Draft Report to

Independent Market Operator of Western Australia

Assessment of Fuel Capacity Requirements to Meet System Reliability in the SWIS

3 March 2010

McLennan Magasanik Associates

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VERSION

Version	Date	Comment	Approved
Draft 0.1	5 March 2009	Issued to IMO for initial review and comment	Ross Gawler
Draft 0.2	12 March 2009	Added commentary on prospective separate treatment of gas supply and liquid storage with regard to aggregate gas supply reliability	
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Draft 0.5	16 December 2009	Results for gas disruption scenarios. Added discussion of trading in daily energy reserves.	Ross Gawler
Draft 0.6	3 March 2010	Enhanced the introduction	Ross Gawler
Draft 0.7	3 March 2010	Removed questionnaire in the previous Appendix A. Change of tense for some forward looking statements that are now past tense.	Ross Gawler

ABBREVIATIONS

The following abbreviations are used in this Issues Paper.

CPRS	Federal Government's Carbon Pollution Reduction Scheme
FSST	Fuel storage, supply and transport
IMO	Independent market Operator of Western Australia
MCAP	
MDQ	Maximum Daily Quantity (of fuel that has a daily transport constraint)
MMA	McLennan Magasanik Associates
POE	Probability of Exceedance
RCM	Reserve Capacity Mechanism that ensures adequate generating capacity in the Wholesale Electricity Market
RM	Reserve Margin
SE	Standard Error
SOO	Statement of Opportunities
SRMC	Short Run Marginal Cost
STEM	
SWIS	South-west interconnected system of Western Australia
USE	Unserved Energy
VOM	Variable Operation and Maintenance
WEM	Wholesale Electricity Market in the South-west interconnected system of Western Australia

1 INTRODUCTION

Annually, each facility wishing to be assigned capacity credits within the Reserve Capacity Mechanism (RCM) must first apply to the Independent Market Operator (IMO) for Certified Reserve Capacity. This is a technical process whereby the IMO must make a determination of the amount of capacity likely to be available during peak demand times. One of the contributing factors to this process is the fuel storage, supply and transport (FSST) arrangements of each facility. These arrangements must be assessed to ensure that adequate capacity is available when it is required.

Current provisions within the WEM require that all capacity be available for at least fourteen hours each day. This is a stringent requirement when applied across all facilities within the SWIS and may potentially overstate minimum levels of availability required to meet the accepted reliability provisions. The potential for over-statement arises because many plants do not need to operate for 14 hours continuously to meet the peak load shape on an extreme day as well as provide reserve capacity for unit outages.

This is a complex issue as the reliability criterion applies on a SWIS-wide basis while Certification assessments are conducted on a facility by facility basis. In the interests of market efficiency it is preferable if fuel storage requirements can be specified according to the required reliability performance of the power market, rather than arbitrary and conservative limits applied to all power plants.

The IMO has requested McLennan Magasanik Associates (MMA) to analyse the power market reliability under alternative schemes that define fuel storage and transport limitations so as to ensure adequate system reliability. Advice was requested in regard to minimum fuel supply and transport provisions within the Reserve Capacity Mechanism and specifically for the purposes of the certification process.

This report summarises the issues that need to be considered in evaluating efficient fuel storage and transport arrangements in relations to system reliability. The report considers the technical feasibility, from the perspective of system reliability, of permitting trading in daily generation maximum energy so that different generators could carry different inventories of fuel on a daily basis, whether it be gas or liquids. It has been shown that within the 0.002% expected unserved energy requirement, different generators could provide different levels of daily energy and trade this capacity among themselves, providing the overall system daily energy capability is maintained. In particular, the daily energy requirement could be relaxed on weekends and in the milder seasons without a significant impact on system reliability. The extent to which this is economically valuable depends on the value of the surplus gas supply capacity that could be realised in other gas markets during the lower demand seasons and weekends.

A second issue related to an examination of emergency responses to gas supply interruptions and how daily maximum energy could improve system reliability under major gas supply contingencies. The report confirms that dual firing of the large base load units at Cockburn and Kwinana and 18 hours of storage at the duel fuelled peaking plants would halve the amount of unserved energy for the large gas supply disruptions. Thus there are substantial potential benefits that could be achieved from a trading mechanism that increases the amount of fuel in storage when the supply system is at greater risk and after a major contingency.

1.1 Assessment of appropriate levels of fuel adequacy

Under the Reserve Capacity Mechanism (RCM) of the current Market Rules, the IMO must assign Certified Reserve Capacity to a facility in accordance with Market Rule 4.11.1.(a):

(http://www.imowa.com.au/Attachments/WEMSRulesUnOfficial/WEM_Rules_UnofficialNew.pdf)

subject to paragraphs (d) and (e) and clause 4.11.2, the Certified Reserve

> *Capacity for a Facility for a Reserve Capacity Cycle is not to exceed the IMO's reasonable expectation as to the amount of capacity likely to be available from that Facility, after netting off capacity required to serve Intermittent Loads, embedded loads and parasitic loads, at **daily peak demand times** in the period from the start of December in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle, assuming an ambient temperature of 41C;*

Currently Market Rule 4.11.1 (a) includes the phrase "*daily peak demand times*" which, in accordance with the associated Market Procedure: Certification of Reserve Capacity has been interpreted as the peak trading intervals of 8:00am to 22:00pm inclusive for any trading day. This translates to facilities being granted a level of Certified Reserve Capacity where they are able to operate for a period of 14 hours on an ongoing basis if called to do so by the system operator to meet market demand. This places a significant burden on facilities, particularly generators to be able to operate at high output levels for a sustained period of time.

Rule 4.10.2 specifies that dual-fuelled power plants must have on-site storage or uninterruptible supply of alternative fuel for up to 12 hours of operation. This is less than the 14 hour duration of "*daily peak demand times*" which implies that it is accepted that 2 hours operation on primary fuel including a change-over period is permissible to meet the 14 hour requirement, although this is by no means absolutely clear in the Rules.

The IMO recognises that a range of plant availabilities are likely to operate within the market and that these will be based on requirements within the bilateral contracting environment and the specific drivers for each of the various investors and Market Participants operating within the Market. These diverse operating patterns within the market are driven by commercial positions that must be balanced with the requirement to meet the reliability requirements established within the RCM framework.

The IMO requested MMA to analyse how "*daily peak demand times*" should be interpreted as an appropriate period of time. In undertaking this engagement the IMO required MMA to provide an analysis of the effective capability of different fuels to meet fuel adequacy required by the Market Rules and an assessment of the capacity certification process criteria in evaluating the capability of the fuel to provide effective fuel adequacy.

In order to adequately address this issue MMA was engaged to:

- Consider the current reliability criterion within the Market Rules in the context of the Wholesale Market Objectives Market Rules and the effect of changing the definition of "*daily peak demand times*";
- Consider the effect on the current and futures levels of Certified Reserve Capacity and how this would translate into Capacity Credits available in the market;
- Make a determination of the current mix of facilities and their ability to meet a time based supply criteria;
- Develop appropriate fuel supply guidelines which would be required in order to meet a revised period for the "*daily peak demand times*". Including
    - Specification of gas volumes and availability requirements;
    - Levels of liquid or alternative fuel storage.
    - The consideration of firm and non-firm fuel supply arrangements;
- Develop of a matrix of events which would (and would not) be covered under a new regime;
- Provide advice and recommendations in respect of the treatment of portfolio participants and for single unit participants.
- Develop an understanding of past and potential future load profiles within the SWIS and facility usage during peak demand times to ensure that ability to service load in peak demand times is not compromised (including associated reserve margins).
- Advise on the value of trading in Energy Reserve with long-term acquisition in a similar manner to the Reserve Capacity Mechanism as well as trading fuel storage and supply obligations among generators so they can meet their bilateral contract obligations at least cost.
- Consider whether separate treatment of gas supply and liquid storage is warranted to recognise the risk mitigation gas supply interruptions with dual fuelled plants.

The outcome of this project is intended to provide recommendations and associated analysis for market rule and procedure changes so that fuel requirements may be appropriately articulated and specified.

MMA is also required to provide any necessary tools and functional specifications so as to allow the IMO to administer the process in a timely, efficient and robust manner.

1.2 Structure of the report

This Issues Paper discusses these requirements in more detail as a basis for public consultation and to inform Market participants of the process and the data requirements. The remainder of the Issues paper has the following structure:

1. Chapter 2 summarises the linkages between fuel supply capacity and system reliability. We identify the key issues to be addressed in the study.

2. Chapter 3 discusses our market modelling methodology and how it is proposed to be applied to determine minimum levels of fuel storage having regard to the relevant uncertainties and risks that storage would not be provided as committed.

3. Chapter 4 outlines the results of a benchmarking study to confirm that we can adequately model observed dispatch and pricing in the WEM.

4. Chapter 5 discusses the analysis of the impact of firm daily fuel supply and storage on the level of expected unserved energy and total system cost having regard to reserve margin and variation in the level of minimum fuel supply and storage.

5. Chapter 6 provides an analysis of some gas supply disruption scenarios and indicated the potential impact of increasing distillate supply to peaking generators during such events.

6. Chapter 7 outlines questions for public consideration and consultation that will form the basis for review and interpretation of the current market modelling work and the basis for further analysis.

7. **Error! Reference source not found.** summarises the questions that will be put to the IMO and Market Participants to obtain information suitable for system energy reserve and reliability modelling.

2 FUEL STORAGE, TRANSPORT AND SYSTEM RELIABILITY

2.1 Power market supply reliability

The reliability of the bulk electricity system from generators to the major transmission supply terminals is critical for the overall security of the system and consequently the quality of supply to customers. There are two measures of reliability, a capacity based standard that is used directly to determine Reserve Capacity requirements and an unserved energy criterion which measures exposure to customer supply disruption. The capacity based standard is actually a real time measure derived from the probabilistic unserved energy criterion which cannot be observed in real time, but is estimated by power market modelling over a period of one year.

These measures are referred to in Clause 4.5.9 (b) of the Market Rules as a part of the **Planning Criterion**:

4.5.9. The Planning Criterion to be used by the IMO in undertaking a Long Term PASA study is there should be sufficient available capacity in each Capacity Year during the Long Term PASA Planning Horizon to:

(a) meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:

i. 8.2% of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and

ii. the maximum capacity, measured at 41°C, of the largest generating unit;

while maintaining the Minimum Frequency Keeping Capacity for normal frequency control. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten; and

(b) limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses).

Ultimately the reliability is measured in terms of the risk of non-supply of energy to customers measured as a fraction of the energy demanded. This is referred to as the expected unserved energy level, measured as 0.002% of energy demanded. The measure is referred to as "expected" because the amount of unserved energy and its timing cannot be predicted because it is the consequence of what appears as random outages of generating plant and transmission connections. The outages are the result of many causes that themselves cannot be predicted because we do not have full knowledge of generation and transmission plant operating conditions in the electricity system.

The unserved energy events are most likely to occur during periods of high system loading due to events such as:

- Insufficient generating capacity due to forced outages of plant that were not scheduled and could not be deferred to a time with lower demand;

- **Generating capacity available to run but subject to disruption to fuel supply or inadequate fuel storage to enable sustained operation;**
- Forecast demand well above expected levels and for which generating plant was not committed in time due to short-term demand forecast error; or
- Transmission outages which cause a constraint that prevents generating capacity reaching the major load centres.

Even during normal loading periods, unserved energy can arise if scheduled outages run longer than planned or if there is a period when a back-log of maintenance needs to be completed to maintain safe operation. The above list is ordered from most important to least important under normal market conditions.

The focus of this study is the importance of the second **bold type** item in the above bullet list. Greater severity of disruption from the other factors including excessive scheduled maintenance will place more importance on the fuel storage and supply reliability. Therefore any standard for fuel storage necessarily implies expectations concerning the performance of the other factors affecting supply reliability. Since liquid fuel storage capacity is not readily augmented once installed, it is important that any requirements for minimum storage capability are not increased for incumbents once established. Therefore a conservative assessment ought to be made for the maximum storage requirement, although that actual fuel inventory may be relaxed when market conditions are more favourable for supply reliability. This Issues Paper sets out a planned process to evaluate fuel storage and supply requirements under normal and worst case conditions so that an appropriate standard may be set in the WEM.

2.2 Current fuel storage requirements in the market rules

If there is a shortage of fuel supply to base load plants or inadequate fuel storage for liquid fuelled peaking plants, then it is possible for the system to run out of energy for electricity production during periods of system stress. In such cases, System Management would need to shed customer load to maintain secure operation of the system. The current Market Rules manage this risk by requiring that all plants are able to supply power over the peak period from 8 am to 10 pm as detailed in Clause 4.11.1 (a) requires:

*"….. the Certified Reserve Capacity for a Facility for a Reserve Capacity Cycle is not to exceed the IMO's reasonable expectation as to the amount of capacity likely to be available from that Facility, after netting off capacity required to serve Intermittent Loads, embedded loads and parasitic loads, at **daily peak demand times** in the period from the start of December in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle, assuming an ambient temperature of 41oC;"*

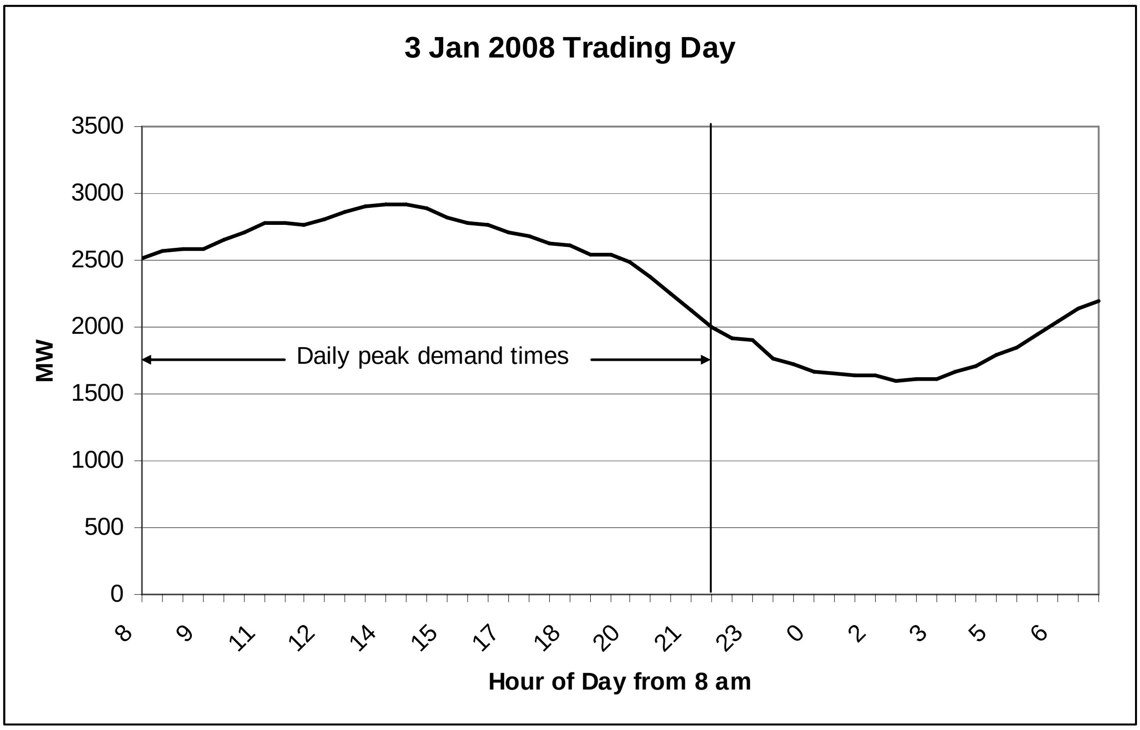
Although "daily peak demand times" are not defined in the Rules, they are taken by the IMO as from 8 am to 10 pm on working weekdays in the peak winter and summer seasons. It is then interpreted that sustained output could be needed from all facilities from 8 am to 10 pm that receive Capacity Certification.

2.3 Efficient fuel storage requirements

It is very unlikely that all power plants would need this level of fuel storage or supply over this period. Accordingly, the current situation for managing fuel constraints is not likely to be optimal for the following reasons:

- Specifying the same fuel capacity sufficient for 14 hours running for all thermal generating units would overstate requirements for normal operating conditions because the peak load varies during the typical peak day as shown in Figure 2-1 for the load on 3 January 2008 at 41.9C maximum temperature. Quite clearly the load is not flat over this peak period so not all available generation need to have fuel for 14 hours of operation. This means that a fixed 14 hour specification for all generators is too conservative and may result in excessive costs imposed on generators without commensurate value for supply reliability. However, care should be taken in specifying a less conservative requirement to make sure that fuel supply and plant outage contingencies are adequately included where they could be significant under more adverse conditions.

Figure 2-1 Typical peak day profile in the SWIS (3 January 2009)



- Most coal fired generators would normally hold fuel stockpiles well in excess of that required for one full week of operation. For such plants, a 14 hour inventory constraint would be readily satisfied. The only significant matter would be the reliability of fuel transfer from stockpile to power station bunker, which would not normally be a significant contributor to partial plant outages. Such fuel transfer reliability for coal plants would normally be included in the estimated forced outage rate rather than be treated as a fuel contingency.

- For some intermediate gas fired plants, they would normally be able to schedule additional gas supply for base or high daily load factor load operation on the peak electricity demand day. However the contracted Maximum Daily Quantity (MDQ) may set an upper limit on what may be nominated for the day.
- For peaking plants on gas, they would not normally order gas for full operation throughout the day, and may indeed face restrictions on the fuel they can order on peak days unless they have firm supply and transport capacity[1]. Additional non-firm gas may be ordered when it is available and the plant can use it economically to meet its bilateral position or sell electricity into the STEM.
- For liquid fuelled or dual-fuelled plants that normally operate infrequently, they would rely on liquid fuel in storage which may be typically three days supply. This would permit 14 hours per day over five week days without replenishment ($3 * 24 = 72 > 70 = 5 * 14$).

In reality, the system requires a mix of plants with different storage volumes which decrease as the marginal cost of operation increases. A plant with a limited storage volume could be treated for the purposes of capacity reserve as having a reduced capacity which makes it equivalent in reliability terms. For example, a 100 MW plant with a 5 hour energy supply might be equivalent to a 50 MW plant with 10 hour storage, if 10 hours were the required standard.

2.4 Assessing fuel storage requirements

The analytical problem in assessing efficient fuel storage and supply requirements is that the minimum fuel storage required by a particular plant to provide its full capacity value depends on the drivers of the overall supply/demand balance, and the energy storage capabilities of all the other plants. It is complex and therefore impractical to define requirements in that way. As a matter of simplification, the same requirement has been specified for all non-intermittent resources.

Ideally, fuel storage requirements should be related to dispatch requirements to meet the system load under a range of credible contingencies with acceptable supply reliability. These dispatch requirements for reserve and peaking duty depend on a wide range of possible system conditions including:

- The weather variations and resulting impact on peak demand duration
- Peak demand forecast accuracy as it affects unit commitment
- The reliability of all generators in the system in terms of the frequency and duration of forced outages
- Intermittent generation contribution during hours of peak demand

[1] For convenience we use the term fuel storage and supply to include the transport component, thus meaning supply to the facility.

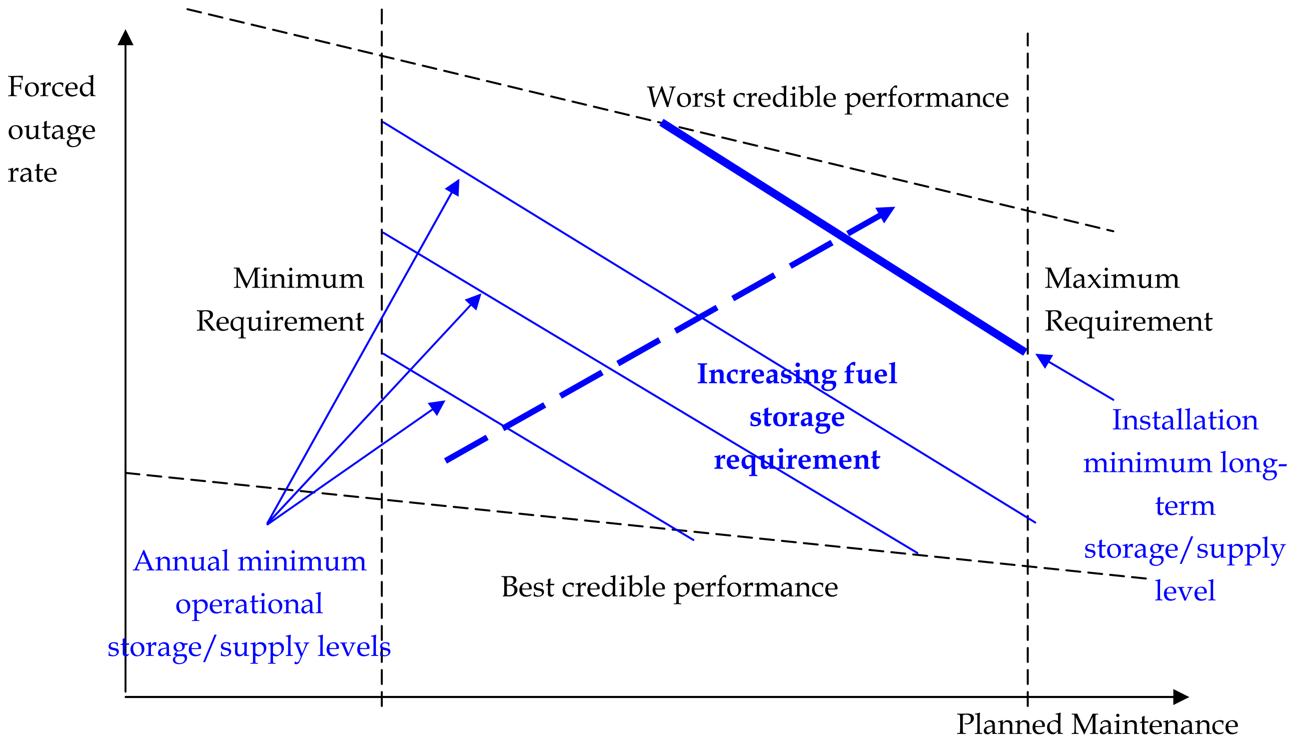
- The reliability of fuel supply, particularly for base load and intermediate units that do not have secondary or back-up fuel supply
- The pattern of transmission losses as affected by dispatch
- The reliability of interconnecting transmission, particularly where constraints affecting dispatch patterns are frequent
- The quantity and timing of scheduled maintenance

Some of these factors change slowly over time such as the relationship between weather and peak loading profiles and the reliability of interconnecting transmission plant. They can be modelled on a stable basis. Other factors may be less stable from year to year (such as gas supply reliability) and would need to be monitored if other than a conservative allowance is made in setting the fuel storage standard. It may be useful to explicitly represent specific gas supply contingency events in the same way that power station contingencies are explicitly modelled in power market reliability analysis, with a forced outage probability and duration for recovery.

The annual scheduled maintenance program can be monitored and short-term storage requirements adjusted if need be on an operational basis to minimise system costs. However, it is much easier to reduce a fuel storage standard and hold less fuel inventory than it is to increase a standard if that would violate physical liquid storage facilities or long-term gas supply contracts. This would be especially difficult if there is no spare capacity in the gas supply infrastructure. Therefore, the IMO should consider the required process as providing a regulatory mechanism to relax fuel storage and supply standards on a short-term operational basis when feasible whilst maintaining a long-term minimum standard applied to physical assets and long-term fuel supply contracts. Any provisions for non-firm fuel supplies should be of secondary significance if the principles for long-term firm fuel supply are well defined and established.

An example as to how a fuel storage standard might be set in the long and short term is illustrated in Figure 2-2. The Figure shows a contour map of fuel storage and supply capacity based on a range of credible system conditions for the amount of planned maintenance (measured in MW-weeks) and the expected level of forced outages (measured in capacity % of the time). There would be a minimum and maximum annual maintenance requirement representative of the normal variation in maintenance levels in a financial year. There would be some uncertainty about forced outage rates. Higher levels of planned maintenance may relate to lower forced outage rates eventually or may be caused by higher forced outage rates beforehand, so the measure of forced outage rates may not be strictly singular. The required total fuel storage (measured in MW- hours per day) would be expected to increase as planned maintenance increases and as the expected forced outage rate increases. For a set of worst combinations of these and other market conditions (such as peak demand and transmission system performance), there would be a requirement for installed fuel storage capacity as a design requirement for Capacity Certification. This is currently defined as the "*daily peak demand times*".

Figure 2-2 Long and short-term fuel storage requirements



On an annual operational basis, the amount of fuel that needs to be stored or gas supply committed may be less than the installation minimum if planned maintenance is reduced and it is assessed that plant reliability has improved, for example after some old unreliable plants have been retired and replaced by new reliable plants. Essentially this would mean that the IMO could adapt the annual fuel storage requirement within an envelope that is defined on a callable basis with suitable notice, perhaps the same notice as the Reserve Capacity Auction. It would be prudent to maintain a conservative fuel storage envelope so that the system can respond to longer term contingencies with additional energy reserve capacity as required.

Thus, using these concepts:

- New plant would be certified if it meets a minimum physical fuel storage or contracted fuel supply daily capacity on a lead time commensurate with the Reserve Capacity acquisition process, currently 3 years.
- One year in advance, and based on committed planned maintenance programs, IMO could relax these requirements on an operational basis to reflect prevailing market conditions, taking into account:
  - Actual supply/demand balance and projected reliability
  - Planned maintenance program
  - Recent and prevailing plant reliability
  - Retirements and performance of new plant

- Uncertainty about demand growth, using the high and low economic growth forecasts.

At the moment the physical capacity and the long-term fuel supply requirements are identical to the annual operational requirement at 14 hours per day. In principle, it is likely that market efficiency could be improved if these two concepts could be separately assessed for various classes of generating plant. The next section poses some options for consideration.

