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REF: TEL/DV/14/159

25th July 2014

Re: I-SEM Draft Decision

Dear Sirs,

Tynagh Energy Ltd (TEL) welcomes the opportunity to respond to the I-SEM Draft Decision. As a member of the Electricity Association of Ireland, TEL supports the collective response of the association. TEL would like to make comments on the following four items:

1. Scheduling Risk
2. Testing Requirement
3. Participation of Variable Generation in the Day-Ahead Market
4. Capacity Remuneration Mechanism

Scheduling Risk

Volume risk (also known as scheduling risk) occurs in a centralised market as a generator cannot guarantee that it will be appropriately scheduled i.e. the generator cannot be certain that their plant will be scheduled when the marginal price is above the cost of generation of their unit. This presents a risk to generators offering long-term hedging contracts, which in turn raises concerns around the lack of forward market liquidity.

The draft decision has recognised this concern as raised by participants. It is proposed that specific measures to promote liquidity will be considered in the detailed design phase. It is not clear what these measures will be or how they will address the continued scheduling risk that generators will experience in the I-SEM.

To quantify the scheduling risk that generators will experience in the I-SEM, TEL, in association with other market participants, commissioned a report from Baringa[1]. This report concluded that scheduling risk will increase for generators in the I-SEM. This is because generators will be required to internalise start-up and no load costs into EUPHEMIA compliant bids that respect the plants technical limitations. These bids will take the form of blocks with a specified duration over which these costs are to be recovered. At the same time generators will have a high level of uncertainty over variable generation and competitor behaviour which

[1] *Scheduling risk under the proposed I-SEM High Level Design*, Baringa (2014)

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will impact their scheduled running and thus the duration over which these costs can be recovered. This risk will be experienced primarily by mid-merit plant.

It will not be straightforward to reflect the flexibility and costs of a generation asset effectively through the available EUPHEMIA offer structures. In fact the options for offering flexibility are reduced compared to the current SEM. The need to recover start costs may be an incentive to reduce the level of flexibility offered as generators will seek to spread these costs over blocks of longer duration to ensure competitiveness. This would suggest there will be more reliance on peaking plant to fill the demand profile as they will be able to offer shorter blocks.

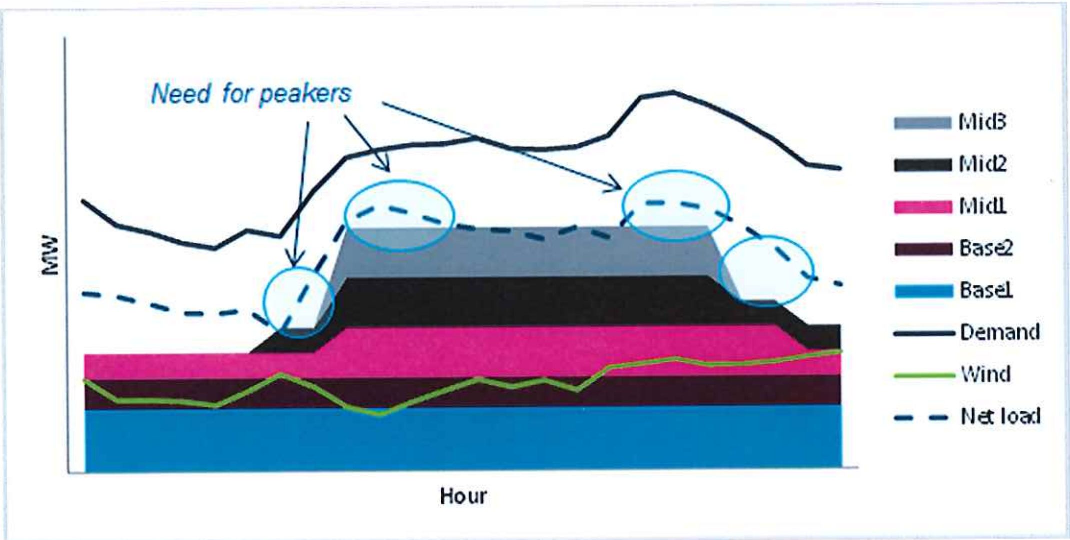
If peakers are to set the price in the Day-Ahead Market on a more frequent basis then there will be an even greater requirement for liquid forward hedging markets than at present. With high levels of variable generation the majority of plant on the island will be operating as mid-merit plant. The scheduling risk that these generators are exposed to will translate into a significant premium being sought in the forward market in offering long term hedging contracts. If this premium is not available then mid-merit plant will not participate in the forward market. Any measures taken by the RAs to foster forward market liquidity must be cognisant of these dynamics and not expose generators to risk that they are unable to manage.

Testing Requirements

The Draft Decision states 'it has been concluded that the EUPHEMIA algorithm is fit for purpose to serve as the means of unit commitment and scheduling of generation in the I-SEM DAM'. This appears to have been based on an analysis (by the RA's, SEMO and expert parties) of the bid types available under EUPHEMIA, and that these will allow the generators to either reflect their costs or their desired volume. TEL accepts that EUPHEMIA bid types will enable cost reflective bidding. However, TEL questions the conclusion that it will be a robust solution without further analysis and testing.

TEL has concerns in relation to the plans for testing of the EUPHEMIA algorithm. This algorithm underpins the success of the I-SEM. EirGrid is not currently in a position to test the algorithm. Only full members of the PCR can initiate testing and as long as EirGrid remains an associate member; it must rely on a full member to run the testing. Once the timing of the testing is agreed, it is necessary to define the goals of the test. TEL's understanding is that the current definition of success for the planned testing is 'Does the addition of the Irish market break the EUPHEMIA algorithm?' i.e. will the addition of I-SEM Offers result in EUPHEMIA failing to solve. TEL contends that this is inadequate. It is necessary that the system does more than just not "fall over", it must be a robust solution for the unconstrained schedule.

Currently, in the SEM the flexible CCGTs can usually be scheduled up or down to meet the demand. This is similar to how the dispatch functions. However this flexibility may not be available at the Day-Ahead due to the offer structures available, as identified in the attached Baringa report. When internalising start-up costs, CCGTs may attempt to spread these costs over a longer block duration to remain competitive. This will effectively remove the flexibility that these plants currently offer. In order to meet the net system demand the market would then need to run peakers for each of the periods where the aggregated CCGT blocks do not meet the net demand curve. The diagram below illustrates this.



[2]

TEL has developed a model to approximate the results of the EUPHEMIA algorithm based on the data that is in the public domain. Using this model and actual System Demand, Wind and EWIC data for 2013 we have calculated that lower merit order plant would have set the price for 327 distinct trading hours under the EUPHEMIA model, as opposed to just 45 distinct trading hours under the SEM. This difference illustrates that the result of the EUPHEMIA algorithm will be significantly different from the current SEM algorithm and may not reflect the underlying costs of the plant that is scheduled to meet demand. TEL urges the RA's to increase the scope of the testing strategy of EUPHEMIA to assess the robustness of EUPHEMIA in arriving at a feasible and efficient unconstrained schedule.

Participation of Variable Generation in the Day-Ahead Market

The Impact Assessment on the preferred option for energy trading arrangements attributes significant benefits to the efficient use of interconnectors at both the Day-Ahead and Intraday. These benefits range from €24 million under a 45% RES scenario to €66 million under a 52% RES scenario. Of these benefits 42% are attributed to efficient Day-Ahead interconnector flows with the remainder being attributed to efficient Intraday trading.

The assumptions made in arriving at these benefits (particularly the Intraday benefits) assume that: i) wind will trade in the Day-Ahead market at its forecasted volume; and, ii) the Intraday market will enable the deviation from these volumes to be traded nearer to real-time[3]. TEL agrees that a high level of participation in the Day-Ahead and Intraday markets by variable renewable generation is required to deliver optimal use of the interconnectors. However we do not agree that balance responsibility will be enough to deliver these benefits.

Balancing responsibility will incentivise variable generation to trade prior to the balancing timeframe only where it is perceived that the balancing price achievable is significantly worse than the price available prior to the balancing timeframe. This will only occur if thermal

[2] *Scheduling risk under the proposed I-SEM High Level Design*, Baringa (2014)
[3] *SEM-14-046*, 5.4.40 and 5.4.48

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generators are entitled to bid the full opportunity cost of reducing output within their balancing bid i.e. Day-Ahead offers from thermal generators will have been constructed using an assumed schedule. If balancing action to accommodate wind result in this schedule changing this may result in additional costs for the generator that were not considered (such as the cost of the subsequent start and the loss of ancillary services revenue where the generator is instructed to shut down). Generators should be entitled to include an appropriate premium or discount to reflect these costs and the value of the flexibility they are providing to the system. If thermal generators were only to include their avoided fuel costs within balancing bids then the mandatory nature of the Balancing market with single marginal pricing would result in a price similar to the Day-Ahead price. A strong price signal is required to incentivise wind into the Day-Ahead Market.

If the majority of wind generation was traded at its forecast volume on the Intraday market, when forecasted wind volumes are more certain, the benefits attributed to the interconnector at Day-Ahead and Intraday would not be realised. Under this scenario the flows on the interconnector are inclined to favour imports into the I-SEM at the Day-Ahead stage when wind is not participating and are more likely to favour exports at the Intraday stage when large volumes of wind participate. Both the IWEA and IWFA responses to the consultation indicated the preference for wind to participate in the Intraday market due to a perceived risk of trading at Day-Ahead when wind forecasts are less certain. This behaviour could cause dramatic changes in the direction of flows on the interconnectors which would not be efficient and will expose consumers to increased costs and furthermore would not be a reliable starting point for physical dispatch.

Stronger incentives need to be applied to ensure that variable generation trades at the Day-Ahead stage. One means of providing this incentive is for support payments for wind to be measured against the Day-Ahead market price. This would provide a strong incentive for wind to participate at Day-Ahead as participation at Intraday would put the wind farm at risk of not receiving the full support payment. Another method of ensuring participation in the Day-Ahead market would be to make participation mandatory but as variable generation participation is based on weather forecasts it is not clear how this would be enforced.

Strong incentives at Day-Ahead would also provide an incentive to improve wind forecasting accuracy. Wind forecasting on an aggregate basis across the whole island is much more accurate than for a single wind farm so the use of an aggregator would mitigate the risk for individual wind farms of participating in the Day-Ahead market.

<u>Capacity Remuneration Mechanism</u>

TEL fully supports the decision to include a Capacity Remuneration Mechanism (CRM) in the High Level Design of the I-SEM. As detailed in our previous response, and supported in the draft decision, energy only markets are prone to market failure which gives rise to the "missing money" problem. This is exacerbated on small island systems with high levels of variable generation. It has been proposed that the CRM will be quantity based and will take the form of Reliability Options. ISO New England (ISO-NE) implemented a Forward Capacity Market in 2008 using quantity based Reliability Options. TEL would advise that the RAs consider the lessons learnt by ISO-NE before implementing a similar scheme in the I-SEM.

a) <u>Original Design of New England Forward Capacity Market</u>

The Forward Capacity Market seeks to send an appropriate price signal to attract new investment and maintain existing resources where and when they are needed, thereby ensuring the reliability of the New England electricity grid. The original design of the Forward Capacity Market operated by ISO-NE was a quantity based CRM. Conventional, variable and import resources could qualify for participation. Variable resources can only qualify up to the

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median measured energy production during defined "reliability hours" in the summer and winter seasons. Import resources must be backed up by an external generating resource.

Eligible resources compete via auction to provide capacity three years in advance of the relevant delivery year. A single clearing price was determined for all cleared resources in the auction up to the level of capacity required to meet the reliability standard; the net installed capacity requirement (NICR). The auction was designed to allow new capacity that was planned and required to meet NICR, but not commercially viable, to set the market clearing price thereby providing a market-based measure of the cost of new entry[4].

