Independent Market Operator

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1 INTRODUCTION

The IMO's Market Rules Evolution Plan (MREP) and recommendations of the Verve Energy Review (Verve Review) both identified the need for review of the Wholesale Electricity Market (WEM) Rules (Market Rules) for a number of aspects of the WEM. As a consequence of these two foundational pieces of work the Oates Review Market Rules Implementation Group was established to undertake a review of the current WEM design. In particular, changes to Capacity Credit arrangements (especially for intermittent resources) and the Market Rules relating to day ahead planning and real time dispatch reflected in the operation of the Short Term Energy Market (STEM), balancing market and ancillary services are being considered.

The aim of the review is to improve the arrangements within the Market Rules relating to:

- Participant's ability to prepare economically efficient and commercially viable resource plans accounting for management of fuel supply and unit commitment;
- Trading and pricing within the STEM;
- Economic efficiency of dispatch and provision of ancillary services;
- Pricing within the balancing market;
- Incentives and arrangements for efficient responses to changing market conditions, for example following generator breakdown; and
- The impact of the operation of, and prices developed within, the STEM and balancing on decisions taken by participants, including for example:
    - The role of STEM in facilitating entry of uncontracted generation capacity;
    - Assessments of the cost of different plant specifications against benefits of improved reliability; and
    - Participation in balancing and ancillary services to the extent feasible under the Market Rules.

2 BACKGROUND

2.1 Why we have the market that we have

The original market design process was aimed at minimising the risks often associated with the reform process by undertaking an evolutionary rather than revolutionary approach. In developing the market design, the goal was to facilitate greater competition and private investment by allowing wholesale purchasers of electricity, such as retailers, greater flexibility as to how, and from whom, they procure electricity. The WEM was also designed to include a mechanism for ensuring that adequate generation and demand-side management capacity was available to satisfy the growing demand for electricity.

In more detail, the main drivers for the market design that was adopted were:

- The South West Interconnected System (SWIS) is a small, geographically isolated system which is not interconnected with any other electricity jurisdiction;
- There was a desire to reduce risk and encourage private investment;
- The initial industry structure was characterised by a small number of market participants, with limited diversity and number of generating plants;
- A number of existing participants were small in size and were expected to be financially vulnerable;
- The significance of the reliability objective to Government;
- As a result of a recognition of current limited competitive tensions; and
- To allow for fairness for all technology and energy options.

A further and key objective during the development and implementation of the market model was to minimise the implementation costs of the wholesale market while maintaining its efficiency and effectiveness.

The resultant, and current, market model involved a combination of:

- a bilateral contract market;
- a binding day ahead Short Term Energy Market;
- balancing and ancillary services mechanisms; and

- a Reserve Capacity Mechanism.

Other circumstances taken into account were:

- Perceptions about market power proved to be very important for private investors. The generation arm of Western Power was retained as a single entity (Verve Energy) rather than being split into a number of generators as in other states. The retail arm was also be retained as a single entity rather than being disaggregated;

- A substantial vesting contract was put in place to ensure an orderly opening of the market to competition. The vesting contract was designed as the key market power mitigation tool in the absence of fully developed competition in the market; and

- The Government had commitments in place to maintain uniform tariffs across Western Australia and to ensure price protection for customers.

2.2 Verve Energy Review

During 2009 the Minister for Energy for Western Australia initiated the Verve Energy Review to report on the causes of Verve Energy's financial position and performance, and present options which might improved Verve Energy's financial outlook and enable it to continue as a viable long term Market Participant making an appropriate contribution to the reliability of the South West Interconnected System.

The key findings from the Verve Review were:

- Verve Energy has suffered significant financial loss over the last three years;

- Verve Energy's forecasts suggest that the future will be better;

- Competition has increased since disaggregation;

- New private sector generation has been secured;

- Significant further investment is required over the next 10 years;

- Climate change and gas prices are a major and imminent challenge;

- The approach to wind generation in the SWIS needs careful consideration;

- There are no easy funding options for investment in the short to medium term;

- As a Market Participant the State is exposed to competitive risk;
- The Market Rules have significant shortcomings;
- The vesting contract has many issues which impact on Verve Energy and the sector;
- The system is now 10% over capacity;
- Increasing concerns about oversupply of base load plant overnight;
- Low tariffs have contributed to losses and represent a barrier to competition; and
- To date reliability measures have worked, and there are no threats going forward.

Following this, the Minister for Energy commissioned a team to implement the recommendations of the Verve Review. This work will cover arrangements around vesting between Verve Energy and Synergy, the Market Rules for the WEM and will also develop a generation outlook.

Changes to the Market Rules are expected in relation to the broader participation in the balancing mechanism, the provision of ancillary services and the provisions relating to pricing in the STEM and balancing mechanism, the acquisition of new capacity and the capacity deficiency penalties. This paper focuses on the first phase of improvements required in the Market Rules.

2.3 Market Rules Evolution Plan

The MREP Issues Paper was presented at the 10 June 2009 Market Advisory Committee (MAC) meeting. This paper identified the areas of the Market Rules that were acknowledged as requiring further work, as raised by various stakeholders during the first few years of operation in the WEM and consolidated during a specific consultation process.

Following this meeting MAC members were invited to indicate the relative priority of each of the issues on the list with the intention that the prioritisation exercise would assist the IMO to set the work priorities for the next phase of Market Rules development.

As a result of the prioritisation process five key issues were identified. These were to:

- Improve the balancing mechanism, with a view to allowing Independent Power Producers (IPPs) to contribute towards balancing where this makes sense economically and improving the mechanism to handle unexpected events between the clearing of the STEM and real time;

- Review certain aspects of the Reserve Capacity Mechanism;
- Review the STEM and identify areas for improvement that assist in increasing trade volume, price relevance and STEM predictability. This could include, but is not limited to moving closer to real time or multiple gate closures, increasing transparency of STEM offers, and undertaking a preliminary (i.e. forecast) calculation of Marginal Cost Administered Price (MCAP) (closer to real time);
- Review a closer alignment of gas and electricity nominations; and
- Review the procurement of ancillary services process and assess whether the provision of Ancillary Services should be opened up to competition for spinning reserve, frequency control and black start.

The IMO considered that the review of the balancing mechanism, STEM, alignment of gas and electricity nominations and ancillary services markets are interrelated and would largely be addressed together, while the review of the Reserve Capacity Mechanism would be a standalone review. In relation to ancillary services, load following (frequency control) in particular is closely aligned with balancing.

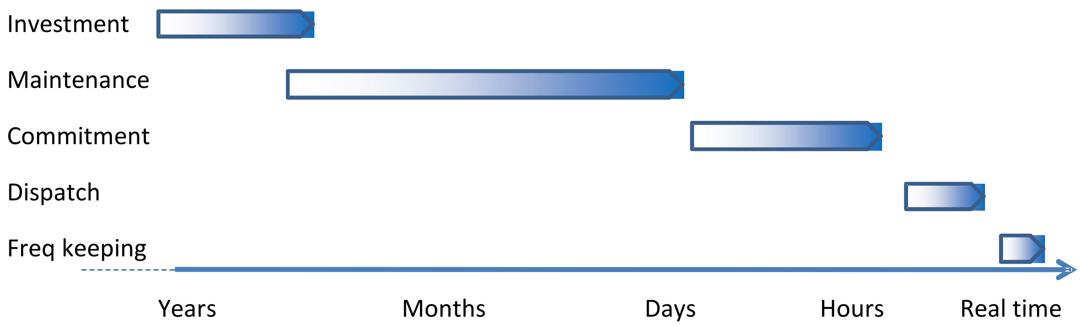
3 TERMINOLOGY/ CONCEPTS

3.1 Coordination concepts

A fundamental requirement of any electricity market is that supply must be physically matched to demand in real time. Achieving this depends on decisions that are made over different timeframes along the lines depicted in Figure 1[1].

1 For simplicity, decisions regarding fuel and other resources are implied within these timeframes and other ancillary services for contingency and/ or voltage management purposes have been ignored.

Figure 1: Illustrative decision timeframes



Working back in time from second to second (real time) operation, supply and demand will be balanced if:

- power system frequency is maintained within the prescribed limits around 50Hz (this has been labelled as frequency keeping in Figure 1);
- generation tracks minute to minute and hour by hour trends during dispatch;
- there is a viable combination of generating units on-line and capable of producing electricity with adequate upward and downward operating range as determined through the unit commitment process in use. e.g. unit commitment decisions can be made by System Management (central commitment) or by the operators of individual generating units (self commitment); and
- there is a viable combination of generating units available for unit commitment at any time as a result of decisions about how much capacity is constructed through the prevailing investment process and the maintenance process.

The focus of this review is on the final few days of operation and in particular:

- the day ahead arrangements (declaration of bilateral positions, operation of STEM, formation of net contract positions, initial unit commitment decisions and resource plans);
- on the day arrangements (commitment/ de-commitment of units, dispatch, balancing and the role of ancillary services); and
- how participants are compensated (pricing) for these services and the costs recovered.

3.2 Summary of current SWIS arrangements

Within the above timeframes, key features of the WEM can be summarised as follows:

- Day ahead arrangements:
  - Participants establish net contract positions (NCP) for the following day. i.e. through bilateral contracts and the day ahead STEM process.
  - Subject to potential amendment by System Management for security purposes, IPPs submit resource plans specifying how they will schedule their generation to match their NCPs, including when generating units will be committed/ de-committed.
  - System Management prepares a dispatch plan for Verve Energy facilities to meet forecast demand (net of IPP plans, intermittent supply etc). The dispatch plans are based on guidelines supplied by Verve Energy (i.e. its internal merit order). System Management decides when to commit/de-commit Verve Energy units.
- On the day arrangements:
  - IPPs commit/ de-commit and dispatch their plant in accordance with their resource plans, subject to System Management security requirements being met[2] (if System Management has to dispatch IPPs off resource plans it uses a 'dispatch merit order' prepared by the IMO from IPP balancing data).
  - System Management commits/ de-commits and dispatches Verve Energy facilities up and down as required to physically balance the market (in conjunction with load following or frequency keeping ancillary services).
- Pricing/ allocation of costs:
  - Verve Energy receives a half hourly administered price (MCAP) for deviations from its NCP (i.e. for balancing support).
  - IPPs dispatched off their resource plan (NCP) by System Management receive their pay as bid balancing price for the quantity involved.

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2 Called dispatch criteria in the Market Rules.

- IPPs which deviated from the NCPs, beyond tolerance limits, and were not dispatched off resource plan by System Management, pay/ receive penalty payments for the quantity involved. i.e. MCAP times peak or off-peak increase penalty factors (UDAP/DDAP).

- Residual costs (differences between balancing payments to Verve Energy, and any IPPs dispatched off their resource plan, less UDAP/DDAP payments) are recovered from/ allocated to market customers.

3.3 Conceptual framework

In the WEM, decisions about commitment and to some extent dispatch could be made either by central bodies such as the IMO and System Management or by individual participants. Although it is generally accepted that System Management should have a right to intervene in the event there is a risk to security or reliability of operation.

Information about physical capability, operating costs, and potential system wide operating conditions and, where relevant, prices are needed by whichever party is responsible for making unit commitment decisions. Similarly shorter term and “real time” information about operating capability is needed by whichever party(ies) are responsible for making dispatch decisions.

The current arrangements in the WEM are a hybrid because:

- subject to possible amendment by System Management for security purposes, IPPs make unit commitment decisions about their plant, submit resource plans that specify their planned dispatch and dispatch their facilities accordingly;
- the WEM is thus organised with self commitment and self dispatch for IPPs; and
- Verve Energy plant is centrally committed and centrally dispatched.

Although there is a range of options, market settlement regimes can generally be classified as net or gross. Net settlement refers to payments, through a body like the IMO for energy produced or consumed for the volume of transactions that are not settled on a bilateral basis directly between participants. Under gross settlement regimes, the entire (gross) volume of energy produced or consumed is settled through a body like the IMO. Under both net and gross settlement arrangements market participants can overlay other settlement mechanisms over any of the IMO settled amounts.

The options for unit commitment, dispatch and settlement can be summarised as depicted in Table 1 below. The row labelled "current" represents the current hybrid configuration and potential enhancements (discussed later). Note that gross settlement options[3] are not practicable in the WEM context given its bilateral focus, and have therefore been shaded in the table.

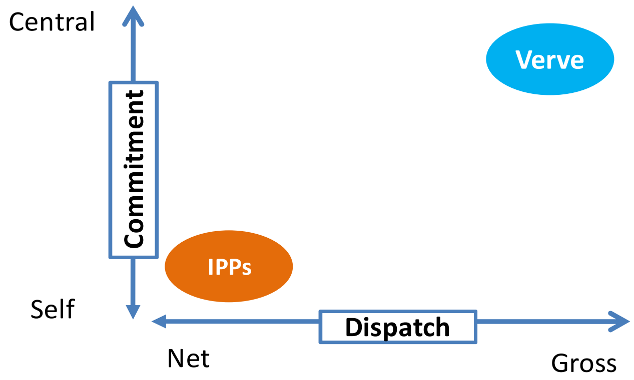
Table 1: Options for commitment, dispatch and settlement

	Commitment		Dispatch		Settlement	
	Central	Self	Gross	Net	Gross	Net
Current	VE	IPPs	VE	IPPs		VE/IPPs
Theoretical Alternatives	VE/IPPs		VE/IPPs		VE/IPPs	
	VE/IPPs		VE/IPPs			VE/IPPs
	VE/IPPs			VE/IPPs	VE/IPPs	
	VE/IPPs			VE/IPPs		VE/IPPs
		VE/IPPs	VE/IPPs		VE/IPPs	
		VE/IPPs	VE/IPPs			VE/IPPs
		VE/IPPs		VE/IPPs	VE/IPPs	
		VE/IPPs		VE/IPPs		VE/IPPs

These concepts provide a useful way of thinking about the different approaches markets adopt for coordinating physical operation within pre-dispatch and dispatch timeframes. For example, the current SWIS arrangements can be characterised as shown in Figure 2.