2.5 Possible options to improve efficiency

There are five classes of approaches to move toward a more efficient approach as summarised in Table 2-1. In addition, the concept of a long-term target and annual declarations as discussed above could be considered. These represent:

- The current method of assuming that storage volume should fully match the peak load period from 8 am to 10 pm. This is the most conservative approach and is not based on any quantified reliability considerations in relation to energy reserve.
- A revision of the current method to recalculate the storage duration based on meeting the unserved energy criterion with full capacity credits based on 41ºC capacity. Only firm fuel supply is credited. This would be much less conservative than the current approach and would be consistent with the unserved energy reliability standard.
- An enhancement to the reliability based method which allows non-firm fuel supplies to be credited either –
    - with a discount to the allowed duration in conjunction with firm fuel supply, or
    - with a discount to the associated capacity so as to meet the unserved energy criterion.

  This would enable some credit to be given to non-firm fuel supplies based on the exposure to shortfall in available quantity at peak times.
- Define classes of capacity that may have differing minimum storage volumes based on their indicative merit order and the type of use given to the unit. For example gas fired CCGT plants and coal plants would be required over most of the 14 hour period, gas fired OCGTs would be in a lower class and liquid fuelled plants would have an even lesser minimum requirement so that if all standards are met the reliability of supply is assured near least cost. This approach can reduce the cost of holding fuel storage commitments without jeopardising reliability.
- Enhance the previous method by permitting trading of stored fuel obligations within the plant classes. This would represent an energy reserve market that would be matched to reliability requirements and would promote least cost solutions, providing that administrative arrangements and monitoring of aggregate fuel storage and supply is effective.

(list continued after Table 2-1)

Table 2-1 Classes of approaches to managing fuel constraints and reliability

Type	Method	Advantages	Disadvantages	Requirements
Common Firm Standard based on Peak Period	**Current method:** Define a minimum firm storage capacity for all plants based on peak period definition.	Simple to apply and monitor. Provides surplus because some plants will more than meet the standard and a uniform measure over the peak period is excessive (Refer Figure 2-1).	Overstates fuel storage requirements and increases physical capital and working capital costs. Imposes unnecessary cost barriers for new peaking capacity.	Audit of fuel supply arrangements when determining certification of capacity.
Common Firm Standard based on Reliability Standard (unserved energy)	Define a minimum firm storage capacity for all plants based on meeting the unserved energy criterion. The criterion would include the unserved energy risk associated with 10% peak demand as well as 50% POE peak demand.	Simple to apply and monitor. Matches the actual reliability requirement on an annual basis. Provides an objective measure of system requirement providing forecast plant performance is accurate.	The minimum storage requirement may vary from year to year according to scheduled maintenance requirements. It requires detailed reliability analysis. It does not match efficient dispatch profiles unless the lower marginal cost generators provide more than the minimum storage.	Audit of fuel supply arrangements when determining certification of capacity. Assessment of the minimum standard that makes each plant have the same reliability value as a plant without fuel constraints. Requires system reliability modelling.

Type	Method	Advantages	Disadvantages	Requirements
Common Firm Standard with non-firm options	Define a minimum firm storage capacity for all plants to meet unserved energy requirement. Assess the equivalent firm value of storage for non-firm fuel supplies based on their probability of interruption when other wise required.	Provides for the inclusion and valuation of non-firm fuel supplies, particularly natural gas.	There may be difficulty in defining the characteristics of non-firm supplies when there is no historical information or if reliability of fuel supply is dependent on dynamic market forces. Potential supply risks if firmness of fuel supply is under-stated.	A system reliability analysis to characterise the reliability impact of non-firm gas supply. Either the duration of non-firm fuel supply is discounted to that equal to that of a firm fuel supply or the equivalent capacity of the plant is discounted.
Fuel Storage Class Requirements without trading of storage	Specify an aggregate fuel storage requirement for defined classes of generators (eg: Gas OCGT, Duel OCGT, Liquid OCGT, Duel CCGT, Coal). Plants may nominate preferred class with IMO assent.	Provides a more economic assessment so that fuel storage requirements are not over-specified. Standards based on technology and fuel type would provide an objective reference.	May be difficult to clearly define plant classes, especially when schedulable renewable energy is involved.	Periodic assessment of the aggregate requirement for each class of generators based on scheduled maintenance, plant mix and load growth.

Type	Method	Advantages	Disadvantages	Requirements
Fuel Storage Class Requirements with capacity trading within plant classes. (Energy Reserve Market)	Specify an aggregate fuel storage requirement for defined classes of generators Plants may nominate preferred class with IMO assent. Generators may trade the obligation to store fuel among parties in the same class. If one generator has insufficient storage to meet its obligation it may buy storage from a generator in the same or higher merit order class which has surplus energy in store. This becomes a market in energy reserves.	Enables a more flexible market arrangement for optimising fuel storage requirements based on purchase and trading of obligations. Spare capacity may be used to better manage contingencies.	Complex and costly to administer and audit. May be difficult to clearly define plant classes, especially when schedulable renewable energy is involved. Requires a new set of Rules to administer an energy reserve market.	Aggregate requirements and issuing of storage obligations that may be traded. Periodic assessment of the aggregate requirement for each class of generators based on scheduled maintenance, plant mix and load growth.
Establishment of Long-term acquisition of Energy Reserve Capacity	Establish an authority to acquire long-term energy storage and supply capacity which can be traded in the WEM. Payments would be made for Energy Reserve Capacity as well as Reserve Capacity payments when additional fuel inventory is required.	Provides more security for long-term energy supply and increased resilience against major energy supply contingencies. Energy Reserve can be traded among participants to match overall system and bilateral trading requirements.	As for previous item. Regulatory process is needed to avoid an appropriate balance of cost and risk management.	Need to set up an authority to manage an Energy Reserve Market.

Type	Method	Advantages	Disadvantages	Requirements
Separate values for gas and liquid fuelled energy storage and supply	Recognise that even firm gas supply has some residual unreliability different from liquids which are dependent on refinery operations.	Could be developed to provide incentive for dual fuelled capacity that improves overall energy security.	Additional complexity in quantifying the relative risk exposure to energy supply for gas and liquids and in pricing the long-term value.	Requires reliability modelling of gas supply and transport in comparison to liquid supply and storage to provide an objective basis to value the liquid storage versus "firm" gas supply. Grades of gas supply firmness would be considered.
Maximum callable fuel storage capacity with annually confirmed requirement	This method involves specifying a long-term maximum callable requirement for defined plants that is rarely changed and an annual requirement set prior to each year which has regards to the current supply/demand conditions. Applies to all of the above methods as a variation.	Provides the opportunity to minimise fuel inventory and firm supply across all plants when there is a capacity surplus and excellent plant performance is projected. Fuel supply and storage can be optimised to minimise costs. Provides a clear basis for long-term requirements that would cover worst credible supply conditions.	Requires an annual process of fuel supply assessment that may be contentious if it imposed sudden additional fuel contract requirements on generators due to deteriorating conditions.	Long-term requirement based on worst credible conditions. This could be consistent with Capacity Accreditation standards. A periodic calibration of a market reliability model based on forced outage performance, peak demand, amount of scheduled maintenance and plant mix assumptions. Formula could be assessed for a five year period with key parameters.

- Provide long-term acquisition of Energy Reserve Capacity to ensure sufficient liquid fuel and natural gas delivery capability for meeting major supply contingencies as they arise.
- Provide a separate value for energy reserve for gas and liquid fuelled capacity on the basis that gas supply is not fully reliable and exposed to disruption of supply arising in the gas processing plants and the gas pipelines. Similarly. Maintenance of liquid storage and supply is dependent on road or pipeline transport and refinery operations.
- For each of these methods, a long-term physical capacity requirement could be set as the basis for plant design and maintenance as well as a less stringent annual fuel storage requirement when market conditions are more favourable for system reliability.

These options progress from the simplest to the most complex with the expectation that each step would increase market efficiency albeit at greater cost to market participants. Without a thorough analysis of market benefits and administrative costs it is not possible to say at this stage which is the best approach.

It is intended that IMO in conjunction with MMA will seek information on the fuel storage and supply arrangements in the SWIS on a technical (and where requested confidential) basis to assess what improvements can be made to the fuel storage and supply standards with respect to capacity certification. MMA will use market modelling to asses the following matters:

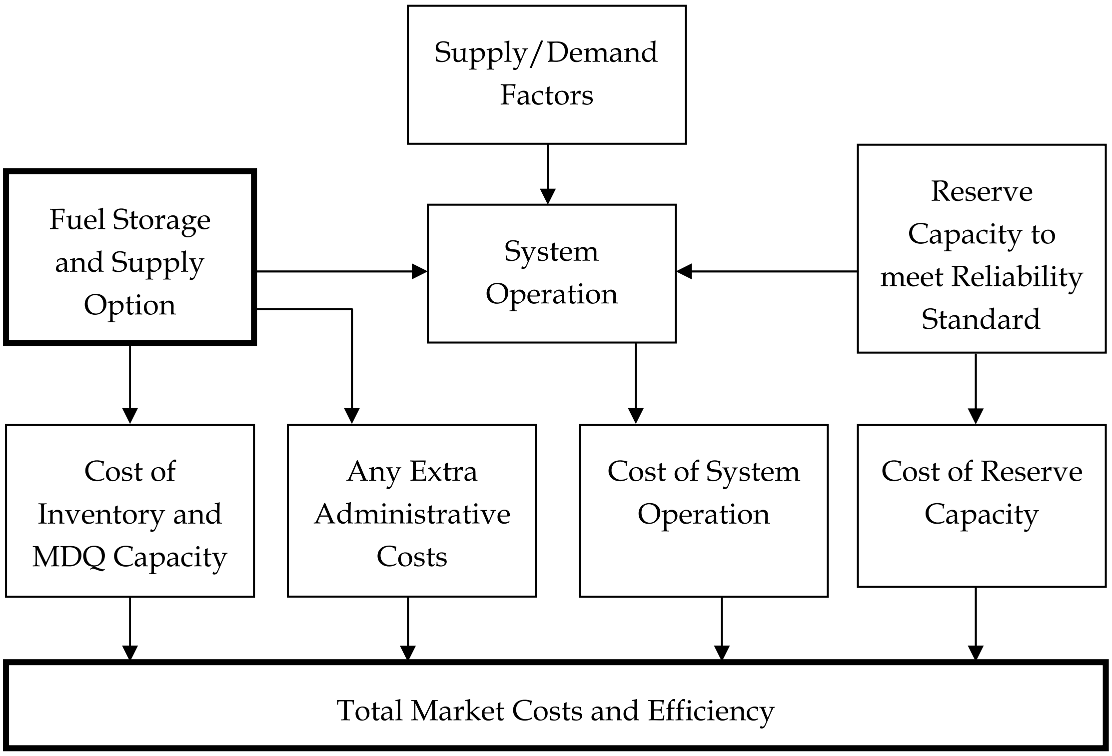
- What have been the normal fuel storage requirements of the major power plants in the SWIS since market inception in September 2006?
- What would the fuel storage and supply requirements be if we were to achieve 0.002% expected unserved energy for a medium growth outlook having regard to 10% and 50% POE peak demands?
- What costs are involved in carrying the additional fuel storage and supply requirement of 14 hours per day as compared to the minimum requirement for balanced supply conditions?
- What additional storage requirements are needed to manage peak demand uncertainty three years in advance having regard to demand forecast uncertainty (using high, medium and low demand growth forecasts)? How does this compare to the current 14 hour standard?
- If plants were to be classed by technology and fuel type, what minimum storage requirement would be needed in a balanced scenario and what would be needed to cover demand forecast error?
- Is this likely that these requirements once specified would be stable over time? How often should they be reviewed?

2.6 Impact on market objectives of current and alternative rules

After we have assessed the relationship between fuel storage and supply reliability, we should then be in a position to indicate the optimum response having regard to market benefits and administrative costs. We shall propose an economic model that may need to be executed with inputs from the main market participants who would have to respond to the corresponding change in approach.

We have set out on this project with the assumption that making the fuel storage requirements less stringent and more dynamic would reduce system costs. However that may increase regulatory, administrative costs and market risks more than the benefits for some of the options to be considered. The relationship between fuel storage and supply requirements and market costs is as shown in Figure 2-3.

Figure 2-3 Impact of fuel storage and supply on market objectives



The savings may come from:

- reduced inventory in liquid fuel that can be realised immediately;
- reduced maximum daily transport quantity in gas supply which tends to be a fixed cost that can eventually be avoided as gas transport is allocated to other needs over time;
- reduced capital costs for new peaking plants related to fuel storage capacity and fuel delivery capability; and

- more effective management of long-term energy supply risks y having an appropriate aggregate requirement for liquid fuel storage capacity, gas supply and transport and the trading facilities to manage the requirements of individual market participants.

The additional costs may come from:

- the upfront costs of changing the Market Rules;
- the additional administrative cost of managing a more complex fuel storage and supply constraint;
- the cost of reviewing and amending the fuel storage and supply constraint over time;
- any costs in responding to increases in the minimum standard at a later time, assuming that the standard is initially reduced on an operational basis;
- administrative costs for setting up an Energy Reserve Market if this option is adopted; and
- some additional production costs when the storage constraints are reached and some fuel supplies are depleted and more expensive replacement fuels are used or electricity demand is shed under more extreme conditions.

2.7 Summary of key issues to be considered

Thus the key issues that need to be quantified and assessed are:

- Mathematical models to quantify the reliability of gas and liquid supply as inputs to the power market reliability analysis. This includes characterising the inherent reliability of the gas supply and transport systems into the Perth region.
- The quantitative relationship between fuel storage and supply capacity on a time based measure and the reliability of the SWIS having regard to the other key factors that influence system reliability.
- Whether a daily measure is sufficient or whether other time periods for storage and supply are required, such as weekly or monthly. Since liquids may be delivered daily by road transport for some power stations, an initial inventory plus a daily supply over a peak week may be considered as a suitable statement of requirement for a peaking plant rather than a daily quantity. An initial daily or weekly quantity may be a convenient measure but may be too conservative.
- Consideration of the accuracy and robustness of measures of fuel delivery performance and how much can we rely on such revised measures if the energy reserve margins are intentionally reduced to save cost.
- The magnitude and uncertainty of the economic benefits that may be gained by relaxing the fuel storage and supply requirements for a range of prospective options.
- An appropriate level of extreme market conditions for which fuel storage capacity and supply requirements must be defined for long-term risk management to cover worst case conditions.

- A methodology for relaxing fuel storage and supply requirements when market supply/demand market conditions are expected to be less onerous than the design maximum.
- A method for valuing liquid storage and firm gas supply so that the value of duel fuelled capability can be recognised and funded.
- An assessment of the costs of establishing and maintaining a new Energy Reserve Capacity Mechanism.

3 MARKET MODELLING METHODOLOGY

3.1 Outcomes required from modelling

The current basis for the market modelling is that the following outcomes are required:

1. We will assess fuel storage and supply requirements to meet the maximum 0.002% unserved energy requirement when considering peak demand uncertainty over the range from 90% POE to 10% POE. For modelling convenience we will neglect the 90% POE peak demand case and model 50% and 10% POE peak demand levels to assess unserved energy

2. We need to assess what fuel storage and supply capacity is potentially needed on a daily basis in the long-term to provide sufficient resilience against extreme system conditions. We would define one or more extreme scenarios including events such as:

   - Plant type fault (say successive four month outages for Muja C/D units as an example)
   - High forced outage rates (say up to 10% across the steam units and 8% for the combined cycle plants, 5% for gas turbines)
   - Scheduled maintenance back-log (measure to be defined)
   - Demand forecast error (based on historical records)
   - Gas supply disruption events for the purposes of valuing liquid fuel storage as back-up to gas supply (based on historical events)

3. We would assess what equal minimum requirement should be applied across all plants that do not have long-term fuel stockpiles.

4. We need to assess what fuel storage and supply capacity is normally required when supply/demand conditions are normal so as to represent what would be typically required. This would be used to develop a pattern of requirements based on plant merit order and technology type.

5. We will then convert the modelling results into a short-term and long-term requirement for fuel storage and supply in accordance with viable options identified from Table 2-1. This will then form the basis for a proposed change in the Market Rules.

6. We will examine the relationship between gas supply reliability in aggregate and the volume of liquid fuel storage that is required to maintain overall supply reliability.

3.2 PLEXOS market model

PLEXOS is a mixed integer linear programming based software program for modelling electricity markets. Generation dispatch, transmission power flow, and ancillary services are co-optimised and integrated with fuel and emissions modelling, providing a versatile suite of features that may be adapted to accommodate most electricity markets. It will be used to represent the SWIS electricity market including the embedded generation resources so as the represent the overall supply reliability.

Due to the broad range of features available in PLEXOS, the software can be used for a multitude of purposes, from detailed operational analysis focusing on the day ahead to long-term planning spanning 20 to 30 years. PLEXOS may also be used as a risk management tool, with distributions of expected outcomes obtained through Monte Carlo simulations of forced outages and stochastic sampling. Prior to optimising dispatch, PLEXOS schedules planned maintenance and randomly pre-computes a user-specified number of forced outage scenarios and/or stochastic samples for Monte Carlo simulation. Dispatch is then optimised to meet load and ancillary service requirements at minimum cost subject to a number of operating constraints, which may include:

- generation constraints: availability (planned and unplanned outages), unit commitment and other technical constraints
- transmission constraints: availability (planned and unplanned outages), linearised DC optimal power flow (OPF) equations, interconnector ratings, and other transmission constraints that may be a function of load, generation or line flow
- ancillary service constraints: maximum unit response, calculation of dynamic risk
- fuel constraints: for example, daily fuel limits or annual take-or-pay constraints
- emission constraints: limits on emission production may be imposed, or carbon prices specified.

In determining this least-cost dispatch, generators formulate bids that are offered into the market to be cleared. These bids may be manually input, or they may be derived dynamically by PLEXOS based on either the short-run marginal cost of the unit, or strategic objectives. Where strategic objectives are considered, bid formulation is optimised on a portfolio basis using game-theoretic models such as Nash-Cournot or Bertrand pricing, or using revenue targeting heuristics.

PLEXOS will provide the following information:

- Total system costs so that any significant economic impacts can be assessed arising from changes in fuel storage requirements. It is expected that the primary economic impacts will be the saving in fuel storage costs as reduced fuel inventory for liquids and reduced Maximum Daily Quantity (MDQ) charges for gas transport.
- The expected unserved energy based on 70 simulations with 20 simulations based on 10% POE peak demand and 50 simulations based on 50% POE peak demand with the

results weighted according to the distribution of peak demand conditions. The unserved energy associated with 90% POE peak demand was extrapolated from results from the 50% POE and 10% POE simulation using an exponential function.

- The maximum fuel used by each power station over a set of simulations. This would provide a basis for estimating a fuel storage and supply capacity that would be unlikely to provide a constraint on efficient dispatch.

3.3 Approach to study development

The approach to the study proceeded through the following planned steps:

- Data collection
- Model formulation and validation
- Modelling the SWIS
- Interpreting the results
- Evaluating Fuel Storage and Supply Options
- Formulating a Storage and Supply Strategy
- Reporting

3.3.1 Data collection and analysis

We sought two historical years of actual SWIS system load that represent 10% POE and 50% POE profiles. The shape and peak demands were adjusted by PLEXOS when using the profile to represent future years. It might be necessary to synthesise a 90% POE load profile for testing purposes for cases where unserved energy at 90% POE peak demand is significant, such as with greater volume of planned maintenance. This has not been required in the work to date.

We assessed the variability of the peak demand based on peak day temperature, the temperature distribution and assess an appropriate weighting to be given to 10%, 50% and 90% POE peak demands to represent the continuous distribution, focusing on the summer period.

We considered formulating a worst case operating scenario that combines peak demand forecast error, additional scheduled maintenance than normal (say 4 weeks measured as MW * weeks / peak demand), higher forced outage rate (say 4% average) and peak demand forecast error (say 3% above forecast 10% POE). Reserve capacity would be set at the normal standard relative to the forecast peak demand. This worst case scenario would be used to estimate ultimate long-term requirements for capacity certification purposes. There will therefore be normal and worst case scenarios. This more adverse case has not been evaluated as yet.

3.3.2 Model formulation and validation

We had already set up a PLEXOS model of the SWIS. We were using estimates of forced and scheduled outages rates from 2007/08 financial year from System Management and the actual load profile. The embedded loads and generation plants that feed the major private loads have also been included where those units are backed up by the main system. Where there is no material back-up of local generation from the main system and no associated capacity obligation, those private loads and generation systems are not being included in the model unless there are significant power flows at the connection point. Fuel costs have been adjusted to fit the observed dispatch and level of STEM prices.

The power station dispatch and level of STEM prices provided by the PLEXOS model were compared with the 2008 actual outcome, and results of this benchmarking exercise are presented in Section 4.

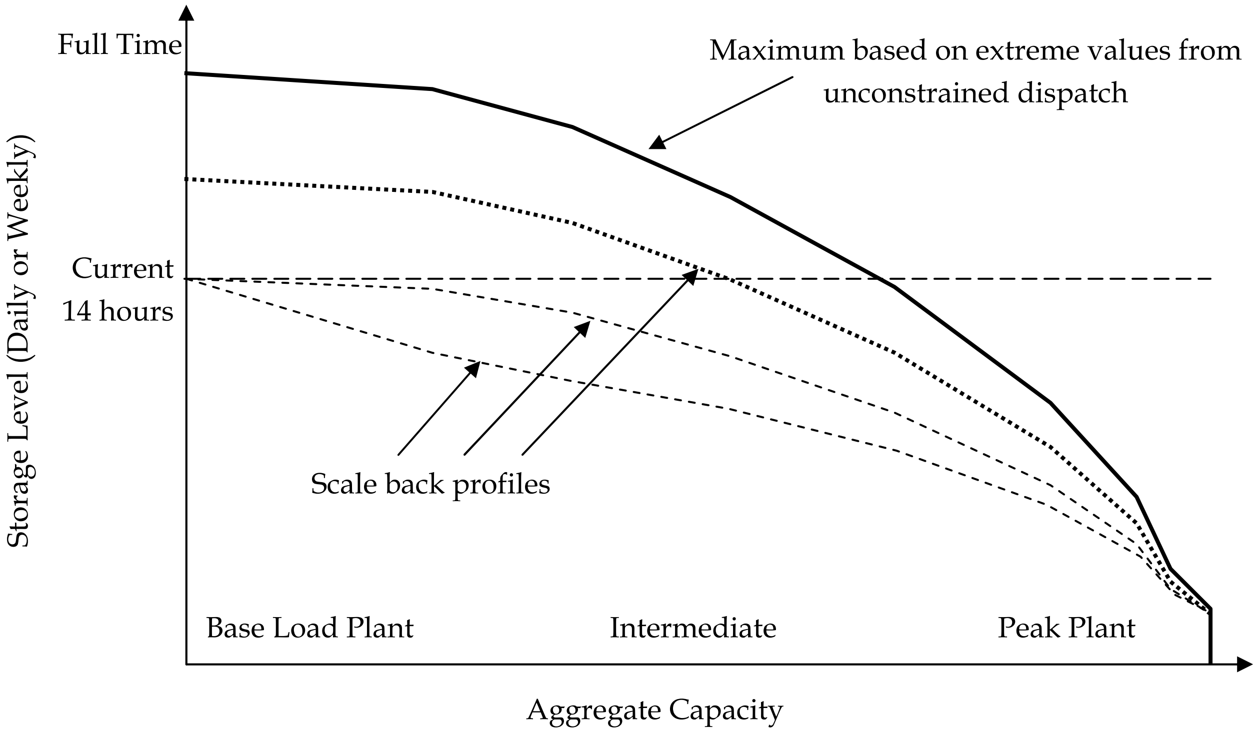
3.3.3 Modelling the SWIS

We shave conducted the following studies for 10% and 50% POE peak demands:

- **Benchmark**: 2007/08 benchmark as described above for actual demand profile;
- **Base case scenario**: 2009/10 to 2014/15 for normal conditions with 14 hour fuel limits on all units except for base load or cogeneration plants. Compare with previous run to confirm that current limits are unlikely to be binding.
- **Stage 1 scenarios**: 2009/10 to 2014/15 with normal conditions and the duration of fuel limits reduced equally until unserved energy is 0.002% averaged over the 10% and 50% POE peak demand range. This provides an option for equal reduction in minimum limit under normal conditions.
- **Stage 2 scenarios**: 2009/10 to 2014/15 with normal conditions and the average limits reduced from the unconstrained case according to the method shown in Figure 3-1. The Figure shows the duration of maximum utilisation as measured by equivalent daily capacity factor as a function of cumulative capacity commencing with base load plants up to peaking plants.

  The generic evaluation of a sculpted storage duration profile that would achieve the standard reliability is illustrated in Figure 3-1. The maximum profile would be obtained from the unconstrained market simulation. For base load plants there would be a minimum level of some 14 to 20 hours. When this limit is reached the curve would be scaled back from some capacity value that represents the base load regime. There would be a minimum storage limit of perhaps 1-2 hours per day for the most costly plants. The curve would be scaled back to find a profile that meets the 0.002% criterion for illustrative purposes. This would provide the basis for assessing a different limit according to merit order and/or technology based classes.

Figure 3-1 Sculpting of storage criterion (conceptual)



- Repeat the previous step for the worst case scenario to assess the limits that would be indicated as meeting long-term potential.
- Replace some of the gas supply in the normal scenario with a non-firm gas supply represented as having a probability of unavailability (say at 50% and 75% probability).
    - For the plants that have access to the non-firm fuel, increase the maximum daily quantity of that non-firm fuel so that the overall supply reliability is restored to 0.002%. This may be estimated by a regression of results over a number of differing cases. Conduct the study at 50% and 75% availability.
    - Leaving the non-firm supply at the standard duration, determine how much additional firm capacity would be needed to restore the reliability back to 0.002%. This would be done by scaling up the capacity of all remaining units in the system rather than adding an additional unit. This would provide a measure of the equivalent loss of capacity value.
- Examine the relationship between aggregate gas supply reliability and contingent events and the required volume of liquid fuel that would be needed to maintain supply reliability. This would involve defining some credible events for gas supply and transport disruptions for which the electricity system should be robust.