All generation that is successful in the auction receives that cleared price in the auction on a monthly basis and has an obligation to supply the capacity into the Day-Ahead and Real-Time energy market whenever the resource is available. Monthly capacity payments are reduced where the price in the Real-Time market exceeds a peak energy rent strike price.

b) <u>Objectives of the Forward Capacity Market</u>

There were four stated objectives of the Forward Capacity market:

i. Procure enough capacity to meet New England's forecasted demand three years in advance

ii. Attract new resources to constrained regions through an additional source of income

iii. Provide compensation for capacity costs of existing resources

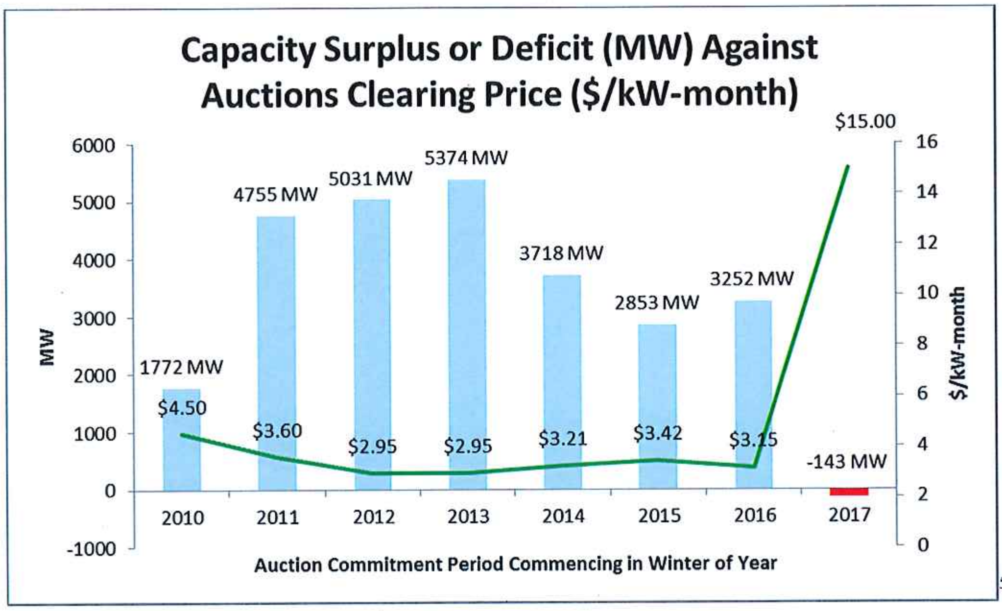
iv. Implement a penalise-for-non-performance approach for not providing capacity during a shortage event

After six years of operation it is worth considering how the Forward Capacity Market has delivered against these objectives and how the I-SEM could incorporate any lessons learned.

i. <u>Procuring enough capacity</u>

The first auction was held in 2008 and for the next seven annual auctions the total capacity acquired at auction was in excess of the level of capacity required. On average there was 12% excess capacity in the first seven years. This resulted in the clearing price at auction being the floor price.

[4] *Overview of New England's Forward Capacity Market*, www.iso-ne.com (2013)



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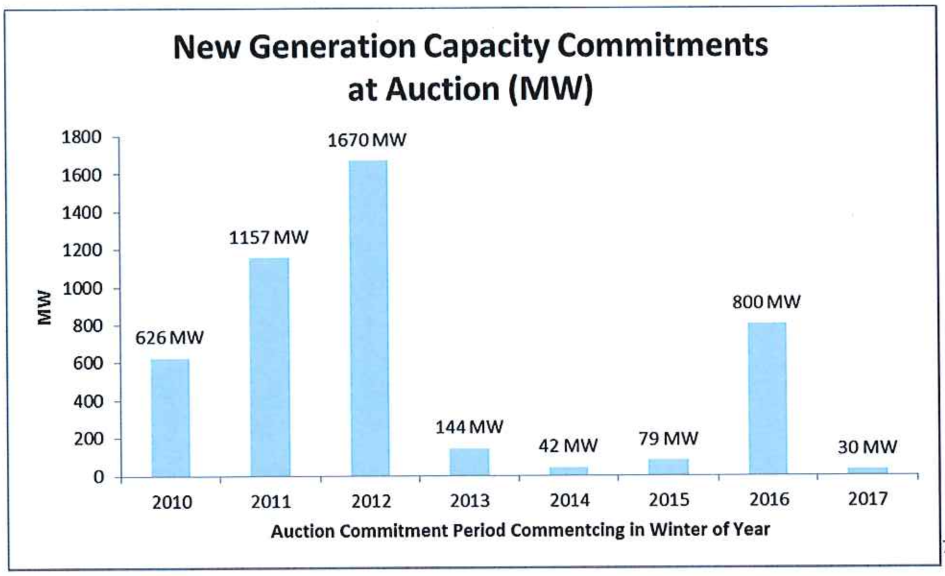
ii. Attract new resources

Prior to the eighth auction for commitment beginning Winter 2017 (held in February 2014), ISO-NE determined that there was a potential for a capacity shortfall[6] resulting from significant retirements with a further 8.3GW of generation capacity at risk of retirement by 2020. Under the Forward Capacity market rules a capacity shortfall would result in the price for capacity being administratively set. The result of the eighth auctions was that the available capacity was only marginally below the required capacity level (0.5% deficit or 143 MW short of 33.8 GW required) but capacity prices had increased 5 fold (from an average of $3/kW-month to a maximum of $15/kW-month).



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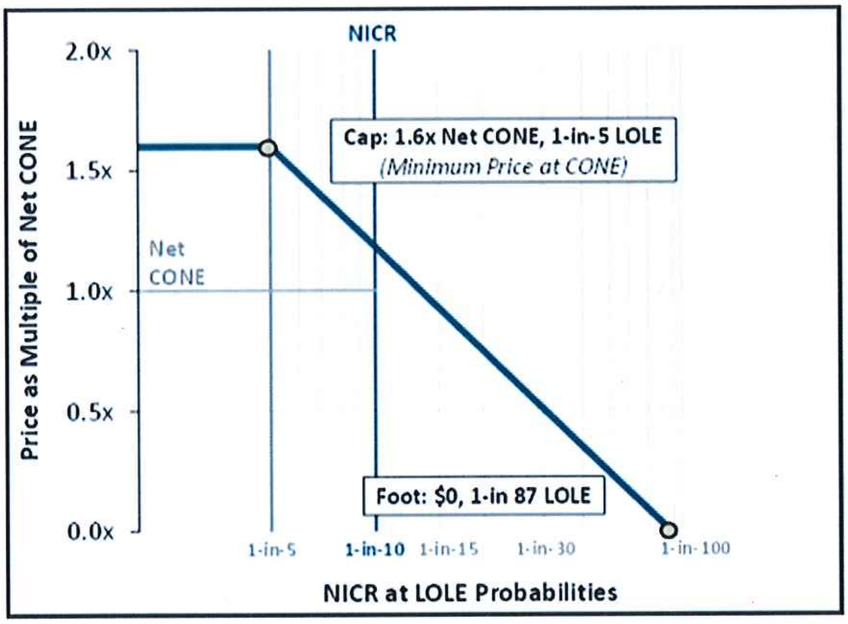
[5] *Capacity Market Information Session*, www.ieso.ca (2014)
[6] *ISO New England Inc.*, 145 FERC ¶ 61,038 (2014)
[7] *Capacity Market Information Session*, www.ieso.ca (2014)

ISO-NE has identified a significant flaw in the existing Forward Capacity Market which contributed the inability to attract new investment. The binary nature of quantity based capacity mechanisms results in a boom-and-bust cycle of investment. This will result in the price for capacity being either at the price floor or the price cap whenever the region is just long or just short capacity. To alleviate this problem ISO-NE will implement a sloped demand curve in the next capacity auction[8] as illustrated in the following chart.



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When available capacity falls below the level that is required to deliver the minimum reliability standard (set at 4.8 hours/year) the price paid for available resources will be the price cap. This is set at 1.6 times the net cost of new entry of a 2 x 1 CCGT (gross cost of new entry minus energy and ancillary service revenue). The price paid for capacity will reduce to 1.19 times the net cost of new entry (net CONE) at the reliability standard, providing a safeguard against underestimating the net CONE. The price continues the downward trajectory until it reaches zero. This demand curve is designed to achieve the required reliability standard over the long term while reducing price volatility and decrease susceptibility to market power abuses.

The CRM in the I-SEM needs to provide a stable price signal for capacity both in the current period of over capacity as well as in the future when new capacity will be required. A volatile capacity price will increase the risk of investment which will neither benefit generators nor consumers. TEL would urge the RAs reconsider the use of a pure quantity based CRM in the I-SEM. A sloped demand curve, adjusted for the nature of capacity on the island, would provide a more stable capacity price and attract new capacity when it is needed in the future. If this issue is not addressed Reliability Options will fail on the stability measure.

iii. Compensating existing resources

The peak energy rent mechanism has two purposes. The first is to remove the incentive for generators to raise prices in the Real-Time market by offsetting high real-time prices with reductions in capacity payment. The second is to act as a hedge for load against high prices

[8] *ISO New England Inc.*, 147 FERC ¶ 61,173 (2014)

[9] *Capacity Market Information Session*, www.ieso.ca (2014)

in the energy market. The draft decision indicates that similar considerations influenced the proposal to implement Reliability Options in the I-SEM.

The peak energy rent strike price approximates the operating cost of the marginal generating unit in New England on any day when the region is approaching shortage conditions. It is calculated for each day as the operating costs of a proxy unit on either gas or distillate. At the time the rules were set in 2006, gas and distillate were similarly priced and so the lower of the two fuels sets the strike price. In the intervening years the price of the two fuels diverged. With the strike price being set by the lower of the two fuels the divergence between gas and distillate resulted in the strike price on occasion being significantly below the operating costs of the most expensive unit. Consequently the peak energy rent mechanism was being triggered more often than expected, and ultimately, the deduction from capacity payments being larger than expected. This led to ISO-NE changing the rules in 2011[10] to calculate the strike price from the higher of the two fuels.

The determination of the strike price and the reference price for use in the I-SEM will be a key determinate of the success of the scheme in providing compensation for existing resources. The strike price must be set at a level above the marginal generator during times of system stress to ensure that the marginal generator can cover its costs. This price must be dynamic and take account of the movement of fuel prices over the life of the reliability option. Generators will not be able to self-commit in the I-SEM so may be exposed to significant risk if the reference price is anything other than the Day-Ahead price. The time required to start large units would also restrict the ability for these units, if offline, to provide at times of scarcity. This may however reduce the level to which reliability options remove supplier exposure to scarcity rents which was a key consideration of the RAs in selecting Reliability Options. TEL seeks clarity as part of the High Level Design decision that the Day-Ahead price will be the reference price for these reliability options.

iv. <u>Delivering reliability</u>

The grid in New England is undergoing rapid transformation with a shift from oil, coal and nuclear to natural gas and renewables. The consequences of this are well known to the SEM; greater operational uncertainty and lower energy market revenues are driving a need for greater flexibility from gas generators who have a greater dependence on capacity revenue. However over the last number of years ISO-NE has also witnessed pervasive and worsening performance of the existing generation fleet in New England. Average system forced outage rates have increased from 3.8% in 2007 to 8.8% in 2013.

These problems have been exacerbated by the design of the Forward Capacity Market. Under the existing design, resources that are successful in the Forward Capacity Market are obliged to offer the capacity into the Day-Ahead energy market, leave the offer open throughout the operating day, and follow dispatch instructions. In addition the resource must be available to operate during periods where the supply of energy and reserves is insufficient to meet the demand. Resources that are not available to operate are subject to a penalty.

ISO-NE has identified the following problems with the current design of the penalty[11]:

- Consequences for non-performance are negligible
- Bias in Forward Capacity Market to clear less-reliable resources as they require less capacity revenue to remain open

[10] *ISO New England Inc.*, 134 FERC ¶ 61,128 (2011)
[11] *Capacity Market Information Session*, www.iso-ne.com (2014)

- A lack of incentive for resources to make investments to ensure they can provide energy and reserves when needed

- "Missing money" paid to all resources instead of those that invest to be able to perform during scarcity conditions

- Lack of investment poses a serious threat to system reliability

To counter these problems ISO-NE has proposed a comprehensive Pay-for-Performance solution[12]. This proposed fix seeks to implement a two-settlement process whereby a capacity resource's total capacity revenue is comprised of a base payment and a performance payment. The base payment is set by the Forward Capacity Market clearing price whereas the performance payment is determined by measuring the resources performance during scarcity events. The performance payment could be positive or negative. Negative performance payment would be capped at the level of the base payment i.e. a resource could not lose more in any one month than it would receive during the month.

One of the significant problems with this approach is that there is limited scope for capacity resources to offset negative performance payments during scheduled maintenance. While TEL supports performance incentives to ensure that reliable generators are rewarded these incentives need to consider the nature of the I-SEM. While the RAs have proposed a secondary market for trading out of obligations the small size of the I-SEM will limit the liquidity in this market.

The I-SEM is a small market with high levels of constraints. Concurrent outage of plant can result in a scarcity event when a plant trips. There have been 28 trips in the first 6 months of 2014. If a generator is not on load during these events due to being constrained off or out of merit they would not be able to deliver energy or reserves during the scarcity event. In implementing a performance incentive consideration will need to be given to the fact the generators are unable to self-commit and will require the TSO to manage the system to ensure that demand and reserves are met. Any performance incentive must recognise that constrained off plant may not be able to deliver during times of scarcity and must therefore not be disadvantaged. TEL seeks clarity as part of the High Level Design decision on whether there will be a requirement for physical delivery against reliability options.

c) Distortion of Cross Border Trade

ACER identified the potential for CRMs to exert distortionary effects between neighbouring states[13]. In designing the CRM the RAs must ensure that the CRM is compatible with neighbouring markets so as not to distort cross border trade. The choice of reliability standard for use in the CRM will be critical in ensuring its compatibility with CRMs in neighbouring markets. The UK is implementing a reliability standard based on a loss of load expectation of 3 hours / year. France has the same standard[14]. Both these markets are implementing CRMs with which the I-SEM CRM must be compatible.

