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17 November 2011

Mr Richard Owens
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Dear Mr Owens

ERC0123 – MEU market power rule change – AER submission on AEMC directions paper

Please find attached the AER's submission on the AEMC's directions paper for the proposed generator market power rule change.

If you have any queries in relation to the issues raised in this submission, please contact Gavin Fox on (02) 6243 1249.

Yours sincerely

Tom Leuner
General Manager – Wholesale Markets

MEU market power rule change – Potential generator market power in the NEM

AER submission on AEMC directions paper

17 November 2011

1. Introduction

The Australian Energy Regulator (AER) welcomes the opportunity to comment on the directions paper for the AEMC's review of the Major Energy Users (MEU) Potential Generator Market Power in the NEM Rule Change Proposal.

Among its roles, the AER monitors the wholesale electricity and gas markets and is responsible for compliance with and enforcement of the National Electricity Rules and National Gas Rules. These roles leave the AER well placed to comment on market power issues in the National Electricity Market (NEM).

At the outset, the AER notes that the issues being considered in this review are inherently complex. Therefore the AEMC is to be commended for the rigorous approach that it is taking in this review. The AER believes that the AEMC's attempt to define substantial market power has added significant direction to the review.

We support the AEMC's approach of seeking perspectives from a number of experts in conducting this review. We believe that the peer review of NERA's report by Professors Joshua Gans and Stephen King has added significant value, particularly on the issue of strategic barriers to entry. We encourage the AEMC to continue to seek a number of perspectives as the review progresses.

We are also pleased that there appears to be a general recognition that the Competition and Consumer Act (particularly s 46) and the good faith clause of the National Electricity Rules, although covering issues that are related to market power, do not in and of themselves explicitly deal with the exercise of market power for financial gain and the inefficiencies this can produce. Section 46 deals with the exercise of market for an exclusionary purpose (i.e. a purpose of deterring a competitor), it does not prohibit market power pricing. The good faith clause of the National Electricity Rules (clause 3.8.22A) is about improving the timeliness of information and the accuracy of forecasts. It does not address market power pricing.

However, the AER does have some concerns with some elements of the approach being adopted by the AEMC. The AER is concerned that the AEMC, by focussing on the definition of substantial market power via analysis of market price Vs long run marginal cost (LRMC), could be overlooking potential analysis of how market power should be defined with respect to individual generators. The submission also highlights a number of practical difficulties associated with the AEMC's LRMC Vs price test. These difficulties are such that the AER would caution against using a single 'bright line test' to the definition of substantial market power.

The remainder of the submission is structured as follows. The next section provides some background on the AER's views on market power issues in the NEM. Section 3 provides general comment on the AEMC's directions paper, while section 4 outlines some challenges for the AEMC in defining substantial market power. Part 5 outlines broad market outcomes in the NEM to make some high level preliminary observations on the AEMC's definition of substantial market power and its proposed test.

2. Background

The AER has been concerned about market power in the NEM for some time and made public statements to this effect in *State of the Energy Market* reports and in reports analysing causes of prices of over $5,000/MWh in the market.

However, the AER has always accepted that in energy only markets short periods of high prices are necessary to signal the need for investment. The AER is not concerned with high prices which are consistent with underlying supply and demand conditions and recognises that these are necessary to sustain a functioning market.

Concerns arise when high average prices are driven not by the dispatch of higher cost plant in response to a tight supply–demand balance, but rather prices reflect economic withholding by generators. Economic withholding refers to circumstances where a significant amount of capacity (particularly baseload and mid-merit plant) which is normally priced at low prices, is bid or rebid at or near the price cap.

Such behaviour can have significant impacts on consumers. As we have noted in our *State of Energy Market Report*, if prices approach the market cap of $12 500/MWh for just three hours in a year, then the average annual spot price may rise by almost 10 per cent.

In light of these concerns, during 2010 the AER undertook further analysis on the issue, including engaging IES, Darryl Biggar and SFS Economics to report on different aspects of market power. IES attempted to quantify the inefficiencies created by higher-cost plant being dispatched in place of lower-cost plant, when that lower cost plant economically withholds capacity. Darryl Biggar's work provided a detailed analysis of actual events in the market to aid in understanding how market power is expressed in the spot market. SFS Economics looked at barriers to entry in the South Australian region.

While the consultants' work does not necessarily reflect the views of the AER, the work demonstrated that there is an issue that requires further investigation. The AER therefore supports the first principles approach that the AEMC is conducting to investigate the scope and extent of the market power issue in the NEM.

3. General comments on AEMC directions paper

The AEMC's framework for assessing the MEU's Rule change proposal involves a three step process.

The first step involves clearly defining the problem that the Rule change proposal is designed to address. The AEMC notes that there was considerable disagreement between stakeholders in relation to the appropriate approach to defining market power. Accordingly, the primary purpose of the directions paper is to define 'substantial market power' in the context of the NEM and to define the 'exercise' of substantial market power. The directions paper notes that only the exercise of substantial market power potentially justifies regulatory intervention in the NEM.

The second step involves assessing whether there is evidence of substantial market power, as defined by the AEMC in step one. This assessment will also consider whether the exercise of substantial market power is likely to persist in future.

If this assessment demonstrates evidence of a problem, the third step is to assess solutions to this problem. The AEMC notes that a Rule change will only be implemented where the potential benefits of removing or constraining the exercise of substantial market power outweigh the detrimental impacts associated with the implementation of any Rule change.

The directions paper largely focuses on the first stage of this process—defining the problem that the rule change proposal is seeking to address.

The issues raised in this review are inherently complex, so the AER supports the staged process being adopted by the AEMC in this review. However, the AER has some concerns that the AEMC, by focusing on "substantial market power" and a price Vs LRMC test at an early stage in the process, could be by-passing a more complete analysis of what market power is in the context of individual generators—the ability to influence price in a way that is not reflective of costs. The exercise of market power by individual generators is harmful and has clear efficiency effects. The debate over the size of that harm and whether it is concerning, and whether possible solutions cause more harm in themselves than the problem, is at risk of being by-passed by focussing solely on a price Vs LRMC test.

Further to the above point, manipulation of prices, be it to lower or raise prices, be it in the shorter-term or medium-term, and be it in energy, contract, retail or frequency control ancillary service markets, may raise strategic barriers to entry and competition concerns in retail and generation markets. For example, bidding by players with market power so that there are sudden and unexpected prices changes, has the potential to prevent and discourage competition, with resulting longer-term effects. In its weekly reporting[1] and its submission to the Tasmanian Electricity Supply Industry Expert Panel's Issues Paper,[2] the AER has highlighted examples of such strategic manipulation in South Australia and Tasmania. The examples highlight how sudden drops in price to near the price floor close to dispatch, driven by rebidding by generators with market power, may have the effect of damaging competition and the longer-term retail and generation price outcomes, whilst at the same time making it appear that yearly average spot prices are relatively benign. The AER therefore considers that analysis of short-term market manipulation by individual firms can greatly assist understanding of longer-term competition and price effects.

4. Definition of substantial market power

The AEMC defines substantial market power as "the ability of a generator to increase annual average prices to a level that exceeds long run marginal cost", and sustain prices at that level due to the presence of significant barriers to entry."

The AER believes that there are a number of challenges associated with this approach of comparing prices with LRMC.

[1] http://www.aer.gov.au/content/index.phtml?itemId=658727
See for example weekly reports that cover the following days: 10 September 2010, 3, 4 and 6 October 2010, 23 February 2011, 7 March 2011 and 17 June 2011

[2] http://www.electricity.tas.gov.au/issues_paper

First, looking at prices, it needs to be specified which price is relevant (time-weighted or volume-weighted). This choice could potentially make a significant difference. The use of volume-weighted pricing would appear to be appropriate, as it would provide more weight to the periods that customers care more about and, likewise, the periods that most generators (other than pure base-loaders) care about.

There will also be significant challenges for the AEMC in defining LRMC. The directions paper refers to the LRMC of adding capacity to meet a specified increment in demand. This raises the question of what incremental change in demand is being referred to, be it a change in energy or a change in peak demand or some mixture of the two? Which generators would be treated as meeting that incremental change will obviously be of critical importance, as the LRMC of baseload is very different to that of peaking plants.