3 Although this may apply in some circumstances (e.g. for uncontracted generation or for intermittent generation).

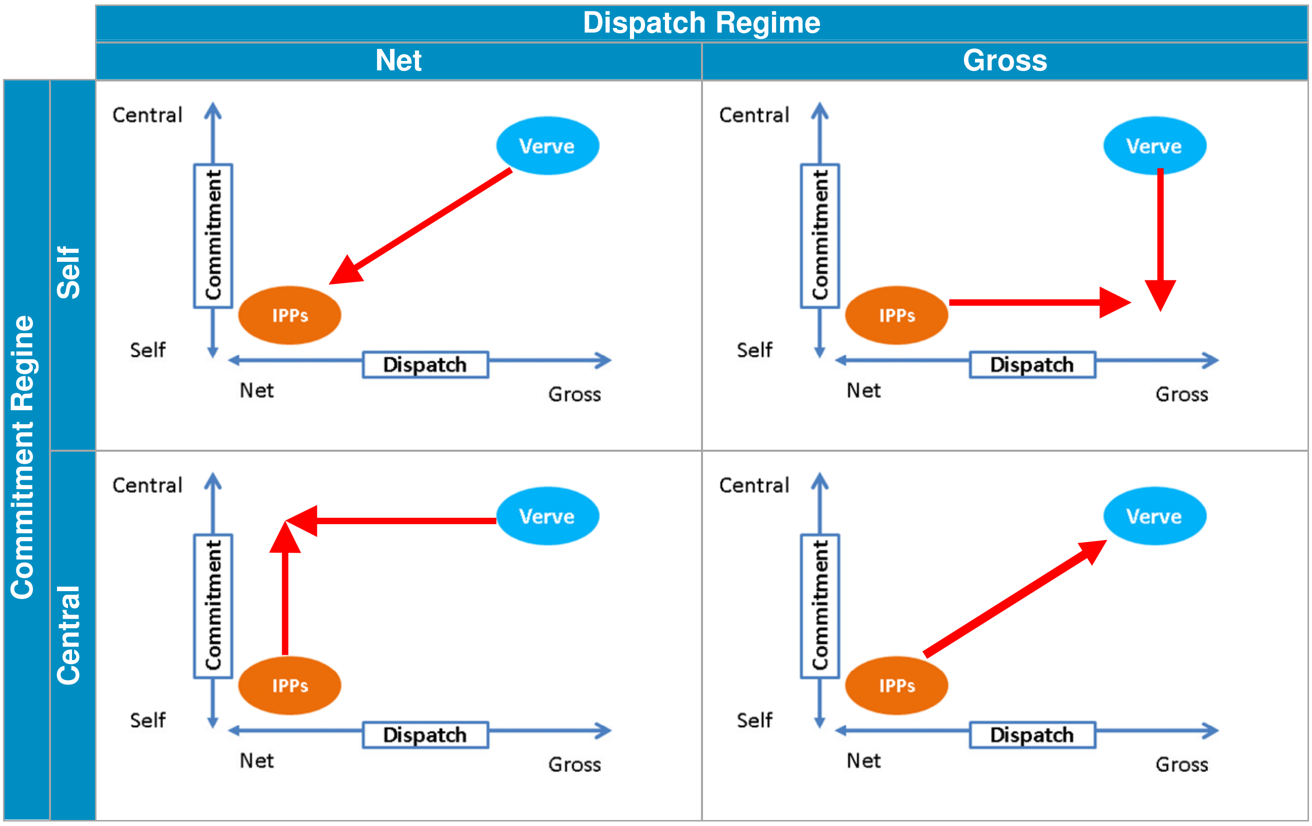
Figure 2: Existing SWIS arrangements



Changes to the Market Rules in relation to unit commitment and dispatch for participation in balancing would, of necessity, involve changes to the split of responsibilities and attendant risks as shown in Figure 3[4].

4 Note that the purpose of highlighting this at this stage is simply to explain the concepts involved; not to suggest any particular option. Potential development options are developed and considered later in section 5.

Figure 3: Coordination options



The arrows in each diagram in the above figure show directionally how the current arrangements would alter. The following sections describe the type of arrangements that would apply **if** arrangements for commitment or dispatch were to be amended.

3.4 Central and Self Commitment Concepts

In order that plant is ready to be dispatched (whether by System Management instructing generators or by generators operating to their resource plans), some decisions must be made in pre-dispatch timeframes. For example, deciding when to bring slower starting thermal generation into service.

Under the central commitment concept, the market would make these commitment/ de-commitment decisions on behalf of participants (as for Verve Energy now). This would involve generators including start-up and shut-down parameters in their offers (costs, times, minimum load etc). The market would then schedule generation to meet expected demand, based on offers, and generators would be instructed when to start-up and shut-down their units in anticipation of dispatch requirements.

Under the self commitment concept, generators would decide when to commit/de-commit units (as IPPs do now) and reflect this in their offers. For example, if a generator considered it profitable to bring a unit into service at a particular time, it would submit a zero (or low) priced offer to ensure it would be dispatched accordingly. Similarly, if it wished to de-commit a unit, it would offer the unit at a price sufficiently high to ensure it is not dispatched. In order to make these decisions efficiently, a generator needs to have a view of expected market prices (in turn depending on the pricing methodology employed) and some flexibility to alter its offers as market conditions alter. On the other hand, System Management and the market in general would want some assurance that plant will not be withdrawn leaving insufficient time for alternatives: this is normally addressed through the concept of a 'gate closure' time for changing an offer prior to dispatch /real time.

A key difference between self and central commitment is the allocation of risk. Under the self commitment concept, generators evaluate the commercial implications of starting or stopping slower starting units given expectations of market revenues, fuel requirements and unit start-up/ shut down costs and times. In this instance, generator offers comprise quantity, price and ramp rate information and market schedules are established on a half hour by half hour basis (accepting that forecast dispatch at the end of one half hour determines the starting point for the next half hour).

Under central commitment, participants submit start up and shut down costs and times, and any constraints/ costs on in service duration (e.g. fuel related), and the market decides whether to commit the unit. In this instance, the market process is more complex having to evaluate requirements over the full scheduling period. i.e. accounting for inter-temporal effects. Generally, market participants would be remunerated for all costs incurred regardless of market outcomes.

3.5 Net dispatch concept

Under this concept:

- All participants (Verve Energy and IPPs) would submit resources plans consistent with their NCPs.

- Participants would submit half hourly increment and decrement offers. i.e. an increment (decrement) offer indicating the amount of generation which it is happy for System Management to dispatch above (below) the resource plan level at a price specified in the offer.

- System Management would dispatch participants above or below resource plan levels, as required to balance the system, using increment and decrement merit orders based on participant increment and decrement offers.

By specifying the price(s) at which they are prepared to be dispatched above or below their resource plans, and by how much, generators could take advantage of profitable buy or sell opportunities. i.e. in effect an on-the-day opportunity to adjust their NCP.

3.6 Gross dispatch concept

Under this concept:

- All participants (Verve Energy and IPPs) would submit half hourly offers – an offer indicating an amount of generation which the participant is happy for System Management to dispatch (or not) at a specified price.

- System Management would dispatch all participants to meet demand using half hourly merit orders prepared from participant offers.

Note that under this concept, there would be no need for participants to submit resource plans. Instead, the market would prepare schedules indicating the amount of generation each participant is expected to produce (like IPP resource plans or Verve Energy dispatch plans).

A participant wishing to operate strictly at its NCP level would offer capacity equivalent to its NCP at zero (or even negative) price and any additional capacity at a very high price. i.e. similar to the way IPPs submit balancing prices now. Alternatively, a participant could offer portions of its capacity at prices it would be happy to reduce and or increase generation.

3.7 Pricing and settlements concepts

Over and above changes to commitment and dispatch pricing could also be altered. Although it is important that pricing be internally consistent with the arrangements for commitment and dispatch decisions about pricing are to some degree separable from the design of the physical arrangement. The following briefly summarises the options – noting that, as with commitment and dispatch the current SWIS design is a hybrid of the two broad approaches. Pricing is clearly important commercially but also for creating incentives for efficient responses to market conditions that nether under or over reward or penalise participants.

Under the net dispatch concept, the basis for payments to generators dispatched off their resource plans by System Management would need to be determined but two general approaches could be considered:

- A single balancing price for each half hour could be set by the highest (lowest) priced increment (decrement) offer dispatched by System Management. All participants dispatched off resource plan by System Management would receive (pay) the single balancing price.

- Alternatively, participants dispatched off resource plan by System Management could be paid at their offered increment or decrement price. i.e. a *pay as offer* approach.

Under the gross dispatch concept, as for net dispatch, payments could either be based on a single balancing price or individual pay as offer approach.

4 EVALUATION FRAMEWORK

The purpose of the above discussion was to explain conceptually the ways in which markets can allocate decision making responsibilities within pre-dispatch and dispatch timeframes. This helps to shape a range of high level development options that could be considered for the WEM. Deciding which development path to follow is therefore an important first step. In order to do so:

- The next section of the paper identifies development options, representative of possibilities in the WEM context, and develops them in sufficient detail to explore the issues and implications of each.

- The subsequent section of the paper considers the relative merits of the options with a view to selecting a preferred development option (or options).

Ultimately, the selected option(s) will need to be assessed formally against the Market Objectives, following more detailed investigation and design and development of a formal rule change proposal. At this stage, selection of a preferred option(s) is necessarily a reasonably qualitative exercise. However, although qualitative in nature, it is proposed that this evaluation be undertaken with respect to the Market Objectives. These are set out in Table 2 below for reference.

Table 2: Market Objectives

Objective	Description
Economic, safe, reliable supply	• To promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system
Competition/ efficient new entry	• To encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors
Non discriminatory	• To avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions
Minimise long term cost to consumers	• To minimise the long-term cost of electricity supplied to customers from the South West interconnected system
Demand management	• To encourage the taking of measures to manage the amount of electricity used and when it is used

[**Note**: MAC members will be aware that a more detailed list of criteria was previously proposed in the form of market-wide, participant and System Management perspectives. Following MAC member feedback and further consideration, it is proposed that overall assessments should be undertaken with respect to the Market Objectives in the Rules. The Market Objectives are more encompassing and avoid potential risks of potential benefits/ costs not being identified and/ or of potential conflicts between the perspectives based check lists and the Market Objectives.]

While the Market Objectives are the primary yard-stick against market development options should be assessed, it may also be informative to consider the implications of the options from the perspectives listed in Table 4.

Table 3: Supporting check-lists

Market wide perspective	
Economic efficiency	• Operational (efficient use of resources) and dynamic (efficient investment)
Costs	• Implementation and transaction costs
Competition	• Short and long term
Transparency	• Predictability, confidence
Reliability	• System security implications
System Management perspective	
Information	• Timely advice of information necessary for appropriate commitment and dispatch (e.g. merit order)
Security Assessment	• Sufficient and timely information for security assessment
Security Intervention	• Appropriate authority for security intervention
Individual Participant perspective	
Commercial risk management	• Participants have sufficient information and ability to manage commercial risks.
Fuel interactions	• Sufficient information and market mechanisms to allow alignment with other energy segments, particularly gas contracting, nomination, timeframes etc.
Physical dispatch	• Confidence and certainty in the dispatch mechanism and its outcomes
Commercial profitability, profit maximisation	• Provide the mechanism for individual participants to participate profitably in the market

5 OPTIONS FRAMEWORK

5.1 Approach

Broadly speaking, development efforts to improve the coordination of resources within day-ahead timeframes could focus on:

- Options to improve the effectiveness/ efficiency of the current arrangements. i.e. with Verve Energy retaining the primary physical balancer role.
- Options to open up the physical balancing role to all participants. i.e. symmetrical treatment of all participants through net or gross dispatch arrangements.

With this in mind, this section explores the following conceptual design options, which have deliberately been selected to cover the broad spectrum of possibilities.

Table 4: Options selected for evaluation

Design principle	Option	Overview
Enhance the current design with Verve Energy as default/ primary physical balancer	A1: Enhanced hybrid	Opportunity for wider participation through balancing support contracts (BSC); supported by appropriate incentives (including pricing and cost allocation); realignment of electricity and gas nominations.
	A2: Enhanced hybrid + renominations	As above plus ability to re-declare contract position and adjust resource plan accordingly.
Open up physical balancing role to all participants	B: Net dispatch	Net dispatch for IPPs and Verve Energy with both eligible to provide balancing support through increment/ decrement offers.
	C: Gross dispatch	IPPs and Verve Energy compete to provide balancing support (on same terms) through offers for gross dispatch.

The two groups describe different strategic paths for the future of the WEM.

5.2 Group comprising Options A1 and A2

For this group, the roles and day to day operation of Verve Energy and System Management would remain closely linked and the current hybrid arrangement for unit commitment and dispatch would continue. Some improvement in transparency would be achievable but to the level achievable if System Management is able to interact with Verve Energy and IPPs on the same basis.

There is some opportunity for IPPs to participate in system balancing but Verve Energy will need to be the default, providing balancing as an inherent part of the central dispatch managed by System Management as it does now. It will be important to ensure that:

- pricing and payments to Verve Energy for the various services it provides are cost reflective – in line with the original intent of the WEM design.
- the allocation of balancing and ancillary services costs are cost reflective;
- there are effective incentives for the participants that cause these costs to take account of them in their decision-making.

Implementation costs will be moderate and the transition will not involve major change to the day to day operation of participants.

The trade-off for lower costs and limited change is that the WEM will remain a bespoke hybrid design where Verve Energy will have a central and distinct role in day to day operation relative to IPPs.

5.3 Group comprising Options B and C

This group provides for more sophisticated market designs with more symmetrical treatment of participants.

Option B would be structured as a net market based on bilateral contracts similar to the original design concept for the WEM. Option C would involve a shift to gross dispatch (not necessarily gross settlement as in a gross pool such as the NEM) where all generators, Verve Energy and IPPs would be centrally dispatched in the same way as Verve Energy is now. Options B and C have different advantages and disadvantages. However, both would be more costly to implement than either option A1 or A2. The trade-off for higher implementation cost and more involved transition is that the WEM would be more robust to future change, be more transparent in its day to day operation and Verve Energy, as a key competitor to new investors, would not be afforded a special role.

In particular, System Management would be far less involved in the day to day operation of Verve Energy. The role of System Management would shift more towards oversight of normal trading activity - intervening in the event of low reserve or other emergency conditions, setting boundaries on energy flows, and procuring ancillary services to manage system and network conditions. This would be a more independent commercially neutral role consistent with the basic concept of a market where Verve Energy and IPPs have equal rights and obligations – albeit that in the near term Verve Energy will be larger than other generation participants and may be subject to commercial or behavioural controls external to the market rules. For example, an obligation to be counterparty to a Vesting contract for the franchise load that Synergy is obligated to supply. A more independent System Manager is a feature of competitive markets around the world, although taking different forms.