The current reliability standard in the SEM is a loss of load expectation of 8 hours / year[15]. This loss of load expectation is almost three times higher than in the UK and France i.e. a reliability standard almost 1/3 as rigorous as our neighbouring markets. The impact of this

[12] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (2014)
[13] *Capacity Remuneration Mechanisms and the Internal Market for Electricity*, www.acer.europa.eu (2013)
[14] *Annex C: Reliability Standard Methodology*, www.gov.uk (2013)
[15] The security standard used for the all-island calculation is 8 hour; Ireland standard is 8 hours while Northern Ireland standard is 4.9 hours, *All-Island Generation Capacity Statement 2014-2023*

lower reliability standard in Ireland is that the CRMs in the UK and France will be procuring a higher capacity margin than the CRM in I-SEM. The capacity price in France and the UK will therefore be higher than in I-SEM. This is likely, over the long term, to lead to a distortion in trade between these member states. Investments in generation will decline in the I-SEM compared to the UK and France which are prepared to procure a higher level of reliability. The RAs must be mindful of this potential when finalising the CRM design.

TEL trusts that these comments prove constructive to the process and look forward to further positive engagement with the RAs and SEMC.

Yours sincerely,

David Vaughan
Commercial Risk and Regulatory Manager

Enc. Scheduling risk under the proposed I-SEM High Level Design: An issues paper

Baringa

Scheduling risk under the proposed I-SEM High Level Design

An issues paper

CLIENT: Tynagh, Viridian, AES, Bord Gáis Energy

DATE: 23/07/2014

FINAL

V1.2

Version History

Version	Date	Description	Prepared by	Approved by
1.0	16/7/2014	Draft for review and comments	DS, AS, AP	
1.1	23/7/2014	DRAFT FINAL Updated following comments from clients	DS, AS, AP	DS
1.2	23/7/2014	FINAL	DS, AS, AP	DS

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1. INTRODUCTION

The SEM Committee published the I-SEM High Level Design Proposed Decision on the 9th June 2014. The proposed design will consist of a financial forward hedging contract market referenced against a physical unconstrained day-ahead schedule produced by the EUPHEMIA algorithm as a part of the European market-coupled auction, together with bilateral within-day trading and a balancing market operated by the system operator. The SEM Committee proposes that the centralised Day-ahead Market (DAM), Intra-day Market (IDM) and Balancing Market will be the exclusive routes for physical contract nomination and physical scheduling of generation. It is proposed that participation in the DAM and IDM will be exclusive but not mandatory, whereas participation in the Balancing Market will be mandatory.

The proposed I-SEM High Level Design is formulated to ensure that the Irish electricity market is compliant with the EU Target Model by 2016. Whilst the proposed design will bring the market more in line with other European markets in some respects, for example allocating interconnector capacity implicitly through day-ahead market coupling and making participants more responsible for balancing their own positions, it would still be unique amongst other European markets which typically are centred around full self-dispatch and voluntary participation in multiple physical traded markets. Furthermore, the proposed design does not explicitly tackle one of the key issues in the current SEM, namely the lack of forward liquidity which is important for a well-functioning market. One of the contributing factors behind poor liquidity in the current SEM is the scheduling risk faced by generators, since they cannot with confidence assume that they will be appropriately scheduled under the central market arrangements against their forward commitments.

Liquid and transparent forward markets enable suppliers to hedge efficiently, thereby shielding consumers from volatile spot markets and enabling competitive tariff structures. Forward markets also provide open access to mitigate market power and concentration, and generate price signals to drive investment. Effective functioning of forward markets is therefore essential for competition and consumer choice.

In this paper, we explore the extent to which scheduling risk would remain under the proposed I-SEM design and the implications for forward market liquidity. We are not implying or proposing solutions to these potential issues within the contents of this paper.

2. PARTICIPATING IN THE I-SEM

The day-ahead market (DAM) forms a central part of the proposed I-SEM High Level Design, providing:

- The basis for the day-ahead dispatch schedule
- The mechanism for allocating capacity on interconnectors with the GB market
- The reference price for settling forward financial contracts, and
- The (likely) reference price for settling reliability options under the proposed Capacity Remuneration Mechanism (CRM)

Since the DAM will be exclusive, dispatchable generators will be strongly incentivised to offer their output through this market (even if it were not mandatory)[1]. Each day the generator will need to formulate its offers using the available exchange offer formats, and consider how best to reflect its underlying costs in its pricing approach. In doing this, it will need to consider external factors such as the level of demand and wind output, and the potential strategies of competitors. It will also need to take a view of the likely initial status of the plant at the start for the trading day, for example whether the plant will be already operating or needs to be started which would require start costs to be recovered in its offer price.

The schedules produced by the EUPHEMIA algorithm at the day-ahead stage are unlikely to be fully feasible, and will need to be adjusted to take into account actual ramping characteristics of individual plant, as well as for system operational reasons, such as managing transmission constraints.

At this stage, it is not decided how much responsibility individual generators will have post the DAM for creating feasible schedules versus the system operator. If it is to be generators, a liquid within-day market will be essential, since the proposed marginal imbalance price arrangements would represent a significant risk for generators (particularly independent generators) constrained to the relatively blocky nature of offers in the DAM.

Participation in the balancing market is mandatory for generators. In pricing their balancing bids and offers, generators will need to consider the impacts on their assumed starting positions used for preparing offers into the next day's DAM. For example, had the generator assumed that it would begin the day generating, any bid to switch off in the balancing market would need to factor in the costs of re-starting the plant (which were not included in the DAM offer price).

Overall, the proposed I-SEM HLD places far more risk on generators associated with managing their own dispatch and internalising their own costs when compared to the current SEM based around a pool and central dispatch. To manage this risk effectively will require access to the tools typically available in bilateral markets based on self-dispatch, namely day-ahead and within-day liquidity and real-time information on system conditions. An imbalance price that accurately reflects the costs of achieving an energy balance across the system (i.e. a price that is not 'polluted' by balancing actions required to maintain the physical integrity of the network such as constraint management), and established through effective competition between providers of balancing energy, will also be essential.

[1] The alternative of attempting to transact all its output in the within-day market would expose the generator to considerable liquidity risk.

3. WHAT IS SCHEDULING RISK?

3.1. Definitions

Scheduling risk occurs in centralised markets, such as the current SEM and the proposed I-SEM, since a generator cannot be certain that its plant will be appropriately scheduled under the market or exchange algorithm. This makes the task of managing earnings risk through hedging forward its output and fuel requirements more difficult than is the case in a self-scheduled market.

A baseload generator, one whose short run costs are predictably below the market price, is unlikely to have significant exposure to scheduling risk. There are no start costs to be recovered, and the baseload generator can hedge its output and its fuel (and carbon) costs in forward markets (to the extent there is sufficient liquidity) and lock in a margin.

Scheduling risk is most acute for mid-merit plant, those generators whose output fluctuates according to system conditions and which may need to be frequently switched off and restarted. High efficiency CCGTs already operate as mid-merit units in the SEM and this trend is likely to continue with even more efficient currently baseload generation moving to mid-merit operation in the future with increasing levels of renewable generation.

A mid-merit generator cannot be certain whether it will be “in-merit”. In a bilateral market with self-dispatch, the mid-merit generator is able to sell electricity forward and hedge its fuel cost for periods with positive spreads (taking into account potential start costs). Having the option to self-dispatch at the time of delivery then guarantees it can lock in the margin on its forward sale. If at the time of delivery the day-ahead price for electricity is above its short run costs (taking into account its start costs if it is not already running) it will choose to generate. However, if the day-ahead price is below its short run costs, it will re-optimise its position, choosing not to generate and instead purchasing its requirements from the day-ahead (or other prompt) market. This allows the generator to then stockpile its fuel (in the case of coal) or sell it (in the case of gas) to achieve additional margin. Under this dynamic, a generator can only improve on the margin it has locked in through its forward hedging strategy.

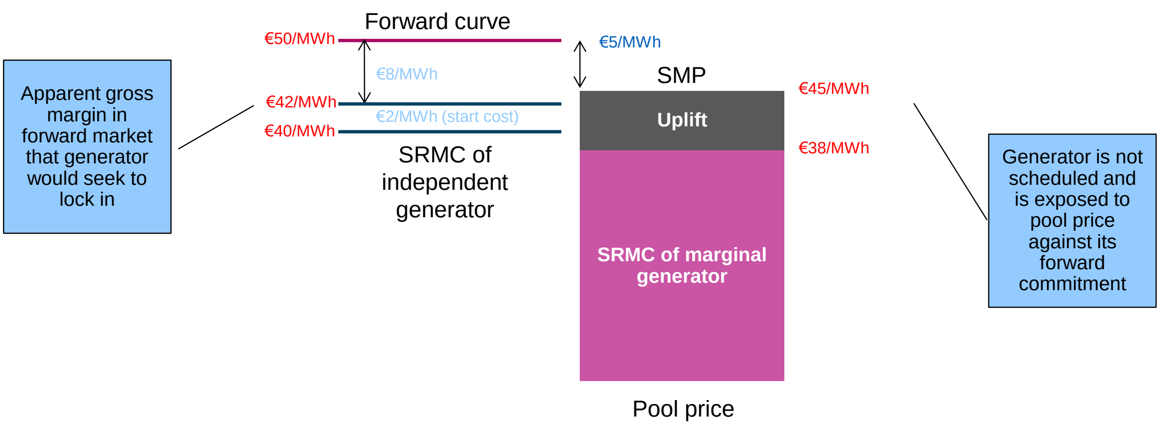
Under a centralised market, the hedging task for a mid-merit plant becomes more complex since it will be dispatched based on the outcome of the market algorithm. At the day-ahead stage there will be considerable uncertainty regarding market conditions, particularly with respect to wind output, and the potential bidding strategies of competitors. In the absence of a Bidding Code of Practice it will be significantly more difficult than under the current SEM to anticipate the offers of competitors, which will increase scheduling risk. A key challenge for generators will be how to internalise start costs and no load costs into offers when there is a high degree of uncertainty regarding the fixed output that these costs can be spread over without increasing risk of exclusion from the DAM schedule. Generators also face the additional problem of how to construct commercial offers that ensure the DAM schedule they receive respects the dynamic technical constraints of their unit(s). It is therefore possible under the proposed design that a generator, bidding at cost, will not be scheduled, even if the DAM price is higher. In this scenario a generator that had hedged forward would be exposed to the market price, at a loss relative to its SRMC. This is scheduling risk.

In the current SEM these important issues are addressed (albeit imperfectly as discussed in Section 3.2 below) through complex commercial and technical offer formats, and the Uplift algorithm, but under I-SEM the under recovery of start-up and no load costs and the receipt of a technically infeasible schedule are likely to represent an increased material risk for generators. The reasons for this are discussed in Section 4 below.

3.2. Scheduling Risk in the current SEM

Under the mandatory pool structure of the current SEM, it is difficult for a mid-merit generator to execute a forward hedging strategy because it cannot determine its own schedule. This creates an anomaly whereby the generator can be 'in the money' in the forward market but is unable to capture the implied margin because it is not guaranteed to be scheduled appropriately through the mandatory pool. This problem is illustrated in Figure 3.1 below.

Figure 3-1 Risks associated with forward hedging under the SEM



In this example, the forward curve (€50/MWh) is trading above the generation costs (including the plant's start cost – spread across its anticipated running hours) of the independent mid-merit generator (€42/MWh). It therefore sells electricity forward and simultaneously hedges its fuel costs, thus in theory locking in a €8/MWh gross margin. At the day-ahead stage the generator submits an offer to the SEM based on its SRMC (€40/MWh). In this illustrative example, the generator's offer price is slightly above the SRMC of the marginal unit on the system (€38/MWh), causing the generator not to be scheduled in the pool. The generator therefore sells back its fuel hedges and in so doing generates a revenue equivalent to its SRMC. This payment offsets the costs of buying power from the pool (€45/MWh) to meet its forward commitments but because the pool has priced above the SRMC of the generator it results in the generator retaining a residual exposure to the pool. This residual exposure constitutes scheduling risk and means the generator only achieves a gross margin of €5/MWh, lower than the €8/MWh expected on its forward sale. This risk may have contributed to the substantial premium on forward sales evident in the current SEM.

In a bilateral market this dynamic is less likely to occur. Generators still face a challenge in optimising their traded position, as this is done primarily with relatively simple traded products, albeit through multiple channels, but they do have the ability to self-schedule to meet physical forward commitments if they are unable to purchase power below its own costs in the day-ahead market, guaranteeing the margin on forward sales.

3.3. Potential scheduling risk issues under the proposed I-SEM HLD

As the example above illustrates, a key source of scheduling risk under the current SEM design is the separation of no load and start costs from SRMCs in the pricing algorithm. This can create a situation where a plant is not dispatched even when prices are apparently above its costs.

Under the proposed I-SEM High Level Design, the generator's no load and start costs are internalised by the generator and hence this specific example would not happen.

However, scheduling risk is unlikely to be eliminated under the new market design since dispatch still relies on the outcomes from a central algorithm (in this case EUPHEMIA) which market participants may not be able to anticipate reliably, particularly in the absence of a Bidding Code of Practice. EUPHEMIA supports complex and sophisticated offer formats to help participants manage their technical and commercial constraints within the day-ahead scheduling process. However, with the exception of the possible partial acceptance on profile offers, complex or sophisticated orders can normally only be executed fully or rejected fully, and this constraint can lead to EUPHEMIA rejecting some complex orders even if they are priced below the outturn market prices. Rejected orders that are apparently in-the-money at outturn prices are termed 'paradoxically rejected orders' in the EUPEHMIA literature.

