Review of wholesale component of Victorian Default Market Offer

prepared for:
GloBird

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Executive Summary

Oakley Greenwood (OGW) has been asked by the energy retailer, GloBird, to comment on a number of specific aspects of Frontier Economics' (Frontier) approach to determining the allowances for the wholesale electricity costs (WEC) for CY2020 that are used by the Essential Services Commission (ESC) to determine the Victorian Default Market Offer (VDO).

The specific aspects that we have been asked to advise GloBird on are:

- The appropriateness of the approach adopted by Frontier to derive the CY2020 load profile, and in particular, whether the load profile should be weather corrected;
- Whether it is appropriate for Frontier to use a median outcome to inform the WEC analysis; and
- Whether Frontier's approach to converting its forecast half-hourly spot prices and load into a WEC is reasonable.

Our key findings are:

- Frontier's approach of randomly sampling demand outcomes from only three historical years of data is unlikely to pick up the natural variations in temperature (and their timings and durations) that would be expected to occur in the future, and which in turn would be expected to impact the demand for electricity and in turn the costs that an efficient retailer would incur in procuring electricity from the market to serve residential and small commercial customers. A high-level analysis of historical temperature data highlights this potential issue. We believe that a better approach (and one that would help to alleviate what we think are the very valid concerns of many retailers such as GloBird) would be to determine the statistical correlation between underlying energy consumption over the three year sample frame (or potentially even over only two years), and temperature (taking into account weekday/weekend and public holiday factors). From there, a similar Monte Carlo analytical technique could be adopted, except that rather than repeatedly sampling final demand from the sample years to create the distribution (which is what Frontier currently do), the approach would be to sample the historical weather records that are related to the time of year/day etc that is being simulated, with final demand being calculated (as opposed to be drawn from history) based on the correlation between demand and temperature (and having regard to other explanatory variables such as day or week). This approach:
  - Utilises the most up-to-date relationship (correlation) between demand and weather, whilst
  - Allowing the simulated load profile that is developed to be genuinely probabilistic, because it samples from the entire temperature history rather than implicitly assuming that the last three years of weather, as well as the timing of when that weather occurs – e.g., weekends V weekdays - is reflective of the full range of outcome.
- Conceptually, it is not clear to us why Frontier utilises a median outcome, instead of calculating and using the "expected value" across all of their modelled outcomes to determine the WEC. For the purposes of this particular exercise, it would appear to us to be more appropriate to calculate what the retailer expects to pay, on average, over all of the modelled simulations, rather than the mid-point of what the retailer would pay under the modelled simulations. To the extent that outcomes are not normally distributed, the median will differ (potentially materially) to the expected value. Moreover, the figures published by Frontier in their report indicate, on face value, that the proposed WECs are less than the expected value.

- Frontier's approach relies on sampling historical spot price data (at the same time as demand) "*so that the correlation between load and prices is maintained*[1]". The problem that we see with this approach is that the correlation between load and price will not actually be the same in the future as compared to the past. In particular, there have been significant changes in the market over that period that mean that this historical relationship will not hold. In particular, FY2016/17 data includes the impact that Hazelwood power station would have had on bidding behaviour up until its shutdown in March 2017 (this is despite Frontier stating that "*the closure of coal-fired power stations may have substantial impacts on price levels and volatility*[2]"). More generally, the NEM is transitioning towards renewable energy. There has been a significant increase in renewable capacity, both wind and solar PV. It is expected that this trend will continue. We would recommend that either:
  - Some forward-looking price simulation for spot prices in CY2020 be undertaken, rather than just relying on historical prices; or
  - To the extent that the above approach is not able to be adopted, Frontier overlay simulated demands on the most recent bid/offer data for the Victorian region (e.g., 2018/19). The benefit of this is that it utilises the most recent revealed linkage between demand and price, thus excluding factors such as the impact of Hazelwood.
- Caps and peak swaps have significantly lower liquidity than base swaps. Small and standalone retailers may therefore struggle to purchase these products with current expected market prices as stated in Frontier's approach. These would result in higher cap and peak prices than currently expected from the historical traded data from ASXEnergy. Small and standalone retailers could eventually manage to buy these peak swaps and caps to meet their hedging need by moving the market to higher prices. It may be such that there needs to be some price discrimination to small and standalone retailers when considering and assessing the WEC, particularly if these providers are considered to be the marginal providers of electricity services in the market. This can be tested by running sensitivity analyses of the WEC on scenarios of the peak swap and cap prices, based on some observed bid and ask spreads.

1 Frontier Economics, *Wholesale electricity cost for 2020 - Report for the Essential Services Commission*, 16 Sep 2019, page 16

2 Ibid, page 8

1. Background

The Victorian Default Offer (VDO) has been widely recognised as the price cap for all small electricity retail customers in Victoria. Within the VDO, the wholesale electricity cost (WEC) is the major component with approximately 40% of the total electricity bill. It is thus important to calculate this WEC correctly, such that it closely reflects the actual cost an efficient retailer would incur in purchasing electricity in the wholesale electricity market, in order to provide a sustainable market signal for prudent retailers to compete in the retail electricity market.

In calculating the WEC, electricity retailers are assumed to purchase a mix of standard forward contracts such as base and peak swaps, caps and possibly other non-standard contracts and balance the expected load shape of its customers against its aggregated hedging contract position on the wholesale electricity spot market. The WEC is thus the average cost of purchasing electricity from both spot payments to the Australian Energy Market Operator (AEMO) and the financial payouts to and from hedging contracts.

In their approach[3], Frontier Economics ('Frontier') calculates the WEC for calendar year (CY) 2020 based on the following inputs:

- The forward quarterly prices of standard contracts, such as the flat/base swap, peak swap and the flat/base $300 cap, which will affect the wholesale hedging cost;
- The simulated spot prices, which will affect the spot exposure cost and the payout on hedging contracts;
- The forecast customer load; and
- The mix of standard contracts that are used to hedge the load using Frontier's portfolio optimisation model STRIKE.

