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Victorian Default Offer

Having studied the Draft Advice (8 March 2019) on the Victorian Default Offer, in particular the determination of the wholesale electricity costs component, Flukes Value Management is moved to take the opportunity to provide this submission.

Flukes Value Management is represented by Darryl Flukes who has been operating in the Victorian wholesale and retail energy markets for over 20 years. A brief resume of this experience, and its relevance to this submission, is attached.

The key points, relating to the wholesale electricity cost component of the VDO price, requiring further deep consideration are set out below:

1. Period over which Futures Contracts are Purchased

Despite the considerable amount of thought and discussion on this point, this is not actually relevant to the setting of the VDO price - using historic prices to set the future VDO price is fundamentally flawed.

As stated in the Draft Advice: "The VDO price is cost reflective - that is, it reflects the cost a retailer incurs in procuring … electricity."

All electricity is procured from the spot market through AEMO i.e. the expected spot market price is the best reflection of the cost of procuring electricity.

Whether or not, or how, a retailer chooses to manage its risk in procuring from the spot market is not relevant to the underlying cost. i.e. the risk management strategy, including when and how a retailer chooses to enter risk management contracts, is not relevant to the cost of procuring and supplying the customer.

Put another way, the futures market is a risk management tool not a market-place for procurement.

More importantly, any exposure to spot market price risk does not occur until the customer is acquired or re-priced (at the end of contract, say). A retailer is unlikely to enter electricity contracts prior to acquiring a customer (or re-setting its price) as this would only incur a speculative risk. Indeed, it is noted that in the Frontier Economics presentation[1] they state "Our preferred approach is to use the most recent prices … because we think economic decisions will be based on the current market value…".

Further, the Draft Advice states that "a fair price is intended to reflect the price that a loyal customer could expect to pay if this market operated like other normally competitive markets". No "normal" market, especially those in commodities (e.g. petrol), price to their customers based on a price for the last 12 months; rather they price on the cost of procuring the product around the time of (or very shortly prior to) selling the product.

On that basis, **the VDO price should be set based on the prevailing market price**, not a historic price, consistent with the preferred approach of the Commission's adviser Frontier Economics.

An added advantage of taking this approach is that the VDO price can more regularly be set to match prevailing market prices so maintaining a competitive market environment (see 1.2 below).

1.1. Inconsistency with Timing of Pricing for the Feed-in Tariff

The issue with using historic prices is further compounded by the inconsistency between the recommended timing of pricing for the feed-in tariff (and LGCs) and the VDO price, which the Draft Advice struggles to reconcile. If the "feed-in tariff is based on the expected level of wholesale prices at the times when electricity is exported to the grid", then the VDO price should correspondingly be based on the expected level of wholesale prices at the times when electricity if consumed from the grid.

There is no logic that results in there being "necessarily different outcomes" nor for the method used for determining the feed-in tariff (and LGCs) differing from that used to determine the VDO price. A customer's load is directly related to its solar export profiles, indeed this export is an integral part of the net (observed) customer load profile.

The Draft Advice states that the "feed-in tariff is based on a 40-day average because that is the market's current expectation of what prices will be in the future". By the very same logic, this should be the basis of determining the VDO price.

1.2. Consequences of Using Historic Prices to set the VDO Price

It is noted in the Draft Advice that one of the relevant matters is the "degree of, and scope for, competition within the industry, including countervailing market power."

By setting the price below the current, prevailing market price (which, through using the 12month average, will, this year, be the result) this will immediately eliminate competition as smaller and new-entrant retailers will not be able to grow their customer base. All customers will logically move to the VDO and only existing retailers (with existing hedges and/or generation) will be able to operate profitably. A short-term win for customers but, through eliminating the ability for smaller retailers to compete and grow, such competitors will have no incentive to remain. Indeed, if they see no growth prospects, they may choose to profitably unwind any existing hedges and transfer their customers.

[1] Technical Workshop Presentation 21 January 2019 Slide 36

Although the opposite may apply, i.e. competition being possible when the prevailing price is below the VDO price, retailers will not be encouraged to enter or grow knowing that growth will not be able to be sustained in future years when the price will, inevitably, later be set below the prevailing cost.

Consequently, pricing off the previous 12months materially impacts the scope for competition and increases the market power of existing retailers; it is therefore unsurprising that "larger retailers tended to favour longer averaging periods" as the Draft Advice notes.

One of the longer-term consequence of setting the VDO on historic prices is smaller, disruptive retailers no longer entering or competing.

Should the Commission choose not to follow its adviser's preferred approach, then those retailers who have taken the more logical economic decision (to hedge as they acquire customers) should not be disadvantaged. It is therefore only reasonable that all retailers be provided the opportunity to average in their hedging contracts in line with the VDO setting through commencing the VDO on 1 January 2020. This would also align with other existing regulatory timetables.