5.4 Strategic implications

Importantly, options A1 or A2 may be part of a transition to either option B or C. All options can begin to address key concerns that initiated this work (noted in the Oates Review and features of the IMO's market evolution plan) regarding competitive balancing, the adequacy of payments for balancing, and how cost reflective are the pricing and allocation of costs for a range of services. Changes are required in the near term to address these matters regardless of longer term plans.

However, the options are likely to be able to address these matters in different ways and to different degrees. In addressing more immediate issues, a transitional strategy could have adverse impacts on longer term investment to the extent it causes or prolongs regulatory uncertainty.

To provide a fuller context for considering these issues, the following sections describe each of the options in more detail. A later section evaluates the options.

6 Option A1: Enhanced Hybrid

6.1 Overview

Under this option:

- The current hybrid regime would be retained - Verve Energy with gross dispatch/central commitment; IPPs with self commitment/net dispatch.
- The timing of electricity nominations would be realigned around gas nomination timing to increase participant flexibility (later STEM in effect). This may also increase incentives for BSCs and/or reduce on the day balancing requirements.
- Either System Management, or System Management and Verve Energy, would enter BSCs with IPPs.

- All balancing activity (BSCs and Verve Energy) would be appropriately compensated and any dis-incentives to enter contracts addressed (e.g. under UDAP/DDAP, pay as bid balancing, capacity obligations etc).

- Parties deemed to be creating the need for balancing/BSC face the costs

- Verve Energy would be retained as the default/ primary balancer;

- There would be opportunities for wider participation in physical balancing, through BSCs, supported by appropriate incentives including pricing and recovery of costs; and

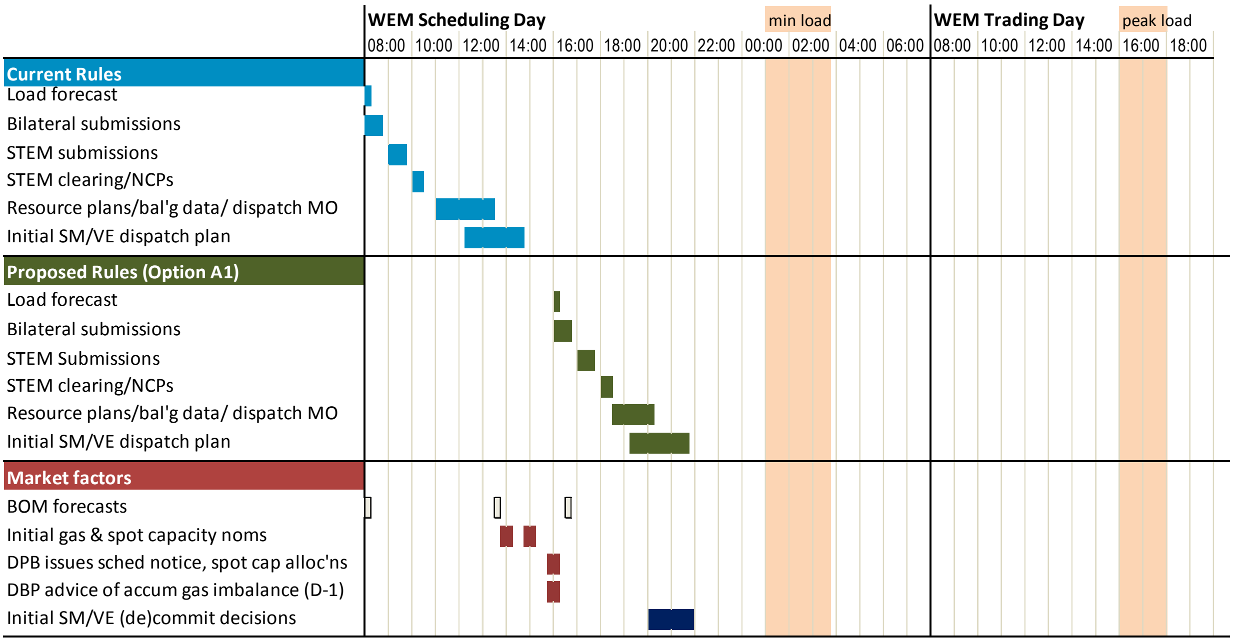
- The timing of electricity nominations would be delayed to enhance the management of gas positions and/or to reduce scheduling/ commitment/ balancing uncertainties.

Key design efforts would centre on shifting the day-ahead STEM process to later in the day and reviewing pricing and cost allocation arrangements (including potential to simplify settlement arrangements, which are currently complex and not easily understood, and any disincentives regarding BSCs). Otherwise the form of current hybrid arrangements would largely be retained.

For initial evaluation purposes, it is sufficient to assume that pricing and cost allocation arrangements will be resolved appropriately (to avoid inappropriate incentives and/ or are reduce unnecessary complexity/ transaction costs).

In relation to the timing of day-ahead processes, it is assumed that these would be realigned to take account of gas market timing and unit commitment/ de-commitment timeframes, particularly in relation to Verve Energy's balancing role. For example, existing processes could be realigned as summarised in Figure 4 below.

Figure 4: Assumed realignment of day-ahead processes under Option A1 (enhanced hybrid)



The diagram shows three sets of timelines, from top to bottom:

- Key day ahead processes under the current WEM rules.
- Indicative timing of the same processes under option A1.
- The timing of other market factors of particular relevance to day ahead decision-making. i.e. BOM forecasts (demand and wind), gas market arrangements and Verve Energy commitment/ de-commitment timeframes.

WEM participant's day-ahead net contract positions are currently confirmed by 10:30 am. It is understood that participants relying on gas supply via the DBP[5] pipeline then submit initial day-ahead gas and spot capacity nominations at 2pm and 3pm respectively and capacity available to them is confirmed around 4pm[6]. They receive confirmation of their previous day's gas imbalance position between 12pm and 2pm. Under Option A1, the timing of WEM submissions would be delayed until after gas positions have been confirmed. For example, as illustrated in Figure 4, the current day-ahead WEM processes could be delayed so that STEM submissions

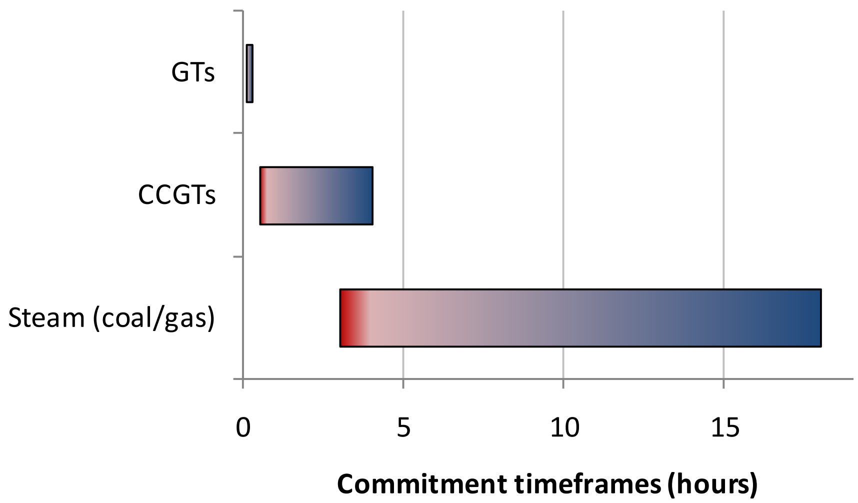
5 Dampier to Bunbury Pipeline.

6 It is understood that actual requirements in individual contracts may differ.

close around 6pm. This would enable WEM participants to prepare submissions based on confirmed gas availability and more up to date BOM forecasts.

NCP confirmation, following STEM clearance, would occur around 6:30pm. IPPs would then prepare and submit resource plans, including any unit commitment/de-commitment decisions between 7pm and 9pm. In this regard, as illustrated in Figure 5, the lead time for unit commitment decisions varies by technology and the length of time a unit has been shut down (generally classified as a hot, warm or cold start).

Figure 5: Illustrative unit commitment timeframes



System Management, as now but later in the day, would prepare Verve Energy's initial dispatch plan based on expected demand net of forecast intermittent supply and IPP resource plans. This process involves fuel scheduling and unit commitment/ de-commitment considerations, taking account of Verve Energy's merit order/ cost guidelines (and potentially BSCs).

System Management has indicated that the period leading up to around 10pm, approximately 6 hours prior to the end of overnight minimum demand period, is a critical time for making unit commitment decisions. Commitment decisions reflect potential operation over the full trading day taking into account start-up and shut down costs, fuel requirements and uncertainty regarding expected demand and intermittent supply net of IPP resource plans.

7 Option A2: Enhanced hybrid + renominations

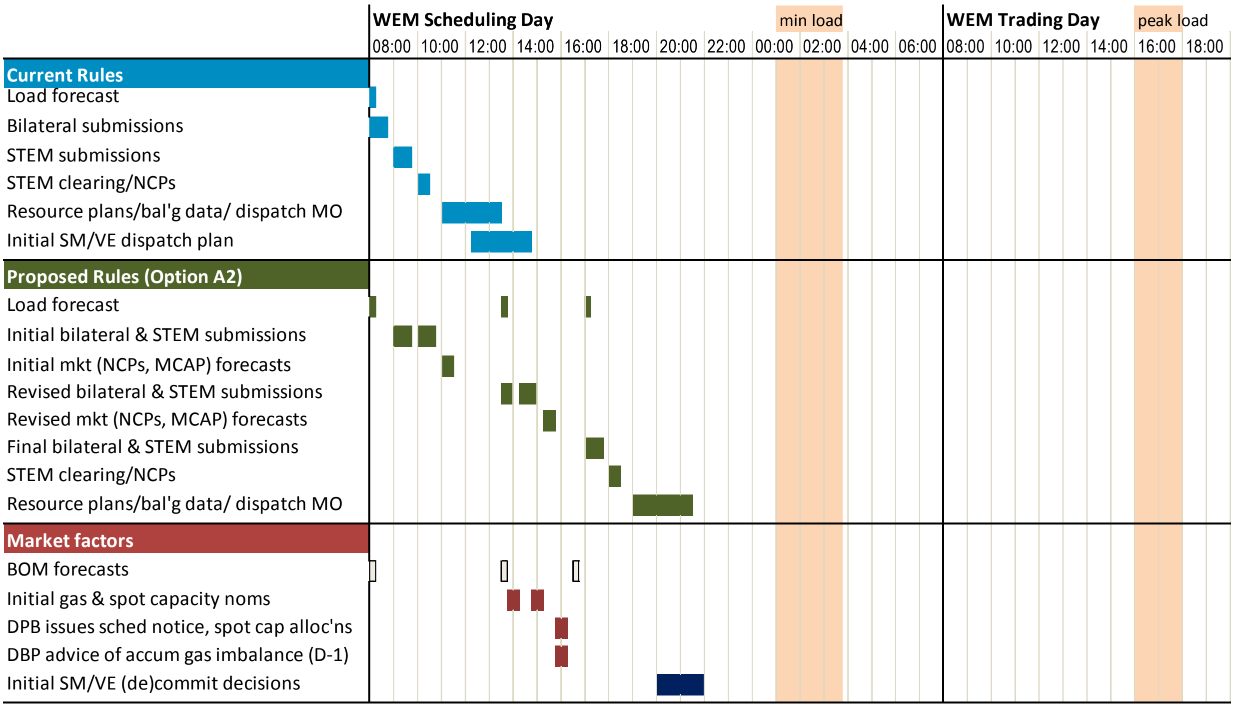
7.1 Overview

This option would extend Option A1 further by providing opportunities for participants to re-submit contractual positions prior to net contract positions and resource plans being finalised. Following initial submissions, participants would receive resulting pre-dispatch forecasts. i.e. their expected NCPs, expected overall system balancing requirements and expected balancing prices (MCAP) for each half hour of the following dispatch day.

In addition to requirements for Option A1, key design efforts would centre on providing for renominations supported by appropriate information/ forecasts to aid participant decision making.

It is assumed that the timing of day-ahead processes under option A2 would be along the lines summarised in Figure 6 below.

Figure 6: Assumed timeframes/ processes under Option A2 (enhanced hybrid + re-nomination)



A design issue that would need to be decided is whether initial and revised nominations are binding or indicative. If binding, then participants would have firm NCPs (bilateral + STEM) following their initial submissions. Subsequent submissions would then result in incremental changes (if any) to NCPs based on any off-market adjustments to previous bilateral positions and/ or any accepted STEM bids or offers. Alternatively, if initial and revised submissions are indicative only, firm NCPs would only be established at the same time in the evening of the day ahead as under Option A1.

A possible argument for initial submissions to not be binding is that initial STEM submissions would be made absent any pre-dispatch forecast. Possible arguments for all submissions being binding include potential incentives to make accurate and cost reflective submissions and/ or a participant being able to elect to participate only in the initial (or revised submission) stage. e.g. a participant could trade-off any transaction costs against perceived benefits of participating in revised and final submissions (in effect making a standing initial submission). Further, pre-dispatch forecasts would be less meaningful if not all submissions were included so under either approach, it would be a requirement to make initial submissions and thereafter if there are any off-market changes to bilateral positions.

On balance it is assumed that all submissions would be binding but with participants electing whether to participate beyond initial submissions (unless they have negotiated a change in bilateral position).

8 Option B: Net dispatch

8.1 Overview

Under this option:

- IPPs and Verve Energy would be subject to net dispatch and self commitment. i.e. Verve Energy would move from gross dispatch and central commitment by System Management, to net dispatch and self commitment.

- Both IPPs and Verve Energy would be eligible to provide balancing support.

- Both IPPs and Verve Energy would submit resource plans, to meet their NCPs, plus half hourly increment (above resource plan) and decrement (below) offers. i.e. “inc” and “dec” offers.

- The market would establish market-wide half hourly inc and dec merit orders from participant inc and dec offers.

- System Management would balance the system by dispatching participants above and below resource plans using the market inc and dec merit orders.

- Participants dispatched for balancing by System Management would be appropriately compensated.

- Balancing costs would be allocated to those contributing to the imbalance (i.e. above or below NCP and not dispatched by System Management).

This option is fundamentally different to the current arrangements, with significant design and operational implications in relation to:

- Verve Energy and IPPs competing for and being dispatched on the same basis to provide balancing support (both preparing resource plans, inc/dec offers and making self commitment decisions).

