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1 February 2012

Mr Richard Owens
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Dear Mr Owens

ERC0123 – MEU market power rule change – Comments from Darryl Biggar on NERA Technical Paper

Please find attached comments from Darryl Biggar on the technical paper published by the AEMC on 22 December 2011 by NERA Economic Consulting and Oakley Greenwood.

While the views expressed in Darryl Biggar's paper are his own and not necessarily those of the Australian Energy Regulator (AER), the AER believes that the paper will assist the AEMC and the AEMC's consultants in taking the next steps in considering the rule change proposal.

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
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An Exploration of NERA's proposed approach to estimating Long-Run Marginal Cost

Darryl Biggar

27 January 2012

In advice prepared for the AEMC in June 2011, NERA proposed a test for the presence of market power in the wholesale electricity market.[1] NERA proposed that substantial market power was present if market prices are significantly and persistently above long run marginal cost (LRMC).

In a more recent paper[2], NERA set out how they propose that LRMC should be estimated. Specifically they propose that the LRMC should be estimated using the perturbation or Turvey approach.[3] The perturbation or Turvey approach to LRMC involves carrying out the following steps:

(a) Forecast the path of demand (including the shape of the demand duration curve – that is the demand at peak and off-peak times and all other times) for each year for a number of years into the future (say 25 years);

(b) For the given forecast path of demand, starting from the existing mix of generation technology, and using a list of all possible future generation expansion opportunities, determine a least cost generation capacity expansion path over a number of years into the future which will be sufficient to satisfy that demand. Let the present value of the cost of generation over the relative time horizon be X;

(c) Consider a permanent increase in demand of some amount (again, this could be peak, off-peak, or intermediate demand, and so on). As before, starting from the existing mix of generation technology, and using a list of all possible future generation expansion opportunities, recalculate the least cost generation capacity expansion path over the horizon which will be sufficient to satisfy that demand. Let the present value of the cost of generation over those years be Y;

(d) The LRMC is then given by the formula:

$$LRMC = \frac{Y - X}{Z} \quad \text{...(1)}$$

Where Z is the present value of the increment in demand.

This proposal raises a number of theoretical, methodological, and practical questions which are explored in this note.

Theoretical issues

The primary theoretical question is the following: Is there any theoretical linkage between average prices (or some measure of average prices) and the Turvey LRMC as calculated using the method above. If not, can the formula above be modified so that there is a linkage of some kind?

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[1] Green, H., Houston, G., and Kemp, A., (2011), "Potential Generator Market Power in the NEM: A Report for the AEMC", NERA Consulting Group, June 2011.

[2] Kemp, A., Chow, M., Houston, G., and Thorpe, G., (2011), "Estimating Long Run Marginal Cost in the NEM: A Paper for the AEMC", NERA Consulting Group, 19 December 2011.

[3] Actually, the December 2011 proposes two approaches to computing LRMC: The perturbation or Turvey approach and the Average Incremental Cost or AIC approach. But the paper expresses a clear preference for the former: "In our opinion the perturbation approach should be preferred over an AIC approach because it most closely aligns with the principles underpinning the concept of LRMC".

NERA do not derive or prove any theoretical linkage between average prices and the Turvey LRMC in their paper – the assumption seems to be that such a link is clear or implicit. I am not aware that Turvey himself drew any link between his concept of LRMC and the average prices in a wholesale market.[4] Turvey proposed his LRMC notion in the context of public utility pricing – particular marginal cost pricing. That is, Turvey's proposal was intended as a long-run pricing policy in a regulated industry, not as a test for market power in a liberalised power market. There seems to be particular interest in the Turvey LRMC concept in regulatory pricing questions in the water industry.

In this first section of this note I set out some theoretical linkages between average prices and costs in a wholesale electricity market and relate them to the NERA proposal above. In the next section I explore what we can learn from an implementation of the Turvey LRMC methodology in practice.

Let's start from the simplest case where (a) there is no lumpiness in generation investment (i.e., generation capacity can be added in arbitrarily small increments and the cost of generation capacity scales linearly with the amount of capacity added); and (b) generation investment is not sunk – that is, it is reversible. This last assumption allows us to focus on each period independently of every other period. I will assume perfect competition between generators. Let's look for the relationship between prices and costs under these assumptions in a free-entry equilibrium – that is, a market in which all generators are free to enter and exit the market. This set of assumptions is very close to the case considered by NERA in section 3.2.2 of their paper under the heading "a simplified modelling approach".