2. Transparency

The Draft Advice states that it has used an approach that "transparently sets out the costs". There are however a number of cost components that, so far as the Draft Advice provides, cannot be considered transparent:

- <u>Monte Carlo simulation</u>: using a Monte Carlo simulation to determine the VDO price is not transparent nor, for many, easily "understood…familiar and readily applicable" as is required by the set criteria. It is certainly not "reproducible" by anyone other than the adviser that devised the simulation.

  It is therefore strongly recommended that a much simpler formula, based on multiples of observable futures prices, be devised and applied. This will enable all participants to quickly and easily determine the VDO price that would apply in future periods, and be able to plan and manage their commercial operations more effectively (so reducing risk and cost).

- <u>Load Profiles</u>: the Draft Advice states that the load profile from 2012-17 is reasonable to use for 2019-20. It would be helpful to provide the data and analysis to validate this as industry experience is quite the contrary (see Section 4 below).

- <u>Feed-in Tariff</u>: to assist with transparency, can the Commission demonstrate that the modelled day-time price outcomes for VDO pricing are consistent with those used for the feed-in tariff.

- <u>Volatility Allowance</u>: there is little visibility on how this is determined other than reference to "3.5 times the standard deviation of wholesale costs" (see Section 5 below).

- <u>WACC</u>: the WACC used in determining the volatility allowance has not been provided.

3. Contract Premium

It is not appropriate to assume a perpetual contract premium over expected spot prices. Like any risk premium, it can be collected over time but eventually there will be a pay-out.

Indeed, the most recent example (Q119) clearly refutes the assumption: the spot price settled around $165/MWh, yet the contract price averaged ca. $116/MWh over 2018 (a 30% discount) and settled on 31 Dec 18 at ca. $130/MWh (a 21% discount).

Therefore, **any assessment of the expected spot price should be based on the prevailing futures price without any discounting**.

4. Changing Load Profiles

As noted earlier, the Draft Advice states that the load profile from 2012-17 is reasonable to use for 2019-20. Industry experience is quite the contrary with load having changed markedly over the previous 5 years, especially for residential customers due to rooftop solar installations and energy efficiency measures.

With profiles changing so markedly the most recent data is most relevant. Recognising that a longer series of date is generally preferable (to dampen annual variability), this needs to be balanced with the accuracy that the most recent data provides.

Further, to capture fully the demand risk profile that retailers are having to consider in their pricing, it is imperative that Q119 is included. Although arguably a one-in-5-year occurrence, retailers have to consider this potential outcome when pricing customers every year and the **Q119 outcome will most closely reflect the risk and cost analysis for 2019-20**.

5. Wholesale Working Capital Requirement & Volatility allowance

The amount of working capital required for wholesale procurement is straightforward to determine, rather than basing on a statistical estimate ("3.5 times the standard deviation").

It is the prudential support requirement of AEMO plus the cash required to meet an AEMO Call Notice resulting from a stress event. Such a stress event is readily defined by the Market Rules being a CPT event[2] occurring during periods of maximum demand (as occurred in January 2019). All retailers must ensure they carry this amount of liquid capital as failing to meet an AEMO Call Notice within 24 hours will result in immediate market suspension and customers being transferred to the Retailer of Last Resort.

Further, it would be useful to compare the volatility allowance with that used by AEMO in setting its prudential requirements (termed "volatility factor"). Is the Commission able to provide this comparison?

[2] Cumulative Price Threshold event, equivalent to 7½ hours at the Market Price Cap (currently $14,500/MWh) after which the spot price is capped at the Administered Price (currently $300/MWh).

6. Other Wholesale Costs

6.1 Futures Brokerage, Exchange Fees and Margins

The external operating costs of a retailer's risk management operation can be material with brokerage, exchange fees etc.

Further, significant capital is required to support ASX margins.

These costs and capital requirements appear not to have been included.

6.2 Environmental Schemes

Note that the Renewable Power Percentage Small Scale Technology Percentage have been updated since the Draft Advice was written to 18.60% and 21.73% respectively.

I trust these points have been helpful and would be pleased to discuss further.

Yours Faithfully,

Darryl S Flukes
for
Flukes Value Management Pty Ltd

Attachment

Resume: Darryl S Flukes

Darryl was CEO of Infratil Energy Australia while its retail business, Lumo Energy, grew from start-up to over 500,000 customers - a key focus of the role being wholesale energy risk management and procurement.

Prior to this he was GM Energy Trading at Southern (now AGL) Hydro where he developed many of the wholesale trading and risk management techniques now applied in the NEM.

More recently he has been providing energy advisory services specialising in wholesale markets, risk management and renewables; advising many energy retailers in the NEM and overseas. He has held director roles at Powershop and Blue NRG as well as chairing their energy risk management committees.

Further back, he chaired the original Australian Financial Markets Association (AFMA) Electricity Committee, and has held director roles at AFMA and the Energy Retailers Association (ERAA).

He is currently chair of ESCO Pacific (a solar farm developer) and a board member of the Clean Energy Council.