THE GENERATOR OPERATIONS SERIES

Report Three: Negative pricing and bidding behaviour on the NEM

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CONTENTS

Above image: Emu Downs Solar and Wind Farms
Cover image: Broken Hill Solar Plant

EXECUTIVE SUMMARY

In 2016, when the Australian Renewable Energy Agency (ARENA) launched the $100 million Large-scale Solar (LSS) funding round, renewable energy (particularly solar) constituted a very small fraction of the energy mix. At then-current capital cost projections, this small contribution was expected to remain small for some time. Accordingly, oversupply of power during periods of high variable renewable generation, which can lead to negative power pricing, was not considered a major risk for projects. Many offtake agreements at the time were considered very low risk despite requiring projects to "switch off" to avoid generating during negative price intervals.

Today, solar energy (both large-scale and rooftop solar) are significant participants in the energy sector and negative pricing is a major risk for investors in the industry. "Economic curtailment" in response to negative pricing is the largest source of variable renewable energy (VRE) curtailment, accounting for 58 per cent of the total [1].

Generator bidding behaviour is becoming increasingly complex. The need to avoid negative pricing, abide by contractual obligations, ensure compliant bidding, minimise curtailment and reduce FCAS costs has led to over 35 per cent of solar and wind farms utilising automated bidding software in the last 2 years. "Rebidding" from generators, where volumes of energy are shifted across fixed price bands post "Gate Closure", has substantially increased as the frequency of negative pricing intervals increase. Generators are increasingly becoming active, rather than passive, market participants, to avoid being dispatched during negative pricing intervals.

An efficient market would see generators always bidding at their short run marginal cost (SRMC). However, this is hampered by;

1. The cost and complexity of dynamic bidding solutions – the SRMC can vary over time, especially for generators with variable fuel input costs (e.g., gas, coal), and to a lesser extent, an opportunity cost with storage.
2. Disorderly bidding (spatial dilution of pricing) - during congested periods, generators may choose to bid below their SRMC to ensure being dispatched ahead of neighbouring generators with the expectation that the Regional Reference Price (RRP) will settle above their SRMC (the bid price and marginal loss factor becomes the deciding factor when prioritising the order of who is dispatched, where the generator with the higher MLF is prioritised).
3. 30-minute settlement requirements (temporal dilution of pricing) - incentives to generate during a negative 5-minute interval because it is expected the 30-minute interval to settle above a generator's SRMC.
4. Contract structures (e.g. generation-following contract-for-difference contracts) that insulate generators from wholesale market price exposure.
5. Possible market power issues – when generators believe they can set the market price.

This study explores bidding practices for semi-scheduled generators and tracks the trend towards more dynamic bidding strategies, with a focus on bidding behaviour during negative price intervals. It analysed four years of the Australian Energy Market Operator's AEMO[1] data to provide a detailed picture of negative pricing in the NEM over time, and across the states. It then analysed the bidding behaviour of all solar and wind farms on the NEM to understand how they're responding to the new risk of negative pricing events. It defines three categories of bidding behaviour and discusses, in detail, the implications and limitations of such strategies. It also proposes rationale for how each generator's type, location and age influence their choice of bidding strategy.

This analysis helps to understand some of the impacts a higher share of renewable generation has had on energy markets and the behaviour of market participants.

1 Data covers periods from July 2016 to June 2021

NEGATIVE PRICING

Negative pricing events across the NEM have been increasing in recent years. There were three times as many negative pricing events across the NEM in 2020 compared with 2016 and over 40 per cent of these occurred from October to December [3]. This trend has continued into 2021. In South Australia, from December 2020 through February 2021, negative pricing occurred in over 20 per cent of trading intervals[2]. NEM-wide, the month of April saw negative prices more than 7 per cent of the time [2]. Figure 1 demonstrates these trends occurring across each NEM region since 2016.

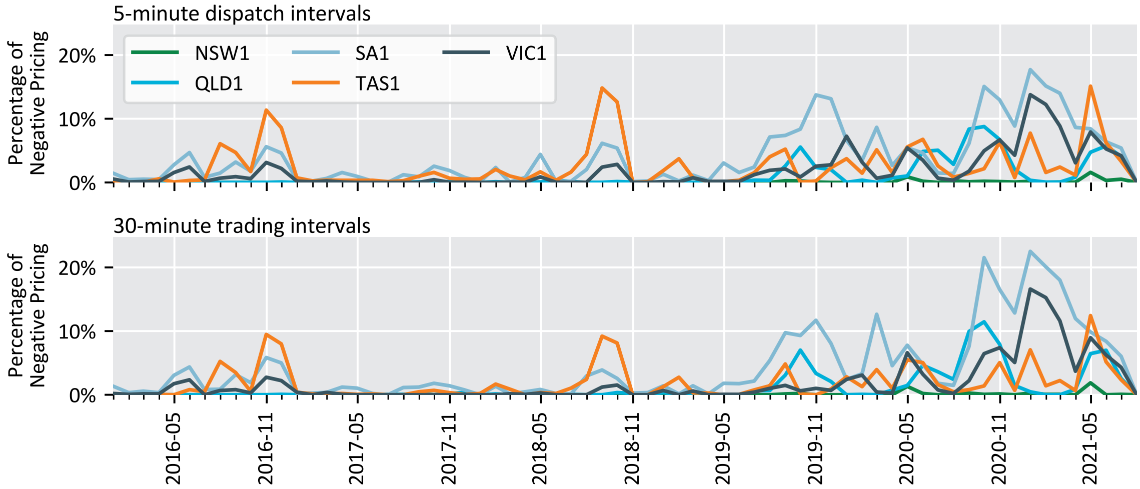

Figure 1. Percentage of time energy dispatch (top) and settlement (bottom) prices were negative, by month, since 2016.

Wholesale electricity prices have been the largest contributing factor to retail price rises over the past few years [4] and are a function of generator bidding behaviour. Generators in the NEM can offer capacity as low as the market floor price of -$1,000 per MWh or as high as the market price cap of $15,000 per MWh. Non-renewable generators typically have higher short-run marginal costs (SRMCs - the cost to generate a small amount of additional energy e.g., supplying coal, natural gas etc.) than renewable generators and will likely bid volumes of energy above $0 per MWh to recoup these. However, other factors such as minimum loading requirements, disorderly bidding, ramping requirements etc. may result in non-renewable generators bidding volumes of energy at -$1,000 to increase the likelihood of being dispatched. It's common for solar and wind generators to bid close to $0 per MWh as their SRMCs are negligible.

Figure 2 provides a breakdown of the 5-minute negative pricing range in South Australia since 2016. The month of January in 2020 in South Australia saw 5-minute dispatch intervals reach negative levels more than 18 per cent of the time. Also shown is the magnitude of negative pricing to be substantially increasing post May 2019. Prices are less than negative $800 per MWh for approximately 2 per cent of the time across several months since October 2020. Not only are negative pricing intervals becoming more common, extreme negative pricing intervals are making up a greater proportion of total negative price events. It is necessary to acknowledge the contribution to negative pricing that interconnector constraints are having. Market forecasters expect the frequency of negative pricing to fall once interconnector constraints reduce and generation is able to more freely move across different regions (an example of an interconnector constraint is solar generation being trapped in Queensland during the Queensland to New South Wales interconnector upgrade).

2 The electricity spot price for a 30-minute trading interval equals the average spot price across the six 5-minute dispatch intervals. This averaged price reflects the price that electricity is bought and sold for on the spot market. The market is moving to 5-minute trading intervals in October 2021.

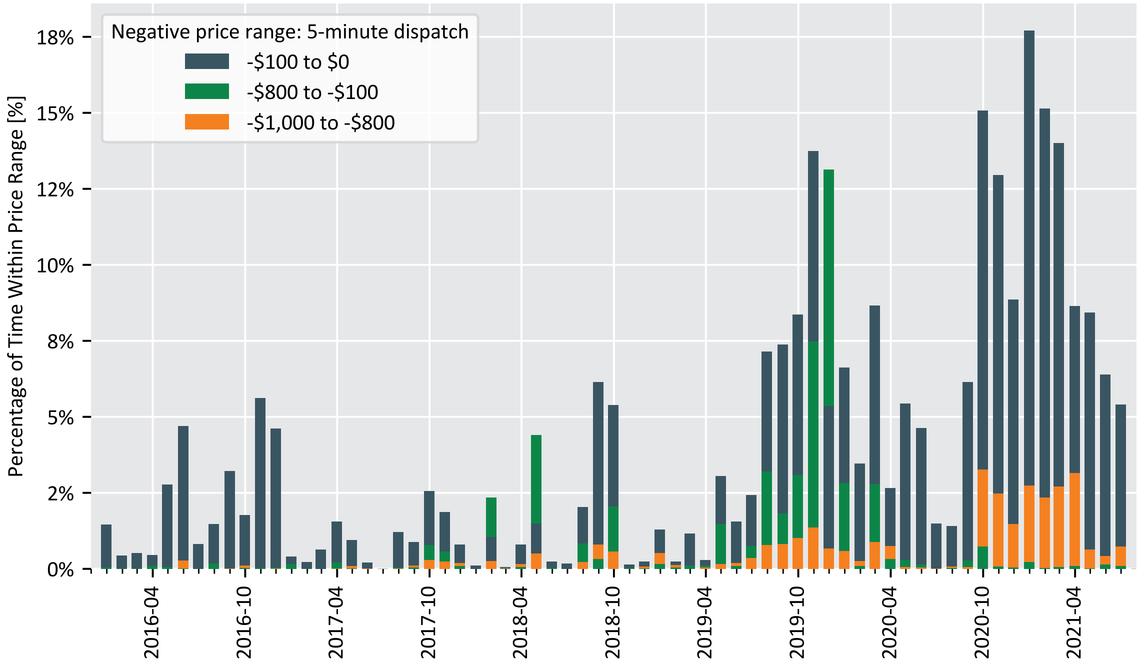

Figure 2. Percentage of time that 5-minute dispatch intervals spent each month in different negative price ranges in South Australia.