In the absence of short run cost bidding principles, the generator may, however, have the option of offering at zero price into the centralised day-ahead market, although it is not clear from the Draft Decision Paper whether zero bidding would be allowed. Zero bidding would guarantee dispatch (unless the marginal unit was also bidding zero[2]) and reduce scheduling risk. The downside for the generator though is that it may have been able to fulfil its forward commitment at lower cost (if the day-ahead market outturned below its own costs). Also zero bidding puts downward pressure on day-ahead prices, particularly in a small market such as the SEM, which may undermine the value of forward contracts. Whilst there could be a rationale for a single unit to bid below cost (if others were not doing it), the price dynamics associated with multiple parties doing so are likely to be unfavourable to generators, and hence we would not expect this to be a sustainable strategy in the longer run.

Exposure to scheduling risk under the I-SEM is compounded by the proposed design of the Capacity Remuneration Mechanism which will be based on financial Reliability Options that are likely to be settled against the DAM price. It is possible under the design that a generator will be exposed to payments under Reliability Options but not been scheduled.

In the next section we provide some worked up case studies to illustrate the options for generators to reflect their cost structures using EUPHEMIA offer structures and the limitations of this which contribute to scheduling risk.

[2] This situation is possible, particularly in periods of high wind output.

4. I-SEM DAY-AHEAD SCHEDULING AND EUPHEMIA

4.1. EUPHEMIA offer types

The pan-European day-ahead market clearing algorithm, EUPHEMIA, can handle a multitude of order formats, ranging from simple hourly and block products through to more complex block formats (e.g. linked, exclusive) and sophisticated conditions (e.g. Minimum Income Conditions). A brief description of each order type is as follows:

- ***Simple Hourly Orders*** consisting of a price and quantity pair for a given hour
- Block Orders applying to multiple hours:
    - ***Simple Block orders*** consisting of a price with a fixed quantity over a set time
    - ***Profiled Block Orders*** consisting of a price with a varying quantity over a set time
    - ***Linked Block Orders*** introducing conditionality such that the acceptance of a 'child' or 'grandchild' block is dependent on the acceptance of a 'parent' block
    - ***Exclusive Groups*** consisting of Simple or Profiled Block Orders where the combined acceptance ratio cannot exceed 1
    - ***Flexible Block Orders*** consisting of a price and quantity pair for a set duration but with the block start time not specified
- ***Sophisticated Orders*** consisting of simple orders with constraints such as Minimum Income Conditions, Scheduled Stop or Load Gradients

While the EUPHEMIA algorithm has been designed to support the full suite of order formats listed above, in practice only subsets of these order formats have been implemented by individual power exchanges to date. EUPHEMIA has been deployed in the North-Western European (NWE) and Iberian regions since 4 February 2014. At present, only OMIE in the Iberian market is supporting sophisticated orders such as Minimum Income Conditions, which are based on the legacy order formats in that market. In the NWE region, the local power exchanges such as EPEX and N2EX have been rolling out 'smarter' block formats but we understand there are no immediate plans to introduce sophisticated orders. Relative to the proposed I-SEM design, the requirements for sophisticated offer formats are less in other European markets given their larger size and more diverse and flexible generation mixes, and the fact that EUPHEMIA is not used as an exclusive route for creating the market schedule.

The RAs' proposed HLD does not specify which EUPHEMIA order formats will initially be supported in the I-SEM DAM. However, as stated in the proposed decision paper, recent analysis has focused on the potential application of Block Orders, and "the requirements for sophisticated constraints such as the Minimum Income Condition may not be as important or as necessary as was previously thought". It is also worth noting that the offer formats available to market participants may not be decided unilaterally by the RAs but through the EUPHEMIA governance arrangements. For the purposes of this study, we assume that Simple Hourly Orders and complex Blocks Orders will be available to I-SEM participants, but not sophisticated orders.

4.2. Mapping of generator technical and commercial parameters to offer types

The current SEM trading arrangements feature a centralised scheduling and pricing algorithm which ensures that generator market schedules are both technically feasible and commercially viable. Generators explicitly submit technical parameters (such as ramp rates, minimum stable levels and minimum run times) for consideration by the algorithm. The Uplift component of the market price in the current SEM guarantees the recovery of variable operating costs, including start and no load costs, for generation plant selected to run in the market schedule.

However, in the I-SEM DAM, as in other more decentralised European power markets, participants will be expected to internalise decisions on how to factor generation technical and cost constraints within their scheduling and pricing. I-SEM participants may consider applying some of the more complex order formats supported by EUPHEMIA to proxy the technical and commercial parameters that are handled explicitly in the current SEM. Here we can consider the potential mapping of current SEM technical and commercial parameters to EUPHEMIA order formats.

Table 4-1 Mapping of Commercial Offer Data

SEM Parameter	Explicit I-SEM proxy	EUPHEMIA Order Types	Observations
Price Quantity Pairs	✓	All formats, including Hourly Orders and Block Orders	• Prices as well as volumes may differ from hour to hour (current SEM limits generators to one set of prices per day)
No Load Costs	×	All formats, including Hourly Orders and Block Orders	• No load costs need to be internalised within Hourly or Block prices • Higher prices for part-load operation can be represented using Linked Block Orders with the parent block incorporating no load costs
Start Up Costs	×	Block Orders, *or* Sophisticated Orders with Minimum Income Condition	• Start costs need to be internalised within Hourly or Block prices • Using Linked Block Orders, start costs could be assigned to the parent block

Table 4-2 Mapping of Technical Offer Data

SEM Parameter	Explicit I-SEM proxy	EUPHEMIA Order Types	Observations
Minimum Stable Generation	✓	Block Orders	• 'All or nothing' acceptance criteria provides a proxy for minimum stable generation (MSG) • The parent block of a Linked Block could be sized at MSG
Minimum On Time	✓	Block Orders	• Duration of a Block Order can represent minimum on times • Except for a Flexible Block Order, the generator will need to pre-determine the hours of the day to which the block applies
Minimum Off Time	✓	Block Orders	• Duration of a Block Order can represent minimum off times •
Ramp Up , Ramp Down Rates	✓	Profiled Block Orders , *or* Sophisticated Orders with Load Gradient	• Unlike the current SEM, generators will need to pre-determine the hours in which the ramp profile applies

The generation and load resources in the SEM have differing commercial and technical characteristics. Technical constraints will be more significant for inflexible resources, while start costs may be more material for some generation types than others. SEM participants may consider applying different EUPHEMIA order formats, reflecting these characteristics. Here we summarise key features and limitations of the different order types, and their potential application (ignoring sophisticated orders, as discussed above).

Table 4-3 Summary of order types

Order Type	Features	Limitations	Potential Application
Simple Hourly Orders	Orders in each hour clear independently.	Risk of technically infeasible schedules for baseload and mid-merit generators, since no modelling of technical constraints.	• Flexible peaking generators • Hydro generators • Pumped storage • Load
Simple Block Orders	Block duration can represent minimum on time constraints. 'All or nothing' acceptance criteria proxies MSG.	Participant needs to pre-determine the hours in which the block applies.	• Baseload generators • Mid-merit generators • Less flexible peaking generators • Load
Profiled Block Orders	Profile shape can reflect technical ramp constraints and/or expectations of market value (e.g. lower volumes offpeak).	Participant needs to pre-determine the profile shape based on market fundamentals as well as internal constraints.	• Baseload generators • Mid-merit generators • Hydro generators
Linked Block Orders	No load and start costs may be allocated to parent block, allowing competitive pricing of incremental energy in child blocks. Allows reflection of higher costs for part-loading. Sale and purchase blocks may be linked.	Required for detail modelling of start and no load costs and technical constraints. Other power exchanges have limited the number of child blocks per parent, reducing potential flexibility. Order may be paradoxically rejected.	• Mid-merit generators • Pumped storage
Exclusive Groups	Allows participant to submit alternative profiles for the market algorithm to optimise, without risk of over-commitment.	Algorithm delivers market optimal outcomes, which may not be the profit maximising outcome for participant. Cannot be combined with Linked Block Orders. Order may be paradoxically rejected.	• Mid-merit generators • Hydro generators • Energy limited plant • Load response
Flexible Block Orders	Fixed duration and volume block with flexible start time to be optimised by market algorithm.	Other power exchanges have limited the number of Flexible Block Orders per portfolio. Order may be paradoxically rejected.	• Energy limited plant • Flexible peaking generators • Load response

In the following section, we consider worked examples of how EUPHEMIA order formats could be applied by different SEM resources, such as baseload or mid-merit generation.

As we note in the table, many power exchanges have placed limitations on the number and size of block orders and other complex bidding formats that participants can submit in the DAM for consideration by EUPHEMIA. These limitations can help ensure the market clearing algorithm reaches a timely and feasible solution. For example, EPEX has restricted Linked Block Orders to only one child per parent, and one 'family' per portfolio and market area. In GB, N2EX allows up to three child (or grandchild) blocks per parent (or child) block. The proposed HLD for I-SEM does not specify what limitations, if any, are likely to be placed on the use of complex order formats by I-SEM participants.

4.3. Potential bidding approaches for SEM generators

In this section, we have developed a series of worked examples to consider how different SEM generation categories (baseload, mid-merit, peaking) could make use of the various EUPHEMIA order formats to manage their scheduling risks. The challenge of achieving a technically and commercially viable schedule is arguably most pressing for mid-merit generators. Peaking generators are typically more flexible, while baseload generators are less concerned about start cost recovery. Given the growing contribution of renewables in the SEM, the majority of CCGT and coal assets will operate as mid-merit going forward. Mid-merit generators are therefore the focus of our worked examples.

We have considered the cases of a typical CCGT and coal-fired unit operating in the SEM. The table below summarises the assumed technical and commercial parameters for these two units, which are based on representative mid-point values in the published 2013 Validated Model, together with observation of actual commercial offer data (for start costs).

Table 4-4 Generic plant assumptions

Parameter	Unit	CCGT unit A	Coal unit B
Maximum Capacity	MW	400	250
Minimum Stable Generation	MW	200	100
Minimum On Time	Hours	4	5
Minimum Off Time	Hours	4	3
Start Cost	€	95,000	30,000

Given these assumptions on the generator’s cost structure and technical constraints, we then consider how EUPHEMIA orders could be formulated.

For the purpose of this study, we have not attempted to simulate the day-ahead market clearing and price formation process in the I-SEM and interconnected markets. For illustrative purposes, we assume that the CCGT and coal units are operated by independent generators and essentially operate as price takers in the DAM. We used historical spot commodity prices (gas, coal, carbon) and electricity price profiles (SEM, GB day-ahead, GB within-day) to illustrate potential scenarios for characteristic days. We also note that the success of a particular offer strategy (in producing a cost-optimal generation schedule for an asset) will also be dependent on the strategies deployed by other generators, which will of course not be known in advance. As we are not simulating the algorithm, this is not something we are aiming to demonstrate directly with these examples, but to which we return in considering the implications in Section 5. Furthermore, the simplified methodology for our illustrative examples assumes that block orders will always be accepted if they are in-the-money, whereas in practice block orders can be paradoxically rejected in the EUPHEMIA market clearing algorithm.

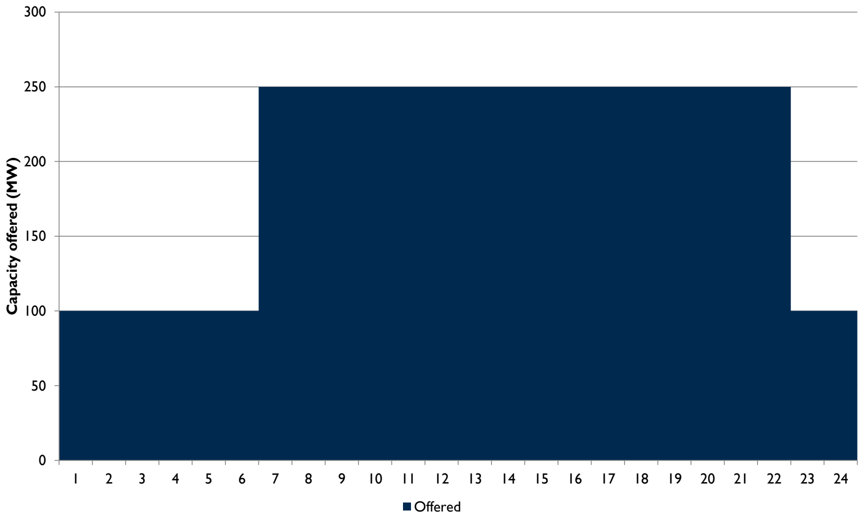
Baseload

The economics of baseload generators are such that they expect to be in-the-money in most periods. Start cost recovery is not generally a consideration given the continuous running profile. A Simple or Profiled Block Order format may be appropriate to represent technical constraints (such as minimum on time) and to ensure the plant is scheduled for the whole day in the DAM.

