Short Run Marginal Cost

Discussion Paper

11 January 2008

Economic Regulation Authority
WESTERN AUSTRALIA

Important Notice

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For further information, contact:

Adam McHugh
Economic Regulation Authority
Perth, Western Australia
Phone: (08) 9213 1900

Contents

1 Introduction

This paper seeks to assist market participants in the understanding of SRMC. In doing so, it sets out to identify what costs may be included in a firm's short run portfolio supply curve calculation and how SRMC may be estimated.

Rules pertaining to the Wholesale Electricity Market (**WEM**) in Western Australia (**WA**) are, in part, designed to replicate the outcomes of a competitive market. Specifically, generators are required to offer electricity at the SRMC of production. Clause 6.6.3 of the *Wholesale Electricity Market Amending Rules (December 2006)* (referred to in this document as the **market rules**) states:

> 6.6.3. A Market Generator must not, for any Trading Interval, offer prices within its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity when such behaviour relates to market power.

The roles of the Economic Regulation Authority (**Authority**) and the Independent Market Operator (**IMO**) with respect to clause 6.6.3. are outlined in clause 2.16.9. and its various subclauses as follows:

> 2.16.9. The Economic Regulation Authority is responsible for monitoring the effectiveness of the market in meeting the Wholesale Market Objectives and must investigate any market behaviour if it considers that the behaviour has resulted in the market not functioning effectively. The Economic Regulation Authority, with the assistance of the IMO, must monitor:
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> …
>
> (b) inappropriate and anomalous market behaviour, including behaviour related to market power and the exploitation of shortcomings in the Market Rules or Market Procedures by Rule Participants including, but not limited to:
>
> i. prices offered by a Market Generator in its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;
>
> …
>
> 2.16.9A. The IMO must assist the monitoring activities identified in clause 2.16.9(b)(i) by examining prices in STEM Submissions, including Standing STEM Submissions, used in forming STEM Bids and STEM Offers against information collected from Rule Participants in accordance with clauses 2.16.6 and 2.16.7.
>
> 2.16.9B. Where the IMO concludes that prices offered by a Market Generator in its Portfolio Supply Curve may not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity and the IMO considers that the behaviour relates to market power the IMO must:
>
> (a) as soon as practicable, request an explanation from the Market Participant which has made the relevant STEM Submission; and
>
> (b) advise the Economic Regulation Authority of its conclusions. The IMO advice must outline the reasons for the IMO's conclusions.
>
> …
>
> 2.16.9G. Where the Economic Regulation Authority determines that prices in the Portfolio Supply Curve, subject to the investigation, did not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity, the Economic Regulation Authority must request that the IMO applies to the Energy Review Board for an order for contravention of clause 6.6.3.

> 2.16.9H. Where the IMO receives a request under clause 2.16.9G the IMO must refer the relevant matter to the Energy Review Board requesting that a civil penalty be imposed on the relevant Market Participant.

In summary, the Authority, with the assistance of the IMO, is responsible for monitoring the effectiveness of the market in meeting the Wholesale Market Objectives and must investigate any market behaviour if it considers that the behaviour has resulted in the market not functioning effectively. If a firm with market power submits a portfolio supply curve that does not reflect that firm's reasonable expectation of SRMC for any given trading interval and the Authority determines that to be the case, the matter must be referred by the IMO to the Energy Review Board requesting that a civil penalty be imposed on the relevant market participant.[1]

Discussion in this paper draws heavily on a technical paper entitled 'Portfolio Short Run Marginal Cost of Electricity Supply in Half-Hour Trading Intervals' (McHugh, 2008) a copy of which is available on the Authority's web site.

1.1 How to Make a Submission

Submissions on any matters raised in this discussion paper should be in written and (where possible) in electronic form and addressed to:

SRMC Discussion Paper
Economic Regulation Authority
PO Box 8469
Perth Business Centre
PERTH WA 6849

Email: SRMC@era.wa.gov.au
Fax: (08) 9213 1999

Submissions must be received by 29 February 2008.

In general, submissions from interested parties will be treated as in the public domain and placed on the Authority's web site. Where an interested party wishes to make a confidential submission, it should clearly indicate the parts of the submission that are confidential. For more information about the Authority's submissions policy, see the Authority's web site.

The receipt and publication of a submission shall not be taken as indicating that the Authority has knowledge either actual or constructive of the contents of a particular submission and, in particular, whether the submission in whole or in part contains information of a confidential nature and no duty of confidence will arise for the Authority in these circumstances.

[1] A firm's market power generally corresponds to its ability to influence the clearing price. Future work will focus on this concept more thoroughly.

Further information regarding this inquiry can be obtained from:

Ms Arian Lowe
Analyst
Competition, Markets and Electricity
Economic Regulation Authority
Ph (08) 9213 1900

Media enquiries should be directed to:

Mr Paul Byrne
Byrne & Byrne Corporate Communications
Ph (08) 9336 2081
Mb (0417) 922 452

1.2 Economic Efficiency

Economic theory labels a market as *efficient* if the net benefits (i.e. the total benefits minus the total costs) created in that market reach a notional maximum. An *inefficient* market wastes resources, either because:

a) more goods could have been created with the same amount of resources, and/or;

b) goods are not allocated in accordance with the tastes and preferences of consumers.

That is, in the short run, economic efficiency requires:

a) technical efficiency;

b) allocative efficiency, and;

c) in the long run, dynamic efficiency.

Under theoretical assumptions that describe a *competitive* market, efficiency will occur naturally. These assumptions are:

1) No market participant has the ability to independently influence the clearing price by virtue of market share or control (i.e. market power).

2) There is no strategic behaviour in the market.

3) All participants are able to make fully informed decisions.

4) There are no costs or benefits that accrue to third parties (i.e. externalities).