There will also potentially be significant debate around the measurement of LRMC. Previous attempts at measuring LRMC have considered factors such as:

- capital costs—including the costs of plant supply and installation; indirect costs such as owner's engineering, start-ups and insurance costs; and financial costs such as due diligence and legal expenses.

- variable costs—including plant operations and maintenance costs; fuel costs and fuel transport costs.

- financial assumptions—including debt and equity (gearing) structure; tax; dividend imputation and inflation.[3]

Clearly, there is considerable conjecture around measuring many of these factors. As French J noted in *AGL v ACCC*, there is "a good deal of room for debate about how to determine LRMC."[4] Indeed, previous attempts to measure LRMC have often come up with a range of forecasts of LRMC.[5]

Finally, one of the threshold issues for the AEMC to consider is whether a single bright-line test will be sufficiently robust to appropriately capture instances of the exercise of substantial market power. NERA notes that there are a number of other measures of substantial market power that are beyond the scope of its report, such as the Lerner Index and the Pivotal Supply Index.[6] These measures focus more on the structure of the market. Market structure is of critical importance because it dictates the potential for market power to be exercised. The AER encourages the AEMC to consider whether these alternative measures should also be used to complement the LRMC Vs price test as a measure of substantial market power.

[3] See for example the discussion in IES (2004*) The Long Run Marginal Cost of Electricity Generation in New South Wales – A Report to the Independent Pricing and Regulatory Tribunal*, February 2004

[4] *Australian Gas Light Company v ACCC (No 3)* [2003] FCA 1525, at 491

[5] See for example IES (2004*) The Long Run Marginal Cost of Electricity Generation in New South Wales – A Report to the Independent Pricing and Regulatory Tribunal*, February 2004

[6] NERA (2011) *Potential generator market power in the NEM – A report for the AEMC*, June 2011

5. Evidence of the exercise or likely exercise of market power

In the directions paper, the AEMC sought submissions on whether there is evidence of the exercise or likely exercise of substantial market power, as defined in the directions paper.

As highlighted above, there are a number of elements of the definition of substantial market power that either need to be clarified or are yet to be developed. Therefore, it is difficult at this stage for the AER to provide any definitive views on whether outcomes in the market provide evidence of substantial market power, as defined by the AEMC.

However, some preliminary observations can be made. Table 1 outlines volume weighted average prices in the NEM since market commencement. It is important to note that these are yearly averages. The AER emphasises that use of yearly averages smoothes out shorter-term

Table 1 - Annual volume weighted average prices ($/MWh)

	QLD	NSW	VIC	SA	TAS
2010-11	34	43	29	42	31
2009-10	37	52	42	82	30
2008-09	36	43	49	69	62
2007-08	58	44	51	101	57
2006-07	57	67	61	59	51
2005–06	31	43	36	44	59
2004–05	31	46	29	39	
2003–04	31	37	27	39	
2002–03	41	37	30	33	
2001–02	38	38	33	34	
2000–01	45	41	49	67	
1999–2000	49	30	28	69	
1998–99*	60	25	27	54	

* 6 months

price effects. For example, shorter term effects which may have significant adverse consequences, such as quarterly prices of over $250/MWh, may be missed. Also, the effects on competition, barriers to entry and efficiency driven by strategic manipulations of individual and shorter-term prices may be overlooked. This is particularly the case when prices are driven very low (i.e. prices are negative) for certain periods during the year, an issue discussed earlier in this submission. In addition, changes in average prices driven by changes in the demand-supply balance are clearly evident in the table below (for example, the higher prices during the periods when generators where affected by the drought). As has been stated previously, the AER is not concerned about high average prices which reflect changes in the demand-supply balance, rather than economic withholding of capacity by generators.

The table indicates that South Australia had three years of high prices from 2007/08 to 2009/10. Prices in South Australia in 2007/08 averaged $101/MWh, in 2008/09 were $69/MWh and in 2009/10 were $82/MWh. The 2007/08 South Australian price was the highest since NEM commencement, the 2009/10 price was the second highest since NEM commencement, and the 2008/09 price was the third highest since NEM commencement. While there are significant challenges for the AEMC in defining LRMC (as highlighted above), it is difficult to see how such price outcomes could be less than a market LRMC.

The price outcomes in South Australia also emphasise the point made in the previous section about the potential problems of relying on a single price Vs LRMC test. Average prices in South Australia in 2010/11 were $42/MWh—a significant fall from price outcomes in the previous three years. However, these prices likely reflect more benign market conditions, growth in wind power and possibly changes in contract positions, rather than any significant change in the underlying market structure. In South Australia, there clearly remains the *potential* for market power to be exercised again in future due to the market structure. This poses the question of whether a single price Vs LRMC test will be sufficiently robust to appropriately analyse the potential for substantial market power concerns going forward.

6. Attached consultancy report by Darryl Biggar

Further to the consultancy report from Darryl Biggar that the AER attached to its earlier submission, the AER has attached a further report from Darryl Biggar to this submission. The views in the consultancy report are not necessarily those of the AER, however, the AER considers that the consultancy report will assist the AEMC and the AEMC's consultants in taking the next steps in considering the rule change proposal.

In particular, Darryl Biggar's work provides useful debate and analysis on the economic theory underpinning the price Vs LRMC test. The AER believes that, even if the AEMC does not adopt the suggested approaches in Darryl Biggar's report, it should be clear about areas where strict economic theory may not support the approach and simplifications or assumptions are being made.

NATIONAL ELECTRICITY AMENDMENT (POTENTIAL GENERATOR MARKET POWER IN THE NEM) RULE 2011

COMMENTS ON THE AEMC'S DIRECTIONS PAPER

Darryl Biggar

8 November 2011

Introduction

On 22 September 2011 the AEMC published a Directions Paper[1] setting out their initial thinking on a Rule change proposal submitted by the Major Energy Users (MEU). That Rule change proposal is intended to control some aspects of the exercise of market power in the NEM. A major element of the Directions Paper is a proposed definition of the terms 'substantial market power' and 'the exercise of substantial market power'.

The Directions Paper reflects the result of a substantial amount of work by the AEMC. It is a useful step forward. However, I have identified several issues which I hope can be addressed before moving to the next stage of the analysis. Specifically these issues can be summarised as follows:

(a) The Directions Paper proposes a test for substantial market power based on a comparison of annual average wholesale prices and long-run marginal cost (LRMC). However, in a wholesale electricity market there is no single LRMC – rather, there is (at least) a different LRMC for each generation technology. This problem of multiple LRMCs is not considered in detail in the Directions Paper.

(b) Given the problem of multiple LRMCs there are two ways to proceed – we could either choose one LRMC against which to compare annual average prices, or we could compare the entire price-duration curve against a benchmark. The former approach risks overlooking the exercise of market power which affects subsets of customers. The latter approach would require substantial amounts of information. I recommend that the AEMC reconsider its approach to the definition of market power – focussing on relatively easily identifiable actions such as the economic withholding of capacity.

(c) The Directions Paper seems to mix the notion of the short-run marginal cost (SRMC) curve and a particular point on that curve (which is referred to by some authors as the variable cost). As a consequence, the Paper says that generators must be able to charge above SRMC in order to cover their fixed costs. Economic theory shows that a price-taking firm (in any sector) will always produce at a point on its SRMC curve – yet, at least in a long-run competitive equilibrium, all the firms in the market are able to cover their fixed costs. In a wholesale electricity market with an efficient mix of generation technologies, each generator may submit an offer curve equal to its SRMC curve and each generator will still recover sufficient revenues to cover its fixed costs.

[1] AEMC 2011, Potential Generator Market Power in the NEM, Directions Paper, 22 September 2011, Sydney.

(d) The Directions Paper asserts that the exercise of market power is an essential feature of an energy-only market such as the NEM. In support of this claim the Paper cites several economists. However, I believe those citations do not support this claim. While it is true that, in practice, certain administrative features of electricity markets may prevent prices rising to a point which reflects the true scarcity value of electricity, I am not aware of an economist which rejects the claim that, in theory, in the absence of market distortions, a perfectly competitive market will deliver economically efficient outcomes – specifically that, where there is an efficient mix of technologies, each firm can offer its output to the market according to its SRMC curve and still recover sufficient revenues to cover its fixed costs. Indeed this point is made by both Frontier and Joskow – in the papers cited by the Directions Paper.