Case 1: Profiled Block Order

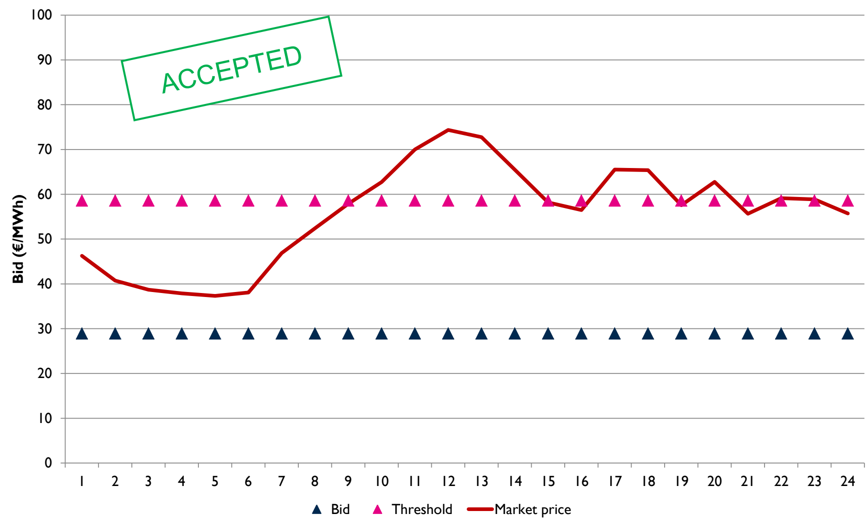
In this example, Coal Unit B expects to be near-the-money during the summer overnight periods and submits a Profiled Block Order to EUPHEMIA, as follows:

Figure 4-1 Case 1 submitted Block Order for Coal B



Coal Unit B is scheduled to be running at the end of the previous day, and so start costs do not need to be factored into its day-ahead bids. The unit's block bid price (reflecting its incremental and no load costs) is below the threshold of the volume-weighted average market clearing price, and the order is accepted.

Figure 4-2 Case 1 Block Order pricing for Coal B



The market price profile in this example implies that Coal Unit B could have sold incremental output overnight. Incremental power could be traded subsequently in the Intra-Day or

Balancing Markets. Alternatively, a Linked Block Order could be submitted to the DAM with child blocks representing incremental output above the base profile of the parent block.

EUPHEMIA does support partial acceptance of Profiled Block Orders, but this feature has not yet been implemented by all participating power exchanges.

Mid-merit

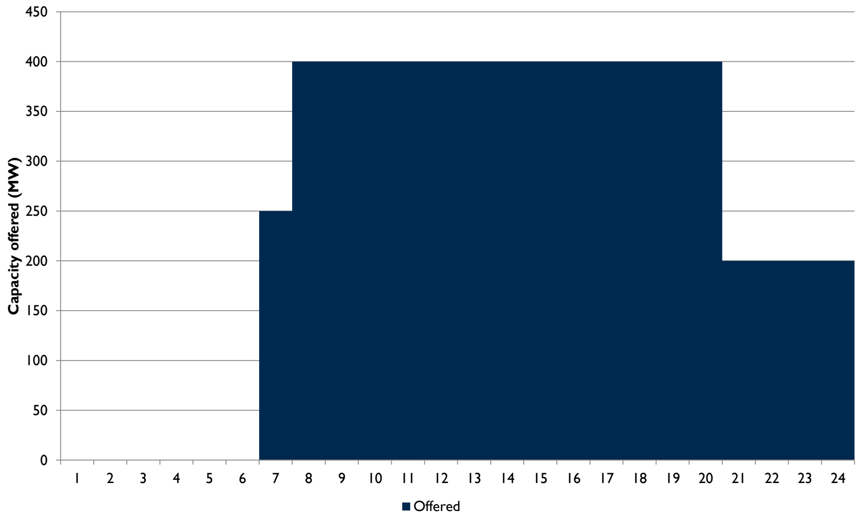
Mid-merit plant may be in or out of the money depending on system and market conditions. As a result, these plant may need to be switched off and restarted on a regular basis. We consider three EUPHEMIA order formats that mid-merit could potentially utilise to manage scheduling risks in the I-SEM DAM – Profiled Block Orders, Linked Block Orders and Exclusive Groups.

Profiled Block Order

Case 2: Profiled Block Order

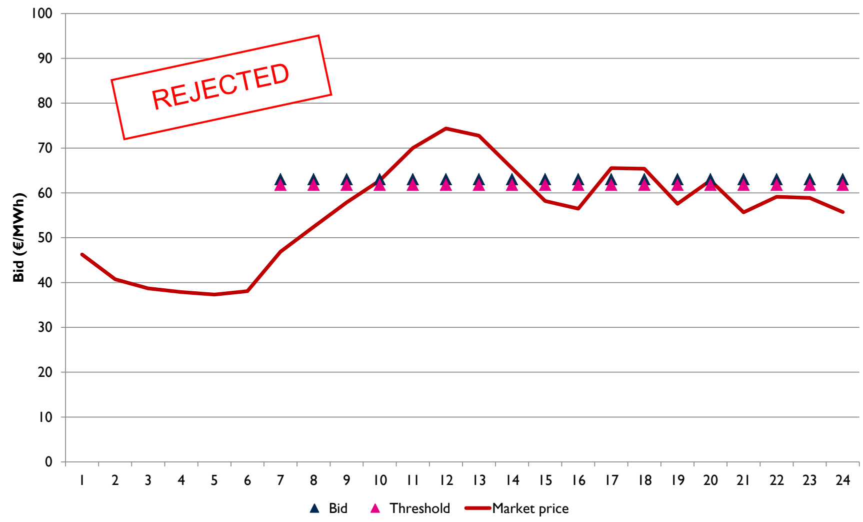
In this example, CCGT Unit A does not expect to be running at the start of the day. It submits a Profiled Block Order to EUPHEMIA, with the offer price reflecting its incremental, no load and start costs. The Profiled Block is 18 hours in duration, and allows for the plant to ramp down to MSG after the expected evening peak.

Figure 4-3 Case 2 submitted Block Order for CCGT A



On this characteristic summer day, the bid price for the Profiled Block Order is marginally above the threshold of the volume-weighted market price, and the order is rejected. Note that the incremental and no load costs of CCGT A are around 47 €/MWh at full load in this example, below the hourly market price for the duration of the Profiled Block Order. The block order is out-of-the-money in this case as a result of the internalisation of the assumed start costs.

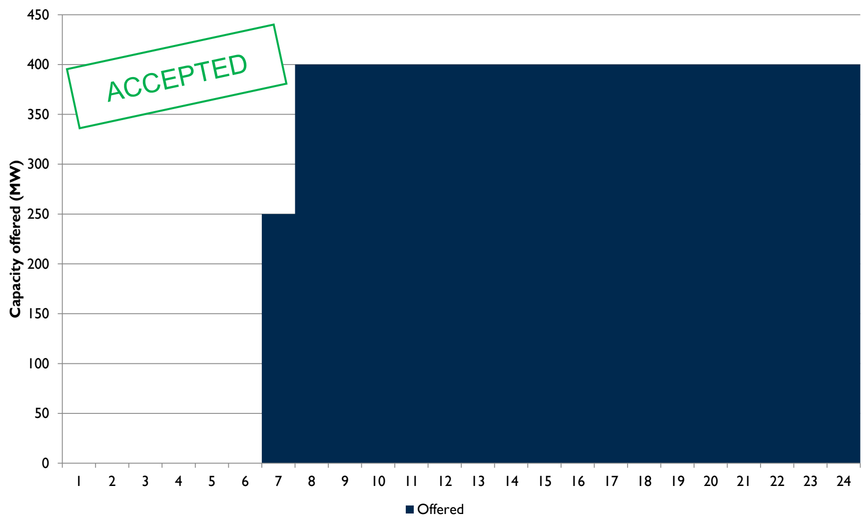
Figure 4-4 Case 2 Block Order pricing for CCGT A



Case 3: Profiled Block Order

Taking the same example as Case 2, let us consider an alternative Profiled Block Order, again 18 hours in duration but with the volume maintained at maximum capacity until the end of the day.

Figure 4-5 Case 3 submitted Block Order for CCGT A



Applying the same (exogenous) market price profile as before, the block offer price in this case is slightly below the volume-weighted average market price, and the order is accepted. The allocation of start costs is key to the comparison of Cases 2 and 3. Spreading start costs over a larger block volume reduces the profile bid price (by 1.5 €/MWh relative to Case 2), which makes the Block Order more competitive in Case 3. This is despite the fact that Case 2 is perhaps a more accurate representation of the likely running profile of mid-merit plant in the SEM.

These examples are of course schematic (and ignore the interaction between EUPHEMIA orders and price formation) but illustrate some of the challenges facing mid-merit generators, such as the potential need to second guess market requirements. These two examples are alternatives for representing the underlying commercial and technical characteristics of the plant and yet lead to different outcomes, and provide a good example of scheduling risk under the I-SEM. Linked Block Orders provide an alternative bidding option and may be better suited to handle uncertainty around off peak running patterns, as we explore below.

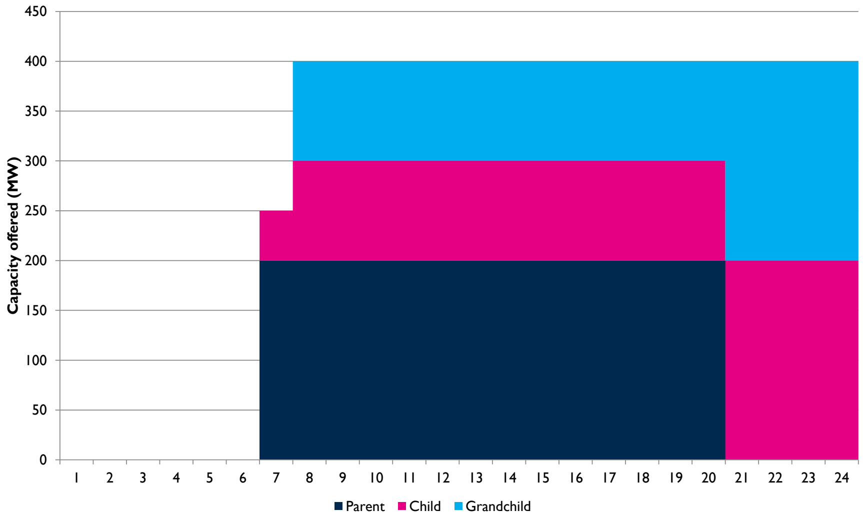
Linked Block Order
<u>Case 4: Linked Block Order</u>

Building on the example of Cases 2 and 3, let us consider how a Linked Block Order could be applied in this scenario instead of a Profiled Block Order. Taking the same overall availability profile as Case 3, a Linked Block Order could comprise a parent block at the MSG level of 200 MW for an extended period (14 hours here). Incremental output up to 300 MW is represented by one or more child blocks, with additional grandchild blocks reflecting incremental costs at the maximum capacity of 400 MW. A single child block at MSG covers the final 4 hours of the day, with incremental output represented by one or more grandchild blocks.

As noted above, day-ahead market operators in other jurisdictions using EUPHEMIA have placed limitations on participants' use of Linked Block Orders, which would rule out some of the formulations we have developed in these case studies. In principle, the flexibility of mid-merit generators to vary their output profile above MSG could be offered to the market as a 'strip' of hourly child blocks for incremental output above the parent block. In practice, participants in, for example, EPEX, are restricted to one child block per parent. If similar bidding restrictions are imposed in the I-SEM, generators will be limited in their ability to adequately incorporate their technical and commercial characteristics within their day-ahead orders.

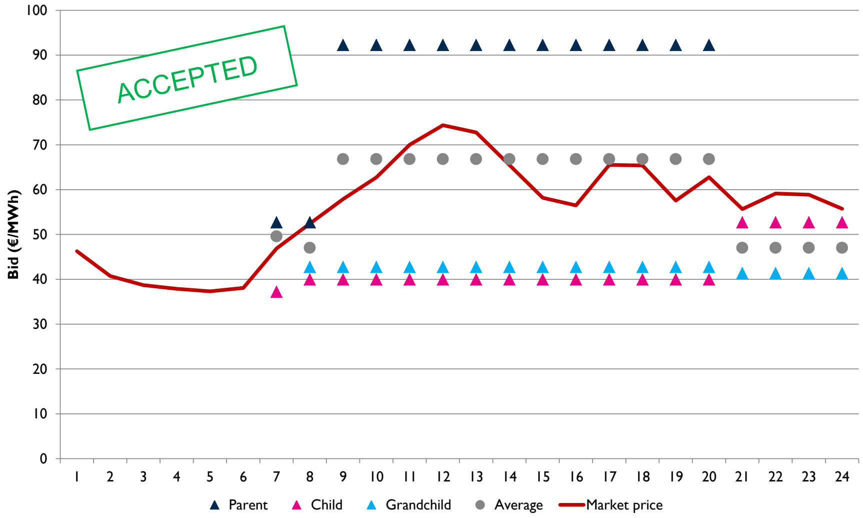
The Linked Block Order structure for this day is illustrated below.

Figure 4-6 Case 4 submitted Block Order for CCGT A



In this example, we assume that the start costs and no load costs for CCGT Unit A are fully allocated to the parent block (with no load costs for the final 4 hours allocated to the adjacent child block). Applying the same market price profile as the previous cases, the combination of parent, child and grandchild blocks is in-the-money and all blocks are accepted. The parent block, incorporating start costs, is out-of-the-money in this example, but this loss is outweighed by the positive margin on the child and grandchild blocks.

