A price mechanism survey of the Australian National Electricity Market

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Krisztina Katona[a,*], Christina S. Nikitopoulos[a], Erik Schlögl[b,d,c]

[a] *Finance Discipline Group, UTS Business School, University of Technology Sydney, Australia*
[b] *School of Mathematical and Physical Sciences, University of Technology Sydney, Australia*
[c] *The African Institute of Financial Markets and Risk Management (AIFMRM), University of Cape Town, South Africa*
[d] *Faculty of Science, Department of Statistics, University of Johannesburg, South Africa*

Abstract

The Australian National Electricity Market (NEM) is an energy-only zonal instance of the integrated pool model without a day-ahead market where a security-constrained economic-dispatch (SCED) engine controls dispatch and sets the price every 5 minutes. After a brief overview of pool markets across the world, this paper provides a detailed description of the NEM market design and price mechanism, drawn from a multitude of industry publications and the available auction data. Then to elucidate the NEM Dispatch Engine's process of wholesale price determination, a bid stack–type modelling framework is constructed from first principles with its suitability and limitations discussed against real-world examples from the NEM's SCED mechanism.

1. Introduction

Electricity is often traded in a natural monopoly and the effectiveness of the design of its market is constantly being probed by industry groups and the public in most jurisdictions across the world. Usually, markets are designed with the aim to provide power in a manner consistent with high standards of reliability and sustainability, maximising consumer welfare. Ideally, prices keep to the grid economics, i.e., they rise at times of scarcity and

*Corresponding author

drop otherwise, and return the true costs of capacity investments. Also, prices should efficiently approximate the plant economics on the supply side, even if those involve lumpy cost components. In fact, they should enclose all aspects of the unit of energy being traded, i.e., market mechanisms ought to minimise out-of-market payments that are not part of the price formation, in order to achieve a price quality wherein trade value maximisation is clearly apparent.

In the face of these challenges and the fact that power markets all have to balance supply and demand at hertz precision at all times, these markets have progressed to operate on vast and varied adequacy planning and dispatch schedules around the world. Some markets organise hourly day-ahead trading, others operate using 5-minute real-time settlement. Some co-optimise operating reserves, others trade those quantities separately from the energy spot market. Some rely on a security-constrained dispatch engine to solve for the efficient equilibrium price, yet others work on an exchange basis. The market methodologies can be very different from country to country and they have important implications for market price discovery.

The present work aims to introduce the zonal market design of the Australian National Electricity Market (NEM) and provide an in-depth survey of its price mechanism. Since price settlement is dispatch-based, i.e., pricing closely depends on efficient target scheduling under the security constraints in the NEM, the question of how the price is set gets complicated quickly due to the physical feasibility involved. It follows that the key security constraints must be identified and their overall effects assessed as part of the survey. The price, formulated as the cost of the marginal increase in load, will then be linked to the dispatch allocation of the last 1 MW energy.

Representing the price as the intersection of short-term supply and demand in a bid–stack–type framework is an implied assumption in a large body of price model literature (Barlow (2002), Howison and Coulon (2009), Aid et al. (2009), Carmona et al. (2013), Aid et al. (2013), Carmona and Coulon (2014), Filipović et al. (2018)). However, price-elastic wholesale load activity, co-optimised ancillary services, network losses, and congestion effects are rarely dealt with in the existing academic bid stack framework. Having unravelled the NEM-specific market design assumptions underpinning the way dispatch scheduling works, in order to replicate these in a bid–stack–type pricing framework one will also have to identify any constraint-driven non-bid factors and explain in detail how they appeared in the zonal market setup in the first place. That in turn enables a more accurate modelling of the NEM electricity market price on merit order bid stack principles. Explaining price formation as determined by the NEM's central dispatch engine within the theoretical bid stack framework as much as possible helps verify the applicability of the existing bid stack models to the NEM. Lastly, having resolved how the price is set, to the point of being able to replicate this process, lends a good vantage point for evaluating different aspects of market price formation in the NEM.

The paper is organised as follows. Section 2 gives an overview of the most common electricity market features worldwide and introduces market bid stacks. Section 3 discusses the most important market design features of the NEM. Then, focusing on the NEM Dispatch Engine, Section 4 details target scheduling (dispatch) and Section 5 outlines price settlement in the Australian market. Finally, Section 6 concludes.

2. Electricity trading worldwide

Electricity is a heavily traded commodity in most markets around the world. Unlike most commodities, however, electricity is not globally transferable, nor is it economically storable. Infrastructural developments such as network extensions and storage technologies hold the potential to unwind these restrictions in the near future. At present, however, electricity is mainly exchanged at local or sometimes coupled markets, and almost always instantaneously.

Local markets typically adopt one of the two dominant market models, the integrated pool model or the exchange model, as classified by Cramton (2017) and Mayer and Trück (2018). The integrated model finds the price as the equilibrium result of a security-constrained dispatch optimisation using actual system information. Pricing is ex-post, and dispatch-based, therefore it more aptly reflects the true grid economics given the security constraints. In contrast, the exchange-based model obtains the equilibrium solution as an optimum result from voluntary bid participation, similar to the financial markets. Pricing is therefore exante, it is not based on actual dispatch, and it may lack validity.[1]

This paper focuses on spot price markets in the integrated pool model, which can be as extensive as to cover various bid offer curves, virtual bids, and forward contracts simultaneously in the market value maximising central dispatch algorithm (Ott (2003) and Cramton (2017)). The simple bid offer curves recording competitive price-quantity bids per unit are relatively widespread. But because the cost function of the market value maximisation often exhibits non-convexities due to the lumpy features of the market, e.g. due to start-up costs, must-run times, unit commitment (on/off) etc., other more involved multi-part bid curves are also fairly common (Hogan (2014) and Cramton (2017)). Multi-part bid curves internalise the fixed energy economics of the plant, including some non-convex start-up and minimum energy costs. Contrary to the simple and the multi-part bid offer curves, which usually involve physical amounts, virtual bids are financially settled (Ott (2003)). According to Cramton (2017), virtual bids have been found particularly useful in resolving cost non-convexities and other spot market frictions by providing liquidity. Furthermore, forward contracting, i.e. bilateral transactions into the spot market, have also been shown to help disincentivise strategic bidding (gaming) in the spot market.

Energy is the main commodity in the various bid offers, but there is reserves trading too, in most dispatch-based markets, to promote reliable non-stop supply. Energy and reserves are more or less identical in material substance, with delivered quantity measured in watt-hours (Wh)[2], but they have very different roles in the system. As in Cramton (2017), "operating reserves" is a broad area covering a number of ancillary services. Generally, the installed capacity on standby in various ancillary services is potentially co-optimised with energy, but an installed capacity on standby earning scarcity rent through the capacity markets may not be. Further, the contracted demand response before involuntary load shedding and the contracted reliability unit commitment are mostly also not co-optimised out-of-market operations, as detailed in Hogan (2014) and Cramton (2017).

Despite the wide range of bid configurations allowed in some integrated market designs,

[1] Mayer and Trück (2018) explain that "As the market is balanced only based on the price, technical limitations can sometimes make it impossible to physically fulfill the trades."

[2] Watt-hours is a unit of energy obtained as a unit of average power (in Watts) multiplied by a unit of time (in hours).

every aspect of market settlement can rarely be covered in one central dispatch. Therefore, uplift payments are also often needed. Common examples include the make-whole payments that compensate when the non-convex costs are not funded by the spot price, the out-of-market service payments mostly for not co-optimised ancillary services, the payments related to out-of-merit interventions such as reliability unit commitment, and the compensation payments for firm access,[3] e.g., when nominally low-priced quantities are curtailed in the dispatch outcome.[4] The uplift payments are normally socialised with no effect on the spot price (Hogan (2014)).

Finally, alternative forms of electricity exchange have also greatly proliferated in recent decades. Some examples are bilateral contracts such as power purchase agreements, behind-the-meter batteries, not-integrated hybrid utilities, e.g., wind farms combined with battery storage, distributed energy resources, e.g., rooftop solar, and decentralised demand response activities. These solutions are all viable, but usually small-scale or increasingly integrated into wholesale trading. In this paper, we only discuss these alternative forms of exchange as relevant to the wholesale spot price.

Exploring the similarities between pool markets worldwide with an emphasis on price discovery, there are two main shared facets between most wholesale markets in the integrated model. First, because the economic objectives of the agents are virtually indistinguishable and the transmission networks acting as the distribution channel have similar physical constraints, the market participants and the governance goals are broadly the same as well. Second, as the price solutions adhere to the merit order rule and constitute uniform prices so that every MW power is sold at the same price to some - albeit varying - degree of price locality, i.e. at a locational marginal price, but not without security constraints, the security-constrained utility maximising price protocols will perforce bear some resemblance too. We discuss these aspects next.

[3]Financial firmness is volumetric certainty about the contracted transfer.

[4]For further discussions about the uplift payments see Hogan (2014) and Cramton (2017). Note further that NERA (2013) (pages 13-16) provides an assessment for the possible curtailment of nominally low-priced quantities.

2.1. Market participants and governance goals

Due to the natural monopolistic setting, the perhaps most overt similarities between the pools at different geographic locations are the similar sets of governance goals and system participants. This section presents the four most general governance goals and the usual system participants involved on the operative side of market conduct.

The rule maker sets out the market regulations in four important directions. The rules are promoting short- and long-run reliability, equitability, and sustainability through generation, storage and transmission investments, market power mitigation, efficient equilibrium price approximation, and efficient hedge markets[5]. First, the market design incentives for new investments aim to meet the dual goal of having sufficient long-term generation capacity as well as adequate operating reserves to manage the short-run scarcity risk. Secondly, market power mitigation is necessary to ensure that the agents are unable to move the prices unilaterally, in order to maintain an equitable market environment and consumer welfare (Cramton (2017)). Thirdly, drawing from the arguments put forward in Hogan (2014), the efficiency of the dispatch-based price outcome, i.e., market price quality, is of interest while aiming to keep the uplift payments at a minimum, so that the spot prices determined at the efficient grid equilibrium better reflect the costs of capacity investments. Finally, liquid and efficient hedge markets are beneficial for participants to continually manage the price risk, basis risk, and dispatch risk involved in their physical and financial positions. Price risk arises out of spot price volatility, whereas basis risk denotes the zonal or nodal price differentials between the prices at different locations due to losses and congestion (AEMC (2018a), page 56). Dispatch risk is about the lack of financial firmness in dispatch; it is the risk of not being dispatched, e.g., being curtailed due to security-constraint costs in spite of bidding price competitively[6].

The distribution system operator (DSO), or so-called the market operator, is the central entity mandated to plan out the processes for orchestrating optimal power flow (OPF) and spot pricing, and to operate the market in real-time, in agreement with the above outlined

[5] See Cramton (2017) for a global overview of electricity market governance objectives and AEMC (2018a) (pages 56-59) for a discussion of particular issues in efficient equilibrium price approximation.

[6] Following the definition of dispatch risk in AEMC (2018a) (pages 57-59).

governance goals. Besides these core functions, market operators may or may not also own and manage assets and hold responsibilities in facilitating auxiliary functions such as forward contracting, financial rights trading, capacity trading, etc., while maintaining some degree of their independence (Cramton (2017) and Hogan (2014)). Whether there is one system-wide DSO, or many operators perform these functions at the same time through coaction, depends on the jurisdiction and the governance choices, as do many other settings (Eydeland and Wolyniec (2003), pages 5-6). However, it follows from the discussion in Cramton (2017) that the independence of the market operator is generally preferred for market power concentration reasons.

The generator and load units are the main body of bidders. Generator units produce and sell electricity. They may be powered by thermal, renewable or nuclear fuels. Or, they can be the energy injection legs of integrated two-way units, i.e., units endowed with storage capabilities such as pumped hydro or battery plant. In contrast, load units buy electricity from the grid. They can be load-only industrial demand response providers or the energy withdrawal legs of storage units (Cramton (2017)). Then the fuel or resource mix of a market describes the relative magnitudes of different fuels in the system, typically by nameplate capacity or by some historical throughput measure.

The transmission network and distribution network providers maintain the closely monitored electric network that connects the units and the end users, as detailed in AEMC (2022a). They keep the high voltage transmission lines, the substations with voltage transformers, the low voltage distribution lines, and the various grid forming and phase control equipment in stable and secure operating conditions. The lines have secure flow limits constraining throughput, and telemetry instruments including weather scans are installed to secure that OPF is being directed within these limits at all times, even during extreme events. Moreover, transmission and distribution lines inevitably incur electric losses due to resistance.[7]

The interconnectors are the actively maintained transmission lines that carry capacities between the regions if a market has multiple interconnected price regions (AEMO (2018a),

[7] Personal communications with Bill Jackson (ElectraNet) Oct 28, 2021.

page 5). Similar to the intra-regional lines, interconnectors, too, have physical capacity limits and incur transmission losses[8]. According to AEMO (2015a) (page 7), these can be directed lines under the market operator's management or market interconnectors that participate by placing bid offer curves.

Finally, the retail utility providers are entrusted with representing the end users in accessing volumes from the wholesale market. They ensure that the demand of the consumers is being made available to them at the flick of a switch. However, the 2000-1 distress of the California market also illustrates the case for efficient hedge markets benefiting retailers.[9]

2.2. Security-constrained least-cost pricing

Energy is typically cleared as a homogeneous commodity in multi-unit auctions,[10] which is an umbrella term including discretionary price, uniform price and Vickery auctions. Any of these settings could apply to electricity pools (Hinz (2004)). We focus on (automated) electricity auctions adhering to uniform price principles only. These trade every MW of delivered quantity at the same price within the price locality, e.g. a price region.

In integrated market models the real-world uniform price auction protocols maximise the economic utility of the customers under security constraints. The uniform price is set as low as possible, given the bid-in quantities (MW offers) in merit order,[11] using three important notions: The first is that stacking the bids from the bid offer curves already in the most basic way develops some implied supply and demand curves, the equilibrium of which defines the price. Second, these implied curves for energy remain well understood in the marginal pricing framework, which also introduces losses, reserves and congestion to price discovery. Third, the physical constraints of the interconnected networks have price effects as well.

2.2.1. Market bid stack framework

The as-bid bid offer curves are a series of price-quantity bids offered by the bid-eligible units to indicate their preferred terms. The standard unit of measurement for the bids is dollar per megawatt hour ($/MWh). These rates are later converted into the sustained rate

[8]The calculation of interconnector losses is detailed in AEMO (2009) (pages 3-4).
[9]A detailed account of the California market crisis is set forth in Cramton (2017).
[10]For auction theory we refer the reader to Krishna (2009).
[11]We use the merit order concept based on Hinz (2004).

of dispatch in megawatt-hours, which can then be apportioned to the duration of the trade period, e.g. to 5 minutes. In most markets, units may change their bids over time, and therefore the merit order is dynamic over time. Alternatively, should the majority of the bidders use the same bids for days or longer, i.e., not change the term structure of their offers, perhaps due to a market specific rule, then the merit order of the bids could be described as non-dynamic (Carmona et al. (2013)).

There are two main types of energy bid offer curves. Firstly, generator bids are positive quantities placed by plants that wish to sell (supply) electricity. Regardless of actual plant availability, generators are usually required to partition their full capacity into quantity blocks and then to assign every block the least price for which they would sell the block. Keeping the increasing price order of the blocks fixed, the generators thus may submit a bid for each of the blocks into which they had split their maximum capacity. The number of blocks is usually capped by the market operator. For the uniform price, the market operator subsequently sorts the cumulative price-quantity blocks of the generator in ascending order on price, i.e., in merit order, and sums the energy quantities offered at or below every price. This gives the as-bid implied inverse supply curve of the generator units, the total generation expressed as a function of the price. The step-wise view thereof is the inverse of the generator bid stack function. In the mainstream structural modelling literature, the generator bid stack function, i.e., the step function that expresses the price as a function of the total generation without load activity, is the as-bid market bid stack function.[12] The market operator may then assume that demand is inelastic (see Section 4.3) and take that the least-cost price is set at the dollar level at which the demand line intersects the market bid stack. Identically, the marginal system cost of energy is the price of the last bid in merit, i.e., it is the most expensive bid still needed to fill demand.

Secondly, two-way fuel units simultaneously offer negative supply (demand) on their load legs and positive supply on their generation legs. The negative supply offers to buy electricity are the load bids. Regardless of the actual availability, the full load capacity on the load legs

[12] The mainstream bid stack price modelling literature mostly but not exhaustively comprises Barlow (2002), Howison and Coulon (2009), Aid et al. (2009), Carmona et al. (2013), Aid et al. (2013), Carmona and Coulon (2014), Filipović et al. (2018).

is partitioned into quantity blocks. The highest buy price is then assigned to each. Keeping the decreasing price order of the blocks fixed, the load units may then submit a bid for each of the blocks, into which they had split their maximum capacity. The number of blocks is capped by the market operator. The construction of the market bid stack function is then not fundamentally different in the presence of two-way fuels, save for that the negative energy quantities are summed with negative signs. For the uniform price, the market operator first computes the cumulative sum of the negative load block quantities at or above every price in the combined bid set. This then gives the as-bid implied inverse demand curve of the load units, the total negative supply quantity over the price range. The step-wise representation of that is the inverse load bid stack. The as-bid load bid stack is the step-wise relation for negative supply that expresses price as a function of the negative supply quantity. Although load bid stacks are not common in the mainstream literature, discussing them here is a step towards realism for markets with considerable two-way fuel and load-only activity. The load bid stacks are coalesced with the generator bid stacks in the market by summing the offered negative and positive quantities, respectively, at every price over the full price range. The elastic implied demand curves of the two-way fuels or the load-only activity (with positive quantities, i.e. the mirror images of the load bid stacks along the y-axis) are then implicit in the market bid stack[13] by construction. The market operator may then use this modified market bid stack to read the price off at the price-quantity point at which the supposedly inelastic demand line intersects it, or by other means find the last available bid.

The assumptions for establishing the merit order market price as the marginal system cost of energy from bidding are direct developments from economic theory. At market level, the uniform price bid stack mechanism we describe is akin to the standard supply-demand mechanism in microeconomics. That is, we let aggregate market demand be fully inelastic and conjecture, based on the mainstream bid stack modelling literature, that the inverse market bid stack represents the aggregate market supply. Also, the merit order corresponds to trade utility maximisation on the basis of price competition. At unit level, in stating that the bid stacks of the generators resemble an implied inverse supply relation, we are

[13]The market bid stack is most generally shown with quantity along the x-axis and price along the y-axis.

affirming a fundamental assumption from the parametric bid stack model literature. For loads, however, the implied inverse demand representation is a new assumption, as load units have not been included in the bid stack modelling literature in this way. The price impact of such an embedded elastic negative supply curve is examined in Table 2.

