Integrated Single Electricity Market (I-SEM)

High Level Design for Ireland and Northern Ireland from 2016

Draft Decision on HLD for I-SEM

SEM-14-046

Initial Impact Assessment

June 2014

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1 SUMMARY

1.1 INTRODUCTION

1.1.1 This paper forms part of the process for implementing a new High Level Design (HLD) for the Integrated Single Electricity Market (I-SEM) in Ireland and Northern Ireland by the end of 2016. The purpose of this paper is to present the Initial Impact Assessment (IIA) of the options **for energy trading arrangements and Capacity Remuneration Mechanisms** (CRMs) described in the February 2014 Consultation Paper on the new HLD for the I-SEM (SEM-14-008).

1.1.2 This IIA informs the Draft Decision of the SEM Committee (SEMC) on the HLD for I-SEM, and should be read alongside the main Draft Decision Document.

1.1.3 The IIA includes:

- **A cost-benefit analysis of the possible differences between consultation options**. This looks separately at energy trading arrangements and at CRMs**,** and includes estimates of wholesale market costs and benefits, and costs of implementation and operation of different arrangements.
- **Qualitative assessment** of the consultation options against the nine assessment criteria set out for the I-SEM HLD, supported by quantitative assessment.

1.1.4 For the cost-benefit analysis, all the wholesale market modelling has been done for four snapshot years (2017, 2020, 2025 and 2030). For each snapshot year, different combinations of weather, demand and availability profiles have been modelled – this provides 15 different market outcomes for each snapshot year. Unless otherwise stated, this IIA reports the average outcome for each snapshot year.

1.1.5 Two reference cases (Base Case A and Base Case B) were used to inform the estimates of the wholesale market costs of different options. The main differences between the input assumptions for each Base Case are the rate of renewable growth in the All-Island Market post 2020, and the cost competitiveness of coal-fired generation against gas-fired generation

1.1.6 In both Base Cases, the All-Island Market meets the 2020 renewable target of 40%. However, post-2020 growth in renewables is assumed to be much stronger in Base Case A (52% renewables by 2030) than in Base Case B (45% renewables by 2030).

1.1.7 In Base Case A, low carbon prices and high gas prices means that coal is more competitive than gas as a fuel for power generation. In Base Case B, higher carbon prices mean that gas-fired generation becomes more cost competitive than coal-fired generation.

1.2 OBJECTIVES OF INTERVENTION

1.2.1 In Ireland and Northern Ireland, the Department of Communications, Energy and Natural Resources (DCENR) and the Department of Enterprise Trade and Investment (DETI) respectively have charged the SEM Committee with responsibility for developing the set of trading arrangements that will be compliant with the EU Target Model. These set of arrangements will be called the Integrated Single Electricity Market (I-SEM).

1.2.2 It is timely to review the design of the All Island Market for electricity given the changes seen since the creation of the SEM, which will have been in operation for over nine years by the end of 2016. This will help to ensure that the I-SEM HLD will deliver the greatest benefits for consumers on the island of Ireland (in line with the overall objective of the SEMC).

1.2.3 The changes since the creation of the SEM include:

- increased DC interconnection capacity with the GB electricity market;
- much higher contribution of variable renewables to the generation mix;
- the development of the EU Target Model which provides an opportunity for closer integration of the All Island Market with other European electricity markets; and
- greater potential for more active involvement of the demand side in the All-Island Market.

1.2.4 The HLD of the I-SEM must be in line with the Principal Objective of the SEM Committee to protect the interests of electricity consumers in Ireland and Northern Ireland. This is supported by the nine assessment criteria for the I-SEM HLD, which have been divided into primary and secondary assessment criteria.

1.2.5 Primary assessment criteria are backed up by the SEM Committee objectives in primary legislation in Ireland and Northern Ireland. Furthermore, they reflect the three pillars of European energy policy of sustainability, competitiveness and security of supply and as such are requirements of European law.

- Internal Energy Market;
- Security of Supply;
- Competition;
- Environmental; and
- Equity.

1.2.6 Secondary assessment criteria are not expressly set out in national or EU legislation (though they are implicit in the SEM Committee's objectives and standard principles of economic regulation). They remain important for the SEMC when reaching a decision on the I-SEM and are as follows:

- Adaptive;
- Stability;
- Efficiency; and
- Practicality.

1.3 ENERGY TRADING ARRANGEMENTS

1.3.1 The February 2014 I-SEM HLD Consultation Paper (SEM-14-008) presented four options for the HLD of energy trading arrangements:

- Adapted Decentralised Market (Option 1 - ADM);
- Mandatory ex-post Pool for Net Volumes (Option 2 - MPNV)
- Mandatory Centralised Market (Option 3 - MCM); and
- Gross Pool – Net Settlement Market (Option 4 - GPNS).

1.3.2 The Consultation Document did not include a 'do nothing' option as that would not be compliant with the requirements of the EU Target Model.

1.3.3 Table 1 summarises the reasons why the qualitative assessment identified the preferred option for energy trading arrangements as being a version of Option 3 with the following modifications:

- Consideration of additional measures to support forward market liquidity (in addition to a highly liquid spot market).
- Possible relaxation of mandatory participation in the DAM; however the DAM, IDM and BM would collectively remain the exclusive route to physical nominations of demand and generation.
- Allowing portfolio bidding for generation in specific instances where the advantages do not outweigh the disadvantages (e.g. aggregation for small renewable generation).

Table 1 – Summary of qualitative rationale for preferred option against each assessment criteria

		Rationale for preferred option
Primary Assessment Criteria	**Internal Electricity Market**	Supports most efficient implementation of the Target Model in the All-Island Market because of emphasis on centralised and transparent arrangements to concentrate physical trading in the DAM and IDM.
	Security of Supply	Delivers the DAM as both a strong reference market for forward trading, and a robust starting point for dispatch (with full integration of physical interconnector capacity). This is supported by a liquid IDM and mandatory BM
	Competition	Facilitates strongest competitive pressures through focus on unit-based bidding by generation into liquid centralised market places with full integration of physical interconnector capacity
	Environmental	Provides the best overall package in terms of delivering market signals to reduce curtailment, and facilitating greater ex-ante trading opportunities for variable renewables (particularly with modification to allow aggregation for small renewable generation)
	Equity	Emphasis on centralised market places ensures market access for all participants, with imbalance arrangements delivering sharper targeting of cost and benefits of (in)flexibility.
Secondary Assessment Criteria	Stability	Retains the strengths of the SEM whilst being much more closely aligned with the prevailing design of European electricity markets
	Adaptive	Benefits of easier coordination of changes to trading arrangements because of emphasis on trading in centralised (European) markets
	Efficiency	Offers a number of advantages for the All-Island Market because that the starting point for dispatch is based on a centralised unit commitment process that fully integrates the available physical interconnector capacity
	Practicality/Cost	Allows aggregation for small renewable generation whilst still maintaining high physical liquidity in centralised ex-ante markets

1.3.4 It is difficult to objectively model different forms of energy trading arrangements, as the quantitative outcomes (e.g. wholesale market costs) will typically be driven by assumptions about the quality of the market outcome under each option – e.g. such as the level of competition assumed for each option.

1.3.5 Therefore, the cost-benefit analysis for the energy trading arrangements is focused on the size of wholesale market benefits that would be needed to justify any increased costs of implementation and operation for the preferred option identified through the qualitative assessment.

1.3.6 There is only a small difference between the options in terms of the best estimate of costs of implementation and operation (on an annualised basis). The high cost of implementing the net pool in Option 2 means that it is estimated to cost €2m/a (on an annualised basis) than the other options.

1.3.7 The estimated implementation and operation costs are sensitive to the assumptions about the extent to which each market participants has to have its own 24 hour trading operation to support highly liquid DAM and IDM (which are seen to be essential to the efficient implementation of the EU Target Model). This is addressed in the modified version of Option 3 by allowing some aggregation for smaller generation, without undermining the liquidity and transparency of the DAM and IDM.

1.3.8 The qualitative assessment of the consultation options identified that the preferred option would best:

- support efficient Day-Ahead allocation of interconnector capacity (through the market coupling process);
- deliver liquid intraday trading that ensured that scheduled interconnector flows responded to changes in the All-Island Market after the Day-Ahead stage; and
- facilitate the deployment of renewables.

1.3.9 Energy market modelling carried out for the cost-benefit analysis has identified the possible benefits in lower wholesale market costs that could be delivered by these three features of the preferred option. These wholesale market cost reductions are summarised in Table 2, which also shows the estimated differences in operation and implementation costs between the preferred option and the other consultation options.

1.3.10 The reductions in wholesale market costs shown in Table 2 represent the 'full' benefit of the strengths of the preferred option compared with the other consultation options. Even if only a proportion of these benefits were realised, then the preferred option for energy trading arrangements could still deliver significantly lower wholesale market costs than compared with the other options.

Table 2 – Annualised costs of preferred option for energy trading arrangements compared with the other consultation options (€m, real 2012 money, costs annualised between 2017 and 2030 with 3.5% discount rate)

Implementation and operation costs	Annualised cost of preferred option compared with other consultation options	
Market participant costs	€0m/a	
Institutional costs	-€2m/a to €0m/a	
Wholesale market costs	Base Case A (52% RES by 2030)	Base Case B (45% RES by 2030)
Efficient Day-Ahead Interconnector Flows	-€28m/a	-€10m/a
Efficient Intraday Trading	-€38m/a	-€14m/a
Lower cost of capital for variable renewable generation	-€32m/a	-€30m/a

1.3.11 In summary, the qualitative and quantitative assessment has identified that the modified version of Option 3 will deliver the biggest benefits for electricity consumers in the All-Island Market. These benefits will be a lower-cost production of secure and sustainable electricity supplies.

1.3.12 The main drivers of these benefits are:

- **concentration of physical liquidity and interconnector capacity into centralised Day-Ahead and Intraday markets built on unit-based bidding for generation** to support competition and routes to market for a range of different market participants.
- **a mandatory Balancing Mechanism after the Day-Ahead stage** to provide the TSO with access to a wide range of bids and offers to help it manage the system efficiently in real time.
- **cost-reflective imbalance prices** to provide efficient short-term signals for market participants (including flexible resources) to reduce the need for the TSO to balance the system in real time.
- **allowing aggregation of small generation in the DAM and IDM** means independent generators can benefit from economies of scale and from diversity in managing their market positions.
- **mechanisms to provide revenue transparency and clear reference prices compatible with the renewable price support arrangements** (i.e., REFIT in Ireland and CfDs in Northern Ireland).

1.4 NEED FOR A CAPACITY REMUNERATION MECHANISM

1.4.1 The February 2014 I-SEM HLD Consultation Paper (SEM-14-008) included a specific question on whether a CRM was needed in the I-SEM HLD. We now present the findings of the quantitative and qualitative assessment of this issue.

1.4.2 The latest annual All-Island Generation Capacity Statement 2014-2023 (GCS) projected a generation surplus out to 2023 on an unconstrained All-Island Market basis. This is based on the notifications by generators of closure decisions, which are

currently based on the fact that there is a CRM in the All-Island Market.

1.4.3 Therefore, to provide the SEM Committee with a wider perspective on the state of generation adequacy beyond 2016, the Regulatory Authorities asked EirGrid to carry out analysis of the implications for generation capacity adequacy in the absence of a CRM as part of the I-SEM. Their assessment is attached as Annex 1 to the Draft Decision Paper.

1.4.4 The EirGrid assessment considers some scenarios for closure of generation plant in addition to those notified by generators for the GCS (2014-2023). These closure scenarios are then tested for capacity adequacy against a reference case, and a number of sensitivities in relation to a tighter security standard, higher peak demand, and reduced interconnector availability.

1.4.5 Plants are assumed to close if based on their generation volumes from a market simulation, they require on average more than €3000/MWh from the energy-only market to recover their required costs on an annual basis (this means also that plants close if they also have no running hours). €3000/MWh is used as the cut-off price as it is the current price cap in the Day-Ahead Market in the price coupled markets of North West Europe.

1.4.6 The SEMC has not intended to use the EirGrid assessment as a stand-alone prediction of generation adequacy in an energy-only market. Rather, it forms part of the package of quantitative analysis to inform the assessment of the possible challenges for generation adequacy under an energy-only market.

1.4.7 The main findings of the analysis are that projections of capacity adequacy are sensitive to assumptions about closure decisions – with capacity adequacy shortages in 2020 and 2023 in these higher closure scenarios. In addition, the availability of interconnector capacity in tight periods is particularly important in determining the extent of capacity adequacy shortages in the higher closure scenarios.

1.4.8 In addition to the EirGrid assessment there is a cost-benefit analysis presented in this Impact Assessment. For this cost-benefit analysis a well-functioning energy-only market has been modelled. It is assumed to be fully competitive, with perfect foresight of 'expected' future revenues. Although there is a price cap of €3000/MWh (to reflect the price cap in the Day-Ahead Market), there is no restriction on price spikes up to that level. However, any price spikes are not assumed to encourage investment in demand-side response or storage.

1.4.9 Because a well-functioning energy-only market has been modelled, it delivers a level of security of supply that meets or exceeds the required security standard in the All-Island market, contrary to the RAs' expectations. In that respect, the modelled base case of an energy-only market is idealistic. However, it still highlights challenges for delivery of generation adequacy in the energy-only market, in particular in relation to:

- the importance of price spikes at times of system tightness - these allow generation plants to recover their fixed costs when they only have a small number of hours of operation.
- how non-renewable plants (that on average would expect to at least cover annual fixed costs from energy market revenues) manage the possibly large variability from year to year in extent of fixed cost recovery (i.e. a plant may have a very bad year or a very good year depending on the level of renewable generation, electricity demand, and availability of other plants).

1.4.10 Table 3 and Table 4 report the number of hours of high prices in an assumed well-functioning energy-only market in Base Case A. The entry and exit decisions of thermal generators in the modelling of the well-functioning energy-only market assumes that plants are able to capture all of these high price periods without regulatory or political intervention.

1.4.11 Table 3 shows the mean number of hours of high prices in each snapshot year, with the number and magnitude of price spikes increasing over time. This is the result of further renewable deployment reducing the running hours for thermal plant, meaning that the fixed costs have to be recovered in fewer hours.

1.4.12 Table 4 reports the number of high price periods in the most extreme year (of low wind generation and low thermal plant availability). It shows that in these circumstances, the price spikes are much more frequent than in the average year.

Table 3 – Number of high price hours in average year in 'well-functioning' energy-only market (Base Case A)

Number of hours	2017	2020	2025	2030
I-SEM price > €2500/MWh	3	7	10	12
I-SEM price > €2000/MWh	3	7	14	14
I-SEM price > €1000/MWh	5	16	33	35
I-SEM price > €500/MWh	19	43	69	71

Table 4 – Number of high price hours in extreme year in 'well-functioning' energy-only market (Case A)

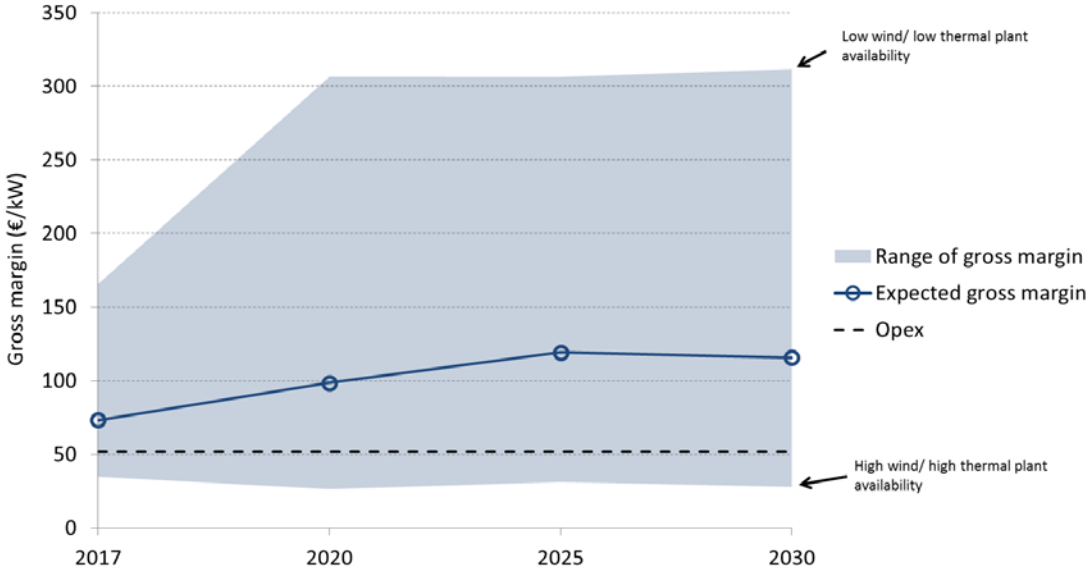
Number of hours	2017	2020	2025	2030
I-SEM price > €2500/MWh	14	33	44	55
I-SEM price > €2000/MWh	14	33	63	63
I-SEM price > €1000/MWh	28	72	115	116
I-SEM price > €500/MWh	79	140	215	216

1.4.13 These price spikes would increase the risk of regulatory or political intervention, especially given a general scepticism about the ability of the market to price scarcity efficiently in all circumstances (for reasons including market power concerns).

1.4.14 Figure 1 shows the expected and range of gross margins for each snapshot year for a 51% efficient (HHV) CCGT in the modelled energy-only market – the gross margin shown here equals wholesale electricity revenues plus net DS3 revenue minus variable fuel and operating costs. Therefore, it would need to be sufficient to cover annual fixed and capital costs in order for the plant to remain viable. In a year with relatively comfortable capacity margins (e.g. as a result of high renewable generation), the gross margin can be as low as around €20/kW. This would not be sufficient for a plant to cover its fixed annual operating costs.

1.4.15 The potential variability in gross margins could then reduce the confidence of plants that they will be able to recover the costs of staying in the All-Island Market – even where the average expected gross margin is sufficient to cover their fixed costs. This will particularly be the case where plants run infrequently, even though they may be essential for security of supply. This then raises the prospect of excess or disorderly exit, which is made worse by the relatively large unit sizes in the All-Island Market and the current existence of a CRM. Excess or disorderly exit would be particularly challenging for the All-Island Market given the relative isolation of the market, placing a high burden on domestic actions to ensure security of supply.

Figure 1 - Gross margin[1] for a 51% efficient (HHV) CCGT (Base Case A)



1.4.16 The qualitative assessment has highlighted a number of challenges for the delivery of generation adequacy under a set of energy-only arrangements in the I-SEM. These have not been specifically captured in the modelling of the well-functioning energy-only market for the cost-benefit analysis.

1.4.17 These challenges primarily relate to:

- **The scope for missing money:** whereby spot electricity market prices do not rise high enough during "scarcity" hours to produce adequate net revenues to cover the capital costs of investment in an efficient level and mix of generating capacity. This may be the result of regulatory intervention because of scepticism of the ability of the market to price scarcity efficiently. The wholesale market modelling has identified that price spikes would need to become higher and more frequent in a future energy-only market, which would increase the stress on this issue.
- **Public good nature of reliability**: which may prevent the ability of an energy-only market to deliver the efficient level of reliability.
- **Impact on entry and exit decisions for non-renewable plant of increased uncertainty over the timing and frequency of operating hours** (which could fluctuate widely from year to year): this is reflected in the range of gross margins for each snapshot year in the quantitative analysis, and may make it harder to strike forward contracts if sufficiently granular products are not available. By reducing variability in gross margin to manageable levels for capacity essential to maintaining security of supply for consumers in the All-Island Market, a CRM would mitigate the impact of the price and quantity

[1] Gross margin shown on this chart equals (wholesale electricity revenues + net DS3 revenue) minus variable fuel and operating costs

risks for plants operating in a high-RES world, and support lower cost financing of generation by reducing revenue volatility.

- **Indivisibility and coordination failures where unit sizes are relatively large compared with the overall market** – this may be a particular problem for efficient exit in a set of energy-only trading arrangements in the I-SEM

1.4.18 In conclusion, the qualitative and quantitative assessments support the retention of a CRM in the HLD of the I-SEM in order to better meet the I-SEM primary objectives, compared with an energy-only market

1.5 FORM OF CAPACITY REMUNERATION MECHANISM

1.5.1 The February 2014 I-SEM HLD Consultation Paper (SEM-14-008) presented a number of different options for the HLD of a Capacity Remuneration Mechanism (CRM) for the I-SEM:

- Strategic Reserve (Option 1);
- Long-term price-based (Option 2a);
- Short-term price based (Option 2b);
- Centralised Capacity auctions (Option 3)
- Decentralised capacity obligations (Option 4);
- Centralised reliability options (Option 5a); and
- Decentralised reliability options (Option 5b).

1.5.2 The long-term price-based scheme (Option 2a) is the option that is closest to the design of the existing CRM in the SEM.

1.5.3 A cost-benefit analysis has been carried out for 4 different CRM designs:

- **Long-term price-based (Option 2a):** modelling is based on the current SEM design.
- **Short-term price based (Option 2b):** modelling uses spot capacity price that is determined as a function of system tightness in each period.
- **Capacity auctions/obligations (Options 3 and 4**): modelling of annual capacity auctions, with demand for capacity set at a level to ensure that the required security standard is met.
- **Reliability options (Options 5a and 5b**): based on the modelling of a 'well-functioning' energy-only market that meets the required security standard – this reflects that the outcome of the qualitative assessment that the reliability options are the CRM that best supports efficient short-term energy price signals.

1.5.4 In line with national and European legislation, Strategic Reserve will remain available as a 'backstop' measure to address specific security of supply concerns on a case by case basis. Therefore, the cost-benefit analysis did not explicitly consider Strategic Reserve as an alternative to the other the CRMs (as it could be introduced alongside any of them). In addition, the costs and benefits of the Strategic Reserve will be very sensitive to the particular circumstances in which it is used.

1.5.5 The cost-benefit analysis did not differentiate between centralised and decentralised

approaches for the quantity-based CRMs, as these were addressed in the qualitative assessment as they can be hard to quantify.

1.5.6 Table 5 summarises the result of the cost-benefit analysis – the costs for the other 3 schemes are shown relative to a benchmark of the long-term price-based CRM (Option 2a). Base Case A was used as the reference scenario for the modelling of the impacts on wholesale market costs and consumer costs.

1.5.7 The cost-benefit analysis provides useful insight into the relative strengths and weakenesses of the different CRM options. However, it is that important the results of the cost-benefit analysis are considered in the light of the unquantified benefits of different CRMs identified in the qualitative assessment. In particular, this applies to the relatively small difference in wholesale market costs, and the consumer bill savings in the short-term price-based scheme.

Table 5 – Annualised costs of different CRMs relative to long-term price based CRM (Option 2a), (€m, real 2012 money, costs annualised between 2017 and 2030 with 3.5% discount rate)

a (2017-2030), real 2012 money, 3.5% discount rate	Short-term Price Based (Option 2b)	Capacity Auctions (Options 3 and 4)	Reliability Options (Options 5a and 5b)
Market participant costs	€0m/a	+€2m/year	+€2m/a
Institutional costs	€0m/a	+€1m/a/year	+€1m/a
Wholesale market costs	-€9m/a	-€5m/a	+€3ma
Total costs	**-€9m/a**	**-€2m/a**	**+€6m/a**
Consumer bills (net of implementation and operation costs)	**-€203m/a**	**-€49m/a**	**-€74m**/a

1.5.8 Table 5 illustrates that compared with the price-based schemes, the quantity-based CRMs have higher costs of implementation and operation for market participants and central institutions. This reflects the active involvement of market participants in submitting bids under the quantity-based schemes. The best estimates is that the additional costs of quantity-based CRMs are relatively small, even though the precise level is sensitive to the level of supporting resources required by each market participant actively involved in the CRM. In the modelling of the short-term price-based CRM, thermal plants stay in the market even if there are a number of years where gross margins are not sufficient to cover annual fixed costs. In practice, the impact of this could be greater exit from the market which would be expected to increase wholesale market costs and costs to consumers in the short-term price-based CRM (and a pure energy-only market) compared to the modelled outcome in the Table.

1.5.9 The cost-benefit analysis has identified how the introduction of effective competition between providers by moving to a quantity-based CRM could deliver large cost savings for consumers, whilst still meeting the required security standard.

1.5.10 Table 6 summarises for each assessment criteria the rationale for the qualitative assessment identifying the quantity-based CRMs, particularly centralised reliability options, as the best option for the CRM HLD in the I-SEM.

