A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta

An assessment undertaken as part of the 2012 State of the Market Report

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PREFACE

The distinguishing feature of the Alberta market compared to most organized electricity markets is that it is 'energy-only', that is, the private sector bears the risk and decides on retirement of generation facilities and investment in new capacity mainly driven by revenues derived, or expected to be derived, from the wholesale market. There is no regulated and centrally administered resource adequacy and planning mechanism. Apart from a price cap and price floor, prices in the spot market are regulated by the forces of competition, within the parameters of the Alberta market design and supporting rules and procedures. Finally, unlike most other organized electricity markets, participants are free to unilaterally engage in strategies to attempt to move the pool price (as long as they do not impede competitive responses) and there is no mechanism to administer prices or offers at some proxy of cost.

Under the circumstances outlined above it is obviously important that competition is doing its job in regulating market outcomes. The MSA can and does exercise its responsibilities to monitor market participant behaviour to ensure that it conforms to the standard set out in the Electric Utilities Act and amplified in the Fair, Efficient and Open Competition Regulation; however from time to time a more searching broad-based assessment needs to be made. This is the purpose of the MSA's State of the Market report.

As part of the work leading to that report the MSA is releasing a number of preliminary reports. In the view of the MSA, competition is a means to an end. The end is economic efficiency. Part of that assessment is that prices over the long-term need to be no higher than is needed to cover the cost (including a return on investment) of the next increment of investment. Measuring those costs, sometimes referred to as the long-run marginal cost of investment, is the subject of this paper.

The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.

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Overview

Our motivation

The Market Surveillance Administrator (MSA) is currently undertaking a State of the Market report, envisioned as an assessment of the state of competition within, and the efficiency of, the Alberta wholesale electricity market. The report presented herein represents a building block to provide input to the MSA's broader State of the Market assessment. Part of the State of the Market report is aimed at establishing an appropriate benchmark, *effective competition*. Testing against that benchmark can be broken down into a number of components. One of these is confirming that price outcomes over the medium term are no higher than they need to be to ensure that sufficient investment occurs.

What we looked at

The benchmark of *effective competition* explicitly recognizes that achieving efficient outcomes over time is one of the principal objectives of the market. To that end, it is acceptable for there to be some degree of efficiency loss in the short-run. A testable benchmark for *effective competition* must ensure that average price outcomes over time are no higher than needed to ensure the market sustains itself, i.e., transfers are sufficient to cover prudently incurred costs over time but are not excessive. Making this assessment requires knowledge of three factors. First, an appropriate measure of costs must be developed. Second, a measure of relevant prices must be determined. Third, a methodology for comparing costs and prices is required.

This paper describes various methodologies for measuring long run marginal cost (LRMC) and relevant prices, as well as a process for comparing them. In principle, the relevant comparison is of future costs and future prices, i.e., a forward-looking comparison rather than a backward-looking comparison.

The standard economic technique used to estimate LRMC is to calculate the minimum present-value cost of meeting a permanent increment of demand. A simpler approach based on the levelised unit electricity cost (LUEC) methodology is proposed as a proxy. The report does not examine cost inputs for various technologies in detail. Instead, cost inputs are drawn from an AESO report. With respect to prices, the complete distribution of historical prices available is taken as given. Forward prices do not provide the same sort of complete distribution. However, different types of forward contracts are traded (e.g., all hours, on-peak hours, and off-peak hours) and so a distribution of forward prices can be constructed from a combination of forward contract prices and historical prices.

What we found

While the major purpose of the report is to establish a method for comparing LRMC and prices, the analysis concludes that the level and distribution of prices is sufficient to warrant incremental investment in peaking generation facilities. Consequently, the MSA has two expectations, either:

- the price signals that appear to make this investment profitable cease (perhaps in response to other changes such as increased price responsive load), or
- investment occurs.

In the event that seemingly profitable investment does not take place, the MSA would initiate a further enquiry into whether barriers to entry were impeding competitive outcomes in the market.

1. Introduction

To assess the economic performance of a market over a lengthy period of time, an appropriate benchmark is required. With respect to Alberta's energy-only electricity market, the appropriate benchmark must account for the fundamental characteristics of the market: investment in electricity generation capacity and demand management programs both involve considerable fixed costs, investment opportunities tend to be lumpy[1], demand is not very responsive to price, and the future is uncertain.

The purpose of this report is to describe an appropriate benchmark for assessing the economic performance of Alberta's market over time and to provide a methodology by which this assessment can be implemented using observed market data.

The most commonly employed benchmark in economic analysis is related to the *model of perfect competition*. Application of this benchmark amounts to a comparison of market price outcomes to the variable cost of the last unit of production (or, equivalently, assessing whether supply is offered to the market at variable cost). The appeal of this benchmark is that it corresponds to an outcome widely considered to be best: the greatest possible amount of economic gains result from profit seeking by individual economic agents (producers and consumers) that leads to efficient and sustainable market outcomes through time, with competition keeping prices low and disciplining behaviour. However, very few real markets meet the stringent assumptions necessary to make this benchmark applicable. Energy-only electricity markets are not an exception.

Notwithstanding the inapplicability of *perfect competition* as a benchmark, a number of real world markets achieve many of the same desirable outcomes. In electricity markets, competition acts to lower prices such that the fixed costs associated with prudent investment can just be recovered, and the market remains sustainable. As a general matter, any market that reaches such an outcome can be thought of as *effectively competitive*. In the context of the characteristics of the electricity market, the MSA defines *effective competition* as:[2]

> A level of competition (and related outcomes) that (i) achieves efficient investment with the lowest possible short-run inefficiencies, (ii) does so over a reasonable timeframe, and (iii) ensures neither collusion, abuse, or anti-competitive practices.

The definition of *effective competition* explicitly recognizes that achieving efficient outcomes over time is one of the principal objectives of the market. To that end, it is acceptable for there to be some degree of efficiency loss in the short-run. A testable benchmark for *effective competition* must ensure that average price outcomes over time are no higher than needed to ensure the market sustains itself, i.e., transfers are sufficient to cover prudently incurred costs over time, but are not excessive..

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[1] 'Lumpy' means that some technologies benefit from scale of production capacity and are not, therefore, economically sensible to install on a small scale (formally, some capacity investments are indivisible).

[2] Critically, an *effectively competitive* outcome does not depend on any assumptions being made about the particular market under consideration. As such, the model of *perfect competition* can be thought of as constituting a special case of a wider class of models, where a particular set of assumptions is made that reaches an equivalent outcome. In other words, *perfect competition* implies *effective competition* but *effective competition* does not necessarily imply *perfect competition*. An equivalent designation for *effective competition* is *workable competition*; a term relied on by many competition authorities. While the terms are synonymous, the label *workable* connotes a standard of minimum sufficiency of market performance that is neither intended nor correct.

In order to test for *effective competition*, the MSA considers four aspects of the market:

- measure short run inefficiencies;
- assess whether there is evidence of dynamic efficiency over time;
- ensure that price outcomes over the medium term are no higher than they need to be to ensure the market is sustainable (new investment occurs when it is profitable); and
- determine whether market participants meet the appropriate standard of conduct (i.e., support a fair, efficient and openly competitive market).

This report is principally concerned with developing a methodology for assessing the third part of this test. The other parts are addressed in other parts of the State of the Market report.[3] Ensuring that price outcomes over the medium term are no higher than they need to be can in turn be broken down into a number of parts. First, we need to specify an appropriate definition of costs (Section 2). Second, we need to examine relevant price data (Section 3). Third, we need to combine the two (Section 4). Empirical results are reported in Section 5 and Section 6 concludes.

[3] For example, the assessment of short run efficiency loss—the first part of the test—is made in another MSA report entitled *Assessment of Static Efficiency in Alberta's Energy-Only Market – An assessment undertaken as part of the 2012 State of the Market Report* (2012).

2. Cost in the long run

In this section we develop an appropriate definition of costs. It is important to be more specific about what costs are included and the relevant time period. In simple terms, relevant costs are those associated with meeting an increment of (extra) demand; the relevant time period is the long run, a time in which all relevant factors are variable. More formally, this is known as the long-run marginal cost (LRMC) of supply. In the context of a market characterized by high fixed cost producers, LRMC can be defined as:

> the change in the total cost of satisfying a permanent increment (or decrement) of demand divided by the magnitude of the increment.

Both the cost and the increment are normally calculated in present value terms, i.e., by considering the equivalent value today of a series of costs and benefits that will occur in the future. Calculating costs and benefits in present-value terms is important because they are typically valued less in the future due to there being alternative uses of current financial resources.

Broadly speaking, costs can be separated into two types: variable and fixed. Variable costs are those that vary with output, e.g., fuel. Fixed costs are all other costs, e.g., overnight capital cost of a generation facility. Assumptions regarding fixed costs are particularly important in electricity markets because fixed costs tend to be substantial and related to discrete investments that yield benefits over very long time periods.

Three standard approaches to the measurement of LRMC are considered in this note:

- the perturbation approach, which is sometimes referred to as the Turvey approach;
- the average incremental cost approach (AIC); and
- the total element/service long-run incremental cost (TELRIC/TSLRIC).

A project-specific alternative measure of cost, the levelised unit electricity cost (LUEC), is considered as well.

This analysis draws on Kemp, et al. (2011), which reports an analysis of LRMC in the context of the Australian electricity market.

Each of the approaches to measuring LRMC is briefly described is Section 2.1, with additional detail, including illustrations, provided in Appendix A. Included is a brief description of the LUEC approach. A comparison of the approaches is reported in Section 2.2. The discussion of certain aspects of the LUEC methodology is provided in Section 2.3.

2.1 Measures of LRMC

Several approaches to measuring LRMC are considered in this section. In each case, costs and changes thereof are measured in dollars ($), while demand and changes thereof are measured in MW.[4] The units of measure are not altered if a variable is represented in present-value form.

2.1.1 Perturbation approach

The perturbation approach to measuring LRMC aligns closely with the stated definition of LRMC. The starting point for this approach is a long-run demand forecast and information regarding the

[4] Strictly speaking quantities are measured in terms of MWh per hour, but since we consider each hour individually, there is no practical distinction.

characteristics of technologies and processes that are available (or reasonably forecast to become available) to the market. An optimization algorithm is then used to determine the lowest-cost combination of technologies that can satisfy the demand forecast. This process is then repeated after modifying the demand forecast by introducing a permanent, unforeseen increment of demand (e.g., 100 MWh per hour). This increment of demand is known as a perturbation of demand. The perturbation approach calculates LRMC as the change in present value terms in total costs between the first and second optimization divided by the magnitude of the increment expresses in present value terms. Additional details are provided in Section A.1 of Appendix A.

The principle benefit of using of the perturbation approach to measuring LRMC is that it reflects the definition of LRMC closely. The principle drawback is its computational difficulty. In particular, a number of non-trivial assumptions must be made, notably the list of technologies and processes available to satisfy demand. It is important to note that while there may be a large number of technologies and processes available in principle, only a subset will be used in the optimization algorithm. This implies that the actual results will approximate the true results.[5]

2.1.2 Average incremental cost (AIC) approach

The AIC approach is an alternative that bears much in common with the perturbation approach. As with the perturbation approach, the starting point here is a long-run demand forecast and information regarding the characteristics of technologies and processes that are available (and reasonably forecast to become available) to the market. An optimization algorithm is then used to determine the lowest-cost combination of technologies that can satisfy the demand forecast. Instead of introducing a permanent demand increment, the total cost of meeting the demand forecast is calculated by dividing the change in future demand. Both the total cost and the future demand changes are expressed in present-value terms. Additional details, including an illustration, are provided in Section A.2 of Appendix A.

The principle benefit of using the AIC approach to measuring LRMC is that it turns out to produce results that are more stable through time than the perturbation approach. While stability may be convenient for analysing results it does not necessarily reflect the true LRMC. In particular, the principle drawback of the AIC approach is that it does not approximate the definition of LRMC as closely as the perturbation approach does.

2.1.3 Total element long run incremental cost (TELRIC) approach

The TELRIC approach is another alternative measure of LRMC that is related to the perturbation and AIC approaches. The most basic version of the TELRIC approach, the so-called “scorched earth” approach, is entirely forward-looking in the sense that it assumes there is no incumbent generation supplying the market and finds the lowest-cost combination of technologies that can satisfy future demand. The calculation takes the total cost of an entirely new set of technologies (i.e., a new generation fleet) and divides it by total future demand (both terms in present value form). Additional details are provided in Section A.3 of Appendix A.

[5] An important corollary is that it matters who or what does the optimization, with the outcome reflecting the assumptions made. For instance, if the optimization is conducted by a central-planning regulator then the outcome will reflect the possibilities it considered feasible. If the optimization is conducted implicitly in a market setting where more technologies and processes are likely to be available, a different result will be obtained. As a general matter, additional options cannot have the effect of raising the LRMC as they could always be ignored. Thus, the LRMC obtained in a market setting is likely to be lower than that obtainable by a central-planning regulator.

The principle benefit of using the TELRIC approach is that it is unburdened by historical decisions regarding investment in generation capacity. This is also its principle drawback in that it ignores constraints that may influence future decisions, e.g., the location of existing generation capacity.

2.1.4 Levelised unit electricity cost (LUEC) approach

Strictly speaking the LUEC approach does not estimate LRMC because the LUEC methodology does not optimise generation developments against an incremental change in demand. However, the LUEC approach can be used to assess the cost of satisfying future demand and/or a demand increment. In short, LUEC is a project-specific calculation of the constant electricity price required to cover all of relevant costs given a set of assumptions. Additional details, in particular regarding the assumptions required to use the LUEC methodology, are provided in Appendix B. The attractiveness of a LUEC approach is that it is relatively simple to compute in comparison to those involving optimization against a demand forecast.

While it is simple to calculate, its interpretation is more complicated and that is the focus of much of this report. Whereas LRMC estimates yield a single number, every technology yields a different LUEC estimate. In the absence of an optimization there is no estimate of what represents the 'best' combination of technologies or how an individual technology would be utilized in a given year,. For example, one of the critical assumptions required for LUEC calculations is the generator's capacity utilization factor. The relationship between LUEC and the assumption regarding the capacity utilization factor is discussed in further detail in Section 2.3.

2.2 Comparison of approaches

Given the definition of LRMC stated at the beginning of Section 2, by construction the perturbation approach is most likely to yield the best estimate of LRMC. In particular, for a specified permanent demand increment it will determine LRMC as the lowest-cost way of satisfying the incremental demand. The AIC and TELRIC approaches do not consider the issue of satisfying a demand increment, rather they consider the issue of satisfying forecast demand at lowest cost, the difference between them being differing treatments of historical decisions. Since the TELRIC approach incorporates the fewest constraints in its optimization algorithm, it is likely to be associated with the lowest estimate of LRMC among the approaches considered.

The LUEC approach, because it is a project-specific measure of cost, is not based in any way on forecast demand. However, the MSA thinks this can be interpreted as a limiting case of the perturbation approach. As stated, the perturbation approach determines the lowest-cost way of satisfying a given permanent demand increment. One way to satisfy the permanent demand increment is to construct new generation capacity dedicated solely to that increment. For example, if the specified demand increment is 90 MW then one way to meet the demand would be to construct generation capacity that could supply 90 MW permanently. Such an approach is not necessarily economically efficient as there may be a way to use existing generation capacity to meet part of the demand increment and avoid constructing additional capacity, thereby reducing the overall cost. This is why the LUEC measure is a limiting case: constructing dedicated capacity is the worst-case, i.e., highest-cost, solution. The LRMC associated with this approach depends on a number of factors, including the size of the demand increment. This is the subject of the next section.

2.3 LUEC and the capacity utilization rate

Calculation of LUEC requires a number of assumptions, which include a capacity utilization rate, an expectation regarding the amount of time in which a generator is expected to be in operation. The impact of this assumption is on the rate at which the fixed costs associated with generation are allocated to each hour. A higher capacity utilization rate implies that fixed costs are allocated over more units of output relative to a lower capacity utilization rate. To the extent that the capacity utilization rate is a variable under the control of a generator's operator, its choice is an economically meaningful variable. From this perspective there are two classes of generators. First, there are those that can, subject to certain technical limitations, choose their input and production level, i.e., capacity utilization rate. This class includes thermal generators fuelled by either natural gas or coal.[6,7] For these generators, there is no reason to believe that any particular assumed capacity utilization rate corresponds to the proportion of hours in which it is economically efficient to run the facility.[8] Second, there are those that cannot choose their input and production level. This class includes wind-powered and run-of-river hydro generation.[9]

For purposes of this section we focus on two types of natural gas-fired generation where generators actively make choices about their capacity utilization rates. These generators are:

- a simple cycle generator (100 MW of net production); and
- a combined cycle generator (800 MW of net production).

Aside from the capacity utilization rate, LUEC computations make use of a significant amount of information, including fuel costs (natural gas prices in this case) and generator-specific characteristics such as overnight capital costs, expected years of service, heat rates, and operations and maintenance costs. As fuel costs are incurred over time, natural gas prices must be forecasted. More generally, all future values must be discounted. An expanded discussion of the LUEC model and related assumptions is provided in Appendix B. In this report we have made no assessment of the cost assumptions for each technology but have instead taken those recently used by the AESO.[10]

In addition to the capacity utilization rate, an assumption regarding natural gas prices is a major factor in the computation of the LUEC. Two basic approaches are considered in this report. First, a forecast of natural gas prices can be used. Current natural gas forecasts tend to possess a common characteristic, namely that prices exhibit a small but persistent average annual increase. This assumption can be characterized as the increasing natural gas price scenario. We also consider a second set of scenarios in which natural gas prices are constant. The reason for considering both assumptions is that if the LUEC is

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[6] A hydroelectric generator with storage typically has some degree of control over its input and production levels on an hour-to-hour basis. However, over longer periods of time the amount of available water is determined by exogenous environmental factors which results in a complex inter-temporal optimisation problem regarding the allocation of water use to each individual level. While profit maximisation suggests that water be allocated to the highest price hours as much as possible, the capacity utilisation rate is not itself endogenous.

[7] In some cases there are restrictions on generators' running hours due to emissions limitations. To the extent that such limitations are binding, they cause generators to take on some of the characteristics of hydroelectric generators in the sense that profit maximisation suggests that emissions be allocated to the highest price hours as much as possible.

[8] There are various ways to characterise the economically efficient operation strategy for a generator (or any other asset). The simplest is to assume that the generator operates at capacity when price exceeds variable cost and shuts down otherwise. This assumption applies to each individual hour and is the assumption made in this paper. Other reasonable assumptions include those that explicitly link generator behaviour across sets of contiguous hours, e.g., the generator may be assumed to schedule its planned outages in the month with the lowest historical average price (such assumptions are complicated by portfolio effects that are relevant at the corporate level of a generation firm).

[9] Portfolio issues regarding the voluntary dispatch-down of wind-powered generators are beyond the scope of this paper. As well, note that a particular hydro generator may be characterised as run-of-river at various times in the year and not others depending on the prevailing environmental conditions, i.e., amount of available water.

