Ontario Wholesale Electricity Market Price Forecast

For the Period May 1, 2018 through October 31, 2019

Prepared for:

Ontario Energy Board

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Submitted by:

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EXECUTIVE SUMMARY

Power Advisory LLC (Power Advisory) was engaged by the Ontario Energy Board (OEB) to produce a forecast of wholesale electricity market prices in Ontario for the May 1, 2018 to October 31, 2019 period. This wholesale electricity price forecast will be used by the OEB as an input to the calculation of the "Global Adjustment Modifier", which is used to reduce the Global Adjustment charges that certain consumers would otherwise pay, as required under the *Ontario Fair Hydro Plan Act, 2017*.

Power Advisory used a complex model of Ontario's electricity market to forecast the Hourly Ontario Electricity Price (HOEP). The model combines regression analysis and dispatch modeling to generate hourly price curves that are consistent with historical market behaviour and reflective of forward-looking analysis that predicts market changes. Amongst other data, the model reflects Ontario's electricity demand and hourly load shape, all committed new entrant generation, all planned generation retirements, the operating profiles of Ontario's hydroelectric generation (including both baseload and peaking resources), the operating characteristics of Ontario's thermal generation and expected fuel and carbon prices. The assumptions used by Power Advisory and their sources are discussed in detail in Chapter 3 of this report.

The table below presents the results of the base case market price forecast resulting from Power Advisory's modeling. The on-peak and off-peak prices presented are simple averages (i.e., not load weighted).

Table ES-1: HOEP Forecast ($ CAD per MWh)

Term	Quarter	Calendar Period	On-Peak	Off-Peak	Average
RPP Period	Q1	May 2018 - Jul 2018	$23.32	$11.31	$16.83
	Q2	Aug 2018 - Oct 2018	$25.08	$13.29	$18.68
	Q3	Nov 2018 - Jan 2019	$28.05	$14.61	$20.74
	Q4	Feb 2019 - Apr 2019	$26.27	$19.23	$22.39
	Average	**May 2018 - Apr 2019**	**$25.68**	**$14.57**	**$19.64**
Other	Q1	May 2019 - Jul 2019	$22.32	$10.96	$16.19
	Q2	Aug 2019 - Oct 2019	$23.94	$12.84	$17.91
	Average	**May 2019 - Oct 2019**	**$23.13**	**$11.90**	**$17.05**

Source: Power Advisory

Notes:

1) Assumes natural gas prices that reflect the exchange rate forecast reported in the Bank of Montreal's "Canadian Economic Outlook" issued April 6, 2018. For the May 2018 to October 2019 HOEP forecast period the average exchange rate is US$1 = C$1.25.

2) On-peak hours are between 7 a.m. and 11 p.m. Eastern Standard Time (EST) on non-holiday weekdays. Off-peak hours are all other hours (weekends, holidays, and overnight). The times for the calculation of on-peak and off-peak hours are not adjusted for Daylight Savings Time (DST).

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1. INTRODUCTION

Power Advisory LLC (Power Advisory) was engaged by the Ontario Energy Board (OEB) to produce a forecast of wholesale electricity market prices in Ontario for the May 1, 2018 to October 31, 2019 period. This wholesale electricity price forecast will be used by the OEB as an input to the calculation of the "Global Adjustment Modifier", which is used to reduce the Global Adjustment charges that certain consumers would otherwise pay, as required under the *Ontario Fair Hydro Plan Act, 2017*. The GA Modifier applies to two types of customers:

- customers that are eligible for the Regulated Price Plan (RPP), but have opted out for a retail contract or for market-based pricing; and,
- customers that are not eligible for the RPP but are qualified for an 8% discount through the *Ontario Rebate for Electricity Consumers Act, 2016* (ORECA).

The GA Modifier is subtracted from the Global Adjustment (GA) line item of the above customers' bills. By subtracting the GA Modifier, these customers receive a benefit that corresponds with that provided to RPP customers through annual adjustments to time-of-use electricity rates. As well, the forecast is used to fulfil the OEB's requirement to calculate what time-of-use (TOU) and tiered RPP prices would have been without the Fair Hydro Plan.[1]

This report presents the results of Power Advisory's forecast, the key assumptions driving this forecast, and the information sources on which these assumptions were based.

