RRO (including the energy and non-energy return margins) must be set such that the final RRO rate allows the RRO providers to earn the same profits as competitive retailers. By this standard, the AUC believes that if it "can ensure that the RRO providers earn economic profits that reflect those earned by competitive retailers in the short run and in the long run, the RRO providers will not impair the development of the competitive retail market based on fair and open competition."[148]

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[146] Ibid., page 49 (pdf).
[147] Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para 131, page 33 (pdf).
[148] Ibid., para 141, page 35 (pdf).

3 The Cost of the "New" RRO

Section 1 provided an overview of the physical and financial aspects of the exchange of electricity in Alberta. Section 2 explained the history of Alberta's default rate for electricity and examined how its three largest providers' Energy Price Setting Plans have carried out the monthly forward market price setting mandated by the Regulated Rate Option Regulation. This section provides an estimate of what ultimately turned out to be the cost of monthly forward market price setting to RRO customers. This cost is measured by comparing what RRO customers actually paid as a result of monthly forward market price setting to what they would have paid under monthly Pool price flow-through price setting.

3.1 Methodology

As explained in section 1.2.1, the price of all of the electricity transacted in the Alberta wholesale market is the AESO Pool price, and therefore the Pool price is the per unit cost of the electricity consumed by RRO customers. Every month, the RRO providers (like any other retailer) are invoiced by the AESO for the cost of the electricity consumed by their customers. The total cost to an RRO provider of the electricity that is actually consumed by and assigned to its customers is equal to their "actual usage" for each hour multiplied by the Pool price for each hour summed over all of the hours in the month.[149] To illustrate, imagine the following three hours:

[149] "Actual Usage" is "Total Usage" net of Unaccounted for Energy (UFE) and Distribution Line Losses (DLL). In other words, it is the amount of electricity that is actually recorded by customer meters and assigned to them as "usage." Because DLL and UFE would exist and need to be accounted for under either PPFT price setting or forward market price setting, they are safely excluded from this discussion.

Table 4: Example of the Hourly Cost of Electricity

Hour	Pool price ($/MWh)	Actual Usage (MWh)	Cost ($)
1	50	300	15,000
2	30	350	10,500
3	80	400	32,000
		Total	**57,500**

In this example, the total cost over all three hours is $57,500. However, it could also be calculated using the actual usage weighted average Pool price (WAPP), which is equal to the sum of the product of the Pool price and the actual usage each hour, divided by the total actual usage over all three hours:

$$\frac{\left(\frac{\$50}{MWh}*300MWh\right)+\left(\frac{\$30}{MWh}*350MWh\right)+\left(\frac{\$80}{MWh}*400MWh\right)}{1050\ MWh} = \$54.76/\text{MWh}$$

Multiplying the WAPP by the actual usage over the three hours yields the same total of $57,500:

$$\frac{\$54.76}{MWh} * 1050\ MWh = \$57{,}500$$

The WAPP is therefore the weighted average price paid by the RRO provider for the electricity its customers consumed. This is important because it allows for total cost of the electricity consumed by RRO customers in any given month (the “Base Energy Cost”) to be expressed as:

$$Base\ Energy\ Cost = WAPP * Q \tag{4}$$

Where:

$WAPP = Weighted\ Average\ Pool\ Price$

$Q = Actual\ Usage$

On the other hand, the total revenue received by the RRO provider in any given month for that same electricity (the “Base Energy Revenue”) is equal to the sum of each rate class' BEC multiplied by its usage. To illustrate, imagine that there are two rate classes, "residential" and "commercial," each with the following BEC and usage for a given month:

Table 5: Example of "Base Energy Revenue"

	BEC ($/MWh)	Actual Usage (MWh)	Revenue ($)
Residential	80	100	8,000
Commercial	60	85	5,100
		Total	**13,100**

The RRO provider's Base Energy Revenue from both rate classes is $13,100, which is equal to the sum of each rate class' BEC multiplied by its usage. The same result is also achieved by calculating the weighted average BEC across the two rate classes and multiplying it by actual usage:

$$Base\ Energy\ Revenue = \frac{\$70.81}{MWh} * 185MWh = \$13{,}100$$

The weighted average BEC across rate classes is therefore the weighted average price paid by RRO customers for the "base energy" they consumed each month.[150] Thus, the "Base Energy Revenue" received by the RRO provider for any given month can be calculated as:

$$Base\ Energy\ Revenue = BEC * Q \tag{5}$$

Where:

$BEC = Weighted\ Average\ Base\ Energy\ Charge$

$Q = Actual\ Usage$

Subtracting the "Base Energy Cost" from the "Base Energy Revenue" yields the "Base Energy Outcome," which for any given month is equal to the difference between what the RRO provider was paid for the electricity consumed by its customers and its actual cost:

[150] For the sake of simplicity and brevity, a separate acronym is not used for the "weighted average BEC." Just keep in mind that, from now on, the "BEC" refers to the "weighted average BEC across rate classes."

$$Base\ Energy\ Outcome = (BEC - WAPP) * Q \tag{6}$$

Where:

$WAPP = Weighted\ Average\ Pool\ Price$

$BEC = Weighted\ Average\ Base\ Energy\ Charge$

$Q = Actual\ Usage$

As can be seen, if the WAPP for any given month exceeded the BEC (i.e. the Base Energy Outcome was negative), the revenue collected from RRO customers was less than the cost their electricity; in other words, RRO customers benefited from monthly forward market price setting because they essentially "under-paid" for their electricity. On the other hand, if the BEC for any given month exceeded the WAPP (i.e. the Base Energy Outcome was positive), the revenue collected from RRO customers exceeded the cost of their electricity; in other words, RRO customers suffered from monthly forward market price setting because they essentially "over-paid" for their electricity.

This "over-payment," if it materialized, was *de facto* a cost of monthly forward market price setting; that is, all else being equal, RRO customers could have paid less under monthly "Pool price flow-through" (PPFT) price setting, whereby the RRO provider simply "flows-through" Pool prices to its customers on a monthly basis by effectively charging them the WAPP.[151]

In addition to the potential over-payment on "base energy" by RRO customers, monthly forward market price setting also has other costs relative to monthly PPFT price

[151] It should be noted here that when I refer to "RRO customers" I am referring to RRO customers in total, and not at an individual or rate class level. To the extent there are different rate classes, each would pay the WAPP based on their own (and not overall) actual usage. This would, however, essentially be a matter of accounting for the RRO provider, and would not change the fact that the weighted average price paid by RRO customers under monthly PPFT price setting would be the WAPP calculated using overall actual usage.

setting. Generally, these are the risks and costs associated with “procurement” (i.e. hedging, either deemed or actual) that would not exist and therefore not be compensated for by RRO customers under monthly PPFT price setting. These risks and costs have been compensated for through various adders reflected in the Energy Charge formula. The total cost of these monthly forward market price setting adders (called the “FMPS Adders” in the following equations and tables) to RRO customers in any given month can be expressed as:

$$Total\ Cost\ of\ FMPS\ Adders = \left(\sum FMPS\ Adders * Q\right) \tag{7}$$

Where:

$Q = Actual\ Usage$

The total outcome to RRO customers, in dollars, of monthly forward market price setting for any given month can therefore be expressed as the “Base Energy Outcome” derived above plus the total value of the adders included in the monthly Energy Charge as a result of monthly forward market price setting. Mathematically:

$$Total\ Energy\ Outcome = [(BEC - WAPP) * Q] + \left(\sum FMPS\ Adders * Q\right) \tag{8}$$

Where:

$WAPP = Weighted\ Average\ Pool\ Price$

$BEC = Weighted\ Average\ Base\ Energy\ Charge$

$Q = Actual\ Usage$

Remember, the first term can be either positive or negative depending on the relative magnitude of the BEC and the WAPP in any given month. The second term is strictly positive, since it includes the $/MWh adders included in the Energy Charge as a result of monthly forward market price setting multiplied by the monthly actual usage in

MWh. Therefore, the Total Energy Outcome for RRO customers as a result of monthly forward market price setting in any given month can be either positive or negative depending on the relative magnitude of these two terms. If positive, it indicates the cost to RRO customers relative to monthly PPFT price setting; if negative, it indicates the savings to RRO customers relative to monthly PPFT price setting.

3.2 Analysis

This section calculates the Total Energy Outcome, in accordance with equation 8, for each month of each EPSP for each RRO provider. Also individually shown for each month are the Base Energy Outcome, which is calculated in accordance with equation 6, and the total cost of the adders deemed to have been a result of monthly forward market price setting (the "FMPS Adders"), calculated in accordance with equation 7.

It is important to note that this analysis assumes that both Pool prices and each RRO provider's monthly actual usage would not have been different over the time periods in question had monthly PPFT price setting been used instead of monthly forward market price setting. I conclude in appendix I that monthly Pool prices likely would not have been different under monthly PPFT price setting, meaning that their use in the analysis is likely reasonable. I conclude in appendix II that monthly actual usage may have been higher under monthly PPFT price setting on account of RRO customers paying lower Energy Charges, on average; meaning that the results of the analysis are likely conservative.

It is also important to note that, in some cases, the RRO providers' actual usage data (either hourly or monthly) is, to my knowledge, not available on the public record. In these cases, forecast actual usage data has been used instead; its use is indicated where applicable.

3.2.1 The 2006 – 2011 EPSPs

3.2.1.1 EEA

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2006	7	138.9	67.5	2.2	470,838	-$33,609,223	$1,057,507	-$32,551,715
2006	8	78.0	68.2	2.3	447,142	-$4,391,347	$1,028,009	-$3,363,338
2006	9	88.3	70.1	2.4	432,188	-$7,870,986	$1,037,404	-$6,833,581
2006	10	185.6	77.6	2.4	476,424	-$51,454,325	$1,141,843	-$50,312,482
2006	11	113.4	74.9	2.3	534,803	-$20,613,583	$1,226,998	-$19,386,584
2006	12	75.3	79.9	2.4	557,027	$2,575,468	$1,352,603	$3,928,071
2007	1	63.8	82.0	2.5	556,046	$10,163,993	$1,376,611	$11,540,604
2007	2	75.8	77.8	2.4	486,685	$963,718	$1,173,213	$2,136,930
2007	3	59.2	74.9	2.3	484,985	$7,579,433	$1,115,165	$8,694,598
2007	4	54.6	75.1	2.4	439,780	$9,003,490	$1,041,396	$10,044,886
2007	5	51.9	72.9	2.3	433,519	$9,141,469	$975,539	$10,117,007
2007	6	53.6	74.3	2.3	434,114	$8,985,787	$1,008,225	$9,994,012
2007	7	171.8	88.1	3.1	501,649	-$41,995,674	$1,554,110	-$40,441,564
2007	8	76.3	100.4	3.8	442,066	$10,648,915	$1,695,332	$12,344,247
2007	9	51.8	101.0	3.7	417,646	$20,558,229	$1,545,287	$22,103,515
2007	10	68.3	91.1	3.3	451,843	$10,297,124	$1,479,769	$11,776,892
2007	11	57.8	91.1	3.2	499,139	$16,588,416	$1,620,062	$18,208,478
2007	12	70.9	92.7	3.3	575,187	$12,524,055	$1,891,857	$14,415,912
2008	1	84.6	84.7	3.2	571,455	$95,467	$1,839,566	$1,935,033
2008	2	67.1	81.7	3.2	511,327	$7,475,437	$1,620,045	$9,095,482
2008	3	87.7	80.3	3.1	481,079	-$3,572,280	$1,497,403	-$2,074,877
2008	4	142.0	88.4	3.4	439,064	-$23,519,735	$1,508,610	-$22,011,125
2008	5	110.0	90.1	3.5	423,586	-$8,464,133	$1,467,940	-$6,996,193
2008	6	91.3	88.2	3.4	411,545	-$1,276,938	$1,410,959	$134,021
2008	7	69.0	108.3	4.7	448,931	$17,653,312	$2,092,723	$19,746,035
2008	8	88.8	105.2	5.1	446,819	$7,336,401	$2,270,267	$9,606,668
2008	9	102.3	89.8	4.3	402,888	-$5,026,049	$1,748,847	-$3,277,202
2008	10	108.1	91.4	4.4	447,342	-$7,480,561	$1,950,211	-$5,530,350
2008	11	103.8	97.1	4.5	471,271	-$3,158,409	$2,120,305	-$1,038,104
2008	12	96.1	107.6	4.8	596,781	$6,822,325	$2,871,349	$9,693,673
2009	1	98.4	89.7	4.4	572,568	-$4,968,479	$2,520,377	-$2,448,102
2009	2	53.8	98.6	4.7	477,389	$21,390,645	$2,264,841	$23,655,485

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2009	3	44.4	81.0	4.2	504,299	$18,464,048	$2,102,828	$20,566,876
2009	4	32.7	64.0	3.8	421,094	$13,192,434	$1,611,841	$14,804,275
2009	5	33.4	65.6	3.9	417,610	$13,473,669	$1,616,681	$15,090,350
2009	6	36.0	60.3	3.9	423,262	$10,256,503	$1,665,367	$11,921,870
2009	7	44.0	75.0	5.0	435,089	$13,479,591	$2,171,752	$15,651,342
2009	8	36.7	73.8	5.0	421,068	$15,611,709	$2,094,804	$17,706,513
2009	9	80.6	59.5	4.5	422,232	-$8,918,861	$1,908,913	-$7,009,948
2009	10	36.3	46.8	4.2	465,345	$4,878,227	$1,933,332	$6,811,559
2009	11	53.6	59.7	4.6	474,551	$2,932,318	$2,172,038	$5,104,356
2009	12	57.0	67.9	5.9	602,302	$6,592,893	$3,556,988	$10,149,881
2010	1	44.8	57.0	5.4	557,663	$6,768,501	$2,997,173	$9,765,674
2010	2	44.8	53.9	5.3	466,884	$4,259,206	$2,477,580	$6,736,786
2010	3	36.5	50.3	4.2	466,665	$6,466,360	$1,968,974	$8,435,334
2010	4	51.7	47.8	4.1	418,476	-$1,621,556	$1,701,621	$80,064
2010	5	146.5	55.6	4.5	423,931	-$38,508,093	$1,894,082	-$36,614,011
2010	6	62.0	64.6	4.9	407,187	$1,059,487	$1,982,089	$3,041,576
2010	7	42.5	76.7	6.0	442,228	$15,113,996	$2,639,452	$17,753,448
2010	8	40.7	72.8	5.9	434,452	$13,966,336	$2,545,953	$16,512,288
2010	9	29.5	57.9	5.2	418,371	$11,880,851	$2,166,269	$14,047,119
2010	10	31.8	46.1	5.1	450,551	$6,460,080	$2,313,569	$8,773,649
2010	11	52.1	46.8	5.9	519,200	-$2,728,857	$3,067,943	$339,086
2010	12	64.2	57.5	6.4	601,875	-$4,038,476	$3,875,601	-$162,875
2011	1	86.5	65.1	6.8	587,035	-$12,595,003	$4,005,778	-$8,589,225
2011	2	133.5	78.6	7.5	516,195	-$28,342,625	$3,881,470	-$24,461,156
2011	3	50.6	61.6	5.4	534,687	$5,899,794	$2,875,842	$8,775,636
2011	4	55.2	104.5	6.8	437,699	$21,590,872	$2,986,307	$24,577,179
2011	5	34.3	54.4	5.2	418,260	$8,412,353	$2,190,633	$10,602,986
2011	6	79.7	59.8	5.6	412,831	-$8,206,959	$2,306,907	-$5,900,052

The following table shows the total, summary results for this EPSP in June, 2016 dollars:[152]

[152] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index each month's dollar values to June, 2016 dollars.

Table 6: Summary Results for First EEA EPSP

	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
Total ($)	$57,986,566	$133,926,290	$191,912,856
Average ($/MWh)	2.04	4.71	6.75
Average ($/Month)	$966,443	$2,232,105	$3,198,548
Median ($/Month)	$6,808,790	$2,154,244	$9,511,865

Notes on this analysis:

1) Each month's WAPP was calculated using hourly Pool price data from the AESO. Because EEA has never filed hourly usage data on the public record, an hourly load profile was approximated for each day of each month by using the forecast usage data from the "Hedging" tab of EEA's monthly filing workbooks. This is EEA's forecast of the average usage for each hour of the day throughout the month.
2) The "Actual Usage" in column D of the table is from AUC Exhibit 0087.18.EEAI-2941.
3) Each month's BEC was calculated using data from EEA's monthly filing workbooks. It was calculated according to the following steps:
    a. The BEC was calculated for each rate class according to the following formula (it is provided here for completeness only and its terms will not be defined; they can be found in the monthly filing workbooks):

       $[(1 - MA\%) * TFLPP] + (MA\% * MAPP)$
    b. The weighted average BEC for all rate classes was then calculated using the "Forecast Load by Rate Class," found in the "Calculation" tab of the monthly filing workbooks.
4) The adders included in the "FMPS Adders" in column C were taken from EEA's monthly filing workbooks. The weighted average adder for all rate classes was

calculated using the "Forecast Load by Rate Class," found in the "Calculation" tab of the monthly filing workbooks. The adders and their individual values over the EPSP in June, 2016 dollars are:[153]

a. Price Index Risk Margin (PIRM) – **Value over EPSP = $91,239,798**

This adder was intended to provide compensation for commodity risk.[154] Commodity risk margins are considered to be a result of monthly forward market price setting because it necessitates the RRO providers charging their customers a BEC that is not equal to the WAPP over any given period of time. This creates the financial risk that the RRO providers do not recover the full cost of the electricity their customers consume and thereby suffer a loss. This adder is considered to be a result of monthly forward market price setting because commodity risk would not exist under monthly PPFT price setting.

b. Plan Implementation Costs (PIC) – **Value over EPSP = $7,109,459**

This adder was meant to recover the "costs to implement the 2006-2011 Plan and include the costs of the Consultation Parties in respect of the Negotiated Settlement, ongoing costs for the roles of the Consultation Parties provided for in the 2006-2011 Plan, the cost of the Independent Advisor in respect of the Negotiated Settlement and the ongoing costs for the roles provided for in the 2006-2011 Plan, the AEUB Cost Assessment and any costs that are a result of Dispute Resolution."[155] These "Plan Implementation Costs" were largely a result of a) multiple parties negotiating the vast minutiae of monthly forward market price setting included in the Terms of Settlement to the EPSP, namely all of

[153] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index the dollar values of each adder over the EPSP to June, 2016 dollars.
[154] EPCOR Energy Alberta Inc., "Application for Approval of a Settlement Agreement in respect of the 2006-2011 Energy Price Setting Plan," March 27, 2006, AUC Application #1454218, page 15.
[155] Alberta Energy and Utilities Board, "Order U2006-109," April 28, 2006, page 31 (pdf).

the components of the Energy Charge formula; and, b) the Consumer Groups who were parties to the negotiated settlement, as well as the "Independent Advisor," having ongoing roles in the procurement activities mandated by the EPSP. This adder is considered to be a result of monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

c. NGX Trading Charge (NGXC) – **Value over EPSP = $1,110,396**

"The NGX charges fees for trading on its systems on a $/MWh basis."[156] Therefore, EEA had to pay the NGX in order to engage in procurement on its trading platform. This adder is considered to be a result of monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

d. Index Support Compensation (ISC) – **Value over EPSP = $3,786,798**

This was a fee paid to EEA by its RRO customers for its consistent procurement using the NGX trading platform. It was essentially a means of subsidizing NGX by paying EEA, the province's largest RRO provider, to consistently use it for its procurement. In EEA's words:

> As the Alberta electricity market is still somewhat illiquid and trading on an electronic trading platform has not materialized in a significant way, the Companies have agreed to actively and consistently support the NGX trading system such that the RRO Price Index can be established each month. For this obligation, the Companies will receive $55,000 per month in compensation. The Companies will

[156] EPCOR Energy Alberta Inc., "Application for Approval of a Settlement Agreement in respect of the 2006-2011 Energy Price Setting Plan," March 27, 2006, AUC Application #1454218, page 17.

also receive a $0.20/MWh liquidity incentive if increased activity occurs on the NGX trading system.[157]

This adder is considered to be a result of monthly forward market price setting because none of these costs would have been incurred under monthly PPFT price setting.

e. Credit Cost (CC) – **Value over EPSP = $1,303,823**

This adder was intended to compensate for the costs associated with EEA having to post credit with its hedge suppliers.[158] This adder is considered to be a result of monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

f. All Energy Risk and Return Margin (AERM), which included:[159]

i. Reasonable return – **Value over EPSP = $17,786,574**

This was EEA's Energy Return margin.[160] I multiplied this adder by 0.85 and included the resulting value as an "FMPS Adder." Considering 85% of the Energy Return Margin to be attributable to forward market price setting is consistent with AEUB Decision 2007-103, in which it grossed down DERS' default gas return amount by 85% on account of its default gas business being "virtually risk free." For a detailed discussion of this Decision, please see appendix III.

ii. Plan Administration – **Value over EPSP = $2,253,503**

This adder was intended to compensate for costs associated with "the additional load forecasting, financial settlement and reporting, hedge calculations and price setting as

157 Ibid., page 14.
158 Ibid., page 16.
159 Alberta Energy and Utilities Board, "Order U2006-109," April 28, 2006, page 3 (pdf).
160 Ibid.

a result of moving from a quarterly price setting process to a monthly price setting process."[161] This adder is considered to be a result of monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

iii. Non-Commodity Risks – **Value over EPSP = $9,335,939**

This adder was intended to compensate for non-commodity risks, including "counter-party or credit risk, settlement related risks, risk of errors as well as risks that result through the natural operation of the 2006-2011 Plan."[162] Because none of these risks were defined or quantified in the EPSP, it is impossible to discern exactly what portion of this adder should be considered a result of monthly forward market price setting and included in the analysis.[163]

The only risk compensated for by this adder that can be identified as strictly resulting from monthly forward market price setting is "counter-party credit risk," which has come to be specifically defined as the risk that "the supplier from whom an energy hedge product or shape risk product was purchased defaults or goes bankrupt and can no longer supply a contracted hedge or shape risk product."[164] Because "counter-party credit risk" is strictly a result of hedging (procurement), it is clear that at least a portion of the value of the "Non-Commodity Risk" adder should be considered as a result of monthly forward market price setting.

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[161] EPCOR Energy Alberta Inc., "Application for Approval of a Settlement Agreement in respect of the 2006-2011 Energy Price Setting Plan," March 27, 2006, AUC Application #1454218, page 15.
[162] Ibid., page 14.
[163] According to EEA's Application, "the level of this risk compensation was part of the 'give and take' of the negotiation process." See: Ibid.
[164] AUC Exhibit 0001.01.AUC-2941, Alberta Utilities Commission, "Notice re: Commission-initiated generic proceeding on the regulated rate tariff," November 22, 2013, page 8 (pdf).

Although its 2006 – 2011 EPSP did not individually parcel out the portion of the adder dedicated to compensating for "counter-party credit risk," EEA's latest EPSP application proposed a standalone adder of $0.29/MWh to compensate for it specifically.[165] The value of this proposed adder is used as a proxy for the portion of the "Non-Commodity Risk" adder in EEA's 2006 – 2011 EPSP specifically dedicated to compensating for "counter-party credit risk."

3.2.1.2 EEC

NOTE: The full implementation of EEC's 2011 – 2014 EPSP was delayed until February, 2012 because it was not approved by the AUC until December 13, 2011.[166] So, although its *de jure* end date was June 30, 2011, the *de facto* end date of EEC's 2006 – 2011 EPSP was January 31, 2012. In order to allow for apples-to-apples comparisons between the EPSPs over the same time period and accurate summary statistics, the analysis that follows is up to and including the *de jure* end date of the EPSP, which was June, 2011. For more details on the "transition period" between the *de jure* and *de facto* end dates of EEC's 2006 – 2011 EPSP, please see AUC Decision 2011-208.

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2006	7	145.5	69.0	2.8	231,141	-$17,695,667	$648,844	-$17,046,822
2006	8	80.7	69.6	2.5	218,697	-$2,410,574	$540,240	-$1,870,334
2006	9	90.2	71.5	2.4	219,717	-$4,104,875	$535,787	-$3,569,088
2006	10	189.0	81.9	2.4	240,021	-$25,706,796	$587,408	-$25,119,388
2006	11	118.0	78.2	2.4	259,424	-$10,318,978	$612,758	-$9,706,220
2006	12	77.6	83.4	2.4	268,127	$1,539,644	$655,486	$2,195,131

[165] Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para. 1494, page 276 (pdf).
[166] Alberta Utilities Commission, "Decision 2011-486," December 13, 2011, para. 104, page 27 (pdf).

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2007	1	65.9	86.1	3.1	265,483	$5,374,737	$809,954	$6,184,691
2007	2	77.7	81.6	3.9	235,890	$927,053	$929,734	$1,856,787
2007	3	61.2	78.9	3.1	234,308	$4,137,966	$721,469	$4,859,435
2007	4	56.1	76.5	3.0	218,071	$4,448,172	$660,388	$5,108,560
2007	5	52.4	73.2	3.1	209,730	$4,360,898	$641,290	$5,002,188
2007	6	54.5	75.8	3.0	198,466	$4,226,125	$601,016	$4,827,141
2007	7	183.7	91.1	3.9	215,255	-$19,934,035	$836,979	-$19,097,055
2007	8	77.0	103.9	3.9	189,496	$5,106,354	$743,184	$5,849,538
2007	9	52.7	105.6	3.9	187,516	$9,935,853	$729,619	$10,665,472
2007	10	69.6	91.7	3.9	202,078	$4,473,795	$781,488	$5,255,283
2007	11	60.2	94.1	3.9	216,107	$7,316,809	$833,526	$8,150,335
2007	12	73.2	93.8	3.9	243,237	$5,006,213	$945,238	$5,951,450
2008	1	88.8	88.2	3.8	238,556	-$152,780	$910,929	$758,149
2008	2	68.8	85.0	3.9	211,921	$3,434,269	$818,096	$4,252,366
2008	3	89.6	82.8	3.8	207,287	-$1,412,493	$791,526	-$620,967
2008	4	141.7	89.6	3.9	193,699	-$10,087,432	$752,178	-$9,335,254
2008	5	109.8	91.7	3.8	187,406	-$3,396,388	$717,341	-$2,679,046
2008	6	92.8	89.7	3.9	180,091	-$559,887	$699,677	$139,790
2008	7	70.4	110.1	4.4	184,002	$7,293,636	$817,458	$8,111,093
2008	8	92.2	106.6	4.5	183,695	$2,652,755	$835,067	$3,487,822
2008	9	104.3	90.8	4.4	176,676	-$2,378,975	$783,976	-$1,594,999
2008	10	112.0	91.8	4.5	191,775	-$3,866,500	$868,766	-$2,997,734
2008	11	105.8	98.7	4.4	199,359	-$1,411,155	$884,632	-$526,523
2008	12	102.6	111.9	4.5	239,004	$2,226,415	$1,083,496	$3,309,910
2009	1	102.8	93.1	4.7	230,532	-$2,247,331	$1,075,609	-$1,171,723
2009	2	54.5	102.6	4.8	200,152	$9,631,114	$965,183	$10,596,297
2009	3	45.0	82.1	4.7	214,145	$7,942,262	$999,152	$8,941,414
2009	4	32.9	68.4	4.8	189,572	$6,723,913	$902,491	$7,626,403
2009	5	33.5	69.8	4.8	184,361	$6,699,464	$881,606	$7,581,070
2009	6	36.0	64.2	4.7	172,551	$4,868,064	$812,031	$5,680,094
2009	7	44.9	77.4	5.6	180,826	$5,881,345	$1,014,656	$6,896,001
2009	8	37.7	76.2	5.5	179,147	$6,906,121	$989,926	$7,896,048
2009	9	87.2	61.0	5.5	176,871	-$4,637,181	$977,347	-$3,659,834
2009	10	36.8	49.5	5.6	200,205	$2,532,943	$1,121,527	$3,654,470
2009	11	54.4	64.1	5.5	200,726	$1,938,818	$1,109,166	$3,047,984
2009	12	57.9	73.7	5.5	238,844	$3,781,552	$1,319,797	$5,101,350

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2010	1	45.3	59.9	5.6	223,003	$3,241,769	$1,243,217	$4,484,986
2010	2	45.2	55.7	5.5	192,346	$2,011,485	$1,058,064	$3,069,548
2010	3	37.2	50.8	5.5	197,157	$2,681,846	$1,087,897	$3,769,744
2010	4	51.8	49.1	5.6	177,782	-$480,442	$990,456	$510,014
2010	5	146.1	57.4	5.5	179,074	-$15,896,696	$985,056	-$14,911,639
2010	6	61.8	67.2	5.5	172,548	$931,955	$949,155	$1,881,110
2010	7	43.5	79.4	6.2	175,840	$6,313,489	$1,090,079	$7,403,568
2010	8	41.3	75.6	6.1	175,982	$6,031,715	$1,077,844	$7,109,558
2010	9	29.8	59.7	6.1	175,031	$5,234,625	$1,075,673	$6,310,298
2010	10	32.0	47.4	6.2	186,191	$2,856,753	$1,157,643	$4,014,396
2010	11	56.2	49.4	6.1	205,218	-$1,382,748	$1,256,903	-$125,845
2010	12	66.0	61.0	6.1	226,589	-$1,129,906	$1,390,103	$260,197
2011	1	92.4	68.9	6.2	225,109	-$5,284,916	$1,388,863	-$3,896,053
2011	2	142.2	82.5	6.1	197,016	-$11,756,790	$1,203,716	-$10,553,073
2011	3	51.5	63.8	6.1	207,368	$2,557,320	$1,265,641	$3,822,961
2011	4	56.0	107.8	6.2	179,420	$9,299,517	$1,116,895	$10,416,411
2011	5	34.2	56.2	6.1	172,192	$3,801,571	$1,052,516	$4,854,087
2011	6	81.4	62.1	6.1	165,450	-$3,183,191	$1,008,152	-$2,175,039

The following table shows the total, summary results for this EPSP in June, 2016 dollars:[167]

Table 7: Summary Results for First EEC EPSP

	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
Total ($)	$24,183,225	$62,329,349	$86,512,574
Average ($/MWh)	1.97	5.09	7.06
Average ($/Month)	$403,054	$1,038,822	$1,441,876
Median ($/Month)	$2,819,423	$1,049,737	$3,963,477

Notes on this analysis:

[167] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index each month's dollar values to June, 2016 dollars.

1) Each month's WAPP was calculated using hourly Pool price data from the AESO. The hourly usage data used to calculate the WAPP from July, 2006 to December, 2008 (inclusive) is from AUC Exhibit 0035.02.EEC-2253. The hourly usage data used to calculate the WAPP from January, 2009 to June, 2011 (inclusive) is from AUC Exhibit 0126.02.EEC-2941.
2) From July, 2006 to December, 2008 (inclusive), the monthly "Actual Usage" in column D is calculated from the hourly usage data contained in AUC Exhibit 0035.02.EEC-2253. From January, 2009 to June, 2011 (inclusive), the monthly "Actual Usage" in column D of the table is calculated from the hourly corrected data from AUC Exhibit 0126.02.EEC-2941.[168]
3) Each month's BEC was calculated using data from EEC's monthly filing workbooks. It was calculated according to the following steps:
    a. The BEC was calculated according to the following formula (it is provided here for completeness only and its terms will not be defined; they can be found in the monthly filing workbooks):

$$(Other\ Procurement\ Arrangements\ Price * Full\ Load\ Percentage)$$
$$+ (New\ RRO\ Arrangements\ Price * (1 - Full\ Load\ Percentage))$$

4) The "FMPS Adders" in column C were taken from EEC's monthly filing workbooks. The adders and their individual values over the EPSP in June, 2016 dollars are:[169]

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[168] EEC did not correctly account for Daylight Saving Time in the hourly data it provided in Exhibit 0126.02.EEC-2941. These errors were manually corrected in the data used for this analysis, and as a result, the monthly "Actual Usage" values in column D vary from the "Actual Usage" values provided in Exhibit 0126.02.EEC-2941 by extremely small amounts (100 – 300 MWh) for the months of March and November for each year post-2009 (inclusive).
[169] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index the dollar values of each adder over the EPSP to June, 2016 dollars.

a. Risk Margin – **Value over EPSP = $34,269,603**

This adder was intended to provide compensation for commodity risk.[170] As previously explained, this adder is considered to be a result of monthly forward market price setting because commodity risk would not exist under PPFT price setting.

b. Administrative Risk Margin – **Value over EPSP = $4,027,157**

Similar to EEA's "Plan Administration" margin, this margin was intended to provide compensation for "all credit and administrative costs, and for risks including counterparty risk, credit risk, settlement risk, legal and operational risk, and Power Pool charge risk."[171] As with EEA, none of these risks were individually defined or quantified in EEC's EPSP. As a result, the same margin of $0.29/MWh applied for in EEA's latest EPSP is used in this analysis as a proxy for the portion of EEC's "Administrative Risk Margin" dedicated to providing compensation specifically for "counterparty credit risk." As explained in the case of EEA, this risk is strictly incurred as a result of hedging (procurement) and would not be incurred under monthly PPFT price setting.

c. Plan Implementation Costs – **Value over EPSP = $776,572**

These are the costs incurred as a result of the participation of the "Independent Advisor" and "Consultation Parties" (consumer groups) in the ongoing implementation of the EPSP.[172] These costs were largely the result of the consumer groups who were parties to the negotiated settlement, as well as the "Independent Advisor," having ongoing roles in the procurement activities mandated by the EPSP. This adder is considered to be a result of

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[170] ENMAX Energy Corporation, "APPLICATION BY ENMAX ENERGY CORPORATION ("EEC") REGARDING A NEGOTIATED SETTLEMENT OF ITS 2006 - 2011 REGULATED RATE ENERGY PRICE SETTING PLAN," April 21, 2006, AUC Application #1455236, page 12 (pdf).
[171] Ibid.
[172] Alberta Energy and Utilities Board, "Order U2006-110," April 28, 2006, page 16 (pdf).

monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

d. The Load Obligation Return Margin, the Going Concern Return Margin, and Payment in Lieu of Taxes (PILOT) – **Value over EPSP = $23,256,018**

These were all components of EEC's Energy Return Margin.[173] Once again, I multiplied the sum of these adders by 0.85 and included the resulting value as an "FMPS Adder." For a detailed explanation of why I consider 85% of the Energy Return Margin to be a result of monthly forward market price setting, please see appendix III.

3.2.1.3 DERS

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	**Month**	**WAPP**	**BEC**	**FMPS Adders**	**Actual Usage**	**Base Energy Outcome**	**Total Cost of FMPS Adders**	**Total Energy Outcome**
2006	7	144.1	65.1	5.5	125,263	-$9,902,451	$690,246	-$9,212,205
2006	8	79.3	65.8	6.4	122,859	-$1,666,950	$789,522	-$877,428
2006	9	87.4	70.8	7.0	121,438	-$2,017,704	$848,333	-$1,169,372
2006	10	183.1	79.1	8.3	136,958	-$14,247,544	$1,143,294	-$13,104,250
2006	11	112.9	75.0	6.7	166,718	-$6,310,384	$1,116,174	-$5,194,209
2006	12	75.5	81.3	9.8	182,186	$1,045,348	$1,777,833	$2,823,181
2007	1	64.8	98.7	10.6	167,187	$5,665,915	$1,773,960	$7,439,875
2007	2	76.4	85.8	8.7	159,516	$1,501,069	$1,382,298	$2,883,367
2007	3	59.9	78.8	7.3	158,269	$2,977,114	$1,149,109	$4,126,223
2007	4	55.0	72.8	7.4	131,931	$2,355,868	$969,788	$3,325,655
2007	5	51.6	67.3	5.7	125,322	$1,976,109	$715,618	$2,691,727
2007	6	53.9	71.4	6.9	119,686	$2,089,860	$820,984	$2,910,844
2007	7	174.4	84.4	8.6	130,901	-$11,782,677	$1,123,922	-$10,658,755
2007	8	75.0	95.6	11.8	124,029	$2,548,610	$1,463,483	$4,012,093
2007	9	52.0	102.1	11.7	124,038	$6,224,143	$1,448,773	$7,672,916
2007	10	68.6	87.6	8.7	137,177	$2,602,144	$1,198,003	$3,800,147
2007	11	58.9	86.6	8.5	156,181	$4,320,907	$1,330,329	$5,651,236
2007	12	71.3	88.2	8.8	187,218	$3,155,012	$1,649,588	$4,804,600
2008	1	85.4	83.1	8.0	181,726	-$401,734	$1,457,092	$1,055,358

[173] Ibid., page 4 (pdf).

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2008	2	67.7	78.1	7.4	167,265	$1,731,391	$1,229,453	$2,960,845
2008	3	87.5	77.5	7.1	149,696	-$1,501,420	$1,067,115	-$434,305
2008	4	142.8	85.2	9.2	132,851	-$7,652,618	$1,225,273	-$6,427,346
2008	5	108.2	85.0	9.7	121,924	-$2,823,654	$1,180,980	-$1,642,674
2008	6	93.1	86.0	9.2	117,213	-$838,582	$1,073,647	$235,065
2008	7	69.2	104.1	11.7	122,212	$4,270,663	$1,428,185	$5,698,848
2008	8	88.0	102.5	11.1	123,440	$1,785,774	$1,374,257	$3,160,031
2008	9	102.8	83.1	8.4	115,776	-$2,278,737	$972,668	-$1,306,069
2008	10	107.6	85.8	8.7	125,503	-$2,730,963	$1,090,735	-$1,640,228
2008	11	100.2	87.1	9.5	139,228	-$1,834,108	$1,317,272	-$516,835
2008	12	99.1	105.4	10.9	178,596	$1,128,965	$1,952,815	$3,081,780
2009	1	99.8	91.4	9.2	177,796	-$1,486,983	$1,628,792	$141,809
2009	2	54.0	102.3	10.7	143,532	$6,922,447	$1,539,720	$8,462,168
2009	3	44.2	84.9	8.0	150,637	$6,126,504	$1,200,173	$7,326,676
2009	4	32.8	68.7	5.8	118,257	$4,241,202	$681,231	$4,922,433
2009	5	33.1	69.7	6.0	112,889	$4,130,542	$682,559	$4,813,101
2009	6	36.1	65.6	5.7	108,090	$3,199,135	$617,979	$3,817,114
2009	7	43.7	78.7	7.7	111,352	$3,901,397	$862,792	$4,764,190
2009	8	36.4	81.1	7.6	111,681	$4,992,870	$845,464	$5,838,334
2009	9	80.2	65.4	5.7	113,942	-$1,691,366	$650,316	-$1,041,050
2009	10	36.5	49.9	5.6	130,608	$1,762,089	$737,519	$2,499,608
2009	11	52.3	61.9	5.7	141,335	$1,363,508	$800,452	$2,163,960
2009	12	56.9	73.9	6.8	178,251	$3,025,906	$1,218,041	$4,243,947
2010	1	44.8	63.7	5.5	176,537	$3,340,069	$975,378	$4,315,447
2010	2	44.9	59.5	5.6	143,563	$2,092,103	$798,070	$2,890,173
2010	3	36.6	55.0	5.6	141,164	$2,598,754	$783,506	$3,382,261
2010	4	51.5	50.1	5.6	121,313	-$167,641	$682,271	$514,630
2010	5	146.6	55.2	5.6	119,682	-$10,942,522	$674,447	-$10,268,075
2010	6	61.6	66.2	6.6	113,160	$523,123	$750,364	$1,273,487
2010	7	42.9	81.4	7.9	117,443	$4,527,363	$927,664	$5,455,027
2010	8	41.0	78.3	7.5	118,698	$4,434,231	$887,459	$5,321,690
2010	9	29.5	63.6	5.7	119,570	$4,079,437	$686,649	$4,766,086
2010	10	31.7	49.0	5.6	130,233	$2,251,089	$723,311	$2,974,400
2010	11	54.3	50.2	5.5	153,746	-$621,371	$847,777	$226,406
2010	12	63.7	57.9	5.7	183,247	-$1,054,199	$1,052,378	-$1,820
2011	1	89.8	65.5	6.5	183,065	-$4,440,333	$1,183,868	-$3,256,465

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2011	2	137.6	82.7	7.8	158,259	-$8,682,262	$1,234,672	-$7,447,590
2011	3	50.4	64.0	6.1	162,884	$2,212,777	$1,000,406	$3,213,183
2011	4	55.3	108.0	10.6	126,926	$6,680,114	$1,347,446	$8,027,560
2011	5	33.3	62.8	5.6	116,391	$3,430,369	$647,308	$4,077,677
2011	6	79.1	64.3	5.9	114,007	-$1,682,688	$674,831	-$1,007,857

The following table shows the total, summary results for this EPSP in June, 2016 dollars:[174]

Table 8: Summary Results for First DERS EPSP

	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
Total ($)	$25,452,769	$72,648,173	$98,100,942
Average ($/MWh)	3.05	8.70	11.75
Average ($/Month)	$424,213	$1,210,803	$1,635,016
Median ($/Month)	$1,979,101	$1,173,633	$3,354,577

Notes on this analysis:

1) Each month's WAPP was calculated using hourly Pool price data from the AESO. The hourly usage data used to calculate the WAPP is from AUC Exhibit 0117.03.DEML-2941.
2) The "Actual Usage" in column D of the table is from AUC Exhibit 0117.03.DEML-2941.
3) Each month's BEC was calculated using data from DERS' monthly filing workbooks. First, the weighted average TEC and 45EC were calculated using the forecast load for each rate class (for those interested, these terms are defined in DERS' EPSP). The

[174] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index each month's dollar values to June, 2016 dollars.

forecast load weighted average TEC and 45EC were then added together to achieve the weighted average BEC.

4) The adders included in the "FMPS Adders" in column C were taken from DERS' monthly filing workbooks. The weighted average adder for all rate classes was calculated using the forecast load for each rate class from the monthly filing workbooks. The adders and their individual values over the EPSP in June, 2016 dollars are:[175]

    a. Parental Corporate Guarantees and Letters of Credit (PCG & LOC) – **Value over EPSP = $464,285**

These were the credit costs associated with having to provide financial security to the counterparties from whom DERS purchased electricity and hedges.[176] Fortunately, DERS listed the credit costs for the AESO and for hedging separately in its monthly filing workbooks; since only the credit costs associated with hedging are considered to be as a result of monthly forward market price setting, only they are included in the "FMPS Adders."

    b. Transaction Charges (TC) – **Value over EPSP = $249,673**

These are the costs "associated with over-the-counter (OTC) arrangements, broker fees, and NGX and Wattex fees."[177] This adder is considered to be a result of monthly

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[175] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index the dollar values of each adder over the EPSP to June, 2016 dollars.
[176] Direct Energy Regulated Services, "APPLICATION FOR APPROVAL OF A NEGOTIATED SETTLEMENT RESPECTING AN ENERGY PRICE SETTING PLAN TO ESTABLISH REGULATED RATES FOR ELIGIBLE CUSTOMERS IN THE ATCO ELECTRIC LTD. SERVICE AREA DURING THE PERIOD JULY 1, 2006 THROUGH JUNE 30, 2011," March 30, 2006, AUC Application #1454813, page 19.
[177] Ibid., page 20.

forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

c. Risk Compensation (RCOMP) – **Value over EPSP = $23,346,837**

This adder was one of the two components of DERS' commodity risk compensation.[178] It also included compensation for Retail Adjustment to Market (RAM) costs and "credit default risk," both of which were provided separately in DERS' monthly filing workbooks. Because RAM costs would also exist under monthly PPFT price setting, DERS' risk compensation adder was adjusted to exclude these costs. The remaining portion of the adder, intended to compensate for commodity risk and credit default risk, is considered to be a result of monthly forward market price setting. The "credit default risk" compensation would be unnecessary without procurement (i.e. there would be no hedges, and therefore no risk from suppliers who might default on providing them). Therefore, this adder (adjusted to exclude the compensation for RAM) is considered to be a result of monthly forward market price setting because both commodity risk and credit default risk would not exist under monthly PPFT price setting.

d. Hourly Load Shape Cost (HLSC) – **Value over EPSP = $27,670,388**

This adder was one of the two components of DERS' commodity risk compensation.[179] This adder is considered to be a result of monthly forward market price setting because commodity risk would not exist under monthly PPFT price setting.

e. Incentive Payments (IP) – **Value over EPSP = $3,427,144**

[178] Ibid., pages 13 - 17.
[179] Ibid.

This was an adder designed to pay DERS $50,000 per month for achieving certain "operational functions." Specifically: "the weekly posting of bids on NGX," "credit limit reporting," "daily trade reporting," and "other reports as requested by the Advisor and the Consultation Parties to support the Gas Index/Heat Rate Products and long term procurement."[180] All of these functions are considered to be in service of hedging (procurement). As a result, this adder is considered to be a result of monthly forward market price setting and would not have been incurred under monthly PPFT price setting.

f. Return Margin (RM) – **Value over EPSP = $17,489,844**

This was DERS' Return Margin.[181] The "energy" portion of this return margin was calculated by the AUC in Decision 2010-055 as $1.58/MWh.[182] Since this was an after-tax return margin, I grossed it up by the applicable tax rate for each month. I then multiplied the resulting before-tax Energy Return Margin by 0.85 and the resulting value was included as an "FMPS Adder." For a detailed explanation of why I consider 85% of the Energy Return Margin to be a result of monthly forward market price setting, please see appendix III.

3.2.1.4 Summary

The following table shows the total, summary results for all three of the 2006 – 2011 EPSPs in June, 2016 dollars:[183]

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[180] Alberta Energy and Utilities Board, "Order U2006-108," April 28, 2006, page 11 (pdf).
[181] Alberta Energy and Utilities Board, "Order U2006-110," April 28, 2006, page 4 (pdf).
[182] Alberta Utilities Commission, "Decision 2010-055," February 8, 2010, para. 93, page 30 (pdf).
[183] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index each month's dollar values to June, 2016 dollars.

Table 9: Summary Results for First Set of EPSPs

	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
Total ($)	$108 M	$269 M	$377 M
Average ($/MWh)	2.19	5.48	7.68
Average ($/Month)	$2 M	$4 M	$6 M
Median ($/Month)	$12 M	$4 M	$17 M

Based on this analysis, monthly forward market price setting is estimated to have cost RRO customers approximately $377 million over the course of the 2006 – 2011 EPSPs. In other words, all else being equal, RRO customers could have paid $377 million less over this time period if monthly PPFT price setting had been used instead. This amount translates into the following average reduction in monthly RRO Energy Charges for each RRO provider:

Table 10: Average Reduction in Energy Charges (First Set of EPSPs)

	Average Reduction in Monthly RRO Energy Charges ($/MWh/Month)
EEA	7.15
EEC	8.23
DERS	12.01
Average	9.13

Therefore, on average, the monthly Energy Charge paid by RRO customers would have been $9.13/MWh lower under monthly PPFT price setting. This equals $0.00913/KWh, which on an average monthly residential bill of 600 KWh would translate to a savings of $5.48.

3.2.2 The 2011 – 2014 EPSPs

NOTE: The 2011 – 2014 EPSPs (i.e. the second set) were supposed to end as of July, 2014; however, the implementation of the third set of EPSPs has been delayed on account of not having been approved by the AUC until late 2015 / early 2016. For the interim "transition" period between the current and new EPSPs, the AUC ordered the RRO providers to adhere to the most recent versions of their 2011 – 2014 EPSPs.[184] Given the continuation of the 2011 – 2014 EPSPs, the analysis of each EPSP in this section spans from July, 2006 up to and including June, 2016.

3.2.2.1 EEA

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2011	7	67.4	86.9	7.4	450,911	$8,805,044	$3,344,819	$12,149,863
2011	8	140.7	114.3	8.3	455,281	-$12,021,015	$3,795,517	-$8,225,498
2011	9	106.6	71.0	6.9	425,623	-$15,153,985	$2,927,501	-$12,226,484
2011	10	75.1	109.0	8.2	452,151	$15,356,122	$3,724,052	$19,080,174
2011	11	122.8	78.8	7.2	505,051	-$22,204,762	$3,624,947	-$18,579,814
2011	12	55.8	117.8	8.6	541,015	$33,550,011	$4,629,278	$38,179,289
2012	1	91.1	133.5	9.1	546,189	$23,160,899	$4,996,846	$28,157,746
2012	2	45.9	123.1	8.7	472,904	$36,517,860	$4,109,481	$40,627,341
2012	3	53.2	68.4	6.9	456,394	$6,945,423	$3,137,300	$10,082,723
2012	4	44.1	61.9	6.6	401,937	$7,173,926	$2,665,109	$9,839,036
2012	5	31.8	53.4	6.3	391,609	$8,475,064	$2,471,876	$10,946,939
2012	6	55.0	66.9	6.8	383,562	$4,565,687	$2,589,751	$7,155,438
2012	7	76.8	77.8	7.2	451,099	$424,185	$3,225,791	$3,649,976
2012	8	62.6	100.9	7.9	432,566	$16,557,230	$3,404,552	$19,961,782
2012	9	121.1	90.0	7.5	389,751	-$12,153,417	$2,930,209	-$9,223,208
2012	10	99.1	89.1	7.5	441,407	-$4,411,770	$3,326,359	-$1,085,411
2012	11	96.4	64.6	6.6	480,477	-$15,246,260	$3,194,210	-$12,052,050
2012	12	62.9	74.0	6.9	545,757	$6,033,863	$3,782,097	$9,815,960
2013	1	61.6	76.6	7.1	512,999	$7,722,972	$3,659,307	$11,382,279
2013	2	29.5	64.0	6.8	423,269	$14,630,377	$2,874,672	$17,505,048
2013	3	112.1	62.2	6.5	453,958	-$22,623,169	$2,960,202	-$19,662,967
2013	4	146.8	70.7	6.7	401,986	-$30,584,374	$2,677,064	-$27,907,310
2013	5	139.6	60.3	6.5	381,142	-$30,239,044	$2,467,343	-$27,771,701
2013	6	115.6	60.2	6.2	372,798	-$20,664,178	$2,326,591	-$18,337,587
2013	7	61.9	94.1	7.4	415,046	$13,365,547	$3,088,735	$16,454,282
2013	8	92.4	100.0	7.6	405,679	$3,090,578	$3,088,828	$6,179,406
2013	9	124.3	92.0	7.4	383,353	-$12,373,759	$2,818,309	-$9,555,450

[184] Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para 27, page 13 (pdf).

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	**Month**	**WAPP**	**BEC**	**FMPS Adders**	**Actual Usage**	**Base Energy Outcome**	**Total Cost of FMPS Adders**	**Total Energy Outcome**
2013	10	69.3	70.1	7.3	405,805	$344,236	$2,953,986	$3,298,222
2013	11	29.7	70.5	7.3	463,894	$18,938,362	$3,363,443	$22,301,806
2013	12	57.1	69.7	7.3	542,157	$6,827,049	$3,936,354	$10,763,403
2014	1	47.6	74.5	7.5	492,687	$13,296,917	$3,699,746	$16,996,663
2014	2	100.4	63.4	7.0	431,636	-$15,940,211	$3,025,503	-$12,914,708
2014	3	44.7	59.1	6.8	436,615	$6,269,037	$2,977,174	$9,246,211
2014	4	31.8	58.8	6.9	381,792	$10,333,957	$2,649,167	$12,983,125
2014	5	58.3	76.6	7.7	372,243	$6,789,343	$2,848,195	$9,637,538
2014	6	45.6	49.8	6.5	367,554	$1,537,419	$2,394,998	$3,932,417
2014	7	137.0	61.0	6.9	410,837	-$31,221,771	$2,850,665	-$28,371,107
2014	8	48.5	68.5	7.2	401,078	$8,034,051	$2,897,277	$10,931,328
2014	9	24.9	68.1	7.2	374,940	$16,167,438	$2,697,122	$18,864,560
2014	10	27.8	74.8	7.8	409,166	$19,211,984	$3,188,724	$22,400,708
2014	11	40.1	60.2	7.1	453,350	$9,111,323	$3,200,386	$12,311,709
2014	12	27.8	64.2	7.2	516,660	$18,809,289	$3,745,304	$22,554,593
2015	1	36.2	62.1	7.1	506,996	$13,133,749	$3,603,187	$16,736,936
2015	2	34.5	55.4	6.8	425,082	$8,857,928	$2,879,969	$11,737,897
2015	3	21.0	45.0	6.3	434,979	$10,481,050	$2,739,845	$13,220,895
2015	4	20.9	48.6	6.5	388,337	$10,739,802	$2,508,426	$13,248,228
2015	5	58.2	34.9	5.8	383,177	-$8,945,700	$2,217,944	-$6,727,757
2015	6	108.3	32.6	5.7	376,690	-$28,513,074	$2,144,112	-$26,368,962
2015	7	24.1	51.0	6.7	414,088	$11,139,196	$2,775,198	$13,914,394
2015	8	36.5	47.2	7.0	399,651	$4,273,588	$2,798,830	$7,072,418
2015	9	21.2	43.3	6.8	380,167	$8,396,182	$2,593,569	$10,989,751
2015	10	22.0	44.6	6.8	408,825	$9,232,721	$2,795,520	$12,028,242
2015	11	21.8	42.1	6.7	445,283	$9,027,266	$2,972,376	$11,999,642
2015	12	21.4	44.7	6.8	498,915	$11,622,319	$3,388,168	$15,010,487
2016	1	22.6	43.0	6.9	482,335	$9,829,885	$3,309,639	$13,139,523
2016	2	17.5	38.1	6.6	445,516	$9,178,972	$2,936,269	$12,115,241
2016	3	14.9	35.3	7.0	429,372	$8,747,585	$3,005,463	$11,753,048
2016	4	13.8	27.3	6.6	369,444	$4,995,897	$2,450,435	$7,446,332
2016	5	16.2	24.6	6.4	363,247	$3,068,738	$2,342,354	$5,411,092
2016	6	15.8	26.9	6.6	364,453	$4,064,218	$2,391,682	$6,455,900

The following table shows the total, summary results for this EPSP in June, 2016 dollars:[185]

Table 11: Summary Results for Second EEA EPSP

	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
Total ($)	$204,309,541	$192,835,474	$397,145,015
Average ($/MWh)	7.87	7.43	15.30
Average ($/Month)	$3,405,159	$3,213,925	$6,619,084
Median ($/Month)	$7,975,633	$3,091,088	$11,178,217

Notes on this analysis:

1) Each month's WAPP was calculated using hourly Pool price data from the AESO. Because EEA has never filed hourly usage data on the public record, an hourly load profile was approximated for each day of each month by using the forecast usage data from the "Hedging" tab of EEA's monthly filing workbooks. This is EEA's forecast of the average usage for each hour of the day throughout the month.
2) For July, 2011 to September, 2013 (inclusive), the "Actual Usage" in column D is from AUC Exhibit 0087.18.EEAI-2941. For October, 2013 to January, 2014 (inclusive), the "Actual Usage" in column D is from AUC Exhibit 0090.02.EEAI-2941. EEA has not publicly provided monthly usage data for the time period post-January, 2014; therefore, for February, 2014 to June, 2016 (inclusive), the "Actual Usage" in column D is the forecast total usage, taken from the "LoadSumM1" tab of EEA's monthly filing workbooks.

[185] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index each month's dollar values to June, 2016 dollars.

This means that, post- January, 2014, the "Actual Usage" values in column D differ from those that actually materialized in an amount equal to the forecast error for each month. However, EEA's forecasts of monthly usage have historically been extremely accurate, with an average error of only 3%.[186] Whether or not EEA has had similar monthly forecast accuracy post-January, 2014 is obviously impossible to know without EEA's actual usage data; however, it provides some assurance that the "Actual Usage" values in column D, post-January, 2014, are likely accurate within a very small margin of error that does not materially affect the results of the analysis.

3) Each month's weighted average BEC was calculated using data from EEA's monthly filing workbooks. The BEC for each month was calculated as the weighted average "Month Ahead Portfolio Price" (MAPP) for all rate classes using the "Forecast Load by Rate Class," found in the "Calculation" tab of the monthly filing workbooks.

4) The adders included in the "FMPS Adders" in column C were taken from EEA's monthly filing workbooks. Where applicable, the weighted average adder for all rate classes was calculated using the "Forecast Load by Rate Class," found in the "Calculation" tab of the monthly filing workbooks. The adders and their individual values over the EPSP in June, 2016 dollars are:[187]

    a. Commodity Risk Compensation (CRC) – **Value over EPSP = $128,110,245**

This adder was intended to provide compensation for commodity risk.[188] In EEA's 2011 – 2014 EPSP, this adder also included the "Liquidity Incentive" paid to EEA in order

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[186] This forecast error was calculated over the time period from July, 2006 to September, 2013 (inclusive) using data from AUC Exhibit 0087.12.EEAI-2941.

[187] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index the dollar values of each adder over the EPSP to June, 2016 dollars.

[188] EPCOR Energy Alberta Inc., "Application for Approval of a Settlement Agreement in respect of the 2006-2011 Energy Price Setting Plan," March 27, 2006, AUC Application #1454218, page 15.

for it to “arrange its auctions in order to achieve the greatest market participation and enhanced involvement by power producers.”[189] This adder is considered to be a result of monthly forward market price setting because commodity risk would not exist, and procurement would not be required, under monthly PPFT price setting.

b. Plan Implementation Costs (PIC) – **Value over EPSP = $3,801,438**

This adder was meant to recover “costs associated with the development of the 2011-2014 plan and the negotiation process of the settlement agreement,”[190] which included the ongoing costs of the consumer groups and the “Independent Advisor.”[191] Like in the 2006 – 2011 EPSP, these “Plan Implementation Costs” were largely a result of a) multiple parties negotiating the vast minutiae of monthly forward market price setting included in the Terms of Settlement to the EPSP, namely all of the components of the Energy Charge formula, and; b) the Consumer Groups who were parties to the negotiated settlement, as well as the “Independent Advisor,” having ongoing roles in the procurement activities mandated by the EPSP. This adder is considered to be a result of monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

c. NGX Trading Charge (NGXC) – **Value over EPSP = $1,797,029**

Over the course of its 2011 – 2014 EPSP, EEA has procured its hedges through auctions held on the NGX. As explained by EEA, “the NGX charges fees for trading and holding auctions on its systems.”[192] This adder has been intended to recover these costs

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[189] Alberta Utilities Commission, “Decision 2011-123,” March 31, 2011, para. 36, page 12 (pdf).
[190] Ibid., para. 41, page 13 (pdf).
[191] EPCOR Energy Alberta Inc., “Application for Approval of a Settlement Agreement in respect of the 2011-2014 Energy Price Setting Plan,” January 10, 2011, AUC Application #1606913, para. 46, page 18 (pdf).
[192] Ibid., para 44., page 18.

from RRO customers, and is considered to be a result of monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

d. Credit Cost (CC) – **Value over EPSP = $2,804,219**

This adder was intended to compensate for the costs associated with EEA having to post credit with its hedge suppliers.[193] This adder is considered to be a result of monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

e. Plan Administration Costs – **Value over EPSP = $2,594,721**

Like in the 2006 – 2011 EPSP, this adder was intended to compensate for the "incremental load forecasting and energy procurement costs that are over and above the amounts requested in EEAI's 2010-2011 RRT Non-Energy Application."[194] This adder is considered to be a result of monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

f. Administrative Risk Compensation – **Value over EPSP = $7,874,047**

This adder was intended to compensate for non-commodity risks, including "counter-party or credit risk, settlement related risks, risk of errors, forecast risk in respect of the cost recovery items… as well as risks that result through the natural operation of the 2011-2014 Plan."[195] Like in its 2006 – 2011 EPSP, none of these risks were defined or quantified in the EPSP, and it is therefore impossible to discern exactly what portion of this

[193] Ibid., para 43., page 17.
[194] Ibid., para 48., page 19.
[195] Ibid., para 29., page 13.

adder should be considered a result of monthly forward market price setting and included in the analysis.[196]

The only risk compensated for by this adder that can be identified as strictly resulting from monthly forward market price setting is "counter-party credit risk." Because, as previously explained, "counter-party credit risk" is strictly a result of hedging (procurement), it is clear that at least a portion of the value of the "Non-Commodity Risk" adder should be considered as a result of monthly forward market price setting.

Although its 2011 – 2014 EPSP did not individually parcel out the portion of the adder dedicated to compensate for "counter-party credit risk," EEA's latest EPSP application proposed a standalone adder of $0.29/MWh to compensate for it specifically.[197] The value of this proposed adder is used as a proxy for the portion of the "Non-Commodity Risk" adder in EEA's 2011 – 2014 EPSP specifically dedicated to compensating for "counter-party credit risk."

g. Energy Return Margin – **Value over EPSP = $45,853,774**

From July, 2011 to July, 2015 (inclusive), this adder was paid to EEA as a standalone "energy" return margin. As with the previous EPSPs, I multiplied it by 0.85 and included the resulting value as an "FMPS Adder." Starting in August, 2015, however, EEA began being paid an all-in-one "reasonable return" that provided compensation for both the "energy" and "non-energy" portions of its RRO business.[198] Therefore, for the post-August, 2015 period, I calculated the "energy" portion of this reasonable return as being 90.3% of the

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[196] According to EEA's Application, "the level of this risk compensation was part of the 'give and take' of the negotiation process." See: Ibid., para 29., page 13.
[197] Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para. 1494, page 276 (pdf).
[198] Alberta Utilities Commission, "Decision 20342-D01-2015," July 21, 2015, para 27, page 8 (pdf).

total adder, which is consistent with the AUC's calculations for DERS' reasonable return in Decision 2010-055. I then multiplied this value by 0.85 and included the resulting value as an "FMPS Adder." For a detailed explanation of the rationale behind these calculations/adjustments, please see appendix III.

3.2.2.2 EEC

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	**Month**	**WAPP**	**BEC**	**FMPS Adders**	**Actual Usage**	**Base Energy Outcome**	**Total Cost of FMPS Adders**	**Total Energy Outcome**
2011	7	73.4	88.6	6.4	171,448	$2,600,031	1,097,695	$3,697,726
2011	8	145.2	113.5	6.3	172,809	-$5,478,791	1,092,967	-$4,385,824
2011	9	114.1	72.4	6.3	165,247	-$6,892,223	1,045,137	-$5,847,086
2011	10	76.9	111.6	6.4	177,595	$6,161,095	1,133,332	$7,294,427
2011	11	131.0	81.6	6.3	188,974	-$9,333,342	1,195,203	-$8,138,139
2011	12	58.6	124.2	6.3	197,904	$12,996,541	1,251,682	$14,248,223
2012	1	102.5	141.3	6.4	197,298	$7,642,880	1,257,492	$8,900,372
2012	2	47.5	124.3	8.1	168,721	$12,958,098	1,360,041	$14,318,139
2012	3	55.8	72.1	7.0	163,867	$2,671,710	1,140,299	$3,812,009
2012	4	44.2	62.1	6.7	147,061	$2,643,761	988,754	$3,632,515
2012	5	31.9	54.2	6.6	142,711	$3,180,218	939,237	$4,119,455
2012	6	54.8	66.8	6.9	137,196	$1,640,397	940,394	$2,580,791
2012	7	84.8	79.7	7.2	150,461	-$773,327	1,076,935	$303,608
2012	8	66.0	101.1	7.8	146,886	$5,149,568	1,151,554	$6,301,122
2012	9	124.6	95.9	7.8	137,010	-$3,936,376	1,062,172	-$2,874,204
2012	10	106.0	85.0	7.5	155,030	-$3,256,375	1,162,809	-$2,093,566
2012	11	101.7	64.0	7.0	162,267	-$6,132,159	1,137,023	-$4,995,136
2012	12	66.0	74.2	7.3	179,338	$1,461,754	1,305,827	$2,767,581
2013	1	64.6	80.5	7.4	170,886	$2,722,212	1,259,743	$3,981,955
2013	2	29.9	67.1	7.1	144,067	$5,350,702	1,024,645	$6,375,347
2013	3	117.1	62.4	7.0	154,669	-$8,456,651	1,080,582	-$7,376,068
2013	4	145.4	73.3	7.3	142,347	-$10,261,941	1,039,458	-$9,222,482
2013	5	140.3	62.1	7.0	133,612	-$10,447,890	937,648	-$9,510,242
2013	6	117.9	67.0	7.1	128,567	-$6,542,350	909,717	-$5,632,634
2013	7	66.8	100.9	8.0	135,779	$4,624,503	1,080,595	$5,705,098
2013	8	95.2	100.3	7.8	133,190	$669,200	1,042,325	$1,711,526
2013	9	132.4	97.6	7.9	129,594	-$4,518,013	1,025,165	-$3,492,848

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2013	10	70.7	70.2	7.1	137,374	-$59,759	981,931	$922,172
2013	11	30.6	68.7	7.1	147,967	$5,648,010	1,051,581	$6,699,591
2013	12	60.3	65.7	7.0	166,272	$886,263	1,171,121	$2,057,383
2014	1	49.5	67.7	7.2	152,334	$2,773,622	1,091,965	$3,865,588
2014	2	105.6	61.9	7.0	143,887	-$6,297,057	1,001,256	-$5,295,801
2014	3	44.9	63.0	7.0	136,430	$2,477,509	959,535	$3,437,044
2014	4	31.2	60.9	6.9	126,854	$3,765,226	880,633	$4,645,860
2014	5	56.3	94.3	7.7	121,971	$4,640,262	945,088	$5,585,351
2014	6	43.7	45.7	6.7	118,576	$244,144	789,882	$1,034,026
2014	7	132.8	66.9	7.0	126,491	-$8,343,377	884,705	-$7,458,671
2014	8	47.6	75.6	7.4	121,655	$3,398,172	897,743	$4,295,915
2014	9	24.4	79.1	7.4	116,695	$6,383,151	859,868	$7,243,019
2014	10	27.4	73.8	7.3	127,337	$5,916,692	927,152	$6,843,844
2014	11	38.7	53.6	6.8	138,361	$2,069,611	938,061	$3,007,672
2014	12	27.3	62.9	7.0	152,658	$5,434,240	1,065,729	$6,499,969
2015	1	35.1	64.0	7.0	141,188	$4,070,745	989,372	$5,060,117
2015	2	33.7	49.9	6.7	122,630	$1,989,549	821,533	$2,811,083
2015	3	20.8	40.4	6.5	125,625	$2,458,009	815,336	$3,273,345
2015	4	20.7	42.2	6.6	112,239	$2,415,002	735,780	$3,150,781
2015	5	55.7	36.6	6.4	106,780	-$2,046,598	683,575	-$1,363,023
2015	6	105.0	29.8	6.3	104,856	-$7,886,089	655,884	-$7,230,206
2015	7	23.7	71.7	7.3	122,166	$5,858,591	888,738	$6,747,329
2015	8	35.6	68.2	7.4	116,850	$3,800,583	866,367	$4,666,950
2015	9	21.0	44.6	6.8	113,330	$2,665,261	772,283	$3,437,544
2015	10	21.7	45.7	7.1	116,557	$2,803,936	825,555	$3,629,491
2015	11	21.6	40.6	6.9	128,526	$2,445,614	886,098	$3,331,712
2015	12	21.2	42.4	7.0	132,190	$2,803,762	919,333	$3,723,095
2016	1	22.5	38.8	6.7	130,042	$2,114,627	876,766	$2,991,392
2016	2	17.4	35.0	6.6	115,707	$2,038,081	765,071	$2,803,152
2016	3	14.8	33.0	6.6	120,289	$2,184,636	792,707	$2,977,343
2016	4	13.7	25.0	6.5	108,403	$1,224,758	700,560	$1,925,318
2016	5	16.1	24.6	6.4	103,680	$888,826	662,736	$1,551,562
2016	6	15.7	26.1	6.5	102,856	$1,072,009	665,282	$1,737,292

The following table shows the total, summary results for this EPSP in June, 2016 dollars:[199]

Table 12: Summary Results for Second EEC EPSP

	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
Total ($)	$58,169,376	$61,352,899	$119,522,275
Average ($/MWh)	6.93	7.31	14.24
Average ($/Month)	$969,490	$1,022,548	$1,992,038
Median ($/Month)	$2,339,368	$1,020,300	$3,164,916

Notes on this analysis:

1) Each month's WAPP was calculated using hourly Pool price data from the AESO. The hourly usage data used to calculate the WAPP from July, 2011 February, 2014 (inclusive) if from AUC Exhibit 0126.02.EEC-2941. EEC has not publicly provided hourly usage data for the time period post-February, 2014. Therefore, for March, 2014 to June, 2016 (inclusive) the AIL weighted average Pool price is used for each month instead. This means that, post-February, 2014, the WAPP values in column A are inaccurate to the extent that the AIL WAPPs differed from the WAPPs based on EEC's usage.

   Since 2013 is that most recent full year for which EEC's actual monthly WAPPs can be calculated using publicly available data, it can be used to get some sense of how the monthly AIL WAPPs compare to EEC's actual monthly WAPPs. Over 2013, the monthly AIL WAPP was 7% lower, on average, than EEC's actual monthly WAPP.[200] Whether or not this relationship was similar post-February, 2014

[199] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index each month's dollar values to June, 2016 dollars.
[200] Calculated using Pool price and AIL data from the AESO.

is obviously impossible to know without EEC's hourly data; however, it provides some inclination that the monthly WAPP values in column A *may* be slightly lower than the values that actually materialized over this time period. If this is the case, then the Base Energy Outcomes and, by extension, the Total Energy Outcomes post-February, 2014, *may* also be slightly too high.

2) From July, 2011 to February, 2014 (inclusive), the monthly "Actual Usage" in column D is calculated from the hourly usage data contained in AUC Exhibit 0035.02.EEC-2253. EEC has not publicly provided monthly usage data for the time period post-February, 2014; therefore, for March, 2014 to June, 2016 (inclusive), the "Actual Usage" in column D is the forecast total usage, taken from the EEC's monthly filing workbooks.

   This means that, post- February, 2014, the "Actual Usage" values in column D differ from those that actually materialized in an amount equal to the forecast error for each month. However, EEC's forecasts of monthly usage have historically been extremely accurate; for example, over 2013 (the most recent full year with publicly available usage data) EEC only had a monthly forecast error of 2%.[201] Whether or not EEC has had similar monthly forecast accuracy post-February, 2014 is obviously impossible to know without EEC's actual usage data; however, it provides some assurance that the "Actual Usage" values in column D, post-February, 2014, are likely accurate within a very small margin of error that does not materially affect the results of the analysis.

[201] Calculated using forecast usage from EEC's monthly filing workbooks and actual usage from AUC Exhibit 0035.02.EEC-2253.

3) Each month's BEC is equal to the "Portfolio Price" contained in EEC's monthly filing workbooks.

4) The "FMPS Adders" in column C were taken from EEC's monthly filing workbooks. The adders and their individual values over the EPSP in June, 2016 dollars are:[202]

   a. Procurement Risk Compensation – **Value over EPSP = $42,824,931**

This adder was intended to provide compensation for commodity risk, and was comprised of a "variable" percentage of the BEC component and a "fixed" $/MWh component.[203] As previously explained, this adder is considered to be a result of monthly forward market price setting because commodity risk would not exist under monthly PPFT price setting.

   b. Administrative Risk Margin – **Value over EPSP = $2,552,268**

This adder was intended to provide compensation for "credit and settlement risk," "administrative costs and risk," and "legal and operational risk."[204] None of these risks were individually quantified in EEC's EPSP. As a result, the same margin of $0.29/MWh applied for in EEA's latest EPSP is used in this analysis as a proxy for the portion of EEC's "Administrative Risk Margin" dedicated to providing compensation specifically for "counterparty credit risk." As explained in the case of EEA, this risk is strictly incurred as a result of hedging (procurement) and would not be incurred under monthly PPFT price setting.

   c. Plan Implementation Costs – **Value over EPSP = $892,634**

[202] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index the dollar values of each adder over the EPSP to June, 2016 dollars.
[203] Alberta Utilities Commission, "Decision 2011-486," December 13, 2011, para. 79, page 21.
[204] Ibid.

These are the costs incurred as a result of the participation of the "Independent Advisor" and the Consumer Coalition of Alberta in the ongoing implementation of the EPSP.[205] These costs were the result of these two parties having ongoing roles in the procurement activities mandated by the EPSP, including load forecast and other activities. This adder is considered to be a result of monthly forward market price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

d. The Load Obligation Return Margin, the Going Concern Return Margin, and Payment in Lieu of Taxes (PILOT) – **Value over EPSP = $15,083,067**

From July, 2011 to July, 2015 (inclusive), these adders were paid to EEA as its standalone "energy" return margin. As with the previous EPSPs, I multiplied it by 0.85 and included the resulting value as an "FMPS Adder." Starting in August, 2015, however, EEC began being paid an all-in-one "reasonable return" that provided compensation for both the "energy" and "non-energy" portions of its RRO business.[206] Therefore, for the post-August, 2015 period, I calculated the "energy" portion of this reasonable return as being 90.3% of the total adder, which is consistent with the AUC's calculations for DERS' reasonable return in Decision 2010-055. I then multiplied this value by 0.85 and included the resulting value as an "FMPS Adder." For a detailed explanation of the rationale behind these calculations/adjustments, please see appendix III.

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[205] For example, see: Alberta Utilities Commission, "Decision DA2014-207," September 8, 2014.
[206] Alberta Utilities Commission, "Decision 20347-D01-2015" July 21, 2015, para 22, page 8 (pdf).

3.2.2.3 DERS

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2011	7	71.1	89.6	6.6	114,600	$2,124,859	$760,671	$2,885,530
2011	8	140.9	121.8	7.1	115,332	-$2,209,623	$821,137	-$1,388,486
2011	9	106.7	73.1	6.4	115,916	-$3,896,661	$740,214	-$3,156,447
2011	10	73.7	115.4	7.0	127,111	$5,304,521	$887,525	$6,192,045
2011	11	127.5	82.7	6.4	147,033	-$6,592,128	$947,893	-$5,644,234
2011	12	57.8	123.4	7.0	156,856	$10,275,996	$1,100,379	$11,376,375
2012	1	98.5	140.8	7.2	157,139	$6,653,231	$1,136,921	$7,790,152
2012	2	46.5	129.3	7.1	136,978	$11,351,046	$973,132	$12,324,179
2012	3	55.0	76.4	6.3	127,604	$2,731,500	$805,871	$3,537,371
2012	4	43.4	65.3	6.2	109,287	$2,392,481	$679,114	$3,071,596
2012	5	31.6	55.1	6.1	101,778	$2,383,480	$619,140	$3,002,620
2012	6	55.3	68.7	6.3	97,737	$1,306,975	$616,191	$1,923,166
2012	7	82.7	81.4	6.5	105,512	-$134,444	$683,510	$549,066
2012	8	63.6	103.5	6.8	103,602	$4,136,463	$707,477	$4,843,939
2012	9	120.8	98.6	6.7	97,400	-$2,154,911	$656,344	-$1,498,568
2012	10	102.7	90.7	6.6	114,176	-$1,361,980	$754,090	-$607,890
2012	11	97.4	66.4	6.2	132,116	-$4,089,614	$819,208	-$3,270,406
2012	12	63.2	77.3	6.4	154,770	$2,184,748	$983,450	$3,168,199
2013	1	62.7	85.2	6.5	144,383	$3,248,173	$934,030	$4,182,203
2013	2	29.5	68.8	6.3	119,795	$4,701,807	$751,072	$5,452,879
2013	3	112.1	64.8	6.2	125,426	-$5,937,525	$779,673	-$5,157,851
2013	4	143.9	75.7	6.4	108,094	-$7,378,697	$695,178	-$6,683,519
2013	5	138.5	63.3	6.3	96,418	-$7,254,941	$605,346	-$6,649,595
2013	6	119.8	69.1	6.4	93,853	-$4,760,704	$600,137	-$4,160,567
2013	7	63.4	104.2	6.9	97,301	$3,970,152	$667,255	$4,637,406
2013	8	94.0	103.1	6.9	96,880	$883,605	$664,300	$1,547,905
2013	9	125.5	106.7	6.9	95,078	-$1,786,239	$659,579	-$1,126,660
2013	10	69.8	73.8	6.4	105,174	$428,133	$670,800	$1,098,932
2013	11	30.2	71.9	6.3	125,620	$5,238,701	$795,756	$6,034,458
2013	12	56.4	69.4	6.3	155,912	$2,022,870	$977,138	$3,000,008
2014	1	48.3	70.9	6.3	136,106	$3,068,785	$855,042	$3,923,826
2014	2	99.0	64.5	6.2	116,807	-$4,023,895	$727,956	-$3,295,939
2014	3	44.9	66.2	6.2	120,888	$2,573,690	$751,300	$3,324,990
2014	4	31.2	62.3	6.2	105,410	$3,275,503	$651,920	$3,927,423

		$/MWh			MWh	$		
		A	B	C	D	E=(B-A)*D	F=(C*D)	G=E+F
Year	Month	WAPP	BEC	FMPS Adders	Actual Usage	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
2014	5	56.3	101.7	6.8	93,974	$4,262,802	$640,555	$4,903,357
2014	6	43.7	46.7	6.0	90,427	$277,016	$543,057	$820,073
2014	7	132.8	69.9	6.3	93,365	-$5,871,577	$592,420	-$5,279,157
2014	8	47.6	78.9	6.5	94,699	$2,956,946	$612,140	$3,569,086
2014	9	24.4	81.5	6.5	92,697	$5,290,922	$604,128	$5,895,050
2014	10	27.4	77.1	6.4	102,040	$5,076,459	$653,726	$5,730,185
2014	11	38.7	54.7	6.0	123,237	$1,974,991	$741,532	$2,716,523
2014	12	27.3	64.7	6.1	152,831	$5,717,817	$932,419	$6,650,236
2015	1	35.1	65.8	6.2	133,211	$4,081,732	$820,399	$4,902,131
2015	2	33.7	50.9	6.0	120,844	$2,078,577	$721,446	$2,800,023
2015	3	20.8	41.4	5.8	122,522	$2,520,158	$715,440	$3,235,598
2015	4	20.7	43.3	5.9	99,984	$2,258,308	$592,450	$2,850,759
2015	5	55.7	37.5	5.9	91,779	-$1,674,085	$538,705	-$1,135,380
2015	6	105.0	30.7	5.8	88,943	-$6,607,275	$513,763	-$6,093,511
2015	7	23.7	77.8	6.5	93,176	$5,040,835	$606,860	$5,647,696
2015	8	35.6	68.3	7.3	92,772	$3,032,293	$679,012	$3,711,305
2015	9	21.0	46.3	7.0	90,386	$2,282,207	$632,526	$2,914,733
2015	10	21.7	46.3	7.0	98,868	$2,437,273	$689,300	$3,126,573
2015	11	21.6	41.8	6.8	122,305	$2,477,892	$835,839	$3,313,731
2015	12	21.2	43.2	6.8	142,662	$3,139,638	$972,217	$4,111,855
2016	1	22.5	40.1	6.8	135,407	$2,373,028	$917,937	$3,290,965
2016	2	17.4	35.8	6.8	117,483	$2,170,283	$793,165	$2,963,448
2016	3	14.8	33.8	6.7	112,065	$2,129,418	$755,275	$2,884,693
2016	4	13.7	25.4	6.7	88,445	$1,036,388	$591,610	$1,627,998
2016	5	16.1	24.7	6.7	88,192	$759,696	$589,207	$1,348,903
2016	6	15.7	27.6	6.7	87,661	$1,046,927	$590,291	$1,637,217

The following table shows the total, summary results for this EPSP in June, 2016 dollars:[207]

[207] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index each month's dollar values to June, 2016 dollars.

Table 13: Summary Results for Second DERS EPSP

	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
Total ($)	$82,246,202	$46,443,300	$128,689,501
Average ($/MWh)	12.05	6.80	18.85
Average ($/Month)	$1,370,770	$774,055	$2,144,825
Median ($/Month)	$2,311,817	$740,589	$3,141,602

Notes on this analysis:

1) Each month's WAPP was calculated using hourly Pool price data from the AESO. The hourly usage data used to calculate the WAPP from July, 2011 January, 2014 (inclusive) if from AUC Exhibit 0117.03.DEML-2941. DERS has not publicly provided hourly usage data for the time period post-January, 2014. Therefore, for February, 2014 to June, 2016 (inclusive) the AIL weighted average Pool price is used for each month instead. This means that, post-January, 2014, the WAPP values in column A are inaccurate to the extent that the AIL WAPPs differed from the WAPPs based on DERS' hourly actual usage.

   Since 2013 is that most recent full year for which DERS' actual monthly WAPPs can be calculated using publicly available data, it can be used to get some sense of how the monthly AIL WAPPs compared to DERS' actual monthly WAPPs. Over 2013, the monthly AIL WAPP was 4% lower, on average, than DERS' actual monthly WAPP.[208] Whether or not this relationship was similar post-January, 2014 is obviously impossible to know without DERS' hourly data; however, it provides some inclination that the monthly WAPP values in column A *may* be slightly lower than the values that actually materialized over this time period. If this is the case,

[208] Calculated using Pool price and AIL data from the AESO.

then the Base Energy Outcomes and, by extension, the Total Energy Outcomes post-January, 2014, *may* also be slightly too high.

2) From July, 2011 to January, 2014 (inclusive), the monthly "Actual Usage" in column D is calculated from the hourly usage data contained in AUC Exhibit 0117.03.DEML-2941. DERS has not publicly provided monthly usage data for the time period post-January, 2014; therefore, for February, 2014 to June, 2016 (inclusive), the "Actual Usage" in column D is the forecast total usage, taken from the DERS' monthly filing workbooks.

   This means that, post- January, 2014, the "Actual Usage" values in column D differ from those that actually materialized in an amount equal to the forecast error for each month. However, DERS' forecasts of monthly usage have historically been extremely accurate; for example, over 2013 (the most recent full year with publicly available usage data) DERS only had a monthly forecast error of 7%.[209] Whether or not DERS has had similar monthly forecast accuracy post-January, 2014 is obviously impossible to know without DERS' actual usage data; however, it provides some assurance that the "Actual Usage" values in column D, post-January, 2014, are likely accurate within a very small margin of error that does not materially affect the results of the analysis.

3) Each month's weighted average BEC was calculated using data from DERS' monthly filing workbooks. The BEC was calculated for each month as the weighted average

[209] Calculated using forecast usage from DERS' monthly filing workbooks and actual usage from AUC Exhibit 0117.03.DEML-2941.

"45 Day Energy Charge" (45EC) for all rate classes using the forecast load by rate class data in the "Rate Class Data" tab of the monthly filing workbooks.

