Barriers to exit for electricity generators in the NEM

A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET COMMISSION

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Background

Frontier Economics has prepared this report with solicitors Johnson Winter & Slattery for the Australian Energy Market Commission to examine whether there are barriers to efficient and orderly exit for electricity generators from the NEM and, if so, the effect of these barriers on economic efficiency. This report:

- Identifies various stages of generator exit and the incentives and rationales for pursuing operational strategies that involve partial closure and
- Identifies and assesses potential barriers at each of the various stages of exit.

Definition of barriers to exit

Economists define barriers to exit as "costs or foregone profits that a firm must bear if it leaves an industry". This definition includes both direct costs of exit as well as indirect opportunity costs that would be borne by plant that exit. The latter category may be interpreted in a way to encompass colloquial notions such as 'first-mover disadvantage', but may not capture all potential reasons why firms making operating losses fail to exit. Economists have also studied circumstances in which firms in declining industries may exit inefficiently.

Implications of barriers to exit

The key implication of barriers to exit and inefficient exit in declining industries is that exit may not occur at the time and in the manner that is socially optimal. This in turn implies a loss of overall economic welfare relative to a world in which exit was socially optimal. If this occurred, it would deny the community access to the cheapest form of production and access to the latest technologies and this could in turn undermine innovation in the economy. Whether barriers to exit are likely to harm economic efficiency will depend on both the barrier in question and at what point – *or in respect of what decision* – inefficiency is to be assessed. Where decisions have previously been made that cannot be costlessly reversed, those past decisions need to be taken as given in assessing whether future decisions are efficient.

Direct and indirect costs of exit

Direct costs refer to obligations to make incremental payments or expenditures as a result of pursuing a partial, temporary or total closure of a plant. The key types of direct costs attributable to partial and/or temporary shut-downs of generators are preservation and reinstatement costs. The key types of direct costs attributable to full closure and exit are site remediation costs and staff redundancy costs. The extent of remediation required will depend on the terms of the instrument imposing the rehabilitation obligation.

Indirect opportunity costs refer to profits foregone by a firm if it leaves an industry. For a typical generator, such foregone profits would be based on the operating profits the generator could expect to earn on its plant if it continued operating *less* the proceeds (if any) from the sale of its plant and the expected return on those proceeds.

The indirect opportunity costs of exit – and hence the barriers to exit – would be higher to the extent that:

- a generator's decision to remain in operation could lead to other generators exiting the market and a higher wholesale price than which currently prevails
- a generator's fixed costs are truly 'sunk'
- a generator has entered into non-tradeable 'take-or-pay' contracts for its inputs and
- a generator expects it could receive government inducements to exit at some later point in time.

Efficiency implications of various barriers to exit

Site remediation obligations should reflect no more than the efficient level of remediation. Whether remediation obligations encourage efficient exit will depend on whether the generator retains the proceeds from the disposal of the site (if any) and the subsequent use to which the site is to be put. Whether staff redundancy costs impose an inefficient barrier to exit depends on whether those costs reflect the outcomes of a previous efficient bargaining process. Where a generator reasonably considers that its continued operation will result in the exit of other generators, a decision to continue operating may not be *ex ante* inefficient; but it could if it leads to lower-cost plant exiting first. The existence of sunk plant or fuel contract costs will not give rise to inefficient exit decisions *given those past decisions*.

Exit by stage and generator type

In general coal-fired generators face higher direct cost barriers to partial and complete exit than OCGT and CCGT plant. Due to the risk of thermal fatigue, coal-fired plant take longer to start-up after a period of being non-operational and they take longer to prepare for short- and long-term mothballing in the event of seasonal or more lengthy shut-downs. Coal-fired generators will also tend to have relatively high opportunity costs of exit due to having lower operating costs than OCGT and CCGT plant. Hydro and renewable generators tend to have high fixed costs and low variable costs, implying that they are likely to be the last generator type to be mothballed or decommissioned as a consequence of low prices. Site remediation costs are likely to be relatively low for renewable plant but potentially very high for hydro-electric plant.

1 Introduction

We have prepared this report for the Australian Energy Market Commission (AEMC) to discuss the nature of potential barriers to exit for generators in the National Electricity Market (NEM). The COAG Energy Council requested advice from the AEMC on barriers to generation exit in April 2015.[1]

The NEM presently has more electricity generation capacity than is required to meet current and forecast demand. This excess generation capacity is the result of reductions in demand for electricity over the last 5-7 years and ongoing subsidised investment in renewable generation plant as a result of the Renewable Energy Target (RET) and various solar rebate and energy efficiency schemes.

The AEMC is aware that some stakeholders are concerned that there are barriers to exit for electricity generators in the NEM. Stakeholders appear to be concerned that:

- These barriers may prevent efficient exit of certain generators
- The absence of a supply-side response to the lower demand being experienced in the NEM may result in lower wholesale electricity prices than would otherwise prevail and
- The lower wholesale prices may cause efficient generators to exit the market.

If this sequence of events were to occur, it would be to the detriment of the National Electricity Objective.

1.1 Our engagement

Frontier Economics has been engaged by the AEMC to report on whether there are barriers to efficient and orderly exit for electricity generators from the NEM and, if so, the effect of these barriers on the economic efficiency of the NEM.

Our report to the AEMC considers two key issues:

- Identification of various stages of exit and the incentives and rationales for pursuing operational strategies that involve partial closure and
- Identification and assessment of potential barriers at each of the various stages of exit.

Where indicated, sections of this report have been prepared with the assistance of solicitors Johnson Winter & Slattery (JWS).

1 Letter from Mr John Ryan, Chair, COAG Energy Council Senior Committee of Officials to Mr Paul Smith, Chief Executive, Australian Energy Market Commission, dated 13 April 2015.

1.2 Structure of this draft report

Our draft report is structured as follows:

- Section 2 provides a brief overview of the economic meaning of barriers to exit and the effect that barriers to exit can have on the efficiency of markets.
- Section 3 describes the broad nature of factors relevant to generation exit in the NEM
- Section 4 discusses ways in which various factors could influence the exit decisions of different types of generator technologies at different stages of exit.
- Appendix A discusses various forms of NEM generator operating patterns and the scope and experience of cessation possibilities for different types of plant.
- Appendix B contains a discussion of the form and implications of generator commercial commitments.
- Appendix C sets out the legislation examined as part of our review of exit barriers.

2 Barriers to exit

2.1 Definition and types of barriers to exit

A firm operating in a hypothetical perfectly competitive market does not, by definition, face barriers to entry or exit. However, such a firm may decide to suspend operations in the short run if its average revenue does not at least equal its average variable costs at the point where its marginal revenue equals its marginal cost.[2] If such conditions continue in the long run, the firm is assumed to be able to costlessly exit the industry.

While barriers to entry have been studied for some time,[3] the economic literature on barriers to exit has emerged relatively recently.

Gilbert defines 'barriers to exit' as "costs or foregone profits that a firm must bear if it leaves an industry".[4]

This definition is broad enough to include a number of factors commonly understood as constituting exit barriers, For example:

- ***Direct costs of exit*** – which include plant shut-down costs, reinstatement costs (if 'exit' is partial or temporary), staff redundancy costs and, in the case of certain electricity generators, site remediation costs. Political and legal barriers that go beyond imposing specific direct costs and literally prevent plant closure – such as an obligation to supply – could be viewed as imposing infinitely high direct costs of exit.
- ***Indirect opportunity costs of exit*** – such as the inability of a firm to move its capital into another activity and earn at least as large a return. This implies that sunk costs can represent an exit – as well as an entry – barrier. Caves and Porter describe the source of such exit barriers as:[5]

> ...inputs that can become attached to the firm and then command persistently low earnings because they are *durable* and *specific* to an activity of the company. Such durable and specific assets... may be specific to the particular business or productive activity, to the company employing them, or to any combination of these. [Emphasis in original]

2 If the firm can earn average revenue in excess of its average variable costs but below its average total costs, it will continue to operate in the short run but will exit in the long run if such conditions persist.

3 See, for example, Stigler, G., (1968); Baumol and Willig (1981).

4 Gilbert, R.J., "Mobility barriers and the value of incumbency", Chapter 8 in Schmalensee, R. and R. Willig (Eds), *Handbook of Industrial Organization*, Volume 1 (1989), North Holland, p.520.

5 Caves, R.E. and M.E. Porter, "Barriers to exit", Chapter 3 in Masson, R.T and P.D. Qualls (Eds) *Essays on Industrial Organization in Honor of Joe S. Bain* (1976), Ballinger Publishing Company, Cambridge MA.

> Indirect opportunity costs could also include government inducements to stay in business or the desire of managers to preserve the quasi-rents associated with their firm- or industry-specific skills.
>
> This definition could potentially extend to include other phenomena that are often described as exit barriers. For example, some commentators refer to strategic considerations such as 'first-mover disadvantage' as a barrier to exit. First-mover disadvantage refers to a firm's expectation that in a non-price-taking environment, the exit of one firm can, by reducing supply, make remaining firms more profitable.[6] Although the notion of first-mover disadvantage emphasises the discouragement to exit arising from the positive impact of a generator's exit on its rivals – which is not how economists tend to think about how firms are motivated – if generators believe that another firm will exit if they do not, it could add to their expected opportunity costs of exit. Such considerations would therefore fall within the standard economic definition of barriers to exit.

Some other factors cited as exit barriers are more difficult to fit within the conventional economic definition. For example, the management literature refers to principal-agent-type problems giving rise managerial obstacles to exit, such as prioritisation of maximising market share and loyalty to staff. Some of these other barriers are often referred to by Bower (1986)[7] and Wood (2008).[8]

The types of barriers to exit faced by generators in the NEM are discussed further in section 3 below.

Inefficient exit without 'exit barriers'

Somewhat separate to the traditional barriers to exit literature, economists have researched the phenomenon of firm exit in declining industries and the circumstances in which such exit may be inefficient. This strand of literature focuses on understanding why apparently inefficient exit may occur in such industries.

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6 AGL comments on first-mover disadvantage as follows: "[E]conomic theory (and game theory in particular) tells us that actions taken by any one supplier to reduce capacity will make competitors better off." and "Given the relatively narrow variance of short-run marginal costs and emissions intensities of existing coal-fired power stations, participants are reluctant to 'blink first' and make competitors economically better off by permanently retiring plant"; see Nelson, T., C. Reid and J. McNeil, "Energy-only markets and renewable energy markets: complementary policy or policy collision?", *AGL Applied Economic and Policy Research, Working Paper No. 43*, available at: http://aglblog.com.au/wp-content/uploads/2014/08/No-43-energy-only-and-renewable-targets-FINAL.pdf (accessed 1 June 2015), pp.2 and 15.

7 Bower, J.L., *When Markets Quake* (1986) Harvard University Press, Cambridge, MA.

8 Wood, A., Capacity rationalization and exit strategies, *Strategic Management Journal*, Volume 30 (2009), pp.25-44.

Ghemawat and Nalebuff's seminal 1985 paper explored Cournot competition in a duopolistic or oligopolistic market with homogenous products, identical unit costs but capacity-dependent fixed costs and (exogenously) declining demand.[9] These assumptions match the NEM's current predicament and could therefore provide useful insights about how the NEM may perform in the future. In such a market, capacity must be progressively reduced or eliminated to maintain profitability and ideally the highest-cost capacity would exit first. However, applying the criterion of 'sub-game perfection',[10] Ghemawat and Nalebuff found that the order of exit is inversely-related to size: the largest firm exits first and the smallest firm exits last. The intuition behind this result is that because fixed costs are proportional to firm capacity, the smaller firm can expect to remain profitable for longer than the larger firm as demand declines; therefore, it makes sense for the larger firm to exit as soon as duopoly profits turn negative. If the assumption of identical costs is relaxed to allow the larger firm to enjoy the benefits of economies of scale, Ghemawat and Nalebuff noted that the outcome could be reversed. However, based on numerical examples, they pointed out that the required cost advantages for larger firms would have to be 'surprisingly substantial' for this to occur. This implies that the order of exit under such conditions need not be efficient – larger firms may exit the market before smaller firms with somewhat higher average costs.

Whinston (1988) extended this work to consider multi-plant firms, finding that Ghemawat and Nalebuff's results do not generalise across all cases.[11] Specifically, when each firm controls several differently-sized plant, there is no theoretical prediction about the order of exit.

In a subsequent paper, Ghemawat and Nalebuff (1990) analysed the case where firms can divest incrementally rather than on an all-or-nothing basis.[12] In this case, larger firms reduce capacity first and continue to do so until they shrink to the size of their formerly-smaller rivals. At this point, all firms with the same capacities shrink together.

Summary

The economics literature defined barriers to exit as costs or foregone profits that a firm must bear if it leaves an industry. This definition includes both direct costs

9 Ghemawat, P. and B. Nalebuff, "Exit", *Rand Journal of Economics*, Volume 16, No.2, Summer 1985, pp.184-194.

10 Sub-game perfection means that each stage of strategic decision-making in a multi-period game is sustainable as a Nash Equilibrium.

11 Whinston, M.D., "Exit with multiplant firms", *Rand Journal of Economics*, Volume 19, No.4, Winter 1988, pp.568-588.

12 Ghemawat, P. and B. Nalebuff, "The devolution of declining industries", *The Quarterly Journal of Economics*, Volume 105, No.1, (February 1990), pp.167-186.

of exit as well as indirect opportunity costs that would be borne by plant that exit. The latter category may be interpreted in a way to encompass colloquial notions such as 'first-mover disadvantage', but may not capture all potential reasons why firms making operating losses fail to exit. Economists have also studied circumstances in which firms in declining industries exit inefficiently.

2.2 Implications of barriers to exit

Economic efficiency

The key implication of barriers to exit and inefficient exit without barriers is that exit may not occur at the time and in the manner that is socially optimal. If this occurred, it would deny the community access to the cheapest form of production and access to the latest technologies and this could in turn undermine innovation in the economy. Ultimately these barriers could cause productivity to decline and this would mean less of the community's needs and wants will be met.

Whether barriers to exit are likely to harm economic efficiency will depend on both the barrier in question and at what point – *or in respect of what decision* – inefficiency is to be assessed. For example, the existence of a sunk cost *per se* does not imply that continued operation would be inefficient *given the existence of that sunk cost*. If, say, the cost of generation plant is completely sunk, then running that generator for so long as it continues to earn operating profits would be more efficient than closing that generator down. However, this is not to say that the economy could not operate more efficiently in an uncertain world if generator sunk costs were lower or did not exist.

Other implications

In the specific context of the NEM, barriers to exit could in principle lead to the types of issues highlighted by stakeholders such as:[13]

- 'Disorderly exit'
- Reduced maintenance, leading to compromised reliability of supply
- Reduced contracting levels.

Some of these outcomes could harm economic efficiency, narrowly-defined, but even if they do not, they may be considered undesirable by policy-makers.

The following section of this report discusses the likelihood that barriers to exit in the NEM will be significant in the context of different forms of exit and

13 See, for example, AGL Working Paper, No.43, *op.cit.*, p.17.

different types of generation technologies and the implications for efficiency where barriers are significant.

3 Broad factors relevant to exit in the NEM

This section explores the broad categories of potential barriers to exit and other factors relevant to generator exit decisions in the NEM. The discussion commences with an overview of the broad types of factors relevant to generator exit and moves on to how such factors could differently affect the decisions of different technologies of generators at different stages of winding-down their operations. This section concludes with a discussion of the efficiency implications of different forms of barriers to exit.

Consistent with the discussion in section 2.1 above, we have formed three broad categories of factors that may influence generator exit decisions. These are:

- Direct costs
- Indirect opportunity costs
- Other barriers or influences

3.1 Direct costs

Direct costs refer to obligations to make incremental payments or expenditures as a result of pursuing a partial, temporary or total closure of a plant.

The key types of direct costs attributable to partial and/or temporary shut-downs of generators are preservation and reinstatement costs.[14] These broadly include the costs (and time) of cleaning and drying plant to prevent or reduce deterioration when out of service, as well as preparing plant for service when being reinstated.

The key types of direct costs attributable to full closure and exit are site remediation costs and staff redundancy costs.

3.1.1 Site remediation

This section has been prepared by JWS and provides an overview of the different sources of site remediation obligations. It illustrates that those costs do not always fall on the registered market participant but in some cases may fall on the owner and operator of the physical plant (who may be an independent power producer (IPP)) or may be retained by previous owners of the plant.

The overview is confined to the plant site. For these generators who also operate mines, remediation regimes applicable to mining operations may apply. It may also be the case that a generation site could be affected by heritage obligations

14 See Parsons Brinckerhoff, *Technical Assessment of the Operation of Coal & Gas Fired Plants,* (Prepared for the UK Department of Energy and Climate Change), December 2014 (PB report), p.35.