[10] AESO (2012), Appendix H, p. 118.

to be compared to electricity prices then the problem of electricity prices being dependent on contemporaneous natural gas prices is of great practical importance.[11]

Figures 2.1 and 2.2 illustrate the LUEC as a function of the capacity utilization rate for two types of natural gas-fired generation technology under the scenarios in which future natural gas prices are increasing and constant at 2011 levels, respectively. Both exhibit a downward-sloping relationship between LUEC and the capacity utilization rate as fixed costs are spread over an increasing amount of production. Alternatives to Figure 2.1 could be constructed using alternative natural gas price forecasts that either currently exist or will be developed in the future. These are not pursued in this paper. Alternatives to Figure 2.2 could be developed that use years other than 2011. As described below, a number of years in addition to 2011 are considered in this paper.

That said, Figures 2.1 and 2.2 are insightful for three reasons:

1) At relatively low rates of capacity utilization, production from a small simple cycle generator is less costly on a per-unit basis than from a large combined cycle generator. This reflects the trade-off inherent in the comparison of these two types of generators; the simple cycle generator has a lower unit overnight capital cost than the combined cycle generator, while the combined cycle generator has a lower heat rate, implying lower variable costs. The threshold that distinguishes these cases, i.e., the intersection of the LUEC curves, differs based upon the assumption made about natural gas prices. In particular, higher natural gas prices lower the threshold at which the simple cycle generator is less costly than the combined cycle generator. This is consistent with the trade-off described above in the sense that the simple cycle generator uses natural gas relatively less efficiently than the combined cycle generator, i.e., has a higher heat rate.

2) They reveal a limiting case regarding the perturbation approach discussed in Section 3.2. For instance, one way of satisfying a 100 MW permanent increment of demand would be to construct a 100 MW simple cycle generator and run it at full capacity. Under the scenarios that assume increasing and constant 2011 natural gas prices, the relevant LUECs are approximately $94/MWh and $60/MWh, respectively. These results can be taken as constituting an upper bound on the LRMC associated with the perturbation approach. As well, note that this result does not imply that such a generator should be run at full capacity. Indeed, as discussed above, such a strategy may not maximize profits as there are likely to be many hours in which price is less than marginal cost and the generator would be better off not producing. In other words, depending on the shape of the price-duration curve it may be optimal for a new generator to enter and operate at a capacity utilization rate less than feasible.[12]

[11] This point is considered in more detail in Section 5 of the report.

[12] The 100 MW increment of demand could also be satisfied, in principle, by running a 800 MW combined cycle generator at 12.5% capacity (assuming that such operation were technically possible, which it is not; alternatively, it could be assumed that the generator ran at capacity for 12.5% of hours and shutdown otherwise). Assuming increasing and constant future natural gas prices, the relevant LUECs are approximately $261/MWh and $236/MWh, respectively. Comparison to the cost of running a simple cycle generator reveals the simple cycle unit to be less costly to operate. Note that had the demand increment been larger, comparable analysis would yield a lower LUEC for the combined cycle generator since it becomes more efficient as its capacity utilization rate increases while an additional simple cycle generator would have to be built. The LUEC associated with the simple cycle generator would retain its interpretation as constituting an upper bound on LRMC associated with the perturbation approach. Also notable is that the entry of an 800 MW generator into the electricity market would have a far greater impact on market outcomes than the entry of a 100 MW generator.

3) The analysis also reveals a condition under which a potential generator would be profitable. In particular, if the average price in a given fraction of hours exceeds the LUEC of any generation technology, a generator operating with that technology would be able to fully recover its costs. A necessary condition related to the conditional average price curve (derived from the price-duration curve as described in Section 4) follows from this condition and is discussed further in Section 5.

Figure 2.1: LUEC with increasing natural gas prices and the capacity utilization rate

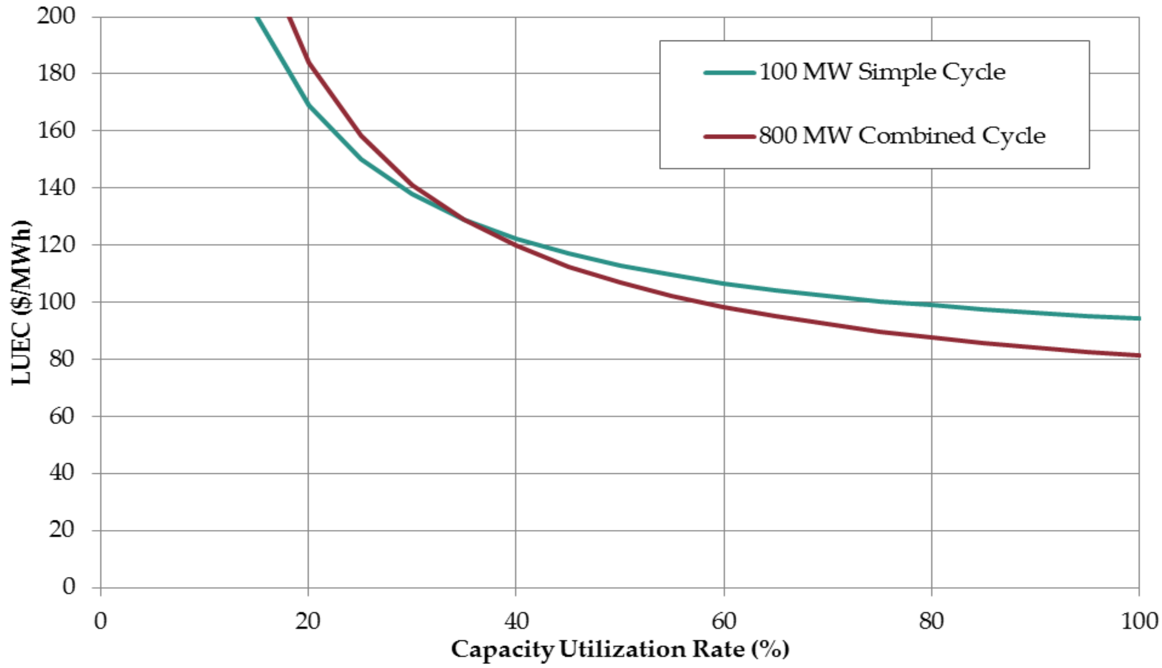
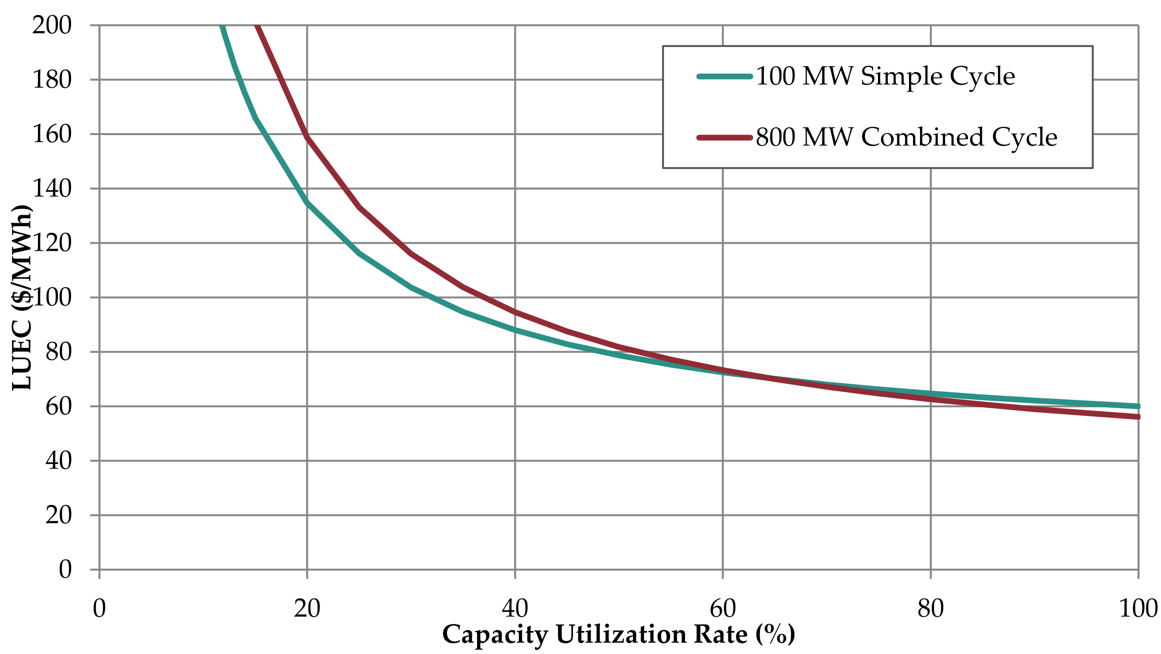


Figure 2.2: LUEC with constant 2011 natural gas prices and the capacity utilization rate



3. Relevant prices

In this section we examine relevant price data such that we may compare these prices against costs in order to assess whether price outcomes over time are no higher than they need to be. We also discuss issues and methodologies regarding price measurement, including problems associated with forward-looking prices.

The relevant prices that drive investment decisions are, in principle, those that are expected to be achieved in the future. These could be either forward prices or long-term bilateral contract prices as either would represent the value the market is expected to place on the provision of electricity in the future. With respect to either price series, the time horizon relevant to any particular investment decision is the expected lifespan of the technologies under consideration, for generation technologies this can be 20 or more years.

However, use of these price series is problematic because they are, in large part, unknown. In the Alberta market there are not frequent transactions for long-term products that would give a good indication of future prices. Electricity price forecasts could be used but are problematic in the sense that they may themselves be based on assumptions about levelised costs or fuel costs.

This leaves two sources of observable data. They are:

1) historical prices; and
2) medium-term forward market prices, where 'medium-term' is defined to be several years into the future but well-short of the expected lifespan of the generation facility under consideration.

Each of these sources of data is discussed below.

3.1 Historical prices

Average annual historical prices are reported in Table 3.1 for all hours, on-peak hours, and off-peak hours.[13] While such statistics are of limited value in describing the full distribution of prices, price-duration curves are a useful tool for facilitating such descriptions.[14] Figure 3.1 illustrates price-duration curves for all hours of the years 2008 through 2011 individually and the years 2002 through 2007 collectively. To clarify the distribution of prices, they are plotted on a logarithmic scale. Given that considerable attention will be paid to the distribution of relatively high prices below, Figure 3.2 illustrates

[13] On-peak hours are defined to be the hours between 07:00 and 23:00 each day, with off-peak hours being the remaining hours of the day. By this definition, on- and off-peak hours are commonly referred to as extended on- and off-peak hours, respectively, but this distinction is not considered here.

[14] Knowledge of the full (empirical) distribution of prices is more meaningful than knowledge of its summary statistics in the sense that it possesses more information content. For instance, the average price conveys no information about the shape of the distribution of prices. Even measures of variability convey relatively little information in the absence of an assumption regarding the theoretical distribution of prices. Note that it is from the distribution of prices that statistics related to prices are derived. Moreover, given the differences in operating characteristics across different types of generators, simple summary statistics convey relatively little useful information about the prices received by generators that can either (i) choose when to operate, e.g., a peaking natural gas-fired generator, or (ii) cannot choose when to operate and do not run in all hours, e.g., wind- and hydro-fuelled generators. In other words, average prices are only relevant for baseload generators that are expected to run as much as technically feasible. The logic of this argument extends trivially to consumers.

the same price-duration curves as Figure 3.1 but is restricted to the hours with the highest 20% of prices. Unlike Figure 3.1, the distribution of prices is clearest when plotted on an unadjusted scale.[15]

While price-duration curves indicate the proportion of hours in which prices exceed a given level, they do not directly indicate the average price that prevails in those hours. An alternative representation of prices can be constructed on this basis and indicates the average price that prevailed conditional on all prices exceeding a given level. This construction is referred to here as the conditional average price. Figure 3.3 illustrates the conditional average price curve, as well as the underlying price-duration curve, for 2011.[16]

Interpretation of the conditional average price curve is relatively straightforward. If a generator produced an equal amount of energy in every hour of the year it would on average receive the annual average pool price. Thus, the value of the conditional average price curve evaluated at 100% of hours in Figure 3.3 is $76.22/MWh, the all hours average price for 2011 (Table 3.1).[17] Alternatively if the generator ran only in the 20% of highest-priced hours, Figure 3.3 shows us they would receive on average $273.48/MWh for each MWh of production.[18]

Table 3.1: Historical average prices, all/on-peak/off-peak hours, $/MWh

Year	All hours	On-peak hours	Off-peak hours
2002	43.93	55.09	21.61
2003	62.99	73.41	42.15
2004	54.59	64.03	35.72
2005	70.36	85.35	40.37
2006	80.79	101.41	39.54
2007	66.95	84.37	32.11
2008	89.95	112.97	43.92
2009	47.81	58.04	27.36
2010	50.68	62.69	26.65
2011	76.22	102.22	24.22
2012[19]	59.48	78.81	20.81

[15] Comparable price-duration curves for on- and off-peak hours are provided in Figures C.1, C.2, C.3, and C.4 in Appendix C.

[16] To use Figure 3.3, select a price level on the vertical axis. The price-duration curve can be used to determine the proportion of hours in which the pool price equalled or exceeded that level. The average pool price in these hours is the conditional average pool price, where conditional refers all prices used in the calculation of the average exceeding the selected price level.

[17] Note that the value associated with two-thirds of hours cannot be interpreted as the average on-peak price. The reason is that there is no guarantee (and generally will turn out not to be the case) that there are no off-peak hours associated with higher pool prices.

[18] Comparable illustrations for the years 2002 to 2007 together, and 2008, 2009, and 2010 individually, are provided in Figures C.5, C.6, C.7, and C.8, respectively, in Appendix C. Conditional average price curves for 2012 to 2014 are provided in Figures 5.3 to 5.5, respectively, in Section 5.

[19] January to September, inclusive.

Figure 3.1: Historical price-duration curves, all hours, by year, logarithmic scale

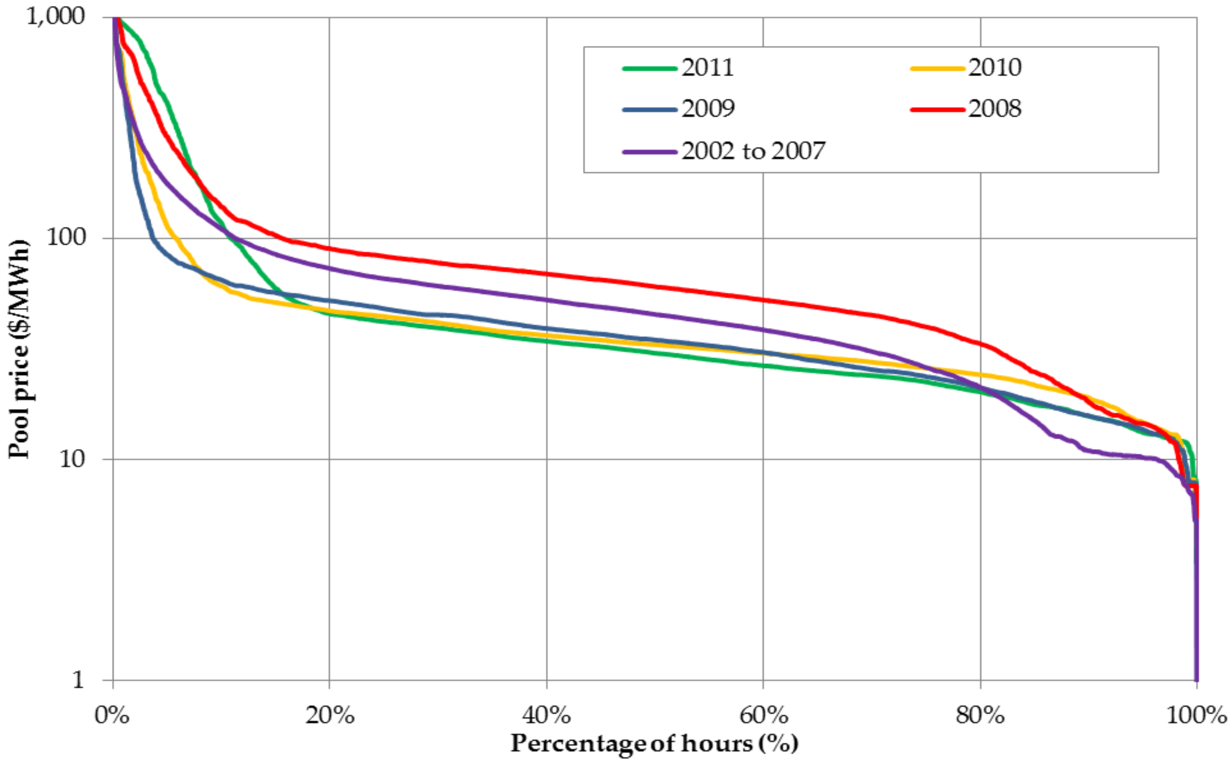


Figure 3.2: Historical price-duration curves, all hours, by year, normal scale, highest 20% of prices