4) The adders included in the "FMPS Adders" in column C were taken from DERS' monthly filing workbooks. The weighted average adder for all rate classes was calculated using the forecast load for each rate class from the monthly filing workbooks. The adders and their individual values over the EPSP in June, 2016 dollars are:[210]

    a. Parental Corporate Guarantees and Letters of Credit (PCG & LOC) – **Value over EPSP = $288,334**

These were the credit costs associated with having to provide financial security to the counterparties from whom DERS purchased electricity and hedges.[211] Fortunately, DERS listed the credit costs for the AESO and for hedging separately in its monthly filing workbooks; since only the credit costs associated with hedging are considered to be as a result of monthly forward market price setting, only they are included in the "FMPS Adders."

    b. Transaction Charges (TC) – **Value over EPSP = $205,176**

These are the costs "associated with over-the-counter (OTC) arrangements, broker fees, and NGX fees."[212] This adder is considered to be a result of monthly forward market

[210] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index the dollar values of each adder over the EPSP to June, 2016 dollars.
[211] Alberta Utilities Commission, "Decision 2011-199," May 5, 2011, para. 39, page 14 (pdf).
[212] Direct Energy Regulated Services, "APPLICATION FOR APPROVAL OF A NEGOTIATED SETTLEMENT RESPECTING AN ENERGY PRICE SETTING PLAN TO ESTABLISH REGULATED RATES FOR ELIGIBLE CUSTOMERS IN THE ATCO ELECTRIC LTD. SERVICE AREA DURING THE PERIOD JULY 1, 2011 THROUGH JUNE 30, 2014," February 9, 2011, AUC Application #1607016, para. 72, page 20 (pdf).

price setting because these costs relate to hedging (procurement) and would not have been incurred under monthly PPFT price setting.

c. Risk Compensation (RCOMP) – **Value over EPSP = $30,041,995**

This adder provided compensation for both non-commodity and commodity risk. Specifically, "load forecast risk," "recovery risk," "credit default risk," "balancing energy," and "price and volume risk."[213] These risks, although explained, were not individually quantified in DERS' EPSP. This makes it impossible to quantify exactly what portion of this adder can be attributed to monthly forward market price setting, and therefore included in the analysis as a "FMPS" adder.

Nonetheless, I consider all of these risks to be a result of monthly forward market price setting. "Credit default risk" because it results from the procurement of hedges, and "balancing energy" and "price and volume risk" because they are commodity related risks.[214] As previously explained, commodity risk would not exist under monthly PPFT price setting, and is therefore attributable to monthly forward market price setting. I consider the first two risks - "load forecast risk" and "recovery risk" – to be non-commodity risks that would not exist under monthly PPFT price setting because no load forecasting would be required and the recovery of costs would be guaranteed.

d. Incentive Payments (IP) – **Value over EPSP = $1,887,277**

This was an adder designed to pay DERS $30,000 per month for achieving certain "operational functions," including "posting of bids on NGX" and "performance of the

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[213] Alberta Utilities Commission, "Decision 2011-199," May 5, 2011, paras. 32 – 37, pages 12 and 13 (pdf).
[214] Direct Energy Regulated Services, "APPLICATION FOR APPROVAL OF A NEGOTIATED SETTLEMENT RESPECTING AN ENERGY PRICE SETTING PLAN TO ESTABLISH REGULATED RATES FOR ELIGIBLE CUSTOMERS IN THE ATCO ELECTRIC LTD. SERVICE AREA DURING THE PERIOD JULY 1, 2011 THROUGH JUNE 30, 2014," February 9, 2011, AUC Application #1607016, paras. 51 and 53, pages 13 and 14 (pdf).

trader."[215] All of these functions are considered to be in service of hedging (procurement). As a result, this adder is considered to be a result of forward market price setting and would not have been incurred under monthly PPFT price setting.

e. Return Margin (RM) – **Value over EPSP = $14,020,517**

This adder was carried over from its previous EPSP, and paid to DERS as its "all-in-one" reasonable return for both the "energy" and "non-energy" sides of its RRO business.[216] I calculated the "energy" portion of this reasonable return as being 90.3% of the total adder, which is consistent with the AUC's calculations for DERS' reasonable return in Decision 2010-055. I then multiplied this value by 0.85 and included the resulting value as an "FMPS Adder." For a detailed explanation of the rationale behind these calculations/adjustments, please see appendix III.

3.2.2.4 Summary

The following table shows the total, summary results for all three of the 2011 – 2014 EPSPs in June, 2016 dollars:[217]

Table 14: Summary Results for Second Set of EPSPs

	Base Energy Outcome	**Total Cost of FMPS Adders**	**Total Energy Outcome**
Total ($)	$345 M	$301 M	$645 M
Average ($/MWh)	8.37	7.30	15.67
Average ($/Month)	$6 M	$5 M	$11 M
Median ($/Month)	$13 M	$5 M	$18 M

Based on this analysis, monthly forward market price setting is estimated to have cost RRO customers approximately $645 million over the course of the 2011 – 2014 EPSPs. In other

[215] Alberta Utilities Commission, "Decision 2011-199," May 5, 2011, page 34 (pdf).
[216] Ibid., para. 45, page 15 (pdf).
[217] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index each month's dollar values to June, 2016 dollars.

words, all else being equal, RRO customers could have paid $645 million less over this time period if monthly PPFT price setting had been used instead. This amount translates into the following average reduction in monthly RRO Energy Charges for each RRO provider:

Table 15: Average Reduction in Energy Charges (Second Set of EPSPs)

	Average Reduction in Monthly RRO Energy Charges ($/MWh/Month)
EEA	14.09
EEC	13.97
DERS	17.40
Average	15.15

Therefore, on average, the monthly Energy Charge paid by RRO customers would have been $15.15/MWh lower under monthly PPFT price setting. This equals $0.01515/KWh, which on an average monthly residential bill of 600 KWh would translate to a savings of $9.09.

3.2.3 Summary of Results for Both Sets of EPSPs

The following table shows the total, summary results for both sets of EPSPs for all three RRO providers from July, 2006 to June, 2016 (inclusive) in June, 2016 dollars:[218]

Table 16: Summary of Results for Both Sets of EPSPs

	Base Energy Outcome	Total Cost of FMPS Adders	Total Energy Outcome
Total ($)	$452 M	$570 M	$1022 M
Average ($/MWh)	5.01	6.31	11.33
Average ($/Month)	$4 M	$5 M	$9 M
Median ($/Month)	$13 M	$5 M	$18 M

Based on this analysis, monthly forward market price setting is estimated to have cost RRO customers approximately $1.022 billion over the course of both sets of EPSPs. In other

[218] The Statistics Canada "All-items" Consumer Price Index for Alberta was used to index each month's dollar values to June, 2016 dollars.

words, all else being equal, RRO customers could have paid $1.022 billion less over this time period if monthly PPFT price setting had been used instead. This amount translates into the following average reduction in monthly RRO Energy Charges for each RRO provider:

Table 17: Average Reduction in Energy Charges (Both Sets of EPSPs)

	Average Reduction in Monthly RRO Energy Charges ($/MWh/Month)
EEA	10.62
EEC	11.10
DERS	14.70
Average	12.14

Therefore, on average, the monthly Energy Charge paid by RRO customers would have been $12.14/MWh lower under monthly PPFT price setting. This equals $0.01214/KWh, which on an average monthly residential bill of 600 KWh would translate to a savings of $7.28.

4 The Benefits of the "New" RRO?

Section 3 estimated the cost of the government's choice of rate design for the "New" RRO, which I have termed "monthly forward market price setting." This cost was estimated by comparing what RRO customers paid as a result of monthly forward market price setting to what RRO customers would have paid under monthly Pool price flow-through price setting. However, as explained in section 2.1, after considering six different rate design options (including PPFT price setting), the government concluded that, in addition to having certain "advantages," monthly forward market price setting would be the most conducive to meeting its objectives for the "New" RRO. Thus, according to the government, these "advantages" and the meeting of its objectives were ostensibly to be the benefits of monthly forward market price setting relative to PPFT price setting. The question is, did these benefits materialize, and if so, did they outweigh the estimated billion-dollar cost of monthly forward market price setting relative to monthly PPFT price setting? After examining them each individually in this section, the answer is arguably "no."

4.1 The Government's Objectives for the "New" RRO

As explained in section 2.1, the government's first objective for the "New" RRO was "appropriate protection." With respect to rate design, this was largely related to reducing RRO customers' exposure to wholesale market (Pool price) volatility. The second objective, "retail market development," related to having an RRO that facilitated the entry of unregulated (called "competitive") retailers into the retail market, and having RRO customers switch to those retailers. Each of these objectives are evaluated individually as follows:

4.1.1 Appropriate Protection

Remember from section 2.1 that, prior to the RROR, the government had tabled the Regulated Default Supply (RDS) Regulation, which was supposed to have taken effect on July 1, 2006. This regulation would have required the RRO providers to use monthly PPFT price setting, but was repealed before it could take effect due to, in part, concerns over potential rate "volatility."[219] In its 2010 Retail Market Review paper, the Alberta Department of Energy explains this concern by stating that "[o]ne of the policy objectives

[219] The other reason it was repealed was because of the concern that RRO customers would not know the RRO rate in advance of consumption. This concern is addressed individually section 4.2.1.

for changing from a Pool price flow-through to [forward market price setting] was to moderate the month-month price fluctuations for consumers."[220]

In that same 2010 paper, the government tested whether this policy objective was being met by comparing the average month-to-month change in RRO Energy Charges that would have been experienced under the originally planned monthly PPFT price setting of the RDS regulation to the those that were actually experienced under EEA's then current EPSP. It did so by comparing the average absolute percentage month-to-month change of EEA's WAPP to the percentage month-to-month change of its actual RRO Energy Charge from July, 2008 to June, 2009 (inclusive).

Based on this analysis, the government found that the average absolute month-to-month price change under monthly PPFT price setting would have been 19%, whereas for the actual monthly RRO Energy Charge it was only 11%.[221] In other words, according to the government's analysis, the average magnitude of the month-to-month change in EEA's Energy Charge under monthly PPFT price setting would have been 8 percentage points (53%) higher than it actually was under monthly forward market price setting.[222] On this basis, the government concluded that "the new regulated rate removes much of the volatility from the wholesale market."[223]

The government's comparative analysis of the average magnitude of the month-to-month change of both prices was, however, quite limited: it only used data from one RRO

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[220] Alberta Department of Energy, "Retail Market Review: An Update and Review of Market Metrics," April 15, 2010: http://www.energy.alberta.ca/electricity/pdfs/retailmarketreview.pdf, page 21 (pdf).
[221] Ibid., page 23 (pdf).
[222] The percentage difference is calculated as the difference between the two values divided by the average of the two values multiplied by 100.
[223] Alberta Department of Energy, "Retail Market Review: An Update and Review of Market Metrics," April 15, 2010: http://www.energy.alberta.ca/electricity/pdfs/retailmarketreview.pdf, page 29 (pdf).

provider (EEA), and only for one year of the "New" RRO, and it was only conducted using one metric (the average absolute month-to-month percentage change). The following tables provide an updated and expanded comparative analysis; provided for both the WAPP and the BEC for each RRO provider are 1) their average absolute month-to-month percentage change, like what the government calculated in its Review paper, and; 2) their standard deviation. The analysis for both sets of EPSPs (July, 2006 – June, 2011 and July, 2011 – June, 2016 inclusive) is as follows:

Table 18: Average Magnitude of Monthly Change (EEA)

		EEA			
		EPSP #1		**EPSP #2**	
		Average Abs. % Δ	**Std. Dev. ($/MWh)**	**Average Abs. % Δ**	**Std. Dev. ($/MWh)**
A	**WAPP**	36%	35.3	47%	38.5
B	**BEC**	12%	16.8	16%	24.0
C=A-B	**Difference**	**24 pp. (101%)**	**18.5**	**30 pp. (97%)**	**14.4**

Table 19: Average Magnitude of Monthly Change (EEC)

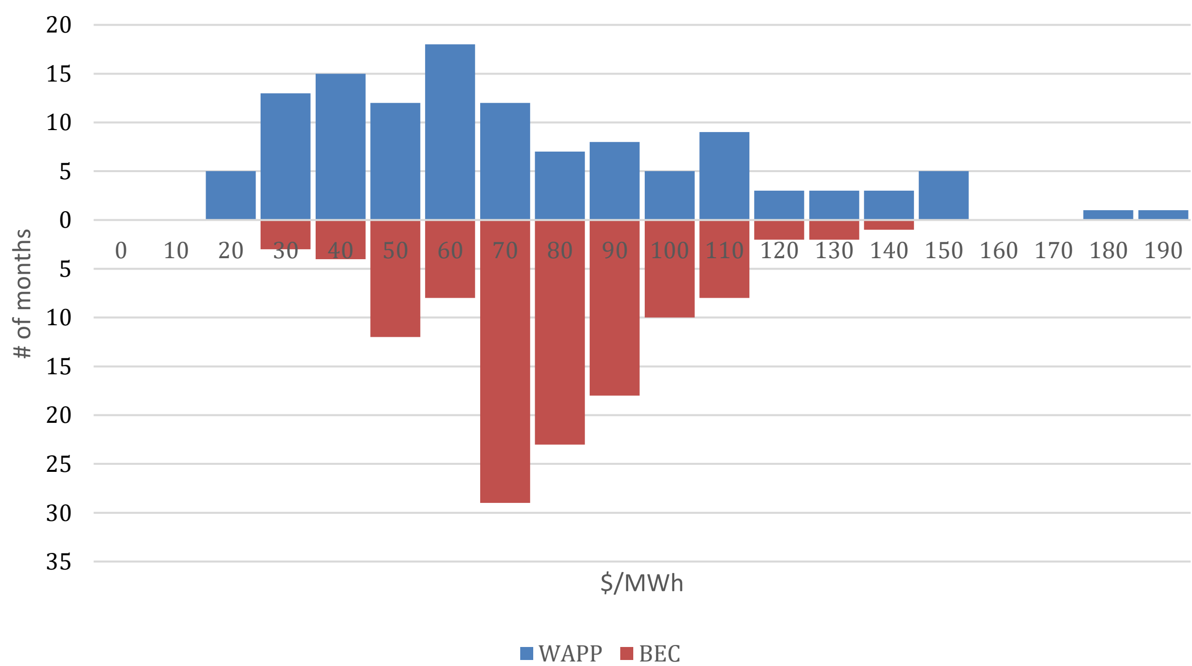
		EEC			
		EPSP #1		**EPSP #2**	
		Average Abs. % Δ	**Std. Dev. ($/MWh)**	**Average Abs. % Δ**	**Std. Dev. ($/MWh)**
A	**WAPP**	37%	36.7	47%	40.0
B	**BEC**	12%	16.9	20%	25.8
C=A-B	**Difference**	**25 pp. (101%)**	**19.8**	**28 pp. (83%)**	**14.2**

Table 20: Average Magnitude of Monthly Change (DERS)

		DERS			
		EPSP #1		**EPSP #2**	
		Average Abs. % Δ	**Std. Dev. ($/MWh)**	**Average Abs. % Δ**	**Std. Dev. ($/MWh)**
A	**WAPP**	36%	35.6	46%	38.8
B	**BEC**	13%	15.0	21%	26.7
C=A-B	**Difference**	**23 pp. (96%)**	**20.5**	**26 pp. (77%)**	**12.1**

Both of these metrics indicate that, over the course of both sets of EPSPs, the average magnitude of the monthly change in the WAPP was substantially higher than it was for the BEC. For the purposes of this paper, however, the concept of "volatility" is considered to encompass more than just the average magnitude of monthly price changes. The range and general distribution of the WAPP and BEC are also useful for understanding the extent to which RRO customers were "protected" by monthly forward market price setting. To illustrate, the following figure shows the distributions of both the average WAPP and BEC for both sets of EPSPs:[224, 225]

Figure 7: Distributions of Average WAPP and BEC



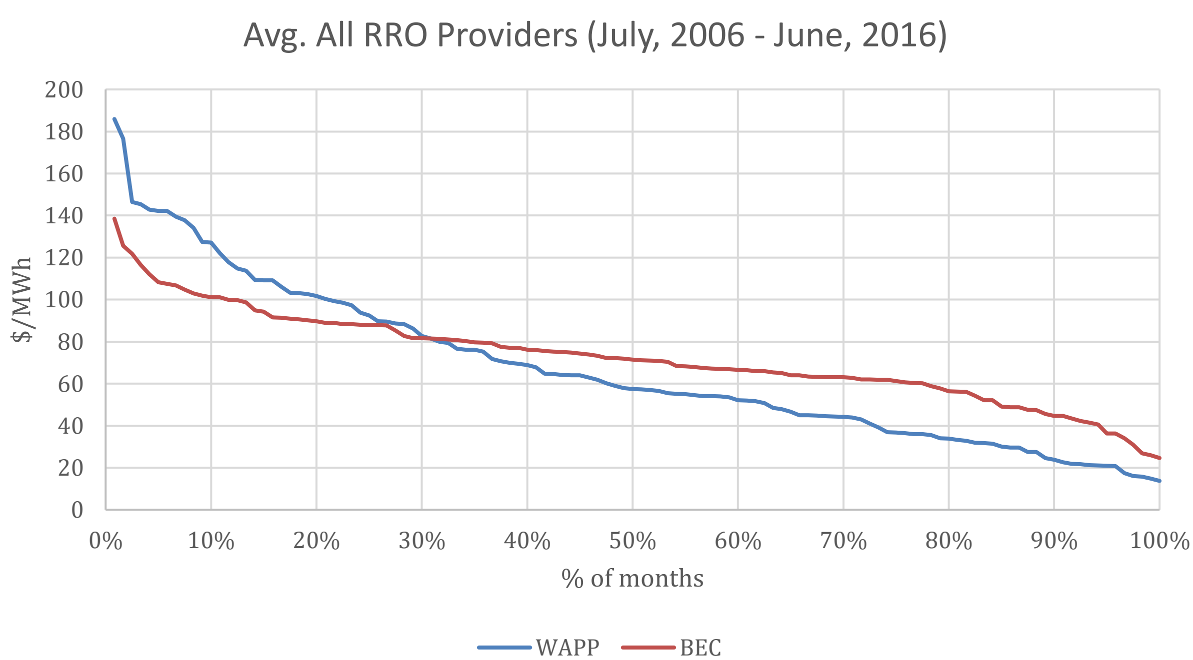
[224] Note: The values on the x-axis represent the upper-bound for each bin. For example, the x-axis value of $30/MWh includes the number of observations greater than $20/MWh and up to and including $30/MWh. For the average WAPP, there are 13 observations in this bin, whereas for the BEC, there are only 3.

[225] The values are averaged across the RRO providers for the sake of brevity (i.e. not having to provide a chart for each RRO provider). The values of the WAPP and BEC for all three RRO providers are extremely close, so averaging them results in extremely accurate values.

As can be seen, the range of the average WAPP was greater than it was for the average BEC. Importantly, the average WAPP exceeded $110/MWh in many more months than did the average BEC (16 to 5, exactly). Therefore, it had more and higher outliers on the upper end of its distribution. As can be seen, these characteristics of the distributions of both prices are obviously important when considering the extent to which RRO customers were "protected" by monthly forward price setting, and so are included in the concept of "volatility."

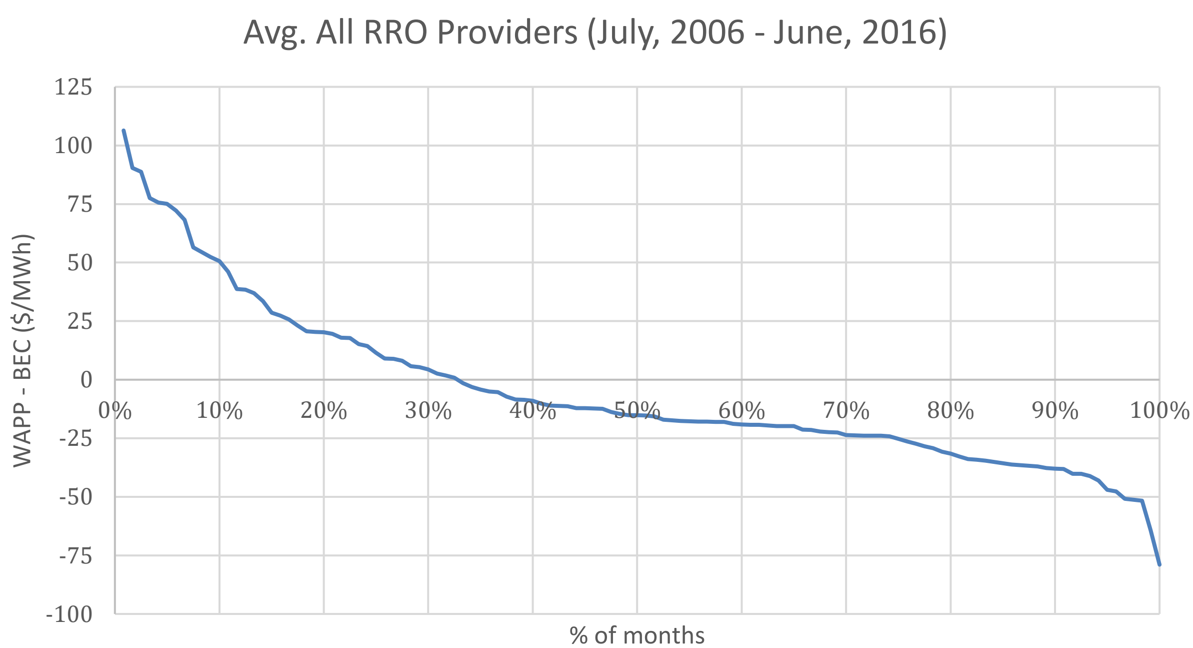
The distributions of the average WAPP and BEC can also be visualized using duration curves, which sort their values from highest to lowest and plot them as a proportion of the 120 months of both EPSPs:

Figure 8: Average WAPP vs. BEC Duration Curve



These curves show that the average WAPP had a higher range than the average BEC, with a maximum of $186/MWh and a minimum of $14/MWh, as opposed to a maximum of $139/MWh and a minimum of $25/MWh for the BEC. The following duration curve shows the difference between the average WAPP and the average BEC for each month (across all three RRO providers) sorted from highest to lowest and plotted as a proportion of the 120 months of both EPSPs:

Figure 9: Difference Between Average WAPP and BEC Duration Curve

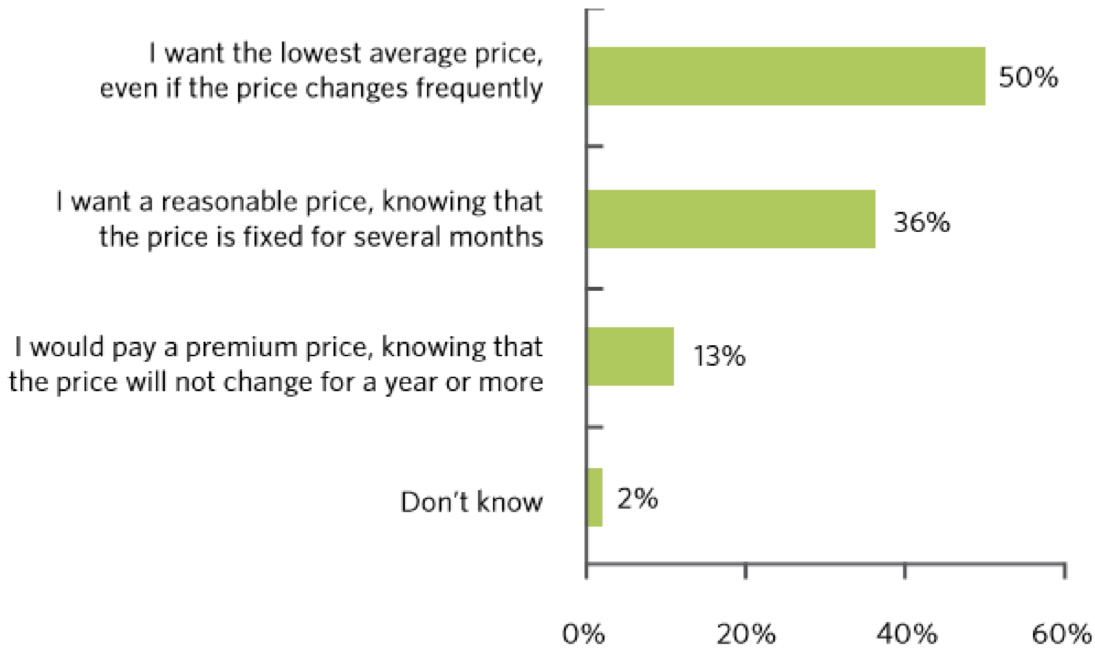


This curve shows that the maximum positive difference between the average WAPP and the average BEC was $106/MWh. The maximum negative difference between the average WAPP and the average BEC was $79/MWh. Additionally, the average WAPP was higher than the average BEC in one third (33%) of months. Over the one third of months for which the average WAPP exceeded the average BEC, it did so by $35/MWh on average. Over the two thirds (66%) of months for which the average BEC exceeded the average WAPP, it did so by $25/MWh on average.

Based on the preceding analyses, monthly forward market price setting did reduce RRO customers' exposure to volatility (as defined above) relative to monthly PPFT price setting. However, as calculated in section 3.2, monthly forward market price setting also came at substantial cost to RRO customers relative to monthly PPFT price setting. Therefore, RRO customers effectively paid a premium to be "protected" from month-to-month volatility. The question is, did RRO customers benefit from this "protection?" There are two reasons why the answer is arguably "no."

First, consumer preferences with respect to price and volatility vary. A telephone survey conducted by the Retail Market Review Committee as part of its 2012 report asked a large sample of Albertans a series of questions related to "volatility and pricing preferences," and its results are captured by the following figure:[226]

Figure 10: RMRC Survey Results #1



The results of the survey are articulated by the RMRC as follows:

> Although 52% of Albertans say they prefer a fixed annual price to one that changes monthly or quarterly, only 13% say they are willing to pay a premium for it. And

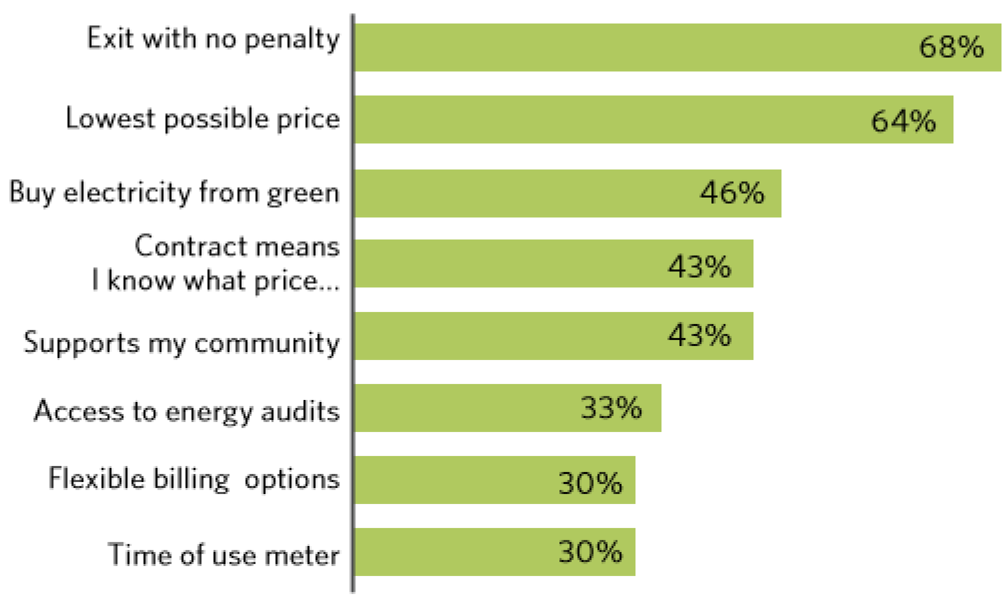
[226] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, pages 91 and 92 (pdf).

50% of Albertans say they prefer paying the lowest possible price, even if that means their bill changes frequently.[227]

Based on these results, the RMRC concluded that "Albertans' desire for longer-term, fixed-price arrangements is in conflict with their willingness to pay a premium to guarantee fixed prices."[228] It is important to note that these results only explicitly relate to the *frequency* with which prices change, and not necessarily the *magnitude* with which they change. Nonetheless, changes of any frequency are, by definition, of *some* magnitude, and therefore these responses do provide some indication of preferences in this regard. As indicated by the survey responses, half of Albertans want the lowest average price, even if it changes frequently, necessarily with *some,* in this context, undefined magnitude.

Another survey conducted by the RMRC with respect to "buying considerations" yielded the following results:[229]

Figure 11: RMRC Survey Results #2



[227] Ibid., page 22 (pdf).
[228] Ibid., page 96 (pdf).
[229] Ibid., page 95 (pdf).

Based on these survey results, the RMRC concluded that "consumer opinions and preferences vary a great deal," but that "price was a top priority for Albertans…"[230,231] As can be seen, 64% of Albertans "felt it was important to get the lowest possible price," whereas only "43% felt it was important to have an electricity contract with a stable price each month.[232] The first conclusion that can be drawn from these results is that the reduction in volatility as a result of monthly forward market price setting and its associated cost relative to monthly PPFT price setting resulted in winners and losers amongst RRO customers. Specifically, those RRO customers who wanted the "lowest possible price," presumably regardless of other considerations, were made worse off.

Given this conclusion, the logical question is naturally "what was the net result?" In other words, did the winners collectively "win" by more than the losers "lost?" It is impossible to answer this question with certainty. However, given the RMRC's survey results, it appears that at least half of RRO customers probably would not have preferred trading the lower monthly bills they would have experienced under monthly PPFT price setting (on average) for the increased stability in their monthly bills as a result of monthly forward market price setting.

The second reason why RRO customers probably did not derive much benefit from this "premium for protection" is the fact, over the time period being considered, the retail market was able to offer RRO customers better "protection" from volatility at lower prices than the government. This was shown in the Utilities Consumer Advocate's evidence for AUC proceeding #2941, in which it calculated that, from 2006 to 2012 (inclusive), three

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230 Ibid., page 96 (pdf).
231 Ibid., page 94 (pdf).
232 Ibid., page 95 (pdf).

and five-year contracts were "cumulatively less costly than the RRO."[233] Specifically, the UCA calculated an average residential customer's spending on the RRO and compared it to the same customer's spending on the lowest price three or five-year product. Its findings are provided in the following table:[234]

Table 21: Cost of RRO vs. Long-term Fixed Price Contracts

	Five-Year Products			Three-Year Products			
Starting Year	Savings (Costs)	Average Savings per Month	Average Percent Saved per Month	Savings (Costs)	Average Savings per Month	Average Percent Saved per Month	Average RRO Cost per Month
2006	$246.19	$4.10	8.17%	n/a	n/a	n/a	$50.24
2007	$642.55	$10.71	20.32%	n/a	n/a	n/a	$52.71
2008	$294.28	$4.90	9.27%	n/a	n/a	n/a	$52.90
2009	$176.75	$2.95	5.78%	n/a	n/a	n/a	$50.95
2010	$167.51	$3.16	6.18%	$131.75	$3.66	7.15%	$51.16
2011	$263.11	$6.42	11.81%	$310.63	$8.63	15.87%	$54.36
2012	$149.20	$5.14	9.68%	($24.80)	($0.86)	-1.61%	$53.14
2013	($1.86)	($0.11)	-0.22%	($7.98)	($0.47)	-0.93%	$50.23
2014	($25.33)	($5.07)	-10.76%	($22.33)	($4.47)	-9.49%	$47.07

As can be seen, the savings from these long-term fixed price contracts was "in some instances significant."[235] However, starting in 2013, these long-term, fixed price contracts did not result in savings over the RRO due to the average RRO Energy Charge being lower than the three and five-year product prices.[236] Nevertheless, the fact remains that over much of the course of the "New" RRO, there were retail options available that were *both* less volatile and less expensive than the RRO. By extension, it is logical to conclude that those RRO customers with strong preferences with respect to volatility very likely would have switched over this time period. This means that the consumers who would have

[233] AUC Exhibit 0139.12.UCA-2941, Utilities Consumer Advocate, "Evidence for AUC proceeding #2941," June 4, 2014, page 17 (pdf).
[234] Ibid., page 19 (pdf).
[235] Ibid.
[236] Ibid.

benefitted the most from the reduction in volatility provided by monthly forward market price setting probably were not even on the RRO over much of the time period being considered.

4.1.2 Retail Market Development

Remember that, in addition to "appropriate protection," the Alberta government's other objective for the RRO has been "retail market development." Its evaluation of "retail market development" has included numerous metrics, including:[237]

- The "customer switching rate," which is "the percentage of customers who have signed a contract with a competitive retailer,"
- "Product diversity," which is "the different types of products offered by competitive retailers,"
- "Market concentration," which is "the number of firms in the market and their respective market shares;" and,
- "Number of retailers," which is "the number of retailers serving different customer groups in Alberta's retail electricity market."

In its 2010 Retail Market Review paper, the government concluded that each one of these metrics was being satisfactorily met by the "New" RRO. It did so on the grounds that customer switching was around 30 percent, 14 retailers were offering a total of 15 different products, and market concentration was sufficiently low to not warrant concern.[238] The government also took assurance from two independent reports that ranked Alberta highly with respect to retail market development. The 2010 Annual Baseline

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[237] Alberta Department of Energy, "Retail Market Review: An Update and Review of Market Metrics," April 15, 2010: http://www.energy.alberta.ca/electricity/pdfs/retailmarketreview.pdf, pages 14 – 28 (pdf).
[238] Ibid.

Assessment of Choice in Canada and the US (ABACCUS) report ranked Alberta third for retail market development out of the 24 jurisdictions it surveyed, and the 2008 VassaETT report ranked Alberta as having the 11th highest switching rates of the 50 jurisdictions it surveyed.[239]

Two years after the government's Retail Market Review paper, the RMRC reflected on these same metrics by noting that "[a]s of July 2012, consumers could choose from 12 retail electricity providers who offer about 50 different products, and one-third of residential consumers were off the default rate."[240] With respect to the "market concentration" metric, it ultimately concluded that that the retail market had developed such that it is "competitive or at least reasonably competitive."[241]

Most recent data indicate that the retail market has "developed" even further since the RMRC's report: as of 2014, switching rates averaged about 42%, and according to the 2015 ABACCUS Report, as of December, 2014, 28 retailers offered a total of 99 products to residential customers.[242,243,244] The point is that, according to these metrics, the retail market has become increasingly "developed" since the beginning of the "New" RRO in 2006, when only three retailers offered but a handful of products.[245] The question is, would

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[239] Ibid., page 15 (pdf).
[240] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 107 (pdf).
[241] Ibid., page 168 (pdf).
[242] Alberta Department of Energy, "Switching Percentage By Group," http://www.energy.alberta.ca/electricity/esi/Table1_Electricity_Alberta_ByGroup.pdf.
[243] Distributed Energy Financial Group, "2015 Annual Baseline Assessment of Choice in Canada and the United States," July, 2015, page 73 (pdf).
[244] It is important to note here that 22 of these "retailers" are all part of the UtilityNet & Partners group of "boutique retailers." The Alberta MSA defines them as individual "brands," but only counts them as one retailer. See: MSA, "2014 Retail State of the Market Report," page 16 (pdf).
[245] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 19 (pdf).

the retail market have developed any less if monthly PPFT price setting had been used instead of monthly forward market price setting? The answer is that there is arguably very little reason to conclude that the retail market would not have developed to at least the same extent that it did under monthly forward market price setting.

Keep in mind that under monthly PPFT price setting monthly RRO Energy Charges would have been *lower* over the course of both EPSPs (see section 3.2.3) and the month-to-month volatility would have been *higher* (see section 4.1.1), on average. Therefore, the first question is "would RRO customers have switched to competitive retailers more or less than they did under monthly forward market price setting?" If RRO customers would have switched in greater numbers than they actually did, then it could be argued that monthly PPFT price would have actually been more conducive to retail market development; and naturally the opposite if they would have switched less.

It stands to reason that if both average prices and volatility decrease, the RRO becomes more attractive to customers relative to other retail options and they are less inclined to switch; and of course the opposite if they both increase. In the case of monthly PPFT price setting, under which average RRO Energy Charges would have been lower and volatility would have been higher, definitive conclusions are hard to draw either way. According to the Market Surveillance Administrator, RRO customers tend to switch in response to volatility; specifically, months with "blow-out" RRO Energy Charges:

> It appears that trends in switching rates consistently lag corresponding trends in relative RRO prices by one month, indicating that residential consumers tend to switch to competitive contracts more readily after a month of high RRO prices. This seems intuitively plausible despite the public availability of RRO prices ahead of

time; it is likely that residential electricity consumers respond to high RRO prices immediately after they see their bill for the previous month.[246]

In this case, monthly PPFT price setting would have been more conducive to switching than monthly forward market price setting. To illustrate, as shown in Figure 7, the average WAPP exceeded $110/MWh in 16 of 120 months. The average BEC, on the other hand, only exceeded $110/MWh in 5 of 120 months. Additionally, the maximum average BEC was $139/MWh; the average WAPP exceeded this amount in 8 months. These descriptive statistics indicate that, under monthly PPFT price setting, there would have been more months of high, “blow-out” prices and thus, based on the MSA’s observation, likely more switching.

In addition to the MSA’s observation, other relationships between site count and RRO Energy Charges have been found. For example, in its rebuttal evidence for AUC proceeding #2941, EEA argued that “there is a direct relationship between the level of the RRO charges and the attrition EEA experiences. The higher the prices, the lower the RRO site count.”[247] Using its own historical site counts and RRO Energy Charges, it calculated a strong negative relationship (with a coefficient of -0.7) between “total site count and the 12 month rolling average RRO rate lagged by 6 months over the January 2008 to April 2014 time period.”[248,] It should be noted that the UCA argued that this observed relationship was “spurious” on the grounds that consumers probably do not “base their decision to leave the

[246] Alberta Market Surveillance Administrator, “2014 Retail State of the Market Report,” November 27, 2014, page 36 (pdf).
[247] Exhibit 0196.02.EEAI-2941, “EEA Rebuttal Evidence for AUC proceeding #2941,” August 20, 2014, page 60 (pdf).
[248] AUC Exhibit 0277.02.UCA-2941, Utilities Consumer Advocate, “Argument,” November 17, 2014, page 17 (pdf).

RRO 6 months ahead of the month in question by calculating their average RRO rate for the past year."[249] However, the fact remains that the relationship was found nonetheless.[250]

Despite these conflicting observations, RRO customers probably derive most of their information about both price level and volatility from a very limited data set (e.g. last month's bill). Consistent with the MSA's observations, it is intuitively plausible that a recent Energy Charge above a certain threshold probably shocks RRO customers and causes them to generally perceive the RRO as both high and volatile relative to other options in the retail market, thus prompting them to search for alternatives. As explained by the RMRC:

> Power prices may spike from month-to-month, but that's a natural thing in the world of electricity, where the effects of weather and facility outages and market pressures make a difference. For the most part, consumers don't notice the valleys, and unless price peaks spike much more dramatically than usual, they pay little attention to their monthly rates.[251]

As a result, given the historical distribution of its prices, it is therefore difficult to definitively conclude that monthly PPFT price setting would have resulted in less RRO customer switching than monthly forward market price setting.

In addition to switching, another consideration with respect to the impact of monthly PPFT price setting on retail market development is the fact that, since 2009, there have been a number of competitive retailers offering PPFT products. As a result, it could be argued that had PPFT price setting been used for the RRO, it could have crowded out these

[249] Ibid.
[250] Ibid.
[251] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 18 (pdf).

retailers and/or their products, thus harming retail market development. In its report, the RMRC acknowledged this argument but made the counter-argument that “pool price flow-through is the option most distant from the core business scope of many of the most active retailers.”[252] The RMRC also went on to argue that having retailers compete to provide PPFT products is not really of value anyway:

> Pool price flow-through would also sterilize a segment of the retail market, as several retailers currently offer pool price flow-through products. However, it can be argued that customers are paying for the pool and market infrastructure that provides this option, and that retailers should be competing on value-added services, not on extracting profits for providing what the market provides at no charge—namely, hourly consumption information and hourly prices.[253]

Notwithstanding their questionable value, it is not necessarily true that having RRO Energy Charges based on monthly PPFT price setting would have “sterilized” those retail offers. Although the manner in which they would have determined the underlying price for electricity would have been the same, the competitive retailers could have aggressively competed with the RRO providers on the non-energy, or what retailers often label as “administrative,” charges. To the extent they would have been more efficient than the RRO providers they could have undercut them and stolen their customers.

Based on the foregoing, there is very little reason to conclude that the retail market would not have developed to at least the same extent that it did under monthly forward market price setting. Even the government has acknowledged that PPFT price setting

[252] Ibid., page 175 (pdf).
[253] Ibid., page 176 (pdf).

would be conducive to "retail market development." According to the UCA, "[a] pool price flow-through–based default rate design that exposed consumers to extensive price volatility would best promote a sustainable competitive retail market."[254] Additionally, when considering options for the RRO's rate design, the Alberta Department of Energy acknowledged in its 2005 Framework paper that PPFT price setting was "likely to stimulate retail competition," the same evaluation it made with respect to the monthly forward market price setting that has been used since then.[255]

4.2 The "Advantages" of Forward Market Price Setting

Remember from section 2.1 that the government cited certain "advantages" of monthly forward market price setting that it used to justify its choice of rate design for the "New" RRO. Like the government's two objectives of appropriate protection and retail market development, these "advantages" are also evaluated individually:

4.2.1 Seeing Prices in Advance of Consumption

Under monthly PPFT price setting, RRO customers would not have known the "price" of the electricity they consumed until after they consumed it. This is because the WAPP charged to each rate class for the month in question, and therefore its RRO Energy Charge, could only be determined after its customers' usage for the month was settled. Forward market price setting, on the other hand, sets the Energy Charge in advance of the month during which consumption occurs; as per Section 12 of the RROR, each RRO provider has to submit its monthly RRO Energy Charge for each rate class to the AUC for approval "no less than 5 business days prior to the commencement of each calendar

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[254] Ibid., page 354 (pdf).
[255] Alberta Department of Energy, "Alberta's Electricity Policy Framework," June 6, 2005: http://www.energy.alberta.ca/Electricity/pdfs/AlbertaElecFrameworkPaperJune.pdf, page 54 (pdf).

month…"[256] As explained in section 2.1, the government stated in its 2005 Framework paper that:

> By using a forward looking price model, customers can see prices in advance of their consumption, and may be able, to some extent, adjust their energy consumption and purchasing patterns.[257]

In this sense, the ability of RRO customers to "see prices in advance of consumption" was certainly a *result* of monthly forward market price setting, but did it have the government's intended effect of having RRO customers adjust their "energy consumption and purchasing patterns?" Using the RRO providers' historical monthly site count and usage data it can be concluded that the answer is likely "no." The following tables provide the correlation coefficients indicating the strength and direction of the linear relationship between each RRO provider's monthly weighted average BEC (across rate classes) and both its total site count and total actual usage:[258]

Table 22: Correlation Coefficients (EEA)

	EEA (January, 2008 - December, 2014)	
	Site Count[259]	**Actual Usage**
Correlation with Monthly BEC	0.16	0.17

[256] Regulated Rate Option Regulation, Alta Reg 262/2005, <http://canlii.ca/t/52f2x> retrieved on 2016-08-26
[257] Alberta Department of Energy, "Alberta's Electricity Policy Framework," June 6, 2005: http://www.energy.alberta.ca/Electricity/pdfs/AlbertaElecFrameworkPaperJune.pdf, page 17 (pdf).
[258] The time periods reflected in the tables were chosen because total site count data has been publicly provided for them.
[259] For the time period from January, 2008 to December, 2010 (inclusive) this data is from AUC Exhibit 0196.06.EEAI-2941; for the time period from January, 2011 to December, 2014 (inclusive) this data is from AUC Exhibit 20342-X0020.

Table 23: Correlation Coefficients (EEC)

	EEC (July 2006 - January, 2014)	
	Site Count[260]	**Actual Usage**
Correlation with Monthly BEC	0.05	0.08

Table 24: Correlation Coefficients (DERS)

	DERS (July, 2006 - July, 2014)	
	Site Count[261]	**Actual Usage**
Correlation with Monthly BEC	-0.03	0.07

As can be seen, there is virtually no correlation between either site count or actual usage with the monthly BEC for any of the RRO providers over the time periods reflected in the tables.[262] This result intuitively makes sense. First off, it seems implausible that the average RRO customer would check the AUC's rate approval postings in the five days prior to a given month, even if they knew where to look (which they very likely do not). Secondly, as explained in appendix II, retail electricity consumers' consumption is very inelastic (unresponsive) to changes in price, so a weak to non-existent relationship between monthly prices and actual usage is to be expected. Finally, even if the average RRO customer did check the AUC's monthly approvals and was aware of the price ahead of consumption, it seems implausible that they would, either in the five days before the beginning of the month or even during the month, switch to a competitive retailer on that

[260] This data is from AUC Exhibit 0101.03.EEC-2941.
[261] For the time period from July, 2006 to June, 2011 this data is from AUC Exhibit 0117.06.DEML-2941; for the time period from July, 2011 to July, 2014 this data is from AUC Exhibit 0243.08.DEML-2941.
[262] Upon examination of the associated scatter plots there is clearly no type of relationship between these variables and the BEC, linear or otherwise; these charts are simply omitted for the sake of brevity.

basis. Thus, a weak to non-existent relationship between monthly prices and total site count is also to be expected.

These results are corroborated by observations made by various stakeholders with respect to both default electricity and natural gas in Alberta. The MSA has observed that RRO customers tend to switch in response to their monthly bills, not the price posted ahead of the month:

> It appears that trends in switching rates consistently lag corresponding trends in relative RRO prices by one month, indicating that residential consumers tend to switch to competitive contracts more readily after a month of high RRO prices. <u>This seems intuitively plausible despite the public availability of RRO prices ahead of time</u>; it is likely that residential electricity consumers respond to high RRO prices immediately after they see their bill for the previous month [emphasis added].[263]

AltaGas Utilities makes a similar observation with respect to the consumption of default natural gas, in that consumers primarily respond to prices on their monthly bills (i.e. after the fact) and not the price posted ahead of the month:

> As explained more fully in AUC.AUI-14, prices have a short run impact on behaviour as customers turn down the thermostat and a longer term impact due to choice of more efficient appliances. Until AMI and smart grid technologies, capable of providing the means for customers to meaningfully respond to real time prices – daily prices in the case of gas – become available, <u>customer decisions respecting consumption behaviour are going to be guided primarily by prices and price related</u>

[263] Alberta Market Surveillance Administrator, "2014 Retail State of the Market Report," November 27, 2014, page 36 (pdf).

information in the gas bill and not by any forecast price filed prior to commencement of the consumption month [emphasis added].[264]

Given the price inelasticity of retail electricity consumption, combined with the fact that the average RRO customer probably is not even aware that prices are posted ahead of time, let alone where to look, it is unlikely the situation would be materially different for default electricity.

4.2.2 Alignment of Pricing Approaches

As explained in section 2.1, the government stated in its 2005 Framework paper that:

> Alignment of natural gas and electricity pricing approaches will make it easier for consumers to understand and compare natural gas and electricity bills, and for retailers to explain, market and sell bundled energy products.[265]

Implied in this claim was that, as a result of the government's rate design for the "New" RRO, the "pricing approaches" used for default electricity and gas would be in "alignment." It would be generous to suggest that this has been the case. Despite the fact that both default electricity and natural gas rates have both been set on a month-to-month basis and based on forward market prices, the technical aspects of their energy price setting have been fundamentally very different. These differences were comprehensively summarized by the AUC in its 2011 "Harmonization Inquiry" report.[266] For the sake of brevity, the AUC's

[264] AUC Exhibit 0090.01.AUI-567, AltaGas Utilities Inc., "Response to AUC.AUI-6," August 23, 2010, page 25 (pdf).
[265] Alberta Department of Energy, "Alberta's Electricity Policy Framework," June 6, 2005: http://www.energy.alberta.ca/Electricity/pdfs/AlbertaElecFrameworkPaperJune.pdf, page 17 (pdf).
[266] Alberta Utilities Commission, "Regulated Retail Energy Harmonization Inquiry," March 25, 2011, Proceeding #567, page 16 (pdf).

summary is not reproduced here, but suffice it to say that the "main differences in the design attributes associated with the energy charge component for regulated retail electricity services and regulated retail gas services" have been extensive.[267] According to the AUC, the main takeaway from its summary is as follows:

> The most notable design difference between the two regulated retail energy services is that RRO providers are not allowed to use any deferral accounts, true-ups, rate riders or other similar accounts for energy-related costs while DGS providers currently use a deferral account for energy-related revenues and most energy-related costs known as the deferred gas account (DGA). Because DGS providers are permitted to use a DGA, customers are exposed to any differences between forecast costs/volumes and revenues and actual costs and revenues associated with the gas energy charge.[268]

As a consequence of trueing-up their monthly gains and losses by using deferral accounts, default gas has fundamentally been a "flow-through" rate, such that it simply "flows-through" wholesale market prices to default gas customers. The RRO, on the other hand, has not been a "flow-through" rate. As explained in section 2.2.1.2, the RROR has prohibited "energy" related costs from being trued-up, and instead the EPSPs have included a variety of risk margins to compensate the RRO providers for both commodity and non-commodity risks.[269] Ironically, if the government had actually wanted to "align"

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[267] Alberta Utilities Commission, "Regulated Retail Energy Harmonization Inquiry," March 25, 2011, Proceeding #567, page 16 (pdf).
[268] Ibid., page 17 (pdf).
[269] It should also be noted here that another consequence of having been a "flow-through" rate is that, unlike with the RRO, default gas providers have not purchased forward market hedges for the purposes of price setting. Instead, they have simply used forward market prices as a forecast of each month's gas costs. The result is that, in addition to not having been paid commodity risk compensation, default gas providers have

the RRO's "pricing approach" with that of default gas, it could have better accomplished that goal by mandating that the RRO use monthly PPFT price setting, which simply "flows-through" wholesale market (i.e. Pool) prices to customers.

It is worth keeping in mind that, even if both default electricity and natural gas were "flow-through" rates, the "underlying" wholesale market prices for electricity and natural gas have very different characteristics. As explained by AltaGas Utilities, a default gas provider, there are "fundamental differences in the characteristics of the physical commodities and their markets…" It explains that "[t]he differences in the nature of the commodities, together with the differences in the design of the two markets, make the volatilities of gas and electricity prices materially different."[270]As a result, even to the extent the government could achieve "alignment" between default electricity and natural gas price setting, the underlying prices of the commodities would still have fundamentally different characteristics.

Notwithstanding the fact that the "pricing approaches" used for default electricity and natural gas have arguably not been in "alignment," it is highly unlikely that it would have even mattered if they were. According to the government, this would have made "it easier for consumers to understand and compare natural gas and electricity bills, and for retailers to explain, market and sell bundled energy products." This claim has two parts, both of which are extremely vague and difficult to interpret. With respect to the first part, presumably the material benefit of increasing consumers' ability to compare their

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not been paid the various adders that have been included in the EPSPs as a result of forward market "procurement" (e.g. incentive payments, etc.) For more detail, see: Ibid., page 18 (pdf).

[270] Exhibit 0029.01.AUI-567, AltaGas Utilities Inc., "AUI Comments on AUC Regulated Retail Energy Inquiry," June 14, 2010, page 8 (pdf).

electricity and natural gas bills is that it increases the ease with which they can substitute between the two commodities.

This claim, however, relies on several untenable assumptions. First, it assumes that customers even generally understand how the price setting methodologies used by the EPSPs and the default gas suppliers work, let alone their intricacies. This is highly implausible. As explained by the UCA, "small customers are generally not aware of the details of the energy price setting plans."[271]

Secondly, it assumes that increasing customers' understanding of their default electricity and natural gas bills would increase their propensity to substitute between the two commodities. Regardless of how their energy charges are set, customers see a price on each monthly bill for both their electricity and natural gas consumption in cents/KWh and $/GJ, respectively. The underlying math used to compute those numbers is irrelevant for consumers making comparisons; they simply look at the two numbers and compare them. In other words, the characteristics of their respective prices, such as average level and volatility, is all that matters; understanding how or why they are set the way they are is arguably irrelevant.

Finally, it assumes that customers would substitute between electricity and natural gas in the first place; which, in all but the very long-term, is extremely impractical. As explained by the UCA, small consumers may adjust their consumption based on commodity prices, but they are very unlikely to actually substitute between commodities:

[271] AUC Exhibit 0105.02.UCA-567, Utilities Consumer Advocate, "Response to AUC-UCA-9(a)," August 23, 2010, page 10.

> In Alberta, small customers generally use natural gas for space and water heating. Since virtually all housing in Alberta incorporates natural gas for space and water heating, small customers generally have no choice but to use natural gas for space and water hearing, regardless of the current market price. Retrofitting a home to substitute electricity for space and water heating is generally not economic or practicable in Alberta. Small customers may have the opportunity to reduce their overall natural gas consumption by retrofitting their homes to include such things as higher-efficiency furnaces, better windows or more insulation. To the extent that such investments in long-lived improvements are based on price (as opposed to being required due to end-of-life considerations or based on home comfort considerations such as reduced drafts), the UCA expects that customers would make their investment decisions based on their expectations of what prices will be over the medium to long term.[272]

As a result, it stands to reason that whatever "alignment" the government achieved between default electricity and natural gas price setting would have had an immaterial effect (if any) on customers' propensity to substitute between the two commodities.

The second part of the government's claim, that "alignment" in pricing between default electricity and natural gas would have made it easier for "retailers to explain, market and sell bundled energy products," is as equally tenuous as the first. It is the equivalent of arguing that in order for a Telecom to market bundled cable and internet services to a potential customer, that customer needs to know how both services' prices

[272] AUC Exhibit 0105.02.UCA-567, Utilities Consumer Advocate, "Response to AUC-UCA-9(c)," August 23, 2010, page 11.

are determined. As previously explained, default electricity and natural gas customers are not generally, let alone intimately, aware of how their rates are set. Customers can evaluate the characteristics of both rates by using just the numbers provided on their monthly bills, and retailers interested in swaying them to switch to either a gas or electricity product can explain the characteristics of their rates for them, regardless of the intricacies of how they are actually set. On this basis, whether customers' electricity and gas rates are set in the same way likely has nothing to do with their decision to switch to either a standalone or duel-fuel product, or its retailer's ability to market them.

To conclude, the use of monthly forward market price setting has arguably not resulted in the "alignment" of the "pricing approaches" used by default electricity and natural gas; there have been extensive fundamental differences between the two, despite the fact that they are both set month-to-month and based on forward market prices. Ironically, the government could have better achieved its goal of "aligning" the two "pricing approaches" by mandating that the RRO use monthly PPFT price setting. Furthermore, the government's claimed benefits of the two rate setting methods being in "alignment," regardless of the extent to which they actually have been, were arguably unfounded and have likely not materialized.

Conclusion

In order to be as concise as possible and maximize readability, this conclusion is in question and answer format. This style is typical of expert evidence in a regulatory proceeding.

Q **What is the purpose of your paper?**

A The purpose of my paper is to estimate the cost of the government's choice of rate design for Alberta's default rate for electricity, known as the Regulated Rate Option (RRO), and weigh that cost against its purported benefits.

Q **And what were the results of this cost/benefit analysis?**

A I estimated that, from July, 2006 to June, 2016, the cost to RRO customers of the government's choice of rate design was approximately $1 billion. I argued that it did not result in any benefits.

Q **Why did you choose to conduct your analysis for the time period from July, 2006 to June, 2016?**

A To my knowledge, the data necessary to conduct the analysis is not publicly available for the time period prior to the "New" RRO, which began in July, 2006.

Q **What was the government's choice of rate design for this time period and how was it executed?**

A Starting in July, 2006 to the present, the government's choice of rate design has been codified by the *Regulated Rate Option Regulation*. It has mandated a price setting methodology I have termed "monthly forward market price setting." Alberta's three main RRO providers have executed this price setting methodology through "Energy Price Setting Plans," (EPSPs) which have been regulated by the Alberta Utilities Commission (AUC).

Q **Does your analysis include all RRO providers?**

A No. Only the three largest RRO providers in Alberta – EPCOR Energy Alberta, ENMAX Energy Corporation, and Direct Energy Regulated Services – have had

EPSPs regulated by the AUC with the requisite data having been provided on the public record. As a result, my analysis only includes these three providers, which together serve 95% of RRO customers.

Q **How did you go about estimating the "cost" of monthly forward market price setting?**

A I ran a counter-factual in which I calculated what RRO customers would have paid for the electricity they consumed under monthly Pool price flow-through (PPFT) price setting, and then compared that amount to what they actually paid under monthly forward market price setting.

Q **Why did you use monthly PPFT price setting as the benchmark for your counter-factual?**

A The Pool price is *the* cost of electricity in Alberta; it is what the RRO providers must pay the Alberta Electric System Operator for the electricity their customers consume. As a result of charging monthly Energy Charges that are *not* based on Pool price, a) RRO customers end up either over or under-paying for the electricity they consume relative to its cost, and b) the RRO providers incur risks and costs that their customers ultimately pay for.

Q **To what extent did RRO customers over or under-pay for the electricity they consumed relative to its cost?**

A This amount is estimated in section 3.2, and I termed it the "Base Energy Outcome." It totaled $452 million over both sets of EPSPs, meaning that RRO customers over-paid for the electricity they consumed relative to its cost by $452 million. This equates to an average of $5/MWh, or $4 million per month, with a median cost of $13 million.

Q **To what extent did the RRO providers incur risks and costs that their customers ultimately paid for?**

A This amount is estimated in section 3.2, and I termed it the "Total Cost of Forward Market Price Setting (FMPS) Adders." It totaled $570 million over both sets of EPSPs, which equates to an average of $6/MWh, or $5 million per month, with a median cost of $5 million per month.

Q **So the sum of these two values is the $1 billion value you provided in your answer to the first question?**

A Correct. The sum of the "Base Energy Outcome" and the "Total Cost of FMPS Adders" is what I termed the "Total Energy Outcome." This amount is estimated in section 3.2, and totaled $1.022 billion over both sets of EPSPs. This means that the total cost to RRO customers of monthly forward market price setting (relative to monthly PPFT price setting) was $1.022 billion. This equates to an average cost of $11/MWh, or $9 million per month, with a median cost of $18 million per month.

Q **Is your calculation of these costs subject to any assumptions?**

A Yes. The calculation of these costs relies on the assumptions that both monthly actual usage and Pool prices would not have been different had the RRO providers used monthly PPFT price setting instead of monthly forward market price setting. In appendices I and II I argue that these assumptions are likely reasonable.

Q **Why did the government decide to mandate monthly forward market price setting in the first place?**

A In 2005 the Alberta Department of Energy (ADOE) stated that it had two objectives for the "New" RRO (post-2006): "appropriate protection" and "retail market development." With respect to rate design, the first objective was largely related to insulating RRO customers from wholesale market (Pool price) volatility. The second objective, retail market development, related to having an RRO that facilitated the entry of unregulated (called "competitive") retailers into the retail market, and having RRO customers switch to those retailers. After considering various other rate design options (including PPFT price setting) the ADOE decided that monthly forward market price setting would be the most conducive to achieving these objectives.

Q **Were the government's objectives for the RRO met as a result of monthly forward market price setting?**

A According to the government, yes. In 2010, the ADOE concluded that the "New" RRO was sufficiently "protecting" RRO customers from the month-to-month volatility of Pool prices, and that the retail market was becoming increasingly "developed."

Q **Do you think that, as a result of meeting these objectives, monthly forward market price setting benefited RRO customers?**

A No. With respect to the first objective of "appropriate protection," I explain in section 4.1.1 that the majority of RRO customers were likely unwilling to pay a premium to reduce their exposure to volatility. With respect to the second objective of "retail market development," I explain in section 4.1.2 that there is very little reason to conclude that the use of monthly PPFT price setting would not have resulted in at least the same level of retail market development as monthly forward market price setting.

Q **Were there any other reasons why the government decided to mandate monthly forward market price setting?**

A Yes. In 2005 the ADOE also claimed that monthly forward market price setting would result in benefits beyond just meeting its two objectives. Specifically, it would allow RRO customers to know the price of electricity ahead of their monthly consumption, which the ADOE claimed would allow them to adjust "energy consumption and purchasing patterns." The ADOE also claimed that monthly forward market price setting would result in the "alignment" of the "pricing approaches" for default electricity and natural gas, thereby making it "easier for consumers to understand and compare natural gas and electricity bills, and for retailers to explain, market and sell bundled energy products."

Q **Do you agree with the government's claims with respect to these benefits?**

A No. In section 4.2.1 I explain that there is little evidence to conclude that RRO customers either switched off the RRO or adjusted their consumption as a result of knowing monthly prices in advance. In section 4.2.2 I argue that monthly forward market price setting did not result in the "alignment" of the "pricing approaches" for default electricity and natural gas, and that even if it had there would have been no material benefit to either RRO customers or retailers.

Q **So ultimately you conclude that monthly forward market price setting provided no benefits relative to monthly PPFT price setting?**

A That is correct.

Q **Has the government ever attempted to measure the cost of its choice of rate design and weigh it against its purported benefits?**

A Not to my knowledge. In its 2010 Retail Market Review paper, the ADOE did not attempt to measure or even acknowledge the cost of monthly forward market price setting, either in terms of the adders paid to RRO providers or the savings that would have resulted under monthly PPFT price setting on average. Yet somehow, it was able to conclude that "[t]o date, the transition to the New RRO has resulted in efficient market outcomes for small customers, retailers, and investors."[273]

Q **Going forward, do you think that the RRO should use monthly PPFT price setting?**

A If the government's intention is for the RRO to continue indefinitely as a legitimate option in the retail market, which appears to be the case, then yes, I do. Monthly forward market price setting has significant costs relative to monthly PPFT price setting, but arguably no relative benefits. By using monthly PPFT price setting, RRO customers would necessarily save several $/MWh in adders paid to the RRO providers and it would be impossible for them to over or under-pay for their electricity relative to its cost. In addition, the use of monthly PPFT price setting would essentially eliminate the currently significant regulatory burden associated with RRO price setting. As explained by the Retail Market Review Committee in its 2012 report, "[a] pool price flow-through option would have a reduced regulatory

[273] Alberta Department of Energy, "Retail Market Review: An Update and Review of Market Metrics," April 15, 2010: http://www.energy.alberta.ca/electricity/pdfs/retailmarketreview.pdf, page 30 (pdf).

burden, as compliance confirmation would be trivial."[274] Pool prices are also determined in the wholesale market; flowing them through to RRO customers would maximize not only the simplicity of the RRO's rate design, but also its transparency.[275]

Q **But what about the month-to-month volatility associated with Pool prices?**

A As explained in section 4.1.1, consumers have varying preferences with respect to price and volatility; therefore, any rate design that deviates from Pool price flow-through at the expense of RRO customers necessarily results in winners and losers. Regardless of the net result, this means that, by "protecting" RRO customers from the inherent volatility of the cost of their electricity, the government is effectively deciding which of them are made better and worse off. Doing so is unnecessary given the existence of a retail market whose very purpose is to cater to the preferences of consumers.

Therefore, rather than "protecting" RRO customers at great cost, the government should focus on enabling RRO customers to satisfy their own preferences by switching off of the RRO. In the words of the RMRC:

> An important conclusion the committee draws from the survey is the need for a robust market with different choices to meet the different preferences of consumers. These choices relate to the things people care about most: price, price volatility, price risk, and energy management to control cost. One

[274] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 176 (pdf).
[275] Ibid., page 175 (pdf).

> pricing program—however well intentioned—will not satisfy everyone. Policy-makers sometimes forget that any rate design set forth in tariff will serve some consumers well, but not others. The survey clearly demonstrates that consumer preferences vary a great deal. Some jurisdictions try to modify default service by offering more choice: green pricing, time-of-day pricing, etc. But is designing different pricing options for consumers an appropriate role for government? Or should government simply create a market structure that allows consumers to express their preferences and demands in the marketplace and allows retailers to serve these preferences and demands? Markets are an efficient mechanism for satisfying a range of consumer preferences and enhancing consumer choice.[276]

When RRO customers switch off of the RRO, they necessarily do so efficiently, and having them switch off of a Pool price flow-through rate, which would be set by the wholesale market *for free*, would solidify retailers' role as providing "value added" services to consumers.[277]

Once again, the Pool price is the default price of electricity in Alberta, and it defines the costs and benefits to consumers and retailers of transacting at any other price. By extension, it should be the price consumers are exposed to by default. In the words of Dr. Joseph E. Bowring, chief economist and president of the PJM interconnection's equivalent of the Market Surveillance Administrator:

[276] Ibid., page 162 (pdf).
[277] Ibid., page 176 (pdf).

There is no conceptual reason for customers to pay a forward price rather than the actual wholesale market price for power. There is only one wholesale market price. The relative volatility of the wholesale price versus the relative volatility of the forward price is not relevant to the choice of default price. If Alberta chooses to rely on wholesale power markets to determine the price of power, then there is only one market price. That one market price is the beginning of customers' choices and not the end. The default price simply defines the relative risks taken by customers and retail suppliers when retail suppliers offer alternatives to the wholesale market price.[278]

Q **Does this conclude your Capstone Project?**

A Yes, it does.

[278] Joseph E. Bowring, "Report to the Alberta UCA: Default Retail Rate for Energy," May 7, 2012, pages 5 – 6 (pdf).

Appendix I: The Effect of PPFT Price Setting on Historical Pool Prices

In the analysis of each of the RRO providers' EPSPs in section 3.2, the WAPP for each month was calculated using historical hourly Pool prices that materialized over the month. Implicit in using historical Pool prices to calculate each month's WAPP is the assumption that they would not have been different had the EPSPs used monthly PPFT price setting instead of monthly forward market price setting. If, as a result of using monthly PPFT price setting, Pool prices would have been higher or lower than they actually were, then the accuracy of the Base Energy Outcome calculated for each month would be compromised.

Why could Pool prices have been different if the RRO providers had used monthly PPFT price setting instead of monthly forward market price setting? The answer lies in the fact that under monthly PPFT price setting, hedging (procurement) would not have been necessary. Because the RRO providers have historically made up a "significant portion" of the demand for certain kinds CFDs in the forward market, the elimination of this demand could have resulted in a reduction in the quantity generators sold forward.[279]

Had this been the case, generators would have generally been longer to Pool prices and therefore might have had more incentive to increase them to the extent possible. If Pool prices would have in fact been higher as a result of the RRO providers using monthly PPFT price setting, then each month's WAPP would have also been higher. This would mean that the Base Energy Outcome calculated for each month in section 3.2 is actually too high. In other words, the cost (benefit) of having used monthly forward market price

[279] AUC Exhibit 0277.02.UCA-2941, "Utilities Consumer Advocate: Argument," November 17, 2014, para. 106, page 36 (pdf).

setting is overstated (understated) in months for which the Base Energy Outcome is positive (negative).

In the parlance of economics, using monthly PPFT price setting could have resulted in generators exercising more "market power," which is the extent to which a firm profitably raises price in excess of their per unit cost.[280,281] One way to measure a firm's market power is by calculating its "Lerner Index," which is essentially the markup of its price over its marginal cost.[282] Deriving the Lerner Index for a generator that has not sold forward and comparing it to the Lerner Index for a generator that has sold forward illustrates how selling forward affects market power.[283]

First, the profit function for a generator that has not sold forward is simply equal to the Pool price minus its marginal cost per unit of electricity multiplied by the amount of electricity it produces (note that the Pool price is a function of market supply):[284]

$$Profit = (P(Q) - c)q \tag{9}$$

Where:

$P = Pool\ price$

$Q = Market\ supply$

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[280] In the context of the Alberta wholesale electricity market, market power is also known as "economic withholding." The MSA defines it as "offering available supply at a sufficiently high price in excess of the supplier's marginal costs and opportunity costs so that it is not called on to run and where, as a result, the pool price is raised." See: MSA Offer Behavior Guidelines, http://albertamsa.ca/uploads/pdf/Consultations/Market%20Participant%20Offer%20Behaviour/Decide%20-%20Step%205/Offer%20Behaviour%20Enforcement%20Guidelines%20011411.pdf, page 11 (pdf).
[281] Jeffery Church and Roger Ware, *Industrial Organization: A Strategic Approach* (Irwin-McGraw Hill, 2000), http://works.bepress.com/cgi/viewcontent.cgi?article=1022&context=jeffrey_church, page 63 (pdf).
[282] Ibid., page 70 (pdf).
[283] It is important to note here that this exercise is for illustrative purposes only. It is based on certain assumptions about the nature of competition in the wholesale market (i.e. that it is "Cournot") that may or may not be accurate. However, as explained by Stoft in *Power System Economics*, the "Cournot model" (i.e. the calculation of the Lerner Index) is still "probably the best available model" to measure market power. See: Stoft, "Power System Economics," page 361.
[284] For simplicity this function does not include fixed costs.

$c = Marginal\ cost$

$q = Generator's\ supply$

In order to derive the Lerner Index, it is assumed that the generator is but one of many competitors in the wholesale market and therefore the generator's supply (q) is distinguished from total market supply (Q). The Lerner index that results from the generator profit maximizing is as follows:[285]

$$L = \frac{s}{e} \tag{10}$$

The denominator, epsilon (ε), represents the "price elasticity of demand," which is the measure of the extent to which load decreases as Pool price increases. The numerator, "s," is the generator's share of total market output $\left(\frac{q}{Q}\right)$.

So what about for a generator that has sold forward? Its profit function is as follows (again, note that the Pool price is a function of market supply):[286]

$$Profit = (P(Q) - c)q + p^F q^F - P(Q)q^F \tag{11}$$

Where:

$P = Pool\ price$

$Q = Market\ supply$

$c = Marginal\ cost$

$q = Generator's\ supply$

$p^F = CFD\ price$

$q^F = CFD\ volume$

[285] Steven Stoft, "Power System Economics: Designing Markets for Electricity," Wiley: 2002, pages 343 – 344.
[286] Ibid., page 364.

The first term is the generator's profit from selling its physical electricity, the second term is the payment it receives from the buyer of the CFD, and the third term is the payment is must make to the buyer of the CFD. Once again, in order to derive the Lerner Index, it is assumed that the generator is but one of many competitors in the wholesale market and therefore the generator's supply (q) is distinguished from total market supply (Q). The Lerner index that results from the generator profit maximizing is as follows:[287]

$$L = \frac{ss}{e} \tag{12}$$

Where:

$$ss = \left(\frac{q - q^F}{Q}\right)$$

As can be seen, the difference between this Lerner index from the one from equation 10 is that the generator's market share is now effectively reduced by the amount that it sells forward. This formula shows that if all of the generator's capacity is sold forward, such that $q = q^F$, then its Lerner Index would be zero and it would not exercise market power.

There is, however, a caveat to this result: The term of the CFD(s) used to sell forward can matter. According to Stoft, the profit function of a generator that has sold forward can only be written as it is in equation 11 *if* "the supplier does not anticipate that today's energy price will affect tomorrow's price of forward contracts, or if the forwards are all very long term so there will be no repeat sales for a long time."[288] As a result, the Lerner Index derived in equation 12 becomes unreliable for measuring the market power of a generator if it has only sold forward for a short-term.[289]

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[287] Ibid.
[288] Ibid., page 363.
[289] Ibid., page 358.

Stoft explains this assertion using the example of a generator that has sold forward 90% of its capacity for the term of just a year. Based on the Lerner Index calculated in equation 12, this would suggest that by doing so the generator would have very little market power, since it would have effectively reduced its market share by 90%.[290] However, this conclusion ignores the fact that the fixed prices that are stipulated in CFDs are derived from the buyer's and seller's expectations of what Pool prices are going to be over the term of the contract, and that these expectations are at least partly based on historical Pool prices. Stoft explains by saying that "when customers evaluate future prices, they will base their estimate partly on this year's prices and partly on other information."[291] As a result, "if this year's [Pool prices] are high, buyers will anticipate high prices next year and will be willing to pay more for a fixed-price forward contract for next year's power."[292]

Using the same example of the generator that sold forward 90% of its capacity for a year, Stoft shows that, if it a) believes that an increase in this year's average Pool raises the expectation of next year's average Pool price by the same amount, and b) has a discount rate of zero, it would have "exactly the same motivation to raise prices as [a generator] with no contract cover."[293] However, he qualifies this conclusion by saying that "[w]hen power is sold a year ahead, the supplier does not receive payment for a year, so the payment is discounted,"[294] and that "[m]ore importantly, when customers evaluate future prices, they will base their estimate partly on this year's prices and partly on other

[290] Ibid., pages 349 – 350.
[291] Ibid., page 350.
[292] Ibid., page 349.
[293] Ibid., page 350.
[294] Ibid.

information."[295] So, ultimately, "perhaps only half of this year's price increase translates into higher expectations of next year's prices,"[296] in which case "selling most of its power forward in one-year contracts could cut a supplier's market power in half."[297]

What this means is that, when profit maximizing in the present, a generator that has sold forward can be thought of as also considering the present value of the CFDs it will sell in the future, the prices of which are a function of current Pool prices. To generalize based on Stoft's explanation, a generator's perception of this present value is influenced by the term of the CFD(s) it has sold forward: The longer their term, the lower the present value and the less market power the generator exercises; the shorter the term, the higher the present value is and the more market power the generator exercises. Ultimately, with respect to mitigating a generator's market power, Stoft explains that "[t]he most effective form of forward contracting is long-term forward contracting,"[298] and that "medium-term contracts, on the order of a year, work only to the extent that suppliers do not believe forward contract prices equal the average level of recent spot prices."[299]

This caveat is important because the "New" RRO has been predicated on "monthly" forward market price setting, which has involved the RRO providers engaging in the procurement of month long hedges for the purposes of price setting. As explained in section 2.2, from 2006 to 2011 the RROR mandated a gradual transition from long-term hedges to monthly hedges, and since 2011 the RRO providers have exclusively "procured" monthly hedges. Based on the foregoing discussion, it stands to reason that the extent to

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295 Ibid.
296 Ibid.
297 Ibid.
298 Ibid., page 346.
299 Ibid.

which the sale of month long hedges mitigates generator market power is questionable. As stated by Stoft, the sale of medium-term (e.g. a year), and by extension presumably short-term (e.g. a month), CFDs only reduce market power to the extent that a generator does *not* believe that future CFD prices are a function of historical Pool prices.

However, it is likely that future CFD prices are a function of historical Pool prices. According to the Alberta MSA, the "[e]xercise of market power is likely to impact future forward prices, for example loads may purchase more forward contracts to avoid pool price volatility pushing the price for those contracts higher."[300] More generally, it stands to reason that calendar month CFD prices *are* a function of previous month's average Pool prices; for example, market conditions in July may provide at least some indication of the market conditions in August. It also stands to reason that they *are* a function of historical Pool prices for that month in previous years; for example, the average Pool price for June 2015 may at least provide some indication of the Pool price for June, 2016. If either of these cases are true, then future calendar month CFD prices *would* be based, at least in part, on historical Pool prices.

According to more recent work on this subject by Vasquez, "past spot price reveals information regarding competitors' parameters, and thus they are signals of the probability of future spot prices."[301] Thus, "a decrease in the spot price will make the forward price lower," and as a result, "there is an additional incentive when playing in the spot market associated with the sensitivity of forward prices to past spot decisions."[302] As a result of

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[300] Alberta Market Surveillance Administrator, "State of the Market Report 2012," December 10, 2012, page 51 (pdf).
[301] Miguel Vasquez, "Analysis of the strategic use of forward contracting in electricity markets," 2012, page 11 (pdf).
[302] Ibid.

generators having this “additional incentive,” he concludes, like Stoft, that contract duration matters with respect to the mitigation of wholesale market power:

> Actually, short duration contracts imply that there is an incentive to raise spot prices caused by the signaling game. On the other hand, large durations eliminate the incentive, as players cannot manipulate the forward price driving up the spot price… Nonetheless, these prices are often actualized every time the contract expires. This price actualization can be thought of as a renegotiation of the contract, which might be manipulated by players manipulating the corresponding spot prices. Therefore, in this case, short duration contracts will not destroy the signaling incentive, and the market will not be more competitive.”[303]

Based on the conclusion that shorter duration contracts do not mitigate wholesale market power, it seems reasonable to conclude that the loss of forward market procurement by the RRO providers as a result of monthly PPFT price setting would not have materially affected the degree of market power exercised in the wholesale market. Therefore, except perhaps for the beginning of the 2006 – 2011 EPSPs when the RRO providers were still procuring mostly longer term hedges, Pool prices likely would not have been materially different over the majority of the time period covered by the analysis in section 3.2.

[303] Ibid., page 27 (pdf).

Appendix II: The Effect of PPFT Price Setting on Historical Consumption

In the analysis of each of the RRO providers' EPSPs in section 3.2, the Base Energy Outcome, the Total Cost of Forward Market Price Setting Adders, and the Total Energy Outcome for each month were calculated using historical monthly actual usage. Implicit in using historical monthly actual usage to calculate each of these is the assumption that each month's actual usage would not have been different had the EPSPs used monthly PPFT price setting instead of monthly forward market price setting. If, as a result of using monthly PPFT price setting, monthly actual usage would have been higher or lower than it actually was, then the accuracy of the Base Energy Outcome, the Total Cost of Forward Market Price Setting Adders, and the Total Energy Outcome calculated for each month would be compromised.

Why could monthly actual usage have been different if the RRO providers had used monthly PPFT price setting instead of monthly forward market price setting? The answer lies in the fact that, as shown in Table 17, monthly RRO Energy Charges would have been lower, on average, under monthly PPFT price setting. In economics, it is generally accepted that, except for all but a class of very rare goods, demand increases as price decreases. Therefore, the question of whether consumption (actual usage) would have been higher under monthly PPFT price setting given that it would have resulted in lower average RRO Energy Charges requires knowing what the "price elasticity of demand" is for retail electricity customers. This is the measure of how sensitive demand is to changes in price, and is expressed as the ratio between the percentage change in quantity to the percentage change in price:[304]

$$PED = \frac{\%\Delta Q}{\%\Delta P} \tag{13}$$

Where:

$PED = Price\ Elasticity\ of\ Demand$

$Q = Quantity$

$P = Price$

Studies have generally found the average PED of retail electricity customers to be between 0 and -1, meaning that for every one percent increase in price, their average decrease in consumption is between 0 and 1 percent.[305] Clearly, the PED among retail electricity customers is generally very low, or what economists call "inelastic," meaning that their consumption is unresponsive to changes in price. Nevertheless, if RRO customers are assumed to at least be somewhat elastic to price (i.e. their PED is not zero), then the analysis in section 3.2 is inherently conservative. This is because the positive Total Energy Outcome for each EPSP only reflects the savings that RRO customers would have experienced on the electricity they actually consumed, and does not account for the gains from trade that would have materialized as a result of RRO customers increasing their consumption in response to lower average RRO Energy Charges.

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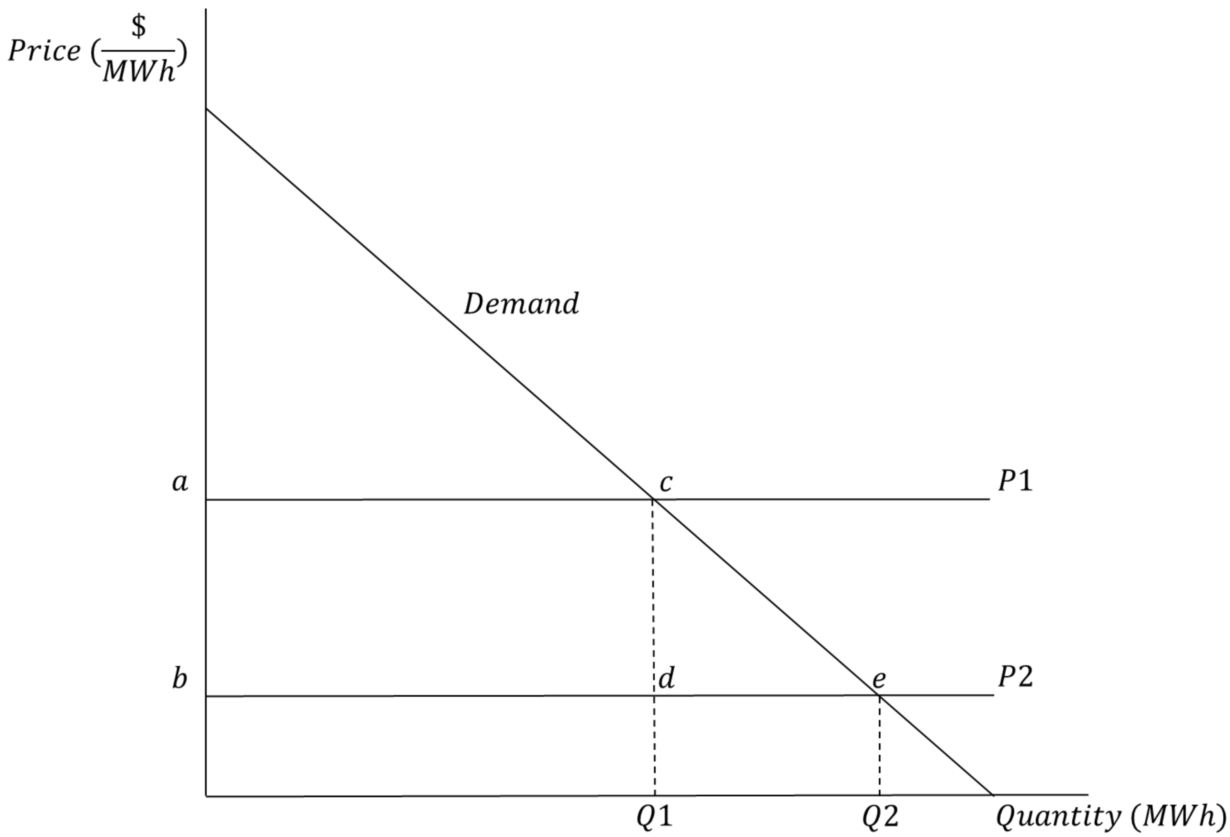
304 Jeffery Church and Roger Ware, *Industrial Organization: A Strategic Approach* (Irwin-McGraw Hill, 2000), http://works.bepress.com/cgi/viewcontent.cgi?article=1022&context=jeffrey_church, page 70 (pdf).
305 Agustin J. Ros, "An Econometric Assessment of Electricity Demand in the United States Using Panel Data and the Impact of Retail Competition on Prices," June 9, 2015: http://www.nera.com/content/dam/nera/publications/2015/PUB_Econometric_Assessment_Elec_Demand_US_0615.pdf, page 2 (pdf).

This can be illustrated using the traditional supply-demand diagram from economics:

Figure 12: Illustration of Increase in Total Surplus



The average decrease in RRO Energy Charges that would have been experienced under monthly PPFT price setting is reflected in the diagram by the price decrease from P1 to P2. As a result of the price decrease, "consumer surplus" would have increased by the square area "abcd." This is the gain in "value" received by consumers as a result of paying less for the quantity they were already consuming (Q1), and is reflected in the Total Energy Outcome calculated for each EPSP.

However, if the PED of RRO customers is assumed to not be zero, then their demand curve is downward sloping, and the decrease in price would have resulted in an increase in the quantity consumed from Q1 to Q2. The resulting triangle "cde" reflects the further increase in surplus that would have resulted from the "gains from trade" experienced on the incremental quantity electricity consumed. The value of this incremental surplus is not reflected in the Total Energy Outcome calculated for each EPSP. Therefore, if it is assumed that RRO customers are not perfectly inelastic to RRO Energy Charges, then the positive Total Energy Outcome calculated for each EPSP actually understates the benefit that would have resulted from having used monthly PPFT price setting instead of monthly forward market price setting.