Let's suppose that there are a set of generation technologies available to the market, generation technology i has a variable cost VC_i (\$/MWh) and a per period fixed cost per unit of capacityFC_i (\$/MW). Let's suppose that we add an additional K_i units of capacity of generation technology i (this additional capacity is assumed to be small enough to not affect the wholesale spot price). The expected profit of this additional generation capacity is:

$$E(\pi_i) = E[(P - VC_i)Q_i(P)] - FC_iK_i$$

Where $Q_i(P)$ is the quantity of output produced by this addition of generation capacity when the wholesale spot price is *P*. The wholesale spot price *P* is assumed to be uncertain. $E[\cdot]$ is the expectation operator.

Under the assumption that the generation market is perfectly competitive, the quantity of output $Q_i(P)$ is chosen such that the generator produces at full capacity $Q_i(P) = K_i$ whenever the spot price exceeds the variable cost $P > VC_i$ and the generator produces nothing $Q_i(P) = 0$ whenever the spot price is less than the variable cost $P < VC_i$. As a consequence it follows that: $(P - VC_i)Q_i(P) = (P - VC_i)K_i$ when $P > VC_i$ and zero otherwise. This implies that the expected profit for a one MW increment of generation technology *i* is:

$$E(\pi_i) = (E[P|P \geq VC_i] - VC_i)Pr(P \geq VC_i) - FC_i$$

Where $Pr(P \geq VC_i)$ is the probability that the spot price exceeds the variable cost of the generation technology and $E[P|P \geq VC_i]$ is the expected wholesale spot price given that the spot price exceeds the variable cost of the generation technology.

In a free-entry equilibrium we would expect generators to enter (or existing generators to expand) to the point where the expected profit of an additional unit of capacity is zero. This implies that the expected spot price must satisfy the following set of relationships:

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[4] Turvey introduces this approach in Turvey, R., (1969), "Marginal Cost", *The Economic Journal*, 79(314), June 1969, 282-299. Another reference is Turvey, R., (2000), "What are marginal costs and how to estimate them". A useful summary is found in a report by Marsden Jacob Associates, (2004), "Estimation of Long Run Marginal Cost (LRMC): A report for the Queensland Competition Authority", 3 November 2004.

$$E[P|P \geq VC_i] = VC_i + \frac{FC_i}{Pr(P \geq VC_i)} = LRMC_i \qquad ...(2)$$

The expression on the right hand side of equation (2) is often referred to as the long-run marginal cost of generation technology *i*.[5]

Equation (2) relates the shape of the price-duration curve in a free-entry equilibrium to the long-run marginal costs of the underlying generation technologies. It says that in a free-entry equilibrium the expected price when the price is above a given variable cost threshold is equal to the sum of the variable cost and the fixed cost divided by the capacity factor for that technology – that is, the proportion of time that that generation technology is active.[6]

It is worth comparing the approach embodied in equation (2) to the approach proposed by NERA. The closest version of the NERA proposal is on page 15 of their submission. A comparison of the NERA proposal and equation (2) reveals three important differences:

(1) First, the NERA approach does not discount the fixed cost of a generation technology by the capacity factor of that technology. This does not matter when we are focussing only on a permanent (or "baseload") change in demand. However, NERA, in their description of the Turvey LRMC approach on page 6 explicitly mention that the change in demand could be a change in *either* "average and/or peak demand" by a small but permanent amount. Equation (2) makes clear that the relationship between average prices and LRMC is more complicated when we focus on other (non-baseload) changes in the demand-duration curve, such as a change in peak demand. In this case we must be careful to be clear as to what notion of average prices is being referred to (as in equation 2, or footnote 5) and whether or not the concept of LRMC is scaled by the capacity factor for the relevant generation technology.

(2) Second, as noted above, NERA do not indicate how their proposed computation of LRMC should be linked to average prices. The expression above in equation (2) shows that it is the expected price *above a given price level* which can be related to the LRMC of different generation technologies. Equation (2) implies a series of equilibrium conditions on the set of expected future prices – not just a condition on average prices. Put another way, equation (2) shows that the entire price-duration curve is determined by the LRMC of different generation technologies. (Footnote 5 suggests an alternative, equivalent, set of relationships).

We can make equation (2) somewhat closer to the approach proposed by NERA by taking a special case: the case of the generation technology with the lowest variable cost – that is, the "baseload" technology. In this hypothetical electricity market the spot price can never drop below the variable cost of the baseload generation technology, so the probability that the spot price will be equal to or higher than the variable cost of the baseload technology is one. As a result, as a special case of equation (2) we have the condition that the average price is equal to the sum of the variable cost and the fixed cost of the baseload technology.

$$E[P] = VC_B + FC_B = LRMC_B$$

Under the assumptions above, with no lumpiness of investment and no sunk investment, the additional cost of adding an additional one MW of baseload technology is just $VC_B + FC_B$ - which is just the LRMC as calculated under the Turvey approach.