The process may be varied if results do not turn out as expected or if some factors are found to be of little impact on the overall reliability. In particular we may examine weekly fuel constrains for some peaking plants that would not be expected to operate every day of a typical peak demand week.

3.3.4 Result interpretation

The results of the studies above will be applied as follows:

- The total production system costs associated with the unconstrained solution and the 14 hour constrained fuel storage and supply will be confirmed as immaterially different, as expected.
- The total system production costs associated with a uniform minimum fuel storage and supply standard will be compared with the current standard. It would be expected to be significantly higher (excluding any savings from lower fuel inventory and gas supply MDQ).
- We will compare the two worst case scenarios with 14 hour fuel storage and equal fuel storage to examine whether the current arrangements effectively manage the extreme case risk.
- The total system costs for the sculpted profile of minimum storage requirements would be expected to be immaterially different from the current situation (excluding any savings from lower fuel inventory and gas supply MDQ). The benefits in terms of holding fuel inventory and purchasing MDQ gas capacity should be material. This would provide the basic justification for a Rule Change to make the limits less stringent if feasible.
- The worst case modelling would test whether the storage requirements for normal and worst case conditions are materially different.
- The results for the worst case scenario would indicate a profile of minimum fuel storage and supply that may be needed to address more severe operating conditions. This would provide a basis for full certification for new plant to provide long-term capability, particularly liquid storage and long-term gas supply and transport.
- The comparisons of capacity results and duration results for the non-firm fuel supply would be examined along the format shown in Figure 3-2 for capacity discount to show how the capacity value of non-firm fuel supplies could be recognised explicitly. This would be converted into a discount function based on commitments to fuel supply reliability.
- Similarly the duration increase needed to reflect the reduced value of non-firm fuel supply could be as illustrated in Figure 3-3. We expect that it would be more robust to discount capacity rather than increase required duration as the benefit of increased duration is more volatile if the fuel supply is less reliable. Capacity discount is easier to understand and apply. It would be delivered as a reduction in the accredited capacity associated with use of a non-firm fuel supply.
- An analysis of aggregate gas supply reliability and liquid storage capacity would be sought as shown in Figure 3-4. The figure illustrates that as gas supply reliability declines, additional storage of liquid fuel is needed to maintain supply reliability.

Figure 3-2 Capacity discount for non-firm fuel supply

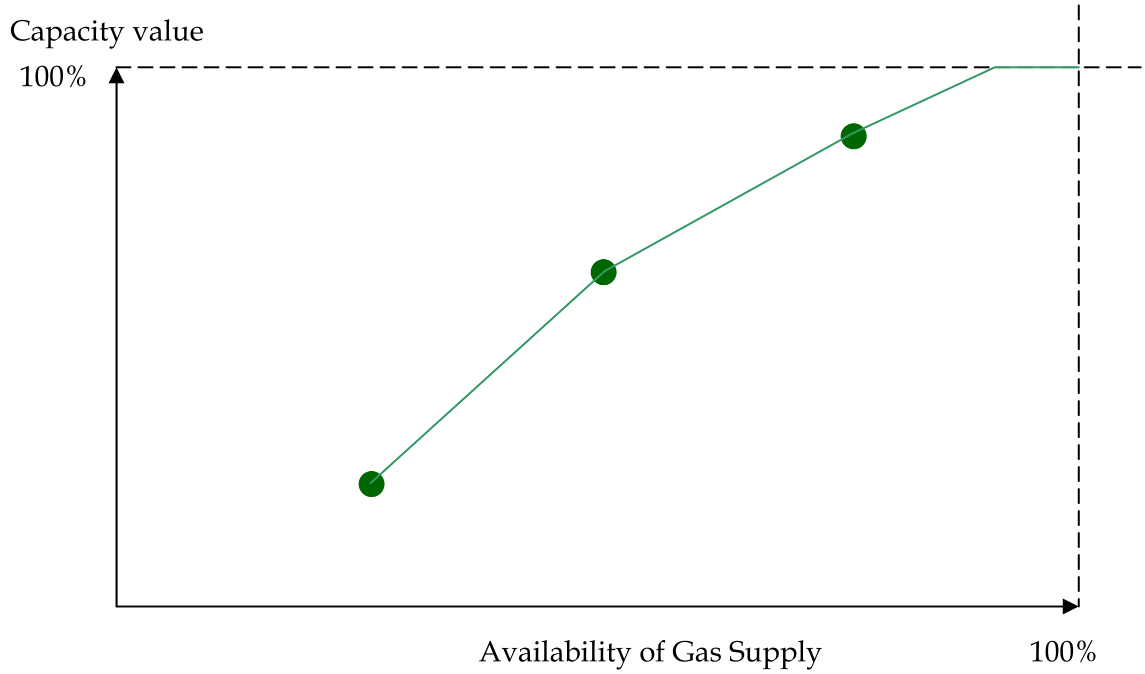


Figure 3-3 Duration increase for non-firm fuel supply

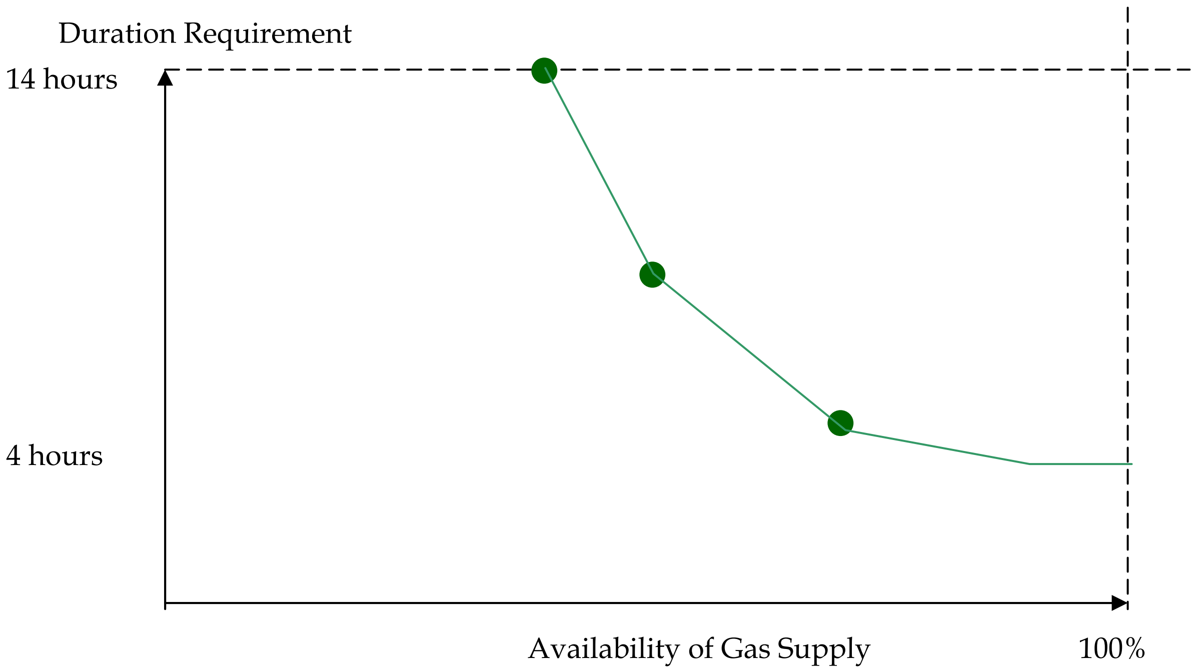
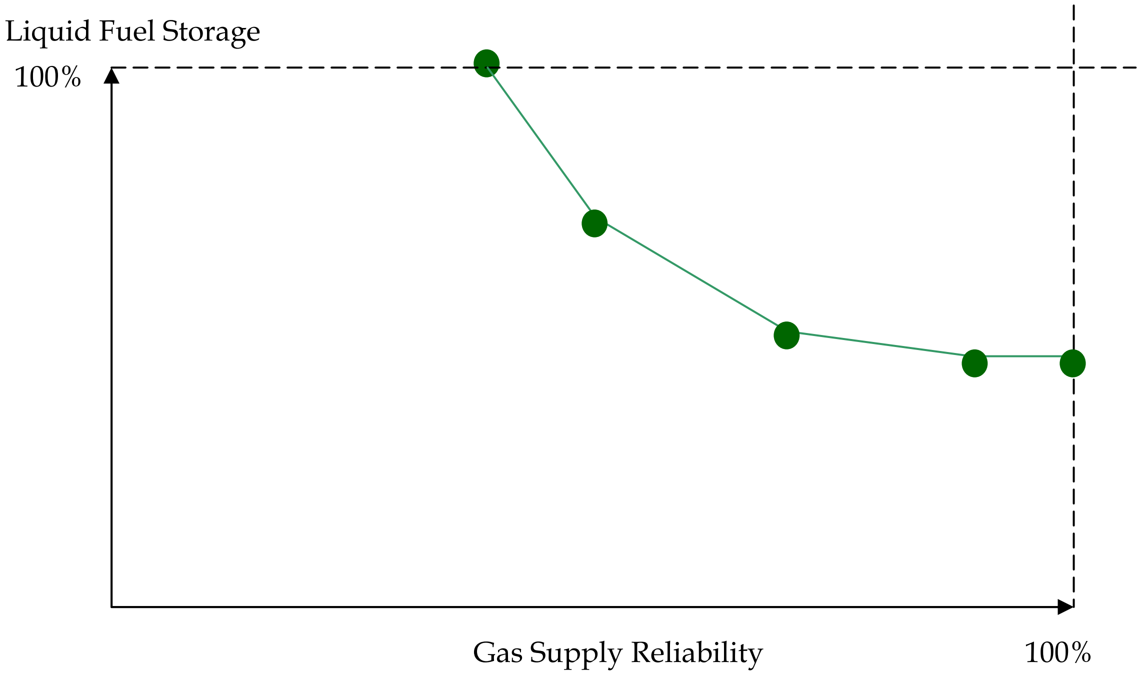


Figure 3-4 Liquid fuel storage versus gas supply reliability



3.3.5 Evaluating fuel storage and supply options

The value of reducing the minimum fuel storage and supply on a daily basis would be assessed as the savings from holding less fuel inventory and purchasing less gas supply MDQ less the increased production cost from the less stringent requirements for fuel storage and supply. We would compare the options of:

- No change to current arrangements
- A single reduced standard adapted to the current operating conditions
- A single reduced standard adapted to worst case operating conditions to see if it is materially different from normal conditions
- A tiered standard based on technology classification for worst case and normal conditions

The addition of a capacity discount would be considered for non-firm fuel supply and the relationship between firmness and the applicable capacity discount.

In the event that fuel supply becomes non-firm, the alternative of providing additional daily quantity to avoid a capacity discount may be formulated.

The analysis should give an indication of which option is most efficient having regard to estimated administrative costs.

3.4 Formulating a storage and supply strategy

Having identified a preferred approach, we would then present the results of the analysis and summarise our conclusions about a workable improvement to the Market Rules with respect to fuel storage and supply requirements to support capacity certification. Assuming that a new tiered standard is proposed, there will need to be methods approved for:

- Classifying power plants according to their role and peak day dispatch. This might initially be based upon the distribution of historical maximum daily dispatch levels by power station or power station unit.
- Setting minimum standards in the long-term that would only need to be reviewed every five years or so at most.
- Setting minimum annual standards for the next reserve capacity cycle and the next 5 years to provide the basis for capacity acquisition and medium term fuel contracting.
- Defining a mechanism for IMO to approve generators meeting any unintended shortfall by purchasing replacement fuel storage or supply from other generators higher up the classification order. This would permit an intermediate plant which has lost a contracted fuel supply to meet its obligation by purchasing additional energy storage from a peaking plant that otherwise would not run on a peak day[1].
- Recognising the capability of non-firm fuel supply and permitting discounted capacity value.
- Defining penalties when a non-firm fuel supply results in a capacity level less than the discounted amount allowed under peak day conditions. This could operate in the same way that mechanical forced outages are treated under Clause 4.26.1.
- Defining a mechanism to discount certified capacity if a facility cannot provide the required fuel storage and supply in accordance with long-term requirements when it is needed[2].

3.5 Providing a long-term process

The IMO has sought to obtain the tools necessary to manage the required treatment of daily fuel storage and supply limits.

It is likely that the analysis will show that a tiered standard would be most efficient and could be practicable if set along the lines of fuel and technology. We would expect that a workable classification for fuel storage and supply would be as shown in Table 3-1. There might not need to be so many classifications depending on how the dispatch results come out. It may be sufficient to have three classes along the traditional lines of base load, intermediate and peaking /reserve duty.

[1] Some quantitative work might eventually be needed to place a limit on the amount of storage and supply that could be allocated in this way. System Management may seek to influence unit commitment and dispatch of plants with limited energy reserves so that fuel is not exhausted over the daily peak cycle.

[2] This would require additional analysis not yet covered under the proposed scope of work of this project.

Table 3-1 Working hypothesis for fuel storage and supply classification

Class	Technology	Fuels	Indicated Role	Indicative Long-term Storage limit	Minimum Requirement under Favourable conditions
1	Cogeneration: Gas turbines with heat recovery	Gas or coal	Base load	18 hours	16 hours
1	Steam cycle	Coal or gas	Base load	18 hours	16 hours
2	Combined cycle	Gas	Base load to intermediate	16 hours	12 hours
3	Combined cycle	Gas and liquid	Intermediate to peaking	14 hours	8 hours
4	Diesel	Gas or land fill methane	Intermediate to peaking	12 hours	6 hours
5	Open cycle gas turbines	Gas and liquid	Peaking	12 hours	4 hours
6	Open cycle gas turbines	Liquid	Peaking/ reserve	4 hours	2 hours
7	Diesel	Liquid	Peaking/ reserve	4 hours	2 hours

MMA envisages that the long-term profile which drives investment in fuel storage and pipeline capacity should be determined by worst case scenarios where energy reserves become critical. This would be reviewed every five to ten years as the plant mix and demand patterns change. The studies may be performed in such a way that the impact of the key factors such as aggregate forced outages, aggregate scheduled maintenance requirements, and peak demand forecast error should be able to be parameterised so that maximum requirements can be tracked over time without additional system studies.

The specific annual requirements that determine how much liquid and solid fuel needs to be stored and how much firm daily gas supply procured can be relaxed according to prevailing conditions if appropriate. This would be assessed in association with defining the Reserve Capacity requirements for the next cycle. Again it may not need to be reviewed every year when the market conditions and plant performance show stability.

Any update in the requirements would follow the methodology outlined in this Issues Paper for the particular option chosen.

We expect that the modelling work over the period to 2014/15 will show the basis for a stable specification of requirements for various classes of plant if the overall plant mix remains efficient from an allocative efficiency perspective. If this is disproven, we shall define the key variables that would require a review of requirements.

3.6 Energy reserve trading

If an Energy Reserve Trading facility is to be established based on long-term acquisition of contracts for capability to store liquid fuels and transport gas when required, then new mechanisms in the Market Rules will be needed. It is possible that the payment for Reserve Capacity might be altered to separately consider the capital costs of fuel storage and the fixed costs of gas transport capability. At this stage it is not proposed to provide a full economic justification for setting up such an Energy Reserve Trading Mechanism. However, some basis analysis will be undertaken with IMO to assess the costs of establishing and operating such a Mechanism to inform the market participants as to whether there is a prima facie case for a full cost/benefit analysis of such a proposal.

3.7 Limitations of the analysis

The analysis to be conducted in this project will not consider all the possible variations in future supply conditions. In particular, changes in the system requirements would need to be reviewed if:

- The amount of intermittent generation in the SWIS were to substantially increase as this would increase the need for energy reserves in aggregate;
- There were to be more large scale base load units added to the system that increased the potential capacity reserve duty of the liquid fuelled peaking plants;
- The gas supply from the North-west Shelf were to become less reliable or be enhanced to a significant degree;
- The Carbon Pollution Reduction Scheme (CPRS) were to have a large impact on the pattern of electricity demand and the use of distributed generation resources.

4 BENCHMARKING OF 2008

4.1 Introduction

This section describes the results of the benchmark of MMA's PLEXOS SWIS database. The benchmark has been carried out by comparing generation, prices, and fuel usage obtained from the PLEXOS model against actual market outcomes for the calendar year 2008. The purpose of developing the model was to prepare for system reliability analysis having regard to the application of minimum fuel supply requirements and a review of the Market Rules which require 14 hours of daily fuel supply for capacity accreditation.

We have modelled the SWIS as a single market 3-node system, with the 3 nodes representing Muja, Goldfields and North Country. This level of aggregation allows representing the major transmission constraints in the system. We have not had access to detailed constraint equations which may be required to accurately represent the inter-regional effects on supply reliability.

The load profile for this benchmarking exercise was obtained from the actual 2008 operating load in the SWIS, which was then prorated between the 3 nodes. Private loads for the model were calculated based on the difference between the known maximum capacity for the facilities and the capacity reported in the 2008 SOO for export to the grid.

Table 4-1 2008 demand in each node

Node	Energy excluding private load (GWh)	Max Demand excluding private load (MW)	Flat Private load (MW)
Muja (Perth)	14725	3150	273.7 until June, 295.8 from July
Goldfields	988	145	122.9
North Country	895	167	0

The tables in Appendix A present the fuel, generator, and transmission line objects (which represent inter-regional links) in the model, and some of their properties. Some of the objects listed may represent the aggregation of one or mode actual facilities. Properties such as fuels' prices and transportation costs and fuel constraints; generators' capacities, heat rates, start costs, VO&M costs, and outage and maintenance rates; and lines' maximum flows were adjusted according to publicly available information (SOO, planning reviews, IMO website, companies' websites). Missing parameters were estimated by MMA based on the nature and known characteristics of the facilities, or based on the actual half-hourly dispatch information provided to MMA by IMO. Actual wind and biomass profiles obtained from actual dispatch data were also included. Also, spinning and load following reserves are included in the modelling.

Limitations in natural gas supply caused by the Varanus explosion were also included in the model. Also included in the model were major outages in generating units, and the recommissioning of Muja G3 and Muja G4 in mid-2008 to deal with the shortfall of gas supply.

4.2 Generation

Figure 4-1 and Figure 4-2 show a comparison of actual and PLEXOS results for total 2008 generation and generators' capacity factors. The figures show that the dispatch obtained by the PLEXOS model is well aligned with the actual dispatch.

Figure 4-1 2008 Generation

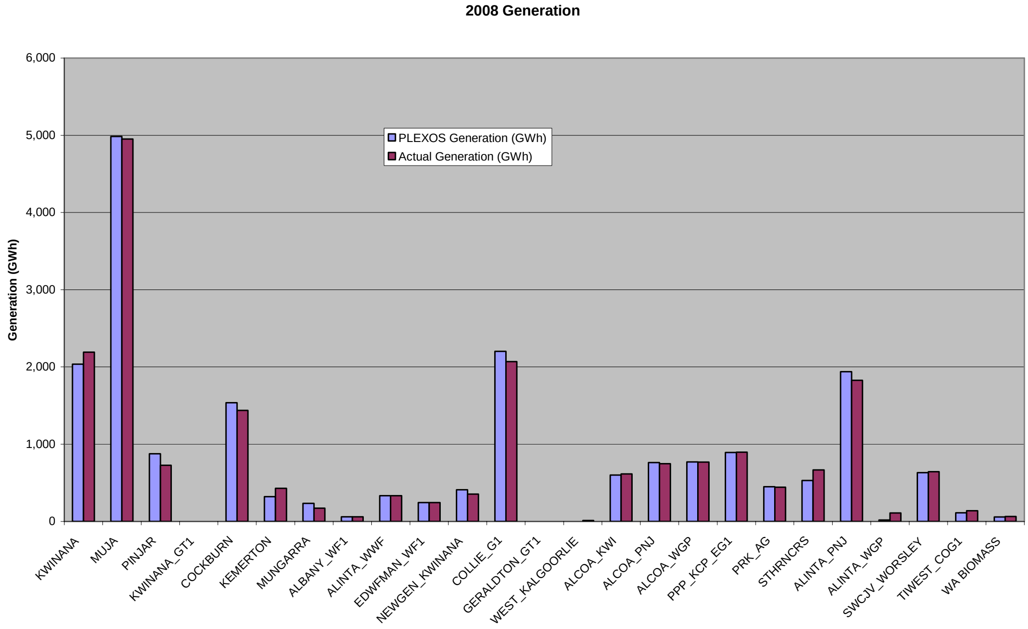
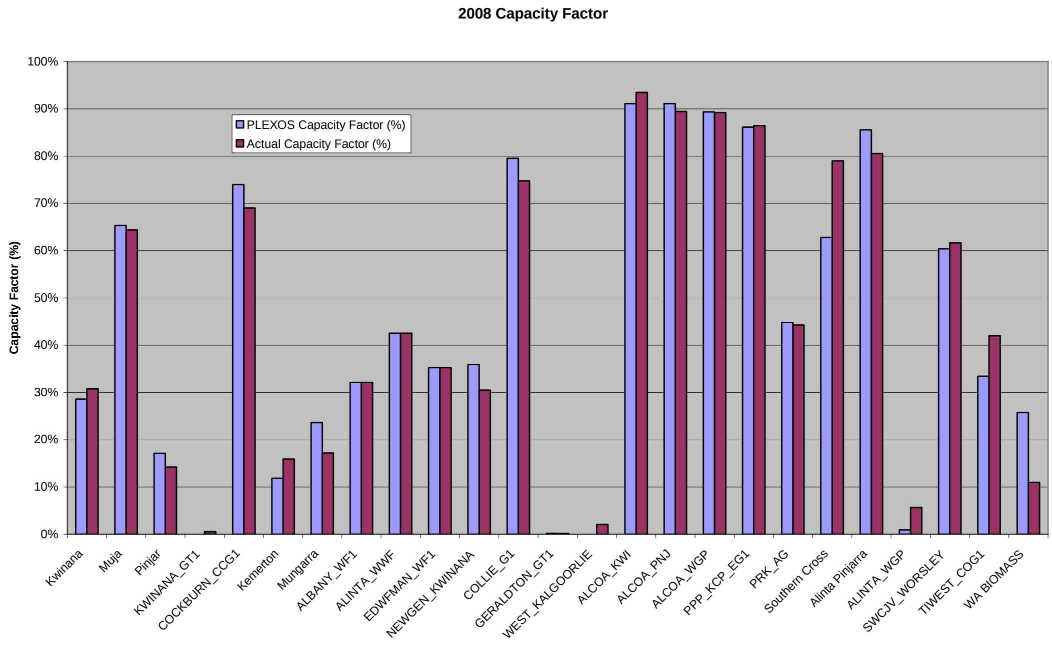


Figure 4-2 2008 capacity factors



4.3 Gas off-take

The actual gas off-take was estimated by summing up the half-hourly gas usage by each of the generating units, based on the dispatch information provided by IMO and our estimated heat rate curves for each unit. The comparison between estimated actual off-take and the PLEXOS result for 2008 is presented in Table 4-2. The difference between the estimated actual gas off-take and the total gas used in our PLEXOS simulations was smaller than 1.8%. This represents the accuracy that we can expect to achieve in applying fuel supply constraints in the modelling in the absence of more detailed information.

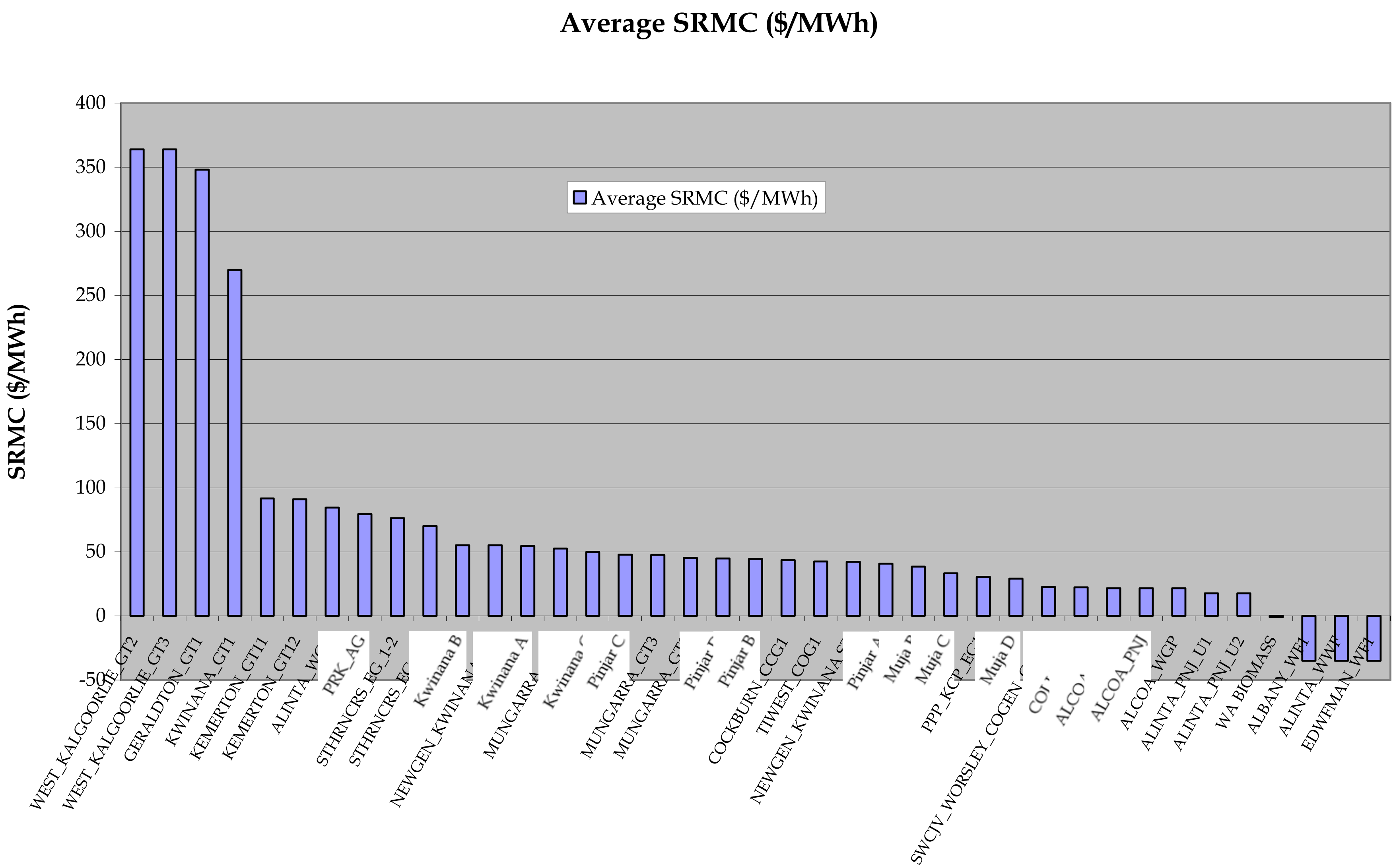
Table 4-2 2008 gas usage

	Total Perth Gas (TJ)	Total Goldfields Gas (TJ)
Estimated actual	114,018	12,122
PLEXOS result	117,428	11,026

4.4 Price

Since the purpose of the database is being used for reliability modelling and not for price forecasting, our interest resides mainly on obtaining an accurate dispatch and fuel usage, and not in obtaining an exceedingly precise price profile. Thus, we are modelling the WEM as a perfectly competitive market and we are not including start-up and shut down-costs on the price calculation. Figure 4-3 shows the average SRMC (yearly) for each of the units, as calculated in the PLEXOS simulation. This figure provides guidance as to the merit order of the units dispatch, which seems adequate based on MMA's understanding of the SWIS.