(and associated costs) which could triggered by the announcement of a power station closure.[15]

Summary of legislative obligations

Each State and Territory has its own regime to impose liability for the remediation of contaminated land:

- *Contaminated Land Management Act* 1997 (NSW)
- *Environment Protection Act* 1970 (Vic), s 62A
- *Environmental Protection Act* 1994 (Qld), Chapter 7 Part 8
- *Environment Protection Act* 1993 (SA), Part 10A
- *Contaminated Sites Act* 2003 (WA)
- *Environmental Management and Pollution Control Act* 1994 (Tas), Part 5A
- *Environment Protection Act* 1997 (ACT), Division 9.5
- *Waste Management and Pollution Control Act* (NT), Part 10 Division 2

There are various differences between the regimes, but generally each imposes a hierarchy of liability with the those lower in the hierarchy only liable if it is not practical to impose the liability on those above (eg because those above no longer exist).

Usually the polluter sits at the top of the hierarchy and is followed by the owner or occupier of the relevant land (irrespective of whether the owner or occupier caused or was otherwise involved in the contamination) and then the state or the relevant local authority for the land.

In the context of contamination caused by the operation of a generating plant, the polluter will be the owner and/or operator of the plant.

In some jurisdictions (eg Victoria), the Environmental Protection Agency (EPA) has a discretion to levy the liability on the polluter or the owner or occupier. Where the liability is levied on the owner or occupier, the owner or occupier has a statutory right to recover the liability from the polluter.

The liability does not crystallise until the relevant EPA issues a notice in respect of the contaminated land. Generally, such notices require the recipient to take remediation action prescribed in the notice and/or implement a plan to manage the contamination the subject of the notice.

15 For example, the old Nymboida Hydro power station in NSW is under consideration for heritage listing and White Bay power station is on the heritage register.

The regimes in most jurisdictions include mechanisms to attach the obligations set out in a notice to the land the subject of the notice so that subsequent purchasers of the land are also bound by it.

Unless there is a risk of the contamination spreading to other land or a real risk to persons or property, a notice is not usually issued until the current operation on the land ceases or there is a change of use of the land which makes the remediation necessary.

In the case of a generating plant which is not otherwise subject to legally enforceable decommissioning and remediation obligations, there is a real likelihood that the owner of the plant will be issued with a notice following closure of the plant so that the land on which the plant was located is suitable for alternative future uses.

Examples

- The Victorian EPA has issued a clean-up notice to Alcoa in respect of the recently closed Point Henry Aluminium Smelter. A similar notice is likely to be issued to Alcoa in respect of its Anglesea Power Station which supplied the smelter and is due to be closed following an unsuccessful attempt by Alcoa to find a buyer for the plant. Alcoa expects the total cost of the clean up to be in the order of $55 million.
- The Electricity Commission of NSW was issued with a series of management orders in respect of various closed power stations in and around Sydney during the 1990s, including the Pyrmont Power Station, the White Bay Power Station and the Balmain Power Station.

Conditions attached to regulatory approvals

Regulatory approvals for generating plant may have conditions attached to them which impose specific obligations on the owner of the plant in relation to its decommissioning and the rehabilitation of the land it is located on at the end of its working life.

These conditions often require the owner of the plant to formulate a binding plan for decommissioning and rehabilitation for approval by the applicable regulatory authority prior to closure of the plant.

In some instances, particularly in relation to major projects which trigger environmental impact assessment processes, proponents are required to prepare a decommissioning and rehabilitation plan as part of the initial application process for planning and environmental approvals and continually update that plan throughout the life of the plant.

Examples

- The Victorian Policy and Planning Guidelines for the Development of Wind Energy Facilities require applicants to prepare and lodge an environmental management plan, including a decommissioning and rehabilitation plan, with their application for planning approval. Draft guidelines published by the NSW and Queensland governments include similar requirements.

- The terms of reference for environmental impact statements or assessments for major generating projects in most jurisdictions typically require the proponent to include a section setting out potential decommissioning and rehabilitation strategies for the plant.

Requirement for new regulatory approvals for decommissioning

Where the planning approval for a generating plant is not expressed to cover the decommissioning of the plant, further approvals will likely be required for decommissioning.

The requirement for fresh approvals provides regulatory authorities with an opportunity to impose conditions regulating decommissioning and site rehabilitation.

Examples

Older coal-fired generating plants approved under antiquated and long since repealed planning regimes, such as the Liddell Power Station in NSW (commissioned in 1971) and the Playford B Power Station in South Australia (commissioned in 1963), are most likely to require new approvals for decommissioning.

It is likely that many of the base load generating plant currently operating in the NEM will not have regulatory approvals for decommissioning already in place and will therefore have to negotiate these arrangements at the time a decision is being made to shut down operations. A consequence of this lack of certainty about decommissioning and rehabilitation regulatory obligations is that the agent responsible for meeting the costs will also be unsure of those costs. Owners of generation plant may include provisions for decommissioning costs in their annual accounts but acknowledge that these are based on assumptions.[16] This uncertainty about these costs may make it difficult for a business to assess the economics of remaining operational or shutting down. While it could be argued that the variance in these shut down costs could be reduced by engaging with the relevant regulatory agencies, this engagement could create its own risks, including inviting a process that could involve considerable costs and/or fresh scrutiny

[16] "AGL estimates the future removal and restoration costs of electricity generation assets, oil and gas production facilities, wells, pipelines and related assets at the time of installation of the assets. In most instances, removal of these assets will occur many years into the future. The calculation of this provision requires management to make assumptions regarding the removal date, application of environmental legislation, the extent of restoration activities required and available technologies.": Note 2 regarding significant accounting judgements, estimates and assumptions for provision for environmental restoration, AGL Financial Report for the year ended 30 June 2014

leading to the imposition of obligations in the operating phase that currently do not exist.

Site leases

Where the land on which generating plant is located is leased, the lease document will usually include provisions which require the lessee to remove the generating plant and return the site to the state it was in prior to the commencement of the lease at the end of the lease term.

At a minimum, this will necessarily require the lessee to remediate any contamination which was caused during the lease term.

However, some leases go further and require the lessee to remediate all contamination which exists on the site at the end of the lease term, irrespective of whether it existed at the commencement of the lease. See below for examples.

Conditions attached to privatisations

When seeking to privatise electricity assets, vendor governments will often seek to transfer to the purchaser any actual or potential liability the government may have to remediate any contamination caused by the historical operation of the asset.

Example 1: Transfer of remediation obligations

In September 2000, as part of the privatisation of the Electricity Trust of South Australia, the South Australian Treasurer entered into long term leases for the coal-fired Northern and Playford B Power Stations and the land upon which they are located near Port Augusta in South Australia pursuant to the *Electricity Corporations (Restructuring and Disposal) Act* 1999 (SA).

The leases impose a range of obligations on the lessee relating to site remediation including:

- the lessor being able to direct the lessee to prepare a plant dismantling plan and carry out that plan at lease end at the lessee's cost
- restrictions on the lessee's use of the land where such use may increase the state's remediation risk and the lessee has not provided the state government with satisfactory security against that increased risk
- the lessee being required at lease end to surrender the land in a condition complying with all applicable laws at that time (unless it exercises an option to purchase the land)
- the lessee being required at lease end to provide an indemnity and security in respect of any material litigation or similar proceedings with respect to the land
- the lessee being required to pay all costs and expenses of the lessor in relation to the return of the land and
- the lessee indemnifying the state government against all losses incurred as a result of being required to remediate the land after dismantling of the plant in accordance with laws applicable at that time.

Example 2: Retention of remediation obligations

In 2011, the NSW government entered into the GenTrader contracts in respect of the Eraring Energy and Delta West power stations. The contracts had the effect of selling the electrical generation output of the power station, but did not transfer ownership in the physical power station assets themselves. A report on the Gentrader transactions indicated that the government retained the remediation obligations in respect of the plants following the transaction.

The physical power station assets have since been sold pursuant to a separate transaction, but it is not clear to what extent, if any, the purchaser assumed the remediation obligations as part of the sale process.

Extent of remediation obligations

The extent of remediation required will depend on the terms of the instrument imposing the rehabilitation obligation.

Where the obligation is imposed by the EPA under environmental legislation, the EPA will usually have some discretion as to the level of rehabilitation required. Complete removal of all contamination may be required, or if that is not possible or reasonably practicable, only such remediation as necessary to ensure the relevant land is suitable for its intended use may be required.

Where the obligation is imposed through the requirement for a decommissioning and rehabilitation plan required as a condition to a planning approval, it usually takes the form of an obligation to return the relevant land to the state it was in prior to the commencement of the project, thus implying the need to remove any contamination arising out of the project. However, there may be some exceptions to this which permit concrete slabs and footings and other sub-surface infrastructure below a certain depth to be left *in situ*. This is usually only permitted where doing so will have no impact on the expected future use of the land.

The nature of a remediation obligation under a site lease will be similar to that described above under a decommissioning and rehabilitation plan. However, if the relevant land is in a particularly strategic location (resulting in the landlord having greater leverage in the lease negotiations), it may go further and require the lessee to remediate all contamination existing at the end of the lease, including any contamination which existed at the commencement of the lease

3.1.2 Staff redundancy costs

Staff redundancy costs are likely to be material and vary according to the numbers and types of staff that will be made redundant as a result of a partial or complete shut-down of a generator. As noted above, seasonal and longer shutdowns that involve mothballing plant will tend to occupy power station staff for a period of time; but ultimately, it is likely to prove economic to make surplus staff redundant. These costs could increase if the plant is subsequently brought back into service. Full exit would impose higher, but once-off redundancy costs; however, even these are likely to be a relatively small fraction of site remediation costs. It is important to note that power station operators are rarely certain about the timing and costs of plant closures, partly because generators rarely know ex ante what their shutdown obligations are likely to be (as discussed above in Section 3.1.1), and also because the business (where unionised) has to negotiate the shut down process with unions which results in uncertainty about the magnitude and timing of staff redundancy costs. This in turn adds to the uncertainties when considering a decision about whether and when to decommission a plant.

3.2 Indirect opportunity costs

Indirect opportunity costs refer to the second part of Gilbert's definition of exit barriers – profits foregone by a firm if it leaves an industry.

For a typical generator, such foregone profits would be based on:

- the operating profits the generator could expect to earn on its plant if it continued operating *less*

- the proceeds (if any) from the sale of its plant and the expected return on those proceeds.

This highlights four important variables:

- The extent to which a generator's decision to remain in operation could lead to other generators exiting the market and higher wholesale prices than which currently prevail
- The extent to which the generator's fixed costs are truly 'sunk'
- The extent to which the generator has already entered into contracts for its inputs and outputs and how feasible it is to trade out of those contracts and
- Any expectation that generators that remain in operation could receive government inducements to exit at some later point in time.

3.2.1 Extent to which remaining in operation could cause the exit of other generators

As noted above, the profits foregone by a firm leaving an industry depend in part on the operating profits the generator could expect to earn on its plant if it continued operating.

This implies that if a generator expects that its decision to remain in operation would result in other generators choosing to exit the market and a higher wholesale price, this would tend to raise the first generator's opportunity costs of exit and hence raise barriers to exit. It is in this way that first-mover disadvantage can be regarded as a conventional barrier to exit.

Conversely, if a generator expects that other generators will not exit even if the first generator remains in service, this limits the lower opportunity costs of exit and hence barriers to exit.

3.2.2 Extent to which plant costs are sunk

A key consideration for a generator thinking about exiting the market is the potential returns the generator could earn by closing the plant and investing the sales proceeds – if any – elsewhere.

If the generator is able to sell its site and/or plant after exiting the market and meeting all of its legal commitments (such as site remediation and staff redundancy costs), this implies that its fixed costs are not completely sunk. In addition to the sale proceeds, any subsequent return the generator can make on those proceeds would reduce the generator's foregone profits by not continuing to operate the plant. In a state of the world in which a generator could sell its plant and site and earn the same net return as it could by continuing to operate its plant, the generator would face no indirect opportunity costs from exit.

3.2.3 Input and output contracts

The same approach as for analysing plant and site costs can be taken to examining any contractual commitments the generator has entered into. Appendix B provides a detailed discussion of the typical commercial arrangements that govern generator operation in the NEM.

If, say, a generator has entered into a 'take-or-pay'-style contract for its fuel and that purchasing commitment cannot be traded to another party, then the cost of fuel is no longer avoidable regardless of whether the generator continues to operate or not. In other words, the cost of fuel is sunk. Accordingly, in deciding whether or not to exit, a generator should ignore the cost of fuel in determining what its operating profits would be if it remained in operation. In other words, a non-transferable take-or-pay contract would increase the opportunity costs of exit and thereby raise the barriers to exit.

Conversely, if a generator has entered into a contract tradeable in a liquid market for an input like fuel, then the existence of the contract should not influence the generator's exit decision. The generator should determine what its operating profits would be if it remained in operation on the basis of the prevailing price of fuel. This means that if the cost of fuel has risen since the contract was signed, and this would reduce the generator's operating profits in the absence of the contract, the generator's opportunity cost of exiting has also reduced. This is because the exiting generator could on-sell the fuel contract at the (higher) market price and lose only the reduced operating profit.

Generators in the NEM tend to enter derivative (rather than physical) contracts in respect of their electricity output. Such hedge contracts are typically settled through the making of 'difference payments' (between the spot price and the contract strike price).

To the extent such contracts are freely tradeable and are binding irrespective of whether the generator remains in operation, they should not influence plant operational decisions. The difference payments under such contracts could be considered sunk costs (or benefits).

However, if a corollary of a generator's exit is claiming bankruptcy so that the owner of the plant can escape settling the derivative contract, the appropriate strategy may be different. On the margin, the ability to avoid 'out-of-the-money' derivative contracts by exiting could encourage exit other things being equal.

3.2.4 Expectations of inducements to exit

Any expectation that governments may provide financial inducements to generators to exit at a later point in time could constitute a barrier to current exit. This is because the possibility of receiving a payment would, other things being equal, increase the expected profits foregone by the generator if it were to exit immediately. While the former Federal Government attempted to negotiate 'contracts for closure' with a number of large coal-fired power stations in 2012,[17] this policy was subsequently abandoned and does not appear likely to re-emerge.

3.3 Other barriers or influences

Other factors may influence generators' exit decisions even if they do not constitute conventional exit barriers. Some of these factors were raised in section 2.1 above.

3.3.1 Desire to avoid boosting other generators' profits

As noted above, AGL described first-mover disadvantage in the following terms:[18]

> Given the relatively narrow variance of short-run marginal costs and emissions intensities of existing coal-fired power stations, participants are reluctant to 'blink first' and make competitors economically better off by permanently retiring plant.

As noted above, to the extent generators are deterred from exiting because of an expectation that if they do not exit, someone else will and this will result in a higher wholesale price, this could be described as a conventional barrier to exit. This is because a generator's expectation that another generator will exit if the first generator remains in operation suggests that the first generator's likely operating profits from remaining in service are higher than its present level of operating profits.

However, a simple desire of a generator to avoid making competitors better off does not fall within the conventional definition of a barrier to exit. In standard economic theory, profit-seeking firms are assumed to not place any value on the profits of their rivals or their own profits relative to others' profits. Nevertheless, this does not imply that NEM participants (or their managers) do not hold such concerns or behave accordingly.

3.3.2 Policy uncertainty

Another potential influence on generation exit cited by AGL and in the COAG Energy Council's request for advice was policy uncertainty, particularly around policy towards climate change and renewables. Recently, the Australian Parliament appears to have reached a compromise on the RET; if carried into

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17 See *Securing a Clean Energy Future: Implementing the Australian Government's Climate Change Plan, Statement by the Honourable Greg Combet AM MP, Minister for Climate Change and Energy Efficiency*, 8 May 2012, available at http://www.budget.gov.au/2012-13/content/ministerial_statements/climate/download/climate_change.pdf (accessed 21 May 2015).

18 AGL Working Paper, p.15.

law, this compromise should remove one form of policy uncertainty and encourage generation investment and exit in accordance with the revised target.

On the other hand, the main political parties continue to disagree about the appropriate policy towards securing greenhouse gas emissions reductions. This disagreement may deter some – say, coal-fired – generators from exiting the market relative to a state of the world where Australia had a sufficiently high carbon price to meet the current emissions reductions target. However, this does not constitute a conventional barrier to exit so much as a policy setting that, if different, would induce exit.

3.4 Implications for economic efficiency

As noted in section 2.2, the implications of exit barriers for economic efficiency depend on the nature of those barriers and the point at which, or *the decision in respect of which*, efficiency is being assessed. Economic efficiency refers to the minimisation of opportunity costs; to the extent that decisions are taken that cannot be costlessly be reversed – ie sunk costs are incurred – those past decisions need to be taken as given in determining whether future decisions are efficient. This framework can be applied to the specific barriers to exit discussed earlier in this section.