Furthermore, the notion that the last bid in merit, rather than the next unused bid, sets the price, is based on the principle proposed in Hua et al. (2019) that a commercial dispatch solver would price the last MW.[14] The left-continuity assumption for the generator and load bids follows from the last MW premise as well.

The above discussion of the price discovery process and the example below demonstrate the mechanics of the implied supply and demand curves and the price calculation with the two types of energy bids. However, the now presented framework is relatively simple in the sense that it omits reserve bids, security constraints, losses, and interconnectors from the price setting context, which we shall later include. This example shows the basic construction of the market bid stack step function with and without two-way fuel activity:

Example 1

We calculate the uniform price on merit order principles to illustrate the price effect of the two-way fuel activity in the market. The two-way loads are assumed to use a generic strategy whereby they bid considerably lower to buy than they bid to sell.

To start, let a market receive three generator bids, 20 MW at \$100, 70 MW at \$1000, and 10 MW at \$10 and no load bids at first. The merit order can then be written as (10 MW, \$10) $\rightarrow$ (20 MW, \$100) $\rightarrow$ (70 MW, \$1000), in increasing order on price.[15]

[14]This relates to the problem of dual degeneracy in the marginal price when that is determined as the dual variable of the demand balance constraint (as in Section 2.2.2). If one was to write a simple linear example for security-constrained least-cost dispatch as a two-band minimisation problem in its Lagrange equation form, such that both bands were completely dispatched, seeking to determine the price as the Lagrange multiplier, one would find that the price cannot be uniquely determined without an assumption about whether the last MW or the next hypothetical MW is used to set the price (Wood et al. (2013), page 114). This pre-assumption case leaves infinite price solutions within the price range defined by the marginal costs considering the last MW and the next MW at the end points of the range, i.e., a problem of dual degeneracy within the range, for the given edge case when both bid bands are fully utilised. Hogan (2012), Ela and O'Malley (2015) and Biggar and Hesamzadeh (2022) reach the same conclusion for more general settings and explain that the problem is due to the (piece-wise) linearity of the solver's objective function and that it implies the time inconsistency of the trade value maximising price outcome.

[15]In this notation, (10 MW, \$10) refers to 10 MW of energy being supplied at \$10 or more until it is

It follows that the generator bid stack, the cumulatively increasing generation offers 1 (10 MW, \$10) $\rightarrow$ 2 (30 MW, \$100) $\rightarrow$ 3 (100 MW, \$1000) is the as-bid market bid stack that is left-continuous. Note the implications of left-continuity. At every bid price the generation quantity goes up to the full bid quantity (inclusive), which implies the possibility of complete dispatch. However, zero dispatch is impossible given the left-continuous definition of the first bid in merit order. Also, should the price fall between two bid prices, the associated quantity is the lower one at the lower price, i.e., suppliers do not offer to sell additional quantities at prices below the next bid price, which makes economic sense. For example, at \$900 that falls on $[\$100, \$1000)$ the generator bid stack takes 30 MW as at \$100, and not 100 MW as at \$1000. Therefore, in the inverse view in Table 1, 1 (10 MW, \$10) is 10 MW on $[\$10, \$100)$, 2 (30 MW, \$100) is 30 MW on $[\$100, \$1000)$, and 3 (100 MW, \$1000) is 100 MW on $[\$1000, \infty)$.

The market operator may then assume that demand is inelastic and use the economic notion that the least-cost price is set at the dollar level at which the demand line intersects the market bid stack. Identically, the least-cost price can also be found as the price of the last bid in merit. For the price calculation, let pool demand be 50 MW. Because 30 MW is not enough to fill 50 MW in full, the last bid used for setting the price at the marginal system cost would be the third in merit order: (70 MW, \$1000). To the same effect, the market operator could just evaluate the last rung of the market bid stack at the demand quantity, 3 (100 MW, \$1000) to get the unit price of the incremental 1 MW energy at 50 MW. The generation-only price is 1000 \$/MWh both ways, as in Table 2.

Now consider adding one positive 35 MW at \$2000, and three negative load bids -20 MW at -\$10, -10 MW at -\$100, and -5 MW at \$900 to the market for the two-way fuels, which sum to zero MW overall. The bid on the generation leg can be appended to the previous generation bid stack (positive supply), and the load leg can be treated as negative supply. First, the load merit order is (-10 MW, -\$100) $\rightarrow$ (-20 MW, -\$10) $\rightarrow$ (-5 MW, \$900) in increasing price order. Then the load bid stack 1 (-25 MW, -\$100)

superseded by the next bid, (20 MW, \$100) supplying an additional 20 MW at at least \$100.

→ ② (-5 MW, -\$10) → ③ (0 MW, \$900) is the cumulatively increasing energy load in merit order that is left-continuous. Note the implications of left-continuity. The load fuels can never be dispatched in the full bid volume, but they can go to nil easily. Also, should the price fall between two bid prices, the associated quantity is the more negative one at the lower price, i.e., buyers offer to buy more quantities at prices below a given bid price. For example, the load bid stack at \$10 that falls on $[-\$10, \$900)$ takes -5 MW as at $-\$1$, and not 0 MW as at \$900). In this way, ① (-25 MW, -\$100) is -25 MW on $[-\$100, -\$10)$, ② (-5 MW, -\$10) is -5 MW on $[-\$10, \$900)$, and ③ (0 MW, \$900) is 0 MW on $[\$900, \infty)$ in Table 1.

Additionally, the generation leg of the two-way fuel gives the last rung of the combined generator bid stack ① (10 MW, \$10) → ② (30 MW, \$100) → ③ (100 MW, \$1000) → ④ (135 MW, \$2000) that is 135 MW on $[\$2000, \infty)$ due to the left-continuity on the inverse.

Table 1: **Market bid stack with two-way fuel activity**

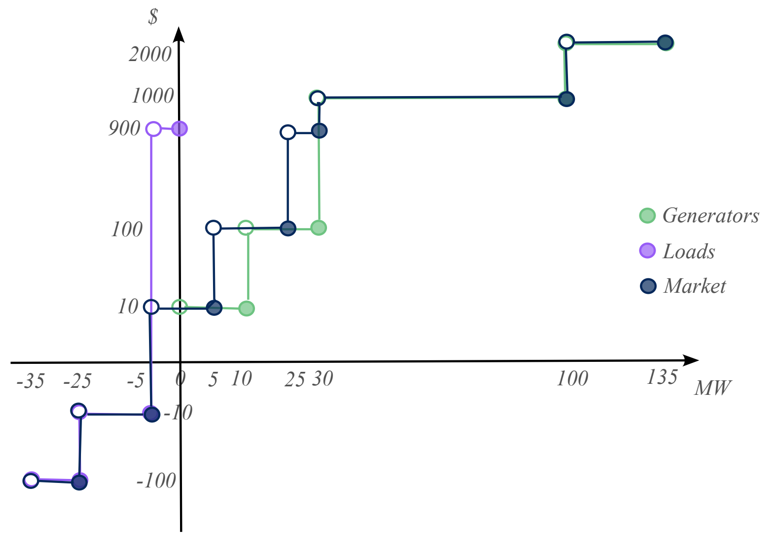
The table coalesces the positive generator bid stack and the negative load bid stack in the market at every price. This gives the market bid stack as ① (5 MW, \$10) → ② (25 MW, \$100) → ③ (30 MW, \$900) → ④ (100 MW, \$1000) → ⑤ (135 MW, \$2000).

Price	Generation fuels: generation bid stack (MW, \$)			Two-way fuels: generation and load bid stack (MW, \$)				Market bid stack
level	① (10, \$10)	② (30, \$100)	③ (100, \$1000)	④ (135, \$2000)	① (-25,-\$100)	② (-5,-\$10)	③ (0, \$900)	(MW, \$)
-\$100	+0 MW				-25 MW			Negative MW
-\$10	+0 MW					-5 MW		Negative MW
\$10	+10 MW						-5 MW	① (5, \$10)
\$100		+30 MW					-5 MW	② (25, \$100)
\$900		+30 MW					-0 MW	③ (30, \$900)
\$1000			+100 MW				-0 MW	④ (100, \$1000)
\$2000				+135 MW			-0 MW	⑤ (135, \$2000)

For the price calculation with load bids, the load-adjusted market bid stack coalesces the positive generator bid stack and the negative load bid stack quantities at every price in the market. As shown in Table 1 and Figure 1, meshing the generation and the load bid stacks gives the load-adjusted market bid stack as ① (5 MW, \$10) → ② (25 MW, \$100) → ③ (30 MW, \$900) → ④ (100 MW, \$1000) → ⑤ (135 MW, \$2000). This ordering can then be used to determine the system cost price at 50 MW demand. Because 30 MW is not enough to fill 50 MW in full, the last rung of the market bid stack, ③ (100 MW, \$1000) would be used for setting the price. That gives a price of 1000 \$/MWh for the last 1 MW.

Figure 1: **Market bid stack**

The figure shows the aggregate market bid stack that coalesces both generation and loads bids as in Example 1.



In edge cases, i.e., at quantities at full bid amounts, the price is still the price at the aggregated market bid curve. For example, 30 MW demand is an edge case, because the first two generator bids in merit order sum to 30 MW, while the offset from the load bid is zero MW, as shown in Figure 1. Here, the price would have been \$100 in the absence of load activity (green), but with loads the price is \$900 instead. Note that because of the left-continuity, this value is consistent with any quantity over the last 1 MW, i.e., on the range of (29 MW, 30 MW]. In this example, at 29 MW there is 1 MW load activity and 30 MW dispatched generation, after which the load is shed at 30 MW over the incremental change, hence it is the price of the load bid that sets the price.

To evaluate the price effect of the two-way fuel activity, i.e., the embedded elastic negative supply curve, we show an illustrative breakdown for different levels of demand in Table 2. As one might expect, the load legs of the loads absorb supply at low prices, which contracts the implied inverse supply curves if demand is low. As a result, the load effect is higher prices at lower levels of demand, i.e., a price of \$100 between 5-10 MW instead of \$10 and \$900 between 25-30 MW instead of \$100 as in Table 1. In summary, when loads follow a broadly typical buy low sell high strategy the price effect is a price increase at lower quantities and a quantity increase at high prices at higher quantities.

Table 2: **Price effect of two-way fuel activity**

The table shows the merit order price effect of adding two-way loads to the market (right) compared to the generator-only setting (left). Price differentials arise between 5-10 MW and 25-30 MW.

Demand	Generation-only	With two-way fuels
[0 MW, 5 MW]	$10	$10
(5 MW, 10 MW]	$10	$100
(10 MW, 25 MW]	$100	$100
(25 MW, 30 MW]	$100	$900
(30 MW, 100 MW]	$1000	$1000
(100 MW, 135 MW]	$2000	$2000

2.2.2. Marginal pricing principles

The market price is thus determined as the marginal system cost of energy, i.e., the cost of an incremental 1 MW load, which is typically given as the dual variable of the demand balance constraint of the linear programming (LP) central dispatch program.[16] Locational marginal pricing (LMP) principles are now introduced for a more complete treatment of security-constrained least-cost marginal price discovery in a general direct current (DC) load flow model in line with the work of Schweppe et al. (1988).[17]

There are two frequent settings of the LMP method, nodal and zonal. The nodal model uses every substation bus (source) separately as an injection point to obtain the gradient of the total system cost for marginal demand withdrawals at the reference node, ex-post, given the dispatch solution (Ott (2003)). It computes many different market prices at a multitude of locations for the same network area. It follows that the nodal LMP can comprehensively price congestion, as it considers various transmission routes separately, as highlighted in AEMC (2020) (pages 18-22). In the zonal (regional) setting, in contrast, the market price is calculated as the gradient of the total system cost for a change in the demand at a single

[16] "Economic theory derives the fact that marginal cost pricing is optimum in a social welfare sense. This can be viewed as a way to introduce spot prices which causes the customer to choose a value for demand which satisfies the social optimality conditions for the demand at the time." as in AEMO (2012c) (page 9).

[17] The standing theory of efficient spot pricing using DC flow approximation by Schweppe et al. (1988) depicts a mostly unregulated, centrally-dispatched, energy-only system with liquid forward markets (Simshauser (2019)). So far, this market design has not become a reality since the inception of the framework, because the theory assumes short-term demand price-elasticity. Even today, consumers are seldom able to react to spot price signals as real-time metering is fairly uncommon (Hirst and Hadley (1999), Stoft (2002), Bidwell and Henney (2004), De Vries (2005), Joskow (2008).)

reference node of the network area (swing bus or sink), ex-post, after the dispatch result is known. Therefore, there is only one zonal price per network area. The zonal setting is usually viewed as an approximation of the fully-fledged nodal LMP design (AEMO (2012c), page 10).

Most commonly, nodal prices can be decomposed into the bid-in marginal system cost, the locational marginal loss, and the locational marginal congestion. A simpler representation of nodal prices in Ott (2003) omits marginal losses, whereas the more general form in Hogan (2014) accounts for both the co-optimised reserve requisites and losses. We can write the price p_i at node i for all k in the binding constraint set B as

$$p_i = \lambda_N^{c,l} - \sum_{\forall k \in B} A_{i,l,k} S_k, \tag{1}$$

where $\lambda_N^{c,l}$ denotes the marginal cost of energy for a unit change in MW injection at node i withdrawn at the reference node N, co-optimised with reserves (upper index c), and after losses (upper index l)[18], which can be collapsed to the as-bid marginal system cost of energy as $\lambda_N^{c,l} := \lambda_i$ neglecting reserves co-optimisation and losses. Then $A_{i,l,k}$ denotes the constraint coefficient, the power flow change over network element (link) l for a unit increase in MW injection at node i and withdrawal at node N. Furthermore, S_k denotes the shadow price (marginal value) of the constraint, the cost of a unit increase in the constraint coefficient with respect to constraint k. Note that $S_k = 0$ for all non-binding constraints. Therefore, p_i at all locations i collapses to the same system price $\lambda_N^{c,l}$ if there are no binding constraints. When there is a binding constraint over any link l, however, that affects every nodal price with a non-zero constraint coefficient $A_{i,l,k}$ for l anywhere in the network.[19]

Hogan (2014) warns that dispatch-based LMP is built on the actual dispatch solution, which is an imperfect approximation of the optimal outcome, and therefore, the accuracy of the constraint coefficients might deviate from the optimal flows when there is reliability unit

[18] Equation (1) restates the first equation on page 534 in Ott (2003).

[19] As Hogan (1999) writes for non-radial networks, "A single transmission constraint in an electric network can produce different prices at every node. Simply put, the different nodal prices arise because every location has a different effect on the constraint. This feature of electric networks is caused by the physics of parallel flows." Otherwise, the constraints over the links only apply for neighbouring nodes.

commitment or other lumpy system requirements. Indeed, sometimes not all binding constraints are used, e.g., contingency constraints may be left out (Ott (2003)). Similarly, based on Cramton (2017), the constraints that are non-competitive by some market concentration or constraint violation measure may be removed to mitigate market power anomalies.

In contrast, the zonal price at reference node N breaks down into the bid-in marginal cost with reserves co-optimisation and losses as

$$p_N = \lambda_N^{c,l}, \tag{2}$$

because $A_{ik} = 0$ at N as in Biggar and Hesamzadeh (2014) (page 154). The shadow price of the constraints (congestion) is no longer explicit in (2) compared to (1).[20]

2.2.3. Security-constraint price effects

Although the security-constraint bottlenecks are not explicit in the zonal price in (2), the physical limitations are nonetheless present in the network and they inevitably influence the viable set of MW offers for dispatch, and therefore also the market price outcome. Whatever bid or bids turn out to be marginal and in what quantity depends both on the demand level and the underlying constraint topography.[21]

Two price channels are associated with the physical constraints that can modify the merit-order-based marginal bid selection for computing the marginal system cost of energy before losses λ_N^c in (2). First, the bid-in quantities are constrained-on or constrained-off in out-of-merit interventions.[22] Second, quantity offsets due to binding constraints over the marginal 1 MW are fairly common. Both price effects stem from preempted constraint violation.

First, the constrained-on quantities are nominally high-priced MW offers that must run either because of binding technical limitations such as a ramp-down rates or to relieve sys-

[20]The nodal structure better disentangles the shadow price of line congestion at least in radial systems. By contrast, the zonal design without nodal price differentials tends to export the price effects of local line limits to entire regions (AEMC (2019a), NERA (2020), AEMC (2020) and Leslie et al. (2019)).

[21]Including the effects of security constraints relaxes the "as-bid" assumption and replaces it with an "as-feasible" view of the market bid stack.

[22]The scenarios shown in AEMC (2018b) (pages 242-254) and AEMC (2018a) (page 57) detail the conditions for constraining quantities. See also AEMO (2021b) (page 6-7).

tem gridlocks by buying, e.g., inertia or system strength counterflows. Analogously, the constrained-off quantities are nominally low-priced MW offers that are curtailed due to binding technical limitations, e.g., thermal constraints, ramp-up rates, the lack of system strength, or any other constraint. While these quantities appear uneconomic and economic, respectively, in a nominal sense, before considering any security-constraint non-bid factors, they are in fact feasible and unfeasible in the least-cost solution given the opportunity costs of breaching the physical limits of the network. On the supply side of things, constrained-on quantities are appended to the merit order, while constrained-off quantities are blocked out never to be included in the merit order. Translating that into the equivalent effect on inelastic demand, constrained-on quantities decrease demand while constrained-off quantities increase it. These modifications indirectly affect the marginal bid set and the price result.

Second, sometimes network elements must reduce throughput to relieve an otherwise violating constraint or to change around quantities (decision variables) within a binding constraint, in order to permit the incremental 1 MW power flow increase on the grid. Although the net amount of reduction and increase would equal 1 MW, these forced changes most probably involve targets summing to more than 1 MW that directly affect the marginal bid set and the price result.

Expanding on Example 1 from Section 2.2.1, Example 2 explains the price impact of these indirect and direct security constraint effects in greater detail.