- Greater separation between, and some reallocation of, System Management and Verve Energy roles.

- The need for rolling gate closure and market forecasts to provide operational flexibility and support decision making in relation to participants making unit commitment decisions and participating in balancing.

Some important design implications of this can be seen in Table 5, which highlights fundamental differences between hybrid (current and enhanced) and net dispatch arrangements.

Table 5: Key differences between market cycles under hybrid and net dispatch options

Feature		Hybrid arrangements			B: Net dispatch
		Current	Option A1	Option A2	
Submissions	Frequency	Single		Up to 3	Multi – Rolling
	Coverage	Next trading day			Up to end next trading day
NCP gate closure	VE & IPP	Morning day ahead	Eve day-ahead	Eve day-ahead	Rolling
Resource plan gate closure	IPP	Morning day ahead	Eve day-ahead	Eve day-ahead	Rolling
	VE	N/A			
Pre-dispatch forecasts		None		Day ahead	Rolling
Commitment	IPP	Self			Self
	Verve	SM			
Dispatch	IPP	Implement resource plan subject to SM/ security criteria (or BSCs)			Implement resource plans subject to SM balancing with inc/dec merit orders
	VE	SM			

In all instances, System Manager intervention for security purposes is assumed.

8.2 Key design issues

Key considerations regarding the design of net dispatch arrangements include:

- The basic market cycle for making submissions, forming NCPs and resource plans and providing pre-dispatch information to participants.
- The frequency at which this cycle repeats and the timing of gate closure (market timelines).
- The nature of the commitment being made at the time of gate closure. In particular, should participants:

- Enter dispatch fully contracted to meet forecast demand at the time of gate closure. i.e. no provision for them to plan to be out of balance at the time of dispatch; or
- Be allowed to enter dispatch without being fully contracted to meet forecast demand. i.e. provision for planned imbalances. For reasons explained later this option is preferred.

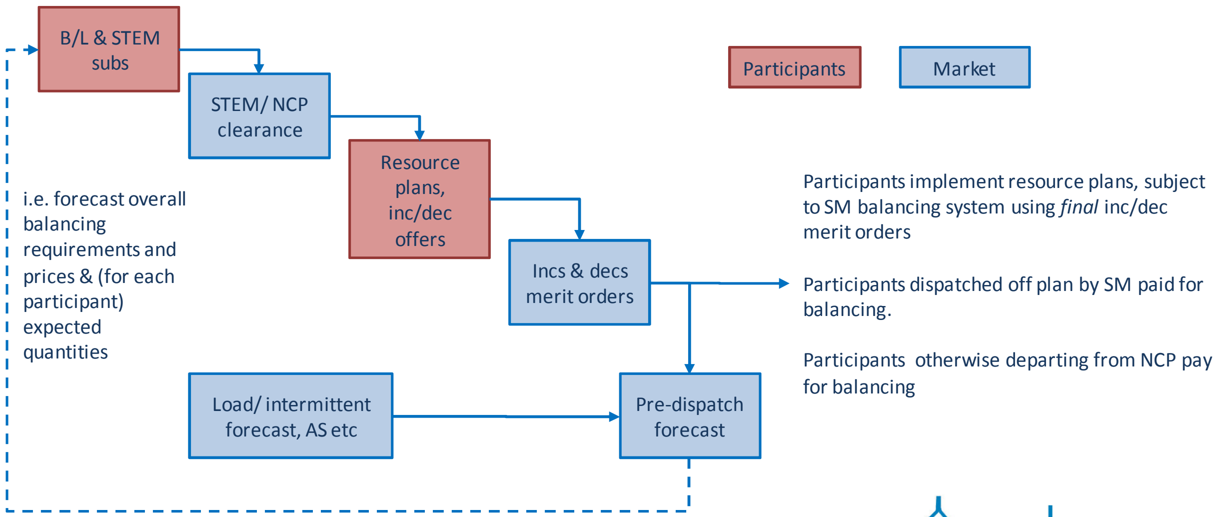
- Self commitment issues and WEM reserve capacity obligations.
- Treatment of changes beyond gate closure.
- Dispatch engine capabilities.
- The formation of balancing prices/ payments.
- Ancillary service arrangements.

These and a number of other issues are explored in the following. Note that the aim is not to develop the design in detail – just to the extent needed to assess feasibility and broad requirements to the extent necessary to enable comparison with the other options being considered.

8.3 Assumed market cycle for net dispatch

A market cycle appropriate for net dispatch in the WEM context could operate along the lines illustrated in Figure 7 below.

Figure 7: Assumed rolling market cycle for Option B (net dispatch)



General design features and working assumptions include:

- The contract adjustment elements of STEM would be retained as a voluntary mechanism. i.e. for participants to contract through the IMO with other participants as now. (Given multiple runs, the possibility of a low cost on-line/ open STEM trading platform could be considered. i.e. participants could submit STEM offers at any time up which could be struck at any time up to a designated gate closure).
- Firm NCP commitments would be established after STEM clearance as now. i.e. NCP = bilateral contracts +/- cleared STEM quantities.
- Resource plans would be based on NCPs (as now for IPPs, but a new requirement for Verve Energy).
- Market pre-dispatch forecasts would advise:
    - All participants of expected net system balancing requirements. i.e. expected demand/ intermittent supply less total NCPs/resource plans.
    - All participants of the expected system balancing price.
    - The relevant participants (only) of their expected balancing volume.
- Pre-dispatch forecasts would cover all load and generation. This would mean:
    - Mandatory participation for all scheduled generation, including facility based incs / decs offers. These would be in the form of raise and lower prices and quantities and ramp rate limits.
    - System Management would forecast demand and intermittent supply.

8.4 Assumed time lines for net dispatch arrangements

In order to provide flexibility for participants to make commitment decisions, adjust their contractual positions and assess opportunities to participate in balancing the market cycle would need to operate on a rolling basis. In principle, maximum flexibility would be available to participants if the market cycle operates very frequently and with short gate closure. However, the market benefits of participants actively participating in a market cycle operating at frequent intervals would need to outweigh any transaction costs incurred. It is difficult to assess these costs from a participant perspective because they will vary by participant and circumstance. However, with voluntary participation other than for initial submissions, participants could each trade-off the benefits and costs of actively participating.

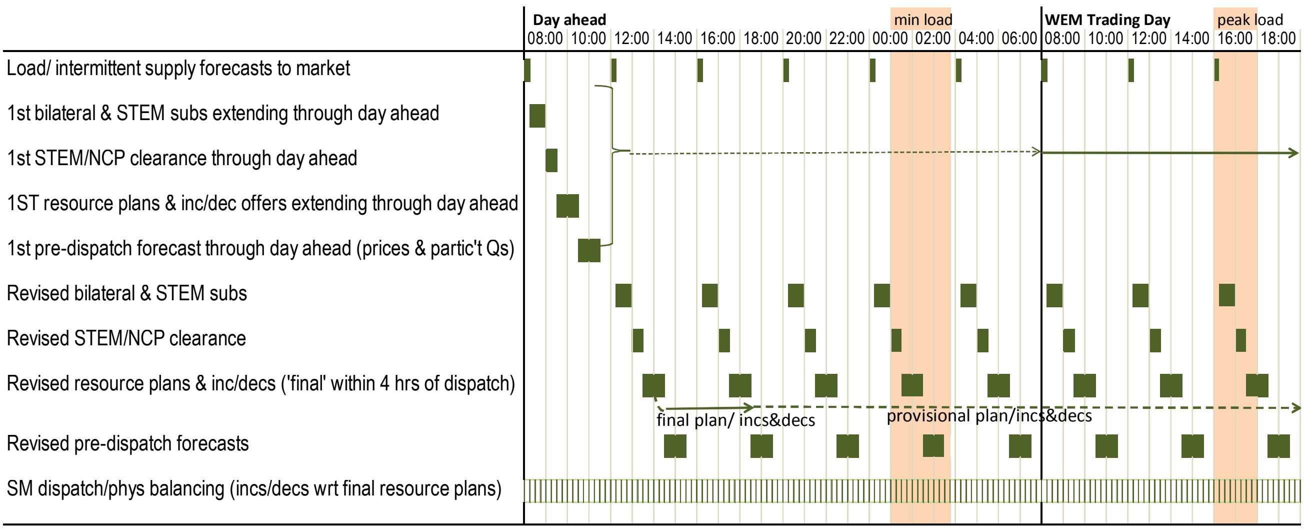
It would be impractical, and also commercially disadvantageous, for Verve Energy not to actively participate and it is inevitable that it would incur additional costs in taking on some of the functions currently carried out on its behalf by System Management (some of these costs may also transfer from System Management). However, it is likely that having decided to actively participate, the incremental costs of doing so more frequently are likely to be relatively low. A similar situation probably also applies in relation to incremental IMO and System Management costs if the market cycle operates more frequently. A limiting factor is likely to be the ability to be the nature and capabilities of System Management tools.

For evaluation purposes and recognising considerable uncertainty at this stage, it is assumed that the nominal net dispatch market cycle would:

- Have a pre-dispatch horizon:
    - For submissions before 8am, to the end of the current dispatch day; or
    - For submissions from 8am, to the end of the following dispatch day.
- Operate at a frequency of 2 to 4 hours.
- Have a rolling gate closure time of 2 to 4 hours (i.e. resource plans and inc/dec offers would become final within 2 to 4 hours of dispatch).

For example, market timelines could be along the following lines assuming a rolling gate closure of 4 hours.

Figure 8: Possible Option B (net dispatch) timelines (assuming 4 hour rolling gate closure)



8.5 Nature of contractual commitments at gate closure

It is proposed that participants could plan to be out of balance at the time of dispatch. i.e by design rather than accident. Residual balancing requirements could thus extend beyond the effect of forecasting inaccuracy (load/ intermittent supply/ forced outages). This has a number of implications for the design and operation of net dispatch arrangements:

- Pre-dispatch schedules would need to account for the possibility of planned imbalances. i.e. System Management would forecast intermittent supply and total demand and scheduled generators would submit inc/dec offers for all of their capacity.
- Pre-dispatch schedules would indicate participation in residual balancing (relative to firm NCP positions).
- Actual balancing will depend on forecast uncertainties and other generators holding to inc/dec offers if dispatched by System Management.
- It would be necessary to monitor compliance with inc/dec offers (non compliance would result in greater pre-dispatch uncertainty and potentially increased risks of other participants incurring otherwise unnecessary costs. e.g. self commitment/ start-up preparations/ fuel preparations based on market pre-dispatch forecasts.

The alternative would be to require all parties to participate in dispatch with a fully contracted plan. In other words:

- Plans / contracts (including balancing) would be established at gate closure and for a nominated period (e.g. a rolling 4 hour window).
- Conceptually, if, at the time of dispatch, load/ intermittent supply forecasts are accurate and plant is available as in resource plans, the system would be in balance. i.e. System Management would not need to dispatch any inc/ dec offers to balance the system.
- This approach would require:
    - Mandatory demand side “bids”, or default forecasting by the System Manager;
    - Settlement arrangements to calculate any “planned” imbalance;
    - STEM and pre-dispatch to cover all demand and be commercially binding from gate closure.

While such an arrangement could address potential risks associated with non compliance with final inc/dec offers, it appears unnecessarily restrictive and potentially inefficient. Other balancing uncertainties are also likely to be significant (for example, intermittent supply). The alternative approach would also require that both the STEM and pre-dispatch schedules be security constrained whereas under the proposed approach, STEM would be purely financial contract adjustment mechanism. The market would need to be carefully designed to ensure the current AFSL[7] exemption remains.

8.6 Self commitment issues in a capacity market

A feature of the WEM is that participants holding capacity credits are expected to make the capacity available for dispatch[8] in order to meet their reserve capacity obligations.

For IPPs holding credits, capacity must be available for net dispatch by System Management (i.e. dispatch off resource plans for security purposes or to avoid the use of distillate). For credits held by Verve Energy, the capacity must be available for central commitment and gross dispatch by System Management. Through Verve Energy dispatch guidelines and IPP balancing data, and outage records, System Management will be aware of plant availability and start-up and shut-down times and costs and, if need be, commit and dispatch facilities accordingly.

Under the current arrangements and with the current thermal technologies, IPPs either tend to run as base load, and therefore commit units whenever they are available, or the units have very short start up times and can be committed on instruction.

In the future with a wider range of technologies and operating conditions it will not always be economically rational for all generating units to be committed on when available. This raises a question about what it means to have made capacity available but at the same time not being required by the rules to make uneconomic commitment decisions.

More particularly, under a net dispatch model with self commitment and rolling gate closure, how will the requirement that participants make capacity available to meet reserve capacity obligations be met? If a unit has not been committed when a final resource plan is submitted (at gate closure) has it been made available for dispatch? In principle, prior System Management approval not to commit the unit at gate closure could be a basis for satisfying reserve capacity obligations. That would probably require the development of criteria for

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8 Rule 4.12.1 (c).

System management to apply or could be construed as a form of central commitment. One option is that capacity for which credits are held must be offered for dispatch in all future pre-dispatch periods for which there is still time to start-up the unit if scheduled in the pre-dispatch schedule[9]. That would enable System Management to assess the likelihood of the unit being required given the full range of capacity available. Where a unit is scheduled in the pre-dispatch schedule, the participant may decide to confirm commitment - this would clearly satisfy the reserve capacity obligation. But if a slow starting unit is scheduled for say just one trading period over the peak then, unless available capacity margins were low (which seems unlikely) it would be reasonable for System Management to agree to the unit not being committed for the period over which gate closure applies. A more objective test could possibly be based on whether specified capacity margins are met and/ or based on a high demand/ low wind forecast.

Given potential security implications and cost implications for participants these issues will require careful consideration in the detailed design stage following decisions about the preferred option and transition path.

8.7 Treatment of changes beyond gate closure

Another design aspect that would need to be settled relates to the management of forecast uncertainty subsequent to gate closure. For example, how would participants and System Management manage swings in forecast demand, fluctuations in wind output and fuel availability? Significant changes may not occur often but will do so at crucial times (elevated price and /or reduced reserves). Shortening gate closure times will provide more flexibility to respond. However, within a trading period these issues can be problematic. For example, fast start OCGTs cannot respond immediately to a dispatch instruction so should incs and decs offers also include commitment parameters such as min run times for OCGTs?

These issues are addressed to varying degree in other markets and would need to be considered here.