Figure 4-3 2008 Average SRMC

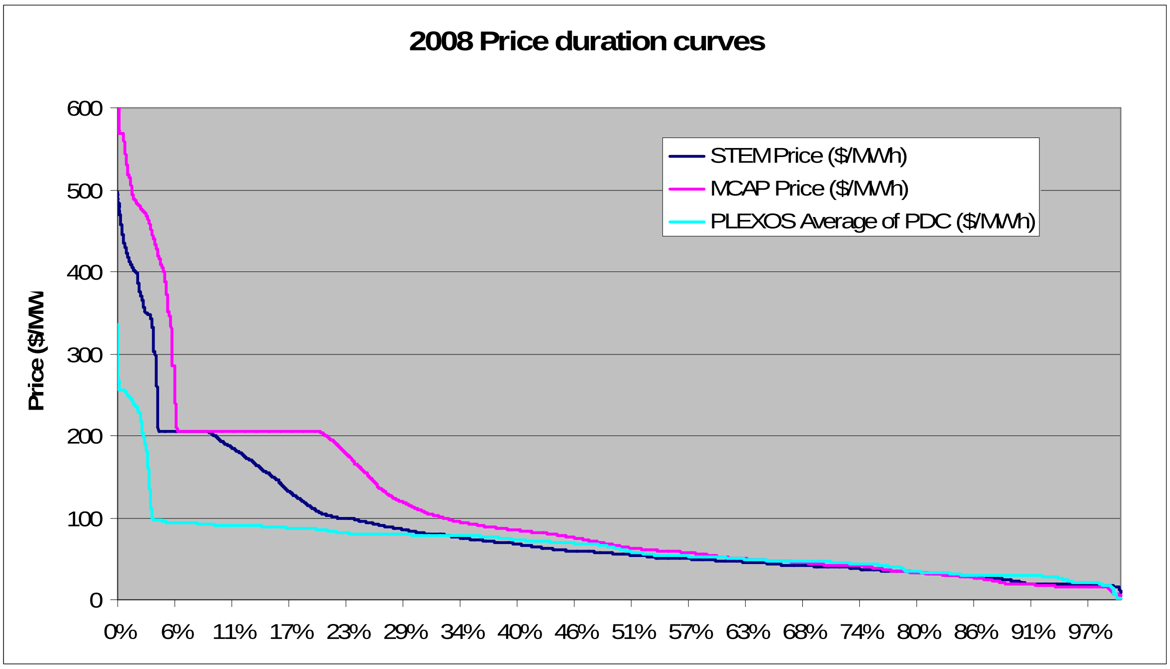


Thus, the prices reported by PLEXOS are based on a SRMC-based dispatch, based on unconstrained uniform pricing (same price for all the nodes). Although start-up and shut-down costs are being considered in the dispatch decisions (in the decision to turn on a generator or not), they are not being included explicitly in the price. Thus, during periods of high demand that may require starting multiple units our PLEXOS model will underestimate the price. Also, the PLEXOS PDC would underestimate the prices as a result of any gaming that may be increasing the prices in periods of stretch demand-supply balance.

Figure 4-4 shows the price duration curve obtained by the PLEXOS model (based on 5 samples). This PDC is calculated by ordering in descending order the average half-hourly prices. This better represents the STEM day-ahead market where prices are based on expected rather than actual generation states. As such, some averaging of expected outcomes is appropriate. As seen in Figure 4-4, the top-end of the PLEXOS PDC is capturing the use of distillate fuel for generation, although not with the same price outcomes that were actually observed. This may be due to the absence of start-up costs in the modelled pricing.

As mentioned, the price is calculated using a uniform pricing for all the nodes, as it is done in the WEM. Since we are not including an uplift to include the start-up and shut-down costs in the price, the PLEXOS model is underestimating the prices in the top 30% of the PDC.

Figure 4-4 Price duration curves



4.5 Conclusion

These results show that we have been able to approximately replicate the actual market dispatch and pricing for the 2008 calendar year. This work involved refining estimates of capacities and costs and plant outages so as to be able to replicate the market behaviour. The next section extends this model out for the next five years so as to assess the impact of fuel supply constraints on supply reliability.

5 FIRM FUEL SUPPLY AND RELIABILITY

5.1 Assumptions

As in the benchmarking exercise, we have modelled the SWIS as a single market 3-node system, with the 3 nodes representing Muja, Goldfields and North Country. This level of aggregation allows representing the major transmission constraints in the system.

The load profiles from July 2009 to June 2015 for the 3 nodes were created based on the forecasted energy and peak demand data reported in the 2008 SOO, which was then prorated between the 3 nodes using historical load trace data. Private loads for the model were calculated similarly as they were calculated for the benchmarking exercise, and were updated when needed.

Appendix A includes tables with most of our fuel, generation, and transmission assumptions. The Kwinana units were retired according to information provided to MMA by IMO. Table 5-1 shows the new entrants MMA estimated for the period going from July 2010 to June 2015. The dates of commissioning were based on information provided by the market participants, or were determined by MMA such that reserve levels remained close to the 8.2% requirement[1]. Table 5-2 shows the reserve levels for the 2010-2015 period.

Table 5-1 New entrants

Power plant	Commissioning Year	Capacity [MW]
Badgingarra	2011	130
BW1_Bluewaters_G1	2010	204
BW1_Bluewaters_G2	2011	204
BW1_Bluewaters_G3	2013	204
BW1_Bluewaters_G4	2014	204
NEWGEN_NEERABUP	2010	330.6
PERTH_ENERGY_GT1	2010	112
GENERIC_OCGT1	2013	165
GENERIC_OCGT2	2015	165

[1] Note that the reserve ratio of 8.2% is separate from the 56 MW required for load following and intermittent generation. The ratio as defined here is (installed capacity -56) divided by the 10% probability of exceedance peak demand.

Table 5-2 Load, firm capacity and reserve margin factor 2010-2015

Fiscal Year	10% POE peak load (without private load) [MW]	Firm capacity [MW]	Reserve margin factor (%)
2010	4,181.5	4,926	17.82%
2011	4,310.5	5,331	23.68%
2012	4,725.0	5,173	9.49%
2013	5,133.0	5,546	8.05%
2014	5,334.5	5,747	7.74%
2015	5,516.5	5,914	7.21%

5.2 Weights for the 10, 50, and 90% POE scenarios

The weights for the 10%, 50%, and 90% POE scenarios were calculated based on 33 years of weather data. Knowing the correlation between peak demand and mean daily temperature provided in the 2008 SOO, we estimated the equivalent "2008" demand for each of the 33 maximum mean daily temperature data points that occurred on weekdays, which gave us a 33-point discrete distribution of the yearly peak demand. Then, we approximated the 33-point distribution by a weighted 3-point distribution (with points given by the 10, 50, and 90 percentiles). The weights of the 3-point approximate distribution were calculated such that the moments of the 33-point distribution matched the moments of the 3-point distribution[2].

Table 5-3 Weights for the 10%, 50% and 90% POE scenarios

Scenario	Weight
10% POE	0.346
50% POE	0.431
90% POE	0.223

These weights in Table 5-3 ensured that the mean and standard deviation of the equivalent 3-point discrete distribution matched exactly the mean and standard deviation of the 33-point distribution (based on 33 years of weather data), and that the 3rd, 4th and 5th moments did not disagree by more than 0.17%.

Since we have only run 50% and 90% POE scenarios, the 90% POE unserved energy and generation costs were estimated by extrapolating from the 10% POE and 50% POE results. This provides a first order adjustment. It is acceptable because the unserved energy associated with 90% POE conditions would be small. We used logarithmic extrapolation for the unserved energy and linear extrapolation for the generation costs, as seen in equations (1) and (2) where the value of m (0.6657) is obtained from the 33-point

[2] A. Miller and T. Rice, "Discrete Approximations of Probability Distributions", Management Science v29, n. 3, March 1983

distribution of peak demand. The value of m is the ratio of the difference between the 50% and 90% peak demands divided by the difference between the 10% and 50% POE peak demands.

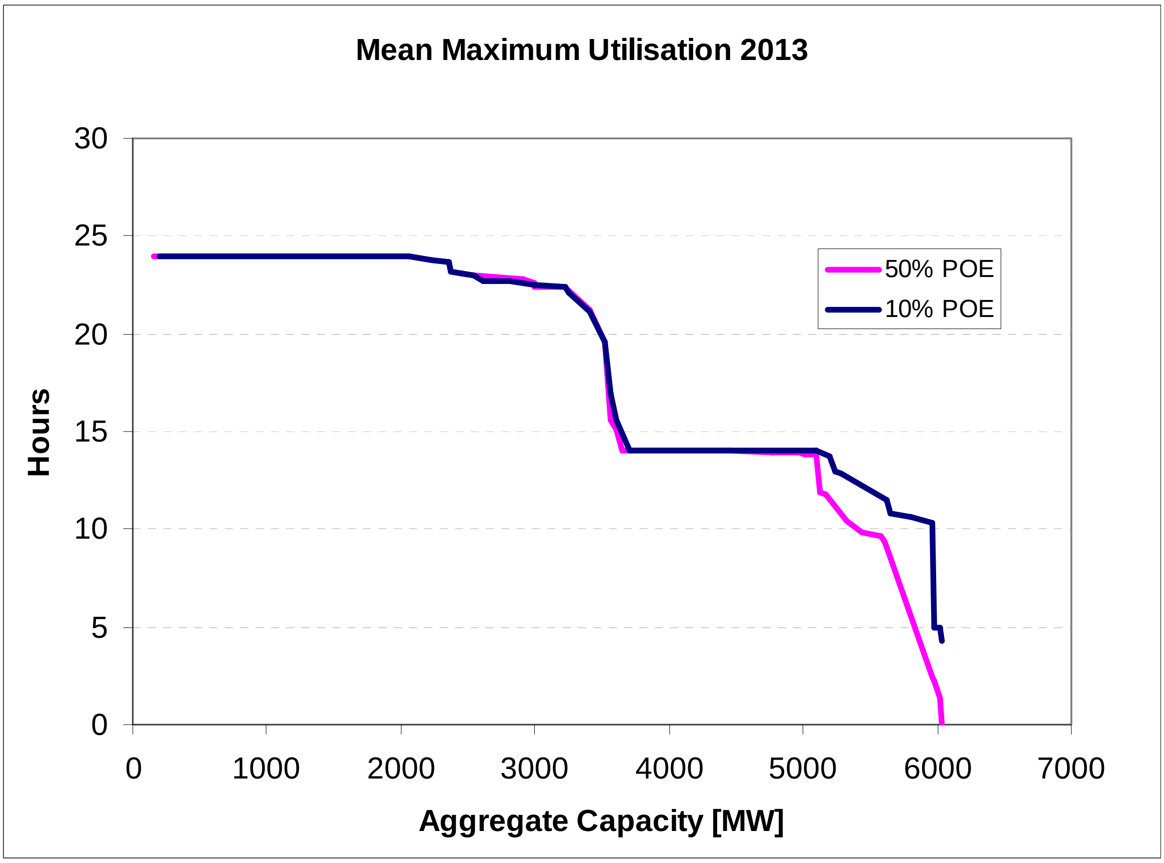
$$USE_{90} = \frac{USE_{50}^{(1+m)}}{USE_{10}^{m}} \qquad (1)$$

$$GenCost_{90} = (1+m) \cdot GenCost_{50} - m \cdot GenCost_{10} \qquad (2)$$

5.3 Base case results

We simulated the system considering a 14 hours maximum daily capacity factor for the units that are not base load or cogeneration units. We looked at the maximum daily utilization of the different generators over the 70 market simulations. Figure 5-1 shows the maximum daily hours of utilisation versus the aggregated capacity, for 2013 (we are using 2013 for illustration as this year's reserve margin factor was closer to the 8.2% value).

Figure 5-1 Mean maximum utilization in 2013



We can observe that around 2,000 MW of generation has a maximum daily utilization of 24 hours, implying that in every sample, at least once a year those generating units were utilised at full capacity during a whole day. Then we have around 1,500 MW of generators which did not operate at full capacity during a whole day (or at least they did not do it in any of the stochastic samples). As it should be expected, most of the generators in the "region" between 0 and 3500 MW of aggregated capacity are base load generators, non-scheduled generators, or cogenerating units.

In the region between 3500 and around 6000 MW we have the generators to which we applied a hard constraint to simulate a 14 hour storage limit. Notice that this is a conservative approach, since some of the generators in this region might be able to secure larger amounts of fuel for short periods of time. Generators in the region between 3500 and approximately 5200 MW are at the 14 hours limit, indicating that this limit is binding for those units at least once a year for each of the samples. These units might find it beneficial to have larger liquid fuel storage (or contract a larger gas MDQ). However with respect to the fuel storage requirement, we have imposed the minimum standard as if it were the maximum provided.

Finally, the rest of the generators in the region beyond 5200 MW (peaking generators) do not consistently use the 14 hours fuel storage, and might find economic benefits in reducing their fuel storage capacity without sacrificing system reliability. Section 5.5 discusses this possibility. As it should be expected, the 10% POE case shows more utilisation of peaking generation than the 50% POE case.

5.4 Unserved energy versus storage hours and reserve margin

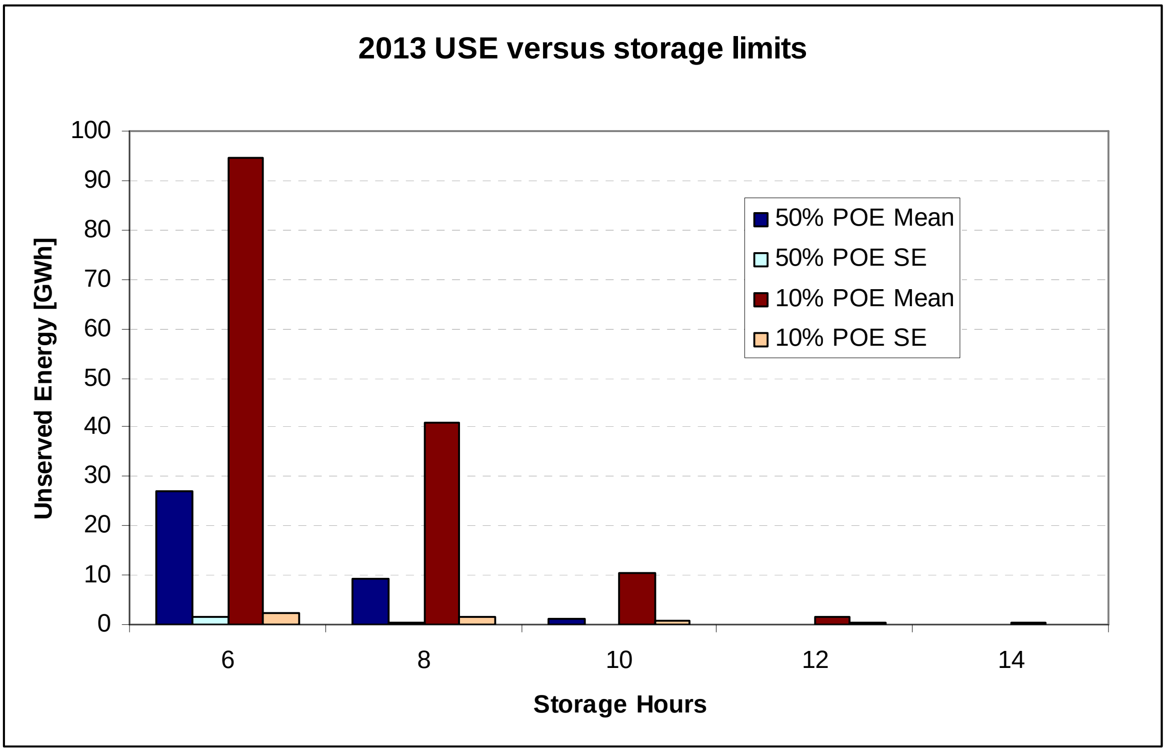
The scenarios analysed in this section consist of 2009/10 to 2014/15 with normal conditions and the duration of fuel limits reduced equally (in 2 hours steps) until the expected unserved energy exceeds 0.002% weighted over the 10% to 90% POE peak demand range. This provides an option for equal reduction in minimum limit under normal conditions.

Notice that the results obtained by this approach are conservative, as the storage limits for all the relevant generators are reduced equally and the limit is treated as a hard constraint. That is, we are not considering the possibility of the plant operators to acquire additional fuel (beyond the 14 hours limit) if needed. We consider this approach to be adequate as what is of interest from a reliability point of view is the firm energy that generators can make available to the system.

For each simulation year (from fiscal year 2010 to 2015), we defined a set of 5 scenarios for the maximum daily fuel availability. These scenarios were created by limiting the intermediate and peak generators with a maximum daily capacity factor corresponding to the equivalent of 14, 12, 10, 8, or 6 hours of available fuel (e.g. a 12 hour limit would correspond to a maximum daily capacity factor of 50%).

For each of the scenarios, we ran up to 50 different outage patterns for the 50% POE demand, and 20 different outage patterns for the 10% POE demand. The number of samples per scenario was chosen such that the sampling error (based on the standard error of the mean) would be small enough such that it was not significant when comparing it with the variability due to the explaining variables. Figure 5-2 shows (for 2013) the mean

Figure 5-2 Mean and standard error of unserved energy for 2013 for different fuel storage limits



and standard deviation, and it can be appreciated that the sampling error (measured as the standard error of the mean) is small when compared with the variability resulting from restricting the fuel availability.

For each sample, we recorded the total unserved energy, the total generation cost (fuel cost plus variable operating and maintenance costs), and the maximum daily capacity factor for each generator. Then, the USE ratio for each scenario was calculated as the ratio between the weighted average of the unserved energy from the simulations and the 0.002% of the 50% POE energy for the respective year. The weighted average was calculated using the weights calculated in section 5.2.

As in our modelling we are using the logarithm of the USE ratio, USE values of zero (occurring for the 14 and 12 hours limit scenarios in 2010 and 2011 when the reserve margin is high) have been omitted. Also, in order to avoid distortions caused by values of unserved energy that are too extreme to be realistic, if under a scenario for a given year the USE ratio was too large, it was not included in the regression analysis. For example, the 6 hour point for 2013, with a USE ratio of 97.3, was not included.

Figure 5-3 to Figure 5-8 show the unserved energy (in logarithmic scale) versus the storage limit (in hours) for the fiscal years 2010 to 2015, for all the points we finally used to fit the model. The same model shown in Equation (3) was used for all years so that we could assess the impact of reserve margin.