Appendix III: Energy Return Margins as "FMPS Adders"

As explained in section 2.2.1.4, the RROR has permitted the RRO providers to "charge customers an amount for a reasonable return for the obligation on the RRO provider to provide electricity services."[306] Over the course of the "New" RRO, this "reasonable return" has been collected from RRO customers through a variety of different return margins. These return margins are listed and summarized as follows:

2006 – 2011 EPSPs

EEA

This EPSP included a "reasonable return for the obligation to serve" of $0.65/MWh that was part of the "All Energy Risk and Return" margin. This margin was an adder included in the monthly Energy Charge, and was determined through negotiations between EEA and the consumer groups.[307] In 2008, EEA applied for and was awarded a standalone "non-energy" return margin in addition to the $0.65/MWh adder in its EPSP.[308] The UCA, who was part of the negotiated settlement agreement for EEA's EPSP, argued against EEA receiving a standalone non-energy return margin, claiming that the $0.65/MWh adder in its EPSP was to "include all reasonable return due to EEAI for the entire obligation to provide electricity services to its eligible customers."[309] The AUC rejected the UCA's argument and concluded that it was "reasonable to infer that the return margin calculated as part of an energy agreement would be related to energy only" [emphasis in original].[310]

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306 Alberta Utilities Commission, "Decision 2941-D01-2015," March 10, 2015: http://www.auc.ab.ca/applications/decisions/Decisions/2015/2941-D01-2015.pdf, para 148, page 36 (pdf).
307 Alberta Energy and Utilities Board, "Order U2006-109," April 28, 2006, page 3 (pdf).
308 Alberta Utilities Commission, "Decision 2010-055," February 8, 2010, para 39 page 17 (pdf).
309 Ibid., para 47 page 19.
310 Ibid., para 70 page 24.

EEC

This EPSP included two return margins: the first was a fixed "Load Obligation Return Margin" that was equal to $0.75/MWh, and the second was a variable "Going Concern Return Margin" that could be up to $0.75/MWh.[311] These margins were adders included in the monthly Energy Charge, and were determined through negotiations between EEC and the consumer groups.[312] Because EEC is a municipally owned utility, its total return was also grossed up to account for Payment in Lieu of Tax (PILOT) after its introduction in January, 2007.[313] These were clearly "energy" return margins given that EEC has been paid a standalone "non-energy" return margin over the course of both its EPSPs.[314]

DERS

This EPSP did not originally include a return margin because DERS and the consumer groups were unable to reach an agreement as to its level in the negotiated settlement.[315] As a result, DERS' "reasonable return" was determined by way of adversarial process in front of the AEUB. In order to decide the quantum of DERS' reasonable return, the AEUB relied upon a series of "benchmark" data that provided calculations of the return amounts earned by competitive businesses with a "significant degree of similarity" to the RRO business; for example, retailers such as grocery stores, department stores, etc.[316] Because the return amounts earned by similar competitive businesses were considered to

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311 Alberta Energy and Utilities Board, "Order U2006-110," April 28, 2006, page 11 (pdf).
312 Ibid., page 5 (pdf).
313 See: EEC Monthly Filings
314 Alberta Utilities Commission, "Decision 20480-D01-2016," April 20, 2016, para 138, page 35 (pdf).
315 Alberta Energy and Utilities Board, "Order U2006-108," April 28, 2006, page 3 (pdf).
316 Alberta Energy and Utilities Board, "Decision 2006-107," November 1, 2006, pages 24 – 44 (pdf).

necessarily include compensation for risk, they were grossed down by 25% to account for the fact that DERS, as per the RROR, was compensated for risk separately through its various risk margins.[317]

Ultimately, the AEUB approved a single after-tax return margin of $1.75/MWh in Decision 2006-107 that took effect in December, 2006 (from July until then DERS was paid an interim return margin of $1.50/MWh).[318] This single return margin was not formally separated into "energy" and "non-energy" margins; however, the AUC later calculated the "energy" portion as being $1.58/MWh and the "non-energy" portion as being $0.17/MWh (both after-tax).[319]

2011 – 2014 EPSPs

EEA

This EPSP included an after-tax return margin of $1.38/MWh. This margin was an adder included in the monthly Energy Charge, and was determined through negotiations between EEA and the consumer groups.[320] In addition to being called the "Energy Return Margin," it was formally recognized as being strictly related to providing compensation for EEA's obligation to "provide electricity services in respect to the <u>energy</u> component of EEAI's customers' bills" [emphasis added].[321] In 2010, EEA applied for and was awarded a standalone "non-energy" return margin equal to 6% of its non-energy operating costs that

[317] Ibid., page 48 (pdf).
[318] See: DERS monthly filings
[319] Alberta Utilities Commission, "Decision 2010-055," February 8, 2010, para. 93, page 45 (pdf).
[320] Alberta Energy and Utilities Board, "Order U2006-109," April 28, 2006, page 3 (pdf).
[321] Alberta Utilities Commission, "Decision 2011-123," March 3, 2011, para. 39, page 12 (pdf).

it earned in addition to its Energy Return Margin over the course of its 2011 – 2014 EPSP.[322]

EEC

This EPSP, like the previous one, included a variable "Going Concern Return Margin" of up to $1.00/MWh and a fixed "Load Obligation Return Margin" of $0.50/MWh.[323] These margins were adders included in the monthly Energy Charge, and were determined through negotiations between EEC and the consumer groups.[324] Because EEC is a municipally owned utility, its total return has also been grossed up to account for Payment in Lieu of Tax (PILOT).[325] These were clearly "energy" return margins given that EEC has been paid a standalone "non-energy" return margin over the course of both its EPSPs.[326]

DERS

This EPSP carried over the $1.75/MWh return margin that DERS was paid over the course of its 2006 – 2011 EPSP.[327] Again, this single return margin was not formally separated into "energy" and "non-energy" margins; however, as previously explained, the AUC calculated the "energy" portion as being $1.58/MWh and the "non-energy" portion as being $0.17/MWh (both after-tax).[328]

Energy Return Margins as "FMPS Adders"

The relevant question for the purposes of the analysis in section 3.2 is "have the return margins paid to the RRO providers been a result of forward market price setting,

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[322] Alberta Utilities Commission, "Decision 2010-571," December 16, 2010, para. 32, page 11 (pdf).
[323] Alberta Utilities Commission, "Decision 2011-486," December 13, 2011, para. 82, page 22 (pdf).
[324] Ibid., para. 84, page 23 (pdf).
[325] See: EEC Monthly Filings
[326] Alberta Utilities Commission, "Decision 20480-D01-2016," April 20, 2016, para. 138, page 35 (pdf).
[327] Alberta Utilities Commission, "Decision 2011-199," May 5, 2011, page 8 (pdf).
[328] Alberta Utilities Commission, "Decision 2010-055," February 8, 2010, para. 93, page 45 (pdf).

and if so to what extent?" Or, put another way, "would the RRO return margins have been different if monthly PPFT price setting had been used instead of monthly forward market price setting?" The AEUB provided an answer to this question in Decision 2007-103, which pertained to DERS' application for its 2007/2008 "Default Rate Tariffs and Regulated Rate Tariffs." The Default Rate Tariff (DRT) is the formal name for the default rate for gas, much like the RRO is the formal name for the default rate for electricity;[329] DERS is both an RRO and DRT provider. This application was for approval of the negotiated settlement reached between DERS and consumer groups for its 2007 – 2008 RRO and DRT non-energy charges.

In their negotiated settlement, DERS and the consumer groups did not reach agreement as to the level of the "reasonable return" for the DRT, and so it was deliberated in front of the AEUB by way of an oral hearing.[330] In its Application, DERS applied for a reasonable return for DRT services "using the same methodology which was utilized in Decision 2006-107 respecting the determination of a reasonable return for RRT services."[331] This was the same decision in which DERS' $1.75/MWh RRO return margin was calculated. The AEUB concluded that the methodology used in Decision 2006-107 was also the "appropriate one to use in determining the DRT return margin."[332] However, the AEUB made one major modification to this methodology: instead of grossing down the calculated reasonable return by 25%, it grossed it down by 85%.[333]

[329] Market Surveillance Administrator, "Alberta Retail Markets for Electricity and Natural Gas: A description of basic structural features," July 17, 2014, http://albertamsa.ca/uploads/pdf/Archive/00-2014/Alberta%20Retail%20Markets%20for%20Electricity%20and%20Natural%20Gas%20071714..pdf, page 9 (pdf).
[330] Alberta Energy and Utilities Board, "Decision 2007-103," December 20, 2007, page 8 (pdf).
[331] Ibid., page 86 (pdf).
[332] Ibid., page 93 (pdf).
[333] Ibid., page 102 (pdf).

As previously explained, in Decision 2006-107 the AEUB decided that the reasonable return calculated using benchmark data from similar competitive businesses needed to be grossed down by 25% to account for the fact that DERS, as per the RROR, was compensated for risk separately through its various risk margins. In Decision 2007-103, the AEUB concluded that the reasonable return calculated for DERS' DRT also needed to be grossed down, not to account for the risk compensation built into the calculated return amount, but because of the "substantial differences in risk faced by the RRO operations and the DRT operations of DERS."[334]

Specifically, DERS does not bear any commodity risk as a result of serving the DRT because all of its commodity profit (i.e. gains and losses on the sale of the actual gas) is subject to deferral account treatment through the Deferred Gas Account (DGA). In other words, any monthly differences between what a default gas provider pays for the actual volume of gas it supplies and the revenue it receives for that gas is trued-up *ex post.*[335] As explained in section 2.2.1.2, this is unlike the RRO, which is forbidden from using true-up mechanisms for energy costs as per the RROR. In the words of the AEUB:

> The Board is aware that the RRT providers are compensated through their risk margins as part of their energy price setting plans, which means that the RRT providers are obviously at risk as far as their energy revenues are concerned. The Board notes that DERS' DRT is not at risk for any of its gas costs, except to the extent that the costs are determined to be not prudent, and that much of its other energy and non-energy costs are also subject to deferral account treatment, which was

[334] Ibid., page 101 (pdf).
[335] Alberta Utilities Commission, "Regulated Retail Energy Harmonization Inquiry," March 25, 2011, Proceeding #567, page 17 (pdf).

acknowledged by DERS during the hearing in response to a Board aid to cross-examination which is attached as Appendix 15 to this Decision. Consequently, the Board considers that DERS' DRT operates under much less risk than the RRT operations of DERS and EEC and at substantially less risk than industries included within the competitive benchmarks [footnotes omitted].[336]

The AEUB quantified this difference in risk between the DRT and RRO by calculating the portion of the costs of each business that were "at risk." As a result of all of DERS' gas commodity costs being subject to true-up, the AEUB concluded that only 1.1% of DERS' DRT costs were at risk, compared to the 89.1% of its RRO costs that were at risk.[337] Due to the significant difference in "at risk" costs between DERS' DRT and RRO, the AEUB concluded that the return amount calculated by the benchmarking methodology required a significantly higher "risk adjustment" than 25%. In its own words:

> … the DRT operations of DERS are virtually risk free, with approximately 1% of its costs being at risk. Consequently, the Board considers that the risk adjustment factor of 25% applied to four of the benchmarks, (Retail Firms (Valueline); Retail Firms (Regressions); Canadian Retail; and Centrica) in Decisions 2006-107 and 2006-108 requires a material adjustment to reflect the significant difference in risk between the RRT and DRT businesses. After careful consideration of the evidence, on balance the Board finds that the risk adjustment required to the several risk related benchmarks to reflect the significant difference between the return margin appropriate for a risk facing enterprise and the DERS DRT should be 85%.[338]

[336] Alberta Energy and Utilities Board, "Decision 2007-103," December 20, 2007, page 101 (pdf).
[337] Ibid.
[338] Ibid., page 102 (pdf).

As a result of DERS' DRT being "virtually risk free," the AEUB grossed down the return amount calculated from the competitive business benchmark data by 85%, an additional 60 percentage points over the amount by which it grossed down the return amount in Decision 2006-107. This result can be used to answer the question posed at the beginning of this section because, as explained in 2.2.1.2.1, the RRO providers' commodity risk stems from the fact that they are required to charge their customers something other than the Pool price. As a result, given the similarities between the DRT and the RRO, it can reasonably be concluded that had PPFT price setting been used instead of monthly forward market price setting, each RRO provider's RRO also would have been "virtually risk free."[339,340]

Therefore, based on the outcome of Decision 2007-103, it is reasonable to conclude that the answer to the question of "would the RRO return margins have been different if PPFT price setting had been used instead of forward market price setting?" is definitively "yes." Given the AEUB's 85% downward adjustment of the reasonable return calculated for DERS' DRT on account of its business being "virtually risk free," the analysis in section 3.2 considers that 85% of each RRO provider's total reasonable return has been a result of monthly forward market price setting. In other words, it considers that 85% of the total reasonable return would not have been required under monthly PPFT price setting because, like the DRT, the RRO would have also been "virtually risk free."

The analysis in section 3.2 reflects this by multiplying each RRO provider's Energy Return Margin by 0.85 and including the resulting value in column C as an "FMPS Adder."

[339] Ibid., page 83 (pdf).
[340] Ibid., page 102 (pdf).

Doing so assumes that the Energy Return Margin paid to each RRO provider was the full "energy" component of its total "reasonable return," and therefore multiplying it by 0.85 yields the full portion of the energy component of the total "reasonable return" that was awarded as a result of monthly forward market price setting.[341,342]

Remember that the analysis in section 3.2 is only concerned with evaluating the performance of the EPSPs, which are strictly related to the "energy" side of the RRO business. As a result, the analysis only considers the "energy" portion of the "reasonable return," which has been paid to the RRO providers through their Energy Return Margins. Based on the outcome of AUC Decision 2007-103, considering 85% of each RRO provider's Energy Return Margin to be a result of forward market price setting is justifiable; however, it is also likely conservative. There is regulatory precedent to support the notion that, had the RRO providers used monthly PPFT price setting, they likely would not have been paid Energy Return Margins at all.

In Decision 2006-107, the AEUB acknowledged that transmission and distribution costs are "essentially flow-through costs with minimal risk"[343] and did not apply any return margin percentage to them.[344] This was also consistent with the Default Gas Supply Regulation, which "indicates that the reasonable return is to be calculated on costs deemed eligible by the Board and that the costs of gas are to be excluded" (remember that the

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341 This is mathematically sound, since multiplying the sum of two numbers by a scalar is equivalent to multiplying the two numbers by the same scalar separately and then adding them together.

342 This was obviously not the case for DERS, since the reasonable return amount calculated in Decision 2006-107 was already grossed down by 25%. However, for simplicity, this is ignored. Doing so is safe because it makes the analysis inherently conservative: if the reasonable return amount for "energy" was calculated as "x," then 0.85x would have been a bigger number than the Energy Return Margin DERS was actually awarded, which was equal to 0.75x.

343 Alberta Energy and Utilities Board, "Decision 2006-107," November 1, 2006, page 22 (pdf).

344 Alberta Utilities Commission, "Decision 2010-055," February 8, 2010, para. 89, page 28 (pdf).

actual costs of the gas purchased by default gas suppliers are flowed-through to their customers by way of true-up).[345] Therefore, it stands to reason that had the RRO providers used monthly PPFT price setting, they also would not have been awarded *any* return on the flowed-through costs of their energy. For this reason, as well as the AEUB's risk adjustment to DERS' DRT return margin, the inclusion of 85% of each RRO provider's Energy Return Margin as part of the "FMPS Adders" in column C of the analysis provided in section 3.2 is likely both reasonable and conservative.

[345] Alberta Energy and Utilities Board, "Decision 2007-103," December 20, 2007, page 86 (pdf).

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May 19, 2017

Mr. Mark Nesbitt

Manager, Investigations and Retail

Suite 500, 400 – 5th Avenue SW

Calgary, Alberta

T2P 0L6

Dear Mr. Nesbitt:

Re: RRO Submission – Options for Enhancing the Design of the Regulated Rate Option

This letter and attachments are in response to the Market Surveillance Administrator's (MSA) NOTICE TO PARTICIPANTS AND STAKEHOLDERS (Notice) dated April 21, 2017 regarding *Options for Enhancing the Design of the Regulated Rate Option (RRO)*.

My recommendations concerning the RRO are submitted as a private citizen of Alberta. The recommendations expressed herein are my own and should not be construed as reflecting the views of any other party. I would like to acknowledge the work of Nic Jansen who I understand is also providing a submission. (See below.) The analysis contained in his Master of Public Policy thesis serves as the analytical foundation for my submission.

When formulating my recommendations about the RRO, I relied on a number of documents including:

1. Joseph Bowring, "*Report to the Alberta UCA: Default Retail Rate for Energy*", Monitoring Analytics, May 7, 2012;
2. Nicolaas Jansen, "*A Review of Alberta's Default Rate for Electricity*", Master of Public Policy Capstone Project, The School of Public Policy, September 13, 2016;
3. Donald G. McFetridge, "*Competition in the Alberta Retail Electric Power Market*" (Public Version), May 20012. A study prepared for the Utilities Consumer Advocate as part of its submission to the Retail Market Review Committee; and
4. Robert F. Spragins, "*Evidence of the Utilities Consumer Advocate In the Matter of Generic Proceeding on the Regulated Rate Tariff"*, Application No. 1610120, Proceeding ID No. 2941, June 4, 2014.

The above noted documents, other than the paper by Mr. Jansen, are included as part of my submission. Mr. Jansen's paper can be found at: http://prism.ucalgaryca//handle/1880/51721

In 2015 and 2016, the Alberta Government announced its target of achieving 30% renewable energy by 2030 and the transition to a capacity market. The Government's initiatives will fundamentally alter the energy landscape in Alberta. Accordingly, my recommendations consider how a different market structure could impact the formulation of a new Regulated Rate Option or Default Rate as I prefer to call it.

Prior to my retirement as Utilities Consumer Advocate in March 2015, I collaborated with John Dalton of Power Advisory LLC on the preparation of a discussion paper concerning options for the RRO. The paper was provided to Alberta Energy and grew out of my concerns about the high cost of the RRO based on my participation in AUC Proceeding No. 2941 and the apparent demise of the Retail Market Review process which was initiated by the former government in early 2012. The retail market review was in response to significant price spikes that occurred late in 2011 and the negative consumer reaction to those spikes. My understanding is that the UCA will submit an updated version of this report as part of its submission to the MSA. I do not refer to this paper in my submission and leave the discussion of its recommendations to the UCA.

My response to the questions posed in the Notice are as follows:

i) whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta;

There should be one RRO rate for all eligible consumers and that rate should be based on a Pool price flow-through (PPFT).

ii) changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement;

The Pool price flow-through is simple, easily understood by consumers and does not require procurement.

iii) introduction of deferral accounts or changes to bill smoothing;

In order to provide predictable and/or stable rates, it will be necessary to use price caps and/or fixed prices in conjunction with deferral accounts. Use of deferral accounts will increase the cost of electricity for consumers due to the interest expense on money borrowed by retailers to fund the purchase of energy when the Pool price exceeds the price cap or fixed price.

iv) when and how a change to the RRO should occur.

A reasonable time period to implement a new pricing system is probably less than one year from the date of decision to proceed.

The above noted responses are more fully explained in the discussion concerning the Specific Recommendations.

Specific Recommendations and Discussion

1. *Preserve and enhance the integrity and operation of the competitive retail market in Alberta.*

Most economists, myself included, believe that competition rather than regulation has the best chance of achieving economic efficiency. Moreover, a competitive market has the greatest potential to encourage innovation in products and services thereby achieving dynamic efficiency. My recommendations will increase competition in Alberta's retail electricity. This will benefit both the industry and consumers.

Alberta has embarked on a program to restructure the electricity market by setting an objective of 30% renewable energy by 2030 and implementing a capacity market. A highly competitive retail market will help ensure that the benefits of changes in the wholesale market will be transferred to retail consumers.

2. *Preserve the ability for consumers to choose the retail service that best meet their needs.*

It is very unlikely that a single product or service can meet the needs of all consumers. This is because the interests, needs, and preferences of consumers can vary significantly. Electricity is no different from any other product, in this regard. For example, some consumers prefer fixed prices and are willing to pay a premium to eliminate price volatility, some prefer variable prices in order to obtain the lowest cost, and some consumers simply don't care and are price takers.

Consumer choice has been a key feature of the Alberta electricity market since it was deregulated in 2001. The MSA reported that in September 2016, 46% of eligible RRO customers had switched off the RRO. In the ENMAX service territory the switching rate is significantly higher at 62%.[1] Whether the switching rates are a sign of retail market success or failure is a matter of perspective – "is the glass half full or is the glass half empty". I take the optimistic view but I also recognize that we should always strive to improve the performance of the market.

The Alberta Energy Business Plan for 2017-20 states a key Strategy is to:

> *3.2 Develop and implement policy to smart regulate Alberta's electricity retail system that will protect consumers, including a Regulated Rate Option that will be capped from June 1, 2017 to May 31, 2021 at no more than 6.8 cents per kilowatt hour to protect families, farms and small business from price spikes.*

[1] See the MSA's retail statistics at http://www.albertamsa.ca/

I understand the political logic behind the strategy; however, it is not without its costs. The irony is that consumers already have the ability to protect themselves from price volatility and can choose a retail product that best meets their needs. The implications of the Government's strategy are that it eliminates the incentive for consumers to make their own decisions, it makes consumers who don't choose a competitive retail product for whatever reason into "free riders" and it unfairly penalizes consumers who have made the effort to educate themselves and make an efficient and effective choice.

Notwithstanding my personal convictions about "letting markets work", my recommendations are intended to address the Government's desire to protect consumers from price volatility. My recommendations do that but within the framework of the competitive market and consumer choice. To do otherwise is to suggest that the Government can make better decisions than consumers. I can say categorically that is not true for me.

3. *Drop the requirement that consumers should know the price of energy in advance of consumption.*

The RRO is based on the presumption that consumers should know in advance the price of energy before it is consumed. This is one of the reasons behind using forward prices. While this is an important principle for virtually all consumer products and services it can be ignored for the purposes of electricity pricing. In the vast majority of purchase decisions made by consumers, they can exercise some degree of discretion. This is not the case for electric energy. The requirement can be dropped two reasons. First, there is an extensive history of electricity prices that is readily available to consumers. The history of prices provides consumers with the historical trend and the possible future direction of electricity prices. Second, electricity is an essential good that consumers cannot function without. I know of no consumers who monitor the RRO price prior to consumption. As a result, consumers tend to be price inelastic and consume electricity regardless of price. Consumers tend to respond more to price trends and/or price spikes when making decisions about the purchase, management and consumption of energy.

4. *The Regulated Rate Option Regulation should be renamed the Default Rate Regulation and amended pursuant to these recommendations.*

The name of the RRO is a misnomer. The RRO is not a regulated price in the traditional sense of utility regulation. The title Default Rate is a more appropriate description and reflects exactly what it is – a rate that applies when a consumers decides not to choose a competitive retail product.

5. *The Default Rate should be based on a Pool price flow through.*

The purposes of *the Electric Utilities Act* (EUA) are enumerated in Section 5. Section 5(e) states a key purpose is to

… enable customers to choose from a range of services in the Alberta electric industry, including a flow-through of pool price and other options developed by a competitive market, and to receive satisfactory service; [Emphasis added]

The Pool price is the actual cost of power and ultimately is the price paid by consumers. All other prices are derivatives of the Pool price. Table 1 compares the average monthly Pool price to the forward price, Spot Power's residential floating rate, and EPCOR's RRO rate for the period 2008 to 2016. The different prices were chosen solely for purposes of comparison to illustrate the concepts underpinning my recommendations. No other meaning should be inferred.

Table 1: Average Monthly Prices

	Pool Price ($/kWh)	Last Forward Price ($/kWh)	Spot Power Residential Floating Rate ($/kWh)	EPCOR Residential RRO Rate ($/kWh)
2008	0.0899	0.0839	-	0.1021
2009	0.0478	0.0572	-	0.0791
2010	0.0508	0.0524	0.0602	0.0659
2011	0.0766	0.0795	0.0994	0.0956
2012	0.0643	0.0711	0.0858	0.0966
2013	0.0799	0.0725	0.0980	0.0861
2014	0.0496	0.0626	0.0662	0.0764
2015	0.0334	0.0442	0.0479	0.0559
2016	0.0182	0.0266	0.0294	0.0425

Because the Pool price is the cost of power it will tend to be the lowest price over time. While other prices may be lower from time to time, particularly the forward price, the long term tendency is for the Pool price to be the lowest price because it represents the cost of power. The price differential between the Pool price and the forward price fluctuates over time and is based on the time value of money and other factors related to varying perspectives amongst buyers and sellers concerning the future price of electricity. The Spot Power floating rate likely includes adjustments for its customer load profile and other costs related to the risk of supplying the floating rate and the EPCOR RRO rate includes risk and return premia that increase the cost of power.

Table 2 illustrates the price differential relationship between the four prices. In 2008 and 2013 the average monthly forward price was lower than the Pool price. The volatility of the Pool price in these years was quite high as illustrated in Table 3. It is worth noting that the forward price differential in these years was not material. For example in 2008 the cost to the average residential consumers was about $3.60 per month (-$0.0060/kWh x 600 kWh/month) and in 2013 it was approximately $4.40 per month (-$0.0074/kWh x 600 kWh/month).

Table 2: Average Monthly Price Differentials

	Forward less Pool ($/kWh)	EPCOR less Forward ($/kWh)	EPCOR less Pool ($/kWh)	Spot Power less Pool ($/kWh)
2008	-0.0060	0.0182	0.0122	-
2009	0.0094	0.0219	0.0313	-
2010	0.0016	0.0136	0.0152	0.0094
2011	0.0029	0.0161	0.0189	0.0227
2012	0.0069	0.0254	0.0323	0.0215
2013	-0.0074	0.0136	0.0062	0.0181
2014	0.0130	0.0137	0.0267	0.0166
2015	0.0108	0.0117	0.0225	0.0145
2016	0.0084	0.0159	0.0243	0.0111

[The RRO Case Model I used for my analysis is attached as part of my submission and contains the detailed information and calculations for the numbers shown in the various Tables in my submission.]

Table 3: Average Monthly Standard Deviation

	Pool Price ($/kWh)	Last Forward Price ($/kWh)	Spot Power Residential Floating Rate ($/kWh)	EPCOR Residential RRO Rate ($/kWh)
2008	0.0182	0.0128	-	0.0105
2009	0.0180	0.0145	-	0.0148
2010	0.0269	0.0108	0.0126	0.0103
2011	0.0293	0.0220	0.0354	0.0239
2012	0.0232	0.0167	0.0286	0.0260
2013	0.0357	0.0159	0.0429	0.0143
2014	0.0286	0.0156	0.0345	0.0083
2015	0.0215	0.0169	0.0278	0.0084
2016	0.0036	0.0041	0.0039	0.0060

There are many reasons supporting the use of the Pool price as the Default Rate. Three that stand out the most are: 1) the Pool price will tend to be the lowest cost to consumers over time; 2) the Pool price will serve as a bench mark that will allow consumers to accurately compare the cost of energy products amongst different retailers; and 3) the Pool price is the closest thing we have to a “price signal” that will guide consumers in terms of making effective energy efficiency decisions and policy makers in terms of resource allocation in the Alberta energy economy. Failure to adhere to strong economic principles could result in an energy policy quagmire similar to what has befallen Ontario.

The number one issue related to the use of the Pool price as the Default Rate is the fact that it is the most volatile price. As stated previously, the Alberta Government has implemented two structural changes in the electricity market that will have a profound impact on reducing future Pool price volatility. This will happen because the transition to renewable energy will likely be financed by capacity payments to cover the fixed cost of generation. As the reliance on capacity payments grow it will change the composition of the Pool price into a weighting of capacity payment and energy costs. In the effect the Pool price will be self-stabilizing and substantially contribute to the realization of the Government’s pricing objective.

One possibility that could accelerate the transition to a capacity market is the recent proposal by ATCO and TransAlta to convert coal-fired generating plants to natural gas. The proposal, if adopted, would accelerate the phase-out of coal plants thus achieving Alberta’s transition to a low carbon economy sooner than anticipated. A method of financing this transition is the use of capacity payments. Using capacity payments has the benefit of providing a way to facilitate project financing that is acceptable to financial lenders. In addition, this will benefit consumers in terms of helping to stabilize the Pool price. The proposal is not without its challenges, however. For example, how will the capacity payment be determined in an environment where a fair competitive process might not be available in this particular instance?

The capacity market will take time to develop. In the short-term, there are, fortunately, several very effective and low cost ways of mitigating the volatility inherent in the Pool price. I will deal with two of these methods – price caps and fixed prices - in the recommendations below. I have not considered other methods because they are more expensive and complicated.

A final comment on the use of the Pool price flow through as the Default Rate is the significant reduction in the regulatory burden. The regulatory process surrounding the review and approval of the RRO is complicated and time consuming and requires a significant commitment by stakeholders – consumers, retailers and regulators - in terms of money and staff. Adoption of the Pool price as the Default Rate will eliminate this requirement. It may be necessary for the Government to consider whether a Default Rate review, complaint and dispute resolution process might be required.

6. *Subject to meeting reasonable criteria, including but not limited to creditworthiness and experience, any retailer should be able to provide the Default Rate.*

Section 103(1) of the EUA provides that

> *Each owner of an electric distribution system must prepare a regulated rate tariff for the purpose of recovering the prudent costs of providing electricity services to eligible customers.*

The effect of this section is to create a legal obligation for the owner to provide the Default Rate. However, there is no compelling reason why a competitive retailer could not undertake this function.

The retail market in Alberta has progressed to the point where it functions extremely well. The settlement system is highly developed and access to billing systems are readily available. There are many retailers and prospective retailers who have a sophisticated understanding of Alberta's energy market. The roles and relationships between the distribution companies and competitive retailers are well understood. In effect, there are very few barriers to entry for new retailers. Despite these factors, competitive retailers are currently denied access to a significant market segment – the group of consumers who prefer a default type of product.

Consumers are protected by the Energy Marketing and Residential Heat Sub-metering Regulation which defines the requirements for competitive retailers. The probability of failure by a competitive retailer, while still possible, is very low.

The retailers affiliated with the distribution utilities will likely oppose this recommendation. That said, I urge the Government to consider the following: 1) regulated retailers have been in a protected position since the beginning of deregulation; 2) during this period of time, regulated retailers have been able to earn a regulated rate of return whereas competitive retailers are at risk; 3) the retail market has evolved to the point where there are few barriers to entry; 4) the affiliated retailers will not automatically lose customers and will be able to retain customers simply through customer inertia (the tendency of consumers to resist change) and the opportunity to provide superior products and services; 5) enhanced competition will lower costs particularly in the area of Administration Fees and facilitate innovation in products and service; and 6) adoption of the Pool price flow through will provide employment and new business development opportunities for Albertans.

7. *Section 23(1) of the Regulated Rate Option Regulation should be changed such that any retailer providing the Default Rate must also provide an equalized billing plan for Default Rate Customers.*

Section 23(1) states that owners (and affiliated retailers) <u>may</u> provide an equalized billing option for RRO customers. However, section 23(2) provides that regulated retailers <u>must</u> provide an equalized billing option for eligible RRO customers. The intent of this section is to provide protection for vulnerable customers. The practical effect of this section is that the option is available to any consumers who asks for it because privacy legislation prohibits retailers from asking a customer for proof that he or she is a vulnerable consumer and therefore entitled to the equalized billing option. This is a fact that is not well known by Alberta electricity consumers. The Government should recognize the practical reality of the situation and change the regulation to require that any retailer that provides the Default Option must also provide an equalized billing option. My recommendation is that the equalized billing option should be in the form of a price cap or fixed price as discussed below.

8. *The equalized billing plan could consist of either a price cap or a fixed price plus a deferral account.*

A price cap or a fixed price, in conjunction with a deferral account, would provide a simple, low cost method of managing volatility associated with the Pool price and would be an effective way of meeting the Government's objective of providing consumers with price stability at low cost. This approach avoids the complexity, hedging costs, associated risk premiums and return a margins that are inherent in other methodologies including the current RRO. Risk of customer migration would not likely be a problem as Default Rate customers would all have essentially the same deal. To date, the retail market has been able to accommodate customer exit from fixed price, long term contracts.

In order to assess the impact of a price cap and a fixed price for the Default Rate, I built a simple financial model to calculate the interest cost associated with the deferral account. I caution that it is a simple model that is designed to illustrate the magnitude of the interest cost and it is not a model for the purpose of policy design.

My approach was to look at the impact of the 6.8 cent/kWh price cap on the Pool price, forward price, Spot Power floating rate and the EPCOR RRO for each year during the period 2008 to 2016. I assumed that a deferral account would accumulate during the year if, in a particular month, the Pool price was higher than the price cap. I calculated the interest cost for 1 kWh for the remainder of the year. The total amount of the deferral account at the end of the year was amortized and paid to retailers in equal amounts in each month of the following year. The model could be run for any price cap, interest rate or time period. Finally, I assumed that retail products with price caps or fixed prices would have a nominal term of 1 year. The results of the analysis are illustrated in Table 4.

Table 4: Interest Cost Impact of 6.8 Cent Price Cap for 1 kWh of Energy

	Pool vs Price Cap	Forward vs Price Cap	Spot Power vs Price Cap	EPCOR vs Price Cap
2008	-0.0019	-0.0013	-	-0.0029
2009	-0.0002	-0.0002	-	-0.0010
2010	-0.0005	0.0000	-0.0002	-0.0003
2011	-0.0014	-0.0013	-0.0028	-0.0024
2012	-0.0007	-0.0007	-0.0018	-0.0024
2013	-0.0019	-0.0008	-0.0029	-0.0015
2014	-0.0006	-0.0003	-0.0010	-0.0008
2015	-0.0002	-0.0002	-0.0005	0.0000
2016	0.0000	0.0000	0.0000	0.0000

Notes: Negative numbers indicate charges to consumers
Positive numbers indicate credits to consumers

I also performed the analysis for a 6.8 cent/ kWh fixed price rather than a price cap. The only difference with this analysis is that in some months there might actually be a credit rather than a debit. In a fixed price arrangement, the months where the Pool price is lower than the fixed price creates a positive balance and offsets the negative months. The analysis for the fixed price is presented in Table 5.

Table 5: Interest Cost Impact of 6.8 Cent Fixed Price for 1 kWh of Energy				
	Pool vs Fixed Price	**Forward vs Fixed Price**	**Spot Power vs Fixed Price**	**EPCOR vs Fixed Price**
2008	-0.0018	-0.0013	0.0000	-0.0029
2009	0.0017	0.0009	0.0000	-0.0009
2010	0.0015	0.0013	0.0007	0.0002
2011	-0.0007	-0.0010	-0.0026	-0.0023
2012	0.0003	-0.0003	-0.0015	-0.0024
2013	-0.0010	-0.0004	-0.0025	-0.0015
2014	0.0015	0.0004	0.0001	-0.0007
2015	0.0029	0.0020	0.0017	0.0010
2016	0.0042	0.0035	0.0033	0.0021

Notes: Negative numbers indicate charges to consumers
Positive numbers indicate credits to consumers

It is clear from the analysis that the interest cost associated with the deferral account is lower than the cost of EPCOR's RRO and will also be lower than the cost of other pricing methods that utilize hedging and other insurance premiums to mitigate price volatility.

9. *If consumers are taking the price risk and a price cap is used, it should be equal to the incremental cost of new generation facilities as determined by the Alberta Utilities Commission.*

An important consideration in the design of retail energy products is who bears the price risk – consumers or retailers? If consumers are taking the price risk they would be subject to the deferral account.[2] Alternatively, retailers can take the price risk if the market price exceeds the price cap or fixed price. In this case, retailers would likely include risk and return premiums to compensate for the potential loss of profits which would increase the cost to consumers more than the cost of the deferral account approach. Ultimately, however, the net effect to consumers from all price stabilization approaches is to increase the cost of electricity regardless of who bears the price risk. Our objective should be to minimize that cost.

If consumers are taking the price risk there should be an independent determination of the price cap. My suggestion in this regard is that the Alberta Utilities Commission

[2] One alternative to consumers funding the deferral account is the Government would fund the account using revenue from the carbon levy. I don't recommend this as it obscures the price signal effectively distorting consumers' decision making and resulting in sub-optimal policy development by the Government.

should determine the level of the price cap based on the incremental cost of new generation. It makes no economic sense to have a price cap that is less than the cost of new generation. To do so sets up a situation where subsidies must be used to encourage new generation. As discussed previously, the development of a capacity market will provide sufficient information to readily determine the appropriate level of the price cap.

10. *If consumers are taking the price risk and a fixed price is used, it should be equal to the Pool price forecast prepared by the Alberta Electric System Operator 30-days prior to the start of the calendar year.*

The Alberta Electric System Operator prepares a long term price forecast for use in transmission planning and other analyses. It is an independent and objective forecast and would be a suitable reference for fixed price products using a deferral account.

11. *If retailers are taking the price risk when Pool prices exceed a price cap or a fixed price equalized billing plan, they may set the price which may be accepted or rejected by consumers at their discretion.*

If consumers are taking price risk, the Government should not rely on retailers to set the price cap or fixed price. The reason is that retailers have an incentive is to understate the price cap or fixed price in order to acquire a customer. If, however, the retailer is going to take the price risk, then the retailer should be free to determine the price which would then be accepted or rejected by the consumer. This situation is no different than retailers setting the price for a fixed price term contracts as is currently done in Alberta's retail market.

12. *Vulnerable consumers should be protected by grants, subsidies and/or rebates.*

All consumers, including vulnerable consumers, should be exposed to the Default Rate because it constitutes a "price signal" about the actual cost of electricity. That said, some consumers are vulnerable because they are not able to protect themselves for whatever reason. A principle of our society is social responsibility and so it is therefore incumbent upon members of society to contribute towards the protection of vulnerable consumers. Vulnerable consumers are best protected through one time grants to aid them thorough a difficult situation or a subsidy or rebate that would assist them for longer periods of time.

13. *The cost of grants, subsidies and rebates for vulnerable customers should be funded by a surcharge on all electricity customer bills.*

There are undoubtedly many ways to source funds to be used for grants, subsidies and rebates. My preferred method is through a rate rider that would be administered by the Alberta Electric System Operator (AESO). The annual budget requirement would be determined and approved by the relevant government departments. The budget requirements would be forwarded to the AESO who would then mange the regulatory process with the Alberta Utilities Commission. Once approved, the funds would be collected and administered by the AESO. The relevant government department would be responsible for dispersing the funds, as required.

In summary, the Pool price flow through as a Default Rate is simple, easily understood by consumers and is a cost effective relative to other methods of providing default service to Alberta electricity consumers. Pool price volatility can be effectively managed using low cost deferral accounts rather than more complicated risk management and procurement processes. Furthermore, enabling any retailer to provide the Default Rate will increase competition, drive down costs and encourage product innovation. I strongly encourage the Government to give serious consideration to adopting my recommendations.

Please do not hesitate to contact me if you have any questions.

Respectfully submitted,

Robert F. Spragins

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Cell: 403.829.6991

Email: rob.spragins@yahoo.ca

Attachments

ALBERTA UTILITIES COMMISSION

IN THE MATTER OF

GENERIC PROCEEDING ON THE
REGULATED RATE TARIFF

APPLICATION NO.: 1610120
PROCEEDING ID NO.: 2941

EVIDENCE
of the
UTILITIES CONSUMER ADVOCATE
Robert F. Spragins

June 4, 2014

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POLICY EVIDENCE OF THE UCA

I. INTRODUCTION

Q 1. Please State your name, title, and business address.

A 1. My name is Robert F. Spragins. I am the Utilities Consumer Advocate (UCA), and was appointed on November 14th, 2011. My address is 9th Floor, 855 – 8th Avenue S.W., Calgary, Alberta T2P 3P1.

Q 2. What is the mandate of the Utilities Consumer Advocate?

A 2. The UCA has a statutory mandate to represent the interests of residential, farm and small business consumers of electricity and natural gas in proceedings before the Alberta Utilities Commission (AUC or Commission). As this proceeding impacts these classes of consumers, I am is taking an active role.

Q 3. Will you please summarize your qualifications, including your business and regulatory experience in the regulated natural gas and electrical industry?

A 3. My curriculum vitae is attached as Appendix A. I have over 36 years of North American energy industry experience. Prior to my appointment as the UCA in November 2011, I spent 9 years at the Alberta Market Surveillance Administrator (MSA) where I was first Manager of Investigations, responsible for investigating a wide range of issues related to the fair, efficient and openly competitive operation of the Alberta electricity market; and then Manager of Retail Markets, where I was responsible for monitoring competition in Alberta's retail electricity and natural gas markets. I have experience in applied economic research, corporate planning, financial analysis, natural gas marketing, regulatory analysis and power generation project development. I hold Bachelor of Commerce and Master of Business Administration degrees from the University of Alberta.

Q 4. Have you previously provided testimony before the AUC?

A 4. Yes, in AUC Proceeding 2718, AESO 2014 ISO Tariff Application and 2013 Tariff Update, Application No. 1609765. I have also prepared written testimony in AUC Proceeding 2155, DERS Interim Amended 2011-2014 EPSP, Application No. 1608874; and AUC Prodeeding 2253, EEC 2011-2014 EPSP Amendment, Application No. 1609038.

Q 5. What is the purpose and scope of your evidence?

A 5. The purpose of my evidence is to state my objective (Section II), and outline the principles (Section IV) that I propose the Commission consider in the context of this proceeding. I offer some concepts for possible benchmarks of RRO performance (Section III), and I describe and assess the value of the RRO to consumers in qualitative and quantitative terms (Section III). I also provide my interpretations of the assessment (Section IV). Finally, I offer some additional remarks (Section V) to address certain issues identified by the Commission at the commencement of this proceeding. An Excel workbook containing the charts, tables and data prepared for this evidence has been included as Appendix B.

Q 6. What results of the Retail Market Review Committee (RMRC) do you consider relevant to the current proceeding?

A 6. The RMRC produced a list of forty-one recommendations, in its September 2012 report, *Power for the People*[1]. Of these forty-one, nine recommendations (33 through 41), related to the RRO. The first six of these recommendations, 33 through 38, related directly to the phasing out the RRO.

RMRC recommendation 39 related to the rural electrification association compliance with the Tarrif Billing Code, and System Settlement Code. Recommendation number 40 suggested amending the *Regulated Rate Option Regulaton* (*RROR*) to extend the procurement window from the 45 day limit to a three to six month period, and that the hedging mechanism be standardized across the Providers, as an NGX platform auction, as currently used by EEA. Finally, recommendation 41 was to amend the *RROR*, to reduce the consumption limit for RRO eligibility from 250 MWh per year to 50 MWh per year.

The Government of Alberta rejected the six recommendations related to eliminating the RRO service[2], and extended the *RROR* to April 30th, 2018. On January 29, 2013, the ADOE amended the RROR to extend the price setting window from 45 to 120 days. This recommendation became fully operational on January 1, 2014. To date, no decision has been made concerning the RMRC recommendation to standardize the procurement model or lower the RRO eligibility threshold.

II. OBJECTIVE

Q 7. What is your objective in this proceeding?

A 7. My objective is to advocate for the lowest regulated rates consistent with reasonable service. This objective is the foundation of the UCA's regulatory activity.

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[1] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta", 2012, page 174

[2] Protecting Electricity Consumers: http://www.energy.alberta.ca/Electricity/3406.asp

Q 8. Would you please elaborate on your objective?

A 8. The goal of achieving the lowest RRO service rates consistent with reasonable service is comprised of two parts. The first part, achieving the lowest regulated rate, is self-evident. All else being equal, consumers are better off paying less for a good or service. The second part, that rates be consistent with reasonable service, requires a more nuanced explanation.

In the context of the RRO service, there are certain considerations, or constraints, that I view as relevant to achieving my objective. These constraints help to establish the level of reasonable service that consumers require, and at the same time limit the rate reductions that are achievable. These constraints are necessary and useful in the overall framework of the RRO, but nonetheless impose varying degrees of limitation on the potential reduction in RRO rates. These constraints are referenced in the *RROR* and commonly accepted regulatory principles.

The considerations or constraints referenced in commonly accepted regulatory principles are the need for quality of service and customer care.

The constraints referenced in the *RROR* include, in no particular order:

i. The requirement that rates be based on forward market electricity prices, per section 11(1)(a)(ii) of the *RROR*:

> **11(1)** Each new RRO rate
> (a) must be based on
> (ii) monthly forward market electricity prices established in a relevant price setting period

ii. The limitations on the use of deferral accounts, per section 6(2) of the *RROR*:

> **6(2)** A regulatory authority must not approve a regulated rate tariff that uses, provides for or contemplates any deferral accounts, true-ups, rate riders or other similar accounts or devices for energy related costs.

iii. The requirement that each owner must make available RRO service to eligible customers, per section 2 of the *RROR*:

> **2** Each owner must make available to eligible customers in the owner's service area the option of being supplied electricity services in accordance with a regulated rate

> tariff instead of purchasing electricity services from a retailer

iv. The requirement that a tariff allow each owner earn a reasonable return in exchange for the obligation to provide service, per section 6(1)(b)(i) of the *RROR*:

> **6(1)** When considering an application for approval of a regulated rate tariff under section 103 of the Act, a regulatory authority must
>
> (a) have regard for the principles that
> (i) a regulated rate tariff must allow for a reasonable return for the obligation on the owner to provide electricity services in accordance with section 2

III. PRINCIPLES

Q 9. What principles do you believe the Commission should rely on when considering the EPSPs ?

A 9. I propose the following principles, in no particular order:

1. The RRO rates within each customer class should not be materially different.
2. The RRO rate setting process should be competitive, where possible, leading to outcomes that are comparable and consistent with competitive outcomes.
3. The RRO rate setting process should have adequate oversight.
4. The risk compensation of RRO Service Providers should be profit and loss neutral.

In my opinion these principles will lead to desirable outcomes in line with my stated objective. However, these outcomes may not be achieved in each circumstance, or in the near term. Each incremental action in line with these principles is desirable in and of itself. That is, in circumstances where outside factors limit the effectiveness of an action aligned with a principle, that action should nevertheless be pursued. As well, there may be instances where a principle conflicts with another. If such a circumstance were to arise, a balance should be sought between the competing principles. The optimal solution is not necessarily one where the outcome of each principle is completely achieved.

Q 10. Could you please elaborate on the first principle?

A 10. The first principle, that the RRO rates within each customer class should not be materially different, is based on the interests of fairness and simplicity for consumers. The ideal outcome of this principle is a single province-wide RRO rate, for each customer class. A single RRO rate for the province is fair to consumers in different regions of the province, drawing on the spirit of postage stamp rates that have a long history in the other Canadian jurisdictions and in Alberta in the 1980's through the *Electric Energy Marketing Act 1981*[3]. In the present market context, there are also competitive contracts that offer a single price to consumers in nearly all regions of Alberta.

For reasons of simplicity and consumer comprehension, a single RRO rate, is preferable. Uniformity is most likely achievable through a single rate setting mechanism, which could also reduce future regulatory burdens, possibly lead to cost savings, and facilitate monitoring and assessment of the pricing mechanism process and outcomes.

Q 11. Could you please elaborate on the second principle?

A 11. The second principle that the RRO rate setting process should be competitive, where possible, and lead to outcomes that are comparable and consistent with competitive outcomes, is in my view, well founded in the *RROR*, in particular Section 4(1) which states:

> **4(1)** The price setting plans referred to in section 3(1)(a) must, with a reasonable degree of transparency, use a fair, efficient and openly competitive acquisition process to ensure that the resulting prices for the supply of electric energy are just, reasonable and electricity market based.

In particular, the EPSPs under consideration in this proceeding should have regard for the competitiveness of the base energy charge hedging mechanism, in its design and execution. This may be achieved using the same tools employed by the broader market, including tactics of position concealment, and the application of a full array of hedging instruments.

Q 12. Could you please elaborate on the third principle?

A 12. The third principle, that the rate setting process should have adequate oversight, stems from the previous principle of competitiveness. Oversight should be carried out by an independent entity with a clear mandate to asess the competitiveness of the processes and outcomes, employing all known best practices and benchmarks where possible.

Oversight should also include visibility of individual cost and revenue components, and where appropriate, enable auditing of RRO accounts including all regulated and non-

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[3] Electric Energy Marketing Act, 1981, Section 14

regulated affiliates involved in the process of energy procurement by or for any regulated or non-regualted affiliate.

Oversight and review should not preclude input from both RRO providers and consumer groups, who should both be afforded equal opportunity to contribute to the assessment of process and outcomes. All parties should have unfettered access to all relevant data, in any level of granularity required, under appropriate procedures for maintaining confidentiality of commercially sensitive information. The performance of the RRO should be transparent, and RRO service providers should not enjoy a systematic information advantage over consumers.

The ability to take meaningful action must be embedded in the oversight structure, and there must be a dispute resolution process available to all parties. Further consultations on revisions to Rule 005 may be a means to establish a meaningful oversight structure.

Q 13. Could you please elaborate on the fourth principle?

A 13. The fourth principle, that risk compensation be profit and loss neutral, means that risk compensation should aim to allow the RRO providers to recover prudent costs and expenses, over the term of the EPSP. The profit the RRO providers are entitled to for the obligation to provide electricity services, should be collected exclusively from the return margin.

This principle is well founded in the RROR, specifically in Section 6(1) which states:

> **6(1)** When considering an application for approval of a regulated rate tariff under section 103 of the Act, a regulatory authority must
>
> (a) have regard for the principle that a regulated rate tariff, including the risk margin described in section 5, must provide the owner with a reasonable opportunity to recover the prudent costs and expenses incurred by the owner,
>
> (b) have regard for the principles that
>
> (i) a regulated rate tariff must allow for a reasonable return for the obligation on the owner to provide electricity services in accordance with section 2, and
>
> (ii) the risk margin described in section 5 must not be considered as a part of that reasonable return,
>
> (c) have regard for the principle that a risk margin approved by it must provide the owner with a just and reasonable financial compensation for the risks described in section 5,

Subsection 6(1)(a) contains specific language that indicates the risk margin must provide the owner with the opportunity to recover prudent costs and expenses. In the context of the risk margin, the recovery of prudent costs can be understood to mean risks that were realized and resulted in a financial loss. The risk margin should aim to recover as close to the full value of the actual losses as possible.

Subsection 6(1)(c) refers to the risk margin providing just and reasonable financial compensation for the risks to which the owner is directly exposed. Financial compensation for exposure to risk implies some forward looking expectation of risk. In general, if expectations are correct, then the longer the time period over which outcomes are realized, the closer expectations should reflect realized outcomes. Forming expectations should not be a one-time upfront exercise. Expectations should be adjusted, when they prove inaccurate, or when new information is available to improve expectations.

Refining expectations contributes to greater certainty in outcomes; however there will still be an element of uncertainty in any risk compensation that is based only on forward looking expectation. All else equal, risk compensation that is based on adjusted expectations should perform better than risk compensation based only on upfront expectations, in terms of allowing the providers to recover the full value of losses.

To address the uncertainty that refined expectations are not correct, or for some other reason that they do not converge with realized outcomes, the *RROR* offers possible relief, in subsection 5(5) which states:

> **5(5)** An owner is not entitled to recover from customers any past costs or expenses related to the risks described in subsections (3) and (4) except through the risk margin approved by the owner's regulatory authority

In Decision 2010-163 the Commission held that:

> "subsection 5(5) provides an express and specific exception to the more general prohibition against collection of past energy related amounts set out in subsection 6(2) of the *Regulated Rate Option Regulation*"

The Commission used this subsection of the *RROR* to compensate a provider for the past cost of uplift charges, described as a "past cost related to the risk of energy cost changes", which were not dealt with in the risk margin of the EPSP.

Accordingly, I am of the view that risk compensation as contemplated in the *RROR* should aim to be proft and loss neutral on an expected basis, and contain provisions to ensure RRO service providers are made whole on a realized basis.

Subsection 6(1)(b)(i) & (ii) speak to the need for compensation or a return margin that is just and reasonable for the obligation to provide service, and the requirement that risk margin not be considered as part of the reasonable return. Combined with the principle that risk margin be profit and loss neutral, the return margin should be thought of as pure profit.

In my view, there is a clear distinction that risk margin must only compensate for risk, and not contain amounts in excess of that required to recover prudently incurred costs and expenses; while the return margin must only provide profit, and not contain amounts to cover realized or expected risk. It is also desireable that risk compensation be structured so that RRO providers are indifferent to the level of base energy charge. To the extent that RRO providers benefit financially from higher base energy charges, they should not have discretion in determing those charges.

IV. CONCEPTS FOR BENCHMARKING THE RRO

Q 14. What are some possible concepts for benchmarks to evaluate the performance of the RRO going forward?

A 14. I offer two concepts that could be incorporated into a benchmark assessment of the RRO rates going forward.

First, Table 1 presents a benchmarking evaluation of the RRO that is illustrative of how one could incorporate the concept of gross mark up over commodity cost. This is analagous in concept to levelized unit cost estimates which do not capture specifics, but generally represent a cross-section of generation plants. The left hand columns of Table 1 present average RRO energy rates from July 2011 through May 2014, and the average base energy charge (BEC), from July 2011 through May 2014, for each of the RRO providers, based on the monthly RRO filings with the Commission. The difference between the base energy charge and the RRO energy price represents a gross markup over RRO hedging costs.

The right-most column of Table 1 presents the average of 5 year retail offers that were available in July 2011, and the weighted average of the 5 year forward curve[4] for flat and peak products (weighted 70% flat, and 30% peak), as at June 30th, 2011. The difference of the average retail offer and the forward market's price expectation at that time, is an estimation of gross markup of the unregulated retail product. Recognizing that

[4] Using NGX Fin FF, FP for AESO Flat, (CA/MWh), Alberta; and NGX Fin, FP for AESO Ext Peak, (CA/MWh), Alberta.

unregulated retailers may well have different cost structures for a five-year fixed product, this estimation could be further refined.

This benchmark is illustrative of the gross mark-ups in a scenario where a customer opts for RRO service in July 2011, or a scenario where the customer opts for a five-year product in July 2011, and the retailer locked in the energy cost to serve that customer, through the forward market at that time.

Table 1 - Estimations of Average Gross Markup from July 2011 to May 2014

	EEA		EEC	DERS		5-Year Product
	EDTI	FORTIS	Calgary	ATCO		
	($/kWh)					($/kWh)
RRO	0.0927	0.0904	0.0928	0.0941	**Retail Offer**	0.0850
BEC	0.0814	0.0796	0.0822	0.0857	**W.A. Fwd Curve**	0.0713
Difference	0.0113	0.0108	0.0107	0.0084	**Difference**	0.0137
% Difference	12.17%	11.96%	11.48%	8.89%	**% Difference**	16.08%

While it is likely not possible to develop an absolute measure of economic viability for unregulated fixed price contracts, it is possible and desireable to compare retail products on a relative basis to indicate how these products are performing for both retailers and consumers. This is particularly true given that all three retailers offer both regulated and competitive products.

Second, a report completed for the UCA by Monitoring Analytics[5] in May of 2012, proposed that the optimal default retail rate is the hourly spot price, where both supply side and demand side of the market face the real time market price, and have the incentive and ability to react to pricing changes accordingly. The report acknowledged that current metering infrastructure limits the ability of small consumers to directly observe the spot price in real time, meaning that this optimal default price is hypothetical at this time. One proxy[6] to this optimal default price is the system load weighted average pool price, which is used in Figure 1 below.

Figure 1 plots the differential between the Average RRO[7] price and the system load weighted average pool price from July 2011 through April 2014. A positive differential

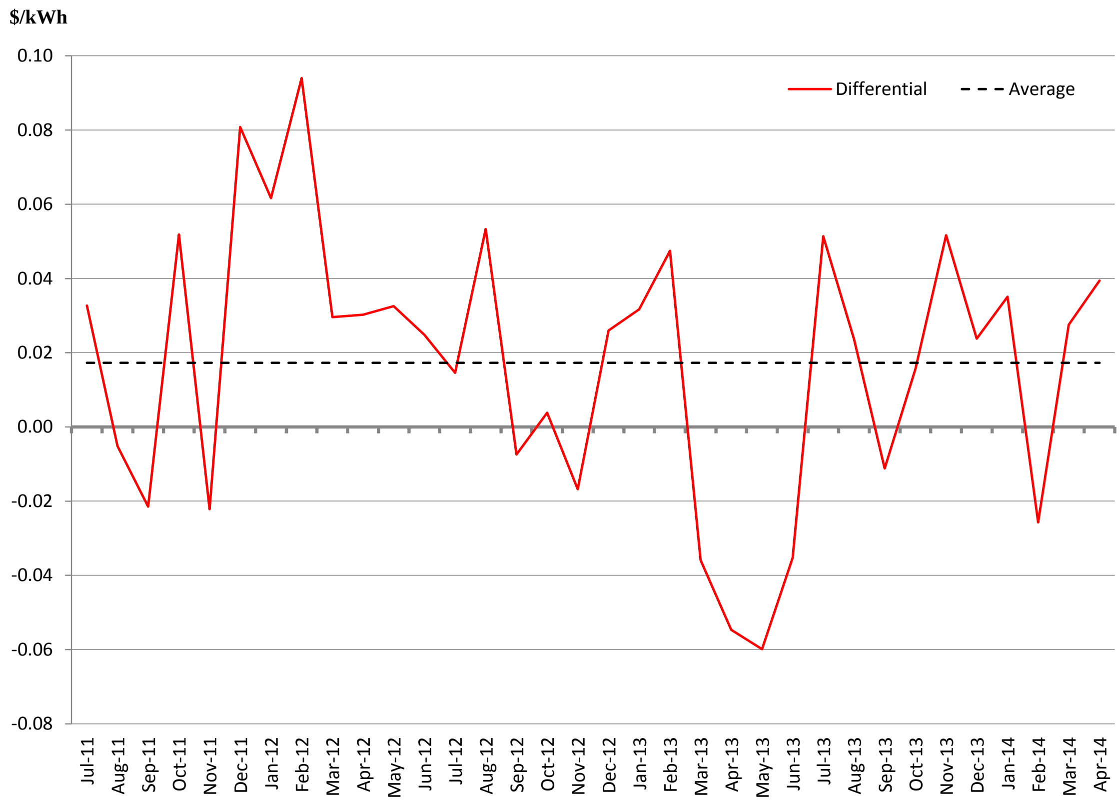
[5] Monitoring Analytics, “Report to the UCA: Default Retail Rate for Energy”, 2012

[6] The system load weighted average pool price is a proxy for the optimal default price because load currently has a limited ability to observe the real time price, and limited incentive to respond accordingly. The default price contemplated by Monitoring Analytics requires that all load have the ability and incentive to respond price changes, which would have an effect on the real time spot price, not present in the system load weighted average pool price.

[7] The monthly Average RRO is calculated as the annual load weighted average of EEC – Calgary, EEA – EDTI, EEA – Fortis, and DERS monthly RRO rates.

indicates the average RRO price exceeded the load weighted average pool price in that month. I note the majority of observations are positive, and the average of all observations is $0.016/kWh. This premium in RRO pricing could represent a number of factors including: 1) a general premium to the forward market over spot, 2) premiums resulting from the RRO hedging mechanism, 3) premiums resulting from risk and return compensation and other costs and fees factored into the RRO rates.

Figure 1 – Differential of Average RRO and Monthly System Load Weighted Average Pool Price



A benchmarking evaluation of the RRO, could also incorporate this concept of the premium to RRO over spot price. Both concepts for benchmarking are best understood from the perspective of relative changes going forward. That is, they are both intended to be directional in nature, and are intended to detect changes in RRO performance without directly attributing the cause. A positive or negative trend would suggest that a review should be undertaken to determine the root cause(s) of the trend.

V. VALUE OF THE RRO TO CONSUMERS

Q 15. What is your qualitative assessment of the value of the RRO to consumers in Alberta?

A 15. One of the ways the RRO brings value to some customers is as a default rate. That is, some consumers may be unaware that competitive contract options exist, while others may be aware but feel the cost of their time and effort to understand the choices available in the marketplace is too high, compared to any possible gain from seeking out a competitive option. This idea is more fully discussed by Dr. Don McFetridge, in his study "Competition in the Alberta Retail Electric Power Market"[8]:

> "the RRO is the default option for eligible electricity consumers. While they can be said to have chosen it over the packages offered by competitive retailers as EPCOR representatives have argued, this choice is open to different interpretations. Some customers may have chosen the RRO explicitly. That is, they may have searched the competitive alternatives and decided that the RRO was superior. Other customers may have been aware that there are alternatives to the RRO but decided that searching them out and evaluating their respective merits was not worthwhile and done nothing. Still others may not have been aware that there are alternatives. This group can be said to have made a choice of sorts but they would likely be on whatever default plan existed regardless of its merits".

Consumers have also expressed their opinions about the value of the RRO through surveys conducted at various points in time. One of the most recent was an online survey conducted by Leger, for the MSA's research into the effects of co-branding in the retail market[9]. The MSA summarized the results of the market research that are relevant to this discussion in the third key finding of the report:

> "3. There is clear evidence that many consumers believe the RRO is a rate that is designed by the government to protect them (it is not designed primarily to protect consumers)".

The MSA provided further insight in the Summary of the report, which states:

> "The attractiveness of the RRO is higher than anticipated. People do actively return to the RRO and there is a consistent stated preference for the RRO across RRO and non-RRO customers"

The MSA's conclusions indicate that consumers value the RRO, even if for reasons that are perhaps misplaced.

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8 Dr. Donald G. McFetridge, "Competition in the Alberta Retail Electric Power Market: Study prepared for the Utilities Consumer Advocate", 2012, page 9

9 Market Surveillance Administrator, "An Assessment of the Influence of Co-Branding on Consumer Choices in Electricity in Alberta", 2014

The Retail Market Review Committee also conducted a consumer survey in May of 2012, to gather the opinions of Albertans about electricity. The survey questioned participants about regulated prices. The RMRC report presented the following results at page 86:

> "Six in 10 Albertans (58%) believed that the government should ensure all residential Albertans have access to a regulated price for electricity. Albertans with this opinion were more likely to believe choice is not important"

The RMRC report also concluded that price was a priority for Albertans, stating at page 88:

> "Price was a top priority for Albertans in many sections of the telephone survey. When survey participants were asked what information people needed to make informed decisions about buying electricity, 57% identified price information. Company reputation came second, at 22%. When survey participants were asked to identify their main concerns with regard to switching electricity providers 55% identified price. Contract related concerns (such as being able to exit an agreement without penalty) came second, at 10%."

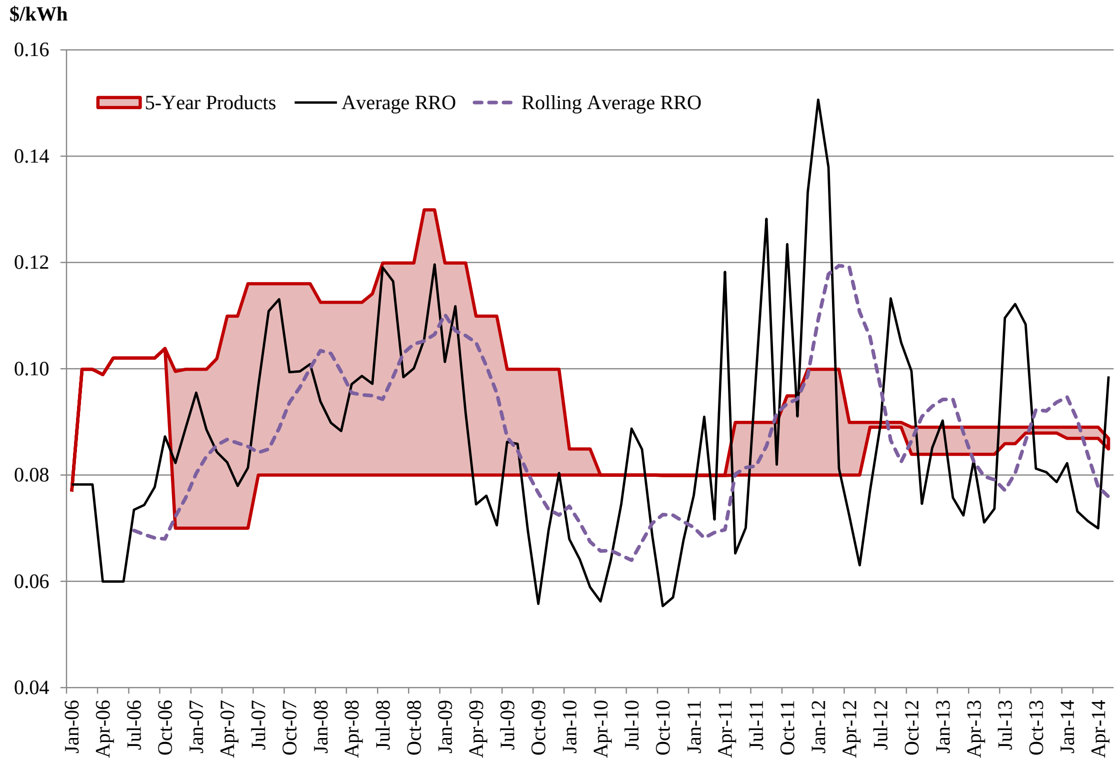
Taken together these survey results indicate that the RRO delivers qualitative value to consumers. A majority of Albertans believe that the RRO should be offered; and some of those who use the RRO service do so by default, while others actively choose the RRO, in some cases returning to it. Consumers also feel 'protected' on the RRO, believing the regulatory processes have their interests in mind.

Q 16. What is your quantitative assessment of the value of the RRO service to consumers in Alberta?

A 16. An insightful quantitative assessment of the value of the RRO to consumers takes place at the level of the consumer pocketbook, that is to say the monthly cost of electricity for the typical residential consumer. This is a relevant perspective, as it is the basis on which consumers make decisions about how to choose between subsititute goods.

To provide some context for this assessment, I first present some historical trends in the retail marketplace, comparing the performance of the RRO against other retail products. Figure 2 plots the monthly Average RRO against the range of prices for five-year fixed price products in each month. At some points in time, numerous five-year products were available in the marketplace, while at other points in time, only a single product was available. Data is plotted from January 2006 to May 2014, corresponding with the time frame of the assessment of impacts on the consumer's pocketbook, presented later in the section. The six month Rolling Average RRO highlights the trend in the Average RRO.

Figure 2 - Average RRO vs. Five-year Fixed Price Product Band



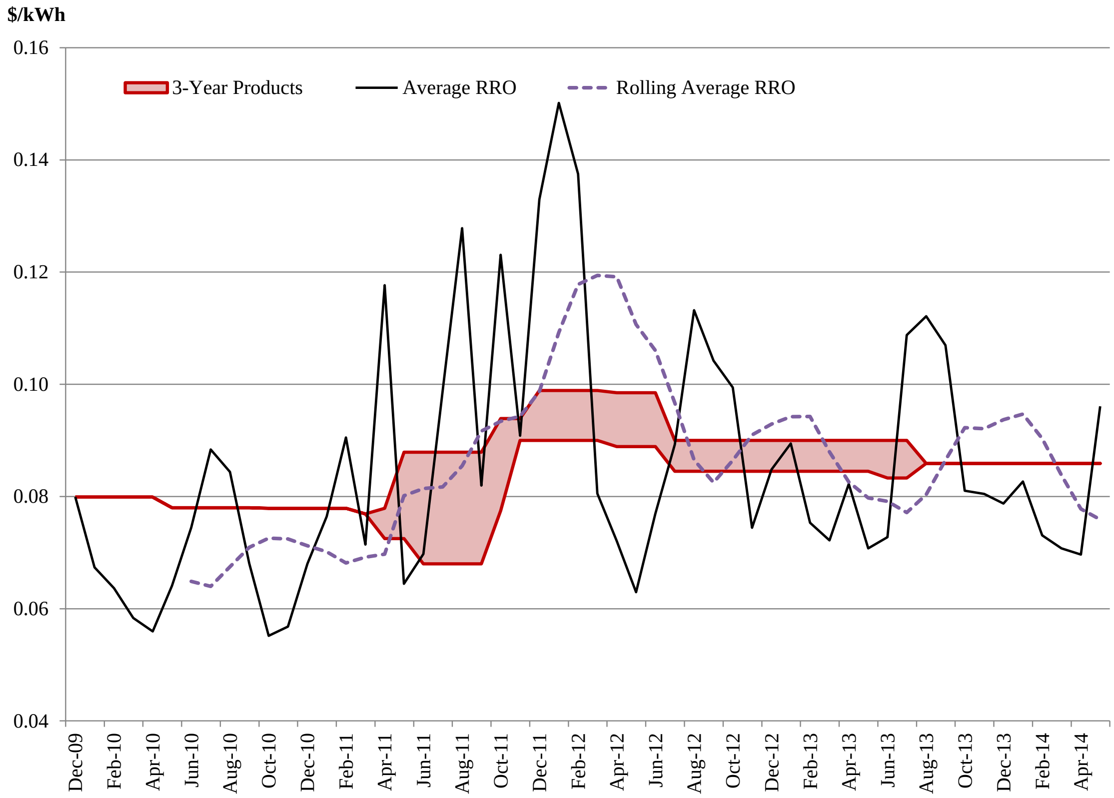
Notes: 1) Average RRO is the load weighted average of Fortis, EDTI, Calgary and DERS Residential RRO energy rates
2) Rolling Average RRO is the six month rolling average of the Average RRO
3) Five-year product price band includes all stand alone electricity offers that do not include upfront fees or deposits. These products are reasonable substitutes for the RRO, from the consumer perspective.

It is challenging to draw direct price comparisons between five-year fixed price products, and a monthly variable product like the RRO, given the differences in the nature of the products. However, the key observation from Figure 2 is that the average RRO rate and the five-year products are generally coincident in price. There are times when the average RRO rate tends to be higher than the five-year product price band, and times when it tends to be lower, but RRO prices do not persistently or completely diverge for any extended period of time.

I also note that the lower bound of the five-year product price band is quite stable from mid-2007 through mid-2012. During this time a product offered by ENMAX set the lower bound of the five-year product band, while other retailers tended to move their product pricing with the RRO trend, as seen against the six-month rolling average curve. After mid-2012 another retailer defines the lower bound of the five-year product band.

Figure 3 presents a similar comparison and shows the average RRO rate against the band of three-year products available in each month. Data is plotted from December 2009 through May 2014, reflecting the presence of three-year products in the retail marketplace. The six-month Rolling Average RRO highlights the trend.

Figure 3 - Average RRO vs. Three-Year Fixed Price Product Band



Notes: 1) Average RRO is the load weighted average of Fortis, EDTI, Calgary and DERS Residential RRO energy rates
2) Rolling Average RRO is the six month rolling average of the Average RRO
3) Three-year product price band includes all stand alone electricity offers that do not include upfront fees or deposits. These products are reasonable substitutes for the RRO, from the consumer perspective

Again, the key observation from this chart is the general coincidence of the product pricing. As with the five-year products, the average RRO rate tends to be higher in some periods, and lower in others, but it does not persistently or completely diverge from the three-year product price band. I also note that the three-year products offered by retailers generally trend with the RRO.

Overall there appears to be a general relationship in the magnitude and trend of pricing between the RRO and the three and five-year products. If we focus on the period of the current EPSP, July 2011 through the end of the plotted data (May 2014), two patterns emerge. In the mid-2011 to mid-2012 period, the RRO pricing is well above the three and five-year product price bands; while in the mid-2012 to mid-2014 period most of the RRO pricing is just below the three and five-year pricing bands.

Table 2 presents a comparison of the cumulative difference in energy costs between different products, from July 2011 through May 2014. For example, cell E3 ($178.09) represents the cumulative cost of energy through the EDTI RRO less the cumulative cost of energy through the lowest price five-year product available each month. A positive value represents a higher cumulative cost of the row product, over the column product. Cell E9 ($5.09), is the monthly average of the cumulative comparison.

Table 2 - Difference in Residential Energy Costs by Product Type July 2011 to May 2014

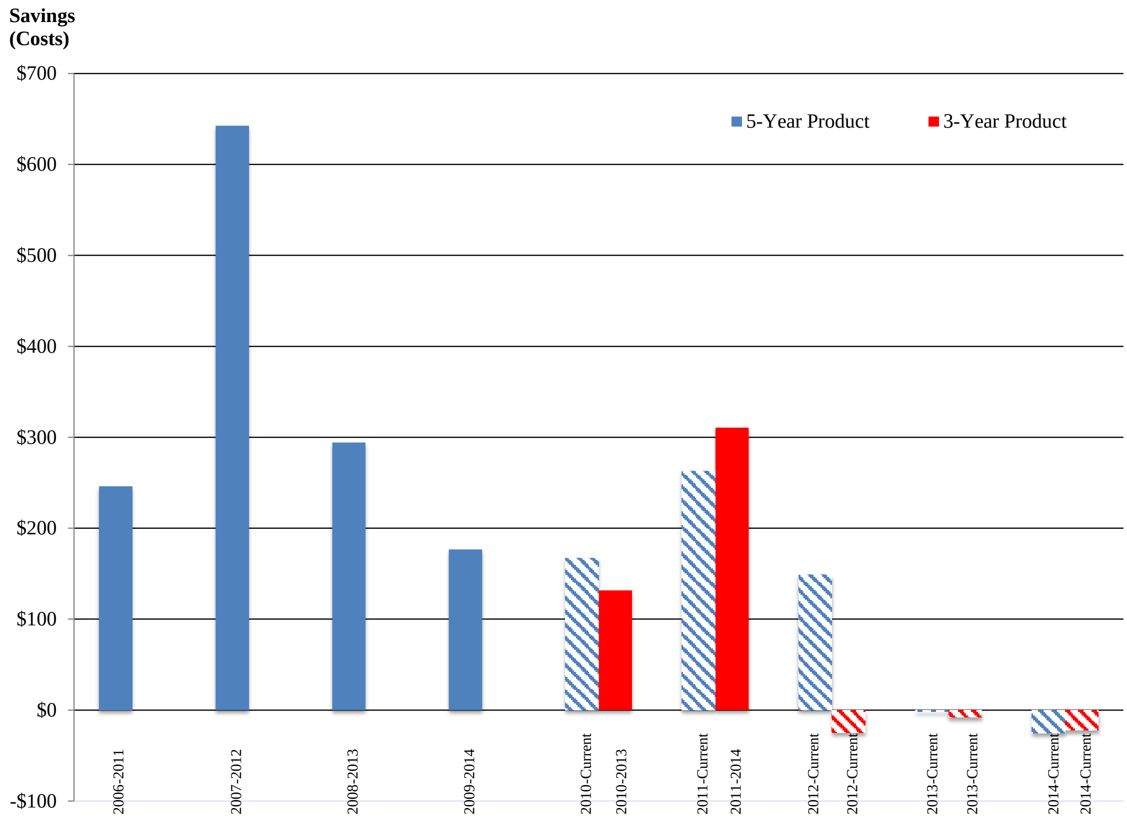
	Column	A	B	C	D	E	F
		DERS	EEC	EEA		Fixed Price Product	
Row		ATCO RRO	Calgary RRO	EDTI RRO	Fortis RRO	5-Year	3-Year
				Cumulative Comparison			
1	DERS RRO	$ -	$ 26.44	$ 29.59	$ 78.02	$ 207.67	$ 203.89
2	EEC RRO		$ -	$ 3.15	$ 51.58	$ 181.24	$ 177.46
3	EDTI RRO			$ -	$ 48.43	$ 178.09	$ 174.31
4	Forits RRO				$ -	$ 129.65	$ 125.87
5	5-Year					$ -	$ (3.78)
6	3-Year						$ -
				Monthly Comparison			
7	DERS RRO	$ -	$ 0.76	$ 0.85	$ 2.23	$ 5.93	$ 5.83
8	EEC RRO		$ -	$ 0.09	$ 1.47	$ 5.18	$ 5.07
9	EDTI RRO			$ -	$ 1.38	$ 5.09	$ 4.98
10	Fortis RRO				$ -	$ 3.70	$ 3.60
11	5-Year					$ -	$ (0.11)
12	3-Year						$ -

Notes: 1) Based on 600 kWh/month consumption for a typical residential customer
2) Based on lowest monthly three and five-year products
3) These results should not be interpreted as representing the impacts to an individual consumer. The analysis omits the search and switching costs that a consumer would face, and it would not be reasonable to assume a consumer would voluntarily switch to a higher priced product.

I note that, without exception, the five-year and three-year products have been cumulatively less costly than the RRO through the current EPSP.

Next we consider the impacts on a typical consumer's pocketbook. Figure 4 presents the cumulative differences in energy costs to consumers between the average RRO and a five-year product, or a three-year product, over each of the years since January 2006. This modelling assumes that a customer chose the lowest price five-year, or three-year product available in January of a given year, and remained on the contract for the full term.

Figure 4 – Cumulative Difference in Fixed Price Product Costs versus Average RRO Costs Realized by Consumers



Notes: 1) Based on 600 kWh/month consumption for a typical consumer
2) Based on lowest price three and five-year products, if available, in January of each year, less the monthly average RRO plotted in Figures 1 and 2. The use of a calendar year for this assessment was arbitrary. Results vary somewhat based on the starting month.

The pattern shaded bars represent less than full contract terms. For example, the five-year contract from January 2010 has seven months remaining at May 2014, but has accrued $200 in energy savings, over the average RRO, since that time. The three-year contract from January 2010 was completed in Decemeber 2012, and resulted in $150 in energy savings over the average RRO.

Table 3 presents the numeric results of Figure 4, indicating the cumulative, monthly average, and percent monthly average savings (or costs) of three and five-year products over the average RRO. The greyed cells represent contract periods that have not yet completed, and are analogous to the pattern shaded bars in Figure 4.

Table 3 - Summary of Figure 4 Results

	Five-Year Products			Three-Year Products			
Starting Year	Savings (Costs)	Average Savings per Month	Average Percent Saved per Month	Savings (Costs)	Average Savings per Month	Average Percent Saved per Month	Average RRO Cost per Month
2006	$246.19	$4.10	8.17%	n/a	n/a	n/a	$50.24
2007	$642.55	$10.71	20.32%	n/a	n/a	n/a	$52.71
2008	$294.28	$4.90	9.27%	n/a	n/a	n/a	$52.90
2009	$176.75	$2.95	5.78%	n/a	n/a	n/a	$50.95
2010	$167.51	$3.16	6.18%	$131.75	$3.66	7.15%	$51.16
2011	$263.11	$6.42	11.81%	$310.63	$8.63	15.87%	$54.36
2012	$149.20	$5.14	9.68%	($24.80)	($0.86)	-1.61%	$53.14
2013	($1.86)	($0.11)	-0.22%	($7.98)	($0.47)	-0.93%	$50.23
2014	($25.33)	($5.07)	-10.76%	($22.33)	($4.47)	-9.49%	$47.07

The savings that accrue to a customer from three and five-year contracts over the RRO are in some instances significant, such as the 2007-2012 period, where savings of a five-year product totalled $642. Typical monthly savings have been on the order of about five dollars per month, or about ten percent, against an average RRO energy cost of about fifty dollars per month. I do not consider savings of this magnitude to be trivial, from a consumer's point of view.

However, not all periods have resulted in such material savings. To date, the 2013 period witnessed a sharp decline in savings, and the 2014 period has been slightly negative for both three and five-year products. These results are generally reflective of Figures 2 and 3, which indicate the Average RRO rate has typically been less than the three and five-year product price bands since about 2013. The results for 2013 and 2014 can be considered in the context of a similar circumstance that occurred from mid-2009 through mid-2011, where RRO rates trended below the five-year product band, but Table 3 shows overall savings still accrued to the five-year products during this time.

Figure 4 and Table 3 illustrate, from the perspective of the consumer's pocketbook, that the fixed price contracts have outperformed the RRO from 2006 through 2012. More recently RRO pricing has been such that it has outperformed the three and five-year products.

VI. INTERPRETATIONS

Q 17. How do you interpret the qualitative and quantitative assessments of the value of the RRO service to consumers in Alberta?

A 17. The qualitative and quantitative assessments presented in the previous section have delivered some unexpected results. The RMRC Report noted in its summary and implications of consumer surveys[10]:

> "Albertans' desire for longer term, fixed-price arrangements is in conflict with their willingness to pay a premium to guarantee fixed prices".

And, in describing the need for review[11]:

> "The rate design strikes a balance between two sometimes conflicting objectives: consumers' desire for price stability and low prices.
>
> …
>
> Longer-term hedges could reduce the month-to-month price fluctuations of electricity prices, but predictability and stability come with a cost. Locked-in prices can be higher than what consumers might otherwise pay".

The concept expressed by the RMRC, that longer term price stability comes with a cost, holds when long term forward prices are flat or rising, but may not be the case if long term forward prices are falling. The quantitative assessment indicates that from 2006 through 2012, inclusive, the three and five-year products consistently produced a lower cumulative cost to consumers than the RRO. This result was observed over periods of rising and falling long term forward market prices. Recognizing that many factors influence unregulated product pricing, this result seems contrary to the RMRC's expectation of the costs of mitigating volatility.

In the more recent period of 2013 and 2014, the disparity in cost to consumers has eroded, to the point that the cumulative RRO cost is less than that of the fixed price products, so far in 2014. It is impossible to know with certainty what has been driving the pricing of the competitive market, but there are numerous possible explanations.

Positing the two ends of the spectrum: in the best case scenario, this outcome could be explained as the result of competition among fixed price products being sufficiently intense to drive down the cost of mitigating volatility; at the other end of the spectrum,

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[10] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta", 2012, page 90

[11] *Ibid*, page 33

the RRO price could be acting as a cap, or a price to beat, and competitive retail products are primarily competing with the RRO, as opposed to each other.

In the conclusion of his 2012 Report, Dr. McFetridge offered the following[12]:

> "The retail electricity market can be regarded at present as being competitive if not highly competitive. The RRO plays an important role in this. Competitive retailers design their offerings with a view to matching if not beating the RRO."

No matter the level of actual competition among the fixed price contracts, one observation remains: over a long time period, and range of market conditions, the unregulated market has been able to price products that deliver less volatility, at a lower price than the RRO. The implication I draw from this obsersvation is that the RRO has had a long, but not universal, record of being overpriced relative to products that contain a premium for long term fixed prices, all else equal, from the consumer's perspective.

VII. TABLE OF CONCORDANCE

Q 18. Does this conclude your policy evidence?

A 18. No, the preceding sections present the main points of my evidence, but to assist the Commission the UCA has also prepared a Table of Concordance which is appended to the cover letter of the UCA filing. There are three scope issues identified by the Commission that have not been clearly addressed by my evidence or that of the experts assisting me. I would like to respond to Commission issues 8, 15, and 28.

Q 19. Please respond first to issue 8 which asks: "What should the duration of the EPSPs be, and could a shorter or longer period be approved under the Regulated Rate Option Regulation, AR 262/2005?"

A 19. The EPSPs should not extend past the expiration date of the *RROR.*

Q 20. Please also respond to issue 15 which asks: "Should there be one central, independent entity responsible for the procurement of energy for all RRO providers? Should such an agency have its own trading shop?"

A 20. As discussed in the evidence of John Dalton, Q&A 43 through 46, in many jurisdictions centralized procurement is the norm and provides efficiency for retail service provision. I am directionally supportive of some version of centralized procurement in the Alberta

[12] Dr. Donald G. McFetridge, "Competition in the Alberta Retail Electric Power Market: Study prepared for the Utilities Consumer Advocate", 2012, page 35

market but note in the responses to the Commission's question, the RRO service providers did not support this concept. A central independent entity would likely require some procurement resources, but depending on the method agreed upon, a trading shop may not be necessary.