Table 6 – Summary of qualitative rationale for centralised reliability options against each assessment criteria

		Rationale for centralised reliability options
Primary Assessment Criteria	**Internal Electricity Market**	Compatible with general European drive towards competitive quantity-based CRMs; with reliability options more consistent with efficient short-term energy price signals needed for efficient market coupling
	Security of Supply	Transparent and flexible mechanism for providing efficient entry and exit signals (in line with the specified security standard), and more compatible than other CRM designs with efficient short-term energy price signals
	Competition	Provide transparent centralised platform for competition that facilitates efficient and coordinated entry and exit signals, whilst using competitive pressures to ensure that consumers don't overpay for adequacy. Centralised reliability options fit well with possible market power mitigation measures in the energy market.
	Environmental	CRM that is most compatible with efficient short-term energy price signals that should encourage the flexible resources that can help to reduce curtailment (e.g. interconnection, storage, demand-side response)
	Equity	Repayments by providers at times of high energy prices is a market-based mechanism to address double payments from capacity and energy markets. Centralised platform supports access for new entrants through a transparent market mechanism, with consumers all effectively paying the same price for the same level of generation adequacy.
Secondary Assessment Criteria	Stability	Offers good stability going forward, as fits well with the philosophy of the I-SEM design for energy trading arrangements, and with direction of travel on CRMs in Europe. This means that it is a timely change from the current scheme – the review of which has been signaled for a number of years.
	Adaptive	*To be determined by the detailed design phase*
	Efficiency	Most compatible with efficient short-term energy price signals that support a more efficient overall dispatch
	Practicality/Cost	Slightly higher implementation costs but the HLD would support more straightforward implementation than other quantity-based schemes

1.5.11 The qualitative assessment has identified a number of unquantified factors that should be taken into account in comparing the different CRM options – for example, in interpreting the result that the consumer bill savings reported in Table 5 are largest for the short-term price based CRM.

1.5.12 The combined impact of these factors would be to strengthen the performance of

the centralised reliability options compared with the modelled outcomes shown in the cost-benefit analysis. These factors include:

- **Importance of hedging for capacity providers and energy retailers –** the quantity-based CRMs, and the long-term price-based CRM offer a hedge for market participants against short-term variability of energy prices and gross margins. However the short term price based option does not offer a similar long-term hedge. The modelling does not fully quantify the benefits of a long term hedge in terms of reduced likelihood price cycles (in terms of entry and exit decisions) and / or lower financing costs.
- **Ability of quantity-based CRMs to differentiate between the duration of capacity price certainty needed by different types of capacity providers -** Mechanisms can be put in place in the quantity-based CRMs that provide long-term capacity price certainty for new entrants (where large upfront investment is typically required) over a number of years whilst not paying that long-term price to existing plants in years when new entry is not required. This would still provide firm signals for efficient entry and exit whilst reducing the total payments by consumers under the quantity-based schemes, compared with the modelled estimate used in the cost-benefit analysis.
- **Requirements for competitive markets for energy and for capacity**– the modelling assumes competitive outcomes for energy and capacity, with no portfolio aspects to bidding behaviour. The qualitative assessment has identified particular concerns about the scope for gaming in the short-term price based CRM as the spot capacity price will be sensitive to the withdrawal of capacity on the day (particularly given the importance of the peakiness of the capacity price function to the overall reduction in consumer bills). Any such gaming could push up consumer bills compared with the modelled outcome.
- **Impact of retaining efficient short-term price signals on incentives to invest in flexible resources** – the modelling does not include any scope for additional investment in flexible resources, such as demand-side response, that could be delivered by efficient short-term price signals. The qualitative assessment identified that reliability options and short term price based CRMs are able to deliver efficient short-term price signals.

1.5.13 In summary, the cost-benefit analysis and the qualitative assessment have both identified strengths for the centralised reliability options compared with the long-term price-based CRM and other quantity-based CRMs.

1.5.14 Although the short-term price-based CRM performs well in the cost-benefit analysis, the qualitative assessment has identified a number of concerns about its suitability to be the sole broad-based CRM in the I-SEM.

1.5.15 Therefore, the overall conclusion of the impact assessment is that the centralised reliability options would be the best HLD for the CRM in the I-SEM.

1.5.16 The centralised reliability options also fit well with the I-SEM philosophy for energy

trading arrangements of market participants having responsibility for trading in centralised, public and transparent marketplaces.

2 PURPOSE OF THIS DOCUMENT

2.1 OVERVIEW

2.1.1 The February 2014 Consultation Paper on the new High Level Design (HLD) for the Integrated Single Electricity Market (I-SEM) in Ireland and Northern Ireland (SEM-14-008) presented a number of options for energy trading arrangements and Capacity Remuneration Mechanisms (CRMs). This Initial Impact Assessment (IIA) provides an evaluation of those different options, incorporating qualitative and quantitative assessment in addition to a cost-benefit analysis.

2.1.2 This IIA informs the Draft Decision of the SEM Committee (SEMC) on the HLD for I-SEM, and should be read alongside the main Draft Decision Document.

2.2 STRUCTURE OF THIS DOCUMENT

2.2.1 This IIA contains the following elements:

- **Objectives of intervention (Section 3)** – the requirement for the HLD of the All-Island Market to fully comply with the EU Target Model by the end of 2016, and prioritisation of the nine assessment criteria set out in the SEMC's Next Steps Decision on Implementing the EU Target Model.
- **Approach to assessment (Section 4)** – balance between qualitative and quantitative assessment, including CBA, and brief summary of approach to wholesale market modelling.
- **Evaluation of consultation options for energy trading arrangements (Section 5)** – a cost-benefit analysis (CBA) alongside a qualitative assessment of the consultation options, and a description of refinements made to the consultation options as a result of the assessment process[2].
- **Evaluation of the need for a CRM (Section 6)** – qualitative and quantitative assessment, including additional generation adequacy analysis by the TSO.
- **Evaluation of the consultation options for the form of CRM (Section 7)** – a CBA alongside a qualitative assessment of the consultation options.
- **Supporting appendices (Appendices 1-3)** – more detail on the sources of the values used in the cost-benefit analysis.

2.2.2 The CBA of the possible differences between consultation options looks separately at energy trading arrangements and at CRMs. It includes estimates of wholesale market costs and benefits, and costs of implementation and operation of different arrangements.

2.2.3 Since the I-SEM HLD Consultation Document (SEM-14-008), the qualitative assessment of the consultation options has been refined by feedback from

[2] The February 2014 Consultation Paper noted that there was scope to amend the specific design of each option as a part of the feedback given through the consultation process, though any refinements should not alter the overall objective of the option.

stakeholders, and further analysis by the Project Team, including quantitative assessment.

2.2.4 This document is an Initial IA. The full IA, to be published alongside the Final Decision of the SEMC on the HLD for I-SEM, will include further analysis of the costs and benefits of the proposed energy trading arrangements and CRM to be implemented in I-SEM. For example, this could consider further assessment of uncertainties, risks and unintended consequences; and distributional analysis.

3 OBJECTIVES OF INTERVENTION

3.1 REASON FOR INTERVENTION

3.1.1 In Ireland and Northern Ireland, the Department of Communications, Energy and Natural Resources (DCENR) and the Department of Enterprise Trade and Investment (DETI) respectively have charged the SEM Committee (SEMC) with responsibility for developing trading arrangements that will be compliant with the EU Target Model. In addition, these trading arrangements should deliver tangible short and long term benefits to all island consumers by ensuring that existing and future assets and infrastructure are used in the most efficient ways to deliver electricity to consumers at lowest cost.

3.1.2 In March 2013 the two Departments endorsed the recommendation in the SEMC's "Next Steps Decision Paper" (SEM-13-009) that the SEM Committee should proceed to develop a High Level Design of the wholesale market arrangements on the island of Ireland.

3.1.3 The Next Steps Decision Paper also set guidelines for the HLD which were endorsed by DETI and DCENR. These included a set of principles that underpin the SEM, and which have formed the criteria for assessment of the HLD for the new set of trading arrangements, which will be known as the Integrated Single Electricity Market (I-SEM).

3.1.4 The Next Steps Decision Paper summarised the view of the SEMC and market participants that the SEM has performed well against its statutory objectives by delivering prices to consumers that are reflective of the long run cost of producing electricity.

3.1.5 It is timely to review the design of the All-Island Market for electricity given the changes seen since the creation of the SEM, which will have been in operation for over nine years by the end of 2016. This will help to ensure that, as far as possible, the HLD for the I-SEM will deliver the greatest benefits for consumers on the island of Ireland (in line with the overall objective of the SEMC).

3.1.6 The changes since the creation of the SEM include:

- Increased DC interconnection capacity with the GB electricity market, with the potential maximum export capacity from the all island market rising from 80MW to 950MW.
- A changing generation mix, with much greater penetration of wind today, and targets for renewable electricity penetration of around 40% by 2020.
- The opportunities for closer integration of the all island market with the European Internal Electricity Market offered by compliance with the requirements of the EU Target Model.
- Potential for more active involvement of the demand side in the all-island Market.

3.2 PROCESS FOR DEFINING ASSESSMENT CRITERIA

3.2.1 In its Next Steps Decision Paper, the SEM Committee (SEMC) decided to use the following criteria in its assessment of the HLD for the new market arrangements.

- the eight criteria used in 2005 to assess the high level design of the SEM;
- one additional criterion of compliance with the European Target Model and integration into the European internal market.

3.2.2 In March 2013, DCENR and DETI formally endorsed this recommendation (as well as others) of the SEMC.

3.2.3 Some ranking of assessment criteria can be helpful in reaching a final policy decision where trade-offs will be required between competing objectives. Recognising this, the SEMC recommended in the Next Steps Decision Paper that '"the relative priority of these assessment principles will be determined by reference to the SEM statutory objectives as set out in legislation in Ireland and Northern Ireland"

3.2.4 Since the publication of the I-SEM HLD Consultation Paper in February 2014, a number of stakeholders have raised the issue of the relative precedence of some assessment criteria over others. These stakeholders have stated that criteria based on statutory objectives and principles enshrined in EU law should take precedence over other criteria.

3.3 OBJECTIVES OF THE SEM COMMITTEE

3.3.1 The Principal Objective of the SEM Committee is:

- 'to protect the interests of consumers of electricity in Ireland and Northern Ireland supplied by authorised persons, where appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity though the Single Electricity market'.

3.3.2 The SEM Committee is required to have regard to a number of ancillary objectives in furthering its principal objective to protect the interests of consumers. These are:

- the need to secure that all reasonable demands for electricity in Ireland and Northern Ireland are met,
- the need to secure that authorised persons are able to finance their activities,
- the need to secure that the functions of the Minister(s), the Commission, the Authority, and the Department(s) in relation to the Single Electricity Market are exercised in a coordinated manner,
- the need to ensure transparent pricing in the Single Electricity Market,
- the need to avoid unfair discrimination between consumers in Ireland and consumers in Northern Ireland,
- the need to promote efficiency and economy on the part of authorised persons,

- the need to secure a diverse, viable and environmentally sustainable long-term energy supply in the Ireland and Northern Ireland,
- the need to promote research into, and the development and use of—
- new techniques by or on behalf of authorised persons, and
- methods of increasing efficiency in the use and generation of electricity.
- the need to secure a diverse, viable and environmentally sustainable long-term supply in Ireland and Northern Ireland,
- the need to consider the effect on the environment in Ireland and Northern Ireland of the activities of authorised persons; and
- the need to promote the use of energy from renewable energy sources.

3.3.3 Further, in carrying out its functions the SEM Committee shall:

- not discriminate unfairly as regards terms and conditions—
  - between authorised persons, or
  - between persons who are applying to become authorised persons.
- ensure that decisions are transparent, accountable, proportionate, consistent and targeted only at cases where action is needed.

3.4 PRIORITISATION OF ASSESSMENT CRITERIA

3.4.1 The assessment criteria have been divided for the purposes of this initial impact assessment into primary assessment criteria and secondary assessment criteria. When making a trade-off between competing objectives in relation to the decision on the I-SEM HLD, the primary assessment criteria take precedence over the secondary assessment criteria. This will mainly apply to the qualitative assessment of the HLD options but will also be taken into account of in all elements of the full IA that will accompany the final decision on the HLD for I-SEM.

3.4.2 Primary assessment criteria are backed up by the SEM Committee objectives in primary legislation in Ireland and Northern Ireland. Furthermore, they reflect the three pillars of European energy policy of sustainability, competitiveness and security of supply and as such are requirements of European law. The primary criteria are:

- **Internal Energy Market[3]:** the market design should efficiently implement the EU Target Model and ensure efficient cross border trade.
  (Source: EU Electricity Regulation 714/2009, European Electricity Network Codes)
- **Security of Supply:** the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards (Source: SEMC Objective on ensuring reasonable demand for electricity is met and that participants are able to finance their activities; Security of Supply Directive (Directive 2005/89/EC))

[3] The IEM compliance criteria has also been an important filter during the initial option development process, so that only compliant options were taken forward. The second stage of the assessment against this criteria then considers the efficiency of implementation of the Target Model.

- **Competition:** the trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner (Source: SEMC Primary Objective, SEMC Objective on transparent pricing; EC Electricity Regulation 714/2009 and EU Treaties)
- **Environmental:** while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables. (Source: SEMC Objective on the environment and promotion of RES; EU Renewables Directive (Directive 2009/28/EC))
- **Equity:** the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner (Source: SEMC Objective to avoid unfair discrimination).

3.4.3 Secondary assessment criteria are not expressly set out in national or EU legislation (though they are implicit in the SEM Committee's objectives and standard principles of economic regulation). They remain important for the SEMC when reaching a decision on the I-SEM and are as follows:

- **Adaptive**: The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner
- **Stability**: the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations
- **Efficiency**: market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.
- **Practicality:** the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.

4 APPROACH TO ASSESSMENT

4.1 OVERVIEW

4.1.1 Undertaking an Impact Assessment is good regulatory practice and is designed to help to inform the development of policy decisions.

4.1.2 Accordingly, in its Next Steps Decision Paper, the SEMC set out its commitment that:

- "The High Level Design shall be subject to an impact statement that is in line with best practice."
- "There will be a cost benefit analysis, carried out at an appropriate stage, which takes into account the key energy policy objectives which are materially affected by the wholesale electricity market high level design."

4.1.3 This commitment recognised that a monetised cost benefit analysis (CBA) is only one part of this process and that impact assessments will always be a mixture of qualitative and quantitative assessments.

4.1.4 Indeed, in the Next Steps Decision Paper, the SEMC noted that it would expect to rely more on qualitative analysis where there are wide ranges of uncertainty associated with costs and benefits, as is the case here. Therefore, this IIA includes quantitative evidence, including a CBA, to provide insights that aid decision making, rather than a mechanistic approach to determining those decisions.

4.1.5 At least as importantly, the quantitative assessment and CBA should highlight where refinements to the proposed set of arrangements would deliver benefits for consumers in the All-Island Market (e.g. by reference to the most important risks that should be mitigated against through changes to the HLD, as well as possible implications for the detailed design).

4.2 ESTIMATING WHOLESALE MARKET COSTS AND BENEFITS

4.2.1 For the cost-benefit analysis, we have modelled four snapshot years (2017, 2020, 2025 and 2030) using Pöyry Management Consulting's power market model, BID3. Linear interpolation is used to produce the results for the intermediate years, e.g. for NPV calculations

4.2.2 For each snapshot year, different combinations of weather, demand and availability profiles have been modelled. This includes 5 historical years for weather and demand (2006-2010), and 3 availability profles for thermal plant (High, Central and Low). This provides 15 different market outcomes for each snapshot year. Unless otherwise stated, this IIA reports the average outcome for each snapshot year.

4.2.3 We use the modelling to estimate the quantitative impact of different HLD options – this includes monetised impacts (e.g. wholesale market costs), and non-monetised impacts (e.g. curtailment of variable renewable generation). This includes an estimate of wholesale market costs, which are defined as:

- annualised capital expenditure on generation and interconnection;
- fixed operating costs for generation and interconnection;
- variable production costs (primarily fuel and carbon);
- Expected Energy Unserved (EEU), which is monetised using the VOLL of €10898/MWh that has been set for the All-Island Market;and
- cost of net imports (i.e. the total payments for imports minus the revenue received for exports)

4.2.4 Two reference cases (Base Case A and Base Case B) are used to inform the estimates of the wholesale market costs of different options. The main differences between the input assumptions for each Base Case are the rate of renewable growth in the All-Island Market post 2020, and the cost competitiveness of coal-fired generation against gas-fired generation.

4.2.5 In the Base Case A scenario, current energy policies are assumed to persist globally. Commodity prices (oil, gas and coal) increase over time in line with increased demand for conventional fuels on a global scale. Coal-fired generation remains more competitive compared with gas-fired generation for the entire modelled timeframe. This comes as a result of relatively higher gas prices and depressed carbon prices. Under this scenario, decarbonisation is delivered with an emphasis on the electricity sector and, in particular, through continuing support towards renewable and other low carbon generation. In both markets (I-SEM and GB), 2020 renewables targets are met. GB continues with a policy of supporting the EU ETS price through imposing a floor on the carbon price and the carbon reduction target by 2030 is achieved through the rollout of a combination of nuclear, CCS coal, wind and solar. In the I-SEM, on the other hand, wind is the major renewable deployed technology with renewable penetration reaching 52% by 2030 (before any curtailment).

4.2.6 Base Case B is a scenario where new policies drive a more concerted transition to alternative forms of energy. A resulting weaker global demand for conventional fuels (due to higher carbon prices) results in gas and coal prices decreasing over time. In this word, the gas to coal relativity reverses in the long term with gas-fired generation becoming more competitive after 2025. Carbon prices rise throughout the period, reaching €76/tonne CO2 in 2030 (in real terms). In this world, decarbonisation is not delivered primarily from emissions reduction in the electricity sector, but from other energy segments. Renewable support is assumed to be weaker and further renewable generation (in the long term) is delivered only on the basis of market revenues. GB maintains a carbon price floor in excess of the EU ETS price, however lower when compared with that assumed in Base Case A. There is lower penetration of renewables (and other zero carbon generation) in both markets. Nonetheless, 2020 targets are met in both markets. Renewable growth in the All-Island Market slows down post 2020, although renewable penetration in the All-Island Market still reaches 45% by 2030 (before any curtailment).

4.2.7 The modelling of the reference cases for Base Cases A and B assumes a well-functioning (ideal) energy-only market. Although there is a price cap of €3000/MWh

(to reflect the price cap in the NWE DAM), there is no restriction on price spikes up to that level[1]. The energy market is assumed to be fully competitive, with perfect foresight of 'expected' future revenues. There is no free-riding problem, the price elasticity of demand is low or zero and investment is coordinated to avoid over or under delivery and a cycle in wholesale prices. Once new entry is needed, the annual level of scarcity rent in the energy price is then assumed to remain new entry levels for the rest of the modelled period.

4.2.8 Appendix 1 contains more information on the approach and input assumptions for the modelling.

5 ENERGY TRADING ARRANGEMENTS

5.1 OVERVIEW

5.1.1 This section of the initial IA describes the findings of the qualitative and quantitative assessment that has informed the SEM Committee's Draft Decision on the HLD on the energy trading arrangements for the I-SEM.

5.2 OPTIONS CONSULTED UPON FOR ENERGY TRADING ARRANGEMENTS

5.2.1 The February 2014 I-SEM HLD Consultation Paper presented four options for the HLD of energy trading arrangements:

- Adapted Decentralised Market (Option 1 - ADM);
- Mandatory ex-post Pool for Net Volumes (Option 2 - MPNV)
- Mandatory Centralised Market (Option 3 - MCM); and
- Gross Pool – Net Settlement Market (Option 4 - GPNS).

5.2.2 Table 7 summarises how each of the four options for energy trading arrangements addressed the design elements identified in the Consultation Document. The table is colour-coded to illustrate the difference in the 'philosophies' underpinning the options. It describes how the options range from market arrangements where market participants have both greater responsibilities and risk mitigation opportunities (coloured in blue), to ones in which there is greater central control of market participants' activities (coloured in orange).

Adapted Decentralised Market (Option 1 – ADM)

5.2.3 Option 1 is characterised by an emphasis on allowing market participants greater choice over the markets and timeframes in which they trade energy to manage risk. This option is therefore coloured in blue, denoting more decentralised arrangements, across all topics in Table 7.

5.2.4 Option1 relies on market participants achieving a balanced position through their ex-ante trading while the TSO assumes a residual balancing role. Gross portfolio bidding is allowed, which allows market participants to use their physical nominations to optimise the position of their own generation portfolios based on all their internal parameters. Demand and generation however are optimised separately. It is possible for generating units to submit unit-based bids into the DAM and the IDM.

Mandatory Ex-Post Pool for Net Volumes (Option 2 – MPNV)

5.2.5 Option 2 allows physical contracting in the forwards timeframe and choice for market participants around their trading in the DA and ID timeframes. However, it ultimately relies on a centralised approach to the determination of dispatch and ex-post prices and quantities. This centralised approach would involve complex bidding for increases or decreases in production into an integrated scheduling and dispatch

process to help the TSO reach a least-cost dispatch for deviations from the nominated positions of market participants.

5.2.6 In Table 7, Option 2 is coloured blue for the DAM and IDM. However, it is coloured orange for the actions taken by the TSO and ex-post pricing and scheduling arrangements, denoting more centralised arrangements.

Mandatory Centralised Market (Option 3 – MCM)

5.2.7 Option 3 emphasises the importance of the DAM as the main market for physical trading of energy between market participants, with the IDM the exclusive route for making adjustments to nominated positions intraday. Mandating participation in the DAM and making the IDM an exclusive market should ensure liquidity in those specific markets. Requirements for unit based bidding by generation is intended to enhance transparency in the markets. This also allows for sophisticated bids in the DA (and potentially ID) timeframes that will allow market participants to use a more complex bidding structure than with portfolio bidding. Like Option 1, it relies on market participants achieving a balanced position through their ex-ante trading while the TSO assumes a residual balancing role. The balancing arrangements revert to a relatively simple 'inc' and 'dec' bid structure.

5.2.8 For Option 3, Table 7 has orange colouring for the DAM and IDM, and blue shades dominating for TSO actions and ex-post pricing arrangements.

Gross Pool – Net Settlement Market (Option 4 - GPNS)

5.2.9 Option 4 is characterised by a centralised approach to the determination of dispatch and ex-post prices and quantities (e.g. through complex bidding into an integrated scheduling and dispatch process to allow the TSO reach a least-cost dispatch). It is open for market participants to carry out voluntary financial trading in the forwards, DA and ID timeframes. Trading in the DAM and IDM determines the physically scheduled interconnector flows. This option retains an ex-post gross mandatory pool (albeit with net settlement) with complex bidding for all physical energy market arrangement within SEM.

5.2.10 In Table 7, Option 4 is coloured blue for day-ahead and intraday markets but dark orange for the actions taken by the TSO and ex-post pricing and scheduling arrangements.