If these conditions are met, economic theory suggests that the price of electricity, or any other good or service, will fall to SRMC. That is to say, price will be set by the cost of the most expensive MWh of electricity produced during the relevant period of generation.

However, electricity markets are rarely, if ever, fully competitive. In the absence of sufficient competition, an alternative is to replicate the competitive (and therefore efficient) outcome through economic regulation and good market management.

Condition 3 above, for example, can be met by timely and centralised release of market information by a market operator (the IMO in the case of WA). Condition 4 can be met by taxes, subsidies or other forms of regulation that adjust the private costs of the firm so as to 'internalise' any external effects. This paper however, is concerned with conditions 1 and 2, which may, in theory, be met at relatively low regulatory cost by putting in place legislation that requires firms to offer their output at SRMC. Provided firms act in accordance with this rule (and provided conditions 3 and 4 are also appropriately managed), the resulting price will be one that equals SRMC at the efficient equilibrium between supply and demand.

1.3 The definition of short run marginal cost (SRMC)

The marginal concept in economics refers to the rate at which one quantity changes with respect to extremely small increases in another quantity. It follows therefore that SRMC is simply defined as *the change in short run total cost for an extremely small change in output*.[2]

[2] The smaller the change in output used as a reference, the more accurate will be the measure of SRMC.

2 Short run cost concepts

Since SRMC relates to the rate of change of short run total cost, an understanding of what constitutes short run total cost is a pre-requisite for determining SRMC. Once such an understanding is developed, SRMC can be derived mathematically. Statistical methods can then be employed enabling data to be entered into an optimisation model (see 'Portfolio Short Run Marginal Cost of Electricity Supply in Half-Hour Trading Intervals' (McHugh, 2007)). Unfortunately, a disparity between accounting concepts of cost and economic concepts of cost can often lead to confusion at the conceptual level. Part of the scope of this paper therefore is to state clearly the economic concept of cost relevant to the operation of a market.

The economic understanding of cost incorporates a number of fundamental concepts that are not immediately intuitive. These are:

- the distinction between the short run and the long run;
- the distinction between sunk and avoidable costs;
- the distinction between fixed, variable, shutdown, and total costs, and;
- the concept of opportunity cost.

This section has two purposes:

1) to describe the above concepts; and

2) to provide clarification as to what should be incorporated in the economic determination of SRMC.

2.1 The distinction between the short run and the long run

The distinction between the short run and the long run in economics is only superficially about any notion of duration or time. Rather, the distinction has more to do with whether or not there is full scope to substitute a more cost effective input for a less cost effective input.

An electricity generator that is able to choose any technique within budget for combining all the various inputs such as plant and machinery, fuel, labour, land, etc. has much more flexibility to minimise cost than a firm that is committed to a certain quantity of one or more inputs. If the price of one type of input changes relative to another, a manager with the full flexibility to utilise any affordable technique can simply choose one that employs less of the more expensive input and more of the cheaper one. If fuel becomes cheap, for example, it may become economic to sell off some expensive assets to provide the necessary cash to purchase more fuel: this is fuel input substituting for capital input.

Alternatively, with rising fuel costs, the installation of fuel saving equipment may become economic: this is capital input substituting for fuel input. When a firm is able to optimise its expenditure in any way it pleases, it is able to choose that *particular* mix of inputs that produce output at the minimum technologically feasible cost. *This can only occur over the long run, when the firm is free of any irrevocable commitments to input*. In other words, the long run is how long it takes for the technologically feasible mix of inputs to be able to be (re)arranged in any combination a manager pleases.

A firm that is irrevocably committed to quantities of one or more input type does not have the same flexibility. In this case the firm is said to face a *short run* decision. *In the short run, the firm must optimise as best it can given that it cannot vary certain quantities of input*. In other words, the short run means that a manager is stuck with some amount of input that cannot be swapped for a different type of input. A firm's portfolio of generating facilities, for example, cannot be varied in the short run. Similarly, sunk labour contracts constitute a short run constraint.

2.2 Defining economic cost: The opportunity cost concept

An economic decision is one in which the decision maker acknowledges all the *alternative opportunities* that are available to create benefits. The question that is always asked in a rational economic decision is therefore "what do I have to give up by taking this course of action?" which is equivalent to asking "is this course of action going to create more net benefits (profit) for myself (my firm) than any other possible course of action?". If the answer to this second question is "yes" then the choice is an *economic* one. If the answer is "no", then the choice is *uneconomic* because an opportunity to create greater net benefits has been forfeited. All economic costs incorporate this notion of opportunity cost.

Since an economic decision takes into account the benefits that have to be given up to achieve *greater* benefits, a further, economically important, question must be asked: "what net benefits (profit) would I have created for myself (my firm) if I had taken the next best course of action?". This question defines the concept of opportunity cost. An opportunity cost is a *potential* benefit that is forgone to create greater benefits. The opportunity cost of an input decision is therefore equal to the benefits that could have been derived from employing resources in their next best use.

To clarify the economic concept of cost, consider the following example. A generating plant, if started, will bring in revenue of $1.2M over a period. If the operating costs over that period were to include past fuel expenditures of $0.6M plus other expenditures of $0.4M, it could be said that the plant would make a $0.2M accounting profit.

However, before committing to operating the plant, it is appropriate to ask: "what alternatives are there?". If the value of the fuel required to operate the plant rose on the current spot market to $0.9M, assuming the firm has the opportunity to sell the fuel, the choice to produce electricity would be uneconomic. In this case, the firm could make an accounting profit of $0.3M by selling the fuel as opposed to a $0.2M accounting profit by selling electricity. In other words, the firm would profit by $0.1M more by selling the fuel and not operating the plant. In *economic* terms, if the plant were to operate it could make an economic loss of $0.1M.