CHANGING GENERATION AND LOAD

The key driving force behind more frequently occurring negative pricing is the combination of cheaper generation with lower demand. This is explained in more detail below [3]:

1. Cheaper generation: There is increased capacity from solar and wind as ageing coal generators continue to exit the market. Over 93 per cent of Australian electricity generation investment since 2012–13 has been in solar and wind, which accounted for 7.7 and 8 per cent, respectively, of the market's electricity needs in 2019 [4]. Falling coal and gas fuel input costs have also contributed to cheaper generation.
2. Lower demand: Comparatively milder weather conditions since the beginning of 2020, as well as increased rooftop solar PV uptake has resulted in record low minimum demand levels.

Across a 24-hour period, negative pricing events typically occur when electricity demand is low and weather conditions are optimal for renewable generation. While historically occurring overnight, they are becoming increasingly common during times when solar resources are optimal. Generally, negative pricing occurs either:

1. Between midnight and six in the morning, when, for example, the South Australian and Victorian wind farms are generating, and the demand is relatively low. The recently commissioned wind farms in Victoria have contributed to the increase in negative pricing during this period, and this trend is on track to match South Australia.
2. During the middle of the day, when the sun is shining brightly on residential and utility-scale solar. Relative to South Australia, Victoria's lower uptake of residential solar hasn't yet reduced demand enough to cause similar levels of negative pricing intervals. Queensland's relatively high uptake of solar causes negative pricing during the middle of the day.

Figure 3 demonstrates how the above phenomena are playing out across each region in the NEM by comparing 2016 and 2020. As variable renewable electricity generators continue to supply more of Australia's energy needs, deeper troughs in both demand and pricing can be expected during the early morning and midday intervals. South Australia has already reached this state, with Victoria also seeing similar patterns. The lack of wind generation in Queensland makes it rare for negative pricing to occur in the early hours of the morning. The last plot in Figure 3 reinforces Tasmania's unique dynamics (e.g., size, relatively flat demand curve, generation mix, limited owners, the Basslink etc.).

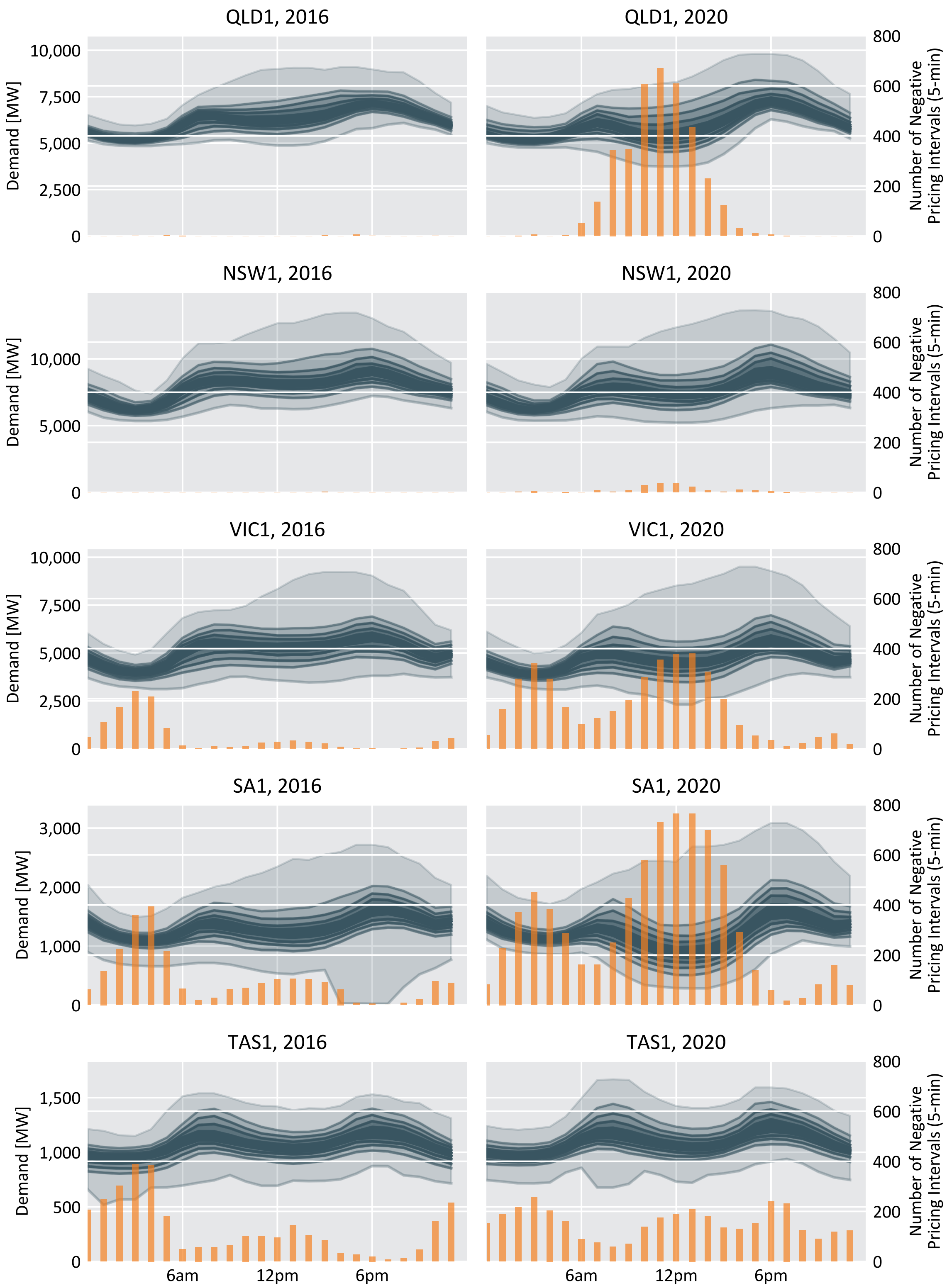

Figure 3. Daily demand profiles (each band is 20% of the data) and number of negative price intervals in each hour.

BIDDING AND REBIDDING ON THE NEM

The increased incidence of negative price intervals presents a challenge for solar and wind generators seeking to maximise revenue in times where the renewable fuel source is available. When the first semi-scheduled wind and solar generators connected to the NEM, they tended to bid close to the market floor of -$1,000/MWh at all intervals where they had available capacity to ensure they were dispatched as often as possible. However, the surge in negative price intervals is driving generators to adopt increasingly more sophisticated bidding strategies to minimise losses.

The simplest illustration of this shift is the increased frequency of rebids by solar and wind generators. Scheduled and Semi-Scheduled units must finalise bids for the following day by 12:30pm the day before (commonly known as Gate Closure). Rebids are when units shift or change the breakdown of volumes of energy across the already then fixed price bands post Gate Closure. Rebids are an intentional market design so that generators can make use of contemporary information. It should be noted that changing volumes against price bands is effectively the same as changing price. Often there is an unexpected need for more or less supply as the dispatch time draws closer. Rebidding is so common that AEMO assigns codes for the different reasons behind each rebid:

- 'P' is a plant or physical change
- 'A' is an AEMO forecast or dispatch change
- 'F' is a financial or commercial change
- 'E' is a rebid to address an earlier error

Figure 4, Figure 5, and Figure 6 show the average number of rebids from VRE generators for each negatively priced 5-minute dispatch interval in Queensland (solar), South Australia (wind) and Victoria (solar and wind), respectively. For solar farms in Queensland, the average number of rebids per negative price interval rose from 0 in November 2017 to approximately 15 in June 2021. Similarly, for wind farms in South Australia, the number rose from 1 in July 2017 to approximately 32 in June 2021. The farms with the most active rebidding exceed 70 rebids per interval in some months. A more muted effect can also be seen in both solar and wind farms in Victoria.