3.4.1 Site remediation costs

A generator's site remediation obligations should reflect no more than the efficient degree of remediation. Whether this is likely to be the case will depend on both:

- whether the generator is entitled to retain the market-based proceeds from the disposal of the site (if any) and
- the subsequent use to which the site is to be put.

Whether the generator retains disposal proceeds

If a generator is required to remediate a site before simply handing it to the government, any site remediation obligations will on the margin promote inefficient deferral of exit. This is because the generator will incur some or all of the costs, but none of the benefits, from an alternative use of the site. Other things being equal, this will encourage the generator to keep the plant operating beyond when it would otherwise be efficient to exit. However, if the generator can keep the market-based proceeds from the disposal of the site, it will have an incentive to exit when it is otherwise efficient to do so.

Subsequent use of the site

The subsequent use of the site will influence the efficient level of remediation that should be undertaken. The subsequent use should in turn depend on the highest net-valued use to which the un-remediated land could be put. For example, if the site could yield:

- $100 gross value if $80 were spent on remediation (ie $20 net value) or
- $50 gross value if $10 were spent on remediation) (ie $40 net value)

then the efficient remediation obligation would be less than or equal to $10.

Note that where the generator keeps the disposal proceeds, whether the generator or the subsequent user of the land pays for the remediation is not relevant to the efficiency of the outcome – the efficient level of remediation will occur either way. The exception is where the remediation is more easily carried out by the generator – say, because of its superior information about what kind of remediation needs to occur to make the site usable for the subsequent use. In this case, the generator should find it profitable to undertake the appropriate level of remediation itself.

If site remediation obligations exceed what the subsequent use of the site will require or justify, the obligations should be reduced to avoid either:

- inefficient levels of site remediation being undertaken or
- inefficient ongoing operation of the plant, where it would exit if not obliged to undertake excessive remediation.

3.4.2 Staff redundancy costs

Whether staff redundancy costs impose an inefficient barrier to exit depends on whether those costs reflect the outcomes of a previous efficient bargaining process. Workers may bargain for redundancy entitlements in forming their employment contracts where their role requires them to make firm- or industry-specific investments in their human capital. While this is likely to have been the case to some extent, it is difficult to know whether prevailing redundancy entitlements are excessive. If they are, then overall economic welfare will be lower than it would be otherwise. In any case, it is likely to be extremely legally and politically difficult to change these entitlements at this stage, so the efficiency of subsequent decisions should be assessed from the perspective of minimising forward-looking opportunity costs.

3.4.3 Continued operation causes exit of others

Where a generator reasonably considers on the best available information that its continued operation will result in the exit of other generators and where the first generator continues to operate on this basis, that decision to continue operating may not be *ex ante* inefficient. Such a decision could be inefficient if it occurs under the circumstances described in the Ghemawat and Nalebuff paper and leads to lower-cost generators exiting before a higher-cost generator (see section 2.1).[19]

3.4.4 Extent to which plant cost sunk

As noted in section 2.2, the existence of plant sunk costs *per se* does not imply that continued operation of a generator would be inefficient *given the existence of that sunk cost*. If, say, the cost of generation plant is completely sunk, then running that generator for so long as it continues to earn operating profits would be more efficient than closing that generator down. However, this is not to say that the economy could not operate more efficiently in an uncertain world if generator sunk costs were lower or did not exist.

3.4.5 Existence of take-or-pay input/fuel contracts

The existence of take-or-pay input-fuel contracts will tend to increase the opportunity costs of exit and hence raise barriers to exit. Whether entry into such contracts in the first place was appropriate will depend on whether such contracts performed a valuable role in underwriting the development of a fuel source that would not otherwise have been efficiently developed. In this respect, take-or-pay fuel contracts share some similarities to staff redundancy costs. In both cases, past decisions in relation to the striking of those terms need to be taken as given in determining whether future decisions are efficient.

3.4.6 Expectations of inducements to exit

Expectations of inducements to exit would tend to deter exit. If such expectations are not rational and well-formed, then the expectations will inefficiently deter exit. If they are well formed, then the sooner the inducements are offered, the shorter the period for which the expectations will deter exit.

3.4.7 Desire to not boost other generators' profits

If a generator holds a desire to not provide another generator with a benefit by exiting, then the reluctance to exit on that basis may be inefficient.

3.4.8 Policy uncertainty

In a sense, policy uncertainty is similar to uncertainty about any parameter relevant to the profitability of a power station – it may deter or hasten exit depending on generators' attitudes towards risk and their expectations regarding

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19 A declining industry with unequal-sized firms and economies of scale.

how the uncertainty will be resolved. For example, the government has been contemplating for some time a new post-2020 emissions reduction target. Generators have been considering the implications for them of different targets and may have chosen to exit or defer exiting depending in part on what target they consider likely to emerge. Other things being equal, social welfare will be higher in a world without such uncertainty; but in the absence of perfect foresight, uncertainty cannot be eliminated.

However, even where policy-makers have stated a particular policy position, generators may defer exit decisions if they do not believe the policy position is credible. This is an implicit rather than explicit form of policy uncertainty. For example, if generators believe that governments are concerned about the need for orderly generator exit, then generators may consider that despite their protestations, governments will introduce more favourable terms for exit in the future if sufficient exit does not occur of its own accord. For example, generators may believe that governments will revert to a contract-for-closure inducement or relax site remediation obligations. Such an expectation of a change in position raises an important *dynamic* or *time inconsistency* problem for such policies.[20] Mankiw describes the phenomenon of time inconsistency as follows:

> In some situations policymakers may want to announce in advance the policy they will follow to influence the expectations of private decision makers. But later, after the private decision makers have acted on the basis of their expectations, these policymakers may be tempted to renege on their announcement. Understanding that policymakers may be inconsistent over time, private decision makers are led to distrust policy announcements.[21]

Specifically, generators may believe that if some generators take policy-makers at their word and exit, but not enough to meet policy-makers' objectives, then the government may change its position and offer inducements or relax site remediation obligations. A generator participant would need to allow for the risk that policy-makers may change their policies and as such may not exit despite policy-makers' public positions. This would likely yield inefficient deferral of exit.

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20 Based on the idea put forward in: Kydland, F. and E. Prescott, "Rules rather than discretion: The inconsistency of optimal plans", *Journal of Political Economy*, (1977) Vol. 85, pp.473-490.

21 See Mankiw's blog here: http://gregmankiw.blogspot.com.au/2006/04/time-inconsistency.html (accessed 2 June 2015).

4 Factors relevant to exit by individual generator technologies and stages

The barriers to exit discussed in the previous section are likely to affect different types of generation technologies (and firm structures) in different ways. For example, to the extent that plant are divisible and can be economically relocated, such as many open cycle gas turbines, sunk costs are not as large and hence do not pose as great an exit barrier as for a coal-fired generator. Similarly, different barriers may arise in relation to different stages of exit.

This section

- Describes the key types and features of generator technologies (section 4.1)
- Summarises the stages of reduced operation and exit that are generally applicable across generation technologies (section 4.2)
- Discusses the incentives for operators to pursue each of these strategies, the barriers that may prevent operators from pursuing each of these strategies and, where relevant, examples of generators that have pursued each of these strategies (section 4.3 and Table 1 to Table 5).

4.1 Description of electricity generation technologies

For the purposes of this report, we have considered five broad generation technologies that are most common in the NEM:[22]

- **Subcritical** and **supercritical, brown coal** and **black coal** generators (coal-fired generators). Coal-fired generators burn coal to produce steam that is used to drive a steam turbine. In general, black coal-fired generators are more thermally efficient than brown-coal fired generators and supercritical generators are more thermally efficient than subcritical generators. Supercritical steam turbines have been in use for a number of decades in the NEM, and a number of more recent power stations in the NEM use supercritical technology.

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22 See Frontier Economics, *Input assumptions for modelling wholesale electricity costs, A final report prepared for IPART*, June 2013, available from the IPART website at: http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews/Retail_Pricing/Review_of_regulated_electricity_retail_prices_2013_to_2016/17_Jun_2013_-_Consultant_Report_-_Frontier_Economics_-_June_2013/Consultant_Report_-_Frontier_Economics_-_Input_assumptions_for_modelling_wholesale_electricity_costs_-_June_2013 (accessed 21 May 2015) (Frontier 2013 report), pp.8-9; Examples of different technology plant operating in the NEM were obtained from the AEMO website at: http://www.aemo.com.au/About-the-Industry/Registration/Current-Registration-and-Exemption-lists (accessed 21 May 2015).

- An example of a:
  - Sub-critical brown coal power station is Loy Yang A in Victoria
  - Sub-critical black coal power station is Bayswater in New South Wales
  - Super-critical black coal power station is Kogan Creek in Queensland
- Relative to other generation technologies utilised in the NEM, coal-fired generators tend to have:
  - Higher fixed costs and lower variable costs (especially fuel costs)[23] and
  - Greater dispatch inflexibilities.[24]

  Accordingly, the cost structures and operational strategies of coal-fired generators tend to favour their operation as baseload plant.

- **Open cycle gas turbine** (OCGT). OCGT power stations consist of a gas turbine (usually running on liquid fuel).[25] OCGT generators are relatively simple and low cost, and can be built quickly. However, they are not very thermally efficient, resulting in relatively high fuel use. For this reason they tend to operate as peaking plant. There are a number of OCGT generators in the NEM, most of which were commissioned by (then) stand-alone retailers to assist in managing their hedging risk.
- **Combined cycle gas turbine** (CCGT). CCGT power stations are, like OCGT power stations, based on a gas turbine. The key difference is that CCGT generators also capture heat from the exhaust of the gas turbine in a heat recovery steam generator (HRSG) to produce steam to drive a steam turbine.[26] The capture of waste heat improves the thermal efficiency of the plant, meaning that CCGT generators use less fuel and produce less carbon emissions than OCGT generators. However, the addition of a heat recovery generator means that CCGT generators have higher fixed costs than OCGT plant. For this reason CCGT generators tend to operate at a higher capacity factor than OCGTs. CCGT generators are common in the NEM – some examples are Pelican Point and Hallett in South Australia and Swanbank E in Queensland.

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23 See, for example, Australian Energy Regulator, *State of the Energy Market 2012*, pp.30-32.

24 PB report, pp.21-34.

25 Frontier 2013 report, pp.8-9; see also PB report, pp.29-31.

26 Frontier 2013 report, pp.8-9; see also PB report, pp.27-29.

- **Hydro-electric**. Hydro-electric power stations use the gravitational force of falling or flowing water to drive a water turbine.[27] Hydro-electric generators are a form of renewable energy. There are a number of forms of hydro-electric generators. The most common form in the NEM are impoundment facilities, which use dams to store river water for release through a water turbine. A number of these also have pumped-storage facilities, which include a pumping facility to return released water to the dam. The largest hydro power stations in Australia are those operated by:
  - Snowy Hydro – such as Murray 1 and 2 in Victoria and Tumut 1, 2 and 3 in New South Wales and
  - Hydro Tasmania – such as Gordon, Poatina and Reece.
- **Other renewable**. There are a number of other renewable generation technologies that operate in the NEM. By far the most common is wind generation, although solar PV is becoming more common. The cost structures and operational strategies of these other renewable power stations tend to be similar so we have dealt with them together for the purposes of this report.

4.2 Definition of stages of reduced operation and exit

Generator exit is not a simple binary decision. Generators can implement any of a number of distinct stages of reduced or suspended operation before they finally and permanently exit the market. We categorise these stages as follows:

- **Dispatch at minimum stable generation.** Where power stations are not recovering their variable costs of production for short periods of time (for instance, overnight) the operators may choose to reduce dispatch to minimum stable generation. This is the minimum level of output a generator can produce without causing technical problems within the plant.[28] Dispatch at minimum stable generation avoids much of the variable costs of generation while also avoiding the costs, delays and performance impacts associated with plant shut-downs and restarts.
- **Two-shifting.** Where power stations are not recovering their variable costs of production over a longer period of time, the operators may choose to temporarily cease operation of particular units, or the entire power station, until prices recover.[29] This strategy would usually be adopted when the expected operating losses from generating at minimum stable generation

27 See, for example, Australian Energy Regulator, *State of the Energy Market 2009*, p.51.

28 See PB report, Table 4, p.23.

29 See PB report, Table 4, pp.17-18.

levels at times when prices are below the variable costs of production exceed the expected costs, delays and performance impacts associated with plant shut-downs and restarts. Two-shifting is generally used to describe cessation of operation on a regular or semi-regular basis, such as daily or weekly.

- **Seasonal shutdowns.** Like two-shifting, seasonal shutdowns involve operators choosing to temporarily cease the operation of particular units, or an entire power stations, because the power station is not expected to recover its variable costs of production for a period of time. Seasonal shutdowns would usually be implemented when the generator's owner expects that the average price over a period of several months – which often correspond to seasons of the year – is below the power station's average variable cost over that period. The 'shoulder' seasons of Autumn and Spring are the periods in which generators most frequently implement seasonal shutdowns.
- **Mothballing.** 'Mothballing' refers to techniques that can be applied to prevent or reduce the deterioration of plant when it is out of service.[30] The purpose of mothballing is to protect a plant from condensation, corrosion and seizure due to lack of use. Mothballed plant will generally require less ongoing maintenance effort and cost than plant that are temporarily shut-down, but will require a longer notice period before being returned to service.

  Mothballing can be:[31]

  - Short-term (3-12 months) – in which case the boiler (of a coal-fired steam turbine) or the HRSG (of a CCGT) is typically retained full of de-oxygenated water
  - Long-term (12 months plus) – in which case the boiler/HRSG is typically fully drained and dried out to prevent corrosion

    The amounts of time required to implement short- and long-term mothballing and reinstatement are broadly symmetrical – that is, it takes approximately the same amount of time to mothball a plant for a short-term period as it takes to reinstate such a plant after a short-term period. The same applies to long-term mothballing.

  Mothballing can also be an:

  - Individual unit(s) of a power station or an
  - Entire power station.
- **Power station decommissioning.** Power station decommissioning occurs when the power station is permanently shut down and major items of plant and machinery are dismantled and removed from site. Following power

30 PB report, pp.35-36.

31 PB report, pp.37-38.

station decommissioning, there are a number of options for the power station site. These range from using the site as a development site for a new power station to completely remediating the site.

Alongside these stages of reduced operation and/or exit, the operators of power stations may make complementary decisions about their broader commercial strategy for the power station. For instance, power station operators may:

- Reduce operation and maintenance spending.
- Reduce stay-in-business capital expenditure.
- Reduce the term of new contracts for fuel supply and delivery and/or reduce the term of new physical/financial electricity contracts.

4.3 Summary of exit barrier by generation type

In general coal-fired generators face higher direct cost barriers to partial and complete exit than OCGT and CCGT plant. Due to the risk of thermal fatigue, coal-fired plant take longer to start-up after a period of being non-operational and they take longer to prepare for short- and long-term mothballing in the event of seasonal or more lengthy shut-downs.

4.3.1 Coal fired

As explained in Table 1, coal-fired generators are not designed to operate in a flexible or intermittent manner or to remain in service for seasonal or cyclical shifts in demand. Prolonged operation at MSG is not an economically sustainable option. The costs of two-shifting coal-fired plant are high, the costs of periodically mothballing and restarting plant are higher and the costs of decommissioning plant are higher still.

4.3.2 OCGT

As explained in Table 2, OCGT plant are the most flexible form of fossil-fuel generation due to the versatility of gas turbines and their lack of thick-walled (eg boiler of HRSG) components. OCGT are flexible in the context of both frequent cycling as well as seasonal or longer shut-downs: The time and cost to mothball and reinstate OCGT plant are much shorter and lower than for coal-fired generators and CCGTs.

However, due to their high fuel costs, OCGT plant cannot economically run at MSG or other levels when spot prices are not relatively high.

4.3.3 CCGT

As explained in Table 3, CCGT plant offer an intermediate level of flexibility and cost between coal-fired and OCGT generators. This follows from the fact that

CCGT plant are a form of hybrid plant, incorporating aspects of both. Initial plant start-up times for CCGT can be quite short in respect of the gas turbine output, but full output loading takes longer. Mothballing and reinstatement times for CCGT are shorter than for coal-fired plant, but still involve more time and cost than for OCGT plant.

4.3.4 Hydro

As explained in Table 4, hydro-electric plant are highly flexible generators that can ramp up and down relatively quickly. This means that they usually do not have to be operating at a minimum level to be able to quickly respond to a rise in price. The variable expense of hydro generator is usually very low (unless the generator is utilising pump storage), but the opportunity cost of water can be very high. Hydro generators typically exhibit very high fixed costs and are built robustly. As a result, there are no examples of any hydro plant in the NEM being completely decommissioned.

4.3.5 Other renewable

Table 5 notes that renewable generators mainly comprise wind generators, solar PV and waste gas from mines and rubbish tips. These power sources have typically been developed pursuant to various government subsidy schemes. Larger-scale renewable generators have often been funded via Power Purchase Agreements that have been underwritten on the basis of the renewable credits they create. The suppliers are therefore keen to produce as many renewable credits as possible to maximise the value of their investment. Because of their high fixed costs and low variable costs, renewable generators are likely to be the last generator type to be mothballed or decommissioned as a consequence of low prices.