As the above example suggests, the past purchase price or past contract price of fuel does not represent a short run economic cost. Rather, the current price that can be obtained by on-selling a quantity of fuel represents what is given up by using it to produce electricity. It follows that if the fuel cannot be immediately on-sold then the opportunity cost of that fuel for a firm in a competitive market may be zero unless there exists a real prospect to either: (a) sell the fuel at some point in the future; or (b) use the fuel in the future production of electricity at higher than current market values.[3] In either case, the current spot price, or alternatively the current market price for fuel contracts, still provides the best basis for the opportunity cost of fuel because the current price reflects the rational expectations (based on the latest information available to the market) of all future prices for the resource. However, this forgone benefit would need to be adjusted downwards by storage costs, inflation, and the interest that could have been earned while waiting for a buyer if the fuel had been converted to cash immediately.

2.3 Sunk costs

As stated in Section 2.1, firms in the short run face either technological or contractual commitments to input. In economics, the costs associated with these commitments are considered *sunk*. They cannot be avoided or reversed in the short run.[4]

Importantly, *the economic cost of a sunk commitment is zero*. As already stated, opportunity cost describes the potential benefits that are forgone by employing a resource in its next best alternative use. By definition, expenditures that are sunk have no alternative use since they cannot be avoided in the short run. It follows that sunk costs have no influence on economic decision making in the short run. Rather, the short run decision is entirely about current expenditure on marginal operating costs compared to market price.

Take, for instance, the decision to build a gas fired power station as opposed to the decision to sell electricity from a gas fired power station that has already been built. The former is a long run decision: the firm must decide whether it believes the investment will be worthwhile based on the present value of the expected flow of future revenues and costs, with the certainty of revenue and cost flow typically guaranteed by long run contracts with take-or-pay provisions (so as to ensure the recovery of sunk costs).

Once the plant is built however, the decision as to how much electricity should be produced becomes a short run decision and the plant's construction costs become relegated to the past. In a competitive market, the firm would face a market price that it cannot control: a "take it or leave it" proposition. Therefore, the optimal economic decision for determining how much electricity should be produced, over and above that for which take-or-pay contracts may exist, is determined simply by whether supply of an additional MWh increases the firm's bank balance or decreases it. This depends solely on whether or not the price that is available for incremental amounts of electricity exceeds the immediate costs of production.

Figure 2.1 provides an example. A firm operating in a competitive market is offered a price of $30 per MWh to supply electricity. If the various current expenditures that the firm must outlay to produce incremental MWh's of electricity are lower than $30, the sale of that electricity will see the firm's profits going up. If, however, an incremental MWh of supplied electricity entails more than $30 of current expenditure, the firm's profits will get

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[3] It is noted that if plant is withdrawn as a result of fuel being withheld then penalties, including withdrawal of capacity credits under the Reserve Capacity Mechanisms, may apply and would need to be taken into consideration. Note, however, that from the regulator's point of view it would be inappropriate to include regulatory penalties in the calculation of SRMC under the legislated SRMC approach as this would result in increased prices, thus reducing the incentives the penalties are intended to instil in producers.

[4] In the long run there are no sunk costs because, by definition, there are no irrevocable commitments to input. There are, however, redundant investments, the scrap value of which may be equal to or close to zero.

progressively smaller for each additional MWh produced. Thus, while the value of the firm before the short run decision is made will have been affected by past decisions on capital expenditure, the amount previously invested will have absolutely no bearing on the best decision that the firm can make *today* to see that the value of the firm heads in the right direction. If, for example, the firm seeks to recover all of its capital costs by asking for a higher price, the buyers in a competitive market will simply get their electricity elsewhere.

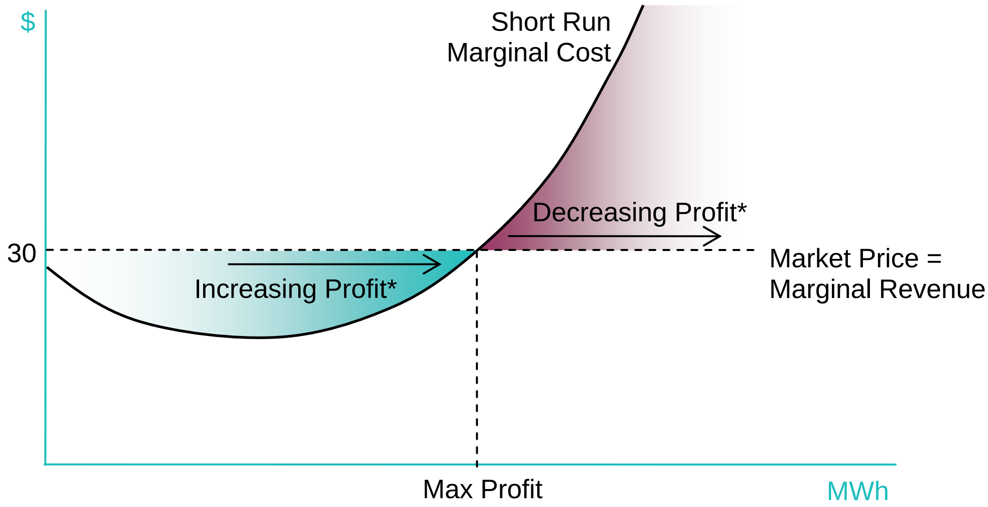

Figure 2.1 – Profit maximising short run supply decision in a perfectly competitive market

* Note: the short run marginal cost curve does not account for avoidable fixed costs such as those associated with the start up of a plant during a trading interval. These must be subtracted from any profit or added to loss for the trading interval. Avoidable fixed costs are independent of output and incurred as a lump sum. They differ from sunk costs in that the latter are incurred prior to the current trading interval and so are unavoidable in the current trading interval.

To define in summary:

- **Sunk costs**. A sunk cost is a fixed cost that cannot be avoided in any given (short run) time period.