2. Scope of work

Oakley Greenwood (OGW) has been asked by the energy retailer, GloBird, to comment on a number of specific aspects of Frontier's approach to determining the allowances for the WEC for CY2020.

The specific aspects that we have been asked to advise GloBird on are:

- The appropriateness of the approach adopted by Frontier to derive the CY2020 load profile, and in particular, whether the load profile should be weather corrected;
- Whether it is appropriate for Frontier to use a median outcome to inform the WEC analysis; and
- Whether Frontier's approach to converting its forecast half-hourly spot prices and load into a WEC is reasonable.

3. Caveats

This report only focuses on the components of the WEC that GloBird has asked us to provide an opinion on. We have not been asked to undertake a comprehensive review of Frontier's entire approach to deriving the WEC, nor have we been asked to opine on other aspects of the VDO.

3 Frontier Economics, *Wholesale electricity cost for 2020 - Report for the Essential Services Commission*, 16 Sep 2019

In completing this report, we have primarily relied upon Frontier's published report, *Wholesale electricity cost for 2020 – Report for the Essential Services Commission*, 16 Sep 2019. Whilst at a general level, this report provides a relatively clear outline of Frontier's approach to developing the WEC, there are certain aspects of Frontier's approach that remain unclear. Where this is the case, we have necessarily had to make a number of assumptions regarding Frontier's approach, and in some cases, we have developed opinions based upon (or raised some questions as a result of) reviewing the graphs that Frontier has published in their report.

4. Weather correction

4.1. Our understanding of the Frontier approach

At a general level, it is our understanding that Frontier:

- Randomly draws actual load data (and the accompanying spot price related to that load so that the correlation between load and prices is maintained) from 3 years of historical data (16/17, 17/18 and 18/19) to generate 500 simulated years[4]; and
- From this, they are able to generate a distribution of outcomes which in turn informs subsequent parts of their analysis.

Frontier states that they have "*not forecast load or prices, but merely drawn from recent history*[5]". They also state that "*implicit in this approach is the assumptions that patterns of load and prices for each of these three historical years can provide useful information on potential load and price outcomes for 2020*[6]". Notwithstanding this, Frontier also states that "*ideally, we would have a longer time series of data…If the price and load data for this longer time series were deemed likely to be a reasonable indication of outcomes for the forecast period, then the longer series of data would likely include a broader range of potential market outcomes that could be captured in our Monte Carlo analysis (discussed in Section 3.3)…. However, in our view, the benefit of having more recent data, and load data that better matches the customers to which the VDO will apply, clearly suggests the data directly provided by AEMO is preferable to longer set of publicly available MRIM data*[7]".

4.2. Our comment on the Frontier approach

Energy demand - as all energy industry participants would be aware – is significantly correlated with temperature. Moreover, this correlation differs depending on *when* certain temperature events occur, and for how long. For example, a 40 degree day on the first weekend in February has a different impact on demand as compared to a 40 degree day on the Monday or Tuesday (or any weekday) following that same weekend. Following on from this, a 40 degree day has a different impact on demand if it were to occur during the Xmas or New Year holiday period, as compared to if it were to occur in the middle of December or in February or even early March.

4 This random drawing of data is from a pool of like data – for example, simulated outcomes for Q1 are drawn only from Q1 historical data, not from other quarters.

5 Frontier Economics, *Wholesale electricity cost for 2020 – Report for the Essential Services Commission*, 16 Sep 2019, page 17

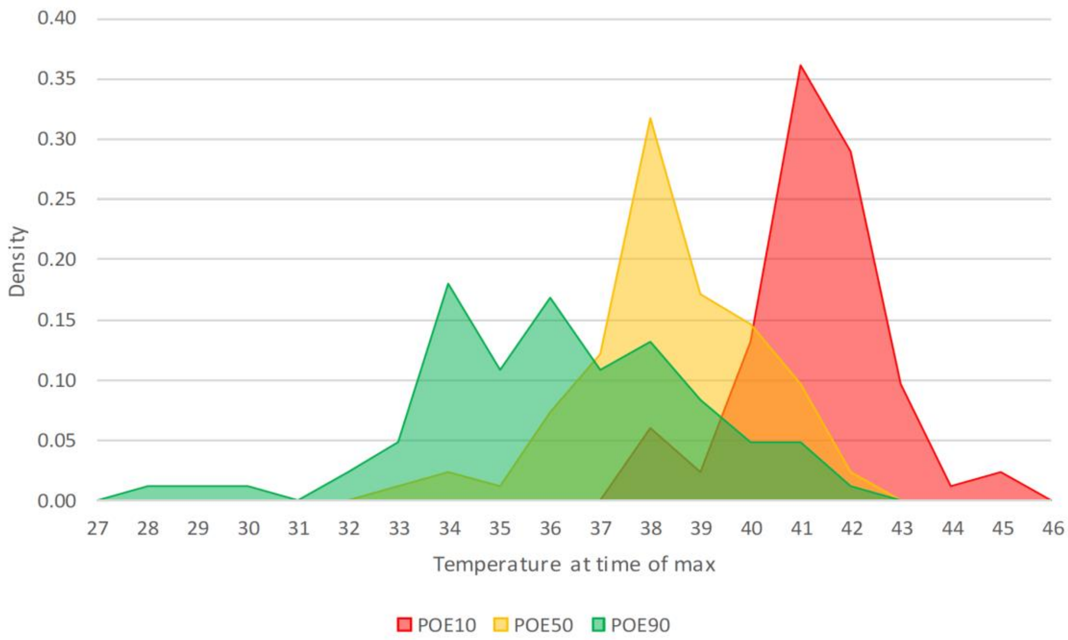
6 Ibid, page 14

7 Ibid, page 8

In their most recent ESOO, AEMO makes numerous statements reflecting the impact that temperature has on demand. For example[8]:

> *"Changing consumer behaviours around cooling preferences, combined with increasing maximum temperatures in summer, put upward pressure on demand on very hot days"*
>
> *"AEMO splits consumption into heating, cooling, and baseload (not temperature sensitive) consumption. Cooling consumption is relatively small on an annual level, but contributes significantly to demand on extreme hot days, which typically drive maximum demand events in the mainland regions"*
>
> *"Maximum demand can occur due to conditions including high temperature, heatwaves (daily rolling average temperature), and low solar output. In Victoria, simulations indicate a 10% POE maximum demand typically occurs between 38°C to 45°C, 50% POE between 35°C and 43°C, and 90% POE between 31°C and 39°C, as shown in Figure 52. PV generation at time of 10% POE is between 70 MW and 700 MW, whereas generation at time of 50% POE is around 150 MW to 1,000 MW. This is largely governed by the expected time of day maximum demand may occur".*

Figure 1: Distribution of temperature at time of forecast summer maximum demand in Victoria



Source: AEMO, *2019 Electricity Statement of Opportunities*, page 109

Notwithstanding this, the Frontier approach implicitly assumes that:

- The weather in their sample frame of 3 years is reflective of what, probabilistically, should be expected to occur in 2020; and
- The timing (e.g., day of week, time of year) of when those weather events occur is reflective of what, probabilistically, should be expected to occur in 2020.

8 AEMO, *2019 Electricity Statement of Opportunities*, pages 28, 57 and 108

Conceptually, relying on only three years of data is an inadequate dataset upon which to rely on to pick up the natural variations in temperature (and their timings and durations) that would be expected to occur in the future, and which in turn would be expected to impact the demand for electricity and in turn the cost that an efficient retailer would incur in procuring electricity from the market to serve residential and small commercial customers. If the impact of low probability, high consequence temperature events is not captured in the modelling of the WEC, an efficient retailer will be underfunded, which in theory, leaves them commercially unviable.

A high level analysis[9] of the historical data highlights how high temperature events have varied historically, and as reference, the (high) temperatures that affected the sample frame relied upon by Frontier.

Table 1: Number of half-hours where temperature was above 40 degrees (ex. holiday periods)

Year	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
2004	0	0	0	0	3	6	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	1	15
2007	0	1	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	14	16	11	11	0
2010	11	0	0	0	0	0	0
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	4	1	0	0
2014	0	19	5	12	9	9	1
2015	0	0	0	0	0	10	0
2016	0	3	9	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	7	0	0
2019	0	0	0	8	8	0	0
TOTAL	11	23	28	40	39	37	16

Source: OGW analysis of historical temperatures at Melbourne Airport Weather Station (derived from NEO, a third party data aggregation product).

9 Due to time constraints, we have only focused on high temperature events in this report. This is not to say that other types of temperature outcomes (e.g., low temperature events in winter) are not also correlated with electricity demand.

The average number of half-hourly periods equalling or exceeding 40 degrees across the entire sample on weekdays that are not in holiday periods[10] is 8.81 per annum. The average over the last three CY years (which equates to those that would have fallen in the last three FYs) is around 13% lower, at 7.66 per annum. Moreover, the outturn impact on demand of these high temperature events in 2019 would have been muted, due to occurrence of load shedding (discussed in more detail below).

If we undertake the same analysis, except we only focus on 40-degree half hourly intervals in the mid to late afternoon[11] (when the highest demands are generally placed on the system), we find that there are on average 4.75 half-hourly periods a year in the sample, but only 3.66 in the last three years (or around 23% less).

Notwithstanding the above, it is clear that the events of 2009 have a significant influence on the number of events contained in the historical data. Whilst this clearly impacts on the final results of any such analysis, it also highlights the volatility in the types of weather outcomes that can occur, and, to the extent that these low probability, high consequence events (years) are not incorporated, probabilistically, into the analysis, then retailers will not be compensated for those types of low probability weather events.

In our opinion, a better approach (and one that would help to alleviate what we think are the very valid concerns of many retailers such as GloBird) would be to determine the statistical correlation between *underlying*[12] *energy consumption* over the three year sample frame (or potentially even over only two years), and *temperature*[13] (taking into account weekday/weekend and public holiday factors). This should be done separately for residential customers with annual consumption less than 40MWh, and business customers with annual consumption less than 40MWh.

From there, a similar Monte Carlo analytical technique could be adopted, except that rather than repeatedly sampling final demand from the sample years to create the distribution (which is what Frontier currently do), the approach would be to sample the historical weather records that are related to the time of year/day etc that is being simulated, with final demand being calculated (as opposed to be drawn from history) based on the correlation between demand and temperature (and having regard to other explanatory variables such as day or week). Sampling of the regression error should also be undertaken and included in the final, calculated, demand.

This approach:

- Utilises the most up-to-date relationship (correlation) between demand and weather, whilst
- Allowing the simulated load profile that is developed to be genuinely probabilistic, because it samples from the entire temperature history rather than implicitly assuming that the last three years of weather, as well as the timing of when that weather occurs – e.g., weekends V weekdays - is reflective of the full range of outcome.

10 Given the focus of this analysis was on hot days, we defined a holiday period as being between the 22nd of December, and the 7th of January, as well as Australia Day.

11 2.30pm to 7pm.

12 That is, overall energy consumption, including that procured from centralised generation plus the amount of energy that is assumed to have been consumed from decentralised, or behind-the-meter PV generation (see below).

13 After making allowances for the impact of load shedding.

Moreover, this approach would address Frontier Economics' comment that "*ideally, we would have a longer time series of data……….then the longer series of data would likely include a broader range of potential market outcomes that could be captured in our Monte Carlo analysis".* By choosing a longer time series of weather data, whilst utilising current demand / weather correlations, this approach satisfies this requirement without also compromising the analysis by bringing in historical correlations between weather and temperature (which may no longer be of relevance). Our alternate approach also aligns with Frontier's underlying requirement that the '*load data should match the customers to which the VDO will apply*' (which we agree with).