Table 1: Coal-fired generation

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
Dispatch at minimum stable generation	Coal-fired generators have a minimum stable generation (MSG) level at which they can operate. MSG applies at a unit level and refers to the proportion of full energy output that is required for boiler combustion to stabilise, the main boiler feed pump to be established and for the oil burners to be shut off.[32] In the NEM, coal-fired generators units have MSG levels of 32% (Eraring) to 63% (Hazelwood), with older plant generally having higher MSG levels than newer plant.[33] Operation at the MSG level may be a result of the operator attempting to minimise the cost of burning fuel (and incurring other variable costs) without incurring the cost, delays and performance effects associated with plant shut-downs and restarts. Where overnight demand for electricity is low, coal-fired generators will often reduce dispatch	The barriers to dispatching coal-fired generators at MSG are largely economic in nature – coal-fired plant tend to operate less efficiently when at MSG than when at higher load, which increases their per-unit costs of operation.	An example of operating at MSG, and the differences that can exist between plants in terms of how much they can curtail output while maintaining stable operation, is shown in Figure 1 in Appendix A. In this example, the MSG characteristics of two coal fired power station *units* are compared using dispatch data for the calendar year 2014 – a NSW black coal generator (Eraring) and a brown coal generator (Loy Yang A) – which are generally representative of the performance characteristics of most black and brown coal generators as far as MSG is concerned. It can be seen that as a share of the capacity of the unit, the Eraring unit can achieve a lower MSG compared to the brown coal generating unit at Loy Yang A. This means that black coal generators are more able to avoid losses by backing off units more than brown coal units.

32 PB report, p.23.

33 See *Fuel and Technology Cost Review – Data (ACIL Allen)* (Excel spreadsheet), available from AEMO website at: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions (accessed 21 May 2015), 'Existing Generators' tab.

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
	to MSG while overnight prices are low, before ramping up their dispatch when prices recover during the day.		
Two-shifting	When operation at MSG is not an efficient response to low prices, coal-fired power stations may opt to temporarily close down individual units or the entire power station. In some case, patterns of two-shifting can be quite regular; for instance, power stations may shut down overnight or on weekends.[34]	The barriers to two-shifting coal-fired generators are significant and both technical and economic in nature. Coal-fired generators are particularly exposed to 'thermal fatigue' due to the alternating heating and cooling of key components such as the boiler and steam turbine. These components have 'yield points' below which the material will deform elastically and return to its original shape when cool. But if the yield point is passed – which can occur due to overheating, especially if excessive ramp rates are applied – some fraction of the deformation will be permanent and non-reversible. Such deformation can lead to premature thermal fatigue cracking and compromise component design life. [35] As a result, coal-fired power stations typically	Although two-shifting of coal-fired generators in the NEM is rare, the Muja plant in Western Australia has operated in a two-shift manner at times. Verve Energy's (now Synergy) Annual Report for 2012 (p.11) stated that two-shifting had affected the Muja plant during the year. Quest Integrity Group noted that Muja A and B may have operated in a two-shift manner prior to its closure in 2007.[39] [Quest Integrity Group, "Review of issues related to Muja Power Station related to boiler tube failure in July 2012 and subsequent repairs" 23 August 2012 – Appendix A in Parsons Brinckerhoff, Muja A/B Power Station Refurbishment – Technical Review, RFQ FIN13047" prepared for the Public Utilities Office, 26 August 2013 (accessed 21 May 2015). There is documented but unidentified evidence of coal-fired plant in the United States regularly being used on a two-shift basis. However, this has caused numerous technical problems such as failures of boiler tubes, cracking of generator rotors, corrosion of turbine parts and cracking in condenser tubes and

34 PB report, pp.17-18.

35 PB report, p.19.

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		have significant start-up and shut-down periods and costs. Start-up times in particular will depend on the length of time the unit has been out of service. For example, a:[36] ● Hot start is a start within 8-12 hours of a unit coming off load, generally during a period of two-shifting. A hot start requires approximately 60-90 minutes before synchronisation to the grid and then another 50 minutes to reach full load. ● Warm start is a start within 8-48 hours of coming off load. A warm start requires approximately 120-300 minutes before synchronisation to the grid and then another 85 minutes to reach full load. ● Cold start is a start more than 48 hours of coming off load. The amount of time required for a cold start will depend on	thick-walled components (such as metal welds, headers and valves).[40][See: Cochran, J., D. Lew and N. Kumar, "Flexible Coal, Evolution from Baseload to Peaking Plant", 21st Century Power Partnership", available at: http://www.nrel.gov/docs/fy14osti/60575.pdf (accessed 22 May 2015)]

39 Quest Integrity Group, "Review of issues related to Muja Power Station related to boiler tube failure in July 2012 and subsequent repairs" 23 August 2012 – Appendix A in Parsons Brinckerhoff, Muja A/B Power Station Refurbishment – Technical Review, RFQ FIN13047" prepared for the Public Utilities Office, 26 August 2013, available at: XX (accessed 21 May 2015) .]

36 PB report, pp.25-26.

40 See: Cochran, J., D. Lew and N. Kumar, "Flexible Coal, Evolution from Baseload to Peaking Plant", 21st Century Power Partnership", available at: http://www.nrel.gov/docs/fy14osti/60575.pdf (accessed 22 May 2015)

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		whether the boiler has been drained, which typically occurs only if long-term (>12 months) mothballing has been undertaken. A cold start with a full boiler requires approximately 360-420 minutes before synchronisation to the grid and then another 90 minutes to reach full load. A cold start with a drained boiler will require much more time. The costs of starting-up include :[37] • Fuel for oil burners • Coal burnt to attain boiler stable operating point and • Electricity to drive auxiliary plant. Therefore, the cooler the plant and the longer the start-up period, the higher will be the start-up costs. Shutting down a coal-fired plant takes less time than starting up, but still requires a process to be followed to maintain stable coal combustion during shut-down. Once the coal has been milled off, oil burners are left running for a few minutes to ensure no explosive coal	

37 PB report, p.26.

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		mixtures remain. Shut-down is conducted as quickly as possible to minimise the cooling of components in order to facilitate as rapid a restart as possible.[38] [DN - examples of shut-down and start-up periods and costs for typical coal-fired power station?]	
Seasonal shutdowns	Seasonal shutdowns occur for the same reason as two shifting: when operation at minimum stable generation does not make economic sense as an ongoing response to low prices. Seasonal shut downs are generally a response to expectations that average prices over a prolonged period will be below average cost.	Seasonal shutdowns of coal-fired generators are less likely to impose thermal fatigue risks than two-shifting, because seasonal shutdowns tend to be (by their nature) less frequent than two-shifting. However, as indicated above, seasonal shutdowns will tend to require cold starts, which impose longer restart times and costs than hot and warm restarts under two-shifting. Given the long duration of seasonal shutdowns, there are other potential barriers. These include: ● Issues associated with managing a workforce during the seasonal shutdown. Depending on the length of the shut-down, some staff may be able to be	Figure 2 in Appendix A shows the dispatch data for Northern Power Station in South Australia owned and operated by Alinta. In April 2012 Alinta announced that it would only operate its Northern Power station during summer months and then in June 2014 Alinta announced that it was putting one unit back in service during winter. This seasonal pattern of production is shown in Figure 2 where Unit 1 operated during winter 2014 but not part of autumn and spring (typically when demand is low), is shown in Figure 2. Figure 2 also shows that Unit 2 did not operate during winter.

38 PB report, p.24.

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		redeployed to plant maintenance and preservation during such periods.[41] • Existence of take-or-pay input (eg fuel) contracts that cannot easily be traded. As noted above, if a generator has entered into a firm fuel contract that it cannot trade out of (or can only trade out of at high cost), this would tend to increase the foregone operating profit from shutting down, which would raise barriers to this form of exit. • Managing existing contract positions for inputs (eg fuel) and outputs (ie electricity) during the seasonal shutdown. For example, even if input and output contracts are tradeable in principle, trading out of committed positions may impose high transactions costs on the business.	
Mothballing	As with other temporary shutdowns, mothballing of coal-fired power stations occurs when expected low prices mean that	As indicated above, mothballing can be for a:[42] • Short period (3-12 months) – in which	In 2012, Alinta Energy announced that it would be mothballing its Playford power station but it would be available for production on a 90 day recall

41 PB report, p.36.

42 PB report, p.36.

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
	the power station is unable to recover its variable costs of production. Mothballing is typically a longer-term strategy than a seasonal shutdown and, when commenced, may be for an indefinite period of time.	case the HRSG is typically retained full of de-oxygenated water or • Long period (>12 months) – in which case the HRSG is fully drained and dried out. The barriers to mothballing CCGT power stations, principally relate to: • The time and non-staff costs of mothballing plant and returning plant to service. For CCGT plant, the duration of:[43] □ Short term mothballing and reinstatement is approximately 2 days each and □ Long term mothballing and reinstatement is approximately 2-4 weeks each; • Issues associated with managing workforce during a long closure. Many staff may be able to be redeployed if mothballing for a short period is undertaken. However, if long-term mothballing is implemented, it would be necessary to reduce staff to a minimum	(http://www.npi.gov.au/npidata/action/load/individual-facility-detail/criteria/state/SA/year/2013/jurisdiction-facility/SA0017). In December 2012, Ratch announced that it was mothballing its old (but recently refurbished) coal fired generator at Collinsville. The plant remains but is not operational nor registered with AEMO (http://ratchaustralia.com/collinsville/about_collinsville.html) Callide A was commissioned in 1965, refurbished in 1998 and recommissioned and then mothballed in 2001. All but one of the four units have been in dry storage since 2001. One unit has been used until late 2014 to trial carbon capture technology (http://www.callideoxyfuel.com/Why/CallideAPowerStation/tabid /73/Default.aspx)

43 PB report, Table 15, p.37.

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		level. This can create delays and costs if personnel then need to be recruited if the plant owners choose to return the plant to service; and • Managing extant contract positions (for fuel and for electricity) during the closure period.	
Decommissioning	Unlike the temporary shutdowns discussed above, decommissioning involves the permanent closure of a power station. Decommissioning of a power station can occur for a number of reasons. First, the same type of economic considerations that lead to temporary closures - prices that are below variable costs - are relevant to permanent closures. A decision to permanently close a power station, however, will involve consideration of expected costs and revenues over the remaining potential life of the power station, including the need for "stay-in-business" capital expenditure in future. Second, power stations may be decommissioned for technical reasons. This may be the result of the power station reaching the end of its technical life	There is a much broader range of potential barriers to decommissioning plant. Direct costs include site remediation costs and redundancy payments to staff. Indirect opportunity costs include the profits foregone by not operating. This includes the value of preserving 'real options' – in the face of regulatory, policy and market risks associated with future spot prices can favour delaying any decision to permanently close a coal-fired power station. Commercial barriers as a result of existing long-term input or output contracts can also be substantial if those contracts are not easily tradeable. For example, if a generator is party to a long-term 'take-or-pay' fuel contract, this will tend to increase the value of profits foregone by continuing to operate. Higher profits from operating will act as a barrier to	In November 2014 EnergyAustralia announced that it was permanently closing Wallerawang Power Station due to low demand and lack of access to competitively priced coal. (http://www.energyaustralia.com.au/about-us/media-centre/current-news/wallerawang-power-station-closure-november). On 12 May 2015 Alcoa announced that it would permanently close its Anglesea power station after it failed to find a buyer for the plant which had been used to supply its now closed aluminium smelter (http://www.alcoa.com/). In addition there have been many examples where coal power stations have been decommissioned, including the demolition of the station and rehabilitation of the site, including for example: • NSW Pyrmont Power Station built in the early 1950's • NSW Tallawarra A and B built in mid 1950s to early 1960s • NSW Wangi A and B built in late 1950s

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
	(ongoing operation may no longer be feasible for engineering reasons) or the power station no longer being able to meet environmental or other operational requirements. For example, as noted in our December 2014 report,[44] a number of plant in the British 'BETTA' and PJM markets will need to close down by stipulated dates as a result of not meeting environmental emissions standards.	exit.	• NSW Wallerawang A and B built in late 1950s and early 1960s • VIC Newport A (1918), B (1923) and C (1950) • VIC Yallourn A (1924), B (1932), C (1954) and D (1957) QLD Swanbank A built 1967 was decommissioned in 2005 and demolished and the site rehabilitated in 2006/07.

44 Frontier December 2014 report, pp.35 and 41-42.

Table 2: Open cycle gas turbine generation

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
Dispatch at minimum stable generation	Aside from some hydro generation facilities, aero-derivative open cycle gas turbine generators operating on light fuel oil or off good quality gas supplies (in terms of pressure) are amongst the most flexible generation plants available in the NEM. The operational flexibility of OCGT plant is attributable to the fact that they comprise only a gas turbine; there is no steam turbine or HRSG.[45] This means that thermal fatigue risks are much lower than coal-fired or CCGT plant. While OCGTs have MSG levels (which tends to be around 40-50%) of their maximum dependable capacity, the way these plants operate, they rarely have to remain operational at these levels. This is because these plants are most economic to run to meet needle peaks in demand, management of system disturbances, and for black start capability.	The barriers to dispatching OCGT generators at MSG are typically economic in nature: because of the high fuel costs of these plant, it is seldom worthwhile to operate these plant if the spot market price is significantly below the fuel cost of the plant. Given the flexibility of OCGTs and their short start-up and shut-down times, it is typically more efficient to cease operation if spot prices fall and restart plant is prices subsequently rise. These plant are designed to have a relatively small number of starts in a year and will tend to operate, in total, less than 2%-3% of the year.	Figure 3 (top panel) in Appendix A provides an example of dispatch of an OCGT peaking plant (Somerton). It shows that production is irregular and production runs are short. The dispatch data shows that in most instances Somerton runs units that are committed at full power but there are some instances where the peaking units are part loaded.

45 PB report, pp.29-31.

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
Two-shifting	OCGT plants are not designed to operate for extended periods even within a day. They are economically suited to limited production over a few trading intervals.	There are no material technical or economic barriers to two-shifting OCGT plant: The start-up time for an OCGT is several minutes and does not vary according to how recently the plant was in operation – ie the hot, warm and cold start classifications do not apply. This is because the plant consists only of a gas turbine with no boiler that can suffer from thermal fatigue.[46] OCGT plants are not economically designed to run more than a few times a year due to typically relatively high fuel costs and low thermal efficiency. Short start-up times mean that start-up costs are relatively low.	
Seasonal shutdowns	Given OCGT's peaking role they tend to run at peak times of the year (summer and winter) and at other times where system disturbances require their operation.	Unlike coal fired generators, OCGT plants require very few staff to maintain and operate the plant. Indeed, most OCGT plants can be operated remotely and maintenance is usually undertaken via an OEM (original equipment	Figure 3 (top panel) in Appendix A shows that for Somerton peaking plant that, for the most part, it operates in summer and winter months when demand is high and more volatile. This is fairly typical for most peaking generators.

46 PB report, p.31.

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		manufacturer) timed maintenance contract. This avoids the difficulty faced by coal-fired generators who struggle to manage the ebb and flow or seasonal operation.	
Mothballing	Mothballing of OCGT power stations would occur if they did not cover their avoidable costs.	As noted above, OCGT plants require very few staff to maintain and operate the plant. This avoids the difficulty faced by coal-fired generators who struggle to find worthwhile employment for staff between the time when a plant is mothballed and when it is returned into service, or the difficulty of hiring staff that have the knowledge and skills to operate older style plants. OCGT tend to be much more of a one-design technology as compared to the more bespoke characteristics of coal-fired generators. This feature makes them more amendable to be recommissioned with relative ease after a period of mothballing. Since many OCGT plants operate on liquid fuel, they are not supplied under long term, take-or-pay fuel supply agreements and therefore these types of agreements do not create obstacles	See below.