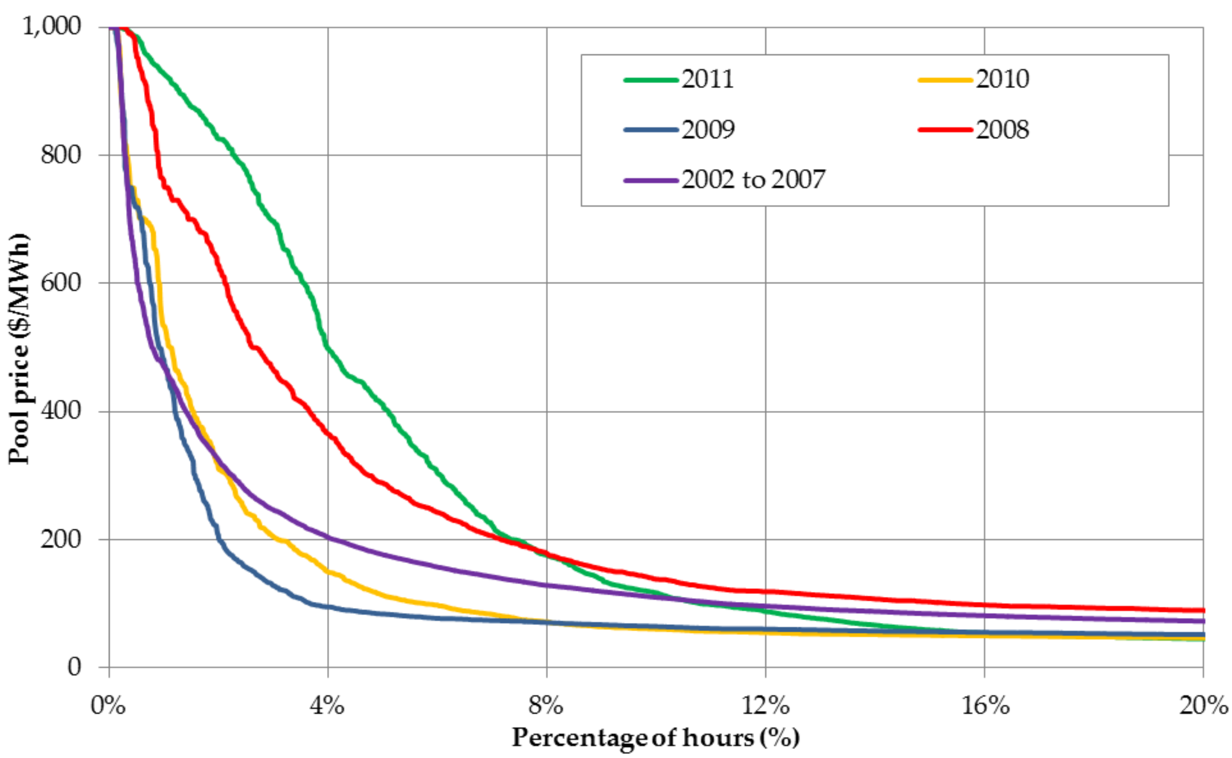
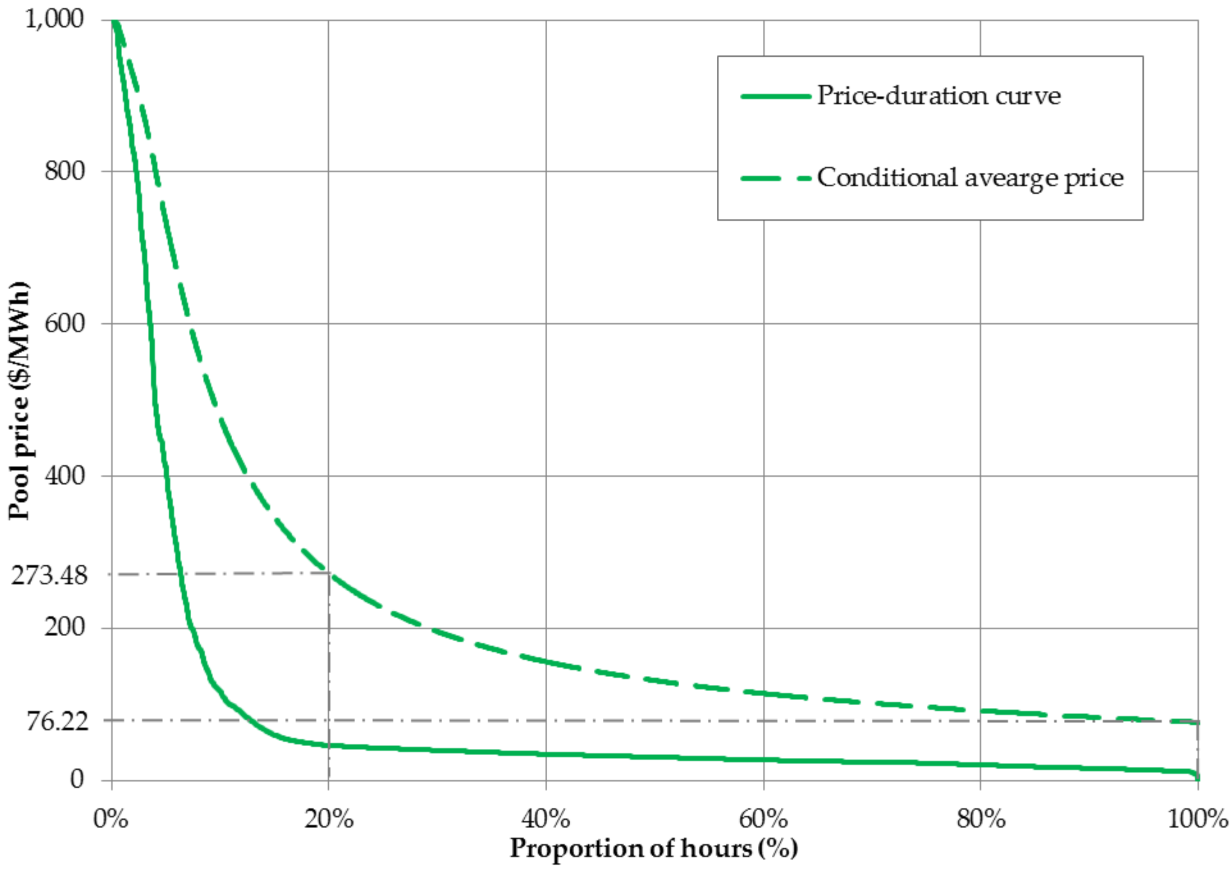


Figure 3.3: Price-duration and conditional average price curves, year 2011



Historical prices are useful because they are outcomes observed in the market that reflect the impact of actual market conditions, such as forced outages and strategic behaviour, that are of clear importance to the future distribution of prices but are difficult to model theoretically. This makes the historical distributions a useful benchmark for comparison. Further, it seems reasonable to assume that given the changing nature of the electricity market and broader economy more recently observed prices will be more meaningful than older prices.

3.2 Medium-term forward prices

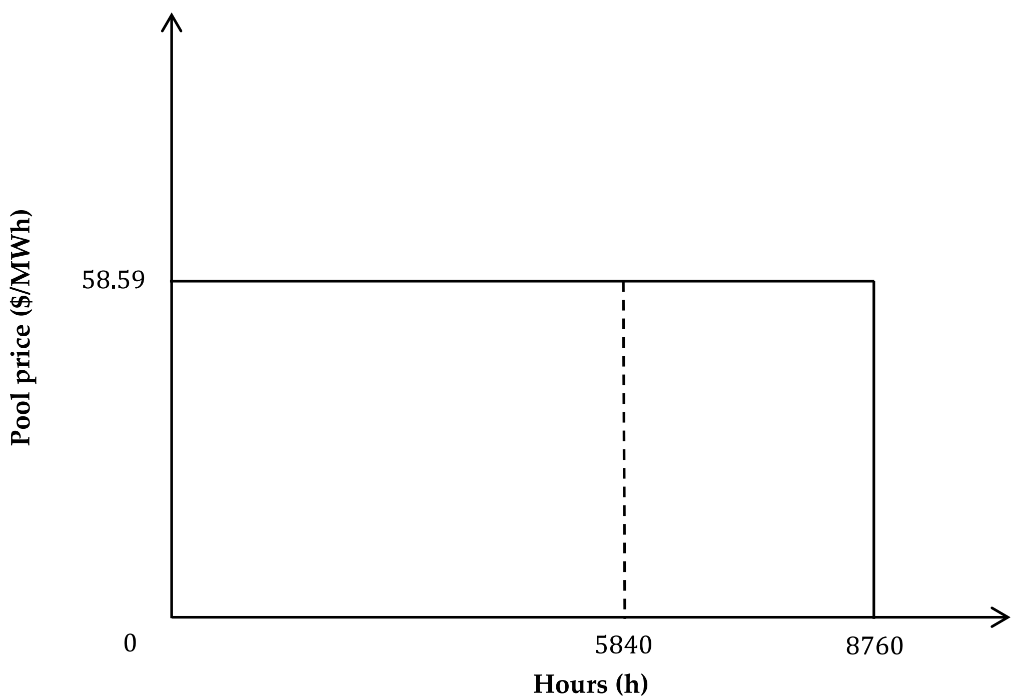
Forward prices are analogous to historical average prices in that they characterise certain points on the price distribution rather than the distribution as a whole. They are useful because they are forward-looking (and hence reflect expected future market conditions) and, in the medium term (a few years into the future), there is sufficiently frequent trading to form a reasonable expectation of the market price. One important disadvantage is they provide little information about the full distribution of prices. The structure of forward market contracts is discussed first and is followed by a discussion of observed forward market prices.

There are three commonly traded annual contracts:

- all hours (flat) (24 x 365 = 8760 hours per year);
- on-peak hours (16 x 365 = 5840 hours per year); and
- off-peak hours (8 x 365 = 2920 hours per year).

In combination, these contracts provide a weak approximation of the shape of the expected price-duration curve.[20] For instance, suppose that for the year 2013 a reasonable expectation of the all hours (flat) price is $58.59/MWh, with on- and off-peak prices of $77.13/MWh and $21.50/MWh, respectively.[21] The structure of these contracts is illustrated in Figures 3.4 and 3.5 in the context of a price-duration curve framework. The Figures clearly illustrate the above-noted fact that forward market prices embody little information related to the expected distribution of prices in comparison with historical observations. As a consequence, construction of useful expected conditional average price curves based on the information illustrated in the Figures is problematic.[22]

Figure 3.4: Illustration of forward prices, flat contract, year 2013



[20] There exist a variety of other contract structures, including ones that define the terms on-peak hours and off-peak hours differently, but they are ignored in this analysis. There is no theoretical limitation on the types of forward contract structures into which market participants could enter.

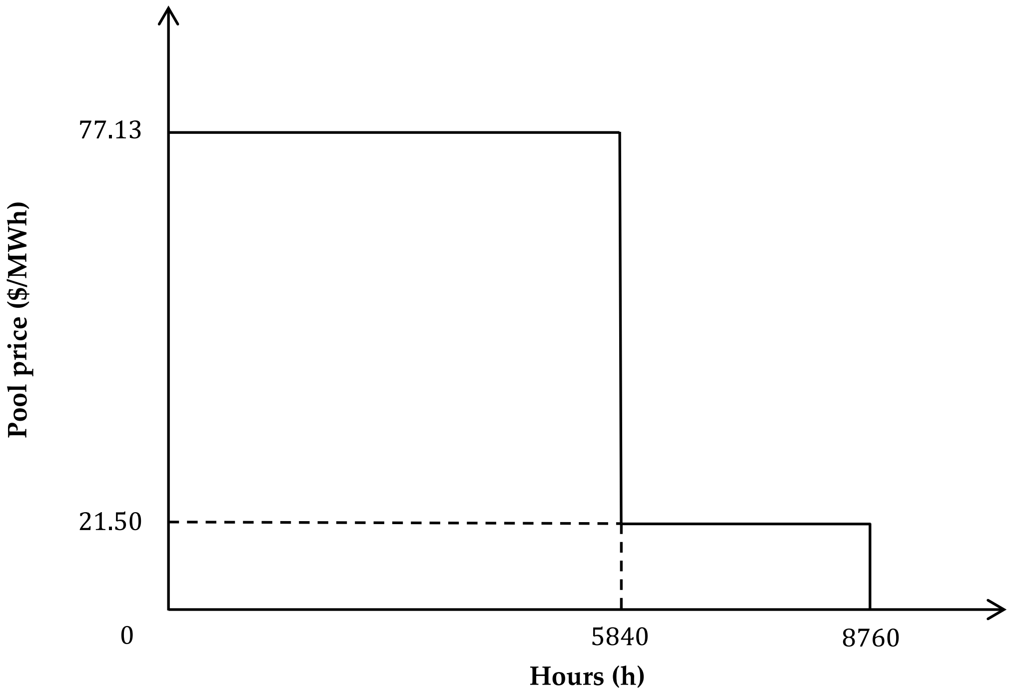
[21] These values are drawn from Table 3.5 below. The all hours contract price is a weighted average of the on- and off-peak hours contract prices, defined by the formula

$$p_{all\ hours} = \left(16 * p_{extended\ on-peak} + 8 * p_{extended\ off-peak}\right)/24$$

The linkage is maintained by financial arbitrage, not a rule or regulation, i.e., it is an equilibrium relationship.

[22] 'Useful' here is meant to imply that the resulting curves suggest future conditional average prices behave in a way comparable to those based on historical prices, e.g., see Figure 3.3. To illustrate the lack of usefulness of conditional average price derived from forward market contract prices alone, consider the flat (all hours) contract illustrated in Figure 3.4. The associated conditional average price curve is entirely coincident with the illustrated price-duration curve.

Figure 3.5: Illustration of forward prices, on- and off-peaks, year 2013



These issues can be overcome by using historical data, especially the type that embodies characteristics likely to persist, to fit forward market prices to a price-duration curve. A methodology that takes into account the forward market data described above is summarized in Appendix D.

Implementing this methodology requires some degree of knowledge of forward market prices. Table 3.2 reports forward market activity related to the fourth quarter of 2012. The data reported relate exclusively to quarterly contracts, i.e., contracts that cover all hours of the quarter. Table 3.3 reports forward market activity for future years, namely 2013 through 2017. The year 2018 is included to partially illuminate the limitations of forward data. All contract types, i.e., annual and daily, are included but volume tends to be dominated by annual contracts. Table 3.4 reports forward market data related to a subset of the data reported in Table 3.3, namely related to contracts executed in September 2012. The purpose of making this distinction is to consider whether more recent data differs materially from data observed before, perhaps due to the (unobserved) availability of new information. In each of the Tables, ‘volume’ is recorded in TWh, ‘trades’ is a count variable, and ‘price’ is recorded in $/MWh.

The data reported in the Tables indicates that the preponderance of executed contracts is flat in shape. There is evidence that forward prices for the fourth quarter of 2012, as well as during off-peak hours in future years, have been relatively stable through time. However, there is also evidence that forward prices for on-peak hours in future years have recently declined, a result supported by several TWh of transactions.

It is not clear what volume of trade is necessary or sufficient in order to draw conclusions, but it is clear that the volume of recorded trade declines significantly with each additional year into the future. A judgement is made that data for the years 2015 and beyond is not sufficiently robust to draw conclusions. Based upon these considerations, including a preference for use of more recent information, the data used in this paper’s analysis is summarised in Table 3.5.

Table 3.2: Forward market activity for Q4 2012 by contract date, quarterly contracts only

Contract date	Flat (all hours)			Off-peak hours			On-peak hours		
	Volume	Trades	Price	Volume	Trades	Price	Volume	Trades	Price
All	3.10	217	72.43	0.04	4	26.31	0	0	–
Q1-Q3 2012	2.50	180	71.98	0.04	4	26.31	0	0	–

Note: Volume is measured in TWh, the number of trades is a count variable, price is measured in $/MWh.

Table 3.3: Forward market activity by year and contract type, all contracts

Time period	Flat (all hours)			Off-peak hours			On-peak hours		
	Volume	Trades	Price	Volume	Trades	Price	Volume	Trades	Price
2013	14.39	749	64.63	0.38	10	20.33	0	0	–
2014	5.67	115	54.15	0.60	24	21.50	0.03	1	55.32
2015	2.72	43	53.75	0.39	17	23.60	0.06	1	57.39
2016	0.66	15	50.45	0	0	–	0	0	–
2017	0.04	1	50.00	0	0	–	0	0	–
2018	0	0	–	0	0	–	0	0	–

Note: Volume is measured in TWh, the number of trades is a count variable, price is measured in $/MWh.

Table 3.4: Forward market activity by year and contract type, contracts executed in September 2012

Time period	Flat (all hours)			Off-peak hours			On-peak hours		
	Volume	Trades	Price	Volume	Trades	Price	Volume	Trades	Price
2013	2.75	352	58.59	0.03	2	21.50	0	0	–
2014	3.15	64	50.61	0.13	7	21.33	0	0	–
2015	1.53	27	49.11	0.09	5	22.08	0	0	–
2016	0.53	12	47.50	0	0	–	0	0	–
2017	0.04	1	50.00	0	0	–	0	0	–
2018	0	0	–	0	0	–	0	0	–

Note: Volume is measured in TWh, the number of trades is a count variable, price is measured in $/MWh.

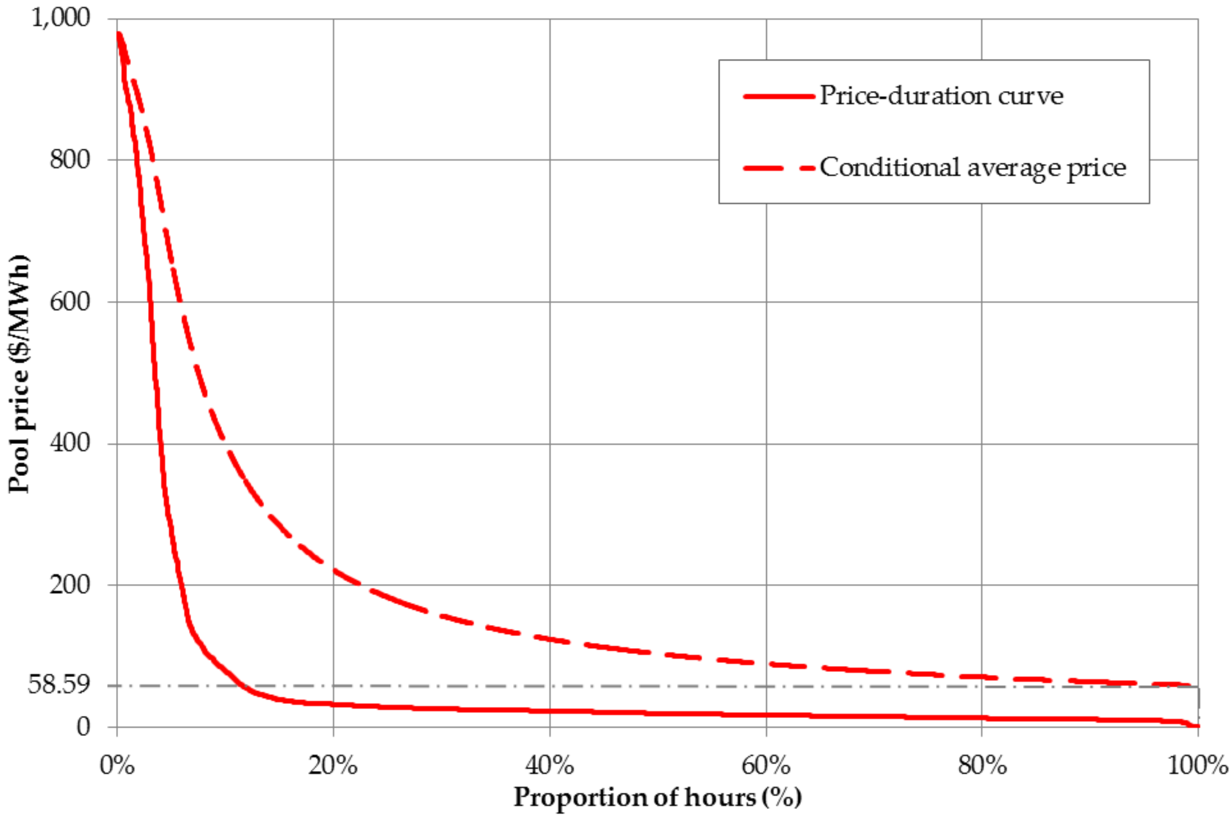
Table 3.5: Forward price assumptions for Q4 2012, and years 2013 and 2014 ($/MWh)

Time period	Flat (all hours)	Off-peak hours	On-peak hours
Q4 2012	71.98	26.31	94.82
2013	58.59	21.50	77.13
2014	50.61	21.33	65.26

Using the forward price data summarised in Table 3.5, Figure 3.6 illustrates the price-duration and conditional average price curves constructed for the year 2013.[23] Note that in this Figure, as with Figure 3.3, 100% of the hours corresponds to the average all hours price, $58.59/MWh, the flat (all hours) forward price for 2013.