Figure 5-3 Unserved energy versus storage hours for 2010

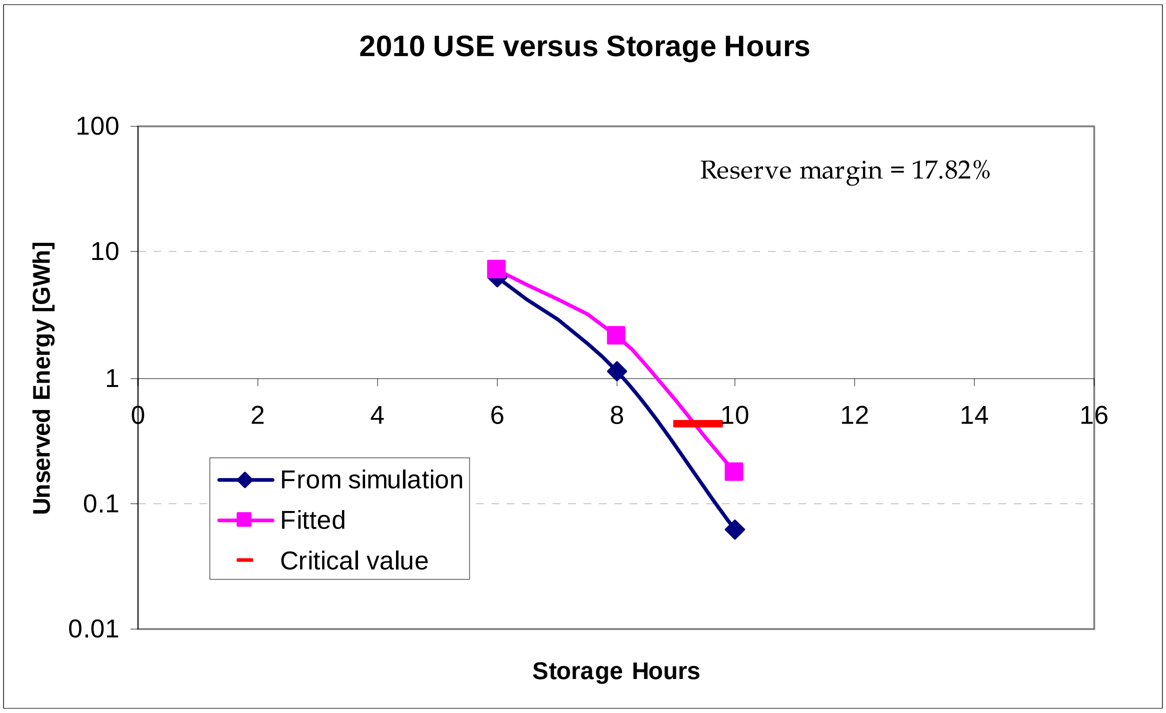


Figure 5-4 Unserved energy versus storage hours for 2011

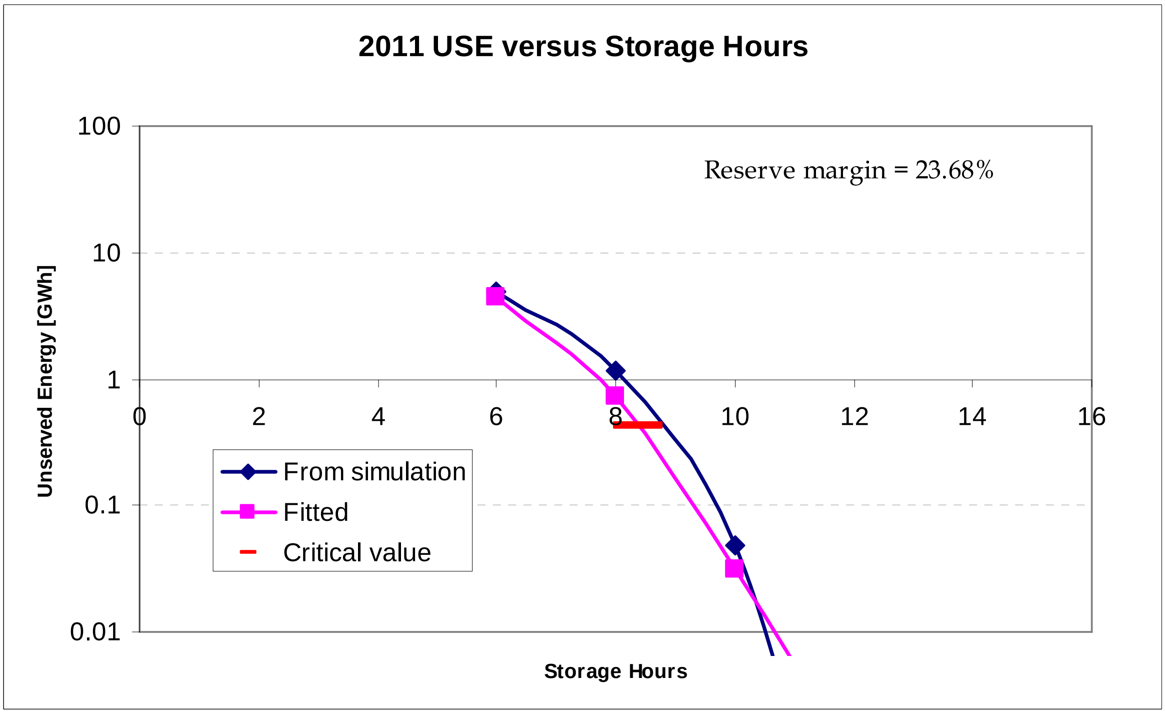


Figure 5-5 Unserved energy versus storage hours for 2012

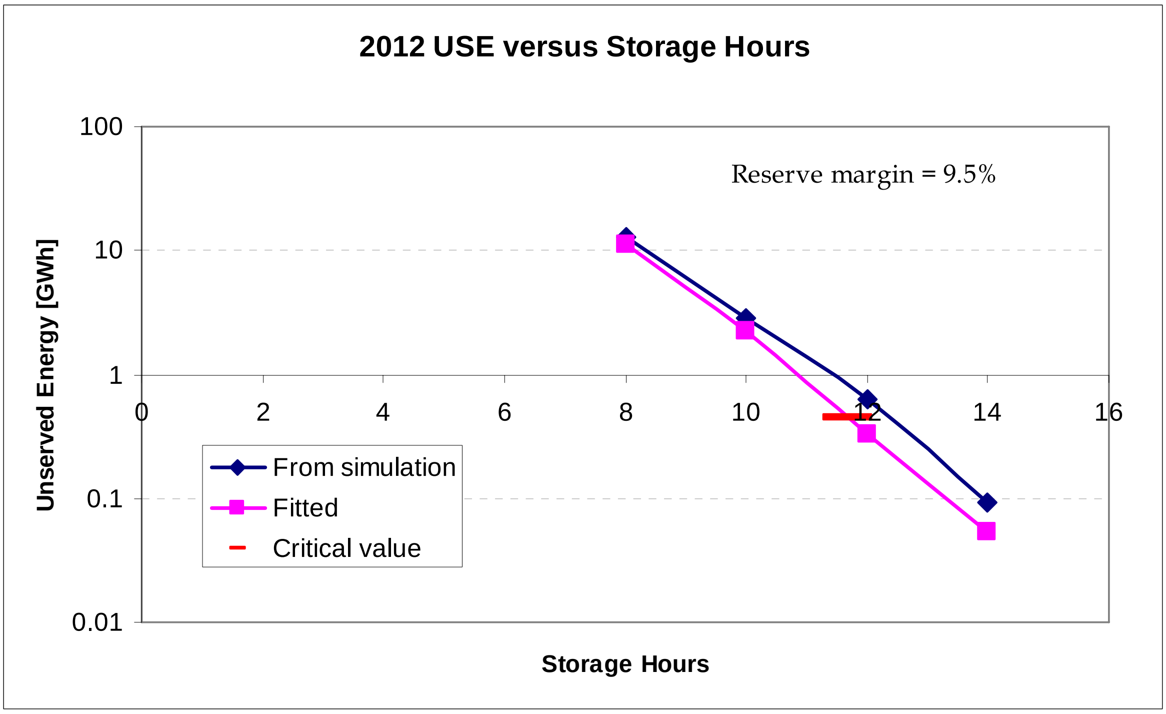


Figure 5-6 Unserved energy versus storage hours for 2013

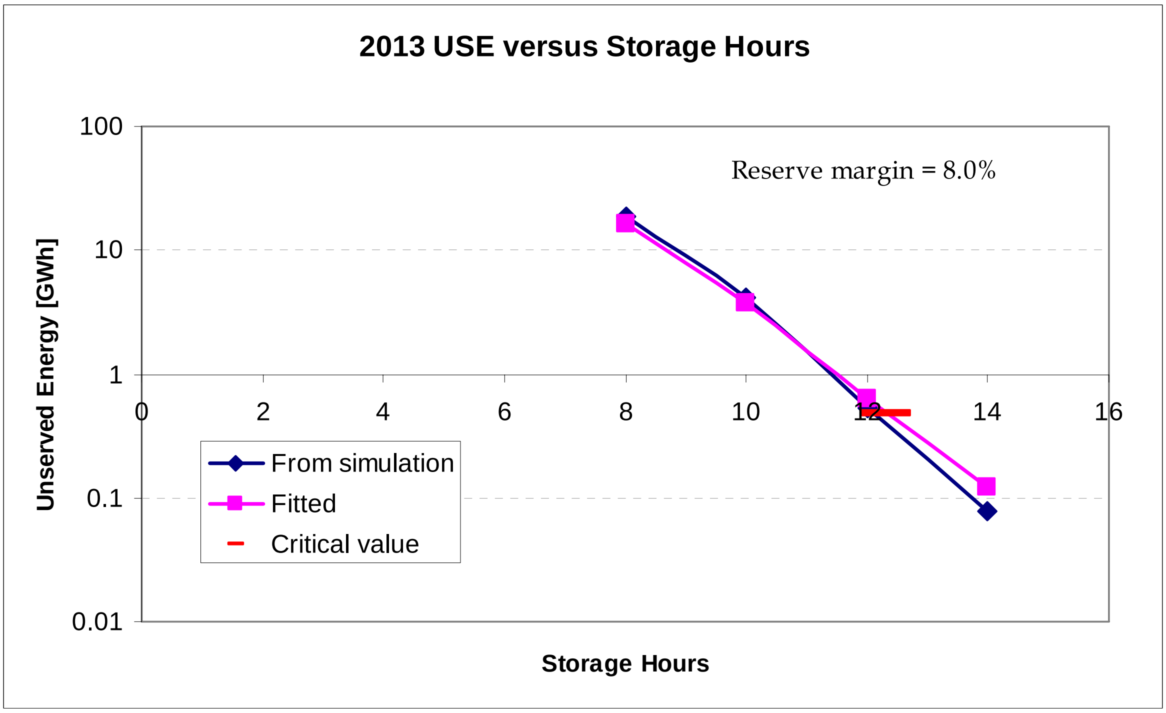


Figure 5-7 Unserved energy versus storage hours for 2014

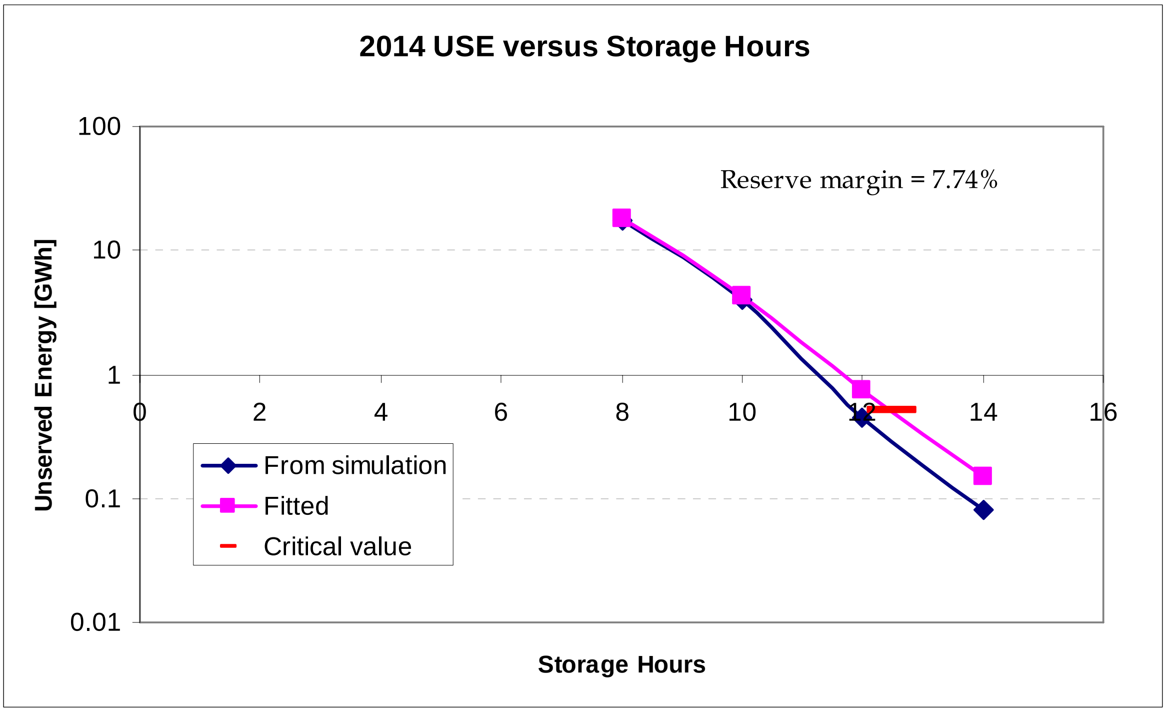
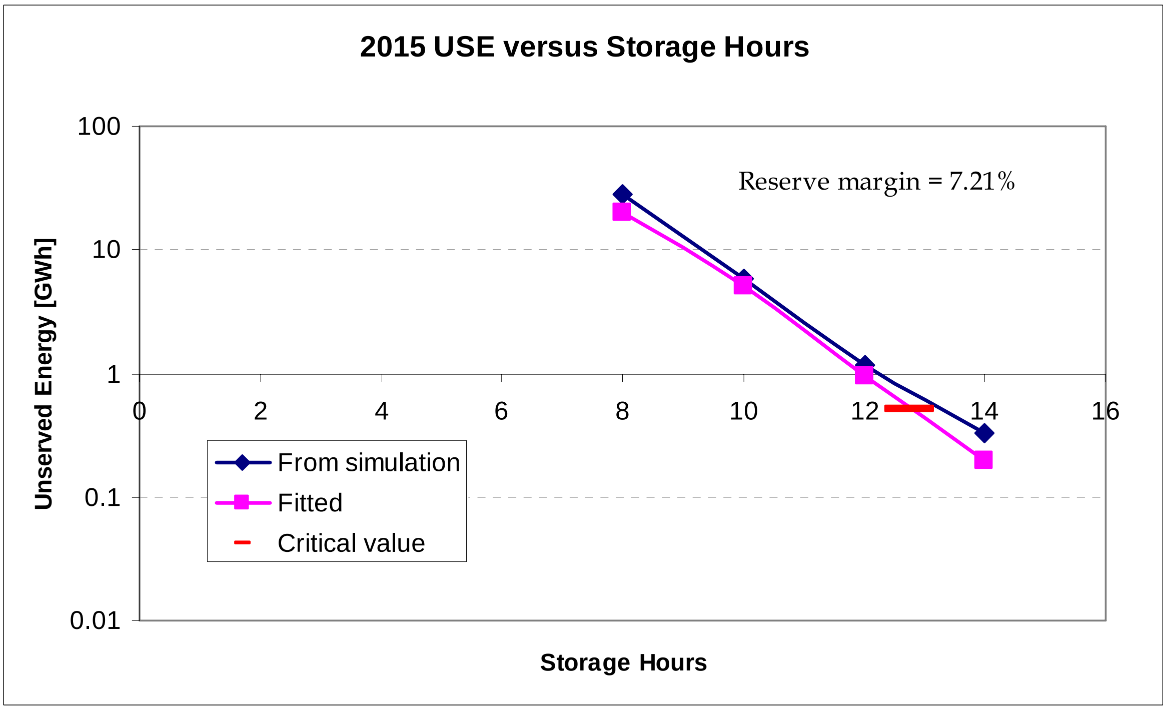


Figure 5-8 Unserved energy versus storage hours for 2015



As the reserve margin factor becomes smaller, unserved energy tends to grow, as it should be expected. We could also observe that in the region of interest the unserved energy decreases approximately exponentially with the storage limit, especially when the reserve margin factor is around 8.2%. For higher values of the reserve margin, the curve tended to become more concave. In order to make further inferences from the simulation results, we fitted the following model to the data:

$$\ln(USE\_Ratio) = d \cdot (R+1) + e \cdot R \cdot x + \left[(a_1 - b_1 \cdot x) \cdot e^{-c_1 x}\right] + \left[(a_2 - b_2 \cdot x) \cdot \left(1 - e^{-c_1 x}\right)\right] \quad (3)$$

Where:

USE_Ratio is the ratio of the unserved energy to the target value

R is the reserve margin factor (standard value 8.2%)

a_1, b_1, a_2, b_2, c_1, d and e are fitted constants

x is the fuel storage limit in hours

Note that we have used the same coefficient for the two exponential terms which allows the function to move from one linear segment fitted by a_1 and b_1 to the second fitted segment based on a_2 and b_2 for higher levels of fuel storage.

This model, which estimates the USE ratio using both the fuel storage-hour limits and the reserve ratio as explanatory variables, was chosen because it captured all the main dependences and features of the curves observed in the simulations. The parameters of the fitted curve, obtained by minimizing the square error, are shown in Table 5-4, while the fitted curves are included in Figure 5-3 to Figure 5-8.

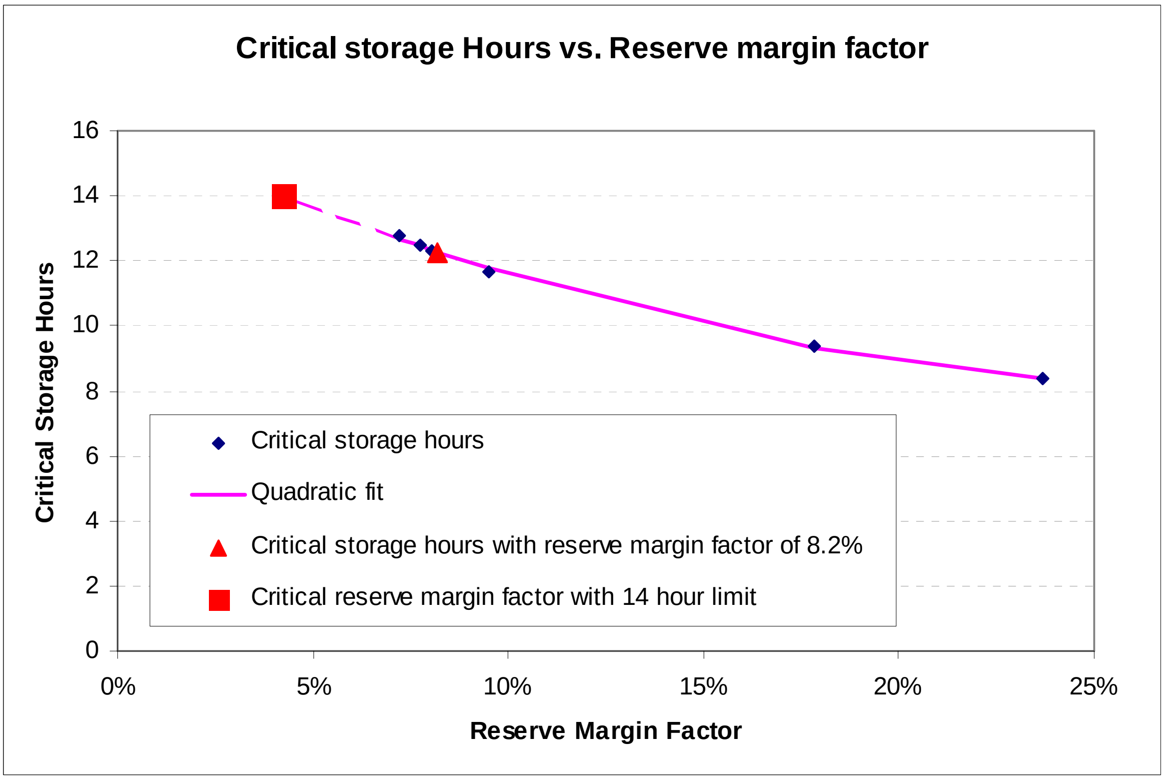
Table 5-4. Parameters of the fitted curve

Parameter	Value
d	23.82
a_1	-56.41
b_1	-13.16
c_1	0.2
a_2	-42.81
b_2	-0.86
e	-5.36

The fitted curves show some variation about the actual data due to variations in capacity mix and forced and planned outage rates in each year. We would not expect a good fit in each year. Indeed, other explanatory variables would include such factors as the distribution of unit sizes, forced and planned maintenance rates. However, in setting a requirement for a particular year, the particular factors for that year should be considered as fixed if reasonably well defined or variable if uncertain.

Figure 5-3 to Figure 5-8 also include the critical values of fuel storage for which the USE ratio becomes 1 (that is, the value at which the unserved energy equals the 0.002% limit). These values are also presented in Figure 5-9, which shows the critical storage hours versus the reserve margin factor.

Figure 5-9. Critical storage hours versus reserve margin factor



We can observe that the critical storage hours decrease as the reserve margin factor increases, and that it does so in an approximately quadratic manner. Using the quadratic fit ($96.22 \cdot RM^2 - 55.73 \cdot RM + 16.19$) we can see that with a reserve margin factor of 8.2% we could get a 0.002% of unserved energy with only a 12.27 hour limit, or that with the current 14 hours limit could tolerate a reserve margin factor of down to 4.25% without exceeding the 0.002% unserved energy limit. This result strongly suggests that there is some room to relax the 14 hours constraint, and section 5.5 will discuss the economic benefits of doing so. However retaining the 14 hour limit would provide some margin against uncertainty in forced outage rates, demand growth, fuel supply reliability and plant commissioning.

Despite the fact that the quadratic fit looks remarkably good, any inferences from this curve should be taken carefully as each data point corresponds to a different year with a slightly different generation mix and different levels of planned maintenance. Ideally a composite function should include parameters for the average level of forced and planned maintenance as well as reserve margin. However it was not considered necessary to explore those relationships in detail at this stage as the study is more conceptual than definitive. It does confirm that the current 14 hour requirement does satisfy the reliability requirement over the next few years if sufficient capacity is provided to meet the current reserve margin standard.

5.5 Assessing the benefits of relaxing the fuel storage constraint

For the purposes of illustrating the potential economic benefits of relaxing the fuel storage limits for peaking generators, we will use results for the 2012/13 fiscal year, as this year's reserve margin (8.05%) is slightly smaller than the reserve margin requirement (thus or conclusions will be on the conservative side). It was not considered necessary to explore all the years to 2014/15 at this stage of the analysis. The intention is to explore the concepts with a realistic example as the basis for discussions about possible changes to capacity management policies and market processes.

On the one hand, in average over all the 10% POE samples (20 samples), Newgen Neerabup, Kwinana G5 and G6, all the Pinjar units (except for Pinjar GT02 and Pinjar GT01), and all the Mungarra units are at the limit of 14 hours. On the other hand, Perth Energy GT1, Pinjar GT01 and GT02, Alinta Wagerup, Geraldton GT1, Kemerton GT11 and GT12, both West Kalgoorlie units, and Kwinana GT1 are all (on average) operating below this limit. That is, those units are not being constrained and the WEM could achieve adequate levels of reliability (below 0.002% USE) with a more moderate fuel supply requirement. Thus, for some of the peaking units there is room for savings in fuel firm supply without sacrificing system reliability. This would be particularly important when gas pipeline capacity is constrained and costly at the margin. This section will attempt to quantify those potential savings.

Figure 5-10 shows the minimum, maximum and mean MDQ profiles for the 20 samples of the 10% POE scenario in 2013, considering a fuel storage constraint of 14 hours. This picture illustrates how much variability there is in the maximum utilization depending on the sample (and its respective outage pattern), and we used it as guidance for setting more relaxed fuel storage requirement profiles.

For those generators whose 14 hours fuel storage requirement is overly constraining (as with a smaller fuel storage requirement the system would still attain adequate reliability levels), we considered the smaller limits based on the values presented in Table 5-5. Figure 5-11 illustrates the adjusted maximum fuel storage profiles in Table 5-5 against the aggregated capacity of the peaking generators. The new limits were rounded from a linear relationship between the fuel supply limit and the aggregate capacity of the peaking plants.

The adjusted profiles (which we called low, medium, and high) correspond to more relaxed fuels storage requirements. The high profile is the closest one to the current 14 hour limit, and the low profile is the more relaxed requirement. As we translate these profiles into maximum daily capacity factor constraints in the PLEXOS model, the low profile is the more constrained one and it should give the highest unserved energy and generation cost. However, this profile will also be the one providing the most saving in firm fuel supply to the generator, so the idea is to find the level of fuel storage requirement that will minimise the total system cost while maintaining adequate levels of unserved energy.

Figure 5-10 Maximum utilisation 10% POE in 2013

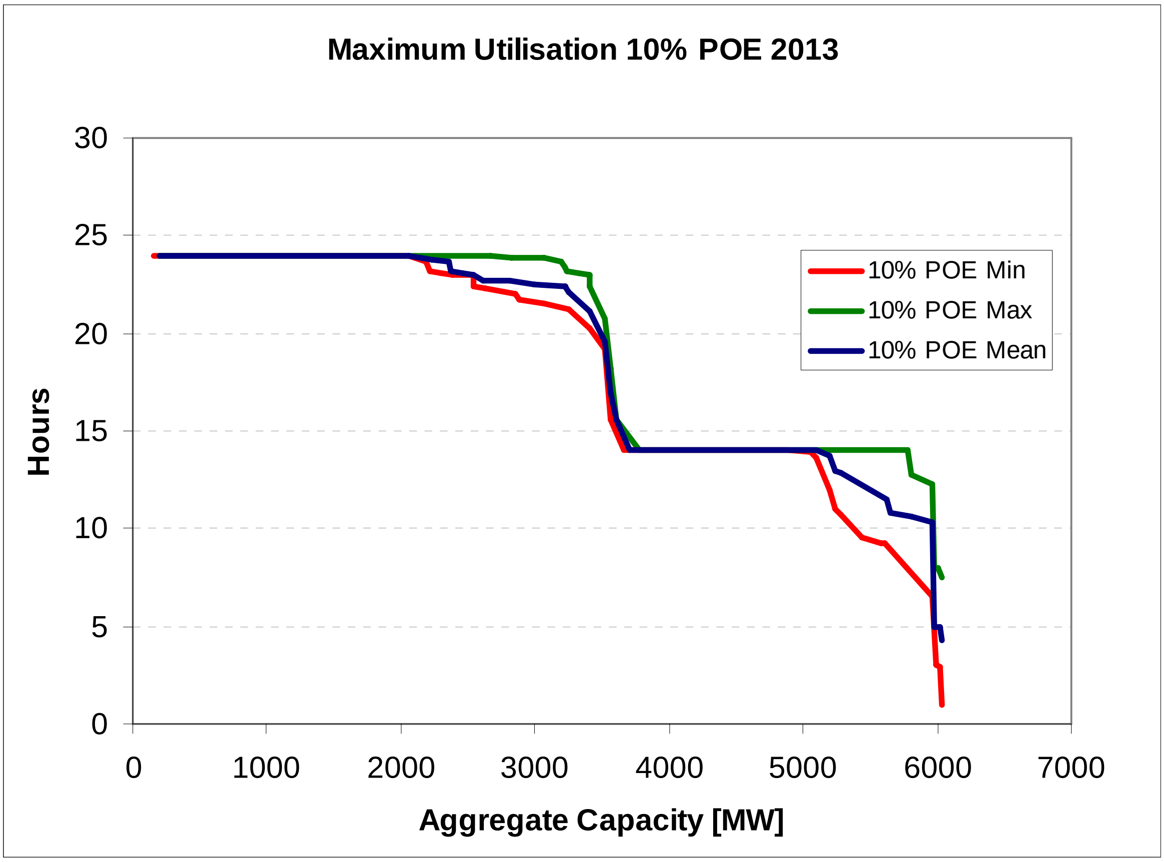
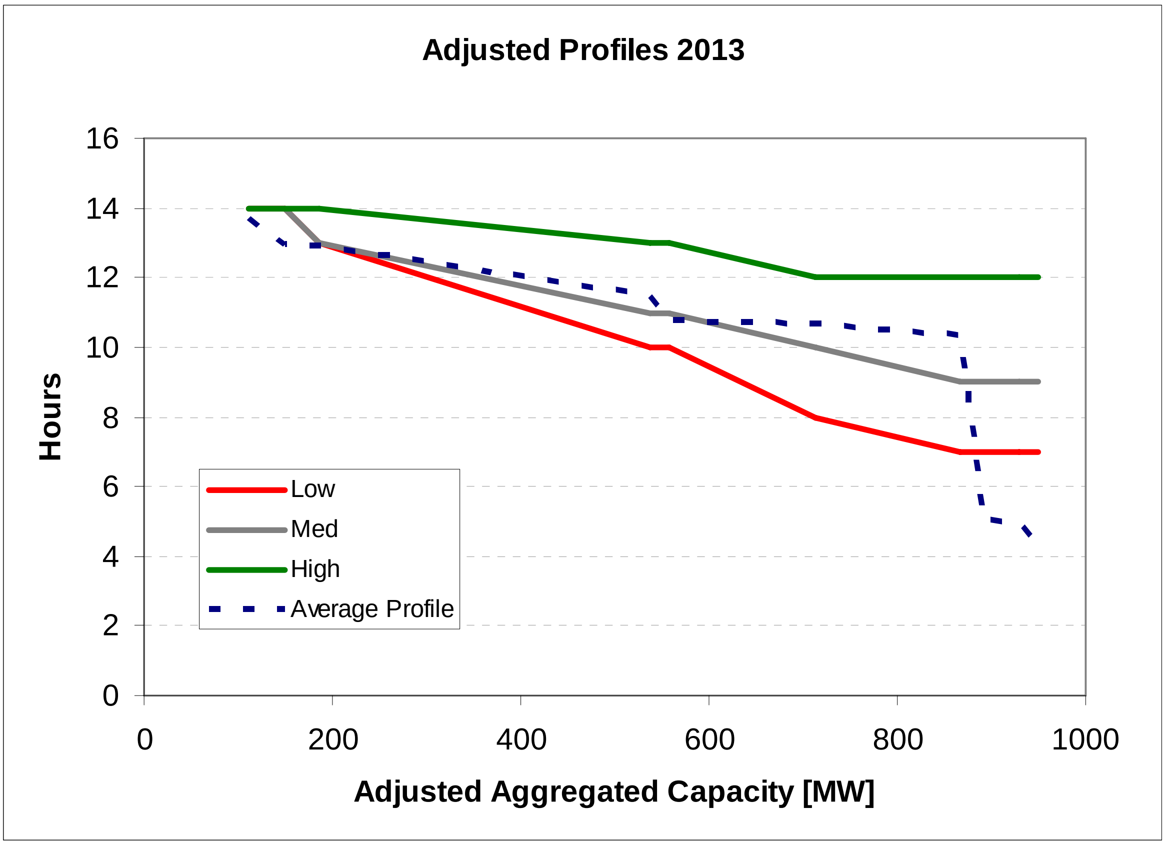


Table 5-5 Adjusted maximum fuel storage profiles for peaking generation

Generator	Aggregated Capacity [MW]	Average Max. Daily Utilization	New Limit (hours)		
			Low	Medium	High
PERTH_ENERGY_GT1	112.0	13.71	14	14	14
PINJAR_GT02	149.2	12.95	14	14	14
PINJAR_GT01	186.4	12.90	13	13	14
ALINTA_WGP	537.4	11.45	10	11	13
GERALDTON_GT1	558.2	10.78	10	11	13
KEMERTON_GT11	712.2	10.63	8	10	12
KEMERTON_GT12	866.2	10.30	7	9	12
WEST_KALGOORLIE_GT3	890.8	5.01	7	9	12
WEST_KALGOORLIE_GT2	929.0	4.96	7	9	12
KWINANA_GT1	949.8	4.28	7	9	12

Slope (hours/MW)	-	-0.00884	-0.00928	-0.00618	-0.00309

Figure 5-11. Adjusted maximum fuel storage profiles for peaking generation



Using the profiles in Table 5-5 and Figure 5-11, we ran again 50 samples of the 50% POE case and 20 samples of the 10% POE case for each one of the profiles. Then we compared their average unserved energy and generation costs with the base case (with a flat fuel storage limit of 14 hours, as described in Section 5.3). Results are presented in Figure 5-12, Figure 5-13 and Table 5-6.