1.1 Contents of This Report

This report is organized into four chapters, starting with this introduction. Chapter 2 outlines the price forecasting methodology and identifies the key forecast drivers. Chapter 3 reviews the forecast assumptions and identifies the information sources on which these assumptions are based. Chapter 4 presents the Ontario wholesale electricity market price forecast results.

[1] O. Reg. 195/17, Section 5 (4): "The Board shall, for the purposes of allowing an electricity vendor or unit sub-meter provider to comply with Ontario Regulation 196/17 (Invoicing Requirements) made under the Act, calculate the time-of-use and tiered rates that would have been effective on May 1, 2018 if they had been determined using the method prescribed by the regulations made under clause 79.16 (1) (b) of the *Ontario Energy Board Act, 1998* and without taking into account any forecasted impact of any provisions of the Act. O. Reg. 517/17, s. 1."

2. PRICE FORECASTING METHODOLOGY

2.1 Overview of Ontario's Wholesale Electricity Market

Wholesale prices in Ontario are determined by the Independent Electricity System Operator (IESO) based on provincial electricity demand and the monies paid to generators to supply it. Generators supplying electricity to the Ontario market must offer their output to the IESO as a series of hourly price and quantity pairs. Based on these offers, the IESO uses a dispatch algorithm to choose the least-cost combination of generation resources which can meet forecast demand in each five-minute interval of each hour. The selection of resources based on cost is subject to technical factors such as ramp rates for gas-fired generation, transmission constraints, and other physical limitations.

For each five-minute interval, the offer price of the most expensive generation selected becomes the Market Clearing Price (MCP) for that period. Each generator in Ontario receives the MCP for its energy output, regardless of what price it offered to the IESO. For each hour, the twelve five-minute MCPs are averaged to determine the Hourly Ontario Electricity Price (HOEP). Thus, the interaction of hourly supply and demand determines Ontario's wholesale electricity market price.

2.2 Overview of the Forecasting Model

The major factors known to drive the equilibrium between electricity supply and demand in Ontario are reflected in Power Advisory's HOEP Forecast Model. Accordingly, the model reflects the history of the Ontario electricity market and specifically the relationship between the drivers of market prices and the resulting market prices. This relationship is then extrapolated forward to produce a forecast of expected wholesale electricity prices.

However, no model can accurately simulate all of the factors and interactions that affect prices in an electricity market the size of Ontario's. In order to retain as much historical information as possible regarding the nuances of market operation, the starting point for Power Advisory's model is hourly prices over the past five years (2013-2017). For each forecast year, the model takes the hourly prices for the first historical base year (2013), reflecting supply, demand, fuel prices, weather, etc. in that year, and adjusts each of these 8,760 prices based on expected changes in supply, demand and fuel prices in each forecast year. For example, if the amount of nuclear capacity in-service in the forecast year is expected to be less than what was available in the base year, supply will be reduced, and prices correspondingly increased to reflect the revised supply mix, in all hours of the forecast year. If more wind capacity is expected to be in service, supply in the forecast year is increased, but with a greater impact on prices in hours which were windier in the base year. The relationship between supply, demand and price is established through regression analysis as part of the modelling process. Prices are further adjusted to reflect market rules on curtailment of wind, solar and nuclear generation, as appropriate. The process is repeated for the same forecast year using each of the remaining four historical base years (2014, 2015, 2016 and 2017), and the results using all five base years are averaged to produce the forecasts shown in this report.

2.3 Key Forecast Drivers

Although other influences exist, forecast price changes are driven by three primary factors:

- **Hourly demand for electricity**, including both changes in total monthly or annual demand, and changes in the time of day when consumers use electricity.
- **Generation in-service**, taking into account capacity additions (such as wind, solar, hydro, gas and other facilities coming into service), retirement of older capacity, the expiration of generation contracts and temporary shut-downs; especially for the refurbishment of the Bruce and Darlington nuclear plants.
- **Cost of burning natural gas**, including both the market price of natural gas and the cost of the greenhouse gas (GHG) emissions. The marginal cost of generating electricity from natural gas is an important determinant of electricity prices in Ontario in many hours during the forecast period. The reason being: 1) when Ontario demand is high relative to supply, the marginal source of supply (which either sets or strongly affects the MCP) is usually either domestic gas generation, or imports from other markets where the price is often set by natural gas generation, and 2) when supply is high relative to Ontario demand, the province exports electricity to neighbouring markets, and the price received is often set by the cost of natural gas generation in those markets.