(e) It is theoretically possible that one of the market distortions which may prevent generators from covering their efficient fixed costs is the (low) level of the Market Price Cap (MPC) or the Administered Price Cap (APC). The Directions Paper suggests that generators should be allowed to exercise market power to recover the rents lost due to the level of the MPC or APC. However, in its review of the level of the MPC, the AEMC expressed the concern that raising the MPC might increase the scope for market power. There is a risk that considering each issue in isolation (i.e., whether or not to control market power, the level of the MPC) taking the other policy as given may lead to worse policy outcomes than the approach of considering both issues simultaneously. As Frontier submits, the market power issue may need to be considered simultaneously with consideration of increasing the MPC.

(f) Finally, the Directions Paper seems to associate price spikes and the exercise of market power, and goes to some length to disassociate transient price spikes from 'substantial market power'. However there is no necessary link between price spikes and market power. Episodes of high prices (price spikes) are an essential part of any energy only market. Market power is associated with the voluntary withholding of generation capacity. Price spikes can (and normally should) occur even when no generator is withholding capacity. Conversely, a generator can withhold capacity, and have a material impact on annual average prices, without ever raising the price high enough to constitute a price "spike". It would be helpful for the Discussion Paper to more clearly separate price spikes from market power.

The remainder of this note explains each of these issues in more detail.

1. In the context of wholesale electricity markets there is no one single LRMC

The AEMC has proposed the following definition for the exercise of "substantial market power":

> "A generator exercises substantial market power where it engages in conduct that has the effect of increasing annual average wholesale prices to a level that exceeds LRMC, and the generator is able (or is likely to be able) to sustain prices at that level due to the presence of significant barriers to entry".

The major problem with this proposal is that in a wholesale electricity market there is no single LRMC. At best there are a range of LRMCs – at least one for each generation technology. This raises the question whether as to which LRMC (or LRMCs) might be relevant for defining substantial market power. This point is also made in the peer review by Gans and King who note that:

"The LRMC approach … should be clarified to recognise that the LRMC differs from generator to generator".[2]

It appears that the intention behind the LRMC concept (in the NERA report and the AEMC paper) is to provide a comparator or benchmark against which we can compare average prices. The idea is that in a competitive market, prices above the benchmark would provide a signal for new entry. If entry barriers are low, average prices would not be expected to depart from the benchmark for long periods of time. The hypothesis is that "the ability to sustain prices above the level that would induce entry in the absence of entry barriers" is an indication of the possible presence of market power.

But we must be careful when applying these concepts from broader competition policy to the electricity market. An efficient wholesale electricity market consists of a mix of different types of generation technologies – baseload, mid-merit, and peaking. These different generation technologies respond to different price signals. There is no single number which provides a signal for new entry in the electricity market – rather the signal for entry is determined by the shape of the price-duration curve. Put another way, there are a series of different signals for entry – for each different generation technology.

In an efficient wholesale electricity market, the mix of different types of generation plant depends on the nature of the variation in demand. If demand never varied more than a few percentage points from its average, the majority of the plant in the market would be baseload plant. On the other hand, if on just a small number of hours in the year, demand rose to two or three times its average, a large proportion of the plant in the market would be peaking plant. The variability in demand can be represented in the (forward-looking) load-duration curve. The optimal long-run or equilibrium mix of plant in a wholesale electricity market depends on both the available generation technologies and the shape of the load duration curve.

Let's suppose we hold fixed the available generation technologies and explore the consequences of a small permanent change in the load duration curve. Specifically, let's explore the consequences of a adding an additional one MWh to the annual load. We will focus on the long-run response once the market has had a chance to adjust the mix of generation capacity to the new load duration curve.

The key point here is that the cost of a given change in the load duration curve depends critically on the nature of that change in demand. A one MWh increment in demand which is spread equally over all hours of the year will be met by an increase in baseload generation. The LRMC of such an increment in demand is therefore the capital costs of the small additional baseload capacity plus the operating costs (in each hour of the year).

Conversely, a one MWh increment in demand only at the peak demand time will be met by an increment in peaking generation. The LRMC of such as increment in demand is the larger incremental increase in capacity required at that peak time, plus the operating costs in that hour.

In general, the standard way to calculate the LRMC of a generation of type i with a fixed cost FC_i (\$/MW/hr), variable cost VC_i (\$/MWh), and a capacity factor p_i is as follows:[3]

$$LRMC_i = \frac{FC_i}{p_i} + VC_i$$

[2] Core Research (2011), page 2.

[3] I am not aware of a single authoritative citation for this formula, but it is present or implicit in many papers. For example the ACIL Tasman (2009) paper on the marginal cost of generation use a version of this equation on page 8, in which it is expressed in this equivalent form: $FC_i = p_i(LRMC_i - VC_i)$.

This LRMC has the interpretation that, given a particular generation technology, it is the expected price when this generation technology is producing at which this generation technology will expect to break even. If the expected price at the time when this generation technology is producing is above this level we would expect to see expansion of the capacity of that generation technology. Conversely, if the expected price at the time when this generation technology is producing is below this level, we would expect to see some of that generation technology capacity exit the market.

Derivation of the LRMC formula

The LRMC formula can be easily derived as follows. Let's consider the long-run expected profit of a price-taking generator with capacity K (MW), variable cost VC (\$/MWh) and fixed cost $FC.K$ (\$/h).

When the spot price is P the short-run profit is $\pi = (P - VC)Q - FC.K$. The profit maximising level of output is where the SRMC curve is equal to the spot price. We are assuming a simple stylized representation of the SRMC curve – equal to VC as long as the output is less than capacity and infinite thereafter. Therefore, if the spot price P is greater than VC, the profit maximising level of output is to produce at capacity $Q = K$. If the spot price P is less than VC, the profit maximising level of output is to produce nothing $Q = 0$.

Therefore, the long-run expected profit is $E\pi = (E(P|VC) - VC)CF.K - FC.K$ where CF is the capacity factor (the fraction of the time that the price exceeds VC) and $E(P|VC)$ is the expected price given that the price is above VC.

Setting this expected profit equal to zero to derive the break-even price we find that:

$$LRMC = E(P|VC) = \frac{FC}{CF} + VC$$

Importantly, the LRMC can vary widely according to the different types of generation technology – and corresponding to the different possible increments to demand. There is no one single LRMC. The appropriate LRMC will differ according to the change in demand we are discussing.

To give an idea of the range of possible values for LRMC, some analysis carried out for the New Zealand Electricity Authority estimated the LRMC of additional coal-fired generation (capacity factor 80%) in the range 130-135 (\$/MWh), geothermal generation (capacity factor 90%) in the range 75-90 (\$/MWh), gas-fired peaking generation (capacity factor 30%) in the range 220-240 (\$/MWh) and diesel peaking generation (capacity factor 5%) in the range 650-711 (\$/MWh).

Similarly, a European study suggests the following LRMCs for north-west Europe:[4]

	Capacity factor (%)	Fixed Cost (euros/MW/hr)	Variable Cost (euros/MWh)	LRMC (euros/MWh)
Nuclear	0.68	33.3	5.0	53.7
Coal	0.68	20.0	20.0	49.2
CCGT	0.46	9.0	40.0	59.7
Peaking	0.02	6.3	71.0	348.4

[4] Scheepers et al (2003). The figures in this table are estimated from the graphs and tables in the paper.

We can draw on the report prepared by ACIL Tasman to estimate similar figures for Australia which range between $50/MWh and $737/MWh, for different generation technologies.

	Capacity factor (%)	Fixed Cost ($/MW/hr)	Variable Cost ($/MWh)	LRMC ($/MWh)
Nuclear (Nuclear_SWNSW)	90.0%	77.74	9.94	96.32
Coal (SC BLACK (AC)_SWNSW	80.0%	34.13	9.72	52.39
CCGT (CCGT (AC)_SWNSW)	50.0%	19.86	41.94	81.67
Peaking (OCGT_SWNSW)	2.0%	12.90	92.72	737.70

(Source: ACIL Tasman (2009), tables 52 and 54, capacity factors estimated).[5]

The key point here is that there is no one single relevant LRMC figure. There are a range of possible values which vary according to the nature of the increment in demand. Without a specification of the increment in demand, the LRMC is undefined.