One objection from the RRO service providers is that the distributor has the statutory obligation to perform, and the right to appoint any other person to carry out the duties of an RRO service provider are established under sections 103 and 104 of the *Electric Utilities Act*. This appointment has been implemented in the Alberta market with DERS providing service for ATCO Electric and EEA providing service for FortisAlberta Inc. Further consolidation to one single entity would require approval of the distribution organizations, but so long as they are no worse off financially, I am not aware of any insurmountable barrier to establishing an independent entity to be responsible for all RRO procurement.

The second objection is that the current structure provides confidence that collectively, the pricing and/or procurement mechanisms are producing RRO rates that are reflective of the month ahead energy market, and that the EPSPs are working well. It is not clear that benchmarking three products, that share many common attributes, against one another is more informative than evaluating RRO performance against a benchmark outside the RRO. Further, exploring options that could lead to better outcomes for consumers is a more valuable objective than maintaining a benchmark, no matter how good the benchmark. With adequate oversight, and appropriate benchmarking and reporting, as discussed earlier in my evidence at A12 on page 6, the confidence in RRO pricing executed by one central provider would be established.

Q 21. Finally please respond to issue #28 which asks: "What can be done to address any new costs that may arise during the course of the EPSPs?"

A 21. New costs should be examined and the appropriate treatment assessed by the Commission based upon criteria similar to those that are used for deferral accounts If deemed appropriate the costs may be collected through the use of a deferral account similar to the manner in which the "uplift" costs were recovered previously. If the nature of the cost changes were extreme, it may require reopening of the then currently approved EPSPs.

Q 22. Does this now conclude your evidence?

A 22. Yes, at this time.

PUBLIC VERSION

MAY, 2012

COMPETITION IN THE ALBERTA RETAIL ELECTRIC POWER MARKET

Study prepared for the Utilities Consumer Advocate

Donald G. McFetridge Ph.D.

Introduction

In March 2012, in response to concerns regarding levels and volatility of the Regulated Rate Option (RRO), the Alberta Government appointed an independent committee to review it. Among the committee's tasks is to review whether a default option is needed, and if needed, discuss ways it could be better designed and delivered.

The Utilities Consumer Advocate (UCA) represents consumers' interests to the committee including matters relating to the pricing and procurement of electricity. In its recommendations to the committee the UCA plans to address three questions. These are:

1. Is the RRO (and a default rate in general) conducive to a competitive retail market?

2. Is the retail market sufficiently competitive such that consumers would not be made worse off by the discontinuation of the RRO?

3. If the RRO is deemed to be conducive to the competitive retail market and that it will not be discontinued, what is the most appropriate method by which to determine its rates?

The objective of this study is to answer Question 2, that is, to determine whether the retail market is sufficiently competitive such that consumers will not be made worse off by the RRO's discontinuation. Among the questions which must be addressed in the course of determining whether the retail market is sufficiently competitive are the following:

- What is the level of concentration in the retail market?
- To what extent are there entry barriers in the retail market?
- To what extent can retailers unilaterally exercise market power, if at all?
- To what extent can retailers collectively exercise market power, if at all?
- Is there any evidence of collusion in the retail market, tacit or otherwise?

- How much value do consumers actually derive from a competitive retail market, if any?
- To what extent is dynamic efficiency achieved with a competitive retail market?

Caveats

Questions 1 and 2 above are related. Competition among retailers may not be sufficiently strong at present to insure that consumers would not be adversely affected by the elimination of the RRO but this may be due to the presence of the RRO itself. The implication is that there is a two part question to answer: Is competition among retailers sufficiently vigorous at present to protect consumers in the event that the RRO is eliminated? If not, would the elimination of the RRO result in a sufficient and timely increase in retail competition?

Elimination of the RRO may make consumers worse off even if the retail market is highly competitive. There are two reasons for this. First, the RRO is a default option. It requires nothing of the consumer. Retail competition may deliver greater benefits but it also requires some effort on the part of the consumer. Second, the regulated rate may ignore relevant costs or be otherwise subsidized. Alternatively, retailers may incur costs that default providers do not incur.

Background

This study investigates the possibility that that consumers would suffer from the elimination of the RRO because retailers are able to exercise market power either unilaterally or jointly.

Market power

A seller in a market is defined to have market power if it can profitably raise its price (or prices) above the competitive level for a significant period of time without a significant loss of business to rivals or to substitute products. A supra-competitive price is defined as one that exceeds both the average cost (including a competitive rate of return) and the marginal cost of the product concerned.

A firm that has market power is assumed by economists to exercise it. A firm exercising market power unilaterally does so in the absence of any expectation of accommodating behaviour by rivals. In contrast, firms exercising market power jointly have agreed either explicitly or tacitly to coordinate their actions whether they involve price increases, output restriction or the allocation of customers.

Unilateral exercise of market power

When discussing the unilateral exercise of market power, the distinction is usually made between differentiated product and homogeneous product markets. In a differentiated products market, the identity and reputation of the seller is important and customers may have strong preferences among brands. In homogeneous product markets, the product is sold by description and the identity of the seller is much less important.

The ability to exercise market power unilaterally in a homogeneous products market comes from a low elasticity of market demand, a large market share and from capacity or logistical constraints on rivals. The ability to exercise market power unilaterally in a differentiated products market can come from strong brand loyalty and innovative products as well as from the factors giving rise to market power in a homogeneous product market.

The unilateral exercise of market power is generally not prohibited by competition law. Indeed, the pursuit of unilateral market power by product, process and organizational innovation (dynamic efficiency) is generally encouraged by public policy. It is the pursuit of unilateral market power by mergers with competitors or by exclusionary or predatory conduct that competition law seeks to prevent. [1]

Joint exercise of market power

Joint exercises of market power in the form of price-fixing, bid rigging, output restricting or market sharing agreements (so-called naked restraints or hard core cartel agreements) are criminal offences under most competition or antitrust statutes. Because they are unlawful, agreements to suppress competition are made and enforced surreptitiously. Enforcement of cartel agreements is problematic because individual cartel members can profit by undercutting the cartel. To succeed, the cartel must be able to detect and punish undercutting behaviour.

[1] Mergers that substantially increase the unilateral market power of the merged entity would be offside S.92 of the *Competition Act* in Canada. Conduct that entrenches or extends unilateral market power substantially would run afoul of S.78 of the *Competition Act* in Canada.

Making and enforcing a cartel agreement is easier under some market circumstances than others.[2] Rivals are more likely to be able to coordinate their actions the more similar are their products and cost structures, the less complex are their products and the slower is the pace of change and innovation in the market. Cartel members have less incentive to undercut the cartel price the smaller and more frequent are the typical transactions in the market.[3] The ability of cartel members to detect undercutting is greater the more stable is market demand and the easier it is for cartel members to monitor their rivals' prices and their customer gains and losses. The ability of cartel members to punish an undercutting rival (once detected) increases with the number of occasions on which they compete with that rival for future business and with their ability to expand output and decrease price.

Fundamental Market Characteristics Militating Against the Exercise of Market Power

As is apparent from the preceding paragraphs, the analysis of the circumstances giving rise to market power can be quite complex. There are, however, some fundamental regularities that must always be considered. In the simplest terms, market power is <u>less likely</u> to exist in a market:

(1) The more elastic is market demand;
(2) The greater is the number of competitors and the more equal they are in size or capabilities;
(3) The lower are the barriers to entry of new competitors and expansion of fringe competitors;
(4) The more active and sophisticated are the customers (or, more generally, counterparties) in the market.

Two-part pricing

As is the case in most retail electricity markets, energy prices (tariffs) have two components. There is a fixed (administration fee) component and a variable component which is linear in the number of kilowatt hours (kWh) consumed (9 cents per kWh, for example). The rate per kWh consumed may itself vary from month to month as the wholesale price of electricity (floating rate plan) or it may be fixed over periods of one to five years (fixed rate plan). The RRO rate is also a two-part tariff.

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[2] For a more detailed explanation of the characteristics of markets that are vulnerable to the joint exercise of market power see, Canada, Competition Bureau, <u>Merger Enforcement Guidelines</u>, October 6, 2011, paras. 6.29 – 6.34.

[3] Conversely, cartel members have a greater incentive to undercut the cartel the larger and less frequent is the typical transaction. This is because profit on an individual transaction can be large and the opportunity for retaliation by other cartel members is delayed and infrequent.

In addition to the energy price or tariff, retail customers pay delivery charges. According to the UCA web site, this may take the form of a fixed transmission and distribution charge or a delivery charge with both a fixed and a variable component.[4]

The RRO

Alberta has maintained a default service option, the Regulated Rate Option (RRO), for retail electricity customers since the retail electricity market to competition in 2001. The purpose of the RRO is to provide default electricity service to smaller customers who do not chose to sign a contract with a competitive retailer, while at the same time facilitating retail competition. Eligibility for the RRO is limited to customers consuming less than 250 MWh per year. This default option has evolved over time.

In its 2004-5 review of the electricity markets in Alberta, the Alberta Department of Energy (ADOE) found the competitive market for the residential and farm classes of consumers had been slower to emerge relative to the market for industrial and large commercial consumers. The ADOE further found that there was a consensus among industry participants that changing the RRO rate to a monthly rate based on average month-ahead forward prices from a rate based on longer term forward prices and adjusted quarterly would stimulate the development of a competitive retail market.

Pursuant to this objective, a “new RRO rate” was gradually phased in beginning July 1, 2006. As of July 1, 2010, the RRO is determined monthly on the basis of average month-ahead forward prices. It is important to understand for purposes of determining the effect of the RRO on the development of the competitive market that the current version of the RRO rate has been in effect for less than two years.

As of February 2012, just over 66% of the customers (sites) eligible for the RRO remained on it implying that just under 34% of the customers eligible for the RRO were being served instead by a competitive retailer.[5] There is also a default supplier provision for customers who are not eligible for the RRO and who have not been able to contract with a competitive retailer.

Market Definition

[4] Utilities Consumer Advocate, Electricity Bills http://ucahelps.alberta.ca/electricity-bills.aspx Retrieved May 3, 2012.

[5] Government of Alberta Energy, “Alberta – Switching Statistics by Customer Group” Table 1, http://www.energy.gov.ab.ca/Electricity/1570.asp Retrieved May 3, 2012.

Competition occurs in markets. As stated above, the intensity of competition in a market depends on the structural characteristics of the market concerned. In order to determine the structural characteristics of a market (for example, the number and size distribution of buyers and sellers in the market), the boundaries of the market concerned must themselves be determined. This exercise is called market definition. Both the geographic and the product market must be defined. In essence, the geographic market is the set of seller locations that are close substitutes for buyers and the product market is the set of sellers whose products are seen as close substitutes by buyers.

Geographic Market

A reasonable definition of the relevant geographic market is the province of Alberta. With the exception of a few boutique retailers, Alberta retailers state that they serve or are willing to serve customers throughout the province. Competitive retailers are excluded from some areas of the province and find it difficult to compete in others (Rural Electrification Associations). While several retailers indicated that they tend to focus their marketing efforts on urban areas, all quote Alberta-wide prices on their own websites, on the UCA website and in some cases on other outside websites. It appears that a potential customer has telecommunications access of some sort to any Alberta retailer.

Product Market

A reasonable definition of the relevant product market is electricity retailing services. This is a differentiated product market in the sense that participating retailers have different brands and reputations, offer different contracts and market them in different ways. Contracts can be either variable rate or fixed rate contracts with a variety of contract durations. Contracts may bundle gas and electricity service. Electric power may be either conventional or “green.” Retailers may market door-to-door, by direct mail, by word of mouth or by the Internet. Retailers may distinguish between larger commercial/industrial customers and residential customers in pricing and other contract characteristics.

The foregoing can be taken to imply that various offerings available to retail customers are close but not perfect substitutes. Most retailers offer or could readily offer a menu of contracts and market them in a variety of ways. For that reason all existing retailers can be regarded as close competitors and therefore included in the relevant product market as defined.

Three further questions remain. First, does the relevant product market include green electricity retailing services? Second, are there separate residential, farm and commercial markets? Third, should RRO providers be included in the market?

Are green energy retailers in the relevant product market?

The UCA website lists four green electricity retailers. These are: Bow Valley Power, Bullfrog Power, ENMAX Energy and Just Energy. All but Bullfrog are also conventional ("brown") electric power retailers as well. Green retailers commit in various ways either to add as much green (usually wind) power to the grid as green customers consume or to purchase other offsets. In return for this they charge a premium over the variable price per kWh. In the case of Bullfrog, the premium is 2 cents per kWh or roughly 20 percent.

On the basis of the retail price differential it appears that green power may not be a particularly close substitute for conventional electric power implying that the retail market for green power is a separate product market and that Bullfrog Power is not a close competitor of conventional electric power retailers. As a practical matter, the size of the retail market for green power is such that its treatment is unlikely to affect inferences regarding retailer market power

Are residential, farm and commercial/industrial customers in separate product markets?

Residential, farm and small commercial customers have different characteristics. They differ in their willingness to switch to competitive retailers. As of February 2012, almost 49% of small commercial customers were being served by competitive retailers as compared with nearly 33% of residential customers and 23% of farm customers. The three classes of customers differ in their average consumption. According to the AUC Harmonization Report

> In 2009, the average annual electric consumption for a residential customer in the service territory of EPCOR Distribution & Transmission Inc. was approximately six megawatt hours. For a small commercial customer, the average annual electric consumption was approximately 27 megawatt hours, while for a medium commercial customer the figure was approximately 206 megawatt hours.[6]

Some market participants have expressed the view that commercial customers are more likely to be used to making decisions regarding competing supply alternatives and to be more sophisticated as a consequence. Others maintain that there is a direct relationship between customer size and the ability to be an effective customer in the competitive retail market:

> EPCOR submitted that the use of consumption thresholds to determine customer eligibility acknowledges that a customer's magnitude of consumption is correlated to a customer's ability to research, analyze, comprehend and shift energy consumption costs by changing their consumption patterns and behavior. EPCOR added that regulated retail electricity services are especially valuable for smaller customers, and in particular residential

[6] Alberta Utilities Commission, Regulated Retail Energy Harmonization Inquiry (March 25, 2011) p.49 (hereafter referred to as the AUC Harmonization Report).

customers, who may not have the time, skills or inclination to survey competitive options and enter into competitive contracts.[7]

The forgoing discussion may imply that the three categories of customers also differ in their respective willingness to pay for electricity retailing services. Retailers are obviously able to distinguish one type of customer from another. The question is whether they do so. The contracts offered by competitive retailers on the UCA web site do not appear to be subject to any eligibility restrictions or qualifications. In terms of the stated pricing policies of retailers, there does not appear to be any basis for treating residential, farm and small and medium-sized commercial customers as separate markets.

On the other hand, there is some evidence that larger commercial customers have a wider choice of retailer and may be able to negotiate more favourable contracts. There is also some indication that there might be less competition among competitive retailers to solicit farm customers. It is difficult for retailers to solicit and/or service farm customers in areas of the province served by Rural Electrification Associations. Some retailers have relatively few farm customers. Others have indicated that they have been pulling back from marketing in areas served by Rural Electrification Associations.

Given the potential difference in the possible competitive dynamics of serving residential and farm customers as opposed to commercial customers, there is merit in distinguishing between the two groups of customers for analytical purposes. There may also be merit in making a further distinction between residential and farm customers. Farm customers may have fewer competitive alternatives although there is nothing to indicate that this has affected the pricing of the retailers who do serve farm customers.[8]

Are RRO customers in a separate product market?

For eligible customers, the RRO option is a close substitute for the products of competitive retailers in the sense that it has similar characteristics (almost identical characteristics in some cases) and customers might be expected to switch between the RRO and the packages offered by competitive retailers in response to differences in their relative prices (or, more broadly, in

[7] AUC Harmonization Report, p.48

[8] In some cases, Rural Electrification Associations offer stable rate contracts to its members that are similar to other competitive retail products. See for example Central Alberta Rural Electrification Association's Cooperative Energy Option which has been priced at 7.25 cents/kWh for the past 24-months. http://www.carea.ca/services/rate-schedules.html

response to relatively small differences in their relative value propositions).[9] The RRO option is in the relevant product market in the sense that competitive retailers must offer a superior value proposition either to induce customers to leave the RRO or to prevent them from returning to it. All indications are that competitive retailers compete with the RRO as well as with each other.

At the same time, however, the RRO is the default option for eligible electricity consumers. While they can be said to have chosen it over the packages offered by competitive retailers as EPCOR representatives have argued, this choice is open to different interpretations.[10] Some customers may have chosen the RRO explicitly. That is, they may have searched the competitive alternatives and decided that the RRO was superior. Other customers may have been aware that there are alternatives to the RRO but decided that searching them out and evaluating their respective merits was not worthwhile and done nothing. Still others may not have been aware that there are alternatives. This group can be said to have made a choice of sorts but they would likely be on whatever default plan existed regardless of its merits. To illustrate, among customers who, by virtue of their size, are not eligible for the RRO, 84% have contracts with competitive retailers while 16% are served under the default supplier provision pursuant to s. 3(1) and 3(2) of the Roles, Relationships and Responsibilities Regulation 2003.[11]

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[9] ENMAX offers a "clone" of the RRO presently. The EasyMax floating rate electricity plan matches the regulated rate in the customer's area with an administration fee that is no higher than the regulated fee. See: AUC Harmonization Report, p.22.

[10] According to the AUC Harmonization Report there were different views as to whether the fraction of customers still on the RRO reflected its attractiveness as a competitive option:

> Calgary argued that regulated retail energy services provide consumers with an alternative to competitive retail energy services, and submitted that regulated retail energy services should not hinder nor enhance the competitive market, recommending that consumers should not be forced to make a choice. Alternatively, the CCA, supported by EPCOR, asserted that customers remaining with regulated retail energy services providers must be recognized as having exercised a choice.
>
> However, the Commission notes the Market Surveillance Administrator's observation that:
>
> The combination of low energy costs and the presence of a competitively priced RRO/DRT may leave very little incentive for customers to switch, especially if they are exposed to relatively low volatility. (pp.79-80)

[11] Government of Alberta Energy, "Alberta – Switching Statistics by Customer Group" Table 1, http://www.energy.gov.ab.ca/Electricity/1570.asp Retrieved May 3, 2012.

Thus it might be that signing up 85% of the sites existing at any point in time represents 100% market penetration for competitive retailing.

The forgoing discussion has the implication that because of its default status, the importance of the RRO as a competitive alternative in the retail market cannot be inferred from the fraction of retail customers it serves. If anything, the share of customers remaining on the RRO overstates its importance as a competitive alternative. Notwithstanding the likelihood that some default customers will not be contestable by competitive retailers as long as they are eligible for either the RRO or some other default supplier provision, the simplest and most expeditious approach to market definition is to include them all in the relevant product market. In so doing, however, the analysis should recognize that the resulting market shares could understate the market power of competitive retailers.

Indicators of the Intensity of Competition among Incumbents

Number of sellers

The number of competing sellers is a crude indicator of the unilateral or potential joint market power of sellers. Obviously, a single seller is a monopolist. Even here the market power of a monopolist depends on the price responsiveness of buyers (price elasticity of demand) and the height of entry barriers. Other things being equal, having more competitors implies more competition but other things are not equal. The relative size of the competitors matters (see below) as do a number of other factors.

According to the UCA web site, there are presently 13 listings for competitive electricity retailers in Alberta.[12] When inter-company linkages are taken into account there are essentially three major retailers (Direct Energy, ENMAX Energy, Just Energy (Alberta Energy Savings)) plus the boutique retailers listed under Utility Network & Partners. Utility Network currently lists nine boutique retailer partners (Milner, Adagio, Bow Valley, Mountain View, Brighter Futures, E.NRG, SPARK, Spot and Vector). By way of comparison, five years ago (January, 2007), there were three competitive retailers (Alberta Energy Savings (Just Energy), Direct Energy, and ENMAX Energy).

According to the Director of Fair Trading, there are 13 licensed electricity retailers in Alberta. They are: Alberta Municipal Services Corp., AltaGas, CP Energy Marketing, Direct Energy, Encana Power & Processing, ENMAX Energy, Hudson Energy, Integrys Energy, Just Energy,

[12] These are conventional or “brown” energy retailers, three of whom also offer green energy. In addition, there is one purely green energy retailer.

Alberta Energy Savings, Utility Network & Partners (Spot Power), Vector Energy, ENMAX Commercial Energy Marketing. Of these, 8 offer contracts to residential customers.[13] Some of these licensees appear to be related (for example, Hudson Energy, Just Energy and Alberta Energy Savings).

How many competitors is enough? One observer has suggested that, among other things, a competitive retail market would require "at least 3 to 5 major sellers and several niche players."[14] At present, there are 3 major sellers serving retail customers. Is this sufficient?

Insights from criteria for deregulation in other markets

Some insights regarding the threshold number of competitors deemed to be required to protect residential consumers is to examine criteria for deregulation in other markets formerly served by regulated utilities. The regulatory forbearance decisions of the CRTC with respect to local residential telephone service, retail Internet service and mobile wireless telephone service provide some insights.

<u>Local residential telephone markets</u>

For example, the condition for deregulating local residential telephone markets is that in addition to the incumbent local exchange carrier (ILEC), there must be at least two facilities-based telecommunications providers (one of which must be a fixed line provider) capable of serving at least 75% of the number of residential local exchange line that the ILEC is serving. In essence, this condition is satisfied if the incumbent local telephone company faces competition from both the local cable provider and an unaffiliated mobile wireless provider.[15]

<u>Retail Internet services</u>

The CRTC has forborne regulation of the market for retail internet services. In a series of decisions the CRTC has repeatedly found that the retail market for internet services (IS) is

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[13] Director of Fair Trading, Alberta Services, "Presentation to the Retail Market Review Committee," April 30, 2012. http://www.energy.gov.ab.ca/Electricity/1570.asp Retrieved May 3, 2012.

[14] Kellen Fluckiger, "What Does It Take to Make Retail Markets Work" (Economics Society of Calgary - Panel Discussion, October 24, 2003). www.esc.ab.ca/esc.ab.ca/doc/Oct03.AlbertaEnergy.ppt www.esc.ab.ca/esc.ab.ca/doc/Oct03.AlbertaEnergy.ppt Retrieved May 3, 2012.

The author also lists low entry costs, a level playing field, buyers armed and ready and a competitive wholesale market as requirements.

[15] Telecommunications Act, Order Varying Telecom Decision CRTC 2006-15 Canada Gazette Vol. 141, No. 8, April 18, 2007.

characterized by intense rivalry among competitors in terms of aggressive marketing techniques, innovative service offerings and price competition. It has also found that there are few entry barriers and that a large number of service providers have entered the market in a relatively short period of time. It is important to understand, however, that the structure of local retail IS markets has typically involved two facilities-based competitors (cable and landline telephone) as well as many resellers operating under mandated regulatory access provisions requiring ongoing enforcement by the CRTC. [16]

Mobile wireless telecommunications

In a series of decisions between 1994 and 1998 the CRTC refrained from exercising its regulatory authority over mobile wireless telecommunications providers on the grounds that this market was workably competitive. This market has been dominated by three vertically integrated providers (TELUS, Rogers and Bell) since the acquisition of Microcell (Fido) by Rogers in 2004. Various views have been expressed as to whether this market is sufficiently competitive.[17] In 2008 the federal government introduced measures to assist new entrants. These included a spectrum set-aside and mandatory tower sharing by incumbents.

Implications of deregulation decisions

The deregulation criteria surveyed above imply that a market of residential customers that is served by three major competitors could be deemed to perform well enough to be preferable to traditional economic regulation. Given the many inefficiencies resulting from regulation, however, this is not a particularly high standard. As the distinguished regulatory economist

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[16] See, for example, Forbearance From Retail Internet Services, Telecom Order CRTC 99-592 Ottawa, 25 June 1999.

[17] In its April 2005 review of the acquisition of Microcell by Rogers, the Competition Bureau stated that it was satisfied that the mobile wireless market would remain vigorously competitive.
See: Competition Bureau Canada, "Acquisition of Microcell Telecommunications Inc. by Rogers Wireless Communications Inc,: Technical Backgrounder" (April, 2005)
http://www.competitionbureau.gc.ca/eic/site/cb-bc.nsf/eng/00257.html

The CRTC's subsequent monitoring reports found that the market was competitive.
See: CRTC, "Telecommunications Monitoring Report: Status of Competition in the Canadian Telecommunications Market" (July, 2006) http://www.crtc.gc.ca/eng/publications/reports/policymonitoring/2006/tmr2006.htm#a4.6

The Telecom Policy Review Panel took the opposite view concluding that the Canadian market underperformed relative to other countries with respect to pricing and market penetration. The Panel cited both the small number of competitors and the joint ownership of wireless and wireline businesses as explanatory factors. Interestingly enough, many national markets with higher penetration rates have fewer competing wireless providers.
See: "Telecommunications Policy Review Panel Final Report 2006" (Industry Canada, Ottawa, March, 2006)
http://www.telecomreview.ca/epic/site/tprp-gecrt.nsf/en/h_rx00054e.html

Alfred Kahn has written, "even very imperfect competition is preferable to regulation."[18] The standard in the current review would likely be higher in that deregulation would presumably involve a further restriction on the availability of the RRO alternative if not its complete elimination. It is reasonable to expect new competitive alternatives to emerge in that event but it is difficult to project how quickly this will occur and what form they will take.

The CRTC experience with deregulation is also instructive in the role facilities-based competition has played. Facilities-based competitors are vertically integrated. In the case of local telephone deregulation, the presence three facilities-based (vertically integrated) competitors was required. In the case of retail Internet services, there are two vertically integrated competitors and in the case of mobile wireless telecommunications, there are presently three. In each market numerous regulatory access provisions have been required to enable non-integrated resellers to compete. In addition to imposing access requirements, the CRTC has often attempted to nurture competition by placing restrictions on the ability of incumbents to compete. Whether this nurturing has actually increased competition on balance is debatable.

The discussion in the preceding paragraph has relevance for the analysis of the state of competition in electrical energy retailing in Alberta in that one major electricity retailer in Alberta is vertically integrated and some other retailers suggest that the playing field is not level as a consequence. In addition, other competitors may have legacy advantages which make the playing field uneven in other respects. This complicates attempts to predict the competitive landscape in the event that the RRO is eliminated. It also complicates attempts to stimulate the development of the retail market.

Size distribution of sellers

Given the number of competitors, competition among them tends to become less intense the more unequal in size they are.[19] The limiting case is the dominant firm which is free to set the market price being constrained only by the ability of customers to find acceptable substitute products and the ability of fringe competitors to expand.

A useful indicator of the ability of a firm to exercise market power is its market share. A useful indicator of the joint market power of the largest firms in a market is the market concentration ratio.

[18] Alfred Kahn, The Economics of Regulation: Principles and Institutions v.II (MIT Press, 1970) p..xxiii
[19] This is one reason why the Herfindahl Hirschman Index (HHI) is used as a structure indicator of market power. The HHI increases as the number of competitors in the market declines and as competitors become more unequal in size.

The first question is how competitive the retail market is now. To answer that properly, the market must be defined to include RRO customers. It is clear that competitive retailers are competing to attract these customers and that their objective is to offer a value proposition that is superior to the RRO. Given this definition of the relevant market, the respective market shares (in terms of number of residential customers) of the three major competitive retailers (as of December 2011) are all well under 20%.[20] The combined market share of these three retailers of both competitive and RRO customers is just over 30%. By all the usual standards, the three largest competitive retailers do not have market power either individually or collectively.[21]

The second question is how competitive the retail market would be if the RRO were eliminated. One scenario would see no new entry and the existing competitive retailers each taking a *pro rata* share of former RRO customers. In this case, the respective market shares (residential customers only) of the incumbent competitive retailers range from under 20% to over 50%. . Their joint market share would be 99.5%. The HHI would be 4065 which is regarded as very high.[22] Given the likely elasticity of market demand (see below) and the fact that these are residential (small) customers, the likely conclusion is that this would not be a particularly competitive market. Given what is known about entry conditions and potential entrants, however, this scenario must be regarded as an extreme case.

The combined shares of competitive retailers of all farm and small business (commercial) customers respectively differ from their share of all residential customers. As of February 2012, competitive retailers accounted for 33% of residential customers while they accounted for 23% of all farm customers and 49% of all small commercial customers. It is clear that even if they acted jointly competitive retailers would have no market power over farm customers.

With respect to small commercial customers, competitive retailers, taken together, now account for a substantial share of all customers and an even larger share of energy consumed (60% as of December 2011). Although this is not an insubstantial collective market share, it is not sufficient to raise any serious concern about joint market power. There are many reasons for this. First, according to several observers, commercial customers have more retailer choices than do residential and farm customers. Second, commercial customers are likely more

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[20] These share data were provided by the Utilities Consumer Advocate.

[21] The formal threshold market share at which the Competition Bureau begins to become concerned about unilateral exercise of market power is 35%. In practice, mergers resulting in a market share less than 40% seldom raise a concern regarding the unilateral exercise of market power. The formal threshold at which the Competition Bureau becomes concerned about the joint exercise of market power is a four firm concentration ratio of 65%. In practice concerns about the joint exercise of market power usually require that the market involved have a number of characteristics conducive to interdependence in addition to high concentration. These characteristics are discussed in the section on the joint exercise of market power in the text.

[22] The maximum value of the HHI is 10,000. A market with 4 equal sized competitors would have an HHI of 2500.

sophisticated and generally more active than residential customers. Third, as will be seen from the discussion below, barriers to entry into retailing are modest so that any attempt to raise retail margins would likely induce entry of new competitors or expansion by fringe competitors. Fourth, there is no evidence of any interdependent behaviour among retailers.

Qualifications

The uncertainty regarding the extent to which consumers on the RRO have actively chosen it has implications for the calculation and interpretation of market shares and concentration ratios. While competitive retailers must compete with the RRO, RRO providers are not active competitors in the market or at least they are not supposed to be. The RRO providers offer a product, the characteristics of which are determined by regulation, and are expected to respond passively to the decisions of customers rather than actively seek to require or retain them. While RRO providers collectively dominate the market (viewed in aggregate), they cannot be said to have market power. For this reason, it is misleading to calculate a concentration ratio or a HHI that includes RRO providers either individually or collectively.

The respective shares of competitive retailers of competitive retail customers alone overstate their <u>current</u> market power whether exercised individually (unilaterally) or jointly. This is because these retailers must compete for customers with the RRO as well as with each other. The respective shares of competitive retailers of competitive retail customers alone might provide some indication of their future market power if the RRO were eliminated entirely and there were no more entrants into the market. Given the conclusions regarding barriers to entry reached later in this study, however, it is reasonable to assume that the elimination of the RRO will attract new entrants (and fringe expansion). For this reason, the respective current shares of competitive retail customers held by retailers also overstates their <u>future</u> market power in the event that the RRO is eliminated. To the extent that incumbents are more successful than entrants in attracting customers forced off the RRO, however, this overstatement is reduced.

A final caveat exists with respect to the size of the customer base that should be assumed when calculating market shares. The respective shares of competitive retailers of all customers (both competitive and RRO) might understate their market power if a portion of RRO customers is either unaware of the existence of a competitive market alternative or is otherwise not contestable by competitive retailers. It may also be that there is always a “float” of sites not in the market. If, for example, some fraction of customers is always on whatever default supply alternative exists, then the maximum potential size of the competitive market is smaller than is implied by either the number of sites or total energy consumption. In this case, including all sites or all consumption in the denominator when retailer market shares are calculated may understate their actual market share and, other things being equal, may understate retailer market power.

Demand Characteristics

Virtually all residential, farm and small business electricity users are either on the RRO or purchase electricity from a competitive retailer (electric power is a necessity). Taking the two alternatives together, demand is price inelastic. An implication of this is that if there were no RRO, the demand for the services of electricity retailers as a group would be price inelastic. Put another way, the price elasticity of market demand for electricity retailing services would be quite low.

Are customers active?

Notwithstanding the low elasticity of market demand, the elasticity of demand for the products of individual retailers could be quite high. This depends on the willingness and ability of customers to shop around and to bargain, that is, to be an active rather than a passive customer. Large customers are normally expected to have the incentive and ability to be active customers. This may not be true for smaller customers, especially in Alberta where the consequences of doing nothing and remaining on the RRO default option may not have been particularly burdensome.

Customers may be less inclined to shop around if they have strong brand preferences. The retail electricity services market is a differentiated products market. To some degree, at least, sellers' reputations and awareness of them matters. Moreover, there is some variability among in the contracts offered. That said, all retailers (other than green retailers) are selling the same electric power so that the scope for differentiation among retailers is limited. One might expect that consumers who do search the market would be reasonably price sensitive. For many, the question would be whether the search is warranted by the potential saving.

Retailers point out that a number of the contracts they offer have no early termination fees and this reduces switching costs. Notice requirements vary but are as little as 15 days in some instances. One retailer indicated that most of its new customers come from the RRO while its customer losses tend to be to other retailers. This retailer also stated, however, the attrition rate on customers once acquired from the RRO is low to moderate and the renewal rate is fairly high. Another retailer indicated that it loses 15 to 30% of new customers signed but it did not indicate where these customers went. A third retailer stated that it had a relatively stable customer base and that customer gains have been largely from the RRO.

Shopping around to compare the offerings of competing retailers is not costly. Retailers have their own web sites. Their offerings are also listed on the UCA web site and on external web sites such as Energyshop.com.

Regulatory impediments to switching

One retailer cited a series of regulatory restrictions on the ability of retailers to attract customers from other retailers and, in some instances from the RRO. According to this retailer, a retailer cannot sign a customer who already holds a competitive contract where that contract is penalty-free to switch. A retailer must wait for a 10 day cooling off period to expire before it can enroll a customer and the customer cannot waive this requirement.

Interviews with small business customers

Interviews with a small sample of small business customers reveal two types of customers. The first type is completely inactive customers (28%). They have remained on the RRO and have not investigated any alternatives. The second type of customer (72%) has been active in one way or another. Some have been active in the sense that they have had a contract with a competitive retailer but have returned to the RRO. These customers appear to have confined their comparison shopping to the RRO and a single competitive retailer. Others have been active in the sense that they have compared the offerings of competitive retailers and have chosen among them. Still others (not many) have been active in the sense that they successfully renegotiated their contract with a competitive retailer although they did not investigate any alternatives or consider switching.

Among the conclusions that can be drawn from interviews with small business customers are:

(1) Some small business customers have not examined any retail alternatives and are on the RRO purely by default.
(2) For another group of customers, the RRO has actively been chosen and constitutes a competitive alternative. Although they might object to losing this alternative, these customers would presumably explore other market alternatives if they were no longer eligible for the RRO.
(3) Another group of small business customers are active in comparing the packages offered by competing retailers and there is some evidence of switching retailers.
(4) While there is some evidence that retailers are willing to negotiate prices on renewal, most of the active small business customers viewed the rates offered by competitive retailers as non-negotiable.

(5) The customer switching data presented on the Government of Alberta Energy web site (and cited above) measures net switches to competitive retailers. It nets out switches away from and back to the RRO. As well, it does not include switches among competitive retailers. As a consequence, this database understates the extent of customer switching activity.

The sample of interviews is too small to serve as a basis for estimating the fraction of this population that could be classed as active customers. It does suggest that there may be a constituency of small businesses that would either be deprived of a favoured alternative or would have to begin treating the choice of their electricity supplier as a business decision if the RRO were withdrawn.

Aggregate switching percentages

The percentage of customers who have switched from the RRO to a competitive retailer indicates something about the relative attractiveness of the contracts offered by competitive retailers relative to the RRO. It also tells us something about the willingness of customers to shop around.

The percentage of residential, farm and small commercial customers that have switched to competitive retailers is reported in Table 1 below. This Table shows net departures from the RRO as a percentage of all customers in each category. It shows a steady increase in the fraction of customers served by competitive retailers with 30% of residential customers, 21% of farm customers and 48% of small commercial customers being served by competitive retailers as of the end of 2011. The last line of Table 1 shows that the percentage of energy sold by competitive retailers exceeds the percentage of customers. This implies that, as expected, the customers who have switched to competitive retailers are larger than the customers who have stayed with the RRO.

Table 1

Percentage of Sites Contracting with Competitive Retailers

2006 - 2011

YEAR (as of year- end)	RESIDENTIAL %	FARM %	SMALL COMMERCIAL %
2006	18.03	11.27	44.33
2007	23.42	15.58	44.57
2008	27.30	17.90	46.39
2009	27.95	18.65	46.71
2010	28.38	19.07	46.81
2011	30.47	20.62	47.85
2011 Energy %	33.08	27.30	59.77

Source: Alberta Department of Energy

The AUC Harmonization Report cites the view of some market participants that the growth in the percentage of customers served by competitive retailers is evidence that the retail market is “viable” and presents an attractive option for consumers:

> Consumer groups also submitted that switching rates in Alberta were comparable to or better than switching rates experienced in other jurisdictions where regulated rates had not been totally eliminated, suggesting that changes to the status quo for regulated retail energy services were unnecessary to achieve a viable competitive retail market. Switching rates from the incumbent electricity provider in other jurisdictions was discussed in the following exchange between Mr. MacBeath, Director of Energy Services for EPCOR and Commission Counsel:
>
> Q. Sir, I don't think you need to turn it up, but please feel free to do so if you like. It's the survey that was attached to one of your IR responses dealing with different jurisdictions.
> ...

> EPCOR attaches some statistics on customer switching in the electric market to the IR. It indicates that after nine years of deregulation in each of Alberta, New Zealand, the Netherlands, and the United Kingdom, only the United Kingdom has a high percentage of switching from the incumbent energy provider to another competitive supplier. Alberta, New Zealand and the Netherlands show a 25 to 29 percent switching rate with the UK at 48.
> As you mentioned, sir, the latest figures from government indicate a 30 percent switching rate for all electricity customers, including commercial, industrial, and residential? I take it from your opening statement that EEAI sees the Alberta switching rate as satisfactory and indicative of a competitive environment in Alberta; correct, sir?
>
> A. MR. MACBEATH: Correct.[23]

This switching rate was regarded as being particularly impressive given that 98% of EPCOR's customers are eligible for the RRO.[24]

Others were of the opinion that the competitive market has stagnated due to the regulatory impediments to its expansion:

> The Commission heard that a consistent policy objective has been in place to create a robust competitive retail energy services market; however retail energy competition according to some parties has been in a period of stagnation for some time caused by the cumulative effects of barriers discussed in this report.[25]

The view that the retail market has stagnated does not appear to be supported by its recent growth as reported in Table 1 above.

<u>Switching behaviour in other markets</u>

It is certainly the case that there are examples of more precipitous losses of market share being experienced by incumbent suppliers in other markets. For example, in Ireland 21% of residential electricity customers left the incumbent retail electricity supplier for a new entrant (the incumbent gas supplier) during a 12 month period in 2009-10.[26]

A broader definition of switching includes switches by consumers among competitive retailers as well as switches from the legacy supplier or regulated option. The incidence of consumer

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[23] AUC Harmonization Report, pp.29-30.
[24] AUC Harmonization Report, p.29.
[25] AUC Harmonization Report, pp.78-9.
[26] World Energy Retail Market Rankings 2010 (VAASA ETT Global Energy Think Tank) p.21.
http://www.eraa.com.au/db_uploads/World_Energy_Retail_Market_Rankings_2010.pdf. Retrieved May 3, 2012.

switching among competitors is a good indicator of the vigour of competition in that it shows both the willingness and ability of consumers to switch suppliers as well as the absence of both contractual impediments to switching and, more generally, any tendency toward market allocation or customer sharing among competitors.

Broader customer switching data do not appear to be available for Alberta but the evidence from some other retail markets is that customers can be very mobile. This implies that given the right circumstances, retail energy markets can be very competitive. According to World Energy Retail Market Rankings five "Super Hot" or "Hot" retail electricity markets have recorded annual switching rates in excess of 20%. These are the states of Victoria, Queensland and South Australia in Australia, Great Britain and New Zealand.[27] Markets with less switching are ranked as "Warm Active", "Active", "Cool Active" and "Dormant." Texas (sometimes mentioned as a model for Alberta) is classed as "Warm Active." Also classed as "Warm Active" is Norway which has an average annual switching rate around 8%. It is also of interest, however, that 70% of residential customers in Norway either remained with the retailer associated with their local distributor or have switched back to it.[28] Although switching statistics are not reported for Alberta (there is apparently no data on switching among competitive retailers), it is ranked as an "Active" market.[29]

Behavioural Indicators of the Intensity of Competition among Incumbents

Product variety

Presently there are 29 different competitive retail electricity contracts listed on the UCA web site. Packages include fixed rate packages of durations up to five years, floating rate packages and "dual fuel" bundled packages. Packages also vary with respect to the fixed and variable components of the tariff and also with respect to notice requirements and termination fees. By way of comparison, there were 9 different packages listed on the UCA website five years ago.[30]

Comparison of competitive retail packages with the RRO

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[27] World Energy Retail Market Rankings 2010 (VAASA ETT Global Energy Think Tank) p.21. http://www.eraa.com.au/db_uploads/World_Energy_Retail_Market_Rankings_2010.pdf
[28] World Energy Retail Market Rankings 2010 (VAASA ETT Global Energy Think Tank) p.31. http://www.eraa.com.au/db_uploads/World_Energy_Retail_Market_Rankings_2010.pdf
[29] World Energy Retail Market Rankings 2010 (VAASA ETT Global Energy Think Tank) p.36. http://www.eraa.com.au/db_uploads/World_Energy_Retail_Market_Rankings_2010.pdf
[30] http://ucahelps.alberta.ca/documents/Rates-January-1-2007.pdf. Retrieved May 3, 2012.

There is evidence that competitive retailers are offering products that are at least as good if not better than the RRO. One indication is that as of February 2012, almost 34% of the customers eligible for the RRO have left it for a competitive retailer.

Some specific competitive retail offerings appear to be at least as attractive as the RRO. ENMAX offers what the AUC Harmonization Report (p.22) calls “a clone” of the RRO in the form of its “EasyMax” floating rate electricity plan.[31] This plan matches the regulated rate in the customer’s area and its administration fee is no higher than the regulated fee.

One retailer interviewed by the UCA states that its objective is to outperform the Regulated Rate Option (RRO) pricewise thereby providing customers with a competitive alternative. Utility Network shows the amount its customers have saved relative to the RRO on its invoices.

Another retailer noted the influence of customer feedback on the design of its offerings. It emphasizes bundled, dual fuel packages with the savings being passed on to consumers.

One retailer observed that fixed price contracts have recently been more advantageous to consumers. It has not compared the two types of contracts over a longer (5 years for example) period.

Discounting and off-list sales

An indicator of the intensity of competition among sellers (and the existence of active customers) is the prevalence of discounting and off-list sales. Two retailers interviewed by the UCA stated that their rates are not negotiable. Another indicated that prices are more negotiable for larger commercial customers. Retention offers are readily available for smaller volume customers and can be lower than the contracted rate depending on when customers pursue this option as fixed rates are constantly reviewed. Another offers gift cards and has offered discounts on existing contracts as inducements to extend or renew a contract.

Variability of market shares

The variability of market shares over time may imply that the firms in the market are competing to take business from each other. It implies at least an absence of market sharing. The respective market shares of the three major retailers varied considerably over the period 2006 to 2011. Two gained share of both competitive retail customers and all customers while one lost share. The time pattern of gains and losses is not the same for all firms. One retailer appears to have gained share up to 2009 and then fallen back.

[31] AUC Harmonization Report, p.22,

Potential Competition: Barriers to Entry

Definition

Barriers to entry are structural characteristics of a market that protects the market power of incumbents by making entry unprofitable.[32] Barriers to entry give incumbents the ability to earn sustained supra-normal profits without attracting entry by new competitors or expansion by existing fringe competitors.

Barriers to entry are also defined as costs borne by new entrants that incumbents either no longer bear or have not had to bear.[33] Sunk costs are costs that incumbents no longer bear in the sense that they can no longer avoid them. Potential entrants bear these costs because they can still avoid them by not entering the market. The asymmetry between incumbents and potential entrants is crucial. If incumbents have the same opportunity cost as entrants, they have no special commitment to the market and there is no barrier to entry.

Economists categorize the conditions of entry as follows: (1) perfect contestability – any excess of price over average cost attracts immediate entry; (2) ineffectively impeded entry – incumbents can earn supra-competitive profits temporarily but these are ultimately competed away by new entrants or expanding fringe competitors; (3) effectively impeded entry – incumbents can sustain prices and profits that are above the competitive level but less than the monopoly level; (4) blockaded entry – a monopoly price and profits does not attract entry. If entry is ineffectively impeded the issue is then one of determining the speed with which entry is likely to occur.

When entry is ineffectively impeded the question is then how long it will take. A market in which a new entrant could become an effective competitor within a year is sometimes classified as having low barriers to entry.

Sources of entry barriers

The major categories of entry barriers are: (1) regulatory barriers to entry; (2) structural barriers to entry (determined by the cost and demand characteristics of the market concerned)

[32] Jeffrey Church and Roger Ware, Industrial Organization A Strategic Approach (McGraw Hill, 2000) p.487
[33] Dennis Carlton and Jeffrey Perloff, Modern Industrial Organization 4th Edition (Pearson Addison Wesley, 2005) p.77.

and; (3) the reaction of incumbents (the feasibility and profitability of pursuing entry-deterring strategies).

Regulatory barriers to entry

The most obvious regulatory entry barrier is an absolute regulatory or legal restriction on the entry of new competitors into a market. Examples include restrictions on the number of taxi licenses issued by a municipal government and restrictions on the quota issued by agricultural marketing boards. Where entry is allowed, entrants may be subject to regulatory costs that incumbents avoid by virtue of being grandfathered. Compliance with the regulatory requirements for entry itself may require a significant expenditure that is not recoverable if entry fails. This is known as a sunk cost barrier to entry (see below). For example, the cost of applying to and negotiating with the relevant regulatory agencies in order to obtain the required business licenses and/or permits is a sunk entry cost and thus a barrier to entry. License fees themselves are a barrier to entry to the extent that they are sunk costs, that is, the amount of the fee is not conditional on remaining in the market.

Several regulatory barriers to entry into electricity retailing are cited in the AUC Harmonization Report. These might better be termed indirect barriers to entry in that they limit the number of customers that are contestable by competitive retailers and this, in turn, limits both the number of competitive retailers that can survive in the market and their respective scales of operation. The regulatory barriers cited include: (1) competitive retailers are explicitly or effectively excluded from operating in certain areas of the province; (2) until very recently, competitive retailers were not allowed to take deposits in advance of consumption which discourages them from seeking out less credit-worthy customers and precludes the development of pre-payment options such as energy debit cards and; (3) in some areas of the province competitive retailers are unable to lock the sites of delinquent customers, a remedy which is available to RRO providers.

<u>Exclusion of competitive retailers</u>

Competitive retailers are excluded from some areas of the province either explicitly or effectively by the practices of incumbent suppliers. According to one retailer, there are certain geographic areas in Alberta where competitive retailers cannot provide competitive retail energy services. These areas are mainly in the service territories of certain municipalities, natural gas co-ops and Rural Electrification Associations (REAs). Several retailers mentioned the City of Medicine Hat as an area in which they were restricted from operating.

With respect to REAs, one retailer stated that they are not regulated and have been able to create convoluted systems to discourage retail competition, e.g., manual transactions and excessive prudential requirements. REAs are not required to be compliant with the Tariff Bill Code (TBC) which is a rule of the Alberta Utilities Commissions regarding the electronic communication of billing information. In the view of this retailer, non-compliance with the TBC erects a barrier to entry/competition because a retailer must utilize manual transactions which increases costs and reduces profit margins.

Prohibition of Deposits

Until very recently, competitive retailers have been prohibited from taking deposits while RRO providers are not. This had the effect of discouraging competitive retailers from seeking out the less credit-worthy customers. It also precluded development of new payment options such as energy debit cards. According to the AUC Harmonization Report:

> Direct stated that Section 18(1) of the *Energy Marketing and Residential Heat Sub-Metering Regulation,* AR 246/2005 prohibits a marketer from collecting a fee or other charge from a consumer until after the energy has been delivered. While competitive retailers are prohibited from taking deposits, regulated retail energy services providers are not. This, it was argued, encourages competitive retailers to only offer their competitive services to creditworthy customers, leaving customers with poor creditworthiness or no credit history to be served by regulated retail energy services providers. It was submitted that Section 18(1) should be repealed or revised to allow competitive retailers to take deposits which would then reduce the credit risk to competitive retailers, provide greater customer choice and facilitate competition in a larger proportion of the retail market.
>
> Direct submitted that if competitive retailers were allowed to collect deposits prior to energy flow, this would also permit introduction of pre-paid energy products in Alberta. Pre-paid energy could be sold in a manner similar to a debit card ...[34]

The AUC Harmonization Report observed that although the infrastructure necessary to support pre-paid energy products does not exist in Alberta, Direct Energy's testimony indicated the kinds of competitive services that could be extended to customers without bank accounts if prohibitions against deposits were removed.[35]

Limitations on recourse for non-payment

In some cases, distributors will not process requests by competitive retailers to cut off customers for non-payment of their accounts thus depriving them of a remedy for non-payment that is routinely available to RRO providers. The AUC Harmonization Report cites the evidence of Direct Energy to this effect and agrees that this remedy should be made available to competitive retailers:

[34] AUC Harmonization Report, pp.75-6.
[35] AUC Harmonization Report, p.75.

> Direct added that, while the Settlement System Code allows for a locked site transaction and regulated energy service providers commonly request disconnection for non-payment, some distributors will not process disconnection requests from competitive retailers.
>
> The Commission is aware that there are certain distributors of electricity and/or natural gas that do not process "cut off for non-payment" requests from competitive retailers. The Commission's Regulatory Policy Division has established a "Cut Off for Non-payment" Working Group to examine how electricity and natural gas distribution companies process cut off non-payment requests from competitive retailers.
>
> The competitive retailers are subject to bad debt risk respecting the entirety of the customer's electricity or natural gas bill. Competitive retailers, as well as regulated energy service providers, are responsible for remitting the distribution portion of the bill to the distributors, even if the retail customer does not pay. Cut off for non-payment appears to be one avenue to follow to control and attempt to collect the bad debt amounts in a competitively neutral manner.[36]

<u>Restrictions on direct marketing and customer solicitation</u>

One retailer interviewed by the UCA cited a series of regulatory restrictions on the solicitation of new customers. Apparently a retailer cannot sign a customer who already holds a competitive contract where that contract is penalty free to switch. A retailer must wait for a 10 day cooling off period to expire before it can enroll a customer and the customer cannot waive this requirement. Retailers are apparently forbidden from marketing outside of specified marketing hours even when specifically requested by the potential customer. There are also restrictions on some forms of publicity.

<u>Differential access charges</u>

Each distribution company (Wire Services Provider) requires a security deposit before a retailer can serve customers on its system. The maximum amount of the security deposit is set by the Distribution Tariff Regulation; however, the actual amount of the security deposit varies across distribution companies.

The security deposit (prudential requirement) a retailer is required to make depends on the billing period of the distribution company as follows:

Prudential Requirement = (Projected daily $ value of distribution charges made by the retailer) x (period equal to the lesser of 75 days or 20 days plus the number of days between

[36] AUC Harmonization Report, pp.75-6.

consecutive bills issued to the retailer plus the number of days from the issuance of a bill by the distributor until payment is due from the retailer).

The prudential requirement increases with the length of the billing period. The respective billing periods of the four distribution utilities are: Fortis, 60 days; ENMAX, 75 days; ATCO, 45 days; EPCOR, 34 days. The implication is that the security deposit a retailer must pay to ENMAX is more than twice as high as the security deposit that EPCOR requires.[37]

One retailer noted that, in addition, one distribution company requires security in one currency, e.g., it does not allow a mix of letters of credit and cash. The retailer expressed the view that non-standard security requirements reduce competition.

It appears to be more costly for retailers to serve customers on some distribution networks than others. This is an impediment to retailers attempting to attract customers from the RRO if RRO providers are not required to post a security deposit. Since ENMAX and EPCOR serve as both RRO and wire services providers it is reasonable to presume that they do not require a security deposit of themselves.

Differential security requirements might also be used strategically by a Wire Services Provider to provide an advantage to a competitive retailer with which it is affiliated. This would be the case if the Wire Services Provider does not require a security deposit from a competitive retailer with which it is affiliated.

This begs the question of whether a distributor should have to require a security deposit essentially from itself. There may be no security issue between affiliated companies. This raises the further question of the trade-off between levelling the playing field and imputing costs to some market participants that they have not incurred.

Cost and time required to satisfy regulatory requirements

One retailer stated that it can be expected to take approximately 6 to 8 weeks to satisfy the regulatory requirements for entry. Retailers cited various regulatory entry costs such as high license fees but it is not clear whether these fees are ongoing costs for incumbents as well as entrants or whether RRO providers must also pay them. According to one retailer, prudential requirements are imposed on competitive retailers but not on RRO providers. According to another, some distributors set prudential requirements so as to benefit the retailer with which they are affiliated.

[37] This information was provided by the Utilities Consumer Advocate.

One retailer noted that municipalities require licenses for door-to-door sales. This is a regulatory cost that RRO providers would not incur.

Structural barriers to entry

Structural barriers to entry into a market depend on the cost and demand characteristics of that market. A structural barrier to entry is said to exist if entrants must make a significant market-specific investment regardless of their scale of entry. This investment is known as a fixed, sunk entry cost.

Sunk cost barriers to entry

Sunk costs are costs that cannot be avoided by leaving the market. The cost of investments that are specialized to the market concerned are at least partially sunk. This includes specialized facilities or equipment, specialized knowhow, management systems or market intelligence and market-specific advertising or promotion. If it takes an entrant time to penetrate the market and attract enough customers to break even, then the losses accumulated during this period are also a sunk investment.

Sunk entry costs constitute a barrier to entry because they cannot be recovered if entry fails. If sunk entry costs are zero (and there are no regulatory entry barriers) then an entrant can hit and run without penalty. Sunk costs also have the effect of committing incumbent firms to the market in that incumbents have already incurred them while potential entrants have yet to do so.

The effect of fixed costs on entry conditions

The number of customers or volume of sales required to break-even (including a normal return on investment) is called the minimum viable scale of entry. The minimum viable scale of entry is greater if costs tend to be fixed with respect to the level of output. Barriers to entry tend to be higher in markets characterized by a relatively high minimum viable scale of entry for three reasons: (1) fixed costs may also be sunk; (2) losses incurred before minimum viable scale is reached are a sunk cost of entry and; (3) a greater the scale of entry is more likely to depress post-entry prices and profits.

Fixed costs of back office functions

There is some evidence reported in the AUC Harmonization Report that is suggestive of significant fixed and possibly sunk ("stranded") investment costs in electricity retailing in the form of back office facilities:

> An underlying reason for this position appeared to be a concern that any significant changes to regulated retail electricity services would cause EPCOR's investments in assets to serve its customers to be stranded. This concern was highlighted in the following exchange between Mr. MacBeath, Director of Energy Services, and Commission Counsel:
>
> Q. You also indicate in your opening statement that EPCOR's primary interest in the inquiry is to ensure the current structure of the RRO remains; correct?
> A. MR. MACBEATH: Correct.
> Q. I take it that EPCOR would stand to lose significant investments and potentially have stranded assets if the RRO function was limited to the provider of last resort function; correct?
> A. MR. MACBEATH: Certainly if we went to a solar (sic)[SOLR - supplier of last resort] concept, presumably there would be fewer customers remain on the RRO to cover the fixed costs to produce the bills, to answer the calls, to collect the money. And we would have the potential to have stranded assets, yes.[38]

Retailers interviewed cited information technology (IT) costs as an important and continuing fixed cost category. Call centres were also mentioned as another major fixed cost. There are, however, also indications that new entrants into electricity retailing need not invest in their own back office facilities. Back office functions can be contracted out to specialized providers or provided by upstream joint ventures. Retailers mentioned that there are specialized billing services providers but also stated that some of these were limited in their scope.

One retailer economizes on back office costs by providing back office (billing) services for its affiliated retail partners. It has also been suggested that that the need to maintain call centers can be reduced by reducing billing errors.

Another organizational form that may economize on back office and other fixed costs in the multi-jurisdictional firm. Firms of this nature may be able to transfer billing and other business systems and accumulated knowhow and brand recognition from other markets. One retailer stated, however, that the market-to-market transferability of office systems is limited, in part, by differences in market design.

<u>Relative importance of fixed costs in general</u>

One retailer estimated that approximately 40% of its costs are fixed.

[38] AUC Harmonization Report, pp.20-21.

<u>Customer acquisition costs</u>

Differentiated products markets are usually by a need for entrants to build brand recognition and trust or, more generally, to incur various forms of customer acquisition costs. Market-specific promotional expenditures to increase name recognition, product awareness and acquire customers can be a sunk investment.[39] If this is a slow process losses are likely to be incurred while break-even market penetration is reached and these are also a sunk investment.

There is some evidence that name recognition (trust, reputation) matters to potential retail electricity customers and that this may take both time and market-specific promotional expenditures for a new entrant to develop.

> Q. What I'm trying to understand, sir, is whether a shorter time period to a big bang, so to speak, whether that is a competitive advantage to the first mover such that it could actually dampen competition by preventing newcomers from coming in, from allowing parties that are in the market but not on the competitive side from developing competitive products because the time is too fast?
> A. MR. STUBBINGS: I think it could move too fast. You used the question about what if the RRO regulation was gone tomorrow. I think if it was gone tomorrow, there would be a strong advantage to the incumbents. I think if you said it is going to disappear in a year or 18 months, I would go back to what Mr. Weismiller just said, that I think there would be a lot of interest in the Alberta market. I think there would be a lot of people clamouring to get a piece of the action, and I think in that period of time the advantage of the incumbents would be minimal.
> Now, having said that, you know, there's always an advantage, I guess, with name recognition and things like that, but again, I think a lot of these things through education and ample notice to providers could be overcome in very short order.[40]

Some retailers emphasize the customer acquisition costs they must incur to attract customers. One retailer estimates that customer acquisition costs could be as high as $130 to $180 per customer. It is clear that RRO providers need not make expenditures to attract or retain customers while competitive retailers must not only provide an attractive product but also make expenditures to inform potential customers about the existence of the retail market in general and about their own product in particular. The fact that they must overcome the inertia associated with the RRO being the default option has probably increased customer acquisition expenditures and slowed the growth of competitive retailing. In response to suggestions that the playing field be levelled by including a deemed customer acquisition cost in the RRO pricing algorithm, however, the AUC Harmonization Report stated:

[39] Customer acquisition costs may be recoverable on exit from the market if subscriber contracts can be sold to other firms.
[40] AUC Harmonization Report, p.22.

> The record before the Commission did not disclose any empirical evidence that the failure to include a cost to acquire presents a barrier to the development of retail competition.[41]

Notwithstanding the lack of evidence before the AUC, it seems reasonable to conclude that the necessity of overcoming the inertia associated with the RRO default option has not helped the development of competitive retailing. This need not imply that customer acquisition costs are a barrier to entry in the usual sense of the term. At present, all competitive retailers whether incumbents or potential entrants are or would be competing to attract customers from the RRO. In this regard, entrants and incumbents are on the same footing. As the number of customers on the RRO declines, retailers might reasonably be expected to devote more of their marketing effort to attracting customers from other retailers. Thus, customer acquisition and retention costs are integral to the ongoing competitive process. In a vigorously competitive market one expects to see retailers incurring costs both to solicit customers from each other and to retain customers being solicited by rivals.

It may still be the case that customer acquisition costs are disproportionately high for new entrants. This may not constitute a serious problem. First, the role of name recognition and, more broadly, of marketing and promotion appears to depend on the business model adopted. Utility Network stated that its affiliates attract customers by word of mouth and it has not tended to take a long time for them to reach the break-even point.

Second, there are at least some potential entrants that already possess the requisite name recognition as well as other assets required for entry. They might be expected to have commensurately lower customer acquisition costs and faster market penetration. Indeed, given the legacy of longstanding relationships between energy (electricity and gas) distributors and their customers, some potential entrants might be better placed than some incumbents with respect to customer acquisition. In this regard, one retailer argued that co-branding should not be permitted.

<u>Break-even scale of operation and time required to break-even</u>

Some retailers estimated the number of customers that would be required to break-even and the time that would be required to attract that many customers. This clearly depends on the business model as well as a number of other factors. The range of estimates provided appears to indicate that a new entrant could reasonably expect to reach the break-even point within a year. The number of customers required to break-even could be 10,000 or, in some instances, much less than that.

<u>Conclusions regarding structural barriers to entry</u>

[41] AUC Harmonization Report, p.74.

While a non-trivial portion of retailers' costs are fixed and entrants must incur customer acquisition costs, minimum viable scale may not be large relative to the market and the time required to reach that scale could be as little as a year. The implication is that structural barriers to entry into electricity retailing are relatively low.

To the extent that structural barriers to entry do exist, there appear to be business models and strategies that enable other potential entrants to avoid or surmount them. There also appear to be participants in related product and possibly geographic markets (RRO providers, distribution companies) that already have the assets required for participation in the market. This can include physical facilities, business systems, technical knowhow, market knowledge, reputation and brand recognition. For example, according to evidence cited in the AUC Harmonization Report, there are potential entrants such as EPCOR who already have a billing system (among other assets) and who could establish a presence in the market really quickly.[42]

Responses of incumbents

New entry or the expansion of fringe firms in a market may also be deterred by the responses of incumbents. This could involve strategic use of the regulatory process, for example, by opposing applications by new entrants to build new facilities or by arguing that new entrants be required to meet higher environmental or safety standards or simply by engaging in delaying tactics. Incumbents might also attempt to deter entry by tying up sources of supply of crucial inputs or by tying up customers in long-term contracts with significant penalties for early termination. What is anti-competitive entry-deterring behaviour under some circumstances is a legitimate business practice under others and it is often difficult to distinguish between the two.

In the Alberta retail electricity market non-integrated retailers must compete with RRO providers who are also distributors and with other retailers who are also both RRO providers and distributors. Given the differences in the characteristics of the competitors and potential competitors in the market, concerns are often raised about the absence of a level playing field which may inhibit the entry and expansion of new competitors.[43] The key issue here is to distinguish between the advantages of incumbents that are based on superior efficiency from those stemming from their legacy status or from regulatory design.

[42] AUC Harmonization Report, p.21.

[43] Just Energy has expressed the view that municipal government involvement in competitive retailing is a significant barrier to entry. See: AUC Harmonization Report, p.21.

For example, RRO providers might hypothetically be concerned with covering their fixed costs and may use their status as distributors to make it difficult for competitive retailers to attract customers from them rather than facilitating their departure as one might expect a transitional default provider to do. A distributor who is also a retailer might attempt to channel customers in its distribution area toward its own retail affiliate or it may impose differential access provisions on competing retailers. In this regard, it has been noted that the security deposit required by the Distribution Tariff Regulation differs among distributors and that this difference might be the result of strategic rather than cost considerations (see the discussion on regulatory barriers to entry above).

To take another example, some retailers have suggested that one of their competitors is engaging in blended or average cost pricing. Average cost pricing was standard utility practice and likely still is in many places. A blended or average cost price would reflect the effect of lower out-of-pocket cost sources of energy such as Power Purchase Arrangements. Non-integrated retailers might be obliged to pay the pool price for power and pass it along. The pool price is the marginal cost of electric power.[44] While economists are of the view that marginal cost pricing provides the appropriate signal for efficient resource use, a municipally-owned provider might interpret its mandate otherwise.

The record of entry and exit

Entry and exit data are open to a variety of interpretations. The absence of entry may imply that entry barriers are high or it may imply that entry is unattractive because competition among incumbents is intense. A record of churning in which entry occurs and fails may imply that entry is attractive but difficult. A record of successful entry could imply either that incumbents have accommodated new entrants or that incumbents have been overwhelmed by new technologies or new business models.

In the context of the retail electricity market, the record of entry and exit tells us something about how much competition there is at present and how difficult entry has been under the current regulatory environment, the most important characteristic of which is the existence of the RRO as the default option. It may also tell us something about how much more entry there would if the default option were restricted or the “choice architecture” were otherwise changed.

[44] It should be pointed out that a Power Purchase Arrangement is vertical integration by contract rather than by ownership and that this contractual option would have been open to any retailer. It should also be noted that while average cost pricing is not efficient, it is also not regarded as being predatory.

There has been some entry into the retail market over the last five years, albeit on a small scale. Spot Power was first listed on the Utilities Consumer Advocate (UCA) web site in January, 2010. Utility Network and seven of its affiliates were first listed on the UCA web site in April 2011.[45] By the end of 2011, one more Utility Network affiliate (SPARK) was listed. By May, 2012, one further Utility Network affiliate (Adagio Energy) had been listed on the UCA web site.

Conclusions regarding entry barriers

It is sometimes difficult to distinguish between entry barriers and costs of doing business. Some products are costly to produce relative to what potential customers are willing to pay. As a consequence, the market for them is small and relatively few suppliers enter it. This need not imply barriers to entry in the sense that incumbent firms have a cost advantage over potential entrants.

The competitive component of the retail market for electrical energy in Alberta is relatively small but barriers to entry, in the sense of cost advantages of incumbent competitive retailers over potential entrants are relatively low. Structural barriers to entry in the form of fixed sunk entry costs are relatively low. Suggestions of strategic entry deterrence by incumbent competitive retailers are speculative at this point. There are regulatory restrictions that have impeded the growth of the competitive component of the retail market as a whole but they do not appear to confer significant advantage on incumbent competitive retailers. This is not to say that the playing field is level. It is not so much tilted as it is bumpy. Some incumbents have legacy advantages but this may be true of some potential entrants as well.

The shift of residential, farm and small business customers from the RRO to competitive retailers has been relatively slow. This is in no small part due to inertia as the RRO is the default option. The decision of small customers to search out alternatives or perhaps not even to pay any attention is not necessarily irrational. The term “regulated” in the RRO may, however, be leading some consumers to draw the false inference that the RRO somehow protects them completely from any and all eventualities. It might be better to call it the Transitional Rate Option (TRO).

The growth of the competitive retail market as a whole has been impeded by some regulatory restrictions on competitive retailers and by some costs that competitive retailers incur that RRO providers either do not incur or, if incurred, are not reflected in RRO rates. This is probably the most difficult issue. There are some costs that are uniquely associated with competition and there does not appear to be much sense in imputing them to RRO providers merely to level the

[45] Spot Power was included in the list of Utility Network affiliates. The other affiliates listed were: Milner, Bow Valley, Mountain View, Brighter Futures, E.NRG and Vector.

playing field. There are also some costs that resellers incur that are avoided by vertically integrated firms. Separating real from artificial cost differences has been a widespread and ongoing regulatory concern.

Conclusions on Competition in Electrical Energy Retailing in Alberta

The retail electricity market can be regarded at present as being competitive if not highly competitive. The RRO plays an important role in this. Competitive retailers design their offerings with a view to matching if not beating the RRO. One retailer opined that the RRO had a negative effect on the margins of competitive retailers.

With respect to the likely state of retail competition for residential customers in the event of the elimination of the RRO, this depends whether there is significant new entry. In its absence, the market could not be described as highly or perhaps even sufficiently competitive given the inelasticity of market demand, the small size of residential customers, the concentration of the market in the hands of three major retailers and the distribution of market shares within that group.

The situation may be different for small commercial customers. They are likely to be more active (including by encouraging new entrants) and they may already have more competitive alternatives.

It is reasonable to assume that there would be significant new retail entry in the event that the RRO is eliminated. Entry barriers into competitive retailing itself are relatively low and there appear to be potential entrants with the capability of competing successfully. Entry has been relatively modest in recent years but it is reasonable to attribute this to the RRO and to some regulatory and institutional impediments to competitive retailing in general.

New entry does not guarantee an entirely smooth ride. While more residential customers are likely to become active, they are small customers and the usual consumer protection and "vulnerable customer" issues will continue to arise. Indeed, given that electrical energy is viewed as a necessity the issue of vulnerable customers is likely to be more important than it is in telecommunications and some other deregulated markets. In addition, level playing field issues resulting from municipal ownership, vertical integration and legacy advantages are likely to require continuing regulatory attention.

Report to the Alberta UCA
Default Retail Rate for Energy

Joseph Bowring

May 7, 2012

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Introduction

The analysis in this report begins with July 1, 2006, because that date was the beginning of the transition period from the prior RRO regime. Under the prior RRO regime retail suppliers used annual purchasing plans which included long term and short term hedges and under which rates were adjusted quarterly. The period following July 1, 2006 included a transition period to a regime incorporating only one month hedges, which became fully effective on July 1, 2010. The report also looks separately at the period following July 1, 2010, as that reflects the operation of the RRO as it is currently structured.

This report does not directly evaluate the competitiveness of the wholesale power market in Alberta, the competitiveness of the retail market in Alberta, the competitiveness of the forward market, or the liquidity of the forward market. But the competitiveness of both the wholesale and retail markets is a critical precondition to the functioning of the retail market with appropriate default pricing and the liquidity of the forward market is a critical precondition to the competitive functioning of the current RRO.

Economics of Default Pricing

In order for a competitive wholesale power market to work effectively, both the supply side and the demand side must face the market price. In order for a competitive wholesale power market to work effectively, both the supply side and the demand side must have a range of options for reacting to the market price. If the price is high, suppliers should have the opportunity to respond and customers should have the opportunity to respond. The wholesale power market design has focused primarily on the supply side of the market, including rules about the behavior of generation owners. The most granular level of supply in the electricity market is the individual generating unit, or in some cases in the Alberta market, the right to a portion of the output of a generating station. The most granular level of demand in the electricity market is the individual customer, with metered purchases. Except for some of the largest customers, there are intermediaries between individual customers and the wholesale market. These load serving entities purchase power in the wholesale power market or in the forward market and resell the power to individual customers.

Suppliers have a number of options for selling power in the wholesale power market. Suppliers can sell at the Alberta wholesale market power price (market price or RT). Suppliers can sell via bilateral contracts which are frequently linked to the market price in some way, including contracts for differences. Suppliers can sell in the forward markets, which include broker based transactions as well as transactions on an organized exchange. Customers also have options but they are somewhat less flexible than those available to suppliers. Customers can sign up with a designated retail supplier and pay the default wholesale market rate plus various mark ups or customers can sign up with a retail supplier and pay the contractual price which may be structured as a flat rate or linked in various more direct ways to the wholesale price, and the associated mark ups, to the retail supplier.

The default rate for suppliers is the market price of electricity. The current default wholesale market price for customers is the forward price of electricity. Suppliers face a different price than customers in real time. If the electricity market is to function effectively, both suppliers and customers should face the same default price.

The incentives that result from different supplier and customer default wholesale market prices may be complex. If customers face a fixed price they have an incentive to continue to use power without concern about the overall supply-demand conditions or prices in the market, even if extreme. If suppliers face the market price, they have an incentive to produce more when prices are high. Conversely, if customers face a fixed price they do not have an incentive to use more when prices are low while suppliers have an incentive to produce less when prices are low.

Both suppliers and customers have opportunities to hedge their positions and modify the determinants of the price they face, through a combination of contracts and forward market positions. Suppliers who have sold their entire output at a fixed price do not have an incentive to respond to real time market prices. If suppliers have sold forward at a price below the current market price, they have an incentive to produce to meet their contract but not an incentive to go to extra lengths to meet demand.

When customers enter into a fixed price contract with a retail supplier, the incentives to respond to prices shifts to the retail supplier. That retail supplier has an incentive to purchase less power for its retail customers when the wholesale price is greater than the fixed contract price. While the retail supplier has an obligation to meet the contracted load, the retail supplier has an incentive to engage in efficient demand side management activities.

A fully functional electricity market means that both suppliers and end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time, and will have the ability to receive the direct benefits or pay the costs of changes in real-time energy use. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

Customers should and do have choices about how to purchase power. As long as the underlying default price is the real time wholesale power price, then the actual choice about the structure of prices actually paid by the customer will be determined in the market, through a voluntary contract with a retailer supplier which most closely meets the wishes of the customer.

Today, customers face the forward price for power as the default rather than directly face the market price. This is suboptimal because there is no necessary relationship between the market price and the forward price. The forward price reflects the judgments of buyers and sellers about expected market results and reflects the risk preferences of buyers and sellers. The forward market reflects hedged positions on both the supply and demand side of the market.

While this was a reasonable compromise at the time the current RRO was developed, it is not the optimal market solution. Customers should face the real time market price as the default and enter into explicit contracts with retail suppliers, if they choose to do so, with defined tradeoffs between price stability and price volatility. When customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. Given that directly facing the real time price is not possible as a result of the meter infrastructure, the best available alternative is to face the monthly real time price.

When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the actual hourly price of power used by customers is determined by the wholesale power market, regardless of the average price actually paid by customers. The transition to a more efficient market requires that the default energy price for all customers be the real time hourly price.

At present, market pricing must be monthly because the meter infrastructure is not adequate to permit hourly pricing. Monthly market pricing is another step in the progression of Alberta markets towards a fully market based outcome. Policy makers need to determine whether the benefits of more sophisticated meters outweigh the costs. Better meters would permit hourly pricing based on the actual real time wholesale market price. In the absence of the meter infrastructure adequate to permit customers to pay the hourly market price for the energy they consume in that hour, monthly pricing based on the average market price is the best available alternative. Even if customers are paying a monthly average market price, real time information is important to customers and will also help with an eventual transition to real time pricing.

There is no conceptual reason for customers to pay a forward price rather than the actual wholesale market price for power. There is only one wholesale market price. The relative volatility of the wholesale price versus the relative volatility of the forward price is not relevant to the choice of default price. If Alberta chooses to rely on wholesale power markets to determine the price of power, then there is only one market price. That one market price is the beginning of customers' choices and not the end. The default price simply defines the relative risks taken by customers and retail suppliers when retail suppliers offer alternatives to the wholesale market price.

While volatility is a reasonable concern of customers, it is not a basis for determining the default price. Volatility can be addressed through the choice of retail pricing options. The actual level of volatility of the real time market price reflects the actual price of power in the Alberta market. Customers should be given as many options as possible for the price they pay, but the offers by retail suppliers should reflect the risks they bear in providing prices to customers that differ from the wholesale market price.

Neither the actual volatility nor the risk associated with the volatility of the real time wholesale market price disappears, regardless of the structure of the RRO. The volatility remains and that risk is simply shifted in part to the retail supplier and is retained in part by the end use customers. When retail suppliers are required to bear risk on behalf of end use customers, there is a cost and that cost is passed on to the customers.

Retail suppliers can continue to offer pricing options based on the forward market prices as well as the competitive pricing options. But customers should also have the option to simply pay the wholesale price, with no risk-based markup.

If the markets work efficiently and there are no transactions costs, there is no reason to expect a systematic difference between the wholesale forward price and the wholesale market price over time. Nonetheless, there is no reason that the forward price should equal the market price at every point, and in fact the forward price has exceeded the market price in recent years with the difference growing significantly in early 2012. If the forward price is the result of willing buyers and willing sellers, the forward prices should reflect the expectations of both buyers and sellers. Buyers will not continue to buy in the forward market if they systematically pay more in the forward market than in the real time market and if they have a choice. Sellers will not continue to sell in the forward market if they systematically receive less in the forward market than in the real time market. This report does not evaluate the extent to which the forward price may be affected by the requirement that RRO retail suppliers purchase forward contracts.

However, an RRO based on the forward price is likely to be higher than an RRO based on the market price because RRO suppliers using the forward market bear risk and credit costs and will charge customers for those risk and credit costs. For example, if a retail supplier promises to provide all the power needs of a customer at a fixed price for the next month, the retail power supplier is bearing the risk that the customer is likely to use less or more power than expected, depending on weather and other factors. The introduction of hedging products of any type shift risks that must be priced by retail suppliers and the evaluation and pricing of that risk relies on judgment to some degree. The way to maximize competitive pressure on retail suppliers is to ensure that customers have access to the actual wholesale market price, without any adders.

Given that the RRO price based on the forward price can be expected to be higher than the RRO price based on the market price, the goal in the design of the default rate should be to have the default rate be equal to the market rate. This eliminates any transactions costs and transactions risks and ensures that customers have the benefit of direct reliance on the price determined in the competitive wholesale power market.

Wholesale Prices, Forward Prices and Retail Prices

The data show that there has been only a tenuous relationship between the market power price and the forward price during the period from July 1, 2006, through February 29, 2012. Forward prices were higher on average than market prices during the period. Use of forward prices is not likely to be the low cost solution for retail customers both because forward prices have been higher than market prices and because use of the forward price as a default shifts risks to the retail supplier for which they charge customers. The possibility that forward market prices are in part a result of the requirement that RRO retail suppliers purchase forwards cannot be ruled out.

Market prices were more volatile than forward prices during this period. There is nothing wrong with volatility when it reflects the underlying dynamics of a competitive market. The wholesale market price reflects the average hourly value of power in Alberta while the forward market price reflects the forward price for a complete month based on transactions over a 45 day trading period. It is unsurprising that hourly prices and even average hourly prices are more volatile than a simple monthly price. Hourly prices reflect varying actual supply and demand conditions in the wholesale power market. If the goal of the default rate and of retail pricing generally is to expose customers to the actual market value of power, volatility is not a reasonable metric for determining the appropriate default rate. If retail customers do not wish to be exposed to the market price, they have a variety of options among retail suppliers.

Wholesale Prices and Forward Prices

Figure 1 shows the Alberta wholesale market power price (market price or RT) and the volume weighted average price (VWAP) from the NGX market for the period from July 1, 2006, through February 29, 2012. The pool prices and forward prices are not correlated. The average wholesale forward price for this period was $73.10, which is 4.7 percent or $3.28 per MWh higher than the average wholesale pool price of $69.82.

The forward price is the volume weighted average price based on purchases on the Natural Gas Exchange Inc. (NGX) market. The RRO suppliers purchase forward power either using Daily Target Pricing or periodic auctions, during the established 45 day procurement period preceding the effective month. The market price is the simple average of the hourly market prices during the month.

Figure 1 Market prices and forward prices

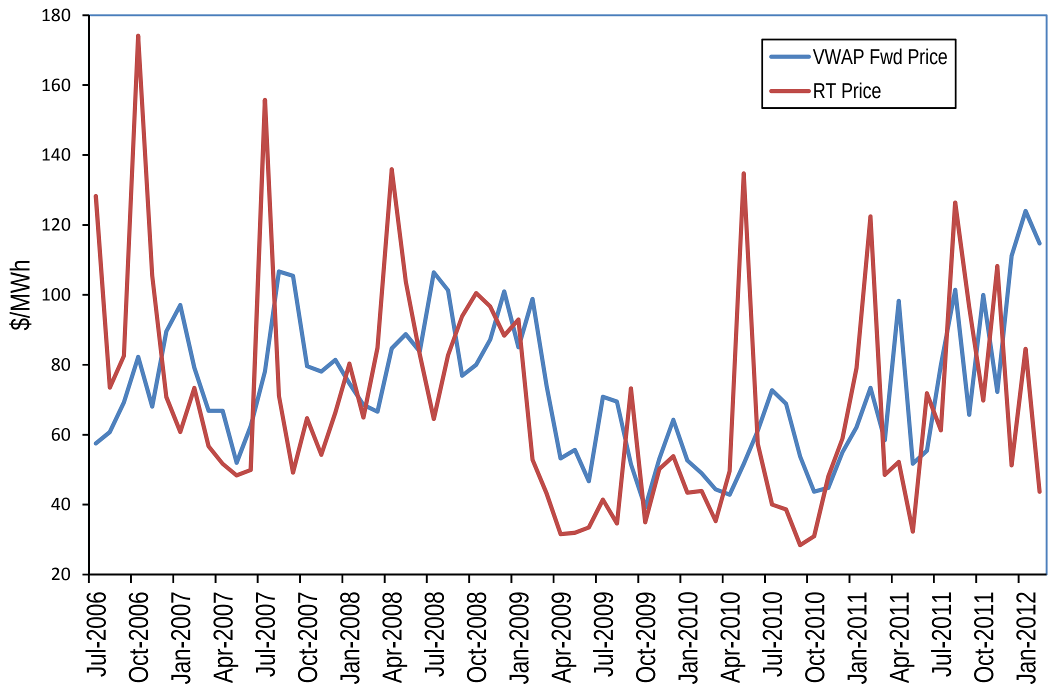


Table 1 compares forward prices and market prices for years and partial years during the period. The forward price was greater than the market price by an average of $3.28 per MWh over the entire period.

Table 1 Forward prices and market prices by year: July 2006 through February 2012

Year	VWA Forward Price	RT Price	Difference
2006 (Jul-Dec)	$71.22	$105.78	$34.56
2007	$79.47	$66.84	($12.63)
2008	$84.98	$89.95	$4.97
2009	$63.46	$47.84	($15.62)
2010	$53.37	$50.77	($2.59)
2011	$77.46	$76.65	($0.81)
2012 (Jan-Feb)	$119.35	$64.11	($55.24)

Figure 2 shows the difference between the market price and the forward price (market price minus the forward price). While the differences vary, the market price was less than the forward price on average over the period and especially during the first part of 2012.

Figure 2 **Difference between the market price and the forward price**

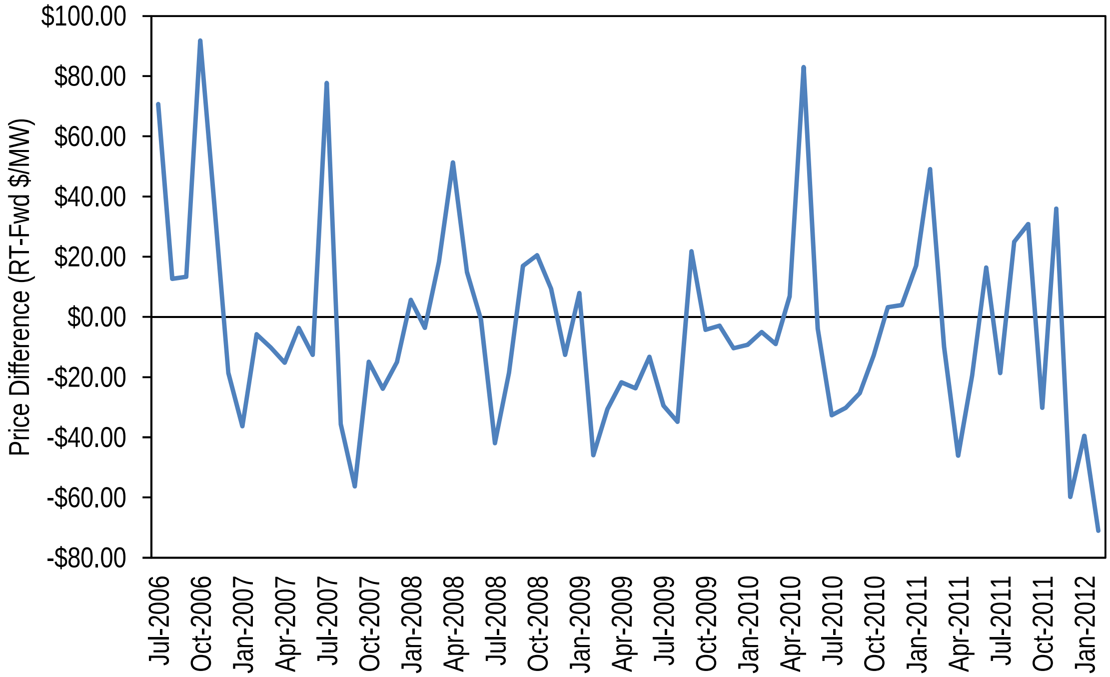


Figure 3 shows the ratio of the forward price to the average monthly market price for the period from July 1, 2006 through February 29, 2012. When the forward price is greater than the market price, the ratio is greater than one. For example, in February 2012, the forward price was $114 per MWh while the market price was $43 per MWh. The ratio for February was 2.6, indicating that the forward price was 2.6 times higher than the market price. For the period, the ratio of the forward price to the market price ranged between 0.38 and 2.63, with an average value of 1.19.