Example 2

As earlier, on a hypothetical grid with no security constraints, the unit price of the incremental 1 MW power at 50 MW demand is evaluated as 1000 \$/MWh using the as-bid market bid stack with two-way fuel activity ① (5 MW, \$10) → ② (25 MW, \$100) → ③ (30 MW, \$900) → ④ (100 MW, \$1000) → ⑤ (135 MW, \$2000). Similarly, price is \$100 at 15 MW demand.

Relaxing the no-constraint assumption, first, the constrained-on quantities are bid-in volumes that must run despite having offered a price in their bids that is above the market price (in the absence of constraints), that is, a price above 100 \$/MWh at 15 MW demand. Assume that 12 MW offered at \$2000 is constrained-on. This will see a negative demand adjustment of 12 MW. The demand after adjustment is 15-12=3 MW. The cost of the last MW supply from 2 MW to 3 MW is obtained as follows. Because 2 MW $\leq$ 5 MW and 3 MW $\leq$ 5 MW, the price is 1 $\times$ 10 \$/MWh using the adjusted demand and the original market bid stack. This shows that constrained-on quantities decrease the market price.

Second, the constrained-off quantities are bid-in volumes that are curtailed despite having offered a price in their bids that is at or below the realised market price, which is \$100 at 15 MW load. This constrained-off amount pops off of the market bid stack and the remaining market bid stack contracts leftward. Equivalently, demand is adjusted upward by 12 MW. For 15 MW demand, the demand after adjustment is 15+12=27 MW and the market bid stack stays as is. Then the cost of the last MW supply from 26 MW to 27 MW is obtained as follows. Because 26 MW $\geq$ 25 MW and 27 MW $\leq$ 30 MW the price is 1 $\times$ 900 \$/MWh. This shows that constrained-off quantities increase the market price.

Moreover, when a network bottleneck reduces MW flows on some nodes and increases them on others, so that the net as seen in dispatch-based pricing is always (approximately[23]) 1 MW, we might observe the following at 50 MW demand. The incremental 1 MW power is subject to a binding constraint $1 \times q_A + 0.8 \times q_B \leq 10$ where q_A and q_B are the node level decision variables. If this constraint is already binding, i.e., $1 \times q_A + 0.8 \times q_B = 10$, then the changes in these decision variables must be such that the constraints left hand side (LHS) does not increase above zero ($1 \times \Delta q_A + 0.8 \times \Delta q_B \leq 0$), but their sum increases by 1 MW ($\Delta q_A + \Delta q_B = 1$). In the solution, $-\Delta q_A$ =4 MW power is removed from the node that serves the quantities 45 to 49 MW in the market bid stack, and Δq_B =5 MW is supplemented from the node dispatching 49 to 54 MW in the market bid stack. This will see no demand adjustment and no change in the original market bid stack, only a significant "multiplier change" in the price calculation. For 50 MW demand, because 44 MW $\geq$ 30 MW and 54 MW $\leq$ 100 MW the price is -4 $\times$ 1000 + 5 $\times$ 1000 = 1000 \$/MWh using the original market bid stack.

[23] Ignoring losses in this discussion.

A small variation to the above example would be a removal of 4 MW power from the node that serves the quantities 16 to 20 MW in the market bid stack, if that corresponds to $-\Delta q_A$ =4MW, as a way of relieving the binding constraint and causing the price effect. In addition, Δq_B =5 MW is also supplemented from the generation node dispatching 49 to 54 MW in the market bid stack. In combination, the reduction and the increase result in a net 1 MW incremental change in quantity. Then the price becomes -4 $\times$ 100 + 5 $\times$ 1000 = 4600 \$/MWh using the original market bid stack, giving rise to a price increase relative to the price ignoring the security constraints.

2.3. Differences in market design and fuel mix

As related to price discovery, the number of prices per market, the timing of the trade intervals, the regulatory price thresholds, the basis for bidding, the extent to which the reserves are co-optimised and the fuel mix are the main differences between the integrated spot market auctions around the world.

To begin with, the market prices are published per price node in nodal markets and per price region in zonal markets (Eydeland and Wolyniec (2003) (page 11) and Cramton (2017)). As regions involve multitudes of nodes, there are only a handful of prices in regional markets, but hundreds easily in nodal pools (PJM (2022)). Yet other markets operate in a single-price setting, where there is only one price per country (Mayer and Trück (2018)).

Secondly, pools specify the dispatch and the trade intervals for the day-ahead, real-time or multi-settlement schedules usually at 5-minute, 30-minute or hourly resolution, which impact the timing of the trade periods. The dispatch interval determines the periodicity for dispatch target allocation and the trade interval is the recurrence of price settlement. These may be aligned for a single schedule, or they may differ. Then there are two kinds of schedules, day-ahead and real-time. The day-ahead market is a form of forward market into the dispatch and trade periods of the next trading day. Plant may plan their delivery both physically and financially using the day-ahead market according to Ott (2003), as is common in many countries in Europe (Mayer and Trück (2018)). In contrast, bidding into real-time markets inevitably gives less predictable quantity outcomes as these are settled directly in the dispatch and trade intervals of the trading day. Real-time markets without day-ahead markets are common in Canada and Australia (Mayer and Trück (2018)). Nodal markets in North America tend to have both day-ahead and real-time schedules in combination. The purpose of this multi-settled design is to enhance the efficiency of the equilibrium price approximation for capacity decisions mainly through arbitrage between the day-ahead and the much more volatile real-time market.[24] Indeed, Ott (2003) shows for such a market that day-ahead and real-time prices strongly converge.

Thirdly, using a regulatory price band consisting of a price floor and a price cap, as mentioned in Barlow (2002), is a common technique for keeping the market price to a particular band.[25] Although these price thresholds are typically imposed at vastly different levels in different countries, the trade-off between a more restrictive and a less restrictive policy is well-understood. A narrower price band promotes price stability and impedes exercising market power, whereas a wider price band rewards private investment into generation and storage infrastructure.[26] The regulatory choice between the two works towards either mitigating or aggravating the positive and potentially negative price spike events.

Fourthly, some pools adopt a cost-based approach to bidding while others accept price-based bids. In the cost-based approach, the bids must reflect the bidder's audited production costs based on the short-run marginal costs of production (SRMC) as discussed in Munoz et al. (2018) and Ward et al. (2019). In the price-based (bid-based) setting, however, bidders are not limited on a cost basis (Munoz et al. (2018)), although regulatory price thresholds may still apply.

Moreover, as energy is aimed to meet end user consumption as precisely as possible, in principle, throughput follows centrally scheduled target directives, i.e. the units receive targets every dispatch interval. But because the scheduled demand by the end of the dispatch

[24]The advantages of the spot-forward arbitrage are detailed in Cramton (2017), Ott (2003) and Hogan (2014).

[25]The use of market price caps is a necessary measure from a theoretical point of view due to supply capacity limits and demand inelasticity. Relatively high levels of demand can threaten blackouts, i.e., that the market fails to clear an equilibrium as supply and demand never match, in which case the spot price tends to infinity (Stoft (2002), Finon and Pignon (2008), Cramton et al. (2013)). Such absurd spikes never arise under the ideal market design, but price caps must be used to avoid them in practise (De Vries (2005)). Indeed, a second-best social solution (second only to Schweppe et al. (1988)) is found by Stoft (2002) who modify this market design by setting the price cap at the dollar amount that consumers would agree to pay on average to avoid blackouts called the Value of Lost Load (VoLL). This optimum does not eliminate rolling blackouts, it optimises their duration, assuming that the administratively set VoLL is indeed an accurate measure of the disutility value (Cramton et al. (2013)).

[26]Personal communications with Bill Jackson (ElectraNet) Oct 28, 2021.

interval is necessarily a prediction, disparities will arise between the scheduled targets and the instantaneous consumption. In response, ancillary-type reserves can be kept on standby to safely balance the electric frequency of the system within a band around e.g. 50Hz (Eydeland and Wolyniec (2003) (pages 8-9) and Cramton (2017)). Energy pools are often augmented by ancillary-type reserves trading, although the details of synchronising energy and reserves are often extremely dissimilar. The two ends of the spectrum are when price settlement for energy and reserves is mostly joint (co-optimised) and the other end is when the two are fully separate, i.e., when all reserves receive out-of-market uplift payments. There are many configurations in-between. Different market designs can be developed to include some ancillary-type reserves in the co-joint processes e.g. frequency balancing, but not others, e.g. voltage stability or system restart services, as is the Australian experience (AEMC (2021b)).

Finally, there are a few reasons as to why the fuel mix would have an important role in market design. One aspect why the fuel mix must be a balanced mix of different resources is MW reliability to avoid short-run scarcity. Renewable energy, particularly wind generation, is highly intermittent, and requires quick-response high reliability complements such as hydro generation, battery throughput, or industrial demand response. Another challenge to the market design in allowing a high penetration of renewables that are inverter-based is that these resources do not provide inertia. Turbine generators that do such as gas and coal are in this case required in the fuel mix. Finally, depending on the dispatch formulation, some fuels are more likely than others to create lumpy costs in the network e.g. definite must-run conditions apply for coal based generation in Cramton (2017), which might make a stronger argument for a mixed integer dispatch solver as part of the market design.

2.4. Financial markets along electricity markets

Electricity markets today are often complemented by derivatives markets for price, congestion and scarcity risk hedging. First of all, they trade firm instruments on a fixed MW of electricity flow as the underlying asset to manage the spot price volatility of physically or financially binding firm positions (ASX (2022)). There are also products more specific to congestion-linked difficulties such as the basis risk and the dispatch risk. Point-to-point financial transmission rights (FTR) trading is common in nodal markets, which also provides financial firmness on the quantity according to Cramton (2017). Similarly, flowgate and other solutions have existed in zonal markets to provide firm access to hedge the dispatch risk associated with security constraints.[27]

Furthermore, capacity markets are annual forwards auctions for electricity trading during scarcity periods based on Cramton (2017). These aim to solve the dual problem of scarcity risk and suppressed spot prices insufficient to cover the costs of new generation investment by introducing another source of revenue for generators that are willing to reserve some of their capacity for reliability response in exchange of some forward-type payments as in Hogan (2014).

Any of these financial contracts are either physically settled, in which case the underlying commodity is physically transmitted, or they might be cash settled, in which case it is not. As trade with physical delivery requires transmission infrastructure, electricity market operators are in a unique position to facilitate trade or act as a counterparty in short-term (for example hourly or daily) derivative contracts with physical settlement if that is possible under the applicable legislation (Deng and Oren (2006) and Cramton (2017)). If not facilitated by the main market operator, physical settlement is either conditional on the cooperation of a private operator according to Eydeland and Wolyniec (2003) (pages 5-6), or off-grid purchase agreements can be struck if the generator is in the immediate vicinity of the buyer, and it is viable for the parties to set up a private transmission line as explained in Broom (2020). Once established, trade with physical settlement has a direct impact on price discovery as it is effectively removing both capacity and demand from the wholesale market.

In contrast, cash settlement makes financial contracts much more accessible, which implies higher liquidity for convenience-related financial reasons. These markets potentially also impact spot price formation, most directly by influencing the participants' bidding decisions.

3. An overview of the National Electricity Market (NEM)

We begin this overview of the Australian National Electricity Market with the sheer size of the grid. Spanning approx. 5,000 km end to end and counting six interconnectors and

[27] For an international review on creating congestion compensation and firm access see NERA (2013) (pages 13-23).

over 55 GW nameplate capacity, the NEM is the longest interconnected market in the world according to AEMC (2022a).[28]

3.1. Institutions

The responsibilities around the orderly operation and the effective oversight of the market are held by the following institutions. Firstly, the Energy Security Board (ESB) oversees that the evolving market design honours the NEM's commitment to efficiently integrating competitive new technologies and reducing the system's carbon footprint while maintaining strong system adequacy (ESB (2021), pages 15-28). Secondly, the Australian Energy Market Commission (AEMC) presides over rule making to promote the long-run interests of consumers as in AEMC (2022b). The AEMC establishes and amends the National Electricity Rules (the Rules[29]) under the National Electricity Law (as per Rule 1.2 in the Rules). Thirdly, the Australian Energy Regulator (AER) enforces the Rules made by AEMC as in AEMC (2022b).

Furthermore, according to AEMC (2022b), the Australian Energy Market Operator (AEMO) is the sole, independent market operator that establishes, reviews and executes procedures to fulfil extensive operative obligations in secure and reliable dispatch and price settlement under 3.2.1 in the Rules.[30] The AEMO automates the security-constrained least-cost auction mechanism in a linear solver framework, the NEM Dispatch Engine[31], which co-optimises the dispatch of energy and market-based ancillary services, such that interconnector flows, too, are synchronised over the five price regions in real-time (see 3.9.2 in the Rules). For the market to operate with the least amount of intervention as per 3.1.4 (a) in the Rules and AEMO (2020g) (page 5), supply-demand and bid analysis both by the market operator and by individual bidders heavily rely on telemetry, price (AEMO (2022f,c)), demand, and supply adequacy forecasts, and other information sources administered by AEMO. A

[28] The rest of Australia belongs to the Northern Territory Electricity Market (NTEM) and the Wholesale Electricity Market (WEM).

[29] The present paper is written using version 175 of the Rules, which is referenced in AEMC (2021b).

[30] The AEMO does not facilitate physically settled bilateral agreements and it is impartial to resolving current market issues.

[31] An open-source reference implementation of the NEM Dispatch Engine is also available thanks to Gorman et al. (2022).

wide array of these resources is also disseminated to registered market participants to inform their bidding and potentially re-bidding actions on the minute as per 3.1.4 (a.2) in the Rules. Some are also publicly available in the NEMWeb (AEMO (2022e)).[32] Finally, the different systems supporting the NEM Dispatch Engine are shown in Table 3.

Table 3: **Market systems**

The table lists the different AEMO data systems that underpin real-time dispatch by delivering pre-calculated values to the NEM Dispatch Engine.

System		Function
Automatic Generation Control	AGC	Communications tool for sending out dispatch instructions (as per 3.8.21 (d) in the Rules) incl. FCAS Regulation targets electronically (p. 9.) AEMO (2021e).
Australian Solar Energy Forecasting System	ASEFS	Solar forecast algorithm for intermittent output (UIGF) feeds to the NEM Dispatch Engine (p. 5.) AEMO (2021k)
Australian Wind Energy Forecasting System	AWEFS	Wind forecast algorithm for intermittent output (UIGF) feeds to the NEM Dispatch Engine (p. 5.) AEMO (2021k)
Electricity Market Management Systems	EMMS	Portal and API interface for submitting bids and intermittent plant availability (p. 1.) AEMO (2017d), (p. 10-11.) AEMO (2021h)
Market Management Systems Data Model	MMS Data	Data model for providing data to market participants. AEMO (2022a).
Market data NEMWeb	NEMWeb	Public website for historical data based on MMS Data. AEMO (2022e).
Network Outage Scheduler	NOS	Planned outage calendar for informing the medium-term adequacy process (p. 9-10.) AEMO (2018b), (p. 12.) AEMO (2020g).
Supervisory Control and Data Acquisition	SCADA	Telemetry system (metering) for informing higher level applications AEMO (2021e).

3.2. Market settings

The NEM operates in a zonal market design. There is one locational reference node, i.e., price node, for each of the five regions in the market - New South Wales (NSW), Queensland (QLD), South Australia (SA), Tasmania (TAS), and Victoria (VIC) - roughly corresponding to the administrative divisions of the country. Therefore, five market prices are issued by in the NEM Dispatch Engine per trade interval.[33] Note further that the nodal LMPs are also calculated in the NEM at every market connection point (bus) as a congestion information

[32]Indeed, a number of publicly available data sources underpin the present survey including the “Register of all current Market Participants” (3.2.1 (b) in the Rules) in AEMO (2020j), the bid submission files of AEMO (2021n) as part of the Market Management Systems (MMS) Data Model in AEMO (2022a), and the NEM Dispatch Engine outcome data of AEMO (2021m).

[33]See the RegionID and BandCost fields in the PriceSetting tab of the AEMO (2021m) data.

resource on mis-pricing as per 3.4.1 (3) and 3.7A (b.2) in the Rules to better understand the costs of security constraints. These costs are, however, not directly expressed in the five zonal spot prices.[34]

Since 1 Oct 2021, both the dispatch interval and the trade interval are 5 minutes in place of the earlier methodology with 30-minute trade intervals but 5-minute dispatch intervals, where six preliminary 5-minute prices had been averaged for every half-hourly price (p. 3, AEMO (2020i)). Therefore, the prices are single real-time (5-minute intraday) prices as there is no multi-settlement, nor market coupling in Australia apart from the import-export between the price regions. The switch to 5-minutes settlement prevents exercising market power through certain gaming strategies to bidding[35] and promotes price transparency.

Moreover, the NEM market design ascertains the following regulatory price threshold settings. A regulatory price floor is administered at −\$1000 per MW and a price cap at \$15,100 per MW as of Oct 2021.[36]. The price cap is also indexed to inflation based on AEMO (2020i) (page 3). This is a relatively unrestrictive policy compared to stricter regulatory thresholds in other markets worldwide.

3.3. Bidding rules

Bidding is price-based in the NEM. Bidding away from the verifiable costs, often by means of bidding software, called disorderly bidding, is fully consistent with the Rules. One implication of this and the fact that the prices are not suppressed between strict regulatory price thresholds is the lack of limitation on market power concentration, i.e., exercising market power through strategic bidding is evidently encouraged. On the other hand, the lack of limitation reinforces price results closer to the costs of capacity investments that better pay for new investments.

The bid-eligible units fall under the three categories of energy bidders (as per 3.8.6 and

[34] From a price quality perspective, explicitly priced congestion effectively recovers the security constraint costs (the shadow price) at different points on the grid. While the cost of congestion is directly expressed in nodal markets, the price only contains vague information about congestion in zonal markets.

[35] One such strategy involved bidding high to move the prices to the market price cap in the first 5-min interval and bidding low for the rest of the 30-minutes to collect the resulting relatively high price (after averaging) in large quantities.

[36] In line with AEMO (2020i) (page 3) and the AEMC reliability standards (as per 3.9.4 in the Rules) AEMC (2021a), respectively.