Table 7 – Summary of consultation options for energy trading arrangements for I-SEM

			Adapted Decentralised Market	Mandatory ex-post Pool for Net Volumes	Mandatory Centralised Market	Gross Pool - Net Settlement Market
Participation in European markets for trading of energy in DA and ID timescales	DA	Portfolio vs. unit bidding	Gross portfolio bidding	Portfolio bidding	Unit bidding	Portfolio bidding
		Mandatory vs. voluntary	Voluntary participation [plus specific liquidity promoting measures]	Voluntary participation [with quantity limitation measures]	Mandatory participation	Voluntary participation
		Bid format	Simple, block (or sophisticated unit) bids	Simple, block (or sophisticated unit) bids	Simple, block or sophisticated bids	Simple, block (or sophisticated unit) bids
	ID	Portfolio vs. unit bidding	Gross portfolio bidding	Unit bidding	Unit bidding	Unit bidding
		Exclusive vs. Non-exclusive	Non-exclusive	Non-exclusive [with same quantity limitation measures]	Exclusive	Non-exclusive
		Bid format	Simple, block [or sophisticated] bids	Simple, block [or sophisticated] bids	Simple, block [or sophisticated] bids	Simple, block [or sophisticated] bids
Process for reaching feasible dispatch position		Starting point of dispatch	- DA nomination is the starting point (updated in the IDM) - Maintaining absolute priority dispatch	- DA nomination is the starting point (updated in the IDM) - Maintaining absolute priority dispatch	- DA nomination is the starting point (updated in the IDM) - Maintaining absolute priority dispatch	- IC quantities determined by DAM and IDM - Maintaining absolute priority dispatch
		Bids to the TSO for balancing and dispatch	Voluntary incs and decs up to IDM GC (mandatory incs and decs for generating units after IDM GC)	Mandatory net (+/-) complex bids for generating units	Mandatory incs and decs for generating units	Mandatory complex bids for generating units
		Timing of bid submission	At DA and then updated continuously	At DA and then updated continuously	At DA and then updated continuously	At DA and then updated at specific windows
Imbalance/Pool settlement			Marginal imbalance price applied to all market participants based on (+/-) energy balancing actions	Net ex-post unconstrained market schedule to minimise production cost that determines the ex-post prices paid to/by all market participants (prices may vary by direction)	Marginal imbalance price applied to all market participants based on (+/-) energy balancing actions	Full ex-post unconstrained market schedule to minimise production cost that results in a single marginal price paid for all scheduled quantities
Arrangements for long-term trading		Internal	Both physical and financial trading	Both physical [with quantity limitation measures] and financial trading	Financial trading	Financial trading
		Cross-border	PTRs to support bids for interconnector capacity	PTRs to support bids for interconnector capacity	FTRs to support bids for interconnector capacity	FTRs to support bids for interconnector capacity

5.3 QUANTITATIVE ASSESSMENT OF IMPLEMENTATION AND OPERATION COSTS

5.3.1 In this section, we set out initial estimates for the non-market costs of implementing and maintaining energy trading arrangements in the I-SEM, i.e., the cost that will be incurred to set up, run and participate in the market. For the avoidance of doubt, this does not cover generation costs (which are quantified in Section 5.4).

5.3.2 We estimate the additional one-off and recurrent costs that could be incurred by Market Participants, the Market Operator and the TSO, and the Regulatory Authorities during the implementation and operation of the new energy trading arrangements.

5.3.3 The non-market costs are estimated for all the four energy trading options that were included in the February 2014 Consultation Paper. Some of these costs will be invariant to the chosen energy trading arrangement for I-SEM and some will be specific to an individual option. These differences are highlighted in the assessment.

5.3.4 Table 8 presents the initial central estimates of the annualised cost of implementing and operating the different options for electricity trading arrangements, which are around €10-15m/year in real terms between 2017 and 2030. Appendix 2 describes the range of and source of the cost estimates underpinning the values shown in Table 8.

5.3.5 To put the implementation and operation costs into perspective, this figure represents around 0.5% of the estimated total wholesale market value in the I-SEM. It is broadly similar across the different consultation options for implementing the requirements of the Target Model.

5.3.6 These costs are annualised over a 14-year assessment period (2017-2030) using an assumed discount rate of 3.5%. This reflects the discount rate recommended in the Treasury's Green Book (Appraisal and Evaluation in Central Government)[4].

Table 8 – Annualised implementation and recurrent non-market costs (€ million/a for 2017-2030, real 2012 money, 3.5% discount rate)

	Market Participant	MO/TSO	Regulatory Authorities	**Total**
ADM (Option 1)	€7m/a	€4m/a	€1m/a	**€12m/a**
MPNV (Option 2)	€7m/a	€6m/a	€1m/a	**€14m/a**
MCM (Option 3)	€7m/a	€4m/a	€1m/a	**€12m/a**
GPNS (Option 4)	€7m/a	€4m/a	€1m/a	**€12m/a**

5.3.7 The results show there is relatively little difference between the four energy trading options. All options will include the connection to the European market places (DAM and IDM) and essentially these costs will be the same for all the options. However

[4] https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

Option 2 incurs more costs as a result of the requirement to change the systems from being a Gross Pool (in the SEM) to a Net Pool. The remaining difference in cost is driven by the cost to adapt/develop IT systems for balancing. The costs for the Regulatory Authorities will be very similar for all options.

We have not quantified the possible change in costs related to credit cover and collateral related to participation in different market timeframes (with different settlement practices). This will vary for the different options, but for Option 4 the savings will not be as substantial. This is because the physical market settlement will be based on the pool settlement that would be expected to follow the settlement timeframe of the current market.

5.4 QUANTITATIVE ASSESSMENT OF WHOLESALE MARKET COSTS

APPROACH

5.4.1 This section describes the results of a quantitative assessment of the wholesale market costs and benefits of different energy market outcomes. Given the inherent difficulties in representing different variants of market design in economic models, we have undertaken a range of sensitivity scenarios and mapped these on to the four options for energy trading arrangements.

5.4.2 It is widely recognised that it can be difficult to model the different forms of energy trading arrangements set out in the consultation. This is because the quantitative outcomes (e.g. wholesale market costs) will typically be driven by assumptions about the market dynamics under each option – e.g. such as the bidding behaviour and level of competitive pressure assumed for each option.

5.4.3 In such circumstances, where direct benefits of a particular option are hard to quantify, one approach is to focus on the analysis of what the level of benefits would have to be to justify the proposal, given the range of implementation costs identified, and the plausibility of this level of benefits. For example, Ofgem used this approach when assessing the introduction of liquidity-promoting measures in the GB wholesale market (in line with its own guidance on conducting Impact Assessments where benefits are hard to quantify)[5].

5.4.4 Therefore, the energy market outcomes modeled here are intended to act as a proxy for the differences identified in the qualitative assessment between the options – this gives an indication of the possible scale of benefits of the preferred option from the qualitative assessment, and how that compares to any differences in costs of implementation and operation.

5.4.5 The differences identified in the qualitative assessment are modeled using the following sensitivities:

[5] Wholesale power market liquidity: statutory consultation on the 'Secure and Promote' licence condition - Impact Assessment, Ofgem,- 20 November 2013

- efficiency t day-ahead interconnector flows;
- effectiveness of intraday trading across the interconnector; and
- perceived riskiness for investment in variable renewable generation (captured as a 1% increase in the cost of capital for wind in the All-Island Market[6]).

5.4.6 All of these sensitivities are modelled for Base Case A and for Base Case B. These sensitivities then inform a comparison of the possible wholesale market benefits for the preferred option identified through the qualitative assessment

EFFICIENT INTERCONNECTOR FLOWS

5.4.7 One of the main goals of the new market design of the I-SEM is achieving efficient interconnector flows with GB[7]. Historically, interconnector flows to and from the SEM have not fully responded to day-ahead price differentials between the SEM and GB in each individual delivery period. Figure 2 shows flows across the Moyle interconnector in each trading period against the price differential (SEM-GB) for 2013[8].

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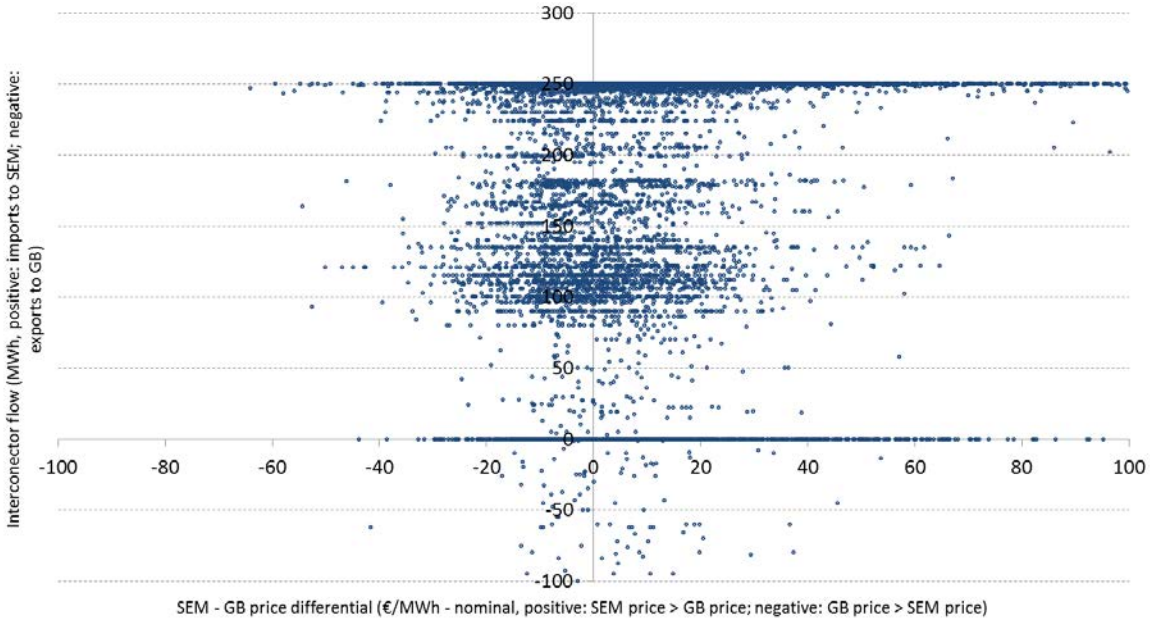
Figure 2 –Flows across Moyle in each trading period and the SEM-GB price differential (2013[9])



6 A change in the cost of capital of this magnitude is consistent with the estimated impact of moving between different support arrangement (renewables obligation and CFD) in GB.

7 And other markets if further interconnection is built.

8 We have chosen to focus on flows with GB in 2013 to avoid factoring in the impact of charges from the GB side (BSUoS and TNUoS), which were no longer faced by interconnection in 2013.

9 The chart shows the difference between the N2EX Day-Ahead prices for GB, and the sum of the day-ahead SMP and the ex-post capacity payments (as a proxy for day-ahead SEM wholesale price). Flows are based on the day-ahead scheduled flows across Moyle

5.4.8 Efficiency requires that flows are always in the same directions as prices and that all available capacity on the interconnectors is used when there is a non-zero price differential. If flows are efficient, the points in Figure 2 should be concentrated in a straight horizontal line in the top right quarter and in the bottom left quarter of the diagram and a vertical line that passes though the origin.

5.4.9 Points in the top right quarter represent flows from GB to the SEM when the price in GB is lower than the price in the SEM. Similarly, points in the bottom left quarter represent flows from the SEM to GB when the SEM price is lower than the GB price.

5.4.10 However, points in the other two quarters represent flows in the opposite direction of the price differential for that individual pricing period.

5.4.11 In theory, assuming no losses across the interconnector, whenever a price differential between the two markets exists, the interconnector should be fully used. When the price in GB is lower than in SEM (allowing for losses), Moyle should have been fully congested in the direction GB to the SEM. When the price in the SEM is lower than in GB (allowing for losses), Moyle should have been congested in the direction SEM to GB.

5.4.12 Figure 2 shows that flows appear to not be fully responsive to price differences with market participants trading electricity primarily from GB to the SEM irrespective of the actual price differential in individual delivery periods.

5.4.13 There are two types of inefficient flow observed in Figure 2:

- flows in the opposite direction to prices (in 33% of periods) – this is shown by points appearing in the top left quarter or bottom right quarter of the chart
- less than full utilisation of the interconnector capacity when a non-zero price differential exists.

5.4.14 These inefficiencies may happen as a result of differences and perceived risks in the nature and timing of price formation in the two markets, and/or the mechanics and strategies of trading across the interconnector.

5.4.15 Our two reference cases (Base Case A and Base Case B) both assume the efficient use of interconnection in terms of flows being consistent with the price differential between the I-SEM and GB in each individual delivery period (taking account of the physical losses on the interconnector). This reflects the assumption that implicit market coupling based on liquid markets (with a strong reference price) should deliver optimal use of interconnection, leading to lower production costs and higher social welfare across the interconnected markets.

5.4.16 On the assumption that price differentials between two interconnected markets will result in an increased flow of energy across an interconnector as arbitrage opportunities are exploited, there will be gains in producers' and consumers' surpluses if the net transfer capacity of the interconnector is sufficiently large for flows across it to have an influence on prices in either of the two markets. These

gains will be additional to the benefits of reductions in fuel and other operating costs.

5.4.17 Increased imports of electricity into the SEM will result in a lower wholesale price of electricity in Ireland, other things being equal. Consumers in the SEM will benefit by these lower prices, but SEM producers will lose out because less infra-marginal rent is earned. The net benefit is what is referred to as consumers' surplus.(Consumers' surplus and producers' surplus are the standard concepts in economics for the measurement of social benefits[10].) Conversely increased exports of electricity from the SEM will result in a higher wholesale price of electricity in Ireland, other things being equal. This will benefit producers in the SEM, because they earn more infra-marginal rent, but SEM consumers will lose out.

5.4.18 Notwithstanding the distribution of costs and benefits, in the presence of market coupling overall, there will be an increase in the social welfare and a reduction in system costs, taking the two (or more) interconnected markets together. Determining who benefits depends on market fundamentals (fuel costs, relative generation and load mix in the two markets, RES penetration in the two markets etc.). The benefits may transfer from one market to the other as market fundamentals change through time. The constant will be that optimal social welfare (taking the two (or more) interconnected markets) is achieved through market coupling. Distributional impacts will be assessed and set out in the final impact assessment.

5.4.19 Through different sensitivities in the modelling we have captured the potential inefficiencies in a structured way[11]. We have chosen to apply different 'rules' for a systematic type of inefficiency which we then relate to the expected risks with the energy options proposed in the consultation paper.

5.4.20 These two types of sensitivities modelled to quantify the impact of inefficient flows are:

- A unilateral 'risk premium' whereby the interconnector only flows from the All-Island Market to GB once the GB price is significantly higher than the price in the All-Island Market. This reflects barriers to trade (for example due to market design misalignments) leading to uneconomic cross border trades, i.e. trades in the wrong direction, in some half hour periods. This can be seen as equivalent to a risk premium being added onto bids into the DAM in the I-SEM, reflecting a number of factors, such as perceived riskiness of participation (e.g. in terms of mitigating exposure to ex-post prices) and/or excessive exercise of market power. We have modelled two 'risk premium' values of €10/MWh and €20/MWh.

10 A simple definition of a consumer's surplus is the maximum sum of money a consumer would be willing to pay for a given amount of a good or service, less the amount the consumer actually pays, which is measured by the area under the demand curve. A producer's surplus is simply economic rent, which is the difference between the price a producer gets for the good or service supplied and the economic cost of the inputs required to produce it, which is measured by the area above the supply curve.

11 Historically, there are irregular patterns in the inefficiencies in the use of the interconnector. To capture this 'irregularity' we would have to take (and apply) a random pattern that may overstate future trading patterns on the interconnector

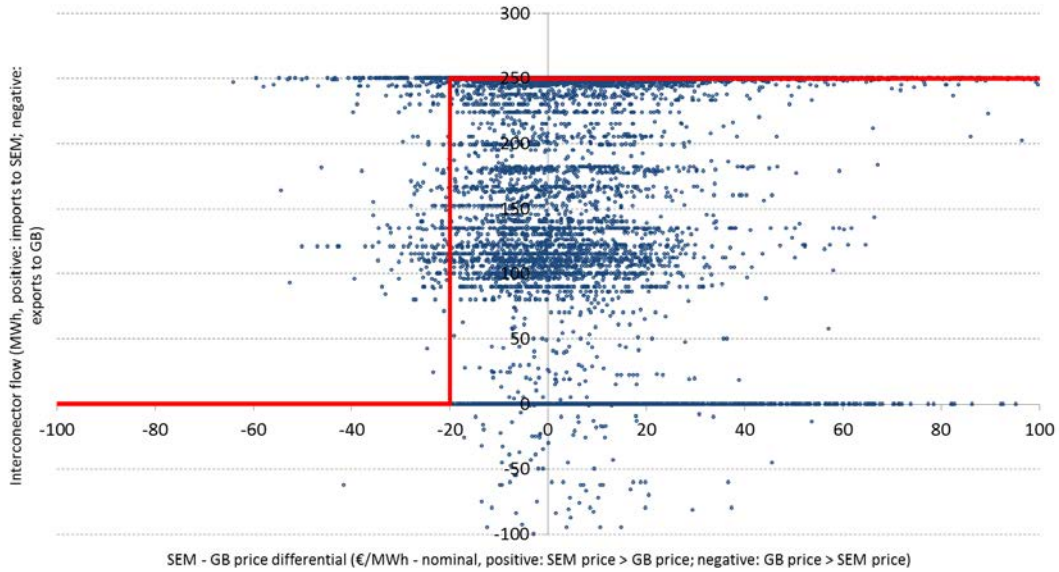
- A 'deadband', whereby the interconnector only flows in either direction when the price differential exceeds a certain absolute value (where this value is in excess of the cost of physical losses). We have modelled two deadband values of €5/MWh and €10/MWh.

5.4.21 Figure 3 shows the flows across the Moyle in 2013 (in the same format as Figure 2), alongside the stylised impact of a €20/MWh 'premium'. Similarly, a €10/MWh premium would result in a similar line with the vertical part of the curve crossing the x-axis at -€10/MWh.

5.4.22 In 2013, GB wholesale prices were on average lower than the SEM wholesale prices. There was only a flow from GB to SEM in only 2% of periods. In 33% of periods, the flow was from GB to the SEM despite the SEM price being lower. Therefore, in the majority of periods when the SEM price was lower than the GB price, flows were from GB to SEM (i.e. in the 'wrong' direction).

5.4.23 For the periods when the flow was in the direction from GB to the SEM despite the SEM price being lower, the SEM price was on average €10/MWh lower (on a straight-line average) and €5/MWh lower (when weighted by flows). Therefore, the two premium levels we have used (€20/MWh and €10/MWh) represent a reasonable range around these average values.

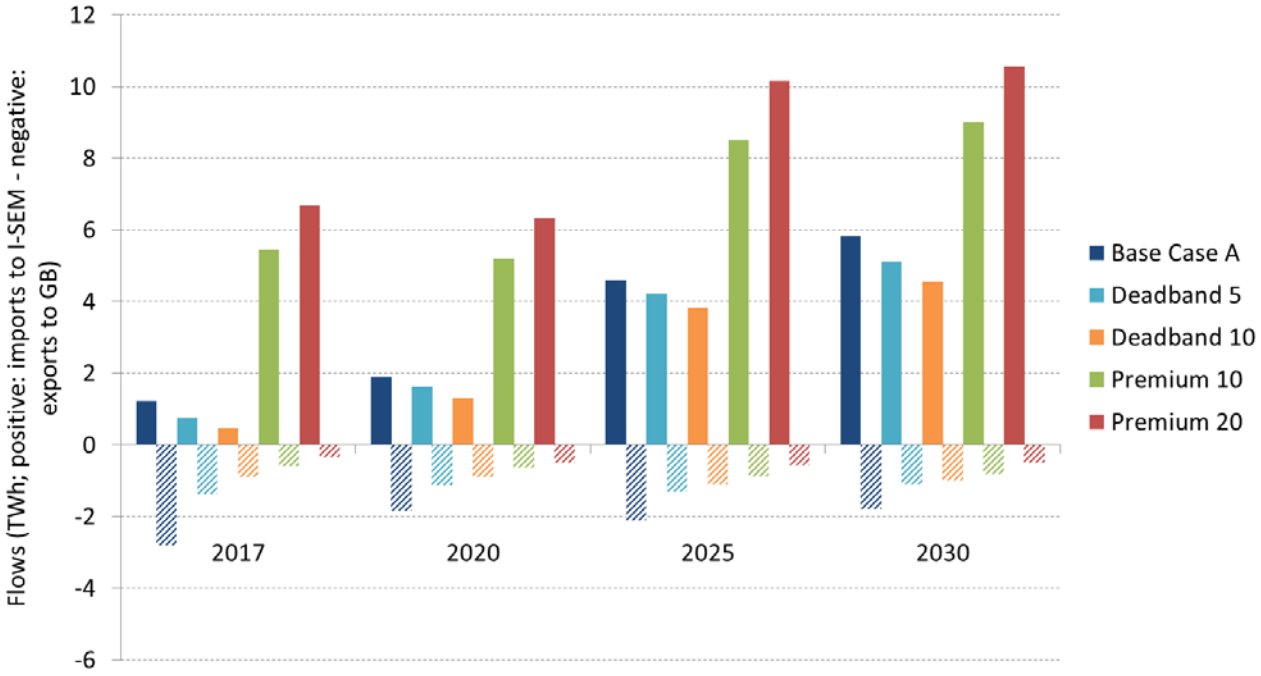
Figure 3 – Flows across the Moyle in 2013[12] and 'premium' of 20€/MWh



5.4.24 The 'unilateral risk premium' has the impact of increasing flows from GB to I-SEM (because I-SEM becomes relatively expensive). The deadband uniformly reduces flows between the two markets. This pattern can be seen in Figure 4.

12 We have used the N2EX Day-Ahead prices for GB, the ex-ante SMP and the ex-post capacity payments to create an ex-ante SEM wholesale price. Under current rules, interconnector flows are based on the ex-ante scheduled quantities (i.e. the modified interconnector unit nominations).

Figure 4 – Annual imports to and exports from the I-SEM in Base Case A[13]



5.4.25 Table 9 shows the NPV of the wholesale market cost increase (2017-2030) for the I-SEM for the two premium cases and the two deadband cases (compared with the two Base Cases).

5.4.26 Table 10 and Table 11 present the breakdown of the change in system costs under each cost element. Since we have assumed that any inefficiency would not result in differences in new build or plant retirement, there is no difference in terms of annual fixed costs and annualised capex.

5.4.27 Generally, the impact of the reduced efficiency of interconnector flows is that, domestic variable costs decrease (with the corresponding decrease in producer surplus in the I-SEM), whereas the cost of net imports increases (with the corresponding decrease in consumer surplus in GB) relative to the two reference cases with efficient cross border trade. However, the opposite happens for the two deadbands in Base Case B.

5.4.28 In Tables 9, 10 and 11 below the scenarios represent inefficiencies in cross border trade. As such positive numbers imply additional costs if the interconnectors are not used efficiently, and the corollary is that they represent the amount of money saved by the efficient use of the interconnectors.

[13] Exports in Base Case A fall between 2017 and 2020 as a result of changing fuel and carbon prices in GB and the All-Island Market, as well as the pattern of low marginal cost build in the two markets.

Table 9 – Change in wholesale market costs for the I-SEM compared with the reference cases

NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Base Case A	Base Case B
Premium €10/MWh	+€391m	+€135m
Premium €20/MWh	+€458m	+€200m
Deadband €5/MWh	+€8m	+€12m
Deadband €10/MWh	+€22m	+€37m

Table 10 – Change in wholesale market costs for the I-SEM compared with the reference case for Base Case A

NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Premium €10/MWh	Premium €20/MWh	Deadband €5/MWh	Deadband €10/MWh
Annualised capex	0	0	0	0
Annual fixed costs	0	0	0	0
Variable production costs	-€3679m	-€4447m	-€248m	-€112m
Cost of EEU	0	0	0	0
Cost of net imports	+€4070m	+€4905m	+€256m	+€134m
Total	**+€391m**	**+€458m**	**+€8m**	**+€22m**

Table 11 – Change in wholesale market costs for the I-SEM compared with the reference case for Base Case B

NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Premium €10/MWh	Premium €20/MWh	Deadband €5/MWh	Deadband €10/MWh
Annualised capex	0	0	0	0
Annual fixed costs	0	0	0	0
Variable production costs	-€2800m	-€3381m	+€236m	+€390m
Cost of EEU	0	0	0	0
Cost of net imports	+€2935m	+€3581m	-€224m	-€353m
Total	**+€135m**	**+€200m**	**+€12m**	**+€37m**

5.4.29 Table 10 and Table 11 highlight the major impact of the 'one-way risk premium' on the wholesale market costs of I-SEM.

5.4.30 The main finding from the modelling of efficient interconnector flows at the Day-Ahead stage is that under both base cases efficient flows brought by market coupling

show significantly higher I-SEM producer surplus and lower I-SEM consumer surplus relative to the unilateral risk premium scenarios.

5.4.31 This is the result of the fact that, in line with the economic principles of international trade, the removal of a one-way barrier to trade (affecting flows from I-SEM to GB) would lead to times of higher price in the I-SEM (and hence lower I-SEM consumer surplus and higher I-SEM producer surplus) and concomitant lower GB prices (with higher GB consumer surplus and lower GB producer surplus). This more efficient pattern of flows would reflect greater opportunities for I-SEM producers to access demand in the GB market (through the removal of barriers to trade and harmonisation of cross border trading rules under the Target Model).