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		to changing the short, medium or long term operations of these plant types.	
Decommissioning	Unlike the temporary shutdowns discussed above, decommissioning involves the permanent closure of a power station. Decommissioning of a power station can occur for a number of reasons. First, the same type of economic considerations that lead to temporary closures - prices that are below variable costs - are relevant to permanent closures. A decision to permanently close a power station, however, will involve consideration of costs and revenues over the remaining potential life of the power station, including the need for "stay-in-business" capital expenditure in future. Second, power stations may be decommissioned for technical reasons. This may be the result of the power station reaching the end of its technical life	There is a much broader range of potential barriers to decommissioning plant. Economic barriers are a result of uncertainty as to future costs and, in particular, revenues. The value of preserving real options in the face of regulatory, policy and market risks associated with future spot prices can favour delaying any decision to permanently close a power station. Regulatory, policy and market uncertainties are increased for operators that are vertically integrated, or where a peaker is used to firm up as the decommissioning of a peaking generator can complicate a gentailer's long term hedging strategy, potentially exposing the business to more contracting risk.	Gas turbines that are no longer required can be dismantled and easily removed to other markets where the capacity is required. For example, the OCGT units at Tamar Valley in Tasmania were relocated from Burlington New Jersey USA.[47] In 1982 Liddell Power Station suffered a type failure of the alternator windings affecting 3 of the 4 units. In response the NSW Electricity Commission purchased twelve 25MW units which were located at different existing power sites, some earmarked for decommissioning. These units operated for a short time and in the years following their use they were relocated to other parts of the State (e.g. 2 units were relocated to Liddell to act as black start units, other units were moved to Broken Hill to replace old diesel units). Over time many of these units were eventually sold off.[48]

47 See: http://www.industcards.com/cc-australia.htm

48 NSW Parliament Weblink: http://www.parliament.nsw.gov.au/prod/parlment/hanstrans.nsf/V3ByKey/LC19870211/$file/483LC051.pdf

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
	(ongoing operation may no longer be feasible for engineering reasons) or the power station no longer being able to meet environmental, safety or other operational requirements.	Uncertainty about policy interventions that affect peak demand (such as subsidisation of energy efficiency and energy storage) could frustrate decisions by businesses to decommission peaking generators. One significant advantage of peaking generators is that they can be relocated with relative ease and at reasonable cost. That is, their costs are not sunk. Similarly these units can be installed relatively quickly so if the market conditions improve then generators can respond in a timely way to take advantage of these more buoyant conditions.	

Table 3: Combined cycle gas turbine generation

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
Dispatch at minimum stable generation	Combined cycle gas generators are more flexible than coal-fired generators, but like all thermal generators they have a MSG level due to the inclusion of a heat recovery steam generator (HRSG), which utilises the heat from the exhaust gases of the gas turbine. As with coal-fired plant, operation at the MSG level may result from an attempt to minimise the cost of burning fuel (and incurring other variable costs) without incurring the cost, delays and performance effects associated with plant shut-downs and restarts. In the NEM, some CCGT plants operate as part of a co-generation facility where their operations are largely governed by the requirements of the steam load. This generally means that those CCGT will have a natural hedge against price downturns at off peak times (to a point).	The barriers to dispatching CCGT at MSG are largely economic in nature – just like coal-fired plant, CCGTs tend to operate less efficiently when at MSG than when at higher load, which increases their per-unit costs of operation. There may be some environmental barriers to operating CCGTs at MSG in cases where emissions exceed permitted limits at lower generation levels because the generator is not burning fuel as efficiently. Most CCGT are connected and run off the gas system and tend to have medium to long term gas supply agreements. For fuel cost to be economic these agreements tend to include a requirement for relatively high and stable load factors. This means that: To the extent that fuel contracts are of a take-or-pay form and cannot be easily traded out of, this increases the operating profits foregone by reducing output and deters operating at lower	Figure 3 (bottom panel) in Appendix A shows an example of a co-generation plant (Smithfield) where the power station has to operate continuously (for at least part of its capacity) to provide steam to an associated facility, In this instance Smithfield provides steam to a co-located cardboard recycling facility. Figure 3 (bottom panel) shows that half the capacity of Smithfield power station is operated continuously to manage its obligations to provide steam to the cardboard recycling facility.

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		(eg MSG) levels. Even if fuel contracts are not fully take-or-pay, any penalties associated with deviating from high load factors could also represent a barrier to operating CCGT plant regularly at MSG.	
Two-shifting	When operation at MSG is not an efficient response to low prices, coal-fired power stations may opt to temporarily close down individual units or the entire power station. In some case, patterns of two-shifting can be quite regular; for instance, power stations may shut down overnight or on weekends.[49]	As noted above under 'Typical rationale', there may be broader business constraints on CCGTs two-shifting if they operate as part of a co-generation facility. The technical barriers to two-shifting CCGT generators are not quite as significant as for coal-fired plant because the gas turbine element of CCGTs is about as flexible as an OCGT. This typically means that synchronisation times are relatively short regardless of the type of start (eg hot, warm, cold) and much shorter than for a coal-fired plant. However, starting up and bringing to full load the HRSG element of a CCGT takes a longer period of time. Because of the high	Two-shifting of CCGT plant is an increasingly common practice in many markets outside the NEM, mainly due to relatively low off-peak demand and the growth of renewable plant, particularly wind. For example, despite being designed to run as a baseload power station, Synergy's Cockburn CCGT plant in Western Australia commenced operating in a two-shift manner in April 2012, shutting down overnight at times of high wind output. Verve Energy Annual Report 2012, pp.11-12.

49 PB report, pp.17-18.

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		stream pressures involved, many CCGT components are thick-walled so the temperature changes do not occur evenly across the components. This results in differing rates of thermal expansion and contraction across the component and high material stresses.[50] This means that excessively frequent and/or rapid start-stop operation can result in thermal fatigue (see also the discussion of coal-fired generation above). As a result, CCGT power stations still take significant time and costs to reach full output. Start-up times to reach full output will depend on the length of time the unit has been out of service as well as on the vintage of the CCGT in question, with modern CCGTs more flexible than older CCGTs. For example, a:[51] Hot start is a start within 8 hours of a	

50 See, for example: http://energyinnovation.ie/2011/07/the-impact-of-two-shifting-on-heat-recovery-steam-generators-in-combined-cycle-gas-turbine-ccgt-power-plants/ (accessed 21 May 2015).

51 PB report, pp.27-29.

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		unit coming off load, generally during a period of two-shifting. A hot start requires approximately 15 minutes before synchronisation to the grid and then another 25-80 minutes to reach full load, depending on the plant technology/vintage. Warm start is a start within 8-48 hours of coming off load. A warm start requires approximately 15 minutes before synchronisation to the grid and then another 80 minutes to reach full load. Cold start is a start more than 48 hours of coming off load. A cold start requires approximately 15 minutes before synchronisation to the grid and then another 190-240 minutes to reach full load. Shutting down CCGTs is typically much faster than starting them up due to the absence of the same technical limitations. Shutting down CCGTs is also faster than shutting down coal-	

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		fired plant, due to the absence of coal combustion to be managed.[52] Similar considerations regarding the influence of input and output contracts apply to two-shifting CCGTs as for operating them at MSG. However, the transactions costs of trading out of these contracts may be less on a per-unit basis if two-shifting is expected to be a regular practice.	
Seasonal shutdowns	Seasonal shutdowns occur for the same reason as two-shifting: when operation at MSG does not make economic sense as an ongoing response to low prices. Seasonal shut downs are generally a response to expectations that average prices over a prolonged period will be below average variable cost.	The most significant obstacle to seasonal shut downs will be management of fuel contracts (which is a soluble problem), management of labour (which is not all that acute for this plant type as these plants do not require a significant permanent labour force).	Due to the drop off in demand, increase in supply of energy from solar panels, the relative abundance of water and high cost of Bass Strait gas, production from the Tamar Valley power station ceased mid CY14. See Figure 4 in Appendix A.
Mothballing	As with other temporary shutdowns, mothballing of CCGT power stations occurs	As for other forms of curtailment or shutdowns of CCGT plants that are	In July 2014 GDF Suez announced that it was going to offer only 230 MW of its 479 MW CCGT capacity

52 PB report, p.29.

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
	when low prices mean that the power station is unable to recover its variable costs of production. Mothballing is typically a longer-term strategy than a seasonal shutdown and, when commenced, may be for an indefinite period of time.	part of a co-generation facility, the requirement to continue providing a steam load will hinder any decision to mothball as it is generally uneconomic to generate steam other than through a generator. Given the small workforce required to run these plants and the broad familiarity with the standard design of most CCGT plants, putting off the workforce will not represent a material barrier to mothballing of CCGT plants.	into the NEM, effectively halving the station's capacity.[53] However, all units remain registered with AEMO and operational.
Decommissioning	Unlike the temporary shutdowns discussed above, decommissioning involves the permanent closure of a power station. Decommissioning of a power station can occur for a number of reasons. First, the same type of economic considerations that lead to temporary closures - prices that are below variable	There are few barriers to decommissioning a CCGT provided any steam load requirements of a co-generation facility are managed. These plant types tend not to generate large site remediation costs, the costs of displacing the workforce is small given these plants require only a small permanent workforce, fuel supply	To-date, no CCGT units have been decommissioned in the NEM as they are relatively new technology. However, Hydro Tasmania is reportedly considering the sale of the 210MW CCGT unit at Tamar Valley Power Station due to the lack of demand.[54]

53 Adelaide Now, Weblink: http://www.adelaidenow.com.au/news/south-australia/pelican-point-powerstation-will-cut-more-than-half-its-generation-capacity-early-next-year-threatening-jobs/story-fni6uo1m-1226978458743. Also in AEMO (2015), *South Australian Fuel and Technology Report*, South Australian Advisory Functions, January.

54 ABC Weblink: http://www.abc.net.au/news/2014-12-04/tas-government-tamar-valley-power-station-sale/5940042

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
	costs - are relevant to permanent closures. A decision to permanently close a power station, however, will involve consideration of costs and revenues over the remaining potential life of the power station, including the need for "stay-in-business" capital expenditure in future. Second, power stations may be decommissioned for technical reasons. This may be the result of the power station reaching the end of its technical life (which is not a problem in the NEM so far) or the power station no longer being able to meet environmental, safety or other operational requirements (also not a problem in the NEM so far given the age of all CCGTs currently operating).	agreements tend not to be so long that a decommissioning cannot be planned for and in any case any gas remaining under an agreement can almost always be redirected to another offtaker. Nevertheless, the indirect opportunity costs of closure may still be significant.. In particular, with CCGT plant, the value of preserving real options in the face of regulatory, policy and market risks associated with future spot prices can favour delaying any decision to permanently close a power station. Regulatory, policy and market uncertainties are increased for operators that are vertically integrated as the decommissioning of a flexible generator such as a CCGTcan complicate a gentailer's long term hedging strategy, potentially exposing the business to more contracting risk. As with OCGT plants, a significant advantage of a CCGT plant is that they can be relocated with relative ease and at reasonable cost. That is, their costs are not entirely sunk. Similarly, these units can be installed relatively quickly so if the market conditions improve	

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		then generators can respond in a timely way to take advantage of these more buoyant conditions. This will all tend to encourage exit at a particular location.	

Factors relevant to exit by individual generator technologies and stages

Table 4: Hydro generation

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
Dispatch at minimum stable generation	Operation at the minimum stable generation level may be a result of the operator attempting to minimise generation when prices are low but leave the plant in a ready state to take advantage of any price rise.	Most hydro plants are highly flexible generators that can ramp up and down relatively quickly. This means that they usually do not have to be operating at a minimum level to be able to quickly respond to a rise in price. Also, the variable expense of hydro generator is very low – but the opportunity cost of water can be very high. Hydro generators exhibit very high fixed costs and the plants are typically built robustly with most major hydro plants that were built in the mid 20th century still operating economically and efficiently today. There are three main types of hydro systems: Impoundment/Storage – this usually involves the storage of a large amount of water which is released to generate electricity when it is most valuable and to maintain a minimum flow downstream and dam level for environmental and recreational use Run-of-the-river/diversion – this type of system usually involves the use of either a natural or man-made barrier which is designed to manage the continued flow of water downstream while also creating opportunities to generate electricity in the process.	Figure 5**Error! Not a valid result for table.** in Appendix A shows the dispatch over 2014 for the run-of-the-river Kareeya power station. It shows that for most of 2014 it had sufficient water to run 4 units at close to full power. In the summer when water was not as available the power station ran 2 units in a regular periodic pattern, supplemented by one unit operating at reduced power continuously to ensure continuous water flow.

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		Pumped storage – these facilities use the intraday differences in the value of electricity to generate electricity from an upper storage when electricity is relatively valuable and then pump the water captured from this operation in a lower storage back to the upper storage at times when the electricity price is low. For this cycling of water to be economic there has to be a large enough value difference between the generation and pump cycle to make up for the additional electricity required to pump water from the lower storage to the upper storage. Generally in pumped storage systems about 70% of the electricity used to pump water is generated from the facility, although this percentage varies. Hydro plants face no technical obstacles to generating at different levels of output. In the case of storage systems and pumped storage generators they do face strong incentive only to use their limited water supplies to generate electricity when it is most valuable. In most cases this coincides with times when the system needs the power most – peak times. Normally, a storage or pump storage hydro generator would not choose to generate at their technical minimum as this would normally result in uneconomic generation. Run-of-the-river generators are generally designed to operate almost constantly at a	

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		minimum level to meet their environmental licence conditions to ensure a stable water flow downstream. They can also ramp up to generate more to make use of excess water. So there are no technical or economic obstacles to a run-of-the-river generator operating at a minimum level.	
Two-shifting	As above	When water is available in storages, a two shifting operation is consistent with the way most impoundment and pumped storage systems would usually choose to function. This means that there are no technical, regulatory or economic barriers to operating as two-shifting operation. In contrast, a run-of-the-river operation may be constrained from moving to a two shifting operation because of restrictions on the way they can use water – that is, they have to constantly run to ensure downstream flow.	Figure 6 in Appendix A shows the intermittent pattern of operation of two hydro generators in the Southern Alps system. The top panel shows the operation of Dartmouth by dispatch interval over CY14. The Murray Darling Basin Commission controls releases from the dam to meet irrigation requirements. Generally water is released into the Murray system and stored in Lake Hume to meet farmers' requirements for summer crops. However, as the data shows, Dartmouth does also operate in winter to help meet peak demand. The data also shows that production from Dartmouth is intermittent throughout summer. Eildon operates in a similar fashion to Dartmouth (see bottom panel of Figure 6)
Seasonal shutdowns	Seasonal shutdowns occur for the same reason as two shifting: when operation at	The most significant obstacle to a seasonal shut down will be the management of water	Figure 7 in Appendix A shows the seasonal pattern of production at Hume power station

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
	minimum stable generation does not make economic sense as an ongoing response to low prices. Seasonal shut downs are generally a response to expectations that average prices over a prolonged period will be below average cost.	resources. Impoundment and pumped storage hydro generators will have to manage their water levels so that they have sufficient headroom in their reservoirs to manage seasonal inflows while maintaining downstream levels. Run-of-the-river generators will not normally be allowed to shut down generation (which are normally associated with water releases) on a seasonal basis to manage supply into the market.	on the Murray River. Water for Hume weir is derived from the Snowy scheme which collects and stores water for irrigation of the Murray Irrigation Area during the summer, among other places.
Mothballing	As with other temporary shutdowns, mothballing of hydro power stations would occur when low prices mean that the power station is unable to recover its variable costs of production. Mothballing is typically a longer-term strategy than a seasonal shutdown and, when commenced, may be for an indefinite period of time.	Given the avoidable costs of a hydro generator are relatively small (ignoring major maintenance expenses) hydro generators are likely to be one of the last generators to be mothballed. It will only be high maintenance costs that will result in a hydro generator being mothballed.	In 1974 No 1 Power Station at Burrinjuck was destroyed by flooding. The power station was built downstream of the dam and was exposed to the risk of flooding.[55] No 1 power station was decommissioned but the other generating units continued operating. In any case this power station was primarily built for the control of flood water and for irrigation, not power generation. This means that the operation of the power station is not essential to justify the continued expense of maintaining the dam. Indeed, this is a feature of most

55 Institute of Engineers (undated), Burrinjuck Dam and No 1 Power Station, Nomination for National Engineering Landmark, submitted by Heritage Committee of Sydney Division of Institute of Engineers Australia. Weblink: https://www.engineersaustralia.org.au/portal/system/files/engineering-heritage-australia/nomination-title/Burrinjuck_Dam_Nomination.pdf

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
			hydro power stations in Australia which means that the mothballing or closure of a hydro power station is unlikely to be associated with the high costs of demolishing a dam and rehabilitating the dam site. Lake Margaret power station in Tasmania is one of the oldest hydro electric power stations in Australia. The power station is located over 300m below the dam wall in Yolande Valley. The power station was closed in 2006 because of the high cost of maintaining the wooden pipeline feeding the power station water from the dam. However, following a major refurbishment the power station was reopened in 2009 after a new wooden pipeline was installed. The 180 MW Dartmouth power station suffered a catastrophic failure in 1990 when two steel beams left in the penstocks after a maintenance cycle were swept into the turbine blades operating at full power. The station was repaired and re-entered service three years later. The nature of the dam prevented water being released downstream through the turbines. The plant had to pump water over the dam wall into the spillway to maintain downstream water

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
			flows and to regulate the dam level.
Decommissioning	Unlike the temporary shutdowns discussed above, decommissioning involves the permanent closure of a power station. Decommissioning of a power station can occur for a number of reasons. First, the same type of economic considerations that lead to temporary closures - prices that are below variable costs - are relevant to permanent closures. A decision to permanently close a power station, however, will involve consideration of costs and revenues over the remaining potential life of the power station, including the need for "stay-in-business" capital expenditure in future. Second, power stations may be decommissioned for technical reasons. This may be the result of the power station reaching the end of its technical life or the power station no longer being able to meet environmental, safety or other operational requirements.	Decommissioning a hydro generator can mean anything from ceasing generation (while still allowing water flows) to the more difficult task of draining a reservoir, demolishing the dam and restoring the river environment to the state similar that that which existed prior to the construction of the dam. Thus far in Australia, no major hydro power station has been decommissioned including the removal of a dam and rehabilitation of the associated site (some dams have been removed, but not ones that have incorporated a generator). There would be few challenges in decommissioning a hydro generator (not involving the removal of the associated dam). This involves some expense in securing the existing generator technology for decommissioning but it would not normally involve the expensive removal of generation equipment and site rehabilitation. However, if decommissioning required the removal of the associated dam and rehabilitation of the site, this would involve a prohibitively high cost and it would likely be cheaper for a hydro generator to undertake the necessary expenses to continue operations.	There appears to be no examples of any major hydro electric facility being entirely decommissioned.