3.8.7 in the Rules), reserves bidders (as per 3.8.7A in the Rules), and market interconnectors, i.e. Market Network Service Providers (MNSPs) (under 3.8.6A in the Rules). The standard bid type involves ten price-quantity pairs, but there are a few more bid types within some bidder categories. Firstly, energy bidders, generators and loads[37] are warranted the standard ten and twice ten price-quantity bid slots every trade interval (as per 3.8 in the Rules), respectively, much like in the example in Section 2.2.1. An upcoming rule change may, however, replace the twice ten bid bands by 20-bid single trader submissions for the two-way fuels (AEMC (2019c), pages 2-4). Additionally, all energy bidders can use fixed bids too, for when they intend to act as price takers and secure trade amounts that might not be otherwise allotted to them in the auction.[38] Secondly, reserves bidders include two groups of service providers, the market-based ancillary service and the non-market scarcity reserves providers. The market ancillary services bids, i.e., the Frequency Control Ancillary Services (FCAS) bids are co-optimised with energy as part of the main dispatch routine in the NEM Dispatch Engine (AEMO (2020i)). There are a number of different FCAS bid types for the different FCAS services, all standard ten slot bids (see Section 4.5.2). Furthermore, non-market reserves occasionally enter the market calculations through placeholder bids for scarcity and distributed capacities, i.e. Reliability Emergency Reserve Trader (RERT) bids[39], as per 3.20.7 (d) in the Rules and AEMO (2020l) (pages 4-11), and Distributed Generation bids.[40] Thirdly, market interconnectors, too, are using the ten standard price-quantity bands to express their MW offers under 3.8.6A in the Rules[41]. Finally, the units are also obliged to provide technical information about their availability in accord with their registration profiles to complete their bid submissions (AEMO (2021n)).

Re-bidding is another facility provided to the bid-eligible market members under 3.8.22 in the Rules. The previously submitted bid quantities can be revised any number of times during the day until the start of the relevant trade interval, i.e., there is "no gate closure"

[37]Two-way fuels and hybrid plant are registered as generators and loads separately within each category based on AEMO (2021i) (pages 5) and AEMO (2020j) Load-only units are registered as loads only.

[38]See the FIXEDLOAD field definition of the AEMO plant commitment (bid) data AEMO (2021n).

[39]RERT is an example of uplift payments.

[40]See the RT_ and DG_ prefixes, respectively, under the DUID field in the AEMO (2021n) data.

[41]Basslink is the only MNPS is the NEM currently under two DUID fields, BLNKVIC and BLNKTAS AEMO (2020j)

for changing the bid quantities other than the start of trade interval based on AEMC (2015) (page ix) and AEMO (2021q) (page 6). Prices, too, can be modified in re-bidding, but only until the start of the trading day, as there is only one price submission per day[42]. There are various valid reasons for re-bidding, but in each case, particularly for late re-bids, regardless of the disclosed re-bid explanations, bidders are obliged to act with fidelity (in good faith) in changing their commitments as per 3.8.22A in the Rules[43].

3.4. Fuel mix

Table 4 shows the NEM fuel mix in regional breakdown. The fuels most dominant in at least one region are listed on top. Coal-fired plant are the most common in NSW, QLD, and VIC and hydro is the most prevalent in TAS. Manifestly, SA is the most diverse region in terms of fuel mix with natural gas and renewable generation in almost 50-50% proportion. The load fuel breakdown at the bottom of Table 4 only shows battery and omits pumped hydro. Again, SA has the largest battery capacity of all NEM regions.

Table 4: **Fuel mix in the NEM**

The table shows the regional fuel mix breakdown for the NEM market with data from calendar year 2010-21. The interconnector count is shown as of 2021, with a new SA-NSW line (through VIC) called EnergyConnect also underway as of the writing of this paper (ElectraNet (2021)). Source: Table O9 for calendar year 2021 in % terms in Department of Industry, Science, Energy and Resources (2022), Table O12 for calendar year 2020 in Department of Industry, Science, Energy and Resources (2021), and AEMO (2017e) (pages 4-8).

	NSW	VIC	QLD	SA	TAS
Generator fuels (%/year)					
Hydro	4.0%	5.5%	1.5%		80.6%
Black coal	69.7%		65.1%		
Brown coal		63.0%			
Natural gas	2.8%	3.2%	14.2%	33.8%	1.0%
Wind	7.6%	16.3%	2.5%	41.2%	15.9%
Solar	13.8%	10.2%	13.2%	23.3%	2.1%
Biomass	1.5%	1.4%	1.8%	0.7%	0.3%
Oil products	0.5%	0.3%	1.5%	1.0%	0.2%
Load fuels (GWh/year)					
Battery		51.4		64.3	
Interconnectors (6)	3	4	2	2	1

As a modern market design principle, the fuel mix should present a reliable and environmentally sustainable fuel combination. Renewable energy including solar and wind

[42]See the OFFERDATE field for the price rows with BIDDAYOFFER_D) in the AEMO (2021n) data.
[43]Personal communications with Bill Jackson (ElectraNet) Oct 28, 2021.

generation are unmistakably paving the way to meeting the up-to-date CO_2 targets in the NEM, but they are highly intermittent, particularly wind. They require quick-response frequency balancing (FCAS) complements such as gas turbines, hydro generation, battery throughput, or industrial demand response for MW reliability. Because FCAS is fully co-optimised with spot energy in the NEM Dispatch Engine, it is already streamlined for the highest optimisation efficiency. Another challenge in allowing a high penetration of renewables incl. distributed energy such as rooftop solar that are inverter-based, is that these resources do not provide inertia. Turbine generators that do, such as gas and coal, are in this case required in the fuel mix. On the other hand, grid forming storage solutions are able to provide a fast frequency response, despite being inverter-based.

3.5. Hedge markets

Finally, the NEM pool is in contact with the Australian Securities Exchange (ASX) offering financial risk management products. First, the ASX trades financially settled contingent products on spot electricity[44] as the underlying flow asset with continuous delivery (ASX (2022)). These are used to hedge price risk.[45] Second, in terms of the basis risk, the regional NEM has fewer price differentials than markets in the nodal design, only the five regional prices. Thus, there is no financial transmission rights (FTR) trading, nor any flowgate-based congestion rights solution, i.e., there are no auction- or exchange-traded financial products to hedge the regional price differentials. Third, in regards of the dispatch risk implicitly covering the congestion rent in zonal settings, hedge markets should provide a form of firm access to hedge the risk of being constrained-off or constrained-on. However, no such contracts are currently available in the NEM outside perhaps "over–the–counter" (OTC) deals. Fourth, utilities and eventually market participant are sometimes exposed to the elevated costs of importing from higher price regions. According to AEMC (2014) (page 13), "currently there is no mechanism available to market customers to be able to hedge against the negative IRSR cost". Finally, no physical contracts are traded at the ASX, nor at any centralised

[44] Referencing the five regional prices obtained in the NEM Dispatch Engine.

[45] However, near-term forward markets for energy are only liquid enough up to three years, while they are non-existent for capacity or quantity of service products, which is problematic both for project financing and because of the incentive reduction effect of forward markets to gaming the spot market (Newbery (2016), Simshauser (2018), Ahlqvist et al. (2018)).

auction or clearing house (non-OTC), and there are no capacity markets alongside the NEM to help manage the scarcity risk. In summary, the ASX only offers hedge products against the price risk.

3.6. Reliability planning

The trade schedule issued every 5-minute dispatch/trade interval marks the culmination of months if not years of market planning. This point is illustrated by elaborating the long-term to short-term to real-time considerations in capacity planning and system upgrades.[46]

Reserves and system upgrades planning is centered on "the reliability standard, set by the NER, [that] specifies that a region's maximum expected unserved energy (USE) should not exceed 0.002% of energy consumption per year" according to AEMO (2020f) (page 21). The AEMO must make every reasonable endeavour to achieve this rate and to monitor other reliability and sustainability proxies in the interim to mitigate the scarcity risk.[47] The AEMO undertakes annual reviews of several forecasting and planning assessments on an ongoing basis including both long-term capacity models and medium- and short-term and security-constrained time-sequential linear programming (LP) reliability models, while also making provisions for the immediate nature of continuous system stability remediation, especially during extreme events, under up-to-date future scenario assumptions.[48]

The Integrated System Plan (ISP) is a comprehensive 20-year ahead roadmap for market upgrades (AEMO (2020e), page 6). Drawing from AEMO (2020e) (page 58), although the integrated methodologies used in the report (a suite of interlinked market models) are primarily aimed at system development analysis while minimising capital expenditure (AEMO (2020e), page 6), the future constraints they formulate on first principles are often also practicable later at higher time resolutions. The ISP model group accommodates weather and climate effects, gas supply, outage simulations, thermal capability, stability, system strength, and inter-regional limitations, unit commitment, inter-temporal plant limits in two-way fuels and bid profiles that depart from the SRMC, to name but the main features of this

[46]Note that there is no day-ahead market in the NEM and therefore no day-ahead information about the next day's scarcity risk. This makes robust real-time adequacy planning a more challenging task in general.

[47]A more detailed record of these success indicators can be found in AEMO (2015b) (pages 4-15) and AEMO (2020f) (page 21).

[48]As stipulated in AEMO (2020f) (pages 15-31, page 49) and AEMO (2020a) (pages 4-8).

comprehensive security-constrained LP framework, in quantitative detail.[49]

The Electricity Statement of Opportunities (ESOO) is a 10-year ahead evaluation of supply adequacy and a reserve requirement breakdown for the USE goal using a system-constrained market simulation over larger time blocks as per 3.13.3A in the Rules and AEMO (2021a) (pages 13-20). Preparing this assessment is inseparable from producing reliable minimum, maximum and mean demand forecasts (AEMO (2021a), pages 21-29), which later form the basis of a cascading sequence of wholesale, distributed (e.g., rooftop solar), and retail (residential and business) consumption projections (AEMO (2021d), pages 12-22). The supply adequacy calculations use the up-to-date Pre-dispatch constraints and projected network constraints to forecast the USE over the 10-year window (AEMO (2015b), page 7-9).

The Energy Adequacy Assessment Projection (EAAP) is a 2-year ahead probabilistic assessment of the available supply capabilities for satisfactory USE results in line with 3.7C in the Rules and AEMO (2020c) (page 4, page 7). The security constrained EAAP solver considers daily generation limits and replenishment information in all relevant fuel types, including reservoir storage and pump generation based on AEMO (2020c) (pages 8-19), using the resource-constrained Generator Energy Limitation Framework (GELF) declarations submitted by the scheduled generators (AEMO (2014a), page 4-5).

In addition, the AEMO administers two more granular security-constrained linear programming Projected Assessment of System Adequacy (PASA) procedures in line with 3.7.1 in the Rules, AEMO (2015b) (pages 11-12), and AEMO (2012b) (pages 8-9). These are the weekly Medium Term PASA (MT PASA) up to two years with a daily resolution, and the two-hourly Short Term PASA (ST PASA), which is six trading days ahead with 5-minute granularity AEMO (2020g) (page 5). Both use the Supervisory Control and Data Acquisition (SCADA) telemetry (see Table 3) and the submitted PASA energy availability of the generating units[50]. Moreover, MT PASA may rely on the GELF resource limit declarations as well (AEMO (2020g), page 8). Another difference is that the MT PASA allocates resource

[49] The ISP methodology is thoroughly presented in AEMO (2020e) (pages 8-59).

[50] See the PASAAVAILABILITY field in the plant commitment data of AEMO (2021n), where "PASA availability includes the generating capacity in service as well as the generating capacity that can be delivered with 24 hours' notice" (AEMO (2020g), page 8).

(energy) constrained capacities that have fuel stockpile or water storage limitations to high demand periods over weekly blocks while the ST PASA uses the daily-resolution submission data for this allocation according to AEMO (2015b) (page 15).[51] Finally, other than the unit-specified plant limit information and the long-run ESOO load, AEMO also prepares the Unconstrained Intermittent Generation Forecasts (UIGF) for wind and solar generation in the dedicated Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS) systems (see Table 3) as inputs to the MT PASA (AEMO (2020g), page 9).

The main MT PASA objective is then to calculate the anticipated USE in the medium term, and indicate the timing and the location of any expected breaches as per 3.7.2 in the Rules. That includes the days at the highest risk of security shortfalls and the Low Reserve Condition (LRC) status (AEMO (2020g), pages 11-12). These tasks require medium-term demand forecasts as discussed in AEMO (2020g) (pages 21-26). The MT PASA process signals the violating network constraints in view of the Network Outage Scheduler (NOS) and the Monte Carlo simulated ambient forced outage landscape (AEMO (2020g) (pages 12-19) and AEMO (2018b) (pages 9-10)). Reversely, the medium-term LRC output also helps participants schedule outages in the NOS.

Getting closer to the time of dispatch, the ST PASA then subsequently publishes the final LRC and the Lack of Reserve (LOR) statuses for the trade interval under 3.7.3 of the Rules and AEMO (2012b) (page 15). As explained in AEMO (2012b) (page 11), the LOR1, the LOR2 and the LOR3 are the largest contingency-linked explicit benchmark triggers for the AEMO to enable intervention procedures such as constraint relaxation, load shedding, and reserve trader bids (see Section 4.6). This also requires a load forecast considering reserve sharing between the regions (AEMO (2012b), page 7). Finally, the last step of the ST PASA cycle feeds the calculated short-term capacity and the forward-looking assessment of the most likely reserve requirements to the Pre-dispatch protocol as in AEMO (2010b) (pages 56-57).

During Pre-dispatch the NEM Dispatch Engine publishes the dispatch and price forecasts

[51] See the DAILYENERGYCONSTRAINT field in the AEMO (2021n) data.

in a security-constrained LP routine in Pre-dispatch mode, at two timescales; there is a day ahead run with 30-minute resolution and an overlapping hour ahead run with 5-minute resolution (AEMO (2021o), pages 6-7). Note, however, the main differences between Pre-dispatch and Dispatch.

Pre-dispatch lacks the following four features of Dispatch (AEMO (2010b), page 7). First, Pre-dispatch used to omit Fast Start inflexibility profiles (see Section 4.5.1).[52] Second, Pre-dispatch does not calculate Unit Economic Participation Factors (EPF) for apportioning aggregate transmission node losses to unit level (see Section 5.2). Furthermore, Pre-dispatch does not consider intervention scenarios (see Section 4.6) and it does not communicate with the Automatic Generation Control (AGC) remote control activation system (see Section 4.5.2) besides the SCADA metering (AEMO (2021o), page 9).

On the other hand, Dispatch lacks two functions that are available in Pre-dispatch (AEMO (2010b), page 7). First, Unit Daily Energy Constraints are used from the bid submissions similar to PASA for energy constrained units in Pre-dispatch[53]. Second, Spot Price Sensitivities, the expected changes to the published price results over changes to the demand and scheduled generation forecasts, are posted as part of Pre-dispatch as in AEMO (2021p) (page 3), but not for the actual Dispatch.

This concludes the reliability assessments undertaken by AEMO and takes us to the start of the 5-minute dispatch and trade interval.

4. 5-minute dispatch in the NEM Dispatch Engine

The Dispatch mode of the linear programming NEM Dispatch Engine algorithm is dedicated to update the security-constrained least-cost MW targets in the market, as per 3.8.1 in the Rules, while maximising the value of trade, and to determine the spot price. This is achieved by using a cost minimising objective function subject to system constraints. Ex-post price settlement then obtains the marginal value of demand, i.e., the marginal price, from the sensitivity solution of this dispatch process in line with 3.1.4 (a.4) in the Rules.

[52]This has, however, been subject to a rule change already, as having these profiles in Pre-dispatch is more helpful for 5-minute settlement than it had previously been for the 30-minute trade intervals (AEMC (2019b) (pages 9-11) and AEMO (2021o) (page 8)).

[53]See the DAILYENERGYCONSTRAINT field of the AEMO (2021n) data.

4.1. 5-minute cycle of dispatch and price settlement

In accordance with the NEM timetable in AEMO (2021q) (page 8), as per 3.4.3 in the Rules, the 5-minute cycle for dispatch and price settlement can be reconstructed to take six steps. The timeline of the 7:05 AM price run is posited as follows.

1. Before 7:00 AM the NEM Dispatch Engine is running in Pre-dispatch mode for two overlapping timescales in parallel to issue price and target forecasts 5 and 30 minutes ahead as per 3.2.2 (b) in the Rules (AEMO (2021q), page 8). Nearing 7:00 AM the forecasts are made available in EMMS to inform bid revisions until 7:00 AM.
2. At 7:00 AM the NEM Dispatch Engine receives a snapshot of the electric system in SCADA. These initial MW values are compared to the MW targets from the previous cycle to verify the units' conformance (see Section 4.2).
3. At 7:00 AM the NEM Dispatch Engine in Dispatch mode collects the forward-looking demand, outage (AEMO (2021e), page 29), and constraint information from the most recent 5-minute Pre-dispatch run.
4. ASAP after 7:00 AM the NEM Dispatch Engine runs in Dispatch mode (AEMO (2021q), page 8), incl. a cascading series of re-runs (see Section 4.6), to schedule the MW quantities and set the price.
5. ASAP before 7:05 AM the AEMO sends out the dispatch instructions incl. the MW target quantities and either the required times of completion or the linear ramp rates to be used through AGC or EMMS for 7:05 AM (AEMO (2021e), page 9).
6. Immediately after that the prices for 7:05 AM are calculated ex-post (see Section 5) and published in EMMS.

4.2. Bid-eligible unit classification and conformance

The NEM Dispatch Engine uses the initial assumption that all bid-eligible units are conforming with the dispatch targets received in the previous time period. However, the devoirs associated with receiving a target are not the same for every bid-eligible unit. Market service providers with a Dispatchable Unit Identifier (DUID) are classed as scheduled, semi-scheduled or non-scheduled. However, only the scheduled and semi-scheduled units are bid-eligible as per 3.8.2 (a) in the Rules.[54]

The vast majority of the large-sized ≥30 MW generation and load units are scheduled (AEMO (2022b), page 2). They receive dispatch instructions in the form of point targets that they must neither exceed nor fall short of.

In comparison, the small-sized ≥30 MW units are mostly non-scheduled units (AEMO (2022b), page 2). They typically do not bid, nor they receive any dispatch targets. Non-scheduled units are unrestricted in their output, which is forecast by AEMO for a demand adjustment according to AEMO (2021d) (pages 13-15). As price takers, non-scheduled units have a negligible impact on the energy spot price.