8.8 Dispatch process capabilities

Security constrained pre-dispatch scheduling capabilities would be required under the net dispatch proposal. It is possible this could be through some form of economic dispatch by adapting a traditional security constrained full economic dispatch engine. i.e. to optimise dispatch based on the aggregate cost of shifting participants off resource plans (based on inc

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9 This could be at a high price reflecting the potential cost of the unit being required only for a short period.

and dec offers) to balance the system to meet expected demand less intermittent supply. However, that would require some potentially complex pricing and dispatch issues to be resolved (for example, how to represent resource plan generation). A detailed design question will be whether it is necessary to move to a software based dispatch process immediately (or at all) as there will clearly be implications for cost and operational management protocols. Moreover, central full economic dispatch is probably unachievable in a net dispatch arrangement without active/ economic contract trading in pre-dispatch timeframes[10].

In this context:

- Incs and decs based merit orders would provide a relatively low cost economic basis for dispatch off contract positions/ resource plans; and
- More active STEM participation and/or management of exposure to residual balancing costs/ payments have economic merit.

8.9 The formation of balancing prices

A methodology for establishing balancing prices and, for pre-dispatch purposes, forecasting expected balancing prices would need to be established. As discussed previously, STEM would be a purely financial / contract adjustment mechanism. Balancing price forecasts would therefore be an outcome of pre-dispatch rather than of the STEM process.

In part the basis for forecasting and setting balancing prices would depend on dispatch engine capabilities. The following reflects the previous discussion in this regard.

For pre-dispatch schedules/ forecasts, it is assumed that:

- Expected residual balancing requirements would be based on:
    - Forecast demand (and estimated losses).
    - Less forecast unscheduled generation.
    - Less total NCPs (aggregate resource plans).

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10 Which could also require changes to existing contract arrangements for participants.

- Balancing price forecasts would be derived from the market-wide incs and decs merit orders (taking account of any ramp rate limits in inc and dec offers) relative to forecast residual balancing requirements.

- Balancing volumes are more likely to be positive (although may be negative if there are planned imbalances and/or significant demand/ intermittent supply forecast inaccuracies)

- Balancing prices are likely to be positive for both increases and decreases.

For settlement purposes, it is assumed that:

- The balancing price would be derived from final/ ex post market-wide incs and decs merit orders (taking account of any ramp rate limits in inc and dec offers) relative to actual residual balancing requirements.

- There would inevitably be constrained on/off situations. For example, the price of an inc offer dispatched by System Management could be higher than the settlement balancing price (a constrained-on situation). This could occur because:

    - The facility was dispatched by the System Manager for security requirements.

    - Or because balancing prices are based on final inc/dec merit orders and half hourly energy (whereas the facility may have been dispatched for part of a half hour).

- In either situation, it is assumed that the participant would be compensated for the difference between their inc off price and the balancing price. This is similar to the current WEM pay as bid construct for IPPs dispatched off plan. If not compensated, the participant could be out of pocket for following a legitimate dispatch instruction. The within half hour issue could be addressed by setting the balancing price at the level of the highest priced in offer that was dispatched. However, that would be inappropriate if the generator was constrained on for local security purposes.

- Similar issues apply in relation to constrained-off situations. More complex market dispatch engines address these issues in part by automating pricing calculations to take account of security constraints. Some of these markets compensate for within half hour constrained on but not constrained off effects and others compensate for neither.

It is assumed that the costs of balancing support would be allocated to out of balance participants that were not dispatched by System Management. Participants could avoid exposure to these costs to the extent they enter dispatch fully contracted. i.e. NCP equal to actual volumes.

The basis for pricing and recovery of balancing costs would require more in depth investigation but the principles are sufficient for initial evaluation purposes.

8.10 Ancillary service arrangements

Note that ancillary service pricing and cost recovery would also need to be determined. Consideration would need to be given to the level of integration between ancillary services (such as frequency keeping and reserves) and energy market dispatch and pricing. Subject to further investigation, under the relatively simple approach to dispatch and pricing assumed for balancing purposes, opportunities for this would be limited. However, net dispatch arrangements would provide an opportunity for all participants to participate in the market for ancillary service provision (as for balancing). In relation to cost recovery, it is assumed that costs would be allocated on a causer pays basis to the extent cause can be attributed.

8.11 Voluntary participation issues

As noted earlier, there would be some inevitable resourcing issues for Verve Energy under the net dispatch option. In establishing capabilities to participate in the rolling arrangements described, Verve Energy would also need to internalise some of functions currently carried out by System Management on its behalf (preparing dispatch plans, scheduling fuel and facilities, and unit commitment decisions). Changes to market processes and System Management activities/ systems would also be required, with potential additional resourcing implications.

Given that these costs (although uncertain) would be an inevitable consequence of moving to a net dispatch market, would active IPP participation be a precondition for doing so? Or would greater separation between System Management and Verve Energy roles of itself be sufficient justification? From an investment perspective, it is likely there would be greater confidence in such a market given increased transparency and the ability for IPPs to participate in balancing on the same basis as Verve Energy. The issue is not whether such arrangements are practical but whether they would have net benefits.

8.12 Nature of Net Dispatch benefits and costs

Potential benefits are likely to arise from:

- More efficient use of resources through:
    - Increased flexibility/ opportunities for participants to manage their contractual positions, including gas, and respond to market conditions (extended into the day of dispatch).

- The ability for IPPs to elect to participate directly in balancing.

- Increased investor/ market confidence as a result of:
    - Greater separation between System Management and Verve Energy roles.
    - Increased transparency with respect to Verve Energy's participation in the market.
    - A more enduring and robust design reducing uncertainty about the future evolution of the market.
- Stronger signals about the value of flexibility in the WEM and the impact of different technologies on the system.

Costs would arise in relation to:

- Developing and implementing changes to the Rules, market systems etc.
- Additional resourcing requirements for participants, IMO and System Management.

These costs are difficult to quantify at this stage but would be significantly more than under the hybrid options.

9 Option C: Gross dispatch

9.1 Overview

Under this option:

- IPPs and Verve Energy would be subject to gross dispatch and self commitment. i.e. IPPs would move from net dispatch to gross dispatch and Verve Energy would move to self commitment.
- Both IPPs and Verve Energy would be eligible to provide balancing support.
- Neither IPPs nor Verve Energy would submit resource plans – instead they would submit half hourly offers for all of their capacity consistent with their NCPs and balancing aspirations.
- The market would establish dispatch merit orders from participant offers.

- System Management would dispatch participants in accordance with dispatch merit orders above.

- Participants dispatched by System Management above (below) their NCP level would receive a half hourly market price for the extra (deficit) quantity. i.e. for balancing quantities.

- Balancing costs would be allocated to those contributing to the imbalance (i.e. above or below NCP and not dispatched by System Management).

As for net dispatch, the gross dispatch option is fundamentally different to the current arrangements with significant design and operational implications. Gross dispatch has some features that are similar to net dispatch and some material differences. For example:

- As for net dispatch, Verve Energy and IPPs would both be eligible to provide balancing support. However:
  - Under net dispatch, participants would submit resource plans (matching their NCPs) and inc/dec offers for dispatch above/ below plans. Resource plans and inc/dec offers would reflect self commitment decisions and inc/dec offers would reflect willingness or aversion to contributing to balancing.
  - Under gross dispatch, participants would submit offers for all of their capacity (rather than incs and decs relative to their NCP/ resource plans). Offers would reflect NCPs, self commitment decisions and the prices at which they are prepared to increase (or reduce) output to contribute more to (buy more from) balancing.
  - Under net dispatch, in the absence of system security requirements, participants would only be dispatched off resource plans in accordance with market-wide inc and dec merit orders. Under gross dispatch, participants would be dispatched by System Management on a market-wide basis in offer price order.

- As for net dispatch, with gross dispatch there would be much greater separation between, and some reallocation of, System Management and Verve Energy roles.

- As for net dispatch, gross dispatch and self commitment would require rolling gate closure and market forecasts to provide operational flexibility and support decision making in relation to participants making unit commitment decisions and participating in balancing.

In this regard, Table 6 highlights some of the fundamental differences between hybrid (current and enhanced options 1A and 1B), net dispatch and gross dispatch arrangements.

Table 6: Key differences between market cycles under hybrid and net dispatch options

Feature		Hybrid enhancements	B: Net dispatch	C: Gross dispatch
Submissions	Frequency	1 to 3	Multi – Rolling	Multi – Rolling
	Coverage	Next trading day	Up to end next trading day	Up to end next trading day
NCP gate closure	VE & IPP	Day ahead	Rolling	Rolling
Resource plan gate closure	IPP	Day ahead	Rolling (+incs/decs)	Resource plans N/A Rolling gross offers
	VE	N/A		
Pre-dispatch forecasts		Only Option 1B (day ahead)	Rolling	Rolling
Commitment	IPP	Self	Self	Self
	Verve	SM		
Dispatch	IPP	Implement resource plan subject to SM/ security criteria (or BSCs)	Implement resource plans subject to SM balancing with inc/dec merit orders	SM dispatch of facilities in accordance with gross offers
	VE	SM		

In all instances, System Manager intervention for security purposes is assumed.

9.2 Key design issues

Gross dispatch requires consideration of similar issues to those under net dispatch, including:

- The basic market cycle.
- The frequency at which this cycle repeats and the timing of gate closure.
- Self commitment issues and WEM reserve capacity obligations.
- Treatment of changes beyond gate closure.

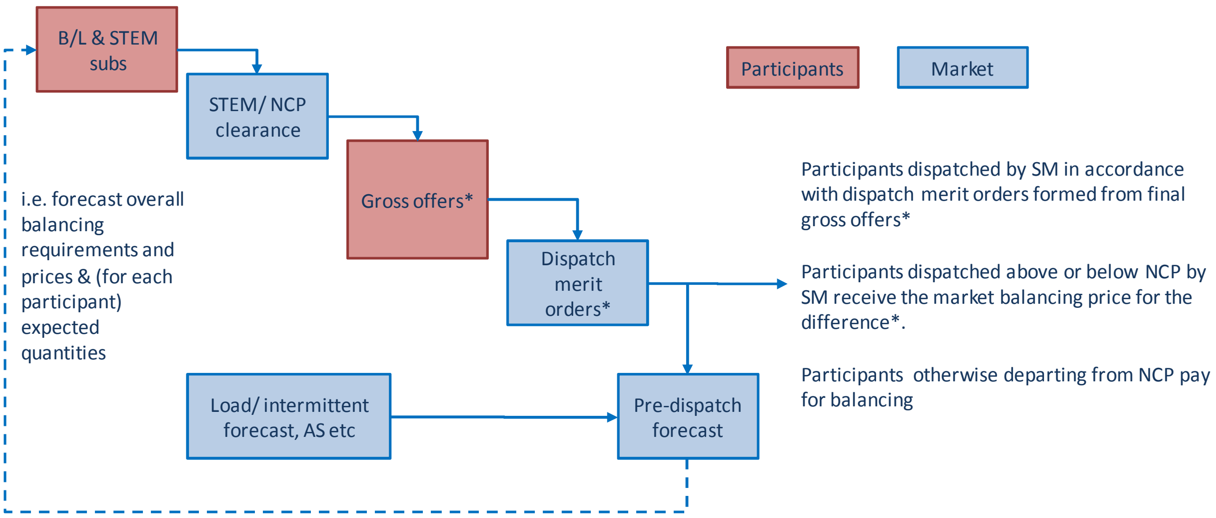
- Dispatch engine capabilities.
- The formation of balancing prices/ payments.
- Ancillary service arrangements.
- Voluntary participation issues.

Accordingly, to avoid repetition and to highlight some important differences the following draws on the previous discussion about net discussion arrangements where relevant. Again, as for net dispatch, the aim is not develop the design in detail – just to the extent needed to assess feasibility and broad requirements to enable comparison with the other options being considered.

9.3 Assumed market cycle for gross dispatch

A market cycle appropriate for net dispatch in the WEM context could operate along the lines illustrated in Figure 9 below. Key differences from the cycle assumed for net dispatch are highlighted with an asterisk.

Figure 9: Assumed rolling market cycle for Option B (net dispatch)



General design features and working assumptions include:

- As for net dispatch, the contract adjustment elements of STEM could be retained as a voluntary mechanism with firm NCP commitments being established after STEM clearance. However:

- Under gross dispatch, consideration could be given to the possibility of running STEM less frequently given the possibility of increased opportunities to trade efficiently through the balancing mechanism. i.e. rather than financially through STEM contracts.

- This assumes it is possible for the ranking of all capacity according to gross offers to provide a more efficient mechanism than the ordering of incs and decs offers relative to resource plans. i.e. as discussed later, full security constrained economic dispatch would be practical under gross dispatch. Under net dispatch this would depend more on economic contract trading activity.

- Participant offers would contain price and quantity pairs and associated ramp rate limits for all of their available capacity. There would need to be provision for multiple price/quantity pairs (i.e. multiple offer tranches[11]).

- Offers would express participants' willingness to generate (or not) amounts of electricity at specified market prices. For example:
  - A very low (even negative) priced offer tranche would indicate a participant's strong unwillingness and/or expected cost to be dispatched below its NCP level (unless market prices would fall to such levels).
  - A very high price offer tranche would indicate unwillingness to be dispatched above NCP level (unless market prices would rise to such levels).
  - An offer tranche priced cost reflectively would be dispatched if the market price was higher (in effect contributing to balancing) or not dispatched if the market price was lower (in effect buying from balancing).

- Market pre-dispatch forecasts would advise:
  - All participants of the expected market price (reflecting the amount of generation offers that that would need to be dispatched to meet demand less unscheduled generation).

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[11] Otherwise participants' abilities to manage contractual positions, represent higher cost fuel tranches and, through offer-based dispatch, respond to market conditions would be constrained, risking inefficient market outcomes.

- The relevant participants (only) of their expected generation levels.

- As for net dispatch, System Management would forecast demand and intermittent supply and it would be mandatory for offers to be submitted for all of their scheduled generation capacity (refer earlier discussion about self commitment and capacity obligations which also applies to gross dispatch).

- Whereas for net dispatch participants would dispatch their facilities in accordance with resource plans, unless dispatched off plan by System Management, under gross dispatch System Management would dispatch all scheduled generation capacity in accordance with the dispatch merit order.

