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On intermittent renewable generation & the stability of Australia's National Electricity Market

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Abstract
Energy-only markets have an inherently unstable equilibrium, even under ideal conditions, because participants are unable to optimise VoLL events. The addition of intermittent renewable generation is thought to make conditions harder. In this article, optimal VoLL events in an islanded NEM region is modelled by substituting high price caps for Boiteux capacity charges, then analysing the impact of adding progressively more Variable Renewable Energy (VRE) – up to 35% market share. Spot market conditions prove stable and tractable provided thermal plant exit and adjust perfectly. But VRE asset allocation is important; absent highly elastic demand or ultra-low cost storage solar PV market share has economic limits because the technology rapidly cannibalises itself. Furthermore, as VRE rises in imperfectly interconnected regions, a tipping point appears to exist where the hedge market enters an unstable zone through shortages of 'asset-backed' firm intra-regional swaps and caps. Government-initiated CfDs for VRE need to be designed carefully to ensure any instability is not exacerbated by extracting contracts from an already short hedge market.

Keywords: Energy markets, missing money, renewables.
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1. Introduction

Australia's National Electricity Market (NEM) formed part of a world-wide electricity industry microeconomic reform experiment which commenced in Chile from 1982 (Pollitt, 2004). England & Wales followed with their landmark 1990 reform while Australia commenced from 1994 (Green, 1998; Nelson & Orton, 2016). The initial wave of restructuring and deregulation had two or three template electricity markets designs involving various combinations of 'energy-only' or 'capacity & energy' market mechanisms, set in gross or net pools with day-ahead or real-time scheduling. These designs shared a market liberalisation objective but adopted different paths to achieve that outcome (Pollitt & Anaya, 2016). Results have been mixed.

By any measure the NEM had been a resounding success[1] and by 2005 was widely regarded as a template for power system reform (IEA, 2005). The NEM is an energy-only gross pool with a real-time (5-minute) uniform first-price auction clearing mechanism and forward derivative markets traded both on-exchange and Over-the-Counter at 300-400% of physical trade.[2]

Pollitt & Anaya (2016, p.75) noted a second wave of world-wide electricity market experiments currently underway – each involving a *'game-changing set of policies'* designed to achieve a decarbonisation objective. Once again, there are two or three template designs involving various combinations of carbon pricing, renewable targets, centrally-initiated CfDs, and distributed resources – and – as with the first wave results will be mixed.

When energy markets were first designed, they were applied to large thermal systems comprising
dispatchable coal, gas and hydro plant. There was little intermittent generation plant (i.e. solar and wind).[3] But Variable Renewable Energy (VRE) sources now form the dominant supply-side entrants in the NEM driven by various policy initiatives, an extremely tight market for gas[4], and an abject inability to 'bank' coal plant due *future* CO_2 emissions risk.

Energy markets can comfortably integrate moderate levels of intermittent generation (Hirth, 2013).[5] However, there is a broader question as to whether current energy markets are capable of accommodating *high-levels* of VRE. While by no means unanimous, an emerging theme amongst British and European energy economists is that energy-only markets are broken given multiple policy objectives (Edenhofer et al. 2013; Helm, 2014; Newbery, 2015; Keay, 2016; Pollitt & Anaya, 2016; Neuhoff et al. 2016; Green & Staffell, 2016). The collapse of the South Australian power system (40% VRE) on 28 September 2016[6] - the first system collapse in Australia since 1964[7] - appears to have removed any doubt in the minds of Australian policymakers that the NEM design requires adjustment. Whether this translates to *tweaking at the edges* or *major surgery* is an open question, but the status quo is widely acknowledged as unacceptable.[8]

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[1] Performance improvements included average cost, price, plant availability, and reserve margins (see Simshauser, 2005). In more recent research, the wholesale market was one of the few areas of the electricity market that was performing well (see for example Nelson & Orton, 2015; Simshauser, 2014). From mid-2016 however, market performance deteriorated significantly.
[2] See Simshauser, Tian & Whish-Wilson (2015) and in particular Appendix III.
[3] Data from the Energy Supply Association reveals that when the NEM commenced in 1998, the market shares of the various technologies were coal (88.4%), hydro (9.3%), gas (2.2%) and VRE (0%). Wind produced less than 1GWh in a 165,000GWh system. By 2015, the energy mix was coal (75.7%), gas (12.9%), hydro (6.4%) and wind/solar (4.9%) with total load of 196,000GWh.
[4] For further details on the Australian east-coast gas market, see Simshauser & Nelson (2015).
[5] See for example Simshauser (2011) in which South Australia is modelled with 17% VRE.
[6] The characteristics that preceded SAs power system collapse are somewhat unique by global standards. SA has among the 'peakiest' system loads in the OECD, the highest take-up rate of rooftop solar PV per capita in the world, a very high market share of utility-scale VRE (primarily wind) which when combined with rooftop solar now produces > 40% of system demand. And, SA is interconnected to one adjacent region (i.e. Victoria).
[7] The New South Wales power system collapsed on 10 June 1964 during an electrical storm.
[8] The Council of Australian Governments 'Energy Council' commissioned the Finkel Review in response.

In this article a single NEM region is modelled with three objectives – to analyse whether with rising levels of VRE (1) stable spot market equilibrium exists for thermal plant; (2) how the market will view VRE asset allocation; and (3) imbalances that may emerge in forward derivatives markets thus presenting policymakers with systemic risks[9]. This article is structured as follows. Section 2 reviews relevant literature and concepts. Section 3 presents Model results of spot market stability and Section 4 explores VRE asset allocation. Section 5 analyses the hedge market. Conclusions follow.

2. Review of literature and relevant concepts

Energy policy starts with three basic objectives; (1) a reliable supply (2) at minimum cost, (3) subject to an environmental constraint. For elected officials, reliability is crucial. Reliability is an all-encompassing term but can be broken down into Resource Adequacy and System Security (Batlle & Perez-Arriaga, 2008). Resource Adequacy refers to sufficient installed capacity to meet instantaneous aggregate final demand, taking into account planned and forced plant outages. Security refers to the ability of Resources to withstand sudden disturbances arising from the loss of system elements in real-time. In energy-only markets, Resource Adequacy and Security are thus public goods (Newbery, 2015).

At the core of the current analysis is whether an energy-only market can produce a stable equilibrium and give policymakers confidence that Resource Adequacy, Security and Systemic Security will prevail with high levels of VRE. This involves examining missing money, missing markets, incomplete markets, shrinking markets and misinformed markets.

2.1 Missing money

The concept of Resource Adequacy in energy-only markets vis-à-vis administratively determined reliability constraints is well understood in energy economics (see Stoft, 2002; Besser et al. 2002; Oren, 2003; Bidwell & Henney, 2004 amongst many others[10]). Entire editions of academic journals have been devoted to the topic.[11] Literature on Resource Adequacy in energy-only markets can be loosely traced back to von der Fehr and Harbord (1995) who noted indivisibility of plant capacity, long construction lead-times, lumpy plant entry, investment tenor and policy uncertainty make merchant generation investments unusually risky. First contributions describing difficulties investing in merchant peaking plant in energy-only markets include Doorman (2000), De Vries (2002) and Stoft (2002). Resource Adequacy became a mainstream issue with Peluchon (2003), Roques et al. (2005), Hogan (2005), Cramton & Stoft (2006), Joskow (2006), Finon & Pignon (2008), Simshauser (2008), Finon (2008) amongst others cataloguing risks to timely entry and supply-side structural faults; first in Europe, then the US and Australia.

In theory, energy-only markets can clear demand reliably and provide suitable investment signals for requisite new capacity (Schweppe et al. 1988). But energy-only market theories are based upon equilibrium analysis and in practice electricity markets can be off equilibrium for extended periods of time (de Vries & Heijien, 2008; Hirth et al. 2016). A long list of explicit and implicit assumptions underpin the theory including unlimited market price caps, limited political & regulatory interference, active demand-side participation, perfect forward markets and a largely equity capital-funded generation fleet able to withstand elongated price cycles.

[9] By 'systemic risk' I am referring to the risk of a large market participant experiencing financial distress through adverse wholesale spot market price exposures, in turn resulting in cascading failures of other market participants (analogous to systemic risks to banking systems during a financial crisis).
[10] See also Neuhoff et al. 2004; de Vries et al. 2004; Wen et al. 2004; Hogan, 2005; Bushnell, 2005; Roques et al. 2005; Cramton and Stoft, 2006; Joskow, 2006; Simshauser, 2008; Finon, 2008, 2011; Hogan 2013; Cramton, Ockenfels & Stoft, 2013; and Spees et al. 2013.
[11] See for example *Utilities Policy* Volume 16 (2008) or *Economics of Energy & Environmental Policy* Volume 2 (2013).

As these assumptions are progressively relaxed it can be shown that energy-only markets with an administratively determined VoLL do not have a stable equilibrium (Bidwell & Henney, 2004; Roques, 2008). Given substantial sunk costs and low marginal running costs, persistent generator bidding at marginal cost in an intensely competitive energy-only market will produce inadequate net revenues – known as the *missing money problem* (Cramton & Stoft, 2006[12]). Compounding matters are wholesale price caps set too low or over-enforced by regulatory authorities along with actions by System Operators which suppress legitimate price signals (Joskow 2008, Spees et al., 2013; Hogan, 2013, Leautier, 2016 and others[13]). Consequently, power markets are rarely in equilibrium.

This matters because capital-intensive merchant generators face rigid debt repayment schedules – which of itself is unremarkable – but becomes problematic in the presence of incomplete forward derivatives markets (see Section 2.3). In consequence, the theory of spot electricity markets suffers from an inadequate treatment of how sunk capital is financed (Joskow, 2006; Finon, 2008; Meade & O'Connor, 2009; Caplan, 2012; Nelson & Simshauser, 2013). High levels of VRE is expected to amplify and complicate matters because such plant is subsidised in side-markets and priority dispatched (Nelson et al. 2012; Joskow, 2013; Newbery, 2015). Given negligible marginal running costs, *merit-order effects* arising from VRE became apparent in markets like Germany as early as 2008 (Sensfuβ et al. 2008).

Three broad remedies are typically suggested to deal with *missing money* viz. (1) introducing capacity markets, (2) raising VoLL, or (3) increasing Operating Reserves.[14] Each of these comes with problems. Introducing capacity markets represents a *partial reversion* to central planning which grinds against the decision to push market and investment risks away from consumers and to investors in the first place (Leautier, 2016).[15] Raising VoLL compounds the risk of, and inability to distinguish, market power (Roques et al, 2005 and others[16]). And increasing Operating Reserves, which has the effect of expanding volumes and increasing the frequency of 'lower value VoLL events', may suffer similar problems. To be sure, none of these represent a choice between markets and intervention because each involve administratively-determined variables (Campton et al. 2013).[17]

Above all, electricity markets are characterised by several non-trivial market failures. Most hard and soft commodity markets clear under scarcity conditions via a combination of demand-bids and supply-inventories. In electricity markets, large segments of real-time aggregate demand are price-inelastic and unable to react to scarcity conditions (Cramton & Stoft, 2008, Batlle &

[12] See also Neuhoff et al. 2004; de Vries, 2004; de Vries et al. 2008; Bushnell, 2005; Roques et al. 2005; Joskow, 2008b; Finon, 2008; Simshauser, 2008; Joskow, 2013; Nelson & Simshauser, 2013; Cramton, Ockenfels & Stoft, 2013; Green & Staffell, 2016; Keay, 2016.

[13] See also Besser et al. 2002; Oren, 2003;de Vries, 2003; Wen et al. 2004; Batlle & Perez-Arriaga, 2008; Finon & Pignon, 2008.