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[5] The expression on the right hand side of equation (2) is a conventional way to express the LRMC. But, mathematically we could multiply both sides of equation (2) by $Pr(P \geq VC_i)$. We could define an alternative form of LRMC (denoted here *TLRMC*) and the following mathematical relationship would then be true:

$$\int_{VC_i} pf(p)dp = VC_i Pr(P \geq VC_i) + FC_i = TLRMC_i$$

Here $f(p)$ is the probability density function for the wholesale spot price.

[6] This result was derived in my earlier submission to the AEMC.

We can go a little distance further to closing the gap between the approach above and the Turvey LRMC by dropping the assumption that generation investment is reversible. Instead, let's make the assumption that generation investment is sunk and irreversible. In this case the investor in a given generation technology will care about the entire path of future prices over the life of the investment. Let's suppose that an investor invests at time zero in a generation technology with a variable cost of VC_i ($/MWh) and a per period fixed cost per unit of capacityFC_i ($/MW). The expected profit of this investment is:

$$E_0(\pi_i) = \sum_t \delta^t E_0(\pi_{it}) = \sum_{t=1} \delta^t E_0[(P_t - VC_i)Q_{it}(P_t)] - \sum_{t=1} \delta^t FC_i K_i$$

Where δ is the constant per-period discount factor, P_t is the (uncertain) wholesale spot price in period *t*, and $Q_i(P_t)$ is the quantity of output produced by this addition of generation capacity when the wholesale spot price is P_t.

As before we can look for the free-entry equilibrium where the expected profit for each generation technology is zero. This implies that the expected future prices must satisfy the following condition:

$$\frac{\sum_t \delta^t Pr(P_t \geq VC_i) E_0[P_t | P_t \geq VC_i]}{\sum_t \delta^t Pr(P_t \geq VC_i)} = VC_i + \frac{\sum_t \delta^t FC_i}{\sum_t \delta^t Pr(P_t \geq VC_i)} \quad \text{...(3)}$$

Equation (3) is a condition on the shape of the average future price-duration curve *over many years into the future*. It says that, on average, the weighted average over time of the expected price above a given variable cost threshold must be equal to the variable cost of that technology plus a term that relates to the fixed cost of the generation technology divided by the capacity factor.

Equation (3) highlights the intuitive point that in the presence of sunk investment the relevant price-cost test in equilibrium does not compare the average prices in a single year with a cost threshold – what is relevant is a comparison of a weighted average of the prices *over the entire life of the investment* with a cost threshold.

In the special case of the baseload generation technology, equation (3) states that in the free-entry equilibrium at all times a weighted average of expected future prices is equal to the sum of the variable cost and the fixed cost of the baseload technology, which is also the Turvey LRMC under these assumptions (recall that we are still assuming that generation can be added in arbitrarily small increments).

$$\frac{\sum_t \delta^t E_0[P_t]}{\sum_t \delta^t} = VC_B + FC_B$$

It is worth noting that this condition applies to forecast average prices. It does not apply to actual, out-turn, or historic market spot prices (although out-turn prices are related to forecast prices). Also, the relevant average here is the simple average of prices – not the "volume-weighted average of market spot prices" proposed by NERA (page 23). In this simple example, the reason is clear. Under these assumptions, the baseload generation technology (in effect) produces at capacity at all times – its output does not follow demand at all. So the relevant average is the simple average of prices, not the volume (demand) weighted average.

In summary, this section on the underlying theory has sought to find a relationship between average prices and some measure of costs in a wholesale electricity spot market. If we are prepared to make certain simplifying assumptions – particularly the assumption that generation can be added in arbitrarily small amounts - we can find such a relationship. However that relationship differs from the approach proposed by NERA in several respects:

(1) It implies a condition not just on average prices but on the entire structure of the price-duration curve;

(2) It implies a condition not on prices in a particular year but on a weighted average of expected future prices over the life of a generation investment.

(3) It implies that the fixed costs of a generation technology should be discounted by the capacity factor of that technology (or, as an alternative, see footnote 5).

The conditions under which equations (2) and (3) were derived are quite stylized. The Turvey LRMC is intended to be applied in a circumstance where generation can only be added in certain discrete lumps. To make further progress, therefore, it is useful to consider an actual implementation of the Turvey LRMC methodology under the assumption that generation can only be added in discrete lumps. This should highlight the methodological issues involved in applying the proposed approach and further clarify the nature of the relationship (if any) between average prices and the Turvey LRMC.