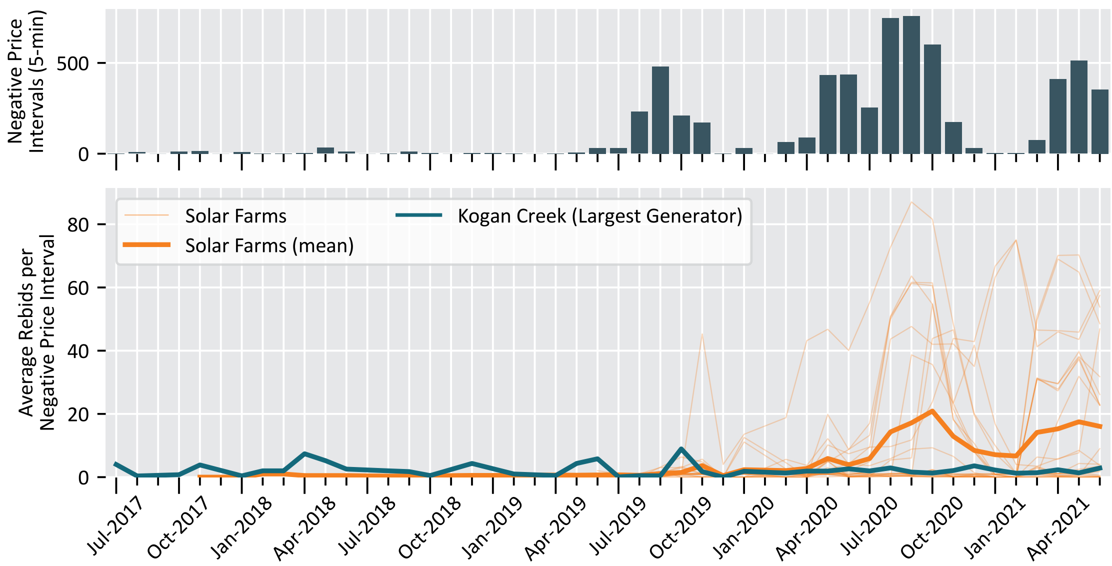

Figure 4. Rebids per negative price interval (5-minute) for solar farms in Queensland compared with the largest thermal generator.

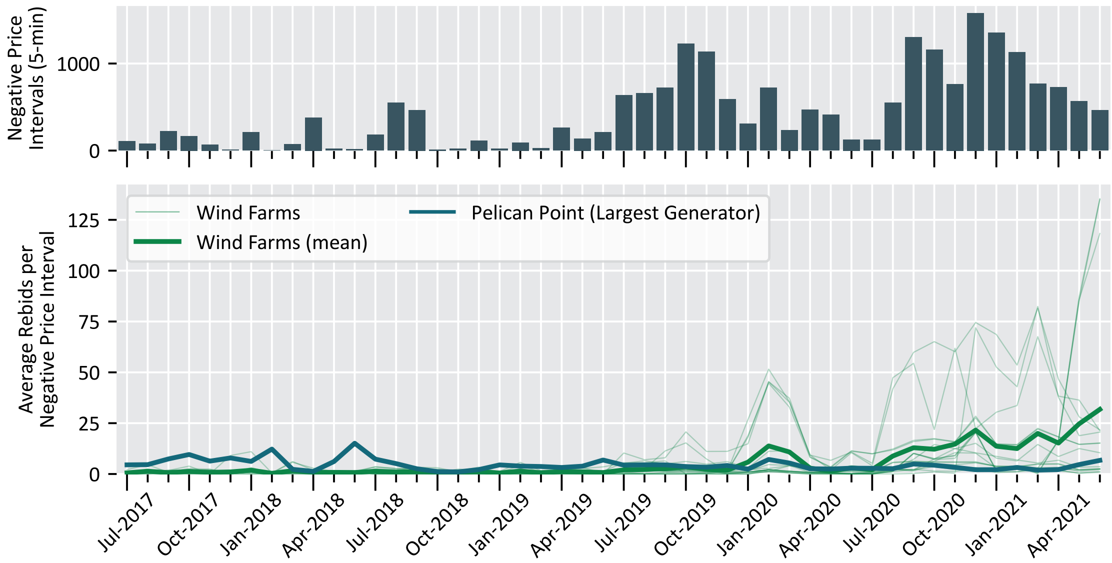

Figure 5. Rebids per negative price interval (5-minute) for wind farms in South Australia compared with the largest thermal generator.

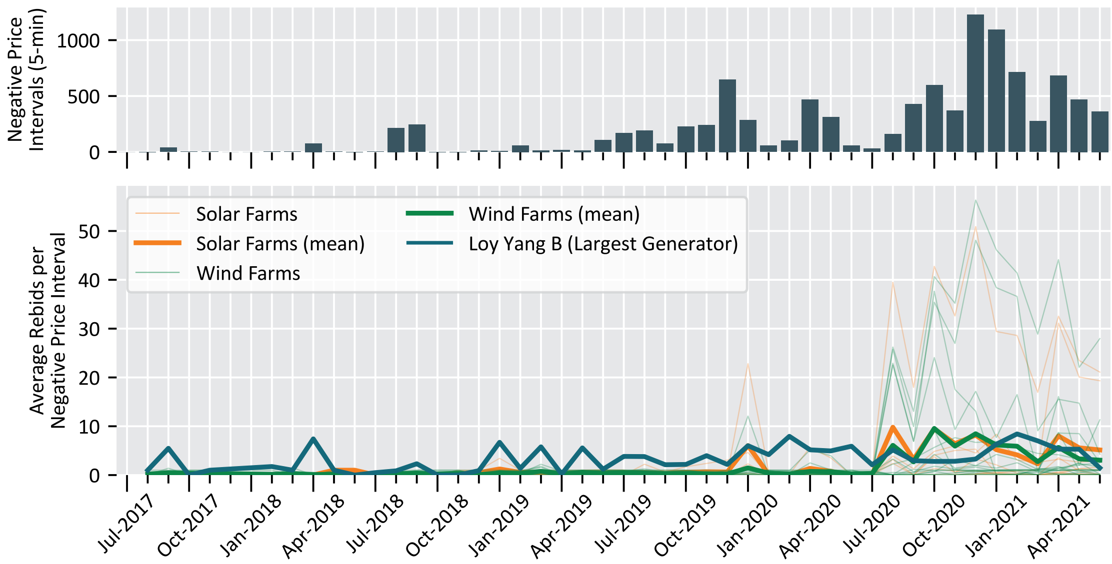

Figure 6. Rebids per negative price interval (5-minute) for solar and wind farms in Victoria compared with the largest thermal generator.

The fact that the average number of rebids per negative price interval across all farms grows over time, is a demonstration that frequent rebidding is becoming a more widespread strategy across the industry in order to manage negative pricing risk. That is, the increase in rebids is not limited to a select number of farms and is not simply the result of a rise in negative price intervals.

The AEMC has reported [6] the following to be some of the problems that arise from late rebidding (any rebid that occurs less than 15 minutes prior to dispatch);

› Wholesale market impacts
  - Large industrial users that buy directly from the wholesale market may run at a loss once faced with non-forecast price shocks – beyond those that are innate to the system.
  - The reduced transparency and predictability of spot prices may result in competitive demand response not having sufficient time to change output and there will be periods when higher cost generation may be dispatched ahead of lower cost plant.

› Contract market impacts
  - The price of cap contracts and other hedge products may be inflated when accurate information is deliberately withheld by generators from the market, leading to spot price volatility in addition to that which is inherent to the system, including price spikes.

- Consumers are likely to bear some of the resulting costs – costs that may be passed to consumers include; unnecessary operating costs on the part of generators, lost value of production on the part of large electricity users, contract market and spot price premiums and, potentially, the consequences of poor investment decisions that are made in the light of distorted information.

Research undertaken by Ernst & Young in 2015 indicates that some participants are paying a premium on contract market products in order to manage the price volatility that arises from deliberately late rebidding. This is estimated to have added around eight dollars per megawatt hour to the price of caps in Queensland in the final quarter of 2014, and around seven dollars per megawatt hour in the first quarter of 2015.

Rebidding is just one of several strategies adopted to manage negative price risk. The section below develops a taxonomy of these strategies and proceeds to classify the behaviour of all solar and wind farms on the NEM over time by the high-level strategy being employed.

Image: Musselroe wind farm

POSSIBLE BIDDING STRATEGIES IN RESPONSE TO NEGATIVE PRICE RISK

The bidding strategies adopted by solar and wind generators on the NEM to manage negative price risk generally fall within one of three categories:

1. **Price Agnostic:** Generators offer 100 per cent capacity at a price close to the market floor of -$1,000/MWh, ensuring dispatch at all times.
2. **Fixed Strategy:** Generators adopt a fixed daily offer profile that defines the level of exposure to negative prices they are willing to accept.
3. **Dynamic Bidding:** Generators submit rebids throughout the day in response to negative price events.

Table 1 shows a high-level summary of the time and cost implications of implementing each strategy.

TABLE 1.