[23] Similar information for the years 2012 and 2014 is provided in Figures D.1 and D.2 in Appendix D. These Figures are comparable to Figure 3.3 above and similar Figures in Appendix C.

Figure 3.6: Price-duration and conditional average price curves, year 2013



3.3 Estimating relevant prices

Having reviewed the available price data, the issue returns to the question of establishing relevant prices for the purposes of comparison to the costs of new investment. Given the limitations of observable price data, the MSA estimates the relevant prices based on recent historical prices and forward prices over the next few years. More specifically, the MSA will consider a five-year period: historical prices for 2010 and 2011, a mixture of historic and forward prices for 2012, and forward prices for 2013 and 2014.[24] In conducting this test in future years, it is expected that a similar five-year window will be considered.[25] In each case the relevant price is not a single number but a distribution of prices that in turn can be summarised either as a price duration curve or a conditional average price curve.

[24] These data are reported, respectively, in Figures C.8, 5, D.1, 4.6, and D.2.

[25] It may be possible to incorporate additional forward price data if liquidity improves.

4. Comparing costs and prices

Having constructed measures of relevant costs and prices in the previous two sections, we now turn to the methodology for comparing them. Section 4.1 describes the basic methodology and Section 4.2 discusses a number of important caveats and potential extensions.

4.1 Methodology

Economic theory suggests that in the long run a well-functioning market will exhibit a relationship between LRMC and prices. On the assumption that generation will enter if it believes it can fully recover its costs, one potential definition of efficient entry is:

> entry is efficient if any generator that can fully recover its costs enters the market.[26]

The problem is that, as described above, neither future prices nor future costs can be readily observed. A proxy of LRMC was developed in Section 2 in the form of the LUEC adjusted for natural gas prices, while the available information regarding prices was discussed in Section 3. Having derived LUEC curves for two potential entering technologies for each year based on the prevailing or expected natural gas prices, and having obtained measures of relevant price, the two can be compared. The most straightforward comparison is between the LUEC and conditional average price curves in each year. The former describe the levelised costs that must be recovered at each level of capacity utilization for the generator to break even. The latter describes the average price received at each level of capacity utilization (assuming the generator can choose the hours in which they run).

For a generator that runs in each and every hour, a simple comparison of average prices to LUEC over a given period would suffice as a test of cost recovery. For generation technologies where capacity utilization is a choice, the relevant comparison is the conditional average price curve with the LUEC curve under a range of assumptions about the capacity utilization rate.

A prospective generator will not enter the market unless it has the expectation that it will fully recover its costs. This is a necessary condition for entry to occur. If the conditional average price curve is above the LUEC curve at any point then there is a capacity utilization rate at which costs can be (at least) fully recovered. If the same condition holds over a range of different capacity utilization rates then the implication is that costs can be fully recovered at any capacity utilization rate within this range. Having specified a five-year window of relevant prices, five separate but similar annual tests present themselves. If in each of the five years it is observed that a particular technology could have fully recovered its costs, the MSA would be concerned that the market was not resulting in dynamic efficiency gains within a timely manner.

The described comparison of costs and prices is reported in Section 6. Before proceeding to that, several important caveats merit note and discussion.

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[26] Entry at the level described would be privately efficient, i.e., firms enter on their own if they perceive doing so to be profitable. Mankiw and Whinston (1986) provide a well-known result regarding efficient entry in the economics literature: the presence of fixed costs can lead to an equilibrium characterized by socially inefficient over-entry. The reason for this possibility is that if each entrant is required to incur a fixed cost and it is possible that fewer firms could serve the market than would do so under privately efficient entry, then too much fixed costs may be incurred if there are too many entrants. Given a variety of issues, most importantly the capacity-related fixed costs relevant in electricity markets, the long lead times associated with constructing generation facilities, and uncertainty regarding input costs, this particular issue is not believed to be of first-order importance in Alberta's electricity market.

4.2 Caveats

There are several important caveats and potential extensions related to the comparison described above that merit note and discussion.

4.2.1 Start-up costs

One important component of costs that is excluded from the LUEC analysis is a generator's start-up costs. This cost is proportional to the number of times the generator is started and depends on the amount of time elapsed since the generator was last in operation. In the LUEC analysis the critical economic variable under consideration was the capacity utilisation rate. The number of times a generator starts is expected to be related to this rate but not in a linear manner. At one extreme, consider a generator with a hypothetical capacity utilisation rate of 100% during a given year. Such a generator could have started once at most and would have incurred start-up costs accordingly.[27] At the other extreme, consider the case of generator that operated one only one hour of the year.[28] Such a generator would have incurred a costs associated with a single start. Ranging between these two extreme capacity utilisation rates is a number of different possibilities that include among them the interesting cases that typify real generator operations.[29] These costs have been excluded from the LUEC calculations described in Section 3.

The result of the exclusion of start-up costs is a source of negative bias with respect to the reported costs and is a matter that requires further research.

4.2.2 Impact of incremental entrance on prices

The conditional average price curve does not take into account the impact that incremental generation investment would have on price. A small peaking generator might have a relatively small impact whereas a large combined cycle plant, even at a low capacity utilization rate, would have a far larger impact.

For this reason, a finding that incremental investment would just be able to recover its costs is not as persuasive as a finding that it would be able to do so comfortably. As a result, the above test is more robust when dealing with technologies that result in smaller increases in supply.

4.2.3 Non-price-taking behaviour

The analysis described in this paper assumes that entrant generation acts as a price-taker, i.e., offers its output to the market at variable cost and operates at full capacity whenever the pool price exceeds that level. For a stand-alone generator that is long in the market, this is a likely to be a profit maximising strategy. Such a generator would not, by definition, be part of either a portfolio of generators or a vertically integrated firm. When considering the profitability of entry, such a generator would have only to consider the direct effect of its entry on market prices in its cost recovery calculations, as there would be no relevant indirect effects.

It is expected, however, that incumbent firms that either have portfolios of generators or are vertically integrated (or both) will be important investors in generation capacity in the future, either to replace an existing but retiring generator, or as a net increase in generating capacity. The incentives facing such firms are more complex than those facing stand-alone generators. The reason is that, in addition to

[27] Once at most in the sense that it could have been started in the first hour of the year (one start) or it could have already been in operation (zero starts).

[28] A capacity utilisation rate of 1/8760 or 0.0114%.

[29] For instance, suppose a generator has a 20% capacity utilisation rate, i.e., it operates in 1,752 hours of a given year.

consideration of the direct profitability of a given investment in its own right, they must consider the indirect impact of the additional capacity on the other parts of the firm. For instance, to the extent that entry reduces the pool prices that would otherwise prevail, a firm with a portfolio of generators would face lower prices across its entire fleet. Therefore, it should not be expected that such firms would act as price-takers.

As a result, it might be expected that in comparison to stand-alone generators, firms with portfolios of generators require higher average prices before investing. However, this incentive is potentially offset by the knowledge that if they do not invest, then a competitor will, and the indirect effect will be incurred on them anyway. In other words, the indirect effect is not a result of a firm's own investment decisions but rather one related to the *effective competitiveness* of the market. This is the most important implication of the possibility of free entry in a competitive market. Moreover, this result is in keeping with the MSA's view that prudent investment should be expected to occur and be able to recover its costs.

4.2.4 Transmission congestion

The analysis reported in this paper implicitly assumes that a generator's choice of its capacity utilisation rate is a function purely of its offer strategy, i.e., a generator is operated when it is in its own interests to do so. Potential constraints in the transmission system, along with the manner in which the system operator handles them, may prescribe the generator's choice in a material way. In particular, if a generator is located in a congested region, then it may be prevented from producing the level of output it desires to given the prevailing pool price.

Except to the extent that transmission congestion impacts pool prices and, therefore, appears in historical prices, the impact of transmission congestion is not considered explicitly in either the cost or price methodology described. To the extent that transmission constraints are binding on a generator, the methodology described in this paper may require adjustment.

4.2.5 Other issues

Several other issues regarding the reported analysis include:

- This simple analysis assumes the ability of a market participant to choose a capacity utilization rate or, equivalently, to choose to run in certain hours and not others. Factors such as technical operating criteria or outages may restrict this choice in practice. Certain factors such as outage rates could be incorporated into the LUEC calculations and/or a modification of the conditional average price curve.
- The described comparison of costs and prices (revenue) does not account for the potential for generators to earn revenue from the provision of ancillary services. This issue could have the effect of making generation that appeared unable to fully recover its costs in the energy market alone succeed in doing so once the additional revenue potential is considered.
- Rare macroeconomic events may impact the application of the methodology by making investment in certain years appear either hugely profitable or loss-making. On the other hand, to the extent that these events may be recurring and representative of the macroeconomic cycle, their inclusion is meaningful.

4.2.6 Implications

Given the issues described above the MSA suggests a weaker interpretation be given to the results. That is, if the levelised costs and relevant prices indicate a technology would be successful in recovering costs in each year and no incremental investment was forthcoming the MSA, would commence additional work to assess whether there were barriers to entry, other impediments, or methodological shortcomings that explained the result.

5. Results

Figures 5.1 through 5.5 show comparisons of conditional average price curve to the LUEC curves associated with the two types of potential generation entrants under consideration in this paper for the years 2010 through 2014, respectively.

With respect to a 100 MW simple cycle natural gas-fired (peaking) generator, a comparison of prices and costs indicates that such generator would have been able to fully recover costs in all years under consideration except 2010, where the revenue short-fall would have been relatively small. Given that the reported analysis excludes potential revenue associated with ancillary services, costs may be fully recoverable in 2010 as well as the other years. This result depends on the caveats described in Section 4.2. Taken together, the results suggest that there exists an opportunity for profitable entry of a peaking generator into Alberta's electricity market.

With respect to an 800 MW combined cycle natural gas-fired (baseload) generator, a comparison of prices and costs also indicates that that such generator would have been able to fully recover costs in all years under consideration except 2010. However, this result depends on the assumption that the entry of such a generator would not have a material impact on market prices, i.e., the price-duration and conditional average price curves. This assumption is likely to be unreasonable in the context of the entry of such a large generator, suggesting that the results are somewhat less robustness to the same finding for the peaking generator.