3. KEY FORECAST ASSUMPTIONS

The major assumptions used in the HOEP forecast model, as well as their sources, are presented below.

3.1 Demand Forecast

The basis for Power Advisory's energy demand forecast is the IESO's 18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System from April 2018 to September 2019 (released March 21, 2018). The IESO's forecast contained in this report takes conservation and demand management programs into account. It assumes "normal weather" – i.e., the energy forecast is based on daily weather conditions that are representative of typical weather conditions for that time of year.

The IESO forecasts demand at the transmission grid level. However, Ontario has a significant and growing supply of generation "embedded" in the distribution network, which supplies a corresponding volume of consumer demand that does not pass through the transmission system. Therefore, the IESO adjusts its forecast of grid-level demand to exclude embedded generation (technically, to exclude the demand that it supplies). Power Advisory's HOEP forecast model takes into account both grid-level demand, and the demand supplied by embedded generation.

The forecast period for this report (May 1, 2018 - October 31, 2019) extends beyond the period covered by the IESO's 18-Month Outlook and therefore Power Advisory has extrapolated the IESO's forecast to cover the entire forecast period. Table 1 shows the forecast of monthly energy consumption used in the model.

Table 1: Forecast Monthly Energy Consumption and Peak Demand

Term	Month	Grid-Level Demand (GWh)	Embedded Demand (GWh)	Total Demand (GWh)	Peak Demand (MW)
RPP Period	May 2018	10.29	0.68	**10.97**	**18,817**
	Jun 2018	10.86	0.65	**11.51**	**21,874**
	Jul 2018	11.64	0.69	**12.33**	**22,002**
	Aug 2018	11.69	0.66	**12.34**	**21,936**
	Sep 2018	10.12	0.62	**10.74**	**19,007**
	Oct 2018	10.70	0.57	**11.26**	**17,843**
	Nov 2018	11.10	0.54	**11.64**	**19,797**
	Dec 2018	11.87	0.40	**12.27**	**20,491**
	Jan 2019	12.69	0.48	**13.16**	**20,233**
	Feb 2019	11.41	0.48	**11.89**	**20,410**
	Mar 2019	11.71	0.59	**12.30**	**20,117**
	Apr 2019	10.28	0.67	**10.95**	**17,879**
	Total/Maximum	**134.35**	**7.01**	**141.37**	**22,002**
Other	May 2019	10.21	0.72	**10.93**	**18,671**
	Jun 2019	10.65	0.67	**11.32**	**21,449**
	Jul 2019	11.73	0.73	**12.46**	**22,174**
	Aug 2019	11.63	0.68	**12.31**	**21,819**
	Sep 2019	10.63	0.65	**11.28**	**19,954**
	Oct 2019	10.40	0.63	**11.03**	**17,338**
	Total/Maximum	**65.24**	**4.09**	**69.33**	**22,174**

Source: IESO, 18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System from April 2018 to September 2019 (released March 21, 2018); Power Advisory

3.2 Supply Resources

Power Advisory's generation capacity assumptions are consistent with the IESO's *18-Month Outlook* (released March 21, 2018). Assumptions regarding expected generation capacity additions, available nuclear capacity and hydro generation, and Ontario's interconnection limits are detailed below.

3.2.1 Generation Capacity Additions

In addition to the existing supply resources, several major projects are expected to come on-line during the forecast horizon, as listed in Table 2. These have been included in the model specification. The IESO capacity additions include the Napanee generating station, a 985-MW gas-fired combined-cycle plant, and 245 MW of hydro, wind and solar generation. The supply contracts of two gas plant generators will expire during the forecast period: the Douglas Generation Station and the Whitby Cogeneration plant.