Methodological issues

An implementation of the Turvey approach to LRMC requires the specification of the following information:

(1) A time period over which the analysis is carried out (usually in the range of 20-50 years) and a discount factor (or interest rate) to apply over that period;

(2) The profile of demand (that is, the time or probability distribution of demand outcomes, or the demand duration curve) over every year in the relevant time period;

(3) The economic characteristics of the existing stock of generation technologies (that is the capacity, fixed cost, and variable cost of the existing stock of generation technologies, together with their remaining economic life);

(4) A set of feasible capacity additions or expansions for each generation technology (that is, the capacity, fixed cost, and variable cost of each expansion option[7], together with its economic life – NERA refer to this as the forecast new entrant costs);

(5) The nature of an increment to demand in each year of the relevant time period – that is, the change in the demand-duration curve in each period – both the amount of the change in demand and whether that change in demand applies to all times or probabilities or only to some times or probabilities (such as only at peak times);

(6) In addition, some assumptions need to be made about the nature of the spot market and the behaviour of generators in that market. The conventional assumption is that the spot market is perfectly competitive and therefore that generators offer their full output to the market at their variable cost.

Given this information, following the steps set out above, an implementation of the Turvey approach requires the computation of the least-cost generation operation and investment path with and without the demand increment, as set out earlier.

A number of questions can be raised at this point:

- What is the appropriate size of the relevant demand increment for the analysis? Should the demand increment be small or large? NERA note that: "The size of the increment can itself affect the estimate of the LRMC, and this influence can vary depending on the balance between existing generation capacity and demand in the year in question". How sensitive is the resulting LRMC measure to the choice of the size of the demand increment?
- Is the LRMC sensitive to changes in assumptions about the growth rate of demand (or the growth rate of components of demand, such as peak demand) over time?
- What is the impact of the existing stock of generation relative to existing demand? Are estimates of the LRMC affected by the existing supply-demand balance?

[7] These might also be differentiated by the time when the capacity expansion option becomes available.

- What is the appropriate minimum size for new capacity investment? How does it vary with generation technologies, or over time?
- In applying this approach to a real-world network, what assumptions should be made about transmission constraints? In particular, how should inter-regional constraints and price-differences between regions be taken into account? How should transmission expansion opportunities be modelled?

To explore the use of the Turvey approach to LRMC let's consider a particular application. This application makes the following assumptions (these assumptions are listed in the same order as the list of information required above):[8]

(1) The time period considered is 50 years. The discount factor was chosen to correspond to an interest rate of 10 per cent per annum.

(2) There are assumed to be five possible states of demand. The demand in each state (and the associated probability) is set out in the table below (these correspond roughly to the demand-duration curve for South Australia). The demand in each subsequent year is assumed to be a constant growth rate of one per cent per year.

Demand state	Demand (MW)	Probability
1	1123.966	0.323345
2	1603.211	0.537043
3	2088.816	0.118322
4	2582.157	0.015468
5	3076.849	0.005822

(3) There are assumed to be four different generation technologies (more precisely: three real technologies and one technology corresponding to voluntary or involuntary load-shedding). The fixed and variable costs of each generation technology are set out in the table below. In addition, the initial stock of capacity of each technology is shown. This generation capacity is assumed to be long-lived (at least longer than the period under study). The initial or starting capacity for each generation technology is assumed to be close to the long-run equilibrium level.

Technology	Variable Cost ($/MWh)	Fixed Cost ($/MW/annum)	Initial Capacity (MW)
1	1	50	1600
2	38	40	480
3	100	35	490
4	4000	0.001	2000

(4) In terms of capacity additions, it is assumed that there are available a large number of units of each generation technology that can be added at any time. Each unit is only available in discrete lumps. The size of the lumps will be chosen (as set out below). For example, units of size 400 MW, or 800 MW might be available to add. The added units have identical fixed and variable costs to the existing stock of units set out above. As with the existing generation capacity, for simplicity each addition to the generation stock is assumed to be long-lived (so that we need only consider capacity additions and not withdrawals or retirements). The generation investment is assumed to be sunk (i.e., once a generation investment is made it cannot be reversed later).

[8] This model ignores transmission constraints and assumes a single wholesale spot price.