A number of other related comments on the Frontier approach include:

- **PV output:** Frontier's approach implicitly assumes that the output of behind-the-meter PV systems in the 3-year sample period is what is expected to occur (in a probabilistic sense) in CY2020. Given the small sample frame, we challenge this assumption. We believe a better approach would be to add-back into historical demand outcomes, the estimated actual production of the PV systems that were in place in those sample years[14]. Once this is done, historical PV production as a percentage of system capacity could be randomly sampled (with this based on the "types" of days being simulated, including the randomly sampled temperature), and then added back into the demand forecast for 2020 based on the expected number of systems in 2020 (which is discussed further below);

14 AEMO calculates this for different weather stations across Victoria.

- **Impact of new PV:** Related to the previous point, Frontier's approach implicitly assumes that there is no change in the amount of PV capacity that is expected to be installed in 2020, despite stating that "*the increasing adoption of rooftop solar PV is likely to materially affect load factors over time*[15]". In justifying this approach, they state that "*while there is some indication that load in the middle of the day is falling slightly – likely as a result or increased solar PV generation – the effect does not appear to be significant. Our assessment suggests that under current market conditions, these changes in load (and, more broadly, the effect that solar PV has on load) would not have a material impact on our estimate of WEC. However, this will need to be monitored*[16]". Firstly, given no quantitative analysis has been presented in the report to this effect, it is difficult to assess the merit of this statement. That said, it would appear to conflict with other publicly available information, that indicates that Victoria will see in the order of 70,000 new PV systems come on board next calendar year[17], which will be in addition to the around 35,000 that are expected to be added between July and December 2019, which in total, would see in the order of 500MW of new behind-the-meter PV capacity having being installed by December of 2020. In addition, by sampling from the last three years of actual data, 1/3 of the data points Frontier is sampling and bringing into its Monte Carlo simulation come from 2016/17, which, by our calculations, contains around half of the behind-the-meter PV capacity that are likely to be installed by the end of 2020[18]. The following figure illustrates that there has been around a 70% increase in output from PV systems between January 2017 and January 2019 – clearly, this will significantly increase again in CY2020 as additional PV systems are installed. For context, in its 2019 ESOO, AEMO forecasts that in Victoria, production from rooftop PV will be of an amount that is equivalent to 5.8% of all operational (sent-out) energy in 2020[19]. The approach that we outlined in the previous dot point would overcome this issue, as it would forecast PV output for CY2020 having regard to the forecast number of PV installations in CY2020 (along with a probabilistic estimate of the output of each system), rather than simply relying on historical PV output.

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15 Frontier Economics, *Wholesale electricity cost for 2020 - Report for the Essential Services Commission*, 16 Sep 2019, page 8

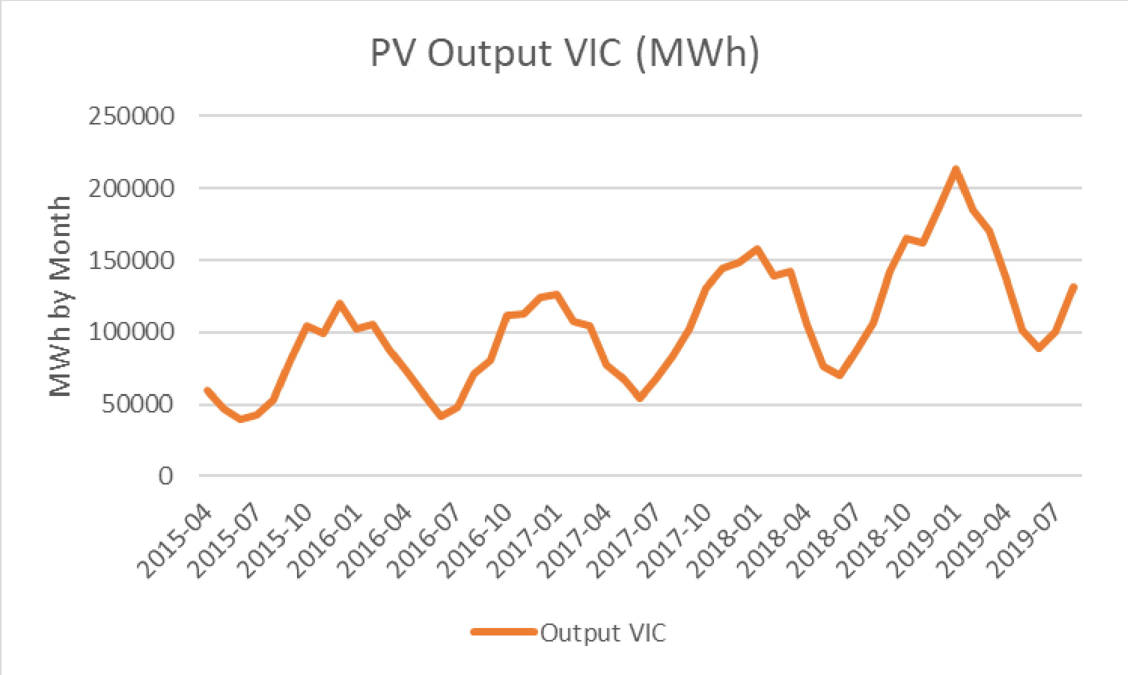
16 Ibid, page 15

17 https://www.solar.vic.gov.au/solar-panel-rebate

18 This is based on a comparison of AEMO 2018 ESOO information, which indicated around 1250MW of installed PV capacity in Victoria in 2017, to AEMO's 2019 ESOO, which indicates that AEMO forecasts around 2200MW of PV to be installed under their central case in 2020.

