THE SCHOOL OF PUBLIC POLICY

MASTER OF PUBLIC POLICY CAPSTONE PROJECT

A Review of Alberta's Default Rate for Electricity

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UNIVERSITY OF CALGARY

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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.

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[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

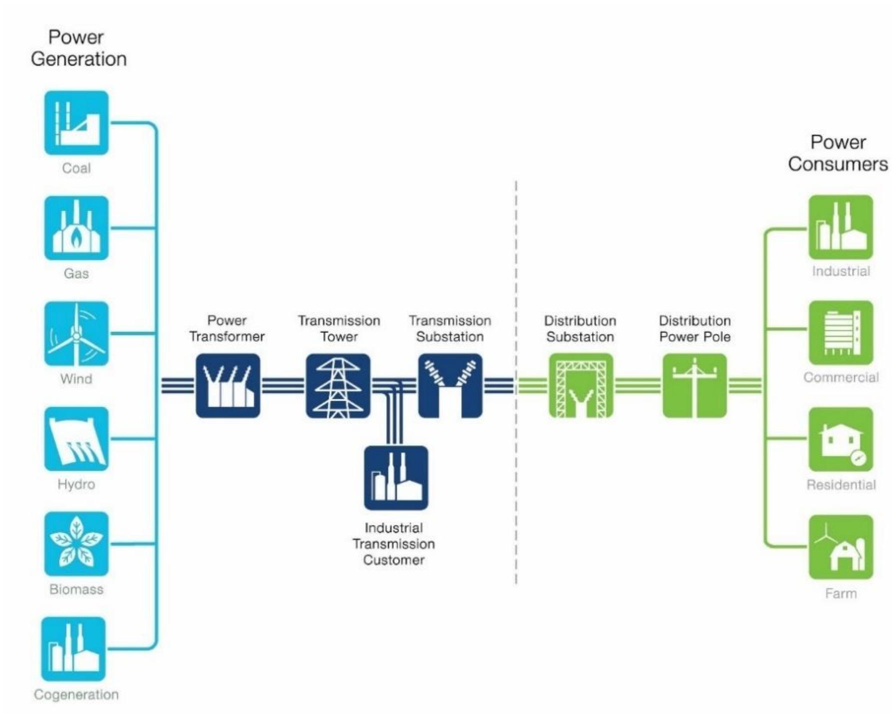
Before the history, operation and performance of the RRO can be examined, a basic understanding of the physical and financial aspects of the exchange of electricity in Alberta is required. This section goes through some basic terminology and concepts that serve as the foundation for the discussion and 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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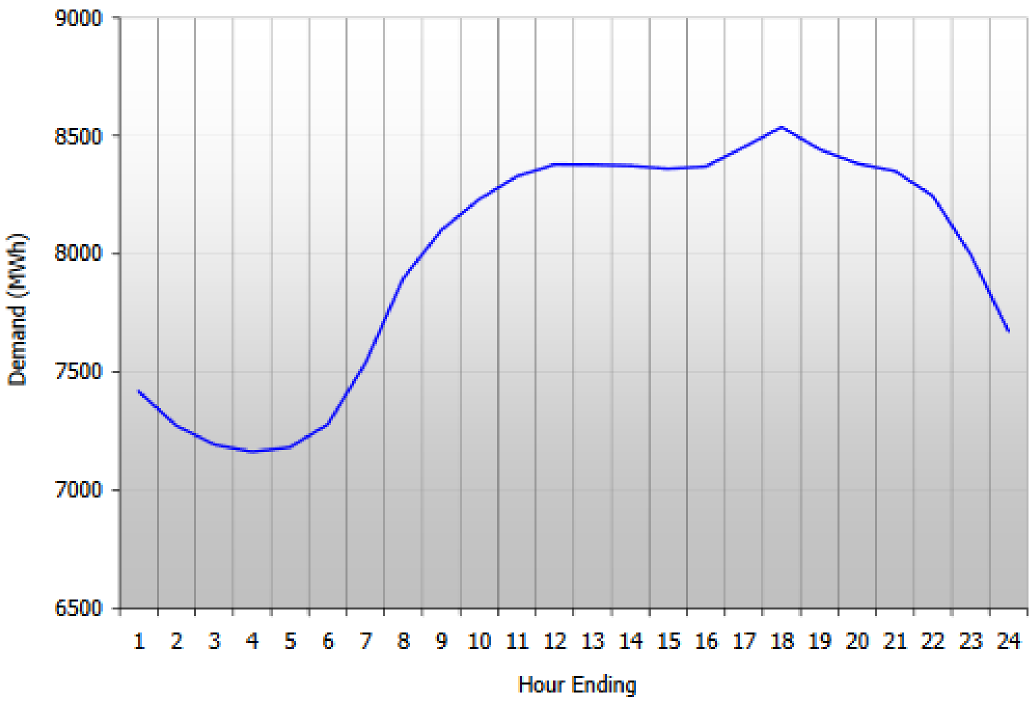
[7] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, page 30 (pdf).
[8] Ibid., page 55 (pdf).
[9] Ibid., page 186 (pdf).