Figure 4-7 Case 4 Block Order pricing for CCGT A

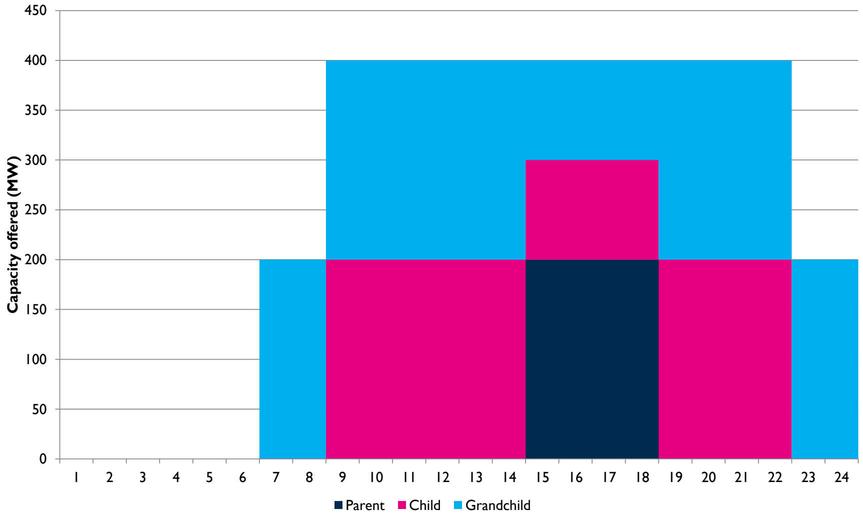


The Profiled and Linked Block Orders for CCGT A in Cases 3 and 4 are near-the-money. As a sensitivity, we found the block orders did not clear if the market clearing price was 1.2% lower across the day. This illustrates that CCGT A could be exposed to scheduling risk by having its block order paradoxically rejected by EUPHEMIA or of misjudging the timing of blocks and offer prices across the day.

<u>Case 5: Linked Block Order</u>

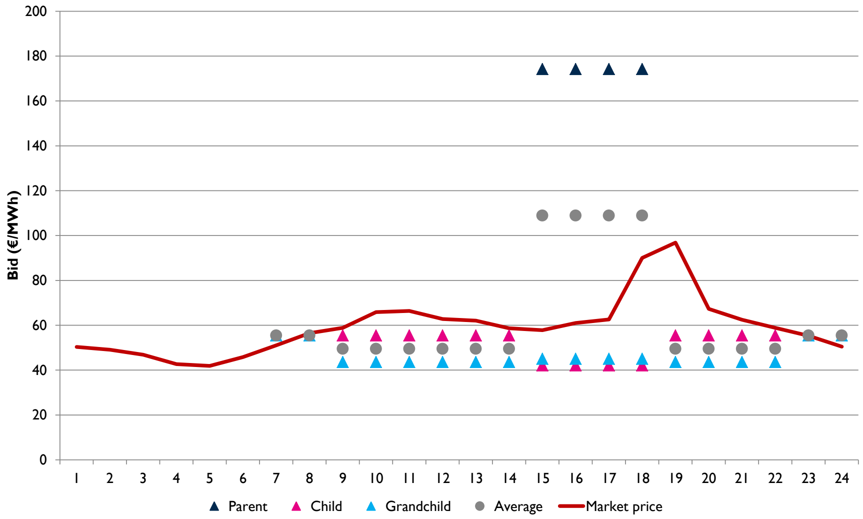
In this example, we construct a Linked Block Order for CCGT Unit A with the intention of presenting the most accurate representation of the unit's technical characteristics and cost structure. In a sense, this is analogous to the bidding methodology in the current SEM trading arrangements. The duration of the parent block matches the unit's minimum on time of 4 hours and the volume represents the unit's MSG of 200 MW. Start and no load costs are fully allocated to the parent block, such that any additional output can be offered at incremental cost. Child and grandchild blocks are then constructed for incremental output and for adjacent periods, as illustrated below.

Figure 4-8 Case 5 submitted Block Order for CCGT A



Given our cost assumptions, the parent block in this example is priced at 174 €/MWh. Applying a market price profile for a characteristic winter day, we find that the parent block is out-of-the-money. However, the combination of the parent, child and some grandchild blocks is in-the-money in this example.

Figure 4-9 Case 5 Block Order pricing for CCGT A



Note that the timing of the parent block in this case does not coincide with the period of highest outturn market prices. Ultimately this did not impact the acceptance outcome in this example (because the family of parent, child and grandchild blocks are considered in combination), but may have done so in other scenarios. In practice, the timing of peak prices in the SEM is likely to become less predictable, due to uncertainty in both the level of intermittent generation and its participation in the I-SEM DAM.

The resulting acceptance profile for CCGT A is as shown below.

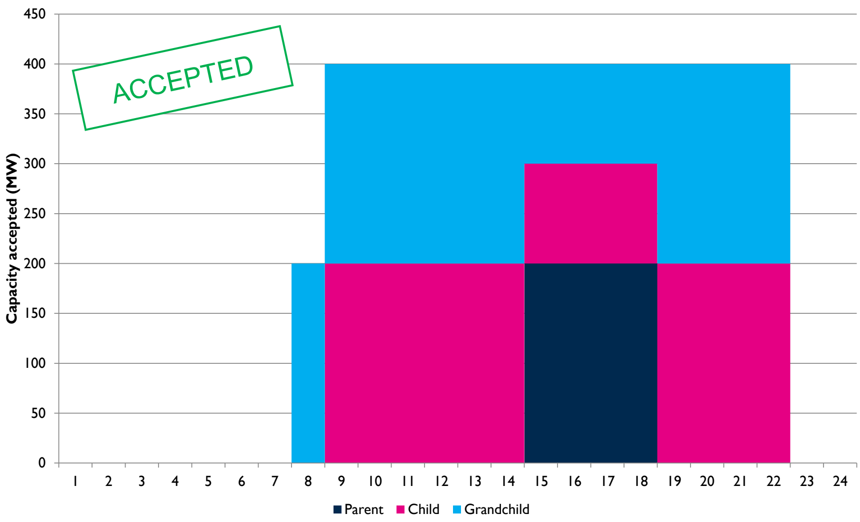
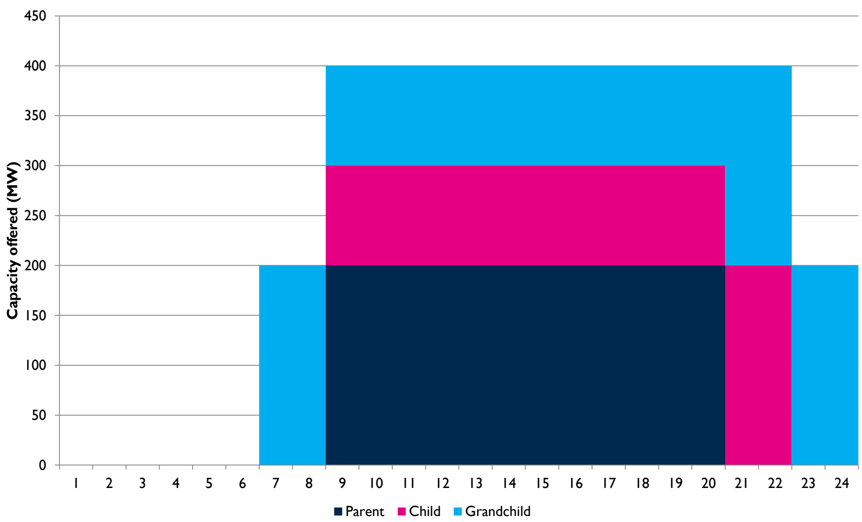


Figure 4-10 Case 5 accepted order volumes for CCGT A

<u>Case 6: Linked Block Order</u>

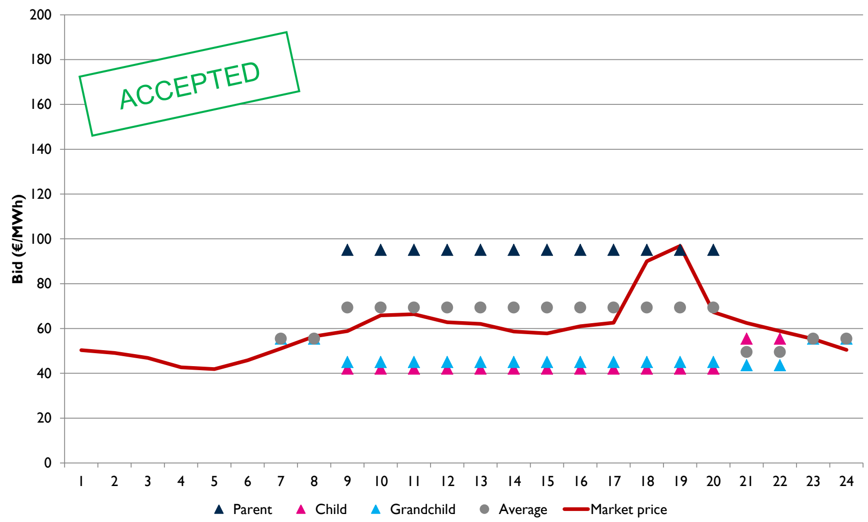
Building on Case 5, let us consider an alternative Linked Block Order using a larger parent block. Applying a 12 hour parent block allows start costs to be spread over a larger volume, potentially creating a more competitive bid price.

Figure 4-11 Case 6 submitted Block Order for CCGT A



As in Case 5, we assume that start and no load costs are fully allocated to the parent, resulting in a parent block price of 95 €/MWh in this example.

Figure 4-12 Case 6 Block Order pricing for CCGT A



Applying the same exogenous market price profile, we obtain the same result in terms of accepted orders. Although margins on individual parent, child and grandchild blocks differ between Cases 5 and 6, the combined margin across the family of blocks does not. In practice, we would expect to see different outcomes in Cases 5 and 6 due to the interaction between near-the-money orders and price formation. Moreover, the mechanics of handling of complex configuration of block orders in EUPHEMIA may mean that the prospects of a paradoxically rejected order differ between the two cases.

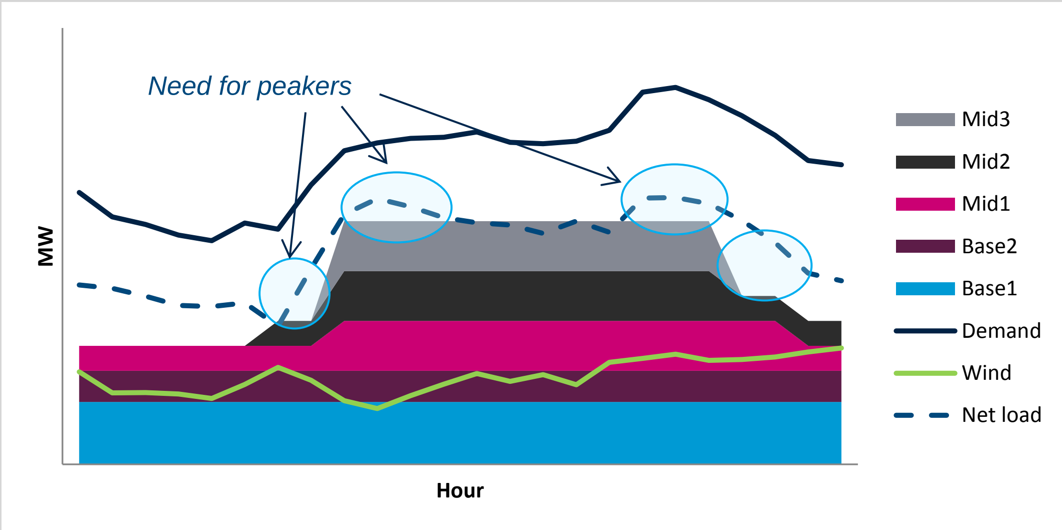
The Linked Block Orders for CCGT A in Cases 5 and 6 are near-the-money. We found that a 0.2% reduction in the market clearing price across the day would lead to the orders being rejected in these cases. Again this illustrates the sensitivity of the outcomes from the central dispatch algorithm to small differences in offer strategies and the potential for increased scheduling risk.

Implications for system flexibility and predicting net load

As we have illustrated in the case studies, baseload and mid-merit generators could potentially use Profiled or Linked Block Orders in the I-SEM day-ahead market to reflect their technical and commercial operating parameters. However, the use of block formats could reduce the flexibility offered to the market, relative to the current SEM arrangements, with generators opting to extend block durations and spread cost recovery. Flexibility may be reduced further by any limitations imposed on the order formats (e.g. a limit on the number of child blocks may prevent a strip of hourly orders being offered for output above the parent block level). Reduced flexibility from baseload and mid-merit market participants would place a greater reliance on peaking generators to ‘fill the gaps’ around the block orders.