The Directions Paper does not seem to specify the increment in demand. In the Directions Paper the LRMC is defined as follows (emphasis has been added in these quotes):

- "LRMC estimates the cost (in net present value terms) of bringing forward a capacity expansion so that it occurs sooner than would otherwise be the case in order *to meet a specified increase in demand.* " (page iii).
- "The operating and capital costs associated with the optimal investment profile needed *to meet the relevant increment … in demand.*" (page 16)
- "LRMC reflects 'the cost of serving *an incremental change in demand …*"
- "LRMC … involves assessing the additional costs … that would be incurred by the need to … meet *that increment in demand*".

The Directions Paper has not specified which increment in demand it is referring to – it therefore does not specify a unique LRMC.

2. Is it useful to compare annual average prices to a single cost benchmark?

Putting to one side the problem that the LRMC is not uniquely defined, we might nevertheless ask the question whether or not a comparison of annual average prices with a single benchmark price level can be a reliable indicator of market power (or substantial market power). For example, does it make sense to assert that sustaining annual average prices above, say, $60/MWh implies the presence of market power whereas annual average prices below, say, $60/MWh implies the absence of market power?

More precisely, let's adopt the philosophy underpinning the LRMC approach - which asserts that substantial market power is exercised when the price is increased to levels that would be sufficient to induce entry in a market with no barriers to entry and exit. With this approach we can ask: Is it the case that a comparison of annual average prices with a single benchmark would detect an increase in prices that would be sufficient to induce entry in a market with no barriers to entry?

5 ACIL Tasman does publish what it refers to as "LRMC" figures in table 53 however these figures are calculated using a common capacity factor of 85% for all stations "for comparability". These figures are not true LRMCs.

The answer to this question is no: A comparison of annual average prices with a benchmark may not detect the exercise of market power by individual generation technologies that do not increase average prices above the benchmark.

- For example, at a time of generally below-average prices (due to say below-average demand, or a surplus of baseload generating capacity), a peaking generator will be able to exercise market power to raise the peak price above the level necessary to induce new peaking generation entry, while not exceeding a given level of average prices overall.

- Alternatively, a baseload generator will be able to exercise market power above the level sufficient to induce new baseload entry while not exceeding a given level of average prices overall.

- Alternatively, a generator with market power at both peak and off-peak times may be able to raise simultaneously raise prices in one period above a benchmark level and reduce prices in another period while maintaining average or expected prices below a threshold level.

To illustrate this point, suppose we have an electricity market with four different generation technologies (and some demand response). The different generation technologies have a variable cost of 10, 20, 50 , and 300 $/MWh respectively, and the demand response is triggered at the price of 5000 $/MWh. The variable costs and the fixed costs of each generation technology are set out in the table below. The equilibrium number of hours that each generation technology is operating is indicated below. The annual average price is $48.75/MWh. In this equilibrium each generation technology just breaks even (the expected profit is zero). For example, in the case of the $300 generation technology, the price is above $300/MWh for 0.2283% of the hours in the year. Given this capacity factor, we can work out the LRMC and the expected profit of this generation technology. The expected profit is zero.

Hours	Price ($/MWh)	VC ($/MWh)	FC ($/MW/h)	Exp Profit ($/h)
5	5,000			
15	5,000			
240	300	300	10.73	0
3000	50	50	18.15	0
5000	20	20	29.32	0
500	10	10	38.74	0

Since the annual average price in this efficient mix of generation technologies is $48.75, let's use this as our benchmark for the detection of market power. We will explore whether a comparison of the annual average price with this level is sufficient to detect the exercise of market power.

Now suppose that, for some reason, there is additional baseload generation in the market. The new equilibrium number of hours that each generator is active is set out in the table below. If we hold other things equal, this depresses the average annual price to $44.30/MWh.

Now suppose that any generator (the generation technology doesn't matter) is able to exercise market power at certain peak times, increasing the wholesale spot price from $5000/MWh to $12,500/MWh for just five hours in the year. The annual average price is only $48.57, so the threshold for the detection of market power is not passed. Yet, as can be seen in the table below, the expected profit for three generation technologies is positive.

In other words, a simple comparison of annual average prices with a benchmark may give rise to a situation where market-power-sufficient-to-induce-entry occurs even though the overall annual average prices do not exceed the benchmark.

Hours	Price ($/MWh)	VC ($/MWh)	FC ($/MW/h)	Exp Profit ($/h)
5	12,500			
15	5,000			
140	300	300	10.73	4.28
2800	50	50	18.15	1.43
4800	20	20	29.32	0.40
1000	10	10	38.74	-0.17

Another way of stating this result is that a generation technology can experience signals for entry (the expected price-above-variable cost for that generation technology may exceed the LRMC of that technology) even though the average prices for the market as a whole do not exceed the benchmark.

This example involved the exercise of market power at peak times, but the example could be changed to illustrate the exercise of market power at off-peak times. Again, the conclusion would be that it is possible for there to be incentives for entry at the level of individual generators, but still not have prices exceed a benchmark level overall.

The outcome could be even worse in the event we have a generator which holds market power at both peak and off-peak times. In this case the generator could, in principle, manipulate prices by raising prices at peak times and lowering prices at off-peak times, while not exceeding a benchmark level overall. This might be the case, for example, for Hydro Tasmania.

My conclusion is that where market power is defined as "average prices in excess of levels that would induce entry in a market without barriers to entry", it is not possible to detect market power using a single benchmark level of prices alone.

Implications for the National Electricity Objective

Another way to look at this problem is from the perspective of electricity customers. The National Electricity Objective requires the AEMC to focus on the long-term interests of consumers of electricity[6].

Consider the case of an electricity user that is considering making an efficient sunk investment in an electricity-consuming device which predominantly uses electricity at peak times (for example, the user might be a shopping centre considering installing air conditioning). The user making the sunk investment would like some assurance or protection against price rises in the future. In the absence of those protections the user will look to other energy sources or will fail to make the investment at all. In other words, the failure to obtain some assurances about the long-term path of prices may induce this user to make inefficient investment and operation decisions.

The question is whether setting a benchmark for average prices at some level is a sufficient protection for this customer. The answer is clearly no. This customer is not at all concerned with average prices – this customer is only concerned with the prices at the time he/she is consuming

[6] The NEO is stated as follows: "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to…"

(or will consume following the investment). As we have seen in the example above, a benchmark based on average prices can allow peak prices to increase while not violating the overall average. The user may be deterred from making an efficient investment. The NEO seeks to promote efficient investment, and efficient operation and use of electricity services for the long term interests of consumers. The use of an average-price-relative-to-benchmark approach may not satisfy the NEO.

This example was based on the case of a peak user. But the example generalises to other cases. A user considering an investment in an electricity-using application at off-peak times also faces the threat of the exercise of market power at off-peak times, which would not be prevented by a rule which compared average prices to a benchmark.

In addition, there may be a problem with market power exercised at times when prices are low. Wholesale electricity prices (like the prices of other commodities) are cyclical – they can be high in "boom" times, and low in off-peak times. Suppose that a few years of below-average demand is anticipated. Should firms be allowed to exercise market power in those years, bringing the annual average price just up to the benchmark threshold? If so, this would deny customers the benefit of lower prices in off-peak years.

Detecting market power using the price-duration curve

As we have seen, an average-price-relative-to-benchmark approach cannot detect market power defined as pricing-sufficient-to-induce-entry. But perhaps the solution is not just to compare average prices to a benchmark, but the entire profile of prices – that is, the price-duration curve.

Under simple assumptions (constant returns to scale, no sunk costs, price-taking behaviour), the entry decision of a generator of a particular technology type depends entirely on the shape of the price duration curve. Specifically, as proven earlier, a generator of a particular type will enter the market if the expected price when that generator is producing exceeds the LRMC as defined earlier. Put another, simpler, way, a generator of a particular type will enter the market if the area under its price duration curve and above its variable cost exceeds the fixed cost of that generator.