9.4 Assumed time lines for gross dispatch arrangements

Similar issues exist as for net dispatch, with self commitment / gross dispatch requiring significant flexibility for participants to make commitment decisions, adjust offers etc. i.e. frequent pre-dispatch forecasts and rolling gate closure. However, as assumed for net dispatch, assuming voluntary participation other than for initial submissions, participants could trade-off the benefits and costs of actively participating in gross dispatch.

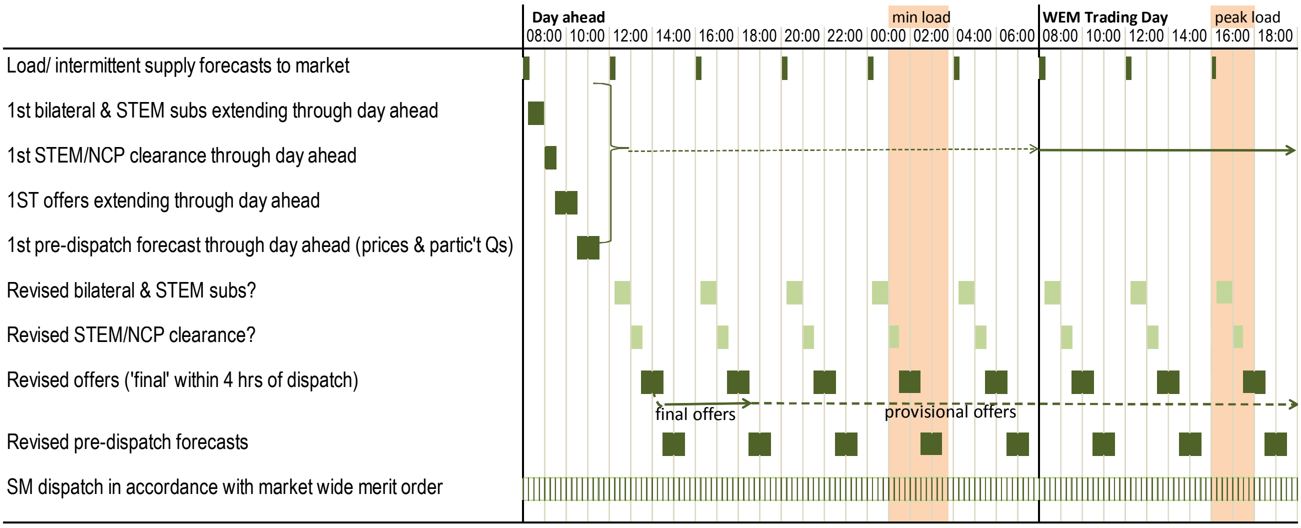
For evaluation purposes it is assumed that a gross dispatch market cycle would:

- Have the same pre-dispatch horizon as assumed for net dispatch (i.e. to the end of the current dispatch day for submissions before 8am; otherwise to the end of the following dispatch day)

- Operate at a rolling frequency of 2 to 4 hours with a corresponding gate closure period. i.e. offers, including commitment decisions, would become final within 2 to 4 hours of dispatch.

For example, gross dispatch market timelines could be along the following lines assuming a rolling gate closure of 4 hours.

Figure 10: Possible Option C (Gross dispatch) timelines (assuming 4 hour rolling gate closure)



The revised bilateral and STEM submission slots in the diagram have been shown as faded to indicate the possibility that they may not be needed under gross dispatch (alternatively, the possibility of a low cost on-line/ open trading platform could be considered). This could provide an opportunity to adopt a shorter gate closure. (As discussed later, there would be merit in considering a traditional security constrained full economic dispatch engine under gross dispatch. If so, this could also shorten pre-dispatch schedule turnaround times and help to shorten gate closure times).

9.5 Nature of contractual commitments at gate closure

Similar issues to net dispatch also apply to gross dispatch although the rationale for participants planning to be out balance at the time of dispatch is possibly strengthened under a full economic dispatch option.

9.6 Self commitment issues

The issues here would be similar to those discussed previously in relation to net dispatch, although flexibility around gate closure and the frequency of market forecasts to participants may become more important considerations. i.e. with units having to be committed on the basis of gross offers rather than through resource plans and incs/ decs (although in principle similar outcomes should be achievable under net or gross dispatch options).

At least in principle System Management could be assigned responsibility for unit commitment of all generators in accordance with complex bid and standing data. Experience elsewhere suggests this is an unwieldy approach as it shifts the decision to the market and involves assessments and is impacted by forecasts for demand, output of intermittent generation and performance of other generators. While it is possible to reduce uncertainty and forecasting errors there is unavoidable residual risk that the input assumptions were incorrect and the market inevitably then must fund the consequences of any decisions that in hindsight are shown to be uneconomic. At present System Management and Verve Energy make these decisions under the rules and Verve Energy carries the commercial risk and, in principle, is compensated as the balancer – albeit with concerns that the level compensation to date has not been adequate. Accordingly full central commitment is problematic, although early versions of the Victorian state market (pre-NEM) and the UK market included central commitment. These markets have now moved away from full central commitment although the current UK market includes features such as warming contracts in order to enable slower starting generators to be in a position to submit balancing offers at gate closure (which is one hour) and be available for dispatch if needed.

Accordingly a working assumption is that:

- All generating units not on approved outages would be presented to the market at start of the day ahead cycle of market operation.
- Pre dispatch runs would account for start up times and ramp rates but take no account of start up costs.
- A participant with a unit that sees dispatch volumes greater than a threshold by a specified time (yet to be determined) would be expected to take whatever action is required to commit and present for real time dispatch. For units currently in service or those with relatively short start up times, no action would be required other than to remain in service or to leave the relevant units ready to start;
- Units that do not see forecast dispatch volumes above the threshold would be able to seek System Management's authorisation to not commit but would be deemed to have met their obligation under the capacity rules to present for dispatch.
- Note if a unit had not been committed and circumstances changed, for example another unit suffered a breakdown, the participant would still be exposed to balancing prices for the replacement energy but would not be penalised for failing to deliver capacity.

For the foreseeable future the number of units affected by such an arrangement will be small, and effectively limited to coal units and some CCGTs. However, this approach would ensure the commercial accountability for commitment decisions sit with the participant within the framework of capacity obligation but oversight of the level of capacity stays with System Management.

9.7 Treatment of changes beyond gate closure

The issues here would be similar to those under net dispatch.

9.8 Dispatch engine capabilities

As for net dispatch, security constrained pre-dispatch scheduling capabilities would be required. However, this could easily be extended to full economic dispatch using a traditional security constrained full economic dispatch engine. While that could be relatively costly, and take some time to procure and implement, this technology is a proven and efficient means of dispatching capacity in gross dispatch markets. Alternatively, for dispatch purposes market wide merit orders could be formed by sorting all offers in price order along.

As discussed below, a traditional security constrained full economic dispatch engine would have advantages in relation to energy price formation, ensuring that dispatch and pricing more readily account for constraints, and potentially co-optimising ancillary services (enabling participants to offer the same capacity for energy and reserves/ frequency keeping selecting the preferred option taking account of interdependencies between them).

9.9 The formation of balancing prices

Depending on the nature of dispatch engine adopted, a similar merit order vs demand based approach could be followed as assumed for net dispatch. i.e. a single merit order for all capacity based on gross offers rather than separate inc and dec offers relative to NCPs/resource plans. Alternatively, with a more complex full economic dispatch engine, prices could be calculated more explicitly, taking account of ramp rates, interactions between capacity available for ancillary services and/or energy dispatch etc. Although constrained on/ off situations (dispatch and pricing) for security purposes would generally be handled directly by such a dispatch engine, the treatment of constrained on/off within half hour would still need to be considered.

If dispatched by System Management, participants would receive () (or otherwise pay) the system price for any differences from NCP.

9.10 Ancillary service arrangements

As noted above, a full economic dispatch engine, if adopted, would enable offers for ancillary service pricing and dispatch to be co-optimised with energy offers for dispatch and pricing purposes. If so, gross dispatch arrangements might facilitate more opportunity for all participants to participate in the market for ancillary service provision (as for balancing). In relation to cost recovery, it is assumed that costs would be allocated on a causer pays basis to the extent cause can be attributed.

9.11 What if IPPs chose not to actively participate?

Similar issues apply as for net dispatch.

10 INITIAL EVALUATION

This section considers the nature of benefits and costs that could arise under the options discussed in the previous section and then makes a qualitative/ high level comparison between the options. The discussion is necessarily qualitative at this stage and intended to be comparative rather than absolute.

10.1 Nature of Option 1A benefits and costs

Potential benefits of Option A1 could include:

- More efficient use of resources through:
  - Flexibility for participants to manage gas positions, including potential to facilitate some short gas trading opportunities among participants and/ or potentially enable participants to take a less conservative approach to their electricity nominations and STEM.
  - Less uncertainty for participants in considering STEM opportunities and, including System Management in relation to Verve Energy facilities, making generation scheduling and unit commitment decisions (due to shorter day-ahead forecasting horizons and more coordinated gas and electricity nominations).
  - Improved incentives and ability to respond to system requirements, including entering BSCs, assuming participants are appropriately compensated, and the costs of balancing and ancillary services appropriately allocated.
- Possibly more efficient investment as a result of improved pricing signals with respect to balancing requirements/ plant mix and the system costs being appropriately factored into investment decisions.

Costs would arise in relation to:

- Developing and implementing changes to the Rules and, if required, changing market and/ or participant systems to support later submissions.
- Addressing any potential contractual impediments to, and/or facilitating the procurement of BSCs by Verve Energy and/or System Management.

- Any additional resourcing requirements for participants, IMO or System Management.

10.2 Nature of Option A2 benefits and costs

In addition to potential benefits under Option A1:

- Resources might be used more efficiently as a result of extra flexibility/ risk management opportunities (including the availability of pre-dispatch forecasts and ability to re-nominate).

- Incremental benefits in relation to new investment might occur to the extent investors gained more confidence about participating in the WEM.

Costs would arise in relation to:

- Developing and implementing changes to the Rules and changing market systems, and participant systems to support multiple/ later submissions and provide pre-dispatch forecasts (should they elect to actively participate). Rule changes to address pricing/ incentives issues are likely to be similar to those under Option A1. Rule changes to support re-nominations would be more significant than for delaying submissions timelines under Option A1.

- Any additional resourcing requirements for IMO, System Management and participants (except for those electing not to participate beyond initial submissions). These are likely to be more significant than for Option A1.

10.3 Nature of Option B (net dispatch) benefits and costs

Potential benefits are likely to arise from:

- More efficient use of resources through:

    - Increased flexibility/ opportunities for participants to manage their contractual positions, including gas, and to respond to market conditions (especially for IPPs) extending into the day of dispatch.

    - The ability for IPPs to elect to participate directly in balancing.

- More efficient investment as a result of:

    - Stronger signals about the value of flexibility in the WEM and the cost impacts of different technologies on the system.

    - Increased investor/ market confidence as a result of greater separation between System Management and Verve Energy roles.

    - Increased transparency with respect to Verve Energy's participation in the market.

    - A more enduring and robust design reducing uncertainty about the future evolution of the market.

Costs would arise in relation to:

- Developing and implementing changes to the Rules.

- Upgrading or replacing IMO, System Management and, for those actively participating, participants systems.

- Additional resourcing requirements for participants, IMO and System Management.

These costs are difficult to quantify at this stage but would be substantially more than under the hybrid options.

10.4 Nature of Option C (gross dispatch) benefits and costs

Potential benefits are likely to arise from:

- More efficient use of resources through:

    - Increased flexibility/ opportunities for participants to manage their contractual positions, including gas, and to respond to market conditions (especially for IPPs) extending into the day of dispatch.

    - The opportunity for IPPs to elect to participate directly in balancing where competitive.

- More efficient investment as a result of:

    - Stronger signals about the value of flexibility in the WEM and the cost impacts of different technologies on the system.

    - Increased investor/ market confidence as a result of greater separation between System Management and Verve Energy roles.

    - Increased transparency with respect to Verve Energy's participation in the market.

  - A more enduring and robust design reducing uncertainty about the future evolution of the market.

Costs would arise in relation to:

- Developing and implementing changes to the Rules.
- Upgrading or replacing IMO, System Management and, for those actively participating, participants' systems.
- Additional resourcing requirements for participants, IMO and System Management.

These costs are difficult to quantify at this stage assuming full security constrained economic dispatch, are likely to be somewhat higher than for the net dispatch option. Costs would be substantially more than under any of the hybrid options. It is likely that proven technology solutions and products used in other jurisdictions, although more expensive to implement, would reduce implementation risks relative to Option B.

10.5 Assessments

The following is an overall summary of evaluation against the check lists for each of the options, building on the above discussion. More detailed analysis behind the checklist summary is included in Appendix 1. It is important to remember that:

- The aim is to provide relative insights to guide consideration of the options and their respective implications, and necessarily involves qualitative judgements.
- Each row in the tables indicates relativity between the options for the particular aspect being considered (as indicated by the number and direction of arrows).
- While it is illustrative to compare rows in the tables, no specific weighting has been assigned to each.

Table 7: Check list summaries

Perspective	Check list	Option A1	Option A2	Option B	Option C
Market wide	Economic efficiency	⇧	⇧ ⇧	⇧ ⇧ ⇧	⇧ ⇧ ⇧
	Transaction costs	⇩	⇩ ⇩	⇩ ⇩ ⇩	⇩ ⇩ ⇩
	Implementation costs	⇩	⇩	⇩ ⇩ ⇩	⇩ ⇩ ⇩
	Competition	⇧	⇧ ⇧	⇧ ⇧	⇧ ⇧
	Transparency	⇨	⇧	⇧ ⇧ ⇧	⇧ ⇧ ⇧
	Reliability	⇨	⇨	⇨	⇨
	Commercial profitability, profit maximisation	⇧	⇧ ⇧	⇧ ⇧ ⇧	⇧ ⇧ ⇧
System Management	Information	⇨	⇨	⇧	⇧
	Economic dispatch 'service'	⇨	⇧	⇧ ⇧	⇧ ⇧
	Security Assessment	⇨	⇨	⇨	⇨
	Authority for Security Intervention	⇨	⇨	⇨	⇨
Participant	Commercial Risk	⇨	⇨	⇧	⇧
	Fuel Interactions	⇧	⇧	⇧ ⇧	⇧ ⇧
	Physical Dispatch	⇨	⇧	⇧ ⇧ ⇧	⇧ ⇧

The following is a qualitative assessment of the options against the Market Objectives, reflecting the above discussion and the detailed check list analysis.