In between are the large-sized ≥30 MW semi-scheduled units, i.e., the wind and solar farms, which merit an additional category due to their characteristically intermittent nature (AEMO (2022b), page 2). The NEM Dispatch Engine relies on the AWEFS and the ASEFS forecasting systems for the UIGF output from semi-scheduled plant as per 3.7B in the Rules and AEMO (2021l) (page 5). These systems integrate technical plant specifications using plant-level conversion models and various aspects of the expected ambient weather conditions using SCADA.[55] One may argue that these models have improved significantly over time.

Indeed, before a recent rule change semi-scheduled units received cap targets[56] in place of a currently much stricter obligation to follow their resource availability as point targets (AEMC (2021d), page ii). The cap targets were only allotted during the semi-dispatch interval when certain trigger conditions were met,[57] otherwise the semi-scheduled plant acted as price takers. So-called semi-dispatch caps (SDC) were issued every trade interval to notify the units whether they were given a target like scheduled units (capped, $SDC = 1$), or they were permitted to operate without limits similar to non-scheduled units (not capped, $SDC = 0$) (AEMO (2021e), page 10). The main reasons for a $SDC = 1$ flag, i.e., for a semi-dispatch interval, were uneconomic bids and constraint-driven transmission bottlenecks.

[54] For the Classification and DUID information see the Generators and Scheduled Loads tab in AEMO (2020j).

[55] The model inputs of the UIGF metric are detailed in AEMO (2016a) (page 2), AEMO (2021h) (page 6-8), and AEMO (2021e) (page 42).

[56] They could fall short of their targets but they must not have exceeded them.

[57] See "semi-dispatch interval" in the Glossary in the Rules in AEMC (2021b).

However, units were able to bid exclusively at the market price floor to receive an $SDC = 0$ and only later decide whether or not to inject any energy into the grid. Depending on the expected market price, they could avoid negative prices and still be conforming with $SDC = 0$.[58] This avoidable source of intermittency by arbitrary ceases of dispatch carried system stability implications. For this and further price quality reasons, a recent rule change requires semi-scheduled plant to dispatch at the level of their resource availability under a $SDC = 0$ flag and at the lower of their resource availability and the cap target under a $SDC = 1$ flag (AEMC (2021d), pages ii, pages 10-11).

Given the unit classification specific targets, an error tolerance system is used to regulate when plant reach non-conformance. This employs two error counts, a large and a small error count, based on which the plant maintain a compliance status throughout the trade intervals as discussed in AEMO (2021e) (page 10, pages 32-41). Starting from the normal status, increasing error counts cause plant to go off-target, and then to gradually worsen to non-responding, NC-pending or non-conforming (AEMO (2021e), pages 32-41). As a direct consequence of this status, non-conforming units cannot set the spot price as per 3.8.23 in the Rules.

4.3. Energy demand elasticity

For the demand side of things, first, we refer to Barlow (2002) for the mainstream argument that electricity demand is mostly inelastic. As technological advances allow new freedoms in consumption planning, however, optimised consumption patterns via smart systems, bilateral agreements, demand response, storage fuel activity, distributed energy solutions, etc., also start to factor into electricity demand both in households and in industrial production. These quantities are conditional on the price of electricity and pose a fundamental challenge to the theoretical inelastic demand assumption.

Electricity is being withdrawn at wholesale, retail, and non-market locations simultaneously. Based on AEMO (2021a) (pages 22-25), unravelling wholesale demand elasticity in the NEM Dispatch Engine must first consolidate all relevant consumption planning practises

[58] Unless a system constraint reason materialised for them to receive a target $SDC = 1$ while bidding at very low prices.

to specify energy demand. As retail participants are becoming more responsive to prices by means of distributed energy resources, e.g., by installing solar panels[59], small-scale batteries, by scheduling energy intensive tasks overnight, and also more indirectly via power purchase agreements, retail consumption decreases with greater price elasticity and wholesale demand, too, follows straight away. Only after these adjustments, retail demand and wholesale demand are virtually indistinguishable in the absence of wholesale storage activity and demand response units e.g. aluminium smelters.

This wholesale energy demand excluding wholesale storage uptake and demand response is predicted by the market operator for every 5-minute trade interval in advance. The demand forecast with 50% probability of exceedance (POE) minus the projected non-scheduled generation and minor adjustment terms for the regional reference nodes, is the scheduled demand currently used as energy demand in the Dispatch run for price settlement (AEMO (2021d), pages 10-11, 13, 16). After the predicted demand measure enters the automated NEM Dispatch Engine auction the only sources of price elasticity are wholesale storage uptake and demand response.[60]

4.4. Objective function in Dispatch mode

Dispatch minimises the whole-of-the-market costs of energy and FCAS simultaneously as per 3.8.1 in the Rules. The objective function can be expressed as

$$\begin{aligned} min \sum_r \sum_b \sum_s \sum_d \sum_{i=1}^{m} \mathsf{bid\_price}_{r,b,s,d,i} \times \mathsf{bid\_qty}_{r,b,s,d,i} + \sum_n \sum_j \mathsf{violation\_degree}_{n,j} \times \mathsf{cvp}_n \times \mathsf{mpc} \\ s.t. \text{ constraints} \end{aligned} \tag{3}$$

where by r we denote the price region (NSW, QLD, VIC, SA, or TAS), by b the bid type (energy, FCAS, or MNSP), by s the service type, by d the dispatchable unit ID (DUID)

[59]The NEM is leading the way in integrating distributed generation, particularly rooftop solar, according to AER (2021) (page 33).

[60]Apart from the numerical example in Section 2.2.1 (see Table 2), the price elasticity of the demand is not quantified in this paper. More readily, total energy demand is assumed mostly but not perfectly inelastic.

of the bid, and by m the number of tranches where i is the ith tranche. For energy, s distinguishes generation from loading, and there are eight different FCAS service types s for ancillary services (see Section 4.5.2). Then, $\mathsf{bid\_price}_{r,b,s,d,i}$ captures the as-bid prices for the $\mathsf{bid\_qty}_{r,b,s,d,i}$ decision variables (in MW). Note that $\mathsf{bid\_qty}_{r,b,s,d,i}$ is only negative for $b = energy$ and $s = loading$ as in AEMO (2010c) (page 13). Furthermore, $\mathsf{violation\_degree}_{n,j}$ is the jth slack/deficit variable in the nth constraint denoting the MW difference between the left hand side (LHS) and the right hand side (RHS) of a given constraint as in AEMO (2011) (page 9). Then cvp_n gives the constraint penalty factor associated with the set of the constraint. An exhaustive summary of the constraint sets is shown in Table 5 with the set level penalty cvp_n values shown for all sets (AEMO (2017f), pages 6-24). Finally, mpc stands for the market price cap at the time (indexed to inflation) in dollar terms, and $\sum_n \mathsf{violation\_degree}_n \times \mathsf{cvp}_n \times \mathsf{mpc}$ captures the violation costs associated with the physical constraints. The objective function (3) turns these penalties into dollar amounts so that the conjoint effect of the as-bid cost of supply and the constraint-invoked penalty costs can be simultaneously minimised.

A binding constraint is any constraint that has LHS=RHS with $\sum_n \mathsf{violation\_degree}_n = 0$. In contrast, any violating constraint would see a LHS different from the RHS, and a non-zero penalty of $\sum_n \mathsf{violation\_degree}_n > 0$. In the absence of binding or violating constraints $\sum_n \mathsf{violation\_degree}_n = 0$ equation (3) collapses to $\sum_r \sum_b \sum_s \sum_{i=1}^{m} \mathsf{bid\_price}_{r,b,s,d,i} \times \mathsf{bid\_qty}_{r,b,s,d,i}$. That is, however, not equivalent to only minimising $\sum_r \sum_b \sum_s \sum_{i=1}^{m} \mathsf{bid\_price}_{r,b,s,d,i} \times \mathsf{bid\_qty}_{r,b,s,d,i}$ to start with. Optimum bid selection purposely absorbs the violation costs associated with physical constraints while establishing a constraint hierarchy, i.e., allowing "conflicting constraints to be violated in a pre-determined priority order based on their relative CVP prices" as in AEMO (2011) (page 6). Lastly, the as-bid costs with an implicit $\mathsf{cvp}_{bid} \leq 1$ tend to have a lower priority than a constraint violation with $\mathsf{cvp}_n > 1$ for the same MW quantity.

Table 5: **Constraint sets in the NEM**

The table shows the system constraints recognised by the main price run of the NEM Dispatch Engine engine as in AEMO (2017f) (pages 6-24), including the usual constraint sets under normal system state and outage events. In specific, this table excludes the constraint sets used by the NEM Dispatch Engine only in What-If and Outturn intervention pricing modes. Note that every listed constraint set holds a multitude of exact linear constraint equations (see Binding Impact tab in AEMO (2020h)). Source: AEMO (2017f) (pages 6-24), however the presented information draws on other AEMO publications too listed in the References. *constraint set item 38 has a variable penalty factor.

Constraint set	cvp_i	Source of RHS	Item #
Operational plant limitations - see Section 4.5.1			
Unit Zero	1160	AEMO (NOS/SCADA)	1
Unit Dispatch Conformance	1160	AEMO (SCADA)	2
Unit Ramp Rate	1155	Bid submission	3
Fast Start Inflexible Profile (T1, T2, T3, T4)	1130	Bid submission	4
Unit Direction System Security	755	AEMO (control room)	5
Unconstrained Intermittent Generation Forecast (UIGF)	385	AEMO (AWEFS/ASEFS)	6
Energy Inflexible Offer (Fixed Loading)	380	Bid submission	7
Unit MaxAvail	370	Bid submission	8
Joint constraints (FCAS) - see Section 4.5.2			
FCAS MaxAvail	155	Bid submission	9
FCAS Joint Ramping	155	AEMO (formula)	10
FCAS EnablementMin and EnablementMax	70	Bid submission	11
FCAS Regulation Raise (RREG)	10	AEMO	12
FCAS Regulation Lower (LREG)	10	AEMO	13
FCAS Contingency Fast Raise 6 second (R6)	8	AEMO	14
FCAS Contingency Fast Lower 6 second (L6)	8	AEMO	15
FCAS Contingency Slow Raise 60 second (R60)	6	AEMO	16
FCAS Contingency Slow Lower 60 second (R60)	6	AEMO	17
FCAS Contingency Delayed Raise 5-minute (R5)	4	AEMO	18
FCAS Contingency Delayed Lower 5-minute (L5)	4	AEMO	19
System conditions - see Section 4.5.3			
Interconnector Zero	1160	AEMO (NOS/SCADA)	20
Interconnector Dispatch Conformance	1160	AEMO (SCADA)	21
Interconnector Capacity Limit	1150	AEMO (ratings)	22
MNSP Interconnector Ramp Rate	1155	Bid submission	23
MNSP Availability	365	Bid submission	24
MNSP Losses	365	Fixed feature	25
Satisfactory Network Limit	360	AEMO	26
Secure Network Limit Stability and Other	35	AEMO	27
Secure Network Limit Thermal	30	AEMO	28
Interconnector Outage (Hard) Ramping	35	AEMO (NOS/formula)	29
Planned Network Outage (Hard) Ramping	26	AEMO (NOS/formula)	30
Planned Network Outage (Soft) Ramping	<1	AEMO (NOS/formula)	31
Interconnector Outage (Soft) Ramping	<1	AEMO (NOS/formula)	32
Non-Physical Loss Oscillation Control	<1	Fixed feature	33
Market requirements - see Section 4.5.4			
Total Band MW Offer	1135	Bid submission	34
Total Band MW Offer MNSP	1135	Bid submission	35
Regional Energy Demand Supply Balance - Load Shedding	150	AEMO (forecast)	36
Regional Energy Demand Supply Balance - Excess Generation	150	AEMO (forecast)	37
Negative Residue Management	2*	Fixed feature	38
Tie-Break	<1	Fixed feature	39

4.5. Constraints in Dispatch mode

Most constraints in the NEM Dispatch Engine are generic constraints[61] formulated as linear equations in the form of

[61] In fact, pursuant to Mackenzie et al. (2020) (page 24), "most changes to the dispatch optimisation process have been done via generic constraints rather than through explicit modifications to the formulation of the

$$\sum_{t}\sum_{i=1}^{c} A_{i,l,k} \times \mathsf{ID\_qty}_i \leq RHS_{pre-calc} + \mathsf{violation\_degree}_k + \mathsf{operating\_margin}_k, \qquad (4)$$

for the kth constraint over link l in price region r over all c connection points, where t denotes the type of each connection point quantity $\mathsf{ID\_qty}_i$ (intra-regional connection point or an interconnector) according to AEMO (2021b) (page 5) and AEMO (2017a) (pages 9-10). The LHS collects the $\mathsf{ID\_qty}_i$ corresponding to the decision variables $\mathsf{bid\_qty}_{r,b,s,d,i}$ in (3) but grouped by connection points, which can be optimised. Then the $A_{i,l,k} \geq 0.07$ terms represent the monitored flow across the network elements for an incremental change at the regional reference node N, i.e., the constraint coefficients, as per AEMO (2021b) (page 9-10) and AEMO (2015a) (page 11).[62] Moreover, the RHS hardcodes various system limits of the constraint (AEMO (2021b), pages 7-8) in the MW term $RHS_{pre-calc}$, which is pre-calculated using real-time telemetry (see Table 3) and pre-processed data from various planning schedules (see Section 3.6) and the $\mathsf{operating\_margin}_n$ managing the approximations and errors associated with the limit (AEMO (2010a), pages 8-12). The aim is to quantify every constraint RHS such that the dynamic MW values on the LHS can be equated to them.[63] Lastly, the orientation of the constraint in (4) is $\leq$, therefore $\mathsf{violation\_degree}_n > 0$ is a surplus variable (AEMO (2017a), page 7), and a positive coefficient $A_{i,l,k}$ means that "a generator may be 'constrained-off' when the constraint binds, while a negative coefficient means a generator is 'constrained-on' " (AER (2012), page 7). Also, the marginal value of the constraint is negative, since "by constraining off the Left Hand Side (LHS) terms these lower the objective function" (AEMO (2021c)). While $\leq$ and $\geq$-type constraints are both fairly common, the $=$ orientation is largely avoided in security constraints (AEMO (2015a)

NEM Dispatch Engine optimisation". This is also revealed in the way more recent system requirements have found their way into the NEM Dispatch Engine, e.g., system strength shortfalls in SA have been resolved using a new class of generic constraints for system strength according to AEMO (2020f) (page 30). See also the Binding Impact tab in the NEM constraint report AEMO (2020h).

[62] According to AEMO (2021b) (page 7), "The constraint equation decides the optimal balance of supply from the various [competing] contributors, while providing a high degree of confidence that that the network limit is not violated." It follows that a high $A_{i,l,k}$ in a "$\leq$"-type equation is a competitive disadvantage.

[63] For reference, see AEMO (2021c), AEMO (2015a) (pages 7-8), AEMO (2021b) (page 16) and AEMO (2021b) (page 5).

(page 7)).

The requirement that the decision variables in the objective function $\mathsf{bid\_qty}_{r,b,s,d,i}$ sum to the r, b, s demand types over all $m \leq 10$ bids by the dispatchable units d in each demand type as $\sum_{i=1}^{m} \mathsf{bid\_qty}_{r,b,s,d,i} = \mathsf{demand}_{r,b,s}$, respectively, in the optimal solution (AEMO (2017f), page 5) is facilitated by the regional energy balance (demand) constraint for $b \neq FCAS$ and a particular region r. This can be written as

$$min \sum_{b} \sum_{s} \sum_{DUID} \sum_{i=1}^{m} \mathsf{bid\_qty}_{r,b,s,d,i} = RHS_{pre-calc} + \mathsf{violation\_degree}_{k}, \tag{5}$$

using the notation of (3) and (4).

As of 2020, there are 13,127 constraint equations in the NEM split across multiple constraint sets shown in Table 5.[64] Many originate in the limit equations calculated by the transmission and distribution service providers, or rarely in the plant specific models developed by AEMO (Mackenzie et al. (2020) (page 25), AEMO (2021b) (page 13), Mountain and Percy (2021)(page 36)). In line with AEMO (2021b) (page 8), an important feature of this fundamental equation set and the way the constraint equations based on this equation set interlink is their overall applicability regardless of whether the system is in a normal operating state or in a heavily constrained outage mode. Moreover, most equations are static, with the exception of dynamic feedback equations shown in AEMO (2021b) (page 16).

The AEMO must further ensure that the constraint formulation is neither overly restrictive (over conservative), nor oppositely too slack (under conservative) (AEMO (2021e), pages 30-31). The former causes concerns from a market efficiency perspective and the latter exacerbates the exposure to safety hazards. However, throughout the 5-minute Dispatch cycles, the AEMO can also relax the over conservative constraint equations, use variable constraint violation penalties, or enact additional quick constraints ad hoc.[65] The freedom of discretionary constraint overrides does, however, not extend to stability constraints (AEMO (2021e), page 28).

[64] See the Constraint Changes tab in AEMO (2020h) and AEMO (2021b) (page 8).

[65] AEMO's use of discretionary constraints is mentioned in AEMO (2017a) (pages 9-11), AEMO (2017f) (page 6), AEMO (2021b) (page 12), AEMO (2021e) (pages 27-28) and AEMO (2020b)(page 8).

Lastly, the NEM Dispatch Engine is a LP solver with only two binary modules. One is related to loss allocation "at connection points where one MLF [marginal loss factor] does not satisfactorily represent active power generation and consumption" (AEMO (2022d), page 75), i.e., dual MLFs are needed for generators versus loads or for different flow directions over an interconnector, as in AEMO (2012c) (page 29). The other one handles the calculation of average losses using special ordered set 2 equations (AEMO (2021e), page 41).[66] Note that none of these cases directly relate to plant level unit commitment. As a consequence, the unit bid stacks are convex,[67] and while the onus is on the units to bid in a way to be able to conform with the received targets, there are additional workarounds for lumpy unit requirements apart from the fast-start flexibility unit commitment profiles (see Section 4.5.1). For example, the solver heavily relies on negative price bids for self-commitment from slow-start units (see Section 4.5.1) and it must take two switch runs to evaluate the on/off status of the Basslink interconnector each dispatch interval (see Section 4.6).