If it is the shape of the price-duration curve which provides the relevant signal for entry in a wholesale electricity market, can we rely on a comparison of a simple average price to a benchmark level to detect the existence substantial market power (defined as pricing-sufficient-to-induce-entry)?

In principle, under the assumptions above (constant returns to scale, no sunk costs), given enough information on the available generation technologies (and demand-side technologies), in principle it would be possible to construct an optimal equilibrium mix of generation technologies and the corresponding price-duration curve (assuming price-taking behaviour). In principle we could then look at the actual price duration curve in the market and compare it to the theoretical benchmark. Where the area under the actual price duration curve and above a given price was materially above the theoretical benchmark (and likely to remain so) this could, in principle, be a sign of market power (defined as pricing-sufficient-to-induce-entry).

For example, in the example used to prepare the tables above enough information was provided to compute the shape of the equilibrium price-duration curve. Under this methodology the regulator would be required to check not just whether the total area under the price-duration curve exceeded the threshold ($48.74) but also that:

The expected price given that the price is above:	Is above:
$300	$661.54
$50	$98.77
$20	$51.09
$10	$48.74

In this simple example, these calculations are in principle feasible. However, I have certain concerns with this approach. In particular, this approach requires significant amounts of information even in theory. Furthermore it relies on strong assumptions. It seems unlikely that it would be practical to compute a theoretical ideal or benchmark price-duration curve for these purposes, especially when we take into account that most of the information on the production costs of generators is held by the generators themselves.

Approaches which rely on a comparison of prices with costs place the market monitor in the position similar to a price regulator, with the similar problems of information asymmetry and distorted incentives.

Rather than linking the definition of market power to a price, it seems to me to be preferable to link market power to the underlying action – the economic withdrawal of capacity. In my paper I proposed the following definition.

> "A generator can be said to exercise market power when it systematically submits an offer curve which departs from its true, underlying, short-run marginal cost curve in order to influence the wholesale spot price it is paid and is therefore dispatched to a price-quantity combination which does not fall on its short-run marginal cost curve. "

For this definition to be made practical we would need to define the term "systematic". For example, we could define "systematic" as "where the behaviour is repeated often enough that, but for the actions of the generator in question, the annual average wholesale price in that region would be ten per cent lower". This definition does not focus just on high price times, or even times when prices are on average high, or on average low.

In my view this latter approach has the following advantages:

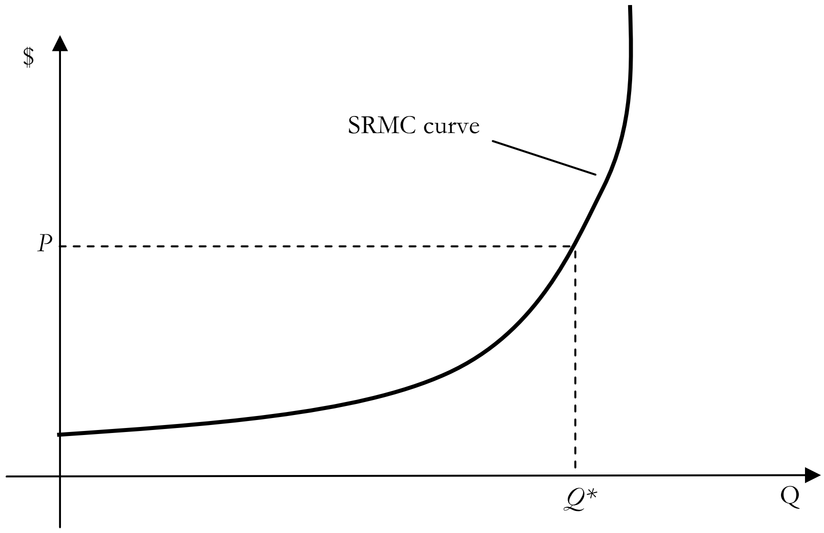
- It relies on easily available information. The offer curve of every scheduled generator in the NEM is available every five minutes. In many instances it is easy to detect when the offer curve of a generator has changed, and the effect of that change on the wholesale price. The SRMC curve of the generator is not as easily available, but could be estimated in the initial "filtering" stages, and subject to careful audit where further investigation is required.
- It does not require estimation of long-run costs – which is likely to be controversial and to rely on generator cost data which is not easily available to a market monitor.
- There is no confusion between price rises due to genuine shortage and price rises due to the exercise of market power – the approach does not focus on the level of prices at all. There is no risk of false detection of market power at times when average prices are otherwise high.
- It detects market power which is exercised both at times of surplus capacity and overall low prices and market power exercised at times of shortage of capacity and overall high prices – it does not allow generators a "free reign" to exercise market power at times when average prices are otherwise low.

It should perhaps be noted that no matter what definition is used for market power, the finding that a generator is exercising market power is not necessarily automatic cause for the imposition of a sanction or other restrictions. This is just the first step in the analysis. Another important step is assessing the scope for barriers to entry – including the impact of the exercise of market power on barriers to entry. However, where a generator is systematically exercising market power and where that market power is unlikely to be eroded within a reasonable timeframe some additional policy measures to mitigate that market power should be considered.

3. The distinction between the SRMC curve and variable cost

In several places the Directions Paper seems to fail to make a distinction between the short-run marginal cost *curve* and a particular point on that curve – which is often referred to as the 'variable cost' of operation of a generator which is operating below its maximum capacity.

In any industry, the short-run marginal cost of production is usually not a single number. Rather, the SRMC is usually represented as a curve – that is a set of points corresponding to a different marginal cost at different levels of output. Figure 1 in my paper represented a hypothetical SRMC curve as shown below:



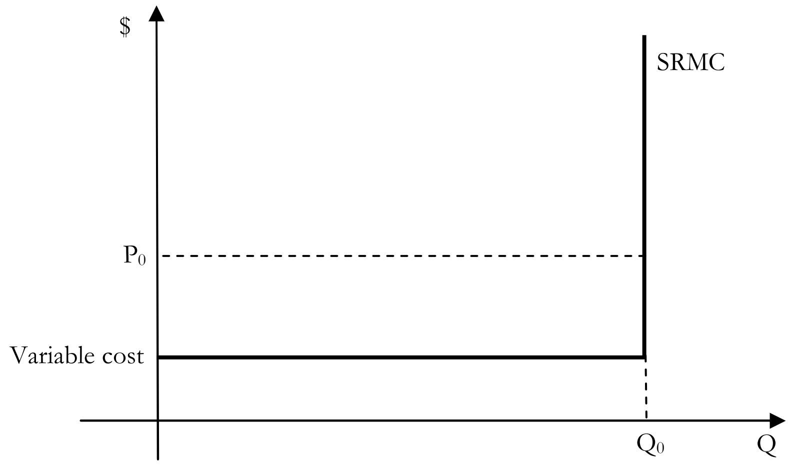
As is clear from this diagram, there is no single value for the SRMC – there are a range of values, each associated with a different level of output.

Economic theory teaches that a price-taking firm will choose to produce up to the quantity where the SRMC is equal to the price.[7] This is often expressed in the phrase: "the (upward sloping) part of the SRMC is the supply curve of the firm".

The Directions Paper asserts that "In a perfectly competitive market, all firms will sell all of their output at their SRMC". This is not quite right. It is more correct to say that in a perfectly competitive market all firms will choose a level of output such that the corresponding point on their own SRMC curve (at that level of output) is equal to the spot price (another way of saying this is that given the spot price, they choose a price-quantity combination which lies on their SRMC curve).

[7] This result follows from the definition of profit and profit-maximisation. Given a prevailing market price P, the profit function of a price-taking firm facing a simple linear price can be written $\pi(Q) = P.Q - C(Q)$ where $C(Q)$ is the cost function. Differentiating this with respect to the level of output, and setting the derivative equal to zero to find the maximum, leads to the conclusion that the firm will choose a level of output Q^* where the price-quantity combination (P, Q^*) falls on the SRMC curve: $P = C'(Q^*)$.