5.4.32 The impact on consumers in the I-SEM would be offset by the increased competitive pressure in the I-SEM coming from efficient coupling with the GB market and any savings to consumers from any changes to the capacity remuneration mechanism.

5.4.33 The two deadbands do not result in a significant increase in wholesale market costs. Flows are in the right direction but are limited when the price differential is small[14].

5.4.34 To illustrate these results further, Table 12 and Table 13 present the annual wholesale market costs for the I-SEM under Base Case A and Base Case B respectively, for the snapshot years that we have modelled. The tables shows the wholesale market costs for the two reference cases alongside the wholesale market cost increase under each of our sensitivities for inefficient interconnection use.

Table 12 – Annual I-SEM wholesale market costs for Base Case A, and the impact of each of the modelled sensitivities for inefficient interconnection

€m, real 2012 money	2017	2020	2025	2030
Base Case A with efficient interconnector flows	**€2407m**	**€2696m**	**€3086m**	**€3530m**
Premium €10/MWh	+€50m	+€34m	+€37m	+€23m
Premium €20/MWh	+€69m	+€42m	+€35m	+€28m
Deadband €5/MWh	+€3m	+€1m	+€0m	-€1m
Deadband €10/MWh	+€6m	+€3m	+€1m	-€1m

[14] It does not capture partial flows (which have been historically observed) even in the case of greater price differences. This sensitivity presents a small degree of inefficiency and may underestimate the overall impact.

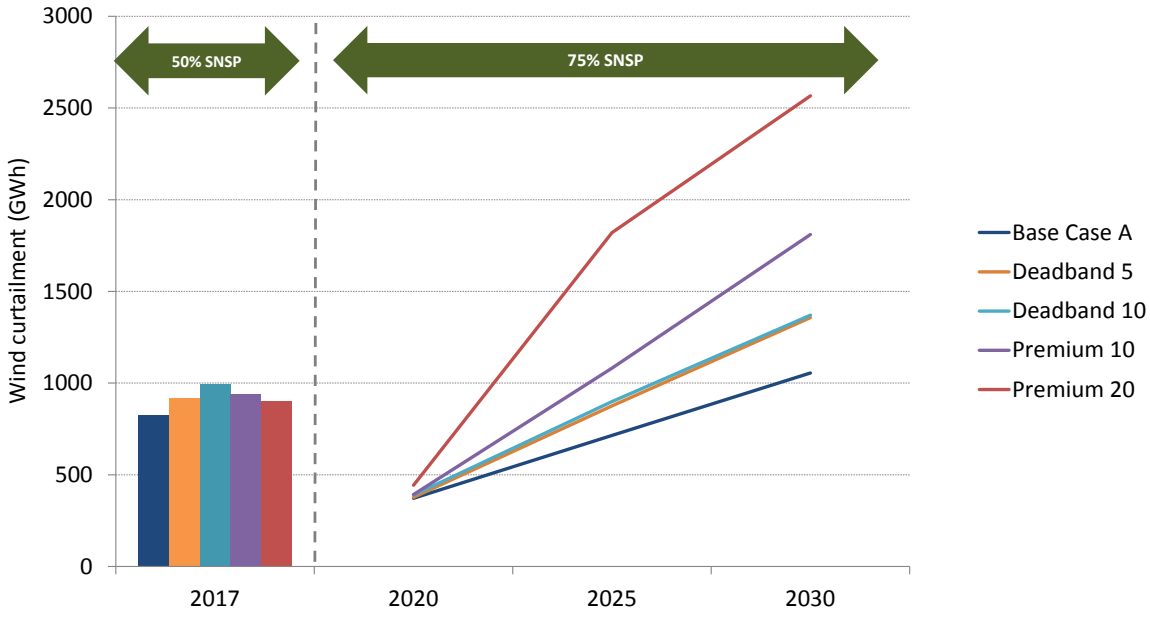
Table 13 – Annual I-SEM wholesale market costs for Base Case B, and the impact of each of the modelled sensitivities for inefficient interconnection

€m, real 2012 money	2017	2020	2025	2030
Base Case B with efficient interconnector flows	**€2489m**	**€2803m**	**€3414m**	**€3943m**
Premium €10/MWh	+€22m	+€14m	+€9m	+€6m
Premium €20/MWh	+€28m	+€20m	+€16m	+€10m
Deadband €5/MWh	+€1m	+€0m	+€1m	+€4m
Deadband €10/MWh	+€3m	+€2m	+€4m	+€6m

5.4.35 Less efficient use of the interconnection should also result in higher wind curtailment, as shown in Figure 5. In this graph, the blue line represents wind curtailment in Base Case A. In this base case, the current relativity of fuel prices continues into the future and wind generation continues to increase after 2020, reaching over 50% of total generation by 2030. As above, barriers to trade (for example due to market design misalignments) leading to uneconomic cross border flows have been modeled under two types of sensitivities to quantify the impact of such inefficient flows. The blue and orange lines represent the wind curtailment when 'deadbands' are applied to this base case and the red and purple lines represent the wind curtailment when 'risk premiums' are applied to the base case.

5.4.36 The graph shows that curtailment increases from 2020 to 2030 in all scenarios due to increasing levels of absolute wind. A similar pattern of results for the wholesale market costs emerges, with the 'unilateral risk premium' under which flows are in the wrong direction having a much bigger impact than the deadbands. This reflects the point that imports into the SEM during periods of high wind production are likely to increase curtailment. Notably, the modelling does not take account of potential TSO countertrading to reduce curtailment. This reflects the principle that market driven cross border flows provide a more reliable and efficient means of minimising curtailment in the long run than curative actions by the TSOs.

Figure 5 – Wind curtailment in Base Case A[15] for reference case and with inefficient Day-Ahead interconnector flows



Assessment of Options based on Efficiency of Flows Modelling

5.4.37 As stated above, there is an inherent difficulty in representing different market designs in economic models since all designs are based on a set of input assumptions, including whether the wholesale electricity market is perfectly competitive or oligopolistic. For example, oligopolistic behaviour can be modelled assuming Bertrand and Cournot behaviour on the part of firms in the sector.[16] However, we do not consider that there is any meaningful way of distinguishing between the options for energy trading arrangements using these techniques. Instead, we have mapped the sensitivity of the scenarios for inefficient cross border trade onto the options for energy trading arrangements.

5.4.38 In Option 1, with Physical Transmission Rights being allocated on the interconnectors in forward timeframes, there could be less capacity available for implicit auctions of interconnector capacity and energy in the DAM and IDM. Flows on the interconnectors would then be less responsive to changing conditions closer to real time. This could reduce the efficiency of flows on the interconnectors and lead to higher levels of curtailment.

5.4.39 In Option 2 there are effectively two distinct markets competing for liquidity, the

[15] Curtailment based on limit of 50% non-synchronous generation in 2017, and limit of 75% non-synchronous generation from 2020 onwards)

[16] Cournot analysis assumes that a firm determines its output while the market price is determined by some unspecified agent so that market demand equals the total amount offered. Bertrand analysis assumes that a firm determines the price at which it sells its output with firms being obligated to meet the resulting customer demand.

European DAM and the ex-post pool. Price-setting generation is likely to be drawn to the European DAM and IDM both to access the interconnectors and to gain the highest price possible. Variable renewable generation on the other hand, if it is conservative in forecasting day ahead volumes or reluctant to forecast at all, will enter the ex-post pool for some or all of its volumes. However the flows on the interconnectors will be set by the DAM and IDM, so the efficiency of flows on the interconnectors would be reduced, potentially leading to higher levels of curtailment.

5.4.40 Option 3 strongly integrates the interconnector into the market arrangements and the use of FTRs to maximise the availability of physical interconnection capacity for the DAM. Exclusive participation in the DAM, along with measures to facilitate participation by variable generation, means that the full competitive pressure of the interconnector is brought to bear on the main spot market in the SEM, increasing overall efficiency across both markets.

5.4.41 High levels of participation in the DAM and IDM by variable renewable generation will better deliver optimal use of the interconnectors. The modified version of Option 3 proposed as the I-SEM High Level Design incentivises high participation in these short term markets through balance responsibility and exclusive physical trading in the centralised, public and coupled market places.

5.4.42 In Option 4 the ex-post pool could discourage voluntary financial trading in the DAM and IDM. Low levels of participation in the DAM and IDM would likely see inefficient patterns of scheduled imports and exports. Variable renewable generation could be tempted to only enter the ex-post pool and therefore interconnector flows would not be fully integrated into the pool process for dispatch. This would reduce the efficiency of flows on the interconnectors and lead to higher levels of curtailment.

5.4.43 For these reasons the SEM Committee considers that its modified version of Option 3 is the superior option for delivering the most efficient cross border flows and the least curtailment of variable renewable generation. The quantitative evidence regarding the reduced social welfare from inefficient cross border trade supports the choice of a modified Option 3 as the most likely to maximise social welfare from market integration.

INTRADAY TRADING BENEFITS

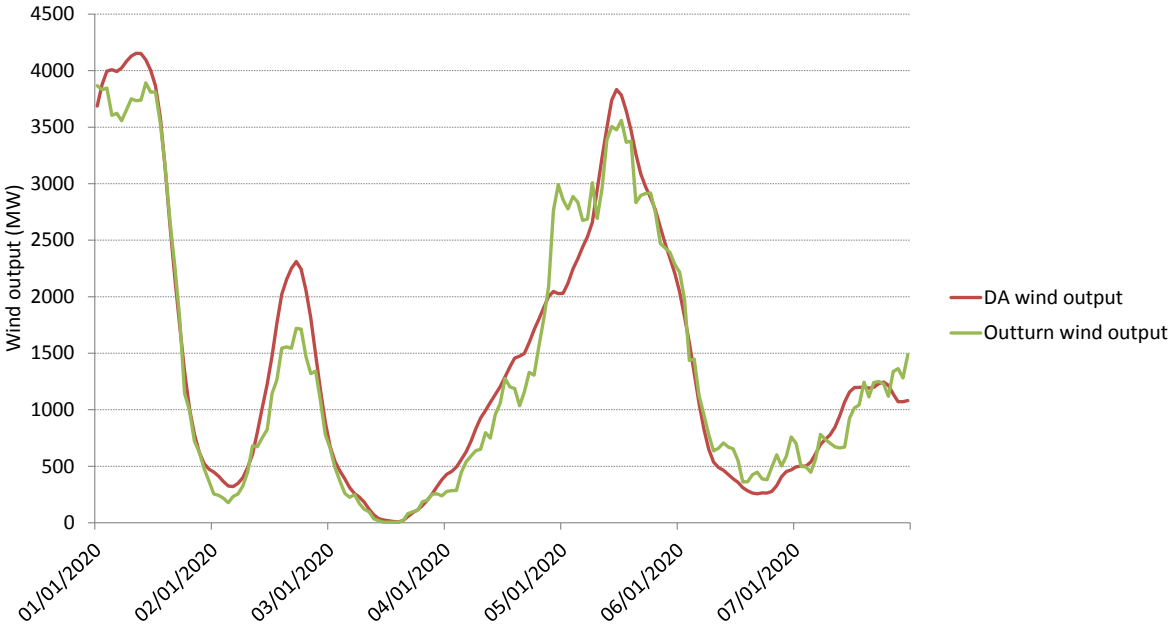
5.4.44 A liquid intraday market can be used to refine market participants' positions closer to real time as conditions change. This is of particular importance to variable renewable generators.

5.4.45 Trading on a common platform intraday and allowing for interconnector flows to respond to changes in plant availability and wind output can lead to a benefit both in terms of lower wholesale market costs (as the most efficient resources can be utilised) and reduced wind curtailment (with less reliance on TSO countertrading).

5.4.46 We have modelled the benefit of using interconnection intraday efficiently when compared with less responsive flows. We assume that the original runs of the two cases, Base Case A and Base Case B, represent the outcome of the Day-Ahead market. We then update demand and wind based on historical analysis of forecast errors.

5.4.47 For a sample week (based on January 2006 historical data), Figure 6 presents day-ahead expectation for wind output alongside the outturn for the whole island of Ireland.

Figure 6 – Outturn and expected Day-Ahead wind output for the whole island of Ireland for a sample week in January 2020 (weather year 2006)



5.4.48 Initially, we assume that flows across the interconnector are based on expected day-ahead wind output (as shown by the red line in Figure 6). We then model the market with updated wind and demand *assuming that the flows across the interconnector cannot respond to those changes*. In this case, there will be an inefficient use of the interconnection as the changes in both wind and demand patterns cannot be reflected in the flows.

5.4.49 For example, if the outturn wind output is lower than expected and the interconnector cannot respond, it may be that a more expensive thermal unit in the I-SEM has to replace the shortfall. If the interconnector could however respond to that change, a potentially cheaper unit in GB could have been utilised.

5.4.50 The benefit arises from allowing interconnector flows to respond to changes in demand and wind after the close of the day ahead market. Table 14 shows the reduction in wholesale market costs as result of allowing trading cross-border intraday. The benefits would have been even greater if outages were included, and

the modelling quantified the additional costs of changes that happened closer to real time[17], which would have to be balanced by more flexible (and expensive) capacity in the absence of a change in interconnector flows.

Table 14 – Overall change in I-SEM wholesale market costs from efficient intraday cross border trading

NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Base Case A	Base Case B
Change in wholesale market costs	-€537m	-€190m

5.4.51 In addition to increased wholesale market costs, the efficient use of the interconnector intraday should also reduce wind curtailment, as shown in Figure 7 below. Table 15 presents the annual reduction in wholesale market costs arising from intraday trading in the modelled snapshots years. Table 16 shows the breakdown of the NPV reduction.

Table 15 – Annual change in I-SEM wholesale market costs from efficient intraday cross border trading

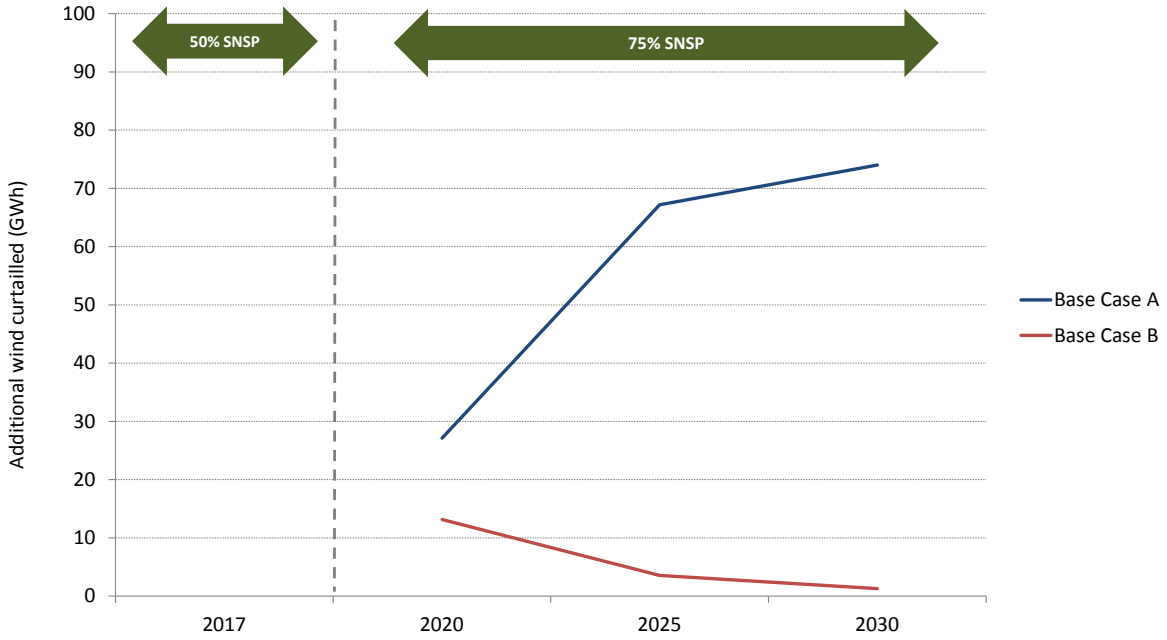
€m, real 2012 money	2017	2020	2025	2030
Base Case A	-€12m	-€17m	-€77m	-€84m
Base Case B	-€17m	-€24m	-€12m	-€19m

Table 16 –Change in wholesale market costs for the I-SEM resulting from efficient intraday cross border trading

NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Base Case A	Base Case B
Annualised capex	0	0
Annual fixed costs	0	0
Variable production costs	-€175m	-€113m
Cost of EEU	-€45m	+€17m
Cost of net imports	-€316m	-€94m
Total	**-€537m**	**-€190m**

[17] In this analysis we assume that there is foresight of changes in wind and demand well in advance of the event

Figure 7 – Additional wind curtailment[18] with no intraday cross-border trading



Assessment of Options based on Efficiency of Intra Day Trading

5.4.52 As with the efficient flows at the day ahead stage, we have mapped the sensitivity scenarios of inefficient cross border trade onto the options for energy trading arrangements.

5.4.53 Intraday trading benefits arise from allowing interconnector flows to change in response to changes in demand, wind and generator availability. A liquid IDM can be used by market participants to change their market positions closer to real time as more information comes to light on generator availability and as demand and wind forecasts become more accurate. This allows interconnector flows to respond to these changes and leads to benefits both in terms of lower overall wholesale market costs (as the most efficient resources can be utilised across Europe) and in terms of reduced curtailment of variable renewable generation.

5.4.54 In Option 1 the presence of forward physical bilateral contracts and the ability for generators to nominate their own physical positions could reduce the access to the IDM. The option for portfolio players to balance deviations between their day ahead contractual position and metered generation within their portfolio reduces liquidity in the intraday market and hence the efficiency of cross border trade through intraday market coupling.

5.4.55 In Option 2 the IDM would be competing for liquidity with the ex-post pool and this could greatly reduce the liquidity and effectiveness of the IDM. Variable renewable

[18] Curtailment based on limit of 50% non-synchronous generation in 2017, and limit of 75% non-synchronous generation from 2020 onwards)

generation, if it is conservative in forecasting day ahead volumes or reluctant to forecast at all, will enter the ex-post pool for some or all of its volumes. The resulting reduced incentive for market participants to trade intraday would reduce the efficiency of cross border flows and hence increase wholesale market costs.

5.4.56 In Option 3 the presence of a balancing mechanism with cost-reflective marginal imbalance prices should provide incentives for generation and demand to enter the IDM to avoid penal imbalance prices. The use of an exclusive and centralised IDM in this option means that it should support a liquid IDM and result in the reduced wholesale market costs and reduced curtailment quantified in Tables 15 and 16 and shown in Figure 7 respectively.

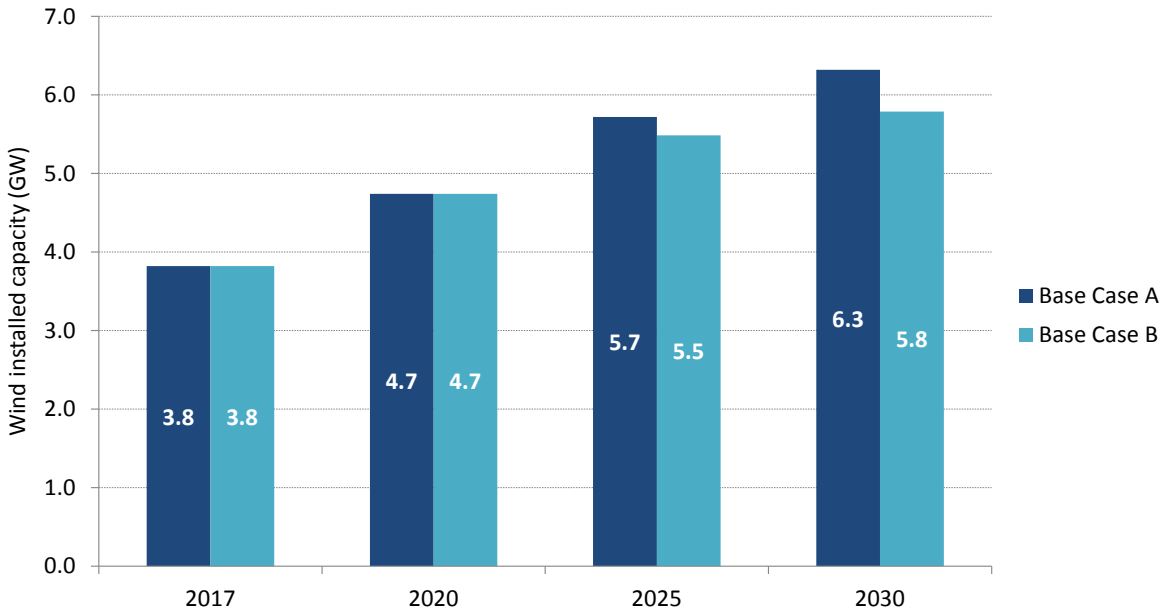
5.4.57 In Option 4 the ex-post pool could result in reduced incentives for participants to trade in the IDM. Generation and demand would not be balance responsible under this model and this would risk reducing liquidity in the IDM and hamper the efficiency of cross border flows.

5.4.58 The SEM Committee consider that the quantitative evidence set out above supports the choice of a modified Option 3 as the most likely of the four options under consideration to deliver the benefits to consumers in the form of efficient intraday trading. This is both in terms of optimal use of flexible resources in both markets and the reduction in the curtailment of variable renewable generation. The modelling supports more efficient cross border trade and more integrated markets as a means of promoting renewable energy sources and meeting national an EU Targets for renewable energy.

IMPACT OF INCREASED COST OF CAPITAL FOR WIND

5.4.59 Wind generation accounts for a significant proportion of the projected wholesale market costs. Figure 8 presents the installed wind capacity in both reference scenarios.

Figure 8 – Installed wind capacity in the I-SEM in Base Case A and Base B



5.4.60 Both Base Cases assume that 2020 RES targets are met. Further decarbonisation is primarily led by stronger renewables penetration under Base Case A in the years after 2020. In both Base Cases, installed wind capacity accounts for more than 45% of the total installed capacity by 2020. This means that the cost of building wind is one of the most important wholesale market cost elements.

5.4.61 In our two Base Cases we have assumed a WACC of 7.9% for onshore wind. In a market where there is increased risk for wind generators we would expect the weighted average cost of capital (WACC) to increase and that this would result in higher overall wholesale market costs. .

5.4.62 A higher cost of capital may also lead to lower investment in wind generation with an impact on decarbonisation efforts. We have not explored the effect of lower wind capacity being installed, but calculated instead the impact on total wholesale market costs for delivering the same amount of wind capacity. The wholesale market cost increase will effectively be borne by end consumer in the form of increased support payments. A less risky environment for wind will mean lower cost of capital and thus lower requirement for support payments.

5.4.63 Table 17 presents the NPV of wholesale market costs for the I-SEM in both Base Case A and Base Case B alongside the wholesale market cost increase assuming a 1% increase in the WACC for wind. This is comparable to the change in WACC assumed by DECC when modelling the difference between moving from the RO (8.3%) to the CfD (7.1%) support scheme under EMR.

Table 17 – Impact of higher cost of capital for wind on overall wholesale market costs for I-SEM

NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Base Case A	Base Case B
Reference case with WACC of 7.9%	€31947m	€34477m
Change in wholesale market costs with WACC of 8.9%	**+€448m**	**+€417m**

5.4.64 Table 18 shows the annual increase in wholesale market costs for the two cases.

Table 18 – Impact of higher cost of capital for wind on annual wholesale market costs for I-SEM

€m, real 2012 money	2017	2020	2025	2030
Base Case A with WACC of 7.9%	€2407m	€2696m	€3086m	€3530m
Change in wholesale market costs with WACC of 8.9%	**+€17m**	**+€29m**	**+€49m**	**+€68m**
Base Case B with WACC of 7.9%	€2489m	€2803m	€3414m	€3943m
Change in wholesale market costs with WACC of 8.9%	**+€17m**	**+€29m**	**+€46m**	**+€62m**

Mapping to Assessment of Options based on Increased Capital Costs for Wind

5.4.65 Based on the above modelling we now consider how increased capital costs for wind could differ between the different options for energy trading. Increases in the cost of capital for new variable renewable generation projects could be driven by increases in either price risk or volume risk.

5.4.66 First, variable Renewable Generation could be faced with increased price risk in Option 1 and Option 2.

5.4.67 In Option 1 the presence of forward physical bilateral contracts and the ability for generators to nominate their own physical positions could reduce the access to the DAM and IDM for smaller players and particularly for variable renewable generation. Variable renewable generation could then be forced into the Balancing Mechanism where it would likely receive a lower price.