Figure 5.1: Comparison of prices and costs, year 2010

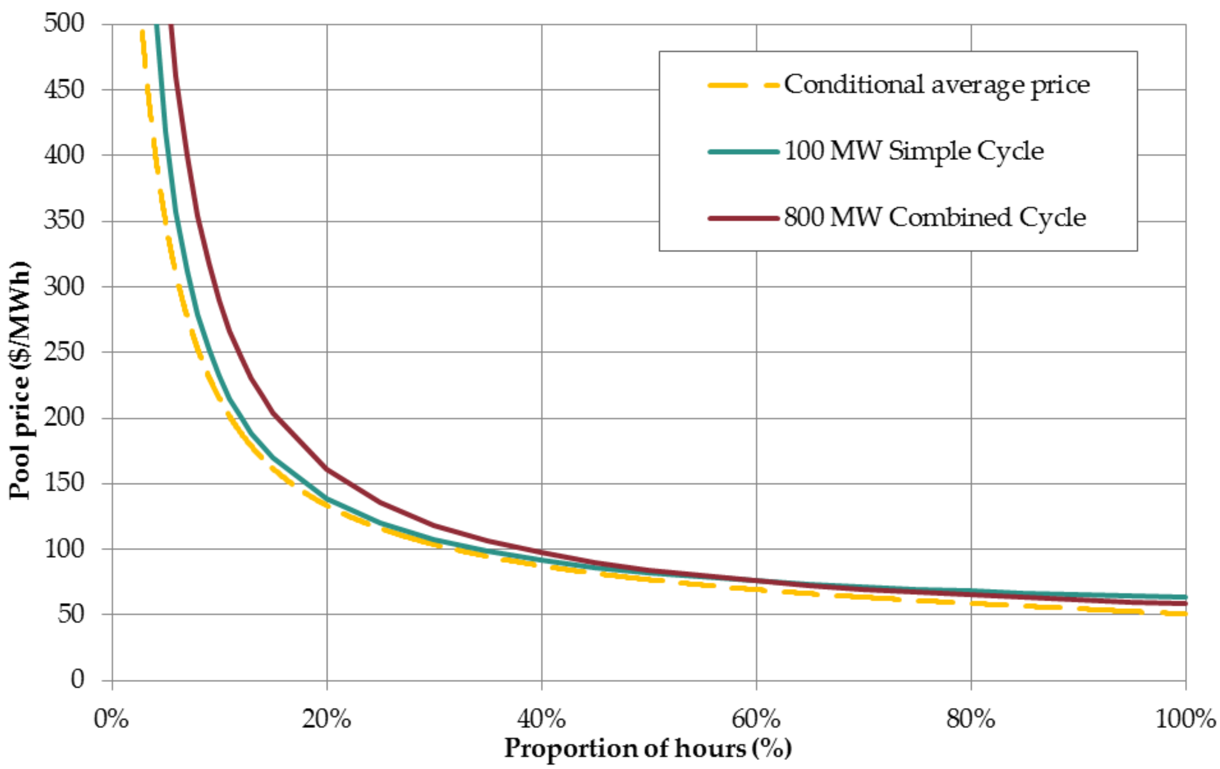


Figure 5.2: Comparison of prices and costs, year 2011

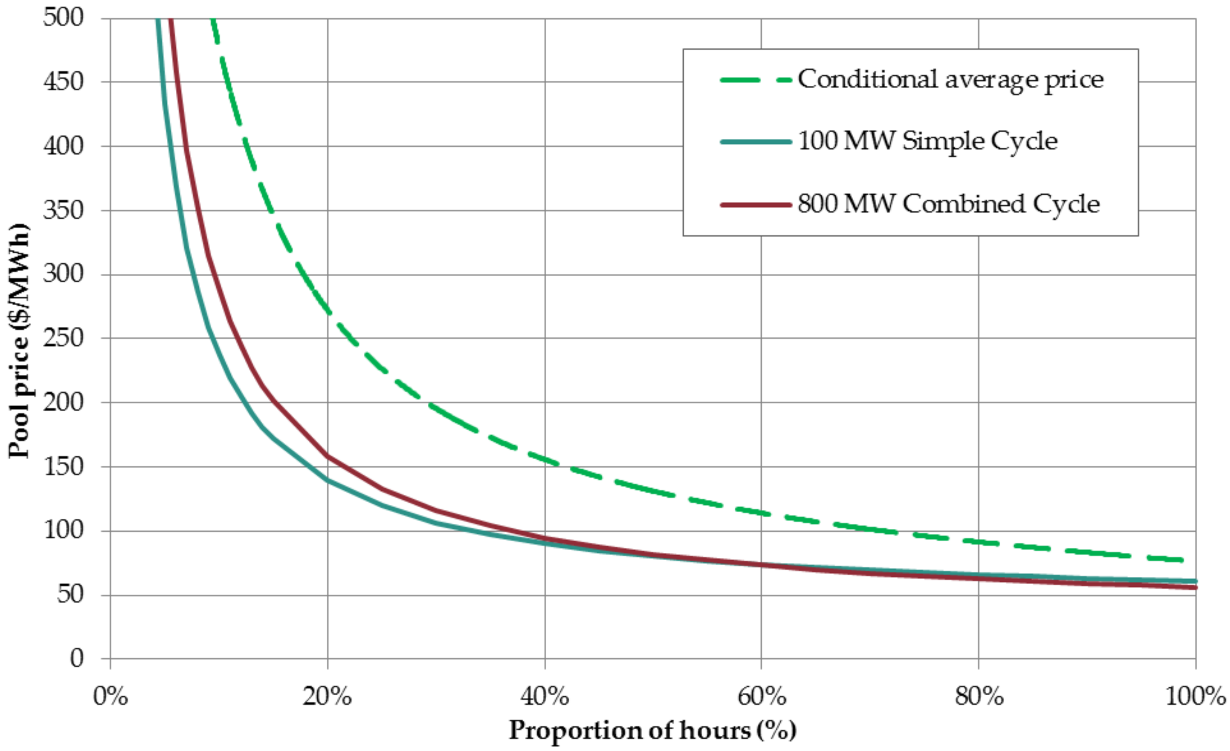


Figure 5.3: Comparison of prices and costs, year 2012

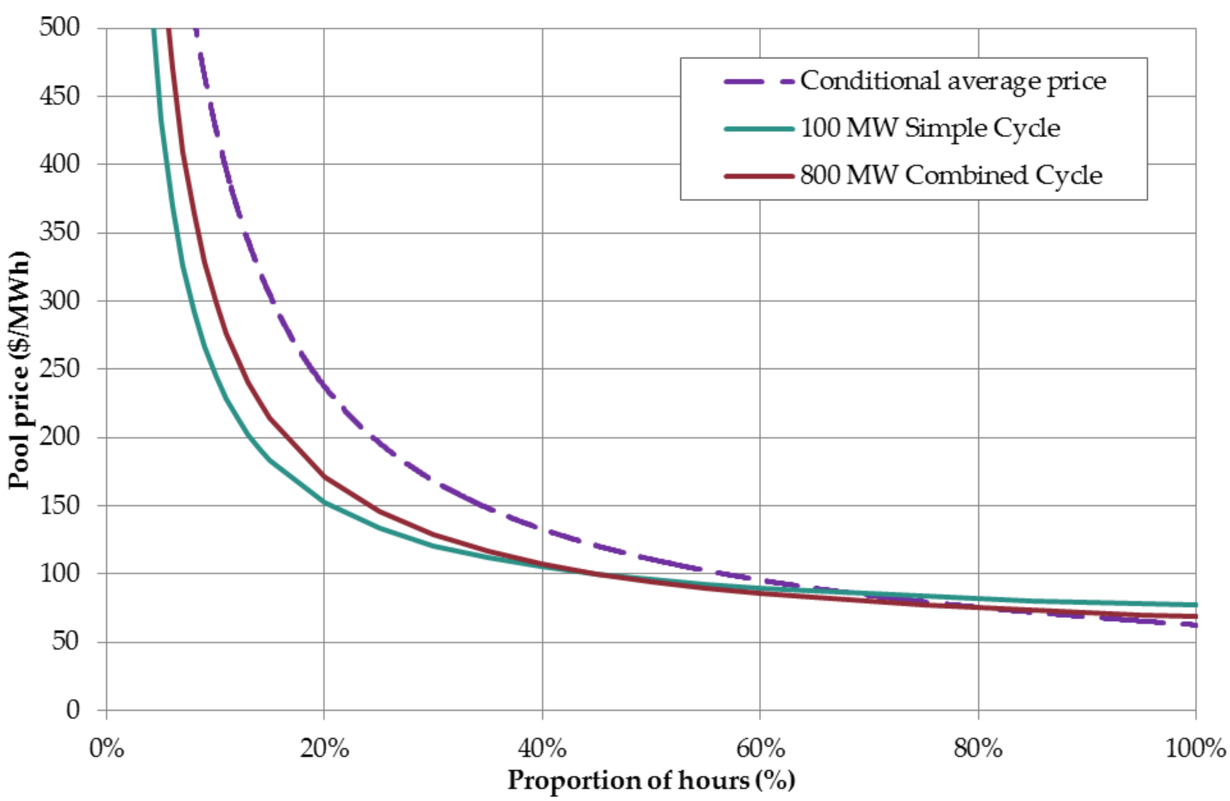


Figure 5.4: Comparison of prices and costs, year 2013

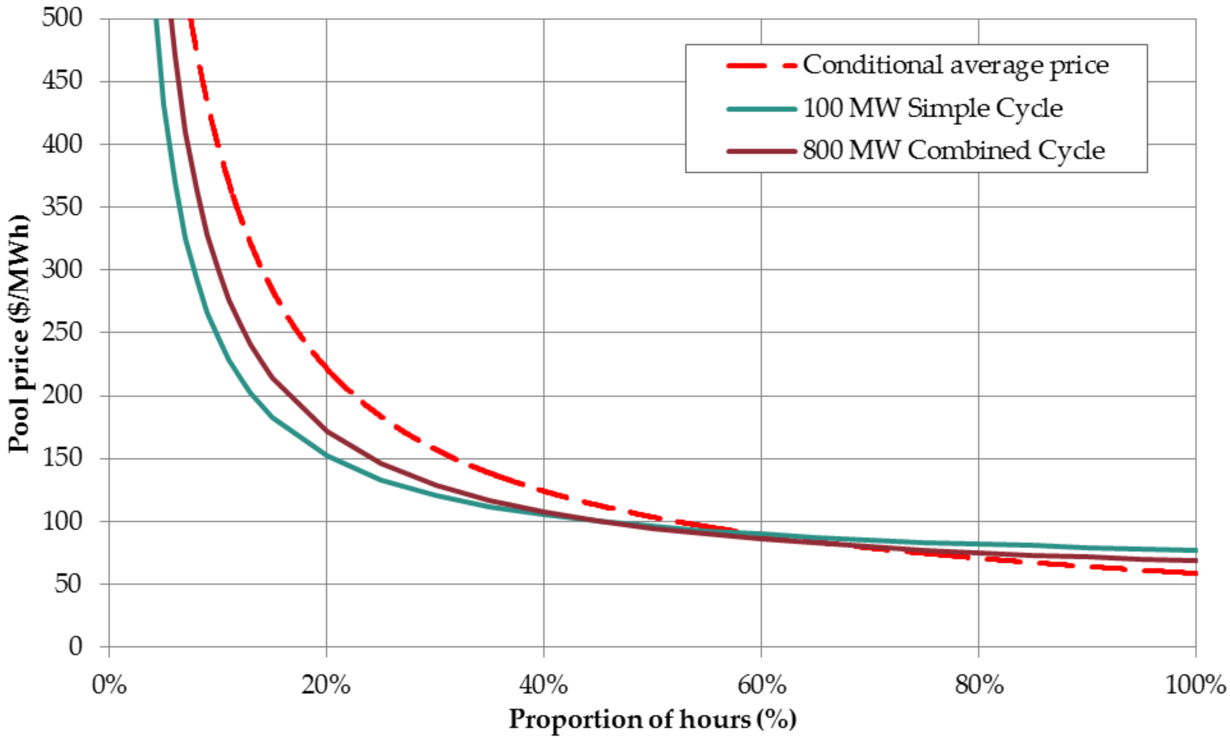
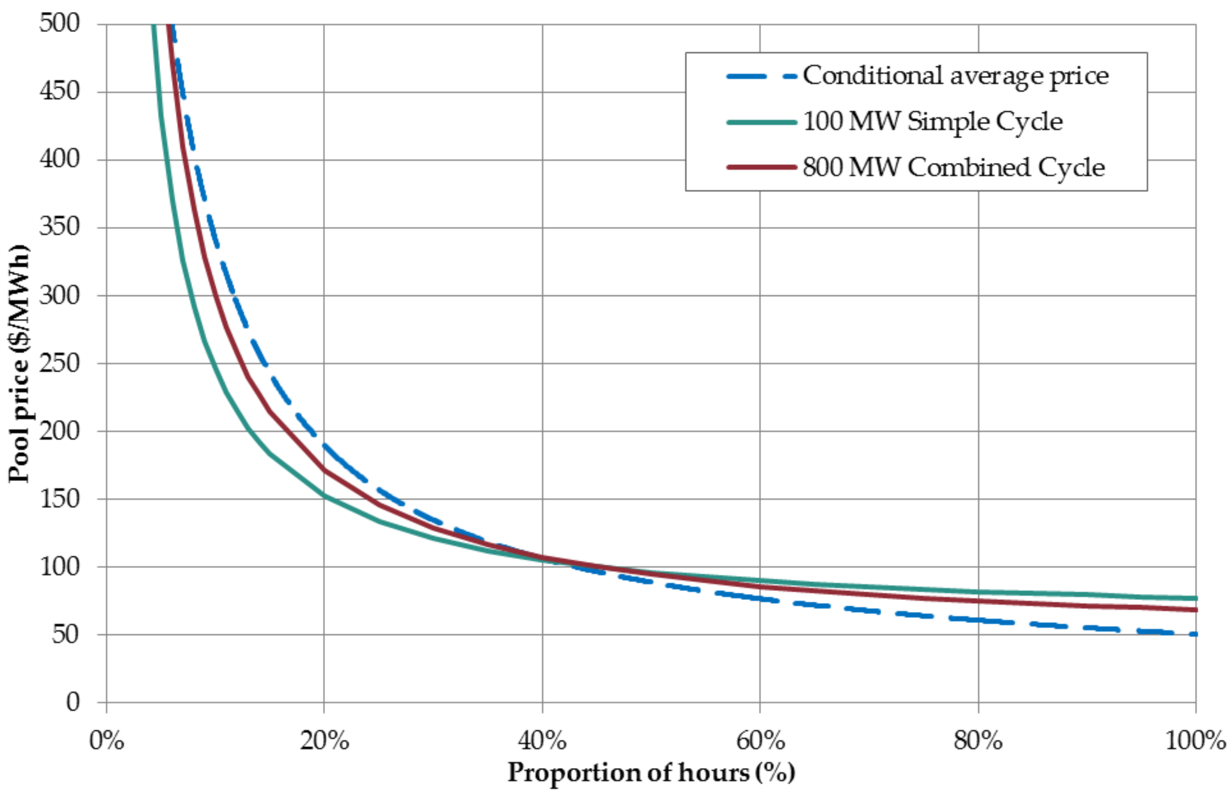


Figure 5.5: Comparison of prices and costs, year 2014



6. Summary and conclusions

In this paper we have considered part of our test for effective competition, that price outcomes over the medium term are no higher than they need to be to ensure the market is sustainable. This is essentially a recognition that a competitive outcome in a market with few barriers to entry is generally characterised by the condition that price equals long-run marginal cost (LRMC). At any given point in time prices may be higher or lower than LRMC, but the market should not sustain such outcomes over the long term. Simply put, if prices are expected to be lower than LRMC, investment will be delayed and capacity might be retired[30], until prices rise. If prices are expected to be higher than LRMC, then investment should occur, which will tend to lower prices towards LRMC.

This paper describes various methodologies for measuring LRMC, relevant prices and a process for comparing them. In principle, the relevant comparison is of future costs and future prices, i.e., a forward-looking comparison rather than a backward-looking comparison.

Various methods of calculating LRMC are proposed. The standard economic approach is to calculate LRMC as the minimum present value of meeting a permanent increment of demand. A simpler approach based on the LUEC methodology is proposed as a proxy. The report does not examine in detail cost inputs for various technologies, these are instead taken from an AESO report. With respect to prices, the full distribution of historical prices is available and is taken as given. Forward prices do not provide the same sort of complete distribution. However, different types of forward contracts are traded (e.g., all hours, on-peak hours, and off-peak hours) and so a distribution of forward prices is constructed from a combination of forward contract prices and historical prices.

While the major purpose of the report is to establish a method for comparison, the analysis concludes that the level and distribution of prices is sufficient to warrant incremental investment in peaking plant. The MSA has two expectations. Either:

- the price signals that appear to make this investment profitable cease (perhaps in response to other changes such as increased price responsive load), or
- investment occurs.

In the event that seemingly profitable investment does not take place the MSA would initiate a further enquiry into whether barriers to entry or other competition issues were impeding competitive outcomes in the market.

[30] This would normally happen when prices are significantly below LRMC.

Appendix A: Measurement of LRMC

Three standard approaches to the measurement of LRMC are considered:

- o the perturbation approach, which is also referred to as the Turvey approach;
- o the average incremental cost approach (AIC); and
- o the total element/service long-run incremental cost (TELRIC/TSLRIC).

A project-specific measure of cost, the levelised unit electricity cost (LUEC), is considered as well in Appendix B. The approaches differ principally in their definition of future capital costs and the quantity of consumption that is considered to be marginal. Each approach is discussed in turn.

A.1 The perturbation approach[31]

The perturbation approach to measuring LRMC considers the impact on cost of a permanent increment (or decrement) of demand. The process implemented to measure LRMC under this approach is as follows:

1) Construct annual forecasts of average and peak system demand over an extended time horizon, say 20 years. The purpose of this step is to obtain information regarding the trend of average and peak demand which must ultimately be satisfied. Implementation of this step in practice will generally require that assumptions be made regarding future macroeconomic conditions and industry-specific development, e.g., the growth rate of gross domestic product (GDP) and investments in oil sands projects.
2) Obtain information regarding the characteristics of technologies and processes available (and reasonably forecast to become available) to meet the demand forecasted in the previous step. This includes incumbent generators and prospective entrants that would constitute supply, as well as demand management measures.
3) Taking incumbent capital as given, determine the lowest-cost program, in present value terms, of generation entrance that would ensure demand is met at each point during the forecast period. This can be thought of as the optimal generation capacity entrance program. The program would account for the relevant reliability standard and would include those demand-side measures that are economically efficient, i.e., those that are less costly than the least-cost alternative supply technology.
4) Augment the average and/or peak annual demand forecasts with a permanent increment (or decrement) of demand. Determine the present value of the demand increment, i.e., discount incremental future demand.
5) Assuming that the technologies and processes available to meet demand are unchanged as a result of the demand increment, find the new optimal generation capacity entrance program that satisfies the increment-augmented demand forecast.
6) Calculate LRMC by dividing the change of the present value of the optimal generation capacity entrance program by the present value of the demand increment, i.e., the cost of servicing the demand increment by the size of the demand increment.

The perturbation approach to measuring LRMC is illustrated in Figures A.1 and A.2. The upper panel of the Figure A.1 illustrates present and forecast demand. For illustrative simplicity, forecast demand is assumed to rise by a constant amount through time. Also illustrated is incumbent generation

[31] For additional detail, see Section 2.3.1 of Kemp, et al. (2011) and Turvey (1969, 1976).

Figure A.1: Optimal generation capacity entrance program

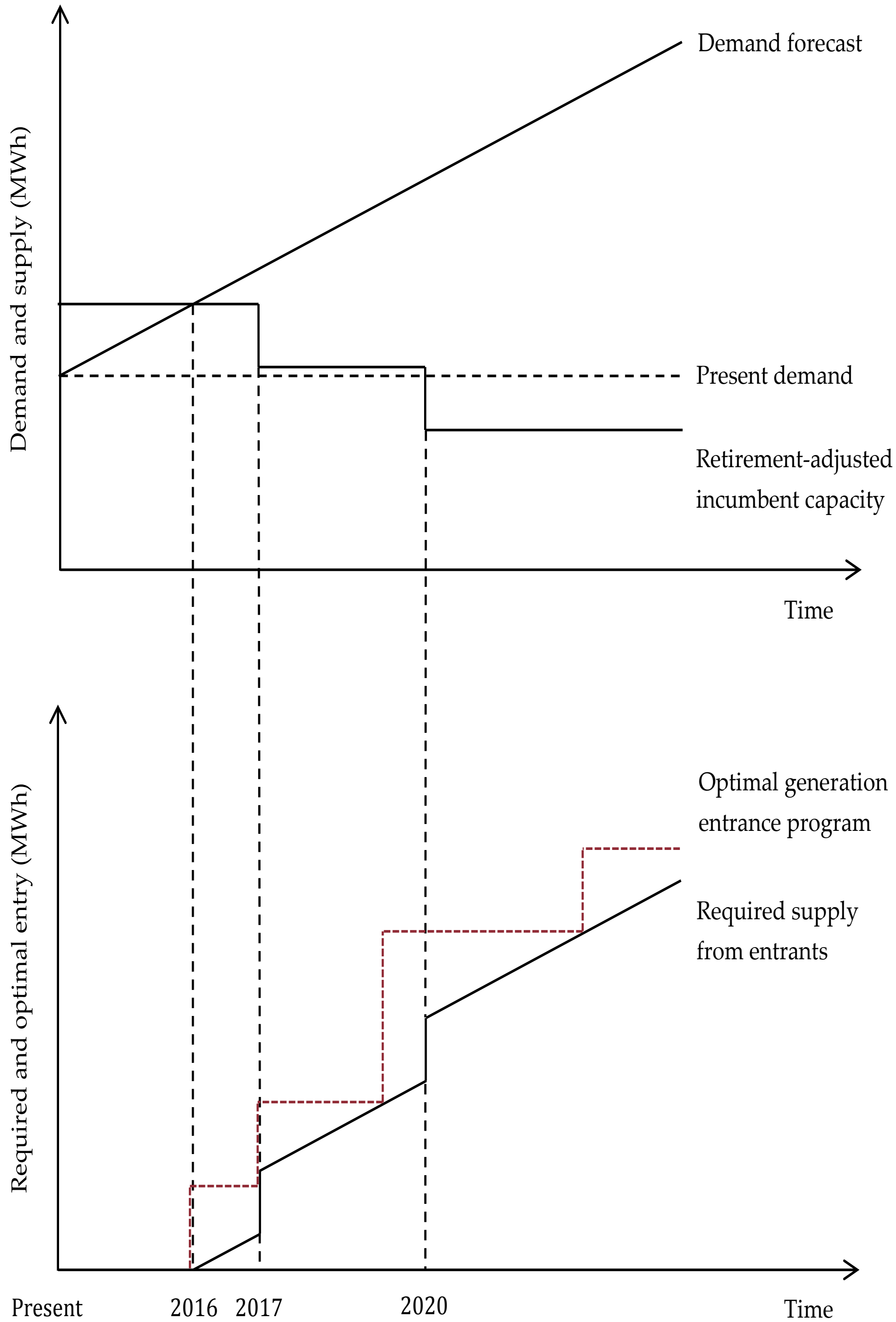
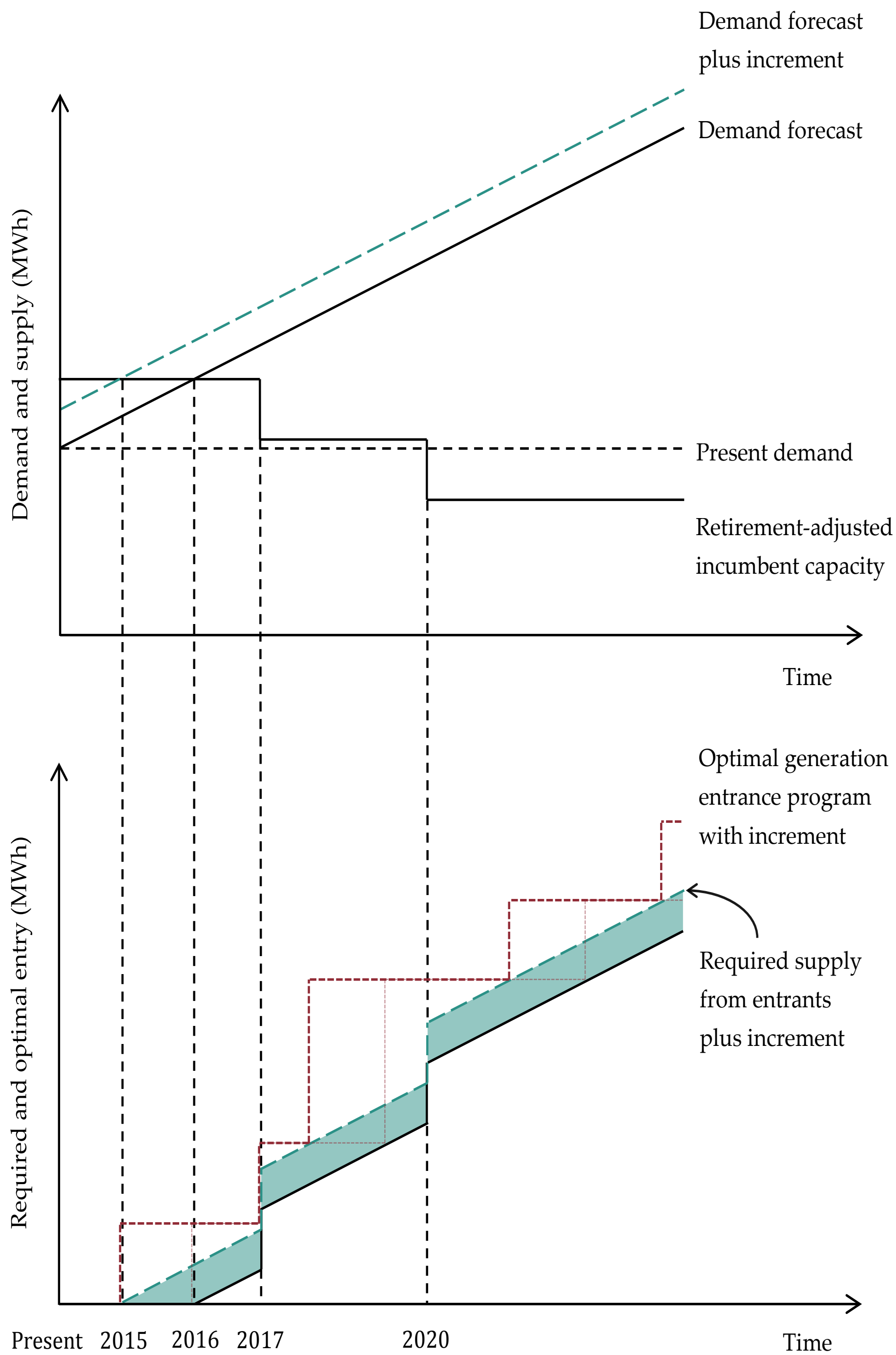


Figure A.2: Demand increment and impact on optimal generation capacity entrance program



capacity, which is adjusted for anticipated unit retirements (hence it is a downward-sloping step function). At the present time in the Figure it is assumed that demand can be satisfied by use of incumbent generation. As time progresses, a combination of increasing forecast demand and unit retirements results in excess demand and a requirement for entry of supply. This is represented by forecast demand exceeding retirement-adjusted incumbent capacity. This difference is re-illustrated in the lower panel of the Figure A.1 as the required supply from entrants, along with an illustrative optimal generation capacity entrance program. Collectively, Figure A.1 illustrates the first three steps of the perturbation approach.