Figure 11: High level assessment of options against Market Objectives

Promotion of Objective	A1	A2	B	C
Economic, safe, reliable supply	⇧	⇧ ⇧ ?	⇧ ⇧ ⇧	⇧ ⇧ ⇧
Competition/ efficient new entry	⇧	⇧ ?	⇧ ⇧ ⇧	⇧ ⇧ ⇧
Non discriminatory	⇧ ⇧	⇧ ⇧	⇧ ⇧ ⇧	⇧ ⇧ ⇧
Minimise long term cost to consumers	⇧	⇧	⇧ ⇧	⇧ ⇧
Demand management	⇨	⇨	⇧	⇧

The checklist analysis and overall assessment highlight that:

- Of the options to enhance the current hybrid design, Option A2 is likely to yield greater benefits.
- Implementation costs are likely to be significantly higher for net (B) or gross dispatch (C) options but with significantly greater net benefits than the hybrid (A) options.
- It is difficult to distinguish net or gross dispatch options at this stage.

This reinforces the discussion in section 5 regarding the fundamental and strategic differences between the A options and the B/C options. In the context of this review, the A Options could address more immediate concerns although may only forestall inevitable questions about how sustainable the hybrid design is. Important decisions are therefore:

- Should the market opt now for a more robust longer term solution, along the lines of Option B or C;
- If so, which one?
- Or should the market persist with the hybrid design by advancing options along the lines of A1 or A2?
- If so, how durable would these options be?

Answers to these questions will guide the next stage of the project.

The Vesting Contract review is likely to affect the outcomes achieved under Options A1 and A2. There may be benefit in the MAC receiving a briefing by the Oates Review Vesting Contract Review team.

Appendix One – Check List Analysis

A1. Overall summary of Options by sub element

	Issue		A1	A2	B	C
Participant Perspective	Commercial Risk	Financial/ Funding	↑	↑	↑ ↑ ↑	↑ ↑ ↑
		Bilateral	↑	↑ ↑	↑ ↑ ↑	↑ ↑
		- Counterparty	⇨	⇨	⇨	⇨
		Regulatory stability/ rule changes	⇨	↑ ?	↑ ↑ ?	↑ ↑ ?
		Statutory	⇨	⇨	⇨	⇨
		Government / Sovereign	↑	↑	↑ ↑	↑ ↑
		WEM Price Risk	↑	↑ ↑ ?	↑ ↑ ↑	↑ ↑ ↑
		Plant Risk	↑	↑ ↑	↑ ↑ ↑	↑ ↑ ↑ ?
		Transaction Cost - direct	↓	↓	↓ ↓	↓ ↓
		Transaction Cost - indirect (e.g. fees)	↓	↓	↓ ↓ ↓	↓ ↓ ↓
	Fuel Interactions	Information	↑	↑ ↑	↑ ↑ ↑	↑ ↑ ↑
		Interaction Gas Nomination Timeframe	↑ ↑	↑ ↑	↑ ↑ ↑	↑ ↑ ↑
		Gas Contracting	⇨	⇨	⇨ ?	⇨ ?
		Short Term Gas Trading	↑	↑	↑ ↑ ?	↑ ↑ ?
		Liquid fuel scheduling (relatively rare risk but can be costly)	↑	↑ ↑ ?	↑ ↑ ↑ ?	↑ ↑ ↑ ?
		Coal plant scheduling	↑	↑	↑ ↑	↑ ↑
		Accommodating intermittent supply	↑	↑	↑ ↑	↑ ↑
	Physical Dispatch	Certainty in operation	⇨	↑	↑ ↑ ↑	↑ ↑
		Robustness (integrity/ feasibility) Verve	↑	↑ ↑	↑ ↑ ↑	↑ ↑
		Robustness (integrity/ feasibility) IPPs	⇨	↑	↑ ↑ ↑	↑ ↑
		Impact of Intermittent on scheduled resource (especially balancer)	↑	↑ ↑	↑ ↑ ↑	↑ ↑ ↑
	Commercial profitability, profit maximisation		↑	↑ ↑ ?	↑ ↑ ↑ ?	↑ ↑ ↑ ?
System Managem't	Information	Information for Commitment	↑	↑ ↑	↑ ↑ ↑	↑ ↑ ↑
		Technical information for Dispatch (on the day)	⇨	⇨	⇨	⇨
		AS	⇨	⇨	⇨	⇨
	Economic dispatch 'service'	Commitment	↑	↑ ↑	↑ ↑	↑ ↑
		Dispatch	↑	↑ ↑	↑ ↑ ↑	↑ ↑ ↑
		AS	⇨	⇨	↑	↑ ↑
	Security Assessment		→	→	→	→
	Authority for Security Intervention		→	→	→	→
Market Wide	Economic efficiency	Better use of resources (operational efficiency)	↑	↑ ↑	↑ ↑ ↑	↑ ↑ ↑
		Investment (dynamic efficiency)	↑	↑ ↑	↑ ↑ ↑	↑ ↑ ↑
	Transaction costs	IMO	↓	↓	↓ ↓ ↓ ?	↓ ↓ ?
		SM	↓	↓ ↓	↓ ↓	↓ ↓
		Verve	⇨	↓	↓ ↓ ↓	↓ ↓ ↓
		IPP	↓	↓	↓ ↓ ↓ ?	↓ ↓ ↓
	Implementation costs	New market systems	⇨	⇨	↓ ↓ ↓	↓ ↓ ↓
		IMO specific	↓	↓ ↓	↓ ↓ ↓	↓ ↓ ↓
		SM specific	↓ ?	↓ ↓ ?	↓ ↓ ?	↓ ↓ ?
		Verve	⇨ ?	⇨ ?	↓ ↓ ?	↓ ↓ ?
		IPP	⇨	↓	↓ ↓	↓ ↓
	Competition	Short Term	↑	↑ ↑	↑ ↑	↑ ↑
		Long Term	↑	↑ ↑	↑ ↑	↑ ↑
	Transparency		⇨	↑	↑ ↑ ↑	↑ ↑ ↑
	Reliability		⇨ ?	⇨ ?	⇨ ?	⇨ ?

A2. Details of market wide perspectives

	Option A1: Enhanced hybrid	
Criterion	**Assessment**	**Rating/ comment**
Economic Efficiency		
Better use of resources (operational efficiency)	*Enhanced operating efficiency (e.g. fuel, O&M, maintenance)*	↑
Investment (dynamic efficiency)	*Enhanced signalling of plant mix requirements (e.g. reward flexibility/ account for system impacts)*	↑ *subject to redesign of pricing and cost allocations*
Transaction costs		
IMO	*Neutral?*	↓ *Assuming pricing/ settlements simplified*
SM	*Initial Verve dispatch plan later in day*	↓
Verve	*No significant change as VE issues MO/guidelines to SM infrequently and SM commits/ dispatches plant*	→
IPP	*Processes later in the day (e.g. evening resource plans)*	↓
Implementation costs		
New market systems	*n/a*	
IMO specific	*Rule changes (pricing esp)*	↓
SM specific	*Adjust systems to match revised timing.*	↓ ?
Verve	*No change?*	→ ? *Potential operating cost reductions if settlement simplified*
IPP	*Neutral?*	→ *Potential operating cost reductions if settlement simplified*
Competition		
Short Term	*Later gate closure and opportunities to reduce balancing requirements/ incentives for BSCs*	↑
Long Term	*More level playing field if compensation and cost allocation appropriate*	↑
Transparency	*No change*	→ *Subject to redesign of pricing and cost allocations*
Reliability	*No change?*	→ ? *some short term operational gains*

	Option A2: Enhanced hybrid+renoms	
Criterion	**Assessment**	**Rating/ comment**
Economic Efficiency		
Better use of resources (operational efficiency)	*Enhanced operating efficiency (e.g. fuel, O&M, maintenance); further enhanced by ability to respond to pre-dispatch/MCAP forecasts*	↑↑
Investment (dynamic efficiency)	*Stronger signalling of plant mix requirements (e.g. reward flexibility/ account for system impacts)*	↑↑ *subject to redesign of pricing and cost allocations*
Transaction costs		
IMO	*Multiple processes required, + higher performance standard, and running processes later in the day*	↓ *Assuming pricing/ settlements simplified*
SM	*Similar to A1*	↓↓
Verve	*VE multiple submissions*	↓
IPP	*Will vary by participant. Could submit once as now or take advantage of multi nominations + longer day*	↓
Implementation costs		
New market systems	*n/a*	
IMO specific	*Adjust systems to match revised timing/ multiple renominations; tighter spec/ performance systems; amend Rules and adjust price determination and settlement systems.*	↓↓
SM specific	*Adjust systems to match revised timing.*	↓↓ ?
Verve	*No change?*	→ ? *Potential operating cost reductions if settlement simplified*
IPP	*Adjust systems to match revised timing + multi nominations; fees (IMO costs) same or perhaps slightly higher*	↓ *Potential operating cost reductions if settlement simplified*
Competition		
Short Term	*Later gate closure and opportunities to reduce balancing requirements/ incentives for BSCs; enahnced by pre-dispatch forecasts, participant flexibility*	↑↑ *Subject to redesign of pricing and cost allocations*
Long Term	*More level playing field if compensation and cost allocation appropriate + as above*	↑↑ *Subject to redesign of pricing and cost allocations*
Transparency	*Market forecasts/ multipass process provide better insights to participants*	↑ *Subject to redesign of pricing and cost allocations*
Reliability	*No change?*	→ ? *Some short term operational performance?)*

	Option B: Net dispatch	
Criterion	**Assessment**	**Rating/ comment**
Economic Efficiency		
Better use of resources (operational efficiency)	*More difficult to achieve than under C (depends on participation) Better dispatch/price alignment. Enhanced operating efficiency (e.g. fuel, O&M, maintenance); further enhanced by ability to respond to pre-dispatch forecasts*	⇧⇧⇧ *Enhanced by rolling forecasts/ gate closure*
Investment (dynamic efficiency)	*Shorter gate closure/ better quality info/ sharper pricing*	⇧⇧⇧
Transaction costs		
IMO	*Multiple processes required, + higher performance standard, and running processes later in the day*	⇩⇩⇩ ? *Depends on degree of automation vs 24/7? Maybe offset by savings from simpler pricing/ settlements*
SM	*No VE dispatch plan/ commitment decisions; predispatch forecast to prepare*	⇩⇩
Verve	*Pick up SM roles, resourcing?*	⇩⇩⇩
IPP	*Rolling/ multiple process*	⇩⇩⇩ ? *Depends on level of participation*
Implementation costs		
New market systems	*Pricing/ dispatch/ predispatch systems*	⇩⇩⇩ *Depending on dispatch models*
IMO specific	*Rule changes / Settlement systems*	⇩⇩⇩
SM specific	*Similar to A2*	⇩⇩ ?
Verve	*Establish capabilities to prepare resource plans*	⇩⇩ ? *Leverage off some SM systems?*
IPP	*Capabilities to participate in rolling regime (if they chose)*	⇩⇩ *Potential operating cost reductions if settlement simplified*
Competition		
Short Term	*Later gate closure and opportunities to reduce balancing requirements/ incentives for BSCs; enahnced by pre-dispatch forecasts, participant flexibility*	⇧⇧ *Subject to redesign of pricing and cost allocations*
Long Term	*More level playing field if compensation and cost allocation appropriate + as above*	⇧⇧ *Subject to redesign of pricing and cost allocations*
Transparency	*Externalises VE res plan/ market wide-merit orderetc*	⇧⇧⇧ *Simpler pricing/ forecasts etc*
Reliability	*No change?*	⇨ ? *Some short term operational performance?)*

	Option C: Gross dispatch		
Criterion	**Assessment**	**Rating/ comment**	
Economic Efficiency			
Better use of resources (operational efficiency)	*Better dispatch/price alignment. Enhanced operating efficiency (e.g. fuel, O&M, maintenance); further enhanced by ability to respond to pre-dispatch/MCAP forecasts*	↑↑↑	*Enhanced by rolling forecasts/ gate closure*
Investment (dynamic efficiency)	*Shorter gate closure/ better quality info/ sharper pricing*	↑↑↑	
Transaction costs			
IMO	*Multiple processes required, + higher performance standard, and running processes later in the day*	↓↓ ?	*Depends on degree of automation vs 24/7? Maybe offset by savings from simpler pricing/ settlements*
SM	*No VE dispatch plan/ commitment decisions. Predispatch forecasts to prepare.*	↓↓	*Depends on degree of systems automation.*
Verve	*Pick up SM roles, resourcing?*	↓↓↓	
IPP	*Rolling/ multiple process*	↓↓↓	*Depends on participation*
Implementation costs			
New market systems	*Pricing/ dispatch/ predispatch systems*	↓↓↓	*Depending on dispatch models*
IMO specific	*Rule changes / Settlement systems*	↓↓↓	
SM specific	*Similar to A2*	↓↓ ?	
Verve	*Establish capabilities to prepare resource plans*	↓↓ ?	
IPP	*Capabilities to participate in rolling regime (if they chose)*	↓↓	*Potential operating cost reductions if settlement simplified*
Competition			
Short Term	*Later gate closure and opportunities to reduce balancing requirements/ incentives for BSCs; enahnced by pre-dispatch forecasts, participant flexibility*	↑↑	*Subject to redesign of pricing and cost allocations*
Long Term	*More level playing field if compensation and cost allocation appropriate + as above*	↑↑	*Subject to redesign of pricing and cost allocations*
Transparency	*Externalises VE res plan/ market wide-merit orderetc*	↑↑↑	*Simpler pricing/ forecasts etc. AS?*
Reliability	*No change?*	⇨ ?	*Some short term operational performance?)*

A3. Details of System Management perspectives

	Option A1: Enhanced hybrid	
Criterion	**Assessment**	**Rating/ comment**
Information		
Information for Commitment	*Less uncertainty: later submissions/ resource plans and demand/ intermittent supply forecasts*	⇧ *Presume resource plan feasibility*
Technical information for Dispatch (on the day)	*No change*	⇨
AS	*No change*	⇨
Economic Dispatch - 'service'		
Commitment	*VE service - Less uncertainty: later submissions/ resource plans and demand/ intermittent supply forecasts*	⇧
Dispatch	*VE - service - Due to reduced scheduling uncertainty (e.g. gas vs distillate)*	⇧
AS	*Potential with shorter*	⇨
Security Assessment	*No change*	⇨
Authority for Security Intervention	*No change*	⇨