19 http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational

Figure 2: Monthly PV Output (MWh)



Source: OGW analysis based on data from APVI website (https://pv-map.apvi.org.au/analyses)

- **Load shedding:** AEMO states that on "*24 and 25 January 2019, the equivalent of approximately 375,000 households were without power for an hour in Victoria and South Australia, due to a combination of factors including extreme temperatures causing high demands and significant levels of unavailable thermal capacity. This load shedding was despite the activation of all available RERT resources that were procured last summer*[20]". Based on reviewing another report, it appears that whilst much of the load shed on the 24th was from the Alcoa Portland aluminium smelter in Victoria, this was not the case on the 25th. Frontier does not appear to mention this issue in its report. As such, we assume that Frontier has not made any adjustment to its analysis for the impact that this load shedding might have had on the amount of energy consumed by residential and small commercial customers under those types of conditions. If so, Frontier's analysis implicitly assumes that if such conditions were to occur in 2020 (i.e., high temperatures driving the "high demand" referred to by AEMO), load shedding would also occur in order to balance supply and demand. That is, lower overall demand would be placed on the system relative to if no load shedding were to occur. We would have thought that the starting point for any modelling of the WEC should be that retailers will have to serve their load, rather than relying on load shedding in order to balance supply and demand during certain types of conditions.

20 AEMO, *2019 Electricity Statement of Opportunities*, August 2019, page 72

5. Use of the median outcome

5.1. Our understanding of the Frontier approach

It is our understanding that the WECs that Frontier have estimated for each distribution region are based on half-hourly spot prices and load from the *median* simulated year (when these years are ranked according to load-weighted price).

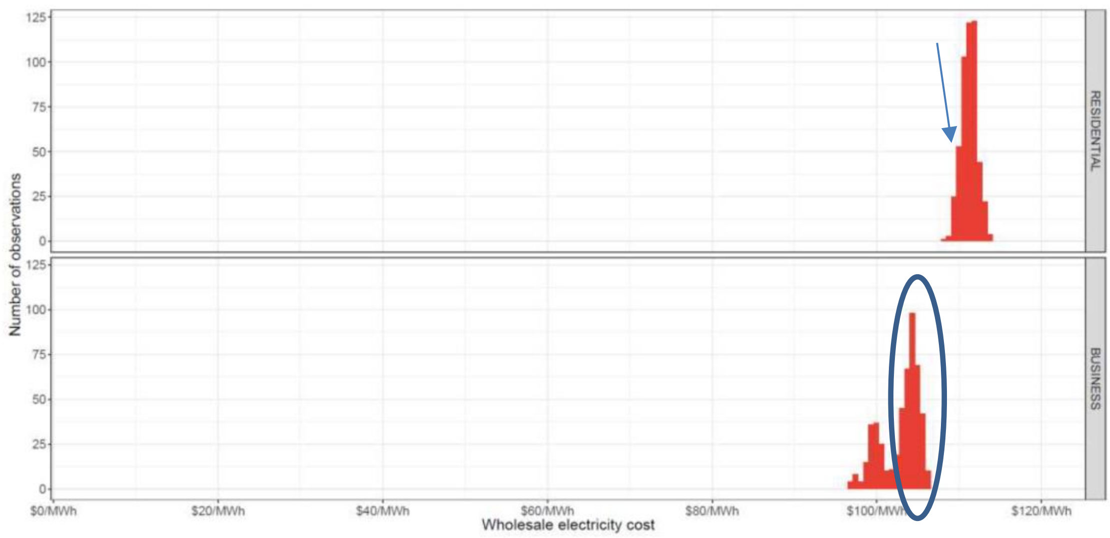
In addition, it appears that Frontier's calculation of its volatility allowance is also related to this assumption. In particular, Frontier state that the volatility allowance, which "*is intended to compensate retailers for the residual risk to which they are exposed, even when contracted at the conservative point*[21]", is calculated based on "*the cost of holding working capital to fund cashflow shortfalls that could arise in years when the actual WEC is higher than we have estimated for the median simulated year. The working capital requirement is based on the difference between the WEC that we have estimated for the median simulated year and the WEC for the most costly simulated year for each distribution area*[22]".

5.2. Our comment on the Frontier approach

Conceptually, it is not clear to us why Frontier utilises a median outcome, instead of calculating and using the "expected value" across all of their modelled outcomes. For the purposes of this particular exercise, it would appear to us to be more appropriate to calculate what the retailer expects to pay, on average, over all of the modelled simulations, rather than the mid-point of what the retailer would pay under the modelled simulations. To the extent that outcomes are not normally distributed, the median will differ (potentially materially) to the expected value.

Whilst it is difficult to draw any definitive conclusions from the information presented in the Frontier report as to the magnitude of this issue, prima facie, the graphs presented in the report appear to indicate that the issue is real. For example, the following figure is an extract from Frontier's report. It represents the "AusNet load wholesale electricity cost distribution".

Figure 3: AusNet load wholesale electricity cost distribution



21 Frontier Economics, *Wholesale electricity cost for 2020 - Report for the Essential Services Commission*, 16 Sep 2019, page 47

22 Ibid

Source: Frontier Economics, *Wholesale electricity cost for 2020 - Report for the Essential Services Commission,* 16 Sep 2019, page 44

In comparison to the above distributions, in Table 2 of its report, Frontier states that the wholesale electricity costs related to residential customers in AusNet's area are $108.95/MWh. Whilst again, we reiterate that it is difficult to draw definitive conclusions from the graphical information presented, it appears that $108.95/MWh is clearly below (see arrow in the above extract) what the average cost would be based on the data presented in the graph for residential customers, given that the three most frequent observations are all at or above $110/MWh. Similarly, for business customers, Frontier's published figure is $102.75/MWh, yet it would appear that the majority of modelled observations (circled in the above extract) are above this figure.

In saying this, we would also note Frontier's pertinent observation that "*these distributions do not reflect the distribution of all possible outcomes that retailers could face. If patterns of spot prices or load are materially different from the historical period on which we based our Monte Carlo analysis, or if average spot prices were too much different from suggested by current ASXEnergy contract prices, the wholesale energy cost could fall outside the range implied by these distributions*[23]". Based on our observations in the earlier section of this report, we believe this may well be the case.