Figure A.2 introduces the increment of demand to the market illustrated in Figure A.1. The shaded area in the upper panel illustrates the increment of demand through time, which is assumed to be a constant amount through time. The increment of demand does not fundamentally alter the process of developing the optimal generation capacity entrance program except that it moves forward the point in time when incumbent generation is no longer sufficient to meet forecast demand. This point is represented by a leftward shift of the point in time when the demand forecast inclusive of the increment exceeds the retirement-adjusted incumbent capacity. As a result, the investment associated with a modified illustrative generation program is shifted forward. This is illustrated in the lower panel of Figure A.2. Together, these are the fourth and fifth steps associated with the perturbation approach.[32]

The final step of the perturbation approach can be expressed as:

$$LRMC^{perturbation} = \frac{\begin{array}{c} PV(cost\ of\ optimal\ generartion\ capacity\ entrance\ program\ with\ increment\ plus\ operating\ costs) - \\ PV(cost\ of\ initial\ optimal\ generartion\ capacity\ entrance\ program\ plus\ operating\ costs) \end{array}}{PV(increment\ of\ demand)} \qquad (A1)$$

where $PV(\cdot)$ denotes the present value function. Consideration of the various components of LRMC in present value is important for two reasons. First, present consumption is more valuable to consumers than future consumption. The practical impact of this is to discount future consumption, with the magnitude of the discount increasing in the distance into the future. Second, presently incurred expenses are more costly than deferred expenses for the same reason.

There are several issues worth additional consideration.

- A much longer period than 20 years would be desirable because the capital assets under consideration in the creation of the optimal generation capacity entrance program generally have much longer useful lives and therefore create benefits that are not counted. However, it is recognized that there is a trade-off between planning to use long-life assets and the quality of demand forecasts necessary to put those assets to use.
- A related concern is that since long-life assets typically have higher overnight costs, a fixed planning horizon, whether it be 20 years or longer, may create an incentive for investment in assets whose useful life:
    - ends at or shortly after the end of the planning period; and/or
    - is relatively short.

[32] Note that the shaded area in the lower panel of Figure A.2 constitutes the part of the increment of demand that could not be served with incumbent capacity. It would be the same as the shaded area in the upper panel if and only if there was no spare capacity at present.

To account for this effect, the optimal program should take into account the residual value of assets in the market at the completion of the planning horizon.

- It is useful to note that the information assembled by a central planner is likely to constitute a fraction of that would is available to be assembled by a wider group of self-interested market participants. For instance, information regarding new and innovative technologies may not be known to or considered by a central planner. This may be especially true in the context of demand management technologies.
- Related to the potentially limited scope of the information assembled by the central planner is the process by which it is used. The lowest-cost program developed by a real central planner would likely reflect some degree of bias associated with a planner's decision-making process. In particular, a real central planner may be biased in favour of technologies with certain characteristics over others. Consider several examples. It may be preferred that:
  - supply be comprised of a small number of large generators rather than a large number of small generators;
  - repairs be made to incumbent generators rather than construction of new facilities;
  - peaking generators be constructed rather than of demand management technologies introduced; and/or
  - central control be exerted over the operation of demand management technologies rather than it be distributed.
- The magnitude of the increment of demand is an important consideration. This is because the optimal program may be sensitive to its size, especially if the increment is smaller than the minimum capacity associated with some different generation technologies.[33]
- Incumbent generation is taken as given, with its capacity cost recognized as being sunk. The decision to retire such a facility (or that of an entrant if its useful life is less than the duration of the planning period) is endogenously determined. In other words, facilities retire because:
  - they reach the end of their useful lives; or
  - because they are uneconomic to run.
- The increment could cause the structure of the optimal program to change, rather than simply shift forward in time. In particular, since investment needs are shifted forward, generation technologies with very high overnight costs become relatively more expensive in present value terms and could be replaced in the optimal program by lower overnight cost units. Alternatively, if the increment of demand is applied only to peak demand, the optimal program could shift to include relatively more peaking generators and relatively fewer baseload generators.
- With respect to determining the optimal program the key issue is obtaining information regarding constraints that are likely to bind in solving the optimization problem, e.g., demand levels and technological characteristics. Other characteristics, e.g., the precise shape of the demand time series, also lead to constraints but may be less important from a long-term planning perspective.

[33] The standard technical definition of marginal cost is that it is the first derivative of the total cost function with respect to output. Such an application of calculus implicitly assumes that the increment is infinitesimally small and is therefore not meaningful in this context.

- The calculation is forward-looking since it involves decision making on the basis of forecast demand and technologies and processes available (and reasonably forecast to become available) in the future.

In summary, the perturbation approach to measuring LRMC involves determining the amount by which discounted costs increase as a result of serving a greater amount of discounted demand. The ratio of these values provide information regarding the rate at which costs change as demand changes, which is the meaning of term marginal cost.

A.2 The average incremental cost approach[34]

The average incremental cost (AIC) approach to measuring LRMC is similar to the perturbation approach in a number of respects, but it is significantly simpler in a number of other ways. The process implemented to measure LRMC under this approach is as follows:

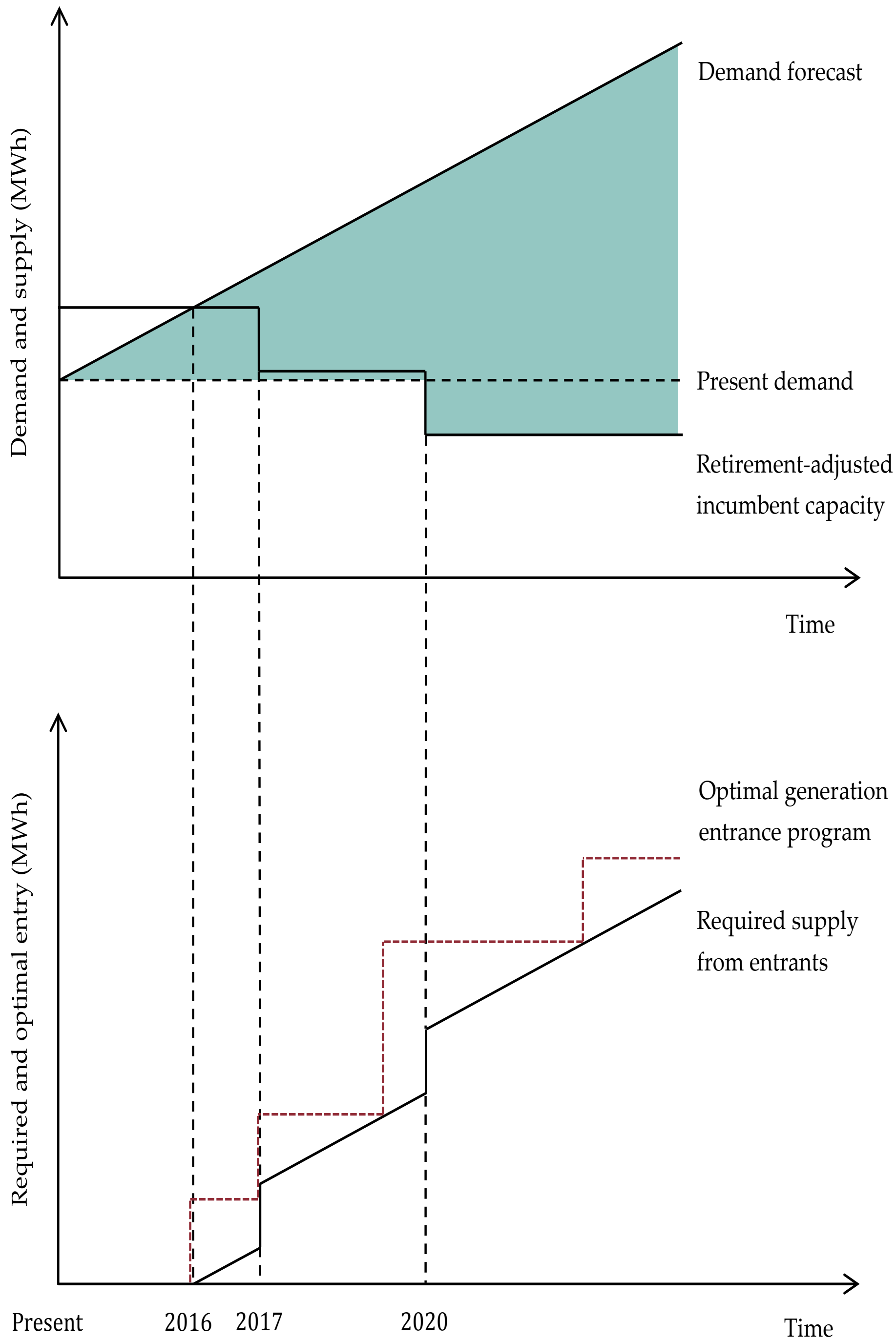
1) Construct annual forecasts of average and peak system demand over an extended time horizon, say 20 years. The purpose of this step is to obtain information regarding the trend of average and peak demand which must ultimately be satisfied. Implementation of this step in practice will generally require that assumptions be made regarding future macroeconomic conditions and industry-specific development, e.g., the growth rate of gross domestic product (GDP) and investments in oil sands projects.
2) Obtain information regarding the characteristics of technologies and processes available (and reasonably forecast to become available) to meet the demand forecasted in the previous step. This includes incumbent generators and prospective entrants that would constitute supply, as well as demand management measures.
3) Determine, in present value terms, the lowest-cost program of generation entrance that would ensure demand is met at each point during the forecast period. This can be thought of as the optimal generation capacity entrance program. The program would account for the relevant reliability standard and would include those demand-side measures that are economically efficient, i.e., those that are less costly than the least-cost alternative supply technology.
4) Determine the present value of demand that:
    a. is in excess of that which is presently demanded; and
    b. cannot be served by incumbent suppliers due to retirements.

    This demand is referred to as incremental demand.
5) Calculate LRMC by dividing the present value of the optimal generation capacity entrance program by the present value of the demand increment, i.e., the cost of servicing the demand increment by the size of the demand increment.

The AIC approach to measuring LRMC is illustrated in Figures A.1 and A.3. Note that the first three steps associated with this approach are identical to the perturbation approach and are illustrated in Figure A.1 (and explained in the previous section). In short, forecast demand is satisfied by finding the optimal generation capacity entrance program.

[34] For additional detail, see Section 2.3.2 of Kemp, et al. (2011).

Figure A.3: Average incremental cost approach to measuring LRMC



Incremental demand is illustrated as the shaded area in Figure A.3. There are two components to incremental demand, as specified above in step 4. First, future demand that is in excess of present demand is defined to be incremental relative to the present. This component is represented by the triangular portion of the shaded area bounded from above and below by the forecast and present demand lines, respectively. Second, future demand that cannot be satisfied with present capacity due to generation capacity retirements also constitutes part of incremental demand. The reason is that generation capacity entry allows this demand to be satisfied and is therefore be considered a benefit associated with incurring the expenses associated with the optimal program. This component is the represented by the balance of the shaded area, the shaded quadrilateral below the present demand line.

The final step of the AIC approach can be expressed as:

$$LRMC^{AIC} = \frac{PV(cost\ of\ optimal\ generartion\ capacity\ entrance\ program + marginal\ operating\ costs)}{PV(additional\ serviceable\ demand)} \quad (A2)$$

where $PV(\cdot)$ denotes the present value function.

Marginal operating costs means the additional operating costs associated with satisfying demand above the present level, including demand that can be satisfied with incumbent capacity. It is important to note that this also includes demand that can only be served as a result of capacity investment, i.e., capacity investment is eventually required to continue servicing present demand and the operating costs associated with this production is marginal. The additional serviceable demand illustrated as the shaded area in the top panel of Figure A.3 is not equivalent to the incremental generation associated with capacity investment. The reason is that available but unused capacity is not an element of marginal cost.

In summary, as its name suggests, the AIC approach to measuring LRMC uses an average of forecast cost per unit of additional serviceable demand to approximate marginal cost.

A.3 The total element / service long run incremental cost approach

The total element/service long-run incremental cost (TELRIC/TSLRIC) approach to measuring LRMC considers the cost of constructing a hypothetical network of generators to satisfy demand assuming there is no incumbent generation.[35] This particular version of TELRIC is known as the "scorched earth" approach since the assumption of no incumbency implies that it models the choices entrants would make if no system previously existed.[36] Thus, its results are unburdened by historical decisions. There exist alternative versions of the TELRIC approach in which certain elements of the present market are incorporated into the procedure described above. In the context of telecommunications regulation the most common version is referred to as the "scorched node" approach in which the nodes of the telecommunications network that exist at present are assumed to be fixed.[37] Broadly speaking, this is equivalent to assuming that the transmission system is to be taken as given in the determination of the optimal program of investment. Since this report takes the structure of the transmission system as given, the procedure outlined below effectively describes a "scorched node" version of TELRIC.

The process implemented to measure LRMC by use of the TELRIC approach is as follows:

[35] See Blackman and Srivastava (2011) for a detailed discussion. There are a number of alternative methods to estimating LRMC with the TELRIC/TSLRIC approach that were initially developed in relation to price regulation in telecommunications markets. The TELRIC acronym is commonly used in Canada and the United States, while TSLRIC is common in the European Union, Australia, and New Zealand.

[36] Ibid., p. 135-6.

[37] Ibid., p. 136.

1) Construct annual forecasts of average and peak system demand over an extended time horizon, say 20 years. The purpose of this step is to obtain information regarding the trend of average and peak demand which must ultimately be satisfied. Implementation of this step in practice will generally require that assumptions be made regarding future macroeconomic conditions and industry-specific development, e.g., the growth rate of gross domestic product (GDP) and investments in oil sands projects. Determine the present value of forecast demand.

2) Obtain information regarding the characteristics of technologies and processes available (and reasonably forecast to become available) to meet the demand forecasted in the previous step. This includes incumbent generators and prospective entrants that would constitute supply, as well as demand-side measures.

3) Assuming there are no incumbent generators, determine the lowest-cost program, in present value terms, of generation entrance that would ensure demand is met at each point during the forecast period. The program should account for operating costs and can be thought of as the optimal generation capacity entrance program. The program would account for the relevant reliability standard and would include those demand-side measures that are economically efficient, i.e., those that are less costly than the least-cost alternative supply technology.

4) Calculate TELRIC by dividing the total cost of optimal generation capacity entrance program by the forecast demand.

The TELRIC approach to measuring LRMC is illustrated in Figure A.4. Demand, for illustrative simplicity, is assumed to be strictly positive at present and rise by a constant amount through time. Total demand is indicated by the shaded area of the Figure, the present value calculation of which constitutes part of step 1.

Since there is assumed to be no incumbent generation capacity at present, immediate entrance is required to satisfy demand. Indeed, the quantity of initial entrance must be at least as great as present demand. Additional entry is subsequently required in order to satisfy on-going demand increases. A lowest-cost, illustrative optimal generation capacity entrance program is also illustrated in Figure A.4. This corresponds to steps 3 and 4.

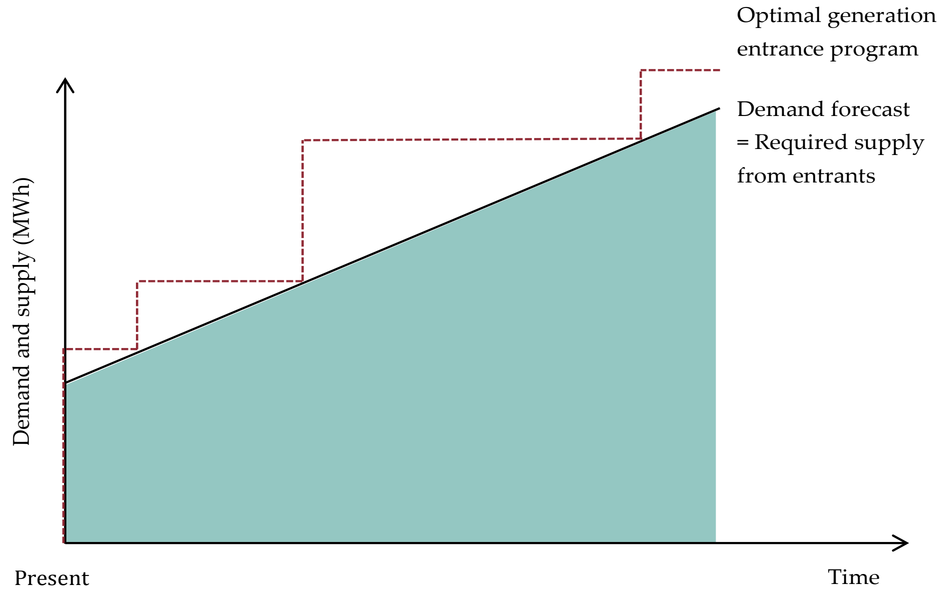
The final step of the TELRIC approach can be expressed as:

$$LRMC^{TELRIC} = \frac{PV(cost\ of\ optimal\ generartion\ capacity\ entrance\ program + marginal\ operating\ costs)}{PV(forecast\ demand)} \qquad (A3)$$

where $PV(\cdot)$ denotes the present value function.

In summary, the TELRIC approach to measuring LRMC assumes that all costs associated with satisfying demand are variable at the time the optimal program is specified, thereby eliminating all inefficiencies associated with historical generation investment decisions.

Figure A.4: TELRIC approach to measuring LRMC



Appendix B: LUEC model and assumptions

The levelised unit electricity cost (LUEC)[38] methodology can, though not strictly a measure of LRMC, be used to assess the cost of satisfying future demand and/or a demand increment. In simple terms, LUEC is a project-specific calculation of the constant electricity price required to cover all of relevant costs given a set of assumptions. The costs recovered include overnight capital, operations and maintenance, fuel, emissions, taxes, financing, and an assumed risk-adjusted rate of return.

One of the critical assumptions required for LUEC calculations is the generator's capacity utilization factor. A further assumption regarding the particular hours in which the generator produces may also be required.[39] A sensitivity analysis is usually conducted regarding this assumption, but the capacity utilization rate is always specified exogenously of market conditions. Also, LUEC estimates are generation technology-specific.

The LUEC calculation is useful because it provides a criterion based upon which a decision to undertake generation investment can be made. In particular, if the expected average spot market price that prevails during the proportion of hours in which the generator produces exceeds LUEC, then there is evidence that the costs associated with the investment can be at fully recovered from the market.[40]

While conceptually straight-forward and relatively easy to calculate, there are a number of short-comings associated with the use of LUEC as a measure of LRMC. Among them are:

- LUEC calculations themselves provide no direct guidance regarding which generation technologies (or the mix of generation technologies) should enter the market. In particular, the attractiveness of a generation technology also depends upon the distribution of prices. As such, conclusions regarding the lowest-cost method of satisfying either a future demand increase and/or a demand increment are not clear.
- In principle, a reasonable economic assumption regarding production is that a generator will generate whenever the system marginal price exceeds its variable costs. The assumption that a capacity factor can be specified in the long-run as a constant fraction independent of market conditions is not reasonable. Optimal generation capacity entrance programs of the type described in relation to the perturbation, AIC, and TELRIC approaches endogenize the proportion of time each generator produces as part of their optimization algorithm.