[14] On capacity markets see Bidwell & Henney (2004);et al (2013); Green & Staffell, (2016). On setting higher VoLL and Vertical Integration see for example Newbery (2006), Finon (2008), Simshauser (2010), Simshauser, Tian & Whish-Wilson (2015). On increasing the requirement for operating reserves and enhancing reliability of supply see Hogan (2005, 2013).

[15] Hogan (2013) also notes there is no simple way to observe and measure delivery. Conversely, Cramton & Stoft (2008) observe that even if capacity is *overbuilt* as a result of capacity mechanisms, the incremental cost to consumers is small because excess 'peaking plant' is the cheapest form of capacity (viz. an extra 10% of peak capacity may increase consumer costs by say 2%). Additionally, Spees et al. (2013 pp15-16) observe that on balance capacity markets in the US have delivered good results in that they met their objective function, mobilised large amounts of low cost supply including Demand Response, energy efficiency, transmission interconnection, plant upgrades, deferred retirements and environmental retrofits.

[16] See also Besser et al, 2003; Oren, 2003; Cramton & Stoft, 2006; Joskow 2008; Simshauser, 2008.

[17] A higher VoLL involves administratively determining a price cap to meet an administratively-determined reliability constraint. As Joskow (2013) notes, the entire logic of capacity markets starts with administratively-determined reliability criteria and involves administratively determining the quantity required to meet that constraint. And relying on FCAS involves administratively determining spinning reserve quantities in order to meet the reliability constraint. Thus each solution involves some form of administrative judgement, and in all cases, the risk of error – viz. exercise of market power with VoLL (Hogan, 2013); over-investment with capacity markets (Leautier, 2016); or market power and excess reserves with FCAS – is ultimately borne by the customer.

Perez-Arriaga, 2008; Roques, 2008; Finon & Pignon, 2008). The supply-side is similarly inelastic in real-time because storage is costly. System Operators must therefore resort to non-price rationing and a regulator is forced to administratively determine VoLL. And participants in energy-only markets are unable to optimise the number of blackout events (i.e. VoLL) that produce stable equilibrium (Cramton et al. 2013).

2.2 Missing Markets

Electricity follows the laws of physics, not economics and consequently energy markets are an imperfect abstract of a complex physical system and prone to 'missing markets' (Newbery, 2015). Some are obvious; in the NEM there is no market for reserve capacity.[18] Other missing markets relevant to rising VRE include Inertia, Fast Frequency Response, Ramping Duties and forward markets for Frequency Control Ancillary Services (FCAS).

A distinguishing characteristic of electricity is a moment-by-moment requirement to match supply and demand. Maintaining continuous electrical flows through a large interconnected power system requires high levels of coordination (MacGill, 2010). While real-time power (MW) is the primary service, FCAS are required to ensure a reliable and high quality power supply (Ela et al. 2012). The purpose of FCAS are to deliver accurate (1) Voltage, required by consumer appliances, and (2) Frequency[19], required by synchronous generators (Stoft, 2002). Any supply-demand imbalance is first signalled by adverse deviations in Frequency.[20] Frequency instability is therefore an outcome, and an indicator of, a disturbance event (Agranat et al. 2015).

By way of brief background, power is generated at a single synchronised AC Frequency measured in cycles per second or Hertz (Hz). In the NEM, thermal generators synchronise to the grid at 50 cycles per second (50Hz) meaning the fleet of turbines all rotate at exactly the same speed (i.e. 50 cycles x 60 seconds = 3000RPM for large steam turbines). It is vitally important that Frequency is maintained as close to 50Hz as possible. Material deviations in the demand-supply balance for even a few seconds can send Frequency outside tolerable limits, at which point generators disconnect themselves to avoid damage[21], potentially culminating in the collapse of a power system (Green & Staffell, 2013).

Multiple FCAS markets exist to achieve delivered power at an accurate Frequency and are typically defined according to response speed and capability of existing conventional generators (Neuhoff et al., 2016).[22] Australia's NEM is somewhat unique amongst restructured electricity markets with its centrepiece being a single platform involving a real-time mandatory gross pool spot electricity market and eight FCAS spot markets, co-optimised across five imperfectly interconnected regions with 5-minute dispatch resolution (MacGill, 2010). A single System Operator coordinates all regions and markets, and again uniquely, without a formal day-ahead market[23] or capacity market (Riesz et al. 2015). The NEM's eight FCAS spot markets are organised into a Regulation market and three Contingency markets for raise and lower services, viz. (i) Regulation FCAS, (ii) 6-second Contingency, (iii) 60-second Contingency (iv) 5-minute

[18] This is of course an intentional design aspect of the NEM. In its place is a very high VoLL, currently $14,000/MWh.
[19] Frequency is the rate at which Alternating Current alternates. In the NEM, AC completes one cycle 50 times per second (50 Hertz). Other markets such as the USA operate at 60 Hertz.
[20] It is also signalled by Voltage but this section is focused on Frequency. For further details on NEM Voltage procurement, see AEMO at https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.ashx (accessed February 2017).
[21] As Agranat et al. (2015) note, low Frequency events can lead to the overheating of generators.
[22] Different markets define contingency reserves differently depending on the type of installed capacity, the nature of events they are required to respond to and the timeframes over which they respond and how such services are activated (Riesz et al. 2015). For example, Rivard & Yatchew (2016) note that in Ontario, contingency reserves (known as operating reserves) are organised into 10-minute synchronised, 10-minute non-synchronised, and 30-minute non-synchronised reserves.
[23] Although the Market Operator does produce a continuously updating 40hr pre-dispatch forecast.

Contingency FCAS services.[24] Generators manage their own unit commitment and other inter-temporal scheduling constraints. Furthermore, FCAS markets are not simply recovered from consumers, but on the basis of 'causer pays'.[25]

Regulation FCAS are provided by generators to the System Operator using Automatic Generation Control (effectively real-time altering of MW output in line with small demand fluctuations in-between 5-minute dispatch intervals) and serve to maintain Frequency within a tight range (49.85-50.15Hz) for 99% of time (see Figure 1). Contingency FCAS deal with the remaining 1% of time involving non-trivial Frequency deviations arising from unexpected breakdowns of large generators, network elements or block-loads. Such conditions require a more substantive response than Regulation FCAS because Frequency will deviate beyond the usual range – the most common occurrence involving the loss of a large generator which may see Frequency fall to 49.5Hz as Figure 1 notes.

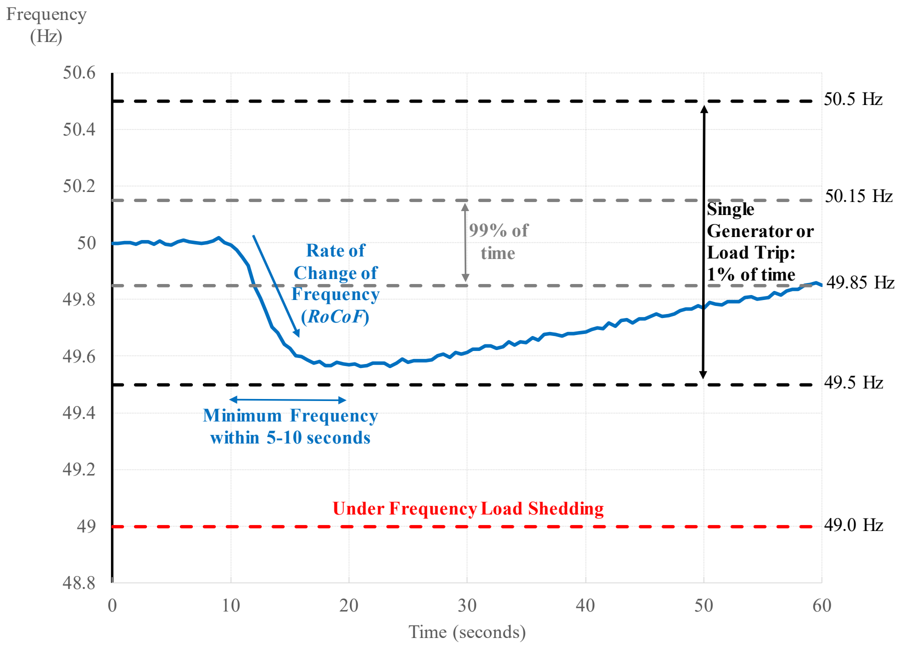
When a supply-side disruption occurs, the speed that Frequency falls (i.e. *the Rate of Change of Frequency or RoCoF*) is crucially important (Keeratimahat et al. 2016). The slower the RoCoF, the easier deviations are to arrest (Agranat et al. 2015). Synchronous generators have a store of kinetic energy due to the rotational momentum in their rotors. Weighing between 106-233t+[26], spinning at 3000RPM and being electrically coupled to the power system means that rotation Frequency has some initial 'Inertia'. Any change to Frequency from a disturbance event will first meet resistance from this passive physical response (Riesz et al. 2015). Inertia services are valuable for maintaining Frequency but historically has been supplied in such abundance that no formal market was considered necessary. 'Inertia' is therefore a missing market.

[24] That is, the 8 markets comprise both (1) raise, and (2) lower markets for each of the 4 services.

[25] For example, generators are responsible for 'Contingency Raise' services (since plant outages generally cause the requirement in the first place), while Loads are responsible for 'Contingency Lower' services. Regulation Raise and Lower is based on how participants have contributed to Frequency instability. This causer pays approach sends a superior signal to market participants, it can be the case that over- and under-frequency contributions by a single generator within a 5-minute dispatch interval cancel each other out and hide Frequency deviations caused by a VRE (or thermal) generator. See Riesz et al. (2015) for further details.

[26] The rotating mass of Queensland 350MW generators are 106t (i.e. High & Intermediate Pressure turbine 16t, Low Pressure turbine 50t and generator 40t). The rotating mass of the 500MW generators in Victoria and 660MW generators in New South Wales are 217.5t and 232.8t, respectively.

Figure 1: **Frequency deviation**



A rapid response is required to arrest Frequency decline – minimum Frequency must be achieved within 5-10 seconds in order to avoid system collapse (Ela et al. 2012). In the NEM, apart from Inertia the first *market response* comes from 6-second FCAS. Synchronous generators usually have store of excess steam and latent energy in boilers which can be released to give an initial boost of output (essentially additional output not associated with 'additional fuel' to boilers). 6-second resources are deployed without System Operator intervention to enable an orderly transition to 60-second[27] raise resources, which further stabilise Frequency and enable an orderly transition to 5-minute resources (Riesz et al. 2015). These collective resources restore the system back to its nominal 50Hz Frequency over a 5-minute window (see Figure 1). If Frequency falls below 49Hz 'automated' non-price load shedding, known as Under Frequency Load Shedding, occurs in order to avoid power system collapse.[28]

A challenge of rising VRE is how Frequency will be managed. NEM VRE sources (solar and wind) are currently connected asynchronously to the power system with power electronic interfaces and are *not* physically coupled to system Frequency. They do not provide Inertia during Frequency deviations (Agranat et al. 2015). Furthermore, NEM-installed VRE plant are not designed to provide FCAS raises services (MacGill, 2010). Consequently, as synchronous thermal plant exit to make way for asynchronous VRE, one can expect the supply of Inertia and FCAS raise to fall (MacGill, 2010; Hogan, 2013; Green & Staffell, 2013; Newbery, 2015). And as the supply of Inertia falls, 6-second FCAS resources may become inadequate to arrest Frequency deviations. A market for Fast Frequency Response (i.e. 1 second) may be required (Agranat et al. 2015). Rising levels of stochastic VRE output may also exceed demand uncertainty, meaning existing levels of Frequency Regulation resources may become inadequate (Riesz et al. 2015).

[27] 6-second & 60-second FCAS are usually operated by governor response or load shedding, and are triggered by Frequency moving outside the normal operating band.
[28] In the NEM, non-price load-shedding or Under Frequency Load Shedding, a highly automated sub-second event, can generally be relied to arrest a 'Rate of Change of Frequency' (RoCoF) of up to 3.5Hz per second. In 2016, South Australia experienced a RoCoF of 6.25Hz per second which resulted in a system collapse.