On a related point, Frontier's inclusion of a working capital requirement implies to us that the distribution of potential WEC outcomes *is not* normally distributed around the mean. In particular, it is not clear what the rationale is for providing a working capital allowance to a retailer *if* WEC outcomes were distributed normally around the mean (and hence the mean equalled the median). This is because the expected value of the downside risk would presumably equate to the expected value of the upside risk. Following on from this, Frontier's approach implies to us that the inclusion of a "working capital" allowance for what we would term to be the downside risk (of the estimated WEC for the median simulated year being less than the estimated WEC for the most costly simulated year) is required because there is no equivalent offsetting upside risk (where the estimated WEC is greater than the least costly simulated year).

From a practical perspective, if Frontier's working capital adjustment does in fact reflect its underlying assessment of the asymmetric risk faced by retailers regarding WECs, it is not clear how Frontier's use of the median outcome compensates retailers for the actual underlying (energy purchase) cost of this risk, noting that providing a "working capital" allowance is not in and of itself, compensating the business for the underlying cost of bearing that risk (only the financing costs).

6. Wholesale price analysis

6.1. Our understanding of the Frontier approach

As stated earlier, our understanding is that Frontier uses Monte Carlo simulations to generate future spot prices in CY2020. 500 yearly paths for every half-hour spot price in CY2020 are randomly drawn from similar characteristic days from 3 historical years (FY2016/17, FY2017/18 and FY2018/19). Each price path is then adjusted such that the average quarterly spot prices matches with the quarterly base swap prices for 2020 from ASXEnergy, less an assumed contract premium of 5 per cent on the underlying average prices.

23 Frontier Economics, *Wholesale electricity cost for 2020 - Report for the Essential Services Commission*, 16 Sep 2019, page 41

In this simulation, the 40-day average of ASXEnergy contract prices for quarterly base swap prices (up to 16 August 2019), rather than the 12-month trade weighted average ones, are used to represent the market's current view of spot prices for each quarter of 2020. As a result, there will be 500 yearly price paths with the same average quarterly prices, but with variance/volatility drawn from historical profiles.

Following on from that, it is our understanding that Frontier assumes that a retailer will only purchase standard contracts such as flat/base swap, peak swap and flat/base $300 cap to hedge their load. The forward quarterly prices of those standard contracts are derived from ASXenergy data. The price for each type of contract is the 12-month trade weighted contract price, that is the average of the daily settlement price for that contract over the last 12 months, but weighting each daily settlement price by the share of the total volume of trade over the last 12 months that happened on that day. In this way, the trading days that have high traded volume will have more weighting in the average price and vice versa, days with zero or low volume will have zero or low weighting.

6.2. Our comment on the Frontier approach

6.2.1. Derivation of spot prices

As outlined earlier, Frontier's approach relies on sampling historical demand, and in doing so, they also draw spot price data at the same time (i.e., from the same historical day) "*so that the correlation between load and prices is maintained*[24]". The problem that we see with this approach is that the correlation between load and price will not actually be the same in the future as compared to the past. In particular, there have been significant changes in the market over that period that mean that this historical relationship will not hold. In particular, FY2016/17 data includes the impact that Hazelwood power station would have had on bidding behaviour up until its shutdown in March 2017 (this is despite Frontier stating that "*the closure of coal-fired power stations may have substantial impacts on price levels and volatility*[25]"). More generally, the NEM is transitioning towards renewable energy. [26] There has been a significant increase in renewable capacity, both wind and solar PV. It is expected that this trend will continue.

Overall, this trend has the tendency to lower the load factor of the regional demand as well as the small customer loads to make it peakier for dispatchable generators. This is because the renewable generation tends to lower the total net energy but does not necessarily reduce the overall maximum peak demand that usually occurs in the evening. While the historical price profile might reflect some degree of interaction between regional demand and strategic bidding behavior of participants, the future regional demand structure with lower load factor would influence the strategic bidding of current market participants and would significantly change the profile of the spot prices in the future years, including 2020. To illustrate this, we have analysed the Victorian spot price duration curves over 3 financial years FY16/17, FY17/18 and FY18/19. It can be observed that:

- The spot price volatility above $300 has increased in both duration and magnitude - Figure 4. This is likely to be mainly due to the tight supply and demand balance due to the shut-down of Hazelwood power station in the end of March 2017.

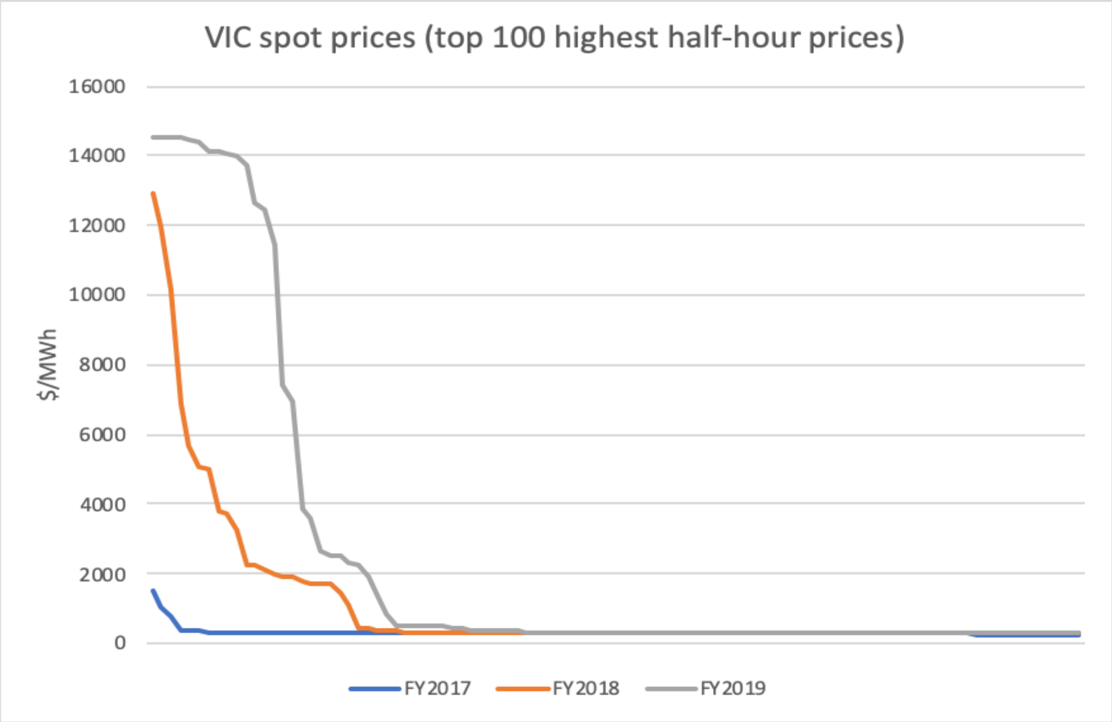
24 Frontier Economics, *Wholesale electricity cost for 2020 - Report for the Essential Services Commission*, 16 Sep 2019, page 16