STRATEGY	TIME	MANAGEMENT COST
Price Agnostic	Low	Low
Fixed Price	Medium	Low/Medium
Dynamic Bidding	High	High

Figure 7 shows how these strategies are applied in practice at four renewable generators in Queensland. These are discussed alongside a more detailed exploration of each strategy below.

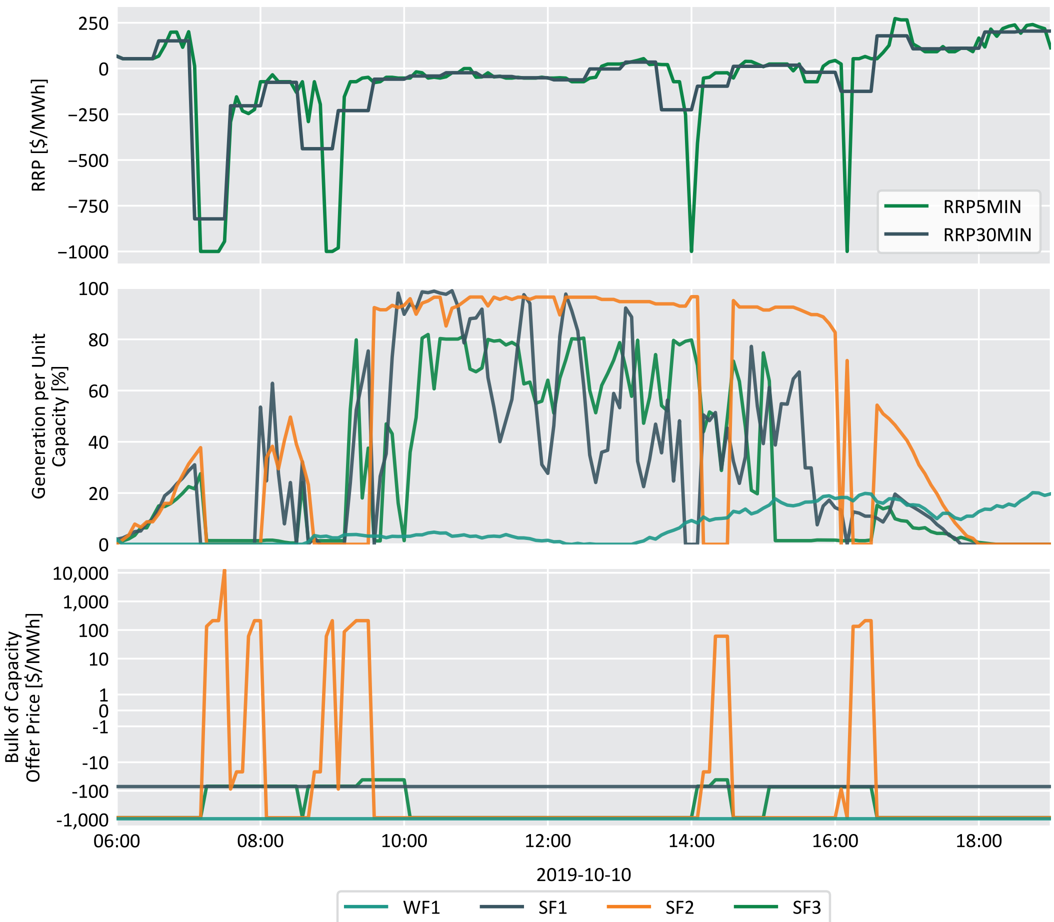

Figure 7 Changing offer price and generation in response to negative pricing for one wind farm and three solar farms in Queensland on 10 October 2019. RRP[3] and Bulk of Capacity Offer Price[4] are explained in footnotes.

3 The Regional Reference Price (RRP) is the electricity price settled in each state/region (i.e. Queensland in this case).

4 The Bulk of Capacity Offer Price is the price at which the largest volume of energy is offered (see Appendix for more information).

PRICE AGNOSTIC BIDDING

In Figure 7, WF1 has adopted a price agnostic bidding strategy. For all intervals throughout the day, it offers its maximum capacity of 178 MW at a price of -$944/MWh. This strategy ensures that the farm is dispatched to its maximum availability at all periods regardless of the spot price and congestion. This is shown in subplot 2 of Figure 7, as the output of the wind farm is not affected by the very low spot prices.

Generators may adopt this strategy if:

a. They are subject to older Power Purchase Agreements that did not anticipate a high incidence of negative prices and guaranteed purchase of all electricity generated at the market price down to the market floor price [6, 7, 8].
b. They are in a region where negative price events during the time at which the generator is generally dispatching remain relatively infrequent (e.g., wind in Queensland).
c. They want to get dispatched ahead of a competitor generator on a congested part of the grid and expect to be settled at a positive RRP.

Figure 9, Figure 10, Figure 11, and Figure 12 demonstrate that many generators originally enable price agnostic bidding strategies only to later adopt more sophisticated bidding behaviour. More than half of the solar and wind farms in NSW continue to use this kind of strategy, a region that remains relatively protected from negative pricing intervals.

FIXED BIDDING

In Figure 7, SF1 has adopted a fixed strategy. For all intervals throughout the day, it offers its maximum capacity of 108 MW at a price of -$70.77/MWh. This means that when the spot price falls below -$70.77/MWh, the farm will not be dispatched and will instead be instructed to switch off by AEMO's dispatch system. This results in the fluctuating output seen in subplot 2 of Figure 7.

Strategies such as these allow the generator to define what level of risk they will accept. For most farms, this strategy involves offering the entire plant capacity at a price that represents the minimum payment the generator is guaranteed to receive per MWh under a Power Purchase Agreement (PPA) and/or from large-scale generation certificates (LGCs). Most recent PPAs include terms that either give the purchaser the power to instruct the generator to switch off during actual or forecast negative price events, or relieve the purchaser from the obligation to purchase where the price falls below a certain threshold [9].

Fixed strategies are a simple way of ensuring compliance with PPA terms and minimising exposure to negative price events. However, these strategies can also be slightly more complex. For example, on several days in September 2019, one solar farm in Queensland periodically increased the offer price from -$849.4/MWh to $0/MWh for the dispatch intervals from 8:35 to 15:00 each day. This was achieved using a fixed, daily bid strategy rather than by responding dynamically to changing variables and submitting a rebid before those intervals. This strategy limited the farm's risk of being dispatched during negative price intervals over the period in the middle of the day when these are most likely to occur, as per Figure 3.

DYNAMIC BIDDING

Dynamic bidding strategies as a response to negative price events involve actively monitoring the spot price and/or forecast price(s) and submitting rebids throughout the day to minimise the volume of energy dispatched during 30-minute periods with negative settlement prices.

In general, these appear to be implemented using automated bidding software, as the farms that adopt this type of strategy will submit multiple rebids for multiple intervals throughout the day as prices change. These strategies vary in complexity, and can be further broken down into the following sub-categories:

› Reactive: Farms submit rebids where volumes of energy are shifted to the highest price band when a very low negative price interval occurs. This minimises their output for the remainder of the 30-minute interval and minimises the energy dispatched in an interval that is likely to be negative. This appears to be the strategy adopted by SF2 in Figure 7.[5]

5 The capacity adjustments occur following the negative 5-minute spot price, and the rebid explanation field in AEMO's 'BIDDAYOFFER' table associated with RRSF1 refers to the '5MIN NEGATAIVE [sic] DP', presumably, dispatch price. For further discussion of RRSF1 on this day, see [12].

› Predictive: Farms monitor the pre-dispatch price or third-party forecasts of the 30-minute settlement price and try to shift capacity in advance to minimise dispatch in 30-minute periods that are likely to be negative, even before any negative spot prices are observed. This appears to have been the strategy adopted by SF3 in Figure 7.[6] The effect is that SF3 increases its bid offer price well in advance of the 16:10 negative price spike and thus has a longer period than SF2 where the output is 0 MW.

› Multi-factored: More sophisticated bidding strategies can look at other input variables, risk mitigation strategies, or objectives.

- For example, generators may significantly increase their offer price in an attempt to avoid being dispatched during intervals with extremely high contingency Frequency Control Ancillary Services (FCAS) prices [10]. This exact strategy was employed by wind farms in Tasmania on two occasions on 12 November and 18 December 2020, which resulted in these farms being the price setters for Tasmania in those intervals [11].
- Another more complex strategy is spreading availability across multiple price bands to optimize the expected revenue for each interval based on the likelihoods and likely magnitudes of different price and dispatch outcomes. This kind of strategy was apparently being used at one solar farm in Queensland on 4 July 2020. As Figure 8 shows, the farm submitted multiple rebids for the interval of 08:35, gradually shifting the offered capacity from lower to higher price bands as the pre-dispatch forecast prices began to indicate the 30-minute settlement price was likely to be negative. However, the spread across multiple bands suggests the strategy is attempting to maximise the expected revenue based on both the likelihood and magnitude of the forecast energy dispatched and price.