With high levels of solar PV comes greater requirements for Ramping Duties; solar PV output naturally declines in the evening which coincides with rapidly rising household peak demand – this combination may produce dramatically steeper rises in intra-period residual system demand. As with Inertia, Ramping capability has been supplied in such abundance no market was considered necessary. Given the experience of solar-rich jurisdictions like California, one may expect the demand for Ramping Duties in the NEM to increase considerably while the exit of thermal plant means supply will fall. Consequently, a market for Ramping Duties also represents a missing market.

Counterintuitively, the NEM's overall quantity of FCAS services dispatched has remained static[29] with procurement undertaken on a global- (not regional-) basis as VRE is rising.[30] Hogan (2013) notes system reliability improves by increasing quantities of FCAS dispatched and while the importance of Operating Reserves have long been known, requirements are frequently given simplified consideration (Hogan, 2005). Spot FCAS prices also appear *inefficiently low* in equilibrium, which as Newbery (2015) explains forms part of the *missing money*. Conversely when thermal plant exits, the price of FCAS raise services rise to non-trivial levels.[31] This tends to suggest volumes procured, procurement location, and co-optimised price setting requires review.

Finally, a crucial missing market in the NEM is a forward FCAS market. It is crucial because spot FCAS market revenues are unbankable, and this alone reinforces development of VRE plant that maximise spot electricity output with no FCAS capability – real or synthetic.

In summary, as VRE enters the demand for Inertia, Fast Frequency Response, Ramping Duties and FCAS quantities rise while simultaneously, exit of thermal plant means supply will fall. Compounding matters, there is no forward market signalling emerging imbalances or looming requirements to incorporate FCAS capability (real or synthetic) into new entrant VRE plant capacity.

2.3 **Incomplete Markets**

Energy markets are never complete or free of market failures (Hirth et al. 2016). A market failure inherent in energy-only markets is their inability to deliver the requisite mix of derivative instruments required to facilitate efficient plant entry (Hansen, 2004; Chao, Oren and Wilson, 2005; Meade and O'Connor, 2009; Meyer, 2012). As Finon (2011) explains, the *canonical model* in deregulated energy-only markets was the Merchant Power Producer, a stand-alone generator that sold its production into spot and short-term forward markets, underpinned by long-dated non-recourse project finance. In the early phases of the global restructuring and deregulation experiment, a vast fleet of merchant plant *was* banked on this basis (Joskow, 2006; Finon, 2008).[32]

But recurring economic damage to merchant generator Profit & Loss Statements, a product of *missing money*, began to take its toll on project bank risk tolerances and credit metrics (Simshauser, 2010). By 2005 more than 110,000MW of merchant plant in the US, much of the

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[29] In the NEM FCAS is determined dynamically in each 5-minute interval, but the parameters have remained static (viz. the single largest contingency event (loss of the largest generator, for example).

[30] FCAS is procured globally across regions subject to network constraints. In periods of higher variability, FCAS regulation automatically rises from the typical set point of 130MW to as much as 230MW (in 60MW increments) to maintain Frequency. But threshold quantities (typically around 990MW in aggregate) have remained static as VRE is rising.

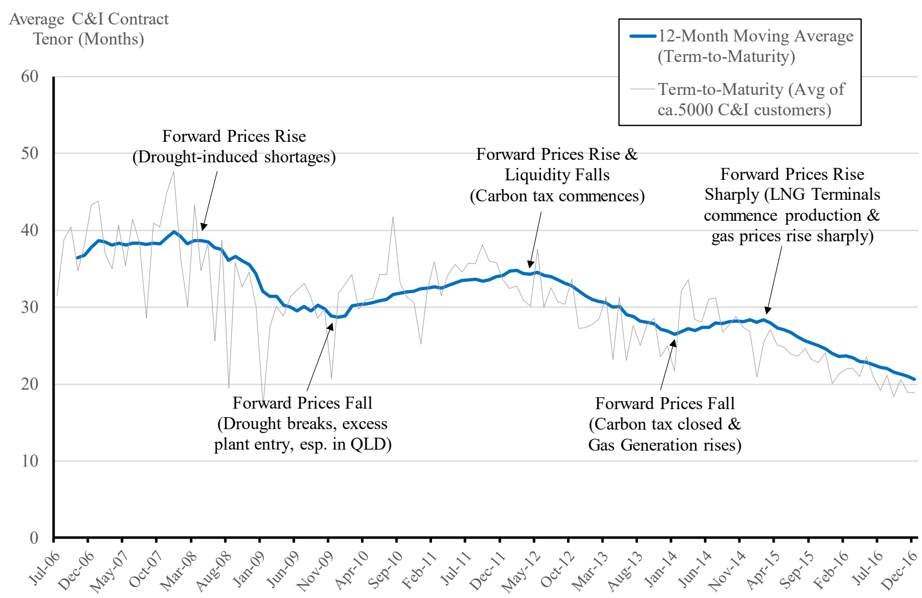
[31] In QLD, NSW and VIC, the spot electricity market forms > 99.7% of total revenue. More recently, 'FCAS raise' services in SA have risen to a surprisingly large 5-7% of market revenues – the point being that FCAS raise services provided by thermal plant have almost no value until plant exit, at which point they become extremely valuable.

[32] This included 230,000MW in the US, 13,000MW in Australia and more than 6000MW of new plant in the UK. See Joskow (2006), Finon (2008) and Simshauser (2010) for details.

Australian merchant fleet and some high profile plant in the UK (e.g. Drax) experienced financial distress or bankruptcy (Finon, 2008; Nelson & Simshauser, 2013). Consequently, the *canonical model* became *un-bankable* in the absence of long-term (i.e. 10+ years) contracts. There is now considerable evidence to support the notion that timely plant entry on a purely merchant basis is intractable[33] in energy-only markets (Joskow, 2006; Howell, Meade & O'Connor, 2010; Caplan, 2012; Nelson and Simshauser, 2013).

Long-dated contracts have become a pre-condition for project finance, and while Australia's NEM is noted for favourable forward market liquidity[34], activity spans 3 years – well short of optimal financing that facilitate efficient ex-ante investment commitment, viz. 12-year semi-permanent project debt set within 18-25 year structures. Forward markets have failed to calibrate beyond 3 years because competitive Retailers cannot afford to hold hedge portfolios dominated by inflexible long-dated contracts when large components of their customer book switch supplier every 2-3 years as Figure 2 illustrates (i.e. large Commercial & Industrial (C&I) customers are now signing, on average, contracts of just 22 months duration). The short-tenor bias of merchant retailers can be traced to excessive retail-level competition, demand uncertainty and risks of being undercut by new entrant retailers with short-dated portfolios (Newbery, 2006 and others[35]).

Figure 2: **NEM average C&I contract tenor: 2006-2016 term-to-maturity**



Source: EnergyAction[36]

2.4 **Shrinking markets**

An under-researched aspect of the NEM is the impact of rising VRE on the supply of forward derivative contracts and in particular, where transmission amongst regions is imperfect. To my knowledge, the only article which approaches the matter of the effects of renewable energy on both the spot and hedge contract market is Acemoglu et al (2017), although their work is

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[33] To be clear, plant will eventually enter on a merchant basis if prices are high enough. But the political economy of such prices makes this problematic.
[34] See for example Chester (2006); Anderson et al. (2007); Howell, Meade & O'Connor (2010); and most recently, Simshauser et al. (2015, Appendix 3 and Figure C.1 on p.54).
[35] See also Green, 2006; Anderson et al. 2007; Finon, 2008; Simshauser, 2010; Howell, Meade and O'Connor, 2010
[36] Based on approximately 5000 C&I customers. Thanks to Michael Fahey (EnergyAction) for providing this data.

focused on the impact of hedge contracts on equilibrium market prices rather than the supply of asset-backed hedges.[37]

Under normal conditions, NEM derivative market turnover runs at multiples of physical spot electricity market (Chester, 2006; Howell, Meade & O'Connor, 2010) although there have been sporadic episodes of hedge contract shortages in certain regions (Anderson et al. 2007[38]). Various Australian regulatory authorities had argued Vertical Integration would drive reductions in market liquidity.[39] But the evidence is that at the height of vertical M&A activity (2005-2012) contract liquidity expanded (Simshauser et al., 2015). Structural imbalances between the retail and generation units of vertical utilities drives activity in the same way that generator market power of vertical utilities can be muted by such imbalances (Bushnell et al. 2007; Mansur 2007). What has had an adverse effect on derivative market liquidity is climate change policy volatility (Simshauser et al. 2015; Nelson & Orton, 2016).

When thermal plant exit in response to rising VRE, additional transmission interconnection to adjacent region(s) can help maintain security of supply. But unless interconnection results in a single region being formed, all else equal, the introduction of VRE and the exit of thermal plant will change the supply mix of asset-backed or 'primary-issuance' intra-regional hedge contracts, viz. falling *firm* swap and cap contracts, and rising *non-firm* VRE contracts.

Unlike merchant coal and gas plant which sell *firm* swap and cap contracts, VRE plant are typically underwritten by long-dated, *non-firm*, joint-product Power Purchase Agreements (PPAs) comprising (underlying) variable power and (headline) Renewable Certificates. And in a more recent trend, sub-national governments have originated policies that underwrite VRE plant via *non-firm*, joint-product Contracts-for-Differences (CfDs).

Non-firm PPAs and CfDs are not perfect substitutes for *firm* swaps and caps, the reasons for which are axiomatic. With moderate levels of VRE, or perfectly interconnected regions, this may pose little problem. But as non-firm VRE instruments form a progressively larger share of the forward market via the ongoing exit of thermal plant, there must be some tipping point whereby a level of instability emerges in hedge markets via shortages of primary-issuance *firm* swaps and caps required by firms with retail exposures.

Non-firm VRE contracts are not good substitutes for firm contracts, but some nominal component can be utilised against peak load in large, diversified Vertical Retailer hedge books. But government-initiated CfDs may be problematic if not designed (nor intended) for secondary market trade. Along with the gradual evaporation of *firm* hedge contract supply as thermal plant exit, government-initiated CfDs can have the (unintended) effect of extracting the replacement *non-firm* contract supply – potentially culminating in hedge contract supply shortages and foreclosing competitive 2nd tier Retailers.

[37] The work by Acemoglu et al. (2019) is a form of application of the seminal works of Allaz and Villa (1993) with a focus on supplier preference for contract quantities and note that these are higher with larger diversified generation portfolios but they do not examine how these forward contracts are covered in the long term, only the mid term (i.e. they implicitly assume a large power system with perfect liquidity and the potential for a Merit Order Effect, meaning thermal plant has not yet exited or adjusted. The main finding is of course consistent with Allaz and Villa (1993) and Bushnell et al. (2007) and Mansur (2007) in terms of the dampening effect of forward contracts on spot prices.