2.4 Avoidable costs

An avoidable cost is an expenditure to which the firm is *not* irrevocably committed or that can be reversed over the time period in question. Therefore, unlike a sunk cost, the economic (opportunity) cost of an avoidable cost will be of positive amount because the money or the resources saved by avoiding the cost could potentially be used to generate benefits elsewhere. Avoidable costs can be broken down as follows:

- **Avoidable fixed costs.** An avoidable fixed cost is an expenditure that must be borne by the firm if it chooses to produce any amount of output in a given time period. That is, an avoidable fixed cost is an expenditure that remains constant for any level of output above zero but that can be avoided by producing zero output. An avoidable fixed cost should not be confused with a sunk cost, which cannot be avoided in the short run even if the firm were to choose not to produce.[5] The most relevant avoidable fixed cost in the context of electricity production is the cost of starting a plant.

- **Shutdown costs.** A shutdown cost is expenditure that must be borne by the firm if it has invested in plant, is operating that plant and chooses to produce zero output in a given time period. A shutdown cost is therefore the opposite of an avoidable fixed cost in that it can only be avoided by producing non-zero output. In the context of electricity production, a plant already operating in a half hour trading interval will suffer a short run shutdown cost if demand for its output does not equal or exceed its minimum technical output (**mingen**).[6] The shutdown cost corresponds to the maximum amount a firm would be willing to pay to avoid the shutdown. This will include any loss in net revenue that could be avoided if the plant remained operational.
- **Variable costs.** A variable cost is a cost that varies with the level of output (beyond mingen) that the firm produces over the relevant time period. Prominent variable costs in the context of electricity production are fuel costs, operating costs, costs associated with wear and tear on plant and equipment. These costs may either vary directly in proportion with output or otherwise change in steps as output increases (e.g. labour costs). Most variable costs increase with output but there are some that decrease with output (i.e. some variable costs are avoidable in the short run by producing higher levels of output). If, for example, an electricity generator has commitments to provide steam to nearby industries, any per unit amount of compensation that they must pay to that firm if they do not provide the steam constitutes a decreasing variable economic cost.
- **Total cost.** Total economic cost is the variable cost for a given level of output plus any avoidable fixed costs or shutdown costs. Sunk expenditures are also a component of total cost, but because they have a zero opportunity value they do not affect its calculation.

Figure 2.2 describes a taxonomy of cost categories consistent with the discussion above. Figure 2.3 provides sequential questions that enable a clear categorisation of the short run total cost components outlined in this section.

5 While all sunk costs can be considered fixed costs, not all fixed costs are sunk (see Wang, H. & Yang, B (2001), "Fixed and Sunk Costs Revisited", *Journal of Economic Education*, Vol. 31, No. 2, Spring, pp. 178-185).

6 Mingen is the minimum amount of output (and hence input) required to keep a plant running.

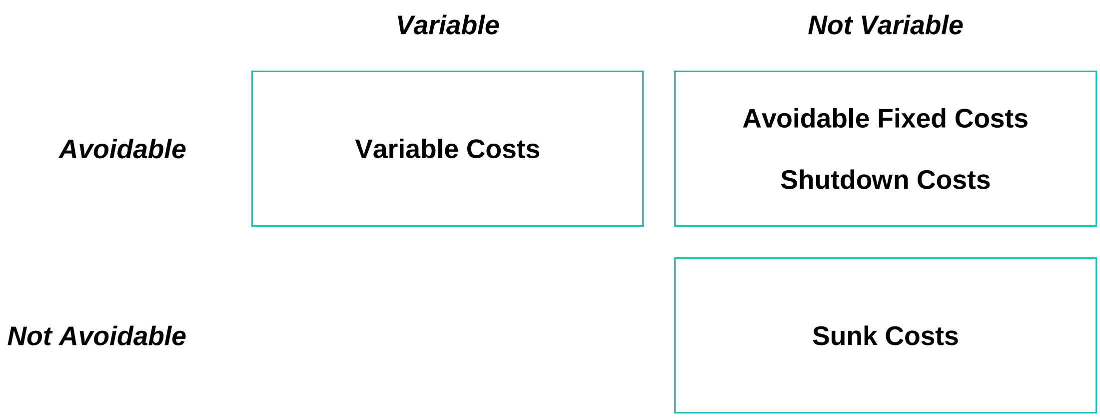

Figure 2.2 – Categorisation of short run economic costs associated with electricity generation with given examples.