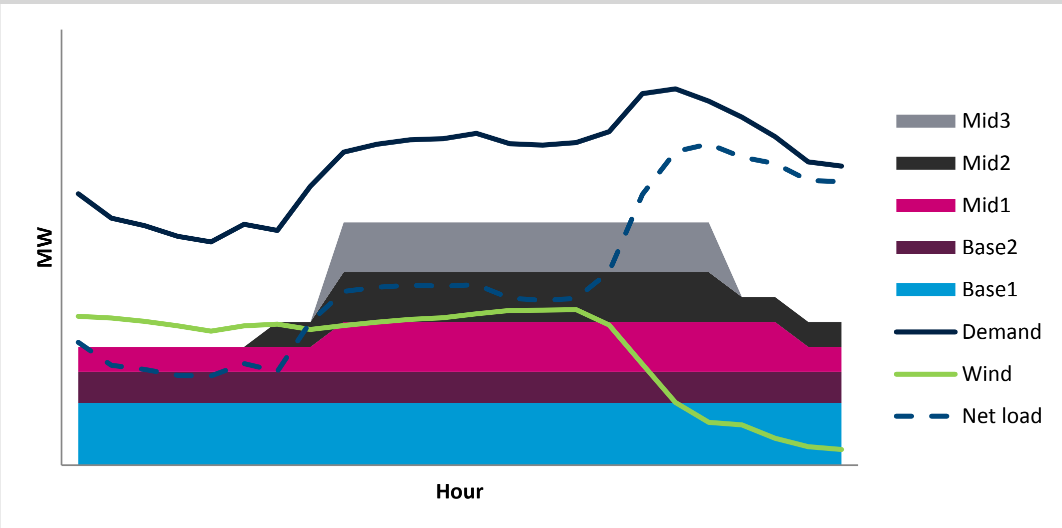
The schematic figure below illustrates how a combination of block orders from base and mid-merit generating units could stack up across the system relative to overall demand, net of wind generation. In this example, the combined profile of block orders broadly follows the system net load profile across the day, but more flexible (e.g. hourly) orders would be needed to match load in each hour. This reliance on flexible hourly orders is accentuated around the edges of the mid-merit blocks.

Figure 4-13 Block orders and system net load



Profiled and Linked Block Orders require participants to pre-determine the start and end times of each block. Participants are therefore at risk of misjudging their block timings and either failing to clear their orders or potentially under-recovering costs (if the profile of accepted orders differs from that expected for cost allocation purposes). With increasing variability in intermittent generation, the net load profile on some days may differ materially from the predicted demand shape. The figure below shows the same demand profiles and block orders with a different aggregate wind profile. Mid-merit block orders structured around day-time operation would be less likely to clear on this day than those supporting a later start and overnight operation.

Figure 4-14 Block orders and wind variability



Case 7: Linked Block Order

Our previous Linked Block Order examples have assumed:

- Start costs are fully allocated to the parent block
- No load costs are fully allocated to the first block (parent or child) in each hour.

Other bidding strategies could consider alternative allocations of start or no load costs, for example:

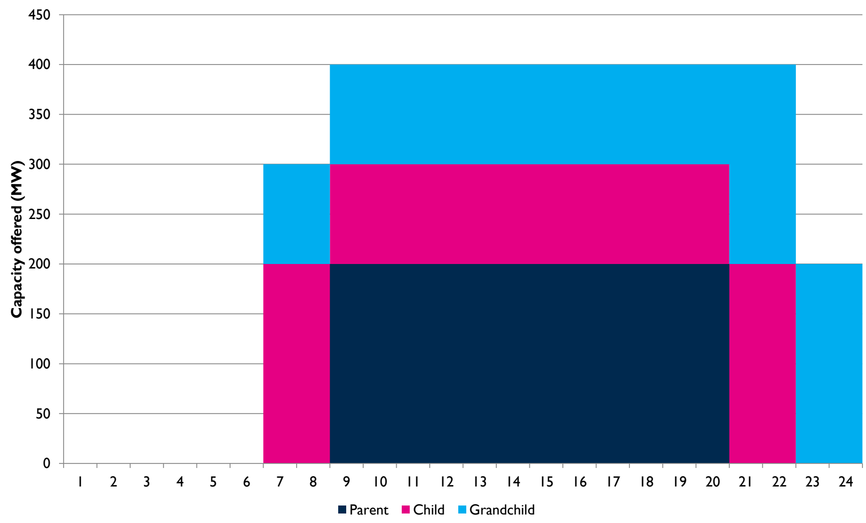
- To improve the competitiveness of the parent block price by allocating some start or no load costs to child and grandchild blocks
- To re-allocate costs between peak and off-peak periods, reducing the price of overnight blocks and potentially avoiding a shutdown

The risk of re-allocating costs away from the parent block or between hours is that some blocks may not be cleared, leading to the potential under-recovery of costs.

For Case 7, we consider a 12 hour parent block structure for CCGT A, as in Case 6. Start costs are fully allocated to the parent block, but no load costs are smeared across the parent, child and grandchild blocks. To improve the competitiveness of overnight pricing, a proportion of the no load costs for the final 2 periods are re-allocated to the grandchild blocks during peak periods (17 to 20).

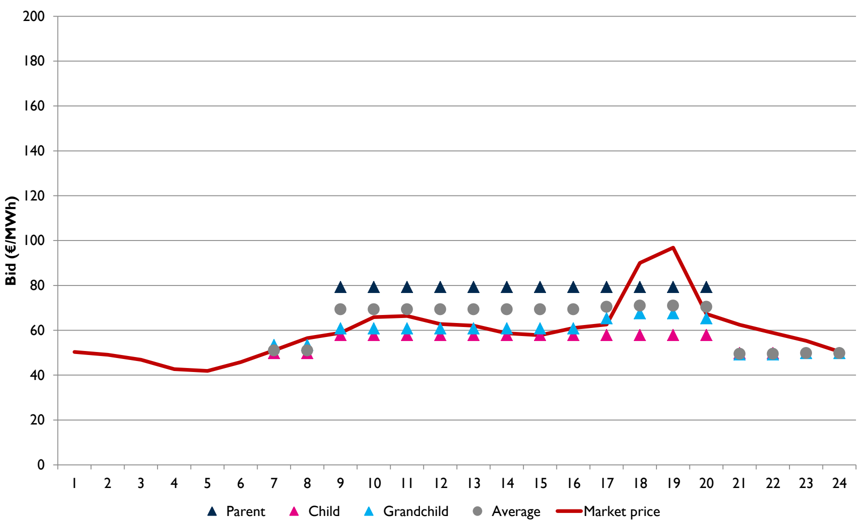
The submitted Linked Block Order structure is shown below.

Figure 4-15 Case 7 submitted Block Order for CCGT A



Having re-allocated a proportion of no load costs, the parent block price is reduced to 79 €/MWh in this example. Applying the same winter price profile, the parent block remains out-of-the-money but a combination of parent, child and grandchild blocks is cleared.

Figure 4-16 Case 7 Block Order pricing for CCGT A

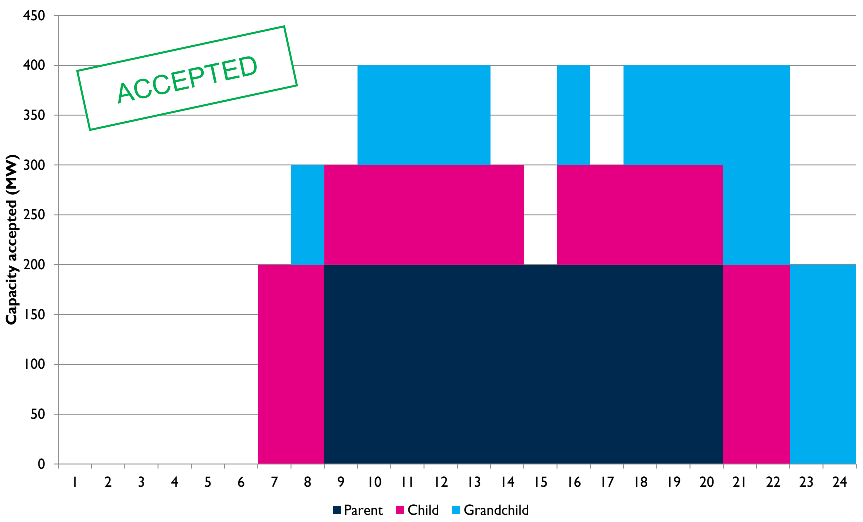


The resulting accepted offer profile is shown below. Compared to Case 6, we find that the addition of no load costs results in child or grandchild blocks not clearing in certain daytime periods (14,15,17). However, additional blocks are cleared during off-peak periods (7,8,23,24), potentially enabling the plant to avoid an overnight shutdown.

In this example, the operating costs for CCGT A are under-recovered by around €7,300 (due to the allocation of no load costs to blocks that were not cleared).

As a sensitivity, we found that a 0.6% reduction in the market clearing price across the day would lead to the family of Linked Block Orders being rejected. Orders would therefore be cleared at lower prices in Case 7 than Cases 5 and 6 for the same characteristic day, but this would result in cost under-recovery.

Figure 4-17 Case 7 accepted order volumes for CCGT A



Case 7 illustrates how different operating outcomes and gross margins could be achieved by varying the allocation of start and no load costs between blocks. Participants may wish to explore a large range of pricing strategies to strike an appropriate balance between achieving a desired operating profile and ensuring cost recovery. However, it is likely that bidding strategies will need to evolve dynamically in response to changing market fundamentals and the actions of competitors.

Managing the scheduling risk associated with this dynamic spot market position will introduce additional complexity for independent generators compared to the current SEM arrangements, and may lead to participants seeking a higher risk premium on forward contracts.

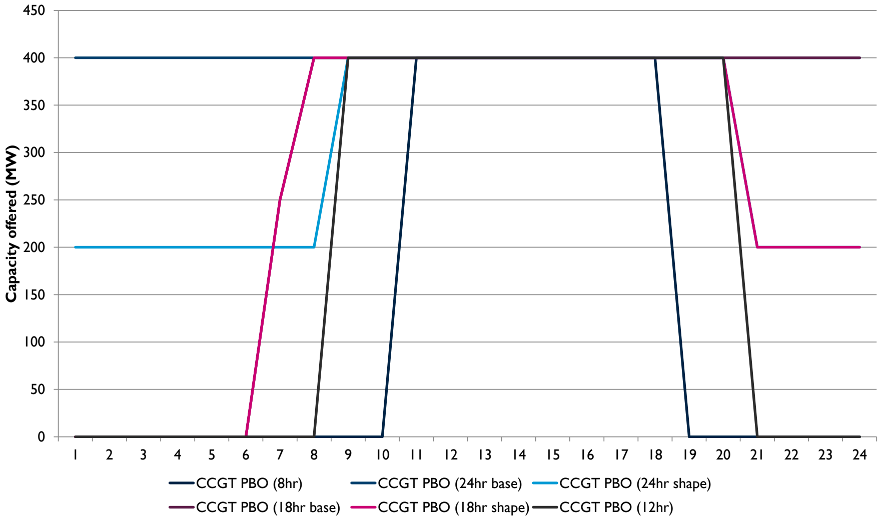
Case 8: Exclusive Groups

As the previous examples have illustrated, Profiled and Linked Block Orders require participants to make judgements regarding block start and end times, and to some extent, the relative competitiveness of their asset across the day. These judgements will be based in part on expectations of market fundamentals and the likely profile of clearing prices. With the increasing growth in intermittent renewables, we can envisage that historical relationships between electricity demand and market prices will no longer hold and the timing of daily peak prices will become less predictable.

Given these uncertainties, there is a risk that participants misjudge the timing of their Block Orders and they fail to clear. Exclusive Groups may help mid-merit generators mitigate this risk by allowing generators to submit a range of alternative operating profiles, leaving the choice of the optimal schedule to be resolved by the EUPHEMIA algorithm. Conversely, Exclusive Groups cannot be combined with parent and child combinations, thus limiting the ability to represent other commercial and technical parameters.

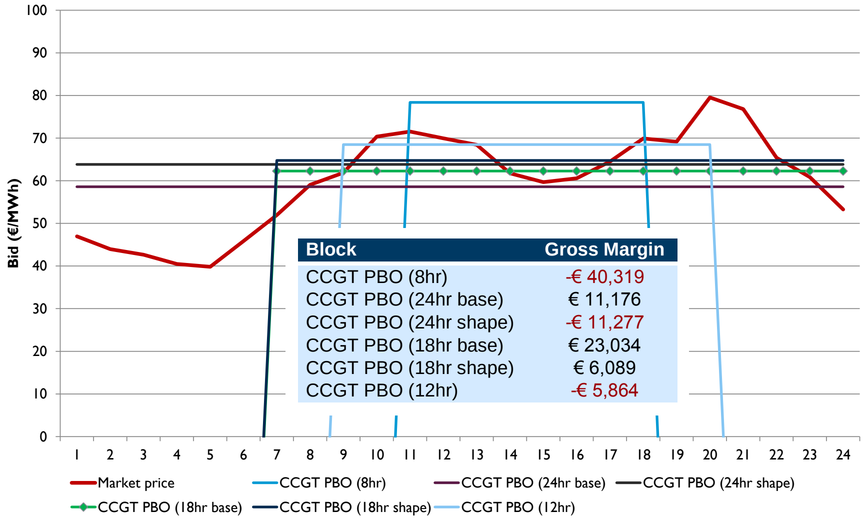
For Case 8, we assume that CCGT A submits an Exclusive Group of six Profiled Block Orders, ranging in duration from 8 to 24 hours. These orders are mutually exclusive, and each is priced to fully recover incremental, no load and start costs over the operating profile.