Figure 3 Ratio of forward price to market price.

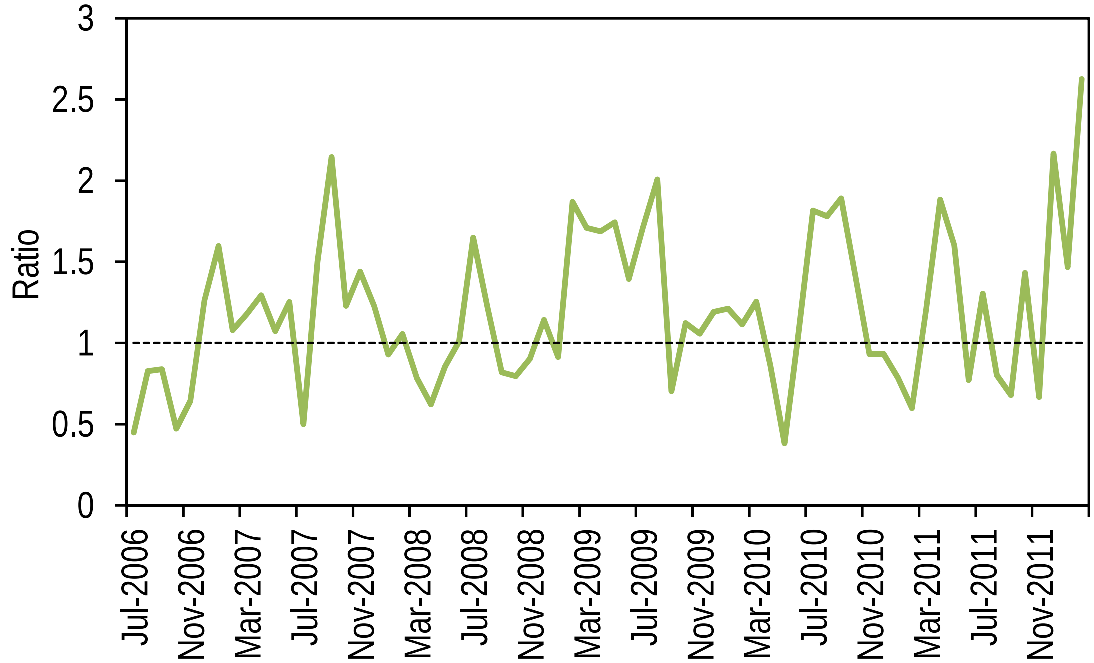


Figure 4 shows a frequency distribution of the ratio of the VWA forward price to the market price for the same period. The forward prices have exceeded market prices by 1.34 times, on average, and are skewed towards higher ratios.

Figure 4 Frequency distribution of the ratio of forward price to market price (July 2010 through February 2012)

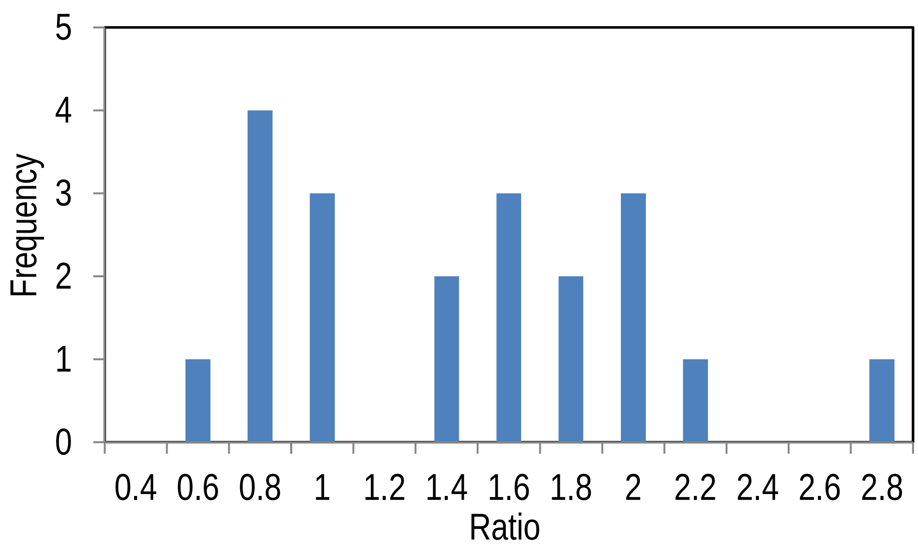
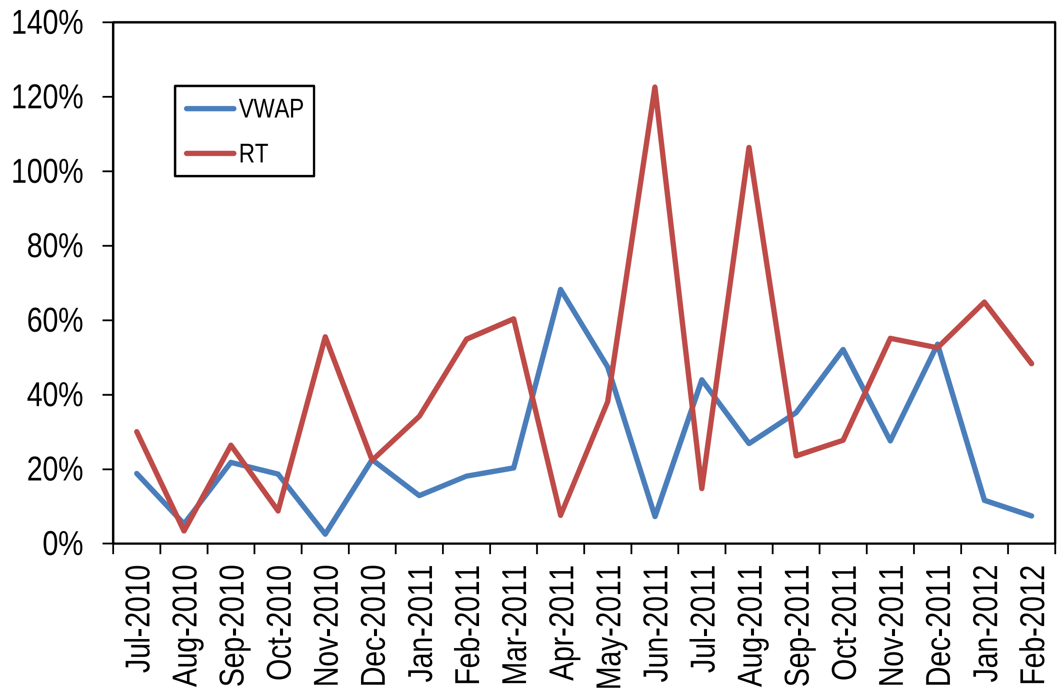


Figure 5 shows the absolute value of the month to month percent change in forward prices and market prices. Changes in market prices exceeded changes in forward prices. The average month to month percent change was 26.2 percent for forward prices and 42.9 percent for market prices for the period from July 1, 2010, through February 29, 2012.

Figure 5 Absolute value of month to month percent change in market prices and forward prices

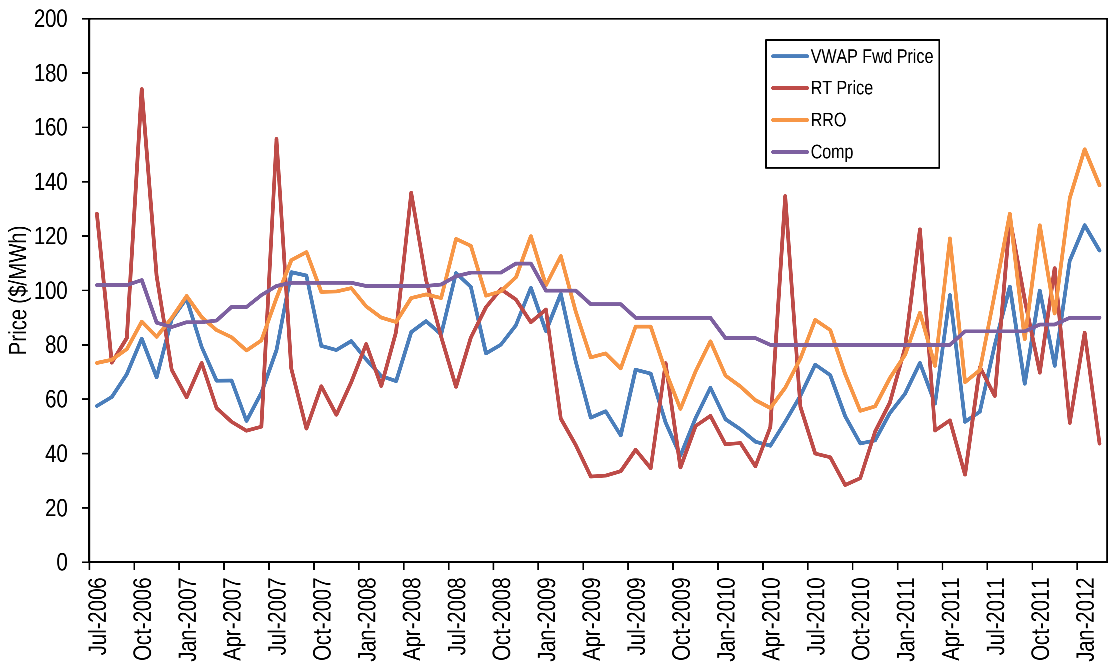


RRO Prices and Competitive Retail Supplier Prices

RRO prices reflected the underlying forward prices, particularly after July 1, 2010 when RRO prices were based completely on monthly forward prices. A comparison between the prices charged by RRO retail suppliers and competitive retail suppliers also reflects the underlying forward prices and the expected relationship between retail prices based on monthly forward prices and retail prices based on five year contracts. The shorter term RRO retail prices are more volatile than the longer term competitive retail prices.

Figure 6 shows the forward price, the market price, the average RRO price and the average five year contract competitive price. The RRO price and the forward price are highly correlated for the period. The average competitive price is not correlated with the forward price. The RRO price became more volatile after July 1, 2010, when RRO prices were based completely on monthly forward prices. The nature of the five year contracts provided by the competitive retailers resulted in a more stable retail price.

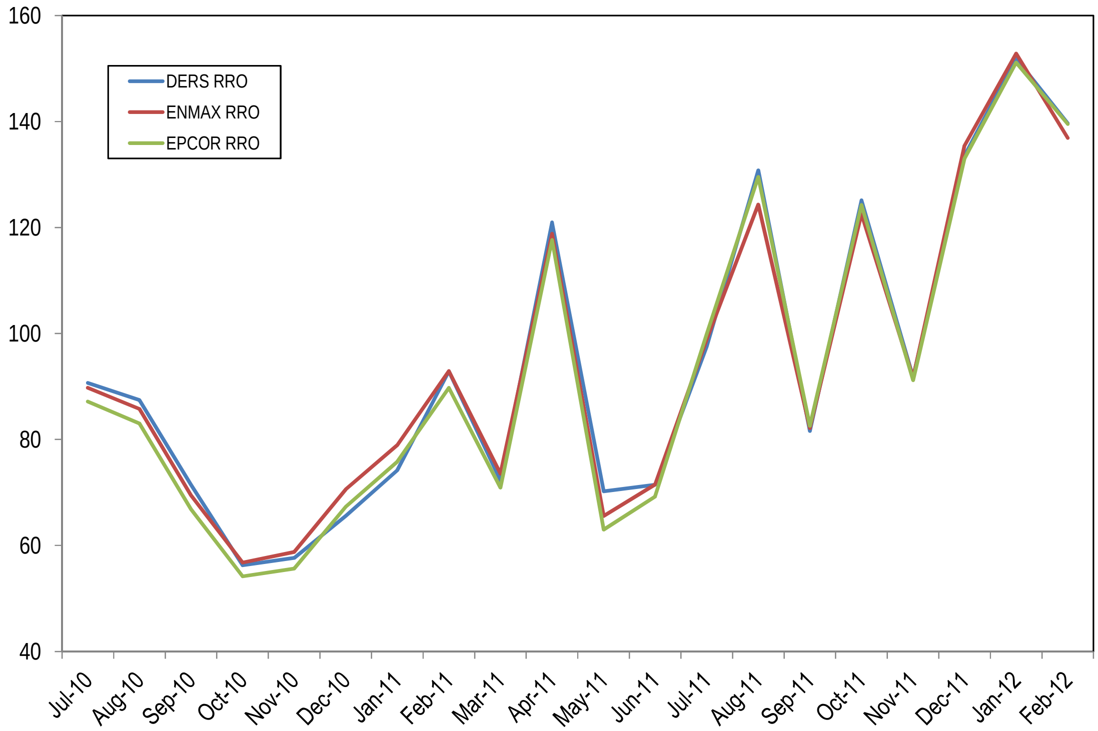
Figure 6 Comparison of retail and wholesale prices



Monthly prices for RRO retailers must be calculated following an individual Energy Price Setting Plan (EPSP), and be approved by the Alberta Utilities Commission (AUC). The RRO retail price charged to consumers includes energy and non-energy components. The energy component is based on the price of the energy obtained on the forward market during the 45 day procurement period. The non-energy components are based on costs to the RRO provider including customer service, transactions costs, volume risk, default risk, billing, incentives, return margins and other charges approved by the AUC. Each month the RRO must submit its rate calculation workbook to the AUC for approval, detailing the energy and non-energy components of the rate. Prices for competitive retail suppliers are not subject to AUC approval, and are determined by individual retail suppliers.

Figure 7 shows retail prices for RRO suppliers from July 1, 2010, through February 29, 2012. The prices of RRO suppliers are very similar. The three RRO retail suppliers are Direct Energy Regulated Services (DERS), ENMAX, and EPCOR.

Figure 7 RRO retail prices: July 2010 through February 2012



In the RRO transition period from July 1, 2006, through June 30, 2010, the average retail RRO price was $8.30 per MWh less than the five year contract competitive retail price. Following the full implementation of RRO pricing on July 1, 2010, through February 29, 2012, the average retail RRO price was $10.07 higher per MWh than the average five year contract competitive retail price.

Table 2 includes summary statistics for the RRO and five year contract competitive retail prices for period from July 1, 2010, through February 29, 2012. The average five year contract competitive retail prices are $10.07 per MWh lower than the RRO prices. In addition, the five year contract competitive prices are less volatile, with a standard deviation $24.82 lower than the RRO retail prices.

Table 2 Minimum, maximum, average and standard deviation of RRO and five year contract competitive retail prices ($/MWh): July 2010 through February 2012

Category	RRO	Competitive	Difference
Min	$55.74	$79.95	$24.21
Max	$151.97	$89.95	($62.02)
Average	$93.53	$83.46	($10.07)
Std Dev.	$28.40	$3.82	($24.58)

Table 3 shows the RRO and five year contract competitive retail prices by year or partial year. Figure 8 compares the RRO and five year contract competitive retail prices by month. Due to recent increases in the forward prices, RRO prices have increased while five year competitive contract prices have remained more stable.

Table 3 Average monthly RRO and competitive prices

Year	RRO	Competitive	Difference
2006 (Jul-Dec)	$81.28	$97.41	$16.14
2007	$94.88	$97.29	$2.42
2008	$101.97	$104.61	$2.64
2009	$81.84	$93.70	$11.86
2010	$67.81	$80.60	$12.79
2011	$96.26	$84.12	($12.14)
2012 (Jan-Feb)	$145.33	$89.95	($55.38)

Figure 8 Annual average RRO and competitive prices ($/MWh)

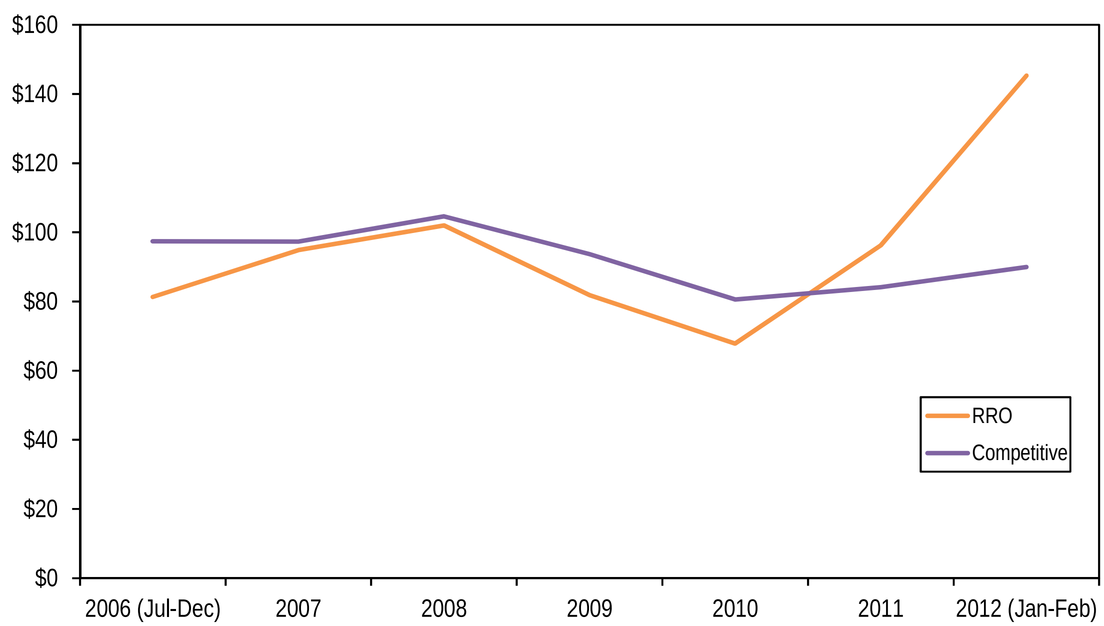


Figure 9 shows the average RRO price, the average of the competitive five year contract prices and the ratio of the RRO price to the average competitive five year contract price. A ratio greater than one indicates that the RRO price is greater than the five year contract competitive price.

Figure 9 Average RRO and five year contract competitive prices

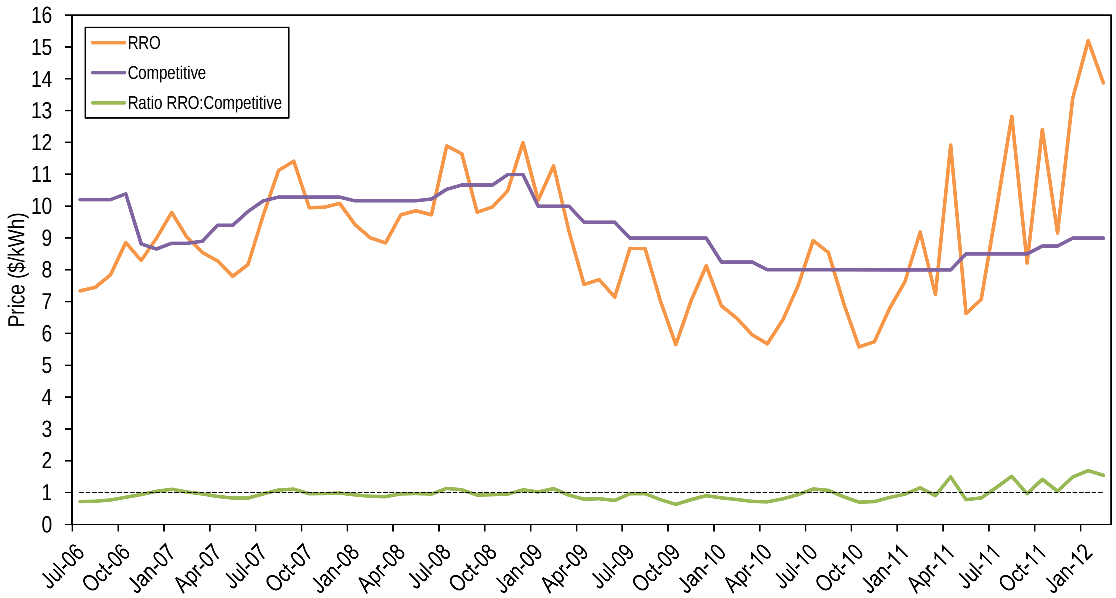


Figure 10 shows the frequency distribution of the average RRO retail price and average five year contract competitive prices ($/kWh) for the RRO transition period and the full RRO period. Darker shades represent the period between July 1, 2006, and July 1, 2010, and lighter shades represent the period from July 1, 2010 through February 29, 2012. RRO retail prices since July 1, 2010, have a wider range than during the transition period and are more frequently higher than competitive prices. Before July 1, 2010, 54 percent of RRO retail prices were less than 9 cents per kWh and 33 percent of five year contract prices were less than 9 cents per kWh. After July 1, 2010, 55 percent of retail RRO prices were less than 9 cents per kWh and 100 percent of five year contract prices were less than 9 cents per kWh.

Figure 10 Frequency distribution of RRO and five year contract competitive prices

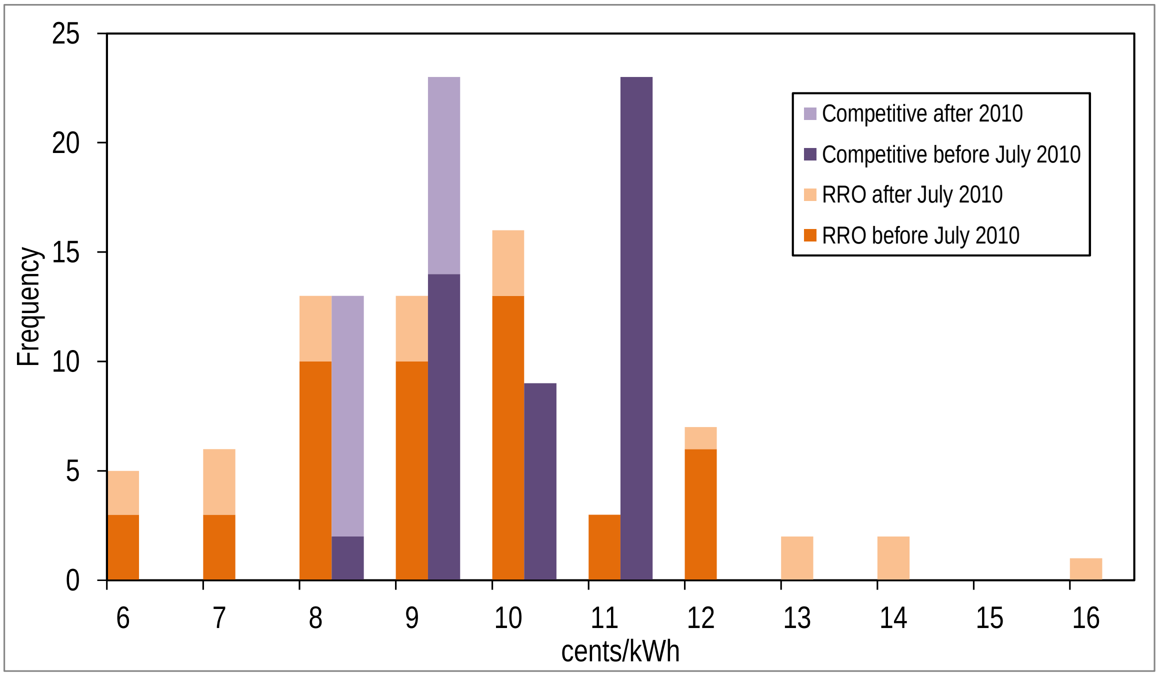


Figure 11 shows the ratio of the RRO retail prices to the five year contract competitive retail prices. The ratio averaged 0.91 prior to July 1, 2010, and averaged 1.11 between July 1, 2010 and February 29, 2012.

Figure 11 Ratio of RRO prices to five year contract competitive prices

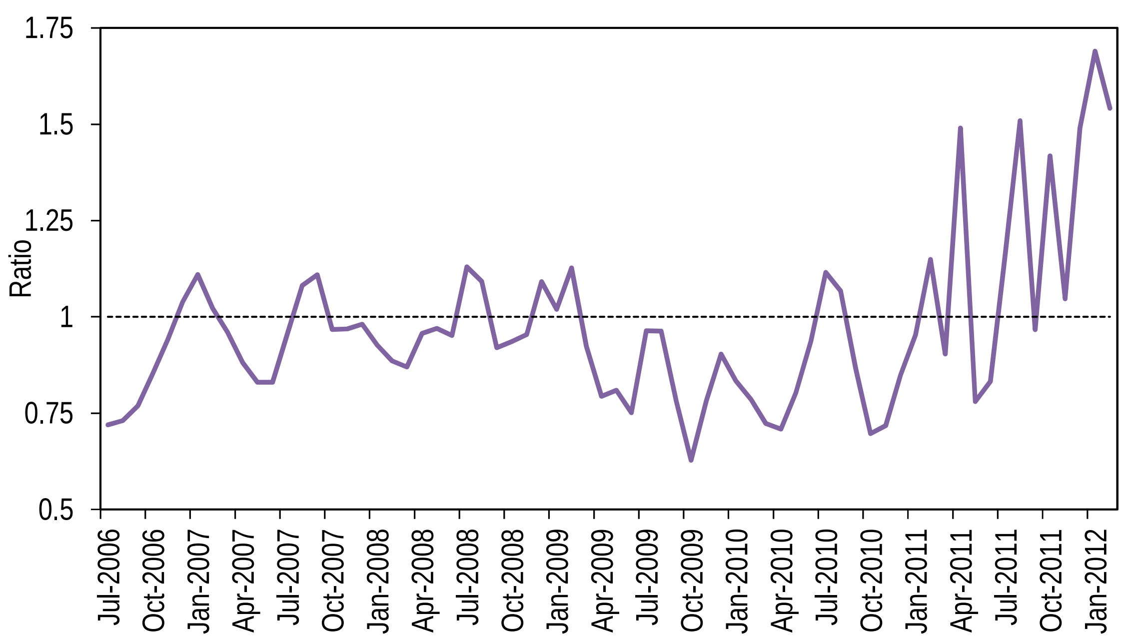
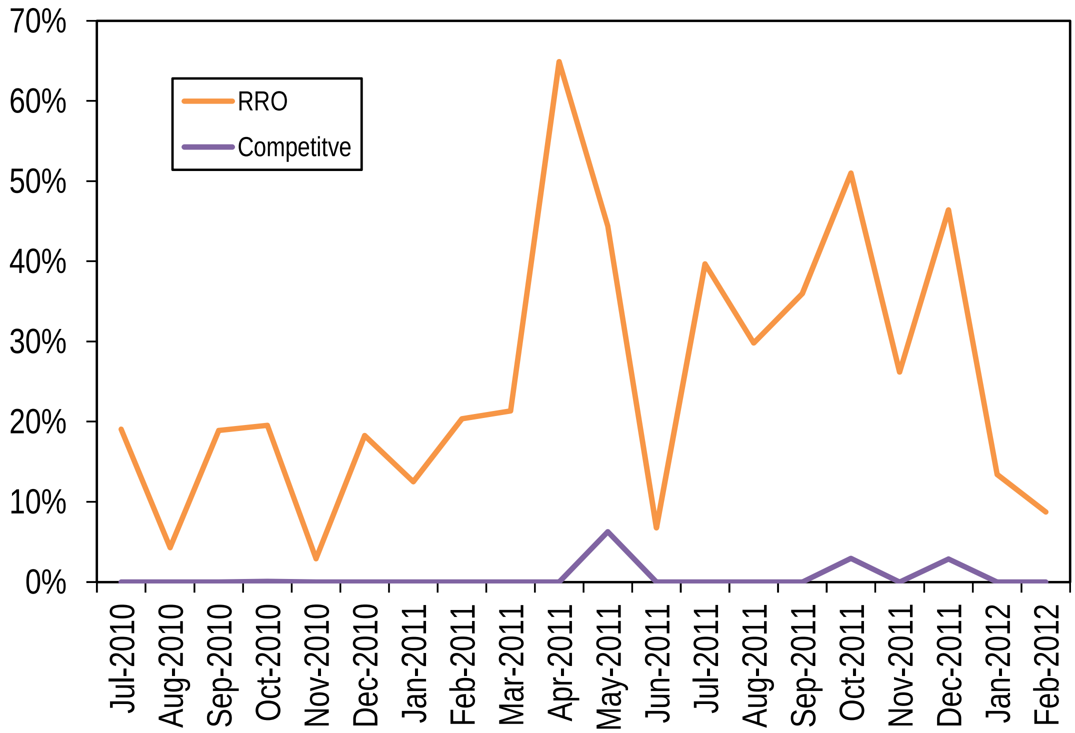


Figure 12 shows the absolute value of the month to month percent change in retail prices for RRO prices and five year contract competitive prices. RRO prices are more volatile than the five year contract competitive prices. The average month to month price change for the period from July 1, 2010, through February 29, 2012, is 25.2 percent for RRO and 0.6 percent for competitive retailers.

Figure 12 Month to month percent change in RRO and five year contract competitive retail prices



Conclusion

The purpose of a default rate is to ensure that all customers face the wholesale market price of power. When both suppliers and customers see the same price signal, both the wholesale and the retail markets can work efficiently and competitively. If there is confidence that the wholesale power market is competitive, there is no need for price protection for customers. Price protection, to the extent that it attenuates the market price signal, could make customers worse off by providing incomplete or untimely feedback to the market, not permitting customers to benefit from adjusting consumption to prices and forcing customer to pay risk premia to retail providers.

If it is determined that there is to be a default rate going forward, it is essential that all retail customers have access to a default rate based directly on the wholesale market price. Such a default rate should be a permanent feature of the markets and not a transitional element. Such a default rate is consistent with and in fact a prerequisite for full competition at both the wholesale and retail levels. A default rate provides retail customers with direct access to the price of wholesale power and provides a market benchmark against which customers can measure retail suppliers.

Regardless of the choice of default rate, it is important to ensure that all retail customers have access to the full range of retail pricing options. If some market sectors, like rural customers, are under served by retail competitors, then it may be appropriate to provide a range of default options to such customers.

The cost of credit associated with RRO providers should be included in the associated retail rate. But the cost of that credit should reflect the reduced risks taken by such providers under a structure that bases the RRO price on the wholesale price because the providers would be simply passing through the actual wholesale price. This credit cost can be expected to be less than the credit costs of retail suppliers who are providing hedged products and who therefore take on price and volume risk.

It would also be appropriate to include an incentive in the new RRO rate, which should reflect both the reduced risk taken by RRO providers who pass through the wholesale market rate and the need to provide an incentive to provide the service. An effective way to determine the appropriate incentive would be an auction of the rights to serve RRO customers. Suppliers would compete on the basis of the mark up over the market price. If there is adequate competition, an auction would be preferable to an administrative determination of the required mark ups including transactions costs, credit costs and incentives.

While the current RRO structure based on the forward price permits customers to know the price in advance of using power, this also means that there are likely be significant deviations between the actual real time price of power and the price customers pay. This is less efficient than basing the RRO price on the real time market price and permitting customers to react to the actual real time price, in real time. In the absence of the meter infrastructure adequate to permit customers to pay the hourly market price for the energy they consume in that hour, monthly pricing based on the average market price is the best available alternative. Even if customers are paying a monthly average market price, real time information is important to customers and will also help with an eventual transition to real time pricing. Real time information on the wholesale market price should be provided to all customers. This could be provided through the wholesale market web page, other web pages or other media.

The average market price is more volatile than the average forward price. There is nothing wrong with volatility when it reflects the underlying dynamics of a competitive market. The wholesale market price reflects the average hourly value of power in Alberta while the forward market price reflects the forward price for a complete month based on transactions over a 45 day trading period. It is unsurprising that hourly prices and even average hourly prices are more volatile than a simple monthly price. Hourly prices reflect varying actual supply and demand conditions in the wholesale power market. If the goal of the default rate and of retail pricing generally is to expose customers to the actual market value of power, volatility is not a reasonable metric for determining the appropriate default rate. If volatility were the central metric, then all customers should have a five year contract price as the default. If retail customers do not wish to be exposed to the market price, they have a variety of options among retail suppliers.

Basing the RRO on the market price rather than the forward price means that the positions of default price customers will not be hedged. When customers buy power at the forward price they no longer have an incentive to respond to the current market price. When customers buy power at the forward price it also means that generation suppliers who sold the forwards no longer have an incentive to either respond to the current market price or to exercise market power by attempting to increase the market price as long as the volumes sold are less than current demand. That is not true when current demand exceeds the volume sold forward.

If the wholesale market is functioning effectively, it should not depend on the RRO customers purchasing forwards as an essential constraint on market power. If generation owners have the ability to exercise market power in the absence of RRO forward purchases, presumably generation owners also have some ability to exercise market power in the forward market when RRO customers are required to buy in the forward market. In addition, the purchase of forwards would not be expected to cover extreme load conditions. RRO suppliers have to manage volume risk by purchasing forwards equal to expected loads. If they buy too little, they have to buy the balance in real time or closer to real time and if they buy too much, they have to sell the power in real time or closer to real time. So, if extremely hot or cold weather resulted in RRO loads greater than RRO suppliers purchased forward, RRO suppliers could be short in real time. This would have the same result for generator market power at times of extreme demand where market power is most likely, as would occur if RRO suppliers did not buy any power in the forward market.

At present, market pricing must be monthly because the meter infrastructure is not adequate to permit hourly pricing. Monthly market pricing is another step in the progression of Alberta markets towards a fully market based outcome. Policy makers need to determine whether the benefits of more sophisticated meters outweigh the costs. Better meters would permit hourly pricing based on the actual real time wholesale market price. Hourly pricing would permit customers to react to prices in real time and individually benefit from that reaction or pay for that reaction. Such demand elasticity would also be the appropriate counter to any ability of generators to exercise market power in real time. While hourly real time pricing is the appropriate goal for the pricing of default service, the relative costs and benefits should determine the speed with which it is implemented. If utilities are replacing old meters, the incremental costs of smart meters are less than if utilities would have to replace meters with remaining life. In addition, smaller scale pilot programs could be implemented to learn practical lessons prior to a larger scale investment in new meters.

The retail market should, like the wholesale market, be monitored to provide current information to policy makers, to ensure that the goals of retail competition are being met and to permit changes in policy as required.

The objectives addressed by this report are the design of a default rate for Alberta that:

- Minimizes volatility.
    - While volatility could be minimized by providing a flat rate to retail customers, the welfare of retail customers and market efficiency will both be enhanced by focusing on providing prices to retail customers that are based directly on the wholesale power market price and permitting customers to choose their preferred tradeoff between volatility and price.
- Promotes fairness to all customers.
    - It is fair that all customers should have the same access to the actual wholesale power price and that all customers should be able to choose among retail suppliers and a variety of tradeoffs between the level of prices and volatility.
- Is simple to understand.
    - The concept of the wholesale market price is easy to understand.
- Is transparent.
    - The wholesale market price concept is extremely transparent. In order to facilitate customer understanding, a requirement to post real time hourly prices on the wholesale market web page, other web pages and other media should be considered.
- Encourages retail market competition.
    - Use of the actual wholesale market price as the default price for retail customers is the option most consistent with encouraging retail competition. With the actual market price as the default, retail suppliers can compete to provide alternate tradeoffs between volatility and price to customers.

- Ensures that customers pay the full cost of electricity.

    - Use of the actual wholesale market price as the default ensures that customers pay the full cost of electricity, and no more and no less.

- Minimizes the delivered price.

    - Use of the actual wholesale market price as the default will minimize the delivered price because it minimizes transactions costs and risks for retail suppliers. Retail suppliers are not required to take risk associated with differences between anticipated and actual customer usage. The result is a reduced risk premium and reduced credit costs.

- Is easy to implement.

    - Use of the actual wholesale market price as the default for retail customers is the easiest option to implement as this option is conceptually simple and therefore minimizes the regulatory costs of implementation.

Table 1: Average Monthly Prices

	Pool Price ($/kWh)	Last Forward Price ($/kWh)	Spot Power Residential Floating Rate ($/kWh)	EPCOR Residential RRO Rate ($/kWh)
2008	0.0899	0.0839	-	0.1021
2009	0.0478	0.0572	-	0.0791
2010	0.0508	0.0524	0.0602	0.0659
2011	0.0766	0.0795	0.0994	0.0956
2012	0.0643	0.0711	0.0858	0.0966
2013	0.0799	0.0725	0.0980	0.0861
2014	0.0496	0.0626	0.0662	0.0764
2015	0.0334	0.0442	0.0479	0.0559
2016	0.0182	0.0266	0.0294	0.0425

Table 3: Average Monthly Standard Deviation

	Pool Price ($/kWh)	Last Forward Price ($/kWh)	Spot Power Residential Floating Rate ($/kWh)	EPCOR Residential RRO Rate ($/kWh)
2008	0.0182	0.0128	-	0.0105
2009	0.0180	0.0145	-	0.0148
2010	0.0269	0.0108	0.0126	0.0103
2011	0.0293	0.0220	0.0354	0.0239
2012	0.0232	0.0167	0.0286	0.0260
2013	0.0357	0.0159	0.0429	0.0143
2014	0.0286	0.0156	0.0345	0.0083
2015	0.0215	0.0169	0.0278	0.0084
2016	0.0036	0.0041	0.0039	0.0060

Table 2: Average Monthly Price Differentials

	Forward less Pool ($/kWh)	EPCOR less Forward ($/kWh)	EPCOR less Pool ($/kWh)	Spot Power less Pool ($/kWh)
2008	-0.0060	0.0182	0.0122	-
2009	0.0094	0.0219	0.0313	-
2010	0.0016	0.0136	0.0152	0.0094
2011	0.0029	0.0161	0.0189	0.0227
2012	0.0069	0.0254	0.0323	0.0215
2013	-0.0074	0.0136	0.0062	0.0181
2014	0.0130	0.0137	0.0267	0.0166
2015	0.0108	0.0117	0.0225	0.0145
2016	0.0084	0.0159	0.0243	0.0111

Table 4: Interest Cost Impact of 6.8 Cent Price Cap for 1 kWh of Energy

	Pool vs Price Cap	Forward vs Price Cap	Spot Power vs Price Cap	EPCOR vs Price Cap
2008	-0.0019	-0.0013	-	-0.0029
2009	-0.0002	-0.0002	-	-0.0010
2010	-0.0005	0.0000	-0.0002	-0.0003
2011	-0.0014	-0.0013	-0.0028	-0.0024
2012	-0.0007	-0.0007	-0.0018	-0.0024
2013	-0.0019	-0.0008	-0.0029	-0.0015
2014	-0.0006	-0.0003	-0.0010	-0.0008
2015	-0.0002	-0.0002	-0.0005	0.0000
2016	0.0000	0.0000	0.0000	0.0000

Notes: Negative numbers indicate charges to consumers
Positive numbers indicate credits to consumers

Table 5: Interest Cost Impact of 6.8 Cent Fixed Price for 1 kWh of Energy

	Pool vs Fixed Price	Forward vs Fixed Price	Spot Power vs Fixed Price	EPCOR vs Fixed Price
2008	-0.0018	-0.0013	0.0000	-0.0029
2009	0.0017	0.0009	0.0000	-0.0009
2010	0.0015	0.0013	0.0007	0.0002
2011	-0.0007	-0.0010	-0.0026	-0.0023
2012	0.0003	-0.0003	-0.0015	-0.0024
2013	-0.0010	-0.0004	-0.0025	-0.0015
2014	0.0015	0.0004	0.0001	-0.0007
2015	0.0029	0.0020	0.0017	0.0010
2016	0.0042	0.0035	0.0033	0.0021

Notes: Negative numbers indicate charges to consumers
Positive numbers indicate credits to consumers

Regulated Rate Option Review
Submission to the Alberta Market Surveillance Administrator
Robert F. Spragins
19-May-17

Table:

Assumptions

	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				Price Differentials				Price Cap Analysis: Pool Price vs Price Cap		Forward Price vs Price Cap		Spot vs Price Cap		EPCOR vs Price Cap		Fixed Price Analysis: Pool Price vs Fixed Price		Forward Price vs Fixed Price		Spot vs Price Cap		EPCOR vs Fixed Price	
Year-Month	Monthly Average Pool Price[2] ($/kWh)	Last Forward Price[2] ($/kWh)	Spot Power Residential Floating Rate[3] ($/kWh)	EPCOR Residential RRO Rate[4] ($/kWh)	Forward less Pool ($/kWh)	EPCOR less Forward ($/kWh)	EPCOR less Pool ($/kWh)	Spot Power less Pool ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)
2008-Jan	0.0803	0.0700	-	0.0929	-0.0103	0.0229	0.0126	-	0.0680	-0.0123	0.0680	-0.0020	-	-	0.0680	-0.0249	-0.0123	-0.0123	-0.0020	-0.0020	-	-	-0.0249	-0.0249
2008-Feb	0.0649	0.0700	-	0.0894	0.0051	0.0194	0.0246	-	0.0649	0.0000	0.0680	-0.0020	-	-	0.0680	-0.0214	0.0031	-0.0092	-0.0020	-0.0040	-	-	-0.0214	-0.0464
2008-Mar	0.0849	0.0670	-	0.0878	-0.0179	0.0208	0.0029	-	0.0680	-0.0169	0.0670	0.0000	-	-	0.0680	-0.0198	-0.0169	-0.0261	0.0010	-0.0030	-	-	-0.0198	-0.0661
2008-Apr	0.1360	0.0935	-	0.0971	-0.0425	0.0036	-0.0388	-	0.0680	-0.0680	0.0680	-0.0255	-	-	0.0680	-0.0291	-0.0680	-0.0940	-0.0255	-0.0285	-	-	-0.0291	-0.0953
2008-May	0.1037	0.0950	-	0.0988	-0.0087	0.0038	-0.0050	-	0.0680	-0.0357	0.0680	-0.0270	-	-	0.0680	-0.0308	-0.0357	-0.1298	-0.0270	-0.0555	-	-	-0.0308	-0.1260
2008-Jun	0.0830	0.0910	-	0.0968	0.0080	0.0058	0.0137	-	0.0680	-0.0150	0.0680	-0.0230	-	-	0.0680	-0.0288	-0.0150	-0.1448	-0.0230	-0.0785	-	-	-0.0288	-0.1548
2008-Jul	0.0645	0.1105	-	0.1192	0.0460	0.0087	0.0547	-	0.0645	0.0000	0.0680	-0.0425	-	-	0.0680	-0.0512	0.0035	-0.1413	-0.0425	-0.1210	-	-	-0.0512	-0.2060
2008-Aug	0.0827	0.0913	-	0.1165	0.0085	0.0252	0.0338	-	0.0680	-0.0147	0.0680	-0.0233	-	-	0.0680	-0.0485	-0.0147	-0.1560	-0.0233	-0.1443	-	-	-0.0485	-0.2544
2008-Sep	0.0939	0.0718	-	0.0998	-0.0221	0.0280	0.0059	-	0.0680	-0.0259	0.0680	-0.0037	-	-	0.0680	-0.0318	-0.0259	-0.1818	-0.0037	-0.1480	-	-	-0.0318	-0.2862
2008-Oct	0.1005	0.0750	-	0.1011	-0.0255	0.0261	0.0006	-	0.0680	-0.0325	0.0680	-0.0070	-	-	0.0680	-0.0331	-0.0325	-0.2144	-0.0070	-0.1550	-	-	-0.0331	-0.3193
2008-Nov	0.0967	0.0815	-	0.1073	-0.0152	0.0258	0.0106	-	0.0680	-0.0287	0.0680	-0.0135	-	-	0.0680	-0.0393	-0.0287	-0.2430	-0.0135	-0.1685	-	-	-0.0393	-0.3585
2008-Dec	0.0884	0.0905	-	0.1188	0.0021	0.0283	0.0305	-	0.0680	-0.0204	0.0680	-0.0225	-	-	0.0680	-0.0508	-0.0204	-0.2634	-0.0225	-0.1910	-	-	-0.0508	-0.4093
2009-Jan	0.0930	0.0843	-	0.0995	-0.0087	0.0153	0.0066	-	0.0680	-0.0250	0.0680	-0.0163	-	-	0.0680	-0.0315	-0.0250	-0.2883	-0.0163	-0.2073	-	-	-0.0315	-0.4409
2009-Feb	0.0528	0.0840	-	0.1095	0.0312	0.0255	0.0567	-	0.0528	0.0000	0.0680	-0.0160	-	-	0.0680	-0.0415	0.0152	-0.2732	-0.0160	-0.2233	-	-	-0.0415	-0.4824
2009-Mar	0.0432	0.0605	-	0.0904	0.0173	0.0299	0.0472	-	0.0432	0.0000	0.0605	0.0000	-	-	0.0680	-0.0224	0.0248	-0.2484	0.0075	-0.2158	-	-	-0.0224	-0.5048
2009-Apr	0.0315	0.0478	-	0.0721	0.0162	0.0244	0.0406	-	0.0315	0.0000	0.0478	0.0000	-	-	0.0680	-0.0041	0.0365	-0.2119	0.0203	-0.1955	-	-	-0.0041	-0.5089
2009-May	0.0319	0.0463	-	0.0738	0.0143	0.0276	0.0419	-	0.0319	0.0000	0.0463	0.0000	-	-	0.0680	-0.0058	0.0361	-0.1758	0.0218	-0.1738	-	-	-0.0058	-0.5147
2009-Jun	0.0335	0.0483	-	0.0682	0.0148	0.0200	0.0347	-	0.0335	0.0000	0.0483	0.0000	-	-	0.0680	-0.0002	0.0345	-0.1413	0.0198	-0.1540	-	-	-0.0002	-0.5149
2009-Jul	0.0414	0.0635	-	0.0848	0.0221	0.0213	0.0434	-	0.0414	0.0000	0.0635	0.0000	-	-	0.0680	-0.0168	0.0266	-0.1147	0.0045	-0.1495	-	-	-0.0168	-0.5317
2009-Aug	0.0346	0.0598	-	0.0835	0.0251	0.0238	0.0489	-	0.0346	0.0000	0.0598	0.0000	-	-	0.0680	-0.0155	0.0334	-0.0813	0.0083	-0.1413	-	-	-0.0155	-0.5472
2009-Sep	0.0732	0.0395	-	0.0679	-0.0337	0.0284	-0.0054	-	0.0680	-0.0052	0.0395	0.0000	-	-	0.0679	0.0000	-0.0052	-0.0866	0.0285	-0.1128	-	-	0.0001	-0.5470
2009-Oct	0.0349	0.0373	-	0.0538	0.0023	0.0165	0.0188	-	0.0349	0.0000	0.0373	0.0000	-	-	0.0538	0.0000	0.0331	-0.0535	0.0308	-0.0820	-	-	0.0142	-0.5328
2009-Nov	0.0502	0.0563	-	0.0679	0.0061	0.0116	0.0177	-	0.0502	0.0000	0.0563	0.0000	-	-	0.0679	0.0000	0.0178	-0.0356	0.0118	-0.0703	-	-	0.0001	-0.5327
2009-Dec	0.0539	0.0595	-	0.0778	0.0056	0.0183	0.0240	-	0.0539	0.0000	0.0595	0.0000	-	-	0.0680	-0.0098	0.0141	-0.0215	0.0085	-0.0618	-	-	-0.0098	-0.5425
2010-Jan	0.0434	0.0480	0.0572	0.0658	0.0046	0.0178	0.0223	0.0138	0.0434	0.0000	0.0480	0.0000	0.0572	0.0000	0.0658	0.0000	0.0246	0.0031	0.0200	-0.0418	0.0108	0.0108	0.0022	-0.5403
2010-Feb	0.0439	0.0463	0.0572	0.0626	0.0024	0.0164	0.0187	0.0133	0.0439	0.0000	0.0463	0.0000	0.0572	0.0000	0.0626	0.0000	0.0241	0.0272	0.0218	-0.0200	0.0108	0.0108	0.0054	-0.5349
2010-Mar	0.0353	0.0433	0.0488	0.0569	0.0079	0.0137	0.0216	0.0135	0.0353	0.0000	0.0433	0.0000	0.0488	0.0000	0.0569	0.0000	0.0327	0.0599	0.0248	0.0048	0.0192	0.0192	0.0111	-0.5238
2010-Apr	0.0497	0.0385	0.0646	0.0547	-0.0112	0.0162	0.0050	0.0149	0.0497	0.0000	0.0385	0.0000	0.0646	0.0000	0.0547	0.0000	0.0183	0.0782	0.0295	0.0343	0.0034	0.0034	0.0133	-0.5105
2010-May	0.1347	0.0575	0.0800	0.0634	-0.0772	0.0059	-0.0713	-0.0547	0.0680	-0.0667	0.0575	0.0000	0.0680	-0.0120	0.0634	0.0000	-0.0667	0.0115	0.0105	0.0448	-0.0120	-0.0120	0.0046	-0.5059
2010-Jun	0.0573	0.0740	0.0760	0.0737	0.0167	-0.0003	0.0164	0.0187	0.0573	0.0000	0.0680	-0.0060	0.0680	-0.0080	0.0680	-0.0057	0.0107	0.0222	-0.0060	0.0388	-0.0080	-0.0080	-0.0057	-0.5116
2010-Jul	0.0400	0.0660	0.0555	0.0872	0.0260	0.0212	0.0472	0.0155	0.0400	0.0000	0.0660	0.0000	0.0555	0.0000	0.0680	-0.0192	0.0280	0.0502	0.0020	0.0408	0.0125	0.0125	-0.0192	-0.5308
2010-Aug	0.0386	0.0633	0.0532	0.0830	0.0246	0.0198	0.0444	0.0146	0.0386	0.0000	0.0633	0.0000	0.0532	0.0000	0.0680	-0.0150	0.0294	0.0795	0.0048	0.0455	0.0148	0.0148	-0.0150	-0.5458
2010-Sep	0.0284	0.0485	0.0412	0.0669	0.0201	0.0184	0.0384	0.0128	0.0284	0.0000	0.0485	0.0000	0.0412	0.0000	0.0669	0.0000	0.0396	0.1191	0.0195	0.0650	0.0268	0.0268	0.0011	-0.5447
2010-Oct	0.0309	0.0420	0.0436	0.0542	0.0111	0.0122	0.0233	0.0127	0.0309	0.0000	0.0420	0.0000	0.0436	0.0000	0.0542	0.0000	0.0371	0.1562	0.0260	0.0910	0.0244	0.0244	0.0138	-0.5308
2010-Nov	0.0481	0.0425	0.0659	0.0557	-0.0056	0.0132	0.0076	0.0178	0.0481	0.0000	0.0425	0.0000	0.0659	0.0000	0.0557	0.0000	0.0199	0.1761	0.0255	0.1165	0.0021	0.0021	0.0124	-0.5185
2010-Dec	0.0589	0.0585	0.0787	0.0673	-0.0004	0.0088	0.0084	0.0198	0.0589	0.0000	0.0585	0.0000	0.0680	-0.0107	0.0673	0.0000	0.0091	0.1852	0.0095	0.1260	-0.0107	-0.0107	0.0007	-0.5178
2011-Jan	0.0790	0.0750	0.1007	0.0758	-0.0040	-0.0008	-0.0032	0.0217	0.0680	-0.0110	0.0680	-0.0070	0.0680	-0.0327	0.0680	-0.0078	-0.0110	0.1742	-0.0070	0.1190	-0.0327	-0.0327	-0.0078	-0.5256
2011-Feb	0.1224	0.0780	0.1497	0.0898	-0.0444	0.0118	-0.0327	0.0273	0.0680	-0.0544	0.0680	-0.0100	0.0680	-0.0817	0.0680	-0.0218	-0.0544	0.1197	-0.0100	0.1090	-0.0817	-0.0817	-0.0218	-0.5474
2011-Mar	0.0485	0.0640	0.0632	0.0709	0.0155	0.0069	0.0224	0.0147	0.0485	0.0000	0.0640	0.0000	0.0632	0.0000	0.0680	-0.0029	0.0195	0.1392	0.0040	0.1130	0.0048	0.0048	-0.0029	-0.5503
2011-Apr	0.0522	0.0830	0.0680	0.1176	0.0308	0.0346	0.0654	0.0158	0.0522	0.0000	0.0680	-0.0150	0.0680	0.0000	0.0680	-0.0496	0.0158	0.1550	-0.0150	0.0980	0.0000	0.0000	-0.0496	-0.5999
2011-May	0.0323	0.0415	0.0468	0.0630	0.0092	0.0215	0.0307	0.0145	0.0323	0.0000	0.0415	0.0000	0.0468	0.0000	0.0630	0.0000	0.0357	0.1907	0.0265	0.1245	0.0212	0.0212	0.0050	-0.5949
2011-Jun	0.0718	0.0532	0.0957	0.0692	-0.0187	0.0161	-0.0026	0.0239	0.0680	-0.0038	0.0532	0.0000	0.0680	-0.0277	0.0680	-0.0012	-0.0038	0.1868	0.0149	0.1393	-0.0277	-0.0277	-0.0012	-0.5961
2011-Jul	0.0612	0.0950	0.0821	0.0999	0.0338	0.0049	0.0387	0.0209	0.0612	0.0000	0.0680	-0.0270	0.0680	-0.0141	0.0680	-0.0319	0.0068	0.1936	-0.0270	0.1123	-0.0141	-0.0141	-0.0319	-0.6280
2011-Aug	0.1264	0.0870	0.1611	0.1295	-0.0394	0.0425	0.0032	0.0347	0.0680	-0.0584	0.0680	-0.0190	0.0680	-0.0931	0.0680	-0.0615	-0.0584	0.1353	-0.0190	0.0933	-0.0931	-0.0931	-0.0615	-0.6896
2011-Sep	0.0966	0.0805	0.1225	0.0826	-0.0161	0.0021	-0.0140	0.0259	0.0680	-0.0286	0.0680	-0.0125	0.0680	-0.0545	0.0680	-0.0146	-0.0286	0.1067	-0.0125	0.0808	-0.0545	-0.0545	-0.0146	-0.7041
2011-Oct	0.0698	0.0840	0.0898	0.1243	0.0142	0.0403	0.0545	0.0200	0.0680	-0.0018	0.0680	-0.0160	0.0680	-0.0218	0.0680	-0.0563	-0.0018	0.1050	-0.0160	0.0648	-0.0218	-0.0218	-0.0563	-0.7604
2011-Nov	0.1082	0.0780	0.1424	0.0912	-0.0302	0.0132	-0.0170	0.0342	0.0680	-0.0402	0.0680	-0.0100	0.0680	-0.0744	0.0680	-0.0232	-0.0402	0.0647	-0.0100	0.0548	-0.0744	-0.0744	-0.0232	-0.7836
2011-Dec	0.0513	0.1350	0.0706	0.1330	0.0837	-0.0020	0.0818	0.0193	0.0513	0.0000	0.0680	-0.0670	0.0680	-0.0026	0.0680	-0.0650	0.0167	0.0814	-0.0670	-0.0122	-0.0026	-0.0026	-0.0650	-0.8486
2012-Jan	0.0845	0.1080	0.1042	0.1511	0.0235	0.0431	0.0666	0.0197	0.0680	-0.0165	0.0680	-0.0400	0.0680	-0.0362	0.0680	-0.0831	-0.0165	0.0649	-0.0400	-0.0522	-0.0362	-0.0362	-0.0831	-0.9317
2012-Feb	0.0437	0.0870	0.0579	0.1395	0.0433	0.0525	0.0959	0.0142	0.0437	0.0000	0.0680	-0.0190	0.0579	0.0000	0.0680	-0.0715	0.0243	0.0892	-0.0190	-0.0712	0.0101	0.0101	-0.0715	-1.0033
2012-Mar	0.0511	0.0640	0.0673	0.0798	0.0129	0.0158	0.0287	0.0162	0.0511	0.0000	0.0640	0.0000	0.0673	0.0000	0.0680	-0.0118	0.0169	0.1062	0.0040	-0.0672	0.0007	0.0007	-0.0118	-1.0151
2012-Apr	0.0417	0.0560	0.0579	0.0730	0.0143	0.0170	0.0313	0.0162	0.0417	0.0000	0.0560	0.0000	0.0579	0.0000	0.0680	-0.0050	0.0263	0.1325	0.0120	-0.0552	0.0101	0.0101	-0.0050	-1.0201
2012-May	0.0295	0.0455	0.0439	0.0636	0.0160	0.0181	0.0341	0.0144	0.0295	0.0000	0.0455	0.0000	0.0439	0.0000	0.0636	0.0000	0.0385	0.1710	0.0225	-0.0327	0.0241	0.0241	0.0044	-1.0156
2012-Jun	0.0493	0.0580	0.0693	0.0784	0.0087	0.0204	0.0291	0.0200	0.0493	0.0000	0.0580	0.0000	0.0680	-0.0013	0.0680	-0.0104	0.0187	0.1897	0.0100	-0.0227	-0.0013	-0.0013	-0.0104	-1.0261
2012-Jul	0.0684	0.0725	0.0918	0.0903	0.0041	0.0178	0.0219	0.0234	0.0680	-0.0004	0.0680	-0.0045	0.0680	-0.0238	0.0680	-0.0223	-0.0004	0.1893	-0.0045	-0.0272	-0.0238	-0.0238	-0.0223	-1.0484
2012-Aug	0.0565	0.0900	0.0788	0.1155	0.0335	0.0255	0.0589	0.0223	0.0565	0.0000	0.0680	-0.0220	0.0680	-0.0108	0.0680	-0.0475	0.0115	0.2008	-0.0220	-0.0492	-0.0108	-0.0108	-0.0475	-1.0958
2012-Sep	0.1104	0.0745	0.1430	0.1036	-0.0359	0.0291	-0.0068	0.0326	0.0680	-0.0424	0.0680	-0.0065	0.0680	-0.0750	0.0680	-0.0356	-0.0424	0.1584	-0.0065	-0.0557	-0.0750	-0.0750	-0.0356	-1.1314
2012-Oct	0.0914	0.0565	0.1191	0.1029	-0.0349	0.0464	0.0115	0.0277	0.0680	-0.0234	0.0565	0.0000	0.0680	-0.0511	0.0680	-0.0349	-0.0234	0.1350	0.0115	-0.0442	-0.0511	-0.0511	-0.0349	-1.1663
2012-Nov	0.0874	0.0760	0.1178	0.0757	-0.0114	-0.0003	-0.0117	0.0304	0.0680	-0.0194	0.0680	-0.0080	0.0680	-0.0498	0.0680	-0.0077	-0.0194	0.1156	-0.0080	-0.0522	-0.0498	-0.0498	-0.0077	-1.1740
2012-Dec	0.0576	0.0658	0.0790	0.0856	0.0081	0.0199	0.0280	0.0214	0.0576	0.0000	0.0658	0.0000	0.0680	-0.0110	0.0680	-0.0176	0.0104	0.1260	0.0023	-0.0499	-0.0110	-0.0110	-0.0176	-1.1916
2013-Jan	0.0580	0.0690	0.0765	0.0888	0.0110	0.0198	0.0307	0.0185	0.0580	0.0000	0.0680	-0.0010	0.0680	-0.0085	0.0680	-0.0208	0.0100	0.1360	-0.0010	-0.0509	-0.0085	-0.0085	-0.0208	-1.2123
2013-Feb	0.0287	0.0543	0.0420	0.0752	0.0255	0.0210	0.0465	0.0133	0.0287	0.0000	0.0543	0.0000	0.0420	0.0000	0.0680	-0.0072	0.0393	0.1753	0.0138	-0.0372	0.0260	0.0260	-0.0072	-1.2196
2013-Mar	0.1056	0.0540	0.1673	0.0729	-0.0516	0.0189	-0.0327	0.0617	0.0680	-0.0376	0.0540	0.0000	0.0680	-0.0993	0.0680	-0.0049	-0.0376	0.1376	0.0140	-0.0232	-0.0993	-0.0993	-0.0049	-1.2245
2013-Apr	0.1377	0.0765	0.1625	0.0821	-0.0612	0.0056	-0.0556	0.0248	0.0680	-0.0697	0.0680	-0.0085	0.0680	-0.0945	0.0680	-0.0141	-0.0697	0.0680	-0.0085	-0.0317	-0.0945	-0.0945	-0.0141	-1.2385
2013-May	0.1277	0.0950	0.1397	0.0710	-0.0327	-0.0240	-0.0567	0.0120	0.0680	-0.0597	0.0680	-0.0270	0.0680	-0.0717	0.0680	-0.0030	-0.0597	0.0083	-0.0270	-0.0587	-0.0717	-0.0717	-0.0030	-1.2415
2013-Jun	0.1048	0.0835	0.0744	0.0707	-0.0213	-0.0128	-0.0340	-0.0304	0.0680	-0.0368	0.0680	-0.0155	0.0680	-0.0064	0.0680	-0.0027	-0.0368	-0.0285	-0.0155	-0.0742	-0.0064	-0.0064	-0.0027	-1.2443
2013-Jul	0.0561	0.0950	0.1103	0.1076	0.0389	0.0126	0.0515	0.0542	0.0561	0.0000	0.0680	-0.0270	0.0680	-0.0423	0.0680	-0.0396	0.0119	-0.0166	-0.0270	-0.1012	-0.0423	-0.0423	-0.0396	-1.2839
2013-Aug	0.0836	0.0750	0.1418	0.1141	-0.0086	0.0391	0.0304	0.0582	0.0680	-0.0156	0.0680	-0.0070	0.0680	-0.0738	0.0680	-0.0461	-0.0156	-0.0322	-0.0070	-0.1082	-0.0738	-0.0738	-0.0461	-1.3299
2013-Sep	0.1120	0.0953	0.0848	0.1052	-0.0167	0.0100	-0.0068	-0.0272	0.0680	-0.0440	0.0680	-0.0273	0.0680	-0.0168	0.0680	-0.0372	-0.0440	-0.0762	-0.0273	-0.1354	-0.0168	-0.0168	-0.0372	-1.3671
2013-Oct	0.0646	0.0550	0.0427	0.0823	-0.0096	0.0273	0.0178	-0.0219	0.0646	0.0000	0.0550	0.0000	0.0427	0.0000	0.0680	-0.0143	0.0034	-0.0728	0.0130	-0.1224	0.0253	0.0253	-0.0143	-1.3815
2013-Nov	0.0283	0.0570	0.0728	0.0824	0.0287	0.0254	0.0541	0.0445	0.0283	0.0000	0.0570	0.0000	0.0680	-0.0048	0.0680	-0.0144	0.0397	-0.0331	0.0110	-0.1114	-0.0048	-0.0048	-0.0144	-1.3959
2013-Dec	0.0523	0.0605	0.0615	0.0815	0.0082	0.0210	0.0292	0.0092	0.0523	0.0000	0.0605	0.0000	0.0615	0.0000	0.0680	-0.0135	0.0157	-0.0174	0.0075	-0.1039	0.0065	0.0065	-0.0135	-1.4094
2014-Jan	0.0452	0.0660	0.1173	0.0869	0.0208	0.0209	0.0417	0.0721	0.0452	0.0000	0.0660	0.0000	0.0680	-0.0493	0.0680	-0.0189	0.0228	0.0054	0.0020	-0.1019	-0.0493	-0.0493	-0.0189	-1.4282
2014-Feb	0.0963	0.0730	0.0590	0.0747	-0.0233	0.0017	-0.0216	-0.0373	0.0680	-0.0283	0.0680	-0.0050	0.0590	0.0000	0.0680	-0.0067	-0.0283	-0.0229	-0.0050	-0.1069	0.0090	0.0090	-0.0067	-1.4350
2014-Mar	0.0437	0.0710	0.0444	0.0699	0.0273	-0.0011	0.0262	0.0007	0.0437	0.0000	0.0680	-0.0030	0.0444	0.0000	0.0680	-0.0019	0.0243	0.0014	-0.0030	-0.1099	0.0236	0.0236	-0.0019	-1.4369
2014-Apr	0.0307	0.0405	0.0733	0.0699	0.0098	0.0294	0.0392	0.0426	0.0307	0.0000	0.0405	0.0000	0.0680	-0.0053	0.0680	-0.0019	0.0373	0.0387	0.0275	-0.0824	-0.0053	-0.0053	-0.0019	-1.4387
2014-May	0.0540	0.0970	0.0591	0.0892	0.0430	-0.0078	0.0352	0.0051	0.0540	0.0000	0.0680	-0.0290	0.0591	0.0000	0.0680	-0.0212	0.0140	0.0527	-0.0290	-0.1114	0.0089	0.0089	-0.0212	-1.4599
2014-Jun	0.0422	0.0400	0.1580	0.0600	-0.0022	0.0200	0.0178	0.1158	0.0422	0.0000	0.0400	0.0000	0.0680	-0.0900	0.0600	0.0000	0.0258	0.0785	0.0280	-0.0834	-0.0900	-0.0900	0.0081	-1.4519
2014-Jul	0.1225	0.0620	0.0624	0.0720	-0.0605	0.0100	-0.0506	-0.0601	0.0680	-0.0545	0.0620	0.0000	0.0624	0.0000	0.0680	-0.0040	-0.0545	0.0240	0.0060	-0.0774	0.0056	0.0056	-0.0040	-1.4559
2014-Aug	0.0452	0.0730	0.0371	0.0802	0.0278	0.0072	0.0350	-0.0081	0.0452	0.0000	0.0680	-0.0050	0.0371	0.0000	0.0680	-0.0122	0.0228	0.0468	-0.0050	-0.0824	0.0309	0.0309	-0.0122	-1.4681
2014-Sep	0.0240	0.0600	0.0401	0.0795	0.0360	0.0195	0.0556	0.0161	0.0240	0.0000	0.0600	0.0000	0.0401	0.0000	0.0680	-0.0115	0.0440	0.0908	0.0080	-0.0744	0.0279	0.0279	-0.0115	-1.4796
2014-Oct	0.0270	0.0700	0.0535	0.0874	0.0430	0.0174	0.0603	0.0265	0.0270	0.0000	0.0680	-0.0020	0.0535	0.0000	0.0680	-0.0194	0.0410	0.1317	-0.0020	-0.0764	0.0145	0.0145	-0.0194	-1.4990
2014-Nov	0.0377	0.0443	0.0403	0.0713	0.0066	0.0270	0.0336	0.0026	0.0377	0.0000	0.0443	0.0000	0.0403	0.0000	0.0680	-0.0033	0.0303	0.1620	0.0238	-0.0527	0.0277	0.0277	-0.0033	-1.5023
2014-Dec	0.0269	0.0550	0.0497	0.0755	0.0281	0.0205	0.0485	0.0228	0.0269	0.0000	0.0550	0.0000	0.0497	0.0000	0.0680	-0.0075	0.0411	0.2031	0.0130	-0.0397	0.0183	0.0183	-0.0075	-1.5097
2015-Jan	0.0339	0.0550	0.0481	0.0730	0.0211	0.0180	0.0391	0.0142	0.0339	0.0000	0.0550	0.0000	0.0481	0.0000	0.0680	-0.0050	0.0341	0.2372	0.0130	-0.0267	0.0199	0.0199	-0.0050	-1.5147
2015-Feb	0.0328	0.0465	0.0328	0.0658	0.0137	0.0193	0.0330	0.0000	0.0328	0.0000	0.0465	0.0000	0.0328	0.0000	0.0658	0.0000	0.0352	0.2724	0.0215	-0.0052	0.0352	0.0352	0.0022	-1.5126
2015-Mar	0.0207	0.0330	0.0328	0.0543	0.0123	0.0213	0.0337	0.0121	0.0207	0.0000	0.0330	0.0000	0.0328	0.0000	0.0543	0.0000	0.0473	0.3197	0.0350	0.0298	0.0352	0.0352	0.0137	-1.4989
2015-Apr	0.0205	0.0438	0.0743	0.0583	0.0232	0.0146	0.0378	0.0538	0.0205	0.0000	0.0438	0.0000	0.0680	-0.0063	0.0583	0.0000	0.0475	0.3672	0.0243	0.0541	-0.0063	-0.0063	0.0097	-1.4892
2015-May	0.0539	0.0283	0.1315	0.0434	-0.0257	0.0151	-0.0106	0.0776	0.0539	0.0000	0.0283	0.0000	0.0680	-0.0635	0.0434	0.0000	0.0141	0.3813	0.0398	0.0938	-0.0635	-0.0635	0.0246	-1.4646
2015-Jun	0.0973	0.0480	0.0368	0.0409	-0.0493	-0.0071	-0.0564	-0.0605	0.0680	-0.0293	0.0480	0.0000	0.0368	0.0000	0.0409	0.0000	-0.0293	0.3519	0.0200	0.1138	0.0312	0.0312	0.0271	-1.4375
2015-Jul	0.0231	0.0940	0.0493	0.0614	0.0709	-0.0326	0.0383	0.0262	0.0231	0.0000	0.0680	-0.0260	0.0493	0.0000	0.0614	0.0000	0.0449	0.3968	-0.0260	0.0878	0.0187	0.0187	0.0066	-1.4309
2015-Aug	0.0341	0.0463	0.0331	0.0581	0.0121	0.0119	0.0240	-0.0010	0.0341	0.0000	0.0463	0.0000	0.0331	0.0000	0.0581	0.0000	0.0339	0.4307	0.0218	0.1096	0.0349	0.0349	0.0099	-1.4210
2015-Sep	0.0209	0.0345	0.0340	0.0539	0.0136	0.0194	0.0330	0.0131	0.0209	0.0000	0.0345	0.0000	0.0340	0.0000	0.0539	0.0000	0.0471	0.4778	0.0335	0.1431	0.0340	0.0340	0.0141	-1.4069
2015-Oct	0.0215	0.0340	0.0339	0.0550	0.0125	0.0210	0.0335	0.0124	0.0215	0.0000	0.0340	0.0000	0.0339	0.0000	0.0550	0.0000	0.0465	0.5244	0.0340	0.1771	0.0341	0.0341	0.0130	-1.3938
2015-Nov	0.0212	0.0340	0.0333	0.0521	0.0128	0.0181	0.0310	0.0121	0.0212	0.0000	0.0340	0.0000	0.0333	0.0000	0.0521	0.0000	0.0468	0.5712	0.0340	0.2111	0.0347	0.0347	0.0159	-1.3780
2015-Dec	0.0209	0.0330	0.0344	0.0549	0.0121	0.0219	0.0340	0.0135	0.0209	0.0000	0.0330	0.0000	0.0344	0.0000	0.0549	0.0000	0.0471	0.6183	0.0350	0.2461	0.0336	0.0336	0.0131	-1.3648
2016-Jan	0.0223	0.0300	0.0290	0.0530	0.0077	0.0230	0.0308	0.0067	0.0223	0.0000	0.0300	0.0000	0.0290	0.0000	0.0530	0.0000	0.0457	0.6640	0.0380	0.2841	0.0390	0.0390	0.0150	-1.3499

2016-Feb	0.0172	0.0305	0.0260	0.0475	0.0133	0.0170	0.0303	0.0088	0.0172	0.0000	0.0305	0.0000	0.0260	0.0000	0.0475	0.0000	0.0508	0.7148	0.0375	0.3216	0.0420	0.0420	0.0205	-1.3294
2016-Mar	0.0148	0.0240	0.0251	0.0452	0.0092	0.0212	0.0304	0.0103	0.0148	0.0000	0.0240	0.0000	0.0251	0.0000	0.0452	0.0000	0.0532	0.7680	0.0440	0.3656	0.0429	0.0429	0.0228	-1.3066
2016-Apr	0.0136	0.0180	0.0251	0.0365	0.0044	0.0185	0.0229	0.0115	0.0136	0.0000	0.0180	0.0000	0.0251	0.0000	0.0365	0.0000	0.0544	0.8224	0.0500	0.4156	0.0429	0.0429	0.0315	-1.2751
2016-May	0.0159	0.0218	0.0276	0.0335	0.0059	0.0117	0.0176	0.0117	0.0159	0.0000	0.0218	0.0000	0.0276	0.0000	0.0335	0.0000	0.0521	0.8745	0.0463	0.4618	0.0404	0.0404	0.0345	-1.2406
2016-Jun	0.0154	0.0280	0.0273	0.0361	0.0126	0.0081	0.0207	0.0119	0.0154	0.0000	0.0280	0.0000	0.0273	0.0000	0.0361	0.0000	0.0526	0.9270	0.0400	0.5018	0.0407	0.0407	0.0319	-1.2087
2016-Jul	0.0182	0.0273	0.0302	0.0498	0.0090	0.0225	0.0315	0.0120	0.0182	0.0000	0.0273	0.0000	0.0302	0.0000	0.0498	0.0000	0.0498	0.9768	0.0408	0.5426	0.0378	0.0378	0.0183	-1.1904
2016-Aug	0.0179	0.0285	0.0302	0.0475	0.0106	0.0190	0.0296	0.0123	0.0179	0.0000	0.0285	0.0000	0.0302	0.0000	0.0475	0.0000	0.0501	1.0269	0.0395	0.5821	0.0378	0.0378	0.0205	-1.1700
2016-Sep	0.0177	0.0220	0.0295	0.0397	0.0043	0.0177	0.0220	0.0118	0.0177	0.0000	0.0220	0.0000	0.0295	0.0000	0.0397	0.0000	0.0503	1.0772	0.0460	0.6281	0.0385	0.0385	0.0283	-1.1417
2016-Oct	0.0254	0.0303	0.0378	0.0446	0.0049	0.0143	0.0192	0.0124	0.0254	0.0000	0.0303	0.0000	0.0378	0.0000	0.0446	0.0000	0.0426	1.1199	0.0378	0.6658	0.0302	0.0302	0.0234	-1.1183
2016-Nov	0.0163	0.0273	0.0280	0.0374	0.0109	0.0101	0.0210	0.0117	0.0163	0.0000	0.0273	0.0000	0.0280	0.0000	0.0374	0.0000	0.0517	1.1715	0.0408	0.7066	0.0400	0.0400	0.0306	-1.0876
2016-Dec	0.0242	0.0318	0.0367	0.0398	0.0075	0.0081	0.0156	0.0125	0.0242	0.0000	0.0318	0.0000	0.0367	0.0000	0.0398	0.0000	0.0438	1.2153	0.0363	0.7428	0.0313	0.0313	0.0282	-1.0594
Total (Credit/(Debit)										-1.0428		-0.6970		-1.3248		-1.6113	1.2153		0.7428		-0.1298		-1.0594	
Average ($/kWh)	0.0567	0.0611	0.0695	0.0778	0.0044	0.0167	0.0211	0.0163 `																
Standard Deviation (+/- $/kWh)	0.0327	0.0229	0.0382	0.0242	0.0260	0.0125	0.0290	0.0255																
Deferral Account ($) (Credit/(Debit)										-1.0428		-0.6970		-1.3248		-1.6113	1.2153		0.7428		-0.1298		-1.0594	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)										-0.0875		-0.0585		-0.1112		-0.1352	0.1020		0.0623		-0.0109		-0.0889	
Total Deferral Account Cost ($) (Credit/(Debit)										-1.0500		-0.7019		-1.3340		-1.6226	1.2238		0.7480		-0.1307		-1.0668	
Interest Cost ($) (Credit/(Debit)										-0.0073		-0.0049		-0.0092		-0.0112	0.0085		0.0052		-0.0009		-0.0074	

References:

1 Alberta Capital Finance Authority
2 Alberta Market Surveillance Administrator
3 Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4 Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

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Robert F. Spragins
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Table:

Assumptions

	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				Price Differentials			
Year-Month	**Monthly Average Pool Price[2] ($/kWh)**	**Last Forward Price[2] ($/kWh)**	**Spot Power Residential Floating Rate[3] ($/kWh)**	**EPCOR Residential RRO Rate[4] ($/kWh)**	**Forward less Pool ($/kWh)**	**EPCOR less Forward ($/kWh)**	**EPCOR less Pool ($/kWh)**	**Spot Power less Pool ($/kWh)**
2008-Jan	0.0803	0.0700	-	0.0929	-0.0103	0.0229	0.0126	-
2008-Feb	0.0649	0.0700	-	0.0894	0.0051	0.0194	0.0246	-
2008-Mar	0.0849	0.0670	-	0.0878	-0.0179	0.0208	0.0029	-
2008-Apr	0.1360	0.0935	-	0.0971	-0.0425	0.0036	-0.0388	-
2008-May	0.1037	0.0950	-	0.0988	-0.0087	0.0038	-0.0050	-
2008-Jun	0.0830	0.0910	-	0.0968	0.0080	0.0058	0.0137	-
2008-Jul	0.0645	0.1105	-	0.1192	0.0460	0.0087	0.0547	-
2008-Aug	0.0827	0.0913	-	0.1165	0.0085	0.0252	0.0338	-
2008-Sep	0.0939	0.0718	-	0.0998	-0.0221	0.0280	0.0059	-
2008-Oct	0.1005	0.0750	-	0.1011	-0.0255	0.0261	0.0006	-
2008-Nov	0.0967	0.0815	-	0.1073	-0.0152	0.0258	0.0106	-
2008-Dec	0.0884	0.0905	-	0.1188	0.0021	0.0283	0.0305	-
Total (Credit/(Debit)								
Average ($/kWh)	0.0899	0.0839	-	0.1021	-0.0060	0.0182	0.0122	-
Standard Deviation (+/- $/kWh)	0.0182	0.0128	-	0.0105	0.0214	0.0094	0.0222	-
Deferral Account ($) (Credit/(Debit)								
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)								
Total Deferral Account Cost ($) (Credit/(Debit)								
Interest Cost ($) (Credit/(Debit)								

	Price Cap Analysis							
	Pool Price vs Price Cap		Forward Price vs Price Cap		Spot vs Price Cap		EPCOR vs Price Cap	
Year-Month	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**
2008-Jan	0.0680	-0.0123	0.0680	-0.0020	-	-	0.0680	-0.0249
2008-Feb	0.0649	0.0000	0.0680	-0.0020	-	-	0.0680	-0.0214
2008-Mar	0.0680	-0.0169	0.0670	0.0000	-	-	0.0680	-0.0198
2008-Apr	0.0680	-0.0680	0.0680	-0.0255	-	-	0.0680	-0.0291
2008-May	0.0680	-0.0357	0.0680	-0.0270	-	-	0.0680	-0.0308
2008-Jun	0.0680	-0.0150	0.0680	-0.0230	-	-	0.0680	-0.0288
2008-Jul	0.0645	0.0000	0.0680	-0.0425	-	-	0.0680	-0.0512
2008-Aug	0.0680	-0.0147	0.0680	-0.0233	-	-	0.0680	-0.0485
2008-Sep	0.0680	-0.0259	0.0680	-0.0037	-	-	0.0680	-0.0318
2008-Oct	0.0680	-0.0325	0.0680	-0.0070	-	-	0.0680	-0.0331
2008-Nov	0.0680	-0.0287	0.0680	-0.0135	-	-	0.0680	-0.0393
2008-Dec	0.0680	-0.0204	0.0680	-0.0225	-	-	0.0680	-0.0508
Total (Credit/(Debit)		-0.2700		-0.1920		0.0000		-0.4093
Average ($/kWh)		-0.2718		-0.1932				-0.4118
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)		-0.2718		-0.1932		0.0000		-0.4118
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)		-0.0228		-0.0162		0.0000		-0.0346
Total Deferral Account Cost ($) (Credit/(Debit)		-0.2737		-0.1945		0.0000		-0.4147
Interest Cost ($) (Credit/(Debit)		-0.0019		-0.0013		0.0000		-0.0029

	Fixed Price Analysis							
	Pool Price vs Fixed Price		Forward Price vs Fixed Price		Spot vs Fixed Price		EPCOR vs Fixed Price	
Year-Month	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**
2008-Jan	-0.0123	-0.0123	-0.0020	-0.0020	-	-	-0.0249	-0.0249
2008-Feb	0.0031	-0.0092	-0.0020	-0.0040	-	-	-0.0214	-0.0464
2008-Mar	-0.0169	-0.0261	0.0010	-0.0030	-	-	-0.0198	-0.0661
2008-Apr	-0.0680	-0.0940	-0.0255	-0.0285	-	-	-0.0291	-0.0953
2008-May	-0.0357	-0.1298	-0.0270	-0.0555	-	-	-0.0308	-0.1260
2008-Jun	-0.0150	-0.1448	-0.0230	-0.0785	-	-	-0.0288	-0.1548
2008-Jul	0.0035	-0.1413	-0.0425	-0.1210	-	-	-0.0512	-0.2060
2008-Aug	-0.0147	-0.1560	-0.0233	-0.1443	-	-	-0.0485	-0.2544
2008-Sep	-0.0259	-0.1818	-0.0037	-0.1480	-	-	-0.0318	-0.2862
2008-Oct	-0.0325	-0.2144	-0.0070	-0.1550	-	-	-0.0331	-0.3193
2008-Nov	-0.0287	-0.2430	-0.0135	-0.1685	-	-	-0.0393	-0.3585
2008-Dec	-0.0204	-0.2634	-0.0225	-0.1910	-	-	-0.0508	-0.4093
Total (Credit/(Debit)	-0.2634		-0.1910		0.0000		-0.4093	
Average ($/kWh)	-0.2651		-0.1922				-0.4118	
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)	-0.2651		-0.1922		0.0000		-0.4118	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)	-0.0222		-0.0161		0.0000		-0.0346	
Total Deferral Account Cost ($) (Credit/(Debit)	-0.2670		-0.1935		0.0000		-0.4147	
Interest Cost ($) (Credit/(Debit)	-0.0018		-0.0013		0.0000		-0.0029	

References:

1 Alberta Capital Finance Authority
2 Alberta Market Surveillance Administrator
3 Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4 Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

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Assumptions

	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				Price Differentials			
Year-Month	**Monthly Average Pool Price[2] ($/kWh)**	**Last Forward Price[2] ($/kWh)**	**Spot Power Residential Floating Rate[3] ($/kWh)**	**EPCOR Residential RRO Rate[4] ($/kWh)**	**Forward less Pool ($/kWh)**	**EPCOR less Forward ($/kWh)**	**EPCOR less Pool ($/kWh)**	**Spot Power less Pool ($/kWh)**
2009-Jan	0.0930	0.0843	-	0.0995	-0.0087	0.0153	0.0066	-
2009-Feb	0.0528	0.0840	-	0.1095	0.0312	0.0255	0.0567	-
2009-Mar	0.0432	0.0605	-	0.0904	0.0173	0.0299	0.0472	-
2009-Apr	0.0315	0.0478	-	0.0721	0.0162	0.0244	0.0406	-
2009-May	0.0319	0.0463	-	0.0738	0.0143	0.0276	0.0419	-
2009-Jun	0.0335	0.0483	-	0.0682	0.0148	0.0200	0.0347	-
2009-Jul	0.0414	0.0635	-	0.0848	0.0221	0.0213	0.0434	-
2009-Aug	0.0346	0.0598	-	0.0835	0.0251	0.0238	0.0489	-
2009-Sep	0.0732	0.0395	-	0.0679	-0.0337	0.0284	-0.0054	-
2009-Oct	0.0349	0.0373	-	0.0538	0.0023	0.0165	0.0188	-
2009-Nov	0.0502	0.0563	-	0.0679	0.0061	0.0116	0.0177	-
2009-Dec	0.0539	0.0595	-	0.0778	0.0056	0.0183	0.0240	-
Total (Credit/(Debit)								
Average ($/kWh)	0.0478	0.0572	-	0.0791	0.0094	0.0219	0.0313	-
Standard Deviation (+/- $/kWh)	0.0180	0.0145	-	0.0148	0.0166	0.0054	0.0181	-
Deferral Account ($) (Credit/(Debit)								
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)								
Total Deferral Account Cost ($) (Credit/(Debit)								
Interest Cost ($) (Credit/(Debit)								