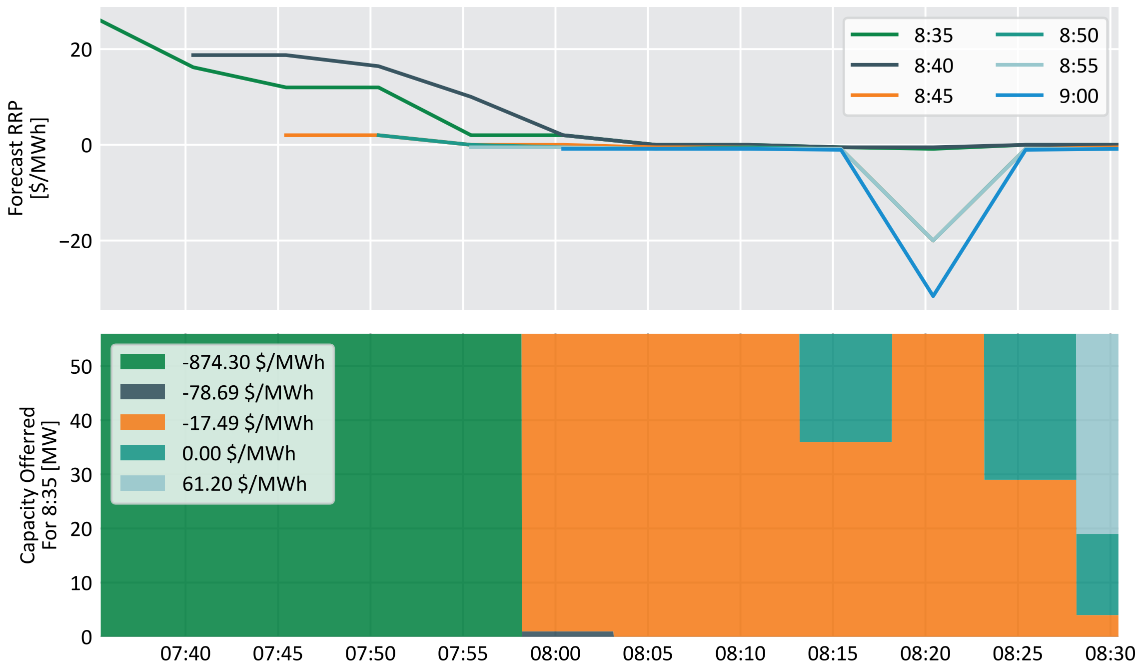

Figure 8. Change in offer availability bands over time in response to changes in forecast 5-minute prices and likely 30-minute regional reference price (RRP) on 4 July 2020. The top subplot shows the forecast 5-minute RRP for each of the time intervals in the legend as reported by AEMO's pre-dispatch system at the times shown on the x-axis. The bottom subplot shows the structure of the capacity bid by one solar farm in Queensland for the 8:35 interval. The bid gradually increases the volume offered in higher price bands as the forecast 30-minute price for the 8:35 to 9:00 settlement interval falls. The rebid explanations indicate that the software is monitoring pre-dispatch prices and adjusting the capacity bid accordingly. See also [12].

Note, regardless of the strategy adopted, the primary decisions the generator must make are:

a. What is the minimum price at which they are willing to be dispatched?
b. To what extent do they wish to protect themselves from the effects of the 30-minute average price falling below that price?
c. What factors other than the wholesale market price should be considered in determining the bid?

6 The rebid explanation field from AEMO's 'BIDDAYOFFER' table associated with a solar generator makes reference to changes in the pre-dispatch price.

d. A fixed strategy can enable a generator to ensure they are not dispatched below a set price, neglecting the effects of 30-minute settlement. Dynamic strategies are necessary if generators wish to address items (b) and (c). However, once 5-minute settlement is introduced, item (b) will no longer be relevant, and the value of dynamic bidding strategies will largely depend on the extent to which the generator is factoring in other dynamic variables such as the FCAS price into whether they wish to be dispatched.

According to automated bidding software provider Fluence [2], in the past two years, more than 35 per cent of grid-scale solar and wind farms on the NEM have begun utilising automated bidding software to assist with:

1. avoiding negative pricing;
2. minimising curtailment due to physical grid constraints;
3. minimising frequency control ancillary service (FCAS) cost allocations;
4. managing discrepancies between local and regional electricity price;
5. abiding by contractual PPA obligations and
6. ensuring rebidding is compliant.

It has been reported that automated bidding software has, in some cases, increased net revenue by over 10 per cent [2].

Image: Woolnorth wind farm

CLASSIFYING GENERATOR BIDDING STRATEGIES ON THE NEM

Bid and dispatch data from AEMO's NEMWEB service[7] has been used to classify the solar and wind generators on the NEM into one of the three strategies outlined above. Note, the purpose of this analysis was to identify which bidding strategies generators were using in response to negative price events. Therefore, the descriptions of the strategies are less useful for describing bid behaviour in general.[8]

The rules-based classification methodology used to classify the bidding strategies is set out in detail in the Appendix, but can be summarised as follows:

- For each region and month, the time intervals are divided into 'negative price related intervals' – 30-minute intervals with at least one negative 5-minute spot price, and the 30-minute intervals either side of said intervals – and all other intervals.
- Each month of generation for each generator receives an initial classification into one of the three bidding strategies.
  - The month of generation will be classified as Dynamic Bidding if the generator is changing its price offer through rebidding more frequently in negative price related intervals than in other periods, which indicates that they are using active rebidding to mitigate negative price risk.
  - If a month of generation is not Dynamic Bidding and has a median offer price below -$200 / MWh, it is classified as Price Agnostic. This indicates a generator that is maintaining a very low price likely intended to guarantee dispatch, with no discernible rebidding activity correlated with negative price intervals.
  - If a month of generation is neither Dynamic Bidding or Price Agnostic, it is classified as Fixed Strategy. This indicates a lack of rebidding activity correlated with negative price intervals, but a set minimum price below which dispatch will not occur.
- The pattern of monthly classification for a given generator is analysed. Isolated single month deviations from an otherwise consistent strategy are re-classified to match the consistent strategy. This is based on the assumption that generators do not frequently change their bidding strategy, and in general appear to retain Dynamic Bidding strategies once they are adopted.

Ignoring isolated deviations from a consistent strategy in the monthly series is further justified on the basis that generators are sometimes required to make changes to their bids for operational, rather than economic reasons. For example, one generator from ARENA's LSS portfolio indicated that they were required to always bid at least 1 MW in their minimum price band to ensure compliance with the reactive power supply requirements set out in their Generator Performance Standards. Following the application of this method, the likely bid strategy adopted by each of the 85 solar and wind generators under consideration can be identified for each month of operation. This is shown for solar and wind generators in South Australia, Victoria, New South Wales, and Queensland in Figure 9, Figure 10, Figure 11, and Figure 12, respectively. Note, the classifications are based on the extent to which the bid patterns followed the expected strategies outlined above.

The data shows an increasing uptake of Dynamic Bidding strategies to address negative price risk over time, particularly in the regions of South Australia and Queensland. Across the NEM, the percentage of solar and wind farms using dynamic bidding strategies has grown rapidly from 19.6 per cent in January 2019 to 64.7 per cent in June 2021. It is important to highlight that the major advantage of dynamic bidding strategies at present is that they improve the ability of generators to avoid being dispatched in 30-minute intervals that ultimately have a negative price. However, once 5-minute settlement commences, fixed strategies set at the minimum price a generator is willing to pay will be equally as effective at preventing dispatch in negative price intervals. Nevertheless, dynamic bidding strategies can enable generators to minimise costs overall by considering other factors such as FCAS costs. This would be even more relevant if solar or wind generators were to participate in FCAS markets [14].

7 The tables used for this analysis are DISPATCHLOAD, DISPATCHPRICE, TRADINGPRICE, BIDDAYOFFER, BIDPEROFFER and DISPATCHOFFERTRK.

8 For example, a generator that is classified as 'Fixed Strategy' may make relatively regular rebids in response to FCAS prices or for other purposes. However, for each month, it is the daily bid that is the primary mechanism by which they are addressing exposure to negative prices.