Notice that as we relax the fuel storage requirement for the generators we are making the optimization problem to be more constrained by forcing the generators not to generate beyond their new storage limit, so both unserved energy and generation costs increase. Therefore, as expected, in Figure 5-12 the unserved energy increases as we relax the fuel storage requirement, with the low profile showing unserved energy only slightly above the 0.002% limit.

Table 5-6 shows that, on the one hand, both generation costs (fuel + VOM costs) and USE costs (calculated using a VoLL of $30,000/MWh) increase as the fuel storage requirement is relaxed for peaking generators. On the other hand, the storage needed and the annual inventory cost decreases increase as the fuel storage requirement is relaxed. The annual inventory cost was calculated based on an estimated gas capacity cost of $1.07/GJ for Perth and $2.50/GJ for Goldfields based on gas pipeline tariffs for daily reservation of transport capacity. We have not included costs for daily gas supply which may be additional.

Figure 5-12 Unserved energy versus slope for the different profiles

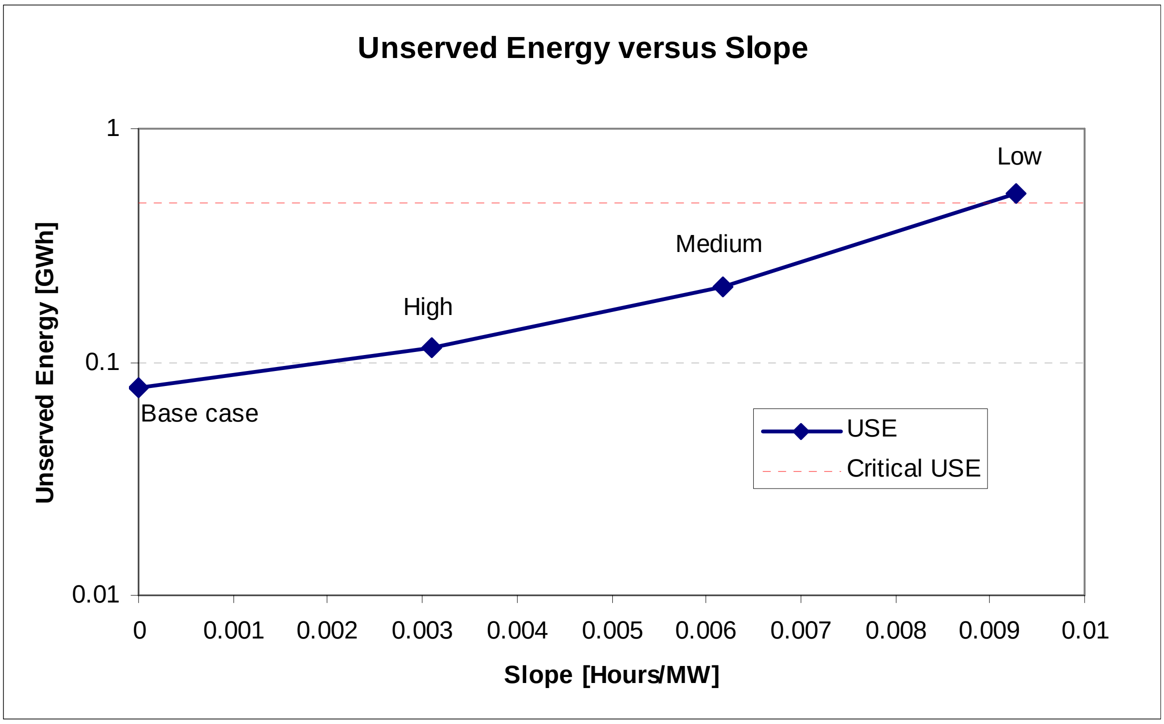
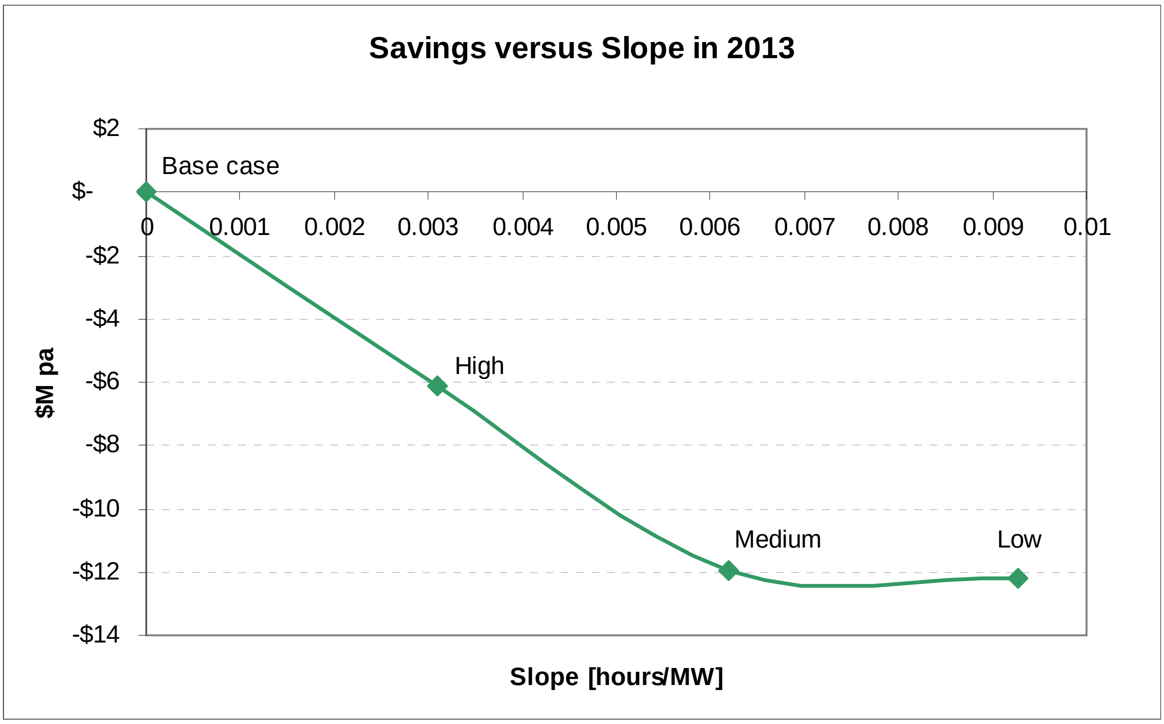


Table 5-6 Cost-benefit analysis

	Slope (hours/MW)	Storage needed (MWh)	Annual inventory cost ($M)	Annual USE cost ($M)	Annual generation cost ($M)	Total cost ($M)	Savings ($M)
Base case	0	13297	$72.69	$0.77	$727.46	$800.92	0.000
High limit	0.00309	11902	$64.49	$2.80	$727.49	$794.79	-6.128
Medium limit	0.00618	10508	$56.30	$5.10	$727.54	$788.95	-11.971
Low limit	0.00928	9113	$48.11	$13.13	$727.50	$788.74	-12.177

Figure 5-13 shows that the savings level as we reach the medium profile (with maximum savings around $12 million per annum), with the low profile being only marginally better in terms of total system cost but with an unserved energy slightly above the 0.002% requirement. Thus there is scope to reduce the requirement for fuel storage for some plants having regard to the fact that there is a substantial amount of base load plant for which 24 hours of fuel supply would be expected. The annual savings in fuel supply could be sufficient to make it worthwhile to facilitate trading in daily fuel supply and storage.

Figure 5-13. Savings for the different profiles with respect to the current limit



5.6 Relaxing the fuel storage requirements in non-peak periods

The previous analyses were performed considering a flat fuel storage requirement during the whole year. An alternative to that approach is to reduce the fuel storage requirement during non-peak periods (weekend and/or non-peak season) in order to maintain adequate reliability levels during peak periods and at the same time allow the generators to sell their excess gas supply capacity during non-peak periods. Thus, the objective is to study if the fuel storage/supply requirement could be relaxed on weekends and non-peak season without threatening reliability, and to calculate the potential savings in doing so. The significant savings would only apply for gas fuel as the inventory cost for liquids would be much smaller than for gas transport.

We have used the year 2012/13 since this year has a reserve margin closer to the 8.2% level and examined three alternative formulations (besides the base case) of the daily fuel constraint as detailed below to compare with the current requirement:

- **Base case**: flat reduction of the fuel storage requirement for the whole year (results presented in sections 5.4 and 5.5)
- **Non-peak-season reduction**: fuel storage requirements were relaxed for non-peak season only (from April to November, for both workdays and weekends)

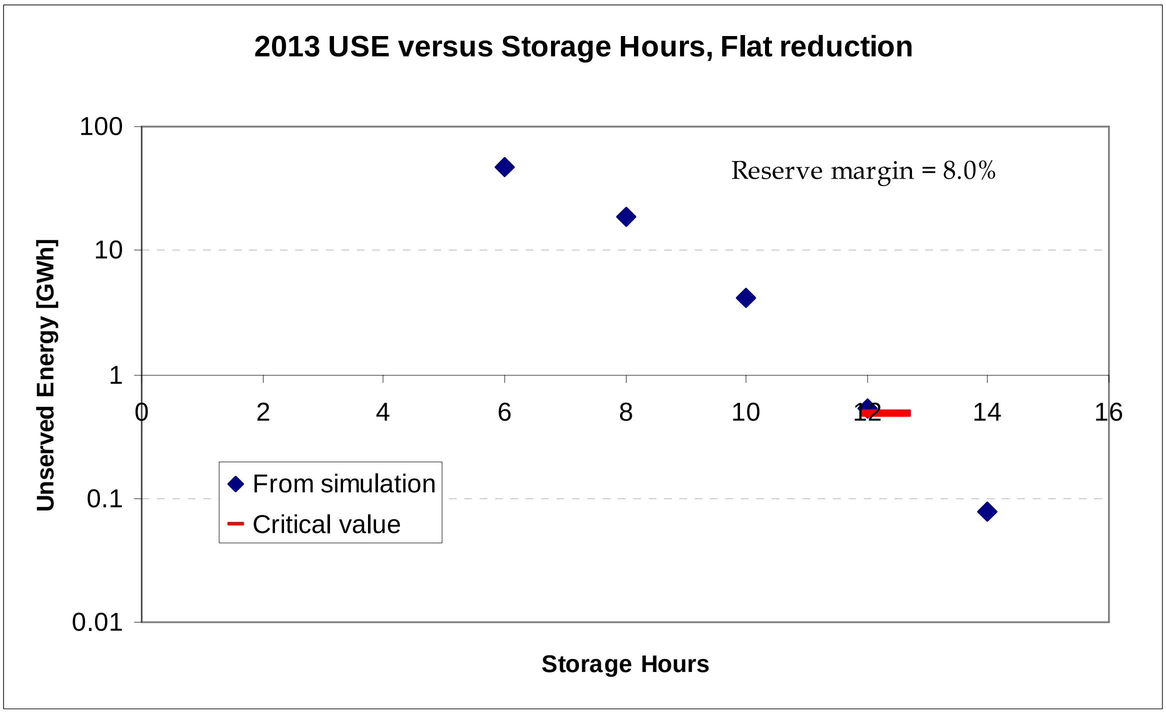
- **Weekend reduction**: fuel storage requirements were relaxed for weekends only (both in peak and non-peak season)
- **Weekend and non-peak season reduction**: the fuel storage requirements were relaxed simultaneously for both non-peak season and weekends (that is, all days from April to November and weekends only from December to March).

As in the base case, the fuel storage requirement was relaxed only for intermediate and peak generation.

5.6.1 Effect on unserved energy

On the one hand, Figure 5-14 shows the unserved energy versus the fuel storage limit for a flat reduction (base case). The critical value of reliability (0.002% unserved energy) is reached at about 12 hours. If we were to relax the fuel storage requirement beyond 12 hours, the unserved energy would be above the acceptable limit.

Figure 5-14. Unserved energy versus storage hours for 2013, flat reduction (base case)



On the other hand, Figure 5-15 to Figure 5-17 show the effect on the unserved energy of relaxing the fuel storage requirement only during non-peak periods. We can observe in all the curves that the unserved energy remains almost constant (and below the critical level) until the fuel storage requirement reaches approximately 10 hours and then starts to increase exponentially (linearly in the logarithmic scale) as we reduce the fuel storage requirement. In consequence, the current 14 hours fuel storage requirement could be reduced during non-peak periods to as low as 10 hours with negligible effect on the system reliability with standard reserve margin based on the 8.2% ratio.

Figure 5-15. Unserved energy versus storage hours for 2013, weekend reduction

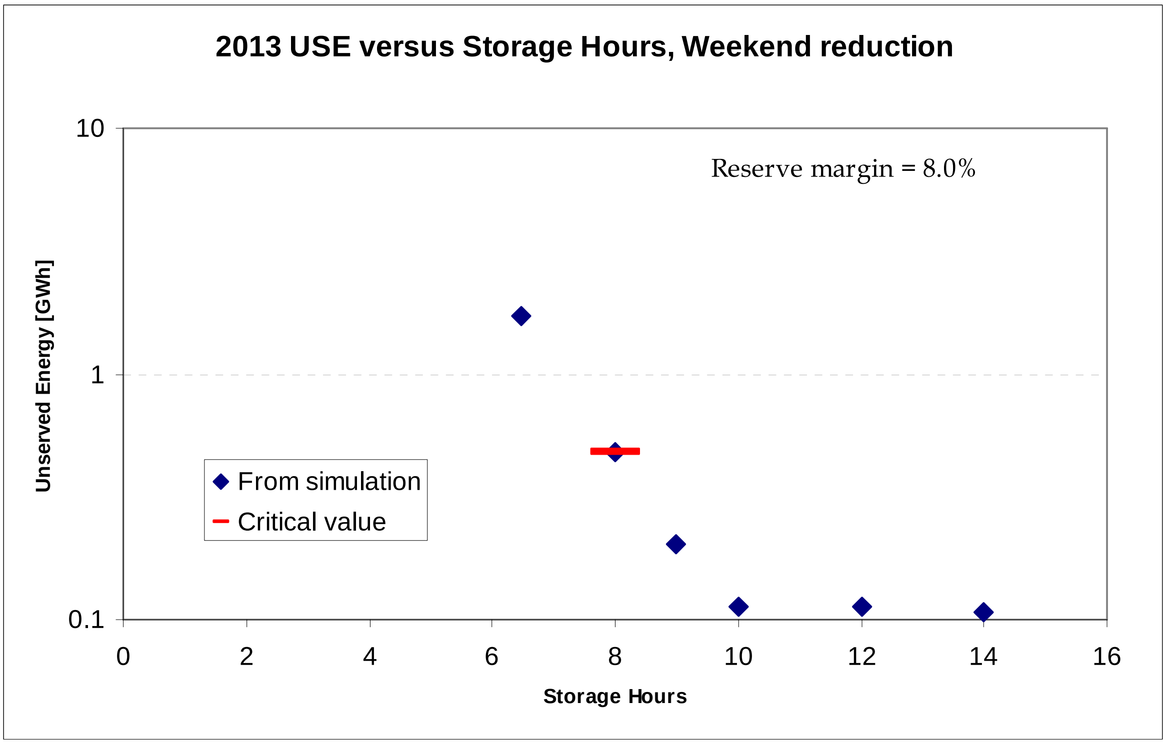


Figure 5-16. Unserved energy versus storage hours for 2013, non-peak season reduction

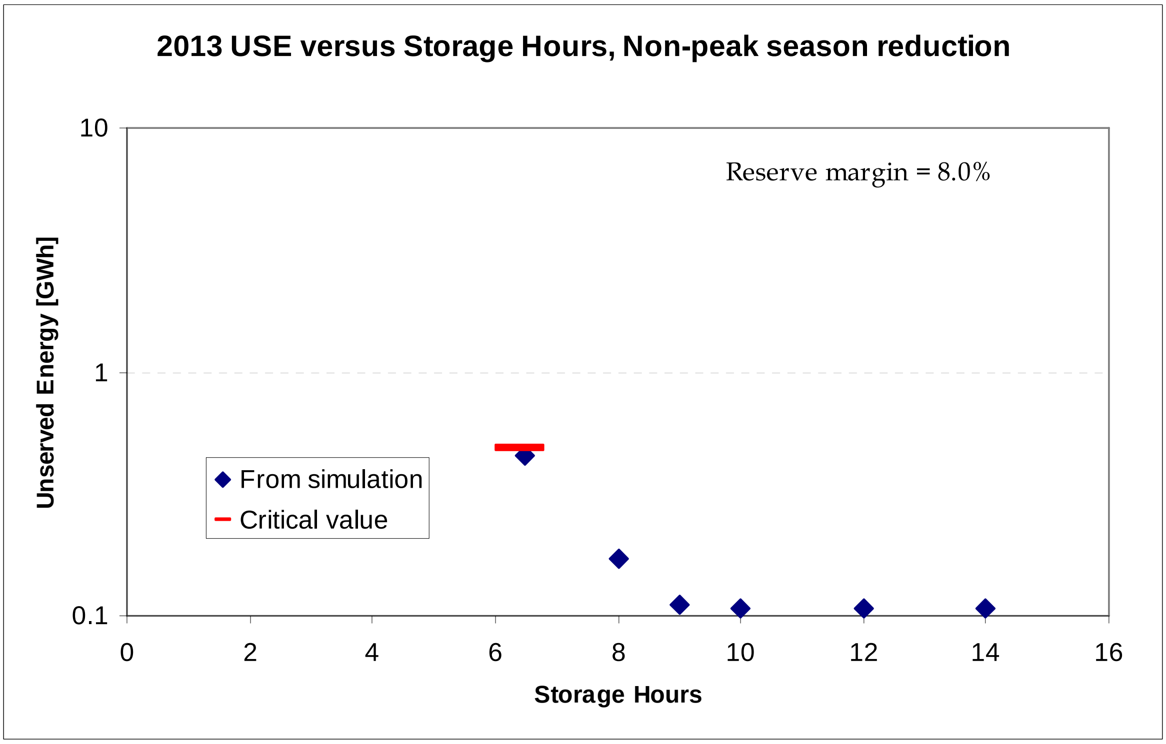
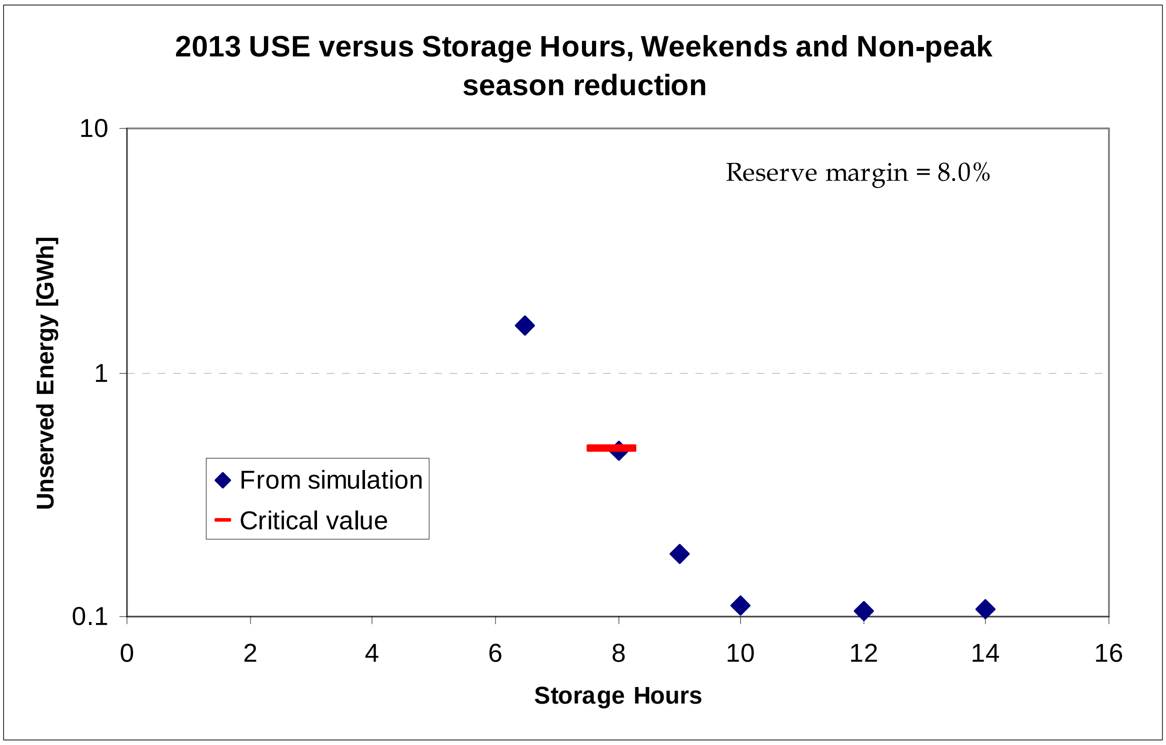


Figure 5-17. Unserved energy versus storage hours for 2013, weekend and non-peak season reduction



In both the weekend reduction case and the non-peak season and weekend case the critical unserved energy level is reached at about 8 hours. In contrast, since load peaks during summer weekends are higher than load peaks during non-peak months, Figure 5-16 shows that during the non-peak months the fuel storage requirement could be reduced to as low as 6 hours without reaching the critical unserved energy value.

In conclusion, there is potential for reducing the fuel storage requirement during non peak periods without threatening system reliability, especially during the winter months. Section 5.6.2 discusses the economic benefits of doing so.

5.6.2 Economic benefits

In order to calculate the economic benefits for the system of having a relaxed storage requirement during non peak periods, we are assuming that during the non-peak periods generators can sell their spare gas transport capacity to other[3] users at a reduced value.

We have calculated the annual savings (with respect to the base case with the 14 hours flat storage requirement) by considering the difference between the total operational costs (fuel costs, VO&M costs, and USE cost) minus the revenue for selling the spare gas transport capacity during non-peak periods at a lower value. By varying both the value at which the spare gas transport capacity has been sold and the storage requirement we obtained the savings profiles seen in Figure 5-18 to Figure 5-22. We do not know how

[3] "Other users" is a generic term to refer to users not involved in power generation for the use of the gas.