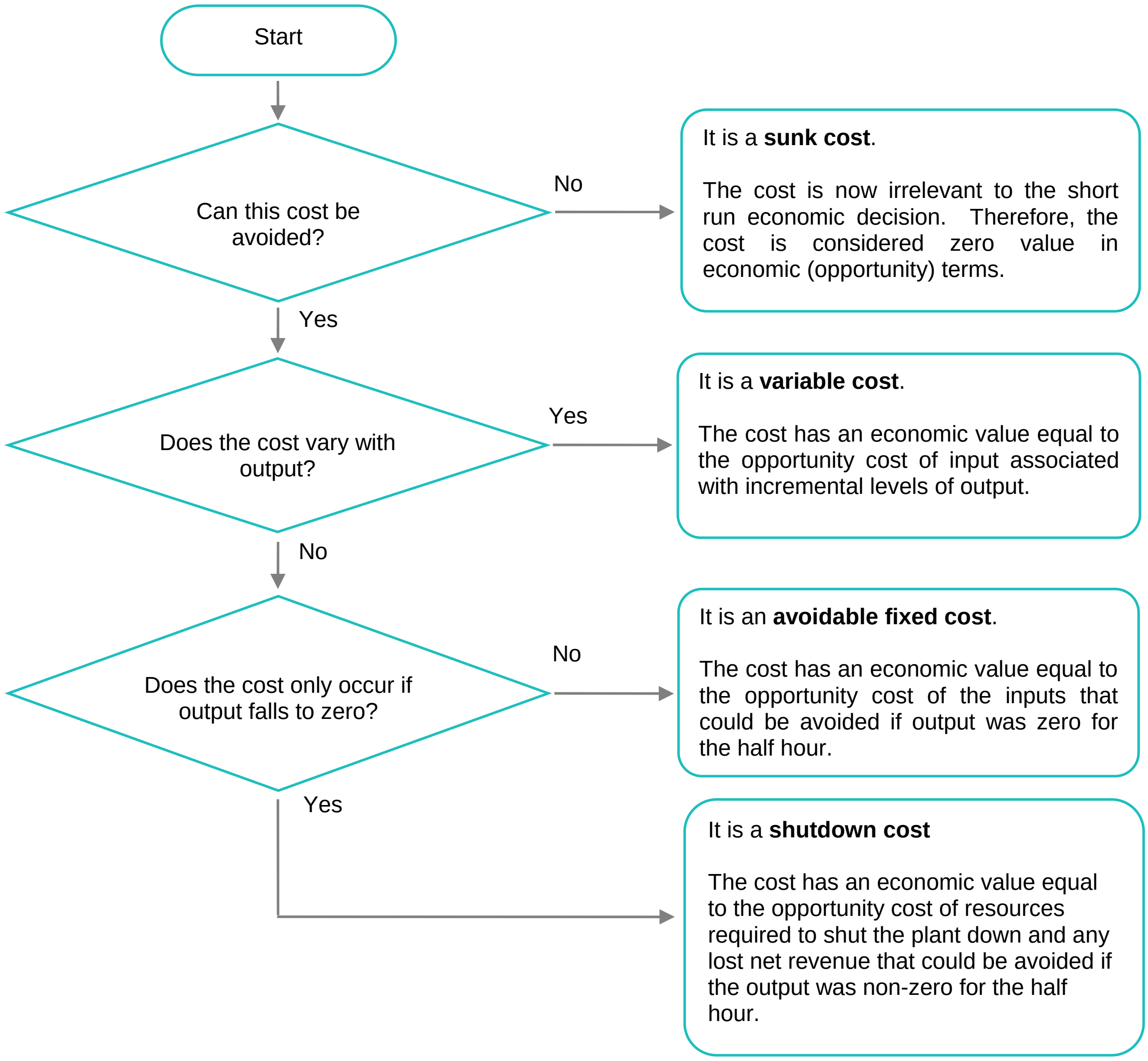

Figure 2.3 – Sequential question method of categorising the components of short run total economic cost for a half hour trading interval.

Below are examples of the costs included in each of the categories identified in Figure 2.2 above.

Variable costs

- Wear and tear on plant and equipment directly attributable to the production of output.
- The expected costs of plant failure - i.e. the probability of plant failure multiplied by the cost of plant failure, where the probability of plant failure increases with the level of output.[7]
- Value of saleable fuel (at the current market rate) used to produce electricity output.
- Value of water and other inputs used to produce electricity output.
- Costs as a result of per unit financial penalties imposed for not meeting contracted output commitments.[8]

Avoidable Fixed Costs

- Fuel, water and other operating costs of starting a plant within the current trading interval.

Shutdown costs

- Fuel, water, and operating and maintenance costs of shutting a plant down within the current trading interval.
- Lost net revenue in future trading intervals as a result of the plant lying idle while awaiting future start up (as opposed to incurring costs resulting from the plant operating at mingen).
- Includes costs associated with a future start up minus mingen costs over the intervening period (adjusted for any avoided cost of base load).

Sunk costs

- Capital cost of plant and equipment.
- Cost of starting a plant prior to the current trading interval.
- Cost of fuel purchased on long term contracts that cannot be on-sold to third parties.
- Labour costs (apart from avoidable labour costs, such as overtime).[9]

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[7] Such costs are associated with unplanned maintenance and include not only repair costs, but also lost net revenues as a result of plant unavailability, as well as financial penalties imposed for unscheduled outage. It should be noted that if the probability of unplanned outage is not correlated with high levels of output, the risk of equipment failure becomes an avoidable fixed cost as opposed to a variable cost.

[8] Note: where such costs relate to regulatory penalties intended to influence a firm's private decision (e.g. penalties for not meeting obligations under the reserve capacity mechanism or for renewable energy certificates) they are not a cost a regulator would allow to be included in SRMC calculations.

[9] Because the hiring of labour occurs over periods longer than a half hour or even a day, such costs are sunk in the short run.

3 Unit commitment

The time it takes to start plants up and shut them down again constrains the availability of various plants for any given trading interval and therefore affects the day ahead estimation of portfolio SRMC. It is reasonable to assume that this unit commitment decision is motivated by the dual incentives of reliability and profit. Therefore, the unit commitment plan, under the assumption of profit maximising behaviour, becomes the foundation upon which a reasonable expectation of portfolio SRMC is built. What follows in this section is a brief discussion of unit commitment considerations and how these impact upon the reasonable, day ahead, expectations of half hourly economic cost.

3.1 Short run time frames: The 24 hour trading day and the half hour trading interval

By the very nature of the product, the scheduling of electricity supply must be considered with reference to very small time intervals. This is because electricity dispatch requires a near perfect instantaneous balancing between supply and demand otherwise the system will move outside of a narrow technical envelope and collapse at great cost.[10] Consequently, market equilibrium is an engineered solution in the first instance and the economically efficient price the retrospective determination of a market operator.

Typically, an electricity market is cleared on a half hourly basis (or more frequently), involving both planned and real time events. In Western Australia, market participants submit portfolio supply and demand schedules on a day ahead basis to the IMO. Electricity generators, therefore, make economic short run decisions that correspond to strictly predefined temporal bounds. The predefined bounds in the Western Australian WEM are a 24 hour trading day (8am to 8am) divided up into 48 half hourly trading intervals. To the extent that real time events differ from the submitted day ahead portfolio supply and demand schedules, a balancing mechanism settles any differences.