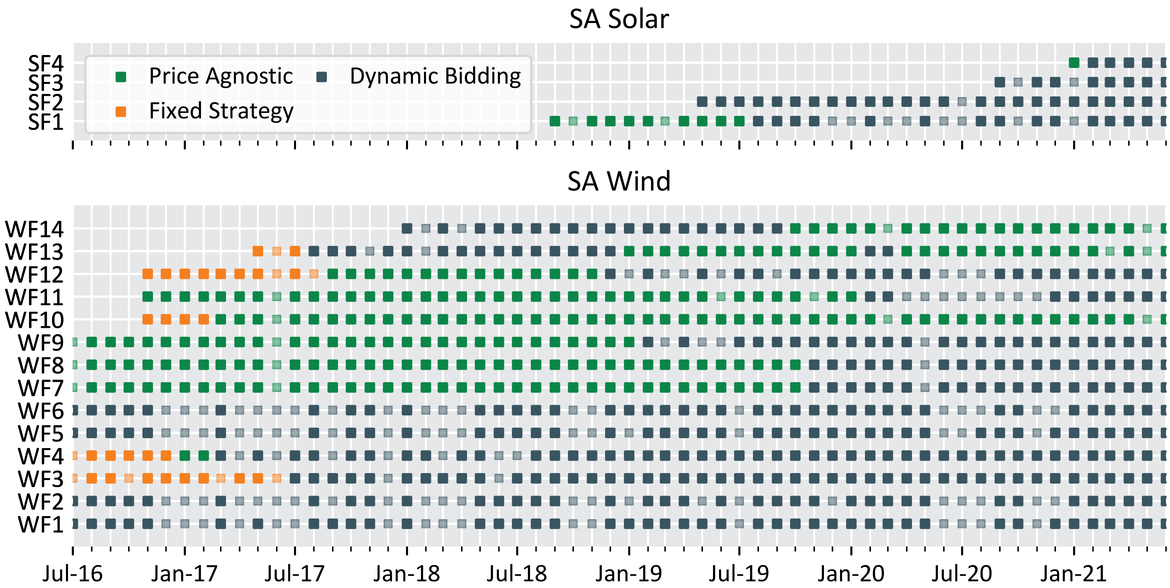

Figure 9. Generator bidding strategy for solar and wind farms in South Australia by month. Shaded squares indicate months where no negative price intervals occurred or where the category was inferred from neighbouring months.

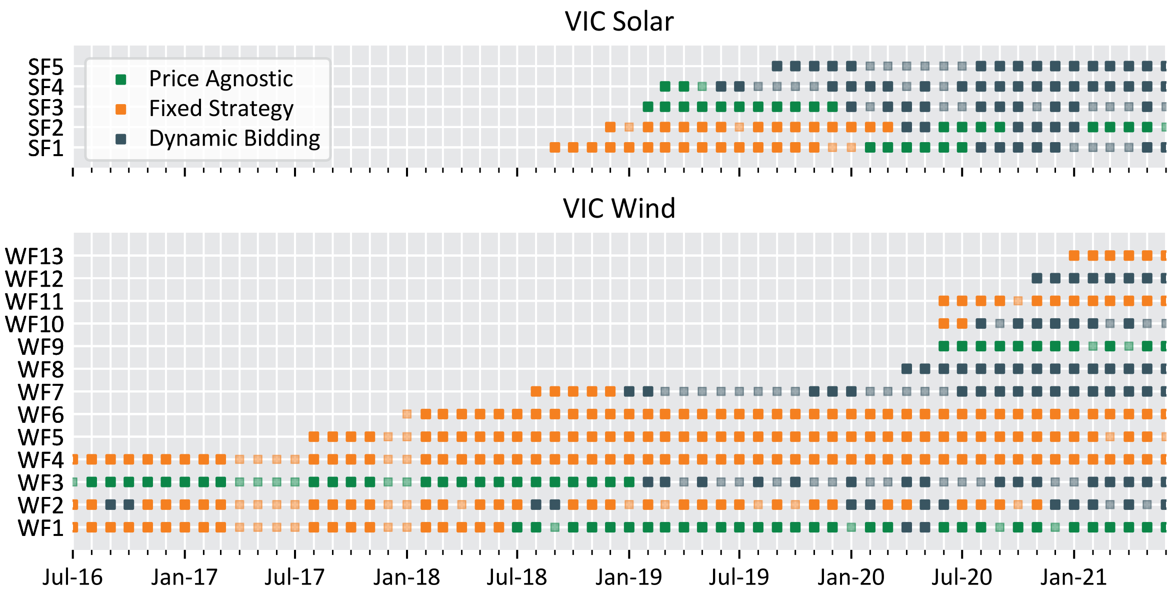

Figure 10. Generator bidding strategy for solar and wind farms in Victoria by month. Shaded squares indicate months where no negative price intervals occurred or where the category was inferred from neighbouring months.

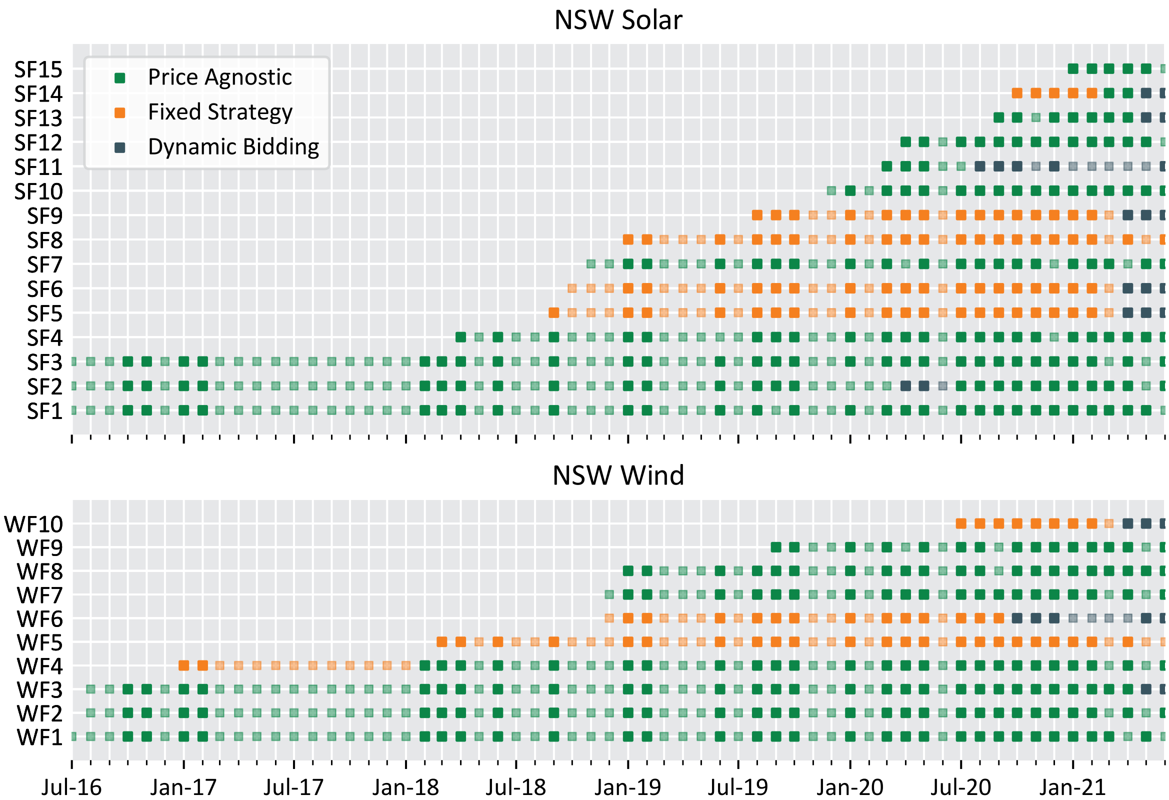

Figure 11. Generator bidding strategy for solar and wind farms in NSW by month. Shaded squares indicate months where no negative price intervals occurred or where the category was inferred from neighbouring months.

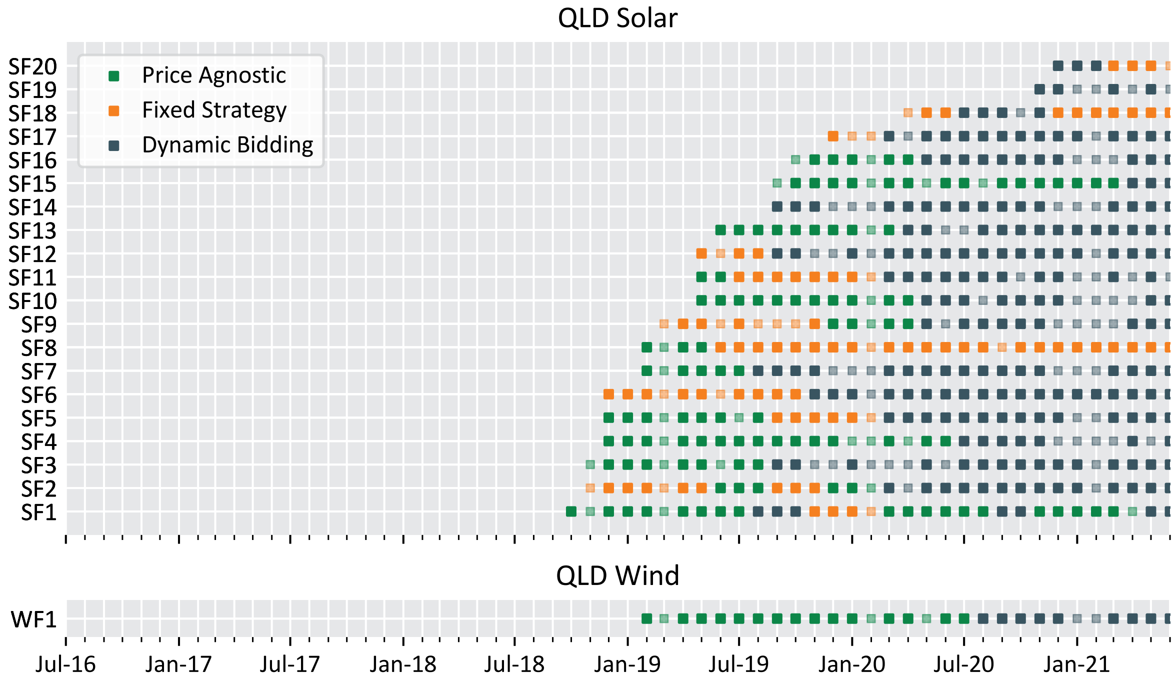

Figure 12. Generator bidding strategy for solar and wind farms in Queensland by month. Note that farms are only included from the date at which they first achieved 95 per cent of their maximum allowable generation in a month where at least one negative price interval occurred. Shaded squares indicate months where no negative price intervals occurred or where the category was inferred from neighbouring months.