4.5.1. Technical plant limitations

Next we show the plant-level operational constraints regulating scheduled generation and uptake from the first segment of Table 5 (items 1-8). The standard bid submission template for all scheduled and semi-scheduled units not only requires the units to specify their terms of trade using ten price-quantity bid pairs, but they are also liable to indicate some other (non-price[68]) availability parameters for the period as per 3.8.6, 3.8.7 and 3.8.19 in the Rules.[69] These inform the NEM Dispatch Engine's constraint RHS values about the physically feasible plant-level unit capacity.

Firstly, the units must report the minimum or maximum MW capacity limits they might

[66] Personal communications with Nicholas Gorman Oct 4, 2022.

[67] Adding almost always convex virtual bids into the bid pool is an effective way of increasing the convexity of the pool for a better optimum schedule approximation according to Cramton (2017). Nonetheless, there are no virtual bids in the NEM.

[68] Disorderly bidding can be an implication of the fact that the price-quantity offer tranches are the only priced bid components: "Thermal generators in particular tend to face 'lumpy' [non-linear] unit start-up costs, minimum generation levels and ramp rate constraints. This means that a generator's bid may need to reflect its judgement as to how long it may be dispatched, to what extent and at what price." (AER (2017), page 26).

[69] These are shown as MINIMUMLOAD, MAXAVAIL, ROCUP, ROCDOWN, T1, T2, T3, T4, DAILYENERGYCONSTRAINT in the AEMO (2021n) data.

have in their normal operation using the MINIMUMLOAD and MAXAVAIL fields (as per 3.8.4 in the Rules).

Secondly, every unit needs to advise AEMO about their ramp rates using the ROCUP and ROCDOWN fields (as per 3.8.3A in the Rules) and the dispatch capability profile, i.e., Fast Start Inflexible Profile. This involves four time parameters T1, T2, T3, and T4 (in minutes) about re-start and ramping. T1 indicates "the time to synchronise" (T1 field definition, AEMO (2021n)) or start up from nil output for a generating unit. For example, a thermal plant with a "hot banking" furnace is faster than a cold one.[70] T2 gives the time to speed up to the Minimum Load MW level as specified by the plant. T3 is the number of minutes a unit can stay on within its feasible output bounds while it is still lower bounded (AEMO (2021f), page 6). T4 indicates the time it takes for the unit to shut down.

The rule around self-commitment (self-dispatch level) states that given the inflexibility parameters as above, "the sum (T1 + T2) must be less than or equal to 30 minutes" (3.8.19 (e.6) in the Rules) and the sum T1 + T2 + T3 + T4 less than 60 minutes (AEMO (2021f), page 5). If not, slow units "must self-commit to be eligible for dispatch" (see 3.8.17 (a-b) in the Rules) until they notify AEMO about their "intention to self-decommit" (3.8.18 (c) in the Rules) "at least 2 days in advance of dispatch" (3.8.18 (b) in the Rules). And "a scheduled generating unit is self-committing if it has a self-dispatch level of greater than 0 MW, where the self-dispatch level equals the sum of all energy bid in offloading (negatively priced) price bands in its dispatch offer" (AEMO (2021e), page 15). In other words, slow start scheduled units have to bid at negative prices or else they receive no targets.

Finally, the daily energy constraint is only populated by units with resource constrained operations (see Section 3.6), such as hydro generators.

Turning our focus on the plant-level constraints from the dispatch engine's perspective, the top priority constraint set[71] is Unit Zero (item 1 in Table 5). This coordinates the rate of change adjustments related to shutting individual units down in the engine representation of the grid, due to a forced or planned outage. Then the second most important constraint set is Unit Dispatch Conformance (item 2 in Table 5), for which the rationale is that

[70] Personal communications with Bill Jackson (ElectraNet) Oct 28, 2021.

[71] The constraint set with the highest constraint violation penalty cvp_i factor has top priority.

non-conformance with the issued targets (see Section 4.2) outside the acceptable operating margins (AEMO (2010a), pages 9-10) carries undesirable consequences for optimum planning, e.g., it is hard to detect issues around overloaded network elements. This constraint forces NEM Dispatch Engine to correct any disconnect between the previous MW dispatch target and the real-time SCADA MW before many other aspects in the optimisation. Most of the remaining constraint sets (items 3-4 and 6-8) are used to stay within the technical and availability requests of the units given their bid submission inputs, whereas Unit Direction System Security (item 5) puts a handle on directing individual unit output arbitrarily as and when needed for network security purposes.

4.5.2. Joint capacity requirements (FCAS)

Reserves service provision is also present in the NEM, both in the form of co-optimised market-based frequency balancing (FCAS) and as auxiliary non-market contracts (AEMO (2021g) (pages 8-12) and AEMO (2012a) (page 6)). The NEM is a co-optimised market, because the energy and FCAS targets are evaluated concurrently in the objective function. The FCAS-registered units first indicate their preference profiles for energy and FCAS provision and after that the task of a physically-constrained minimum price optimum target co-allocation falls to the joint capacity engine constraints in the second segment of Table 5 (items 9-19).

Table 6 shows the standard ancillary service contract types in the NEM under the broader categories of market and non-market services. Market services only include frequency balancing (FCAS), whereas non-market provision separates into System Restart (SRAS) and Network Support and Control Ancillary Services (NSCAS). As opposed to market services, non-market enablement is not part of the co-optimisation. Therefore, these have no direct effect on the energy spot price.[72] NSCAS are usually only enabled at times of network failures called credible contingencies, e.g., generator trips, short-circuiting, insulation faults, etc. (AEMC (2021c)) and SRAS only after full or partial system blackouts. These are provided mostly by non-market participants endowed with the required equipment and deemed apt

[72]Note however that "Where applicable, AEMO will apply constraint equations to reflect the network support agreement between the service providers and the generators, so that the market dispatch is consistent with operation under those agreements." (AEMO (2021b), page 11)

Table 6: **Ancillary services**

The table shows the different ancillary service types in the NEM as per Rule 3.11 in the Rules including both the market-based FCAS specifications and several standard bilateral non-market Network Support Agreements as per AEMO (2021g) (pages 8, 13)

Service	Category	Function
FCAS Regulation Raise (RREG/R5RE)	Market	Continuing response over AGC to even out minor frequency drops.
FCAS Regulation Lower (LREG/L5RE)	Market	Continuing response over AGC to taper minor frequency hikes.
FCAS Contingency Fast Raise 6 second (R6SE)	Market	6 second frequency response after a credible contingency.
FCAS Contingency Fast Lower 6 second (L6SE)	Market	6 second frequency response after a credible contingency.
FCAS Contingency Slow Raise 60 second (R60S)	Market	60 second frequency response after a credible contingency.
FCAS Contingency Slow Lower 60 second (R60S)	Market	60 second frequency response after a credible contingency.
FCAS Contingency Delayed Raise 5-minute (R5MI)	Market	5-minute frequency response after a credible contingency.
FCAS Contingency Delayed Lower 5-minute (L5MI)	Market	5-minute frequency response after a credible contingency.
NSCAS Network Loading (NLAS)	Non-market	Manual MW load control on interconnectors after a credible contingency.
NSCAS Voltage Control (VCAS)	Non-market	Automatic enablement to absorb or supply reactive power after a credible contingency.
NSCAS Transient & Oscillatory Stability (TOSAS)	Non-market	Monitored fast-regulation of voltage, inertia and load against circuit faults after a credible contingency.
System Restart (SRAS)	Non-market	Instructed system restart after a partial or full system blackout.

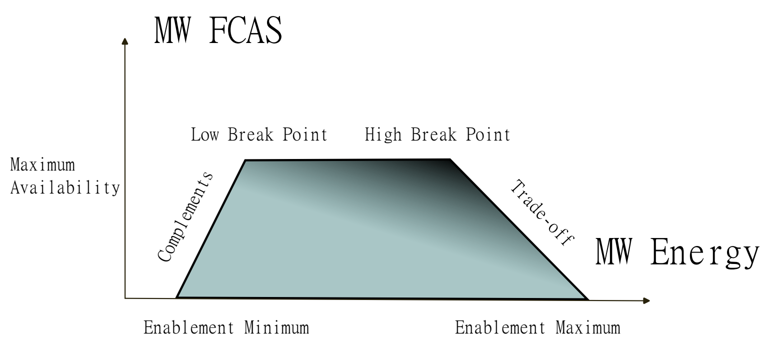
by AEMO on a case-by-case basis as per the preexisting bilateral contracts in the standard non-market procedures as an example of uplift payments as in AEMO (2021g) (pages 13-14).

FCAS relates to the rotational speed on the network such that "frequency is maintained within the normal operating band of 49.85Hz to 50.15Hz" (AEMO (2021g), page 6). If consumption suddenly drops but generators keep injecting the same MW load then the frequency of the system will increase towards 50.15Hz and FCAS Lower services are necessarily called upon to withdraw quantities for balancing. Analogously, if consumption suddenly spikes but generators keep injecting the same MW load, then the frequency of the system decreases towards 49.85Hz, and FCAS Raise services are required for system security according to AEMO (2021g) (page 5). As shown in Table 6, there are two disparate mechanisms for frequency balancing, regulation and contingency, that both incorporate lowering and raising. Contingency services are enabled using remote devices to detect and counteract contingency event related frequency breaches at 6 second, 60 second, or 5-minute notice according to AEMO (2021g) (page 6) and AEMC (2021c). Regulation works through AGC at 4 second frequency (AEMO (2021e) (page 10) and AEMO (2021g) (page 6)). The requirement has a base value of 120-130 MW and a cap of 250 MW as in AEMO (2015a) (page 27). The mainland contingency requirement (demand) depends on the dispatch amount of the largest online generator (largest contingency) minus load relief, while in TAS it also depends on inertia as per AEMO (2015a) (pages 19, 25).

Units bidding in regulation and contingency FCAS use a similar bidding template per FCAS service as for energy.[73] Apart from the ten price and quantity bands and the same availability-related fields as in the energy bid template, the ancillary submissions must also input the following four FCAS trapezium variables (see Figure 2) as per AEMO (2021g) (page 10).[74] The first two, ENABLEMENTMIN and ENABLEMENTMAX, correspond to the lowest and highest MW levels of energy dispatch required to provide a particular FCAS. Additionally, LOWBREAKPOINT and HIGHBREAKPOINT bound the energy MW levels needed for servicing the stated MAXAVAIL quantity in the particular FCAS. These variables are then further scaled to AGC enablement and UIGF limits within the NEM Dispatch Engine AEMO (2017c) (pages 10-13).

Figure 2: **FCAS trapezium**

The figure shows an FCAS trapezium for a single service, where the shaded area captures service availability based on the bid submissions. The upward sloping segment of the trapezium captures a complementary relationship between energy and the particular FCAS service, whereas the downward slope indicates a trade-off between the two. Source: AEMO (2017c).



The optimum combination of the regulation, contingency and energy targets, i.e., the MW thermal loading on the LHS of the joint FCAS constraints in Table 5, are subject to the respective service demand levels (items 12-19) individually and confined to unit level

[73] See the BIDTYPE field definition in the bid submission data of AEMO (2021n).

[74] These are shown as ENABLEMENTMIN, ENABLEMENTMAX, LOWBREAKPOINT and HIGHBREAKPOINT in the AEMO (2021n) data.

capacity limitations on the RHS (items 9-11) collectively. The capacity limits of every service are more restrictive than stated in the FCAS trapeziums as they take into account concurrent dispatch in other services and energy as well. More specifically, "FCAS availability for a unit at a given energy target is the maximum amount of the service that the unit can provide when it is fully delivering the amounts of all other services for which it is enabled at that energy target" as per AEMO (2017c) (page 23). Different kinds of joint ramping constraint equations (under item 10) are applied to enforce this (AEMO (2017c), page 14-26).

First, the energy and regulating FCAS capacity constraints reinforce the scaled regulation service trapeziums. Second, the joint ramping constraints limit every regulation service trapezium to the area defined by the AGC ramp-up and ramp-down rates. Third, the joint capacity constraints capture the offset between regulation, contingency and energy by shifting the sloped lateral sides of the contingency trapeziums to narrow service availability by the concurrent regulation targets. At last, the most restrictive of all the above relations emerges as the limiting constraint for each service.

The conjoint nature of FCAS and energy grants that when the co-optimisation constraints bind they may alter the energy target. In fact, it is not uncommon for a unit to be "trapped within the FCAS trapezium" (AEMO (2017c), page 20), i.e., for the NEM Dispatch Engine not to ramp up or ramp down a unit's energy dispatch as it is supporting regulation or contingency provision.

4.5.3. Secure and reliable system conditions (excluding FCAS)

We now turn to the main body of non-plant constraints that aim to avoid equipment damage and safety hazards in general to lend reliability to the operation of the complex electric network as a whole. The third segment of Table 5 (items 20-33) showcases interconnector operations, network stability, thermal capacity limits, and outage management as the most important non-plant aspects to system security.

First, Interconnector Zero (item 20) is the highest priority network constraint that handles both planned and forced outages, i.e., the full loss of a directed or MNSP interconnector at any notice, for a minutely accurate representation of the disconnected element in the NEM Dispatch Engine so that power flows avoid black lines (AEMO (2017f), page 7). However, interconnector limits also apply absent line disconnections. When interconnectors (incl. MNSP) are fully operational, the security objective is to keep those to the advised thermal capacity ratings (AEMO (2021b), page 8), availability limits and ramp rates, and also to correct non-conformance (see Section 4.2) if needed (items 21-24). Moreover, based on AEMO (2017f) (page 12), there are minor equations for preventing "non-physical circulating flows in both MNSP flow offer directions at once" (item 25) and managing frequency variation after a rate of change of frequency (ROC) in loading MW on a network element.[75] Note that ROC corrections are also possible by enabling NLAS (see Table 6).

The second highest priority in network security is maintaining every Satisfactory Network Limit (item 26), i.e., no exceedance to line ratings, no transformer overheating, no outage, etc.[76]. Provided these are met, an operationally stable network under this set of constraints is in a normal system state (NIL) according to AEMO (2020b) (page 8).

Secure Network Limit Stability and Other constraints (item 27) manage voltage, oscillatory and transient stability, incl. system strength (AEMO (2017f) (page 16) and AEMO (2021b) (page 8)). A large amount of stability is already provided by the network elements, e.g., generating plant, over the normal course of operation at no cost. Stability constraints are then used, in addition, to prevent unsafe variances to these limits.[77] Also, note the AEMO has the option to use NSCAS (see Table 6) for managing network stability when the marginal value of the binding constraint being offset is greater than the cost of the NSCAS providing the offset (AEMO (2012a), pages 7-8).[78]

The last constraint set under NIL is the Secure Network Limit Thermal (item 28), which control the pre- and post-contingency MW capacity loading (Mackenzie et al. (2020), page 26). These are often formulated as feedback equations using the ratings or limit equations provided for each line by its operator to AEMO, i.e., the thermal capacity limits are usually written as two bounds around the initial MW flows as measured in SCADA (AEMO (2021b),

[75] See the Binding Impact tab in AEMO's constraint report AEMO (2020h).

[76] For a brief summary about this limit refer to AEMO (2015a) (page 9), AEMO (2020k) (page 6) and AEMO (2017f) (page 12).

[77] See the Binding Impact tab in AEMO's constraint report AEMO (2020h).

[78] There is an excellent discussion on the future system strength in the NEM by Mountain and Percy (2021) who review the topic with high renewable energy penetration and electricity storage incl. grid forming batteries in view.

page 16).

Moving on to the outage constraints (items 29-32), these are, in principle, very similar to the Zero limits in that they invoke line limitations, i.e., islanding, which tend to cause significant changes in the flow direction as stated in AEMO (2017f) (pages 7-23). Hard and soft ramping distinguishes the constraints applied over different but overlapping timescales to achieve smooth and steady switches if at all possible, considering phase changes (AEMO (2021b), page 22). Finally, the Non-Physical Loss Oscillation Control (item 33) is put in place to prevent directional over-oscillation, i.e., repeated directional changes in subsequent trading intervals over an interconnector, beyond the degree at which it can no longer be safely managed (AEMO (2017f), page 23).

4.5.4. Market requirements

The system-level operational constraint sets warranting economic-dispatch are shown in the last segment of Table 5 (items 34-39). These involve market offers, expected demand, settlement residues and price-ties.

The first constraint set in priority order is Total Band MW Offer (incl. MNSP) (items 34-35). This keeps the dispatch targets by the NEM Dispatch Engine to the total band size of the ten bid quantities of the units. The total quantity band, as explained in AEMO (2017f) (page 10), "must add up to equal or greater than (as designed) the registered maximum capacity". Therefore, the bidded quantities are typically greater than or equal to the nameplate capacity, i.e., not all are available. In the context of this paper, refer to Table 7 for a summary of the various capacity measures mentioned so far, where the indicators are displayed starting with the least restrictive Total Band MW Offer on top. From there, the onus is on the engine to determine the available target quantities using the sophisticated set of constraint rules from Table 5.

Regarding the Regional Energy Demand Supply Balance (items 36-37), the economic objective is to match demand with supply. Nearing the start of every 5-minute trade cycle, the preceding efforts in forecasting the usual patterns of consumption minus distributed generation approximate the value of the total quantity to be cleared, i.e., scheduled, in 5 minutes' time. This enters the engine as the regional Total Demand (p. 17.) AEMO

Table 7: **Capacity indicators**

The table shows multiple capacity indicators and measures to express the contingent capacity of a unit in decreasing order of magnitude.

Availability	Source	Function
Total Band MW Offer	Bid submission	All bidded quantity by the BANDAVAIL1-10 field definition in AEMO (2021n).
Rated capacity	Plant survey	Nameplate capacity after seasonal adjustments (AEMO (2020e), page 24).
Generator energy limitation	GELF declaration	Stockpile scarcity or water storage-bound daily or weekly maximum capacity as estimated over the long run (AEMO (2014a), page 4).
PASA availability	Bid submission	Capacity currently in service or available for service within 24 hours by the PASAAVAILABILITY field definition in AEMO (2021n) in line with AEMO (2020g) (page 8).
Daily energy constraint	Bid submission	Stockpile scarcity or water storage-bound daily or weekly maximum capacity as indicated by the units in real-time by the DAILYENERGYCONSTRAINT field definition in AEMO (2021n).
MaxAvail	Bid submission	Maximum availability for the 5-minute trade interval as indicated by the units by the MAXAVAIL field definition in AEMO (2021n).
Shadow price free bid capacity	NEM Dispatch Engine	Headroom around initial MW before dispatch constraints start binding (Mackenzie et al. (2020), page 34).
Dispatch targets	NEM Dispatch Engine	NEM Dispatch Engine target outcome (AEMO (2021e), page 9).