3.2 Linkages between unit commitment and short run economic cost

In the State's wholesale electricity market there are essentially two relevant short run questions facing electricity generators:

1) How should resources be allocated over the trading day?

2) What is the profit maximising output for each half hour trading interval?

These two questions are inextricably linked. If the primary goal of the firm is to maximise profit over the trading day, this can only be achieved under competitive conditions if the SRMC of electricity supply is set at marginal revenue in each half hourly period. However, the optimal allocation of resources through the trading day will affect the SRMC of supply in each trading interval. The profit motive will cause a firm to attend to this allocation of

[10] Electricity supply tolerances are defined and regulated in technical rules, which are very narrow to maintain the integrity of the system. Electricity market equilibrium is therefore quite artificial and heavily dependent on engineering and information technology for its existence.

resources, known as unit commitment, as efficiently as possible. Hence, the assumption of profit maximising behaviour by a firm simplifies analysis.

The profit motive, however, can be a two edged sword. While it provides firms with the incentive to minimise their costs of production, a profit maximising firm with the ability to raise price by virtue of market power can extract excessive profits at the expense of consumers, resulting in less net benefits for society as a whole. This is to say that in the presence of market power the profit maximising level of output will not be economically efficient.

A firm operating in a competitive (efficient) market, however, would find the profit maximising level of output occurs where price equals SRMC in each half hour trading interval. This would produce a socially optimal outcome.[11] The approach taken in the WEM is to attempt to replicate this outcome by requiring generators to submit their electricity supply offers so as to reflect SRMC in each trading interval. To the extent this can be implemented, enforced, and provided the economic definition of cost is used, the level of profit will reflect an efficient market outcome thereby arresting the problem of market power.

3.3 The mix of generation technologies

Figure 3.1a shows a typical diurnal pattern of electricity output. Given the periodic pattern of demand a mix of technologies is required to continuously balance system output with load over a trading day. Generation technologies can be categorised as either intermittent, base-load, mid-merit or peaking plants. The following characteristics generally apply:

a) Currently, plants that use intermittent resources such as wind and solar provide a relatively uncertain (stochastic) level of output in a trading interval, but have zero fuel costs and so are typically the lowest SRMC plants. This is particularly likely to be the case where environmental and technological regulations such as renewable energy certificates, tradable pollution permits, and/or carbon taxes are significant.

b) Base-load plants have low variable costs but high startup and shutdown costs, and have a relatively limited capability to ramp output up or down to follow load. Base-load generation in WA often uses coal to produce steam to be converted into electricity.

c) Mid-merit or load following units are normally medium cost plants both in terms of variable cost, startup cost and shutdown cost, and are quite effective at adjusting (ramping) output up or down to cover reasonably rapid changes in demand. In WA mid-merit plants are usually natural gas fuelled turbines or co-generation plants.

d) Peaking plants in WA are typically based upon gas turbine technology. These units are very effective at following load and can be started up and shutdown quickly and cheaply. However, they are usually the highest variable cost plants in a portfolio, particularly when distillate is used as the fuel input.

[11] Assuming any externalities are internalised through supplementary government policy.