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

[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

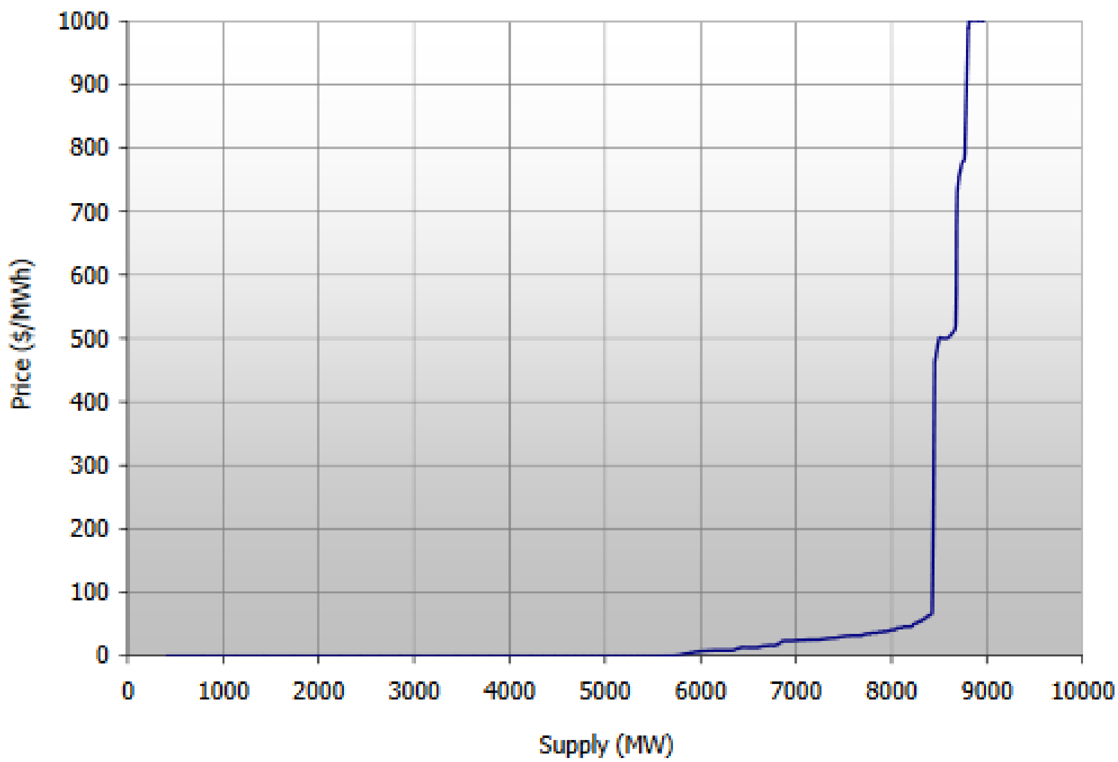
Block	Capacity (MW)	Price ($/MWh)
0	150	0
1	150	10
2	20	300