(2021d). Then balancing demand and supply within a narrow but initially symmetric - as the associated penalty factors are the same - headroom is achieved using the two Regional Energy Demand Supply Balance constraint sets shown in Table 5 (AEMO (2017f), pages 13-14).

Thirdly, inter-regional residue settlement as per 3.6.5 in the Rules requires constraints for the counter-price flows. Negative residues arise when the NEM Dispatch Engine optimum dispatch solution directs counter-price flows through directed (non-MNSP) interconnectors, i.e. when electricity generated in a high price region is consumed in a low price region (AEMO (2018a) (page 5) and AEMC (2013) (page i)). This is a perfectly legitimate NEM Dispatch Engine outcome as long as it minimises the objective function (3), but problematic because AEMO receives less from retailers than it is liable to pay out for wholesale generation, as stated in AEMC (2013) (page 5). The costs are borne by the market customers in the importing region as in AEMC (2014) (page 18). The coordination involved is commonly known as Negative Residue Management (NRM) (AEMO (2018a), page 6). The main platform for NRM is the Settlement Residue Auctions (SRA) as per 3.18 in the Rules, where the accumulated negative residues are settled and distributed. The secondary trading of these cash flows is also permitted more recently.[79] As relevant to real-time dispatch, the NRM constraint (item 38) with a low constraint violation penalty in Table 5 is in fact a dynamic penalty factor that can be raised by AEMO for the purposes of counter-price flow management.[80] According to AEMO (2018a) (page 5), as a general rule AEMO should "cease" ["clamp"] the accumulation of negative inter-regional settlement residues in the NEM when this accumulation reaches or exceeds the negative residue accumulation threshold of -$100,000 (as of 1 July 2010)". Congestion and disorderly bidding are the two main drivers of negative residue accumulation, and there is a continuing discourse between industry reference groups and AEMC to streamline the NRM process to reduce the gaming of the counter-price flows and maximise consumer welfare AEMC (2013) ((pages 13-14), AEMC (2014) (pages 17-25) and AEMC (2020) (page 59)).[81]

Finally, there is a small but important consideration in managing price-tied dispatch outcomes. Should the kind of NEM Dispatch Engine case solution occur wherein a number of bids, none of which bind or violate any constraints, are equally feasible on a price basis, AEMO then has to allocate targets equitably. The Tie-break constraint set (item 39) with a minimal effective violation penalty is used for this purpose. The quantity targets for the price-tied energy bids are split in proportion to the MW quantities in the relevant bid slots, whereas price-tied FCAS bids are "dispatched randomly" (AEMO (2017f), page 24).

[79] A detailed overview of SRAs is provided by AEMO (2014c) (page 5) and AEMO (2019b) (pages 6-22)

[80] Automated counter-price flow management is discussed in AEMO (2017f) (page 21), AEMC (2013) (page 9) and AEMO (2018a) (page 6).

[81] It is alarming from a market power concentration point of view that plant at certain electric locations have access to unilaterally moving the real-time spot price through strategic (disorderly) bidding. Based on participants' submission on issues papers, particularly Generation (2013) (page 1), "Remote generators in the higher priced region can bid in ways to relieve NRM constraints on an interconnector that was otherwise "clamped" to limit negatively priced flows", i.e., to relieve the clamp and then to restart it, known as "cycling". The increased negative residue that accumulates through cycling is later distributed among the generators in the higher priced region in negative residue auctions. Therefore, cycling is detrimental to consumer welfare in the low-priced region. The same issue may arise in new locations once the new high-voltage alternating current (HVAC) interconnector EnergyConnect is built.

4.6. Out-of-market operations

The usual functions of the main NEM Dispatch Engine run are not fulfilled until a cascading series of out-of-market operations are also evaluated (AEMO (2021e), page 15). These include alternative network constraint formulations as NEM Dispatch Engine re-runs as per 3.8.10 (e) in the Rules and price administration under system distress, should such a scenario arise, as per 3.14 in the Rules.

The NEM Dispatch Engine is being re-run on on ongoing basis as part of the market methodology for three reasons. Firstly, the Basslink's control system[82] must enforce security rules that are hard to integrate into the NEM Dispatch Engine using linear constraints according to AEMO (2021e) (page 17). In particular, there is a No-Go zone for power flows between $\pm$ 50 MW and FCAS transfer is not always possible near full capacity.[83] Therefore, there is always a normal NEM Dispatch Engine run in Dispatch mode using the SCADA indicated Basslink status (on/off), as well as a re-run that assumes Basslink to be offline. The lower cost solution of the two is ultimately selected for the dispatch solution (AEMO (2021e), page 17).

Secondly, there is also an automated Over Constrained Dispatch (OCD) process that rectifies when the solution of the engine in Dispatch mode still contains constraint violation costs that drive the price results near or beyond the market price thresholds (AEMO (2017a) (pages 5, 9), AEMO (2021e) (pages 15-16), AEMO (2011) (page 8)). Barring any serious distortions requiring a market notice and intervention, e.g. a serious MW shortfall or a voltage instability, the arising variances can usually be resolved by relaxing the RHSs of the violating constraints iteratively or manually.[84] [85]

Another reason for out-of-market re-formulations is a market intervention. If the ST PASA routine detects a high risk of supply inadequacy, it communicates the intervention conditions to the real-time Dispatch solver immediately using the dedicated LRC and LOR

[82]The Basslink HVDC undersea cable is a scheduled market interconnector (MNSP) across the Bass Strait between VIC and TAS AEMO (2020j), Basslink Pty Ltd (2022).

[83]For technical details we refer the reader to AEMO (2021e) (pages 17) and AEMO (2021b) (pages 18-19).

[84]Figure 1 in AEMO (2021e) depicts the OCD flowchart.

[85]The only exception being that price-tied bids (item 39 in Table 5) are split out on a pro-rata basis as per 3.8.16 in the Rules, i.e., this constraint is not relaxed during OCD. See the Tbslack entries in the DispatchedMarket field in the PriceSetting tab of AEMO (2021m).

notices (see Section 3.6). These then initiate the following two layers of re-runs. The general requisite is that AEMO seeks to restore the market price outcome to the level that had prevailed had the intervention scenario not arisen, as per 3.9.3 (b) in the Rules, while making every possible effort to secure non-market quantities to meet the reserve shortfall (AEMO (2021j) (page 5) and AEMO (2019a) (page 4)).[86] This is usually performed in two re-runs by means of voluntary or involuntary load shedding and non-market reserve contracts.[87] The first re-run is in Outturn mode and it determines the new target quantities using reserve trader (RERT) bids for the non-market quantities, and the direction constraints specific to Outturn (AEMO (2017f) (pages 7-24), AEMO (2021e) (page 19) and AEMO (2021j) (page 4)). Then the second layer to the intervention policy is another run in What-if mode. This removes the RERT bids and the direction constraints, and seeks to recover the price under the original circumstances (AEMO (2017f) (pages 7-24), AEMO (2021e) (page 19), AEMO (2021j) (page 5)). A binary label shows in the solution files whether there had been an intervention during a Dispatch run.[88]

Price administration under system distress involves administered pricing and suspension pricing. First, administered pricing periods realise an inter-temporal limitation on the energy spot price as per 3.14.2 in the Rules. Under the AEMC reliability settings in AEMC (2021a), a pricing cap of APC≈ \$300 (as per 3.14.1 (a) in the Rules) is applied to curb the duration of high price periods when the energy spot price is successively high and breaches the effective 7-day cumulative price threshold (CPT). The CPT is \$1,359,100 as at Oct 2021. In case of a CPT exceedance, the energy spot price is set to the APC until the CPT breach is thereby subdued. Similarly, an administered pricing floor of APF≈ -\$300 applies when prices skew

[86] Market price levels that would have arisen from the alternative network formulations are thereby averted, i.e., the spot prices do not reflect the grid economics under scarcity. Instead, market-price-cap-level out-of-market uplift payments are paid out for the non-market demand response and unit commitment quantities that have been used to avoid load shedding. From a price quality perspective, the out-of-market payments pay for providing the emergency loads, but they do not encourage new investments in general that might minimise the scarcity risk to begin with.

[87] Non-market reserve contracts include provisioned arrangements through Clause 4.8.9 directives (AEMO (2014b), page 7) using constraints beyond the constraints in Table 5 in a pre-set priority flow. Note that the details of the related re-runs are available in AEMO (2017f) (pages 7-24), AEMO (2021j) (pages 5-10) and AEMO (2019a) (pages 4-6).

[88] See the Intervention field in the TraderSolution tab in the NEM Dispatch Engine solution data of AEMO (2021m).

oppositely as per 3.14.1 (b) in the Rules. Second, suspension pricing applies during severe demand deficit for example after a voltage collapse as per 3.14.3 in the Rules. The price methodology for a black system or emergency scenarios relies on a market suspension pricing schedule consisting of historical price averages (AEMO (2017b), page 4). At these times, non-market ancillary services are predominantly used to re-start parts of the network (AEMO (2012a), page 8).

5. Price settlement in the NEM Dispatch Engine

Ex-post price settlement computes the marginal value of an incremental change in load at the RRN, as per 3.9.2 (d) in the Rules, as the dual variable (shadow price) of the regional energy balance constraint (items 36-37 in Table 5) as in Mackenzie et al. (2020) (page 28). Besides, as 3.8.1(c) in the Rules requires the market operator to implement a constraint relaxation routine according to AEMO (2017a) (page 5) to preempt infeasible dispatch solutions, this involves the assignment of constraint violation penalties to every constraint to establish the priority order of the constraints (AEMO (2017a), page 5), as shown in the objective function (3), as well as the OCD re-runs that relax the violating constraints removing these penalties from the dispatch solution (see Section 4.6). The regional original price (ROP) then contains the pre-OCD constraint violation penalty costs, but the regional reference price (RRP) does not, according to AEMO (2016b) (page 4). In what follows we refer to the RRP as the unit price of electricity in the NEM.

This sensitivity is represented by net 1 MW change in load before losses, i.e., $\lambda_N^{c,l}$ in (2) can be decomposed into the quantity-weighted average of the marginal bid prices. The marginal MW change is met by a NEM-wide combination of n energy and FCAS bids collectively called the price setter bids.[89]

Example 3

Continuing Example 1 from Section 2.2.1, whilst omitting the security constraints from Section 2.2.1 for simplicity, we can write the targets associated with each bid as in columns (b) and (c) in Table 8. Then, conceptually, the differences in the targets

[89] See the PriceSetting tab of the AEMO (2021m) data.

in column (b) at 50 MW minus those in column (a) at 49 MW give the (marginal) quantities for each bid in column (c). The price is then expressed as the sumproduct of the values in the quantity column (c) and the bid price column (d). In particular, $1 \times \$1000 = \$1000$ sets the price.

Table 8: **Price settlement - An as-bid $\lambda_N^{c,l} := \lambda_i$ setting**

The table shows all bids in the market and identifies the 70 MW at $1000 as the price setter bid behind the incremental change in the market-wide target allocation from 49 MW to 50 MW given a market demand of 50 MW.

Bid	Bid type	Service type	Target (49 MW) (a)	Target (50 MW) (b)	Quantity (c) = (b) - (a)	Price (d)	(c) × (d)	Comments
10 MW at $10	Energy	Generator	10 MW	10 MW	0 MW	$10	$0	
20 MW at $100	Energy	Generator	20 MW	20 MW	0 MW	$100	$0	
70 MW at $1000	Energy	Generator	19 MW	20 MW	1 MW	$1000	$1000	The only price setter bid is marginal in exactly 1 MW.
35 MW at $2000	Energy	Generator	0 MW	0 MW	0 MW	$2000	$0	
-20 MW at -$10	Energy	Load	0 MW	0 MW	0 MW	-$10	$0	
-10 MW at -$100	Energy	Load	0 MW	0 MW	0 MW	-$100	$0	
-5 MW at $900	Energy	Load	0 MW	0 MW	0 MW	$900	$0	
							Price: $1000	

5.1. Reserves

For a greater degree of realism $\lambda_N^{c,l} := \lambda_N^c$, the following example shows FCAS reserves impacting the market price.

Example 4

In Table 9, five price setter bids are involved in setting the price, one energy bid and four FCAS bids. One generation bid by unit POAT220, a gravity hydro generator located in TAS, sees the complete marginal target increase of 1 MW. At the same time, POAT220 no longer provides 5-minute raise regulation FCAS (-0.67 MW) or 60 second raise contingency FCAS (-0.12 MW) due to the trade-off it apparently has between energy and reserves provision. These services are recovered by enabling units MP2 and MP1 in the same amounts instead, respectively, but this afflicts higher prices. We also see that these net to 0 MW and have no role in supplying the marginal change in energy. Even though the FCAS target variation sums to zero, the FCAS price increase $-0.67\times\$5.5+-0.12\times\$0.61+0.67\times\$7.99+0.12\times\$2.01 = \$1.83$ is reflected in the energy spot price. The price is the marginal quantity weighted average of the energy bid prices plus the ancillary service distortion as an additive cost $1 \times \$25.36 + \$1.83 = \$27.19$.

Table 9: **Price settlement - FCAS effects in a $\lambda_N^{c,l} := \lambda_N^c$ setting**

The table shows the price setter bids behind the incremental change in volume for TAS as at 5:05 AM 15 Jul 2021. Source: NEOPoint (2021), AEMO (2021m).

Unit ID	State	Bid type	Service type	Quantity (1)	Price (2)	(1) × (2)	Comments
POAT220	TAS	Energy	Generation	1	$25.36	$25.36	The only price setter bid is marginal in exactly 1 MW.
POAT220	TAS	FCAS	R5RE	-0.67	$5.5	-$3.67	
POAT220	TAS	FCAS	R60S	-0.12	$0.61	-$0.07	
MP2	NSW	FCAS	R5RE	-0.67	$7.99	$5.33	
MP1	NSW	FCAS	R60S	-0.12	$2.01	$0.24	
						Price: $27.19	

5.2. *Losses*

For the $\lambda_N^{c,l} := \lambda_N^l$ setting, the marginal MW change is adjusted for intra- and inter-regional losses, owing to the fact that almost all network elements, including lines, are imperfect conductors (AEMO (2012c), page 5). Under marginal pricing, the zonal design of the NEM approximates nodal LMP in using marginal loss factors (MLF) as per AEMO (2012c) (pages 10-11), which represent marginal losses, i.e., "the incremental change in total losses for each incremental [1 MW] unit of electricity" (AEMO (2020d) (page 5), AEMO (2012c) (page 15)). MLFs are forward-looking estimates (AEMO (2020d), page 5), note however that average losses are typically lower than marginal losses as in AEMO (2012c) (page 10).

There are two kinds of MLFs in the NEM. Intra-regional MLFs are static loss factors within the regions under 3.6.2 in the Rules. These MLFs are the volume-weighted average changes in load at the RRN (swing bus) for changes in injection at the unit connection points, calculated from historical network flow data using TPRICE as in AEMO (2012c) (pages 5, 11, 20) and AEMO (2020d) (page 14). The static MLF is then applied as the divisor of the as-bid price at the source to obtain the (typically higher) intra-regional MLF–adjusted bid price at the RRN of the region.

In contrast, inter-regional (interconnector) MLFs are dynamic loss factors between the regions updated every dispatch interval using a number of system variables, mainly demand and interconnector transfers, in loss factor equations as per 3.6.1 in the Rules. These equations "describe the variation in loss factor at one RRN with respect to an adjacent RRN" (AEMO (2022d), page 48), which also come from the load flow calculations in TPRICE, as in AEMO (2020d) (page 15). The MLF equation coefficients for demand and interconnector transfers are estimated using linear regression. The MLF estimated dynamically using this inter-regional MLF equation is then applied as an RRP multiplier to obtain the spot price at the RRN of the focus region (AEMO (2012c), page 22).

We can also establish the trade directions from the inter-regional MLFs in general observing the DUID-level marginal quantity values[90]. We have the following relations for a 1 MW change in the focus region's generation. If the DUID-level marginal quantity is less than 1 MW and positive, e.g. 0.95 MW, then the focus region is exporting 1 MW less and some DUID in the other region is recovering the lost amount after inter-regional line losses by increasing its own generation by 0.95 MW. Similarly, if the the DUID-level marginal quantity is greater than -1 MW and negative, e.g. -0.95 MW, then the focus region is exporting 1 more and some DUID in the other region is matching the incoming amount after inter-regional line losses by decreasing its own generation by 0.95 MW. However, if the DUID-level marginal quantity equals 1 MW exactly then the focus region is increasing its own generation by 1. Analogously, if the DUID-level marginal quantity is greater than 1 MW, e.g. 1.05 MW, then the focus region is importing 1 MW more from the DUID in another region, which has to increase dispatch by 1.05 MW to account for the increased demand before inter-regional line losses. Similarly, if the DUID-level marginal quantity is less than -1 MW, e.g. -1.05 MW, then the focus region is importing 1 MW less from the DUID in another region, which has to decrease dispatch by 1.05 MW to account for the decreased demand before inter-regional line losses. In contrast, if the DUID-level marginal quantity equals -1 MW exactly then the focus region is decreasing its own generation by 1 MW. We use these results to construct the upcoming examples.

The following example recreates and for exposition purposes refashions the conditions in Example 4 to show the price effects of intra- and inter-regional losses.

Example 5

Focusing on the top segment of Table 10, the bid price at the RRN ($25.36) would be equal to the as-bid price ($24.58) without intra-regional line losses. However, as in 3.8.6

[90] Which correspond to the Increase field values in the PriceSetting tab of the AEMO (2021m) data, particularly the energy offer (ENOF) attributes. The load offers (LDOF) have the opposite signs.

(h) in the Rules, we must account for the intra-regional MLF too. The as-bid price, the price placed by POAT220 in its bid submission is \$24.58. Only after dividing that by the intra-regional MLF we see the additive intra-regional loss adjustment of 78 cents (as \$24.58 + \$0.78 = \$25.36). In both segments of Table 10, the price setter bid price of the POAT220 hydro plant is \$25.36 after intra-regional MLF as measured at the regional reference node (RRN). Furthermore, the single price setter bid by POAT220 is only subject to intra-regional losses. There are no inter-regional losses as it is located in the focus region, TAS. This we can also see from the fact that marginal quantity is at exactly 1 MW. The TAS price is then $1 \times \$25.36 = \$25.36$.