In the economic analysis of power systems it is common to approximate the SRMC curve of a generator using the stylized shape set out in the diagram below (from Figure 2 of my paper). In this stylized representation, the SRMC curve has two components – a horizontal part and a vertical part. The horizontal part reflects the additional cost of producing an extra unit of output when the generator is not operating at capacity. The vertical part represents the additional cost of producing an additional unit of output when the generator is operating at capacity. Since, in this stylized representation, the generator is not physically capable of producing more output when it reaches capacity the SRMC (theoretically) becomes infinite at that point (the SRMC curve becomes vertical).



Importantly the constant SRMC in the region in which the generator is not operating at capacity I have referred to as the "variable cost" of the generating unit. This terminology was introduced by Stoft (2002) in his textbook on power system economics. Stoft makes the point that the infinite slope in the SRMC curve in the stylized representation above is an approximation. In the real world, the SRMC curve may be steeply sloped as output reaches capacity but that slope is not infinite. He goes on:

> "Such supply curves will have constant marginal costs up to the nominal 'maximum' output level, but above that marginal costs will increase rapidly. If the supply curve is flat at $30 but the market price is $50, the generator's marginal cost will be $50 and it will produce on the steeply sloped segment. *When referring to such a generator, it is both wrong and confusing to say its marginal cost is $30 as is the custom. To avoid this confusion, the marginal cost a generator's supply curve to the left of the 'maximum' output level will be termed its* ***variable cost***".[8]

When discussing market power issues it is important to make a distinction between the SRMC curve and a point on that curve (the variable cost). A price-taking generator will always produce at a point on its SRMC curve. However, it will usually be receiving a price well above its variable cost (and therefore will be receiving a contribution towards its fixed costs). The point (P_0, Q_0) on the diagram above is a point on the SRMC curve, but the generator is clearly receiving a contribution to its fixed costs (equal to the area below the price and above the variable cost multiplied by the quantity).

There are several places in the Directions Paper where I have some concerns over the use of the term SRMC. For example, on page 29 there is a suggestion that SRMC varies over time especially at times of scarcity:

[8] Stoft (2002), page 70. Italics added.

"SRMC does not simply reflect costs such as fuel costs, but also reflects the costs of shortages faced by consumers. SRMC therefore varies and can increase dramatically in periods of scarcity."

However, this statement may reflect a misunderstanding. The SRMC curve of every generator can (and usually will) remain largely fixed over time (putting aside changes in input costs and plant outages). However, the wholesale spot price will vary continuously to balance supply and demand. At every point in time, every price-taking generator will be producing at a point on its own SRMC curve where the SRMC is equal to the spot price. As the wholesale price changes there is *movement along* the SRMC curve. The SRMC curve itself remains largely fixed over time.[9]

On pages 11 and 37 there is a suggestion that the presence of negative spot prices in some trading intervals requires generators to bid above SRMC in other trading intervals:

> "This issue [of under-recovery of fixed costs] is likely to be exacerbated by the existence of low or negative prices in some trading intervals, which could prevent a generator from even recovering its SRMC on average if it was unable to bid above SRMC in other trading intervals"[10]
>
> "The Biggar report … implies that a generator should not be able to bid above its SRMC in some trading intervals even if spot prices are negative during other trading intervals."[11]
>
> "He [Biggar] considers that generators with low SRMCs will be able to earn some contribution to their fixed costs whenever the spot price is above their SRMC"

As noted above, a price-taking generator (as any price taking firm) will *always* produce at a price-quantity combination on its SRMC curve – even if the spot price is negative in some periods. Such a firm receives a contribution to cover its fixed costs whenever it is producing at a point on its SRMC curve where the price is above the lowest point on the SRMC curve (in this case, the variable cost). In periods when the price is low or negative most generators will receive no contribution towards their fixed costs (at times of low or negative prices most generators will not be producing at all; however, in the presence of start-up costs some generators may choose to produce in periods of low or negative prices, resulting in a negative contribution to fixed costs). But in periods when prices are high (above variable costs) the same generators will receive a contribution towards their fixed costs.

It is important to be clear that even if generators were required to offer their output to the market at a curve which exactly matched their SRMC curve (which is not being proposed) they would still receive a contribution towards their fixed costs. The reason is as follows – as market demand varies, the wholesale spot price varies, and generators move to a different point on the SRMC curve. Whenever the wholesale spot price is above the variable cost of a generator, that generator will receive a contribution to its fixed costs. The presence of low or negative prices in some trading intervals does not prevent a generator earning a contribution to its fixed costs in other trading intervals even if that generator were restricted to submitting an offer curve equal to its SRMC curve. Even if a generator were required to offer all of its capacity at its variable cost the wholesale spot price may still rise above that variable cost.

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[9] I recognize that in making this statement the AEMC is drawing on work carried out by NERA. I question the analysis in the NERA paper, especially the analysis set out in Appendix A.1 of the NERA paper. This analysis seems to be, at best, unhelpful.

[10] AEMC (2011), footnote 13, page 11.

[11] AEMC (2011), page 37.

Just to clarify, my paper did not say that generators will be able to earn some contribution to their fixed costs whenever the spot price is above their SRMC. In fact, as I have emphasised, in the case of a price-taking generator the spot price is never above the SRMC - the firm always produces at a price-quantity combination *on* the SRMC curve. My paper instead said:

> "Generators with a lower SRMC are able to earn a contribution towards their fixed costs whenever the wholesale price increases above their *variable costs*, as normally occurs when generators further up the merit order being dispatched".[12]

Also, it is important to be aware of the following: Economic theory shows that (provided there are no other market distortions), in an efficient mix of generation technologies, even if every generator offered its output to the market in a manner which matches its SRMC curve, it is still possible for every generator to earn sufficient revenue to cover its fixed costs (this point is made, for example, in Joskow 2006 and in the Frontier report, both of which were cited by the AEMC).

In some contexts the use of the term SRMC in place of the term variable cost is relatively benign[13] (the meaning can be understood from the context). However when discussing market power issues the use of SRMC in place of variable cost can lead to misunderstanding.

3. Is the exercise of market power a fundamental and necessary requirement of an energy only market?

A fundamental theoretical question to address is whether or not some degree of exercise of market power is required in an energy-only market. The Directions Paper notes the argument made by Origin and others that "transient market power is an essential feature of an energy-only market"[14]. For example, Origin Energy submitted that:

> "An inherent and necessary feature of an efficient energy-only market is the ability of the marginal generator to on occasion bid strategically (i.e. above SRMC) to recover its fixed costs." [15]

(This argument is also attributed to AGL, TRUenergy, International Power, and the ESAA). The Directions Paper goes on to quote from Frontier suggesting that Frontier also support this argument. In fact, Frontier, amongst many points made in their paper, make the opposite argument (that market power is not necessary to achieve an efficient outcome in an energy only market).

In section 3.4.2 the Paper suggests that, in contrast to those who "reject the argument that generators need to be able to … exercise some market power … in order to recover their fixed costs"[16], a number of economists argue that:

> "An energy only market cannot be effective and sustainable if generators are not able to bid above their SRMC at least occasionally in order to recover their fixed costs. This issue is an application of what is often referred to as the 'missing money problem'".[17]

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[12] Biggar (2010), page 23.

[13] In the quote from Frontier on page 33, Frontier also use the term SRMC where it is clear that they mean variable cost.

[14] AEMC (2011), page 33.

[15] AEMC (2011), page 33.

[16] AEMC (2011), page 40.

We have discussed the distinction between the SRMC curve and variable cost in the previous section. It is universally acknowledged that the wholesale spot price must from time to time rise above the variable cost of all generators (including the most expensive generator in the market). The issue here is apparently not the relationship between the wholesale spot price and variable cost. Rather, the issue here seems to be specifically about the exercise of market power – that is, whether or not a generator must submit an offer curve which results in a price-quantity combination which does not lie on its SRMC curve in order to recover its fixed costs.

In support of the claim that a number of economists argue that some market power is essential in an energy-only market the paper quotes Joskow (2006) and Brennan (2003). In both cases I have interpreted the reports in a different way to the Directions Paper:

For example, the Paper quotes Joskow as stating that:

> "[I]n order to attract investment and balance supply and demand with traditional levels of reliability, competitive wholesale markets must produce "rents" over and above the short-run marginal cost of operating generating facilities in order to provide compensation for the capital costs of these facilities."