Table 2: Major Generation Capacity Additions

Project Name	Resource Type	Capacity (MW)	In-Service Date
Napanee Generating Station	Gas	985	2018-Q3
North Kent Wind 1	Wind	100	2018-Q2
Amherst Island Wind	Wind	75	2018-Q3
Loyalist Solar Project	Solar	54	2018-Q3
Yellow Falls	Hydro	16	2018-Q2
Douglas Generating Station	Gas	-122	2018-Q4
Whitby Cogeneration	Gas	-56	2019-Q2

Source: IESO, 18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System from April 2018 to September 2019 (released March 21, 2018), Table 4.2.

In addition to the transmission-connected projects shown in Table 2, the IESO's *18-Month Outlook* forecasts the addition of 187 MW of distribution-connected bioenergy, hydro, solar and wind projects during the forecast period (May 2018 – October 2019). Including the above additions, the model assumes that 2,810 MW of solar capacity and 5,100 MW of wind capacity will be in-service by the end of the forecast period (October 2019), capable of generating enough electricity to meet approximately 12% of Ontario's demand. Increases in wind and solar put downward pressure on Ontario's wholesale electricity prices.

3.2.2 Nuclear Capacity

Unit 2 of the Darlington Nuclear Generating Station has been out of service for refurbishment since October 2016 and is expected to remain out of service for the remainder of the forecast period. Although the other three Darlington units, and 6 of the 8 Bruce units, are scheduled to undergo refurbishment, none of them are planned to be taken out of service before the end of the forecast period, according to the IESO's *18-Month Outlook*.

Based on this, and historical generation patterns, the HOEP forecast model assumes total nuclear generation of 136 TWh over the forecast period, as shown in Table 3 below. This implies a capacity factor of 85.1%, which is calculated as the average power generated over the rated peak power available through the nuclear fleet, excluding Darlington 2 which is out of service. It takes into account expected curtailment of some of the Bruce units during times when domestic supply exceeds demand. All plants show higher capacity factors during summer and winter and lower capacity factors during the shoulder seasons (spring and fall); indicative of the planned maintenance that tends to be scheduled for the shoulder seasons when demand is lower.

Table 3: Forecast Nuclear Generation

Term	Month	Nuclear Generation (TWh)
RPP Period	May 2018	6.94
	Jun 2018	7.47
	Jul 2018	8.04
	Aug 2018	7.99
	Sep 2018	7.30
	Oct 2018	7.30
	Nov 2018	7.76
	Dec 2018	8.03
	Jan 2019	8.22
	Feb 2019	7.07
	Mar 2019	7.70
	Apr 2019	7.02
	Total	**90.84**
Other	May 2019	6.95
	Jun 2019	7.48
	Jul 2019	8.04
	Aug 2019	7.99
	Sep 2019	7.30
	Oct 2019	7.31
	Total	**45.07**

Source: Power Advisory

3.2.3 Hydro Generation

Hydroelectric generation can vary significantly from year to year depending on the level of precipitation in the province. The starting point for Power Advisory's HOEP forecast model is historical supply and demand for the five base years (2013-2017). During these years, annual output of transmission-connected hydro ranged from 35.0 TWh (in 2016) to 36.9 TWh (in 2017). This range is reflected in the forecast, which is based on an average of the forecast developed using each of the five base years. The forecasts of hydro output are adjusted for changes in installed hydro capacity between the forecast year and the base year (such as the addition of the 16-MW Yellow Falls Hydroelectric Generating Station, expected to come into service in the second quarter of 2018).

3.2.4 Transmission Capabilities and Constraints

Unlike many electricity systems which have different electricity prices in different areas, Ontario has a uniform electricity price that applies across the entire province. HOEP therefore does not directly reflect transmission constraints within Ontario. The forecast model reflects this, and does not model internal transmission constraints. To the extent that transmission constraints have indirect impacts on wholesale market prices, these are implicitly factored into the model through the use of historic price curves.

External transfer limits can also affect Ontario prices. Limited transfer capability can mean higher prices when demand exceeds supply, because less expensive imports cannot be brought in, and lower prices when supply exceeds demand, because suppliers cannot sell their surplus in other markets. The transfer capabilities of transmission interconnections with adjacent markets are shown in the IESO's *Ontario Transmission System* report, differentiated by season and direction of flow. Table 4 shows the ratings of Ontario's interconnections with adjacent markets based on the information presented in this report.