Notwithstanding these short-comings, LUEC can be used to provide information about LRMC, in the context of a perturbation of demand in particular. However, unlike the other measures of LRMC discussed in Appendix A, LUEC does not provide a single estimate of LRMC and an associated optimal generation mix. Rather, it estimates the costs associated with constructing a generator of each available technology under a variety of assumptions. These estimates can be used to establish bounds on LRMC.

[38] LUEC is known by a variety of alternative names, including levelised cost of energy (LCOE).

[39] Some generators are assumed to produce in all the hours in which they are not on outage. Other generators are assumed to produce in, say, 30% of the hours. A common assumption is that these are the 30% of the hours with the highest prices (thereby yielding the highest average price associated with producing in the specified proportion of hours) but other assumptions might be reasonable.

[40] In forming expectations of pool prices, generators are expected to account for the impact of their entry (and the entry of other generators if relevant) on the distribution of pool prices. In particular, entrants must form expectations regarding the magnitude by which their decision to enter would lower market prices. With respect to average prices, the relevant average is unweighted because revenue is the sum of production capacity multiplied by the pool price summed across the relevant set of hours.

The assumptions used in the LUEC model were, to the maximum extent possible, sourced from AESO (2012). Since significant parts of the analysis undertaken in this paper rely on allowing the capacity utilization rate to vary, it makes little sense to fix such values at those assumed in AESO (2012). The key assumptions are summarised in Table B.1.

Table B.1: Key LUEC assumptions, by generator type

Variable	Units	800 MW combined cycle	100 MW simple cycle
Net power	MW	800	100
Heat rate	GJ/MWh	7.2	9.8
Overnight capital cost	$/kW	1,625	1,150
Fixed O&M	$/kW-year	9.00	14.00
Variable O&M	$/MWh	3.30	4.30
Discount rate	%	8	8

With respect to natural gas prices, when the analysis calls for historical natural gas prices, observed natural gas prices are used. When the analysis requires a forecast of natural gas prices, the forecast used in AESO (2012) is used with a downward adjustment for 2011 and 2012 prices being less than forecast.

Appendix C: Historical price data

This Appendix expands on the historical price data reported in the main text by distinguishing between prices observed during on- and off-peak hours, and by considering additional years.

Figures 3 and 4 illustrate in the main text the price-duration curves for all hours of the years 2008 to 2011 individually, and the years 2002 to 2007 collectively. As with those Figures, some Figures here display their information on a logarithmic scale as to accentuate the relevant characteristics. This Appendix provides a similar analysis with the distinction that on-peak and off-peak prices are illustrated separately.

Figure C.1 illustrates price-duration curves for on-peak hours only of the years 2008 through 2011 individually and the years 2002 through 2007 collectively using a logarithmic scale. Figure C.2 illustrates the same data but is restricted to the top 20% of prices on a normal scale. Figures C.3 and C.4 illustrate the equivalent data related to off-peak hours only.

Figure 5 in the main text illustrates the price-duration curve for the year 2011 along with the associated conditional average price curve. Comparable illustrations for the time period 2002 to 2007, and the years 2008, 2009, and 2010 are provided in Figures C.5, C.6, C.7, and C.8, respectively. Historical data regarding the year 2012 is discussed in Appendix D since the year is not complete.

Figure C.1: Historical price-duration curves, on-peak hours, by year, logarithmic scale

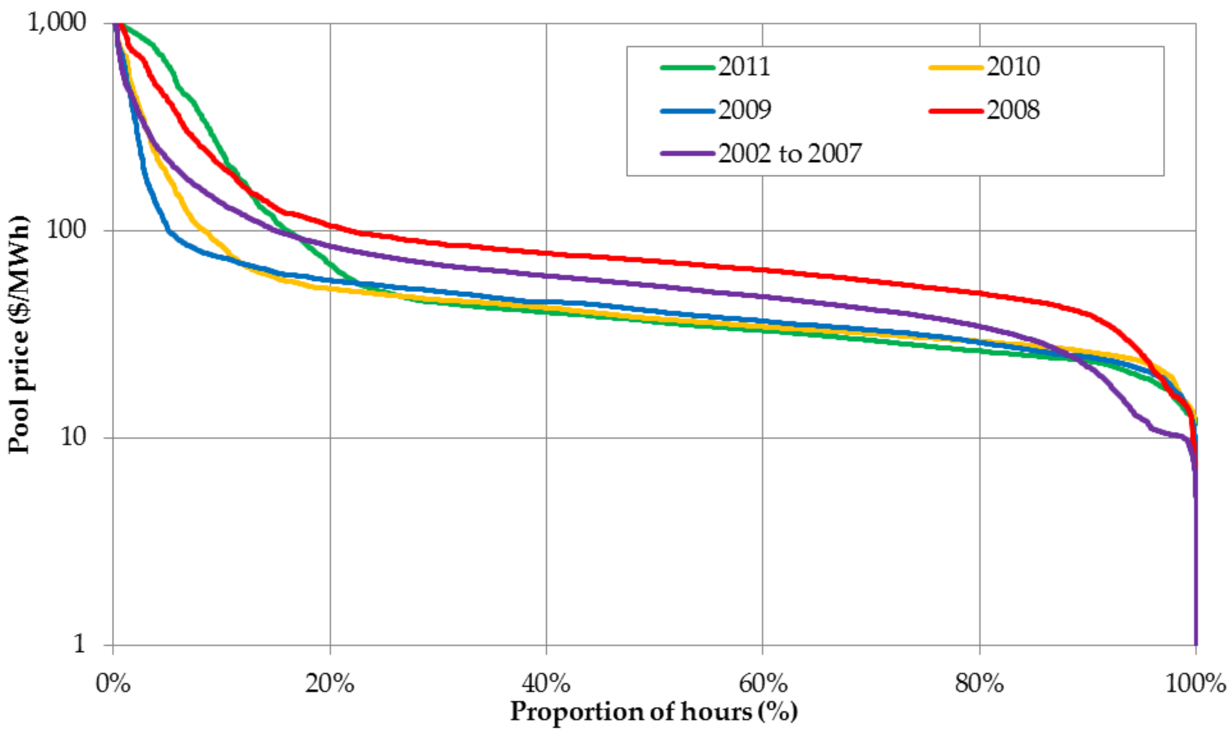


Figure C.2: Historical price-duration curves, on-peak hours, by year, normal scale

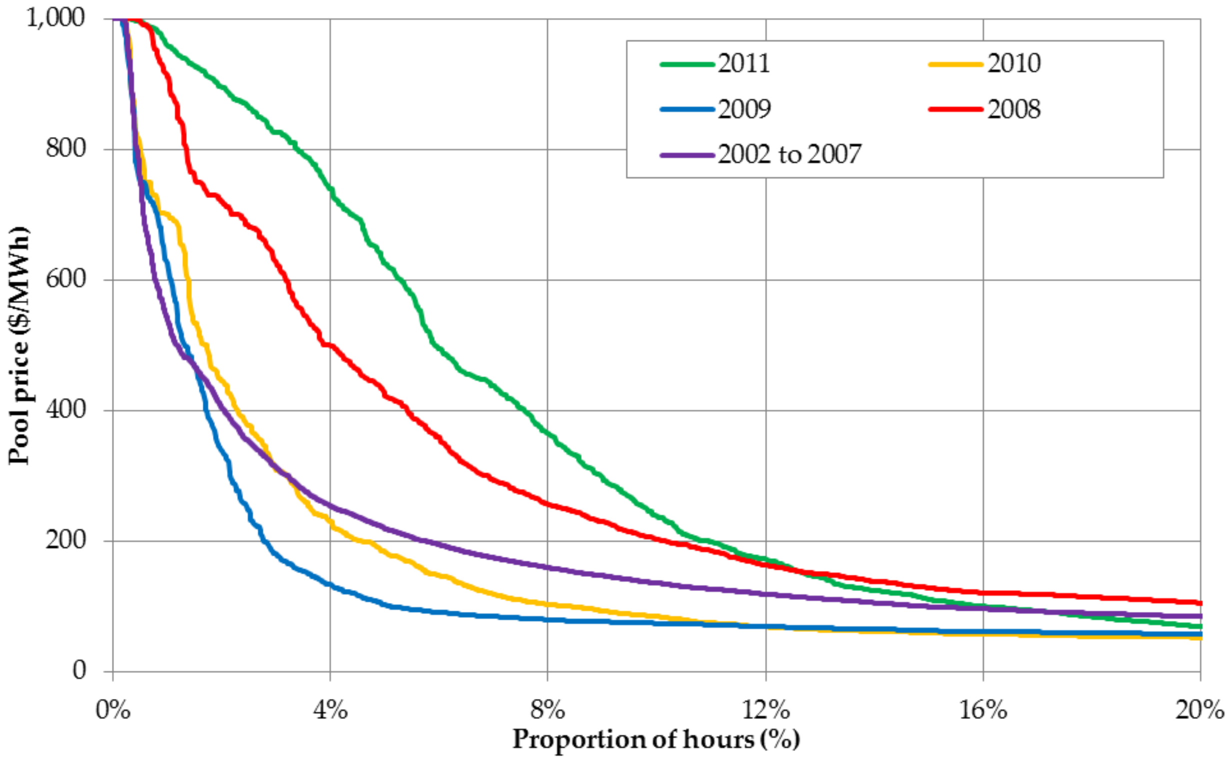


Figure C.3: Historical price-duration curves, off-peak hours, by year, logarithmic scale

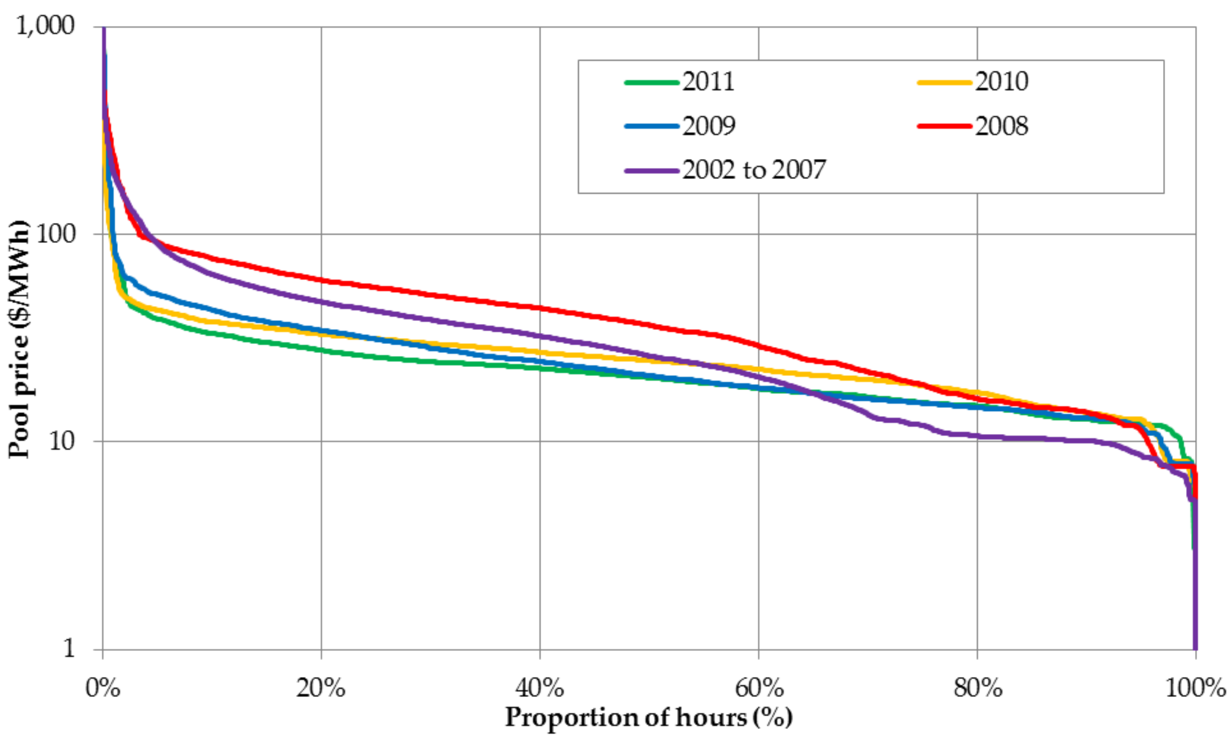


Figure C.4: Historical price-duration curves, off-peak hours, by year, normal scale

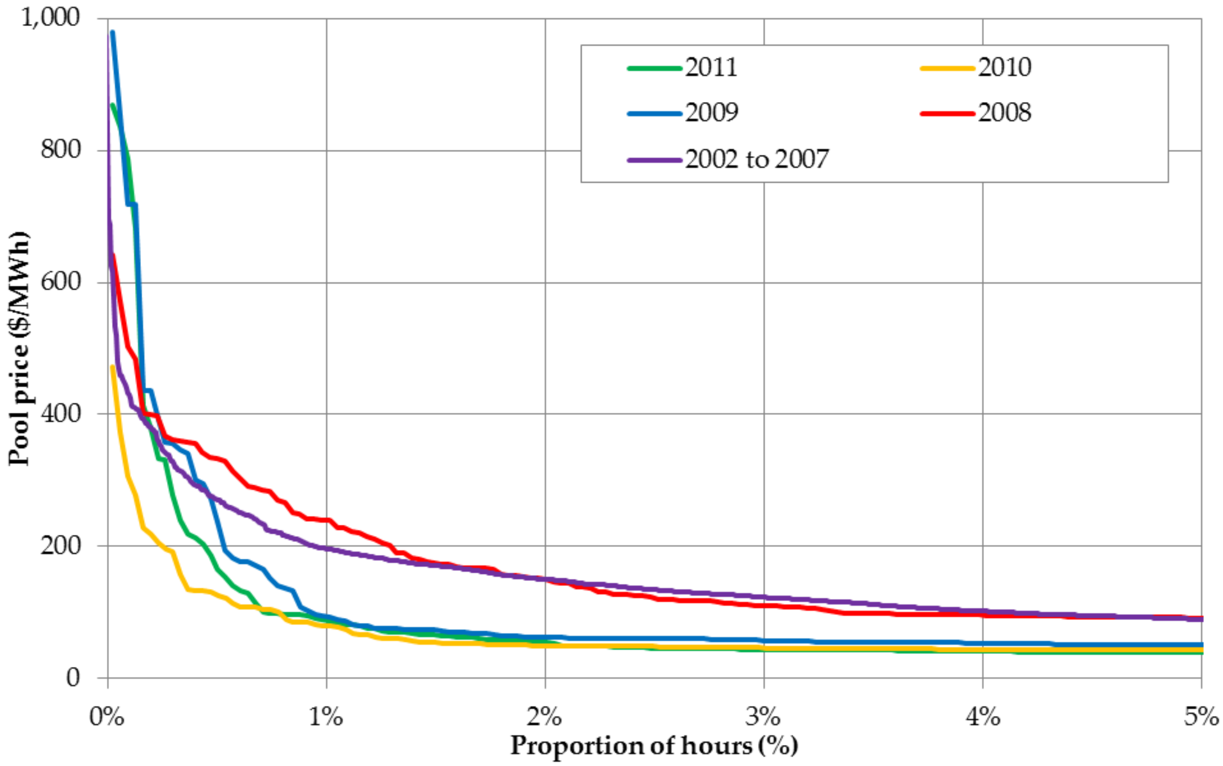


Figure C.5: Price-duration and conditional average price curves, years 2002 through 2007