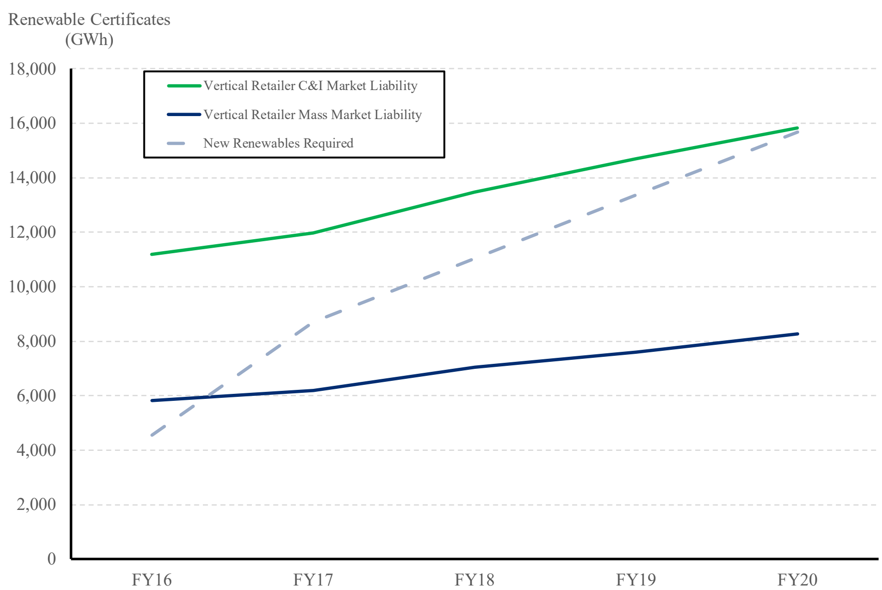
[38] See also Simshauser, Molyneux & Shepherd (2010) on episodes of hedge contract supply shortages in the NEM.

[39] Such criticism came from (i) the Australian Energy Regulator, (ii) the Australian Energy Market Commission, (iii) the Australian Competition and Consumer Commission and (iv) the Australian Government (various references spanning 2011-2014) in spite of quantitative evidence to the contrary. See See Simshauser, Tian & Whish-Wilson (2015, especially Section 2).

2.5 **Misinformed markets**

Just as Resource Adequacy meets resistance in energy-only markets, Renewable Targets meet similar resistance due to missing money and incomplete markets. Renewable Targets place a liability on Retailers to purchase a set percentage from renewable sources. VRE plant require long-dated PPAs written by counterparties with investment-grade credit ratings to facilitate finance and therefore, entry. Vertical Retailers with investment-grade credit ratings have two broad customer classes; loyal Mass Market and non-loyal large C&I customers. The latter are sophisticated buyers that switch supplier frequently, and may even purchase their own Renewable Certificates. Consequently, Vertical Retailers tend to acquit Renewable liabilities for loyal Mass Market customers via long-dated VRE PPAs but it would be highly irregular (and risky) for Vertical Retailers to write 15-Year VRE PPAs for their non-loyal C&I customers[40]. Renewable Target policies thus face market resistance because Vertical Retailers can only reasonably underwrite so much VRE plant before their own Balance Sheets become stressed (Neuhoff et al. 2016). And very few 2nd Tier Retailers have investment-grade credit ratings. Dargue & Koenders (2016) estimate the underlying C&I PPA gap could be as much as 7,000 GWh out of 15,100 GWh new VRE required as Figure 3 notes:

Figure 3: **Vertical Retailer Renewable Certificates vs Total Market**



Source: Dargue & Koenders (2016), Company Reports.

Sub-national governments recognised these shortfalls and many constructed 'reverse auctions' involving various forms of CfDs to bridge the Renewables contracting gap. While a ca.2300MW shortage was estimated, sub-national government CfDs totalling 3000 MW were telegraphed to the market.[41]

Section 2.4 explained government-initiated CfDs can produce a shrinking market and under-supply of intra-regional hedge contract capacity. But the market can become misinformed and

[40] Recall from Figure 2 these customers sign contracts for, on average, 22 months.

[41] As at March 2017, 750MW had been executed. The QLD Government had executed 150MW of CfDs and telegraphed a further 400MW. NSW Government telegraphed 250MW of CfDs. ACT had executed 600MW of CfDs. The VIC Government had telegraphed up to 1500MW of CfDs by 2020 and a further 3900MW by 2025. There are also a number of PPAs (VIC Government tenders totalling 171MW for Renewable Certificates, and Sydney Northwest Metro totalling 52MW) but these appear to be well-constructed, non-distortionary, government contracts designed to meet retail liabilities. Similarly, at the time of writing the Qld Government was working on 'recycling' its 150MW CfDs back into the secondary market in order to minimise any such distortions.

regions 'overloaded' if non market-participants (i.e. governments) over-rely on Levelised Cost of Electricity (LCoE) during CfD execution.

Used carefully, LCoE estimates are essential *inputs* to system planning. LCoE estimates are not, however, *outputs* for investment commitment. Setting policy and executing CfDs on the basis of LCoE will eventually produce distortionary outcomes, expose taxpayers to unnecessary losses, and produce misinformed markets.

The physical properties of electricity are largely homogeneous over space and time. But as Hirth et al. (2016) explain, from a market perspective there is rich price variation over time, space and lead time-to-delivery making the traded commodity a heterogeneous good.[42] As they explain, the economic value of plant output is not identical and assuming otherwise introduces two biases; base plant is favoured over peak, and stochastic plant is favoured over dispatchable plant. As a stand-alone metric, LCoE is flawed because it treats technology output as homogeneous products as if governed by the law of one price (Joskow, 2011; Mills & Wiser, 2012; Edenhofer et al. 2013).

In real-time, the law of one price does apply; output from wind and solar are good substitutes for thermal generation. However, each year there are 105,120 NEM prices[43] and when demand is higher than forecast, all else equal, dispatchable generators increase output and receive a higher average price. Conversely, stochastic generators rarely reduce output in periods of oversupply, and hence sell disproportionately at lower prices (Dargue & Koenders, 2016; Hirth et al. 2016).

Furthermore, as VRE technologies move from niche to material market shares, deployment success becomes a significant driver of market value (MacGill, 2010; Joskow 2011; Nicolosi, 2012; Mills & Wiser 2012; Hirth, 2013). Green & Staffell (2016) note this is *amplified* when thermal plant fails to exit. Consequently, the market value of VRE is affected by 'correlation effects', 'merit-order effects' and 'price-impression effects' (see Section 4).[44] Tangentially, as VRE market share increases Nicolosi (2012, pp.35-38) identifies a *'utilisation effect'* and a *'flexibility effect'* on thermal plant whereby their annualised capital costs increase as the annual capacity factor of such plant declines, and an increasing incidence of negative prices.

3. On the stability of the spot market

In order to analyse the stability of spot markets with rising levels of VRE, the NEMESYS-PF Model has been used. NEMESYS-PF formally integrates a Corporate & Project Finance Model with a single-year dynamic, partial equilibrium, security-constrained unit commitment simulation Model with half-hourly resolution and price formation based on a uniform, first-price auction clearing mechanism. As with Bushnell (2010), the Model assumes perfect competition and essentially free entry to install any combination of capacity that satisfies differentiable equilibrium

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[42] Heterogeneous goods satisfy three conditions; (1) an inability to arbitrage (i.e. storage is costly); (2) no single efficient technology exists (e.g. in electricity planning there is typically an efficient combination of base, intermediate and peak plant); and (3) non-horizontal supply costs (e.g. electricity merit-order supply curves are always upward sloping). As Hirth et al. 2016, p.5) explain, *storage* links electricity in time, *transmission* links electricity in space and *flexibility* (i.e. balancing services) links electricity in lead-time.

[43] In the NEM, dispatch has 5-minute resolution and thus 105,120 dispatch intervals each year.

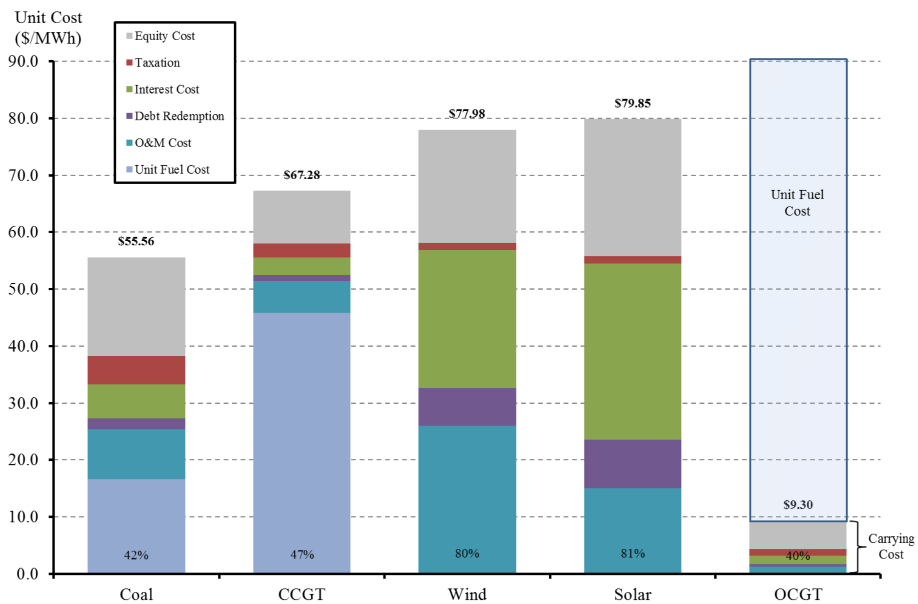
[44] Taking solar PV as an example, the *correlation effect* starts positive due to the diurnal correlation between solar resources and electricity demand. The *merit-order effect* is a well-known economic result; the price of a good falls as supply is increased. As thermal plant exits, merit-order effects can be expected to unwind but the stochastic nature of VRE plant means a *price-impression effect* persists. In an expansive literature review on the topic, Hirth (2013) reveals that as solar is progressively increased from 0% to 10-15% market share, its *relative value* drops from slightly more than 100% of base prices to 70% (i.e. *price-impression effect*). And as wind output is increased from 0% to 30% market share, its relative value drops to 70% of base prices.

conditions, with VRE plant output being determined exogenously. Model details are contained in Appendix I.

3.1 Generalised long run marginal cost estimates

Salient features of the present exercise are as follows. Thermal plant (Coal, CCGT, OCGT) are Balance Sheet-financed (gearing ca.40-47%, BBB credit rating) and VRE plant (Wind, Solar) are Project Financed (ca.80% debt) and underpinned by investment-grade PPAs. Relevant assumptions are outlined in Appendix I. Generalised long run marginal cost estimates from the Model are presented in Figure 4, and are a high-resolution LCoE incorporating debt-finance and taxation variables. Gearing levels for each plant are displayed at the base of each bar. Thus in Figure 4, Coal has 42% gearing and a generalised long run marginal cost of $55.56/MWh comprising Unit Fuel Costs of $16.62/MWh, O&M Costs of $8.74/MWh, Debt and Interest Costs of $1.90 and $6.04/MWh, and Taxation and Equity Costs of $5.01 and $17.25/MWh, respectively.

Figure 4: **Generalised long run marginal cost by technology**



3.2 Base Case

The Base Case load curve utilises QLD 2016 data (9097MW peak demand, 54900GWh energy demand, ex-1500MW rooftop solar PV). An own-price elasticity estimate of -0.10 is used in all scenarios. The QLD system is modelled without interconnection to neighbouring NSW. The perfectly divisible plant stock is optimised and includes a starting reserve margin of 13% to ensure the NEM's administratively determined reliability constraint of no more than 0.002% Lost Load is met. Plant are initially assumed to be perfectly available with no ramp rate constraints. Availability assumptions are relaxed in Section 5. Coal plant minimum loads are assumed to be 40% of Maximum Continuous Rating, and VRE plant are constrained-off if necessary (i.e. coal 'min gen' is priority dispatched).

One crucial deviation from the NEM's energy-only market design has been incorporated in the present Modelling exercise; there are no VoLL events, instead Boiteux capacity payments are paid to all dispatchable plant at a rate exactly equal to the carrying-cost of an OCGT (see Fig.4). This ensures that in the Base Case, the market *'clears financially'* and has two primary benefits; (1) it removes noise associated with market power and the optimal value, and number of, VoLL events; and (2) it allows impacts of rising VRE to be isolated. As in the NEM, Renewable Certificates are incorporated for VRE plant with the value equal to the differential between the market value of output, and generalised long run marginal costs estimates. Base Case results, where the power system has been optimised without utility-scale VRE plant, are presented in Table 1.