Joskow here refers to the "short-run marginal cost of operating generating facilities". He does not refer to the short-run marginal cost *curve*. It is reasonable to interpret the "SRMC of operating generating facilities" as referring to the *variable cost* of the generator. Joskow is making the point that competitive wholesale markets must produce rents over and above the variable cost of operating generating facilities to provide compensation for the capital cost of those facilities. As I have emphasised above, there is no dispute over this point. Prices must rise to the point where each generator is able to earn a contribution towards its fixed costs.

Joskow is *not* saying that the exercise of market power (i.e., price-quantity combinations above the SRMC curve) is necessary to provide compensation for capital costs. To do so would contradict the economic principle that perfectly competitive markets deliver efficient outcomes. It would also contradict Joskow's analysis in the very same paper as explained below.

The Directions Paper summarises Joskow's position as:

> "Professor Paul Joskow considers that the missing money problem would be likely to arise if all generators were forced by market power mitigation measures to bid at SRMC".[18]

This summary seems to be incorrect because earlier in the same paper[19] Prof Joskow goes to some length to work through a series of examples illustrating how generators recover sufficient revenues to cover their fixed costs in a competitive market. One of those examples includes some demand response. This case shows that with all generators offering their full capacity to the market at their variable cost (in other words, their offer curve matches their SRMC curve) then, in the efficient mix of generation capacity, all generators cover their total costs (these results are reported in Joskow's Table 8). Joskow clearly believes that (absent other market distortions) at least in theory, in an efficient equilibrium mix of technology, generators can offer at SRMC and still cover their fixed costs.

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[17] AEMC (2011), page 40.

[18] AEMC (2011), page 41.

[19] Joskow (2006), pages 15-23.

The Directions Paper also quotes from Frontier in support of this argument that transient market power is required to allow generators to recover their fixed costs. This quote is on page 33 of the Discussion Paper:

> "The NEM was designed as an energy-only market in which all plant would recover their variable and fixed costs through the spot market and derivatives contracts settled against spot market outcomes. For this to happen, the spot price must be able to at least occasionally rise above the SRMC of the most expensive plant in the market to enable that plant (typically a distillate or gas-fired peaking plant) to recover its fixed costs."

Again I believe that Frontier is not arguing that there must be an exercise of market power. In contrast, Frontier is merely asserting that the wholesale spot price must increase above the variable cost of the most expensive plant in the market. This point, as we have seen, is not in doubt.

Moreover, in the same submission Frontier explains at length that even if every generator submits an offer curve equal to its SRMC curve, in an efficient mix of generation technologies, each generator will be able to cover its fixed costs. In other words, no market power is required. This material in set out under the heading "Optimal Plant Mix and Cost Recovery" and is extracted in full in the box below. Far from arguing that market power is essential for cost recovery, Frontier is making the point that – at least in a theoretical ideal market – no market power is required. Generators are able to cover their fixed costs even if they submit an offer curve which reflects their SRMC curve.

Optimal Plant Mix and Cost Recovery – From Frontier (2011)[20]

The energy-only market design is not only intended to yield consistent levels of unserved energy and installed generation capacity, it can also produce an efficient technology mix of plant. In a theoretically ideal (fully-competitive) energy-only market, for a given: MPC; mix of generation technologies (differing cost and operating characteristics); shape of load (flat, peaky), price-taking generator bidding behaviour should result in:

- the optimal technology mix and timing of generation investment as well as the optimal operation of these generators, together ensuring that long-run total costs of meeting load are minimised and

- a path of market prices that results in this optimal mix of plant, based on optimal dispatch, perfectly recovering all generators' total costs (fixed and variable) over time

The precise conditions necessary for this outcome are not borne out in practice due to a range of real-world market imperfections and failures. Nevertheless, it is illustrative to recap how in theory an energy-only market seeks to ensure the efficient mix and operation of generation plant as well as cost recovery for that efficient mix of plant.

The top panel of Figure 4 below shows the total cost, per MWh, of three generation technologies at different operating capacity factors. The y-intercept denotes fixed cost and the slope of the line denotes variable cost. Depending on the duration of operation, each technology is at some point least-cost in $/MWh terms (i.e. it lies on the dotted red line).

These 'screening curves' can be used to determine the optimum plant mix for a given shape of

[20] Frontier note that a complete exposition of this result can be found in Stoft, S., Power System Economics, Designing Markets for Electricity, IEEE Press, 2002, Part 2.

load. Taking as given the optimal annual number of hours of unserved energy, it is possible to derive the optimal proportion of the year that each plant should run and the resultant optimal level of installed capacity of each plant from the middle panel of Figure 4.

Under the assumptions of a fully-competitive market, the optimal duration of unserved energy, combined with the optimal plant mix and operation given technology costs and the shape of load, can be used to derive an optimal price-duration curve as per the bottom panel of Figure 4. This resultant price-duration curve is sufficient to ensure that all technologies in the optimal mix can recover their total costs (variable and fixed) over time. Each technology recovers only its variable costs when it is setting the price (i.e. it is the marginal generator). Each technology recovers both its variable and a portion of its fixed costs when the market price rises above its variable cost. This means that:

- the most expensive generation technology recovers its fixed costs only during periods of unserved energy when the market price is equal to the MPC (ignoring instances of voluntary load shedding that lead to prices being set between that plant's SRMC and MPC)
- all other generation technologies in the optimal mix also rely on MPC prices at these times to ensure they fully recover their fixed costs. For example, a baseload unit will recover some of its fixed costs when a mid-merit plant is marginal and setting the price, but will not recover all its fixed costs unless the optimal duration of MPC prices occurs

In support of its case that economists argue that the exercise of market power is an essential requirement of energy-only markets, the Directions Paper goes on to quote from a paper by Tim Brennan. The Directions Paper summarises this paper as saying:

> "Professor Timothy Brennan explains the potential damage that could arise if market power was defined as pricing above SRMC (or average variable cost, which is often used if SRMC is not available)".

I believe this summary of Brennan's paper is incorrect as Brennan clearly states in one of the opening paragraphs that he has no problem with defining market power as the relationship of price to SRMC[21]. His concern is with defining market power as the relationship of price to *variable cost*. In other words, his concern is not with the theory but with how the theory is applied in practice. Brenann's paper says:

> "The rationale for using price-cost margins is essentially that, in a competitive market, price-taking firms will supply output up to the point where the marginal cost of production just equals the market price. A substantial difference between price and marginal cost indicates that firms are not taking price as given.
>
> *In a nutshell, the flaw in those electricity market studies is not that the price-cost margin is theoretically inappropriate, but that it is inappropriately implemented.* The proxy for "marginal cost" used to

[21] Of course, we could ask: What does it mean to compare the price (which is a number) to SRMC (which is a *curve*)? Economic theory usually focuses on the Lerner Index – which is the margin between the price and a point on the SRMC curve – specifically the SRMC at the output level chosen by the firm. As we have seen several times a price-taking firm will choose a price-quantity combination which lies on the SRMC curve, so for a price-taking firm the Lerner Index is zero.

estimate price-cost margins is typically the average variable or operating cost of the last or marginal generator that would be dispatched to meet energy demand."[22]

Brennan does not say that defining market power as pricing above the SRMC curve is "damaging" as the Directions Paper implies. Rather he explicitly endorses this approach as "theoretically appropriate". His concern is with defining market power as pricing above *variable cost*. As we have seen several times, there is no dispute that the spot price must on occasion increase above the variable cost of the most expensive generator in the market.