A small number of generators in the plots above appear to alternate between bidding strategies several times. There are several possible explanations for this. First, alternating strategies may reflect relatively active asset manager's trialling different strategies or changing strategies in response to market conditions. Second, the changing strategies may actually be in response to operational challenges, such as GPS compliance or responding to local grid constraints. Finally, the true strategy adopted by generators may not fall neatly within any of the defined strategies and their associated classification rules adopted in this methodology. The observed alternating of strategies may instead be an indication of a strategy that is poorly captured by the three defined categories in the analysis.

This points to the general caveats of the analysis method adopted:

- Bidding behaviours adopted for operational purposes cannot always be distinguished from bidding behaviours adopted in response to negative price events.
- Any strategies falling outside the defined rules of the three categories may be improperly classified. For example, aggregation at the monthly timescale may obscure strategies that change or are cyclical over longer or shorter time periods.
- In months where very few negative price intervals occurred in a given region, the signals indicating Dynamic Bidding may be either exaggerated or too weak to be properly detected.

Image: Gullen Range wind farm

REGIONAL VARIATION

Negative pricing occurred more frequently in the month of July 2021 than any other month in the NEM's history. The recent, and relatively rapid, rise of negative pricing intervals on the NEM indicates that generators are, more than ever, paying, rather than getting paid, to produce electricity. This is particularly true where the offtaker is bearing negative pricing risk and/or where the plant (such as a coal-fired generator) cannot quickly ramp (switch on and off) in response to short term price signals. Negative pricing intervals typically occur at times when demand is relatively low and renewable generation is relatively high. For most regions, this seems to be occurring either in the early hours of the morning before 6am (when wind production can be high, but demand is low), and/or during the middle of the day (when rooftop solar and utility solar are generating). Some of the trends across each region are described below:

1. South Australia's 5-minute dispatch price intervals are negative more frequently than any other region on the NEM. This is due to a relatively low demand being met with a large renewable contribution, particularly from rooftop solar. 30-minute settlement prices in the state were negative for over 20 per cent of the time in January 2021. The magnitude of negative pricing has also substantially increased post May 2019. Prices sat lower than -$800/MWh for more than 2 per cent of the time across several months since October 2020.
2. Negative pricing trends in Victoria are on track to match South Australia's as the uptake of rooftop solar increases and continues to reduce daytime demand. Both South Australia and Victoria are seeing noticeable dips twice per day ("double bathtubs") for both demand and pricing.
3. Queensland has experienced significant negative pricing during the daytime as solar dominates renewable generation in the state, particularly during grid upgrade works that restricted the flow of solar power across the interconnector to load centres [2].
4. New South Wales is still slightly protected from negative pricing because of high demand, relatively low renewable contribution, and its location on the NEM enabling importing and exporting via interconnectors.

RECENT AND FUTURE CHANGES TO THE RULES

Over the past 2 years, the strong desire to avoid dispatch during negative pricing intervals has led to some generators withdrawing offered electricity volume after the price had been set (i.e., by self curtailing). This behaviour contributed to raising reliability and system strength concerns, which led to a rule change for semi-scheduled generators in April 2021. This rule change requires them to always inform the market operator of the intention to move from anticipated generation output by rebidding and waiting to receive a price dispatch target. The average number of rebids for solar farms in Queensland per 5-minute negative price interval rose from zero in November 2017 to approximately 15 in June 2021. Similarly, rebids for wind farms in South Australia per 5-minute negative pricing interval rose from one in July 2017 to approximately 32 in June 2021. The increase in rebids is not limited to a select number of generators; rather, it is becoming a widespread strategy across the industry, particularly for assets located in regions most prone to negative pricing intervals.

Automated bidding behaviour is not always properly integrated with dispatch offers and may not allow for the appropriate ramping across a dispatch interval [15]. Market bodies have become increasingly concerned about the system security risks of semi-scheduled renewables changing their output without lodging a rebid in response to negative prices. This has led to the AER submitting a rule change.

The National Electricity Rules (NER) require scheduled and semi-scheduled generators to comply with dispatch instructions. Not doing so may place the public in danger and/or damage equipment and is considered hazardous behaviour. While the rules have recently changed, a contradiction to this was the provision allowing semi-scheduled generators to operate freely except during semi dispatch intervals.[9] Scheduled generators on the other hand were obliged to strictly follow dispatch instructions [15].

As the frequency of negative pricing intervals has increased, so too has the non-compliance with dispatch instructions from semi-scheduled generators. Output from semi-scheduled generators has been rapidly reducing to zero to avoid negative pricing without first receiving approval from AEMO to do so. Without intervention, this behaviour will be more frequent as substantial variable renewable energy development is forecast. The recent rule change seeks to prevent this behaviour from occurring and hopes to improve AEMO's ability to manage the power system. The recent rule change aims to ensure that semi-scheduled generators:

1. Only deviate from anticipated generation levels after receiving a revised dispatch target from the AEMO in response to a rebid, and
2. Operate to the full potential given available resources [15].

It has been reported by some experts that batteries will benefit most from 5-minute settlement periods due to their technical capabilities, with their wholesale revenue expected to increase anywhere between 3-10 per cent. For renewables, perfectly avoiding negative price periods is the major driver of improving revenues, irrespective of the 5-minute rule change. The breakout box below demonstrates a hypothetical example of how 5-minute settlement periods will incentivise investment towards more dispatchable generation [5].

9 A dispatch interval where generation is required to remain below a cap specified by AEMO.

5-MINUTE VS. 30-MINUTE SETTLEMENT

Under the current market system, generators are economically incentivised to dispatch during settlement periods where 5-minute price spikes increase the 30-minute settlement price. Generators are likely to rebid, or shift, volumes of energy across the already fixed 10 price bins for the remaining 5-minute dispatch intervals in a way to increase the likelihood of being dispatched. This is known as the pile-in effect.

To help manage this risk, the settlement period for the electricity spot price will change in October 2021 from 30-minutes to 5-minutes to align the timeframes for dispatch and settlement prices [2]. Therefore, peaking plants will not need to bid as high to achieve the same margin, since revenue will no longer be reduced by 30-minute averaging. This may flow on to reduced revenue for non-flexible generators [5].

Figure 13 provides a hypothetical example of two generators dispatching across a 30-minute period. Generator 1 consistently dispatches 10 MWh of energy in each 5-minute interval (i.e. representing a fixed generation profile). The 5-minute price peaks to $1,000/MWh in the fourth interval, where Generator 2 dispatches 25 MWh (i.e. representing a peaker plant). The 30-minute settlement price is $238/MWh. The bottom plot demonstrates how the revenue for each generator changes across 5-minute and 30-minute settlement periods (i.e. pre and post October 2021).

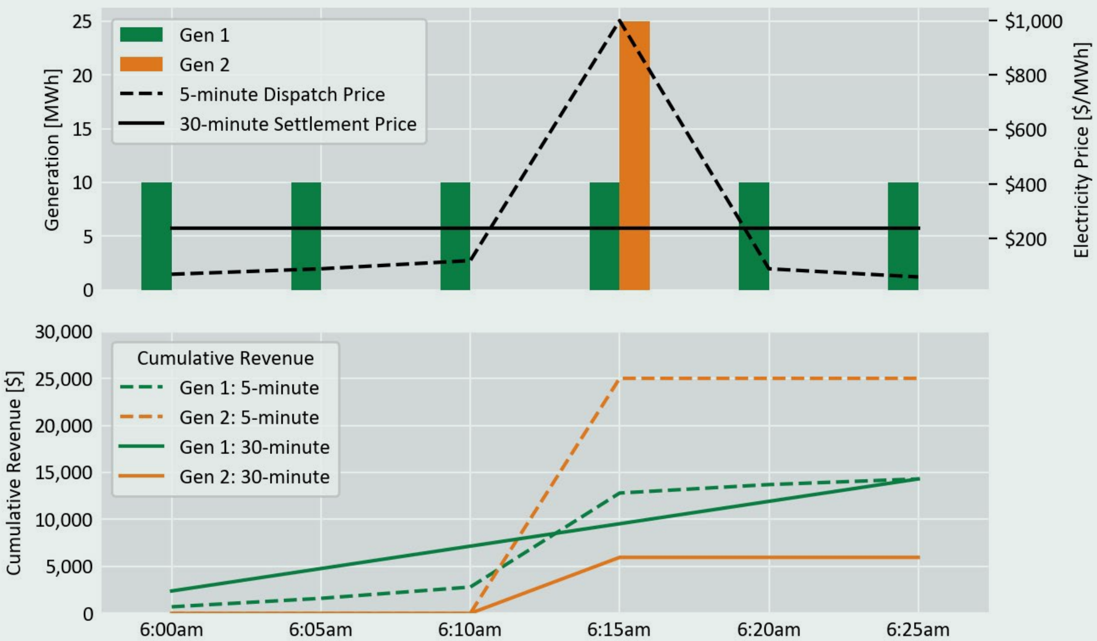

Figure 13. Example of how revenue for two different generators is impacted by the 5-minute settlement period.