25 Ibid, page 8

26 AER, 2018, *State of the Energy Market,* 2018

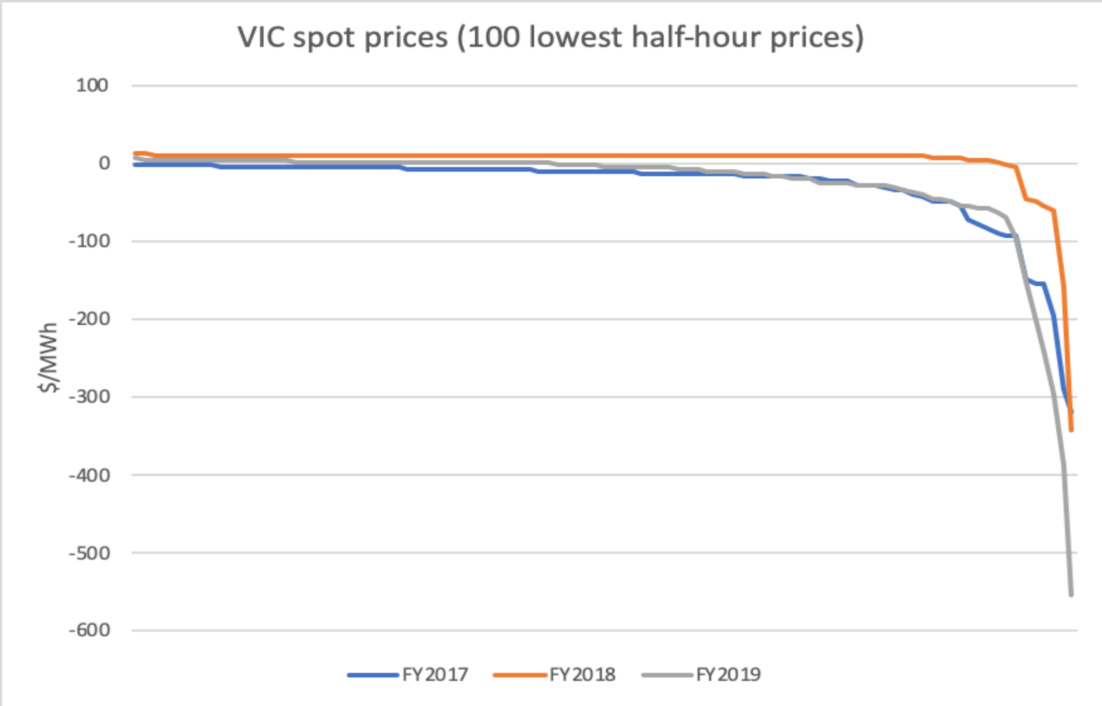
- FY 18/19 experienced significant low and negative prices, as can be seen in Figure 5. This is mainly due to the impact of significant renewable energy generation across the NEM, particularly in VIC and SA.
- There were more prices occurring between \$100 and \$300 in FY 18/19 as compared to those of previous years, as can be seen in Figure 6 . This may be related to strategic spot bidding: time constraints have limited our ability to investigate this area further.
- Obviously, there have been significantly increases in average price in Victoria region over the years, \$66.6, \$92.3 and \$109.8/MWh in FY 16/17, FY 17/18 and FY 18/19 respectively.

Figure 4: Victorian spot prices (top 100 half hours)