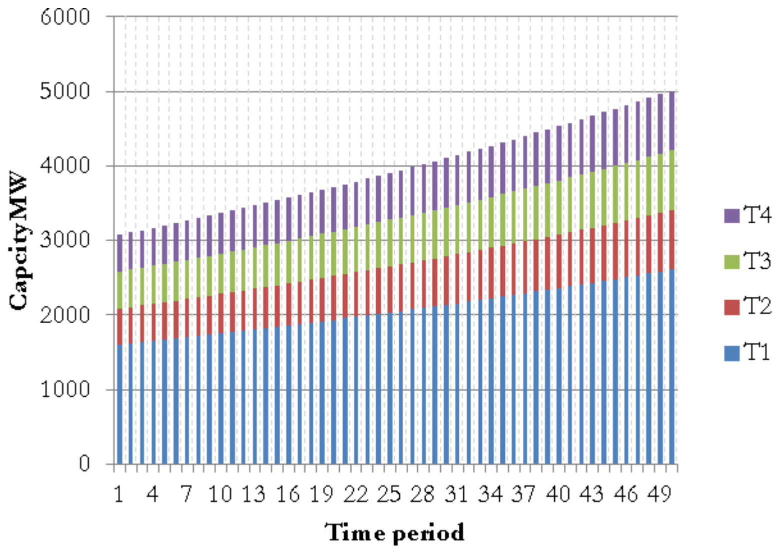
(5) For most of what follows we will focus on a simple fixed addition to demand that applies at all times (i.e., a baseload increase in demand). Later we will consider an increment to demand which applies only at peak times.

(6) We will assume, in effect, that the wholesale spot market is perfectly competitive so that the dispatch of individual generators is in accordance with their variable cost.

To get some idea of what we might expect from this model, let's start with the simplest case in which the size of the lumps of additional capacity are arbitrarily small. In this case the model reduces to the case of the first model discussed in the theory section above (the fact that the generation investment is sunk is irrelevant since the optimal path of generation capacity is for the capacity of each generation technology to only expand in each period).

The following chart shows the optimal volume of each generation technology in each period. As can be seen, the optimal volume closely follows the expansion path of demand.

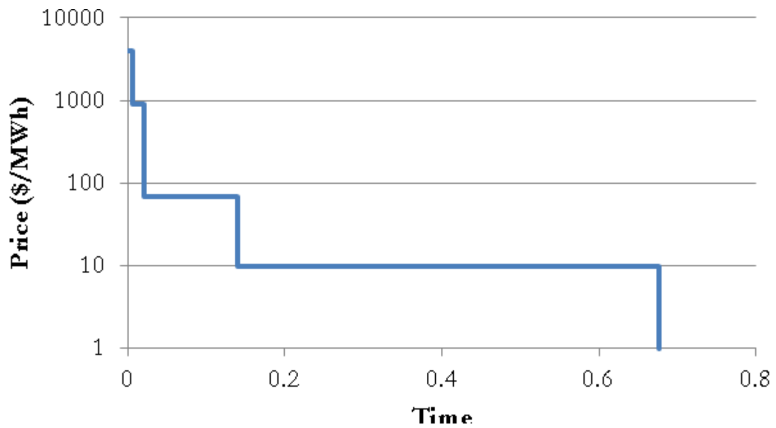
Figure 1: Generation expansion path when generation added in arbitrarily small amounts



(Here T1, T2, T3 and T4 correspond to the generation technologies described on the previous page).

Importantly, under the assumption that generation can be added in arbitrarily small amounts, both the average price and the price duration curve *remain constant throughout the period.* As expected the average price is just equal to the sum of the fixed and variable cost for the baseload technology (as demonstrated in the theory section above). Since the fixed cost of the baseload technology is $50/MW/annum and the variable cost is $1/MWh, the simple (not volume weighted) average price in each period is $51/MWh. The constant price-duration curve is set out below:

Figure 2: Price-duration curve (for all time periods) when generation added in arbitrarily small amounts



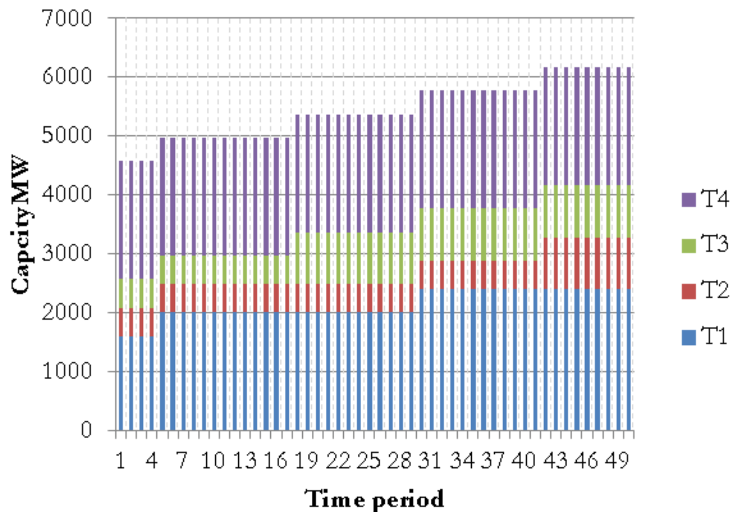
Now, consider a demand expansion of say, 100 MW (the actual amount doesn't matter in this special case of infinitely-divisible generation capacity). Applying the perturbation methodology, the difference in the present value of the cost of generation divided by the present value of the demand increment is precisely $51/MWh. The Turvey approach (perhaps unsurprisingly) yields the same result as the simple methodology described above in this circumstance with infinitely-divisible demand, and where we have focused on a baseload expansion of demand.