Table 1: **Production duties and financial position of plant – Base Case**

	Generation	Capacity (MW)	Production (GWh)	Fixed Costs ($m)	Running Costs ($m)	Resource Cost ($m)	Avg Unit Cost ($/MWh)	Market Share	CF_j^i (%)
1	Wind	0	0	0	0	0	0.00	0.0%	0.0
2	Solar	0	0	0	0	0	0.00	0.0%	0.0
3	Coal	6,014	50,842	2,052	845	2,896	56.97	92.6%	96.5
4	CCGT	758	2,906	142	133	276	94.83	5.3%	43.8
5	OCGT	3,508	1,175	286	106	392	333.36	2.1%	3.8
6	Total	10,280	54,924	2,480	1,084	3,564	64.88	100.0%	61.0

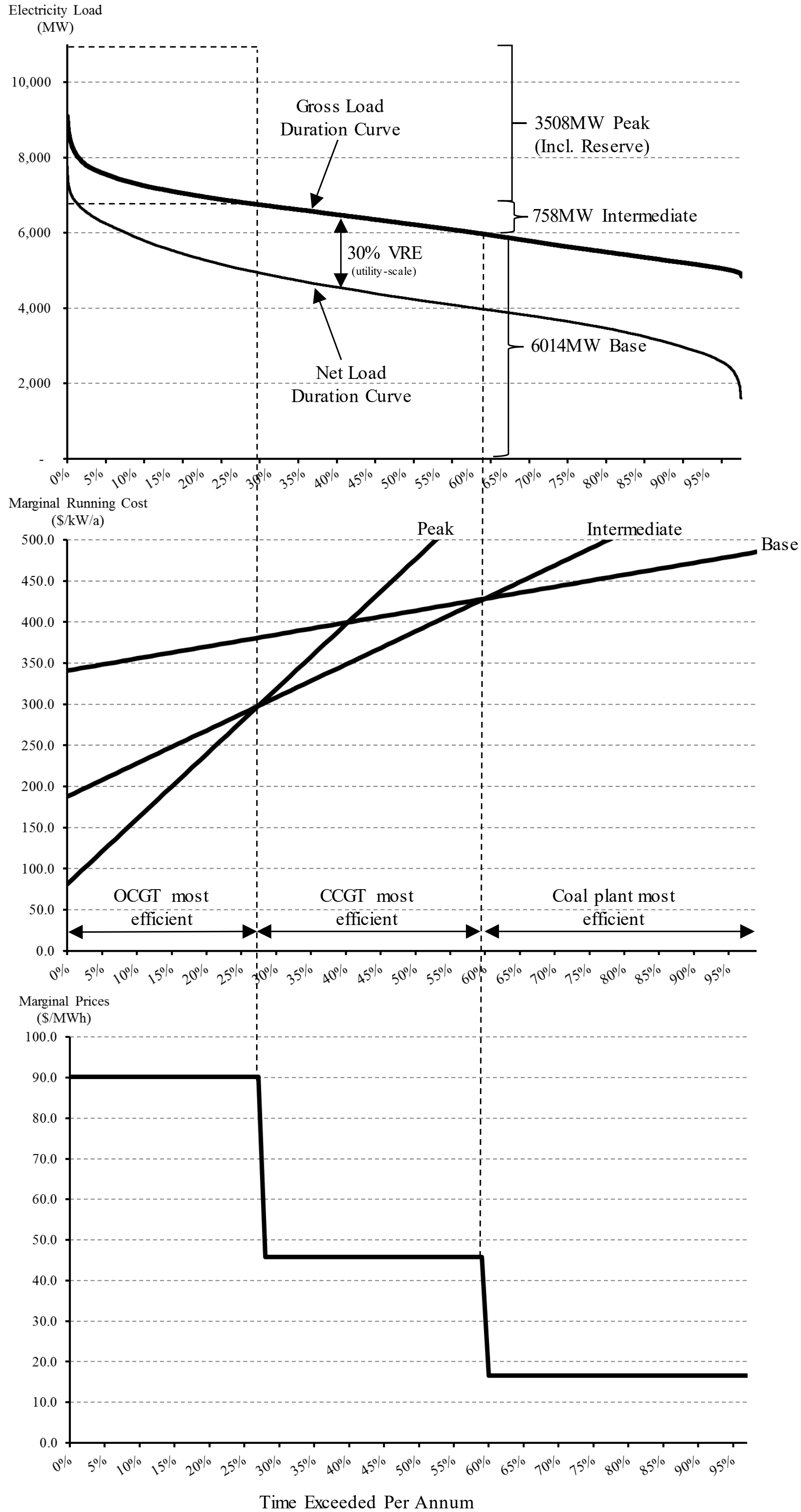
		Average Spot Price ($/MWh)	Spot Market Revenue ($m)	Capacity/RE Payments ($/MW)	Capacity/RE Payment ($m)	Total Revenue ($m)	Resource Cost ($m)	Revenue Shortfall ($m)	
7	Wind	43.40	0	0.00	0	0	0	0	
8	Solar	51.59	0	0.00	0	0	0	0	
9	Coal	47.33	2,406	9.30	490	2,896	2,896	0	
10	CCGT	73.58	214	9.30	62	276	276	0	
11	OCGT	90.19	106	9.30	286	392	392	0	
12	Total	49.64	2,726	9.30	837	3,564	3,564	-0	
13	System Avg Cost	64.88							
14	Missing Money	15.25			$15.25/MWh				
15	Peak Price	83.78						Base Price (time-weighted):	46.26
16	Shoulder Price	52.59						Load-Weighted Avg Spot Price:	49.64
17	Off-Peak Price	23.32						Avg Renewable Certificate Price:	0.00

In Table 1, Lines 1-6 highlight 10280MW of plant is deployed including 6014MW of coal. Resource Costs amount to $3,564m, System Average Cost is 64.88/MWh and the Capacity Factor (CF) of the power station fleet is 61.0%. Price and revenue parameters are presented in Lines 7-17. The Load-Weighted Average Spot Price is $49.64, and given System Average Costs of $64.88 the *missing money* amounts to $15.25/MWh. Missing money is eliminated via Boiteux capacity payments paid to each MW installed at a rate exactly equal to the carrying cost of OCGT plant[45] (i.e. $9.30/MW, see OCGT in Figure 4). Note the time-weighted *Base Price* is $46.26/MWh (Line 15) – a result that will be used as a benchmark throughout this research.

Figure 5 presents a static equilibrium analysis based on the seminal works of Berrie (1967). The top chart highlights two Load Duration Curves, a Gross Load (i.e. net of 5% rooftop solar PV) and Net Load (i.e. net of 35% VRE output). The optimal plant mix is derived from the middle chart which extracts the LCoE results from Figure 4 and transposes these data into Marginal Running Cost Curves for the three thermal technologies. The points of intersection are transposed to the Load Duration Curve to identify the optimal mix of Base, Intermediate and Peak plant. The bottom chart shows the distribution of prices; recall there are no VoLL events, just three spot prices prevail in equilibrium, averaging $46.26/MWh.

[45] In this instance, $9.30/MW x 10280MW ÷ 54,924GWh = $15.25/MWh. Simshauser & Ariyaratnam (2014 see Appendix) provide a mathematical proof.

Figure 5: **Static partial equilibrium (net of 5% rooftop solar PV)**



3.3 Mid-term and long-term scenarios

Utility-scale VRE is progressively introduced rising to 30% market share. Recall Gross Load is net of 5% rooftop Solar PV – thus scenarios run from 5-35% VRE (viz. 0-30% utility-scale VRE plus 5% small-scale VRE). Following Hirth (2013), two timeframes are analysed; Mid-Term and Long-Term and are distinguished by how the capital stock adjusts rather than time. In Mid-Term scenarios, thermal plant is held constant (Figure 6). In Long-Term scenarios, thermal plant adjusts perfectly; coal exits and gas plant enters while meeting reliability constraints (Figure 7).

Figure 6: **Mid-Term capacity for rising VRE (no plant exit)**

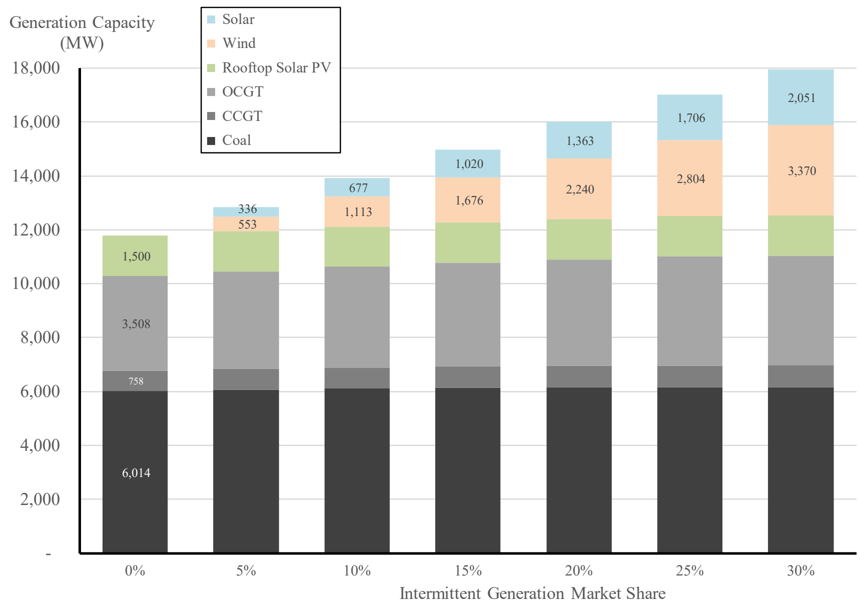
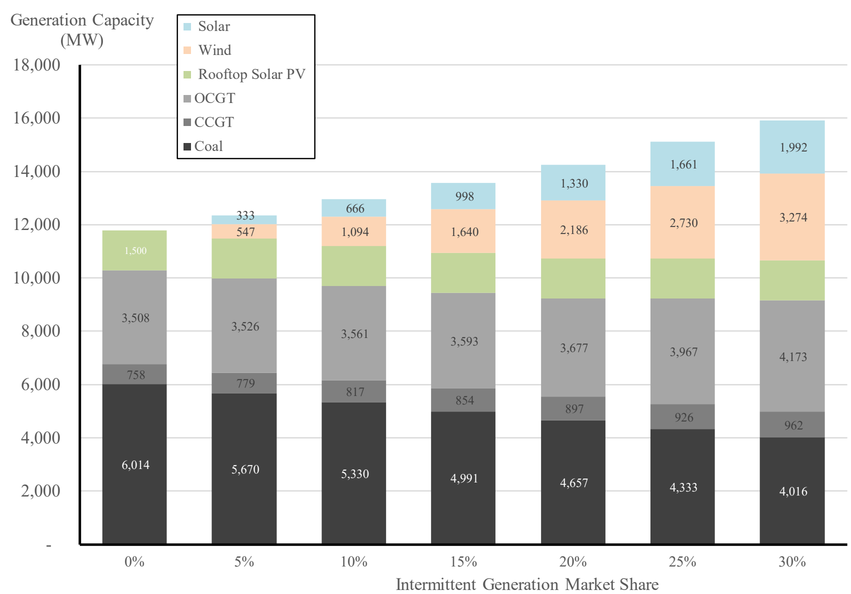


Figure 7: **Long-Term capacity for rising VRE (thermal plant adjusts perfectly)**



Mid- and Long-Term 30% VRE scenarios are presented in Tables 2-3. In the Mid-Term (Table 2), no coal plant exits and Resource Costs rise to $4,579m or $81.26/MWh (line 6) while Base Prices fall to $19.55/MWh (line 15). This result reflects an acute *merit-order effect* that cannot be remedied by capacity payments.[46] However, VRE plant clear financially (Lines 7-8) via rising Renewable Certificate prices, averaging $60.72/MWh (line 17).