Table 4: Ontario Interconnection Limits

(MW)	Flows Out of ON		Flows Into ON	
	Summer	Winter	Summer	Winter
Manitoba	225	300	293	368
Minnesota	150	150	100	100
Michigan	1,700	1,750	1,700	1,750
New York	1,950	2,100	1,800	1,950
Québec	2,135	2,170	2,730	2,750

Source: IESO, Ontario Transmission System, December 12, 2017

3.3 Natural Gas Prices

Given the uncertainty associated with fuel price forecasts, Power Advisory typically relies on liquid financial and physical markets to specify natural gas market price forecasts. For Ontario electricity prices, the most relevant pricing hub is the Dawn/Union hub in Southwestern Ontario. While trade volumes at this hub are lower, and therefore less widely reported than at other gas hubs, S&P Global Market Intelligence reports forward prices for up to ten years into the future, based on trades brokered by OTC Global Holdings. Power Advisory uses these prices in its forecasts.

Future prices based on trading over a single day may be pushed up or down by very short-term factors that do not reflect long-term trends. To reduce the impact of such volatility on forecast prices, an average of settlement prices over the most recent 21 days is used. This approach mirrors what Union Gas and Enbridge Gas Distribution use to forecast natural gas prices in their quarterly rate adjustment mechanism (QRAM) applications to the OEB.

These forward prices are reported in US dollars and therefore must be converted into Canadian dollars. The price forecast reflects an average exchange rate of $1.25 CAD between May 2018 and October 2019. The monthly exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook" issued April 6, 2018. As well as affecting the forecast of the natural gas price in Ontario, the forecast exchange rate affects the GHG emission allowance price forecast (see below), and the price of electricity imports from, and exports to, neighbouring markets.

3.3.1 GHG Emission Allowance Price Forecast

In May 2016, the *Climate Change Mitigation and Low-carbon Economy Act, 2016* received Royal Assent and Ontario Regulation 144/16, was issued. Together, the legislation and regulation provide details about the Cap and Trade Program, which began January 1, 2017. Under the legislation, large final emitters, natural gas distributors and electricity importers are required to verify and report their greenhouse gas emissions to the provincial government and have to match their total emissions in each compliance period with an equivalent amount of "allowances."

Accordingly, the HOEP forecast takes into account the cost of GHG emission allowances incurred when burning natural gas to generate electricity, and when importing electricity from U.S. markets such as New York and Michigan. For May-December 2018, a price of C$18.44/tonne is used, as this was the settlement price in the joint California-Québec-Ontario emissions auction held on February 21, 2018. The settlement price was slightly above the reserve price of US$14.53 (C$18.34). Additional auctions will be held in May, August and November 2018.

For January to October 2019, Power Advisory has forecast the GHG allowance cost to be C$20.00/tonne. This decision is based on the federal government's intention to set a minimum carbon tax starting at $20/tonne by 2020. It is possible that the implementation of this policy could be delayed, or that Ontario could receive credit for its other emission reduction efforts, such that the federal minimum price would not apply. In that case, the auction price would apply. The reserve price would be approximately US$15.55 (the 2017 reserve price, plus inflation, plus 5%), which would be equivalent to C$19.35 at the forecast exchange rate, and the settlement price may be higher than this as it was in the February 2018 auction. Whether the 2019 allowance price is based on federal policy, or provincial policy, the result will be a price of approximately $20/tonne.

To calculate the impact of GHG allowance prices on the cost of domestic gas generation, an emissions factor of 54.1 kg per MMBtu[2] was used. This was added to the market price of natural gas to get the effective price, used in deriving hourly electricity price curves for the forecast period.

3.3.2 Natural Gas Price Forecast

Natural gas price assumptions are presented in Table 5 below. The forecast average Dawn/Union hub natural gas market price for the RPP Period (the twelve months beginning May 2018) is C$3.30/MMBtu, and the forecast effective price, including the impact of GHG allowance prices, is C$4.33/MMBtu. The forecast average market price over the entire 18-month period is C$3.14/MMBtu, and the forecast effective price is C$4.19/MMBtu. The twelve-month forecast was used in the *Regulated Price Plan Supply Cost Report May 1, 2018 to April 30, 2019* to calculate the GA Modifier and what RPP prices would have been effective May 1, 2018, if determined by the OEB in the normal course and without taking into account any forecasted impact of the OFHP Act.