Applying the same methodology to other changes in demand we can work out the LRMC of each different generation technology. Under the assumption of perfectly-divisible demand, the LRMC of each generation technology is as given in the table below:

Technology	Variable Cost ($/MWh)	Fixed Cost ($/MW/annum)	LRMC ($/MWh)
1	1	50	$51
2	38	40	$324.51
3	100	35	$1743.96
4	4000	0.001	$4000.17

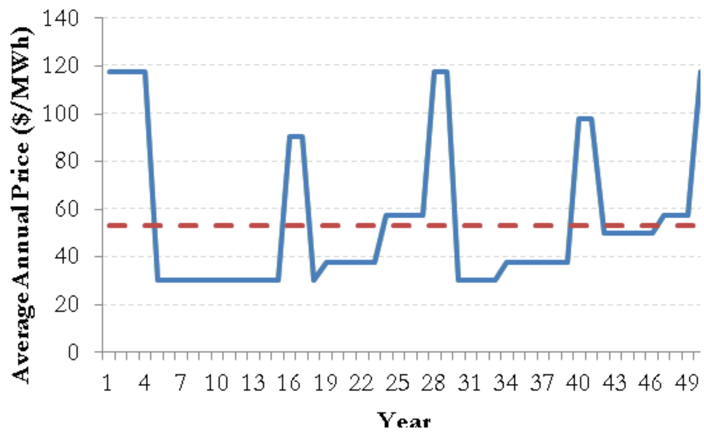
Now let's re-introduce the restriction that new generation capacity can only be added in arbitrarily small lumps. Specifically, let's assume that new generation capacity can only be added in lumps of, say, 400 MW. The new least-cost generation capacity expansion path is shown below in Figure 3. As can be seen in Figure 3, in the least-cost generation capacity expansion path, 400 MW of the baseload capacity is added between years 4 and 5, and again between years 29 and 30. 400 MW of the mid-merit technology is added between years 41 and 42. 400 MW of the peaking technology is added between years 17 and 18. No other generation investment is required in the optimal generation expansion path.

Figure 3: Generation expansion path when generation capacity added in lumps of 400 MW



In contrast to the previous case in which generation capacity could be added in arbitrarily small amounts, the average price is no longer stable over time. The following chart shows the average price over the time horizon under consideration:

Figure 4: Annual average price and LRMC, generation added in 400 MW lumps



By adding an additional 100 MW to (baseload) demand, and re-computing the least-cost generation expansion path we can determine the Turvey LRMC. We find that this new increment to demand brings forward some generation investment. Specifically, an additional 400 MW of baseload capacity is added before year 1 and before year 27 (previously year 5 and year 30 respectively). The mid-merit capacity investment is deferred until year 49 (previously year 42) and the peaking capacity investment is brought forward to year 15 (previously year 18). The overall cost of generation is higher. Computing the difference and dividing by the present value of the demand change results in an LRMC for the baseload technology of $53.40/MWh. This is not too different from the benchmark value of $51/MWh computed for the case of infinitely-divisible generation capacity above.

But does it make sense to compare the average annual price to this LRMC value? The model shows that the average annual price fluctuates substantially above and below this LRMC value for long periods of time. As can be seen in Figure 4, the average annual price for the first 4 years is $117.72/MWh. Then, when 400 MW of baseload generation is added, the average annual price drops to $30.19/MWh and remains there for 11 years. The model suggests that there may be sustained, prolonged departures from the baseload-LRMC value, even in a model in which we have assumed perfect competition and socially-optimal generation investment. This raises questions about whether or not we can use a comparison between average annual prices and computed LRMC to detect the presence of market power.

The weighted average long-term price in this model, over the entire 50 year period, is $58.26/MWh, compared to the benchmark of $51/MWh. We might ask how long an averaging period would we require for the average wholesale spot price to approximate the LRMC? In this particular example, it takes 15 years for the weighted average annual wholesale spot price to come within 5 per cent of the LRMC. Apparently a relatively long time period is required to draw conclusions on differences between the average annual price and the Turvey LRMC.

So far we have seen that the model predicts sustained departures between average annual prices and the Turvey LRMC. We might also explore the sensitivity of the model to various assumptions. Is the Turvey LRMC sensitive to the assumptions we make in the modelling process?