Figure 5-18. Savings profile with a 10% value of transport cost recovery

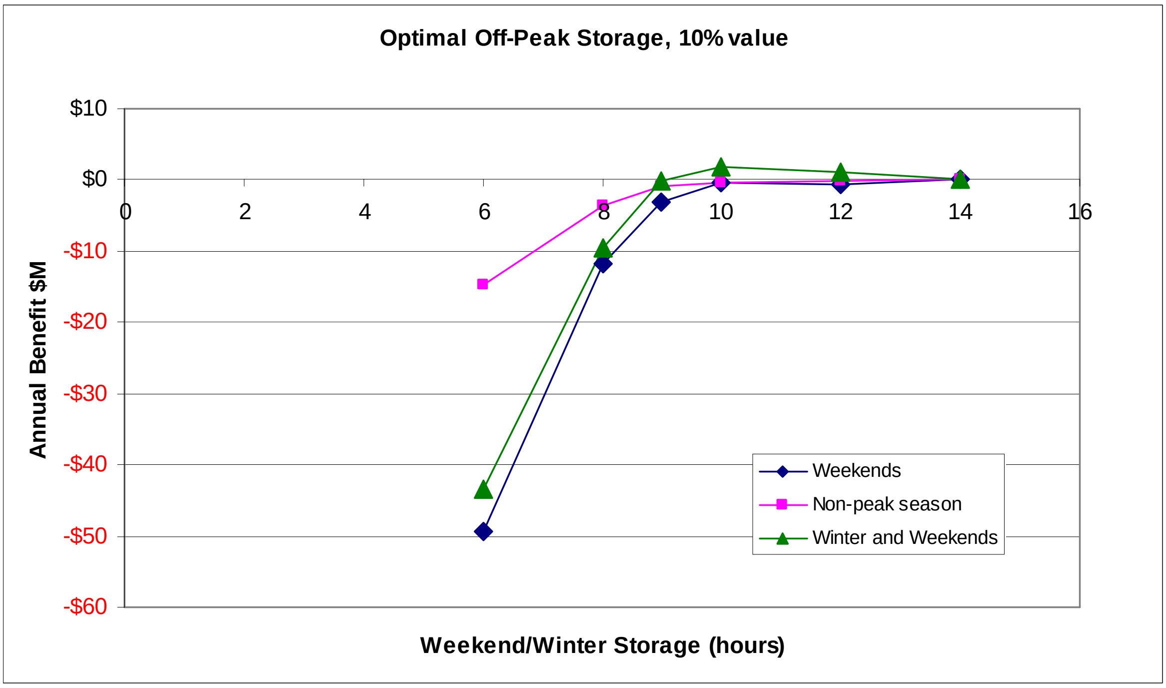
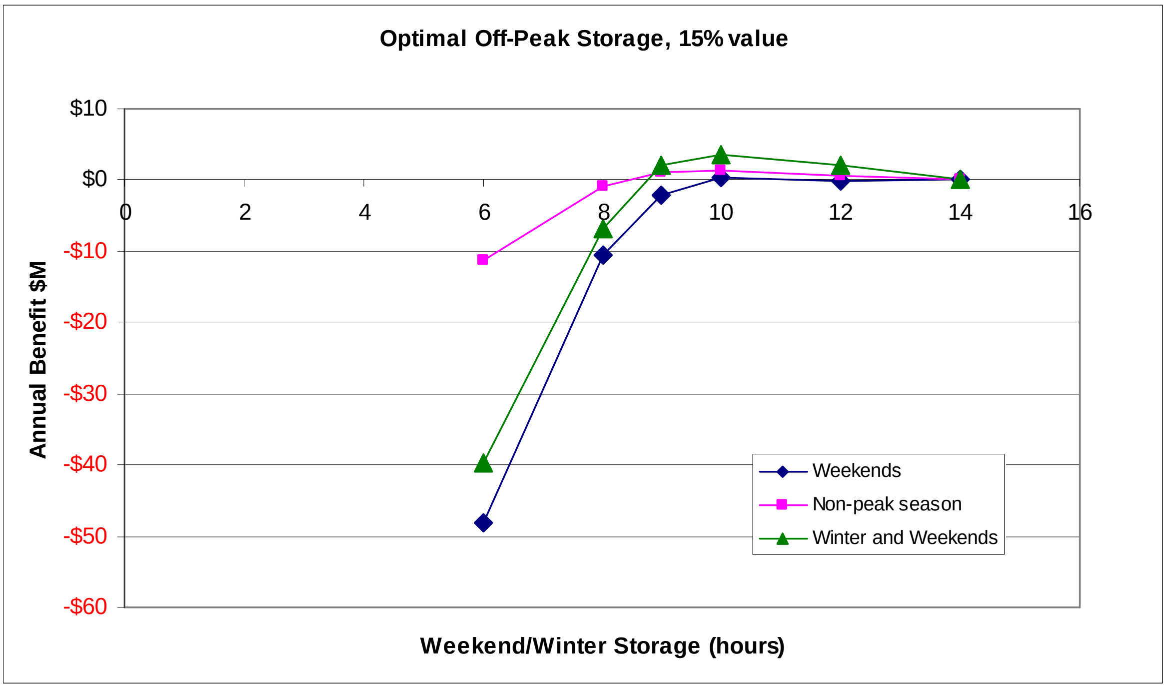


Figure 5-19. Savings profile with a 15% value of transport cost recovery



much of the gas transport cost could be recovered under these circumstances. Accordingly, we have modelled recovery in the range of 10% to 30% to illustrate the potential benefits.

Figure 5-20. Savings profile with a 20% value of transport cost recovery

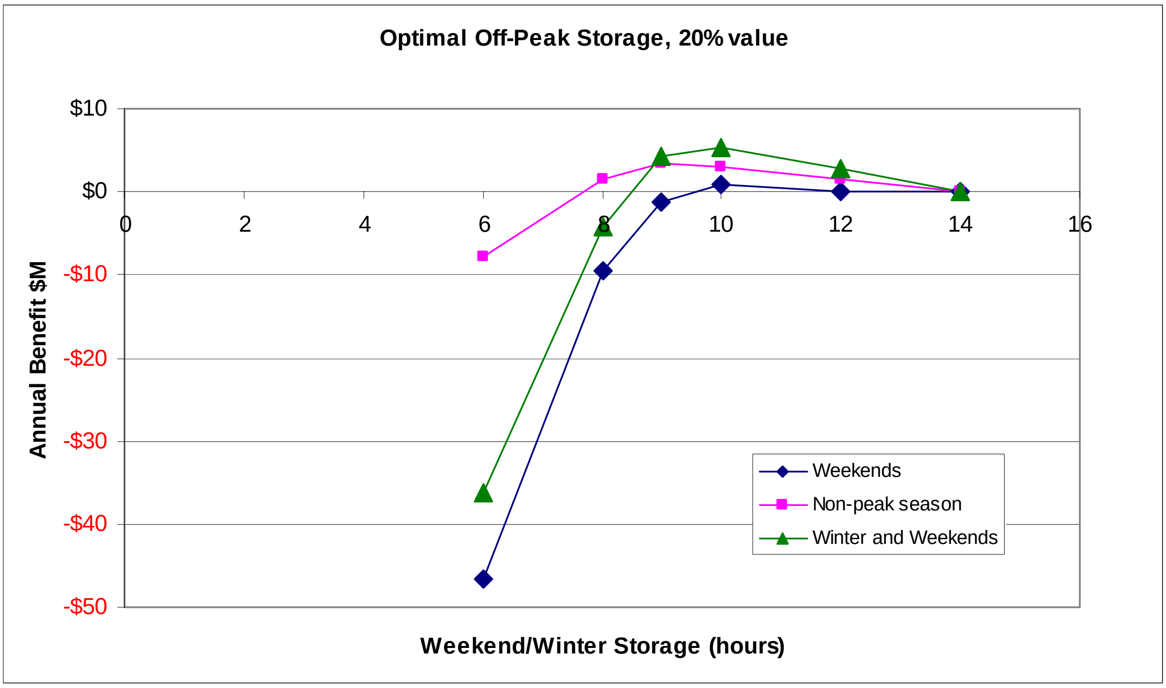


Figure 5-21. Savings profile with a 25% value of transport cost recovery

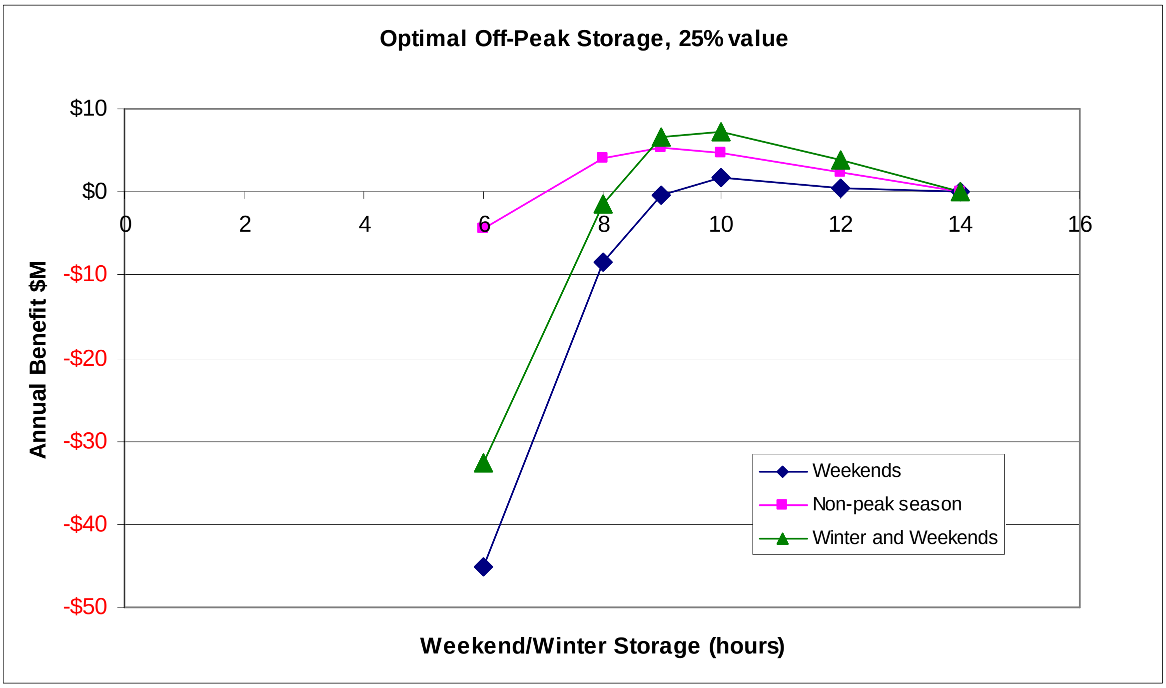
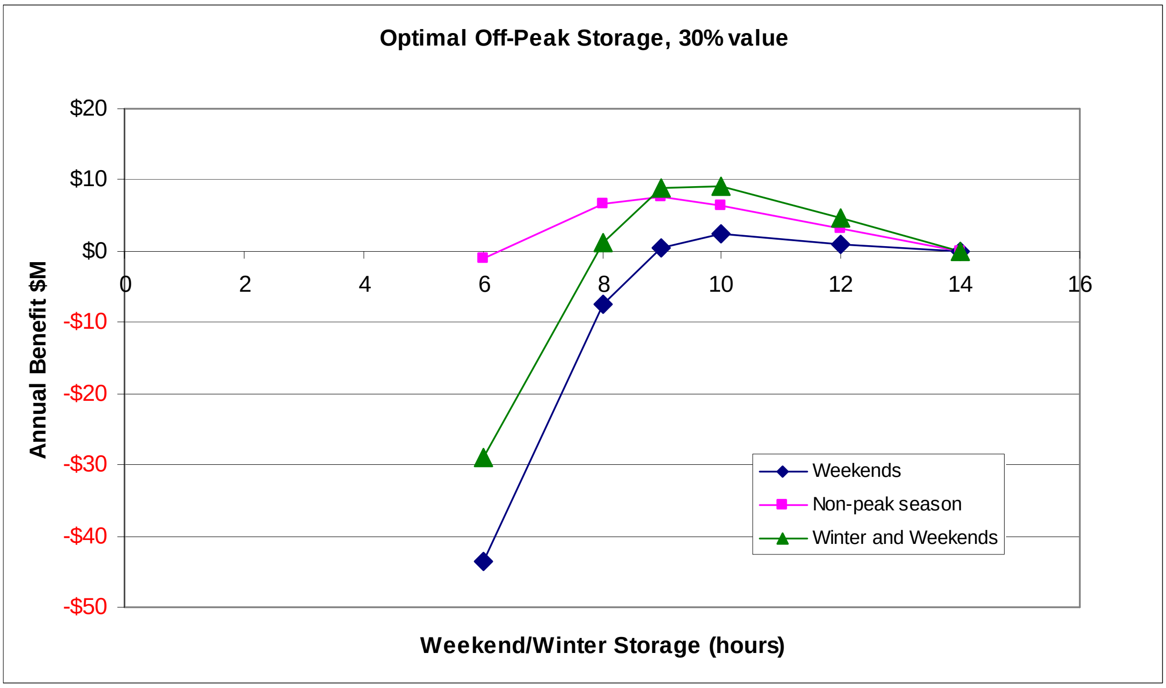


Figure 5-22. Savings profile with a 30% value of transport cost recovery



The profiles show that the savings are heavily dependent on the value at which the spare gas transport capacity is sold. As expected, as the value at which the spare gas transport capacity is sold increases, the system savings also increase. And if the fuel storage requirement is reduced too much, the increased system operational costs (because of using more expensive generation and the increased unserved energy) obliterate any savings that could be incurred by reselling the spare gas transport capacity during non-peak periods.

Most of the potential benefits are obtained by reducing the fuel storage requirement during non-peak season, with the savings of the weekend reduction case being considerable smaller and more dependent on the value at which the spare gas transport capacity is sold. In fact the weekend reduction case only shows small positive benefits with a value of recovery of gas transport cost above 20% and for storage requirement levels above 10 hours.

If the value at which the spare gas transport capacity is sold is too low, the savings remain small or non-existent. For example, with a 10% value there would not be any benefits in the weekend reduction and in the non-peak season reduction cases and only a small benefit ($1.78 M with a 10 hour reserve requirement level) in the weekend and non-peak season reduction case.

As said before, the non-peak season reduction case shows greater benefits than the weekend reduction case, with them becoming positive for storage requirement levels above 8 hours and with a value greater than 15%.

5.6.3 Summary of less restrictive daily fuel supply requirement during non-peak periods

Table 5-7 summarizes the results of sections 5.6.1 and 5.6.2. This table shows the daily fuel supply requirement (in hours) required to either comply with the unserved energy target (0.002%) or to maximize the system savings.

Table 5-7 Summary of less restrictive off-peak fuel supply results 2012/13

Principle	Objective	Peak Season		Off-peak seasons	
		Work day	Weekend	Work day	Weekend
Current requirement	Do nothing	14	14	14	14
All days the same	Unserved energy target	12	12	12	12
Off-peak season reduction	Unserved energy target	14	14	6.4	6.4
Weekend reduction all year	Unserved energy target	14	8	14	8
Weekend and off-peak season reduction	Unserved energy target	14	8	8	8
Off-peak season reduction	Maximum savings (up to 30% value recovery)	14	14	9	9
Weekend reduction all year	Maximum savings (up to 30% value recovery)	14	10	14	10
Weekend and off-peak season reduction	Maximum savings (up to 30% value recovery)	14	10	10	10

Using exclusively the unserved energy target (0.002%) as a criterion, the requirement could be reduced down to: 12 hours for a flat reduction (all days the same), 6.4 hours if the reduction were only during the off-peak season (April to November), 8 hours if the reduction were only applied to weekends, and 8 hours if the reduction were applied to both non-peak season and weekends.

However, because of increased generation and unserved energy costs associated with a more relaxed daily fuel supply requirement, a requirement based exclusively on the unserved energy target is not necessarily the one offering the maximum savings. In fact, the economic benefits are maximized with a requirement of about 9 or 10 hours. It is worth noticing that the savings are greater when the requirement is relaxed during the off-peak season, while the savings for the weekend reduction case remain modest and very dependent on the value of recovery of gas transport cost.

5.7 Trading Mechanism

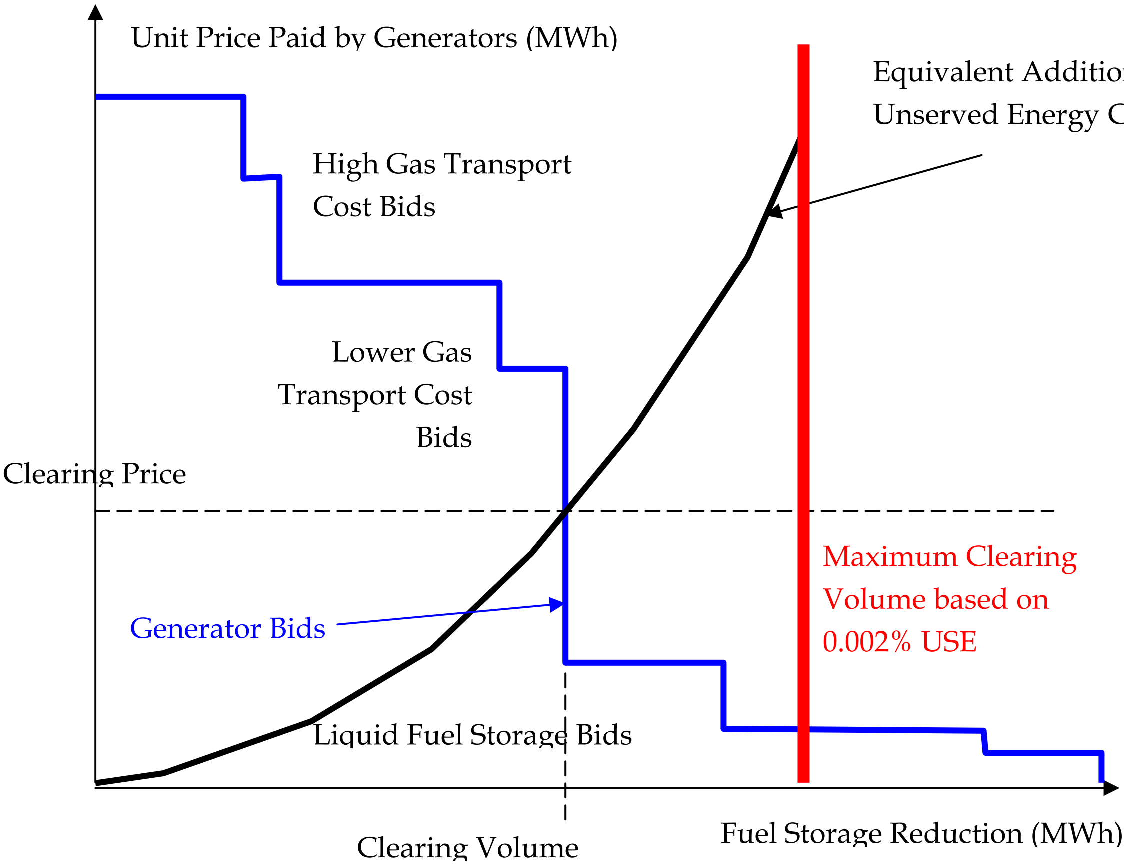
The next question is therefore the extent to which a trading mechanism could be designed to allow some generators to relax their fuel supply arrangements and therefore appropriate some of the $12 M per annum net benefit that is available. The potential annual saving in inventory cost is $16 M as seen in the change in the Annual Inventory Cost from $72 M to $56 M per annum. The savings in fuel supply inventory cost is partly offset by $4 M extra cost for unserved energy in this example for 2012/13.

5.7.1 One-sided trading

A possible trading mechanism would involve generators offering to pay to be relieved of fuel inventory below the 14 hour standard as measured in daily MWh. The Table 5-6 shows that daily supply could be reduced by 2,789 MWh in 2012/13 (13297 – 10508 = 2789 MWh). This could be distributed across a range of capacity bands as illustrated in Figure 5-11 or possibly equally for up to some 900 MW of eligible capacity. Possible allocations might need to be tested based on planned maintenance and expected forced outage rates. However these factors are unlikely to limit the options for allocating reduced fuel supply.

To encourage generators to bid competitively, a clearing pricing mechanism would be suitable so that all generators pay the same unit price for fuel supply reductions, as measured in $/MWh/day. Since generators are paying to receive the benefit, there is less likely to be abuse of market power. If all generators bid a zero price, the optimal quantity would be zero due to the rising cost of unserved energy. If all gas supplied generators bid their actual saving in gas transport costs, then the Goldfields generator bids would be accepted first because they would be prepared to pay the most. The lowest bid that minimises the market cost having regard to a notional cost of unserved energy (say $30/kWh) would then be the basis of payment by all generators. That would maximise the market benefit. Every generator whose bid was accepted would benefit, except perhaps the accepted bid to the extent that it was below the actual marginal cost of fuel supply cost. The concept is illustrated in Figure 5-23.

Figure 5-23 One-sided Concept for Trading Reductions in Daily Fuel Supply or Inventory



The increase in the unserved energy cost would be translated back into the equivalent value of reduced fuel storage for comparison with the generator bids. The clearing price would be set to maximise economic value from the trade-off between fuel inventory savings and the level of expected unserved energy.

To the extent that generators could predict the clearing price/volume based on their own reliability analysis, they may refuse to bid if their cost of daily fuel inventory is below the expected value. If there was a lack of reliable market information on the trade-offs, then bidding might be insufficient to provide an efficient result. Lack of provision of possible fuel supply reduction would not be of concern to customers as they would benefit from the higher supply reliability if no fuel supply reduction were accepted. If generators bid very low prices, there would be no clearing volume and customers would receive no supplementary cash flow from the auction.

The IMO would distribute the net proceeds of the auction, after allowing for administrative costs, to wholesale market customers in proportion to their peak demand capacity obligation. This would reflect the fact that peak demand is the primary driver of reliability, not energy consumption. Whilst no analysis has been undertaken, MMA expects that the transaction costs would be less than $1 M per annum. If there was the prospect of an auction not producing value commensurate with its costs, then the auction could be cancelled for the relevant capacity year. This might occur where:

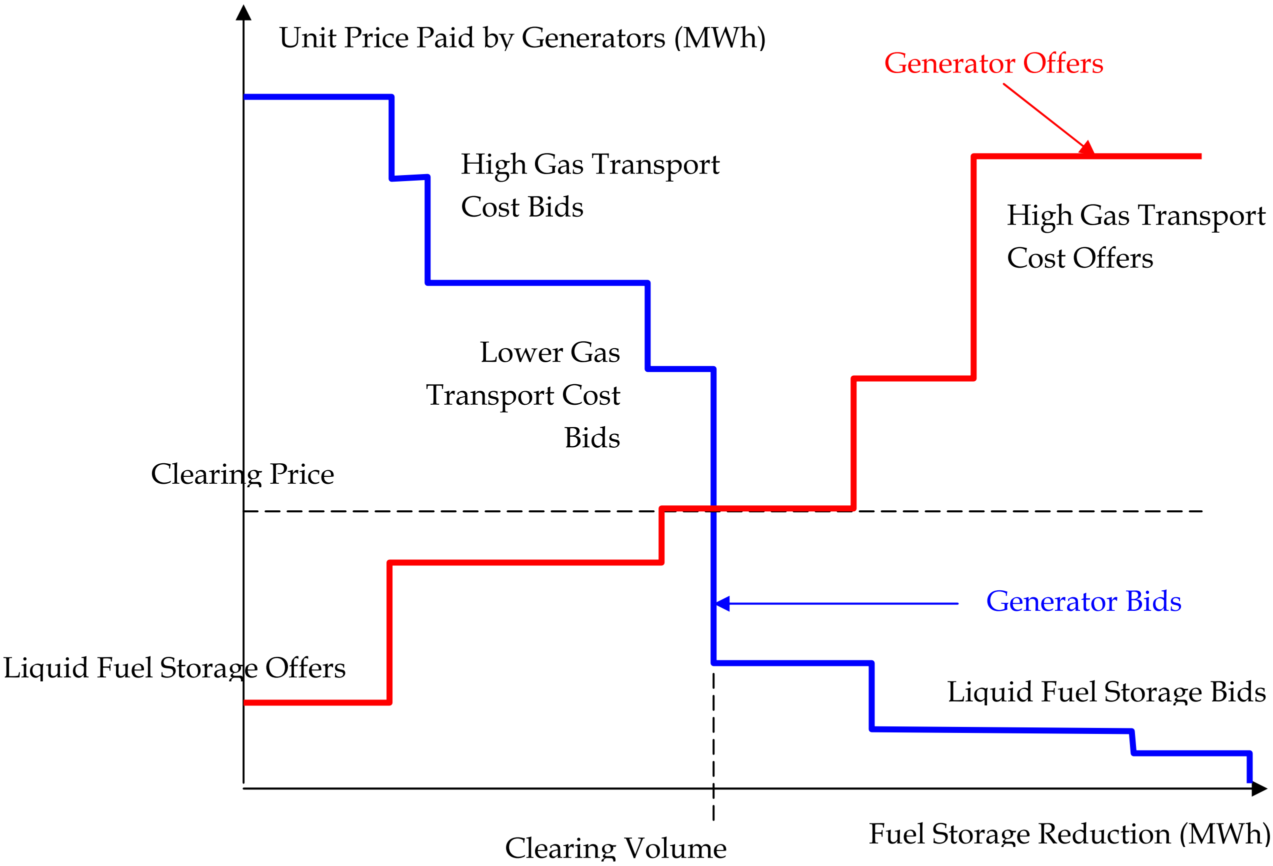
- the expected unserved energy was already close to 0.002% and fuel supply would need to be near 14 hours to maintain reliability
- the reserve margin is expected to be less than 5% with limited opportunity for supplementary reserve capacity being available, or where
- there is a surplus of fuel supply capacity and savings in reducing requirements are unlikely to be significant.

5.7.2 Two-sided Trading

The trading could be further enhanced by being two-sided, in that generators could also be paid to provide more than 14 hours of daily fuel supply. This would be beneficial where gas supply is insecure or there are capacity shortages and peaking plant might need to run at higher levels of utilisation. In this case the buyers and sellers could be matched to a net position that matches the required expected unserved energy. The buyers would bid daily supply reductions to buy and the sellers would offer to sell daily supply increases for which they would be paid. The net position of buy and sell would then be referenced to the change in unserved energy cost relative to no change from the standard 14 hour requirement. The proposed method to achieve this would be:

- Rank all bids for daily fuel supply reduction from highest price to lowest price (blue line in Figure 5-24)
- Rank all offers for daily fuel supply increase from lowest price to highest price (Red line in Figure 5-24)
- Clear the market to match bids and offers for no net change in daily fuel supply. These transactions would be cleared first to optimise the benefits among generators without any impact on customers. This would reduce the overall cost of generation and these benefits would be passed through to customers in part through competition and lower energy prices. The clearing price and volume is illustrated in Figure 5-24.
- For the remaining bids to buy daily fuel supply reductions, conduct a one-sided auction as above to utilise the remaining opportunity within the 0.002% reliability criterion. The quantities included would be those to the right of the Clearing Volume in Figure 5-24.

Figure 5-24 First Stage of Two-sided Concept for Trading Reductions in Daily Fuel Supply or Inventory



The advantage of the two-sided approach is that the overall daily fuel supply arrangements could be more efficient so that fuel inventory is better matched to market production role, bilateral contract obligations and the management of gas supply and transport. The primary disadvantage would be that there would be times when the administrative costs of such a market enhancement would be greater than the available benefits. It may be see in Figure 5-24 that there is a prospect of greater use of liquid fuel storage to reduce commitment to firm gas supply and transport which is much more costly.