Table 5: Other renewable generation

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
Dispatch at minimum stable generation	Operation at the minimum stable generation level may be a result of the operator attempting to minimise generation when prices are low but leave the plant in a ready state to take advantage of any price rise.	Renewable generators mainly comprise wind generators, solar PV and waste gas from mines and rubbish tips. These power sources have typically been developed pursuant to various Federal and State government subsidy schemes to encourage the development of these technologies. Larger-scale renewable generators have often been funded via Power Purchase Agreements that have been underwritten on the basis of the renewable credits they create. The suppliers are therefore keen to produce as many renewable credits as possible to maximise the value of their investment. This means that renewable generators almost always generate when they can – for example, when the wind blows, when the sun shines and when a mine or tip gives off methane (i.e. all the time). The above does not mean that the output of these technologies cannot be controlled. For example, output of the newer variable speed wind generators can be controlled by pitch adjustment	Figure 8 in Appendix A shows the pattern of output of Lake Bonney wind farm In South Australia over the FY 2012. While there are peaks and troughs in production it is clear that output is highly random, reflecting the randomness of the wind that drives the turbines.

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
		to the blades, yaw adjustment by rotating the wind turbine with respect to the direction of the wind, and/or using and internal brake on the rotor shaft. For waste gas facilities, for facilities where gas can be controlled the power generator can be wound back to produce less electricity and the gas preserved for future use. Where gas cannot be controlled the gas is vented when power station output is reduced. With regard to solar, where reflectors are used they can be reoriented to reduce output. For PV systems, they tend to be configured to automatically produce the maximum amount when the circumstances suit. However, all grid connected systems have anti-islanding to protect the grid when there is an outage on the grid. Having said this, this form of control is not in the hands of the 'producer' as it is mandatory and automatic.	
Two-shifting	As above	As above	
Seasonal shutdowns	Seasonal shutdowns occur for the same reason as two shifting: when operation at	As above Seasonal weather patterns affect the	No examples for wind or solar facilities. Queensland sugarcane and other biomass facilities

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
	minimum stable generation does not make economic sense as an ongoing response to low prices. Seasonal shut downs are generally a response to expectations that average prices over a prolonged period will be below average cost.	amount of production from wind and solar facilities but this generally results in variation, not shutdowns. As such, seasonal shutdowns would be likely to reduce revenue more than costs over a given period. In the case of biomass facilities, seasonal shutdowns are usually motivated in response to fuel scarcity as opposed to managing profitability.	operate seasonally on the harvest cycle but would likely produce year round if economically priced fuel was available.
Mothballing	As with other temporary shutdowns, mothballing generally occur when low prices mean that the power station is unable to recover its variable costs of production. Mothballing is typically a longer-term strategy than a seasonal shutdown and, when commenced, may be for an indefinite period of time.	Renewable generators are typically characterised by having large fixed and very low variable costs. Renewable generators can therefore withstand drawn-out periods of low prices, especially since they are usually developed off the back of Power Purchase Agreements that guarantee the recovery of their fixed and variable costs (or sale of renewable certificates which are less affected by underlying energy market prices). This means that renewable generators are likely to be the last generator type to be mothballed or decommissioned as a consequence of low prices.	

Factors relevant to exit by individual generator technologies and stages

Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
Decommissioning	Unlike the temporary shutdowns discussed above, decommissioning involves the permanent closure of a power station. Decommissioning of a power station can occur for a number of reasons. First, the same type of economic considerations that lead to temporary closures - prices that are below variable costs - are relevant to permanent closures. A decision to permanently close a power station, however, will involve consideration of costs and revenues over the remaining potential life of the power station, including the need for "stay-in-business" capital expenditure in future. Second, power stations may be decommissioned for technical reasons. This may be the result of the power station reaching the end of its technical life or the power station no longer being	Renewable generators ought to be the easiest of all electricity supply sources to decommission since they are not associated with toxic sites nor major land works that need to be rehabilitated.	The Clean Energy Council (CEC) has identified only one wind farm decommissioned in Australia to-date.[56] The CEC assert that strict planning guidelines prevent obsolete wind farms from being abandoned. To the extent that environmental planning laws prevent obsolete wind farms from being abandoned this is likely to prevent long term mothballing of wind farms. In respect of solar panels, technological developments mean that much of the materials used in solar PV systems can be recycled. Once these panels come to the end of their useful life these (mostly) small scale facilities can be replaced and recycled.[57]

56 See Clean Energy Council, *Wind Energy: The Facts, Decommissioning Wind Turbines*, July 2013, available at: https://www.cleanenergycouncil.org.au/technologies/wind-energy.html (accessed 1 June 2015).

57 See http://www.renewableenergyfocus.com/view/3005/end-of-life-pv-then-what-recycling-solar-pv-panels/ (accessed 1 June 2015).

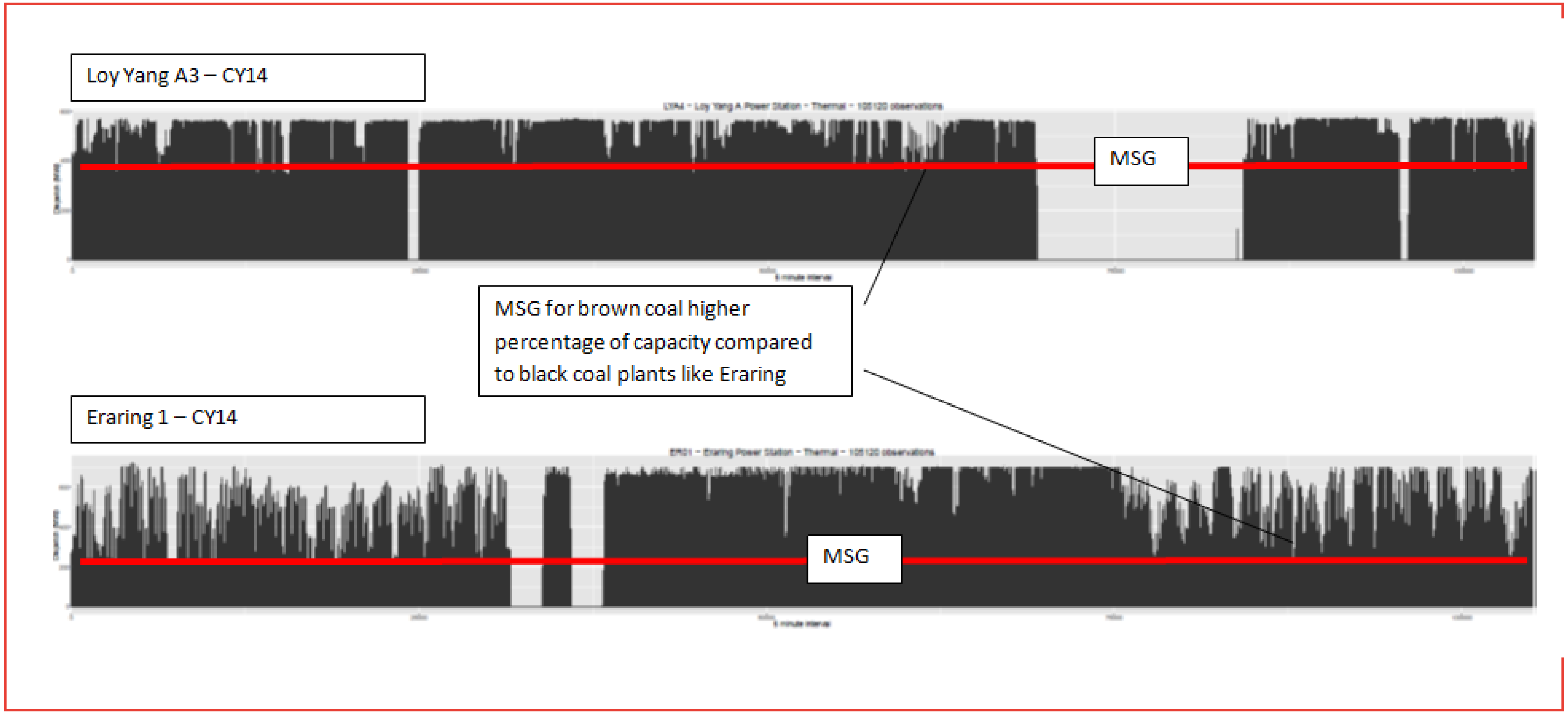
Stage of reduced operation or exit	Typical rationale	Potential barriers to this stage	Example
	able to meet environmental, safety or other operational requirements.		

Factors relevant to exit by individual generator technologies and stages

Appendix A – NEM generator operating patterns

This Appendix contains charts of the operating patterns of selected generators in the NEM highlighted in the body of the report.

Figure 1: Loy Yang and Eraring



Appendix A – NEM generator operating patterns

Figure 2: Northern

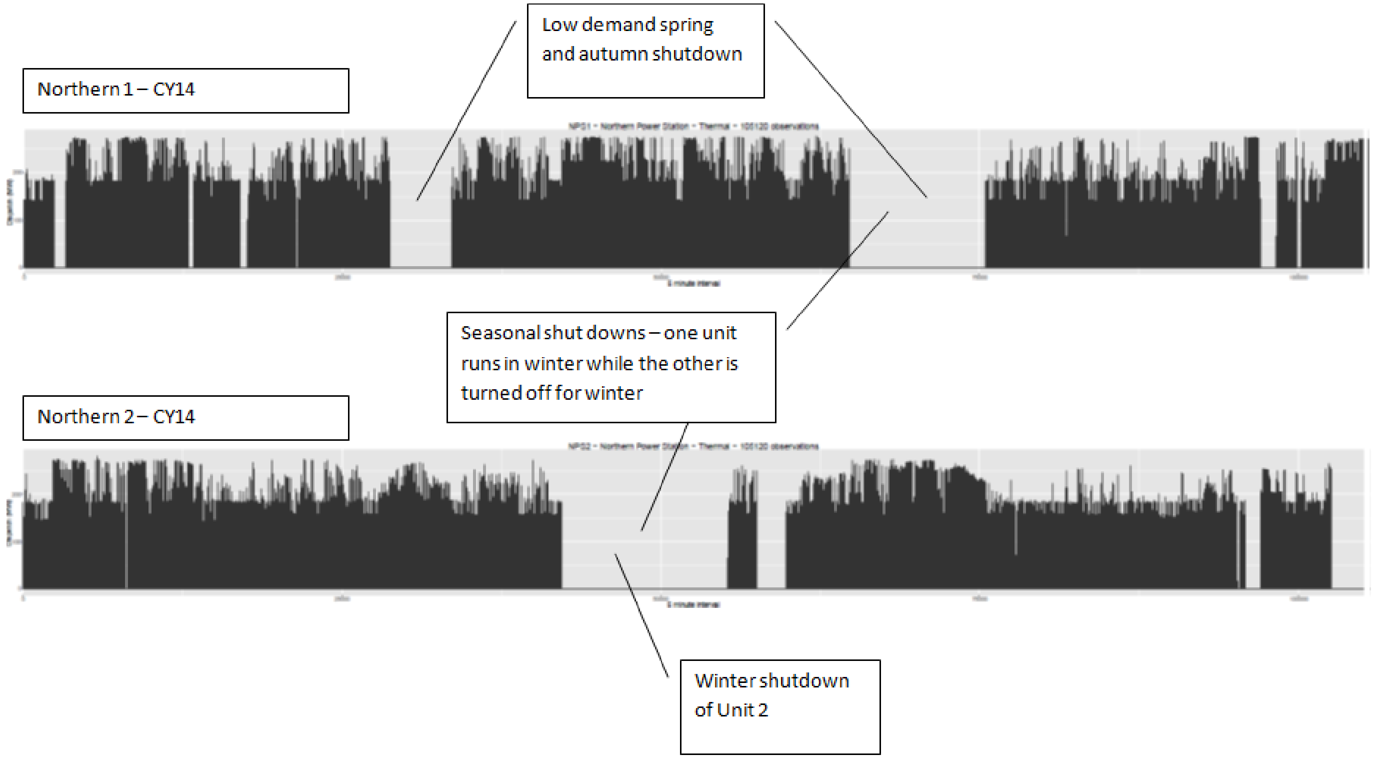
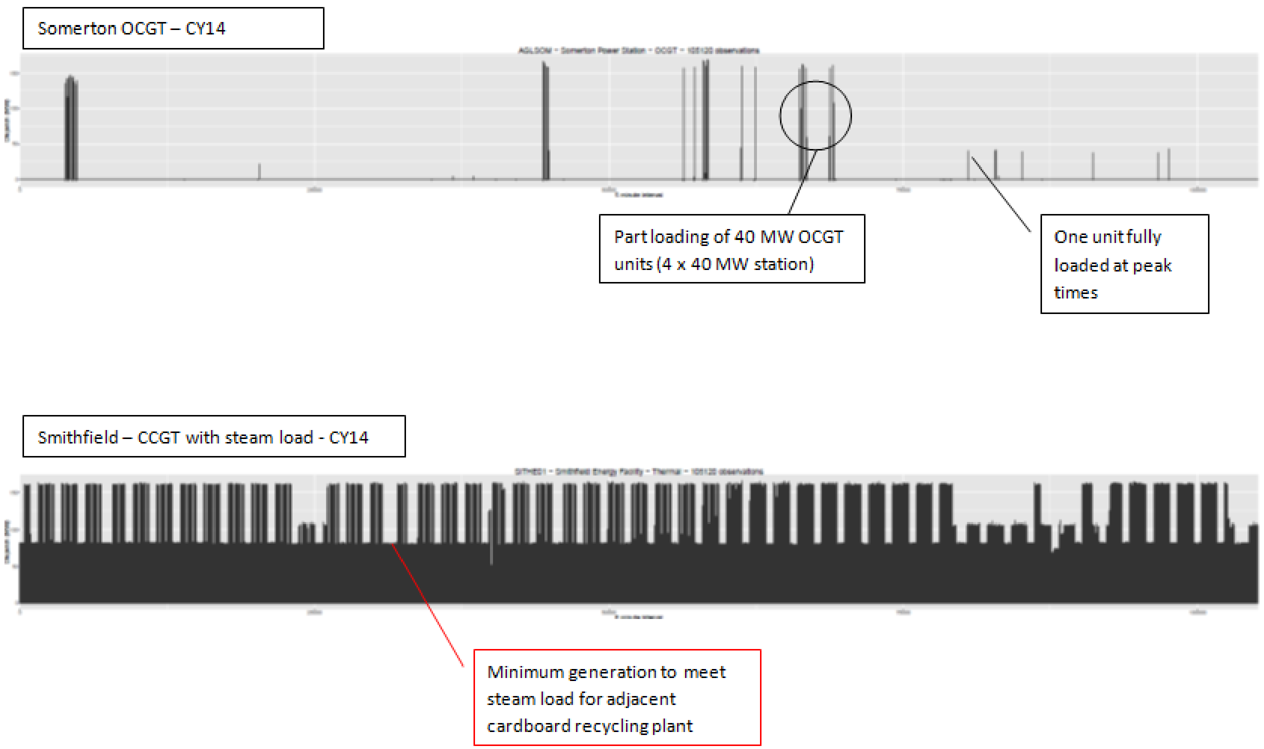