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,

[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

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[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

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[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

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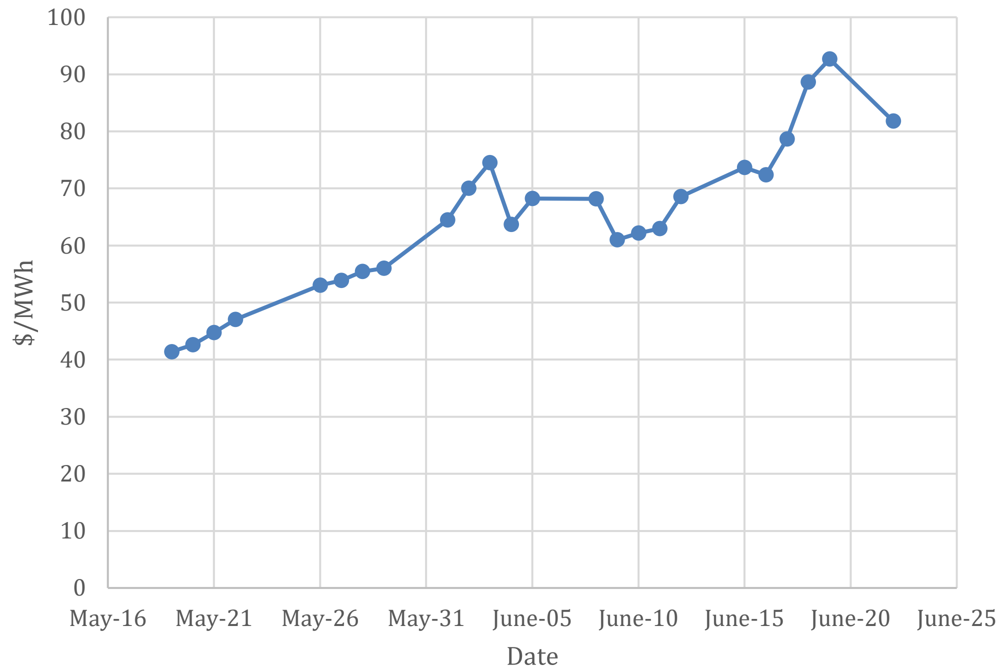
[48] Ibid., page 28 (pdf).
[49] AUC Exhibit 0139.02.UCA-2941, Utilities Consumer Advocate, "Evidence of Jason Beblow," June 4, 2014, page 24 (pdf).
[50] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: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

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[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 appropriate price of electricity,"[74] provide small consumers with "some degree of price protection,"[75] and "protect consumers from too much 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

[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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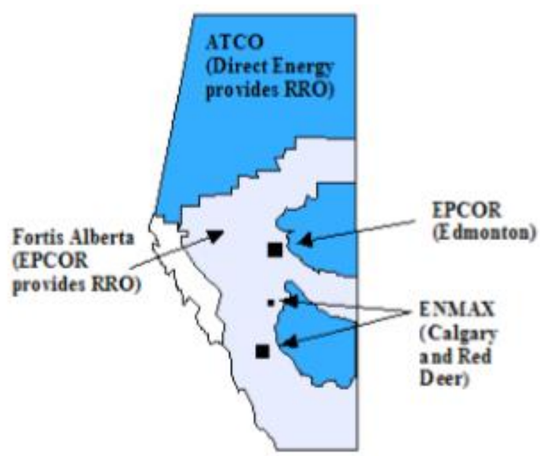
[82] Ibid.

[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

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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.

[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:

$$Energy\ Charge = BEC + [RM + F\&C + ERM] \tag{1}$$

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:

[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 45^{th} day preceding the month and ended on the 5^{th} business day preceding the month; as of 2013 the price setting window has begun on the 120^{th} day preceding the month and ended on the 5^{th} 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:

$$Profit = (BEC * Q) - (P^P * Q) + (P^P * V) - (BEC * V) \tag{2}$$

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:

$$Profit = (BEC - P^P) * (Q - V) \tag{3}$$

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.