Generator 1 receives $14,300 under both the 30-minute and 5-minute price settlement scenarios. Generator 2, is rewarded an additional $19,000 for providing generation when it is most needed, as signaled by the market. The 5-minute settlement period essentially signals investment towards more flexible assets, while aiming to reduce the pile-in effect.

SUMMARY

There are many unknown factors, some of which are often confidential and unique to each asset, influencing bidding behaviour. These might include the desire to avoid being switched off, compliance with a trading strategy required by project investors, or that the exposure to spot prices is reduced through hedging.[10] These unknown factors can make it difficult to understand why a generator chooses certain bidding behaviours. Despite this, the method of categorising bidding behaviour across all solar and wind farms on the NEM has revealed clear patterns. Over time it seems that age and location are good indicators as to which bidding behaviour strategy is likely to be adopted by an individual generator:

- Age: VRE generators installed prior to July 2018 are almost 50 per cent more likely to adopt a price agnostic bidding strategy. This may be reflective of older offtake agreements in which all of the power was sold under an offtake agreement and the purchaser bore the risk of negative price events. Since then, dynamic bidding strategies have become more prevalent over time for all VRE generators.
- Location: Solar and wind farms located in regions more prone to negative pricing (e.g., South Australia, Queensland and Victoria) are more likely to implement dynamic bidding.

Most solar farms in Queensland, and wind farms in South Australia, implement Dynamic Bidding. Negative pricing within these regions is common during the hours of generation for these technologies, which explains why many of these assets now actively participate in the market. Unsurprisingly, the smallest portion of solar and wind farms enabling Dynamic Bidding is in New South Wales, the region with least exposure to negative pricing intervals. This study found that 71 per cent of all solar farms, and 59 per cent of all wind farms on the NEM now utilise Dynamic Bidding. In the 30 months, since January 2019, the number of solar and wind farms utilising Dynamic Bidding has increased by 45 per cent.

The following table summarises what proportion of solar and wind farms implemented each of the bidding behaviour strategies.

TABLE 2. SUMMARY OF BIDDING BEHAVIOUR STRATEGIES ADOPTED BY SOLAR AND WIND FARMS TO MANAGE NEGATIVE PRICE RISK.

STATE	NUMBER OF SOLAR FARMS	NUMBER OF WIND FARMS	PRICE AGNOSTIC [%]	FIXED STRATEGY [%]	DYNAMIC BIDDING [%]
NSW	15	10	56	8	36
VIC	5	13	16.7	27.8	55.6
QLD	20	1	0	14.3	85.7
SA	4	14	16.7	0	83.3
TAS	0	3	0	0	100
		Solar All Regions	20.5	9.1	70.5
		Wind All Regions	26.8	14.6	58.5
		January 2019 Comparison	53.2	27.7	19.1
		June 2021 Comparison	23.5	11.8	64.7

Once the market moves to 5-minute settlement (proposed October 2021), generators will no longer have to bid in anticipation of how averaging across a half hour period will impact settlement prices.

While sophisticated automated bidding software is often used to optimise revenue across all markets (e.g., energy and FCAS), generators wishing to participate only in the wholesale energy market during uncongested periods should bid at their SRMC (which changes for generators with variable input costs) and be paid that amount. During congested periods, generators may still choose to bid below their SRMC to ensure being dispatched ahead of neighbouring generators with the knowledge that the Regional Reference Price (RRP) will settle above their SRMC (the generator's bid price and marginal loss factor ends up being the deciding factor on dispatching generators with competing bids). Peaking plants may be able to reduce their bids while maintaining margins, which could ultimately reduce revenue for other less-dispatchable generators that were previously relying on higher 30-minute averaged settlement prices.

10 Hedging is a risk management strategy employed to offset losses in investments by taking an opposite position in a related asset

Whilst the introduction of the 5-minute settlement period may favour dispatchable generation, it will almost certainly help VRE generators avoid dispatch during negative price intervals. This study has been valuable in highlighting how policy and market design can have unintended consequences for market participants. A simple truth that emerges from the complexities of the analysis, is that balancing the market implications of a higher renewables grid will be just as important, and challenging, as the technical challenges raised by the new generation sources.

Image: Lake Bonney wind farm

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APPENDIX

The classification of monthly generator bid behaviour was conducted as follows:

1. The analysis was limited to solar and wind farms which had reached 95 per cent of maximum allowable generation by at least 1 January 2021. This restricts the analysis to 85 generators. For each farm, months prior to the achievement of 95 per cent of maximum allowable generation were excluded from the analysis.
2. Dispatch intervals in which the 5-minute spot price was negative were identified. Any 30-minute interval containing at least one negative 5-minute spot price was classed as a negative price interval. Any such interval and any 30-minute interval either side is a 'negative price related interval' (NPRI). All other intervals are not NPRIs.
3. All bids associated with each 5-minute interval were identified. For each bid, the price at which the largest volume of energy is offered was identified as the Bulk of Capacity Offer Price.[11]
4. For each generator for each month, the following statistics are calculated for NPRIs and all intervals other than NPRIs (Not NPRI).
   a. Offer Price Changes per Interval: Intervals in which the Bulk of Capacity Offer Price changed at least once for different bids associated with the same interval are classified as Offer Price Changes. The number of offer price changes is divided by the total number of intervals.
   b. Bid Price Changes per Interval: If the Bulk of Capacity Offer Price for the bid actually used in dispatch changed from the previous 5-minute interval, the interval is classified as a Bid Price Change. This is the number of bid price changes divided by the total number of intervals.
   c. Effective Rebids per Interval: A rebid is linked to an interval even if the availability bands for that dispatch interval do not change. An effective rebid is a rebid that changed the availability in at least one price band for a given interval. The Effective Rebids per Interval is the total number of effective rebids divided by total intervals.
   d. Median Bulk of Capacity Offer Price.
5. The following further statistics are calculated for each month:
   a. Offer Price Change Ratio: ratio of offer price changes per interval in NPRIs versus not NPRIs.
   b. Bid Price Change Ratio: ratio of bid price changes per interval in NPRIs versus not NPRIs.
   c. Effective Rebid Ratio: ratio of effective rebids per interval in NPRIs versus not NPRIs.
6. Each generator in each month received an initial classification as follows:
   a. Dynamic Bidding: Where the Offer Price Change Ratio is finite and greater than 1 and either the Bid Price Change Ratio or the Effective Rebid Ratio is finite and greater than 1. This indicates that rebidding activity is concentrated in intervals that are negative price events or which are linked to negative price events. This is consistent with a dynamic bidding strategy that is actively changing the offered availability in each price band to minimise the likelihood of dispatch during a negative price interval.
   b. Price Agnostic: Where the conditions for Dynamic Bidding do not apply and the Median Bulk of Capacity Offer Price is less than -$200 / MWh for both NPRI and other periods. The value of $200 / MWh represents the upper limit of energy prices under older PPAs entered into in approximately 2012 [13]. A farm that bids at less than -$200 / MWh is therefore unlikely to be relying on a guaranteed offset to prevent losses which would be expected if using a fixed strategy.
   c. Fixed Strategy: Where the conditions for Dynamic Bidding and Price Agnostic strategies are not satisfied. These are intervals where rebidding is not linked with negative price events and may be indicative of unrelated strategies, and the median offer price is greater than -$200 / MWh, indicating a considered level of risk.
7. It is assumed that generators do not change bidding strategies often. If two consecutive intervals and the majority of all subsequent intervals are initially classified Dynamic Bidding, all subsequent intervals are classified as Dynamic Bidding. Otherwise, single months where a generator was classified as following a particular strategy or consecutive months where the generator alternated its strategy, when all prior and subsequent months were classified under a different, single strategy, were re-classified to be the same as the strategy for the prior and subsequent months. Further, months where no negative price intervals occurred in the relevant region were classified based on the past or subsequent months where negative price intervals did occur.

11 See, eg, Figure 7.

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