In the bottom segment of Table 10, however, there are two different price setter bids. One by unit A located in TAS and another by unit B located in VIC. The as-bid price is \$24.58 and the intra-regional loss is 78 cents on unit A, as before. In comparison, the as-bid price is \$23.00 and the intra-regional loss is 300 cents on unit B.[91] This is a scenario where the marginal MW is met by local generation in 0.60 MW and partly by generation increase elsewhere (in VIC). We also know that TAS is importing from VIC because the generation increase in VIC is more than the difference of 1 MW and 0.60 MW. VIC has to increase generation by more than 0.40 before line losses in order to deliver 0.40 exactly to TAS. The TAS price is then $0.6 \times \$25.36 + 0.5 \times \$26 = \$28.22$.

Table 10: **Price settlement - Loss effects in a $\lambda_N^{c,l} := \lambda_N^l$ setting**

The table shows the price setter bid(s) contributing to the incremental change in the energy demand for TAS in two hypothetical scenarios. One, where the price is fully set by bid(s) from the region (above), and another where there are additional unit(s) supplying from another region (below).

Price for TAS with intra-regional line losses:

Unit ID	State	Bid type	Service type	Quantity (1)	Price (2)	As-bid price	(1) × (2)	Comments
Unit A	TAS	Energy	Generation	1	\$25.36	\$24.58	\$25.36	
							Price: \$25.36	

Price for TAS with both intra-regional and inter-regional line losses:

Unit ID	State	Bid type	Service type	Quantity (1)	Price (2)	As-bid price	(1) × (2)	Comments
Unit A	TAS	Energy	Generation	0.60	\$25.36	\$24.58	\$15.22	
Unit B	VIC	Energy	Generation	0.5	\$26.00	\$23.00	\$13.00	
							Price: \$28.22	

[91] From the higher dollar loss we infer that unit B is electrically further away from the reference node within its own region.

5.3. Loads

The examples have so far only looked at instances when a generator incrementally increased output to arrive at the marginal 1 MW change. We now look at a case with a change in loading (storage uptake).

Example 6

For a real world example see Table 11 where a single bid by the HPRL1 battery load unit sets the price. Load in the system rises by decreasing the target of the load unit. The price is the marginal quantity weighted average of the energy bid prices $-1.18 \times -\$56.74 = \$66.81$.

Table 11: **Price settlement - marginal load in a $\lambda_N^{c,l} := \lambda_i$ setting**

The table shows the price setter bid behind the incremental change in volume for NSW as at 5:45 AM 16 Sep 2021. Source: NEOPoint (2021), AEMO (2021m).

Unit ID	State	Bid type	Service type	Quantity (1)	Price (2)	(1) × (2)	Comments
HPRL1	SA	Energy	Load	-1.18	-\$56.74	\$66.81	NSW imports 1 MW more (after losses) from SA where loading (storage uptake) at -\$56.74 decreases by 1.18 MW.
						Price: \$66.81	

5.4. Real-world examples with binding constraints

Whenever a plant, FCAS, thermal, stability, or economic constraint is binding over the incremental MW increase congestion is concomitant. Constraint equations from the constraint sets from all segments of Table 5 might invoke line closures and resource trade-offs as per 3.6.4 (a1) in the Rules. This typically complicates price settlement and induce detectable price effects[92]. Below we present three not atypical real-world examples in the full $\lambda_N^{c,l} := \lambda_N^{c,l}$ setting with reserves, losses, and loads, and with one or more binding security constraints.

Example 7

For NSW, the incremental increase in energy requires a marginal quantity increase by the brown coal units LYA1, LYA2, LYA3 and LYA4 in VIC, while the local, nominally

[92]From a price quality aspect, prices should keep to grid economics, i.e., they should rise at times of scarcity and drop otherwise to return the true costs of capacity investments. However, when constraints equations bind the prices tend to rise and drop irrespective of the overall scarcity level.

lower priced solar farm LIMOSF21 (NSW) sees a marginal quantity decrease of 0.11 as in Table 12.[93] That is because a congested network element (e.g., a line) requires backing off cheaper quantities so that load can be increased by injecting more expensive quantities elsewhere on the grid. More specifically, the N^^N_NIL_3 voltage stability constraint, which is a less than or equal to constraint and features LIMOSF21 with a coefficient of 1 and the VIC1-NSW1 interconnector (at the boundary) with a coefficient of 0.093 at the LHS, is binding.[94] Given an inter-regional MLF of 1.077 over VIC1-NSW1 (AEMO (2021m)), and a proportioning of 34.38% of the losses to VIC, the extra flow at the boundary due to losses is 1.077/1.027=1.0497 MW per 1 MW increase in flow at the boundary as in AEMO (2009) (page 5), times a quantity multiplier of 1.104, because 1.104×1.077=1.19 gives back the change in VIC. That is a change in flow at the boundary of 1.0497×1.104=1.159, which in turn creates a constraint LHS increase of 1.159×0.093=0.11. This amount if offset by changing the target of LIMOSF21 by -0.11 as shown in Table 12. As a result, the NSW price can be written as the sum product $1.19 \times -\$31.05 - 0.11 \times -\$1000 = \$71.12$, which, quite extraordinarily, gives a positive price using solely negative marginal bids ($-\$1000$ and $-\$31.05$).

Table 12: **Price settlement - High price in a $\lambda_N^{c,l} := \lambda_N^{c,l}$ setting**

The table shows the price setter bids behind the incremental change in volume using the actual engine outcomes for NSW as at 2:55 PM 15 Jul 2021. Source: NEOPoint (2021), AEMO (2021m).

Price for NSW:

Unit ID	State	Bid type	Service type	Quantity (1)	Price (2)	(1) × (2)	Comments
LYA1, LYA2, LYA3, LYA4	VIC	Energy	Generation	1.19	-\$31.05	-\$37.08	NSW imports 1.19 MW more quantities (before losses) generated in VIC for -\$31.05.
LIMOSF21	NSW	Energy	Generation	-0.11	-\$1000	\$108.20	NSW generates 0.11 less at -\$1000.
						Price: \$71.12	

Example 8

Overall more than ten price setter bids are involved in setting the price in the focus region SA in Table 13. The marginal increase in energy in SA requires flow modifications over the V-S-MNSP1 (Murraylink) and the VIC1-NSW1 interconnectors, and

[93]There is also a tie-break and associated costs in the order of magnitude of 1e-4 for LIMOSF21 as in AEMO (2021m).

[94]The binding constraint information and the proportioning factors are obtained using Nempy as in Gorman et al. (2022) with default data settings for the dispatch interval.

therefore dispatch target changes in NSW and VIC, but interestingly, not in the focus region SA. The following dynamic unfolds. First, SA is importing from VIC through Murraylink to meet the 1 MW increase in load in SA, where this is met by a -0.961 MW flow at the boundary, a value obtained using the inter-regional MLF of 0.872 over V-S-MNSP1 (AEMO (2021m)) and a proportioning of 72.31% of the losses to VIC to calculate 0.872/(1+(0.872-1)×0.7231)=0.961, as in AEMO (2009) (page 5), and a negative sign as it is an easterly flow[95]. Then, after rounding, the change on the VIC side of Murraylink is 0.872 MW and 1 MW on the SA side, as computed as the at the boundary flow 0.961 plus incremental losses 0.961×(0.872-1)×0.7231=-0.088 (from region): 0.961-0.088=0.872, and as the at the boundary flow minus incremental losses 0.961×(0.872-1)×(1-0.7231)=-0.034 (to region): 0.961+0.034≈1.

At the same time one of the voltage stability constraints N^^N_NIL_3, which is a less than or equal to constraint, is binding.[96] The LHS of this constraint includes V-S-MNSP1 with a -0.5197 coefficient and VIC1-NSW1 with 0.09287. Therefore, as the additional -0.961 MW negative flow at the boundary of V-S-MNSP1 increased the LHS of the constraint, the VIC1-NSW1 flow must increase in a northerly direction by -0.961×(-0.5197/0.09287)=5.378 MW at the boundary to neutralise that LHS increase.

Then, with an inter-regional MLF of 1.147 (AEMO (2021m)) and a proportioning of 34.38% of the losses to VIC, the change on the VIC side of VIC1-NSW1 is approximately 5.6 MW and 4.9 MW on the NSW side after rounding, computed as the at the boundary flow 5.378 plus incremental losses 5.378×(1.147-1)×0.3448=0.271 (from region): 5.378+0.271≈5.6, and as the at the boundary flow minus incremental losses 5.378×(1.147-1)×(1-0.3448)=0.517 (to region): 5.378-0.517≈4.9.

Then, the 6.5 MW increase in dispatch in VIC by the units LYA1, LYA2, LYA3 and LYA4 at -$31.05 is the sum of the flows sent through the two different interconnectos, 0.872+5.6≈6.5, as shown in Table 13. Also, the 4.9 MW decrease at NSW other end of VIC1-NSW1 is met by the higher cost ($43.60) black coal units ER01, ER03 and

[95]Note that any positive interconnector flow travels northward or westward as in AEMO (2023)

[96]The binding constraint information and the proportioning factors are obtained using Nempy as in Gorman et al. (2022) with default data settings for the dispatch interval.

ER04.

Regarding the related update in ancillary services, the units ER01, ER03 and ER04 are impelled to lower their 5-minute regulatory FCAS provision after decreasing their energy output and the next least expensive service provider LOYYB2 must step in at a higher price. Even after some losses in value on FCAS, however, the engine has realised considerable value as the price result for SA is $-\$348.86$ despite using much higher priced marginal bids for energy ($-\$31.05$ and $\$43.60$).[97]

Table 13: **Price settlement - Low price in a $\lambda_N^{c,l} := \lambda_N^{c,l}$ setting**

The table shows the price setter bids behind the incremental change in volume using the actual engine outcomes for SA as at 12:40 PM 15 Jul 2021. Source: NEOPoint (2021), AEMO (2021m)

Price for SA:

Unit ID	State	Bid type	Service type	Quantity (1)	Price (2)	(1) × (2)	Comments
LYA1, LYA2, LYA3, LYA4	VIC	Energy	Generation	6.51	-\$31.05	-\$202.25	SA reduces exports to VIC by 1 MW. 6.51 MW more quantities are generated in VIC for -\$31.05, of which 4.92 MW arrive at NSW.
ER01, ER03, ER04	NSW	Energy	Generation	-4.92	\$43.60	-\$214.50	Imports into NSW replace 4.92 MW \$43.6 dispatch in NSW.
ER01, ER03, ER04	NSW	FCAS	L5RE	-4.92	\$0.00	\$0.00	With 4.92 MW NSW-generated energy being replaced by imports there is 4.92 MW less capacity in NSW to provide L5RE FCAS.
LOYYB2	VIC	FCAS	L5RE	4.92	\$13.80	\$67.89	The next least expensive L5RE FCAS provider.
						Price: -\$348.86	

There is one further remark to Table 13 containing information about SA. At the time of this data, system strength directives under the Rules had that "the minimum requirement in South Australia drops to two synchronous units online, mainly for system security reasons rather than to address the system strength shortfall. This requirement remains until the commissioning of Project EnergyConnect (if built)" (AEMO (2020f), page 30). The input bid data and the cleared target output data in the NEM Dispatch Engine solution files of AEMO (2021m) indeed confirm that two synchronous units were kept online despite of bidding at prices near the market price thresholds, which is an example of constrained-on bids that are implicit but not directly observable in the price setter bid selection.

[97]Based on personal communications with Allan O'Neil in the second half of Nov 2022.

Example 9

The present example explains a price outcome for NSW where changes in the Basslink market interconnector come into play. In order to meet the incremental increase in load, the ER02 local unit is directed to increase generation by 1 MW for \$55.01 in NSW as the flow through the VIC-NSW interconnector is blocked by the binding voltage stability constraint V^^N_DPWG_X5_1. The increase in energy dispatch also allows the ER02 unit to raise its FCAS lowering service enablement over two response time categories, 60-second and 5-minute, for \$1.03 in both. These FCAS increases do, in turn, lead to increases on the LHSs of a binding loss of Basslink (F_MAIN++NIL_BL_L60) and loss of a potline mainland constraints (F_MAIN++APD_TL_L5), respectively.[98]

In both equations the increase in the mainland enablement of L60S and L5MI, where ER02 has a constraint coefficient of 1, as part of the regional coefficients for NSW1L60S and NSW1L5MI, the Basslink interconnector flow TVMNSP1 is positive in the northerly direction. Therefore, the engine is able to offset the increase caused by ER02 by decreasing the TVMNSP1 by 1 MW, for trade value maximisation. Decreasing the northerly flow is achieved by increasing the southerly flow, i.e., by sending an additional 1 MW to TAS without increasing the LHSs of the constraints by more than 1 MW after losses. This is satisfied by increasing the target for the NUMURSF unit in VIC by 1.06 MW after losses and decreasing it for TUNGATIN in TAS by 1 MW. Notice also the price effect of the market interconnector; should the bid price of T-V-MNSP1 be different from \$0.0, one would see an additive price impact.

Due to this increase on the LHSs of the binding mainland constraints, however, it is no longer possible to decrease the L60S and L5MI FCAS targets back to net nil from the mainland. Any such change in FCAS would have to come from TAS. Accordingly, TUNGATIN (TAS) decreases the L5MI service by 1 MW, but neither TUNGATIN, nor any other unit would be able to decrease L60S back to net nil because of a binding local L60S constraint in TAS F_T+NIL_ML_L60. Considering all these changes over

[98] The binding constraint information and the proportioning factors are obtained using Nempy as in Gorman et al. (2022) with default data settings for the dispatch interval.

the last 1 MW, the NSW price result is $37.78.[99]

Table 14: **Price settlement - Mid price in a $\lambda_N^{c,l} := \lambda_N^{c,l}$ setting**

The table shows the price setter bids behind the incremental change in volume using the actual engine outcomes for NSW as at 11:25 AM 17 Sep 2021. Source: NEOPoint (2021), AEMO (2021m).

Price for NSW:

Unit ID	State	Bid type	Service type	Quantity (1)	Price (2)	(1) × (2)	Comments
ER02	NSW	Energy	Generation	1.00	$55.01	$55.01	1 MW energy increase in the focus region as the VIC-NSW interconnector is blocked by a binding voltage stability constraint.
ER02	NSW	FCAS	L60S	1.00	$1.03	$1.03	1 MW L60S FCAS increase provided by ER02 more economically than by mainland competitors.
ER02	NSW	FCAS	L5MI	1.00	$1.03	$1.03	1 MW L5MI FCAS increase provided by ER02 more economically than by mainland competitors.
T-V-MNSP1	TAS	-	Interconnector	1.00	$0.00	$0.00	TAS is sending 1 MW less through Basslink.
NUMURSF1	VIC	Energy	Generation	1.06	-$18.90	-$19.98	On the mainland end of Basslink generation increases for -$18.90.
TUNGATIN	TAS	Energy	Generation	-1.00	-$0.87	$0.87	On the TAS end of Basslink generation decreases for -$0.87.
TUNGATIN	TAS	FCAS	L5MI	-1.00	$0.18	-$0.18	The L5MI FCAS increase is offset by a decrease in TAS that does not affect any binding constraints.
						Price: $37.78	

In summary of the Examples 1-9, the energy spot price is the cost of the marginal increase in supply at the regional reference node, discretised as 1 MW, but with several security constraint factors at play. First, as emphasised in Section 2.2.3, the curtailed (constrained-off) and the must-run (constrained-on) quantities implicitly influence the price outcome by changing the supply pool of bids even in their simplest form. More directly, FCAS reserves, losses, and binding security constraints change the price calculation directly in a way that is irreproducible using the usual merit order rules, i.e. such that the 1 MW change in power takes rearranging more than 1 MW of resources. In effect, security-constrained least-cost pricing comes down to pricing the MW changes that the NEM Dispatch Engine deems as the most economic way of delivering an extra unit of demand at the regional reference node. It follows that price replication in a traditional bid stack type model framework using historical data under the NEM assumptions is mostly only practicable when the price is not susceptible to these effects. Collating the market bid stack, adjusting it for the constrained-off quantities, adjusting the demand for the constrained-on quantities, and letting the inelastic demand line

[99]Based on personal communications with Allan O'Neil on 4 Nov 2022.

intersect the bid stack gives only the price *before* various non-bid effects. Furthermore, we can also decompose the price with non-bid effects and put the pieces back together, as shown in Examples 7-9, but it is relatively challenging to predict some of the multiplicative components in a bid stack price model setting, which highlights the limitations of the traditional bid stack price modelling approach.

6. Conclusions

Any up-to-date account of price discovery in the NEM will comprise reliability planning, trade value maximising real-time dispatch and ex-post price settlement. Prices are based on the optimal dispatch scheduling outcome preceded by years of reliability planning to ensure that the resources from which the engine is scheduling gives an adequate solution. Then the objective function of real-time dispatch underpinning price settlement ensures that the trade value maximising optimal dispatch schedule is physically viable given the security constraints. Finally, price settlement is performed valuing the incremental unit of load.

The commonly used bid stack model framework can be extended to include price-elastic wholesale load activity, co-optimised ancillary services, network losses and congestion effects as required under the NEM market design assumptions. Some of these enter in the bid stack collation, others are non-bid factors such as the constrained-on and constrained-off adjustments or the additive adjustments for intra-regional losses and FCAS. The multiplicative non-bid factors involve security constraint–driven resource trade-offs. In such an extended bid stack model framework, security constraints are no longer overlooked. This is an important insight for electricity price modelling not only in Australia but perhaps internationally as well.

Finally, in the broader context of sustainability in worldwide electricity markets, the NEM is an innovative leader in integrating renewable fuels and battery solutions despite of the operative challenges involved. Inverter-based power resources cannot provide inertia, therefore new system strength constraints had to be introduced causing some renewable capacities to be constrained-off. In addition, rapid frequency balancing has become important now more than ever to stabilize the hertz equilibrium of the system in the presence of intermittent capacities, which sometimes causes additive FCAS price components to arise. Also, given the market interconnectness we see that low-bidding renewables can impact the price outcome in multiple regions because the NEM Dispatch Engine is a market-wide trade value maximisation routine. Evidently, these solutions also induce observable price effects in the continuing transitional shift to clean energy.

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