	Option A2: Enhanced hybrid+renoms	
Criterion	**Assessment**	**Rating/ comment**
Information		
Information for Commitment	*Less uncertainty: later submissions/ resource plans and demand/ intermittent supply forecasts; opportunities for participants to respond to pre-dispatch forecasts*	⇧⇧ *Presume resource plan feasibility*
Technical information for Dispatch (on the day)	*No change*	⇨
AS	*No change*	⇨
Economic Dispatch - 'service'		
Commitment	*VE serice - Less uncertainty: later submissions/ resource plans and demand/ intermittent supply forecasts; opportunities for participants to respond to pre-dispatch forecasts*	⇧⇧
Dispatch	*Due to reduced scheduling uncertainty (e.g. gas vs distillate); enhanced futher by pre-dispatch forecasts and ability to renominate*	⇧⇧
AS	*No change*	⇨
Security Assessment	*No change*	⇨
Authority for Security Intervention	*No change*	⇨

	Option B: Net dispatch		
Criterion	**Assessment**	**Rating/ comment**	
Information			
Information for Commitment	*More frequent and better quality pre-dispatch information; less uncertainty*	⇧⇧⇧	*Presume resource plan feasibility*
Technical information for Dispatch (on the day)	*No change (repackaged)*	⇨	*Need to manage transition*
AS	*No change*	⇨	
Economic Dispatch - 'service'			
Commitment	*Potential advisory info service*	⇧⇧	*e.g hi/lo demand/wind and commitment scenarios*
Dispatch	*Simplified and assumes resource plans/ incs and decs (basis for economic dispatch) from all*	⇧⇧⇧	
AS	*Probable improvement (given shorter gate closure) need to consider fully*	⇧	*Ability to alter AS commitment witihn day*
Security Assessment	*No change*	⇨	
Authority for Security Intervention	*No change*	⇨	

	Option C: Gross dispatch		
Criterion	**Assessment**	**Rating/ comment**	
Information			
Information for Commitment	*More frequent and better quality pre-dispatch information; less uncertainty*	⇧⇧⇧	
Technical information for Dispatch (on the day)	*No change (repackaged)*	⇨	*Need to manage transition*
AS	*No change (repackaged)*	⇨	*Need to manage transition*
Economic Dispatch - 'service'			
Commitment	*Potential advisory info service*	⇧⇧	*e.g hi/lo demand/wind and commitment scenarios*
Dispatch	*Simplified and assumes roffers (basis for economic dispatch) from all*	⇧⇧⇧	
AS	*Potential co-optimisation of AS*	⇧⇧	
Security Assessment	*No change*	⇨	
Authority for Security Intervention	*No change*	⇨	

A4. Details of participant perspectives

	Option A1: Enhanced hybrid	
Criterion	**Assessment**	**Rating/ comment**
Commercial Risk		
Financial/ Funding	*More flexibility to manage commercial risks = less debt/ funding risk*	↑
Bilateral	*Later nominations; more flexibility to manage and/or cover*	↑
- Counterparty	*No change*	→
Regulatory stability/ rule changes	*No material change*	→
Statutory	*No change*	→
Government / Sovereign	*More certainty/ stability, at least in near term*	↑
WEM Price Risk	*Shorter horizons/ less uncertainty*	↑ *Subject to detailed design relative to Opt B and C*
Plant Risk	*Less uncertainty, starts/ stops, cycling*	↑
Transaction Cost - direct	*Additional resources (later in day); allocation of system costs?*	↓ *Offset by any simplificaions*
Transaction Cost - indirect (e.g. fees)	*IMO/ SM system changes*	↓
Fuel Interactions		
Information	*Imbalance position known when making WEM submissions*	↑
Interaction Gas Nomination Timeframe	*Less conservative/ more certain WEM nominations*	↑↑
Gas Contracting	*No change*	→
Short Term Gas Trading	*Potential opportunities in window between gas and electricity nominations*	↑
Liquid fuel scheduling (relatively rare risk but can be costly)	*More certainty regarding gas positions/ capabilities (esp later in day)*	↑
Coal plant scheduling	*Some potential gains due to less uncertainty*	↑ *Assuming incentives/ BSC issues resolved*
Accommodating intermittent supply	*Shorter horizons/ less uncertainty/ balancing risks*	↑
Physical Dispatch		
Certainty in operation	*No change wrt real time dispatch*	→
Robustness (integrity/ feasibility) Verve	*Less dispatch plan uncertainty*	↑
Robustness (integrity/ feasibility) IPPs	*No change (self commitment/ dispatch)*	→
Impact of Intermittent on scheduled resource (especially balancer)	*Shorter forecast horizons*	↑
Commercial profitability, profit maximisation	*Appropriate compensation; BSC opportunities; manage bilateral/ gas positions*	↑

	Option A2: Enhanced hybrid+renoms	
Criterion	**Assessment**	**Rating/ comment**
Commercial Risk		
Financial/ Funding	*More flexibility to manage commercial risks = less debt/ funding risk. Good dynamic efficiency signals.*	↑
Bilateral	*Renominations provide more flexibility to manage and/or cover risk than for A1*	↑↑
- Counterparty	*No change*	→
Regulatory stability/ rule changes		↑ ? *Dependent on simplification in practice*
Statutory	*No change*	→
Government / Sovereign	*More certainty/ stability, at least in near term*	↑
WEM Price Risk	*Shorter horizons/ less uncertainty combined with market price forecasts/ ability to respond*	↑↑ ? *Subject to detailed design relative to Opt B and C*
Plant Risk	*Less uncertainty, starts/ stops, cycling*	↑↑
Transaction Cost - direct	*Additional resources (later in day); allocation of system costs?*	↓ *Offset by any simplificaions*
Transaction Cost - indirect (e.g. fees)	*IMO/ SM system changes.*	↓ *Increased Fees probably more for A2, A2 Opportunity Cost*
Fuel Interactions		
Information	*Market forecasts, including likely balancing price enable better assessment of electricity and gas positions*	↑↑ *MCAP infor aubject to A2 into day(0)*
Interaction Gas Nomination Timeframe	*Less conservative/ more certain WEM nominations*	↑↑
Gas Contracting	*No change*	→
Short Term Gas Trading	*Potential opportunities in window between gas and final electricity nominations*	↑ *Subject to gas trading arrangement*
Liquid fuel scheduling (relatively rare risk but can be costly)	*More certainty regarding gas positions/ capabilities (esp later in day), enhanced futher by pre-dispatch forecasts and ability to renominate?*	↑↑ ?
Coal plant scheduling	*Some potential gains due to less uncertainty*	↑ *Assuming incentives/ BSC issues resolved*
Accommodating intermittent supply	*Shorter horizons/ less uncertainty/ balancing risks*	↑
Physical Dispatch		
Certainty in operation	*Better due to reduced balancing requirement*	↑
Robustness (integrity/ feasibility) Verve	*Less dispatch plan uncertainty, potential for reduced balancing requirements*	↑↑ *Subject to resolving gentailer submissions, more predictable pre dispatch price info*
Robustness (integrity/ feasibility) IPPs	*Ability to adjust nominations taking account of gas positions and/ or market pre-dispatch forecasts vis a vis electricity positions*	↑ *Subject to resolving gentailer submissions predictable pre dispatch price info*
Impact of Intermittent on scheduled resource (especially balancer)	*Subject to SM forecast data and ability to respond to market forecasts*	↑↑
Commercial profitability, profit maximisation	*Appropriate compensation; BSC opportunities; manage bilateral/ gas positions*	↑↑ ? *Subject to assessment re cost reflective cost allocations may mean + or - for different participants.*

Criterion	Assessment	Rating/ comment	
Commercial Risk			
Financial/ Funding	*IPPs better able to manage contract risk. VE relative exposure? Good dynamic efficiency/ certainty about market design etc*	↑↑↑	*Assuming balancing is cost neutral activity (pricing etc)*
Bilateral	*Renominations provide more flexibility to manage and/or cover risk than for A1*	↑↑↑	*Potentially more than A2?*
- Counterparty	*No change*	→	
Regulatory stability/ rule changes	*Major change = more stable/settled regime; less doubt about future direction*	↑↑ ?	*Implies significant simplification*
Statutory	*No change*	→	
Government / Sovereign	*Longer term solution = more certainty/ stability; more resilient to policy initiatives*	↑↑	
WEM Price Risk	*Shorter horizons/ less uncertainty combined with market price forecasts/ ability to respond*	↑↑↑	*Pluses and minuses depending on detailed design*
Plant Risk	*Less uncertainty, starts/ stops, cycling*	↑↑↑	
Transaction Cost - direct	*VE will need to carry out some SM functions. Net increase in participant efforts (if chose to actively participate)*	↓↓	*Simpler pricing/ settlement will partially offset*
Transaction Cost - indirect (e.g. fees)	*Recovery of IMO and SM set up costs. Ongoing IMO amd SM effort for multiple/ rolling gate/ forecasts*	↓↓↓	*Simpler pricing/ settlement will partially offset*
Fuel Interactions			
Information	*Rolling contract adjustments, pre-dispatch Q & P forecasts, should enable better assessment of electricity and gas positions*	↑↑↑	*Assuming short gate closure*
Interaction Gas Nomination Timeframe	*Less conservative/ more certain WEM nominations*	↑↑↑	*Rolling subs/ inc&decs to within trading day*
Gas Contracting	*Potentially improved negotiating position due to increased flexibility*	→ ?	
Short Term Gas Trading	*Potential opportunities extend to dispatch day*	↑↑ ?	*Subject to gas trading arrangement*
Liquid fuel scheduling (relatively rare risk but can be costly)	*More certainty regarding resource plans, gas positions/ capabilities (esp later in day), enhanced futher by pre-dispatch forecasts and ability to renominate?*	↑↑↑ ?	*Assuming short gate closure*
Coal plant scheduling	*Less uncertainty/ more flexibility/ stronger pricing incentives*	↑↑	
Accommodating intermittent supply	*Shorter horizons/ less uncertainty/ balancing risks. More scheduling flexibility*	↑↑	*Assuming short gate closure*
Physical Dispatch			
Certainty in operation	*Better due to reduced balancing requirements/ better balancing forecasts*	↑↑↑	
Robustness (integrity/ feasibility) Verve	*Potential for reduced balancing requirements/ less uncertainty/ rolling adjustment (some AS/ SM risks as to why things happen. E.g. constr on-off (But IPP not VE*	↑↑↑	*Subject to resolving gentailer submissions predictable pre dispatch price info*
Robustness (integrity/ feasibility) IPPs	*Potential for reduced balancing requirements/ less uncertainty/ rolling adjustment*	↑↑↑	*Subject to resolving gentailer submissions predictable pre dispatch price info*
Impact of Intermittent on scheduled resource (especially balancer)	*Forecast confidence levels and market ability to respond greater with rolling window*	↑↑↑	
Commercial profitability, profit maximisation	*Appropriate compensation for balancing services and more flexibility to manage bilateral/ gas positions*	↑↑↑ ?	*Subject to assessment re cost reflective cost allocations may mean + or - for different participants.*

Criterion	Assessment	Rating/ comment
Commercial Risk		
Financial/ Funding	*Pluses and minuses for all operationally; Good dynamic efficiency/ stable market etc*	⇧⇧⇧
Bilateral	*Harder to protect inflexible bilateral contract position?*	⇧⇧
- Counterparty	*No change*	⇨
Regulatory stability/ rule changes	*Major change = more stable/settled regime; less doubt about future direction*	⇧⇧ ? *Implies significant simplification*
Statutory	*No change*	⇨
Government / Sovereign	*Longer term solution = more certainty/ stability; more resilient to policy initiatives*	⇧⇧
WEM Price Risk	*Shorter horizons/ less uncertainty combined with market price forecasts/ ability to respond*	⇧⇧⇧ *Pluses and minuses depending on detailed design*
Plant Risk	*Less uncertainty, starts/ stops, cycling*	⇧⇧⇧ ? *Potentially better than B*
Transaction Cost - direct	*VE will need to carry out some SM functions. Net increase in participant efforts (if chose to actively participate)*	⇩⇩ *Simpler pricing/ settlement will partially offset*
Transaction Cost - indirect (e.g. fees)	*Recovery of IMO and SM set up costs. Ongoing IMO amd SM effort for multiple/ rolling gate/ forecasts*	⇩⇩⇩ *Simpler pricing/ settlement will partially offset*
Fuel Interactions		
Information	*Rolling contract adjustments, pre-dispatch Q & P forecasts, should enable better assessment of electricity and gas positions*	⇧⇧⇧ *Assuming short gate closure*
Interaction Gas Nomination Timeframe	*Less conservative/ more certain WEM nominations*	⇧⇧⇧ *Rolling offers to within trading day*
Gas Contracting	*Potentially improved negotiating position due to increased flexibility*	⇨ ?
Short Term Gas Trading	*Potential opportunities extend to dispatch day*	⇧⇧ ? *Subject to gas trading arrangement*
Liquid fuel scheduling (relatively rare risk but can be costly)	*More certainty regarding gas positions/ capabilities (esp later in day), enhanced futher by pre-dispatch forecasts and ability to renominate?*	⇧⇧⇧ ? *Assuming short gate closure*
Coal plant scheduling	*Less uncertainty/ more flexibility/ stronger pricing incentives*	⇧⇧
Accommodating intermittent supply	*Shorter horizons/ less uncertainty/ balancing risks. More scheduling flexibility*	⇧⇧ *Assuming short gate closure*
Physical Dispatch		
Certainty in operation	*Reduce balancing requirements, dependent on offer strategy*	⇧⇧
Robustness (integrity/ feasibility) Verve	*Potential for reduced balancing requirements/ less uncertainty/ rolling adjustment/ pluses and minuses - black box uncertainty? Offset by AS co-opt?*	⇧⇧ *Subject to resolving gentailer submissions predictable pre dispatch price info*
Robustness (integrity/ feasibility) IPPs	*Potential for reduced balancing requirements/ less uncertainty/ rolling adjustment*	⇧⇧ *Subject to resolving gentailer subissions predictable pre dispatch price info*
Impact of Intermittent on scheduled resource (especially balancer)	*Forecast confidence levels and market ability to respond greater with rolling window*	⇧⇧⇧
Commercial profitability, profit maximisation	*Appropriate compensation for balancing services and more flexibility to manage bilateral/ gas positions*	⇧⇧⇧ ? *Subject to assessment re cost reflective cost allocations may mean + or - for different participants.*