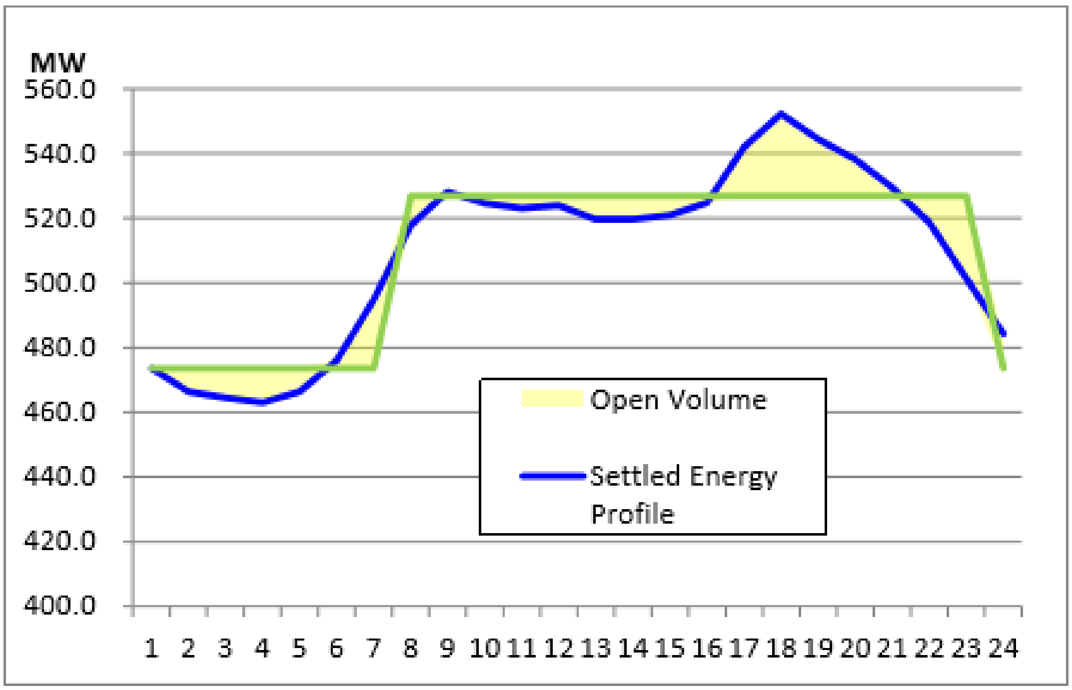
The point of this example is to illustrate that the profitability of any volumetric position is a function of the Pool price. As a result, an RRO provider bears commodity risk if its load is not perfectly hedged. Because the current EPSPs require the RRO providers to hedge their forecast load with standard 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

[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

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[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]

[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

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[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)