Various scenarios are set out in the table below. For example, if we consider adding generation capacity in units of 800 MW (rather than 400 MW) we find that the Turvey LRMC is $71.91/MWh (scenario 4 in the table below) – an increase of approximately 40 per cent. If we add generation capacity in units of 800 MW, but start with more baseload generation capacity (say 2000 MW, rather than 1600 MW, scenario 7 below) we find the Turvey LRMC is $41.89/MWh (a reduction of around 20 per cent). These results suggest that the Turvey LRMC is somewhat sensitive to the underlying assumptions.

Scenario	Time periods (years)	Minimum generation capacity expansion (MW)	Baseload generation capacity (MW)	Demand change relative to base (MW)	Turvey LRMC	Year 1 average price
1	50	None	1600	0	$51.00	$51
2	50	400	1600	0	$53.40	$117.72
3	50	400	1600	+200	$49.81	$30.19
4	50	800	1600	0	$71.91	
5	50	800	1600	+200	$83.91	
6	50	800	1600	-100	$69.94	$30.19
7	50	800	2000	0	$41.89	$30.19
8	50	800	2000	200	$57.40	$30.19
9	50	20	1600	0	$51.32	$50.06
10	50	20	1600	200	$51.00	$30.19

The computation of LRMC discussed above related only to a permanent or baseload increment to demand. One of the points emphasised in the section above was that there is a separate LRMC for each generation technology (or, put another way, for each different change in the demand-duration curve). This can also be illustrated using the model above. Let's return to the case in which generation can only be added in 400 MW lumps. Let's consider a change in just peak demand (demand states 4 and 5 in the table describing demand above). The Turvey LRMC computed using the NERA methodology for this change in demand is $38.35/MWh. As footnote 5 suggests, this value can be compared to a measure of prices. The corresponding value in the benchmark network is $37.13/MWh. To convert this to the conventional LRMC that I am using in this note we need to divide through by the capacity factor of the associated generation. This yields a peak-generation LRMC of $1801.20/MWh which is relatively close to the theoretical value (for infinitely divisible generation) of $1743.96/MWh.

The scenarios above were computed using a publicly available linear programming problem (GAMS). It is possible to run small versions of these problems (for a time period of 10 years) on the free, demo version of GAMS. The larger versions of these problems (using the full 50 year time horizon) can be solved using free on-line GAMS services. The GAMS code to generate these results is reproduced in the Appendix. These models are relatively quick to solve. Even using 50 time periods, the execution time for each demand scenario using the on-line GAMS solver is reported as 0.007 seconds.

This section solved a set of explicit hypothetical scenarios to find the Turvey LRMC. The results here are merely illustrative. The model used here had five demand states and four generation technologies. If we change these assumptions, with more demand states, or more generation technologies, it is likely the results would change.

Conclusion

This note makes the following key points:

- NERA have proposed a test for market power which involves comparing annual average prices with the Turvey LRMC. NERA does not to my knowledge derive or prove a theoretical link between annual average prices and the Turvey LRMC. Neither does Turvey propose such a link. Understanding the theory behind such a link is essential if the Turvey LRMC is to be used as a test for market power.
- It is possible to derive a theoretical link between a form of average prices and a version of LRMC if we make certain simplifying assumptions (such as the assumption that generation can be added in infinitely-small amounts). The analysis set out in this paper suggests that for each generation technology, there is an equilibrium relationship between a long-run weighted average of expected prices when prices are above the variable cost of that generation technology and a measure related to the cost of that generation technology, which is often known as the LRMC of that generation technology. The Turvey measure of LRMC reduces to the LRMC measure in equations (2) and (3) under the assumption that generation can be added in infinitely-small amounts and under the assumption that we are focussing exclusively on baseload increments to demand.
- When generation capacity can only be added in discrete lumps there is no theoretical link between annual average prices in any given year and a measure of LRMC. The modelling carried out for this paper shows that when generation is added in discrete lumps the annual average price may lie above or below the LRMC measure for relatively long periods of time (5-10 years) even when the market is perfectly competitive. This calls into question the value of comparisons between average prices and a LRMC threshold as a test for the presence of market power.
- Over a long enough time frame, with unchanging generation technology, the weighted average of expected future prices appears to approach the Turvey LRMC value. The length of the time frame required will depend on factors such as the growth rate of demand and the size of the minimum generation increment. In the one example considered in this note, it took 15 years for the weighted average of annual expected prices to come within 5 per cent of the LRMC.
- Computation of the Turvey LRMC requires assumptions about the future path of demand, future generation costs, and future technological options, over quite a long time frame (50 years in the case of the analysis in this paper). The computed LRMC value can be sensitive to these assumptions, potentially giving rise to disputes.