6 GAS SUPPLY DISRUPTION

Using the same SWIS PLEXOS model, we simulated a set of gas supply disaster scenarios in order to assess the benefits, in terms of reduced unserved energy, of different mitigation measures. Whilst the current levels of fuel storage may be acceptable for normal fuel supply conditions, the ability to increase daily fuel supply levels during contingencies may be beneficial under fuel supply disruption situations. It may therefore be efficient to purchase a service for supplementary fuel supply storage that can be utilised during emergency conditions. There would be two components to this service:

1. a long lead time capacity to store fuel or option to purchase from alternative gas supplies if they were available say from a storage facility

2. a short lead time capacity to activate the emergency supplies, by ordering liquid fuel for the storage capacity or to activate supply from a gas storage facility.

6.1 Scenarios considered

First we defined a set of plausible gas supply disruption scenarios to model. On the one hand, events such as an earthquake in the Collie Basin interrupting coal-fired generation or a situation of no wind for a week are considered to be of very rare occurrence and are thus considered outside the scope of this study. On the other hand, major gas supply disruptions are considered to be a more plausible occurrence (typically assumed to occur in the order of at least once in every 25 years).

The analysis was conducted for the fiscal year 2013 (July 2012 to Jun 2013) as this is the year in our previous modelling having a reserve margin close to the 8.2% standard.

In the Evans & Peck report to the Gas Supply and Emergency Management Committee (GSMEC)[4] four gas supply disruptions scenarios were considered. Of these 4 scenarios, 3 are considered to be of large impact and thus were used as the basis for our analysis. The gas supply disruption scenarios were modelled as presented in Table 6-1.

These gas disruption scenarios were modelled in PLEXOS by limiting the total amount of gas available to gas-fired generators. The limits on gas supply were modelled in detail by using the profiles given in the Evans & Peck report. The start dates of the events were placed in the Summer, with scenario 1 and 2 having 2 alternative starting dates. The dates were chosen such as to maximize the impact of the events. Plants using distillate were modelled with a limited liquid fuel supply of 3 days a week during the first 3 weeks and a less limited supply afterwards, as it is estimated that after 3 weeks additional shipments of diesel could be sourced. We did not model the event occurring in winter as we would expect less onerous conditions despite the lower gas supply for power generation. This could be tested if required as an extension to this work.

[4] *"Options to avoid or Minimize Gas Supply Disruptions and to Mitigate Their Effects"*

Table 6-1. Gas supply disruption scenarios

Scenario Code	Event	Gas still available for electricity generation (Summer)	Gas still available for electricity generation (Winter)	Duration	Start Dates
1a	Loss of Karratha Gas plant	43 TJ/day	7 TJ/day	3 months	1-Jan-2013
1b					1-Feb-2013
2a	Loss of Varanus Island	72 TJ/day	19 TJ/day	6 months	1-Dec-2012
2b					1-Feb-2013
3	DBNGP breach north of Mondarra	35 TJ/day	35 TJ/day	7 days	6-Mar-2013

6.2 Mitigation alternatives considered

In addition to the base case, we modelled some mitigation options based on the alternatives identified in the Evans & Peck report as cost effective:

- o Dual-firing conversion of some CCGT units: we modelled the conversion of Cockburn and NewGen Kwinana. Combined with the dual-firing conversion, we also modelled an increase in the fuel supply limit from 14 to 18 hours of operation per day.
- o Utilization of between 35 TJ/day to 100 TJ/day from increased gas storage (from either Mondarra storage reservoir or a refrigerated storage facility in Kwinana): we modelled an additional supply of 100 TJ/day of gas (for up to 90 days)
- o More secure liquid fuel supply: we modelled an increase to 4.5 days of fuel per week (from 3 days of fuel per week)

6.3 Approach to study development

For this stage of the work, reserve capacity was set at the normal standard relative to the forecast peak demand. The 2012/13 year was used as this year's reserve margin was closer to the 8.2% standard. The approach to the study proceeded through the following planned steps:

- Modelling each gas supply disruption scenario in the existing PLEXOS database maintaining the 14 hours of fuel storage for the peaking plants.
- Assessing the impact of each gas supply disruption scenario assuming no other changes

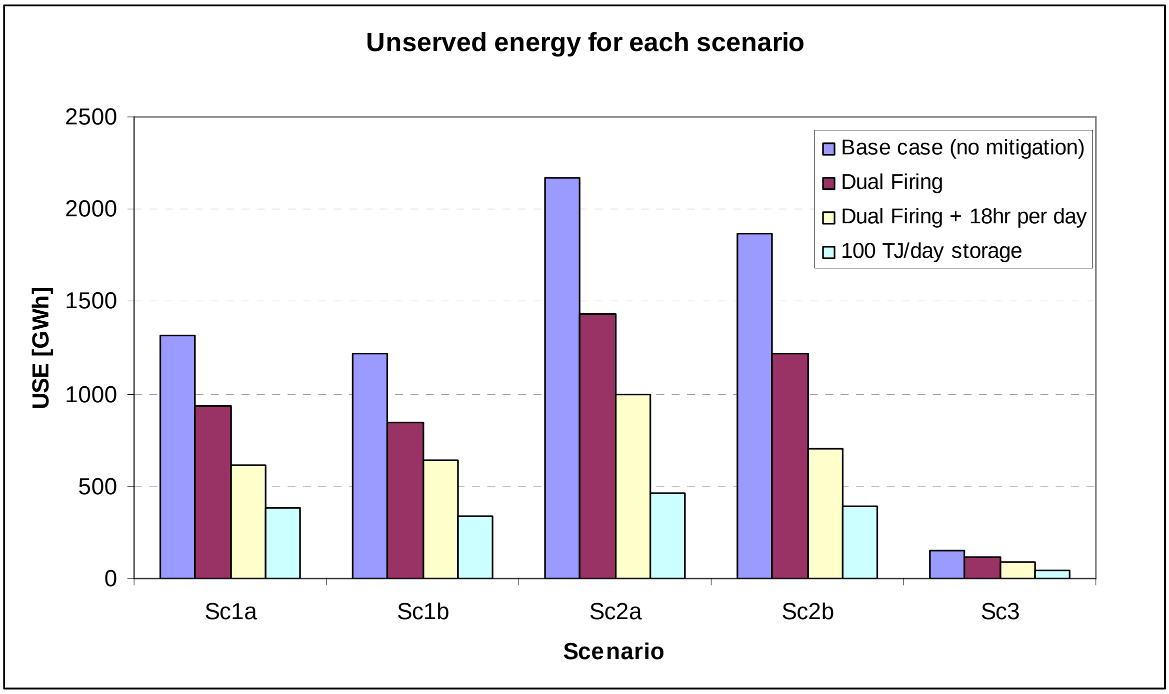
- Using the previous results to formulate and assess an additional set of scenarios with different mitigation alternatives such as increased fuel storage for the liquid fuelled gas turbines, dual-firing conversion of some gas-fired units (Cockburn, NewGen Kwinana).

6.4 Results

The expected unserved energy without mitigation is quite substantial as shown in Figure 6-1 (about 1,200GWh for scenario 1; 2,000GWh for scenario 2; and 150GWh for scenario 3). The unserved energy target (0.002%) for this year is 0.484 GWh including the embedded private loads.

The impact of increasing the liquid fuel storage from 3 days per week to 4.5 days per week in terms of reducing the USE was immaterial in the absence of any other mitigation (and was not included in the plot as it looks the same as no mitigation). The dual-firing conversion of Cockburn and Newgen Kwinana showed a reduction of about 30% of USE with respect to the base case. The dual-firing conversion of Cockburn and Newgen Kwinana plus an increase from 14 to 18 hours in fuel storage showed a reduction of about 50% of USE with respect to the base case. The gas storage alternative had the most significant impact, with an unserved energy of only about 25% of the base case.

Figure 6-1 Unserved energy without mitigation



6.5 Implications for emergency energy reserve trading

These results show that the impact of these more extreme contingencies can be markedly reduced if access to liquid fuelled generation can be made available with minimum delay. In the ordinary course of business it might not be expected that market participants would make the investment needed to mitigate these gas supply contingencies due to their infrequency despite their severity. Any obligations to customers would be set aside under Force Majeure contract provisions. The analysis shows that both gas storage and additional energy available from peaking plants would make a substantial contribution to mitigating the loss of energy supply.

Accordingly, MMA recommends that consideration be given to extending a market based mechanism for daily energy reserve trading as discussed in Section 5.7 with provisions for extension to cover emergency conditions. This could involve:

- a payment for reserve storage capacity for liquids that may be called upon under emergency conditions and utilised for delivery of additional distillate to support power generation
- a payment for gas storage capacity in terms of a maximum delivery in TJ/day and possibly a payment for aggregate storage if necessary.

The parameters of the emergency daily fuel supply would include:

- a reference level that would be expected to be available under normal conditions. This is currently defined as for 14 hours of operation for peaking plant or 12 hours for dual fuelled plant;
- an additional daily quantity available for power generation most probably determined by the generation capacity for distillate fuelled plant or the fuel flow from a storage facility for gas;
- a daily replenishment rate for liquid fuels based on supply arrangements with refineries and importers. The replenishment rate might be less than the daily consumption rate so that storage could be depleted partially during the week and restored over the weekend;
- a notification period between the issue of the request and full operations
- a fixed periodic payment for making the long-term capacity available
- a variable payment which is made when the emergency service is activated.

It would be anticipated that such a service could be competitively sourced in the WEM as most of the generators would have the capacity to provide an increase in liquid storage, convert for duel fuel operation or secure fuel supply from gas storage given sufficient lead time to put the required facilities in place.

7 PUBLIC CONSULTATION

The IMO welcomes public consultation on these matters and in particular would request that Market Participants indicate their assessment of:

- their willingness to provide information on their fuel storage and fuel supply capabilities in terms of the long-term potential and their capability over the next three years leading up to the next Reserve Capacity Cycle;
- their view as to whether fuel storage and supply requirements for the purposes of ensuring system reliability could be relaxed and whether this would lead to significant cost reductions for the Market Participant;
- how storage and supply requirements should be defined to reflect operational practices and dispatch patterns ;
- whether an initial daily inventory for liquids and a daily gas supply is a sufficient measure of requirement. Should other factors be considered over a longer period such as a working week, particularly for liquid fuelled peaking plants that normally only run a few hours per day and deplete a three day fuel inventory over a week or fortnight;
- whether their bilateral obligations are likely to require more stringent fuel storage and supply requirements than a minimum value required solely for system reliability. It is recognised that some participants will be in a better position to answer this question when the MMA system reliability analysis is available;
- their view as to the potential value of the broad options for change indicated in Table 2-1 and their advantages and disadvantages that would need to be considered in quantitative analysis;
- whether there is likely to be any significant value in reducing fuel supply and storage obligations in non-peak months and /or weekends;
- whether a separate payment for Energy Reserve Capacity associated with capacity for liquid fuel storage and firm or non-firm gas transport would assist market participants to better manage long-term supply risks whilst at the same time meeting their bilateral supply obligations;
- whether a trading mechanism for adjusting daily fuel supply obligations would be beneficial in reducing generators' costs or increasing profitable revenue.
- the feasibility of defining the parameters of a non-firm fuel supply recognising that it is the firmness of when it is called that is important, rather than the availability of the supply over the whole year. This is a particular issue for non-firm gas supply as it depends on gas consumption by other parties and the reliability of gas transport as affected by compression and resulting transport capacity. How can this non-firmness

be reasonably estimated and quantified for reliability modelling purposes? Is it a feasible endeavour?

- the evaluation methodology outlined in Chapter 3 and whether the key issues will be adequately considered using this approach.

APPENDIX A SYSTEM DATA

Table 7-1. Fuels in the PLEXOS model

Category	Name	Description	Price until 30/06/2008 ($/GJ)	Price from 1/07/2008 ($/GJ)	Generators using the fuel
Coal	MUJCGRIF	Griffin coal for Muja	2.4	2.4	MUJA_G5, MUJA_G6, MUJA_G7, MUJA_G8
Coal	NEWCOAL	New coal	2.3	2.3	BW1_BLUEWATERS_G2, BW1_BLUEWATERS_G3, BW1_BLUEWATERS_G4, BW1_BLUEWATERS_G1, MUJA_G7, MUJA_G8
Coal	WESCOAL	Wesfarmers coal for Muja and Collie	2.2	2.2	COLLIE_G1, MUJA_G5, MUJA_G6, MUJA_G7, MUJA_G8
Gas	ALCOAGAS	ALCOA gas	2.59	2.51	ALCOA_KWI, ALCOA_PNJ, ALCOA_WGP
Gas	GASSTKS	Same gas as JVPGAS, but third tier	8.03	7.78	COCKBURN_CCG1, KWINANA_G1, KWINANA_G2, KWINANA_G3, KWINANA_G4, KWINANA_G5, KWINANA_G6, KWINANA_GT1, MUNGARRA_GT1, MUNGARRA_GT2, MUNGARRA_GT3, PINJAR_GT01, PINJAR_GT02, PINJAR_GT03, PINJAR_GT04, PINJAR_GT05, PINJAR_GT07, PINJAR_GT09, PINJAR_GT10, PINJAR_GT11
Gas	JVPGAS	North West Shelf Joint Venture (NWSJV). Includes the first and second tiers	4.72	4.58	COCKBURN_CCG1, KWINANA_G1, KWINANA_G2, KWINANA_G3, KWINANA_G4, KWINANA_G5, KWINANA_G6, KWINANA_GT1, PINJAR_GT01, PINJAR_GT02, PINJAR_GT03, PINJAR_GT04, PINJAR_GT05, PINJAR_GT07, PINJAR_GT09, PINJAR_GT10, PINJAR_GT11, PPP_KCP_EG1, TIWEST_COG1
Gas	KALJV	Kalgoorlie (Goldfields) gas	8.03	7.78	PRK_AG, STHRNCRS_EG_1-2, STHRNCRS_EG_3-4

Category	Name	Description	Price until 30/06/2008 ($/GJ)	Price from 1/07/2008 ($/GJ)	Generators using the fuel
Gas	KEMERTON GAS	Gas for Kemerton units	8.03	7.78	KEMERTON_GT11, KEMERTON_GT12
Gas	MUNGAS	Mungarra gas	4.72	4.58	MUNGARRA_GT1, MUNGARRA_GT2, MUNGARRA_GT3
Gas	NEWWAGAS	New gas	8.03	7.78	NEWGEN_NEERABUP, PERTH_ENERGY_GT1, ALINTA_WGP, SWCJV_WORSLEY_COGEN_COG1
Gas	PPP2	Gas for Kwinana cogen plant	4.72	4.58	NEWGEN_KWINANA GT, NEWGEN_KWINANA ST
Gas	WACOGEN	Gas for Alinta Pinjarra plants	2.43	2.35	ALINTA_PNJ_U1, ALINTA_PNJ_U2
Other	WA BIO	Biomass, waste & landfill gas	0.27	0.32	WA BIOMASS
Other	WA DIST	Distillate	22.76	22.53	KEMERTON_GT11, KEMERTON_GT12, PINJAR_GT01, PINJAR_GT02, PINJAR_GT03, PINJAR_GT04, PINJAR_GT05, PINJAR_GT07, PINJAR_GT09, PINJAR_GT10, PINJAR_GT11, ALINTA_WGP, GERALDTON_GT1, WEST_KALGOORLIE_GT2, WEST_KALGOORLIE_GT3

Table 7-2. Generators in the PLEXOS model

Category	Name	Node	Company	Power Station	Fuel 1	Fuel 2	Fuel 3
Biomass	WA BIOMASS	Muja	WA Biomass	-	WA BIO	-	-
Coal	COLLIE_G1	Muja	Verve Energy		WESCOAL		-
Coal	MUJA_G3	Muja	Verve Energy	Muja B	WESCOAL	MUJCGRIF	-
Coal	MUJA_G4	Muja	Verve Energy	Muja B	WESCOAL	MUJCGRIF	-
Coal	MUJA_G5	Muja	Verve Energy	Muja C	WESCOAL	MUJCGRIF	-
Coal	MUJA_G6	Muja	Verve Energy	Muja C	WESCOAL	MUJCGRIF	-

Coal	MUJA_G7	Muja	Verve Energy	Muja D	WESCOAL	NEWCOAL	MUJCGRIF
Coal	MUJA_G8	Muja	Verve Energy	Muja D	WESCOAL	NEWCOAL	MUJCGRIF
Cogen	ALINTA_PNJ_U1	Muja	Alinta	-	WACOGEN	-	-
Cogen	ALINTA_PNJ_U2	Muja	Alinta	-	WACOGEN	-	-
Cogen	ALINTA_WGP	Muja	Alinta	-	NEWWAGAS	WA DIST	-
Cogen	SWCJV_WORSLEY_COGEN_COG1	Muja	Verve Energy	-	NEWWAGAS	-	-
Cogen	TIWEST_COG1	Muja	Verve Energy	-	JVPGAS	-	-
Distillate	GERALDTON_GT1	North Country	Verve Energy	-	WA DIST	-	-
Distillate	WEST_KALGOORLIE_GT2	Goldfields	Verve Energy	-	WA DIST	-	-
Distillate	WEST_KALGOORLIE_GT3	Goldfields	Verve Energy	-	WA DIST	-	-
Gas	COCKBURN_CCG1	Muja	Verve Energy	-	JVPGAS	GASSTKS	-
Gas	KEMERTON_GT11	Muja	Verve Energy	-	KEMERTON GAS	WA DIST	-
Gas	KEMERTON_GT12	Muja	Verve Energy	-	KEMERTON GAS	WA DIST	-
Gas	KWINANA_G1	Muja	Verve Energy	Kwinana A	JVPGAS	GASSTKS	-
Gas	KWINANA_G2	Muja	Verve Energy	Kwinana A	JVPGAS	GASSTKS	-
Gas	KWINANA_G3	Muja	Verve Energy	Kwinana B	JVPGAS	GASSTKS	-
Gas	KWINANA_G4	Muja	Verve Energy	Kwinana B	JVPGAS	GASSTKS	-
Gas	KWINANA_G5	Muja	Verve Energy	Kwinana C	JVPGAS	GASSTKS	-
Gas	KWINANA_G6	Muja	Verve Energy	Kwinana C	JVPGAS	GASSTKS	-
Gas	KWINANA_GT1	Muja	Verve Energy	-	JVPGAS	GASSTKS	-
Gas	MUNGARRA_GT1	North Country	Verve Energy	-	MUNGAS	GASSTKS	-
Gas	MUNGARRA_GT2	North Country	Verve Energy	-	MUNGAS	GASSTKS	-
Gas	MUNGARRA_GT3	North Country	Verve Energy	-	MUNGAS	GASSTKS	-
Gas	PINJAR_GT01	Muja	Verve Energy	Pinjar A	JVPGAS	GASSTKS	WA DIST

Gas	PINJAR_GT02	Muja	Verve Energy	Pinjar A	JVPGAS	GASSTKS	WA DIST
Gas	PINJAR_GT03	Muja	Verve Energy	Pinjar B	JVPGAS	GASSTKS	WA DIST
Gas	PINJAR_GT04	Muja	Verve Energy	Pinjar B	JVPGAS	GASSTKS	WA DIST
Gas	PINJAR_GT05	Muja	Verve Energy	Pinjar B	JVPGAS	GASSTKS	WA DIST
Gas	PINJAR_GT07	Muja	Verve Energy	Pinjar B	JVPGAS	GASSTKS	WA DIST
Gas	PINJAR_GT09	Muja	Verve Energy	Pinjar C	JVPGAS	GASSTKS	WA DIST
Gas	PINJAR_GT10	Muja	Verve Energy	Pinjar C	JVPGAS	GASSTKS	WA DIST
Gas	PINJAR_GT11	Muja	Verve Energy	Pinjar D	JVPGAS	GASSTKS	WA DIST
New Entrants	NEWGEN_KWINANA GT	Muja	NewGen	-	PPP2	-	-
New Entrants	NEWGEN_KWINANA ST	Muja	NewGen	-	PPP2	-	-
Non-Scheduled	ALCOA_KWI	Muja	Alcoa	-	ALCOAGAS	-	-
Non-Scheduled	ALCOA_PNJ	Muja	Alcoa	-	ALCOAGAS	-	-
Non-Scheduled	ALCOA_WGP	Muja	Alcoa	-	ALCOAGAS	-	-
Non-Scheduled	PPP_KCP_EG1	Muja	Verve Energy	-	JVPGAS	-	-
Non-Scheduled	PRK_AG	Goldfields	Goldfields Power	-	KALJV	-	-
Non-Scheduled	STHRNCRS_EG_1-2	Goldfields	Southern Cross Energy	-	KALJV	-	-
Non-Scheduled	STHRNCRS_EG_3-4	Goldfields	Southern Cross Energy	-	KALJV	-	-
Wind	ALBANY_WF1	Muja	Verve Energy	-	-	-	-
Wind	ALINTA_WWF	North Country	Alinta	-	-	-	-
Wind	Badgingarra	Muja	Griffin Power	-	-	-	-

Wind	EDWFMAN_WF1	North Country	EDWF	-	-	-	-

Table 7-3. Generator properties in the PLEXOS model

Generator	Units	Max Capacity (MW)	Min Stable Level (MW)	Committed Load (MW)	Maintenance Rate (%)	FOR (%)	MTTR (hrs)
WA BIOMASS	1	25.8	-	-	-	8	24
Bridgetown Biomass	1 from Dec 2009	40					
BW1_BLUEWATERS_G1	1 from Nov 2009	204	102	-	5.8	4	72
COLLIE_G1	1	315	160	-	16	4	72
MUJA_G3	1 from 21/08/08 to 21/12/08	55	28	-	17.5	13.09	72
MUJA_G4	1 from 21/08/08 to 21/12/08	55	28	-	17.5	13.09	72
MUJA_G5	1, retires 2020	185	65	-	15	7	72
MUJA_G6	1, retires 2021	185	65	-	15	7	72
MUJA_G7	1	211	70	-	10	3.8	72
MUJA_G8	1	211	70	-	10	3.8	72
ALINTA_PNJ_U1	1	129	84	-	5	1.75	72
ALINTA_PNJ_U2	1	129	84	-	5	1.75	72
ALINTA_WGP	2	175.5	25	-	3.1	1.75	72
SWCJV_WORSLEY_COGEN_COG1	1, retires Feb 2014	119	95	-	9.6	1.66	72
TIWEST_COG1	1	37.7	14	-	2.2	0.7	72
GERALDTON_GT1	1	20.8	8	-	0.6	4.7	72
WEST_KALGOORLIE_GT2	1	38.2	10	-	0	1.99	72
WEST_KALGOORLIE_GT3	1	24.6	10	-	0	1.99	72
COCKBURN_CCG1	1	236.6	165	-	10.1	3	72
KEMERTON_GT11	1	154	80	-	3.8	1.5	72
KEMERTON_GT12	1	154	80	-	3.8	1.5	72
KWINANA_G1	1, retires Feb 2010	111.5	45	-	16.3	7.1	72
KWINANA_G2	1, retires Feb 2010	111.5	45	-	16.3	7.1	72
KWINANA_G3	1, retires Feb 2009	109	40	-	15.4	4.27	72
KWINANA_G4	1, retires Feb 2009	109	40	-	15.4	4.27	72
KWINANA_G5	1, retires 2016	185	50	-	21	4.27	72
KWINANA_G6	1, retires 2016	185	50	-	21	4.27	72
KWINANA_GT1	1	20.8	6	-	0.9	4.3	72
MUNGARRA_GT1	1	37.2	10	-	11.5	4.7	72
MUNGARRA_GT2	1	37.2	10	-	11.5	4.7	72
MUNGARRA_GT3	1	38.2	10	-	11.5	4.7	72
PINJAR_GT01	1	37.2	10	-	11.5	0.45	72
PINJAR_GT02	1	37.2	10	-	11.5	0.45	72
PINJAR_GT03	1	38.2	10	-	11.5	0.76	72
PINJAR_GT04	1	38.2	10	-	11.5	0.76	72
PINJAR_GT05	1	38.2	10	-	11.5	0.76	72
PINJAR_GT07	1	38.2	10	-	11.5	0.76	72

PINJAR_GT09	1	116	35	-	10	2.66	72
PINJAR_GT10	1	116	36	-	10	2.66	72
PINJAR_GT11	1	123	35	-	10	2.66	72
BW1_BLUEWATERS_G2	1, from Nov 2009	204	102	-	5.8	4	72
BW1_BLUEWATERS_G3	1, from Oct 2012	204	102	-	5.8	4	72
BW1_BLUEWATERS_G4	1, from Oct 2014	204	102	-	5.8	4	72
NEWGEN_KWINANA GT	1, from 5/08/2008	160	105	-	3.8	3	72
NEWGEN_KWINANA ST	1, from 5/08/2008	160	52.4	-	3.8	3	72
NEWGEN_NEERABUP	2, from 1/11/2009	165	51.5	-	3.8	3	72
PERTH_ENERGY_GT1	3 from 1/05/2010, 4 from 1/05/2011	28	10	-	3.8	3	72
ALCOA_KWI	1	75	62.5	70	3.8	4.85	24
ALCOA_PNJ	1	95	63.33	85	3.8	4.85	24
ALCOA_WGP	4	24.5	18.5	4x18.5	3.8	4.85	24
PPP_KCP_EG1	1	118	47	38.8	3.8	3	72
PRK_AG	3	38	26.67	3x15.33	3.8	2	24
STHRNCRS_EG_1-2	2	10	3.5	2x7.6	3.8	3	24
STHRNCRS_EG_3-4	2	38	13.5	2x28.9	3.8	3	24
ALBANY_WF1	12	1.8	-	-	-	-	-
ALINTA_WWF	54	1.65	-	-	-	-	-
Badgingarra	65	2	-	-	-	-	-
EDWFMAN_WF1	48	1.65	-	-	-	-	-
KALBARRI_WF1	2	0.8	-	-	-	-	-
WA BIOMASS	1	25.8	-	-	-	-	-
Bridgetown Biomass	1 from Dec 2009	40	-	-	-	-	-

Table 7-4. Transmission Links in the PLEXOS model

Line	Min Flow (MW)	Max Flow (MW)	
Muja to Goldfields	167	-100	
Muja to North Country	80	-65 (summer)	-70 (winter)