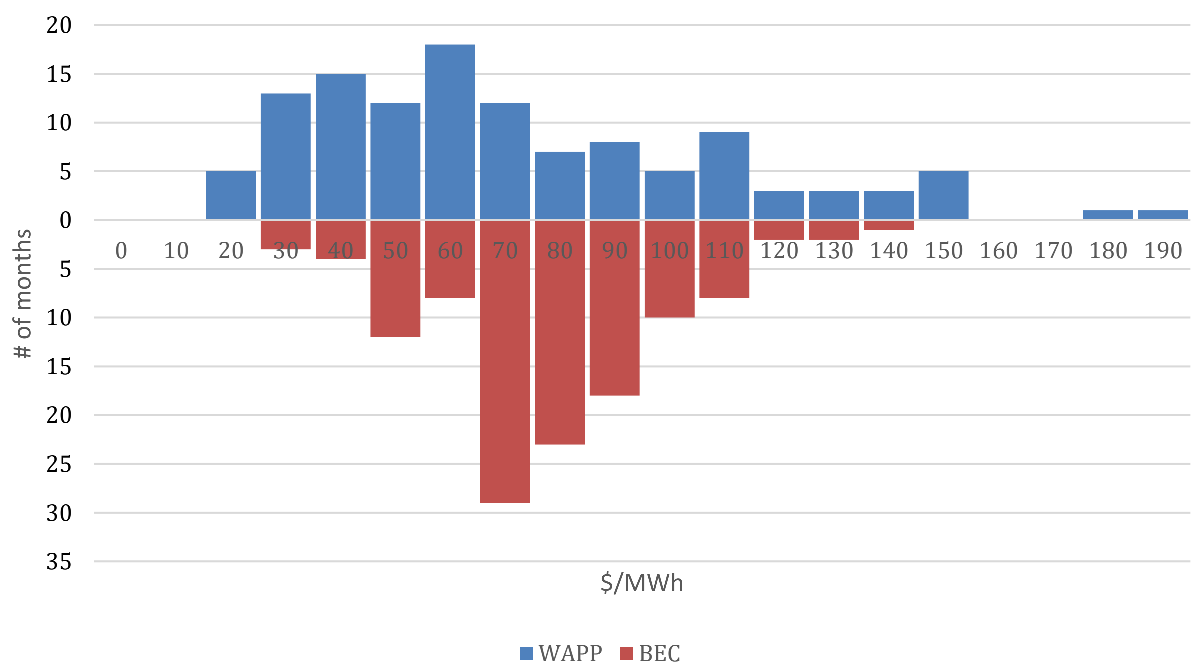
		EEC			
		EPSP #1		**EPSP #2**	
		Average Abs. % Δ	**Std. Dev. ($/MWh)**	**Average Abs. % Δ**	**Std. Dev. ($/MWh)**
A	**WAPP**	37%	36.7	47%	40.0
B	**BEC**	12%	16.9	20%	25.8
C=A-B	**Difference**	**25 pp. (101%)**	**19.8**	**28 pp. (83%)**	**14.2**