Figure 4-18 Case 8 submitted Block Order Groups for CCGT A



Applying a characteristic autumn price profile, three of the six Block Orders are out-of-the-money. If multiple blocks are in-the-money as in this case, EUPHEMIA will select the Block Order which maximises social welfare. Here we assume the accepted Block Order has the highest implied gross margin. This is a 18 hour base profile, as shown in Case 3.

Figure 4-19 Case 8 Block Order pricing for CCGT A



Peaking

Peaking plant are generally more flexible than mid-merit plant. This flexibility can be offered to the DAM using Simple Hourly Orders, assuming plant technical constraints are not binding (e.g. minimum on time of 1 hour or less).

Less flexible plant may consider applying Simple Block Orders, Profiled Block Orders or Linked Block Orders to ensure their technical constraints are adequately represented.

As with mid-merit generators, one of the challenges for peaking participants using Block Orders will be judging the most appropriate block timings for the market. Exclusive Groups may provide one solution to this problem. Flexible Block Orders also rely upon EUPHEMIA to optimise the timing of accepted orders from a market perspective, removing the need for participants to pre-determine their operating schedule. Flexible Block Orders may be particularly suitable for energy-limited resources, as well as demand response.

5. IMPLICATIONS

5.1. Introduction

In this section we lay out the implications of the I-SEM arrangements for scheduling risk, and the broader market impact. This draws on the illustrative examples explored in Section 4, but also takes into account a broader set of considerations, given the limitations of the simplified approach we have used for these.

5.2. Single Asset

Reflecting flexibility and costs is not straightforward

From the perspective of a single mid-merit asset, as the examples above demonstrate the I-SEM arrangements mean that it is not straightforward to reflect the technical characteristics and costs of the asset effectively through the available EUPHEMIA offer structures. This could be further exacerbated if there are limitations on how participants can apply the offer structures (such as limiting the number of children in a Linked Block Order). This means that a generator who has hedged forward will face scheduling risk in attempting to re-optimise a position at the day-ahead stage – as this could result in the asset not being scheduled in periods where prices clear above the cost of running the plant, creating a negative outcome relative to the hedged forward margin.

Risk is greatly exacerbated without a liquid IDM

This risk would be significantly mitigated if the DA market was accompanied by a liquid intraday market, actively trading from the publication of the DA auction results through to gate closure. This would enable generators to trade out positions from the DA swiftly at limited cost. In the long run the intent is for this to be provided by the harmonised European intraday trading platform, but the timeframe for that is unclear, and it is almost certain that this will not be in place for a material period of time following the introduction of I-SEM.

Exclusive DAM also limits position management

In no other European market is the DAM the exclusive route for physical trading. This means that market participants can manage their position through a combination of auction participation, standard bilateral trading, and structured products, enabling a much greater level of control, particularly important for mid-merit plant, even prior to the intra-day market, enabling further re-shaping and refinement. None of these will be options for I-SEM participants. Only under I-SEM would generators be reliant on the specifics of EUPHEMIA offer structures to reflect cost and flexibility.

There is a possible incentive to zero-bid, reducing market efficiency

A possible consequence of this is that mid-merit plant may choose to avoid this risk by 'zero-bidding' at the DA stage to match forward contracted positions, unless a less prescriptive version of the Bidding Code of Practice was retained in some format. This enables the plant to reduce scheduling risk and therefore risk to hedged margin. However, at times where the cost of generation for the plant was higher than the resulting clearing price, this would be neither an efficient market solution nor an optimal economic outcome for the plant.

There may be an incentive to reduce the level of asset flexibility offered

There are further consequences for a single asset that make the bidding strategy more difficult. There are clearly a reduced set of options for offering generation flexibly to the market compared to the current SEM. The need to recover start costs could lead to a tendency to offer longer duration 'blocks' than could be technically offered (such that the increment associated with the start cost is spread more widely). In addition, it is likely that there will be limits on the number of child blocks that could be offered, which could mean that a potential "hourly strip" of child blocks on a single parent block would need to be aggregated up.

Risk of cost under-recovery depending on cost allocation in bidding strategy

Further, the offer strategy for a single asset using Linked Block Orders will face choices about how to spread start-up and no load costs across the parent and child block prices. Loading the full possible start-up cost and no-load cost into the parent block increases the risk that the parent will be out-of-the-money, although these losses may be offset by positive margins on child blocks in determining the final clearing outcome. On the other hand, spreading no-load or start costs across child blocks increases the competitiveness of the parent block, but at the risk of cost under-recovery if child blocks are not cleared with the parent. The examples in Section 4 (albeit simplified through imposing an exogenous change to market price) demonstrated how sensitive offer acceptance could be. Taken together with the potential for paradoxically rejected bids this highlights the potential for significant scheduling risk associated with judgements around offer parameter choices.

Risk associated with start-of-day state uncertainty will be reflected in balancing bids and offers

A key uncertainty at the point of submission for DA offers is the running state of the asset at the start of the offer period. Whilst there will be a current traded position, there will still be uncertainty as to any balancing actions that may be executed in the interim. Offers will need to be made based on an assumed schedule. If a balancing bid or offer is then accepted, then additional costs may be incurred (for example, start costs if a balancing bid is accepted for the plant to turn off) and it is likely that the plant would seek to recover these through an appropriate premium (discount) on its balancing offer (bid).

Generators cannot combine complex options and hence cannot mitigate all risks

Given that participants will have to choose between the use of offering a set of alternative profiles, versus using a parent-child structure, this implies that they will need to weigh up the uncertainties associated with the within-day shape of prices against the uncertainties associated with accepted volume and duration (and corresponding risk of under-recovery). For example, on a day with significant uncertainty as to wind generation, and hence to the profile of net demand, the participant might choose to utilise a set of profiles to have alternative blocks covering different potential peak periods, rather than offering a parent that might turn out to have been set at a period of low net-demand. This suggests that additional information will be important, particularly in regard to wind and demand forecasts.

Risk increased due to uncertainty in competitor strategies

In developing an offer strategy, a generator will need to take into consideration the potential strategies that could be followed by competing generators. The issues outlined above are likely to drive diversity in strategies, and these are likely to evolve in a dynamic way in response to analysis of market outcomes (assuming that such strategies are relatively unconstrained by bidding principles). It is likely that market participants with sufficient resources will aim to model the EUPHEMIA algorithm to enable them to test and develop the sophistication of their strategies. So the scheduling risk inherent in the limitations in EUPHEMIA offer structures will be magnified by the uncertainty and potential instability in strategies applied by different competitors. This is compounded at times when GB and SEM price levels are similar as generators will then need to consider both SEM participant strategies and the potential level and shape of GB offers. Whilst it is difficult without conducting detailed modelling to compare the scheduling risk under current SEM arrangements (associated with the Uplift methodology) and under the proposed I-SEM arrangements, it could be that this "competitive strategy dynamic" leads to a higher degree of scheduling risk. It is possible that over time there could be some stabilisation as strategies mature, but a risk of a return to a more volatile environment will always be present.

5.3. Different technologies

Risks are most material for mid-merit thermal assets

For plant that are typically running baseload, or for wind (or other intermittent plant) with very low short-run costs, this risk is not relevant. For very flexible plant designed specifically as peakers (such as OCGTs), then the risk is low as these plant can have a more straightforward strategy of offering fully loaded hourly prices (whereby they would recover start costs even if they were scheduled for a single hour). The type of plant for which the risk is most material will be thermal plant that are at mid-merit positions in the stack – which could, depending on relative commodity and carbon price levels, be either gas or coal plant. This is likely to be a substantial subset of I-SEM installed thermal capacity given the high levels of wind generation in the I-SEM.

Very flexible peaking plant may be beneficiaries

Given the implications above for such plant, and in particular that there could be a tendency to create offer structures which are less flexible than under the SEM, that would suggest, as illustrated above, that peaking plant could be direct beneficiaries, as there could be more reliance on these assets to provide the hourly profile given the possibility of more 'blocky' offers from mid-merit plant. The impact of scheduling of peaking units (potentially at unintuitive times) could lead to price volatility increasing the market risk for other participants.

5.4. Asset portfolio

Portfolio provides a diversity benefit

As I-SEM requires unit level bidding, then similar considerations to those described above will be relevant for mid-merit assets within a broader portfolio. However, having a portfolio position is nevertheless likely to bring benefits. A portfolio player knows what the rest of its portfolio is doing with regards to commercial offers. In the context of the proposed High Level Design this provides an information advantage over a stand-alone generator who needs to guess this information to determine its most effective strategy. The advantage increases with the size of portfolio. In the current SEM this information asymmetry is managed through the Bidding Code of Practice which guarantees generators can compete on equal terms. However, without bidding principles it is very difficult to estimate the offer prices of competitors. Furthermore, it is not clear how unit-based bidding would in practice be interpreted where offers can be 'co-ordinated' across a portfolio. For example, with a hypothetical portfolio of three mid-merit plant, a strategy might involve zero-bidding for some volume of generation whilst offering capacity from other similar assets through parent/child offers placed at different times of the day.

We note that the High Level Design proposal for a single price cash-out means that longs and shorts in a generation portfolio will effectively net out. While unit bidding is proposed for the DAM and IDM, cash-out will be at a portfolio level. This would potentially advantage portfolio players and reduce within day liquidity, although other aspects of the detailed design may constrain participant behaviour from benefitting from this apparent anomaly.

Complex algorithm likely to encourage complex portfolio strategies

More generally, those players with a portfolio of assets are likely to be able to develop more sophisticated strategies over time, given the complex nature of the DAM in terms of offer structures and price setting. This may be especially true in a small market such as the I-SEM, where single plants represent a material share of the stack. It is likely that these players will aim to replicate the EUPHEMIA algorithm to develop and test these strategies, and assess the potential portfolio benefits in terms of an increased level of infra-marginal rent. It may prove very difficult from a regulatory perspective to distinguish between valid commercial strategies and strategies that are potentially anti-competitive or abuse a position of market power at certain times.

Given the potential for additional value to accrue to very flexible plant, then a portfolio with a significant proportion of such capacity could benefit.

5.5. Market clearing, balancing and dispatch

Potential for artificial price spikes and troughs, and increased volatility

We have discussed above the implications for a single asset or a group of assets. There is a further consideration as to how the combined strategies across the market may interact within the algorithm and how this could affect clearing prices in the auction. This is obviously contingent on the interaction between multiple strategies across different market participants, and is also likely to be dynamic, as strategies are evolved based on experience and observation of competitors. However, there is a concern that the consequence of strategies designed to mitigate scheduling risk, when translated across the market, could lead to inefficient outcomes. For example, if a material number of mid-merit plant were to zero-bid, this could exacerbate an issue that will face the market anyway as wind deployment increases, potentially leading to spuriously low prices at times, possibly combined with spikes as more peaking plant are required to create required shape. Such inefficient volatility is likely to deter forward trading and new investment, to the extent that prices are in part an outcome of the specifics of EUPHEMIA and associated strategies, rather than fundamental costs. In a similar manner, interconnector flows could be distorted in an inefficient manner.

Mismatch between DAM schedule and feasible physical schedule could be exacerbated

Given the nature of the EUPHEMIA algorithm, which was not designed to determine optimal physical dispatch, it is clear in any event that there is no guarantee that the result of the DA auction will be technically feasible, particularly for mid-merit plant. It is not yet clear in the I-SEM design how this will be managed (at least prior to any intra-day market) in terms of the steps to a feasible dispatch schedule that EirGrid can operate against. The types of issues discussed above could exacerbate this issue further.

5.6. Forward trading

Potential impacts on forward liquidity

Relative to the current SEM, the complete removal of bidding principles would mean in theory that an individual generator could ensure dispatch in the DAM to match a forward traded position by offering at a very low price below cost (assuming others were not doing the same). However, in doing so, it is likely to be reducing its expected earnings (since it will not be re-optimising at the day-ahead point, and since that strategy may restrict its ability to offer close to cost at other times), which could either deter forward hedging or result in an inefficient premium on forward prices. This could ultimately increase costs to consumers.

Further, to the extent that a material volume of mid-merit capacity did hedge forward, and then employed adapted DAM strategies to reduce scheduling risk, this could distort price formation in the DAM, in turn presenting a concern for the further development of liquidity.

Forward liquidity may also be impacted by uncertainty around price setting in the DAM, given the volatile nature of prices that could emerge as a result of the dynamic evolution of participant bidding strategies and the clearing algorithm's handling of complex orders in a small market.

6. CONCLUSIONS

In this paper, we have highlighted a number of potential risks associated with using the EUPHEMIA algorithm as the primary mechanism for scheduling plant, a concept without precedent in other European markets.

We believe that scheduling risk, present in the current SEM, is likely to endure and may increase under the proposed design, at least initially, impacting on forward market liquidity and prices. We have illustrated a number of examples that illustrate the potential risks. Uncertainty surrounding estimating the level of net demand and how to internalise start-up and no-load costs in offer structures represent the greatest challenge. The uncertainty is further compounded by the proposed relaxation of the Bidding Code of Practice which will make it more difficult to anticipate the offer strategies of competitors. In this respect, portfolio players will have a key advantage.

Given that the primary requirement for a liquid forward market is full confidence that the day-ahead index is reflective of supply/demand fundamentals, transparently derived, and free from potential distortion associated with particular participant strategies, we believe that the set of issues outlined in this document warrants careful consideration if this key objective of the new arrangements is to be met.