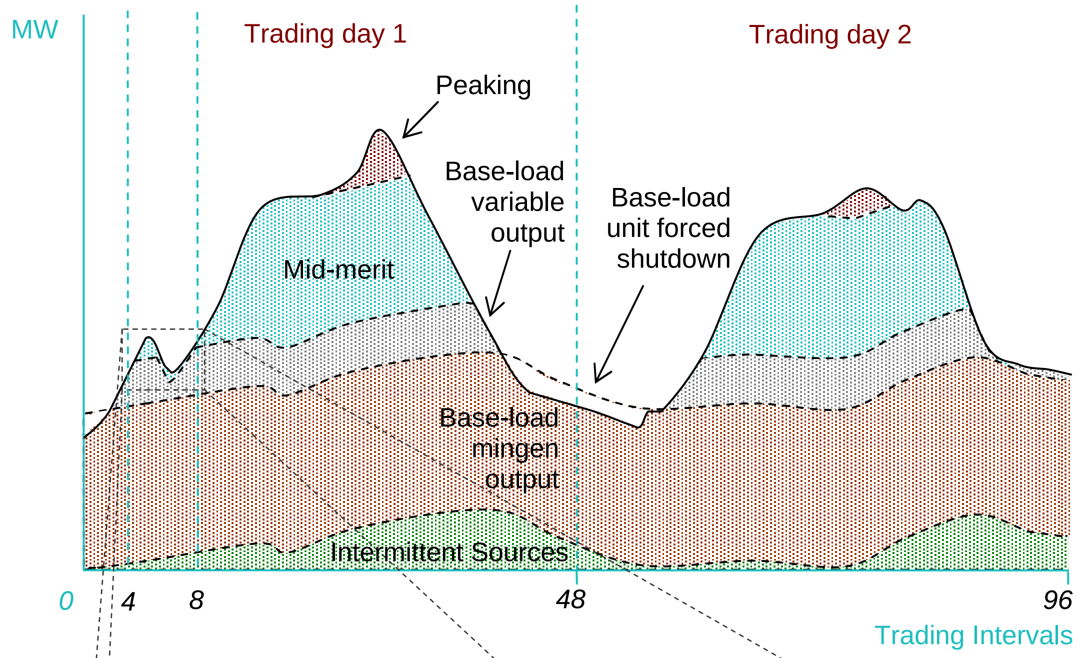

Figure 3.1a – Electricity output over two trading days

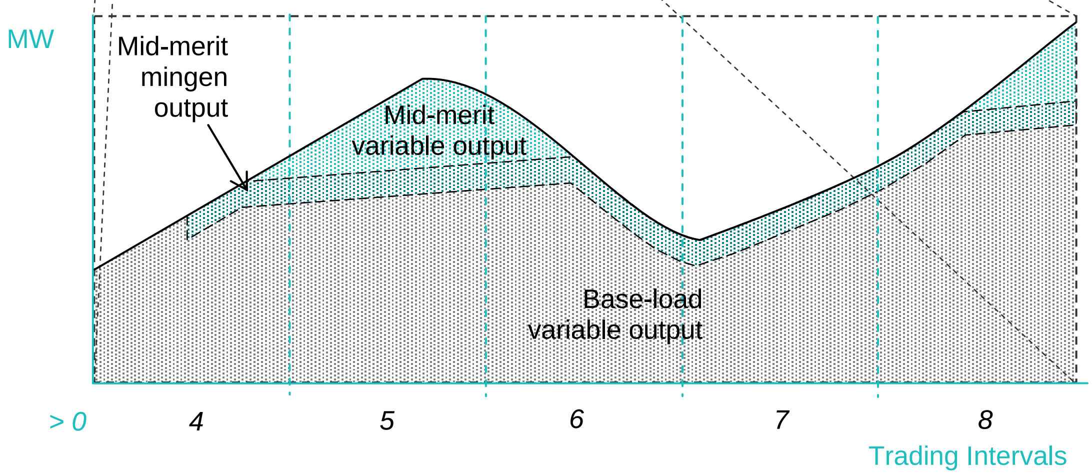

Figure 3.1b – Electricity output over five trading intervals

3.4 Shutdown costs vs. mingen costs

In maximising profits over a trading day, a critical consideration is the comparison between the cost of a future startup for a plant (which can be large) and the cost of keeping the plant running at mingen over the intervening period. The primary example is base-load generation. Whenever possible, coal fired base-load facilities will continue to operate even when electricity demand is low. This is because the costs associated with shutting a coal fired base-load plant down are large.

The opportunity costs of forcing such a plant below mingen will include not only the immediate costs associated with taking the plant offline but also the cost of starting the plant up again when it is required.[12] The time that it takes to have such a plant come back into operation can be considerable. If this causes the plant to be unavailable when it is needed there will be an additional opportunity cost associated with lost revenue in future trading intervals while the plant is lying idle. In other words, while within the trading interval it may be cheaper to shut a plant down than to run the plant, it may not be the best decision over the trading day. Therefore, the impact on cost in future trading intervals must be considered in the current decision. For this reason, and for reasons of security and reliability, coal fired plants are, ideally, only shut down for scheduled maintenance.[13]

Figure 3.1a shows a typical diurnal pattern of electricity output. Given the periodic pattern of demand, the previous startup of a plant (i.e. in a prior half hour trading interval) constitutes a sunk expenditure over the short run time period of half hourly electricity supply. That is, once a plant is started, the associated expenditure is committed and can no longer be avoided. Conversely, the costs of operating a plant at mingen or above are not sunk because they can be avoided by shutting the plant down for the relevant half hour trading interval. Note, however, that the shutdown cost can be either greater than or less than the cost of operating at mingen, depending on the particular technology involved. Where the cost of operating a plant at mingen is substantially lower than the cost of shutting the plant down, a shutdown decision over a temporary period of low demand may prove uneconomic. In any case, the standard opportunity cost criterion applies: the value of resources in their alternative use should be fully accounted for. For example, the decision as to whether the mid-merit plant in Figure 3.1b should be shutdown prior to trading interval 7, or alternatively, left operating at mingen, would have to account for the avoided cost of variable base-load (that is, the cost of base-load output the mid-merit plant will offset if it is not shutdown).

3.5 Time averaging of cost estimations

Technological (metering) constraints typically require electricity output to be measured in units of power. Conversely, market measures of electricity supply require a comparison to be made between price and energy. As such, a suitable method must be adopted to bridge between inter-interval representations such as Figure 3.1a and Figure 3.1b (which give electricity output in units of power on their vertical axes against time on the horizontal axis) to intra-interval representations such as Figure 2.1 (which gives electricity output in units of energy on the horizontal axis against monetary units on the vertical axis).

However, because electricity supply systems require output to be continuously balanced against load, it is extremely unlikely, given the volatility of electricity demand, that the system's output will be constant with time, even over small trading intervals. As a result some degree of time-averaging will be required to convert dynamic electricity supply data (i.e. power with respect to time over a trading day), to static, economic, representations of electricity supply (i.e. energy with respect to price over a trading interval). This is likely to

[12] To avoid costly damage to steam turbines associated with expansion and contraction, venting steam at low demand is not an option for most base-load plants. If this were technologically feasible, it would be cheaper to operate a coal fired base-load plant at mingen and vent steam during periods of low demand for electricity rather than shut it down.

[13] The costs alluded to here can be avoided if a firm commits itself to a low (possibly negative) bidding strategy that ensures dispatch. This can be thought of as a payment to the market that ensures against another producer dispatching energy into the system. This discourages alternative sources of supply enough to enable the base-load plant to be kept above mingen. A profit maximising firm would be willing to pay the market up to the opportunity cost of shutting the plant down not to supply electricity.

produce a level of inaccuracy in cost estimations whenever mid-merit plants and, in particular, peaking plants, which have the ability to ramp output up or down relatively quickly to follow load, are required to be operated to a high degree of intra-interval variability in output.

A related constraint arises because of the relative inability of some power stations to ramp output up or down quickly enough to respond to rapid fluctuations in electricity demand. As already mentioned in Sections 3.3 and 3.4 above, base-load plants are designed to operate continuously, typically at their rated capacity, and are only shut down for planned or unplanned maintenance. Moreover, while some base-load power stations are able to be run at reduced output, others cannot ramp output up or down at all, and those that can vary output will do so at a much slower rate than mid-merit and peaking plants. Therefore, there is likely to be a limit to a base-load plant's feasible variability in output from one trading interval to the next. In this way, optimisation of plant and equipment over the trading day may impose limits to the range of output that some plants can offer for particular trading intervals.