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

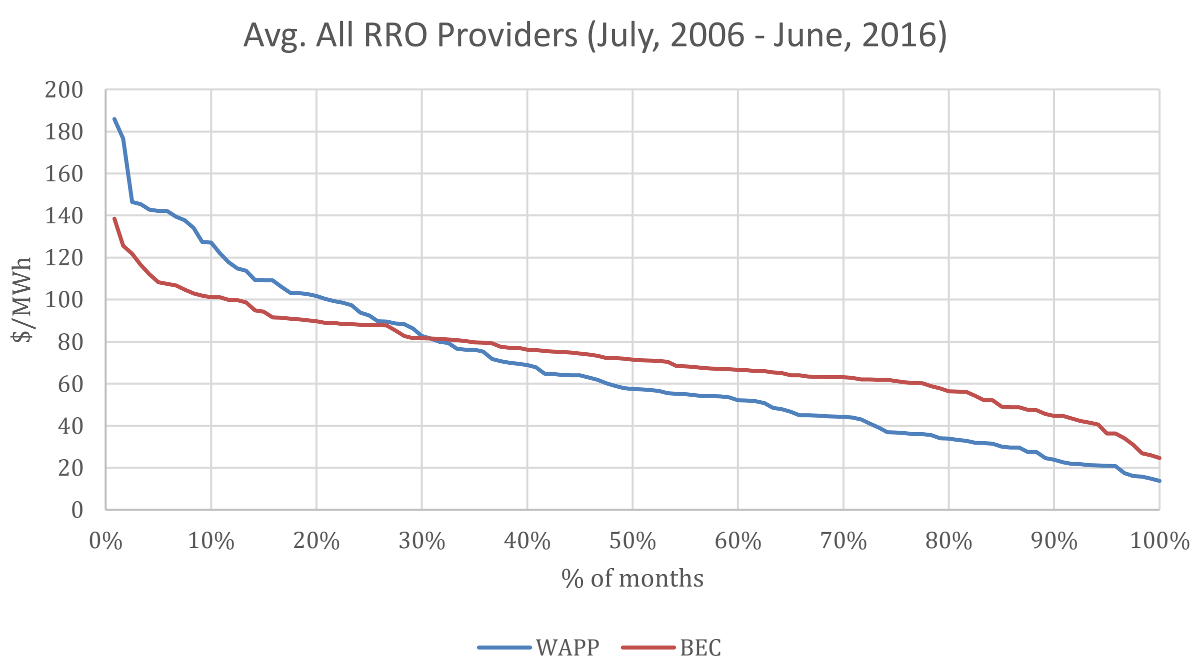


[224] Note: The values on the x-axis represent the upper-bound for each bin. For example, the x-axis value of $30/MWh includes the number of observations greater than $20/MWh and up to and including $30/MWh. For the average WAPP, there are 13 observations in this bin, whereas for the BEC, there are only 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."

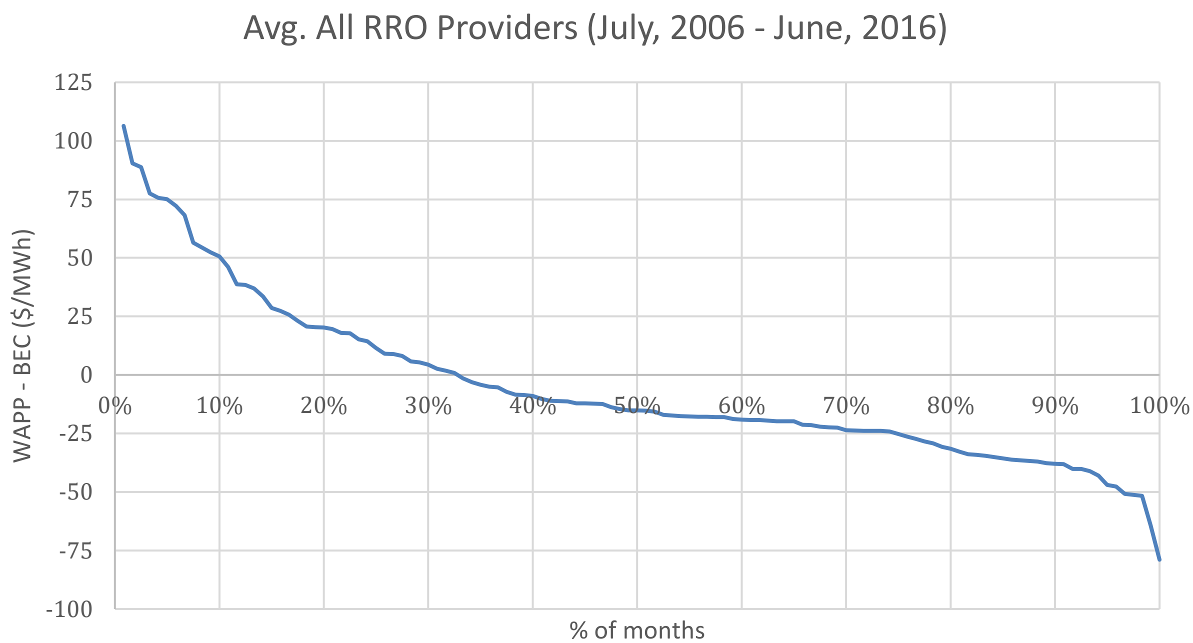
The distributions of the average WAPP and BEC can also be visualized using duration curves, which sort their values from highest to lowest and plot them as a proportion of the 120 months of both EPSPs:

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

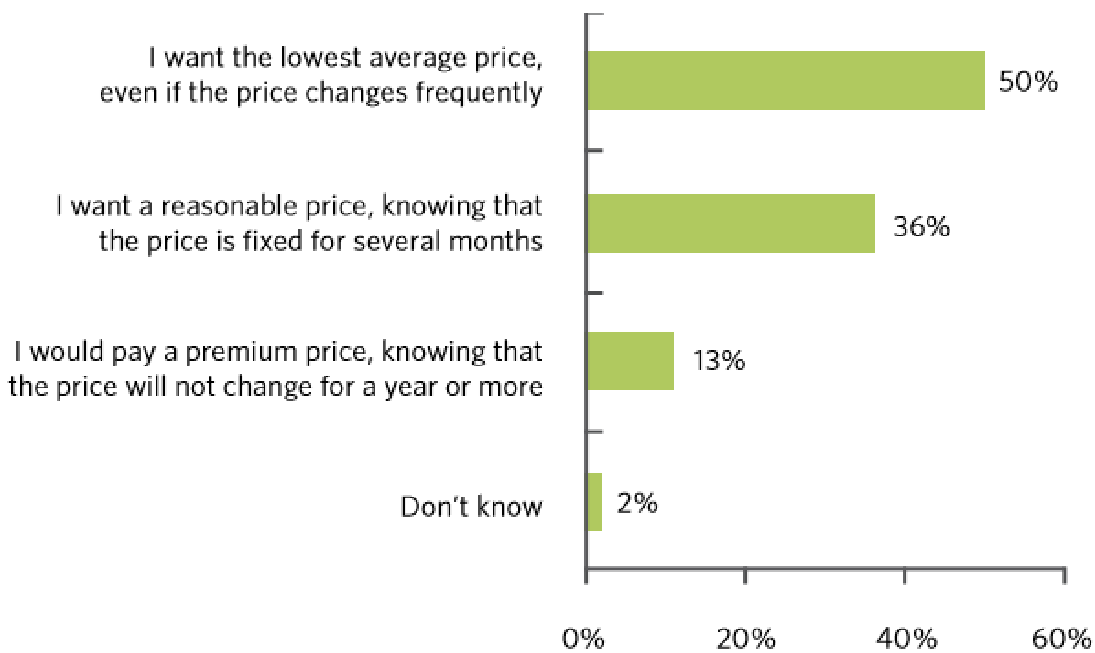


This curve shows that the maximum positive difference between the average WAPP and the average BEC was $106/MWh. The maximum negative difference between the average WAPP and the average BEC was $79/MWh. Additionally, the average WAPP was higher than the average BEC in one third (33%) of months. Over 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

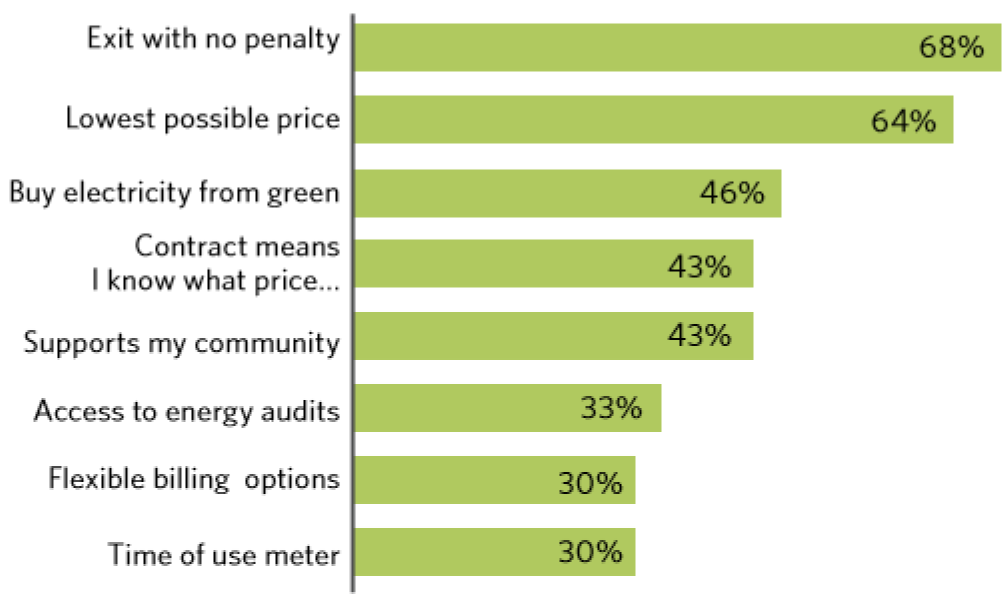
[226] Retail Market Review Committee, "Power for the People: Report and recommendations for the Minister of Energy, Government of Alberta," September 2012: http://www.energy.alberta.ca/Electricity/pdfs/RMRCreport.pdf, pages 91 and 92 (pdf).