Table 2: **Mid-Term 30% VRE scenario**

	Generation	Capacity (MW)	Production (GWh)	Fixed Costs ($m)	Running Costs ($m)	Resource Cost ($m)	Avg Unit Cost ($/MWh)	Market Share	CF_j^i (%)
1	Wind	3,370	11,800	861	59	920	77.98	20.9%	40.0
2	Solar	2,050	5,057	404	0	404	79.85	9.0%	28.2
3	Coal	6,166	39,145	2,103	650	2,754	70.35	69.5%	72.5
4	CCGT	810	314	152	14	167	530.13	0.6%	4.4
5	OCGT	4,070	30	331	3	334	11,240.89	0.1%	0.1
6	Total	16,466	56,346	3,852	726	4,579	81.26	100.0%	39.1

		Average Spot Price ($/MWh)	Spot Market Revenue ($m)	Capacity/RE Payments ($/MW)	Capacity/RE Payment ($m)	Total Revenue ($m)	Resource Cost ($m)	Revenue Shortfall ($m)	
7	Wind	18.02	213	59.97	708	920	920	0	
8	Solar	17.38	88	62.47	316	404	404	0	
9	Coal	20.87	817	9.30	327	1,144	2,754	1,610	
10	CCGT	59.99	19	9.30	78	97	167	69	
11	OCGT	90.19	3	9.30	340	343	334	-8	
12	Total	20.22	1,139		1,769	2,908	4,579	1,671	
13	System Avg Cost	81.26							
14	Missing Money	61.04			$31.39/MWh				
15	Peak Price	32.75						Base Price (time-weighted):	19.55
16	Shoulder Price	17.88						Load-Weighted Avg Spot Price:	20.22
17	Off-Peak Price	16.41						Avg Renewable Certificate Price:	60.72

Falling Base Prices are unsustainable. In the Long-Term thermal plant are forced to exit and adjust. Table 3 shows perfect adjustment; compared to the Base Case – at 30% VRE market share 2000MW of Coal exits and 900MW of flexible gas plant enters. Base Price (line 15) is restored to $46.23/MWh and capacity payments ($9.30/MW) clear missing money. Renewable Certificates fall to $38.30/MWh.

Table 3: **Long-term 30% VRE scenario**

	Generation	Capacity (MW)	Production (GWh)	Fixed Costs ($m)	Running Costs ($m)	Resource Cost ($m)	Avg Unit Cost ($/MWh)	Market Share	CF_j^i (%)
1	Wind	3,274	11,490	839	57	896	77.98	21.0%	40.1
2	Solar	1,992	4,924	393	0	393	79.85	9.0%	28.2
3	Coal	4,016	32,887	1,370	546	1,916	58.27	60.1%	93.5
4	CCGT	962	3,574	181	164	345	96.39	6.5%	42.4
5	OCGT	4,173	1,843	340	166	506	274.60	3.4%	5.0
6	Total	14,417	54,719	3,122	934	4,056	74.13	100.0%	43.3

		Average Spot Price ($/MWh)	Spot Market Revenue ($m)	Capacity/RE Payments ($/MW)	Capacity/RE Payment ($m)	Total Revenue ($m)	Resource Cost ($m)	Revenue Shortfall ($m)	
7	Wind	39.74	457	38.24	439	896	896	0	
8	Solar	41.40	204	38.45	189	393	393	0	
9	Coal	48.30	1,589	9.30	327	1,916	1,916	1	
10	CCGT	74.47	266	9.30	78	344	345	0	
11	OCGT	90.19	166	9.30	340	506	506	0	
12	Total	49.01	2,681		1,374	4,056	4,056	1	
13	System Avg Cost	74.13							
14	Missing Money	25.12			$25.11/MWh				
15	Peak Price	82.97						Base Price (time-weighted):	46.23
16	Shoulder Price	47.54						Load-Weighted Avg Spot Price:	49.01
17	Off-Peak Price	29.97						Avg Renewable Certificate Price:	38.30

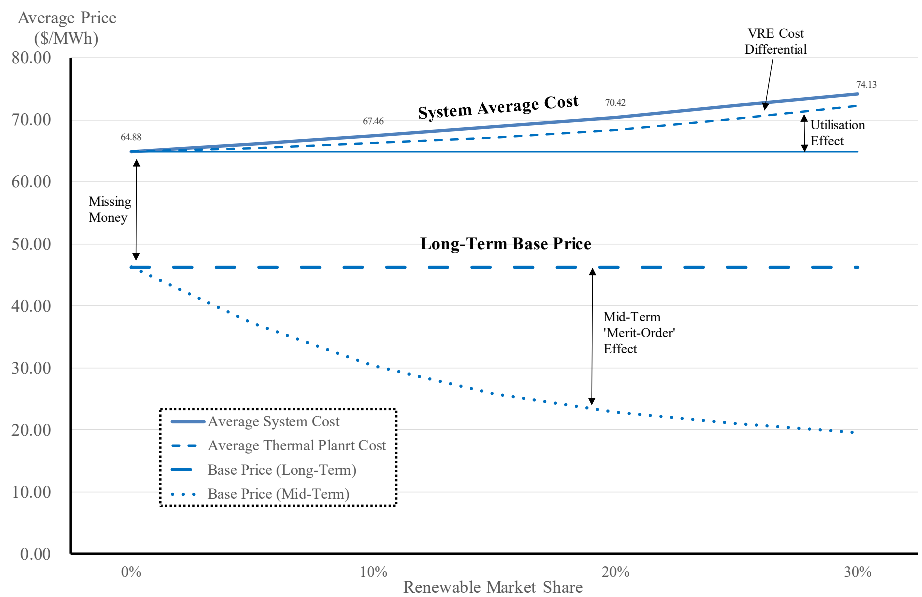
Figure 8 presents the evolution of Base Prices (Mid- and Long-Term) and cost traces for varying levels of VRE market share, along with other elements not obvious or clear from inspection of Tables 1-3. First, the top Line in Figure 8 presents the evolution of System Average Cost,

[46] Note capacity payments are allocated at $9.30/MW on the optimal capacity identified in Table 3.

starting at $64.88 and rising to $74.13/MWh with 30% VRE. The two Lines immediately below identify two forces driving System Average Cost movements. (1) The *utilisation effect* pushes up System Average Cost via a deterioration in the thermal fleet's capacity factor, progressively falling from 61.0% in the Base Case to 47.8% in the 30% VRE scenario. (2) The *VRE Cost Differential* drives System Average Cost up through the higher cost structure of VRE plant. Of these, *utilisation effects* are more significant.

Next, note the equilibrium Long-Term Base Price of ca.$46.26/MWh is maintained throughout any VRE market share *provided* thermal plant exits and adjusts. The gap between System Average Cost and Long-Term Base Price is the *missing money*, and is recovered via capacity payments (and Renewable Certificates). The gap between Mid- and Long-Term Base Prices is the *merit-order effect*, and occurs while thermal plant fails to exit and adjust.

Figure 8: **Evolution of system costs & prices**



Figures 5-8 and Tables 1-3 identify a series of important results. First, they demonstrate that in theory, energy-only markets can produce a stable equilibrium for any level of VRE up to 30% (35% including rooftop solar PV). However, it requires thermal plant to exit and adjust perfectly, and, it requires the optimal level and number of VoLL events in the absence of capacity payments.

Second, two forces work together to force adjustment; (1) *merit-order effects* damage thermal plant Profit & Loss Statements through lower prices, and (2) coincident *utilisation effects* impose further damage by forcing thermal plant up their (downward sloping) cost curves. Consistent with *game-changing policy*, VRE plant have a side-market which shields them from adverse impacts (i.e. Renewable Certificate subsidies) thus allowing continual entry regardless of how long it takes for thermal plant to exit and adjust.

Finally, market analysis and policy development needs to be thoughtful about *merit-order effects*. Merit-order effects can be shown to exist, but benefits to consumers translate only in the Mid-Term. In the Long-Term, thermal plant will exit and adjust. And to be clear, merit-order effects are *not* welfare enhancing.[47]

[47] Nelson et al. (2012, pp293-295) discuss this in some detail.

4. On the ability of markets to optimise VRE asset allocation

Recall from Section 2.5 that static LCoE analyses produce two inherent biases; base over peaking, and stochastic over dispatchable plant (Joskow, 2011). Tables 1 and 3 showed results for 0 and 30% VRE which revealed certain characteristics about dynamic market values of VRE plant output but a more granular analysis is required, which is presented in Figures 9-13.

4.1 Static analysis of the value of VRE output at 15% market share

Figure 9 shows the evolution of Market Values of Wind output at 15% market share. Following Hirth (2013), the waterfall chart decomposes the forces progressively affecting wind output market values, in the Mid-Term, and in the Long-Term.

Figure 9: **Market Value of wind output (15% Market Share)**

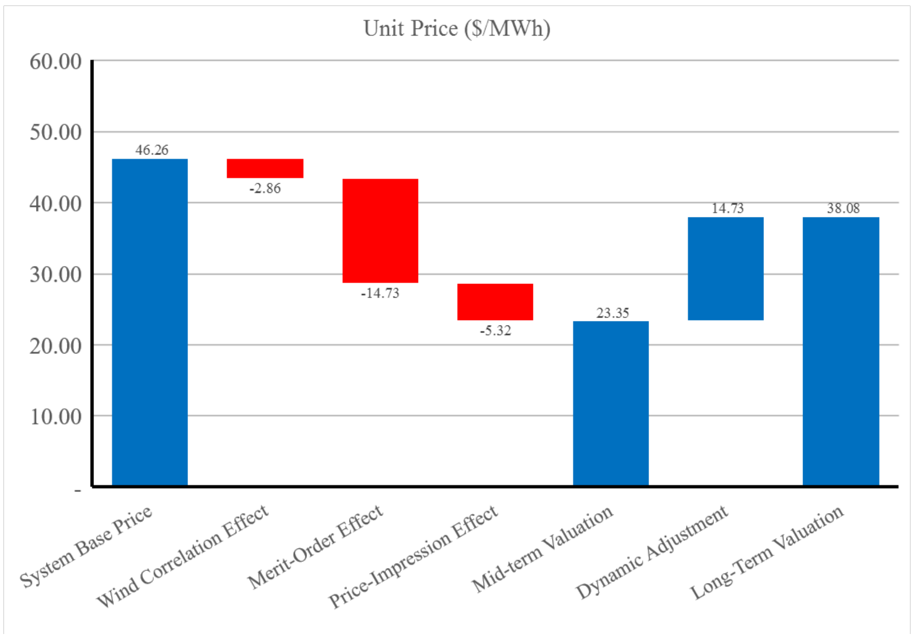


Figure 9 commences with the Base Price ($46.26/MWh). The first variable impacting the Market Value of Wind output is a *correlation effect*. QLD wind resources are marginally negatively correlated to wholesale demand and price and so the market value of the first wind farm is marginally below Base Prices (-$2.86/MWh).