Price Cap Analysis

	Pool Price vs Price Cap		Forward Price vs Price Cap		Spot vs Price Cap		EPCOR vs Price Cap	
Year-Month	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**
2009-Jan	0.0680	-0.0250	0.0680	-0.0163	-	-	0.0680	-0.0315
2009-Feb	0.0528	0.0000	0.0680	-0.0160	-	-	0.0680	-0.0415
2009-Mar	0.0432	0.0000	0.0605	0.0000	-	-	0.0680	-0.0224
2009-Apr	0.0315	0.0000	0.0478	0.0000	-	-	0.0680	-0.0041
2009-May	0.0319	0.0000	0.0463	0.0000	-	-	0.0680	-0.0058
2009-Jun	0.0335	0.0000	0.0483	0.0000	-	-	0.0680	-0.0002
2009-Jul	0.0414	0.0000	0.0635	0.0000	-	-	0.0680	-0.0168
2009-Aug	0.0346	0.0000	0.0598	0.0000	-	-	0.0680	-0.0155
2009-Sep	0.0680	-0.0052	0.0395	0.0000	-	-	0.0679	0.0000
2009-Oct	0.0349	0.0000	0.0373	0.0000	-	-	0.0538	0.0000
2009-Nov	0.0502	0.0000	0.0563	0.0000	-	-	0.0679	0.0000
2009-Dec	0.0539	0.0000	0.0595	0.0000	-	-	0.0680	-0.0098
Total (Credit/(Debit)		-0.0302		-0.0323		0.0000		-0.1477
Average ($/kWh)		-0.0306		-0.0326				-0.1491
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)		-0.0306		-0.0326		0.0000		-0.1491
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)		-0.0026		-0.0027		0.0000		-0.0125
Total Deferral Account Cost ($) (Credit/(Debit)		-0.0308		-0.0329		0.0000		-0.1502
Interest Cost ($) (Credit/(Debit)		-0.0002		-0.0002		0.0000		-0.0010

Fixed Price Analysis

	Pool Price vs Fixed Price		Forward Price vs Fixed Price		Spot vs Fixed Price		EPCOR vs Fixed Price	
Year-Month	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**
2009-Jan	-0.0250	-0.0250	-0.0163	-0.0163	-	-	-0.0315	-0.0315
2009-Feb	0.0152	-0.0098	-0.0160	-0.0323	-	-	-0.0415	-0.0731
2009-Mar	0.0248	0.0150	0.0075	-0.0248	-	-	-0.0224	-0.0954
2009-Apr	0.0365	0.0515	0.0203	-0.0045	-	-	-0.0041	-0.0996
2009-May	0.0361	0.0875	0.0218	0.0173	-	-	-0.0058	-0.1054
2009-Jun	0.0345	0.1221	0.0198	0.0370	-	-	-0.0002	-0.1056
2009-Jul	0.0266	0.1487	0.0045	0.0415	-	-	-0.0168	-0.1223
2009-Aug	0.0334	0.1821	0.0083	0.0498	-	-	-0.0155	-0.1379
2009-Sep	-0.0052	0.1768	0.0285	0.0783	-	-	0.0001	-0.1377
2009-Oct	0.0331	0.2099	0.0308	0.1090	-	-	0.0142	-0.1235
2009-Nov	0.0178	0.2277	0.0118	0.1208	-	-	0.0001	-0.1234
2009-Dec	0.0141	0.2419	0.0085	0.1293	-	-	-0.0098	-0.1332
Total (Credit/(Debit)	0.2419		0.1293		0.0000		-0.1332	
Average ($/kWh)	0.2434		0.1298				-0.1346	
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)	0.2434		0.1298		0.0000		-0.1346	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)	0.0204		0.0109		0.0000		-0.0113	
Total Deferral Account Cost ($) (Credit/(Debit)	0.2451		0.1307		0.0000		-0.1355	
Interest Cost ($) (Credit/(Debit)	0.0017		0.0009		0.0000		-0.0009	

References:

1 Alberta Capital Finance Authority
2 Alberta Market Surveillance Administrator
3 Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4 Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

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Robert F. Spragins
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Table:

Assumptions

	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				Price Differentials			
Year-Month	Monthly Average Pool Price[2] ($/kWh)	Last Forward Price[2] ($/kWh)	Spot Power Residential Floating Rate[3] ($/kWh)	EPCOR Residential RRO Rate[4] ($/kWh)	Forward less Pool ($/kWh)	EPCOR less Forward ($/kWh)	EPCOR less Pool ($/kWh)	Spot Power less Pool ($/kWh)
2010-Jan	0.0434	0.0480	0.0572	0.0658	0.0046	0.0178	0.0223	0.0138
2010-Feb	0.0439	0.0463	0.0572	0.0626	0.0024	0.0164	0.0187	0.0133
2010-Mar	0.0353	0.0433	0.0488	0.0569	0.0079	0.0137	0.0216	0.0135
2010-Apr	0.0497	0.0385	0.0646	0.0547	-0.0112	0.0162	0.0050	0.0149
2010-May	0.1347	0.0575	0.0800	0.0634	-0.0772	0.0059	-0.0713	-0.0547
2010-Jun	0.0573	0.0740	0.0760	0.0737	0.0167	-0.0003	0.0164	0.0187
2010-Jul	0.0400	0.0660	0.0555	0.0872	0.0260	0.0212	0.0472	0.0155
2010-Aug	0.0386	0.0633	0.0532	0.0830	0.0246	0.0198	0.0444	0.0146
2010-Sep	0.0284	0.0485	0.0412	0.0669	0.0201	0.0184	0.0384	0.0128
2010-Oct	0.0309	0.0420	0.0436	0.0542	0.0111	0.0122	0.0233	0.0127
2010-Nov	0.0481	0.0425	0.0659	0.0557	-0.0056	0.0132	0.0076	0.0178
2010-Dec	0.0589	0.0585	0.0787	0.0673	-0.0004	0.0088	0.0084	0.0198
Total (Credit/(Debit)								
Average ($/kWh)	0.0508	0.0524	0.0602	0.0659	0.0016	0.0136	0.0152	0.0094
Standard Deviation (+/- $/kWh)	0.0269	0.0108	0.0126	0.0103	0.0262	0.0060	0.0293	0.0195

	Price Cap Analysis							
	Pool Price vs Price Cap		Forward Price vs Price Cap		Spot vs Price Cap		EPCOR vs Price Cap	
Year-Month	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)
2010-Jan	0.0434	0.0000	0.0480	0.0000	0.0572	0.0000	0.0658	0.0000
2010-Feb	0.0439	0.0000	0.0463	0.0000	0.0572	0.0000	0.0626	0.0000
2010-Mar	0.0353	0.0000	0.0433	0.0000	0.0488	0.0000	0.0569	0.0000
2010-Apr	0.0497	0.0000	0.0385	0.0000	0.0646	0.0000	0.0547	0.0000
2010-May	0.0680	-0.0667	0.0575	0.0000	0.0680	-0.0120	0.0634	0.0000
2010-Jun	0.0573	0.0000	0.0680	-0.0060	0.0680	-0.0080	0.0680	-0.0057
2010-Jul	0.0400	0.0000	0.0660	0.0000	0.0555	0.0000	0.0680	-0.0192
2010-Aug	0.0386	0.0000	0.0633	0.0000	0.0532	0.0000	0.0680	-0.0150
2010-Sep	0.0284	0.0000	0.0485	0.0000	0.0412	0.0000	0.0669	0.0000
2010-Oct	0.0309	0.0000	0.0420	0.0000	0.0436	0.0000	0.0542	0.0000
2010-Nov	0.0481	0.0000	0.0425	0.0000	0.0659	0.0000	0.0557	0.0000
2010-Dec	0.0589	0.0000	0.0585	0.0000	0.0680	-0.0107	0.0673	0.0000
Total (Credit/(Debit)		-0.0667		-0.0060		-0.0307		-0.0399
Average ($/kWh)		-0.0673		-0.0060		-0.0309		-0.0401
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)		-0.0673		-0.0060		-0.0309		-0.0401
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)		-0.0056		-0.0005		-0.0026		-0.0034
Total Deferral Account Cost ($) (Credit/(Debit)		-0.0677		-0.0061		-0.0311		-0.0404
Interest Cost ($) (Credit/(Debit)		-0.0005		0.0000		-0.0002		-0.0003

	Fixed Price Analysis							
	Pool Price vs Fixed Price		Forward Price vs Fixed Price		Spot vs Fixed Price		EPCOR vs Fixed Price	
Year-Month	Price Differential ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)
2010-Jan	0.0246	0.0246	0.0200	0.0200	0.0108	0.0108	0.0022	0.0022
2010-Feb	0.0241	0.0487	0.0218	0.0418	0.0108	0.0216	0.0054	0.0076
2010-Mar	0.0327	0.0814	0.0248	0.0665	0.0192	0.0408	0.0111	0.0187
2010-Apr	0.0183	0.0997	0.0295	0.0960	0.0034	0.0442	0.0133	0.0320
2010-May	-0.0667	0.0330	0.0105	0.1065	-0.0120	0.0322	0.0046	0.0366
2010-Jun	0.0107	0.0437	-0.0060	0.1005	-0.0080	0.0242	-0.0057	0.0310
2010-Jul	0.0280	0.0717	0.0020	0.1025	0.0125	0.0367	-0.0192	0.0118
2010-Aug	0.0294	0.1010	0.0048	0.1073	0.0148	0.0515	-0.0150	-0.0032
2010-Sep	0.0396	0.1406	0.0195	0.1268	0.0268	0.0783	0.0011	-0.0021
2010-Oct	0.0371	0.1777	0.0260	0.1528	0.0244	0.1027	0.0138	0.0117
2010-Nov	0.0199	0.1976	0.0255	0.1783	0.0021	0.1048	0.0124	0.0241
2010-Dec	0.0091	0.2067	0.0095	0.1877	-0.0107	0.0941	0.0007	0.0247
Total (Credit/(Debit)	0.2067		0.1877		0.0941		0.0247	
Average ($/kWh)	0.2080		0.1891		0.0948		0.0249	
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)	0.2080		0.1891		0.0948		0.0249	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)	0.0175		0.0159		0.0080		0.0021	
Total Deferral Account Cost ($) (Credit/(Debit)	0.2095		0.1904		0.0954		0.0251	
Interest Cost ($) (Credit/(Debit)	0.0015		0.0013		0.0007		0.0002	

References:

1 Alberta Capital Finance Authority
2 Alberta Market Surveillance Administrator
3 Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4 Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

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Assumptions

	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				**Price Differentials**			
Year-Month	**Monthly Average Pool Price[2] ($/kWh)**	**Last Forward Price[2] ($/kWh)**	**Spot Power Residential Floating Rate[3] ($/kWh)**	**EPCOR Residential RRO Rate[4] ($/kWh)**	**Forward less Pool ($/kWh)**	**EPCOR less Forward ($/kWh)**	**EPCOR less Pool ($/kWh)**	**Spot Power less Pool ($/kWh)**
2011-Jan	0.0790	0.0750	0.1007	0.0758	-0.0040	0.0008	-0.0032	0.0217
2011-Feb	0.1224	0.0780	0.1497	0.0898	-0.0444	0.0118	-0.0327	0.0273
2011-Mar	0.0485	0.0640	0.0632	0.0709	0.0155	0.0069	0.0224	0.0147
2011-Apr	0.0522	0.0830	0.0680	0.1176	0.0308	0.0346	0.0654	0.0158
2011-May	0.0323	0.0415	0.0468	0.0630	0.0092	0.0215	0.0307	0.0145
2011-Jun	0.0718	0.0532	0.0957	0.0692	-0.0187	0.0161	-0.0026	0.0239
2011-Jul	0.0612	0.0950	0.0821	0.0999	0.0338	0.0049	0.0387	0.0209
2011-Aug	0.1264	0.0870	0.1611	0.1295	-0.0394	0.0425	0.0032	0.0347
2011-Sep	0.0966	0.0805	0.1225	0.0826	-0.0161	0.0021	-0.0140	0.0259
2011-Oct	0.0698	0.0840	0.0898	0.1243	0.0142	0.0403	0.0545	0.0200
2011-Nov	0.1082	0.0780	0.1424	0.0912	-0.0302	0.0132	-0.0170	0.0342
2011-Dec	0.0513	0.1350	0.0706	0.1330	0.0837	-0.0020	0.0818	0.0193
Total (Credit/(Debit)								
Average ($/kWh)	0.0766	0.0795	0.0994	0.0956	0.0029	0.0161	0.0189	0.0227 `
Standard Deviation (+/- $/kWh)	0.0293	0.0220	0.0354	0.0239	0.0349	0.0149	0.0344	0.0065

	Price Cap Analysis							
	Pool Price vs Price Cap		**Forward Price vs Price Cap**		**Spot vs Price Cap**		**EPCOR vs Price Cap**	
Year-Month	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**
2011-Jan	0.0680	-0.0110	0.0680	-0.0070	0.0680	-0.0327	0.0680	-0.0078
2011-Feb	0.0680	-0.0544	0.0680	-0.0100	0.0680	-0.0817	0.0680	-0.0218
2011-Mar	0.0485	0.0000	0.0640	0.0000	0.0632	0.0000	0.0680	-0.0029
2011-Apr	0.0522	0.0000	0.0680	-0.0150	0.0680	0.0000	0.0680	-0.0496
2011-May	0.0323	0.0000	0.0415	0.0000	0.0468	0.0000	0.0630	0.0000
2011-Jun	0.0680	-0.0038	0.0532	0.0000	0.0680	-0.0277	0.0680	-0.0012
2011-Jul	0.0612	0.0000	0.0680	-0.0270	0.0680	-0.0141	0.0680	-0.0319
2011-Aug	0.0680	-0.0584	0.0680	-0.0190	0.0680	-0.0931	0.0680	-0.0615
2011-Sep	0.0680	-0.0286	0.0680	-0.0125	0.0680	-0.0545	0.0680	-0.0146
2011-Oct	0.0680	-0.0018	0.0680	-0.0160	0.0680	-0.0218	0.0680	-0.0563
2011-Nov	0.0680	-0.0402	0.0680	-0.0100	0.0680	-0.0744	0.0680	-0.0232
2011-Dec	0.0513	0.0000	0.0680	-0.0670	0.0680	-0.0026	0.0680	-0.0650
Total (Credit/(Debit)		-0.1983		-0.1835		-0.4026		-0.3358
Average ($/kWh)		-0.1996		-0.1843		-0.4052		-0.3376
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)		-0.1996		-0.1843		-0.4052		-0.3376
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)		-0.0168		-0.0155		-0.0340		-0.0283
Total Deferral Account Cost ($) (Credit/(Debit)		-0.2010		-0.1856		-0.4081		-0.3399
Interest Cost ($) (Credit/(Debit)		-0.0014		-0.0013		-0.0028		-0.0024

	Fixed Price Analysis							
	Pool Price vs Fixed Price		**Forward Price vs Fixed Price**		**Spot vs Fixed Price**		**EPCOR vs Fixed Price**	
Year-Month	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**
2011-Jan	-0.0110	-0.0110	-0.0070	-0.0070	-0.0327	-0.0327	-0.0078	-0.0078
2011-Feb	-0.0544	-0.0655	-0.0100	-0.0170	-0.0817	-0.1144	-0.0218	-0.0296
2011-Mar	0.0195	-0.0460	0.0040	-0.0130	0.0048	-0.1096	-0.0029	-0.0325
2011-Apr	0.0158	-0.0303	-0.0150	-0.0280	0.0000	-0.1096	-0.0496	-0.0821
2011-May	0.0357	0.0055	0.0265	-0.0015	0.0212	-0.0884	0.0050	-0.0771
2011-Jun	-0.0038	0.0016	0.0149	0.0134	-0.0277	-0.1161	-0.0012	-0.0783
2011-Jul	0.0068	0.0084	-0.0270	-0.0137	-0.0141	-0.1302	-0.0319	-0.1102
2011-Aug	-0.0584	-0.0499	-0.0190	-0.0327	-0.0931	-0.2233	-0.0615	-0.1717
2011-Sep	-0.0286	-0.0785	-0.0125	-0.0452	-0.0545	-0.2778	-0.0146	-0.1863
2011-Oct	-0.0018	-0.0803	-0.0160	-0.0612	-0.0218	-0.2996	-0.0563	-0.2426
2011-Nov	-0.0402	-0.1205	-0.0100	-0.0711	-0.0744	-0.3740	-0.0232	-0.2658
2011-Dec	0.0167	-0.1038	-0.0670	-0.1382	-0.0026	-0.3766	-0.0650	-0.3308
Total (Credit/(Debit)	-0.1038		-0.1382		-0.3766		-0.3308	
Average ($/kWh)	-0.1044		-0.1386		-0.3790		-0.3325	
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)	-0.1044		-0.1386		-0.3790		-0.3325	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)	-0.0088		-0.0116		-0.0318		-0.0279	
Total Deferral Account Cost ($) (Credit/(Debit)	-0.1051		-0.1396		-0.3817		-0.3348	
Interest Cost ($) (Credit/(Debit)	-0.0007		-0.0010		-0.0026		-0.0023	

References:

1 Alberta Capital Finance Authority
2 Alberta Market Surveillance Administrator
3 Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4 Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

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Assumptions

	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				**Price Differentials**			
Year-Month	**Monthly Average Pool Price[2] ($/kWh)**	**Last Forward Price[2] ($/kWh)**	**Spot Power Residential Floating Rate[3] ($/kWh)**	**EPCOR Residential RRO Rate[4] ($/kWh)**	**Forward less Pool ($/kWh)**	**EPCOR less Forward ($/kWh)**	**EPCOR less Pool ($/kWh)**	**Spot Power less Pool ($/kWh)**
2012-Jan	0.0845	0.1080	0.1042	0.1511	0.0235	0.0431	0.0666	0.0197
2012-Feb	0.0437	0.0870	0.0579	0.1395	0.0433	0.0525	0.0959	0.0142
2012-Mar	0.0511	0.0640	0.0673	0.0798	0.0129	0.0158	0.0287	0.0162
2012-Apr	0.0417	0.0560	0.0579	0.0730	0.0143	0.0170	0.0313	0.0162
2012-May	0.0295	0.0455	0.0439	0.0636	0.0160	0.0181	0.0341	0.0144
2012-Jun	0.0493	0.0580	0.0693	0.0784	0.0087	0.0204	0.0291	0.0200
2012-Jul	0.0684	0.0725	0.0918	0.0903	0.0041	0.0178	0.0219	0.0234
2012-Aug	0.0565	0.0900	0.0788	0.1155	0.0335	0.0255	0.0589	0.0223
2012-Sep	0.1104	0.0745	0.1430	0.1036	-0.0359	0.0291	-0.0068	0.0326
2012-Oct	0.0914	0.0565	0.1191	0.1029	-0.0349	0.0464	0.0115	0.0277
2012-Nov	0.0874	0.0760	0.1178	0.0757	-0.0114	-0.0003	-0.0117	0.0304
2012-Dec	0.0576	0.0658	0.0790	0.0856	0.0081	0.0199	0.0280	0.0214
Total (Credit/(Debit)								
Average ($/kWh)	0.0643	0.0711	0.0858	0.0966	0.0069	0.0254	0.0323	0.0215
Standard Deviation (+/- $/kWh)	0.0232	0.0167	0.0286	0.0260	0.0231	0.0144	0.0288	0.0058

	Price Cap Analysis							
	Pool Price vs Price Cap		**Forward Price vs Price Cap**		**Spot vs Price Cap**		**EPCOR vs Price Cap**	
Year-Month	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**
2012-Jan	0.0680	-0.0165	0.0680	-0.0400	0.0680	-0.0362	0.0680	-0.0831
2012-Feb	0.0437	0.0000	0.0680	-0.0190	0.0579	0.0000	0.0680	-0.0715
2012-Mar	0.0511	0.0000	0.0640	0.0000	0.0673	0.0000	0.0680	-0.0118
2012-Apr	0.0417	0.0000	0.0560	0.0000	0.0579	0.0000	0.0680	-0.0050
2012-May	0.0295	0.0000	0.0455	0.0000	0.0439	0.0000	0.0636	0.0000
2012-Jun	0.0493	0.0000	0.0580	0.0000	0.0680	-0.0013	0.0680	-0.0104
2012-Jul	0.0680	-0.0004	0.0680	-0.0045	0.0680	-0.0238	0.0680	-0.0223
2012-Aug	0.0565	0.0000	0.0680	-0.0220	0.0680	-0.0108	0.0680	-0.0475
2012-Sep	0.0680	-0.0424	0.0680	-0.0065	0.0680	-0.0750	0.0680	-0.0356
2012-Oct	0.0680	-0.0234	0.0565	0.0000	0.0680	-0.0511	0.0680	-0.0349
2012-Nov	0.0680	-0.0194	0.0680	-0.0080	0.0680	-0.0498	0.0680	-0.0077
2012-Dec	0.0576	0.0000	0.0658	0.0000	0.0680	-0.0110	0.0680	-0.0176
Total (Credit/(Debit)		-0.1021		-0.1000		-0.2590		-0.3474
Average ($/kWh)		-0.1026		-0.1009		-0.2603		-0.3503
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)		-0.1026		-0.1009		-0.2603		-0.3503
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)		-0.0086		-0.0085		-0.0218		-0.0294
Total Deferral Account Cost ($) (Credit/(Debit)		-0.1033		-0.1016		-0.2621		-0.3527
Interest Cost ($) (Credit/(Debit)		-0.0007		-0.0007		-0.0018		-0.0024

	Fixed Price Analysis							
	Pool Price vs Fixed Price		**Forward Price vs Fixed Price**		**Spot vs Fixed Price**		**EPCOR vs Fixed Price**	
Year-Month	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**
2012-Jan	-0.0165	-0.0165	-0.0400	-0.0400	-0.0362	-0.0362	-0.0831	-0.0831
2012-Feb	0.0243	0.0078	-0.0190	-0.0590	0.0101	-0.0261	-0.0715	-0.1547
2012-Mar	0.0169	0.0247	0.0040	-0.0550	0.0007	-0.0254	-0.0118	-0.1665
2012-Apr	0.0263	0.0510	0.0120	-0.0430	0.0101	-0.0153	-0.0050	-0.1715
2012-May	0.0385	0.0896	0.0225	-0.0205	0.0241	0.0088	0.0044	-0.1671
2012-Jun	0.0187	0.1083	0.0100	-0.0105	-0.0013	0.0075	-0.0104	-0.1775
2012-Jul	-0.0004	0.1079	-0.0045	-0.0150	-0.0238	-0.0163	-0.0223	-0.1998
2012-Aug	0.0115	0.1193	-0.0220	-0.0370	-0.0108	-0.0271	-0.0475	-0.2472
2012-Sep	-0.0424	0.0769	-0.0065	-0.0435	-0.0750	-0.1021	-0.0356	-0.2828
2012-Oct	-0.0234	0.0536	0.0115	-0.0320	-0.0511	-0.1532	-0.0349	-0.3177
2012-Nov	-0.0194	0.0342	-0.0080	-0.0400	-0.0498	-0.2030	-0.0077	-0.3254
2012-Dec	0.0104	0.0445	0.0023	-0.0377	-0.0110	-0.2140	-0.0176	-0.3430
Total (Credit/(Debit)	0.0445		-0.0377		-0.2140		-0.3430	
Average ($/kWh)	0.0453		-0.0382		-0.2149		-0.3458	
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)	0.0453		-0.0382		-0.2149		-0.3458	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)	0.0038		-0.0032		-0.0180		-0.0290	
Total Deferral Account Cost ($) (Credit/(Debit)	0.0456		-0.0385		-0.2164		-0.3482	
Interest Cost ($) (Credit/(Debit)	0.0003		-0.0003		-0.0015		-0.0024	

References:

1. Alberta Capital Finance Authority
2. Alberta Market Surveillance Administrator
3. Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4. Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

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Table:

Assumptions

	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				**Price Differentials**			
Year-Month	**Monthly Average Pool Price[2] ($/kWh)**	**Last Forward Price[2] ($/kWh)**	**Spot Power Residential Floating Rate[3] ($/kWh)**	**EPCOR Residential RRO Rate[4] ($/kWh)**	**Forward less Pool ($/kWh)**	**EPCOR less Forward ($/kWh)**	**EPCOR less Pool ($/kWh)**	**Spot Power less Pool ($/kWh)**
2013-Jan	0.0580	0.0690	0.0765	0.0888	0.0110	0.0198	0.0307	0.0185
2013-Feb	0.0287	0.0543	0.0420	0.0752	0.0255	0.0210	0.0465	0.0133
2013-Mar	0.1056	0.0540	0.1673	0.0729	-0.0516	0.0189	-0.0327	0.0617
2013-Apr	0.1377	0.0765	0.1625	0.0821	-0.0612	0.0056	-0.0556	0.0248
2013-May	0.1277	0.0950	0.1397	0.0710	-0.0327	-0.0240	-0.0567	0.0120
2013-Jun	0.1048	0.0835	0.0744	0.0707	-0.0213	-0.0128	-0.0340	-0.0304
2013-Jul	0.0561	0.0950	0.1103	0.1076	0.0389	0.0126	0.0515	0.0542
2013-Aug	0.0836	0.0750	0.1418	0.1141	-0.0086	0.0391	0.0304	0.0582
2013-Sep	0.1120	0.0953	0.0848	0.1052	-0.0167	0.0100	-0.0068	-0.0272
2013-Oct	0.0646	0.0550	0.0427	0.0823	-0.0096	0.0273	0.0178	-0.0219
2013-Nov	0.0283	0.0570	0.0728	0.0824	0.0287	0.0254	0.0541	0.0445
2013-Dec	0.0523	0.0605	0.0615	0.0815	0.0082	0.0210	0.0292	0.0092
Total (Credit/(Debit)								
Average ($/kWh)	0.0799	0.0725	0.0980	0.0861	-0.0074	0.0136	0.0062	0.0181
Standard Deviation (+/- $/kWh)	0.0357	0.0159	0.0429	0.0143	0.0301	0.0167	0.0397	0.0312
Deferral Account ($) (Credit/(Debit)								
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)								
Total Deferral Account Cost ($) (Credit/(Debit)								
Interest Cost ($) (Credit/(Debit)								

	Price Cap Analysis							
	Pool Price vs Price Cap		**Forward Price vs Price Cap**		**Spot vs Price Cap**		**EPCOR vs Price Cap**	
Year-Month	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**
2013-Jan	0.0580	0.0000	0.0680	-0.0010	0.0680	-0.0085	0.0680	-0.0208
2013-Feb	0.0287	0.0000	0.0543	0.0000	0.0420	0.0000	0.0680	-0.0072
2013-Mar	0.0680	-0.0376	0.0540	0.0000	0.0680	-0.0993	0.0680	-0.0049
2013-Apr	0.0680	-0.0697	0.0680	-0.0085	0.0680	-0.0945	0.0680	-0.0141
2013-May	0.0680	-0.0597	0.0680	-0.0270	0.0680	-0.0717	0.0680	-0.0030
2013-Jun	0.0680	-0.0368	0.0680	-0.0155	0.0680	-0.0064	0.0680	-0.0027
2013-Jul	0.0561	0.0000	0.0680	-0.0270	0.0680	-0.0423	0.0680	-0.0396
2013-Aug	0.0680	-0.0156	0.0680	-0.0070	0.0680	-0.0738	0.0680	-0.0461
2013-Sep	0.0680	-0.0440	0.0680	-0.0273	0.0680	-0.0168	0.0680	-0.0372
2013-Oct	0.0646	0.0000	0.0550	0.0000	0.0427	0.0000	0.0680	-0.0143
2013-Nov	0.0283	0.0000	0.0570	0.0000	0.0680	-0.0048	0.0680	-0.0144
2013-Dec	0.0523	0.0000	0.0605	0.0000	0.0615	0.0000	0.0680	-0.0135
Total (Credit/(Debit)		-0.2633		-0.1133		-0.4181		-0.2178
Average ($/kWh)		-0.2655		-0.1140		-0.4216		-0.2191
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)		-0.2655		-0.1140		-0.4216		-0.2191
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)		-0.0223		-0.0096		-0.0354		-0.0184
Total Deferral Account Cost ($) (Credit/(Debit)		-0.2673		-0.1148		-0.4245		-0.2206
Interest Cost ($) (Credit/(Debit)		-0.0019		-0.0008		-0.0029		-0.0015

	Fixed Price Analysis							
	Pool Price vs Fixed Price		**Forward Price vs Fixed Price**		**Spot vs Fixed Price**		**EPCOR vs Fixed Price**	
Year-Month	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**
2013-Jan	0.0100	0.0100	-0.0010	-0.0010	-0.0085	-0.0085	-0.0208	-0.0208
2013-Feb	0.0393	0.0493	0.0138	0.0128	0.0260	0.0175	-0.0072	-0.0280
2013-Mar	-0.0376	0.0116	0.0140	0.0268	-0.0993	-0.0818	-0.0049	-0.0329
2013-Apr	-0.0697	-0.0580	-0.0085	0.0183	-0.0945	-0.1763	-0.0141	-0.0469
2013-May	-0.0597	-0.1177	-0.0270	-0.0087	-0.0717	-0.2480	-0.0030	-0.0499
2013-Jun	-0.0368	-0.1544	-0.0155	-0.0243	-0.0064	-0.2544	-0.0027	-0.0527
2013-Jul	0.0119	-0.1426	-0.0270	-0.0513	-0.0423	-0.2967	-0.0396	-0.0923
2013-Aug	-0.0156	-0.1582	-0.0070	-0.0583	-0.0738	-0.3705	-0.0461	-0.1383
2013-Sep	-0.0440	-0.2022	-0.0273	-0.0855	-0.0168	-0.3873	-0.0372	-0.1756
2013-Oct	0.0034	-0.1988	0.0130	-0.0725	0.0253	-0.3620	-0.0143	-0.1899
2013-Nov	0.0397	-0.1591	0.0110	-0.0615	-0.0048	-0.3668	-0.0144	-0.2043
2013-Dec	0.0157	-0.1434	0.0075	-0.0540	0.0065	-0.3603	-0.0135	-0.2178
Total (Credit/(Debit)	-0.1434		-0.0540		-0.3603		-0.2178	
Average ($/kWh)	-0.1447		-0.0544		-0.3634		-0.2191	
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)	-0.1447		-0.0544		-0.3634		-0.2191	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)	-0.0121		-0.0046		-0.0305		-0.0184	
Total Deferral Account Cost ($) (Credit/(Debit)	-0.1457		-0.0548		-0.3659		-0.2206	
Interest Cost ($) (Credit/(Debit)	-0.0010		-0.0004		-0.0025		-0.0015	

References:

1 Alberta Capital Finance Authority
2 Alberta Market Surveillance Administrator
3 Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4 Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

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	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				Price Differentials			
Year-Month	Monthly Average Pool Price[2] ($/kWh)	Last Forward Price[2] ($/kWh)	Spot Power Residential Floating Rate[3] ($/kWh)	EPCOR Residential RRO Rate[4] ($/kWh)	Forward less Pool ($/kWh)	EPCOR less Forward ($/kWh)	EPCOR less Pool ($/kWh)	Spot Power less Pool ($/kWh)
2014-Jan	0.0452	0.0660	0.1173	0.0869	0.0208	0.0209	0.0417	0.0721
2014-Feb	0.0963	0.0730	0.0590	0.0747	-0.0233	0.0017	-0.0216	-0.0373
2014-Mar	0.0437	0.0710	0.0444	0.0699	0.0273	-0.0011	0.0262	0.0007
2014-Apr	0.0307	0.0405	0.0733	0.0699	0.0098	0.0294	0.0392	0.0426
2014-May	0.0540	0.0970	0.0591	0.0892	0.0430	-0.0078	0.0352	0.0051
2014-Jun	0.0422	0.0400	0.1580	0.0600	-0.0022	0.0200	0.0178	0.1158
2014-Jul	0.1225	0.0620	0.0624	0.0720	-0.0605	0.0100	-0.0506	-0.0601
2014-Aug	0.0452	0.0730	0.0371	0.0802	0.0278	0.0072	0.0350	-0.0081
2014-Sep	0.0240	0.0600	0.0401	0.0795	0.0360	0.0195	0.0556	0.0161
2014-Oct	0.0270	0.0700	0.0535	0.0874	0.0430	0.0174	0.0603	0.0265
2014-Nov	0.0377	0.0443	0.0403	0.0713	0.0066	0.0270	0.0336	0.0026
2014-Dec	0.0269	0.0550	0.0497	0.0755	0.0281	0.0205	0.0485	0.0228
Total (Credit/(Debit)								
Average ($/kWh)	0.0496	0.0626	0.0662	0.0764	0.0130	0.0137	0.0267	0.0166
Standard Deviation (+/- $/kWh)	0.0286	0.0156	0.0345	0.0083	0.0289	0.0111	0.0308	0.0445

	Price Cap Analysis								Fixed Price Analysis							
	Pool Price vs Price Cap		Forward Price vs Price Cap		Spot vs Price Cap		EPCOR vs Price Cap		Pool Price vs Fixed Price		Forward Price vs Fixed Price		Spot vs Fixed Price		EPCOR vs Fixed Price	
Year-Month	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Monthly Price ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)	Price Differential ($/kWh)	Deferral Amount ($/kWh)
2014-Jan	0.0452	0.0000	0.0660	0.0000	0.0680	-0.0493	0.0680	-0.0189	0.0228	0.0228	0.0020	0.0020	-0.0493	-0.0493	-0.0189	-0.0189
2014-Feb	0.0680	-0.0283	0.0680	-0.0050	0.0590	0.0000	0.0680	-0.0067	-0.0283	-0.0056	-0.0050	-0.0030	0.0090	-0.0403	-0.0067	-0.0256
2014-Mar	0.0437	0.0000	0.0680	-0.0030	0.0444	0.0000	0.0680	-0.0019	0.0243	0.0188	-0.0030	-0.0060	0.0236	-0.0167	-0.0019	-0.0275
2014-Apr	0.0307	0.0000	0.0405	0.0000	0.0680	-0.0053	0.0680	-0.0019	0.0373	0.0561	0.0275	0.0215	-0.0053	-0.0220	-0.0019	-0.0294
2014-May	0.0540	0.0000	0.0680	-0.0290	0.0591	0.0000	0.0680	-0.0212	0.0140	0.0700	-0.0290	-0.0075	0.0089	-0.0131	-0.0212	-0.0506
2014-Jun	0.0422	0.0000	0.0400	0.0000	0.0680	-0.0900	0.0600	0.0000	0.0258	0.0959	0.0280	0.0205	-0.0900	-0.1031	0.0081	-0.0425
2014-Jul	0.0680	-0.0545	0.0620	0.0000	0.0624	0.0000	0.0680	-0.0040	-0.0545	0.0413	0.0060	0.0265	0.0056	-0.0975	-0.0040	-0.0465
2014-Aug	0.0452	0.0000	0.0680	-0.0050	0.0371	0.0000	0.0680	-0.0122	0.0228	0.0641	-0.0050	0.0215	0.0309	-0.0666	-0.0122	-0.0587
2014-Sep	0.0240	0.0000	0.0600	0.0000	0.0401	0.0000	0.0680	-0.0115	0.0440	0.1081	0.0080	0.0295	0.0279	-0.0387	-0.0115	-0.0703
2014-Oct	0.0270	0.0000	0.0680	-0.0020	0.0535	0.0000	0.0680	-0.0194	0.0410	0.1491	-0.0020	0.0275	0.0145	-0.0242	-0.0194	-0.0896
2014-Nov	0.0377	0.0000	0.0443	0.0000	0.0403	0.0000	0.0680	-0.0033	0.0303	0.1794	0.0238	0.0513	0.0277	0.0035	-0.0033	-0.0929
2014-Dec	0.0269	0.0000	0.0550	0.0000	0.0497	0.0000	0.0680	-0.0075	0.0411	0.2205	0.0130	0.0643	0.0183	0.0218	-0.0075	-0.1004
Total (Credit/(Debit)		-0.0829		-0.0440		-0.1446		-0.1084	0.2205		0.0643		0.0218		-0.1004	
Average ($/kWh)		-0.0835		-0.0444		-0.1460		-0.1092	0.2216		0.0645		0.0213		-0.1011	
Standard Deviation (+/- $/kWh)																
Deferral Account ($) (Credit/(Debit)		-0.0835		-0.0444		-0.1460		-0.1092	0.2216		0.0645		0.0213		-0.1011	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)		-0.0070		-0.0037		-0.0122		-0.0092	0.0186		0.0054		0.0018		-0.0085	
Total Deferral Account Cost ($) (Credit/(Debit)		-0.0841		-0.0447		-0.1470		-0.1099	0.2231		0.0650		0.0215		-0.1018	
Interest Cost ($) (Credit/(Debit)		-0.0006		-0.0003		-0.0010		-0.0008	0.0015		0.0004		0.0001		-0.0007	

References:

1 Alberta Capital Finance Authority
2 Alberta Market Surveillance Administrator
3 Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4 Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

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	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				Price Differentials				Price Cap Analysis: Pool Price vs Price Cap		Forward Price vs Price Cap		Spot vs Price Cap		EPCOR vs Price Cap	
Year-Month	**Monthly Average Pool Price[2] ($/kWh)**	**Last Forward Price[2] ($/kWh)**	**Spot Power Residential Floating Rate[3] ($/kWh)**	**EPCOR Residential RRO Rate[4] ($/kWh)**	**Forward less Pool ($/kWh)**	**EPCOR less Forward ($/kWh)**	**EPCOR less Pool ($/kWh)**	**Spot Power less Pool ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**
2015-Jan	0.0339	0.0550	0.0481	0.0730	0.0211	0.0180	0.0391	0.0142	0.0339	0.0000	0.0550	0.0000	0.0481	0.0000	0.0680	-0.0050
2015-Feb	0.0328	0.0465	0.0328	0.0658	0.0137	0.0193	0.0330	0.0000	0.0328	0.0000	0.0465	0.0000	0.0328	0.0000	0.0658	0.0000
2015-Mar	0.0207	0.0330	0.0328	0.0543	0.0123	0.0213	0.0337	0.0121	0.0207	0.0000	0.0330	0.0000	0.0328	0.0000	0.0543	0.0000
2015-Apr	0.0205	0.0438	0.0743	0.0583	0.0232	0.0146	0.0378	0.0538	0.0205	0.0000	0.0438	0.0000	0.0680	-0.0063	0.0583	0.0000
2015-May	0.0539	0.0283	0.1315	0.0434	-0.0257	0.0151	-0.0106	0.0776	0.0539	0.0000	0.0283	0.0000	0.0680	-0.0635	0.0434	0.0000
2015-Jun	0.0973	0.0480	0.0368	0.0409	-0.0493	-0.0071	-0.0564	-0.0605	0.0680	-0.0293	0.0480	0.0000	0.0368	0.0000	0.0409	0.0000
2015-Jul	0.0231	0.0940	0.0493	0.0614	0.0709	-0.0326	0.0383	0.0262	0.0231	0.0000	0.0680	-0.0260	0.0493	0.0000	0.0614	0.0000
2015-Aug	0.0341	0.0463	0.0331	0.0581	0.0121	0.0119	0.0240	-0.0010	0.0341	0.0000	0.0463	0.0000	0.0331	0.0000	0.0581	0.0000
2015-Sep	0.0209	0.0345	0.0340	0.0539	0.0136	0.0194	0.0330	0.0131	0.0209	0.0000	0.0345	0.0000	0.0340	0.0000	0.0539	0.0000
2015-Oct	0.0215	0.0340	0.0339	0.0550	0.0125	0.0210	0.0335	0.0124	0.0215	0.0000	0.0340	0.0000	0.0339	0.0000	0.0550	0.0000
2015-Nov	0.0212	0.0340	0.0333	0.0521	0.0128	0.0181	0.0310	0.0121	0.0212	0.0000	0.0340	0.0000	0.0333	0.0000	0.0521	0.0000
2015-Dec	0.0209	0.0330	0.0344	0.0549	0.0121	0.0219	0.0340	0.0135	0.0209	0.0000	0.0330	0.0000	0.0344	0.0000	0.0549	0.0000
Total (Credit/(Debit)										-0.0293		-0.0260		-0.0698		-0.0050
Average ($/kWh)	0.0334	0.0442	0.0479	0.0559	0.0108	0.0117	0.0225	0.0145		-0.0295		-0.0262		-0.0704		-0.0051
Standard Deviation (+/- $/kWh)	0.0215	0.0169	0.0278	0.0084	0.0271	0.0153	0.0270	0.0313								
Deferral Account ($) (Credit/(Debit)										-0.0295		-0.0262		-0.0704		-0.0051
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)										-0.0025		-0.0022		-0.0059		-0.0004
Total Deferral Account Cost ($) (Credit/(Debit)										-0.0297		-0.0263		-0.0709		-0.0051
Interest Cost ($) (Credit/(Debit)										-0.0002		-0.0002		-0.0005		0.0000

	Fixed Price Analysis: Pool Price vs Fixed Price		Forward Price vs Fixed Price		Spot vs Fixed Price		EPCOR vs Fixed Price	
Year-Month	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**
2015-Jan	0.0341	0.0341	0.0130	0.0130	0.0199	0.0199	-0.0050	-0.0050
2015-Feb	0.0352	0.0692	0.0215	0.0345	0.0352	0.0551	0.0022	-0.0028
2015-Mar	0.0473	0.1166	0.0350	0.0695	0.0352	0.0903	0.0137	0.0108
2015-Apr	0.0475	0.1640	0.0243	0.0938	-0.0063	0.0840	0.0097	0.0205
2015-May	0.0141	0.1781	0.0398	0.1335	-0.0635	0.0205	0.0246	0.0452
2015-Jun	-0.0293	0.1488	0.0200	0.1535	0.0312	0.0517	0.0271	0.0723
2015-Jul	0.0449	0.1937	-0.0260	0.1275	0.0187	0.0704	0.0066	0.0789
2015-Aug	0.0339	0.2276	0.0218	0.1493	0.0349	0.1053	0.0099	0.0887
2015-Sep	0.0471	0.2747	0.0335	0.1828	0.0340	0.1393	0.0141	0.1029
2015-Oct	0.0465	0.3212	0.0340	0.2168	0.0341	0.1734	0.0130	0.1159
2015-Nov	0.0468	0.3681	0.0340	0.2508	0.0347	0.2081	0.0159	0.1318
2015-Dec	0.0471	0.4151	0.0350	0.2858	0.0336	0.2417	0.0131	0.1449
Total (Credit/(Debit)	0.4151		0.2858		0.2417		0.1449	
Average ($/kWh)	0.4178		0.2876		0.2430		0.1457	
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)	0.4178		0.2876		0.2430		0.1457	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)	0.0351		0.0241		0.0204		0.0122	
Total Deferral Account Cost ($) (Credit/(Debit)	0.4207		0.2896		0.2447		0.1467	
Interest Cost ($) (Credit/(Debit)	0.0029		0.0020		0.0017		0.0010	

References:

1 Alberta Capital Finance Authority
2 Alberta Market Surveillance Administrator
3 Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4 Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

Regulated Rate Option Review
Submission to the Alberta Market Surveillance Administrator
Robert F. Spragins
19-May-17

Table:

Assumptions

	$/kWh	$/MWh
Price Cap	0.068	68.00
Fixed Price	0.068	68.00
Amortization Period (Years)		1
Amortization Period (Months)		12
Interest Rate (%)[1]		1.285

	Prices				**Price Differentials**			
Year-Month	**Monthly Average Pool Price[2] ($/kWh)**	**Last Forward Price[2] ($/kWh)**	**Spot Power Residential Floating Rate[3] ($/kWh)**	**EPCOR Residential RRO Rate[4] ($/kWh)**	**Forward less Pool ($/kWh)**	**EPCOR less Forward ($/kWh)**	**EPCOR less Pool ($/kWh)**	**Spot Power less Pool ($/kWh)**
2016-Jan	0.0223	0.0300	0.0290	0.0530	0.0077	0.0230	0.0308	0.0067
2016-Feb	0.0172	0.0305	0.0260	0.0475	0.0133	0.0170	0.0303	0.0088
2016-Mar	0.0148	0.0240	0.0251	0.0452	0.0092	0.0212	0.0304	0.0103
2016-Apr	0.0136	0.0180	0.0251	0.0365	0.0044	0.0185	0.0229	0.0115
2016-May	0.0159	0.0218	0.0276	0.0335	0.0059	0.0117	0.0176	0.0117
2016-Jun	0.0154	0.0280	0.0273	0.0361	0.0126	0.0081	0.0207	0.0119
2016-Jul	0.0182	0.0273	0.0302	0.0498	0.0090	0.0225	0.0315	0.0120
2016-Aug	0.0179	0.0285	0.0302	0.0475	0.0106	0.0190	0.0296	0.0123
2016-Sep	0.0177	0.0220	0.0295	0.0397	0.0043	0.0177	0.0220	0.0118
2016-Oct	0.0254	0.0303	0.0378	0.0446	0.0049	0.0143	0.0192	0.0124
2016-Nov	0.0163	0.0273	0.0280	0.0374	0.0109	0.0101	0.0210	0.0117
2016-Dec	0.0242	0.0318	0.0367	0.0398	0.0075	0.0081	0.0156	0.0125
Total (Credit/(Debit)								
Average ($/kWh)	0.0182	0.0266	0.0294	0.0425	0.0084	0.0159	0.0243	0.0111 `
Standard Deviation (+/- $/kWh)	0.0036	0.0041	0.0039	0.0060	0.0030	0.0052	0.0056	0.0017
Deferral Account ($) (Credit/(Debit)								
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)								
Total Deferral Account Cost ($) (Credit/(Debit)								
Interest Cost ($) (Credit/(Debit)								

Price Cap Analysis

	Pool Price vs Price Cap		**Forward Price vs Price Cap**		**Spot vs Price Cap**		**EPCOR vs Price Cap**	
Year-Month	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**	**Monthly Price ($/kWh)**	**Deferral Amount ($/kWh)**
2016-Jan	0.0223	0.0000	0.0300	0.0000	0.0290	0.0000	0.0530	0.0000
2016-Feb	0.0172	0.0000	0.0305	0.0000	0.0260	0.0000	0.0475	0.0000
2016-Mar	0.0148	0.0000	0.0240	0.0000	0.0251	0.0000	0.0452	0.0000
2016-Apr	0.0136	0.0000	0.0180	0.0000	0.0251	0.0000	0.0365	0.0000
2016-May	0.0159	0.0000	0.0218	0.0000	0.0276	0.0000	0.0335	0.0000
2016-Jun	0.0154	0.0000	0.0280	0.0000	0.0273	0.0000	0.0361	0.0000
2016-Jul	0.0182	0.0000	0.0273	0.0000	0.0302	0.0000	0.0498	0.0000
2016-Aug	0.0179	0.0000	0.0285	0.0000	0.0302	0.0000	0.0475	0.0000
2016-Sep	0.0177	0.0000	0.0220	0.0000	0.0295	0.0000	0.0397	0.0000
2016-Oct	0.0254	0.0000	0.0303	0.0000	0.0378	0.0000	0.0446	0.0000
2016-Nov	0.0163	0.0000	0.0273	0.0000	0.0280	0.0000	0.0374	0.0000
2016-Dec	0.0242	0.0000	0.0318	0.0000	0.0367	0.0000	0.0398	0.0000
Total (Credit/(Debit)		0.0000		0.0000		0.0000		0.0000
Average ($/kWh)		0.0000		0.0000		0.0000		0.0000
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)		0.0000		0.0000		0.0000		0.0000
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)		0.0000		0.0000		0.0000		0.0000
Total Deferral Account Cost ($) (Credit/(Debit)		0.0000		0.0000		0.0000		0.0000
Interest Cost ($) (Credit/(Debit)		0.0000		0.0000		0.0000		0.0000

Fixed Price Analysis

	Pool Price vs Fixed Price		**Forward Price vs Fixed Price**		**Spot vs Fixed Price**		**EPCOR vs Fixed Price**	
Year-Month	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**	**Price Differential ($/kWh)**	**Deferral Amount ($/kWh)**
2016-Jan	0.0457	0.0457	0.0380	0.0380	0.0390	0.0390	0.0150	0.0150
2016-Feb	0.0508	0.0965	0.0375	0.0755	0.0420	0.0810	0.0205	0.0354
2016-Mar	0.0532	0.1497	0.0440	0.1195	0.0429	0.1239	0.0228	0.0582
2016-Apr	0.0544	0.2041	0.0500	0.1695	0.0429	0.1668	0.0315	0.0897
2016-May	0.0521	0.2562	0.0463	0.2158	0.0404	0.2072	0.0345	0.1243
2016-Jun	0.0526	0.3088	0.0400	0.2558	0.0407	0.2479	0.0319	0.1562
2016-Jul	0.0498	0.3586	0.0408	0.2965	0.0378	0.2857	0.0183	0.1744
2016-Aug	0.0501	0.4087	0.0395	0.3360	0.0378	0.3235	0.0205	0.1949
2016-Sep	0.0503	0.4590	0.0460	0.3820	0.0385	0.3620	0.0283	0.2232
2016-Oct	0.0426	0.5016	0.0378	0.4198	0.0302	0.3922	0.0234	0.2466
2016-Nov	0.0517	0.5533	0.0408	0.4605	0.0400	0.4322	0.0306	0.2772
2016-Dec	0.0438	0.5971	0.0363	0.4968	0.0313	0.4635	0.0282	0.3054
Total (Credit/(Debit)	0.5971		0.4968		0.4635		0.3054	
Average ($/kWh)	0.6013		0.5002		0.4668		0.3074	
Standard Deviation (+/- $/kWh)								
Deferral Account ($) (Credit/(Debit)	0.6013		0.5002		0.4668		0.3074	
Deferral Account Adjustment ($) (Credit/(Debit)($/kWh/Month)	0.0505		0.0420		0.0392		0.0258	
Total Deferral Account Cost ($) (Credit/(Debit)	0.6055		0.5037		0.4701		0.3096	
Interest Cost ($) (Credit/(Debit)	0.0042		0.0035		0.0033		0.0021	

References:

1 Alberta Capital Finance Authority
2 Alberta Market Surveillance Administrator
3 Alberta Utilities Consumer Advocate: http://ucahelps.alberta.ca/historic-rates.aspx
4 Alberta Utilities Commission: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/HistoricRRO-July2006-Feb2016.pdf, http://www.auc.ab.ca/regulatory_documents/Pages/Monthly_energy_charges_approval.aspx

Options for Enhancing the Design of the Regulated Rate Option (RRO)

Participant and Stakeholder Response

May 19, 2017

Response submitted jointly by the REA Working Group:
Battle River Power Coop
EQUS REA
Lakeland REA
North Parkland Power REA
Rocky REA

With assistance from:
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In response to the request by the MSA for feedback on the questions posed, a Rural Electrification Association (REA) Working Group is appreciative of the opportunity to provide input into the process of RRO reform consideration. The Operating REA Working Group is comprised of:

- Battle River Power Coop
- EQUS REA
- Lakeland REA
- North Parkland Power REA
- Rocky REA

Provision of Regulated Rate Option (RRO) for the Operating REA Working Group (REA WG) represents approximately:

- 22.16 MW of load on average for each hour
- 194,122 MWh annually of load
- 12,940 sites consuming on average 1,250 kWh per month
    - Across the REA WG entities, the RRO roughly comprises approximately 28% to 69% of REA member sites.
        - Specific site level RRO composition of total members served varies due to site movement within and in some cases outside of the REA

As such, the provision of RRO service is an important part of the REA WG's service offering to their respective members. Given the significant portion of retail services devoted to the provision of RRO services, the REA WG acknowledges the importance of this feedback process. Should any response lack clarity or require further elaboration, the REA WG would be happy to provide any information requested. The response document is delineated into the following categories:

1. Background of REA WG Members
2. Responses to Questions Posed by the MSA
3. Summary Messages

The following response document represents the views, perspectives, and comments of the REA WG.

Background on REA Working Group REA Members

Rural Electrification Associations (REA) operate under the *Rural Utilities Act* (http://www.qp.alberta.ca/documents/Acts/R21.pdf) and *Rural Utilities Regulation* (http://www.qp.alberta.ca/documents/Regs/2000_151.pdf). The Act establishes the organisation, governance, and makes provisions for the management of business and affairs of rural utilities associations. REAs provide RRO service to members, but it is imperative to clarify that **REAs are not retailers** and do not have the same structure or motivation as competitive retail entities. REA members own the distribution wires through the REA, and the REA entity then provides various levels of energy retail services for the members that includes the provision of RRO service.

As owners of distribution systems, the REAs are under a consistent competitive threat from Investor Owned Utilities (IOU) such as ATCO Electric and Fortis Alberta. With few growth prospects in the province IOUs see the distribution systems owned by the REAs as opportunities for growth, as evidenced by their investor publications and various acquisitions of REAs including, but not limited to: Manning REA, VNM REA, Stry REA, and Peace Country REA. As of January 2016, out of the 398 original REAs, 255 have sold their assets to private electric companies, while the remaining 143 have amalgamated to the point that only 38 REAs remain. Of these, two more have voted to demutualize and sell their assets.[1] Having to wear increased liability, imposed by the Government through changes to the RRO service provided by the REA WG simply adds to the competitive threat.

[1] https://words.usask.ca/thinkingaboutcoops/2017/03/14/power-struggle-rural-electrification-in-alberta/

Retail Functions / Services

The provision of energy services is very consistent across the REA WG; the spectrum of services offered, and associated comments, by REAs include:

- Provision of Regulated Rate Option
- Energy / Stable / Cooperative Rate
- Price Risk Mitigation and Portfolio Management
- Billing of Revenue
- Settlement of Supply Expenses

Within the REA WG all of the REAs provide stable cooperative rates and also provide the regulated rate option. Membership movement from the RRO rate to the stable cooperative rate or vice versa within the REA structure doesn't allow the members to avoid costs of hedging losses as members own the entire entity and gains and losses are shared. In short, REA members wear the outcome of hedging gains and losses regardless of whether they are on the regulated rate option or on the stabled cooperative rate option.

The REA WG provide stable cooperative rates to their members under 6.1 of the Roles, Relationships and Responsibilities Regulation 2003 (Alberta Regulation 169/2003) which is carrying out the <u>functions of a retailer</u>, but not being an actual Retailer. The contract durations are normally in the 1 to 5 year range, but it is important to point out that no stable cooperative rates are month-to-month products similar to the RRO, rather they are fixed for annual terms. It is important to note that the provision of RRO service by the REA WG has followed the Regulated Rate Option Regulation (Alberta Regulation 262/2005). http://www.qp.alberta.ca/documents/Regs/2005_262.pdf. Specifically, all of the members of the REA WG have hedged for future RRO load in alignment with the Act, have calculated corresponding RRO rates monthly, have submitted those rates to the appropriate Regulatory Authority, which in the case of the REAs is their Board of Directors, and have posted the rates appropriately for their REA members. The REA WG members have implemented long term hedging programs of various duration and volume across each REA in alignment with the proportional volume of load represented by RRO consumption. Currently, given the low forward market prices, the Mark to Market on the hedge book for the RRO is out of the money, most notably for the balance of 2017 and 2018 with mark to market losses paring for 2019 and 2020. The sophistication of the REAs with respect to hedging strategy is based on their approved hedging programs, regular reporting, alignment with external portfolio management consulting services, and their internal policies and procedures to ensure alignment with the regulation. To suggest that the REA WG are not sophisticated in hedging or price risk management is unfounded.

To summarize, REAs are member owned cooperative entities that own distribution systems and also provide retail functions to only their members in a manner that is considered not for profit; as the members own the gains and loss of the complete entity. The REAs are consistently under threat of acquisition by IOUs; moreover, even though the REAs have followed RRO regulation with regard to commodity hedging and pricing, they risk being competitively disadvantaged due to government direction and regulatory changes.

Questions Posed by the MSA

The members of the Operating REA Working group offer the following responses to the questions presented by the MSA in the 21-Apr-17 Options for RRO Enhancing the Design of the RRO document with the objective of presenting advantages and disadvantages with focus on clarifying the resulting effects on the Operating REAs.

Should there be one RRO rate for all eligible consumers (or customer category) in Alberta;

The concept of a single RRO rate for all eligible customers or even one per customer category across the province would be extremely difficult to achieve with any level of consistency across providers without creating sections of large scale cross subsidization. Furthermore, this narrow focus on commodity costs, completely ignores the invoice composition of existing RRO customers within the province. For most RRO customers the commodity portion of their bill is only between 15-20% of the total invoice. That said the capacity to create a provincial RRO rate involves many layers of complexity due to the different Load Profiles/Shapes across RRO providers and variability within comparable rate classes.

Disadvantages – One Single RRO Rate for Alberta

- One single rate for Alberta would not be practically applicable unless all RRO Providers are hedging the same way. And unless the GoA provides ample time for these changes (i.e current hedging practices are expired or hedged volumes are bought) or addresses the issue of existing RRO hedges prior to implementing, this change does not allow the REAs to compete on a level playing field. Moving to this type of structure without an approach for the treatment of the Operating REAs long term hedges would be inequitable; moreover, this action could result in significant losses that will jeporadize some REA’s financial solvency.

- The REA WG believe this change can only be achieved through the creation of a centralized procurement program and even then, unless everyone in the province shares the same load profile one single commodity price will not work. The price has to be based on the load profile of the RRO volume, and even if broken down and allocated properly there will still be cross subsidization. That is, the transfer price for the commodity hedges would be too high for RRO customer profiles with a flatter load profile and these customer bases would be subsidizing the peakier load shapes of other RRO providers.

- REA WG members don't have a high exit rate as they are the owners of the system; REAs are effectively self-contained. If there is a high degree of cross subsidization of rates between providers this could be extremely damaging for the REAs as they don't have a large customer base to absorb this potential cost.
    - If the cross subsidization issue is ignored, at best, this solution would only allow for the creation of a standardized commodity cost across all RRO providers; however, commodity cost is only one of the components that need to be accounted for in the final RRO Rate.

- Other costs/line items would differ on an RRO provider by provider basis and you would end up with unequal "rates" in the end. Other items that make up the RRO rate that differ by provider currently include:
    - Line Losses
    - Unaccounted for Energy (UFE)
    - Retailer Adjustment Mechanism (RAM)
    - Uplift Charges

- Commodity Risk Compensation
- Return Margins
- Rate Riders
  - The other items above make up ~25% of the average RRO Rate in 2017. Therefore, the actual portion of the RRO bill that can be standardized only accounts for 10-15% of a customer's total monthly invoice amount. As the bottom line is the total cost of delivered power, fixing the price per unit on commodity does little to ensure a fair playing field across distribution charges.

- The current EPSP proceedings have been ongoing for over three years, and seeing that none of the Big Three RRO providers (Direct Energy, Enmax, Epcor) have ever been willing to agree to standardized methodology for anything regarding methodology or costs across their EPSPs, it's extremely difficult to envision a structure that the Big Three RRO Providers as well as every other municipality and REA can agree to.
  - If the GoA forces rate standardization on these entities they will just proliferate the RRO consumer's bill with Rate Riders to account for any losses they can/will justify as the result of such a change.
  - Year to date 2017, based of publically filed data on the AUC website, 10% of a Direct Energy Regulated Services Residential customer's RRO bill is made up of Rate Riders

- The single rate structure would result in extra costs being allocated to the Operating REAs for a function that they currently manage as part of their existing operations
  - If the management of this is moved to a centralized organization, this would result in the potential for lost jobs and reduces the value of the REAs service offering from the

perspective of the Operating REA Working Group. The unique identity and services of the REAs are diluted by a one rate across all bodies proposal

    - Overall this proposal would increase the costs of administration required to carry out the RRO process. While this change would likely save money for the Big 3 RRO providers, it would not for the REA WG. Additionally, this devalues the service functions that REAs provide, and reduces member engagement, which is a key component of the REAs corporate identity

- The bottom line is that there is too much variability across load profiles, whether that be different load profiles (like irrigation, residential, small consumer, farm, etc.) and too much variability across distribution networks for the same load profile (i.e. Fortis, ATCO, ENMAX). The variability across volume profiles means that a single price across the RRO will result in cross subsidization whether it be across customer classes or distribution networks.

- It is important to note that the RRO price is a function of commodity block prices and commodity risk compensation. One common rate for the RRO would mean that commodity risk compensation (CRC) for each RRO Customer profile would be the same, and that is not justifiable or realistic.
    - Weighted average hedge price is based on a forecast of commodity volume exposure, and CRC is based on actual volumes consumed and the associated hourly gains and losses. Every site will consume more or less than the forecast and this variance will not be consistent across the province because weather is not consistent across the province (as weather is one of the most influential aspects to electrical load).

Advantages – One Single RRO Rate for Alberta

- One aggregated portfolio that results in one weighted average hedge price that is properly allocated to profiles for each provider which results in different prices to consumers would work; however, this does not exactly fit the one price scenario and is more closely tied to the central procurement proposal. That said;
    - The range of rate differences would be relatively small for the vast majority of customer classes.
    - If hedges are procured at an aggregate level then the weighted average hedge price must be prorated down according to each RRO consumer profile. The result is a different price for each load profile. EPCOR undertakes this process to ensure there is no cross subsidization across profiles, but the result is clearly different RRO commodity prices for each consumer profile.
    - All parties would know that they were treated equally in the hedging aspect (procurement was completed all together). This treatment is fair, and then proper allocations based on load profiles would also be fair.

- This would allow more transparency in non-energy costs and overhead costs across RRO providers, and also transparency to consumers on the merits of their consumption profile.
    - In theory, it would breakdown all the areas outside of commodity that entities providing the RRO service would compete on, however because the IOUs do not treat the Operating REAs fairly with respect to distribution allocation or expansion of service, the true comparison gets muddied.

- The concept of a single rate throughout the province may eliminate or reduce customer confusion as to why there were different rates in different parts of the province for a service that is extremely homogenous.

- Depending on the level of the single price, postage stamp RRO pricing could be a positive stimulus for Retail growth in the province as Retailers would have only a singular market price to beat.

Changes to Procurement

The next segment of the response relates to making changes to the procurement structure for the RRO. The REA WG feel that this type of discussion is extremely premature as the REAs are still in the process of working with the Department of Energy to address the REA's concerns with the GoA's mandated RRO Price Cap and treatment of the REA WG hedge arrangements. Changing the way RRO procurement is currently executed strands a significant amount of forward hedges commitments, made under the present regulations, which exist for entities such as the REA WG. In essence, the GoA is asking the MSA to investigate making changes to the game when some entities are still half-way through it. Without a satisfactory resolution to the hedging concern, making untimely changes to procurement methodology for the RRO will lead to member non-confidence due to significant losses being incurred via RRO provision . Resulting in corporate instability that exposes the REAs WG to further acquisition attempts from IOUs (ATCO/FortisAlberta).

Assuming that the issues at hand regarding the hedging programs of the REA WG are mitigated properly, the REA WG would be supportive of this form of review regarding current procurement practices. The REA WG views this as an opportunity for the GoA to create a level playing field for ALL RRO providers by resetting the bar and developing a standardized process across ALL RRO providers.

Advanced Procurement

Disadvantages – Advanced Procurement

- Fixed price hedges cannot be procured for longer durations than the commitment made by the consumer. Misalignment of contract commitment term with procurement is ill conceived. And given that under current legislation the RRO consumer can walk away from RRO commitment at any time, the length of procurement should match, otherwise:
    - The price risk is passed on to consumers.
    - The gain or loss from an RRO Consumer leaving is worn by a group of people that does not include the RRO consumer that has left. Not fair or right.
    - If you want a monthly commitment, then you can have monthly procurement.
        - That is, if you want 1 year forward procurement, then you need to have a 1 year commitment to remain on the RRO.
    - If you don't have consumer commitment aligned with procurement commitment you create a speculative position that can result in gains or losses.

- Due to the relatively small size of the REAs they cannot absorb losses like large integrated wholesale/retail entities and procurement term versus future volume forecast alignment issues are currently one of the more imperative issues with their current hedging strategies.

- Should the government mandate advance procurement in a long term manner, the result would be a locked in price component for a long period time, but that price may be well above or well below the current market. As such, that long term price may be the impetus for RRO consumers moving off the RRO thus stranding high priced hedges and leaving a smaller group of RRO consumers to wear the loss. This would effectively be a death spiral.

- If the market moves lower, and the RRO customers move to a competitive retailer then the RRO provider is left holding the bag, they will be applying the losses to a smaller group of remaining RRO customers. As previously stated the RRO has no “real” contract term or exit fees; therefore, this type of procurement leads to extreme volume risk at the back end of the term.
- Hedging strategy and volume forecast to correctly implement this strategy is a substantially more difficult than current 45-120 day methodologies.
- The further out in terms of procurement, the large the quantum of gains and losses that can occur. When brought back to a customer level, the adjustments could be astronomical compared to the bill.

- Proposing long term procurement without a mechanism to manage/allocate gains and losses is extremely dangerous. This type of procurement strategy is not in the RRO customers’ best interest, as the elevated risk of term procurement does not always outweight price stability , for example in 2010 Lethbridge RRO customers paid $20/MWh over the average market RRO rate due to long term hedges they procured at untimely market conditions.

- Long term procurement plans must have appropriate risk premiums applied to them, which increases the price, which negates the perceived lower costs of the current forward curve.

- Stability does not Guarantee Low Rates. Price stability can be achieved by procuring for a long time frame into the future, but this doesn’t guarantee the lowest price and has by far the greatest volume risk.

- At the same time if this is a direction that the GoA is determined to move in, then they will need to fast track the changes to take advantage of the historically low market/forward prices.
- However, making this type of announcement and subsequent transacting will move the forward market substantially higher.

- A stable price per unit does not translate into consistent bills from month to month. Consumer usage is a volatile bill component that has a direct impact on Distribution and Transmission charges (which far outweigh commodity costs)

Advantages – Advanced Procurement

- In concept, going to longer term hedges would not have opposition from REA WG as this is currently what they are doing now. The opposition comes from resetting the strategy on the fly before there is a determination of what happens to existing REA WG hedges and hedging programs.

- Again, as with a single Alberta RRO Rate this type of change could ease the burden of customer knowledge and comprehension regarding RRO pricing.

Centralized Procurement

Disadvantages – Centralized Procurement

- The REA WG's existing structure of sophisticated hedging would be eliminated, removing a part of their service offering and the value they provide to members, leading to reduced community economic employment and and development.

- Results in reduced REA governace, diminishing their responsibility and jurisdiction to their members, therefore diluting the value of the REA

- Centralized procurement would essentially lead to dictated rates and, due to the historical role of REA management, REA WG members will likely apply the performance of the RRO commodity price to the REA management (which may not be accurate). That is, REAs would effectively be accountable for actions they do not control.

- If central procurement is implemented there is uncertainty and unanswered questions regarding Commodity Risk Compensation (CRC).
    - In order to undertake the Beblow Method of CRC (recently approved by the Commission for the Big 3 RRO Providers) the actual hourly gains and losses for all sites provided are required. This would require a sizeable amount of work.

- With central procurement, only consumption can be hedged (not inclusive of Line Losses and Unaccounted for Energy) even though consumers wear the price risk on total settled energy (Consumption + Line Losses & UFE); therefore, allocations back to RRO providers would need to include forecasts and true ups on LL and UFE. This additional layer of complication is likely to cause increased risk premium allocation, administrative burden, and cost for the REA WG.

- To avoid issues as noted above with commodity risk compensation, the options available are limited to either procuring load following products from the market, which will be costly as it is an illiquid non-transparent product carrying a high degree pricing premium that would only be supplied by two or three parties in Alberta OR a new commodity risk compensation structure that is equal, fair, and applicable to every RRO needs to be created. Unfortunately, this creates another cross subsidization challenge.

- Centralized procurement has to be associated with the procurement of hedges only. It cannot include commodity risk compensation (CRC). CRC effectively has to be at a provider level, however, CRC is part of the "Commodity" cost in the current RRO Enery Price Setting Plans.
  - Someone will have to validate all of the CRC calculations and volume forecasts.
  - Weighted average hedge price is based on a forecast of commodity volume exposure, and CRC is based on actual volumes consumed and the associated hourly gains and losses. Every site will consume more or less than forecast and this variance will not be consistent across the province because weather is not consistent across the province (as weather is one of the most influential aspects to electrical load).
  - The method of CRC currently approved by the AUC could work for each of the REAs, however the outcomes of CRC would be different because consumers in each REA would have different consumption patterns (i.e. irrigation and grains dryers in different geographic regions will have diverse daily consumption volumes due to weather conditions across the province) which would result in different gains and losses for each hour, and these have an effect on total CRC.

Advantages – Centralized Procurement

- Movement to central procurement is necessary to create anything approximating a consistent RRO rate across the province.
  - Homogeny of procurement procedures and processes will not transpire if procurement stays with the providers.

- Without some form of government intervention, separation of the procuring entity from the RRO providers would be virtually impossible.
- Creates separation of retail offerings from the Big 3 RRO providers and their competitive arms (EEA/Encore, EEC/Enmax, DERS/DEML).
- The separation of portfolios from providers is much better from a procurement standpoint.
  - Reduces grey areas.
  - Self-supply limitations for RRO providers are eliminated.
  - Augment flexibility to conceal position and secure larger deals in the OTC market.
- There would not be a problem acquiring necessary volumes whatever the RRO pricing window
  - 45 days, 120 days, annually etc.

- Would be the most efficient procurement methodology with respect to volume acquisition.
  - As previously noted, it will not result in the exact same price across profiles or distribution networks without significant cross subsidization.
  - Creates economies of scale.
  - Potential for multiple purchasing entities for portions of load or for different RRO providers as an option.

Options that do not require advanced procurement;

When considering RRO options that do not require advanced procurement, the REA WG assumes that the MSA is referring to the potential return from a form of flow through pricing mechanism for the RRO product. While the REA WG does not ultimately believe this concept is completely against the spirit of the

RRO, the move back to a flow through of Alberta Hourly Power Pool price as the RRO Rate would require some revision to the existing RRO legislation (AR 262/2005). At the same time, if the REA WG hedges remain unresolved changing the RRO rate to a flow through price would be potentially crippling to the REA WG in a relatively short time frame. As such, the REA WG cannot support this type of change without financial settlement of all their existing hedges.

Disadvantages – Options that do not require Advanced Procurement (Flow through pricing for RRO)

- Previously the GoA's attempt to move the RRO to flow through pricing was extremely unsuccessful and the ultimate impetus for the move to the advanced procurement model (that was also unsuccessful), the failure of that methodology led to realignment of the RRO to the current format.
    - Empowers a "what have you done for me lately" mentality when spot pricing becomes volatile
    - Metering cycles can span inordinately high spot periods that don't align with published monthly pricing, and flow through rates lead to far more customer complaints, concerns and questions even when pricing is good.
    - In combination with the fact that RRO consumers are metered by Daily Cumulative Meters (DCM) and as such are assigned a deemed profile, the application of hourly prices to a deemed profile results in RRO consumer confusion with regards to justification of bill amounts.

- The REA WG membership is comprised of predominantly farming communities that budget quite closely, and therefore limited variability from month to month even on the commodity component of their bill is important to our members.
    - Customer base wears all the risk, and price volatility is the nemesis of the RRO rate base.

- Hard for Customers to validate rates as they are based on deemed load shapes with limited visibility and flow through prices must be trued up to account for UFE and Line Losses.
- High spot prices generate extreme amount of negative press, political pressure and customer complaints from REA WG members (and traditionally from all constituents).

- The REA WG members have greater volume than the average residential site, so greater price per unit volatility applied to greater volumes means more expense risk for farm customers as opposed to Residential urban RRO customers.

- Because no RRO Provider can keep consumers on the RRO, they are free to leave whenever they want. In the case of the REA WG organizations this creates a lot of position risk as RRO customers can move back to the Stable Cooperative Rate or to a retailer.

- As previously stated, the misalignment of hedging due to changing of exposures (RRO which would involve no hedging to Stable Cooperative rate which is for all intents and purposes an annual) creates mismatch of volumes that results in risk. That is, when spot prices are low, REA members will move to the RRO, and when RRO prices are higher than the cooperative stable rate they will move back to the cooperative rate further exacerbating hedging complexity.

- This would dilute the value proposition of the REA WG organizations, creating lost value of service offerings, and product distinction with the potential for job loss and reduced REA financial solvency

Advantages – Options that do not require Advanced Procurement (Flow through pricing for RRO)

- Lower average consumer cost
    - In the current market the customers would be getting lower costs, and over the history of the RRO the spot price averages have been lower than the RRO average prices.

- From the RRO provider perspective the flow through rate eliminates any supplier risk and requirements for hedging.

- Customer Risks can be managed via cap or collar mechanisms, but this would require the implementation of deferral accounts and revisions to the existing RRO legislation.

Introduction of deferral accounts or changes to bill smoothing;

The current legislation for the provision of RRO service (AR 262/2005) states very clearly in Section 3(2) that "A proposed regulated rate tariff must not use, provide for or contemplate any deferral accounts, true-ups, rate riders or other similar accounts or devices for energy related costs". Obviously should this directive change, then this section of the RRO Regulation would require updating. In doing so, although somewhat innocuous, the small change would have significant effects on the rest of the competitive market in that competitive retailers, who prospectively price commodity risk, would have to compete with an entity that is able to recover all risks with 100% accuracy. With the door open on commodity deferral accounts, the impetus for accurate volume forecasting diminishes and open positions are immaterial to RRO providers. If deferrals are allowed on the energy component of the RRO, which effectively means that the consumer wears all the risk of hedging, then serious consideration should be given to the more cost effective means of RRO consumers bearing all of the risk in straight flow through options.

Disadvantages – Deferrals or Bill Smoothing

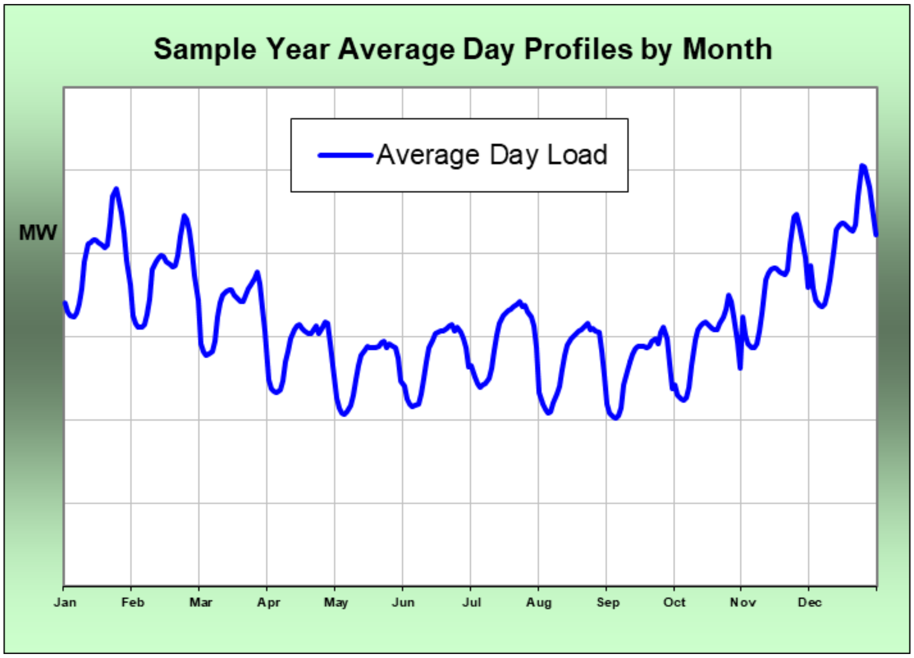
- Deferrals aren't theoretically fair: a group of people that have created a loss or a gain are not the same group of people that either get it or pay for it.

- Cost Breakdown - currently the bill is made up of transmission, distribution, energy, fees, administration, and energy. Over the last twelve months the energy component only comprises about 15% to 20% of the average RRO customer's bill.

- The volume component, which changes each month, can affect the total cost of delivered power as much or more than movements in price. The consumption of identical sites with the same profile can vary significantly from one part of the province to another simply by virtue of the weather each location is facing.

- Stable energy rates as the lead proponent to create bill smoothing will create disappointing results. Even if the Energy Rates remains stable, Rate Riders, Distribution and Transmission Rates all have consumption volume based components that fluctuate on a monthly basis based on changes to energy consumption. Even if Energy Rates increased 100%, the Energy Portion of a customer's bill would still only account for 25% of an average monthly total.

- Fixing price is only part of the equation. There is no denying that a consumer's electricity consumption changes from month to month, and the impact of volume fluctuations on distribution, transmission, and even administration outweighs the paralleling effects on commodity.
    - An visual example of the Average Day profile by month for the REA WG is as follows:



- As displayed in the graph above, month to month volume variation for REA WG members produces variance in monthly invoices regardless of rate stability
- If the GoA implements bill smoothing or budgeting that incorporates bill consumption volume averaging, and the option remains for RRO consumers to leave with limited notice, there could be significant outstanding receivables should an RRO consumer leave after a period of invoicing associated with the highest volumetric months of the year. In short, this presents significant risk to the RRO Provider and if priced correctly to account for these risks, the corresponding premiums would result in significantly higher costs to RRO consumers.

- Implementation of deferral accounts also will increase the regulatory cost and burden on the REAs, as this new enhancement would require the REAs to go through the AUC approval process due to the complexity and rationalization needed to implement these deferrals.

Advantages – Deferrals or Bill Smoothing

- If deferrals or bill smoothing is mandated, the REAs within the REA Working Group have the capabilities and skill to implement it. Because REAs are not for profit and the owners of the business normally have a long term view of investment, deferrals or true ups would not be an issue.

When and how a change to the RRO should occur.

Given the significant hedging volumes that have been executed in line with the current RRO regulation and the financial impact it has, and will continue to have, on the REA WG members, the REA WG resoundingly supports that any changes to the RRO take place after the resolution of the existing RRO hedge position issue. Further, there are significant electricity market risks and political risks that are causing greater upheaval in the market. Specifically, the RRO Price Cap, the introduction of a Capacity Market, the Renewable Energy Program, and the transition of coal fired assets represent massive structural changes to the market which may or may not pan out as intended.

Comments on When and How a Change to the RRO Should Occur

- The REAs have already been buying long term hedges to smooth the price over the long term. Now that the price cycle is perceived to be at a lower level the consideration to reset this strategy is not prudent.
    - Mandating longer term hedge acquisition will result in forward markets moving higher, thus working in contravention of the perceived low market prices currently being experienced. Of note, RRO prices are based on forward markets and hedging, not spot prices.
    - Should resetting the long term strategy be desired, the REA WG reiterates that the playing field must be leveled before doing so and this will effectively require clearing up existing

hedges or waiting until a point at which no RRO Provider has hedges (i.e. stopping the execution of hedging for RRO now will not affect the existing hedges in place). Should this strategy be implemented, there will be a lot of speculation around what forward rates could be at the time existing hedge positions were actualized. Forward prices at that time could be much higher than they could have been hedged at now.

- Changes to the RRO should only be undertaken after careful consideration and consultation with stakeholders. Quick turnarounds, such as this response, may not allow some stakeholders adequate time for consideration or response.

- Modifications to the RRO should be initiated after RRO consumer groups call for changes to these structures. The existing RRO system is not perfect, but it is manageable for all parties. REA members on the RRO all had and continue to have ample opportunity to convert to competitive contracts and they were not forced into high rates. Current GoA intervention, notably in the form of the RRO Price Cap, is upsetting this balance and resulting in hedging losses for REA WG members.
    - Of note, the RRO Price Cap is intended to be implemented on June 1, 2017 which is less than two weeks away and, at the time of the creation of this response, there has been little to no clarity on how it will be accomplished or what an entity must do to qualify for the full cost coverage.

- Make the change for a time point in the future, allowing for current practices to be stopped and preparations for new ones to occur (unless the GoA intends to buy out the hedges that currently exist for the RRO exposure of the REA WG).

- This has to be a longer term change process if leveling the playing field immediately is not an option.

- After the effects of the Price Cap have been experienced in the market. That may turn out to be great or be a huge backfire. A staged pragmatic approach would be prudent as opposed to a knee jerk reaction or a massive wholesale change.

- Stakeholder engagement can be undertaken now, and determination of a new RRO structure can be decided on, however changes shouldn't be implemented until the end of the current RRO regulation in April of 2020.

Summary Messages

- REAs are in a heightened position of risk because they took a long term hedging positions, and the government has designs on reseting their existing position to the exact same struture without a completed arrangement to resolve the REAs hedges (take a long term position, but do it now because the prices are low, in fact artificially low, due to government interference).
    - REAs are hanging in limbo, and attempting to stay competitive with equity eroding.
- There is a need for further stakeholder engagement.
    - For something as important and intricately connected as the provision of RRO service, the MSA should be following its customary Stakeholder Consultation Process. Undertaking a truncated form of stakeholder engagement will result in perspectives being missed and impactions resulting in financial losses not being considered. Proposals for any change to the RRO regulation should be presented and vetted by all Stakeholders prior to recommendation to the Government. For simplicity, presentation of any proposed "straw dog" will allow the entire market the opportunity to comment in greater detail than just the categorical areas provided in this engagement. The MSA may want to follow the AESO's lead in the Capacity Market implementation involving Stakeholder Working Groups that have been created to ensure proper vetting and validation of proposed changes. In short, it is imperative that the Government of Alberta does not rush into RRO regulation modification. Doing so could result in the same financial consequences of subsequent actions as is currently being experienced with the PPAs.
- The Working Group of Operating REAs will do whatever the GoA dictates for the RRO, but need to be kept whole and not put into a competitive disadvantage based on the hedging practices they have historically followed in line with the RRO regulation.

RRO Review – MSA

May 19th 2017

Preamble:

It is interesting to observe that the Minister has tasked the Market Surveillance Administrator (MSA) with a review of alternatives for the Regulated Rate Option (RRO). This is the correct entity to examine alternatives as the RRO is and will continue to be a product of the de-regulated energy market. The term Regulated Rate is a misnomer – only the process and a small percentage of the monthly rates are regulated, the balance of the monthly charge is a product of the forward market and the procurement methodology.

As the Independent Advisor for all three of the major RRO providers for the past seventeen years I have had the opportunity to have first-hand experience with a variety of procurement alternatives, risk mitigation strategies and rate setting mechanisms and to view the effects of these alternatives on consumers.

As we look forward in a market that is undergoing significant structural change as it transitions from predominately coal-based generation to increased levels of renewables and low emissions generation the need to review the Regulated Rate alternatives as the default supply pricing for consumers is essential. This paper takes a look back over the past sixteen years to ascertain what lessons may be learned and looks at the 'new' objectives for the RRO on a go forward basis with potential options to achieve these objectives.