5.4.68 In Option 2 there are effectively two distinct markets competing for liquidity, the

European DAM and the ex-post pool. As argued earlier, price-setting generation is likely to be drawn to the European DAM and IDM. Variable renewable generation on the other hand, if it is conservative in forecasting day ahead volumes or reluctant to forecast at all, will enter the ex-post pool for some or all of its volumes. Therefore the ex-post pool will deliver lower prices to variable renewable generation as it will be saturated with low cost generation.

5.4.69 Second, variable renewable generation could be faced with increased volume risk in Option 1, Option 2 and Option 4.

5.4.70 In Option 1 with PTRs being allocated on the interconnectors in forward timeframes then there could be less capacity available for the DAM and IDM. Flows on the interconnectors would then be less responsive closer to real time as conditions change. This would reduce the efficiency of flows on the interconnectors and lead to higher levels of curtailment.

5.4.71 In Option 2 there are effectively two distinct markets competing for liquidity, the European DAM and the ex-post pool. Price-setting generation is likely to be drawn to the European DAM and IDM in order both to access the interconnectors and to gain the highest price possible. Variable renewable generation on the other hand, if it is conservative in forecasting day ahead volumes or reluctant to forecast at all, will enter the ex-post pool for some or all of its volumes. However the flows on the interconnectors will be set by the DAM and IDM so this would reduce the efficiency of flows on the interconnectors and lead to higher levels of curtailment.

5.4.72 In Option 4 the ex-post pool could discourage voluntary financial trading in the DAM and IDM. Low levels of participation in the DAM and IDM would likely see inefficient patterns of scheduled imports and exports. Variable renewable generation could be tempted to enter only the ex-post pool. Interconnector flows would not be fully integrated into the pool process for dispatch. This would reduce the efficiency of flows on the interconnectors and lead to higher levels of curtailment.

5.4.73 Option 3 integrates the interconnector into the energy trading arrangements and the use of FTRs maximises the availability of physical interconnection capacity for the DAM and IDM. The exclusive nature of trading through the DAM and IDM provides assurance to variable renewable generation that they will have access to liquid and efficiently priced markets. The exclusive nature of trading through the DAM and IDM will also provide variable renewable generation with greater opportunity to manage their exposure to imbalance prices, compared with Option 1.

5.4.74 The emphasis in Option 3 on trading in the DAM will also help to provide a clear reference price for the renewable support arrangements in terms of REFIT and CfDs.

5.4.75 For these reasons the SEM Committee considers that its modified version of Option 3 is the superior option for reducing the price and volume risks facing variable renewable generation, thereby delivering the lowest possible cost of capital for new

investment in variable renewable generation and ultimately the greatest benefit for end-customers of all four options under consideration.

5.5 SUMMARY OF QUALITATIVE ASSESSMENT OF THE FOUR CONSULTATION OPTIONS

5.5.1 The context of the All-Island Market means that it is important to have a centralised and transparent set of energy trading arrangements in place in I-SEM.

5.5.2 Of the four options presented in the Consultation Document, Option 3 performs strongest overall against the assessment criteria. It concentrates physical liquidity in the European DAM and IDM, which act as the centralised market places. This integrates the interconnector into the market arrangements. There is also an emphasis in Option 3 on unit-based bidding by generators in the physical spot markets, which will support transparency and help to promote competition.

5.5.3 The actions of the TSO to deliver a secure system are supported by the operation of a mandatory balancing mechanism from the day-ahead stage onwards. The imbalance prices in Option 3 will reflect the costs of actually balancing the system with balance responsibility for all parties. This supports the principles of equity and efficiency.

5.5.4 The exclusive nature of trading through centralised DAM and IDM will also help to provide assurance to market participants, in particular suppliers and smaller variable renewable generators, that they will have access to the risk management tools needed to accompany the introduction of greater balance responsibility. The emphasis on trading in the DAM and the IDM is also compatible with the renewable support arrangements in terms of REFIT and CfDs, which rely on transparency of revenue and/or clear reference prices.

5.5.5 The qualitative assessment process also highlighted a number of elements where the design of Option 3 requires further development and specification and these are reflected in the draft decision of the SEMC on the final set of energy trading arrangements.

- Need for consideration of additional measures to support forward market liquidity as spot market liquidity on its own will not guarantee the development of forward market liquidity.
- The necessity of other aspects of the I-SEM design to provide incentives for market participants to participate in the DAM to deliver high liquidity.
- Relaxation of unit-based participation requirements in the DAM and IDM for some variable renewable generation to allow for aggregation opportunities as another route to market and one which allows variable renewable generation to manage risks of imbalance exposure.

5.5.6 While a well-functioning implementation of Option 1 has the potential to do well against a number of the criteria, its success would ultimately rely on the adaptations required in the various timeframes and could impose high transaction costs on small

participants. In the context of I-SEM, the significant reliance on the success of such interventions sees Option 1 fare less well under the assessment criteria. In particular, there could be a significant reliance on bilateral physical trading if market maker type obligations did not work as well as expected.

5.5.7 Option 2 is seen as untested and riskier and costlier to implement than any of the other options, particularly within the tight timescales for the I-SEM. The assessment has also not identified additional benefits against the primary assessment principles that could justify the additional risk and/or cost. One of the biggest challenges for this option is that there are effectively two markets competing for primacy in the trading of physical quantities - the European DAM, and the ex-post pool

5.5.8 Of the four options under consideration, Option 4 is the option closest to the current SEM. However, Option 4 could still represent significant change from the current SEM arrangements in a number of areas. The key reasons that Option 4 fares less well in the qualitative assessment is the potential for less than efficient integration of the interconnectors into the market. If the correct incentives cannot be created for participation in the DAM and IDT, efficient dispatch and price formation would be adversely affected which could have impacts in other areas, including the levels of wind curtailment.

5.6 QUALITATIVE ASSESSMENT AGAINST PRIMARY ASSESSMENT CRITERIA

The Internal Electricity Market

The market design should efficiently implement the EU Target Model and ensure efficient cross border trade.

5.6.1 All four of the HLD options presented in the Consultation Document would ultimately comply with the high-level requirements of the five pillars of the EU Target Model:

- Capacity Calculation and Zones Delimitation;
- Cross Border Forward Hedging and Harmonisation of Capacity Allocation Rules;
- Day Ahead Market Coupling;
- Intra Day Continuous Trading;
- Cross Border Balancing.

5.6.2 Therefore, the qualitative assessment considers only how the options differ in relation to how efficiently and easily compliance may be achieved, particularly in relation to day-ahead and intraday price coupling, and cross-border balancing. It also considers any issues for the options in complying with the European requirement for the implementation of the new HLD by the end of 2016

Option 1 - Adapted Decentralised Market (ADM)

5.6.3 At a high level, Option 1 should do well in terms of meeting the spirit of the internal electricity market, given that it shares many features with the prevailing market

design across many European markets.

5.6.4 However, the effectiveness of the day-ahead and intraday market coupling will depend on the liquidity in these market timeframes. This, in turn, is dependent on the effectiveness of the liquidity-promoting measures for the DAM and the IDM. While, the detailed design of any regulatory measures to promote liquidity in the DAM would need to be developed in the detailed design phase, there is a high reliance on their success to achieve cross border efficiencies.

5.6.5 The development of a separate balancing mechanism in Option 1 should make compliance with the target model for electricity balancing easier, given that many EU markets including GB has a dedicated balancing mechanism.

5.6.6 The use of Physical Transmission Rights in the forward timeframe would likely reduce liquidly in the DAM. This could reduce the efficiency of price formation in the DAM and IDM.

Option 2 - Mandatory Ex-Post Pool for Net Volumes (MPNV)

5.6.7 A key challenge for Option 2 is that there are effectively two markets competing for primacy in the trading of physical quantities: the centralised European DAM (and IDM) and the ex-post pool. If measures are put in place to ensure that sufficient price-making generation is committed through the pool, then this could restrict participation in, and ultimately the efficiency of, the European centralised markets. Such measures would also create barriers to trade between Member States which would be contrary to EU single market rules.

5.6.8 Option 2 is a pool-based option that could work with continuous intraday trading. However, the parallel operation of a mandatory pool for dispatch in the intraday timeframe may work better if there are periodic auctions alongside continuous trading (which would allow a pause in continuous trading to allow the running of the pool).

5.6.9 Option 2 does not fit naturally into existing types of balancing arrangements, which could make it harder to accommodate the requirements emerging under the balancing target model. While compliance with the target model for balancing is not unachievable given the central dispatch provisions in the Network Code, it would be more a more complex exercise to achieve all the benefits from efficient cross border balancing.

5.6.10 Timely compliance may be most difficult with Option 2. While it retains a pool-based approach, major changes to existing SEM systems would be needed (e.g. introduction of physical nominations and net complex bids into the pool, possible changes to the recovery of start and no-load costs, changes to the timing of bid resubmissions). This would be challenging under existing timelines, especially given that there is little international experience to draw upon.

Option 3 - Mandatory Centralised Market (MCM)

5.6.11 Option 3 is designed to deliver a high level of liquidity in the DAM and the IDM, which are the core centralised European markets for delivering the effective price coupling at the heart of the Target Model.

5.6.12 High levels of liquidity in the DAM under Option 3 are supported by the use of Financial Transmission Rights in the forwards timeframe. FTRs will ensure that the full capacity of the interconnectors is available for DA coupling.

5.6.13 The development of a separate balancing mechanism in Option 3 should make compliance with the target model for electricity balancing straight forward given that many EU markets, including GB, has a dedicated balancing market.

Option 4 - Gross Pool – Net Settlement Market (GPNS)

5.6.14 For Option 4, the effectiveness of market coupling both at the day-ahead stage and intraday will depend on the effectiveness of the incentives and liquidity-promoting measures for the DAM and the IDM. The detailed design of any such regulatory measures to promote liquidity in the DAM would need to be finalised as part of the implementation phase of this revised HLD.

5.6.15 With Option 4, the DAM and IDT will set the flows on the interconnectors. Therefore the drawbacks of less than efficient DAM and IDT participation are particularly acute in terms of overall costs and benefits to consumers.

5.6.16 Option 4 is a pool-based option that could work with continuous intraday trading. However, the parallel operation of a mandatory pool for dispatch in the intraday timeframe may work better if there are periodic auctions alongside continuous trading.

5.6.17 Option 4 does not fit naturally into existing types of balancing arrangements, which could make it harder to accommodate the requirements emerging under the balancing target model and make it a more complex exercise to achieve all the benefits from efficient cross border balancing.

5.6.18 In Option 4, the matched trades in the day-ahead and intraday European coupling arrangements are not 'physically firm' for individual All-Island market participants (i.e. cannot be used to support physical nominations of production or consumption to the TSO for use in dispatch). However they do produce 'physical' cross-zonal flows which are nominated to the TSO by the shipper, which appears to be consistent with the wording in the current drafts of the CACM Network Code.

5.6.19 While financial spot trades of this nature may be unusual in the European context, they are used in other electricity markets, such as can be found in the USA.

However, it is our understanding that using 'financial' instruments to determine cross-border flows would be unique in Europe as market splitting/coupling has historically been carried out by spot exchanges or spot market operators (NordPool Spot first, then EPEX Spot, Belpex, APX, OMIE, GME, which are all physical exchanges proposing physical contracts). [19]

5.6.20 This may require a greater level of discussion with European stakeholders over the operation of the proposed arrangements for trading in the DAM and the IDM as these arrangements will be less familiar in the context of European market integration.

SUMMARY

5.6.21 All four options are compliant with the requirements of the EU Target Model. The arrangements proposed in the Option 3 will concentrate physical liquidity into the European spot markets – with FTRs ensuring that interconnectors are fully integrated into the price-making process in these markets. Therefore, on balance, this is assessed as representing the most efficient implementation of the EU Target Model, given the current context of the All-Island market with a high emphasis on centralised and transparent trading arrangements for spot physical markets.

Security of Supply:

The chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.

5.6.22 There are two dimensions to security of supply: short-term issues and long-term issues. Short term issues generally refer to the ability of the TSO to deliver a secure system in dispatch. In the longer term, the issues are around having sufficient installed capacity on the system and the strength of forward contracting as a price signal to incentivise efficient entry and exit.

5.6.23 In all four options under consideration, the TSO will need detailed physical and feasible nominations for each participant to inform its dispatch processes. In practice, the TSO's dispatch planning processes will also be informed by its own information and forecasting, as well as the information provided by market participants.

5.6.24 The EirGrid response to the February 2014 Consultation stated that system security can be maintained under any of the four HLD options for energy trading arrangements.

[19] Other financial instruments are allowed under the EU Target Model in relation to cross-border risk hedging – e.g. FTRs and CfDs – but these do not determine the physical flow on the interconnectors.

Option 1 - Adapted Decentralised Market (ADM)

5.6.25 The TSO has highlighted the afternoon/early evening of D- 1 (after the DAM results) as being an important point for receiving these physical nominations. In addition, the management of changes in interconnector flows may be easier for the TSO if the physical contract nominations are as close to final as possible after the DA stage as this should reduce the likelihood of large swings in the scheduled interconnector flows close to real-time.

5.6.26 Option 1 should deliver participant nominations which will be derived from bilateral trading in the forwards timeframe and the DAM. High levels of bilateral trading in the forwards timeframe could reduce the levels of demand unserved at the DAM stage. This could foreclose the market for non-vertically integrated participants and variable renewable generation. Given priority dispatch for renewables in subsequent timeframes there is a potential for high levels of redispatch in Option 1.

5.6.27 In Option 1, the TSO will have scope and tools to take action before the IDM gate closure, including through a balancing mechanism (BM) that will start operation after the DA stage. However, the BM in Option 1 only becomes mandatory after the gate closure of the IDM which is close to real time. This would likely mean that there are fewer bids and offers in Option 1 available to the TSO in the BM until close to real time. This sees Option 1 being judged as performing quite low on short term security of supply in I-SEM.

5.6.28 In terms of longer term security of supply, the existence of physical contracting in the forward timeframe should see Option 1 perform well in terms of longer term security of supply. This would allow long term contracting of plant which can support market entry.

Option 2 - Mandatory Ex-Post Pool for Net Volumes (MPNV)

5.6.29 In Option 2, the TSO will in all likelihood have sufficient information available for dispatch given that there will be nominations from participants and also complex bids for the ex-post pool available from DA onwards.

5.6.30 One key issue with Option 2 the relationship between the forwards, DAM and IDT processes and the ex-post pool. If there is a split in liquidity between the earlier timeframes and the ex-post pool, there could be inefficient unit commitment or inefficient levels of levels of dispatch. This is because the firm trading timeframes for participants would overlap with the TSO pool-based processes.

5.6.31 A liquid DAM may help to encourage forward trading, but this risks weakening the advantages of the pool in Option 2. If the pool is the main focus of liquidity, there may be similar challenges to those experienced under the current SEM of encouraging forward trading with an ex-post pool as a reference market. The challenge is not the timing of trades, but that it is perceived to be harder to manage scheduling risk in an ex-post pool with complex bidding structures.

Option 3 - Mandatory Centralised Market (MCM)

5.6.32 The strong emphasis on very liquid trading at the DAM in Option 3 is key for informing the physical nominations at that stage in Option 3. In effect, full participation, albeit on a "best endeavours" basis, should give a full initial schedule to the TSOs which is set competitively in the DAM.

5.6.33 In Option 3, the TSO will have scope and tools to take action before the IDM gate closure, including through a balancing mechanism that will start operation after the DA stage. This is particularly so in Option 3 where the balancing mechanism becomes mandatory after the DA stage and so the TSO has bids from the entire system at an early stage.

5.6.34 In terms of longer term security of supply, the liquidity of the DAM is seen as important in determining the incentives from the energy market for new entry (or exit) – for example, by providing strong and robust reference prices to support forward trading. Option 3 performs well on this as it is designed specifically to deliver a very high level of liquidity in the DAM.

Option 4 - Gross Pool – Net Settlement Market (GPNS)

5.6.35 Ensuring that the TSO has access to a full set of bids and offers for (re)dispatch from an early point onwards is seen as helpful for it in managing the system. This is inherent in the Option 4 given the existence of the mandatory pool with complex bids submitted initially at the day-ahead stage.

5.6.36 The TSO dispatch processes to deliver a secure and safe system in Option 4 are likely to be broadly similar to the current arrangements. The biggest differences are likely to relate to the scheduling of plant closer to real time. The interconnectors will be scheduled based on the DAM and IDT markets. If effective incentives are in place for participation in these markets, cross border flows could change intraday based on new information such as increased or reduced wind. The ability to update bids by generators in the ex-post pool will also mean the TSO expected or actual dispatch could be changed closer to real-time. This will depend on the extent to which the bids of domestic generation changes intraday.

5.6.37 One of the relative disadvantages of this Option 4 is that the interconnector flows would not be fully integrated into the pool process for dispatch as they are inputs into the process rather than being determined within the pool itself. This could reduce the coordination and efficiency of overall dispatch and could increase reliance on TSO countertrading.

SUMMARY

5.6.38 Option 3 has a number of features that should be particularly helpful in delivering a secure system. Its strong emphasis on the DAM should give a robust starting point for dispatch. The interconnectors are fully integrated into the physical spot markets,

which inform the detailed, feasible physical nominations from the market participants. The release of the contractual schedule from a highly liquid DAM should help to deliver a good-quality set of nominations for the TSO as the starting point for dispatch. The highly liquid and transparent DAM in Option 3 will be a strong reference market to support the development of liquid forward financial trading, which should support long-term security of supply.

5.6.39 The operation of a mandatory balancing mechanism after the day-ahead stage will provide the TSO with access to a wide range of bids and offers to help it manage the system, primarily for energy balancing, but also to support its wider set of arrangements for procuring system services.

5.6.40 Options 1, 2 and 4 should deliver security of supply but the potential for inconsistencies between timeframes may make a less robust starting point of dispatch or could require greater re-dispatch.

Competition:

The trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner.

Option 1 - Adapted Decentralised Market (ADM)

5.6.41 Option 1 could enable market participants to be more innovative in terms of trading strategies. This could include, for example, different approaches to trading demand or wind generation in the face of forecast error and asymmetric imbalance prices. This could provide benefits to consumers either in terms of lower costs and/or more attractive products and services.

5.6.42 In an efficiently functioning Option 1, the ability to choose a trading strategy could also act as a constraint on the exercise of market power; e.g. if there is gaming in a particular market, then participation may decline which mitigates the negative impact of the gaming.

5.6.43 However, the potential downside of Option 1 is that this innovation would have little transparency, could benefit the individual participant be to the detriment to the market as a whole, and might only be required because of design inefficiencies in other aspects of the market. This could be particularly the case in I-SEM where there are a number of players that are not vertically integrated and rely on an open competitive and centralised market place. Therefore the success of Option 1 relies heavily on the adaptations, such as liquidity promoting measures, that would be required.

5.6.44 Following on from this, another key consideration for Option 1 is the extent to which the nature of the All Island Market means that in practice significant regulatory intervention would always be needed to create the conditions for effective

competition and that without such intervention a fully competitive framework could not develop.

Option 2 - Mandatory Ex-Post Pool for Net Volumes (MPNV)

5.6.45 A key feature of Option 2 is the ability to trade physical bilateral contracts in the forwards timeframe. Therefore the levels of competition within the industry structure will determine its success. If there are high levels of physical contracts within vertically integrated players, there could be increased transactions costs and greater barriers for smaller players.

5.6.46 The existence of an ex-post pool, however, should create a route to market for small players especially since there is an optimisation of physically contracted capacity in the pool algorithm. This should provide a strong reference price for independent and small generators or suppliers, similar to the arrangements in the SEM.

5.6.47 One key potential downside of Option 2 would be where the majority of physical trading concentrates in the pool at the expense of the earlier markets and in particular the DAM and IDM. This could reduce cross border competition where a high level of I-SEM demand is met by internal generation.

Option 3 - Mandatory Centralised Market (MCM)

5.6.48 Option 3 is designed to focus competition for physical volumes in the centralised European DAM and IDM. As the interconnector capacity is fully integrated into the market arrangements, it can act as a competitive constraint on possible market power.

5.6.49 The emphasis on liquid centralised market places is a key attribute of Option 3. It provides competitive but equal routes to market for all players including independent and small generators or suppliers. In addition, a reliable day ahead price should encourage the participation of the demand side.

5.6.50 High levels of participation, in particular in the DAM, will provide a competitive method of price formation in the I-SEM, given the requirement for unit based bidding. Unit based bidding has many positive attributes which are accentuated in a market like I-SEM, where market power is a concern, and transparency has a premium. Unit based bids provide significant transparency in the behaviour of individual participants and promote understanding and ultimately confidence in the price formation in the market. This, combined with the scope for different bidding approaches catered for in Euphemia, sees a reliance on unit-based bidding do higher than portfolio bidding in the assessment.

5.6.51 The exclusive nature of the intraday market in Option 3 is another significant feature in relation to competition. This exclusivity means that all players must settle any

imbalance on an open marketplace rather than within a portfolio. This creates non-discriminatory access for independent and smaller participants.

Option 4 - Gross Pool – Net Settlement Market (GPNS)

5.6.52 Option 4 is designed to concentrate competition for physical quantities in the ex-post pool. This would provide a route to market, with a strong reference price, for independent and small generators or suppliers, similar to the arrangements in the current SEM. The requirement for complex (unit-based) bids and mandatory participation in the pool means that there would be transparent bidding in this option, which would facilitate ex-post market monitoring.

5.6.53 One issue for Option 4 is the extent to which the DAM and IDM will be sufficiently liquid to support effective competition in those markets. Participation in these cross border markets will set interconnector flows and so their success is key to achieving competitive outcomes in the I-SEM. Low levels of participation in the DAM and IDT would likely see inefficient patterns of scheduled imports and exports.

SUMMARY

5.6.54 It is important that stakeholders have confidence that the conditions are in place for effective competition, i.e., transparency of trading behaviour and outcomes. Features that are seen as positive for transparency are the use of unit-based bidding and reliance on centralised market places, which are at the core of Option 3. If trading is concentrated in the European markets, then the power exchanges operating these markets can also support the regulators' market monitoring activities, as market surveillance is typically a key activity of the European power exchanges.

5.6.55 Overall, Option 3 appears to best meet the competition criterion, in the I-SEM context, given its focus on liquid centralised exclusive market places and unit based bidding.

Environmental:

While a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.

5.6.56 Assessment of performance under this criterion considers the direct impact of the market arrangements on renewables, in terms of possible routes to market and compatibility with renewable support schemes. It also considers the extent to which the option facilitates flexible resources that could help the system to accommodate the output patterns of variable renewables.

Option 1 - Adapted Decentralised Market (ADM)

5.6.57 Option 1 has an ex-post imbalance mechanism with prices reflecting the costs of marginal TSO actions in balancing the energy on the system in each settlement period. This naturally poses challenges for all market participants and so it is important to have liquid markets to trade out positions. Variable generation is particularly reliant on liquid trading places given that it is less predictable closer to real time.

5.6.58 The presence, in Option 1 of physical forward contracting, a voluntary DAM, portfolio bidding and a non-exclusive intraday market would likely pose challenges for participants but in particular small variable generation players. Option 1 does have a number of adaptations and so the success of those adaptations will determine the success of the market for smaller players.

5.6.59 Related to the above, the presence of a robust reference price is key for renewables and renewables support schemes. The success of the adaptations and liquidity promoting measures would therefore be key in the success of Option 1 here.

5.6.60 The use in Option 1 of a dedicated balancing mechanism with cost-reflective marginal imbalance prices should provide robust incentives for the development of flexible resources that offer its services for energy balancing close to real time. Valuing flexibility appropriately in the energy market should reduce the cost of separate mechanisms which incentivise the delivery of the flexibility required to help the system accommodate higher levels of variable generation.

Option 2 - Mandatory Ex-Post Pool for Net Volumes (MPNV)

5.6.61 The use of a pool to determine the ex-post prices in Option 2 likely reduces the exposure of variable generation to the impact of it being less predictable closer to real time. This is because all generation and load, whether predictable or unpredictable, face the same ex-post price established through the ex-post unconstrained schedule. This should be a positive attribute for renewable generation

5.6.62 The existence of a liquid ex-post pool with an optimisation of already contracted resources will be positive for renewable generation but there is a potential that overall market efficiency for renewables could be reduced under Option 2. If there is significant concentration of volumes in the ex-post pool there could be less than efficient use of the interconnectors. This concentration could be influenced by many factors including liquidity issues in earlier timeframes. The efficient use of interconnectors is a key issue for the renewables industry and inefficient use, particularly in the IDM could increase curtailment of wind.