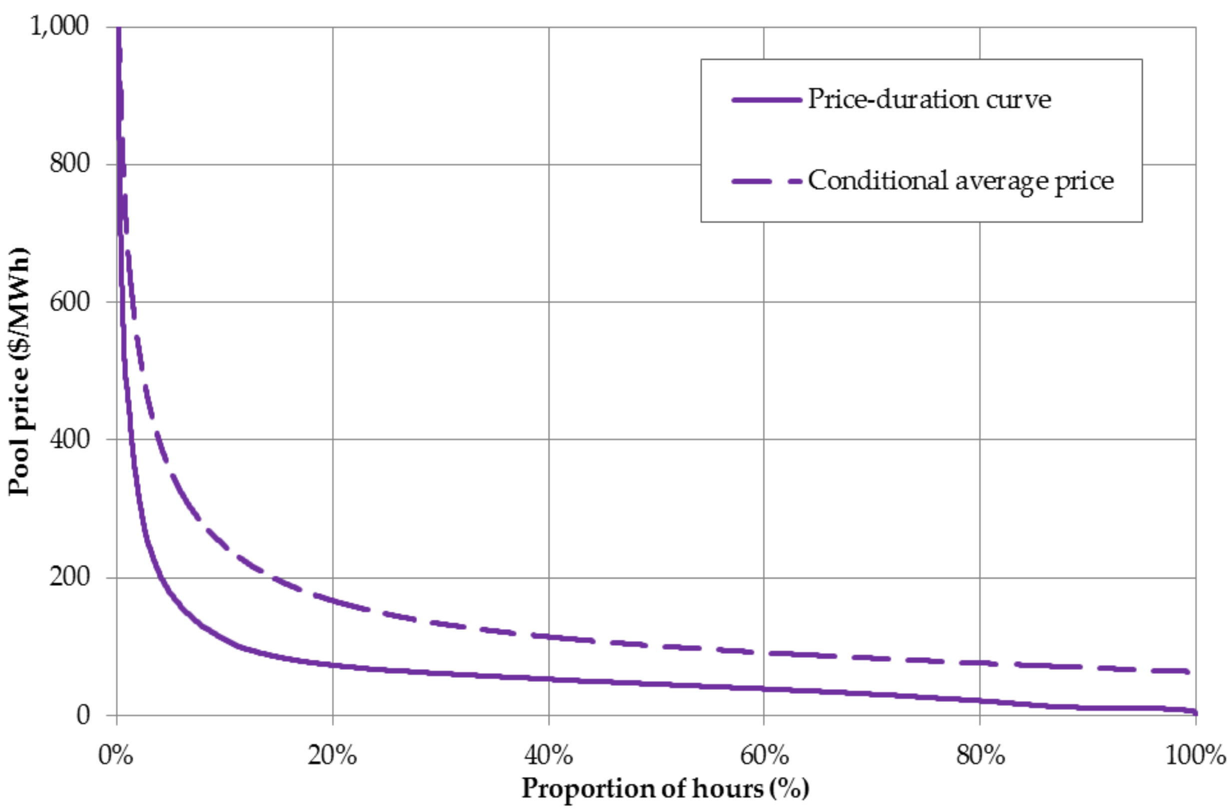


Figure C.6: Price-duration and conditional average price curves, year 2008

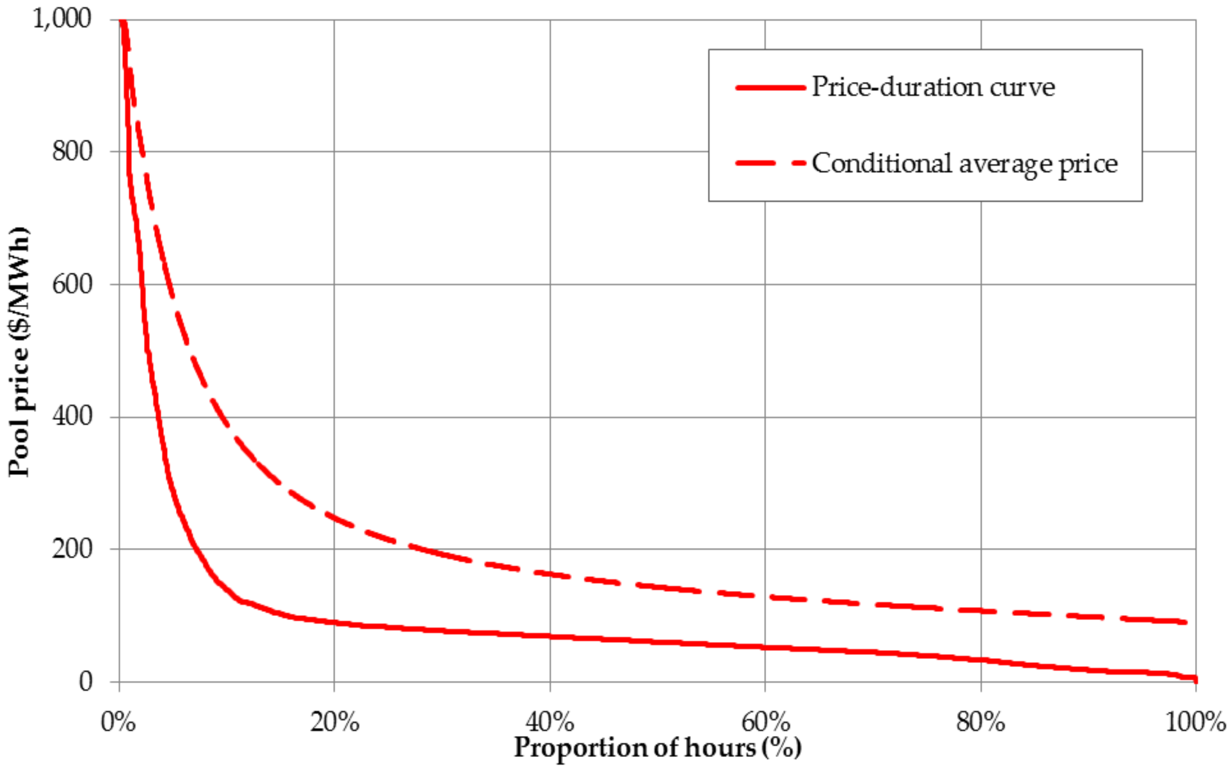


Figure C.7: Price-duration and conditional average price curves, year 2009

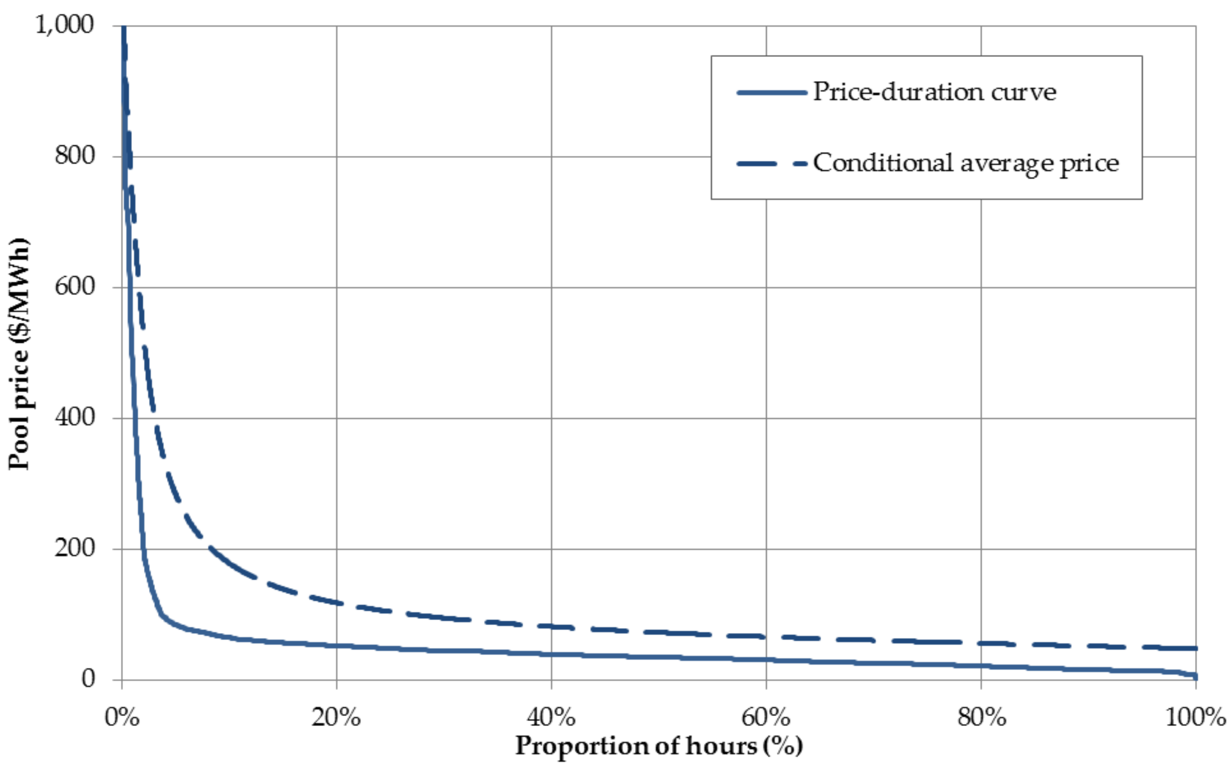
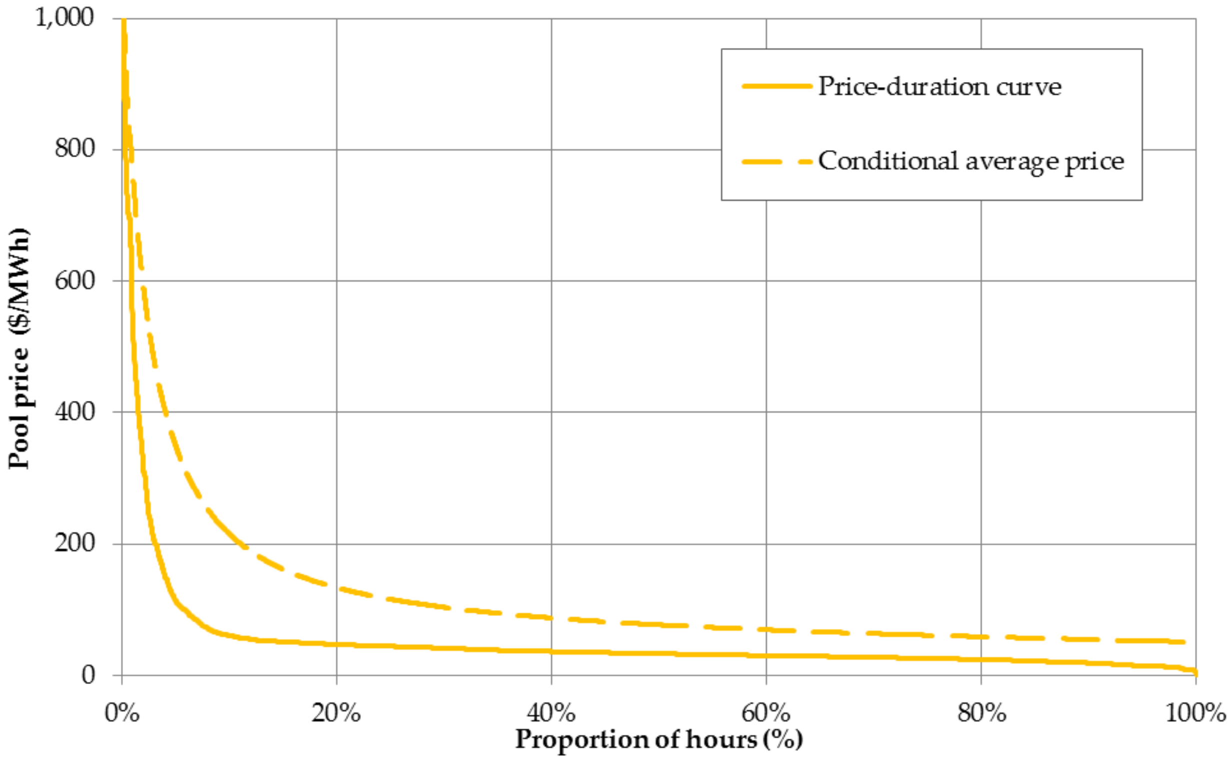


Figure C.8: Price-duration and conditional average price curves, year 2010



Appendix D: Construction of forward price distribution

As described in Section 3.2, forward prices are analogous to historical average prices in that they characterise points on the price distribution rather than the distribution as a whole. As illustrated in Figures 3.4 and 3.5, the forward price-duration curve that can be constructed with forward prices does not provide information regarding the full expected distribution of future prices that is comparable to that available with historical prices as illustrated in Figures 3.1, 3.2, 3.3, and variously in Appendix C. Detail regarding the distribution is important because of how it characterises the revenue obtained by generators in the market as well as those considering entry. Thus, it would be useful to use the forward market (average) prices to construct full forward price distributions. While there are innumerable potential procedures for achieving such an end, the purpose of this Appendix is to describe the procedure employed in this report.

In general terms, the procedure for constructing a forward price distribution has two steps. First, select a historical period for which the actual price distribution has a *shape* that is reasonably expected to be realised again, considering factors such as strategic behaviour that results in economic withholding on the part of generators. Second, recognising that there is likely to be a discrepancy between the actual average price observed in the selected historical year and the forward price, adjust the historical price-duration curve so that the adjusted average equals the forward price. Additional detail regarding this adjustment is provided below. While it is possible to implement the procedure on the historical price-duration curve corresponding to all hours of the selected year, since data regarding both the on- and off-peak forward prices are available, it is possible to adjust both the selected year's on- and off-peak price-duration curves separately. Indeed, separate adjustment of the on- and off-peak prices is preferred since it makes use of more information available from the forward market.

The period January to September 2012, inclusive, is selected as the base period used to construct forward price-duration curves for the fourth quarter of 2012, as well as the years 2013 and 2014. Market outcomes observed during this period reflect both the importance of economic withholding in the determination of spot market prices as well as recent macroeconomic conditions relatively well. This renders the observed shape of the price-duration curve relatively likely to be observed again (the first step of the procedure outlined above). The all hours, on-peak hours, and off-peak hours average prices for the base period are recorded in Table 3.1 and are $59.48/MWh, $78.81/MWh, and $20.81/MWh, respectively.

For illustrative purposes, consider the fourth quarter of 2012. As reported in Table 3.5, the observed forward prices are $71.98/MWh, $94.82/MWh, and $26.31/MWh, for all hours, on-peak hours, and off-peak hours, respectively. In comparison to the base period, the forward prices are approximately 20-25% greater than the corresponding average observed prices in the base period. The simplest procedure for constructing a forward price-duration curve is to multiply each of the observed prices by the ratio, allowed to differ across off- and on-peak hours, implied above. It would, however, not be appropriate to implement this adjustment if it would result in the post-adjustment price being either above the price cap or below the price floor. To incorporate the price cap into the adjustment process, post-adjustment prices are limited to a maximum of $1,000.00/MWh; to incorporate the price floor into the adjustment process, post-adjustment prices are limited to a minimum of $0.00/MWh. The adjustment ratios required to implement this procedure for the fourth quarter of 2012, as well as the years 2013 and 2014, are summarised in Table D.1.

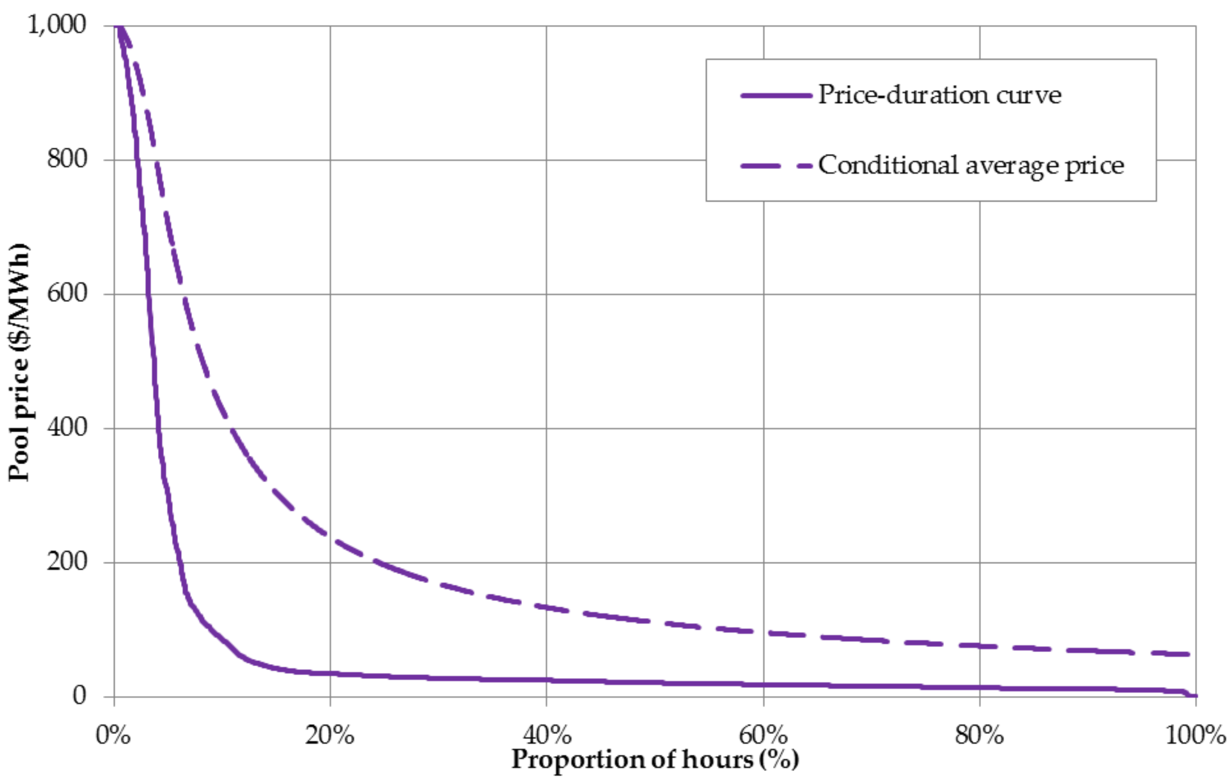
Table D.1: Adjustment ratio for off- and on-peak hours by forward period

Forward period	Off-peak hours	On-peak hours
Q4 2012	1.2770	1.2517
2013	1.0330	0.9787
2014	1.0247	0.8281

An all hours forward price-duration curve can be created for each forward period by combining the appropriate on- and off-peak price-duration curves (with proper sorting of the combined data series). The forward price-duration curves for the years 2013 and 2014 can be used without further modification to undertake the comparison described in-text. Construction of a year 2012 price-duration curve requires that the forward fourth quarter 2012 price-duration curve be combined with observed prices from the period January to September, 2012 time period. This can be done straight-forwardly, recognising that the period of observed price outcomes constitutes three-quarters of the year while the period of forward prices constitutes the remaining one-quarter of the year, with weights defined accordingly.

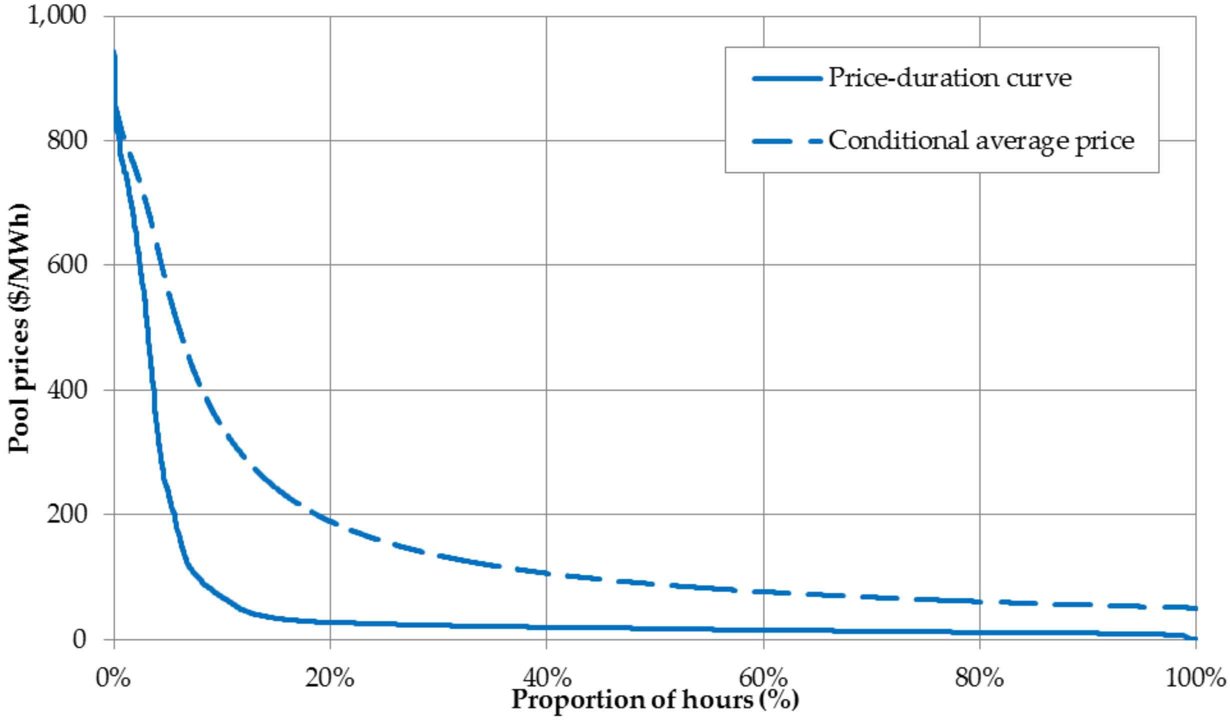
Figures D.1 and D.2 illustrate, respectively, the price-duration and conditional average price curves for the years 2012 and 2014. A comparable illustration for year 2013 can be found in Figure 3.6 in Section 3.2. Finally, if the price adjustments necessary to implement this methodology were meaningfully larger, alternative methodologies should be explored.[41]

Figure D.1: Price-duration and conditional average price curves, year 2012



[41] No definition of the present usage of the term 'meaningful,' which is inherently arbitrary, is specified in this paper.

Figure D.2: Price-duration and conditional average price curves, year 2014



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The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.