[2] Ontario Ministry of Energy, *Default Emission Factors for 2018 for Ontario's Cap & Trade Program* (http://www.energy.gov.on.ca/en/ontarios-electricity-system/climate-change/default-emission-factors-for-2018-for-ontarios-cap-trade-program/), Section 2.2.3.

Table 5: Natural Gas and GHG Allowance Price Forecasts

Term	Month	Forward Price @ Dawn Hub US$/MMBtu	Forward Price @ Dawn Hub C$/MMBtu	GHG Allowance Price C$/tonne	Effective Gas Price C$/MMBtu
RPP Period	May 2018	$2.47	$3.17	$18.44	**$4.17**
	Jun 2018	$2.47	$3.16	$18.44	**$4.16**
	Jul 2018	$2.46	$3.14	$18.44	**$4.14**
	Aug 2018	$2.47	$3.14	$18.44	**$4.14**
	Sep 2018	$2.46	$3.11	$18.44	**$4.11**
	Oct 2018	$2.45	$3.08	$18.44	**$4.08**
	Nov 2018	$2.57	$3.23	$18.44	**$4.23**
	Dec 2018	$2.84	$3.56	$18.44	**$4.56**
	Jan 2019	$3.04	$3.79	$20.00	**$4.87**
	Feb 2019	$3.01	$3.74	$20.00	**$4.82**
	Mar 2019	$2.86	$3.55	$20.00	**$4.63**
	Apr 2019	$2.40	$2.97	$20.00	**$4.05**
	Average	$2.62	$3.30	$18.95	**$4.33**
Other	**May 2019**	$2.30	$2.85	$20.00	**$3.93**
	Jun 2019	$2.32	$2.87	$20.00	**$3.95**
	Jul 2019	$2.30	$2.84	$20.00	**$3.92**
	Aug 2019	$2.28	$2.80	$20.00	**$3.88**
	Sep 2019	$2.28	$2.80	$20.00	**$3.88**
	Oct 2019	$2.29	$2.81	$20.00	**$3.89**
	Average	$2.30	$2.83	$20.00	**$3.91**

Source: S&P Global Market Intelligence, Power Advisory

4. REVIEW OF FORECAST RESULTS

The results of Power Advisory's base case market price forecast are shown in Table 6. Consistent with previous editions of this report to the OEB, these prices are presented as simple averages, with high-demand and low-demand hours having equal weight.

The forecast prices show a distinct seasonal pattern (higher in summer and winter, lower in spring and fall) which reflects Ontario's load shape, typical hydroelectric generation output profiles, and the timing of maintenance outages. Electricity demand in Ontario tends to be higher in summer (due to air conditioning) and in winter (due to heating) than in spring and fall. Hydroelectric generation tends to be highest in May and June due to the downstream effects of snowmelt (called the spring freshet). Maintenance outages, particularly at nuclear and thermal generation facilities, are most often scheduled in the shoulder seasons. The effect of these planned outages is to mitigate the downward price impact of reduced load in the shoulder seasons and increased hydroelectric generation in the spring.

Table 6: HOEP Forecast (C$/MWh)

Term	Quarter	Calendar Period	On-Peak	Off-Peak	Average
RPP Period	Q1	May 2018 - Jul 2018	$23.32	$11.31	$16.83
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1) Assumes natural gas prices that reflect the exchange rate forecast reported in the Bank of Montreal's "Canadian Economic Outlook" issued April 6, 2018. For the May 2018 to October 2019 HOEP forecast period the average exchange rate is US$1 = C$1.25.

2) On-peak hours are between 7 a.m. and 11 p.m. Eastern Standard Time (EST) on non-holiday weekdays. Off-peak hours are all other hours (weekends, holidays, and overnight). The times for the calculation of on-peak and off-peak hours are not adjusted for Daylight Savings Time (DST).

Power Advisory's forecast is based on a set of assumptions related to supply and demand that have been derived from best available information. Although Power Advisory has taken great care to ensure the forecast is sound, by their nature forecasts are uncertain and cannot be guaranteed.