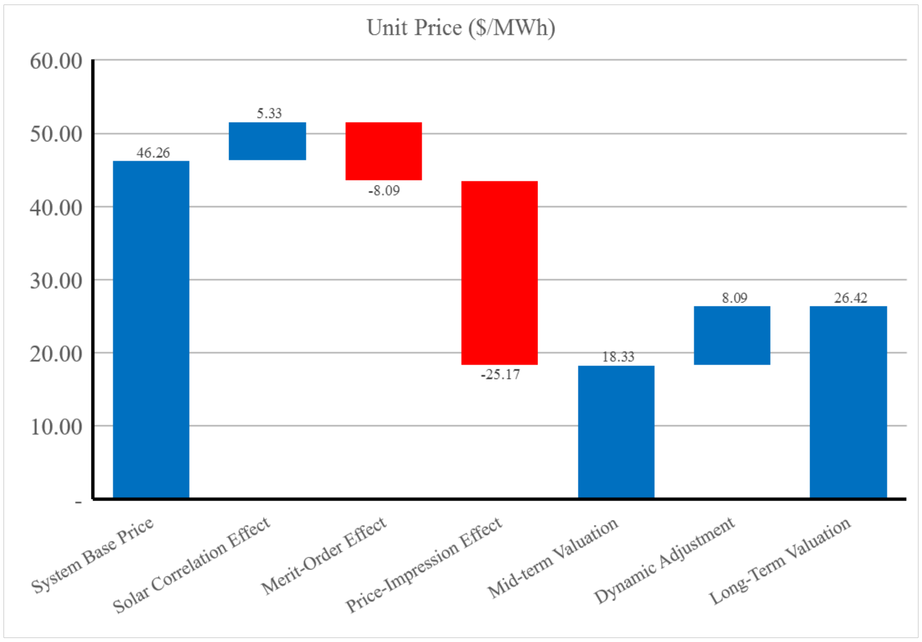
As Wind is progressively added to the plant mix, two further forces impact Market Value; a *merit-order effect* which is transient, and a *price-impression effect*, which is enduring. Merit-order effects reflect transient oversupply. Price-impression effects occur because of the stochastic but correlated nature of wind resources. Therefore, as each new wind farm enters, they progressively (and cumulatively) impact Market Values of the entire wind farm fleet (-$5.32/MWh). In the Mid-Term, the Market Value of Wind output falls to $23.35/MWh but merit-order effects are transient and will unwind in the Long-Term, thus rebounding to $38.08/MWh.

Figure 10 presents the equivalent analysis for utility-scale Solar PV at 15% market share. This is a striking set of results vis-à-vis *price-impression effects* and is consistent with Hirth (2013)[48],

[48] Empirical results in Hirth (2013) from Europe indicate that for every 1% increase in the market share of Wind, its market value drops by 1.62% for thermal systems but only 0.22% for hydro systems (although Hirth cautions that the sample size is small).

Nicolosi (2012)[49] and Mills & Wiser (2012)[50]. The first bar starts with the Base Price ($46.26/MWh). Unlike wind, *correlation effects* of the first solar PV farm are positive because solar output is positively correlated to demand and price (+$5.33/MWh). Merit-order effects for solar PV are comparatively minor compared to wind (-$3.39). However, unlike wind which stochastically add energy output across the entire day, solar PV output has a concentrated daytime bias. Price-impression effects are, therefore, acute (-$25.17/MWh). Consequently, there is little difference between Mid- and Long-Term results because price-impression effects dominate. As Hirth et al. (2016) note, what is special about VRE is not the existence, but the size of the change in system costs as renewables move from low to high market shares.

Figure 10: **Market Value of solar output (15% Market Share)**

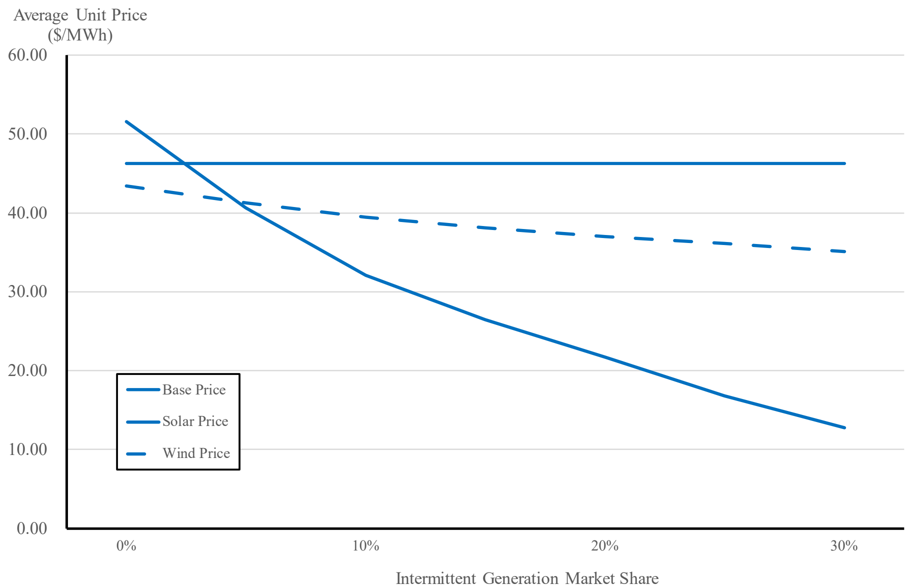


4.2 **Dynamic analysis of the value of VRE output 0-30% market share**

Figure 11 shows dynamic analyses for wind and solar output market values from 0-30% market share with continuous adjustment by thermal plant – thus removing transient merit-order effects. For wind, notice the starting point aligns with Figure 9 (viz. $43.80/MWh). Thereafter *price-impression effects* results in wind output progressively declining to $35/MWh. Solar PV results are consistent with Hirth (2013) and others. Because solar PV output is concentrated it has a more acute price-impression effect; essentially, the technology cannibalises itself at a fast rate.

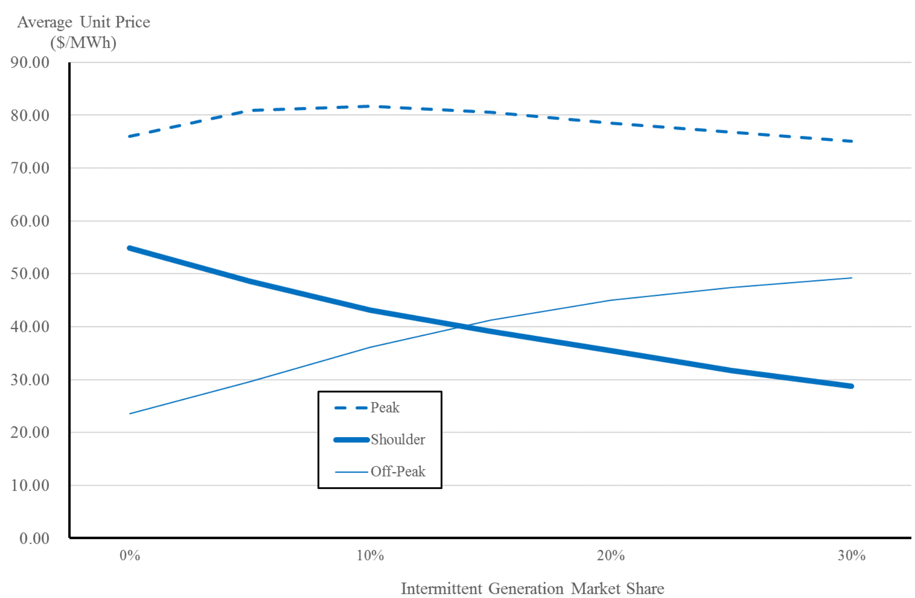
[49] See esp figure 6.17
[50] See especially pp55-57.

Figure 11: **Long-Term Market Value of solar PV output (0-30% market share)**



If solar PV was grossly over-represented in the VRE fleet Time-of-Use market prices are capable of being reversed (given costly storage and inelastic demand). Figure 12 presents a dynamic comparison of peak (4pm-8pm), shoulder (7am-4pm, 8pm-10pm) and off-peak (10pm-7am) prices as solar market share increases from 0-30%. Shoulder (i.e. daytime) prices drop as solar PV market share rises. Conversely, off-peak prices rise as inflexible coal plant exit, off-peak duties increasingly fall on higher-marginal running cost CCGT plant.

Figure 12: **Time-of-Use prices & solar PV 0-30% market share**



4.3 On the market's ability to optimise VRE asset allocation

In theory at least, market participants will optimise the asset allocation of wind and solar PV in the same way that the market regulates and optimises the asset allocation of base and peak plant. When combined with wind resources, there is an optimal solar PV market share higher than that implied in Figure 11 (where solar PV is the *only* VRE source). Determining optimal VRE asset allocation has many dimensions, including total market share of VRE, correlation between wind and solar output, differential rates at which unit costs of technologies decline, site-specific resource endowments & transmission/connection costs, and speed of thermal plant exit and adjustment. It would be unhelpful to model such rich variation but two variables are worthy of exploration to illustrate the principles; (1) VRE market share, and (2) mix of non-correlated technologies. Figures 13-15 show how the market would regulate asset allocation for VRE Targets of 10%, 20% and 30% market share with thermal plant adjusting perfectly.

It is important to stress that in the following analysis, while system load adjusts for each combination of VRE plant (i.e. own-price elasticity of -0.10), cost estimates for technologies are fixed; viz. all wind and all solar PV plants have identical cost structures to those in Figure 4. Figure 13 reveals that under these conditions, the optimal asset allocation between wind and solar at 10% VRE market share is 50/50. As VRE market share rises to 20%, optimal asset allocation is 60/40 (Figure 14) and finally for 30% VRE market share, optimal asset allocation is 70/30 (Figure 15).