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

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[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

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:

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[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:

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[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:

$$ss = (\frac{q - q^F}{Q})$$

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]

[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

[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

[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:

$PED = Price\ Elasticity\ of\ Demand$

$Q = Quantity$

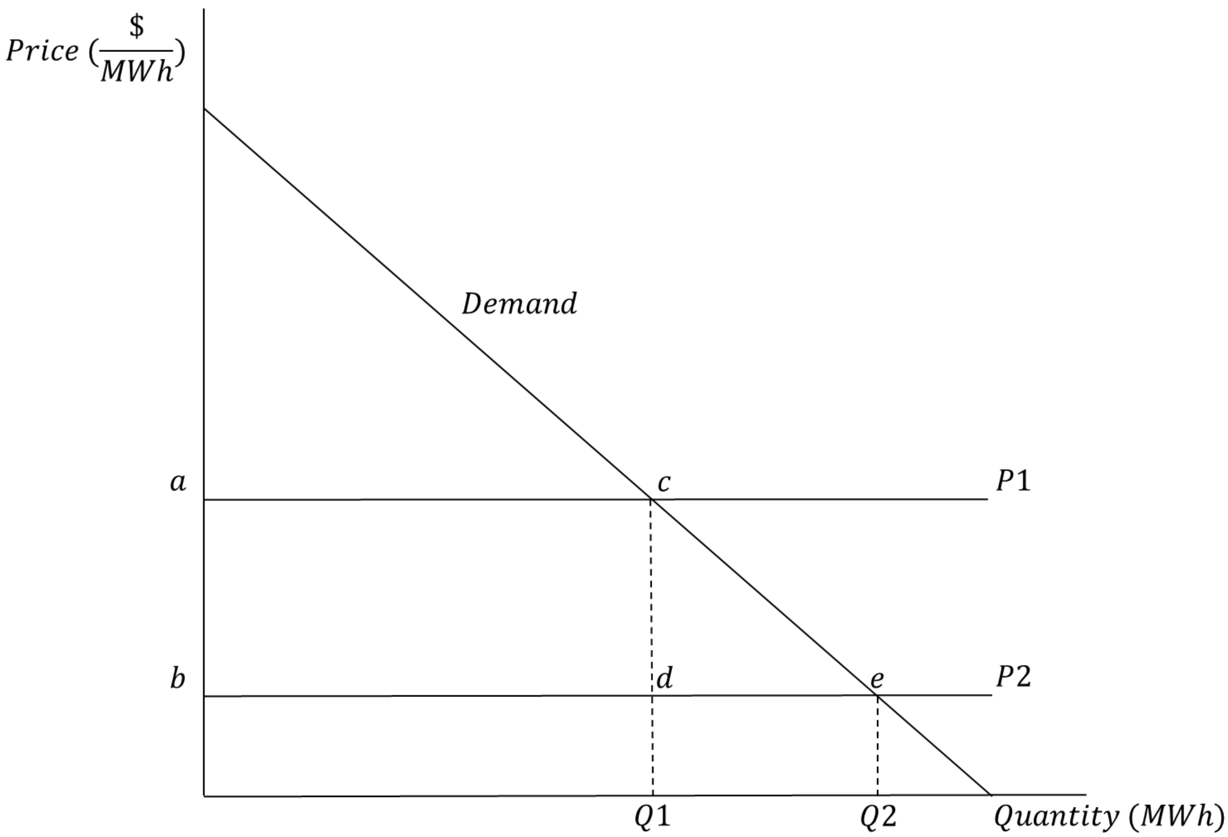
$P = Price$

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.

[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 energy 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]

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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

[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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