The second part of this note focussed on applying the Turvey LRMC method under a specific set of assumptions. Further analysis could expand the range of assumptions considered here, such as more demand states, or more generation technologies. In particular, further work is needed on the application of the Turvey LRMC method in the presence of transmission constraints.

On the basis of the analysis in this note I conclude that there are theoretical and methodological issues which call into question the value of the Turvey LRMC concept as the basis for a price-cost test for the presence of market power.

Darryl Biggar

Appendix

The following is the GAMS code for solving the Turvey LRMC. This code can be run on GAMS on a local computer, or submitted remotely to a GAMS solver, such as http://www.neos-server.org/neos/solvers/milp:XpressMP/GAMS.html

```
*
*
* Computation of LRMC: Model 3
*
* This version assumes generation investment
* can only be added in discrete lumps
*
sets
  t time periods /1*50/
  i plant technologies /t1,t2,t3,t4/
  s demand states /s1*s5/
  ds demand offsets /d1*d4/

Option solprint=off, limrow=0, limcol=0 ;

Parameters

  VC(i) variable cost of plant type i in dollars per MWh
   / t1 1, t2 38, t3 100, t4 4000 /

  FC(i) fixed cost of plant type i in dollars per MW
   / t1 50, t2 40, t3 35, t4 0.001 /

  Prob(s) Probability of demand state s arising
   / s1 0.323345, s2 0.537043, s3 .118322, s4 0.015468, s5 0.005822/

  Initial_Demand(s) Initial load in state s
   / s1 1123.966, s2 1603.211, s3 2088.816, s4 2582.157, s5 3076.849/

  K(i) initial capacity of plant type i
*  / t1 1603.211, t2 485.605, t3 493.341, t4 494.692 /
*   / t1 1600, t2 480, t3 490, t4 2000 /
   / t1 1600, t2 480, t3 490, t4 2000 /

  Exp_Option(i) Expansion option for plant of type i in MW
   / t1 400, t2 400, t3 400, t4 400 /

  Demand_Offset(s,ds) Demand offset in MW
   /s1*s3.d1 0, s1*s3.d2 0, s1*s3.d3 0, s1*s3.d4 0,
    s4*s5.d1 0, s4*s5.d2 100, s4*s5.d3 200, s4*s5.d4 300/ ;
 ;

Parameters
   dr(t) discount rate to be applied in period t
   dgr growth rate of demand in percentage per year
   Demand(t,s) load at time t in state s ;

dgr = 0.01 ;
dr(t) = 1/(1+0.1)**(Ord(t)-1);

Variables
  dispatch_cost     total dispatch cost in dollars per hr

Positive Variables
  g(i,t,s) dispatch of plant type i at time t in state s in MW ;

* Binary Variables
```

```
Integer Variables
  b(i,t) invest in expansion option of plant type i at time t ;

Equations
  obj_function           objective function
  prod_limit(i,t,s)      output constraint on plant i at time t in demand level s
  energy_balance(t,s)    energy balance constraint at time t in demand level s
  sunk_investment(i,t)      constraint which forces an investment made to stay made
;
 obj_function ..  dispatch_cost =e= sum( (i,t,s),VC(i)*g(i,t,s)*Prob(s)*dr(t))

+sum((i,t),FC(i)*(K(i)+b(i,t)*Exp_Option(i))*dr(t));

 prod_limit(i,t,s) .. g(i,t,s) =l= K(i)+b(i,t)*Exp_Option(i) ;

 energy_balance(t,s) .. sum( i, g(i,t,s)) =e= Demand(t,s) ;

 sunk_investment(i,t+1) .. b(i,t+1) =g= b(i,t) ;

model optimal_dispatch /all/ ;

Parameters
  Price(t,s) Spot price at time t in demand level s
  Capacity(i,t) Capacity of type i at time t
  Profit(i,t) Annualised profit of plant i at time t
  Average_Price(t) Average price at time t ;

Loop (ds,
   Demand(t,s) = Initial_Demand(s)*(1+dgr)**(Ord(t)-1)+Demand_Offset(s,ds);

   solve optimal_dispatch using mip minimizing dispatch_cost  ;


   Price(t,s) = energy_balance.m(t,s)/Prob(s)/dr(t);
   Average_price(t) = Sum(s, Price(t,s)*Prob(s));
   Capacity(i,t) =  K(i)+b.l(i,t)*Exp_Option(i);
   Profit(i,t) = Sum(s, (Price(t,s)-VC(i))*g.l(i,t,s)*Prob(s))
              - FC(i)*Capacity(i,t);

   display dispatch_cost.l,Demand,Price,Average_Price,Capacity,Profit,dr;
   );
```