Lessons from the first sixteen years:

Alberta has had a Regulated Rate for residential, small commercial and farm customers since the initial industry de-regulation in 2000. The first RRO rates were to be established by the distribution providers in 2001; were determined by negotiated settlements with consumer groups; and were largely based on the procurement of energy from the de-regulated market facilitated by the PPA auctions.

The Regulations initially anticipated that the RRO would be transitional as retail offerings became competitive and widely available, ending within three years for some consumer segments and within five years for all sectors. Unfortunately the energy market in 2000 and 2001 did not un-fold as anticipated with very high prices occurring in the California and Pacific Northwest domino'ing into the Alberta market. RRO Rates in 2001 were set by Regulation and a means to recover shortfalls between market prices and rates was established using deferral accounts between consumers and RRO Providers.

These rocky beginnings for RRO have not been the only issue over the ensuing 16 years as the transitional nature of the Rates has been adjusted and extended to accommodate lower levels of retail competition than expected. In 2017 some 60% of RRO eligible consumers are still on the regulated rates and each of the three major providers continue to use short term market procurement mechanisms to acquire energy and set rates.

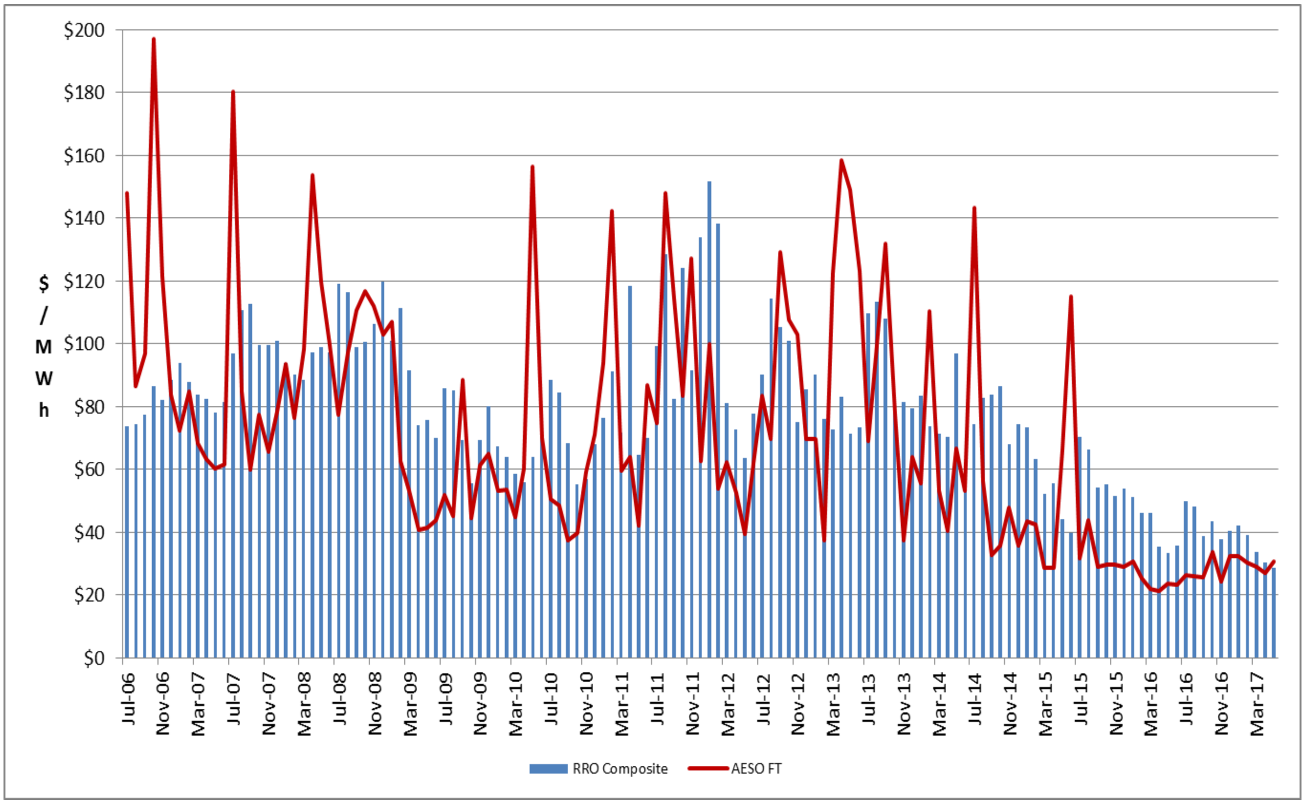


Figure 1 - Monthly RRO vs Hourly Flow Thru

Over time the market-based energy component of the rates has made up some 90%+ of the monthly rates and additional charges for risk mitigation, return margins, portfolio credit costs and recovery of industry charges such as AESO fees, hourly uplift and RAM make up the remaining 8 to 10% of the monthly rates. From 2002 to 2006 the three major providers used a variety of procurement mechanisms, risk mitigation and rate structuring methodologies to meet 'default supply' pricing with the expectation of full retail completion by 2006. As it became apparent that an RRO mechanism would be required beyond 2006, the current RRO Regulations were implemented.

Figure 1 provides a look at the RRO Rates since July 2006 to May 2017 set out as a volume weighted average composite of the Residential Rates for the three main Providers (EPCOR, Enmax, Direct Energy). As a comparison, the graph includes the equivalent month's AESO hourly flow thru cost adjusted for the peakier load shape for residential consumers and including an administrative and return margin of $7.00/MWh to reflect the add-on charges such as AESO fees and a cost for billing, collections and credit.

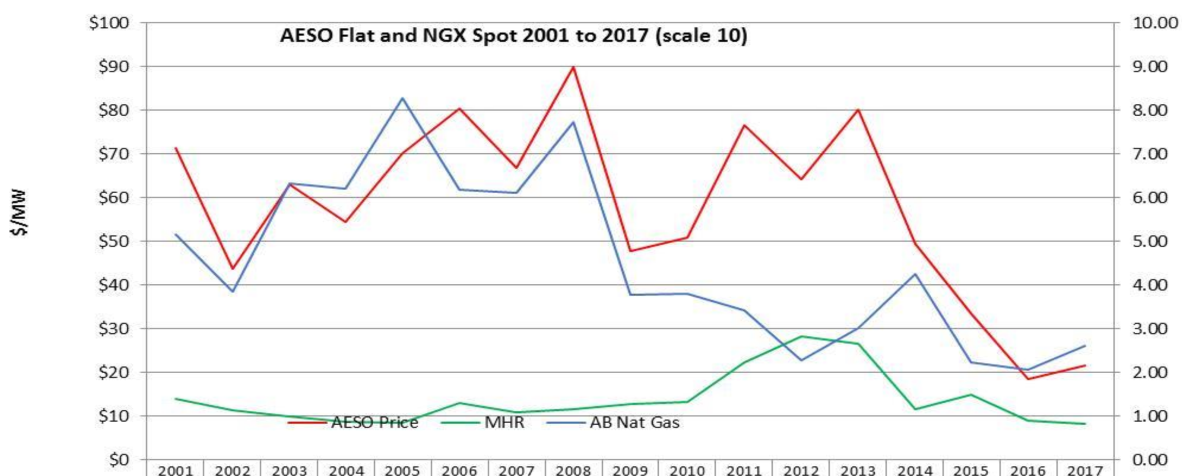
It is edifying to spend a bit of time looking at these two price outcomes through time to ensure we do not draw some wrong conclusions for future RRO mechanisms. The RRO regulations for the eleven year time period in the graph have essentially required the RRO provider to acquire energy in the short-term market –a maximum of 45-days ahead until a very recent change to 120-days ahead. This short term market is primarily influenced by short term price volatility in the hourly market and the perceptions of forward price volatility over the next two to three months.

Two Distinct time Periods:

The result has been a relatively high degree of rate variability due to a lagged tracking of the short term hourly price. It is useful to examine this data in two time periods as this may help any examination of future RRO alternatives.

From July 2006 to June 2015 the power market reflected a range of market fundamentals including the impact of gas prices (see Figure 2 below), short and longer term generation and transmission outages, weather, 'economic withholding' strategies, and general supply and demand shortages and surpluses. Over this time period the RRO was primarily a construct of short term forward prices, a risk margin to compensate for differences between load shapes and block products and variances in forecasts, a return margin for provision of services, and a charge for other administrative costs.

The average RRO rate over this time period was $85.28/MWh and ranged from a high of $151 to a low of $40/MWh. By comparison the average flow through cost for consumers with a similar load shape and including the return margin and administrative fee of $7.00/MWh averaged $79.85/MWh with a high of $196 and a low of $29/MWh. The difference between the two is approximately $5.50/MWh, an amount roughly equal to the risk margins required for managing the portfolio and forecast risks required by the RRO Regulations.



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
AESO Price	71.41	43.84	62.98	54.53	70.19	80.48	66.84	89.93	47.89	50.78	76.60	64.29	80.19	49.45	33.41	18.40	21.63
MHR	13.9	11.4	10.0	8.8	8.5	13.0	10.9	11.6	12.7	13.4	22.3	28.3	26.6	11.6	15.0	8.9	8.3
AB Nat Gas	5.15	3.86	6.32	6.20	8.28	6.18	6.12	7.73	3.78	3.80	3.43	2.27	3.02	4.25	2.23	2.07	2.62

Figure 2 - Hourly Power and Nat Gas Prices

Over the past two years from July 2015 to May 2017 the Alberta power market has had substantive changes and the RRO rates and Flow Thru prices reflect these differences. The average RRO rate has dropped to $44.86/MWh and the Flow thru cost to an even lower value of $28.55/MWh. The $16.30/MWh differential between the two is much greater than the previous differential that roughly equated to the risk margin. This $16.00 differential reflects three main factors:

- a significant reduction in the variance between hourly peak prices and flat prices From July 2006 to Jun 2015 - AESO 7X16 price averaged $85.25/MWh compared to AESO 7X24 averaging $66.71 a difference of $18.50/MWh – From July 2015 to May 2017 AESO Peak was $22.36 compared to AESO Flat at $20.36 just a $2.00/MWh differential. Over the same 23 month period the forward market still showed an $8.50/MWh differential between Flat and Peak;
- the RRO still reflects added values for risk margin to offset forecast variance and shaping risks; and most significantly
- the current forward market transacts at a significant premium to the hourly market each month due to a lack of sellers willing to take positions to delivery. The NGX 45-Day Index for the July 2015 to May 2017 time period averaged $33.07/MWh a $12.70 premium to the average AESO 7X24 price of $20.36/MWh. This reflects the lower number of forward sellers from the PPAs that were turned back to the Balancing Pool and the current offer strategy of the Balancing Pool in the hourly market.

  As a comparison the Average NGX Index price from July 2006 to June 2015 was $69.13/MWh, a premium of just $2.40/MW from the July 2006 to June 2015 average AESO 7X24 price of $66.71/MWh.

The consequence is that around $10/MWh of the difference between the RRO rates and the AESO Flow thru in the past 23 months is a result of the absence of sellers in the forward market – the balance being some $3.50 of risk margin and $2.50 from lower peak to flat price ratios.

Although we may see a continuation of these trends in the next six to twelve months, it is important to recognize that these market factors are unlikely to continue over the medium and longer term timeframes. It would be very risky to adopt an RRO that reflects short term hourly prices on the basis of the past two years of experience when almost all factors indicate probable returns to price volatility and to significant risks for un-hedgeable add on costs.

Looking Forward:

The Minister in her letter outlines three major objectives for examining alternatives to the RRO:

> "conduct an analysis and provide a report with options for enhancing the design of the Regulated Rate Option to provide ***long-term***, ***stable*** and ***affordable*** prices for Alberta's electricity consumers into the future."

It is interesting to observe that these were NOT the initial objectives of the RRO in 2001, and have never been the primary objectives for RRO. As indicated the historic role of RRO was to provide a mechanism for distribution providers to charge consumers for the use of electricity that were not on a retail contract. The intent of the RRO Regulations was twofold:

- Ensure that RRO Rates were not an impediment to the development of the Retail market; and
- Ensure that the requirement to procure energy for the Rates was fostering the development of the forward market for electricity

These requirements resulted in energy procurement strategies that required all buying in the open and competitive forward market and restricting portfolios to short term products, generally month ahead contracts that reflected significant underlying short term price volatility from perceived and actual shortages of energy.

Although it is difficult to speculate on what the RRO rates would have been with a change in the primary objectives for establishing rates to the three objectives set out by the Minister; by looking to provide longer term, stable and affordable rates then strategies such as buying annual contracts for portions of the portfolios, flowing through a percentage of the peak volumes to real-time pricing to reduce settlement, shape and forecast risks. Setting rates on a quarterly or semi-annual basis and/or setting maximums for rate variations between periods and using deferral mechanisms to transfer costs to later periods could add significant rate stability at lower rate levels.

Such strategies would most certainly have had adverse consequences for retail marketing and we would likely see higher levels of consumers staying with the RRO Rates. Suffice to say that a policy that emphasizes long-term rate stability and affordability is at best market neutral with respect to retailers and potentially adverse if external factors are used to offset costs to RRO consumers. The proposed rate cap of 6.8 cents per kwh is a case in point as the early indications were that this cap would be maintained by payments from the funds collected from carbon pricing.

It is not clear if the Minister is allowing for such offsets in the request to the MSA, but it must be assumed that some form of Rate setting that considers factors other than just energy pricing and adding margins for risks, administration and returns for service need to be considered.

The Minister further requested that the MSA identify options that provide for: "affordability of electricity; predictable and stable rates; and minimized regulatory and administrative costs." She also requested that the report "identify any issues or possible challenges associated with transitioning from current Regulated Rate Option arrangements to alternative approaches.

i) whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta;
ii) changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement;
iii) introduction of deferral accounts or changes to bill smoothing; and
iv) when and how a change to the RRO should occur.

Avoid the Ontario Syndrome

It is apparent from these requests that during the period of transitioning the energy market from its current dependence on coal-based generation to greater reliance on natural gas and renewables, that the consequences do not accrue to consumers as they have in Ontario. In 2008 Ontario embarked on a program to transition its power market to zero coal, more renewables, continued use of nuclear, incentives for energy efficiency and greater use of natural gas for baseload and peaking requirements.

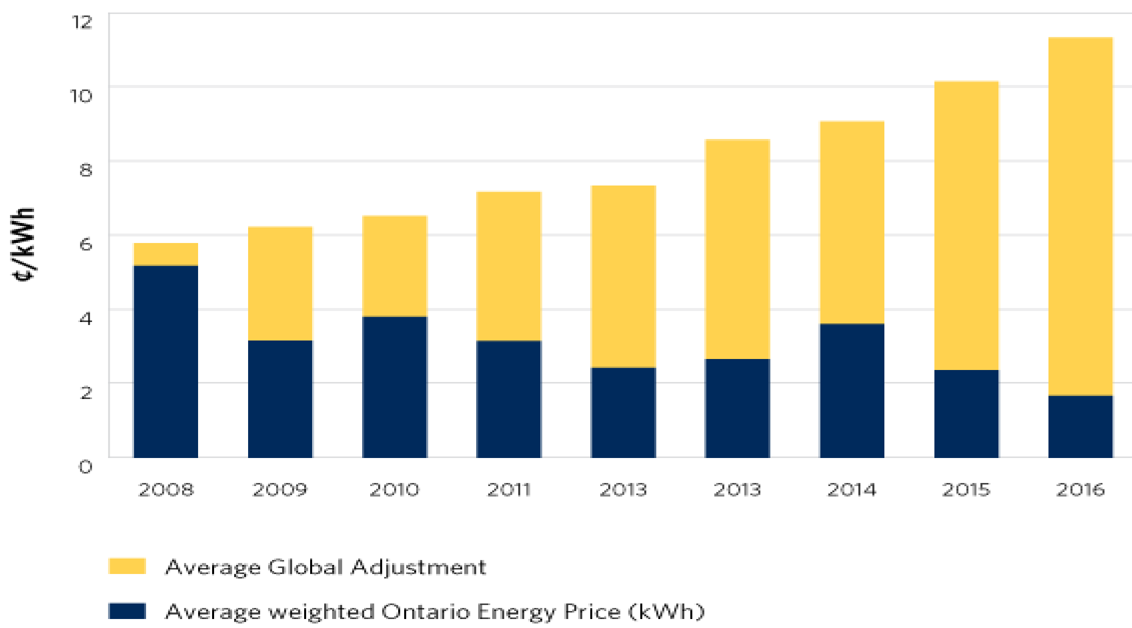


Figure 3- HOEP & GA - IESO Website

Many of these changes to the market were facilitated through direct contracting by the Ontario Power Authority (OPA) rather than by allowing energy prices to rise to attract the needed investments. The result has been a significant increase in the need for cost recovery from electricity consumers through a direct charge mechanism termed Global Adjustment and relatively little concern for actual price levels in the hourly market.

The impact of this is seen in the graph in Figure 3 from 2008 to 2016. The energy component of pricing was over 90% of the combined Hourly Price and GA charge in 2008 with an overall cost of just under 6 cents/kwh. By 2016 the combined cost has risen to over 11 cents per kwh with less than 15% of this being energy. The consequence for Regulated Rate programs that are primarily based on energy hedges is that a significant portion of the cost to the consumer is not included in the energy cost and hence is not included in the Rates.

If we look at Alberta's current initiatives in the Alberta market we see a number of activities that are not directly included in hourly pricing and hence would not be reflected in forward costs. An indication of the forward prices not reflecting all initiatives as energy prices is seen in Figure 4 below. Note that the Calendar prices for Cal 21 and Cal 22 moved below their $60/MWh levels in early 2017 as it has become apparent that the initiatives such as renewable contracting and capacity markets are no longer priced as hourly energy.

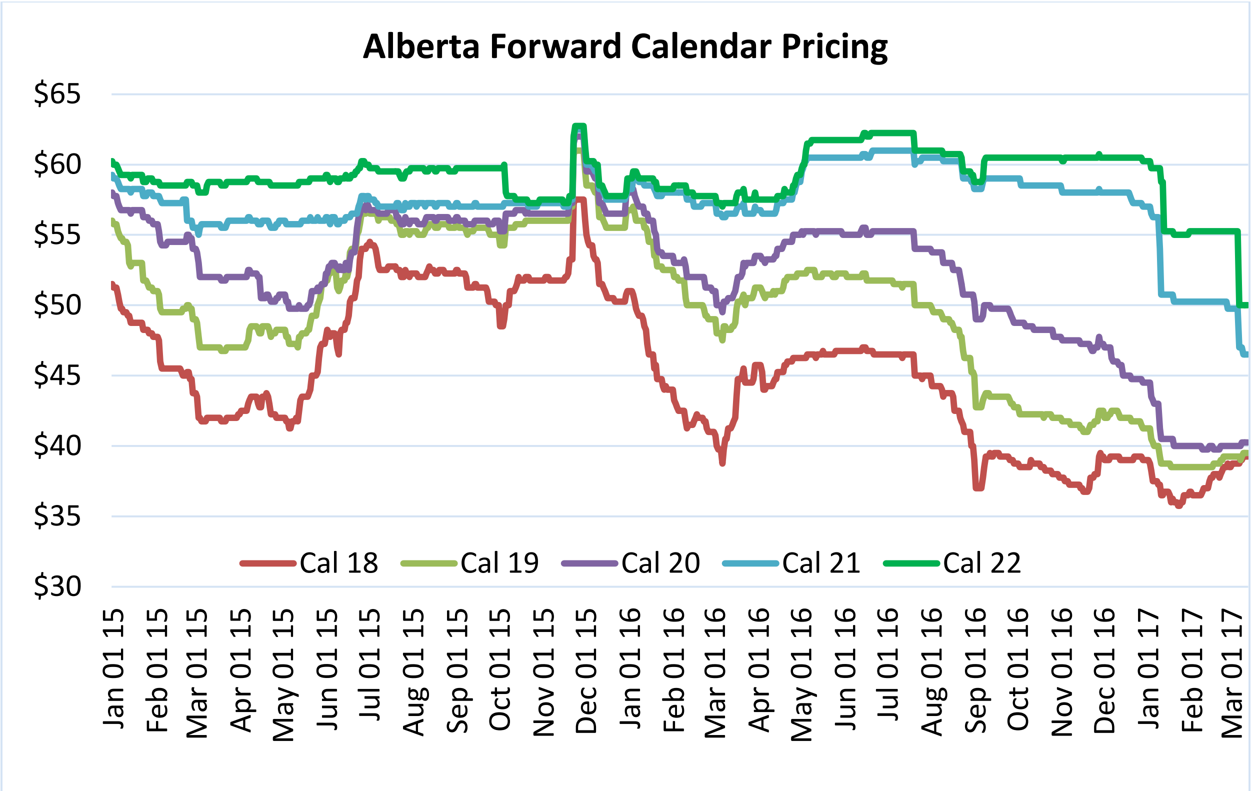


Figure 4 - Forward Calendar Pricing - Jan 2015 to April 2017

Included in these Government and AESO initiatives are:

- recovering losses incurred in operation of the PPAs by the Balancing Pool;
- Early coal phase-out – negotiated to 2030 – payments direct to generators;
- Bilateral contracting for renewables – up to 5000MWs
- Capacity markets;
- Enhanced Interties supporting low emissions imports
- Carbon pricing – up to $50/tonne by 2022
- Coal to natural gas conversions
- Distribution connected generation
- Energy efficiency programs

In addition to these initiatives the market will also encounter a significant transition in 2021 as the current PPAs expire and revert to their original owners. These owners may choose to continue to operate or will look to early closure or potential conversion to gas fired generation.

In addition the MSA has begun to examine the Enforcement Guidelines with respect to Economic Withholding and all ten of the responses from sellers and generators has indicated a need to retain the ability to exercise economic withholding. In the 2011 to 2013 time period economic withholding was a very effective mechanism to sustain market prices higher than those supported by natural gas prices alone as seen in Figure 2.

In those three years the Market Heat Rate (MHR) averaged 25.7 times as compared to the longer term average excluding those three years of 11.1. It can be expected that generation owners may return to use of economic withholding at the conclusion of the Balancing Pool's operation of the PPA units.

The result is that a Regulated Rate mechanism that only uses prices from the forward market may not meet any of the Minister's objectives for long term stability and affordability. Additionally the potential risks in the short term hourly market with loss of capacity on early closure of coal units, added costs from carbon pricing, uncertainty in operation of capacity markets, higher costs from renewables, and retention of economic withholding would indicate that hourly flow through is unlikely a means to achieve either stability or affordability.

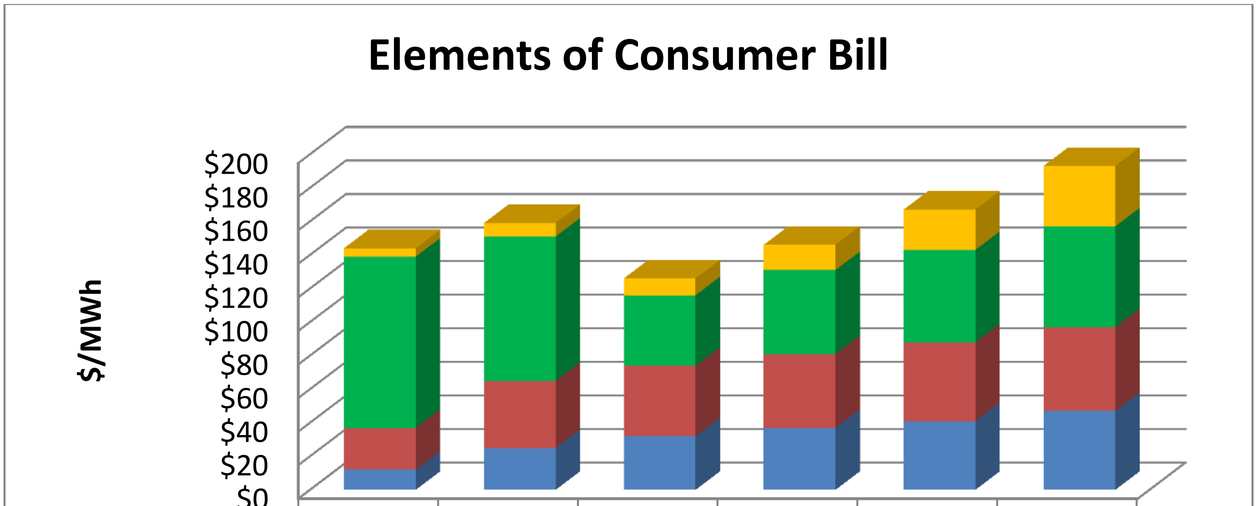
Additional Concerns:

The range of alternatives for a Regulated Rate that provides long term stability and affordability is relatively limited if it is restricted to the current structure with energy hedges plus factors for risk, administration and returns for service. The concern is that consumers don't just look at the energy portion of their monthly bill with respect to concerns for affordability. There are four major components to consumer bills that need to be considered as illustrated in Figures 5 and 6 below. Figure 5 has values from 2008, 2012, and 2016 and projected to 2018, 2020 and 2024. Figure 6 shows the four elements as a percentage of the total cost in the same time periods

The four Elements are transmission, distribution, energy and 'Other' and are estimated composite costs for a typical consumer in Alberta with each cost expressed as $/MWh in Figure 5. Transmission costs have risen due to the major transmission re-build initiated in 2008 and expected to level off by 2024. Distribution costs vary significantly across the province based on the service territories and are much higher in rural areas than the major cities. All distribution charges are expected to be moderated by Performance Based Rate-making (PBR) through time. Transmission and Distribution (T&D) was around 25% of consumer costs in 2008, but have risen to nearly 60% as energy prices declined by 2016 and costs rose. In the long term T&D will likely make up about 50% of consumer costs.

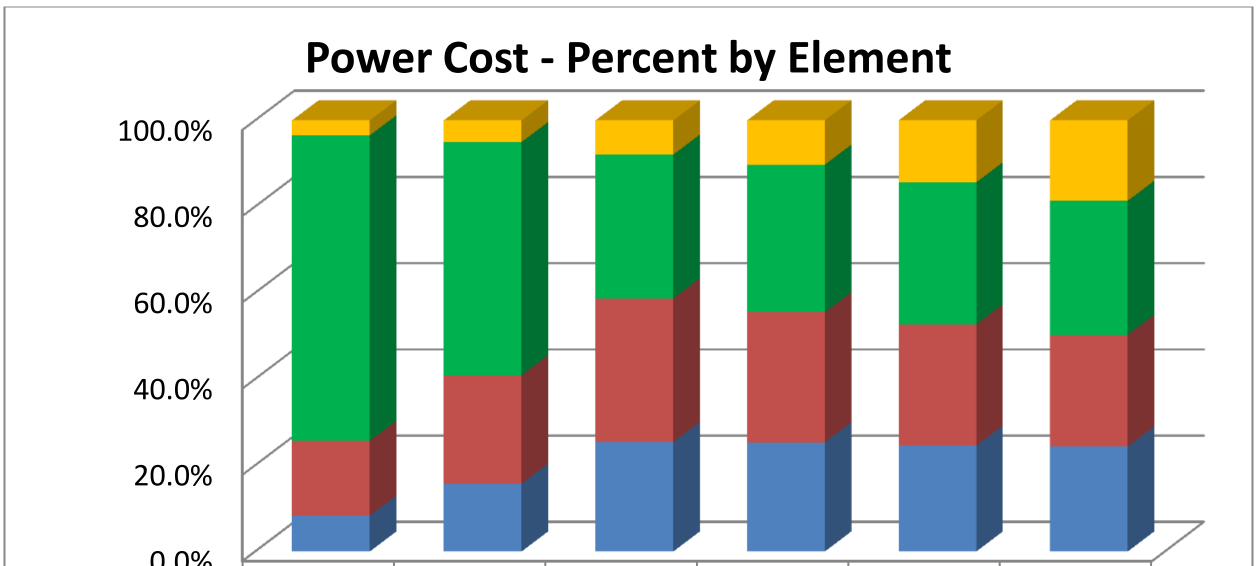
In 2008 the high prices for electricity driven by high gas prices resulted in the energy component of the cost exceeding 70% of the consumer bill and the result was effective hedging with the RRO program. However electricity prices have declined and the energy component in 2016 was less than one third of the monthly cost. Based on the current forward price curves this may further decline to 30% of the cost depending on where the costs of the various initiatives end up.

In the two graphs all costs not included as T&D or Energy are being included in the 'Other' category and include the charges for the various AESO initiatives. These are likely to rise to 15% of the overall costs by 2021. This is without any impact of the use of potential carbon revenue funding for projects such as energy efficiency, renewable contracting, or coal conversions. If these costs are included and added to the consumer's bill, then Other will increase rapidly and significantly. Unfortunately this is more of the Ontario Syndrome – financing for most of Ontario's 'green initiatives' ended up in Global Adjustment add-ons.



	2008	2012	2016	2018	2020	2024
Other	$5.00	$8.00	$10.00	$15.00	$24.00	$36.00
Energy	$102.00	$86.00	$42.00	$50.00	$55.00	$60.00
Distribution	$25.00	$40.00	$42.00	$44.00	$47.00	$50.00
Transmission	$12.00	$25.00	$32.00	$37.00	$41.00	$47.00

Figure 5 - Elements of RRO Consumers Bill



	2008	2012	2016	2018	2020	2024
Other	3.5%	5.0%	7.9%	10.3%	14.4%	18.7%
Energy	70.8%	54.1%	33.3%	34.2%	32.9%	31.1%
Distribution	17.4%	25.2%	33.3%	30.1%	28.1%	25.9%
Transmission	8.3%	15.7%	25.4%	25.3%	24.6%	24.4%

Figure 6 - Percentage by Element

Any new RRO alternatives must consider the potential for 'hedging' the 'Other' charges as well as energy if the objective is to provide stable and affordable rates. Currently the T&D component is regulated and the tariff charged by the distribution owners for transmission and distribution must be approved by the regulator (AUC). The RRO Provider should be viewed as a portfolio manager that includes elements of energy hedges as well as components of the new initiatives being undertaken by the AESO.

For example this could include consideration of using a Renewable Portfolio Standard (RPS) mechanism for RRO that would parallel the overall levels of Renewables in Alberta, and could consider direct contracting of renewables by the Providers.

Similarly the RRO Provider could act like LDCs in some jurisdictions with Capacity Markets and become the "Buy" counterparty to the Capacity Market sellers, separate and apart from any central buying by the AESO.

Extending the RRO portfolio to include short and longer term energy, renewable targets, callable capacity contracts, and counterparty contracting for emissions reductions initiatives would enable the components of the 'Other' charges to be included in the Rate setting rather than being external add-ons and would allow them to be managed to preserve affordable and stable rates.

Possible Options:

The requirement then is to design an RRO program that manages both the energy and Other elements and remains consistent with an un-regulated power market. This can be achieved by enhancing the portfolio available to the RRO providers to include longer term instruments, to include elements in the "Other" charges and to provide for setting rates for longer terms with features to support rate stability.

The term for new Regulated Rate Regulations should be set to 2030 with distinct three time periods:

- Three years to December 2020
- Five years from January 2021 to December 2025
- Five years from January 2026 to December 2030

Up to 2025, all consumers below 205MWh of annual consumption would continue to be eligible for the RRO rate which should be properly renamed as the Default Supply Charge (DSC). The main characteristics of each of the three time periods should include elements of the following:

- Three year term 2018 to 2020
    - Transitional from energy only to broader portfolio
    - Would include energy hedges only – could include monthly and quarterly products;
    - Rates based on procurement of hedges out to 2020;
    - Risk margin includes a fixed and variable component (for example $2.00/MWh plus 2% of hedges)
    - Return Margin set by similar to current regulations
    - Procurement methodology to be proposed by Providers
    - Rates include agreed administrative and external costs

    - Rates set quarterly starting in January 2019
    - Rate variability limited to 20% higher than previous quarter
    - Overall Rate Cap of 6.8 cents set for any quarter
    - Costs in excess of rate cap carried to subsequent quarters for recovery (recovered from carbon fund in 2021 if necessary)
    - Portfolio design to include elements of renewable and carbon offset programs as well as the pending capacity market for 2019 and 2020

The first five year term for RRO after the end of the PPA era would be to achieve rate stability as the market accommodates reduced supply from coal and greater supply from renewables. The use of direct contracting by the RRO suppliers would provide an added 'buy' element to the AESO being the sole counterparty for new sellers.

- Five Year term 2021 to 2025
    - Portfolio to include energy and counter-party contracts for new initiatives
    - Include a renewable portfolio standard (RPS) component equivalent to the provincial targets (30% renewable by 2030)
    - Allow for direct contracting of renewable by the portfolio with offsets to any charges from the AESO for all contracted renewables
    - Allow for direct participation in Capacity Markets as counterparty to sellers – with a call on contracted capacity
    - RRO providers entitled to any offsets for carbon reductions in respective portfolios
    - Rates set quarterly with 20% maximum variability
    - Risk margin, portfolio management fee and return margin set annually and reviewed for adequacy by the MSA
    - Energy Portfolio to include longer term (multi-year), quarterly, and monthly contracts
    - Portfolio can include a flow-through element up to 5% of forecasted energy
    - Portfolio and risk management fees established with performance incentives and penalties
    - Remove 250MWh annual maximum – allow any consumer to sign on to RRO

The second five year term should be directed to the RRO or DSC becoming a full competitive offering in the market including in completion across the three main distribution jurisdictions.

- Second five year term 2026 to 2030
    - Review adequacy of contracting terms
    - Review return and portfolio margins
    - Review need for geographic monopoly areas
    - Consider allowing RRO providers to compete openly for customers in other RRO markets
    - Review adequacy of Quarterly rates

Oversight:

It is anticipated that the RRO or DSC would ultimately be ‘policed’ by the market and would require minimal oversight or regulatory intervention. Despite the term RRO being retained and including the perception of a ‘Regulated’ Rate, the Rate cannot be Regulated in an open and competitive energy market. It must include elements of energy and hedged offsets to other initiatives if put in position in advance of central AESO contracting. As such the rates cannot be subject to short term review by the Regulator without causing undue prudency risk. Simply put the RRO provider cannot be second guessed every month on every decision.

The result is that the RRO needs to be a framework rather than a prescriptive process. It needs to encompass reasonableness tests, incentives for performance, and consequences for adverse results. It need not be reviewed by the AUC but should attract periodic oversight by the MSA with administration of incentives and penalties.

The alternative is the mechanistic approach used in Ontario with a third party determination of the energy component of the consumer bill every six months with a true-up of any variances and a mammoth monthly add-on for Global Adjustment that dominates the charge to the consumer.

A much more effective means to achieve rate stability and affordability is to include all new initiatives as hedgeable offsets within the RRO portfolios and let market forces achieve positive outcomes.

Specific Comments:

The Minister further requested that the MSA identify options that provide for: “affordability of electricity; predictable and stable rates; and minimized regulatory and administrative costs.” She also requested that the report “identify any issues or possible challenges associated with transitioning from current Regulated Rate Option arrangements to alternative approaches.

- whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta;

  No – need to enhance buyer involvement in the market – not limit it –already have too much central buying by the AESO.

- changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement;

  Yes – see above portfolio approach

- introduction of deferral accounts or changes to bill smoothing; and

  Yes to a limited extent and only as a risk mitigation strategy

- when and how a change to the RRO should occur.

  Start in 2018 with three year transition – then 5 year programs

Sheldon Fulton

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May 19, 2017

Market Surveillance Administrator
Attn: Mark Nesbitt, Manager, Retail and Investigations
VIA EMAIL: stakeholdersconsultation@albertamsa.ca

RE: Options for Enhancing the Design of the Regulated Rate Option (RRO)

Dear Mr. Nesbitt:

TransAlta is pleased to provide the following comments to the MSA. TransAlta proposes changes to the current RRO procurement process that will meet the stated objectives of the Minister of Energy, namely:

- Affordability of electricity;
- Predictable and stable rates; and
- Minimized regulatory and administrative costs.

The MSA has also asked specifically that stakeholders consider:

(i) Whether there should be one RRO rate for all eligible consumer (or customer category) in Alberta;

TransAlta supports the establishment of a single RRO methodology for all RRO providers. Currently, there are different methodologies across the RRO providers. This change aligns with the needs of Albertans in that by having a single RRO procurement methodology across the Province, regulatory and administrative costs will be reduced.

(ii) **Changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement;**

TransAlta proposes increasing the hedging window for all RRO providers from 120 days in advance to up to one year. This will help reduce volatility for RRO consumers and provide more stable and competitive electricity prices.

TransAlta also suggests the procurements be held at the same frequency as done currently, but with all RRO providers adhering to an auction process similar to that of EPCOR.

(iii) Introduction of deferral accounts or changes to billing smoothing;

TransAlta takes no position on the introduction of deferral accounts or changes to smooth bills.

(iv) When and how a change to the RRO should occur.

TransAlta believes that changes should be implemented as soon as possible.

Should you have any questions or comments, please do not hesitate to contact the undersigned.

Yours truly,

TRANSALTA CORPORATION

GLENN MACINTYRE
Senior Regulatory Advisor, North American Gas and NE Power

TransCanada
In business to deliver

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450 – 1st Street SW
Calgary, Alberta
T2P 5H1

Janene Taylor
tel 403 920 7682 / **fax** 403 920 2464
email janene_taylor@transcanada.com

May 19, 2017

Via Email

Market Surveillance Administrator
#500, 400 – 5th Avenue SW
Calgary, Alberta
T2P 0L6

Attention: Dr. Matt Ayres
Market Surveillance Administrator

Dear Matt,

Re: Market Surveillance Administrator ("MSA") Notice to Participants and Stakeholders Options for Enhancing the Design of the Regulated Rate Option ("RRO") TransCanada Energy ("TCE") Comments

In the MSA's Notice to Participants and Stakeholders (the "Notice") dated April 21, 2017, the MSA indicated that the Minister of Energy has requested that the MSA conduct an analysis and provide a report with options for enhancing the design of the RRO. In the Notice, stakeholders are asked to assist in identifying options, advantages and disadvantages associated with transitioning from the current RRO arrangements to alternative approaches. Specifically, the MSA requested that market participants address four specific issues, which TCE has commented on below.

i) Whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta;

While TCE does not believe it is necessary for there to be one RRO rate for all eligible consumers within a given customer class, TCE does see certain benefits associated with transitioning to one RRO rate.

TCE understands, based upon previous analyses undertaken by the MSA,[1] that the Energy Price Setting Plans (EPSP) for each of the three RRO providers have historically produced very similar RRO rates. That the rates are not markedly different suggests that there are potential regulatory and consumer cost efficiencies that could be achieved by moving to one RRO rate; by reducing the regulatory burden placed upon the Alberta Utilities Commission (AUC), the consumer advocacy groups and the RRO providers that arise from the approval of three separate EPSP.

In addition, although there has not been significant disparity between the rates charged by each of the RRO providers historically, should RRO rates begin to diverge, TCE suggests this would not be a desirable outcome. Moving to a single RRO rate for all consumers would eliminate the possibility of this occurring, and would ensure fairness for RRO consumers regardless of where they reside in the province.

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[1] MSA 2015 Fourth Quarter Report, at page 16, available at http://albertamsa.ca/uploads/pdf/Archive/0000-2016/Reports/2015%20Q4%20Quarterly%20Report.pdf

ii) Changes to procurement, including advanced procurement of longer term products, centralized procurement or options that do not require advanced procurement;

Centralized Procurement
TCE submits that a shift to one rate for all eligible consumers would likewise support a shift to centralized procurement of the RRO load obligation for all three RRO providers. A shift to centralized procurement, in turn, would have the benefit of consolidating potential supply to the RRO, which could drive more competitive outcomes. Regardless of whether the RRO obligation is procured centrally or by each of three RRO providers as it is today, all procurement should continue to be done through the market and prices should be set competitively.

Longer Term Products
At present, forward procurement to satisfy RRO load is limited by the RRO Regulation, which sets out a 120-day price setting window for RRO rates.[2] Should the procurement of longer term products be permitted, TCE expects that this would reduce the volatility that RRO consumers are currently exposed to intra-year (or month to month) and would therefore produce more predictable and stable rates within a delivery period (i.e., one year).

Although this may be a desirable outcome, it should also be noted that reducing the volatility consumers are exposed to within a delivery period may result in changes in behaviour for both consumers and suppliers. For example, reducing volatility through the procurement of longer term products may:

- Generate less liquidity in the market compared to monthly or quarterly procurement mechanisms by reducing the number of times the RRO providers go to the market to buy;

- Result in larger changes in the RRO rate from one delivery period to the next (i.e., from year to year); and

- Reduce the incentive for RRO consumers to switch from the RRO rate to a competitive contract offered by a competitive retailer.

iii) Introduction of deferral accounts or changes to bill smoothing;

As discussed above, the use of longer term products may reduce volatility and act to smooth the RRO rate that consumers are exposed to, however, it likely increases the need for deferral accounts to deal with the greater differences that will occur between the RRO rate that was set in advance and the actual cost of electricity for that delivery period.

TCE does not oppose changes to the RRO Regulation that increase the stability and predictability of the RRO rate provided that those changes ensure that RRO consumers continue to face the true price of the electricity they consume and that these prices are based on market outcomes.

However, to the extent that deferral accounts are permitted[3] and they act to reduce volatility and smooth the RRO rate there is a reduction in the correlation between the RRO rate set and the price of electricity for that delivery period. As discussed above, this in turn may reduce incentives for RRO consumers to switch to competitive contracts and could impact the competitiveness of the retail electricity market.

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[2] Regulated Rate Option Regulation, Alta. Reg. 262/2005, Section 11.
[3] At present, the RRO Regulation does not permit deferral accounts; see Regulated Rate Option Regulation, Alta. Reg. 262/2005, Section 3(2).

iv) When and how a change to the RRO should occur;

The RRO providers are either in the midst of, or have recently completed a regulatory process for the approval of their EPSP. In addition, the market is transitioning from an energy market to one with a capacity market, with first delivery expected in 2021 and TCE expects that the cost associated with procuring capacity will likewise be passed through the RRO rate to consumers in addition to the energy charge.

Both the results of the MSAs report and the need for mechanisms for the RRO providers to pass along the cost associated of capacity to RRO consumers may necessitate changes to the RRO Regulation. Any changes to the RRO Regulation would, in turn, necessitate the initiation of additional regulatory processes with respect to these EPSP, which could take as long as one year to complete. Therefore, given the significant change and resulting uncertainty created by the change in market design and the time required to amend the EPSP, TCE recommends that any changes to the RRO Regulation or the RRO Rate should be aligned with the development of the capacity market. Preferably, further consultation on this matter should be deferred until the design of the capacity market is more certain.

TCE appreciates the opportunity to provide feedback on this matter. If you would like to discuss this further, please feel free to contact me by phone at 403-920-7682 or by email at janene_taylor@transcanada.com.

Sincerely,

Original Signed By

Janene Taylor
Manager, Market Services & Regulatory
Western Power

utilitiesconsumer
advocate

May 19, 2017

Mark Nesbitt (delivered by e-mail)
Manager, Retail and Investigations
Market Surveillance Administrator (MSA)
Suite 500, 400 - 5th Avenue SW
Calgary, AB T2P 0L6

Dear Mr. Nesbitt,

RE: Options for Enhancing the Design of the Regulated Rate Option (RRO)

Thank you for your notice dated April 21, 2017 seeking stakeholder involvement to assist in identifying options for enhancing the design of the RRO. The Utilities Consumer Advocate ("UCA") appreciates the opportunity to provide input on this matter for your consideration.

The UCA has conducted research and analysis to identify the key issues with the current RRO for consumers and to identify alternatives, including advantages and disadvantages, to address these issues. We have attached a document titled "UCA Report - RRO Alternatives" with our findings for your review. This report discusses the advantages and disadvantages of several options for the RRO, including:

- Pool Price Flow Through;
- Forecast Price with Deferral;
- Forward Market Index;
- Fixed Price Offer;
- Forward Market Auction;
- Long Term Hedging; and
- Centralized Procurement (see Section 6.2 of the Report).

From this research and analysis, the UCA recommends that the *Regulated Rate Option Regulation* (RROR) is amended to introduce a centrally administered procurement process with long-term contracts as an alternative to the current RRO (see section 7 of the Report).

In response to the specific considerations proposed by the MSA in its notice to stakeholders, the UCA submits the following comments.

i) Whether there should be one RRO rate for all eligible consumers (or customer category) in Alberta

The UCA submits that having one RRO rate for all consumers that are currently eligible in Alberta would benefit consumers by introducing cost savings associated with reduced regulatory burden and improved simplicity and transparency. This could be aligned with the option of centrally-administered procurement (see Section 6.2.7 of the Report). The risk of having one RRO rate for all eligible consumers, depending on how it is implemented, is that it may mean substantive changes to the regulatory framework which may lead to higher prices for consumers. With this option, the UCA submits there would need to be regulatory mechanisms for sufficient cost oversight and accountability of the centralized procurement agency and the RRO provider. The UCA also submits there should be profit and loss neutral risk compensation for the RRO provider (see section 4.2.1 of the Report). The RRO rate should not be tied to other government initiatives, such as promoting renewable generation in the province, to further mitigate the risk of increased prices.

ii) Changes to procurement, including advanced procurement of longer term products

The UCA submits that changing to a centrally administered procurement process with long-term contracts (e.g., one year hedges) would help achieve the following:

- Regulatory efficiency: centralized procurement reduces regulatory burden and regulatory costs;
- Volatility: longer term hedging avoids month to month volatility;
- Price: centralized procurement avoids undue costs associated with return margins and procurement administration;
- Confidentiality: centralized procurement avoids confidentiality issues; and
- Transparency: long-term hedging and centralized procurement reduces complexity and improves transparency for consumers.

The option of centralized procurement along with longer term hedges would align with the government's objective of stabilizing the RRO price and enhancing transparency for consumers. See sections 6.2.6, 6.2.7, 6.3, and 7 of the Report for more information.

iii) Introduction of deferral accounts or changes to bill smoothing

The option of long-term hedging would help to reduce month to month price volatility for consumers. The main risk associated with introducing long term hedging to stabilize the RRO is that it would result in a higher RRO price (on average) for consumers.

An analysis of the benefits and risks associated with deferral accounts is included in section 6.2.2 of the Report.

iv) When and how a change to the RRO should occur

The UCA submits that changes to the RROR would be required and that these changes should occur the near term to mitigate the risk of additional regulatory burden considering RRO providers are beginning to prepare and file their EPSPs for the period 2018-2022 and that there are significant costs for consumers associated with these proceedings (see Section 2.3 of the Report).

Please note, these recommendations are based on initial analysis conducted by the UCA and do not necessarily reflect the views of Service Alberta. For further information or if you have questions, please contact me at (403) 476-4998 or megan.gill@gov.ab.ca.

Sincerely,

Megan Gill
Manager, Market Policy and Analysis
The Office of the Utilities Consumer Advocate

utilitiesconsumer advocate

Regulated Rate Option
Market Policy & Analysis Report

May 19, 2017

Table of Contents

Executive Summary

The Regulated Rate Option (RRO) is the monthly default rate for electricity automatically provided to all eligible customers who have not entered into a contract with a competitive electricity retailer. The RRO is available to low-volume users of electricity, including residential, farm and irrigation consumers. There are three RRO providers currently operating in Alberta and each is responsible for establishing the RRO pricing for customers in their respective distribution service areas and submitting an Energy Price Setting Plan (EPSP) to the Alberta Utilities Commission (AUC) for approval.

The Government of Alberta recently requested the Market Surveillance Administrator (MSA) conduct an analysis and prepare a report with options for enhancing the RRO. With this Report, the UCA will provide input to the MSA and present options to address the issues with the current regulatory framework and rate setting methods, including:

1) Regulatory inefficiency: reduce regulatory burden and minimize costs associated with regulatory review and approvals;
2) Volatility: minimize volatility and fluctuations in the electricity rates paid by participating consumers;
3) Price: ensure fair and reasonable prices and avoid undue costs associated with risk margins, return margins, and procurement administration;
4) Competition: preserve open competition in the wholesale market and consumer choice in the retail market.
5) Confidentiality: maintain position concealment to preserve competition in the wholesale market and minimize RRO prices; and
6) Transparency: reduce complexity and improve transparency to allow consumers and other interested parties to make informed decisions.

This Report provides a review of what has been done in other jurisdictions with respect to default rate policies and identifies possible procurement and rate setting options to address issues with the RRO in Alberta, including price volatility and regulatory inefficiencies.

Based on the evaluation of the options, it is recommended that the government make amendments to the *RROR* to introduce a centrally administered procurement process with long-term contracts (e.g., one year hedges) as an alternative to the current RRO. Introducing both of these alternatives simultaneously would help stabilize the RRO while also significantly reducing regulatory burden.

Another important consideration is timing of implementation, especially considering that the current EPSPs are due to expire in 2018 and some RRO providers have already filed their 2018-2021 EPSPs. It is recommended that the government implement changes in the near term to mitigate the risk of additional regulatory burden.

1 Purpose

The purpose of this Report is to identify issues related to the existing framework for the Regulated Rate Option (RRO) in Alberta and propose alternate solutions. This report includes research and analysis to answer the following questions:

- What are the issues with the current RRO? How did these issues arise? (Section 2)
- Who are the key stakeholders with an interest in RRO policy? (Section 3)
- What work has been done to address issues with the RRO? What position has the UCA taken on these issues in the past? (Section 4)
- What are the policy issues or other direct causes of problems with the current RRO? (Section 5)
- What have other jurisdictions implemented with respect to the RRO? What alternatives to the RRO could be implemented in Alberta? (Section 6)
- What are the next steps to improve the RRO in Alberta? (Section 7)

The desired outcome of this analysis is to address issues with the current RRO in order to better protect consumers in Alberta.

2 Background

2.1 What is the RRO?

The RRO is the monthly default rate for electricity automatically provided to all eligible customers who have not entered into a contract with a competitive electricity retailer. The RRO is available to low-volume users of electricity, including residential, farm, and irrigation consumers, as well as any other consumers with annual consumption less than 250 megawatt hours (MWh) of electricity[1].

2.2 History of the RRO

When the retail market in Alberta opened to competition in 2001, the government mandated a default rate, which it called the Regulated Rate Option or RRO. The RRO was established as an opt-out service that consumers were placed on automatically until and unless they switched to a different retailer.

For the years 2001 to 2006, the RRO was for the most part based on long-term (quarterly or yearly) hedges, which resulted in relatively stable rates".[2] The first five years gave retailers time to implement internal systems, develop marketing plans, and create new products and services. The intention at that time was for the RRO to be a last resort rate necessary to provide time for retailers to make these decisions and ensure that all Albertans received electricity during the transition period.

[1] See Section 1(d) of the *Regulated Rate Option Regulation*

[2] Alberta Utilities Commission, *Regulated Retail Energy Harmonization Inquiry*, March 25, 2011.

In 2004 and early 2005, Alberta's Department of Energy (DOE) engaged in a review of Alberta's electricity markets. They found that the competitive retail market for residential and farm consumers (smaller consumers) had been slower to emerge relative to the market for industrial and large commercial consumers. At the time there was a general consensus among industry participants that a move from longer-term hedged service to a design incorporating monthly forward hedging would better stimulate the development of a competitive retail market by introducing volatility into the RRO.

The DOE recommended that the small consumer market have the benefit of a transitional rate design under which such consumers were gradually transitioned to a monthly forward hedge.[3] The Alberta government passed the *Regulated Rate Option Regulation* (*RROR*) in December of 2005 to reflect this recommendation. The actual design of the default rate and rules for how electricity is procured are set out in the *RROR*, which came into effect on July 1, 2006. By 2010, the transition from longer term hedges to monthly hedges was fully completed.

2.2.1 Retail Market Review Committee

In its 2010 Retail Market Review, the DOE stated that it was satisfied with the progression toward an RRO with monthly forward hedging.[4] The rate design was then seen as striking a balance between two often conflicting objectives for consumers: price stability and low prices. However, in the winter of 2012, a combination of severe weather conditions and demand in the market exposed RRO customers to higher than normal prices. The government received many complaints and, thus, in February of 2012, it announced a plan to address the volatility and costs associated with the RRO. The plan called for an independent review of the RRO in order to reduce rate volatility and costs for consumers. The Retail Market Review Committee (RMRC) was established as a result.[5]

Following the recommendations of the RMRC, the DOE extended the forward purchase time on electricity contracts to protect consumers from price fluctuations. The average price of all the trades made within the price setting period constitutes the basis for the RRO price. By increasing the number of days in the window, the average price is less volatile. The *RROR* was amended effective January 29, 2013[6] to extend the price setting period for procurement of energy from 45 to 120 days.

The RMRC concluded that the default rate was a significant impediment to the development of a competitive retail market.[7] Its recommendation was that phasing out the default rate and replacing it with a new default rate—the "provider of last resort" (POLR) service—was the best option. Under POLR

[3] This transition would take place from 2005 to 2010, with a 20% year-on-year increase in the proportion of hedges that were monthly. Thus there was a blended hedge until 2010, when 100% of hedges were monthly.

[4] *Retail Market Review*, page 14. For example, the Alberta retail electricity market had by that time shown a continuous increase in the number of customers switching from the RRO to competitive market products—in every customer class. From January 2002 to February 2010, the percentage of total sites that had switched to a competitive retailer increased from 3 percent to 30 percent (approximately).

[5] *Power for the People*, 1-2.

[6] AR 11/2013.

[7] Ibid., p. 2

service, consumers are effectively required to obtain supply from a competitive retailer and only access default supply as a last resort if the retailer becomes unable to perform under its contracts. The purpose of the POLR, it said, was to ensure the continuity of electricity service and protect consumers when unexpected or unavoidable things happen in the competitive marketplace.

The RMRC made six recommendations to the Alberta government with respect to eliminating the RRO. One recommendation was to "amend the *RROR* to reduce the consumption limit for RRO eligibility to 50 MWh per year". In addition, the RMRC also recommended that only residential consumers should be eligible for the RRO, which would move commercial and farm customers to competitive retailers. The government rejected all six recommendations from RMRC associated with eliminating the RRO, opting to extend the current RRO until April 30, 2018. They stated that "almost 65 percent of Albertan's choose the RRO, and we respect that choice."[8]

2.3 Regulatory Framework

Under the *Electric Utilities Act* (*EUA*), the *RROR* requires RRO providers to develop Energy Price Setting Plans (EPSPs) that are to be approved by the Alberta Utilities Commission (AUC). The EPSPs set out how energy will be procured for customers and how the rates paid by customers will be calculated, typically for a period of four years.

There are three RRO providers currently operating in Alberta (Direct Energy Regulated Services (DERS), ENMAX Energy Corp. ("EEC" or "ENMAX"), and EPCOR Energy Alberta GP Inc. ("EEA" or "EPCOR")) and each is responsible for establishing the RRO pricing for customers in their respective distribution service areas and submitting an EPSP to the AUC[9]. The individual EPSPs for each of the major providers are highly complex. They include: (i) a price setting methodology that outlines how the monthly RRO will be based on the forward market price; (ii) a risk margin that specifies the means and quantum of the compensation to be paid to the provider for risks incurred by basing the price on the forward market price; (iii) a return margin that provides the compensation for the service provided; and (iv) various other adders.

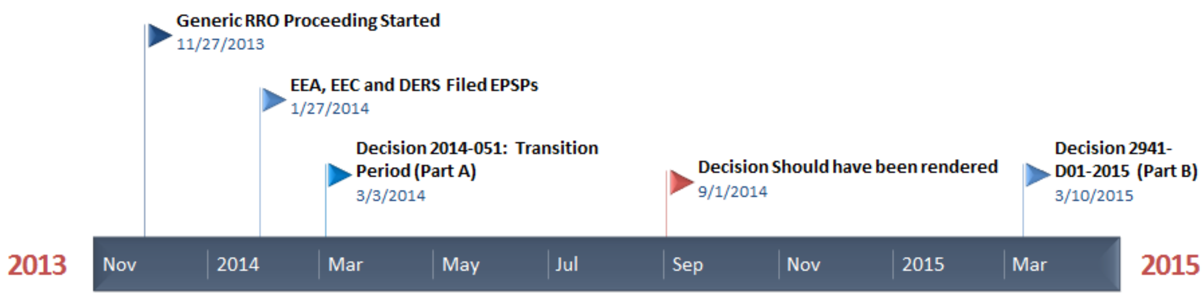
In some cases, EPSPs have been approved through a negotiated settlement process which entails a direct negotiation between the RRO providers and customer representatives, which is then subject to

[8] http://www.alberta.ca/release.cfm?xID=33587874B7848-C9BD-B08D-541C9A3C4641B2C2

[9] DERS is the RRO provider in the ATCO Electric Ltd. service area, EEC is the RRO provider in the Calgary service area, and EEA is the RRO provider for both the Edmonton and the FortisAlberta service areas. The RRO rates for municipal utilities are approved by their city councils and for Rural Electrification Associations by their board of directors. RRO rates for municipal utilities are approved by their city councils and for Rural Electrification Associations by their board of directors.

approval by the AUC.[10] The EPSPs of all three RRO providers for the period between 2011 and 2014 were approved through this negotiated settlement process, and were set to expire on June 30, 2014.[11]

In other cases, a full regulatory approval process has been conducted whereby the EPSPs are submitted to the AUC for approval and customer representatives have the opportunity to intervene in the process. A generic proceeding was initiated by the AUC in 2013 for the 2014-2018 EPSPs in an effort to understand any similarities among the proposed EPSPs of the three RRO providers and lead to a more efficient process for regulatory review. As part of this proceeding, RRO providers were required to submit their 2014-2018 EPSPs in January 2014. Despite the generic proceeding, the approval process has extended well beyond the estimated timeframe provided by the AUC[12] (see Figure 1 below).



[10] Negotiated settlements are governed by AUC Rule 018 which specifies the minimum requirements of an application and the rules of process. AUC Rule 018 also states that negotiations may only commence with the approval of the Commission.

[11] The EPSP for DERS was approved in Decision 2011-199. The EPSP for EEC was approved in Decision 2011-486. The Commission issued Decision 2011-123 on March 31, 2011, initially approving EEA's EPSP, which was to be effective from July 1, 2011 to June 30, 2014. EEA filed three amendment applications to its 2011-2014 EPSP, which were approved in Decision 2011-259, Decision 2011-314, and Decision 2013-021. In Decision 2013-292, the Commission approved an EPSP amending agreement and amended EPSP for EEA, which is effective August 7, 2013.

[12] See AUC Bulletin 2010-16.

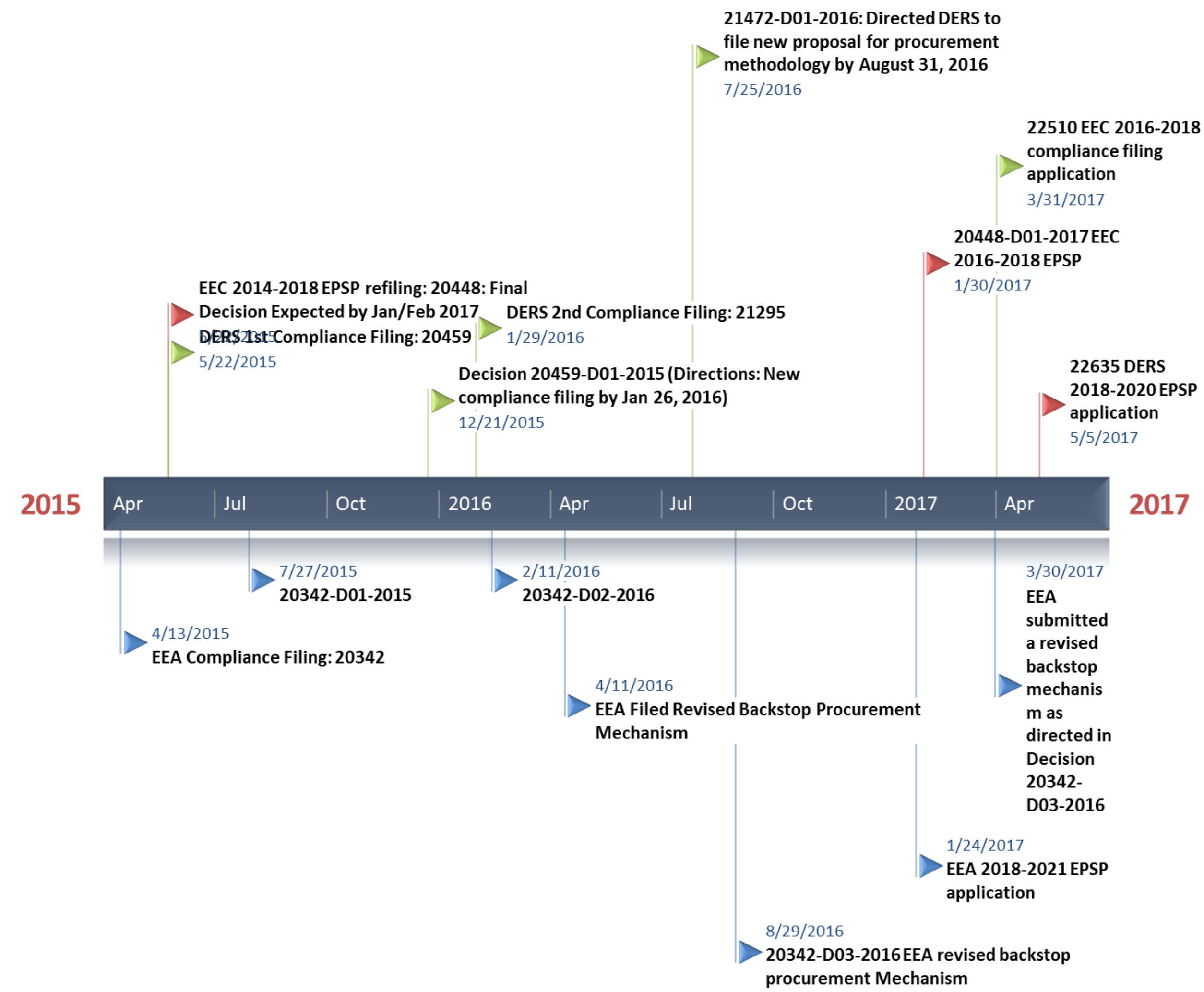


Figure 1: Regulatory Timeline for AUC Generic RRO Proceeding and 2014-2018 and 2018-2021 EPSPs

With numerous compliance filings and procedural motions regarding confidentiality issues, this generic proceeding is still ongoing more than two years later.

Meanwhile, RRO providers are beginning to prepare and file their EPSPs for the period 2018-2022. EPCOR and DERS have filed theirs while EEC is still involved in proceedings to have their 2014-2018 EPSPs approved. The extended timelines of these proceedings creates even more regulatory burden and results in significant ongoing costs associated with the RRO process.

2.3.1 Regulatory Costs

Since each of the RRO providers has a separate and distinct EPSP with separate procurement functions, there is duplication of various functions at each RRO provider as well as the greater administrative costs for all parties that review and comment on elements of these EPSPs. As a result, there are significant costs associated with implementing the RRO in the current regulatory framework.

As an intervener in proceedings before the AUC, the UCA has spent a considerable amount in costs (over $1.54 million) related to RRO since the start of the generic proceeding for 2014-2018 EPSPs in 2014. These expenditures from UCA include both legal fees and fees associated with retaining industry expert testimony services. There are a limited number of professionals in the industry who are qualified to provide expert testimony services which results in higher fees. Furthermore, professionals who are qualified to provide such services also typically work as power traders in the wholesale market which may contribute to issues of confidentiality and open competition in the wholesale market.

Considering there are other parties involved in these proceedings, including RRO providers and the AUC, it is estimated the total regulatory costs associated with RRO since 2014 (at July 31, 2016) is upwards of $5 million. These costs are ultimately passed on to consumers on their electricity bills.

Furthermore, there has been a lack of progression towards a final decision from the AUC on two out of the three 2014-2018 EPSPs and the regulatory costs associated with these proceedings will continue to increase indefinitely until a final decision has been made on all EPSP and Compliance Filing applications.

2.4 RRO Rate Setting Methods

The RRO rate can be set either before or after the billing period in question. Rate setting methods that set the rate before the billing period are known as *ex ante* rate setting methods; those that set the rate after are *ex post* rate setting methods. Currently, the RRO rates for each of the three providers are set before the billing period in question by flowing through the forward market price on a monthly basis. The *RROR* defines the relevant price setting period for procurement of energy as being up to 120 days prior to the month in question.

2.4.1 Energy Charge

The base energy charge is the underlying price of energy to which all energy related adders are applied to achieve the final RRO rate[13]. The RRO provider procures energy through an open access wholesale electricity market. This is referred to as the "forward market" where electricity is bought and sold before the physical commodity is actually produced. In the forward market, the RRO provider pays the seller the agreed upon contract price in dollars per MWh for a certain period of time for the total contract volume. The EPSP of each RRO provider calculates the energy charge for any given month as the average price paid by the provider for forward electricity purchased during the price setting period to meet the provider's load (electricity demand) forecast for that month.

DERS and EEC[14] both use the **Forward Market Daily Target Price** setting method for the energy charge, while EEA uses the **Forward Market Auction** method. In the Forward Market Daily Target Price setting method, the RRO provider buys forward market electricity from willing sellers whose offers are less than

[13] If forward market hedging is undertaken by the RRO provider, this component would represent the weighted average unit cost ($/MWh) of all forward market hedge products acquired by the RRO provider.

[14] In proceeding 2941 EEC proposed to use a Forward Market Index but the Commission denied this proposal.

or equal to the Daily Target Price established by an Independent Advisor. In the Forward Market Auction rate setting method, the RRO provider hosts an auction in which it buys forward market electricity from willing sellers. EEA purchases certain volumes of energy at an auction held on a certain day within the 120-day period preceding the consumption month. With both rate setting methods, the RRO charged to consumers for the month in question is equal to the average price the provider pays for electricity plus the risk margin, return margin, and other additional adders applied.

2.4.2 Risk and Return Margins

An RRO provider purchasing a forward contract for a fixed quantity at a fixed price based on the forecasted demand quantity will find that when demand exceeds its forecast and it is under hedged, the spot price will be high and most likely will exceed its regulated sale price, resulting in losses. Likewise, when demand is low below its forecast, the spot price at which the RRO provider will have to settle its surplus will be low and most likely below its purchase price, again resulting in losses.

The *RROR* allows for RRO providers to recover all prudent costs and expenses and also for a reasonable return for the obligation to provide electricity services ("return margin"). In addition, it allows RRO providers to receive just and reasonable financial compensation for the authorized risks ("risk margin").

The AUC is required to approve a return margin value that is separate and distinct from the risk margin. The *RROR* specifies a variety of risks that are to be included in the risk margin, as well as any other risks the AUC deems appropriate. The single largest risk facing RRO providers is their exposure to commodity risk that arises from taking forward market contracts (hedges, or contacts for differences) to spot, as is required by the *RROR*, and as specified by their EPSPs. Because of the separation of risk and return, the RRO providers have historically earned profits through the risk margin.

In separating of risk margin and return margin, the *RROR* has created ongoing regulatory debate, since at least 2006, of what fair compensation for both risk and return ought to be.

2.4.3 Price and Volatility

Since each of the three RRO providers have different EPSPs, consumers are subject to different RRO prices depending on which area of the province they reside. The average price from all three RRO providers has averaged approximately 7.9 cents per kWh since 2011. For residential-class electricity consumers, this energy charge represents between approximately 19 and 38 percent of a typical consumer's total bill, with non-energy charges—such as distribution, transmission, local access fees, and taxes—being the balance of charges[15].

The UCA receives numerous calls regarding the RRO and many consumers have questions about how the price of the RRO is established and why their rates change each month. For example, in the first three months of 2012, following an increase of electricity prices to over $130 per MWh, the number of calls

[15] Source data from January 2016 provided from the Department of Energy and Alberta Utilities Commission.

received by the UCA regarding the RRO increased significantly compared to the previous year as illustrated in Figure 4 below.[16]

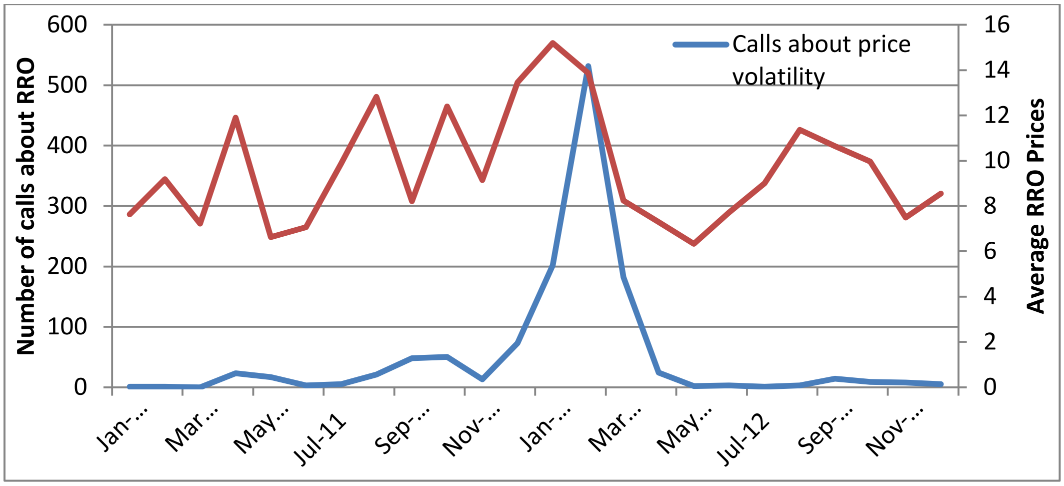


Figure 4: Customer calls and average RRO prices

In recent months, the RRO price has been at historical lows and dropped to approximately 5 cents per kWh in July 2016 (see Figure 2 below). This is due to all-time low wholesale electricity prices (or "pool prices") as favourable temperatures, weak natural gas prices, healthy levels of generation and a slow-down in Alberta's economic growth have resulted in an over-supply of electricity.

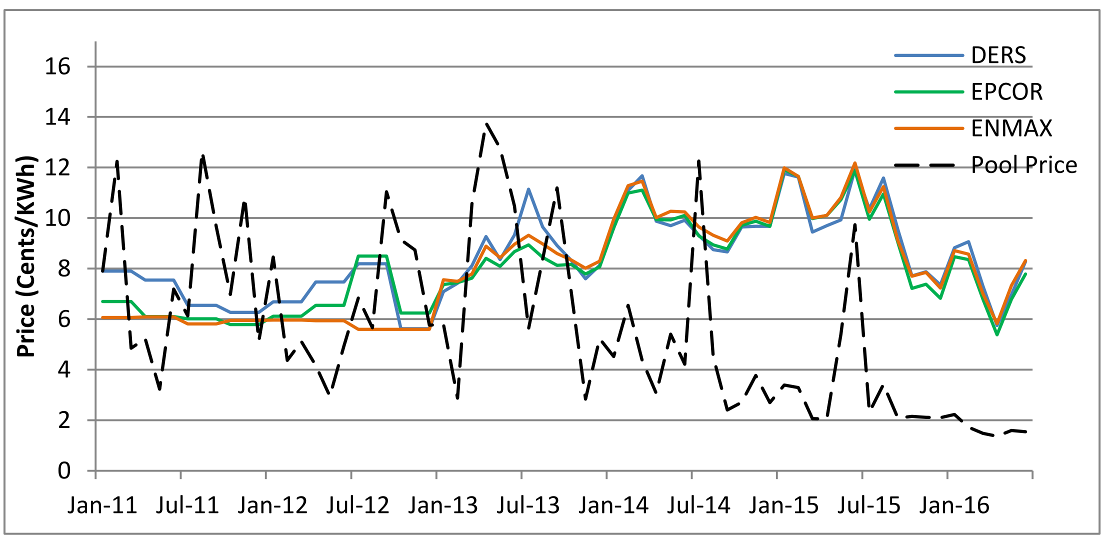


Figure 2: Average Monthly Electricity RRO Prices and Pool Prices from 2011-2016

[16] UCA Service Type Report Adv. 2012.pdf. Customers calls about their high energy costs due to an increase in the RRO prices fall under the "Education" category.

Wholesale electricity prices can be volatile and unpredictable due to generator and transmission outages and market dynamics. Monthly RRO prices reflect that uncertainty as well as normal volatility, and higher risk premiums mean that the RRO bears less relation to the actual cost of energy. The volatility of electricity prices in the wholesale means that RRO customers will naturally see fluctuations on their monthly bills.

Alberta's new climate change initiatives will potentially impact both price and volatility in the electricity market. [17] The Climate Leadership Panel indicated in its "Report to Minister" that introducing a carbon price should increase prices, as should removing coal capacity from the system. Conversely, the addition of renewable generation, the output-based allocations and the construction of new gas generation to fill the void left by coal will lower wholesale prices, or at least limit increases. The panel pointed out that residential consumers, farms, or small businesses have the option to purchase electricity under the RRO or they may sign a contract at a fixed or floating price with a retailer:

"… different customers will be affected in different ways by changes in the electricity price, with some more exposed to volatility than others. Over the longer term, prices for all consumers will reflect changes in average pool prices, but some will feel the impacts of these changes more quickly than others".[18]

See Appendix A for more information on forecasted RRO prices.

More information on the governments Climate Leadership Plan and recent government initiatives can be found in Section 4.3 of this Report.

2.4.4 Competition

As per section 6 (1) (d) of the *RROR*, the RRO must not impede the development of an efficient market for electricity based on fair and open competition. RRO providers have argued that there must be sufficient "headroom" in regulated prices, in order to allow competitive retailers to earn profit. In other words, a low default price would compete with other retail products. However, the UCA has argued that a competitively priced RRO (one whose price approaches cost) will drive other product costs down, creating an efficient, competitive market outcome.

In its Retail Market Update 2015[19], the MSA concluded that low price environment and competition in the wholesale and retail markets has provided significant value to consumers.

"Competition among competitive electricity retailers has pressed the contract prices available to consumers to very low levels. It also remains the case that contract provisions are highly advantageous to consumers; for instance, most competitive contracts have provisions that allow consumers to cancel without penalty (the retailer has no such option). In line with low competitive contract prices, RRO prices

[17] http://www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf p.53

[18] Ibid., p. 54

[19] MSA, Retail Market Update 2015

(Regulated Rate Option prices, which are based on electricity forward prices) have also recently been at very low levels. Both of these outcomes are related to the state of competition in the wholesale electricity market, where prices have recently been at historically low levels".

The obligation for RRO providers to serve all RRO customers in their respective distribution service area can lead to concerns among non-RRO retailers about the effects of co-branding and the ability to acquire market share. For example, both the regulated and competitive providers of Direct Energy use "Direct Energy" in the brand name, and this creates concerns about the possibility to influence consumers as well as issues regarding joint costs not being adequately reflected in prices.

2.4.5 Confidentiality

Private ownership and government regulation is the current model of RRO service in Alberta. Because of this, the EPSPs governing the RRO providers are extremely prescriptive in how the hedges that build up the RRO are procured. Highly prescriptive commodity procurement plans may easily be deciphered by competitors in the forward market, which can be taken advantage of, driving prices higher. The UCA has argued that the procurement of RRO volumes must rely on "position concealment"[20] and that hedging must be directed or subject to direct real time oversight to protect the consumers' interest.

There was an issue of a confidentiality breach during ENMAX's compliance filing proceeding before the AUC which allowed other RRO providers to access confidential information about their procurement methodology, which in turn could allow them to act strategically based on such information. The confidentiality breach resulted in the need for DERS to file a new EPSP application. This in turn has created further delays respecting the approval of the RRO providers' EPSPs for the period 2014-2018, which entail additional regulatory and legal costs for all parties involved. As discussed in section 2.3, these costs have been significant in the past several years and because the regulatory approval process continues to be extended, with no end in sight, there is rising concern from the UCA as these costs are ultimately passed on to consumers.

2.4.6 Transparency

During the generic RRO proceeding and the compliance filings, the UCA proposed that RRO providers file detailed, transparent information as part of their monthly filings to allow interested parties to understand and assess rates payable by customers. Specifically, the UCA proposed information on profitability, position coverage, execution timing risks, calculation of the commodity risk compensation, performance measurement of the forecast, and data for ex-post auditing. However, the AUC did not support ex-ante information and considered that continued reporting together with ex-post auditing was sufficient in allowing interested parties to monitor rates and challenge monthly rate filings.

[20] Position Concealment is akin to not showing your hand in a card game. When suppliers are unclear about how much volume needs to be purchased for the RRO, or what price can be paid, they are inclined to bid aggressively and compete with one another.

The complexity and lack of transparency in the rate setting mechanisms for the current RRO may make it difficult for consumers to understand how default prices are established and effectively contrast these to competitive alternatives in order to make an informed decision in their choice of retailer.

2.5 Summary of Issues

Recently, the Minister of Energy requested that the Market Surveillance Administrator (MSA) conduct analysis and prepare a report with options for enhancing the RRO. Accordingly, the UCA has the opportunity to assist the MSA by providing input and options to address issues with the current regulatory framework and rate setting methods, including:

1) Regulatory inefficiency: reduce regulatory burden and minimize costs associated with regulatory review and approvals;
2) Volatility: minimize volatility and fluctuations in the electricity rates paid by participating consumers;
3) Price: ensure fair and reasonable prices and avoid undue costs associated with risk margins, return margins, and procurement administration;
4) Competition: preserve open competition in the wholesale market and consumer choice in the retail market.
5) Confidentiality: maintain position concealment to preserve competition in the wholesale market and minimize RRO prices; and
6) Transparency: reduce complexity and improve transparency to allow consumers and other interested parties to make informed decisions.

Addressing these issues has the potential to impact over a million Albertans eligible for the RRO.

3 Key Stakeholders

3.1 Department of Energy (DOE)

The DOE acts as the steward of Alberta's energy system on behalf of Albertans and establishes the framework to ensure responsible electricity markets for the reliable delivery of electricity to all consumers[21]. The DOE is responsible for administering the *Electric Utilities Act (EUA)*, *Alberta Utilities Commission Act (AUCA)* and the *Regulated Rate Option Regulation*.

The Alberta government, through the DOE, sets policy related to the province's electricity system and oversees the organizations responsible for all aspects of electricity in Alberta. Government works to ensure that consumers pay a reasonable price for electricity. Over the years, the DOE has shown an interest in stabilizing the RRO. This is a current priority for the DOE as part of the government's recent initiatives.

[21] http://www.energy.gov.ab.ca/Org/Publications/AR2015.pdf

3.2 Utilities Consumer Advocate (UCA)

Within Service Alberta, the UCA represents the interests of residential, small business and farm electricity and natural gas consumers in Alberta. Alberta consumers are represented by the UCA in regulatory hearings before the AUC and policy developments with other government departments and agencies.

The UCA has an interest in improving the RRO to ensure that consumers get their utility services at the lowest possible cost, consistent with reasonable levels of service. The UCA also has an interest in advancing consumer understanding of the RRO through education by providing tools, information and advice to help Alberta consumers make informed energy choices.

3.3 Alberta Utilities Commission (AUC)

As an independent, quasi-judicial agency of the Government of Alberta, the AUC regulates investor-owned electric utilities to balance the interests of consumers and the utility companies. The AUC must ensure RRO rates are just, prudent and market based, and the AUC must be satisfied that RRO providers' expenditures in providing service are reasonable. The AUC must also ensure the RRO providers' have the opportunity to earn a fair and reasonable return. Competitive retailers are not under the jurisdiction of the AUC.

3.4 RRO Providers and Retailers

Retailers in Alberta manage the administration and billing of electricity consumers. Consumers can choose either regulated service from a RRO provider or a contract from a competitive retailer. As discussed in Section 2.3, RRO providers are regulated by the AUC and are responsible for establishing the RRO pricing for customers in their respective distribution service areas. RRO providers have an interest in potential changes to the *RROR* or to the procurement mechanism included in their EPSPs because these changes could affect their risk, return margins and market share.

Competitive retailers are considered "market participants" and under s. 6 of the *EUA* and are to conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the electricity market. There are more than 30 competitive retailers of electricity and natural gas in Alberta. The largest players in the competitive retail market include ENMAX, Direct Energy, and Just Energy. Competitive retailers may be concerned with the impact on fixed contracts in the competitive market of stabilizing RRO as well as their ability to compete with RRO providers.

3.5 Consumers

There are approximately 1.8 million customer sites served by electricity retailers and the majority of these consumers are eligible for the RRO[22]. Residential consumers make up approximately 79% of all retail sites and only 19% of total consumption from retailers as shown in Figure 5 below.

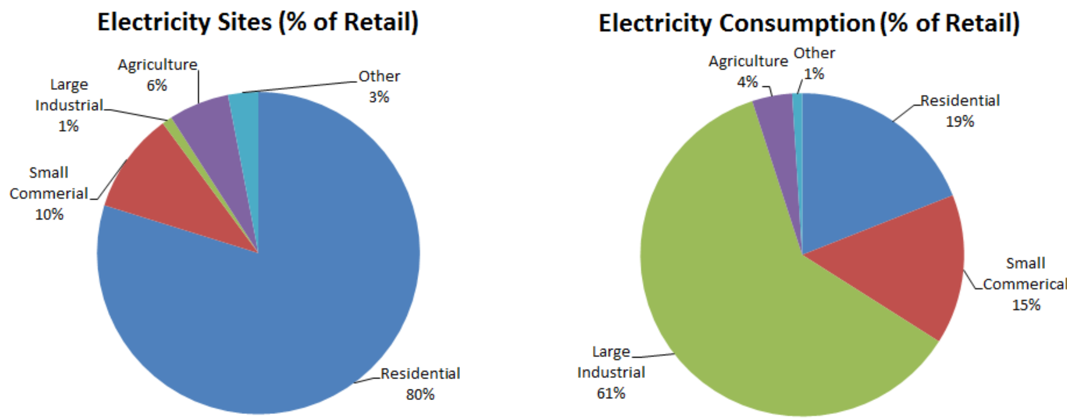


Figure 5: Residential Consumers as a Percentage of Sites and Consumption

Over time, consumers in Alberta have gradually moved away from the RRO. However, approximately 56% of residential consumers have chosen to remain on the RRO (see Figure 6 below)[23]. There are also a considerable number of customers who return to the RRO after their contracts with competitive retailers expire or for other reasons.

More small commercial consumers choose to sign a contract with a competitive retailer and only 40% remain enrolled on the RRO.

[22] Residential, small commercial (annual consumption less than 250 MWh), farm and irrigation consumers are eligible for the RRO. An average residential consumer uses approximately 7 MWh per year.