Figure 3: Somerton and Smithfield



Appendix A – NEM generator operating patterns

Figure 4: Tamar Valley CCGT

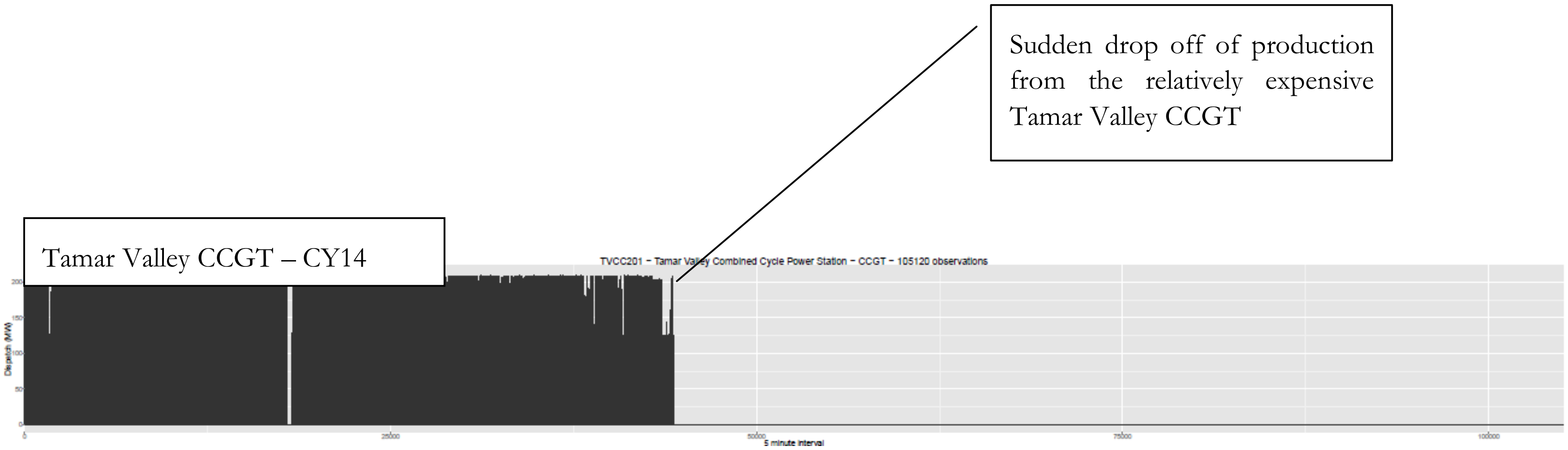
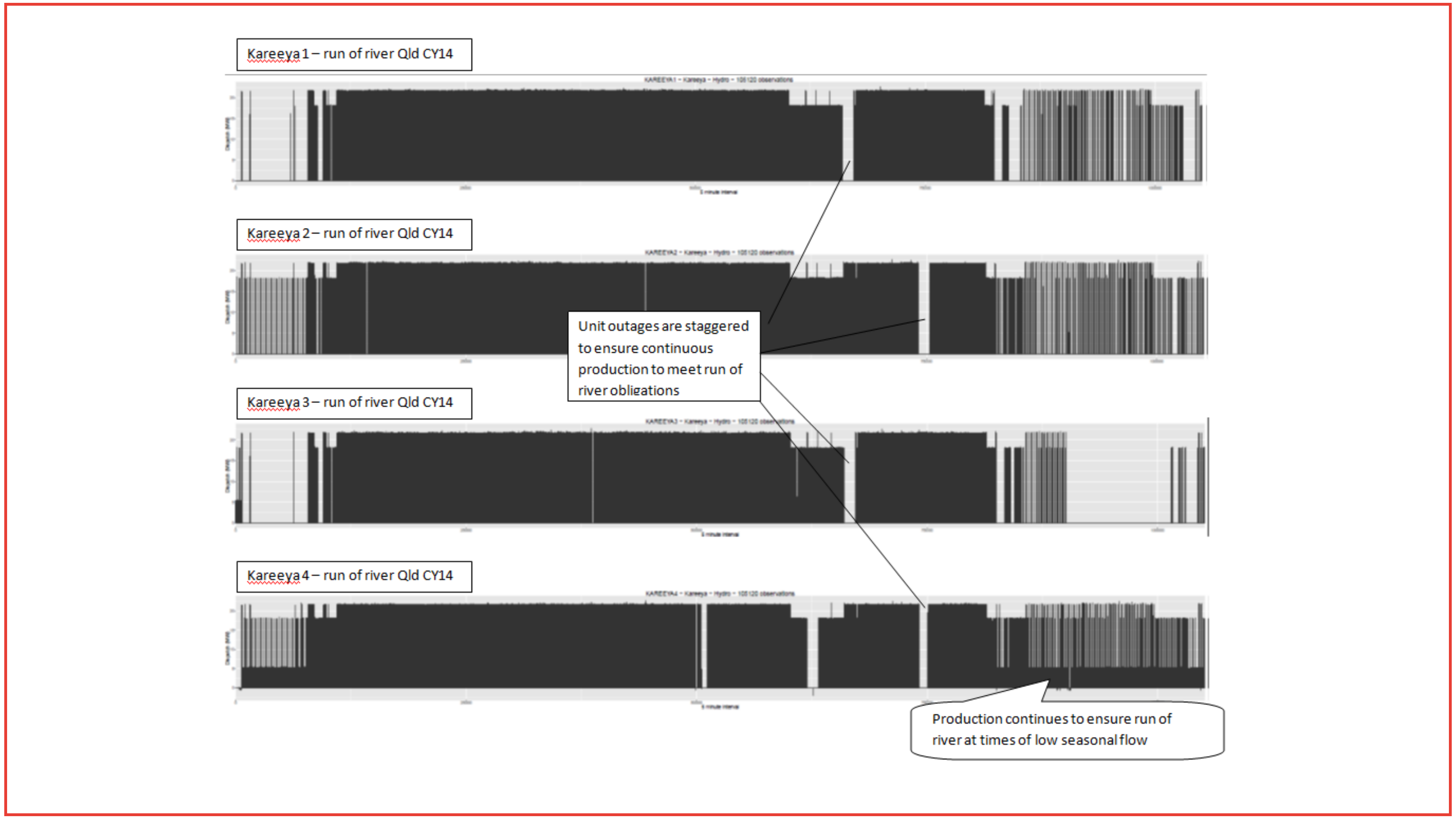
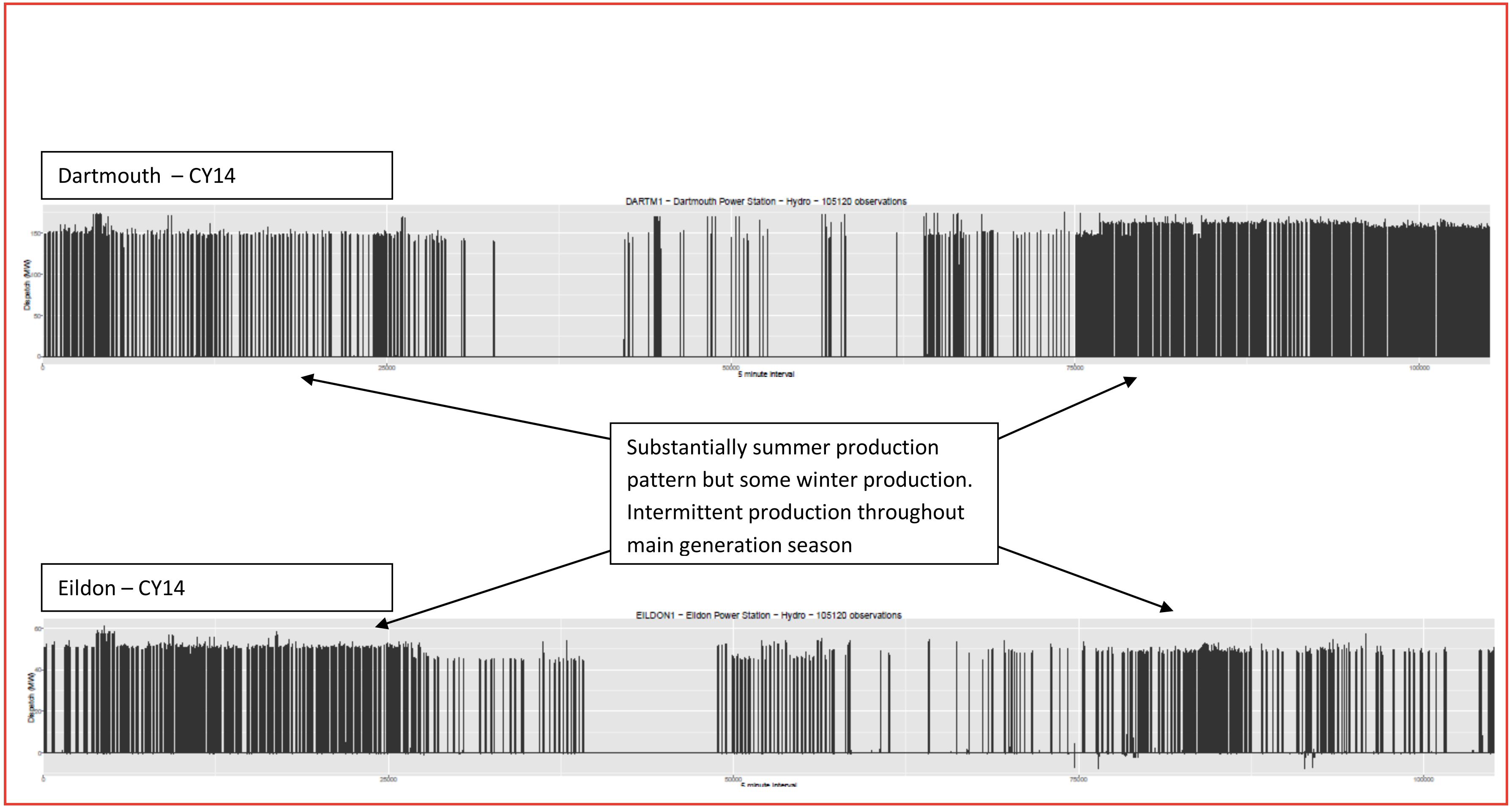


Figure 5: Kareeya (run of river)



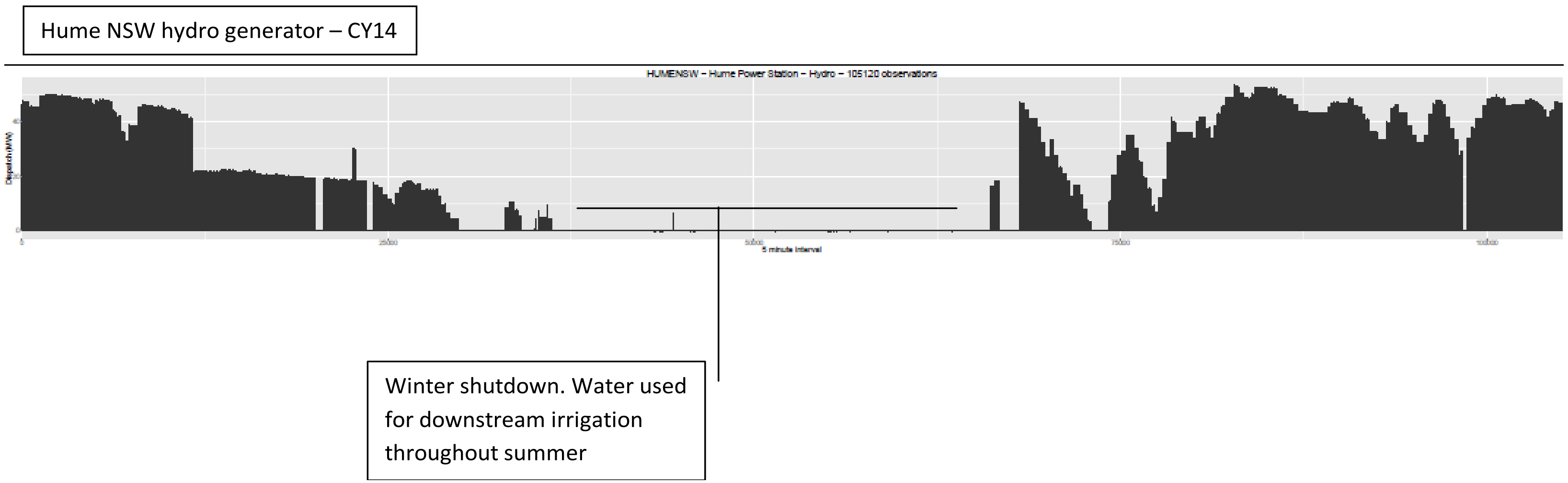
Appendix A – NEM generator operating patterns

Figure 6: Southern Alps hydro generators



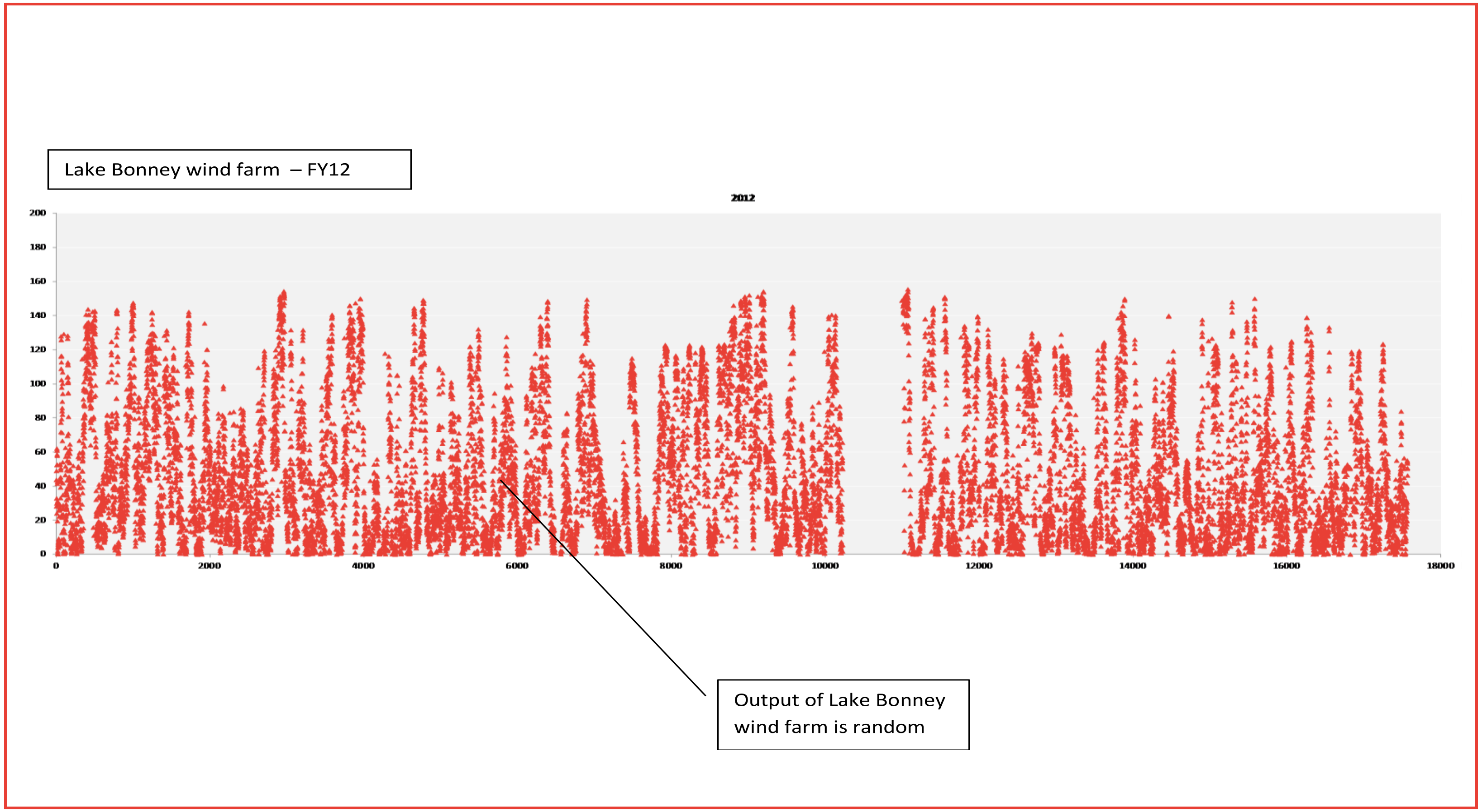
Appendix A – NEM generator operating patterns

Figure 7: Hume NSW hydro generator



Appendix A – NEM generator operating patterns

Figure 8: Lake Bonney wind farm (FY 2012)



Appendix A – NEM generator operating patterns

Appendix B – Forms and implications of generator commercial commitments

This Appendix has been prepared by Johnson Winter & Slattery (JWS).

There is a variety of commercial frameworks under which generators make their capacity available to the NEM. In order to put in context the commercial issues that are likely to arise when considering a form of exit, this Appendix provides a general description of two commercial models for thermal plant:

Ownership and operation of a generator by an independent power producer (**IPP**) who sells the electrical output under contract to a NEM market participant and

Ownership and operation of a generator by an entity that is also a NEM market participant (**Gentraders**). Gentraders may be part of a group that also retails power (**Gentailers**).

This is followed by commentary about how these commercial arrangements may have an impact on a decision to exit the market.