Finally, it should be noted that demand cannot be perfectly predicted a day ahead, and the optimal allocation of generation resources is required to be reactive to market conditions in real time. Therefore, plant availability, and the range of output deemed to be available from particular plants, may need to be adjusted to reflect response time considerations.

4 Determining SRMC

4.1 Plant SRMC

It is important to reiterate here that the information given in Section 2 (above) pertains to the determination of short run *total* cost, and that SRMC is not short run total cost itself, but its *rate of change*. Therefore, determining a plant's SRMC is the same process as asking the question: by how much does short run total cost change if a plant's output is increased by a single MWh? If, for example, a plant can produce 100 MWh in a half hour trading interval at a cost of $5,000, or can produce 101 MWh in a half hour trading interval at a cost of $5,040, the SRMC of the 101st MWh for that plant will be $40.

Typically, a plant's short run total cost is a monotonically increasing relationship between price ($) and output (MWh) for a half-hour trading interval. However, there are some cases where short run total cost will *decrease* over a range of output (for example: as a result of shutdown costs or contractual obligations with per unit financial penalties for not meeting a predefined level of output).[14] Unless such a decreasing relationship exists, SRMC will be of non-negative value across its whole range.

The standard approach is to depict the SRMC curve as U shaped for a single plant. However, there are some industrial processes for which a plant's SRMC will not be U shaped: SRMC may, for example, increase linearly with output or stay flat up to the capacity of capital in place. A U shaped SRMC curve for plants would be expected if the thermodynamic properties of fuel burn (i.e. an initially improving thermal efficiency without output to a maximum, beyond which thermal efficiency decreases with output) is the predominant determinant of a plant's SRMC. Where the risk of equipment failure and therefore unplanned outages increases substantially with higher levels of output, an increasing SRMC curve is likely in that case. Essentially, this becomes an issue of measurement. Hence legislative powers, and the cooperation of market participants in data collection, are of critical importance to the Authority in carrying out its obligations under clause 2.16.9 of the market rules.

4.2 Portfolio SRMC

The construction of the portfolio short run total cost curve optimises the share of portfolio output across plants so as to minimise the total cost of generating electricity to meet the distribution of demand across the network. This can only be achieved once a set of short run total cost curves are built up at the level of individual generating facilities after accounting for line losses. An optimisation process is then used to construct a *portfolio* short run total cost curve from this set of curves, with the rate of change of this curve describing portfolio SRMC. The optimal proportion of each plant's contribution to portfolio output will vary as portfolio output varies.

The shape of SRMC curves for individual plants is paramount in determining the shape of the portfolio SRMC curve. If the portfolio consists of plants with U shaped SRMC curves, choosing the optimal mix of generation out of the portfolio will lead to a 'saw tooth' shaped portfolio SRMC pattern. In other words, portfolio SRMC will not be a monotonically

[14] For more detail on this subject, please see McHugh (2008), *Portfolio Short Run Marginal Cost of Electricity Supply in Half Hour Trading Intervals*, Economic Regulation Authority, Western Australia.

increasing function. If, however, the portfolio consists of plants with monotonically increasing SRMC curves, the portfolio SRMC curve will also be a smoothly monotonically increasing function. Finally, if plants tend to have a flat SRMC curve up to its capacity, the portfolio SRMC curve will comprise a step function made up of the plants in a SRMC order of merit. The concept of a 'marginal plant' can only apply in this latter circumstance. In the first two scenarios, portfolio optimisation equalises the marginal cost of each plant so that all plants are 'equimarginal'.[15]

[15] For any given level of total output in a production process with more than one cost component, the total cost of the process is minimised if the marginal costs of each of the cost components are equal.

5 Conclusions

In the WEM, and in wholesale electricity markets more generally, an efficient rationing of scarce resources will only occur if: (a) generators are paid their marginal costs of production, while; (b) consuming firms pay (equivalent to) a competitive price for their business inputs. In other words, efficiency will only occur if the wholesale price of electricity equals its SRMC of supply. A wholesale price above SRMC will lower the wealth generation potential of the market as a whole. Critically, given that no market operates in isolation, an inefficient wholesale electricity price will distort the broader economy, leading to a widely distributed loss of wealth.

The presence of market power in the WA electricity industry has resulted in regulation intended to replicate the outcomes of a competitive market. Clause 6.6.3 of the market rules requires generators to offer their electricity at a price that reflects their reasonable day ahead expectations of SRMC. These offers must be submitted as a portfolio supply curve in an increasing sequence of steps and under the constraint of price floors and fuel specific price caps. Clause 6.6.3 of the market rules requires generators to offer their electricity at a price that reflects their day ahead expectations of SRMC.

SRMC modelling has great potential in delivering commercial gains through improvement in business operations that have not yet been exposed to the rigour of a competitive market. Developing an understanding of a generator's cost structure should, therefore, be seen not only as a social benefit but also as a private benefit to market participants. Projections suggest that the current condition of acute market power is likely to persist in the WEM in the medium term at least, with acute market power defined as the absolute majority share of installed capacity in the SWIS by a single generating firm. Hence the SRMC monitoring approach appears likely to remain a key part of the regulatory regime for some time.

The information provided within this paper is intended to improve the understanding of the SRMC concept within the Western Australian electricity industry. Clearly, information flow of this nature is requisite for the effectiveness of clause 6.6.3 of the market rules. Likewise, a flow of information in the opposite direction (i.e. from market participants to the Authority) will be of critical importance. Legislative powers granted to the Authority under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* provide the Authority with an ability to request such information. The quality of the data remains an area of priority. However, provided the data input is sound, the modelling techniques developed by the IMO and the Authority in conjunction with this paper place the Authority in a good position to determine a firm's reasonable expectations of portfolio SRMC.

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