5.6.63 However, a likely weakness of the pool-based Option 2 is that flexible resources required to help manage variable renewable output do not receive the full value of this flexibility in the pool. This would be the case if the pool algorithm effectively

assumes perfect foresight at the day-ahead stage, which means that flexible resources that respond close to real-time do not access a premium (pay as cleared) market price for providing that service.

Option 3 - Mandatory Centralised Market (MCM)

5.6.64 The focus in Option 3 is on liquid centralised market places for all market participants with full integration of the interconnectors into the market. This sets a level playing field for all participants to trade and to trade out positions in centralised market places. This provides an assurance to smaller players that the balance responsibility they assume can be managed in a fair and efficient manner.

5.6.65 The use in Option 3 of a dedicated balancing mechanism with cost-reflective marginal imbalance prices should provide appropriate incentives for the development of flexible resources that offer its services for energy balancing close to real time, within market timescales.

5.6.66 The existence of and focus on liquid centralised market places should allow for the establishing of reliable reference prices for renewables support schemes.

Option 4 - Gross Pool – Net Settlement Market (GPNS)

5.6.67 The use of an ex post pool to determine the prices in Option 4 would reduce the exposure of variable generation to the impact of it being less predictable closer to real time. This is because in this option all generation and load, whether predictable or unpredictable, does not have balance responsibility and faces the same ex-post price established through the ex-post unconstrained schedule. This should be a positive attribute for variable renewable generation.

5.6.68 However, it is possible that overall market efficiency for renewables could be sub-optimal under Option 4, given the risk that the incentives for participation in earlier markets could be less than reduced by comparison with the other options. This is because trades are financially firm for the individual participant but physically firm for the market as a whole.

5.6.69 If there is significant concentration of volumes in the ex-post pool there could be less than efficient use of the interconnectors.

5.6.70 Another potential weakness of Option 4 is that flexible resources required to help manage variable renewable output do not receive the full value of this flexibility in the pool. This would be the case if the pool algorithm effectively assumes perfect foresight at the day-ahead stage, which means that flexible resources that respond close to real-time do not access a premium (pay as cleared) market price for providing that service.

5.6.71 The scope for flexible resources to benefit from intraday prices will depend on the

extent to which variable renewable generation will be sufficiently encouraged to trade in the intraday market, given the relative attractiveness of the ex-post pool price for variable renewable generation.

SUMMARY

5.6.72 The key elements of Option 3 provide the best package of the four options in terms of facilitating renewable deployment in the I-SEM.

5.6.73 The greater reliance on market-based signals for flexibility and strong integration of interconnectors into the physical spot markets should help better manage changes in renewable generation in the All-Island market.

5.6.74 The emphasis on liquid, centralised DAM and IDM will provide independent renewable generators with more opportunity to manage their exposure to imbalance prices, as well as providing robust reference prices for renewable support schemes.

Equity:

The market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner

5.6.75 As explained in the February 2014 Consultation Paper, there are two main aspects to the assessment of equity. The first is about the equality of access to different markets for a range of market participants, such that for a market to be equitable it should present the same set of challenges to all participants. In reality the market model on its own is unlikely to be the only factor in determining equity. The characteristics of the participant will also have a significant bearing. However to the degree that the market model has some bearing on equity, one of the key features of market design is market access.

5.6.76 The second aspect is the delivery of an allocative efficient outcome where prices reflect marginal costs (including an appropriate allowance for risk). Prices that are cost-reflective can in turn be perceived as 'fair' and non-discriminatory. In practice, cost-reflective pricing is closely associated with the competition criterion, since competitive markets will generally be allocatively efficient.

Option 1 - Adapted Decentralised Market (ADM)

5.6.77 A well-functioning Option 1 should deliver equitable outcomes and allow for innovation which benefits the market as a whole.

5.6.78 However, of all the options Option 1, places the greatest reliance on competitive market structures underlying the market. In the absence of such a competitive structure, it places reliance on adaptations to achieve competitive outcomes.

5.6.79 The combination of forward physical contracting, a voluntary DAM, portfolio bidding and a non-exclusive intraday market would likely favour portfolio players in the first instance. While competitive pressures, such as cheaper generation being available to meet demand, should drive competitive outcomes such an outcome is not always certain. For example, if a portfolio player can meet its demand from an independent generator for marginally less than running their own plant, they may still choose to run their own plant, especially if this means the marginally cheaper plant doesn't run.

5.6.80 Were such an outcome as mentioned above to occur there would likely be higher transactions costs and greater barriers to market participation for non-portfolio players.

5.6.81 In Option 1, the imbalance price is intended to reflect the marginal cost to the TSO of balancing the residual difference between energy supply and demand (i.e. the physical volumes neither settled in an ex-ante market nor on the basis of a trade with the TSO to manage a system constraint). The second aspect of equity - of cost-reflective pricing - would therefore be met.

Option 2 - Mandatory Ex-Post Pool for Net Volumes (MPNV)

5.6.82 Option 2 should allow market access for a wide range of market participants on an equitable basis. In particular the existence of an ex-post pool should provide route to market for smaller players although there is a reliance on certain levels of liquidity.

5.6.83 The existence of physical trading in the forwards timeframe may however, favour portfolio players and may pose difficulties for smaller participants trading in earlier timeframes. This would be particularity the case for smaller suppliers looking for forward liquidity.

5.6.84 In Option 2, the costs of the TSO's energy balancing actions are socialised in the ex-post price, and in dispatch balancing costs. Whether this is equitable will be determined by the extent to which it is judged that the recovery of these balancing costs should be targeted at the market participants who are deemed to have caused them. This, in particular raises questions as to whether those providing flexibility to the system are being appropriately rewarded for it in the energy market.

Option 3 - Mandatory Centralised Market (MCM)

5.6.85 The focus on exclusive liquid centralised markets in Option 3 is key in terms of providing an equitable route to market for market participants. In particular, Option 3 relies on the DAM and IDM as exclusive routes to physical contract nominations before the balancing mechanism. In addition Option 3 uses FTRs on the interconnectors to maximise the availability of physical interconnection capacity for the DAM and IDM.

5.6.86 The requirement for unit-based bidding into the DAM and IDM will also level the playing field between portfolio and non-portfolio players in terms of optimising internally between thermal generation. However, portfolio wind players may benefit compared with individual wind farms from a more diversified imbalance risk.

5.6.87 The existence of a highly liquid DAM should provide a robust reference price for forward trading and other financial contracting. This combined with the suite of products available in European market timeframes should support confidence in forward trading for entities with and without a physical presence in the market.

5.6.88 In Option 3, the imbalance price is intended to reflect the marginal cost to the TSO of balancing the residual difference between energy supply and demand (i.e. the physical volumes neither settled in an ex-ante market nor on the basis of a trade with the TSO to manage a system constraint). The second aspect of equity - of cost-reflective pricing - would therefore be met by Option 3.

Option 4 - Gross Pool – Net Settlement Market (GPNS)

5.6.89 The gross mandatory pool in Option 4 should provide an equitable route to market for participants in I-SEM. This combined with a robust reference price should give confidence in the market.

5.6.90 However, Option 4 may pose questions around the equity for cross border players. The level of integration between I-SEM and GB would depend on the level efficiency of interconnector utilisation. If, in an extreme example, all demand was to purchase from the ex-post pool there would be no demand in the DAM and IDM and so cross border generation would not get access to I-SEM.

5.6.91 In Option 4, the costs of the TSO's energy balancing actions are socialised in the ex-post price, and in dispatch balancing costs. Whether this is equitable will be determined by the extent to which it is judged that the recovery of these balancing costs should be targeted at the market participants who are deemed to have caused them. This, in particular raises questions as to whether those providing flexibility to the system are being appropriately rewarded for it in the energy market.

SUMMARY

5.6.92 The highly liquid DAM and IDM in Option 3 provides all market participants with access to ex-ante markets including the full integration of interconnector capacity into the market. These markets also provide tools for market participants to manage exposure to cost-reflective imbalance prices that target the recovery of energy balancing costs.

5.6.93 Robust reference prices and the suite of order structures in Euphemia should provide forward liquid opportunities for different types of market participants.

5.7 QUALITATIVE ASSESSMENT – SECONDARY ASSESSMENT CRITERIA

Stability:
The trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.

5.7.1 The assessment of this HLD criterion considers how robust the set of energy trading arrangements may be to any future changes in circumstances without major disruption.

Option 1 - Adapted Decentralised Market (ADM)

5.7.2 Option 1 represents the most radical change from the current SEM given the introduction of bilateral physical contracting and a move away from any mandatory markets. However, Option 1 also represents a market design which likely most closely aligns with the designs of many markets across Europe. Therefore, Option 1 should be robust to future changes in direction at EU level

Option 2 - Mandatory Ex-Post Pool for Net Volumes (MPNV)

5.7.3 Although Option 2 retains some elements of a pool-based approach for dispatch with complex bids and ex-post pricing, there could be significant changes from the current market arrangements in the move to a net pool. The introduction of physical contracting represents a key change.

5.7.4 The future stability of Option 2 would be open for debate. With Option 2, the I-SEM would not only have a market not in line with many other European countries, it would also be unique. This poses a significant challenge in terms of stability.

Option 3 - Mandatory Centralised Market (MCM)

5.7.5 Like the current SEM, Option 3 is focused on trading in centralised market places with transparent bidding. However, this is done through centralised European markets rather than an all-island pool as under current arrangements, which means that there will be significant changes required to the SEM. However, once established, Option 3 will provide a stable set of arrangements looking forward which will build confidence, deliver efficiency and encourage investment.

Option 4 - Gross Pool – Net Settlement Market (GPNS)

5.7.6 Of the four options in the consultation paper, Option 4 is the closest to the current SEM. However, it could still represent significant change in the energy trading arrangements.

5.7.7 The issue in terms of forward-looking stability would be that the I-SEM design would still be different to the other markets across Europe with which I-SEM will integrate.

This could pose challenges for future changes in the direction of the target model.

5.7.8 In addition, Option 4 has the greatest reliance on financial trading as a hedging tool, which means that this option could present risks in terms of exposure to possible changes in financial trading regulations with respect to the treatment of non-physical trades in the DAM and IDM.

SUMMARY

5.7.9 In summary, all four market designs require a change to the current SEM. Option 4 could, in theory, require the least change, but change could still be substantial. Options 1 and 3 are expected to require similar levels of change from the current SEM arrangements while Option 2 would probably require the most change and represent the biggest challenge for the stability of the arrangements.

5.7.10 Option 3 strikes a good balance. It retains an emphasis on physical trading in centralised, transparent marketplaces, whilst facilitating much closer integration with other European electricity markets.

Adaptive:

The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.

Option 1 - Adapted Decentralised Market (ADM)

5.7.11 In Option 1, there is expected to be low reliance on specific local arrangements for the majority of physical trading. If there is a liquid DAM and IDM, then most of the trading will happen on the organised, centralised European markets. This could make it hard to make all-island specific changes to the trading arrangements based on changing circumstances within the SEM, which was a concern for a number of respondents.

5.7.12 The governance arrangements for the European DAM and IDM will allow for changes to be made to the DAM and IDM arrangements in the future, with representatives of the I-SEM having a role in these governance arrangements. As this option is in line with the general thrust of the current market coupling arrangements, it is expected that the governance should be able to accommodate any changes required for the I-SEM.

Option 2 - Mandatory Ex-Post Pool for Net Volumes (MPNV)

5.7.13 Option 2 is a hybrid approach and so the adaptability issues will depend on whether the physical trading is concentrated inside the pool (or bilateral arrangements), or whether it is concentrated in the centralised European markets.

5.7.14 A reasonable concern is that this option will suffer from the worst of both worlds; i.e. vulnerability to external change (as there may be few if any markets in Europe with a similar design); but also high costs of change since the systems will all be bespoke.

Option 3 - Mandatory Centralised Market (MCM)

5.7.15 Option 3 has a high reliance on physical trading through the European DAM and IDM. This could make it hard to make all-island specific alterations to the trading arrangements based on changing circumstances within the SEM, which was a concern for a number of respondents.

5.7.16 The governance arrangements for the European DAM and IDM will allow for changes to be made to the DAM and IDM arrangements in the future, with representatives of the I-SEM having a role in these governance arrangements. As Option 3 is strongly in line with thrust of the current market coupling arrangements in the NWE region, it is expected that the governance arrangements should be accommodate any changes required for a I-SEM based around this option.

Option 4 - Gross Pool – Net Settlement Market (GPNS)

5.7.17 The use of a gross mandatory ex-post pool of Option 4 may make it easier to make all-island specific changes to the local arrangements governing the pool. However, it may be harder to coordinate these changes with developments across Europe, which is important for compliance with the requirements of the Electricity Balancing Network Code. This will depend on the provisions put in place for arrangements for integrated scheduling and dispatch arrangements that are allowed under the Electricity Balancing Network Code.

SUMMARY

5.7.18 The aim of integrating more closely with European markets means that all of the HLD options presented in the Consultation Document rely on an effective DAM and IDM for successful implementation. The ability to influence the arrangements in the DAM and the IDM will be greater in Option 1 and Option 3, where the HLD is more closely aligned with the prevailing European market design.

5.7.19 In addition, in Option 3, greater reliance on physical trading in centralised market places will make it easier to coordinate and implement agreed changes that are designed to apply to all physical trading.

5.7.20 The detailed design and most critically the systems implementation are important in ensuring that any set of energy trading arrangements are suitably adaptive. For example any future changes agreed to the rules or mechanisms for energy trading need to be implemented without excessive delays or costs of introducing change resulting from system issues. Therefore, adaptability in systems should be designed in from the start, under any of the proposed HLD options for energy trading arrangements.

Efficiency:

Market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.

Option 1 - Adapted Decentralised Market (ADM)

5.7.21 A decentralised unit commitment process could emerge in Option 1 if unit-based physical nominations are driven by direct bilateral trades, management of a vertically integrated portfolio that does not go through the DAM, or the conversion of portfolio-level results from the DAM and IDM.

5.7.22 Therefore, the centralisation of the commitment process in Option 1 will depend primarily on the liquidity of the DAM and the voluntary use of unit-based bidding in the DAM. [20] It will also be affected by the degree of participation in the balancing mechanism which only becomes mandatory after intraday gate closure.

5.7.23 The impact of non-energy factors (e.g. reserve) on the dispatch position produced by the physical nominations from market participants under Option 1 will depend on the arrangements put in place for the procurement of system services (which will be determined under the DS3 work programme[21]).

Option 2 - Mandatory Ex-Post Pool for Net Volumes (MPNV)

5.7.24 In Option 2, there is mandatory participation for generating units based on complex bids submitted after the day-ahead stage and updated throughout the day. In this option, the full (three part) complex commercial bids currently used in the SEM are used for unit commitment within the pool. However plants can provide contractual nominations to provide a starting point above zero into the pool.

5.7.25 Therefore, the degree to which initial unit commitment (in the form of detailed physical nominations of generation profile) is centralised will depend on the form of trading outside the pool, including the nature of bids (both in terms of format and

[20] The February 2013 Next Steps Decision Paper described the European DAM as essentially being a centralised market.

[21] Further information on the DS3 project is available at http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=06c22cd8-a936-426b-ac21-ed28b5292566, or at http://www.eirgrid.com/operations/ds3/

whether unit or portfolio) into the market.

5.7.26 The impact of non-energy factors (e.g. reserve) on the dispatch position produced by the physical nominations from market participants under Option 2 will depend on the arrangements put in place for the procurement of system services (which will be determined under the DS3 work programme).

Option 3 - Mandatory Centralised Market (MCM)

5.7.27 In Option 3, the emphasis is on centralisation of the commitment and dispatch process in a liquid DAM, with a mandatory BM from the Day-Ahead Stage onwards. This centralised commitment process will use the different bid formats that have been developed in other markets to allow market participants to manage the risk of start-up costs (in the optimisation by Euphemia across a whole trading day), without requiring the full (three part) complex bids currently used in the SEM. The bid formats that may be best suited to the circumstances of the All-Island Market will be explored further during the detailed design phase.

5.7.28 Some respondents raised questions around the potential risk of the reliance on the Euphemia algorithm particularly in relation to its ability to accommodate start-up and no-load costs, and produce overall least cost dispatch, given the inevitable need to re-dispatch plant to provide reserve and to meet system constraints. Other respondents stated that block bids (of various forms) could accommodate commercial and technical characteristics.

5.7.29 The implications for participants of reliance on the Euphemia algorithm will also be dependent on the process through which the market schedule (MWh per trading period) for generation (including demand-side units) is converted into more granular and feasible planned physical nominations for use in dispatch. This will be determined as part of the detailed design phase.

5.7.30 In Option 3, the physical nominations from generators are linked to trades made in the centralised market places (DAM, IDM and/or BM), which are on a unit basis. The scope for these physical nominations to reflect non-energy factors (e.g. reserve) will depend on the rules governing the bidding of market participants, which will be determined by the detailed design of the energy trading arrangements.

Option 4 - Gross Pool – Net Settlement Market (GPNS)

5.7.31 In Option 4, here are no physical nominations from participants (other than interconnectors) based on an unconstrained energy market schedule. Instead, the starting point for unit commitment and dispatch are complex bids submitted into a mandatory pool at the day-ahead stage, with subsequent update windows for bids.

5.7.32 Scheduled interconnector flows are held firm from the results of the European DAM and IDM. One possible issue for Option 4 is the liquidity of the DAM price based on

voluntary trading (given a strong ex post Pool), and the extent to which that provides an effective signal for demand side response (and interconnection flows) in the ex-ante markets.

SUMMARY

5.7.33 Previous reports for the RAs have noted that an efficient dispatch outcome should be achievable under different dispatch arrangements, including central or self-dispatch[22].

5.7.34 In the context of the All-Island market, Option 3 has a number of advantages in facilitating efficient dispatch, since the starting point for dispatch is based on a centralised unit commitment process that fully integrates the available physical interconnector capacity.

5.7.35 The detailed design phase will determine how and when non-energy factors are taken into account in the dispatch process – e.g. how non-energy factors may be reflected in the physical nominations that provide the starting point for dispatch.

Practicality/Cost:
The cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced

Option 1 - Adapted Decentralised Market (ADM)

5.7.36 For Option 1, the main issues for practicality and cost of implementation relate to the balancing mechanism and the costs of the routes to market available to different types of participants.

5.7.37 The balancing mechanism used in Option 1 already exists in different forms in a number of other European markets. This should help to reduce the cost of implementation, although the cost will ultimately be dependent upon the customisation that is required for the All-Island market. This would be established at the detailed design phase.

5.7.38 Option 1 includes a number of different possible routes to market for physical electricity, including optimisation within portfolios, bilateral trading, aggregation (with aggregated volumes traded in the centralised markets), and the centralised European market places. The practicality and cost of accessing these various routes may differ significantly by type and size of market participant (e.g. in terms of collateral arrangements), with the risk that the costs are much higher for smaller market participants.

[22] For example, see page 26 of the September 2012 Easter Bay Report.

Option 2 - Mandatory Ex-Post Pool for Net Volumes (MPNV)

5.7.39 Option 2 poses particular challenges with respect to practicality and cost of implementation. The data flows and pricing algorithm involved in the pool may require a substantial change from that of today to allow for the net pool concept and are likely to be unique worldwide. This means that Option 2 has the highest central estimate of implementation and operation costs.

5.7.40 In addition, the costs of participation in the European markets may be higher for generating units because of the need to maintain parallel systems for IDM and for the pool (mandatory after the day-ahead stage) with quite different bid structures.

Option 3 - Mandatory Centralised Market (MCM)

5.7.41 For Option 3, participation in the European DAM and IDM is the only route to physical contract nomination (outside of the Balancing Mechanism). This would allow smaller market participants to benefit from cost advantages of centralised trading mechanisms.

5.7.42 However, if generation trading is only allowed on a unit basis, then all generators would need to have direct access to systems and resources to individually manage their position throughout the trading day (e.g. in response to changes in forecasts of generation availability). Facilitating some form of intermediary arrangements would help to mitigate this cost, as it would allow smaller generators to benefit from economies of scale in trading resources.

5.7.43 Option 3 uses a balancing mechanism. As this already exists in different forms in a number of other European markets, this should help to reduce the cost of implementation, although the cost of implementation will ultimately be dependent upon the customisation that is required for the All-Island market. This would be established at the detailed design phase.

5.7.44 Respondents have also raised issues around the practicality of relying on European intraday solution that is not yet in place as the only route to intraday physical contract nomination. This should not raise issues for the intraday trading within the All-Island Market but possible fallback measures for the allocation of intraday interconnector capacity to allow intraday trading with GB. These may need to be considered as part of the detailed design phase in case of further delays in the NWE intraday project. In practice, fallback measures would need to be considered for all options to address a range of possible contingencies – e.g. IT outage with Europe.

Option 4 - Gross Pool – Net Settlement Market (GPNS)

5.7.45 In Option 4, the data flows and pricing algorithm involved in the pool may be able to build on the system and processes currently in place. Some change will definitely be required, e.g. more frequent rebidding, more data to be provided by market

participants to facilitate the net settlement process, and the net settlement process itself. Therefore, the cost of implementation will be determined by the extent of these changes, which would be defined at the detailed design phase.

5.7.46 For Option 4, the costs of participation by all island market participants in the European markets in this option may be greater if that trading is deemed to be subject to financial trading regulations with respect to the treatment of non-physical trades. For example, it would need to be determined whether the reporting (and licensing) requirements for all island market participants trading outside the pool would fall under financial regulation (such as MIFID II) rather than energy market regulation (such as REMIT).

SUMMARY

5.7.47 There are some implementation and operation costs that are common to all four HLD options. For example, central systems will need to be developed and/or procured to allow All Island market participants to access the European DAM and IDM under any of the options.

5.7.48 Similarly, market participants are likely to require some new systems or interfaces (or to participate through an intermediary if this is permitted) in any of the four options if they wish to participate in the European DAM and/or IDM. For effective participation in a continuous IDM, the ability to trade 24 hours a day is likely to be a requirement (which could be delivered by an intermediary). This is already a feature of other European markets including GB, and the necessary trading infrastructure will already be in place for some market participants.

5.7.49 Section 5.3 sets out some initial estimates of the possible costs of implementing and operating the proposed energy trading arrangements (from the perspective of market participants, MO/TSO and the RAs). Initial estimates of the annualised cost of implementing and operating the new set of trading arrangements are around €10m-€15m/year in real terms between 2017-2030. This figure represents around 0.5% of the estimated total wholesale market value in the I-SEM.

5.7.50 Option 2 has the highest estimated costs (€14m) as a result of the much higher cost of implementing the net pool in Option 2. The other three options all have a central estimate of annualised cost of €12m, which means that there are few if any additional costs associated with obtaining the greater benefits identified in Option 3.

5.7.51 An important component of implementation and operation costs is the trading costs for market participants. The assessment against the primary assessment criteria has highlighted the importance of a liquid DAM and IDM in the effective implementation of any of the options. If this requires all market participants to have systems and staff that allow 24 hour trading, then this could push up the recurrent costs of operation for the I-SEM.

5.7.52 This would be mitigated by the facilitation of intermediary arrangements that allow small market participants to benefit from economies of scale in trading. Option 3 would best allow these intermediary arrangements to be put in place whilst still maintaining high liquidity in the centralised markets (as opposed to allowing general bilateral trading and/or widespread trading within portfolios).

6 IS A CRM NEEDED IN THE I-SEM?

6.1 OVERVIEW

6.1.1 This section of the impact assessment describes the findings of the qualitative and quantitative assessment that has informed the SEM Committee's Draft Decision to keep a CRM in the HLD of the I-SEM.

6.2 ADDITIONAL TSO ASSESSMENT OF GENERATION ADEQUACY

6.2.1 The latest annual All-Island Generation Capacity Statement 2014-2023 (GCS) projected a generation surplus out to 2023 on an unconstrained All-Island Market basis[23]. This is partly as a result of increased wind generation capacity and the continuing impact of the financial crisis in 2008 on load, although the capacity margin is expected to tighten in the period to 2023 as demand growth erodes excess capacity on the system.