[23] See section 2.1.1 of MSA's Retail Market Update 2015 Report: http://albertamsa.ca/uploads/pdf/Archive/000-2015/2015-11-23%20Retail%20market%20update%202015%20.pdf

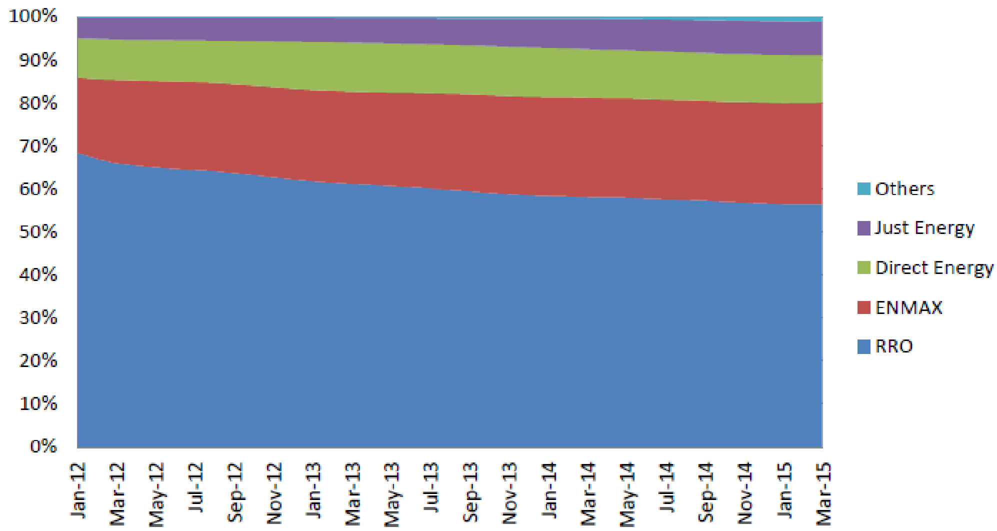


Figure 6: Percentage of Residential Consumers on RRO from 2012 to 2015

Source: MSA's Retail Market Update 2015 Report

Consumers on the RRO may be interested in stable electricity prices, even if it means paying a slightly higher price per MWh of electricity since a slightly higher price for low volumes of electricity consumption may not be significant if their electricity use is low, whereas stable prices will allow these consumers to better predict monthly charges and budget accordingly.

4 Policy Environment

4.1 Applicable Rules and Legislation

4.1.1 *Electric Utilities Act (EUA)*

The *EUA* provides the underlying authority for the structure of the electricity industry in Alberta. One purpose of the Act as stated in Section 5 (h), is "to provide for a framework so that the Alberta electric industry can, where necessary, be effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency."

Section 103 of the *EUA* provides that each owner of an electric distribution system must prepare a regulated rate tariff for the purpose of recovering the prudent costs of providing electricity services to eligible customers. The charge for electric energy set out in the regulated rate tariff must be determined in accordance with the regulations.

Section 105 (1) (i) states that the owner of an electric distribution system has the duty to act as a regulated rate provider to eligible customers who pay a regulated rate for electricity. This duty has been carried out by the RRO provider on behalf of the owner.

4.1.2 Regulated Rate Option Regulation (RROR)

Under the *EUA*, the *RROR* requires that RRO providers offer a regulated rate to electricity consumers who use less than 250 MWh per year.

With respect to the price setting plans, section 4 (1) of the regulation specifies: **"**The price setting plans referred to in section 3 (1) (a) must, with a reasonable degree of transparency, use a fair, efficient and openly competitive acquisition process to ensure that the resulting prices for the supply of electric energy are just, reasonable and electricity market based."[24] Section 5 provides that the risk margin must be just and reasonable. The risk margin may only cover risks to which the RRO provider is directly exposed and may not include risks that are borne by a person other than the provider. Risks covered by the risk margin may include all risks associated with energy related costs and non-energy related costs that the AUC considers reasonable and prudent. Section 6 states that the AUC must provide the RRO provider with a reasonable opportunity to recover the prudent costs and expenses incurred by the RRO provider. It also states that the AUC must have regard for the principle that the RRO must not impede the development of an efficient market for electricity based on fair and open competition.

Section 10 states that a RRO provider must set a new RRO rate for each calendar month. Each new RRO rate must be set in accordance with the new RRO rate energy price setting plan referred to in section 3(1)(a) and the calculations referred to in section 11. Section 11(1) provides that each new RRO rate must be based on regulated rate customer load forecasts made during a relevant price setting period, and monthly forward market electricity prices established in a relevant price setting period.

4.2 AUC Proceedings

In the latest generic proceeding, each of the RRO providers submitted EPSPs with a proposed time period of July 1, 2014 to April 30, 2018. The three RRO providers also submitted evidence on the reasonable return, with each one of the providers requesting a pre-tax reasonable return amount of $8.21 per MWh.

The UCA argued in favor of centralized procurement[25] and the RRO providers' argued that "one advantage of different energy procurement methodologies is the ability to compare the resulting rates and, as a result, assess the relative merits of each methodology".[26] Ultimately, the AUC found that there was no legislative requirement under the *EUA* or the *RROR* for the RRO providers to have centralized procurement and that there was insufficient evidence on the record to assess the advantages and disadvantages of centralized procurement. Ultimately, the AUC decided that no central procurement should be implemented and did not order the RRO providers to standardize the way the RRO is bought and priced on behalf of consumers.

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[24] Ibid., p. 4

[25] Procurement done by either a Third Party or a Government agency as opposed to each RRO provider using different energy procurement methodologies.

[26] Decision 2941-D01-2015, (March 10, 2015), para. 693.

Notwithstanding, the AUC made some specific directions in respect to each RRO provider's procurement and base energy pricing, which are specified in Appendix B.

4.2.1 UCA Involvement in AUC Proceedings

During the course of the generic RRO proceeding, the UCA filed extensive and detailed evidence which highlighted the UCA's regulatory objective to "advocate for the lowest regulated rates consistent with reasonable service". The UCA presented a qualitative and quantitative assessment of the value of the RRO to small consumers in Alberta. The UCA argued that the RRO as a default rate is valuable to those consumers who would prefer not to choose a specific electricity service. The UCA also expressed that many consumers represented by the UCA feel that the RRO offers them protection and that the RRO is actively sought by some consumers over the unregulated alternatives. The quantitative assessment by the UCA determined that the RRO and fixed price unregulated products have been generally comparable since 2006, in that they have not persistently diverged. In some months, the RRO price has been higher than the unregulated offerings and in some months lower. However, on an aggregate basis, the fixed price competitive retail products have been cumulatively less costly than the RRO, while also delivering less volatility than the RRO.

The UCA proposed the following four principles to be considered when approving the 2014-2018 EPSPs:

1. The RRO rates within each customer class should not be materially different. For reasons of fairness and simplicity to consumers, rates within each customer class should be as similar as possible.
2. The RRO rate setting process should be competitive, where possible, leading to outcomes that are comparable and consistent with competitive outcomes. RRO rates should be similar to competitive product offerings, so as not to impede the competitiveness of the market.
3. The RRO rate setting process should have adequate oversight. Adequate oversight, with unfettered access to information, is important to ensure that, on behalf of the RRO customers, the RRO rate setting process and outcomes are competitive and fair. Adequate oversight builds consumer confidence in the retail market.
4. The risk compensation of the RRO providers should be profit and loss neutral.

The UCA argued that an efficient market is an outcome of a highly competitive market, where firms produce at their marginal costs, where there can be no further gains from trade, and where consumer surplus is maximized.[27] The UCA's concern however, was not just with increasing consumer surplus, or enjoying a relatively "larger" surplus, but in fact maximizing consumer surplus, which produces the economically efficient outcome. The UCA's objective of the lowest regulated rates consistent with reasonable service was entirely congruent with an efficient market outcome in a competitive retail

[27] In the case of inelastic demand, that is a vertical demand curve, the efficient market outcome can technically occur at any price along vertical demand curve, resulting in a wealth transfer from consumers to producers, at any point above the price where consumer surplus is maximized. This result is not consistent with the competitive outcome where suppliers produce at the marginal cost, and consumer surplus is maximized.

electricity market. The UCA argued the outcome of these proposals would achieve the UCA's objective, and the AUC's objective of just and reasonable rates. The UCA also argued that RRO providers should be compensated for losses resulting from risks identified in sections 5(3) and 5(4) of the *RROR*. This compensation should be just and reasonable and avoid both an excess of risk compensation and a deficiency. Risk compensation that is profit and loss neutral ensures the RRO providers are able to earn the return margin approved by the AUC. Based on expert testimony by Mr. Jason Beblow, an expert in energy commodity portfolio management, the UCA opined:

- There must be consumer oversight and involvement in the hedging or procurement process including load forecasting and hedge execution as the RRO providers are not specifically incented to have a lower base energy charge;
- There must be effective and timely reporting of load forecast performance and hedging details by the RSPs to consumer representatives;
- The previously modified 120 day pricing window should be continued;
- The primary execution mechanism for hedge transactions should leverage standard derivative products on the Natural Gas Exchange (NGX) trading platform by way of consumer driven hedging that promotes position concealment and introduces uncertainty to other players in the market to achieve balance in the supply demand equation of product pricing;
- The secondary execution mechanism for hedge transactions employed for backstop and position concealment should leverage competitive requests for quotations in the over the counter ("OTC") market in order to realize pricing opportunities and to minimize credit and other costs;
- The final hedge volume targets should be equal to the average hourly off peak and peak forecast load; and
- The primary recommendation is all commodity gains and losses (as energy related costs) should be subject to deferral account treatment.

UCA expert, John Dalton opined in his evidence[28] for Proceeding 2941 that Centralized Procurement is successfully used in a number of jurisdictions including New Jersey where it is utilized for the Basic Generation Service (BGS) auction where one auction is held to procure BGS for all the New Jersey Local Distribution Companies (LDCs). Maine also employs centralized procurement. The AUC found it was not necessary for the three RRO providers to employ a common energy procurement methodology. In the AUC's view, the UCA had not demonstrated that there were tangible, material benefits associated with the common energy procurement methodology it had recommended, compared to the individual energy procurement methodologies.

In Decision 2941-D01-2015, the AUC directed the RRO providers to follow the "Beblow Method"[29] of commodity risk compensation, which is consistent with the UCA's principle that risk margin should be

[28] Exhibit 139.08, the evidence of Mr. John Dalton, PDF pages 31 and 32
[29] As per evidence filed by Mr. Jason Beblow on behalf of the UCA (see section 5 of Exhibit 0284.01.UCA-2941 Reply Argument).

profit and loss neutral, which allows RRO providers to earn the approved return margin, without (significantly) over earning, or under earning, due to gains and losses on commodity risk. In addition, the AUC requested that the RRO providers provide information as to the amounts collected through their non-energy charges and to present it in dollars per MWh[30].

4.3 Government Initiatives

4.3.1 RRO Price Ceiling

In 2016, the Government of Alberta announced its plan to implement an RRO price cap of 6.8 cent/kWh from June 2017 to June 2021. This rate ceiling will be automatically applied to consumers' bills on the regulated rate; consumers on the RRO will pay the lower of the market rate or the government's ceiling rate.

4.3.2 Minister's Letter to the MSA

On April 18, 2017, the Minister of Energy issued a letter to the MSA requesting a report on the RRO by June 1, 2017, to identify options for enhancing the RRO and provide for:

- Affordability of electricity
- Predictable and stable rates and
- Minimized regulatory and administrative costs

The Minister requested that the report "identify any issues or possible challenges associated with transitioning from current Regulated Rate Option arrangements to alternative approaches. Rather than providing a recommendation, the report should provide advantages and disadvantages of the different options identified."

5 Policy Issues

As described in the previous section, the *EUA* provides a policy framework to ensure consumers have a choice to choose a competitive retail product or to choose the default RRO service. The *EUA* also provides a framework for the competitive wholesale market to ensure an efficient market for electricity is maintained based on fair and open competition. As such, it is important to consider that rules and regulations related to the RRO (for small consumers) must be compatible with rules and regulations related to the competitive wholesale market (for large consumers).

Within the existing policy environment, the key policy issues related to RRO can be summarized as follows:

1) Changes to the *RROR* are needed to minimize the volatility of the RRO rate in an optimized way.

[30] In EEA's 2018-2021 EPSP, it has proposed moving to a descending clock auction to replace the "Beblow Method" for risk compensation.

2) Changes to the *RROR* are needed to standardize the procurement process across all RRO providers to ensure the RRO process can be more "*effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency",* pursuant to the *EUA*.

Any policy changes would need to ensure consumers receive electricity services at the lowest possible cost, consistent with reasonable service, while also allowing RRO providers to earn a fair return. Furthermore, it is important to improve transparency for consumers and maintain customer choice and open competition in the retail and wholesale electricity markets.

6 Options Analysis

This section provides a review of what has been done in other jurisdictions with respect to default rate policies and identifies possible procurement and rate setting options to address issues with the RRO in Alberta, including regulatory inefficiencies and price volatility.

6.1 Jurisdictional Review

6.1.1 Ontario

Currently, Ontario municipalities can choose one of three ways for the supply of electricity:

1. The Regulated Price Plan (RPP) which is based on a fixed price set by the Province. For larger volume accounts, greater than 250 MWh, the RPP ended in November 2009 (The City pays RPP for all its smaller accounts).
2. Market pricing for interval metered accounts and larger volume municipal accounts as started in November 2009. Weighted Average Hourly Price (WAP) applies to conventional meters and Hourly Ontario Electricity Pricing (HOEP) applies to interval meters.
3. A contract from a competitive retailer where the price is set at a point in time for the future supply of electricity.

The RPP is based on price forecast with a deferral account and is administered by the Ontario Energy Board (OEB). Under the RPP, prices are reset every six months and adjusted according to a forecast of market and contract prices and any required true-ups, with residential consumers paying for electricity through tiered or time-of-use prices. Virtually all generation in Ontario is under some form of contract or regulated price. Therefore, changes in market prices are mitigated by the contract prices resulting in smaller deferral account balances. The RPP is designed to ensure that consumers pay the total cost of their electricity over time, but it allows true-ups and requires that the Ontario Independent Electricity System Operator (IESO), which is the contract counterparty for most of the new generation developed in Ontario, administer a deferral account.[31] Customers that leave the RPP and elect to be served by a competitive supplier pay a "final variance settlement amount" to the degree that there is a negative balance (i.e., costs incurred have been greater than forecast) in the deferral account. This avoids the

[31] The Ontario Power Authority was initially the contract counterparty, but it was merged with the IESO on January 1, 2015.

potential for cost shifting from these customers to those that remain on the RPP and eliminates the potential for strategic behaviour whereby customers leave the RPP to avoid paying for the cost of high balances accrued in the deferral account.

The OEB sets prices for time-of-use customers (e.g., effective May 1, 2017, 7.7 cents per kWh for off-peak, 11.3 cents per kWh for mid-peak and 15.7 cents per kWh for on-peak) and also sets tiered prices for customers not on time-of-use prices (As of May 1, 2017, 9.1 cents per kWh up to a certain threshold[32] each month, and 10.6 cents per kWh for electricity used per month over this amount).

In Ontario, default electricity prices are relatively stable and competitive retail electricity contracts have more price volatility because of a variable global adjustment (GA)[33]. A study[34] on Ontario's retail energy sector shows that 5 year contract price plus GA is well above RPP electricity cost every month.

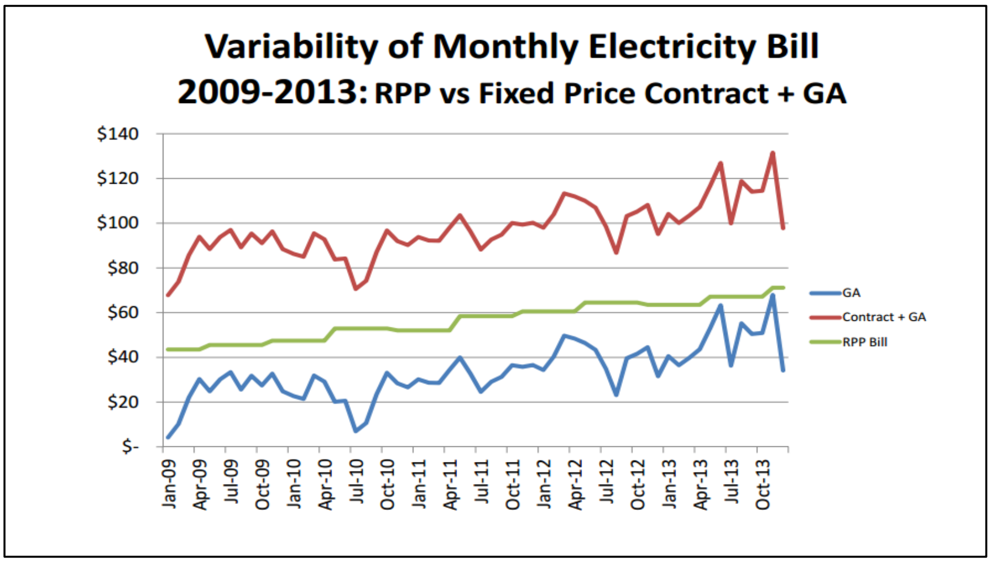


Figure 7: Monthly Electricity Bills (800 kWh/month) for RPP and Fixed Price Contract for Ontario

6.1.2 US Northeast

In the U.S. Northeast default service is typically provided on a full requirements basis using an auction or request for proposals (RFP) to select default service providers. This approach is used in New Jersey,

[32] The price threshold – the amount of electricity that is charged at the lower price – changes twice a year for residential consumers. The price threshold will be 600 kWh per month in the summer (May 1st to October 31st) and 1,000 kWh per month in the winter (November 1st to April 30th).

[33] In Ontario, consumers who pay the Hourly Ontario Energy Price (HOEP), or have signed a retail contract need to pay for Global Adjustment (GA). This charge account for the differences between the market price and the rates paid to regulated and contracted generators and for conservation and demand management programs. GA covers the cost for providing both adequate generating capacity and conservation programs for Ontario. When the HOEP is lower, then the GA is higher in order to cover the additional costs. The GA also changes when new projects come into service, contract payments take effect or as a result of changes in demand. For more information: http://www.ieso.ca/Pages/Ontario's-Power-System/Electricity-Pricing-in-Ontario/Global-Adjustment.aspx

[34] http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0158/ECPA_Review_Presentation_Dewees.pdf

Massachusetts, Rhode Island, Connecticut, Maine, Maryland and the District of Columbia. These states are in electricity markets that are considerably larger, have greater liquidity, and are better interconnected with adjacent electricity markets than Alberta. This is critical to the success of these full requirements service auctions.[35]

The approach employed in each of these states varies, but the basic framework is similar. The supplier bears virtually all the price and volume risks associated with providing the default service. Major differences in how the auctions are structured include the term and who conducts it, reflecting different policy objectives for the default service (e.g., mitigation of price volatility) and perspectives regarding who is best positioned to procure such supplies (e.g., utility commission staff versus the default service providers or their agents).[36]

6.1.2.1 New England

In New England, participants can buy and sell energy for delivery on the following day in the day-ahead energy market. The ISO also provides two virtual energy products, virtual supply and virtual demand, that are settled based on day-ahead and real-time locational marginal price differences and add liquidity to the day-ahead market. Virtual products are used by participants to hedge physical positions or to arbitrage price differences between the day-ahead and real-time energy markets.

If a supplier selling energy in the day-ahead market is not able to physically provide the contracted energy in the real-time market, or if it is not economic for them to do so, they are able to buy out their position at real-time prices. Similarly, if a load serving entity buys energy in the day-ahead market and does not consume the contracted amount they can sell the additional megawatts that were purchased in the day-ahead market but not consumed in the real-time. There is risk associated with both of these situations if a day-ahead seller must buy out their position at a high real-time price, or if a buyer must sell their surplus at a low real-time price. Virtual transactions can be used to hedge this risk.

6.1.2.2 Connecticut

Connecticut regulators recognized the risks associated with hedging and the consequences for retail competition: long-term contracts which turn out to be higher than market prices place a burden on consumers; long-term contracts which turn out to be lower than market prices can freeze competitors out of the marketplace. Connecticut relies on “laddering” for resource procurement – buying small blocks of power over time and blending the results. Electric Local Distribution Companies (LDCs) conduct standard service supply auctions where bidders submit monthly price bids ($/MWh) for a 12-month period. The LDC RFPs solicit bids for various tranches, with tranches bid at different time periods so that customers receive the benefit of an average of market prices.

[35] Exhibit 139.08, the evidence of Mr. John Dalton
[36] Exhibit 139.08, the evidence of Mr. John Dalton

Recently Connecticut banned variable pricing (i.e., different rate from month to month) effective from October 1, 2015[37].

6.1.2.3 Maine

Maine's law[38] allows retail consumers to purchase electricity supply from licensed competitive electricity providers, and requires customers not served competitively to accept standard offer (i.e., default/regulated service) electricity regulated by the Maine Public Utilities Commission (MPUC). The MPUC sets standard offer rates to serve default customers.

Maine employs centralized procurement whereby the MPUC staff administers the RFPs for standard offer electricity supply, which are sealed bids. Separate RFPs are issued for each local distribution company, but the submission schedules are generally the same. Suppliers are selected by MPUC staff and ultimately execute a standard offer electricity supply contract with each LDC. With laddered supply contracts that represent one-third of the standard offer electricity supply load, the RFPs are designed to produce price stability.

6.1.2.4 New Jersey

New Jersey employs a descending clock auction which provides a high level of price transparency. Under the descending clock auction bidders indicate the number of tranches that they are willing to supply at the specific price level. The multiple-auction round format permits each supplier to revise its bids based on market signals in earlier rounds. Without the ability to learn from others' bids, suppliers will increase their price to reflect the additional uncertainty. While forward markets provide significant price transparency, bidders are required to "price in" the volume risk.

The New Jersey Basic Generation Service (BGS) auction has a provision for "volume cutbacks" whereby if the amount of supply offered is below a specified multiple of the amount to be procured, the volume to be procured is reduced. This provision effectively places suppliers on notice that they have one chance to participate in the auction. As a centralized procurement model, the BGS auction is held to procure BGS for all the New Jersey Local Distribution Companies (LDCs).

6.1.2.5 Pennsylvania

In 2008, legislation established new policies to govern default service: The default service provider (distribution utility) must submit a plan to acquire generation supply by competitive means and "at the least cost" and obtain a "prudent mix of contracts to obtain least cost on a long-term, short-term and spot market basis…". The original statutory obligation to acquire default service at "prevailing market prices" was repealed.

[37] http://wtnh.com/2015/06/24/connecticut-bans-variable-rate-electricity-contracts/
[38] Title 35-A, Chapter 32: Electric Industry Restructuring

The law also endorses a variety of competitive acquisition approaches, including auctions, requests for proposals and bilateral agreements[39]. The default service must be unbundled and will change at least quarterly to reflect the underlying contracts. Most procurement plans have been negotiated for each utility that includes laddered fixed price full requirements wholesale market contracts and some purchase of spot market blocks of energy for a small portion of the load. The “Price to Compare”[40] must be a fixed rate and appear on the customer’s bill. The “Price to Compare” must be adopted on a quarterly basis for residential customers (and monthly for larger C&I customers).

6.1.3 California

The current state of California’s electricity markets is a hybrid system of regulation and deregulation. Today’s system is comprised of deregulated wholesale markets administered by the California Independent System Operator (CAISO) and regulated retail markets overseen by the California Public Utilities Commission (CPUC).

The CAISO wholesale energy market is comprised of distinct day-ahead[41] and real-time processes. The day-ahead market is made up of three market processes that run sequentially. First, the ISO runs a market power mitigation test. Bids that fail the test are revised to predetermined limits. Then the integrated forward market establishes the generation needed to meet forecast demand. And last, the residual unit commitment process designates additional power plants that will be needed for the next day and must be ready to generate electricity. Market prices set are based on bids. A major component of the market is the full network model, which analyzes the active transmission and generation resources to find the least cost energy to serve demand. The model produces prices that show the cost of producing and delivering energy from individual nodes, or locations on the grid where transmission lines and generation interconnect.

The real-time market is a spot market in which utilities can buy power to meet the last few increments of demand not covered in their day-ahead schedules. It is also the market that secures energy reserves, held ready and available for ISO use if needed, and the energy needed to regulate transmission line stability.

Following passage of AB 327 in 2013, the CPUC is working to replace the four-tier structure with a two-tier or a three-tier structure. The price difference between the tiers would be no more than 20 and 33 percent respectively. While this would seem to discourage conservation and efficiency, and reduce the economic incentive for installing solar for the higher energy users, the proposal also includes a shift to time-of-use (TOU) rates by 2019. TOU rates could change the entire equation, giving customers an

[39] A bilateral contract in an electricity market is an agreement between a willing buyer and a willing seller to exchange electricity, rights to generating capacity, or a related product under mutually agreeable terms for a specified period of time.

[40] Each local electric utility has a “price to compare.” The price to compare is the price charged by the local utility for the portion of service that is open to competition. The price to compare is given in cents per kilowatt hour (kWh).

[41] In Daily Pricing structures, prices are fixed across blocks of time, but the price for at least one of the blocks (or certain hours within the block) has the potential to vary daily, either on a regular or occasional basis. The varying price may be announced on a day-ahead or hour-ahead basis.

incentive to shift their loads to off-peak time periods, lowering their bills while also helping the utility company shave peak demand.

TOU rates take into consideration differences in the cost of producing and delivering electricity throughout the day, charging a higher price during peak hours (usually a handful occurring at the same time each weekday) and less at all other times. The proposal orders California's three investor-owned utilities—Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric—to start TOU pilots by next year, and to make TOU rates the default structure in 2019.

6.1.4 Texas

Texas is the only jurisdiction in North America that has carried through with a planned phase out of default service. Default service in Texas (the "price-to-beat" or PTB) was provided by the affiliated Retail Energy Provider (REP)[42]—the company affiliated with the incumbent utility. On January 1, 2002, over 5.6 million electricity consumers were moved from the regulated electric utility to the affiliated REP. Price regulation was removed and customers were advised to shop if they were not satisfied with the price or type of service provided by the affiliated REP. Default service was scheduled to last for five years, and ended in December 2006.

Three general methods of pricing are used for electricity contracts in deregulated Texas markets. They are flat fixed pricing, block and index pricing[43], and real-time pricing.[44]While Texas has a predominantly bilateral power market, there are short-term and other transactions which are carried out in the Electric Reliability Council of Texas (ERCOT)-administered spot energy market (i.e., the balancing market). ERCOT is currently the sole retail competition transaction clearing house for the entire state. Prices are based on mutual agreement or long-term contract between the parties, and are not known by ERCOT. These agreements are incorporated into base energy schedules which are submitted to ERCOT on a daily basis.

A key feature of the ERCOT competitive retail electricity market is that it is based on "bilateral" transactions between buyers and sellers of energy. Scheduling entities[45] are required to turn into ERCOT balanced energy schedules of load and energy required to serve the load. The balance schedules are a result of bilateral trades between load and resource entities. ERCOT only operates the electricity market needed to mitigate the energy imbalances that result due to the differences between the real time system requirements and the system loading anticipated in the balanced schedules. This is unlike some other markets, where power generating companies sell electricity into a "pool" and load serving

[42] Since other new electric companies were also allowed to enter the market in Texas, the competitive subsidiary companies of the vertically integrated investor-owned utilities (or their successors) were called "affiliated" companies: affiliated PGCs and affiliated REPs.

[43] In block and indexed pricing contracts, customers pay hourly prices indexed to the relevant wholesale energy market, but enter a forward contract at a fixed price for a fixed block of load, typically fort a wide peak period, which operates as a financial contract for differences.

[44] https://assets.recenter.tamu.edu/documents/articles/2061.pdf

[45] Qualified scheduling entities (QSEs) submit bids and offers on behalf of resource entities (REs) or load serving entities (LSEs) such as retail electric providers (REPs).

entities purchase from the same "pool" in an exchange where the amount of demand and supply sets market prices for buyers and sellers.

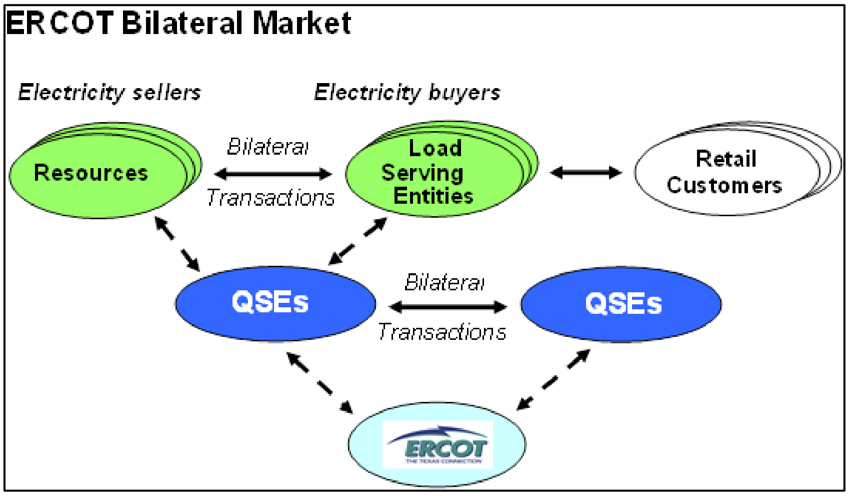


Figure 8: Texas Deregulated Market Structure

In Texas, electric utilities provide transmission, distribution and metering services to REPs. The REPs – which have the relationship with retail consumers – then decide how best to recover the T&D costs (wires charges) from retail consumers.

In June 2016 the Texas Coalition for Affordable Power found that Texans living in areas with retail electric deregulation consistently paid higher average electric rates than Texans living in deregulation-exempt areas[46].

6.1.5 British Columbia

BC Hydro's 2005 Transmission Service Rate application included a provision for a Retail Access Program (RAP) which was subsequently approved by the Commission in 2006. But the IPP energy was consistently more expensive than BC Hydro supply, as the government did not consider the implications of industrial customers seeking large quantities of energy from the market at the time.

BC Hydro currently uses a Revenue Requirement model where the revenue requirement is the total annual revenue required by a public utility to recover the cost of providing utility service to its customers including a fair return on its investment. [47]

6.2 Review of RRO Alternatives

This section describes a range of possible alternatives to the current RRO, including:

[46] http://www.businesswire.com/news/home/20160608005203/en/Texas-Coalition-Affordable-Power-Average-Electricity-Prices
[47] See Lowell E. Alt Jr., "Energy Utility Rate Setting", 2006, at page 21

- Pool price flow through;
- Forecast pool price with deferral account;
- Forward market index;
- Fixed price offer;
- Forward market auction;
- Long-term hedging; and
- Centralized procurement.

6.2.1 Pool Price Flow Through

Under the pool price flow through option, all customers on the RRO would pay the pool price for their hourly consumption. This approach is similar to the model used in Ontario when its wholesale and retail electricity markets opened in 2002. It is also similar to the default gas rate in Alberta for small consumers that don't elect a competitive natural gas retailer.

In order to implement this option, amendments to the *RROR* would be required, including:

- Section 11(1)(b) which states each new RRO rate "must not be based on prices established before or after a relevant price setting period"; and
- Section 5 would need to reflect that there would be no volume or price related risks borne by the RRO providers.

The main advantages of the pool price flow through option are transparency, simplicity and reduced regulatory costs relative to the current EPSPs. It would also allow consumers to avoid paying various risk premiums and margins that are embedded in the current EPSPs. The pool price flow-through option offers the lowest cost to consumers given that it avoids all hedging costs and should have the lowest returns given the passive nature of this service offering[48].

The disadvantage with this option is that it does not address the issue of price volatility; consumers would be exposed to prices more volatile than current RRO prices. The underlying principle of this approach is that markets and private enterprise are best suited to mitigate volatility and offer the fixed price contracts. For example, customers who want price stability could seek out fixed price contracts in the retail market where the costs of mitigating volatility are reflected in the fixed price. However, low-income customers may not have the option of choosing a competitive product if they cannot satisfy the credit requirements. Exposing these vulnerable customers to the volatility of the pool price is a risk of this approach. Furthermore, this option introduces price risk for consumers as they would not know the price until after the end of the period.

[48] UCA had estimated (March 2015) pool price flow through would offer savings of about $60 million per year relative to the 2011-2014 EPSPs. This estimate does not take into consideration other potential impacts on Pool price or impacts on competitiveness in the wholesale market.

Another disadvantage related to this option is the impact on the wholesale market. The forward market volumes used to satisfy RRO supplier obligations are a major source of liquidity in the market. A reduced level of forward market liquidity could increase the risk of the exercise of market power by Alberta generators which could ultimately lead to higher pool prices in the wholesale market.

6.2.2 Forecast Price with Deferral

This approach would require all RRO providers to use a forecast of the pool price and a deferral account to capture differences between forecast and actual pool prices. This option is very similar to Ontario's RPP. The RPP Regulation requires the OEB to forecast the cost of electricity used by these consumers and to ensure that the prices reflect that cost. The *Ontario Energy Board Act* requires the OEB to adjust RPP prices with a view to clearing any balances in the IESO variance account over a 12-month period. As required by the RPP Regulation, the initial RPP commodity prices determined by the OEB under both the tiered structure and the time-of-use structure were set to remain in effect for a period of at least 12 months.[49]

This option would require changes to sections of the *RROR,* including:

- According to Section 3(2), "A proposed regulated rate tariff must not use, provide for or contemplate any deferral accounts, true-ups, rate riders or other similar accounts or devices for energy related costs." This clause prohibits the use of deferral accounts for energy related costs. The solution could be to adjust this section to accommodate deferral accounts. For example, according to subsection 6.1 under section 78 of the *Ontario Energy Board Act*, the Ontario Energy Board is required to issue an order at least once every three months for electricity commodity-related variance and deferral accounts and to determine whether and how amounts recorded in these accounts shall be reflected in rates. This legislative requirement is also in place for non-commodity-related variance and deferral accounts except that the Board must issue an order at least once every twelve months.
- According to Section 6(2), "A regulatory authority must not approve a regulated rate tariff that uses, provides for or contemplates any deferral accounts, true-ups, rate riders or other similar accounts or devices for energy related costs". This provision also rules out deferral accounts.
- Section 11(1)(b) prohibits the use of deferral account option.

Using a forecast of the pool price is likely to result in less volatility compared with the pool price flow-through option, by effectively averaging pool prices over a longer period. However, this approach would not address the month to month volatility related to the current RRO if a monthly pool price forecast is used[50]. This approach is relatively simple and would avoid the complexity, hedging costs, and associated

[49] http://www.ontarioenergyboard.ca/oeb/_documents/eb-2004-0205/rpp_manual.pdf

[50] However, government has recently taken some initiatives to reduce month-to-month volatility. RRO price cap (would be effective since June 1, 2017) will protect consumers from extreme level of volatility. Moreover, with capacity market in place since 2021, the volatility and the pool price are expected to decrease (similar to Ontario's HOEP which is almost always lower than Alberta's pool price) since generators will receive capacity payments.

risk and return margins that are reflected in the current RRO. Moreover, this same rate setting method is used for Default Gas Supply (DGS), under the *Default Gas Supply Regulation*. The competitive retail natural gas market has grown at a similar rate as the electricity market, suggesting that this approach wouldn't have an adverse impact on the development of the competitive retail electricity market.

Although this approach would provide a standard procurement method for all three RRO providers, there would still be regulatory inefficiencies and costs associated with approving the risk and return margins. These margins would also be reflected in the RRO price. If such an approach was used for the RRO, an exit fee would be needed so that customers are not able to leave when high negative account balances have been established without paying their share of the balance. Furthermore, it might be appropriate to have an entry fee or a minimum enrollment period to reduce the incentive for customers to return to default service when there is a positive balance in the deferral account.

Managing balances in the deferral account will represent a cost to the RRO provider that will need to be compensated. High level analysis conducted by the UCA suggests that deferral account balances could exceed $60 million or about $60 per customer.[51] While an exit fee for departing customers would reduce risks to RRO customers and the RRO provider, it would represent a barrier for customers wanting to switch to a competitive offering.

6.2.3 Forward Market Index

Under this approach, all RRO providers would set the energy price component of the RRO based on the average price of all transactions within the forward electricity market on a specific trading platform such as NGX for a given period. An index tracks the performance of a commodity's spot price. For example, NGX's natural gas index tracks Alberta's one month spot price for natural gas. In essence, it is a benchmark of the spot price that can be traded against. If there was an index for Alberta's electricity one month spot price, it could be traded against in forward contracts instead of the actual spot price. This option would greatly reduce the risk to those who hold short positions in forward contracts, thereby increasing liquidity. It would, theoretically, reduce forward prices (and thus RRO prices) by reducing the risk premium imposed by sellers.

With an index, there is an incentive to procure contracts at the lowest possible price. If a RRO provider can procure below the index price, it will earn a profit on those purchases equal to the difference times the volume. Another benefit of this approach is that it would be highly transparent and relatively easy to implement. It allows customers to know the cost of energy prior to the month of consumption, with no need for a true-up or deferral account. In addition, it avoids intra-month fluctuations in the cost of energy from pool price volatility. It would promote short-term forward market liquidity.

[51] The $60 million is the maximum deferral account balance established based on historical prices. The estimated cost of maintaining the deferral account balance and any necessary financial security is less than $2 million per year.

The primary disadvantage of this approach is the risk of the index being manipulated by RRO suppliers who are seeking higher returns. With the wholesale price component of the RRO based on an index, not the prices for volumes that were used to provide the RRO, RRO providers would be able to benefit from higher forward prices. The index derived price would represent just one element of the total RRO paid by customers. Therefore, the RRO price setting process would be as complex and time consuming as it currently is, with the same need for adders and risk premium.

6.2.4 Fixed Price Offer

With this approach, the RRO price would be set as a fixed price in line with what the RRO has averaged over the last six years and slightly above current competitive retail rates. If the pool price is lower over the period, RRO customers would be able to realize savings or a “shopping credit” by migrating to a competitive retailer.

This approach reflects no hedging. Differences between the pool price and this fixed commodity price would be accumulated in a deferral account, which could be used to offset higher pool prices when they are experienced. Customers would have the option of leaving the RRO to “cash out” and they would receive a credit that represents their share of the accumulated balance in the account when they leave the RRO.

This approach was used in Pennsylvania when its retail market first opened. A similar pricing structure was proposed which was intended to allow competitive retail offers to provide savings and induce customers to migrate to the competitive retail market. However, with the shopping credit fixed, a subsequent increase in wholesale prices caused the shopping credit to be less than market prices and competitive retailers abandoned the Pennsylvania retail market.

This approach can be relatively simple to administer, particularly relative to the current RRO and low cost given that there’s no hedging. Furthermore, under the proper market conditions, it can provide a significant inducement to customer switching, which can accelerate the development of the competitive retail market.

However, the lack of hedging for this approach poses considerable risk, particularly given the volatility of pool prices. Therefore, any positive balance that is built up can be quickly drawn down. In sum, there is an appreciable risk that government would have to significantly increase the default rate during periods of high pool prices and this could be viewed as a failure of government policy. Allowing customers to access this “shopping credit” by leaving the RRO would accentuate this risk and cause default service to become a haven for vulnerable customers, making increases in the rate more problematic.

6.2.5 Forward Market Auction

In the Forward Market Auction rate setting method, all RRO providers would establish the RRO price based on the results of an auction. The auction could be for an obligation to serve a share of RRO load such that the RRO provider would bear the price as well as volume risks associated with variations over time in the amount of energy that is consumed. The costs of managing these risks would be embedded in the RRO price, eliminating the need to establish such risk premiums and return margins administratively. This rate setting method would substitute competition and market outcomes for administratively determined risk premiums and RRO providers' returns. This is the approach that is currently used by EEA in Alberta and is commonly used in the US Northeast.

This option provides a less cumbersome way for RRO providers to procure RRO supply and there are fewer costs associated with the procurement of power along with easier procurement in general due to the sellers essentially coming to the buyer. This option is likely to have the most favourable impact on the wholesale market given that it requires wholesale market participants to assemble the various wholesale products necessary to provide a fixed price retail service.

The main disadvantage with this option is that it does not address price volatility. Another challenge associated with this approach is the limited number of suppliers in Alberta that are able to provide electricity products other than base load supply. This is likely to result in premiums associated with the provision of this service. Over time it is expected that these premiums would induce additional entry of generators that are able to provide this service. Therefore, we would not expect this premium to be sustained. According to UCA's expert testimony in past proceedings, the forward market auction system may result in gaming practices with the presence of low-volume buyers in the market. Over time with no barriers to entry, economic theory suggests that any premiums associated with the forward market auctions attributed to Alberta power market dynamics would be bid down and may be less than the additional administrative costs associated with the existing EPSPs and return margins that are being earned by the RSPs.

6.2.6 Long-Term Hedging

Currently, RRO procurement only involves month-ahead contracts. Extending the term of an RRO product to quarterly (seasonal) or annually would eliminate the volatility within the term.

This option would require changes to some sections of the *RROR,* including:

- According to Section 10(1), "A [RRO provider] must set a new RRO rate for each calendar month"
- According to Section 7(3), "In an approval under subsection (1), a regulatory authority must select one of the following methods to determine regulated rates:
    - (a) Acknowledgment of each monthly rate calculated by a [RRO provider] through its price setting plans;
    - (b) Approval of each monthly rate separately.

Although this option addresses the issue of price volatility within the term, the inter-term volatility from one quarter, or one year to the next, may result in material price changes that can drive rate shock. Extending the term of the RRO also presses it into closer competition with existing long-term contracts offered by retailers. In this alternative, the RRO could be positioned in the longer-term fixed price segment of the market, leaving the shorter term, lower cost, higher volatility open for new product entry, and hopefully some competition.

6.2.6.1 Annual Hedges

By requiring RRO providers to procure year-ahead contracts, the RRO price would become fixed for that year. This would be very similar to a fixed price competitive contract, and would essentially eliminate volatility. This may result in, on average, higher RRO prices due to increased risk premium associated with longer term contracts. Competitive retailers who offer fixed contracts may oppose this option, as the RRO may become the “price to beat”.

6.2.6.2 Seasonal Hedges

Seasonal prices are fixed within a season (e.g., summer, non-summer) but may vary between seasons. The prices represent average differences between power costs in the designated seasons. Because they are announced months in advance, they provide customers with signals regarding differences in expected power system costs by season, and may thus provide weak incentives about, for example, the cost of air conditioning or space heating. However, they do not signal changes in actual power system conditions as they evolve in the short term.

6.2.6.3 Blend of Short and Long-Term Hedges

This approach would require RRO providers to procure a mix of month-ahead and longer term contracts, similar to Pennsylvania where legislation requires default service providers to obtain a “prudent mix of contracts to obtain least cost on a long-term, short-term and spot market basis.” Procurement that is based on a portfolio of hedges could serve to smooth RRO rates further, and eliminate inter-term rate shock. If a fraction of the RRO load is procured with a multiyear hedge, while another fraction with a one year hedge, a further fraction on a monthly hedge, and perhaps even some of the load taken to the wholesale market, the RRO rate could be significantly smoothed, with the short term hedges offsetting some of the premium built into the long term hedges.

As with the annual hedging approach, blended hedging would reduce volatility but would on average result in higher RRO prices. Theoretically, the price increases *should* be less than with the full one-year contract. There could be an experienced portfolio manager, working on behalf of consumers, to determine the weightings and appropriate allocation of a portfolio to offset the increased costs of longer term hedges. However, the savings should exceed the costs associated with retaining these professionals to ensure the expense can be justified before the AUC.

6.2.7 Centralized Procurement

Under centralized procurement the roles of the individual RRO providers in procuring RRO supply would be consolidated such that a central agency or entity provides this service. In proceeding 2941, the UCA recommended a common energy procurement methodology. Centralized procurement would allow the procurement entity to realize economies of scale for energy procurement and result in reduced administrative, legal, credit and overall costs as the procurement and settlement functions are centralized and the fixed costs of providing these services are amortized over more energy. This approach is independent of the form of EPSP employed. The centralized procurement entity would be responsible for executing the trades and hedges required to fulfill the requirements of the EPSP.

Under this approach, risk compensation and risk management reside within one organization. The input price to the retailer would be the same across all RRO providers; therefore, the RRO product would be supplied with no energy price differentiation. This option would be consistent with the central procurement model used in New Jersey and in Maine. This option would also present an opportunity for allowing competitive retailers to offer the RRO rate which may enhance competition in the retail marketplace and address co-branding issues.

This option requires sections of the *RROR* to be amended:

- According to Section 2 (requirement to provide regulated rate tariff), “Each [RRO provider] must make available to eligible customers in the [RRO provider]'s service area the option of being supplied electricity services in accordance with a regulated rate tariff instead of purchasing electricity services from a retailer”. Removal of reference to the “service area” should be done in conjunction with a centralized procurement model.
- According to Section 6(1)(f), when considering an application for approval of a regulated rate tariff under section 103 of the Act, a regulatory authority must “approve the price setting plans referred to in section 3(1)(a) in a manner that ensures that the procurement risk of acquisition remains with the [RRO provider].”

Centralized procurement would result in regulatory efficiencies and reduced costs associated with EPSPs.[52] Centralizing the procurement function should result in reduced administrative, legal, credit and overall costs as the procurement and settlement functions are amortized over more energy. This option would address the issues of confidentiality in the current regulatory proceedings and allow a higher level of transparency throughout the process. This option would also maintain an active hedging strategy to keep suppliers in check and discipline the exercise of market power to avoid issues associated with the competitiveness of Alberta's wholesale market.

The major disadvantage of this approach is that it requires significant changes to the overall regulatory framework and would require more time and resources for upfront implementation. This option is also expected to yield significant opposition from RRO providers. RRO providers are likely to oppose this approach given that it would diminish their role of providing default service and impact profits from risk and return margins. Depending on how the default product is structured, it also may be opposed by competitive retailers who view it as a threat to their service offerings. If there's no margin earned by the procurement entity and the RRO price is reduced, then competitive retailers will be concerned that this retail option could undercut their competitive product offerings. The RMRC report states:

[52] Exhibit 139.08, the evidence of Mr. John Dalton

"*Longer-term or hedged energy procurement is fundamentally inconsistent with the development of a competitive electricity retail market, and cannot be supported. Activities in other jurisdictions have demonstrated that it discourages market entry and the development of new products and services*."

However, if the default product does not directly compete with competitive retail products, this is arguably better for the market and consumers.

6.2.7.1 Centrally Managed Hedging with Risk Flow through to RSPs

Under this approach a hedging strategy for the RRO would be implemented by a separate entity on behalf of the RRO providers. The hedging entity would have no balance sheet or financial capability. Therefore, it would need to flow through all costs and risks to the RRO providers who would in turn bill consumers based on the commodity price derived by the hedging entity's transactions. RRO providers would receive commodity risk compensation and a return margin which is negotiated or determined by the AUC as part of the EPSP review.

There are a number of disadvantages to this approach. It requires RRO providers to accept a commodity risk determination which might not align with the procurement approach unless the procurement approach employed by the hedging entity is prescribed in considerable detail. This approach doesn't appear to address the major sources of costs that could be avoided by consumers, i.e., the risk premium and return margins. In fact, it may result in greater risk premium given the disconnect between the party administering the hedging strategy and the party bearing the risks associated with the implementation and execution of the strategy.

6.2.7.2 Bidding for RRO Obligation

One variant on the centralized procurement model would be to bid out the right to serve as the RRO for all of Alberta to a separate legal private entity. The RRO procurement provider would need to be selected through a competitive bidding process for a government contract to ensure the entity is working on behalf of consumers. There would need to be standards in place and incentives for the entity to improve efficiencies and optimize the price for consumers.

The primary benefit of this approach is that the return margin and effectively the risk margins would be determined by the market, rather than administratively (i.e., assumed risk margins that overstated the risk would cause bidders to seek a lower return margin and vice a versa). While structuring the competitive process would be relatively time consuming to implement initially, the potential savings from reduced effort associated with administering, negotiating and approving the terms of the RRO are significant, with the savings offered by market determined risk and return margins also potentially significant. With the RRO obligation bid out for multi-year terms, subsequent processes for selecting the RSPs would be easier to administer.

One challenge could be ensuring that the RRO procurement providers employ the specified hedging strategy rather than a lower risk strategy that imposes greater volatility upon consumers. If the hedging strategy were a simple strategy such as a multi-month pool price flow-through, then there wouldn't be an issue with policing such a strategy.

6.2.7.3 Centrally Managed Hedging with Risk Internalization

Another alternative is to have the RRO supply procurement provided by a government or quasi-government agency, such as the Balancing Pool. Under this approach, the party that provides the RRO procurement service would be designated and the risk management would reside internally within a non-profit government organization.

This model is being employed by Gas Alberta Inc. (Gas Alberta), which was established in 1973 to extend gas services to areas of Alberta without gas service and to establish member-owned cooperatives that would provide natural gas service to these communities. Gas Alberta was to purchase and manage gas supplies on behalf of these rural gas distribution utilities and by so doing allowed these utilities to benefit from its procurement and contracting expertize and to secure more competitive prices given higher gas volumes. In 1998 Gas Alberta was incorporated to allow it to operate independently from the government. It operates on a non-profit basis similar to cooperatives. Gas is sold to customers, who are its shareholders, on a forecasted pooled rate, with any differences between the actual costs incurred versus the billed amounts recovered from or returned to customers through revisions to rates or by refunds. A variable rate charge is used to recover operating and corporate costs.

Having a non-profit government agency responsible for procurement would ensure risk and return margins are minimized. This approach would also introduce an opportunity for RRO supply to be procured solely or partially from contracted generation under the government's proposed Renewable Energy Program[53]. This would result in an offering for low-volume consumers that are not impacted by price volatility in the wholesale market. This option would significantly reduce regulatory burden by eliminating the need for EPSPs and regulatory approvals.

This approach is still likely to generate opposition from the RRO providers who will have diminished opportunities to profit from return margins provided by the RRO. This option would eliminate competition that would result from the other alternatives of central procurement where private entities are given the opportunity to bid as the sole provider of RRO supply procurement services.

6.3 Evaluation of RRO Alternatives

There are advantages and disadvantages associated with each option. For example, the long-term hedging option stabilizes the RRO but may result in higher costs for consumers. Further evaluation of the RRO alternatives are included in Appendix C and summarized in Table 2 below.

Table 2: Summary of Options

[53] http://www.aeso.ca/rep/background.html

Category Weighting:	20%	15%	15%	15%	15%	20%	100%	
	Consumer		Competitive	Wholesale Market		Administrative		
	Volatility	Price	Retailer	Liquidity	Competitive	/ Regulatory	Total	**Weighted**
Current RRO	3	2	3	2	3	1	14	**2.30**
Pool Price Flow-Through	1	5	5	1	1	5	18	**3.00**
Forecast Price with Deferral	3	4	2	1	1	5	16	**2.80**
Forward Market Index	3	1	3	3	3	1	14	**2.30**
Fixed Price Offer	2	4	3	1	1	4	15	**2.55**
Forward Market Auction	3	3	2	5	5	4	22	**3.65**
Long-Term Hedging	4	1	2	2	3	1	13	**2.20**
Central Procurement - Risk Pass Through	3	2	2	3	3	4	17	**2.90**
Central Procurement - Bid for RRO Obligation	3	4	2	5	4	4	22	**3.65**
Central Procurement - Risk Retained	3	3	2	5	4	4	21	**3.50**
Long-Term Hedging + Central Procurement - Bid for RRO Obligation	4	4	2	5	4	4	23	**3.85**
Long-Term Hedging + Central Procurement - Risk Retained	4	3	2	5	4	4	22	**3.70**

1 = Least Favourable 5 = Most Favourable

7 Conclusion & Recommendations

There are several issues associated with the current RRO market condition and policy environment, including price volatility and costs.

Based on the evaluation of the options, it is recommended that the government make amendments to the *RROR* to introduce a centrally administered procurement process with long-term contracts (e.g., one year hedges) as an alternative to the current RRO. Introducing both of these alternatives simultaneously would help achieve the following:

- Regulatory efficiency: centralized procurement reduces regulatory burden and regulatory costs;
- Volatility: longer term hedging avoids month to month volatility;
- Price: centralized procurement avoids undue costs associated with return margins and procurement administration;
- Confidentiality: centralized procurement avoids confidentiality issues; and
- Transparency: long-term hedging and centralized procurement reduces complexity and improves transparency for consumers.

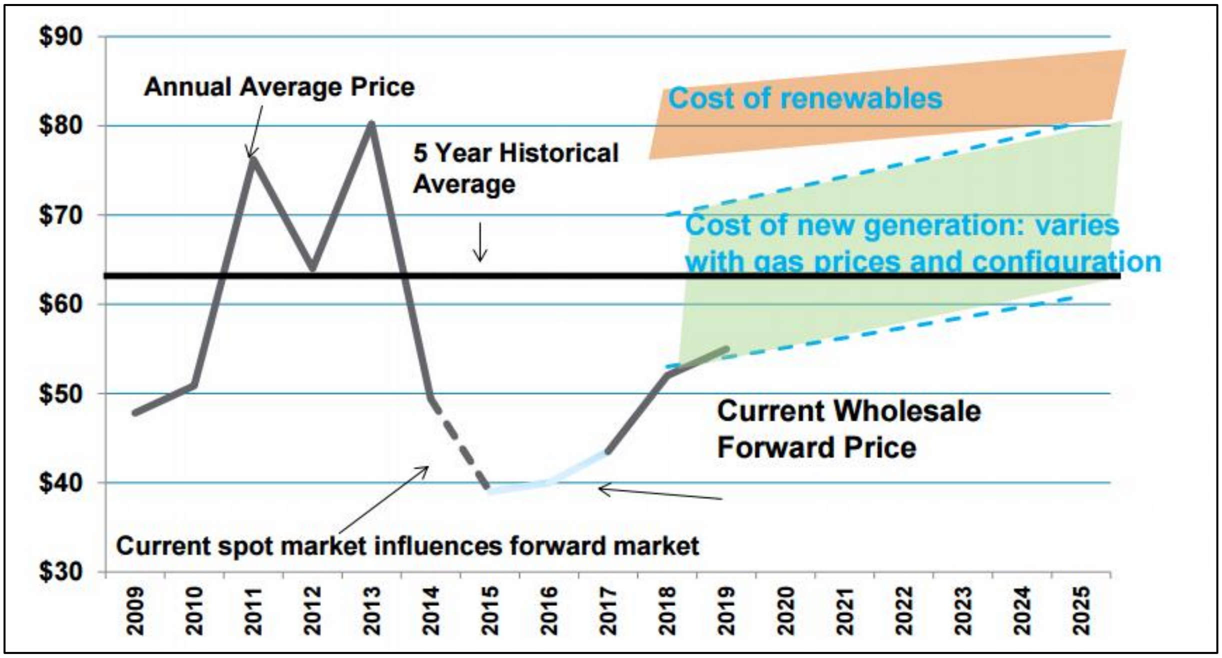
The option of centralized procurement along with longer term hedges would align with the government's objective of stabilizing the RRO price and enhancing transparency for consumers.

The main risk associated with introducing long term hedging to stabilize the RRO is that it will result in a higher RRO price (on average) for consumers. The price increase can be minimized by having the RRO supply procurement provided by a government or quasi-government agency, such as the Balancing Pool.

Another risk associated with this option is the potential impact on competition in the wholesale market and retail market. To mitigate this risk, the government should consult with stakeholders before changes are implemented to understand the impact on consumers, government, retailers, and other market participants.

Another important consideration is timing of implementation, especially considering that the current EPSPs are due to expire in 2018 and EPCOR and DERS have already filed their 2018-2021 EPSPs. It is recommended that the government implement changes in the near term to mitigate the risk of additional regulatory burden and associated costs.

Appendix A: Forecast Prices



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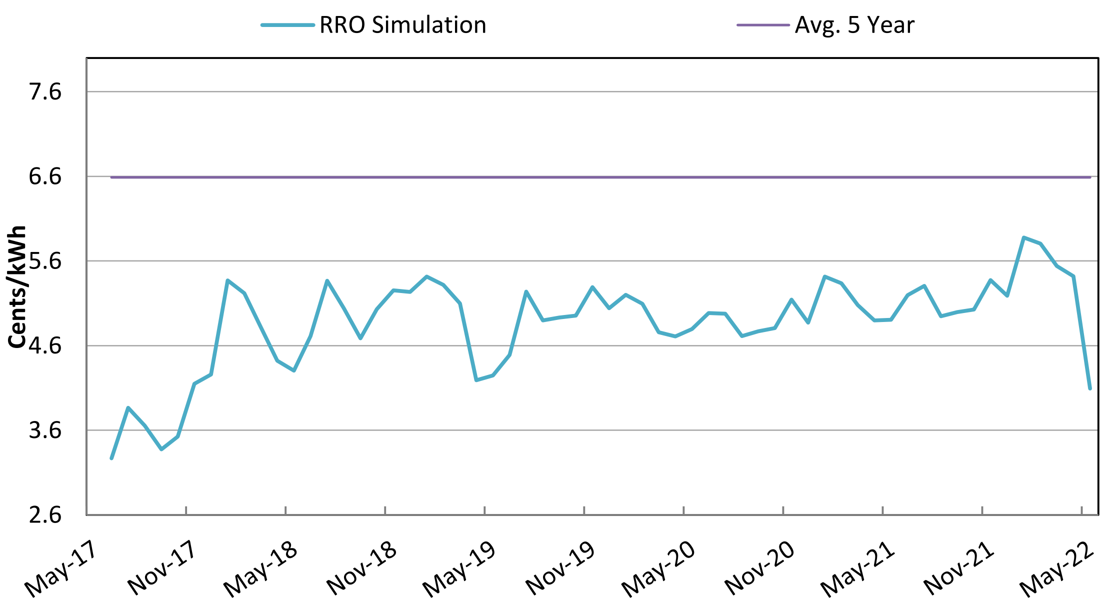

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[54] Source: http://www.bonaccord.ca/assets/agenda-item-8.2---energy-management.pdf
[55] Source: UCA 2016-08-15 Weekly Market Report

Appendix B: Directions from AUC Proceedings

DERS:

In Decision 2941-D01-2015 the procurement and base energy pricing for DERS are as follows:

- DERS applied to continue the use of block procurement through the execution of forward market hedge products. The AUC accepted this proposal.
- DERS proposed that daily target prices for the forward market hedge products will be set by an independent market consultant (IMC). The AUC denied this request and instead directed DERS to set the daily target prices.
- DERS proposed that hedge volume targets will be set at the average load requirements. The AUC did not accept this proposal and instead directed DERS to file an analysis that justifies its hedge volume targets.
- DERS applied to set the base energy charge (BEC) using the weighted average price of the forward market hedges executed during the 120-day allowable price setting period, and to gross up the base energy charge for distribution line losses (DLL) and unaccounted for energy (UFE). The Commission accepted these proposals.

The Commission ordered DERS to file its compliance filing, incorporating the findings and directions in this decision (i.e., 2941-D01-2015), on or before April 13, 2015. DERS' compliance filing to the generic decision was Proceeding 20459. In Decision 20459-D01-2015, the Commission directed DERS, as part of the application for approval of its 2017 Regulated Rate Tariff non-energy rates, not to include any amount for return. Moreover, as of January 1, 2017, DERS was directed to revise the after-tax return amount included in the monthly energy charge to $2.83/MWh.

DERS filed an application on January 29, 2016 (proceeding 21295), requesting approval of its 2016-2018 EPSP second compliance filing, pursuant to the Commission's directions in Decision 20459-D01-2015. This compliance filing proceeding is still on-going.

DERS submitted their 2018-2020 EPSP application on May 5, 2017 (proceeding 22635). DERS noted that the *RROR* currently expires on April 30, 2020 and hence selected the term May 1, 2018 to April 30, 2020 for their EPSP. In DERS' EPSP application,

- The energy procurement section is redacted.
- DERS proposed base and peak block procurement hedging and Forward Market Daily Price Setting (same as current procurement methodology).
- DERS requested a commodity risk compensation of $7.97/MWh.
- DERS' proposed energy return margin is $5.53/MWh (after-tax) in proceeding 22004; Current DERS energy return margin: $2.65/MWh (after-tax; Decision 20349-D01-2015).

EEA:

In Decision 2941-D01-2015 the procurement and base energy pricing for EEA are as follows:

- EEA applied to acquire blocks of forward market hedge products through a series of NGX auctions. EEA proposed that six NGX auctions, plus a contingency auction, be used over the 120-day allowable price setting window. The Commission accepted EEA's proposals.
- EEA proposed that hedge volume targets for off-peak products be set at the average of the hourly load for the off-peak hours. EEA proposed that hedge volume targets for the on-peak products be equal to the 75th percentile of the average hourly load for the on-peak hours, less the flat volume amount. The Commission did not accept this proposal and instead directed EEA to file an analysis that justifies its hedge volume targets.
- EEA applied to set the BEC using the weighted average price of the forward market hedges acquired during the 120-day allowable price setting period, and to gross up the base energy charge for DLL and UFE. The Commission accepted these proposals.

The Commission ordered EEA to file its compliance filing, incorporating the findings and directions in this decision, on or before, April 13, 2015. EEA's compliance filing to the generic decision was Proceeding 20342. In Decision 20342-D01-2016, the Commission approved EEA's compliance filing to Decision 2941-D01-2015 and ordered EEA to file an application for an amendment to its 2014-2018 EPSP to give effect to a new backstop supply mechanism consistent with the Commission's views and directions in Decision 2941-D01-2015, by no later than April 11, 2016. This proceeding (Proceeding 20342) is still dealing with revised backstop procurement mechanism and is still on-going.

EEA submitted their 2018-2021 EPSP application (proceeding 22357) on January 24, 2017. In its 2018-2021 EPSP, EEA proposed a new auction mechanism for its energy procurement and price setting framework. According to the 2018-2021 EPSP, EEA will move to a descending clock auction format and will competitively procure strips of monthly full-load energy contracts for approximately 50% of EEA's actual RRO customer load, with the other 50% of EEA's actual RRO customer load continuing to be procured through flat and peak block hedges. The full cost of energy is equal to the volume-weighted average of the auction-clearing prices for the Full-Load strips procured for that month through the competitive acquisition process; hence the Full-Load strips procurement price is inclusive of commodity risk compensation. Therefore, EEA will replace the current commodity risk compensation method by the proposed auction mechanism.

EEC:

- In its 2014-2018 EPSP, EEC applied to separate the pricing and procurement aspects of its EPSP. The BEC would be determined using the Natural Gas Exchange (NGX) Alberta Flat RRO 120 Index price, grossed up for DLL and UFE. Procurement would be managed entirely at the discretion of EEC's unregulated trading department, EEC Wholesale Trading. The Commission denied EEC's proposed EPSP.

EEC's Compliance filing to the generic decision was Proceeding 20480. In Decision 20480-D01-2016, the Commission found EEC had not complied with Direction 6 from Decision 2014-347. The Commission accepted EEC's proposal to make the necessary adjustment as part of its compliance filing. Therefore, the Commission directed EEC in its compliance filing to remove any costs related to financial metrics based on EEC that were included in its variable pay programs as part of this application.

The Commission directed EEC, as part of the application for approval of its 2017 and subsequent year's non-energy rates, to exclude any amount for reasonable return.

EEC filed 2016-2018 EPSP in proceeding 20448. In 20448-D01-2017 the procurement and base energy pricing are as follows:

- EEC proposed a block process for the procurement of forward market electricity products, using a daily target pricing mechanism and a weekly target volume methodology. Commission agreed with EEC's position.
- EEC proposed to acquire the services of a trader from the unregulated side of the company, EEC Wholesale Trading, who would be responsible for procuring all of its required forward market electricity products (i.e., dedicated trader). The Commission directed EEC to update its EPSP to incorporate a number of safeguards designed to address the confidentiality concerns and avoid possible conflicts of interest.
- Under its proposed EPSP, EEC can, under certain conditions, self-supply forward market electricity products, which would form part of the base energy charge. The Commission directed EEC to update its EPSP to incorporate more clarification clauses and additional wording be added to EEC's self-supply mechanism.

EEC submitted 2016-2018 EPSP compliance filing under proceeding 22510 on March 31, 2017.

Appendix C: Evaluation of RRO Alternatives

Pros of the Pool Price Flow-Through:

- It offers the lowest cost to consumers.
- Minimizes or eliminates the risk margins or other adders necessary for providers.
- Simplicity and transparency.

Cons of the Pool Price Flow-Through:

- Does not address volatility
- Difficult to implement as it entails changes to the *RROR.*

Pros of the Forecast Price Rate Setting Method:

- Transparency. Prices reflect market outcomes (if forecast is of Pool price for billing period).
- Efficiency and stabilization. Forecasted price can easily be standardized among all RRO providers.
- Reduces prices. Use of deferral accounts reduces or eliminates risk adders paid to providers and therefore reduces the price to consumers.
- Addresses volatility. Capable of handling longer forecast periods such as 3-months or seasonal pricing.

Cons of the Forecast Price Rate Setting Method:

- Difficult to implement in the short term. It is infeasible under Alberta's current legislation and would require new legislation to replace the RROR.
- Reduces competition. The use of deferral accounts could negatively impact the development of the competitive market.

Pros of the Forward Market Index:

- Lower prices. With an index, there is an incentive to procure contracts at the lowest possible price. If a provider can purchase its CFDs below the index price, it will earn a profit on those purchases equal to the difference times the volume.
- Transparency. With an index, the price is transparent and simple to understand. The daily price could be posted on NGX, and the concept of an average is easy to understand.

Cons of the Forward Market Index:

- Anticompetitive behaviour. With an index, providers may find it beneficial to collude in an attempt to keep their indexed energy charge as high as possible. While the current system of Daily Target Price Setting eliminates or at least reduces this problem, it suffers from lacking a built-in incentive structure to keep prices low—that incentive is exogenously imposed by an imprecise, opaque, and costly (e.g., IA and consultation fees) daily target pricing mechanism.
- Manipulation of the index by both providers and sellers is an issue. There are many means by which to manipulate an index, all of which would have to be considered.

- Difficult to implement as it would require changes to the current RRO providers' rate setting methods.

Pros of the Fixed Price Offer:

- Least volatility.
- Simplicity. Relatively simple to administer, particularly relative to the current RRO and low cost given that there's no hedging.
- Competition. Under the proper market conditions, it can provide a significant inducement to customer switching, which can accelerate the development of the competitive retail market.
- Transparency. Provides better transparency.

Cons of the Fixed Price Offer:

- Cost and Risk. The price and volumetric risks are severe because supply and demand conditions usually shift adversely together as demonstrated by the California electricity crisis in 2000 and 2001, which led three large investor-owned-utilities in California to bankruptcy or near bankruptcy. There is an appreciable risk that government would have to significantly increase the default rate during periods of high pool prices and this could be viewed as a failure of government policy.
- Implementation. Needs RROR amendment for implementation.

Pros of the Forward Market Auction:

- Allows a RRO provider to go out into the forward market, and in theory receive the efficient price for their hedges for next month's forward power price.
- Is a systematically less cumbersome way for RRO providers to purchase their CFDs. There are fewer costs associated with the procurement of power along with easier procurement in general due to the sellers essentially coming to the buyer.
- Fairly transparent and easy to understand, depending on how it is run.
- Easy to implement

Cons of the Forward Market Auction:

- Does not address volatility and stability. It is well documented that in Alberta's forward market when there is an announcement of planned generator outages, the forward market strongly reacts, price rises, and then market dynamics bring price back down to the equilibrium price. If an RRO provider's auction is scheduled one day after an outage announcement takes place, the cost of hedges will be artificially higher than the equilibrium price for that month. Furthermore, it is very possible that some time after the announcement in the same month the outage can be rescheduled or canceled and the forward price then falls dramatically.
- Any NGX participant knows how much RRO volume is transacted via NGX auctions because it is settled in blocks all at the same time. This gives suppliers clear visibility into how much has been transacted and how much remains to be hedged, allows them to telegraph upcoming auctions.

- Participants are not financially motivated to drive down prices, rather they want to keep it as high as possible and get the last block lifted.
- Auctions rely very heavily on the seed price and therefore there is a great deal of risk around setting the seed price.
- The auctions are basically a one sided transaction with one way information visibility that gives the sellers all the information to get the last price, not the lowest price. The buyer in the auction is more of a captive price taker.
- Suppliers know RRO buying is coming (telegraphed) so they get prepared and get the majority of their selling (hedging for generators) done during the auction times and don't need to participate outside of the auctions.

Pros of the Long-term hedging:

- Volatility. Offers less volatility than current RRO.
- Simplicity. Long term hedging might reduce the complexity of the current RRO.

Cons of the Long-term hedging:

- Price. Higher RRO prices due to increased risk premium associated with longer term contracts.
- Implementation. Difficult to implement in the short term as it requires changes to the RROR.
- Competitive retailers who offer fixed contracts may oppose this option, as the RRO may become the "price to beat".
- Longer term hedges may cause rate shocks. Rate shocks should be less for shorter term hedges (i.e., seasonal or monthly hedges).
- A blend of long and short term hedges brings complexity with it (though a prudent mix could make the RRO smoothed).

Pros of centralized procurement:

- Price. Least costly among all hedging mechanisms (since it eliminates hedging by several companies).
- Transparency. Provides better transparency.
- Confidentiality. Since hedging gets centralized, confidentiality issues are better addressed
- Provides better regulatory efficiency as it reduces administrative and legal costs.
- Simplicity. Simpler than other hedging mechanisms.

Cons of centralized procurement:

- Implementation. Needs RROR amendment for implementation. Furthermore, there might be opposition from the RRO providers.
- Volatility. If the hedging period remains the same then this centralized procurement will not have any impact on reducing volatility
- Competition. Though this system reduces the ability of suppliers and buyers to act strategically in the forward market, it might impose potential risk for competitive retailers.

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April 26, 2017
Enhancing the Design of the Regulated Rate Option (RRO)

The announcement last December of the intent to implement a RRO Cap was punctuated by Premier Notley and Energy Minister McCuaig-Boyd in a photo op with an Edmonton family to announce the need for stable electricity prices.

Quotes

> ***"Our government inherited a volatile electricity system that doesn't look out for consumers or work for investors."***
>
> ***"This government won't put Alberta families, jobs or the economic gains we are beginning to see at risk in a volatile electricity market."***
>
> ***"Electricity system reforms, will ensure stable and affordable electricity prices going forward."***

On April 6, 2017, Minister McCuaig asked the Market Surveillance Administrator to conduct an analysis and provide a report with options for enhancing the design of the Regulated Rate Option. It was asked that the options provide long-term, stable and affordable prices for Alberta's electricity consumers into the future, while minimizing regulatory and administrative costs. It was encouraging that the MSA was asked by the minister to identify any issues or possible challenges associated with transitioning from the current Regulated Rate Option arrangements to alternative approaches.

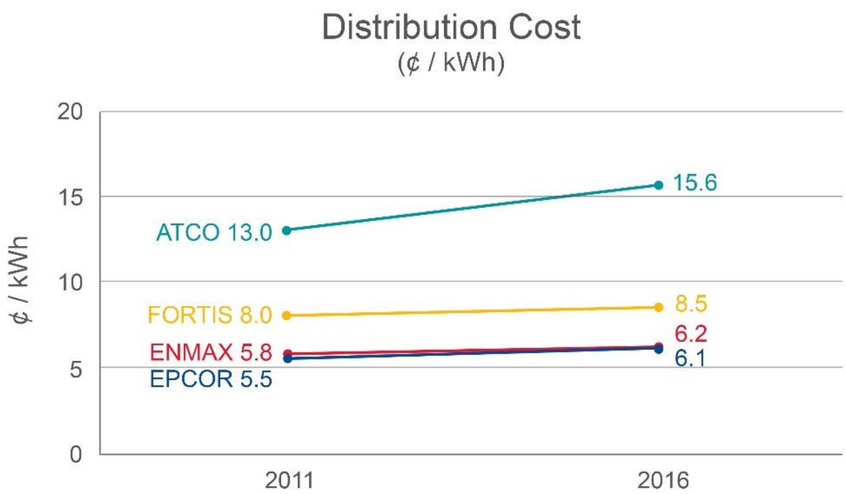
The items now being considered by the Minister are:

1. Should there be one RRO rate?
2. Changes to procurement.
3. Introduction of deferral accounts.
4. When and how should a change to the RRO occur?

There are four questions that also need to be asked and addressed:

1. What is the load and number of customers in Alberta that is no longer on the RRO?
2. What is the potential damage that might be done to the competitive market?
3. What is the possible cost of the RRO Cap?
4. Who pays? (The reality is that you cannot cap the RRO in an 'Energy Only Market' without someone picking up the cost of doing so.)

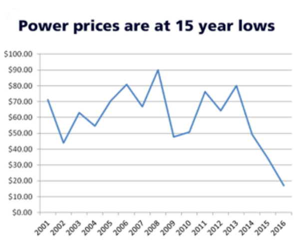
The reality is that the cost of energy isn't the problem. If the government is really interested in helping the consumer lower their monthly utility bill. The cost of distribution has gone up, while the energy component has dropped.



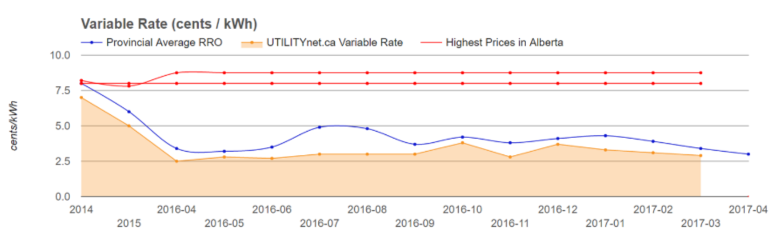
Voters are being told that the policies announced related to the RRO cap would be designed to protect consumers from the volatility of the market and high energy prices. We suggest that it is wrong to look at the market conditions of 2011/2013 and suggest that the numbers at that time are symptomatic of the market conditions today. A lot has changed, and new generation has been brought online.

It is essential for our political leaders to understand:

- Today, about half of all consumers in Alberta have moved off of the RRO and are profiting from very low and stable prices.
- Businesses have the option of becoming Self-Retailers and buying off the Spot Market.
- Supply is up by 50% and wholesale prices fell by 52%.
- Consumers who are looking for guaranteed stability have purchased fixed price supply agreements stretching out to 2020 for under 6 cents per kWh.
- Nearly $17 billion has been invested in new generation over the last two decades by the private sector.
- While wholesale prices have dropped dramatically, some RRO providers are overcharging consumers. This has absolutely nothing to do with price volatility, but rather profiteering at the expense of Alberta REA members by their respective associations.



Source: www.ippsa.com



Source: www.utilitynet.ca

Consumers, through various media releases, are being hyped into the misconception that the policies announced related to the RRO cap would be designed to protect them from the volatility of the market and high energy prices. The variable retail price compared to the RRO tells a different story. The market is not volatile, but rather the opposite.

Every month, as a competitive retailer we have out-performed the RRO. Possibly the government should be promoting the small independent business owners who have proven that they can offer consumers lower prices, rather than propping up RRO providers who under the cap will be subsidized.

It is vital that our political leaders understand the points mentioned above, to ensure private sector investments are not put at further risk. Investor confidence is the key to building a stable market, not price caps. Consumers today have the option of buying electricity from competitive retailers in the 3 cents per kWh range. For years, the private sector has been focused on offering the best solution and lower prices to consumers.

One of the Problems

Consumers today in the ATCO Wires Zone are paying over 150% more on their utility bill for delivery charges compared to a similar residential consumer located in Edmonton or Calgary. Yes, rural consumers are paying more for delivery charges – but the cost of energy is the same regardless of where you live.

The cost of energy isn't the problem.

The differential paid by consumers living in ATCO territory compared to a similar consumer in the Fortis Territory are paying 85% more for delivery.

Putting a cap on the RRO when the problem is in the distribution system is a blind kneejerk strategy. This is something that community economic development organizations should be up in arms about. Business owners, where the cost of their utility bill is a major line item on their balance sheet, should locate their business in a low-cost zone in the province. If the government wants to encourage diversified economic growth, this is problem that should be looked at.

I sincerely hope the Premier and Minister are provided with information explaining that the same firms that have profited from the revenue structure of the RRO and who will profit from the end of competitive market participants (by tilting the paying field) are the same players who sold out and exported jobs out of the province (Enmax and Tata; ATCO and Wipro; and Direct and HCL).

The MSA has been invited to provide input, which we hope that the political leaders will listen to. We also hope that the Minister is provided with a total picture of the issues.

We will respond to the MSA's request for answers to the four questions raised by the deadline of May 19, 2017, but prior to doing so we have some questions. A discussion on the RRO Cap will help mold our opinions and evaluations offered.

We asked these questions of Alberta Energy and never had a reply. In fairness to Philip Shum, he has not yet received approval to discuss this new program with Competitive Retailers. This in itself is discouraging and somewhat seems at odds with the spirit of open consultation that the industry once enjoyed.

1. The 6.8 cent/kWh RRO cap rate was set without consultation with the industry or explanation. What was this number based on? If you know the answer, please share with us the numbers, as we think someone has seriously under-stated the cap and we need to know what we are competing against.

2. Is the motivation of the cap based on the expectation the Spot Market will increase? Any idea when?
3. What is the corresponding spot market or hedge price pertaining to the cap? 6.8 cents = cost per MW?
4. Customers on the government RRO represents 55% of the market load. Is this number correct? If the government expects everyone to pay for the cost of the subsidy – why shouldn't everyone benefit? Possibly capping the Floating Rate or capping the cost of generation would accomplish a similar objective.
5. How much does the government expect the RRO cap to cost? How do they intend on funding the subsidy?
6. Consider opening the RRO to be provided by competitive retailers. This would help level the playing field and give consumers the protection that they need. It would also bring jobs back to Alberta that have been exported by the largest RRO provider in the province.
7. Recommendation – limit the RRO cap to vulnerable Albertans.

Unintended Consequence of the RRO Cap

The average residential consumer uses about 8,000 kWh per year and a farm consumer uses about 12,000 kWh per year; but what about the commercial market? Will many commercial customers using less than 250,000 kWh per year move back to the RRO? If industry/commercial clients move en masse to the RRO, competitive retailers will suffer damages. These damages will need to be liquidated to cover the hedges that were purchased to ensure and secure guaranteed stable rates. This is a major and potential serious consequence to re-structuring the market when millions of dollars have been committed to buy long term hedges that in turn back fixed retail prices.

The MSA might want to consider attempting to quantify the potential damages to the market and ensure the government knows the possibility of major write-down which could very easily lead to major financial hardships or bankruptcies.

The Real Market at Work

Our political leaders often refer to the volatility of the wholesale hourly or daily spot market, and they naively posture that consumers need to be protected. It is important to understand the nature of the forward market and that the RRO is not based on the daily spot market, but rather, it is backed with forward purchased hedges. At the same time, consumers who are on fixed competitive contracts are provided a guaranteed retail price that is not influenced by the spot market nor the volatility in the RRO. The market already has a built-in safety-net for consumers.

This then begs the question; how much of the energy market in Alberta is actually hedged compared to being vulnerable to the AESO spot market? The fear we have is that the decisions made for the proposed RRO Cap are based on an uninformed emotion or political ideology. These will result in another round of unintended consequences, similar to the expensive decision the NDP made which resulted in the Coal PPAs being cancelled and turned back to the Balancing Pool.

We believe in and support the governments objective of protecting vulnerable Albertans. Many of the Energy Marketers within our network took the step of offering seniors in our province a discounted electricity rate. It was well received. The province can help protect those who do not have good credit and cannot buy fixed rated contracts. We are in agreement, that there are consumers that should be given protection from policies that might cause economic hardships.

Eligibility

- Please look at the numbers. To give every consumer who uses 250,000 kWh per year or less an artificial cap is an unbalanced benefit that someone has to pay for. Put the consumer who uses 250,000 kWh per year into perspective. The average household of four residents uses about 8,000 kWh per year. There is a major gap between these two customer segments.

  Let's hypothetically say that the RRO went to 9.8 cents per kWh over the year, as such the subsidy would be 3 cents. For a small residential consumer, a subsidy of 3 cents would cost the government $240 per year for each household on the RRO. For a business customer at the top end of the 250,000 kWh RRO threshold, the government will be paying out $7,500 in subsidies. Multiply these numbers by the number of customers that would be eligible for the subsidized cap = how many billions are needed to be financed to cover the potential cost over the years ahead.

- If we look at some of the REAs who are currently retailing for more than 8 cents per kWh today; is it the government's intention to preserve the REAs inflated profit margin and roll back the retail rate to REA farming members? An REA today can buy electricity for their members for anywhere from 2 to 4 cents per kWh. They add over 100% margin and retail their RRO for over 8 cents. NPP REA as an example is retailing their RRO for 8.75 cents per kWh. So, why is the government pegging the 6.8 cent cap as a means of subsidizing the REA who is overcharging consumers? This doesn't seem right; does it?

- Here is a very real scenario, and it happened in the early days of deregulation. The RRO was pegged artificially low and industrial clients with sites less than 250,000 kWh stayed on the RRO. This is what could happen in the future. When the spot market balloons upwards above $60/MW and you have an RRO that is capped at 6.8 cents then all the Oil & Gas industry participants that have thousands of sites will move from Self-Retail over to the RRO and will profit from the subsidies that the government has designed. We looked at just two of our many Oil & Gas sector clients who we know will move their sites onto a subsidized RRO at 6.8 cents when or if the market spikes. Based on the number of sites and consumption for these two Oil & Gas Self-Retailers, it will cost the government about $6 million per year under the capped strategy. Is this what we want to do?

Politics

Here is a political question we need to ask our own MLAs: "Will the government treat all Albertan's fairly?"

The Future

We struggle with trying to figure out our going forward strategy and how we can compete against the largest competitor of all: our own government.

The government inherited a market that is serviced by independent retailers who are offering consumers lower prices than the governments RRO. The retail price difference between the Floating Retail Rate and the RRO already offers consumers substantial savings. Why not simply promote "what is working" rather than kill the section of the market that consumers are benefiting from. Wholesale prices are at 20 year lows because the private sector invested billions of dollars into new generation over the last two decades.

The market has a Capacity of over 16,000 MW of generation and the provincial demand is running in the 9,000 - 11,000 MW range. Over capacity is a result of the provincial economy being in a slump and this in part has driven the wholesale market down.

Is the market broken? Yes, I guess it is. Wholesale prices are too low and need to be increased if new generation is to be encouraged.

But, how do you plan for the future when there are conflicting political messages?

Mixed Political Messages

- The NDP's 2015 election platform included a promise to "properly and effectively 'smart regulate' Alberta's electricity retail system," with the goal of stabilized power prices and protection from financial manipulation. Is this really a problem today?

- PC critic Rick Fraser postured the position that the RRO Cap is the NDP's attempt to cover themselves and prevent a situation like what's happening in Ontario where rates have sky-rocketed. He also stated; "a deregulated power market may have its problems, but it has worked for the province."

- Wildrose critic Don MacIntyre said the 6.8-cent ceiling means that "the NDP government has essentially admitted that their policy changes mean Albertans should expect nearly a doubling of current electricity costs.

- The market here was deregulated in 2001, and remains one of only two "energy-only" models in North America (the other is Texas). The set-up means power generators are only paid for the energy they produce; not how much they are capable of producing. The Premier's perspective is that the energy-only model isn't attracting investors any more. "Investors who would otherwise have put capital in are otherwise starting to hedge their bets," she said. "It's our view that, that is the fundamental problem we need to address at this point."

- Notley says money from the carbon tax can be used if needed to fund this program. "If additional funding becomes necessary, we'll use funds from the carbon levy to pay for the cost that go above 6.8 cents." Is there enough money in this fund?

Will the government protect all Albertan's or just those who are being promised protection if they are on the RRO?

Please feel free to contact me for further discussion on this topic.

Cheers,

Nick Clark
Managing Partner, Utility Network & Partners