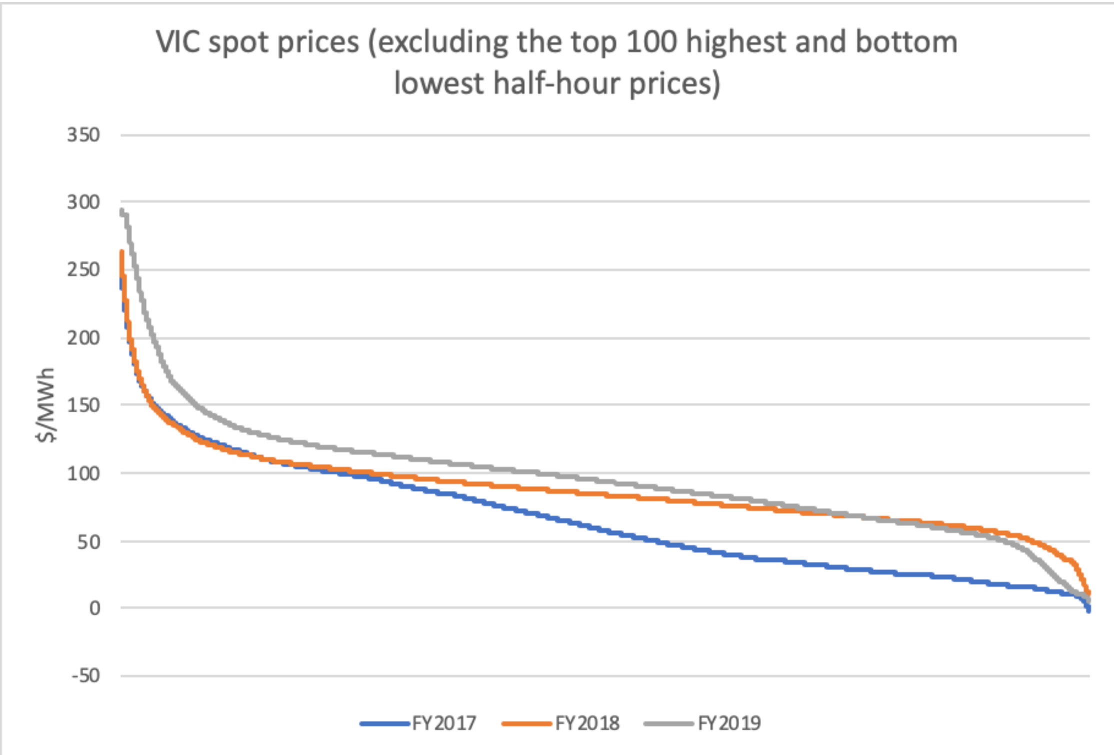
Source: OGW analysis

Figure 5: Victorian spot prices (lowest 100 half hours)



Source: OGW analysis

Figure 6: VIC spot prices excluding the 100 highest and 100 lowest prices



Source: OGW analysis

Therefore, it would more closely reflect the reality if there were some forward-looking price simulation for spot prices in CY2020, rather than just relying on historical prices.

To the extent that this approach is not able to be adopted, we believe that an alternate approach to undertaking the task of calculating the WEC would be to overlay simulated demands (using the approach outlined in earlier sections of this report, namely one that relies on randomly selecting historical temperature and PV outcomes to drive outturn demand[27]) on the most recent bid/offer data for the Victorian region (e.g., 2018/19). The benefit of this is that it utilises the most recent revealed linkage between demand and price, thus excluding factors such as the impact of Hazelwood.

6.2.2. Contract purchases

Frontier's underlying assumption that a retailer will only purchase standard contracts such as flat/base swap, peak swap and flat/base $300 cap to hedge their load, with these derived from forward quarterly prices of those standard contracts are derived from ASXenergy data, is reasonable.

In particular, it is based on a reliable market reference price and reflects the fact that a prudent retailer hedges their load over time and hence diversifies the price risk over most recent 12 months. However, we would note that small and standalone retailers might find it hard to purchase peak and cap contracts. In particular, forward contract liquidity is not high for a number of reasons which impact different types of contracts differently.

Firstly, as a result of vertical integration, 'gentailers' can internally hedge against price risk in the wholesale market, reducing their need for hedging from contract markets[28]. Secondly, the increased penetration of variable renewable energy might partly contribute to the low liquidity, which has declined over time (ASX and OTC). Intermittent and weather dependent renewable generation is not able to provide the firmness for contract trading unless they are firmed by storage, hydro or gas plants. While some firming products have been offered by some market participants with flexible generation capacity, for example, ERM/TFS with a solar firming product and AGL with a similar wind firming product,[29] to our knowledge, there has not been any report saying that this firming market is particularly active.

This reduced liquidity has a negative impact, creating a potential barrier to entry and expansion for generators and retailers that are not vertically integrated, particularly for small and standalone retailers. The ACCC, in its recent inquiry, found that larger, vertically integrated retailers could access cheaper wholesale electricity compared to smaller retailers.[30] In addition, the ACCC identified small or new retailers as having significantly fewer trade options available in accessing hedging contract products in both ASX and OTC.

This overall observation is true in the Victorian market, which has extensive vertical integration and a high level of penetration of renewable energy. Small and standalone retailers in Victoria might find it hard to access hedging products to effectively hedge the wholesale risks.

27 With any other unmodelled demand (e.g., industrial loads) added on to create a total demand forecast.

28 AER, 2018, *State of the Energy Market,* 2018

29 AER, 2018, *State of the Energy Market*, 2018

30 ACCC, *Retail Electricity Pricing Inquiry - Final Report*, July 2018, pp. 111-113

Despite the lower overall liquidity, the market for flat/base swap may be liquid enough for small retailers to buy. This is evident through the large trading volumes shown in reports published on the websites of the AER, ASXEnergy and reflected in figure 15 of Frontier's report.[31] It is thus reasonable to apply Frontier's approach for base/flat swap component of a contract portfolio.

However, caps and peak swaps have significantly lower liquidity than base swaps. Figure 16 of the Frontier's report[32] shows thinner trading volumes for those contract types. Small and standalone retailers may therefore struggle to purchase these products with current expected market prices as stated in Frontier's approach, because of the following:

- The lower load factor of regional demand and customer load profile due to increasing penetration of renewable energy, particularly solar PV, would create higher demand for peak swap and cap contracts (while reducing the need for flat/base swap); and
- The tight supply-demand balance in VIC and SA, particularly summer 2020.[33]

These would result in higher cap and peak prices than currently expected from the historical traded data from ASXEnergy. Small and standalone retailers could eventually manage to buy these peak swaps and caps to meet their hedging need by moving the market to higher prices.

It may be such that there needs to be some price discrimination to small and standalone retailers when considering and assessing the WEC, particularly if these providers are considered to be the marginal providers of electricity services in the market. This can be tested by running sensitivity analyses of the WEC on scenarios of the peak swap and cap prices, based on some observed bid and ask spreads.

31 Frontier Economics, *Wholesale electricity cost for 2020 - Report for the Essential Services Commission*, 16 Sep 2019, page 25

32 Frontier Economics, *Wholesale electricity cost for 2020 - Report for the Essential Services Commission*, 16 Sep 2019, pages 26-27

33 AEMO, *2019 Electricity statement of opportunities*, August 2019