6.2.2 The GCS is broadly consistent with the general approach to generation adequacy assessments that is currently used across Europe. It is nationally focused and based on notifications provided by generators, which are underpinned by the assumption that the existing capacity regime will remain in force. Based on these assumptions, the GCS assessment would suggest that there should be no overall shortage of capacity in the first few years of the operation of the I-SEM. However, the question of whether a capacity remuneration mechanism is required or not can only be answered by looking at how the capacity margin would evolve in the event that generators were to rely on revenues from the energy market alone to recover their avoidable fixed costs. Moreover, SONI is now putting in place supplementary measures to ensure sufficient generation capacity is available in Northern Ireland to address a potential risk to security of supply as a result of local constraints on the transmission system.

6.2.3 The European Commission, ACER and national regulatory authorities see generation adequacy assessments as an important input into the discussion of the need for CRMs in different European markets. ENTSO-E has been asked to consider possible improvements to existing adequacy assessment methodologies in the context of increasing shares of variable generation across Europe and the better use of interconnectors at the day ahead and intraday stages. It is to be expected that the way in which generation adequacy is assessed across Europe will develop over time, with more coordination and harmonisation at regional and European level. Through involvement in ACER and ENTSO-E, the SEM RAs and the TSOs will contribute to this development.

[23] http://www.eirgrid.com/media/Generation%20Capacity%20Statement%202014.pdf

6.2.4 The development of capacity adequacy assessment methodology at the European level is particularly relevant to the All-Island Market in the context of:

- increased regional coordination of adequacy assessments, including the incorporation of generation and load correlations across neighbouring countries and of cross-border capacity; and
- improvements in the methodology, including the scope for incorporating an assessment of generation economics (e.g., in response to policy changes rather than relying purely on notifications from market participants).

6.2.5 Given this and to provide the SEM Committee with a wider perspective on the state of generation adequacy beyond 2016, the Regulatory Authorities asked EirGrid to carry out analysis of the implications for generation capacity adequacy in the absence of a CRM as part of the I-SEM design. This purpose of the EirGrid study was to conduct a number of further sensitivities to those studied in the GCS in an effort to estimate the implications for generation adequacy in an energy only market. Their assessment is attached as Annex 1 to the Proposed Decision Paper.

6.2.6 EirGrid's study finds that there is no shortage of supply in 2017 in the central scenario, which uses the median demand forecast; full reliance on interconnector imports; and an LOLE of 8 hours a year. But adequacy is in short supply in 2020 and 2023 in the central scenario.

6.2.7 EirGrid's assessment of generation adequacy in an energy-only market is subject to a number of caveats and should not be relied on as a standalone assessment of future generation adequacy for the All-Island system. Rather, it should be seen as an important check on other quantitative elements of the Proposed Decision on CRMs, notably the most recent GCS (covering the period 2014-2023) and Pöyry modelling undertaken as part of this impact assessment.

6.2.8 The EirGrid assessment consists of two parts. It first calculates which generators would not be able to recover their annualised costs from energy payments in a theoretical energy only market. These generators are then assumed to shut down and generation adequacy is then re-calculated with them removed from the generation portfolio.

6.2.9 As well as estimating the impact on potential plant closures in an energy only market of the ability of generation to recover its annualised costs, the EirGrid study considers a number of sensitivities around the central reference scenario. These include:

- Tightening the adequacy standard from 8 hours loss of load expectation (LOLE) a year to 3 hours LOLE/year[24].
- Reducing the reliance on interconnectors to half of the available import

[24] LOLE represents the number of hours a year in which, over the long-term, it is statistically expected that supply will not meet demand

capacity.

- Reducing the reliance on interconnectors to zero.
- Using a high demand forecast, representing a particularly cold (1-in-10 year) winter.
- No price cap scenario where only plants that did not run in the initial energy only model runs are removed from the generation portfolio.

6.2.10 These scenarios are intended partially to give a wider picture of future generation adequacy for the All Island System and partially to coordinate the approach more with neighbouring Member States. In the latter respect it is notable that Ofgem, who are responsible for assessing generation adequacy and the risks to electricity security of supply in Great Britain assume in all scenarios that the Moyle and East West Interconnectors flow in the direction from GB into Ireland.[25] By contrast, in their reference scenarios, Ofgem assume no net flows of energy from GB to mainland Europe.

6.2.11 From one perspective, the EirGrid GCS is consistent with this assumption in that it assumes that the GB-Ireland interconnectors are always available for import to the SEM. However, it is prudent, and consistent with Ofgem's approach to its larger connecting market of continental Europe, to consider scenarios where the interconnectors may not be available for full import, for example due to periods of concomitant peak demands in GB and Ireland.

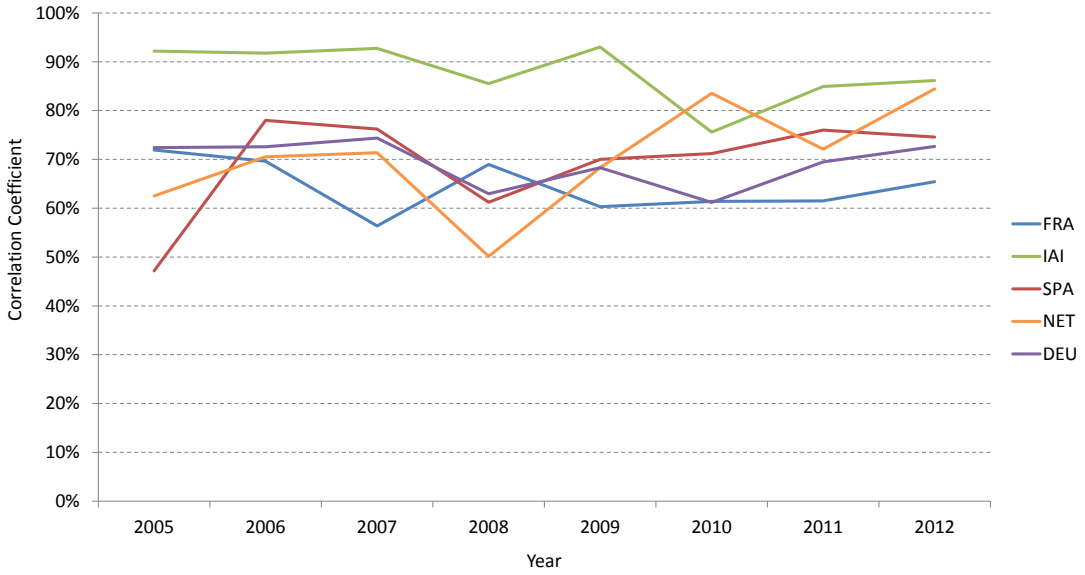
6.2.12 A further area of potential consistency with Ofgem's GB assessment is the security standard, which the All-Island GCS assumes to be a loss of load expectation of 8 hours a year, while Ofgem uses a tighter LOLE of 3 hours a year.[26] The target in the other countries interconnected with GB are 3 hours a year in France and 4 hours a year in the Netherlands.

6.2.13 In relation to the assumed availability of interconnection for full imports in tight capacity periods in the All-Island market, previous analysis by Pöyry for Ofgem identified a very high correlation between capacity margins in GB and the All-Island market (as shown in Figure 9 where IAI is used to denote the All-Island Market). This is primarily driven by high correlations in peak demand between the two markets though Pöyry also found high (positive) and statistically significant wind correlations between GB and Ireland.

[25] See Ofgem, Electricity Capacity Assessment Report, July 2013https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013.pdf

[26] The GB standard of 3 hours LOLE a year was determined by dividing the cost of new entry (estimated at £47/kWh) by the value of lost load (estimated to be £17/kWh) and rounding up to 1 significant figure.

Figure 9 – Correlations of GB capacity margins with other systems (annual, without interconnection flow)



Source: Pöyry Management Consulting[27].

6.2.14 The correlation is only medium for periods of low capacity margins in GB (<20%) and is not statistically significant for periods of very low capacity margins in GB (<10%). However, with tightening margins in GB (2% forecast for winter 2015/2016), high positive correlation between wind output in the All-Island Market and in GB, and an increasing amount of wind on the system in GB, the correlation between low capacity margins in the two islands may increase yet further. This highlights the relevance of the sensitivities around interconnection described in EirGrid's generation adequacy study.

6.2.15 In summary, EirGrid's study finds that there is no shortage of supply in 2017 in the central scenario, which uses the median demand forecast; full reliance on interconnector imports; and an LOLE of 8 hours a year. But adequacy is in short supply in 2020 and 2023. These results are broadly replicated under the various combinations of sensitivities around interconnector availability, higher demand and the tighter security standard (of an LOLE of 3 hours a year). Only the no price cap scenario, where the initial Plexos modelling incorporated no 'cut off' energy price, does the adequacy model show a surplus of generation in the majority of scenarios to 2023.

6.2.16 EirGrid's study is subject to a number of important caveats:

- The cost recovery methodology uses Plexos to estimate generation running hours for a median year. It is not used to model any of the I-SEM options nor produce energy prices based on those options.
- The study assumes that generators get no revenue from the sale of ancillary

[27] Analysis of the correlation of stress periods in the electricity markets in GB and its interconnected markets. A report to Ofgem, Pöyry Management Consulting. March 2013

services.

- This study looks at security of supply in the context of revenues only from the sale of energy. However, in cases where revenue shortfalls leading to a capacity shortage have been identified, it cannot be inferred that a CRM is necessarily required to meet this shortfall.
- The cost recovery methodology looks only at a likely set of conditions to determine the dispatch of units on the system. In reality the processes used by generation companies to decide which units should be withdrawn or kept in the market are likely to be more complex.
- Other than in the no price cap scenario, the study assumes that generators receive revenue only from energy payments, and that average revenues of €3,000 /MWh are achievable across all running hours. It may not be possible for generators to achieve such revenues in practice.

6.3 ASSESSMENT OF REQUIREMENT FOR CRM IN THE I-SEM

6.3.1 The real-time nature of electricity and the high value users place on its reliability means that its economics differ from most other goods and services. An efficient electricity system would have an excess of usable capacity at almost all times, other than a few hours each year (on average) in line with the security standard.

6.3.2 There has been a longstanding debate about whether energy only markets can deliver sustained generation adequacy or whether there are market or other failures that result in insufficient incentives to ensure generation adequacy in an energy-only market.

6.3.3 In an energy-only market, the net revenue necessary to cover avoidable fixed costs derive from a combination of:

- infra-marginal rent (IMR), which is captured by operating at greater cost efficiency than the price-setting (marginal) plant, which is readily predictable;
- 'scarcity rent', which is captured through price spikes at times of relative system scarcity, which may be relatively unpredictable.

6.3.4 The following paragraphs discuss whether an energy only market can be expected deliver the efficient amount of generation adequacy.

MISSING MONEY

6.3.5 The ultimate source of the “missing money” problem is that spot electricity market prices do not rise high enough during “scarcity” hours to produce adequate net revenues to cover the capital costs of investment in an efficient level and mix of generating capacity. In a perfectly functioning energy-only market, energy prices need to be allowed to rise to “scarcity” levels, well above the short run marginal cost of the least efficient plant on the system at the time and arguably as high as the value of lost load. The inability - for whatever reason - of an energy-only market to fully remunerate the efficient level of reliability will give rise to a ‘missing money’

problem.

6.3.6 The existence of price caps or bidding restrictions is one of the most common reasons cited for 'missing money'. These price interventions may be explicit, such as the PCAP in the SEM or the €3000/MWh limit in Euphemia. They may also be 'implicit' either as a result of (perceived or actual) intervention in response to prices spikes by regulators or governments, or the operating practices of the system operator (see paragraphs 6.3.10 and 6.3.11 below).

6.3.7 There are some circumstances that would increase the likelihood of regulatory intervention (whether actual or perceived):

- scepticism about the ability of the market to price scarcity efficiently. This might be because scarcity inevitably creates a perceived opportunity to abuse a monopoly position, with the result that any pure energy-only market will run into market power problems, regardless of its market structure. Sooner or later energy prices will be capped; or, more importantly, market participants will expect prices to be capped, thereby dulling the incentives to build new capacity;
- the lack of an active demand-side, which can mean that market prices are more liable to rise without limit at times of scarcity and are therefore more prone to regulatory/political intervention.

6.3.8 The importance of market power mitigation in the All-Island Market may increase the (perceived) risk of regulatory intervention in response to price spikes. This risk may be reduced by the use of long-term hedging products to mitigate the impact of price spikes on end consumers. These products (e.g. in the form of directed contracts or one way CfDs, including reliability options) could form part of the market power mitigation tools set in place as part of the energy trading arrangements.

6.3.9 With respect to the demand-side, 87 MW of capacity was registered with demand side units (DSUs) in the SEM at the start of 2014, compared with 41MW in 2012. There are also a number of measures that should facilitate increased demand-side participation in the future. This includes the introduction of a firm day-ahead schedule and price under I-SEM, efficient short-term price signals, and the roll-out of smart metering in Ireland and in Northern Ireland. [28] In the medium term, the responsiveness of the demand-side may increase, though the pace and scale of this increase will depend on technological and behavioural changes.

6.3.10 Moreover, in most electricity markets, energy prices under scarcity conditions depend critically on decisions made by the system operator. For example, before implementing rolling blackouts, system operators often reduce system voltage to stabilise the system. This has the effect of reducing demand, thereby reducing

[28] The May 2011 Demand Side Vision for 2020 Decision Paper (SEM/11/022) D identified the creation of a visible and firm day-ahead schedule (and price) for the All-Island Market as being a high value measure to support demand side participation.

wholesale prices relative to their 'normal' level and at times when scarcity is at its peak.

6.3.11 Voltage reductions are not free. If they were free the system could simply be run at a lower voltage. Voltage reductions lead lights to dim, equipment to run less efficiently and on-site generators to turn themselves on, etc. These are costs that are widely dispersed among electricity consumers and are not reflected in market prices. Thus, the aggregate marginal social cost of voltage reductions is not reflected in market prices.

6.3.12 This implies that market price signals at times when generation capacity is in short supply are biased downwards, typically leading to underinvestment in reliability over time.

PUBLIC GOOD NATURE OF RELIABILITY

6.3.13 The principal market failure associated with an energy only market is that reliability has all the characteristics of a public good. A public good is a good that is both

- non-excludable in the sense that individual consumers of electricity cannot be effectively excluded from the supply of system-wide reliability.
- non-rivalrous, in the sense that consumption of reliability by one individual consumer does not reduce the reliability enjoyed by others.

6.3.14 This is because consumers cannot choose their individual preferred level of reliability during rolling blackouts, except by installing their own generating equipment. Their lights go out along with their neighbours' lights, since the system operator cannot selectively disconnect any but the largest consumers. This means that, even if the other market or regulatory imperfections are resolved, the market alone cannot be relied upon to provide the efficient level of reliability.

RISKS FACED BY THERMAL GENERATION WITH HIGH VARIABLE GENERATION

6.3.15 There is a government policy target of 40% renewable generation by 2020 in both Ireland and Northern Ireland. This target is expected to be largely delivered predominantly by wind generation. This would represent the highest level of penetration by wind for any synchronous system in Europe.

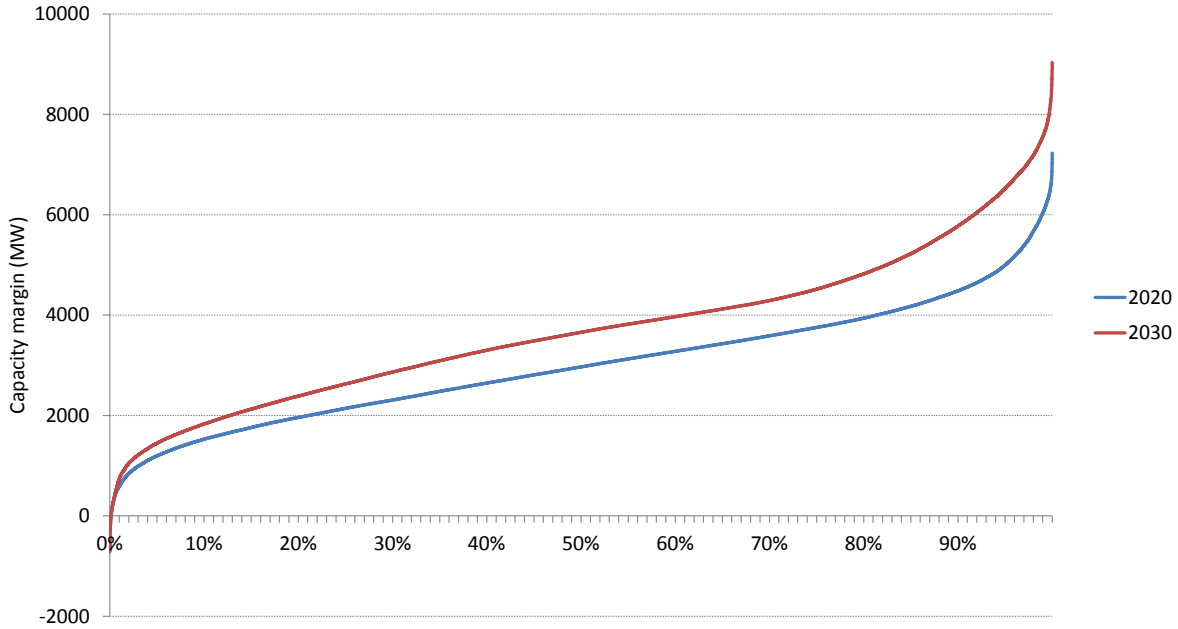
6.3.16 Large scale deployment of variable renewables has some important consequences for conventional thermal generation in the market:

- total energy requirements from thermal generation (TWh) are falling relative to requirements for capacity (GW) and
- the residual thermal generation fleet is facing major changes in operating patterns, with increased emphasis on flexibility to respond to weather variation, forecast error at short notice and a consequent exposure to volume risk as well as price risk.

6.3.17 One of the impacts of high penetration of variable renewable generation is that some conventional thermal capacity is required on the system to cover for low wind output (coupled with high demand) over a limited number of periods.

6.3.18 As wind installed capacity increases, capacity margins become wider for the majority of the periods across a year, as shown in Figure 10 below. The line represents the percentage of hours in a year in which the capacity margin is below the level on the y-axis.

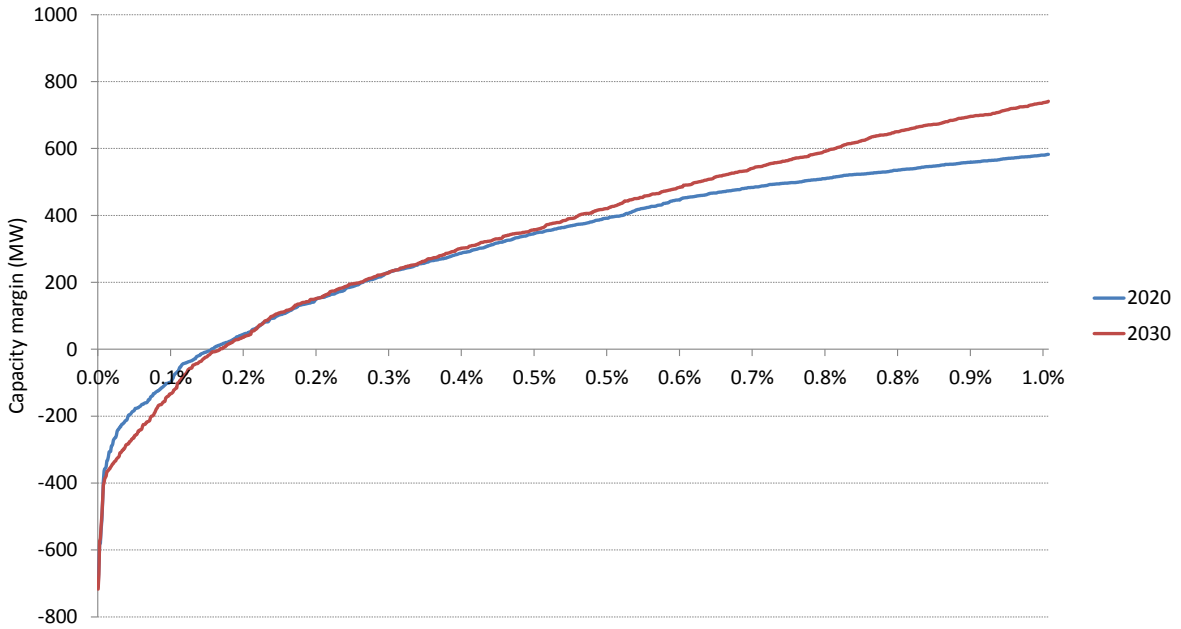
Figure 10 – Hourly capacity margins for I-SEM in 2020 and 2030 in the energy-only market (Base Case A)



6.3.19 The chart shows the hourly capacity margins for Base Case A from our quantitative assessment of an assumed well-functioning energy-only market (described in more detail in Section 6.6). The higher the wind installed capacity, however, the lower the marginal wind contribution to the capacity margin becomes and hence how much less conventional thermal capacity can be displaced.

6.3.20 Over some high demand and low wind periods, there will still be need for a certain amount of capacity. This is shown in Figure 11, where the capacity margin in the top 1% of periods is similar in both years (2020 and 2030), even though in 2030 capacity margins are greater for most of the year.

Figure 11 – Hourly capacity margins for I-SEM in 2020 and 2030 in the tightest 1% of periods in the energy-only market (Base Case A)

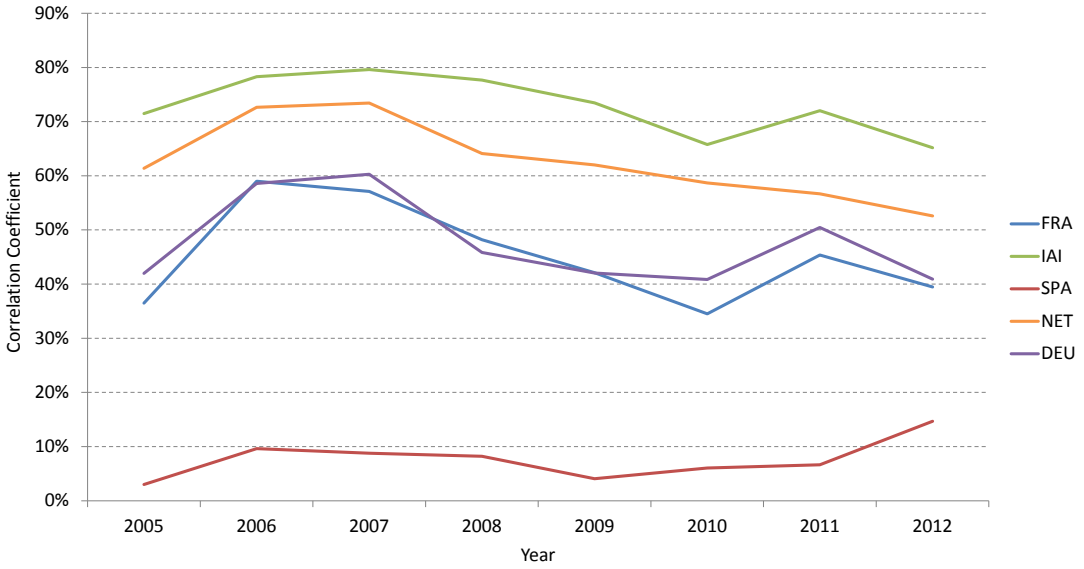


6.3.21 GB is also planning the large-scale deployment of wind (both onshore and offshore). Analysis conducted by Pöyry for Ofgem found high (historical) correlation between wind output in the All-Island Market and in GB. This is shown in Figure 12 below (in which the All-Island Market is denoted as IAI).

6.3.22 So, the challenges around variable electricity are not significantly reduced by consideration of variable electricity in GB, the neighbouring system to the All-Island market (compared with a situation where there was negatively correlated output of variable generation in the two systems).

6.3.23 The high penetration of renewables means that even new-build thermal generation may now expect to run in mid-merit (at best) rather than at baseload. For both mid-merit and peaking plants, there is increased reliance on the more unpredictable scarcity rent element which can increase the perceived risk of entering (or continuing to operate) in the energy-only market.