Figure 13: **Welfare maximising asset allocation: 10% VRE Target**

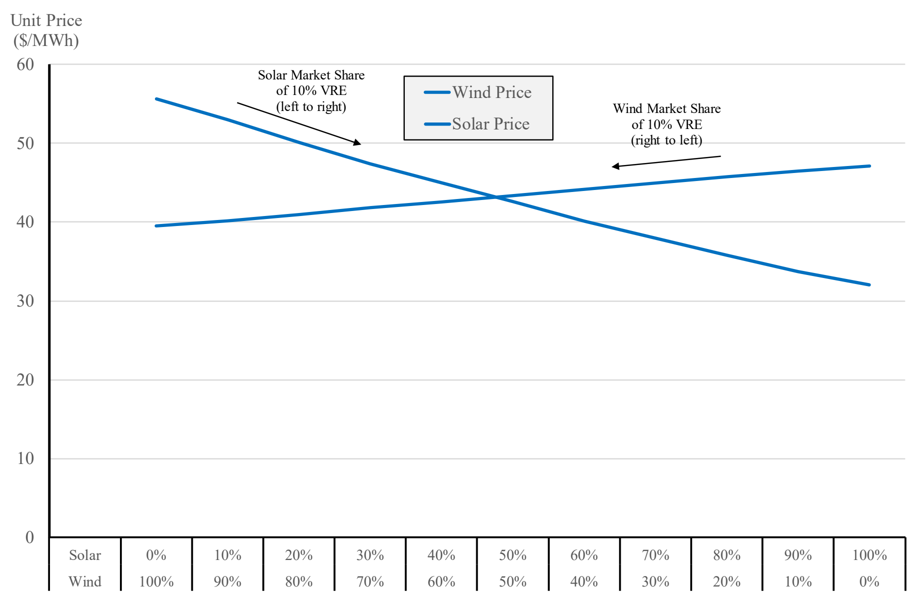


Figure 14: **Welfare maximising asset allocation: 20% VRE Target**

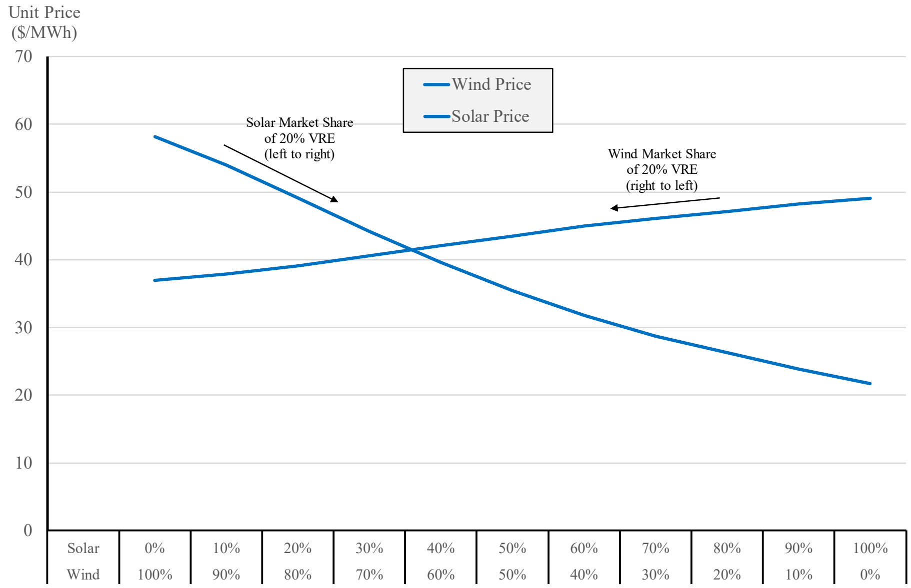
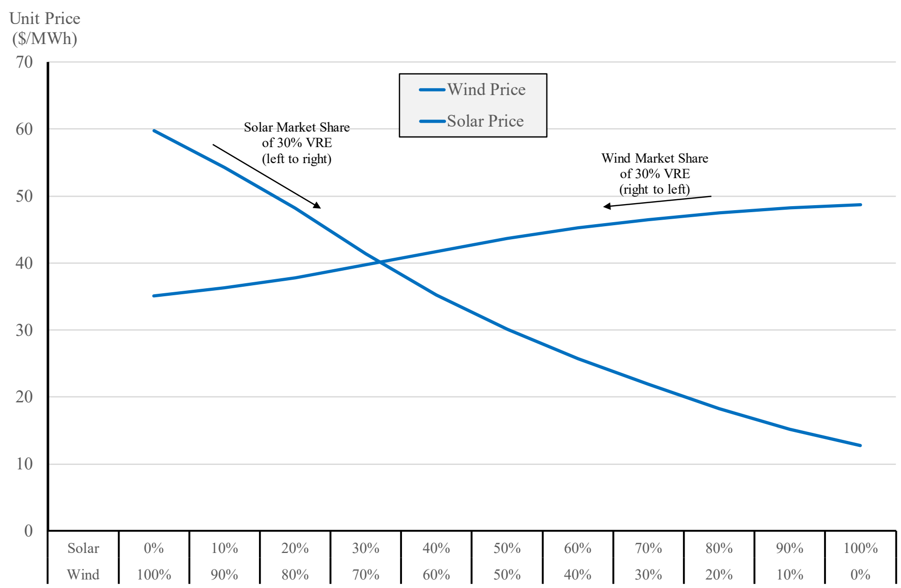


Figure 15: **Welfare maximising asset allocation: 30% VRE Target**



Provided market participants are profit-maximising, focused on the Market Value of output, one should expect the market to regulate entry to an optimal asset allocation. Conversely, government-initiated CfDs based on LCoE (rather than market value) risk distorting the market, resulting in a misinformed market.

5. On the stability of the hedge market

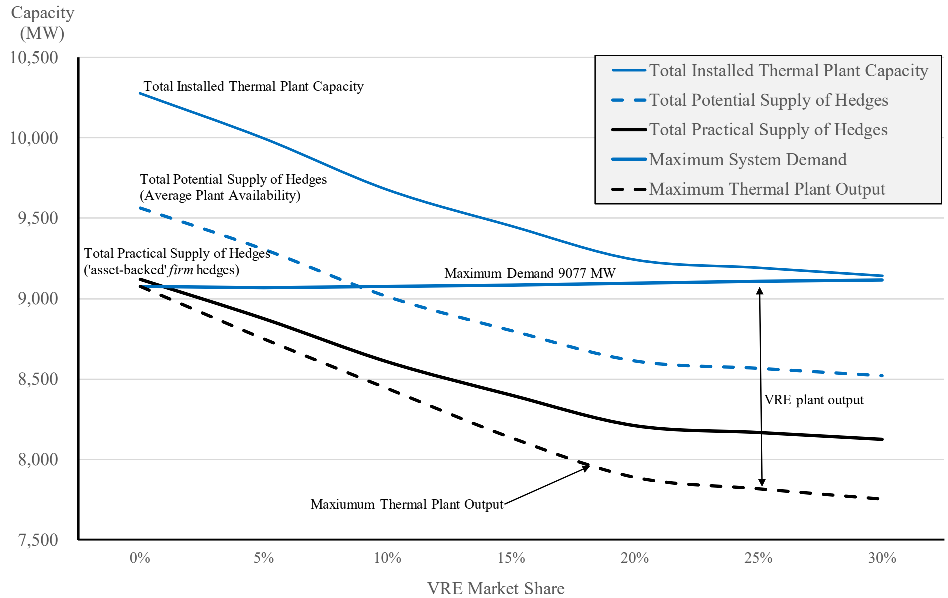
As far as I am aware, there has been no direct analysis of the underlying stability of the market for forward hedge contracts as VRE resources rise and thermal plant exit and adjust in imperfectly interconnected regions. Identifying the supply of hedge contracts is inherently difficult (viz. with turnover of 300-400%, there are more just asset-backed traders on the sell-side). But understanding the supply of asset-backed forward contracts provides some indication of stability and systemic security. In Simshauser et al. (2010), individual generation plant capacity was modelled according to a binomial distribution using a Monte Carlo simulation to produce half-hourly availability. The data were then collated and assembled into joint probability availability curves for each generation portfolio, and from there a PoE90 limit was identified as the maximum supply of asset-backed hedges for each portfolio. The same process has been applied in the present analysis assuming 3 large generation portfolios exist, with a more aggressive PoE80 limit for the supply of asset-backed forward contracts (i.e. implying a high degree of co-insurance amongst portfolios).

Figure 16 reveals the results and identifies the possibility of an 'unstable zone' in the hedge market. That is, while Section 3 demonstrated spot markets can reach a tractable equilibrium at 35% VRE, the hedge market appears to become increasingly unstable as thermal plant exits. To be clear, this is *not* a Mid-Term problem (i.e. because plant has not exited), it is a Long-Term problem following thermal plant exit.

In Figure 16 the supply of asset-backed hedge contracts (y-axis) is measured against VRE market share (x-axis) with perfect thermal plant exit and adjustment. Maximum System Demand of 9077MW (horizontal line) was a PoE30 weather event, not a PoE10 event which is typically what an energy retailers plan for. Note Total Installed Thermal Plant Capacity starts at 10280MW (per Table 1) and falls to 9141MW (per Table 3). Plant is no longer perfectly available, and so the reserve margin expands from 13% to 18% (vis-à-vis Net Load Duration Curve) to meet reliability constraints. Total Potential Supply of Hedges (dashed line) represents the average availability of thermal plant given by the average outage rate (viz. starting at 9600MW and falling to 8500MW as thermal plant exits). But generators *do not* hedge 100% of average expected available capacity – they examine the probability of largest and coincident unit outages in the context of adverse spot prices, and additionally, seek to retain some risk-adjusted spot price exposure.[51] The PoE80 joint-probability distribution of the thermal generation fleet is represented by the 'Total Practical Supply of Hedges' (solid line) starting at 9200MW and falling to 8200MW.

[51] The extent to which a generator will seek spot price exposure is a dynamic question. Generator appetite for spot price exposure is inversely related to the reserve plant margin and any time when base plant is 'under-weight' in the plant mix.

Figure 16: **Maximum system demand vs. supply of 'primary-issuance' hedge contracts**



If thermal plant fails to exit or is above optimal levels, no shortage would appear (i.e. Mid-Term). And similarly, even with optimal levels of thermal plant exit and moderate levels of VRE, the market may operate without concern because some component of VRE PPAs will be considered *firm*, and inter-regional hedges and speculative traders may fill any residual gap. But at high levels of VRE, it is not at all clear that a sufficient supply of asset-backed *firm* hedge contracts will exist.

If government-initiated CfDs have the compounding effect of extracting *non-firm* hedge capacity from the market (per Section 2.5), a chronic shortage of hedge contracts may be revealed and weigh heavily on retail competition – 2nd tier non-integrated retailers may be inadvertently *foreclosed* by this combination of forces. This appears more than a theoretical possibility, with early signs occurring in South Australia at the time of writing.

6. Concluding remarks

The purpose of this article was to analyse NEM stability with rising VRE. Starting with a Base Case of coal and gas plant, VRE resources were added until their market share reached 35% comprising 5% small-scale and 30% utility-scale. The literature review revealed energy-only markets are *tough neighbourhoods* under ideal conditions due to missing money (i.e. extended periods of sub-optimal net revenues), incomplete markets (i.e. absence of buyers for long-dated derivative instruments), missing markets (i.e. no markets for Inertia, Fast Frequency Response, Ramping Duties and forward markets for FCAS), shrinking markets (i.e. the gradual reduction in the supply of asset-backed *firm* hedge contracts) and misinformed markets (i.e. Government-initiated CfDs reliant on LCoE rather than market values).

Section 3 Modelling results confirmed spot electricity markets can maintain equilibrium conditions for the entire envelope of VRE (i.e. 0-35% market share) *provided* thermal plant exit and adjust perfectly. *If* VoLL is correctly priced relative to reliability criteria, and *if* the market optimises VoLL event frequency, there is no reason to think energy-only markets cannot produce equilibrium conditions. Of course, there is a long way between theory and practice. In the real world, energy-only markets are *off equilibrium* for extended periods, and rising VRE makes this more, rather than less, likely because of the addition of two new variables requiring optimisation, viz. thermal plant exit, and thermal plant adjustment.

Section 4 analysed optimal VRE asset allocation. Above all, modelling results demonstrated the dangers of LCoE as a metric. LCoE calculations are necessary inputs for power system planning. They are *not* outputs for investment commitment. As VRE becomes a larger share of the market, sub-national government CfDs execution based on LCoE analysis may produce a misinformed market through non-rational commitment. Why this matters is prior commitments by market participants, acting in good faith and attempting to acquit policy objectives, can be adversely affected as Figures 9-11 highlight. There is nothing inherently wrong with governments stepping into a market to ensure policy objectives are met, particularly if known market failures exist (e.g. Figures 2-3). But how governments do this is important; they need to play by the same rules otherwise the market may become misinformed.

Section 5 analysed the hedge market with a focus on the supply of asset-backed primary issuance (i.e. *firm* swaps and caps). As VRE rises hedge contract shortages appear more than a theoretical possibility. There will be no problem in the Mid-Term because excess thermal plant exists as VRE enters. Shortages may become apparent in the Long-Term as thermal plant exits, just as spot prices rebound.

Ironically, in the Mid-Term ample hedge contract capacity will exist because thermal plant will not have exited, but the spot market will be inherently unstable through merit order-effects. Conversely, in the Long-Term the forced exit of thermal plant produces a stable spot market equilibrium but a shortage of asset-backed hedge contract supply. At such a tipping point, only Vertical Retailers will be assured of managing VoLL exposure. 2^{nd} Tier non-integrated retailers may face policy-induced foreclosure. This risk would be heightened if government-initiated CfDs for VRE plant extract non-firm contract supply. Each time a government originates investment, unless there is a purposeful mechanism to ‘recycle’ underpinning contracts into the hedge market, further shortages may appear. How this is resolved seems worthy of further research.

Ultimately the solution to this Mid-Term/Long-Term disequilibrium may reside in expanding the volumes and services in FCAS markets; this expansion synthetically shifts the demand curve to the right and results in greater system reserves. And as Cramton & Stoft (2008) note, of all the forms of excess capacity in the energy supply chain, peak generating capacity (viz. OCGT) is least damaging and may well reconcile gaps in the supply of hedge contracts. This also seems worthy of further research.

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