Borenstein and capacity markets

The Directions Paper acknowledges Borenstein's position that price-taking generators do not need to exercise market power in order to recover their fixed costs. However, the Directions Paper goes on to downplay this position on the grounds that Borenstein is "expressly based on the existence of a reserve capacity market".[23]

I do not believe that Borenstein is referring to capacity markets (the term "capacity market" does not appear in that paper). He does refer to the presence of additional markets which he calls "reserve markets". This is set out in his first footnote:

> "In a competitive electricity market with completely inelastic demand, the price of energy indeed would never exceed the marginal cost of the highest marginal cost producer, but that producer would also be receiving revenues in the reserve market in return for standing ready to produce when demand peaks. The California electricity market has this "stand-by payment" structure for spinning, nonspinning, and replacement reserves, as well as regulation energy."[24]

From the context it is clear that Borenstein is not referring to capacity markets, but to markets for what are sometimes known as "Operating Reserve". The Wikipedia entry for "Operating Reserve" in electricity markets distinguishes spinning reserve, non-spinning reserve, frequency-response or regulation reserve, and replacement reserve - exactly the markets to which Borenstein is referring. In the NEM, the same services are known as Frequency Control Ancillary Services (FCAS). Generators in the NEM can offer into the markets for FCAS services and receive payments for providing these services. Such payments provide an additional contribution to their fixed costs.

It is incorrect to dismiss the Borenstein paper on the grounds that it assumes the existence of a capacity market. The Borenstein paper does assume the existence of other additional markets – but these same markets already exist in the NEM.

Conclusion on the need to exercise market power

In conclusion, there are a variety of reasons why, in practice, a wholesale electricity market may fail to deliver economically efficient operating and investment signals. However, the claim that specific economists believe that the exercise of market power is an essential feature of a wholesale energy-only market and that without the exercise of market power, generators will be unable to recover their fixed costs, does not seem to stand up to scrutiny.

I therefore consider that the central claim made by Borenstein and Bushnell (2000) still applies:

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[22] Brennan (2003), page 60 – emphasis added.

[23] AEMC (2011), page 40.

[24] Borenstein (2000), page 57.

"There is simply no support in theory or practice for the claim that firms – even firms in capital-intensive industries – must exercise market power in order to cover their costs. … Finally economic theory does not support an argument that price must exceed the competitive level for firms to break even. In fact, under reasonable conditions, the absence of market power leads to normal returns on investment with exactly the socially optimal quantity of electricity generation capacity".[25]

4. The impact of the MPC

In several places the Directions Paper appears to suggest that the exercise of market power in the NEM is essential to allow generators to recover their fixed costs due to the impact of the market price cap (MPC). For example, on page 40 the Directions Paper quotes from Hogan who notes that where market price increases are limited by administrative actions such as price caps, the "rents" available to generators are reduced, potentially reducing the incentives to maintain or build new generation facilities.[26] Again, on page 38:

"The Commission considers that a Rule that sought to prevent the exercise of market power as Biggar defines it would either require other market design changes to allow generators an opportunity to recover their efficient fixed costs (such as a higher MPC or a capacity mechanism) or would result in the early retirement of some generation capacity and more periods of supply shortages".

In effect, the Discussion Paper is asserting: given the current level of the MPC, some exercise of market power in the NEM is essential to allow generators to recover their fixed costs. The implication is that, as long as the MPC is at its current level, we should not introduce policy measures which restrict the ability of generators to exercise a degree of market power.

However, if the level of the MPC is a concern why not simply increase the MPC?

The problem here is that, in the absence of mechanisms to control market power, one of the arguments against raising the MPC is that it might allow generators to exercise higher levels of market power. This threat of enhanced market power was raised as an argument against raising the MPC at the last review.

One of the reasons for having market price caps in the first place is to mitigate the worst excesses of market power.[27] In a report commissioned for the AEMC, Frontier explicitly acknowledge that increasing the MPC may increase the incentive to exercise market power:

"A high MPC can create incentives for generators to exercise transient market power in the NEM. … If it occurs frequently, transient market power can raise wholesale prices and compromise economic efficiency in both the short and long run. *Increasing the MPC is*

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[25] Borenstein and Bushnell (2000), page 10.

[26] The Hogan quote does not explicitly draw the conclusion that therefore some exercise of market power is an essential feature of an energy-only market. However, this quote is placed in the context of a discussion which is arguing why the exercise of market power is necessary to overcome the "missing money" problem – of which market price caps are one source of "missing money".

[27] Joskow (2006) notes that: "Especially during high demand periods as capacity constraints are approached, this creates significant opportunities for suppliers to exercise unilateral market power. In the U.S., FERC has adopted a variety of general and locational price mitigation measures to respond to potential market power problems in spot markets for energy and operating reserves. These mitigation measures include general bid caps (e.g. $1000/MWh) applicable to all wholesale energy and operating reserve prices, location specific bid caps (e.g. marginal cost plus 10%), and other bid mitigation and supply obligation (e.g. must offer obligations) measures."

likely to increase existing incentives to exercise transient market power because it increases the 'payoff' to any given generator from engaging in economic withholding strategies. Various regulatory and market design options are available to mitigate generators' incentives to exercise transient market power. The regulatory options include measures to restrain generators' offers directly and downward adjustments to the MPC and/or CPT".[28]

There is a risk here that defining policy issues narrowly may result in sub-optimal outcomes. It may be that if we take the level of MPC as given, that some form of market power is necessary to allow some generators to cover their fixed costs, and that mechanisms to mitigate market power are not needed. On the other hand, it may be that if there are no mechanisms are in place to control market power, it may be seen as undesirable to raise the level of MPC.

One potential solution, of course, is to consider these two issues together. If it is, in fact, the case that the level of MPC is a material constraint on the ability of generators acting competitive to recover their fixed costs, then consideration should be given to increasing the MPC *at the same time* as mechanisms are put in place to mitigate any market power.

This point is clearly made by the NEM Generators Group:

> "In order to avoid deterring efficient generator entry and to ensure the NEM reliability standard continues to be met following the Rule change, the MPC may need to be revised higher. Raising the MPC has implications for the level and volatility of wholesale spot prices, and consequently, for wholesale contract prices and retail competition."[29]

In short, it seems to me that the argument that "we cannot implement market power mitigation mechanisms because we have set the MPC too low to allow generators to recover their fixed costs", is not a strong argument. If the MPC is distorting market price outcomes it should be raised or removed (some other wholesale electricity markets do not have market price caps at all). Although Frontier has concerns about the Rule change proposal, it makes clear that combining the proposed Rule with an increase in the MPC could improve overall outcomes:

> "Assuming the Rule change is accompanied by an increase in the MPC, dynamic efficiency could be improved compared to the status quo. This is because, again assuming that generators will not substitute MPC-bidding strategies with strategies of not offering all available capacity to the market, the level and pattern of market prices will be more consistent with those expected in a fully-competitive market than at present. This would result in a more efficient pattern of generation investment going forward".[30]

5. Price spikes versus economic withholding

The Directions Paper seems to associate or identify price spikes with the exercise of market power. Similarly, the Directions Paper seems to go to some length to distance transient price spikes from the exercise of market power. For example, the association between price spikes and market power can be seen in the following quote:

[28] Frontier (2010), page 3, emphasis added.

[29] NEM Generators Group submission 29 June 2011.

[30] Frontier (2011), page 37.

> "Price spikes may constitute evidence of substantial market power if they occur to such an extent and with sufficient frequency that they cause annual average wholesale spot or contract prices to exceed LRMC."[31]

It is valuable to be clear that there is no necessary connection between price spikes and the presence of market power. Prices can spike with no generators exercising market power. On the other hand generators can exercise substantial market power without prices ever reaching exceptional levels.

In an energy-only market occasional high prices are necessary if all generators are to cover their fixed costs. If there is a shortage of generation capacity these price spikes might cause annual average wholesale spot prices to exceed some benchmark level. Yet such price spikes would have no connection to market power unless at the time of high prices, some generator was producing less than it was physically able to produce. High prices do not imply the exercise of market power.

Neither does the absence of high prices imply the absence of market power. A generator may withdraw enough capacity to increase the price from, say, $50/MWh to $100/MWh. If it does so frequently enough, there may be a very substantial impact on the annual average wholesale price, even without prices ever reaching exceptional levels. Low average prices do not imply the absence of market power.

Conclusion

The AEMC Directions Paper represents a good deal of valuable work on the part of the AEMC. However, it appears that there remain certain areas for further work, particularly in the use of concepts such as LRMC and SRMC. In my view it would be helpful to clarify these issues before progressing to the next stage of the analysis.

[31] AEMC (2011), page iii.

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