IPPs

Nature of IPPs

In the context of the NEM, an IPP will own and operate the plant but does not take the risks associated with NEM participation. Decisions about when to generate and at what level (and therefore, what price to bid into the NEM and what hedging is required) are made by the party buying the generation output from the IPP (the **Offtaker**). The NER supports this commercial structure through the intermediary arrangements and (in some cases) by means of derogations. These provisions, in general terms, exempt the plant operator from the obligation to register and require another person to register in their place.

The generation output from an IPP would typically be sold under a long term power purchase agreement (**PPA**) with the Offtaker. The PPA supports the initial investment decision and any third party financing as well as any long term commitments given by the IPP to fuel suppliers and infrastructure providers. If the IPP is responsible for fuel supply, it will need long term fuel supply agreements and generally, transportation contracts to transport the fuel by pipeline or rail. The Offtaker may instead supply the fuel (the tolling model). Generally the IPP will arrange the contract for connection to the grid.

All these third party contracts are likely to be based on a take-or-pay model, with the result that there is a fixed minimum annual cost for fuel, transport and (depending on how regulation applies) connection regardless of how much power is generated.

Long term PPAs take a number of different forms and are of varying complexity. When negotiating a PPA, key concerns of the parties will include the following:

- The IPP will wish to secure a revenue stream to cover its fixed and variable costs.
  - The fixed costs are incurred regardless of whether the plant is called on to generate and would typically include capital costs (including its investment return) fixed operation and maintenance costs and fixed third party costs such as take-or-pay commitments to fuel suppliers and infrastructure providers. Typically the tariff structure allows for recovery of fixed costs through regular periodic payments which reflect the MW capacity of the plant which was available to generate during the period the payment relates to.
  - The variable costs are incurred when the plant is producing electricity and will include fuel costs (if the IPP and not the Offtaker is paying for fuel) and variable operation and maintenance costs. Typically the tariff structure provides for these costs to be recovered on a per MWh basis for generation and a per-start basis for starts.
- The Offtaker will wish to ensure the PPA gives the IPP incentives to operate and maintain the plant in a manner that maximises availability (the time when the plant is available to operate at its usual capacity), reliability (broadly, the tendency not to trip or otherwise require unplanned outages), performance (operating in a manner consistent with design parameters and connection obligations) and, if the Offtaker is paying for fuel, efficiency (output per unit of fuel used).
  - Typically, the 'availability' element in the tariff structure will be set based on an assumption about the level of availability consistent with good operating and maintenance practices and the degree of excess capacity, if any, in the plant. If availability falls short of this assumption, the IPP will suffer a loss of revenue.
  - A charge abatement or liquidated damages regime is typically used to provide incentives to maintain reliability, performance and (where relevant) fuel efficiency.
- The IPP will wish to ensure that the Offtaker only requires the plant to operate in accordance with its intended design. The PPA will allow the Offtaker to control the times and level of operation through bidding into the NEM but subject to operating constraints. Depending on the plant type, these may include minimum run hours, minimum and maximum levels of

generation, a maximum number of starts per year and bidding that is otherwise consistent with operating parameters.

- Given the incentives in the PPA described above, the IPP will be concerned with any operating regime that may impact on availability, reliability, performance or (in appropriate cases) fuel costs. For example, plant degradation may result from long periods in storage and so a plant designed for baseload operation may have in increased risk of trips if moved to a different operating mode.
- The IPP will also be concerned to preserve the validity of the warranties given by the equipment supplier and by the maintenance provider. These warranties will be based on a commitment to operate the plant in the manner for which it was designed.

Implications of IPP exit decisions

Dispatch at minimum stable generation

We would not expect this strategy to raise any major concerns for the IPP in the commercial model described above. Commercially it may prefer to operate at a higher level of output (for example if it benefits from the variable element in the tariff) but the two-part tariff model is intended to facilitate plant operation at minimum output levels.

The Offtaker will be able to mitigate variable PPA costs but the fixed costs will remain payable subject to any incentive regime.

Two-shifting or seasonal shutdowns

If the plant has been designed for two-shifting or seasonal shutdowns and the PPA has been designed to accommodate those operating modes, then we would expect few issues. If not, we would expect there to be significant issues to be resolved between the IPP and the Offtaker before the operating mode can change materially.

In our experience, resolution of these issues can require extensive renegotiation of the PPA and related agreements and so will not be undertaken lightly by either party.

The IPP will wish to ensure that the change in operating mode does not lead to a loss of revenue. While there may be no direct loss of revenue under a PPA based on an availability tariff, the IPP may be concerned about the impact of long shutdowns or increased starts on reliability (and hence availability), performance or efficiency which would in turn increase the IPP's exposure to the liquidated damages regime.

The IPP will also be concerned at any changes that invalidate, or reduce the value of, plant or maintenance warranties or require renegotiation of maintenance contracts.

There may be very little opportunity to reduce fixed costs payable to fuel or infrastructure suppliers; nor however should these need renegotiation unless the new operating regime is likely to isolate any flow rate restrictions relating to gas supplies. The Offtaker may be unable to reduce fixed costs by negotiating a new operating regime and indeed may be faced with a claim for an increase. It may nonetheless benefit from reduction in variable costs and if it is also the fuel supplier for the plant, from increased flexibility to divert the fuel (particularly gas) to other uses.

The Offtaker may itself face additional market risk if the new operating regime has a negative impact on plant performance.

Mothballing

We are aware of, but do not regard as typical, long term PPAs that allow the Offtaker to require the IPP to mothball the plant.

Mothballing may enable the Offtaker to reduce the fixed charges under the PPA and (where it is the fuel supplier) to divert the fuel.

An IPP operating under a long term PPA is likely to have similar concerns about the effect of mothballing on the plant to those described above.

Power station decommissioning

An Offtaker's decision to pursue early termination of a PPA will likely require the Offtaker to pay termination charges covering the remaining life of the PPA. Some PPAs include provisions about the calculation of termination payments and if not negotiation will be required.

In either case, the termination charges are likely to cover both payments to the IPP and payments associated with the termination of long term fuel supply, infrastructure and maintenance contracts.

Closure may not trigger rehabilitation costs for the Offtaker since it is likely that the IPP itself will retain those rehabilitation obligations. Sources of rehabilitation obligations are discussed below at 2.2.

Gentrader model

Nature of Gentrader arrangements

In the Gentrader model, the plant owner and operator is also the market participant. The decision to invest in the plant is underpinned by the owner's views about market conditions and the needs of its own portfolio.

Like the IPP, the Gentrader will face a range of fixed costs including financing, fixed costs under long term fuel supply and infrastructure arrangements and fixed operation and maintenance costs.

The Gentrader will have the same operational concerns as an IPP; that is, it will be seeking to maximise the availability, reliability, performance and fuel efficiency of its plant and will wish to maintain the validity of equipment supply and maintenance warranties. The Gentrader's exposure to poor plant performance arises both through loss of revenue from the National Electricity Market and (where the plant is part of a portfolio of generation, electricity derivatives and retail commitments) increased exposure to high market prices.

Implications of Gentrader exit decisions

The Gentrader's commercial model gives it greater flexibility, compared to the Offtaker in an IPP model, to make decisions about running at a reduced level of output, two-shifting or mothballing, since it will both enjoy the benefits and carry the costs and risks. The Gentrader may also have greater flexibility to reverse those decisions when market conditions change compared to the IPP, where that option may be foregone as the result of a renegotiation.

The Gentrader's ability to reduce fixed costs is likely to be constrained by take or pay provisions in long term contracts for fuel (assuming it is not self-supplying) and infrastructure services.

A decision to close and decommission a plant is likely to trigger termination payments under long term contracts with third parties and may trigger site remediation obligations, as discussed in the body of this report.

Appendix C – Jurisdictional instruments

This Appendix has been prepared by Johnson Winter & Slattery (JWS).

Table 6: South Australia

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Electricity Act 1996 (SA) *Electricity (General) Regulations* 2012 (SA) (These instruments regulate the electricity supply industry in South Australia.)	Electricity generation requires a licence under section 15. Licences are subject to the conditions set out in these legislative instruments and the licence itself.	None identified	The Essential Services Commission of South Australia (**ESCOSA**) must make generation licences subject to certain conditions some of which could potentially impose costs on a generator's ability to reduce operations or exit the market. These include conditions requiring: compliance with codes or rules made by ESCOSA (s 21(1)(a)) the holder not to do anything affecting the compatibility of the generating plant with any transmission or distribution network it forms part of that could prejudice public safety or the safety of the power system (s 22(1)(b)) and the holder to prepare and periodically revise a safety and technical management plan dealing with prescribed matters, including the safe commissioning, operation, maintenance **and decommissioning** of electricity infrastructure owned or operated by the person (s 22(1)(c) and Regulation 72(2)(a)). Licences can be surrendered under section 29 by the holder giving at least six months notice to ESCOSA.

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Subordinate Instruments[58]	Compliance with these subordinate instruments required by conditions of generation licence under section 21(1).	None identified	The Electricity Transmission Code requires generators that are required under the terms of their licence to provide access to their plant to entities holding transmission or distribution licences to enter into agreements providing for such access (paragraph 7.1.1). These agreements are not publicly so it is not possible to confirm whether their terms could obligations or restrictions on the generator's ability to reduce operations or exit the market (although we consider that this would be unlikely).
Electricity Corporations (Restructuring and Disposal) Act 1999 (SA) (This Act provides for the privatisation of certain publicly owned electricity assets in South Australia.)	No generation licensing obligations	No express barriers to exit although certain agreements entered into pursuant to this Act imposed conditions relating to minimum operating and non surrender periods	Under this Act, the South Australian Government took steps to maintain certain generation capacity for certain periods of time. Under section 17 the Treasurer was required to endeavour to ensure that certain leases entered into with respect to prescribed electricity assets contained specified terms. One such term was a right for the lessor to terminate the lease if the lessee caused a substantial cessation of use of the leased assets for their intended purpose in the

58 Covers the following instruments to the extent that they apply to holders of electricity generation licences issued under the *Electricity Act* 1996 (SA): the Electricity Transmission Code (TC/07), the Electricity Distribution Code (EDC/12), the Electricity Metering Code (EMTC/08) and the Electricity Industry Guideline No. 4 Compliance Systems and Reporting (EG4/4) as well as several publicly available electricity generation licences granted under the *Electricity Act* 1996 (SA).

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
			electricity supply industry. We have reviewed the publicly available information relating to one long term lease for generating plant entered into pursuant to this Act – the lease entered into in September 2000 for the Northern Power Station (a coal powered station located near Port Augusta). The information available indicates that the lessor was required to maintain the generating plant at its capacity at the lease commencement for a "minimum operating period" (the first 10 years of the lease). The reports indicate that the purpose of this condition was to provide certainty as to the assessment of the electricity demand/supply balance in South Australia over that period.

Table 7: Victoria

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Electricity Industry Act 2000 (Vic) (Regulates the electricity supply industry in Victoria)	Electricity generation requires a licence under section 16. Licences are subject to the conditions set out in these legislative instruments and the licence itself.	None identified	The Essential Services Commission (**ESC**) may impose conditions on a licence that could potentially impose costs for reducing operations or exiting the market including conditions, amongst other things: • requiring the licensee to enter into agreements on specified terms or on terms of a specified type (s 22(b)) • requiring the licensee to observe specified orders in council, codes, standards, rules and guidelines (s 22(l)) • presenting the licensee from engaging in or undertaking specified business activities (s 22(o)) and • specifying methods or principles to be applied in the conduct of activities authorised by the licence (s 22(q)) The ESC may revoke a generation licence in accordance with the procedures set out in the licence (s 29(3)).

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Subordinate Instruments[59]	Compliance with these subordinate instruments required by conditions of generation licence	None identified	A review of certain publicly available generation licences shows that they may be revoked at any time at the request or with the consent of the licensee. The licences do not state when the ESC may agree to revoke a licence.

[59] Covers the following instruments to the extent that they apply to holders of electricity generation licences issued under the *Electricity Industry Act* 2000 (Vic): the Electricity Distribution Code and the Electricity System Code as well as several publicly available electricity generation licences granted under the *Electricity Industry Act* 2000 (Vic).

Table 8: Queensland

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Electricity Act 1994 (Qld) *Electricity Regulation* 2006 (Qld) (These instruments regulate the electricity industry and electricity use in Queensland)	A generation authority is required to connect generating plant to the transmission grid or supply network under section 87. Generation authorities are subject to the conditions set out in these legislative instruments and the generation authority itself.	None identified	Conditions that generation authorities are subject to that could potentially impose costs on a generator's ability to reduce operations or exit the market include requirements: • to properly take into account the environmental effects of their activities under the authority (s 27(c)) and • to comply with all protocols, standards and codes applying to the entity under the *Electricity Act* 1994 (s 28) Section 26(2) states a generation authority does not relieve the holder or anyone else from complying with laws applying to the development, building, operation or maintenance of generating plant. Reviewing each of these laws is beyond the scope of this report although it is possible that they could impose costs for generators seeking to exit the market (for example environmental remediation costs). Generation Authorities can be surrendered by the holder giving at least six months notice to the Department of Energy and Water Supply under section 185.
Subordinate Instruments –	Compliance with these subordinate	None identified	None relevant to review

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Electricity Industry Code	instruments required by conditions of generation licence under section 28		

Appendix C – Jurisdictional instruments

Table 9: New South Wales

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Electricity Supply Act 1995 (NSW) *Electricity Supply (General) Regulation* 2014 (NSW) *Electricity Supply (Safety and Network Management) Regulation* 2014 (NSW) (These instruments regulate supply of electricity in the retail market and the functions of persons engaged in the conveyance and supply of electricity in NSW)	No licence or other authority required to be held for generation under these instruments	None identified	None relevant to review

Table 10: Tasmania

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Electricity Supply Industry Act 1995 (Tas) *Electricity Supply Industry Regulations* 2008 (Tas) (These instruments regulate the electricity supply industry in Tasmania)	Electricity generation requires a licence under section 15 Licences are subject to the conditions set out in these legislative instruments and the licence itself	None identified	Conditions that generation licences are subject to that could potentially impose costs on a generator's ability to reduce operations or exit the market include: • conditions determined by the Tasmanian Economic Regulator (s 22(1)(a)) • requirements to comply with standards, codes and requirements stated in the licence or prescribed by regulation (s 22(1)(b)) • requirement to comply with the Tasmanian Electricity Code (s 22(1)(d)) and • requirement to comply with directions or requirements given or made by the Regulator under the Act, regulations or the Tasmanian Electricity Code (s 22(1)(e)) Generation licences can be surrendered by the holder giving at least six months notice to the Tasmanian Economic Regulator under section 30.

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Subordinate Instruments[60]	Compliance with these subordinate instruments required by conditions of generation licence under section 21(1)(d)	None identified	None relevant to review

[60] Covers the following instruments to the extent that they apply to holders of electricity generation licences issued under the *Electricity Supply Industry Act* 1995 (Tas): the Tasmanian Electricity Code, Electricity Emergency Management Planning Guideline, Guideline on Incident Reporting for the Tasmanian Electricity Supply Industry, Electricity Supply Industry Performance and Information Reporting Guideline, as well as several publicly available electricity generation licences granted under the *Electricity Supply Industry Act* 1995 (Tas).

Table 11: Australian Capital Territory

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
Utilities Act 2000 (ACT) *Utilities (Electricity Restrictions) Regulation* 2004 (ACT) *Utilities (Electricity Transmission) Regulation* 2006 (ACT) *Utility Networks (Public Safety) Regulation* 2001 (ACT) (These instruments regulate the provision of services by certain utilities in the ACT)	Electricity generation requires a licence under section 21 where the generator is connected to an electricity network. Licences are subject to the conditions set out in these legislative instruments and the licence itself.	None identified	The Independent Competition and Regulatory Commission (**ICRC**) has not granted any electricity generation licences under the *Utilities Act* 2000 (ACT) as at the date of this report. Conditions that generation licences are subject to that could potentially impose costs on a generator's ability to reduce operations or exit the market include: • compliance with industry and technical codes that apply to the utility (s 25(2)(a)(iii)-(iv)) – as at the date of this report none of these codes are expressed to apply to generation licence holders • compliance with directions given to the holder by the ICRC (s 25(2)(a)(v)) • compliance with a technical regulator's direction given under the *Utilities (Technical Regulation) Act* 2014 (ACT) (s 25(2)(a)(vi)) • requirement to maintain any capacity determined in accordance with technical and prudential criteria adopted by ICRC to operate a viable business (s 25(2)(b)) Generation licences can be surrendered by the holder giving notice to the ICRC (s 41). The

Appendix C – Jurisdictional instruments

Legislation/instrument	Electricity generation licensing obligation	Regulatory barrier to exit conclusion	Other observations
			surrender takes effect 90 days after the date of notice unless ICRC accepts an earlier surrender.

Appendix C – Jurisdictional instruments

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