Figure 12 – Correlation of wind output in GB with other systems (annual)



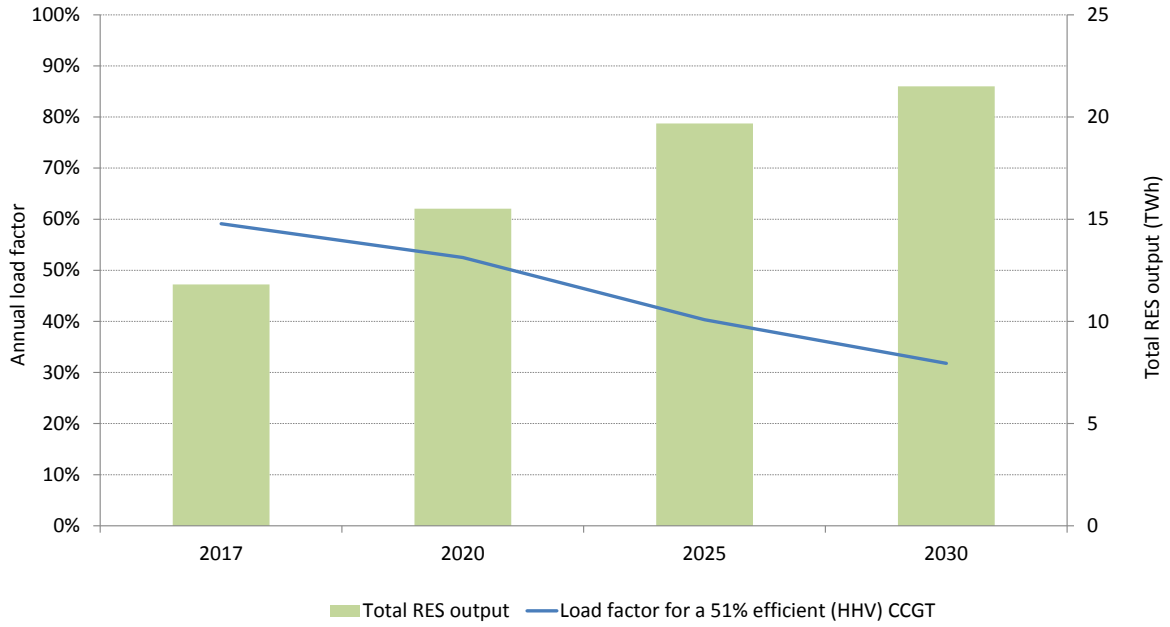
Source: Pöyry Management Consulting[29].

6.3.24 This change in operating patterns can make it much harder for energy-only markets alone to deliver investment with a "reasonable" risk profile, even in the absence of market features such as bidding restrictions and price caps.

6.3.25 Figure 13 shows how the load factor of a 51% efficient (HHV) CCGT changes over time in Base Case A. In 2017, the plant has an annual load factor of around 60%. By 2030, the annual load factor of the plant has dropped to about 30%, meaning that the plant is much closer to running like a peaking plant. The drop in load factor is not the result of new entry by more efficient plants between 2017 and 2030, but rather by the increased output of renewable generation (as denoted by the green bars in Figure 13).

29 Analysis of the correlation of stress periods in the electricity markets in GB and its interconnected markets. A report to Ofgem, Pöyry Management Consulting. March 2013

Figure 13 – Annual load factor for a 51% efficient (HHV) CCGT in the I-SEM (Base Case A)



6.3.26 At the same time, there may be a reduced number of hours of scarcity (assuming a system with adequate generation capacity), since there will be variable renewable output for some but not all of the peak demand hours. So the volatility of scarcity rent will increase as it is recovered in fewer hours. As a result, higher price spikes (even for fewer periods) may increase the (actual or perceived) threat of political and/or regulatory intervention.

6.3.27 Table 19 and Table 20 report the number of hours of high prices in an assumed well-functioning energy-only market in Base Case A. The entry and exit decisions of thermal generators in the modelling of the well-functioning energy-only market assumes that plants are able to capture all of these high price periods without regulatory or political intervention.

6.3.28 Table 19 shows the average expected number of hours of high prices in each snapshot year, with the number and magnitude of price spikes increasing over time. This is the result of further renewable deployment reducing the running hours for thermal plant, meaning that the fixed costs have to be recovered in fewer hours.

6.3.29 Table 20 reports the number of high price periods in the most extreme year (of low wind generation and low thermal plant availability). It shows that in these circumstances, the price spikes are much more frequent than in the average year.

Table 19 – Number of high price hours in average year in 'well-functioning' energy-only market (Base Case A)

Number of hours	2017	2020	2025	2030
I-SEM price > €2500/MWh	3	7	10	12
I-SEM price > €2000/MWh	3	7	14	14
I-SEM price > €1000/MWh	5	16	33	35
I-SEM price > €500/MWh	19	43	69	71

Table 20 – Number of high price hours in extreme year in 'well-functioning' energy-only market (Case A)

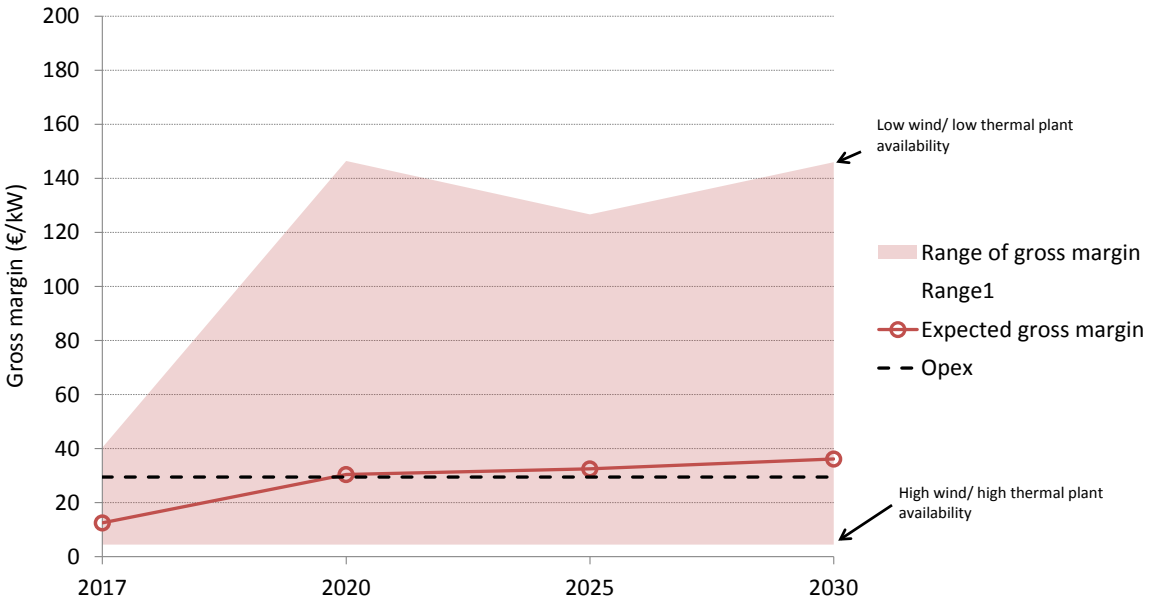
Number of hours	2017	2020	2025	2030
I-SEM price > €2500/MWh	14	33	44	55
I-SEM price > €2000/MWh	14	33	63	63
I-SEM price > €1000/MWh	28	72	115	116
I-SEM price > €500/MWh	79	140	215	216

6.3.30 Figure 14 and Figure 15 show the expected and range of gross margins for each snapshot year for a two example plants in the modelled energy-only market – the gross margin shown here equals wholesale electricity revenues plus net DS3 revenue minus variable fuel and operating costs. Therefore, it would need to be sufficient to cover annual fixed and capital costs in order for the plant to remain viable.

6.3.31 Figure 14 shows the expected range of the gross margin for a 29% efficient (HHV) OCGT. It shows that while the average gross margin is sufficient to cover the fixed operating costs from 2020 onwards[30], the gross margin realised in any year is highly sensitive to the level of demand, renewable generation and availability of thermal plant. In a 'bad year', the OCGT might realise virtually no gross margin from the energy market during a high wind year. On the other hand, if there is a significant number of periods with low wind (coinciding with relatively high demand) its gross margin could amount to over €120/kW in 2020, 2025 and 2030.

[30] The opex requirement shown on the chart is an average requirement across OCGTs, which means that there are some OCGTs with lower fixed costs (and hence remain viable at lower expected gross margins).

Figure 14 –Gross margin[31] for a 29% efficient (HHV) OCGT (Base Case A)

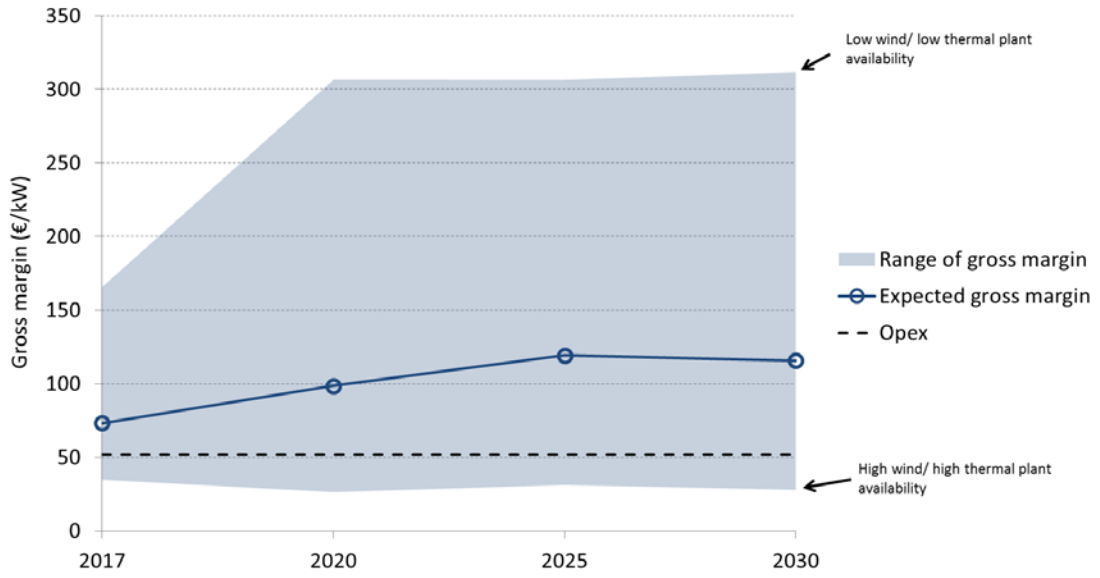


6.3.32 Figure 15 shows the expected and range of gross margins for each snapshot year for a 51% efficient (HHV) CCGT in the modelled energy-only market. In a year with relatively comfortable capacity margins (e.g. as a result of high renewable generation), the gross margin can be as low as around €20/kW. This would not be sufficient for a plant to cover its fixed annual operating costs. However, there is a wide range in possible gross margins, which could be as high as €300/kW in a year with low renewable generation, high demand and low generation availability. Achieving this level of gross margin relies on the level and frequency of price spikes illustrated in Table 20.

6.3.33 The potential variability in gross margins could then reduce the confidence of plants that they will be able to recover the costs of staying in the All-Island Market – even where the average expected gross margin is sufficient to cover their fixed costs. This will particularly be the case where plants run infrequently, even though they may be essential for security of supply. This then raises the prospect of excess or disorderly exit, which is made worse by the relatively large unit sizes in the All-Island Market and the current existence of a CRM. Excess or disorderly exit would be particularly challenging for the All-Island Market given the relative isolation of the market, placing a high burden on domestic actions to ensure security of supply.

31 Gross margin shown on this chart equals (wholesale electricity revenues + net DS3 revenue) minus variable fuel and operating costs

Figure 15 - Gross margin[32] for a 51% efficient (HHV) CCGT (Base Case A)



6.3.34 In summary, a large fraction of the net revenues or quasi-rents from energy sales in spot electricity markets, which are required to cover the costs of capital investments, will increasingly be produced in a very small number of hours each year when capacity is fully utilized. Moreover, owing to uncertainty on both the demand and supply sides, these hours will not appear uniformly from year to year but will fluctuate widely from year to year.

FORWARD CONTRACTING

6.3.35 For a peaking plant, all of its net revenues are derived under these conditions. Accordingly, investors will be concerned about actions by regulators or discretionary behaviour by system operators (see above) that might have the effect of constraining prices in exactly those few hours with very high prices when investors expect to earn most of the net revenues required to cover their capital investment costs.

6.3.36 Opportunism, whether by counterparties or the regulatory authorities, can lead to under-investment. Credible long-term contracts are an efficient institutional response to these sorts of problems, since long term power supply contracts with credit worthy buyers can allow investors in generating plant to shift this risk to consumers.

6.3.37 However, traditional traded hedging instruments for firm quantities such as forward energy contracts are not well-suited to managing the combination of price and volume risk faced by some plants in a high-RES world. Volume risk reflects the fact

[32] Gross margin shown on this chart equals (wholesale electricity revenues + net DS3 revenue) minus variable fuel and operating costs

that the operating profile for low-merit thermal plants is not known in advance. So there may be no way to trade profitably (i.e. through a positive forward spread) as there is not a sufficiently granular forward product available. [33]

6.3.38 Insufficient forward contracting opportunities have been highlighted as an issue for delivering sufficient generation adequacy through any possible set of energy-only trading arrangements in the I-SEM. The design of the I-SEM will emphasise the importance of measures to promote forward market liquidity and this will rely on sufficient spreads and/or sufficiently granular forward products.

INDIVISIBILITY AND CO-ORDINATION FAILURE

6.3.39 The indivisibility issue arises when generating unit sizes are relatively large relative to total market size. This means that the entry or exit decision of an individual plant can have a significant impact on prices. For example, the new entry reduces prices below the sustainable new entry level for a number of years (hence delaying/discouraging new entry).

6.3.40 The indivisibility of additions to (and retirements of) installed capacity is linked to another possible market failure, that of co-ordination failure. In a perfectly functioning market, decisions to build new capacity are made independently. This induces strategic uncertainty: the profitability of one's own investment in new plant will depend on the decision of others whether also to invest or not. This may result in a new entrant delaying its decision until the prospective capacity margin is tight enough to support more than one new entrant; or in entering quickly to ward off competition. The optimal strategy implies a random element and so the outcome is likely to be inefficient; and these concerns would apply with more weight to a small market where a new entrant will have a significant effect on prices.

6.3.41 Indivisibility was highlighted as a key challenge for the All-Island Market in the development of the arrangements for the SEM, though since the creation of the SEM, some proposed new generation projects are around 100MW, much smaller than CCGT scale (400MW). This should have somewhat reduced the impact of the indivisibility issue for new entry.

6.3.42 However, the relatively large size of some existing CCGTs means that the assessment of generation adequacy in the All-Island Market in the next few years can be sensitive to the exit decision of a relatively small number of CCGTs.

[33] For example, suppose a super-peak product covers 100 hours. There may be a negative spread for the low-merit plant over the whole 100 hours, but there are 20 hours in which its operation is profitable. However, those 20 hours are not known in advance and hence cannot be captured in a forward product with a positive spread.

SUMMARY ASSESSMENT

6.3.43 In conclusion, this Impact Assessment, including the TSOs report published alongside it, sets out the justification for a CRM both qualitatively (measured against the I-SEM objectives) and with the support of quantitative analysis of some issues for generation adequacy in an energy only market driven by the changing nature of challenges faced by generation (such as lower running hours and major shifts in operating patterns) as the increasing levels of low carbon technologies come on the system.

6.3.44 The evidence gathered here thus supports the SEM Committee Decision to maintain a CRM as part of the all island market so as to better meet the I-SEM primary objectives of security of supply, competition, environment and equity than would be the case for an energy only market. The evidence also suggests that the IEM primary objective is not undermined by a CRM, and that the choice of CRM can be made such that distortions to cross border trade are minimised.

7 FORM OF CRM

7.1 OVERVIEW

7.1.1 This section of the impact assessment describes the findings of the quantitative and qualitative assessment that has informed the SEM Committee's Draft Decision on the form of the CRM in the HLD of the I-SEM.

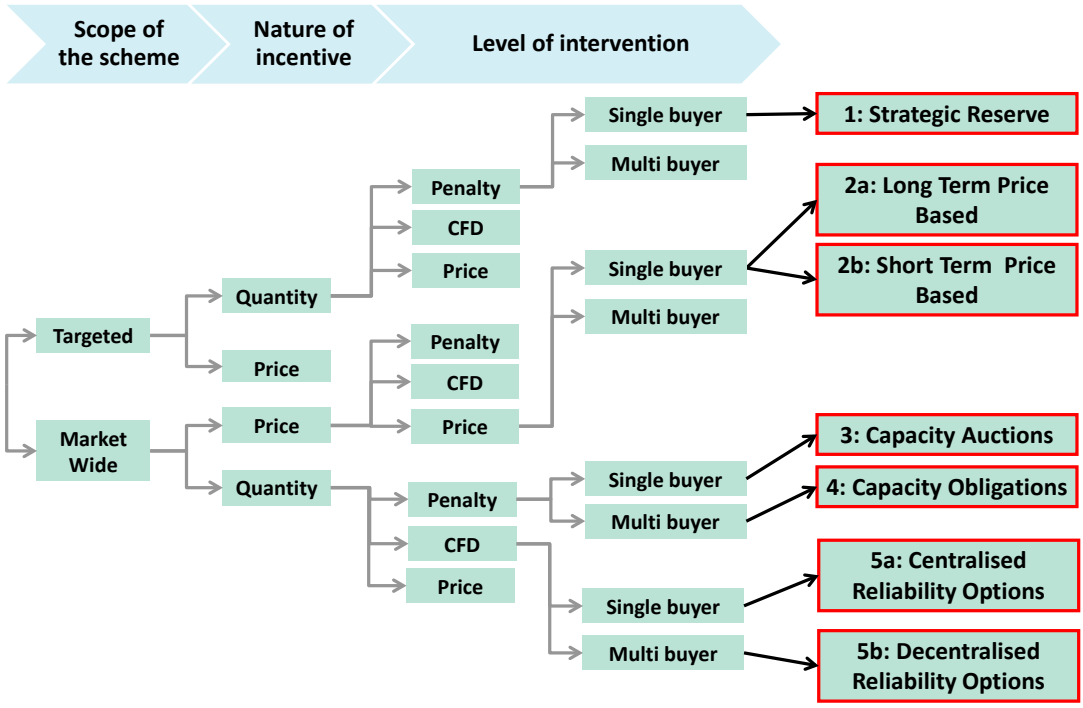
7.1.2 In line with National Legislation in Ireland and Northern Ireland and the Security of Supply Directive (Directive 2005/89/EC), Strategic Reserve will continue to be available as a 'backstop' measure to address specific security of supply concerns on a case by case basis.

7.2 CRM DESIGN OPTIONS FOR CONSULTATION

7.2.1 The February 2014 Consultation Paper presented a number of CRM options for consultation, as summarised in Figure 16. These options are designed to illustrate the main differences between each design approach; and there a number of possible variations on each of these broad approaches.

7.2.2 These options were presented independently of the four HLD options for energy trading arrangements, on the grounds that each of the seven CRM options could be implemented alongside any of the four energy trading options.

Figure 16 – Capacity Remuneration Mechanisms in February 2014 Consultation



7.2.3 **Strategic Reserve (Option 1)** is a form of targeted contracting which is implemented to reward generating or demand reduction capacity that is not adequately rewarded through existing revenue streams but is deemed by the TSO to be needed to meet some specific system requirement not recognised in those revenue streams.

7.2.4 In a pure strategic reserve scheme, the reserved capacity is ring-fenced from direct participation in other markets (e.g. energy or system services). In circumstances where it is called upon to deliver energy, the pricing is set in a way which minimises the impact of the plant on the wider market.

7.2.5 The February 2014 I-SEM HLD Consultation Paper presented two **price-based CRMs (Options 2a and 2b)** for consultation. In this context, a 'price-based' CRM is defined as a scheme where capacity remuneration depends on availability in a particular period (i.e. there is no advance commitment to deliver capacity).

7.2.6 The Consultation Paper described a **long-term price-based CRM (Option 2a)** as being one in which a central body fixes the total pot for capacity payments in advance, possibly based on the security standard and the cost of new entry; and possibly with some certainty for several years into the future. As this option is designed to give long-term signals, the size of the pot is assumed to be weakly influenced (if at all) by the projected capacity margin for the given period.

7.2.7 In this design of the long-term price-based CRM, the annual capacity pot is then converted into a string of spot capacity prices (e.g. differing by each half hour), with the spot capacity price in particular periods set to reflect the tightness of the capacity margin. [34]

7.2.8 By fixing the pot rather than the capacity price directly, the average capacity price itself is lower when there is more capacity on the system for a given pot, but the relationship is not particularly strong in the vicinity of the required amount of capacity to meet the security standard.

7.2.9 In a long-term price-based CRM with a fixed total value, there needs to be some mechanism to reconcile the actual money paid out with the pot set at the start of the year. In the current SEM this is done through monthly ex-post capacity price calculation.

7.2.10 In a **short-term price-based CRM (Option 2b)**, the capacity price for each settlement period (e.g. half hour) is determined by the system tightness in that settlement period. There is no fixed annual pot to be recovered under a short-term price scheme and therefore the amount to be given out has no upper or lower bounds.

[34] There is typically some intermediate steps of profiling the pot into intermediate periods (such as months or weeks).

7.2.11 The old England and Wales Pool incorporated a short term price-based capacity remuneration scheme. Generating units that were dispatched received an additional payment (over and above the spot energy price) equal to LOLP x (VOLL - SMP), where SMP was the system marginal price and LOLP is the Loss of Load Probability.[35] Those units that were available but not generating received LOLP x VOLL.

7.2.12 The Consultation Paper presented **four quantity-based schemes (Options 3, 4, 5a and 5b)**. In this context, a 'quantity-based' scheme is defined as one in which a central body determines the amount of generating or demand reduction capacity to be procured and uses a market mechanisms (typically an auction) to discover a price for this capacity (perhaps with some price/quantity trade-off included in the procurement process). [36] The procurement would generally be open to all resource types that can meet the required performance criteria[37].

7.2.13 The quantity-based schemes can be described broadly as having an advance payment for capacity, with a commitment to deliver either capacity or energy in the certain required periods and face a penalty if unable to do so.

7.2.14 In all of the quantity-based mechanisms, there is a requirement for a re-trading mechanism to allow providers of capacity contracts to manage their risk of non-availability closer to real time. This is of particular importance where there is a multiyear gap between commitment and delivery.

7.2.15 Different market participants will have different preferences for how far ahead this commitment is made. The timing of allocation of capacity contracts will therefore affect the type of providers willing to participate. For example, generators typically may prefer longer lead times that give them time to make (or avoid) capital expenditure, e.g. building, refurbishing or reopening plant, or closing or mothballing plant. Demand-side reduction capacity may prefer shorter commitment periods.

7.2.16 The central determination of the required amount of capacity and the commitment (and consequent penalty exposure) are the major differences between the quantity-based CRMs and the price-based CRMs presented in the February 2014 Consultation Paper.

7.2.17 It is likely that with a quantity-based scheme, in a situation of overcapacity relative to system needs, not all generators in the market would get a contract to receive capacity payments; or that the capacity price in the auction would be driven to low

[35] LOLP is the probability that generation will be insufficient to meet demand at some point over a specific time period. LOLE is a measure of how long, on average, the available capacity is likely to fall short of the demand and is expressed in terms of the expected number of days in the year when the daily peak demand exceeds the available generating capacity.

[36] This differs from a long-term price-based scheme, where the capacity pot is determined centrally (e.g. by the RA) and is then spread across the available capacity.

[37] These criteria may be more explicit in the capacity auctions/obligations than in the reliability options where it will be driven more by the choice of reference market for example.

levels. On the other hand, it is possible that some providers might not want a contract for all their eligible capacity (given an exposure to penalties for unavailability/non-delivery).

7.2.18 The main differences between the four quantity-based options presented in the consultation document are:

- the determination of when delivery (or availability) is required and the penalty for non-delivery (or unavailability); and
- the role of suppliers in the procurement process.

7.2.19 In the **capacity auctions CRM (Option 3)** presented in the Consultation Paper, generators contract with a central counterparty and the initial allocation of the capacity contracts is done solely by the central counterparty, with no role for suppliers. An administrative process is used to determine when delivery is required, and the methodology for the penalty for non-delivery is determined centrally.

7.2.20 In the **capacity obligations (Option 4)** presented in the Consultation Paper, energy suppliers are responsible for procuring the capacity contracts to meet a centrally defined obligation. The penalty mechanism is also defined centrally. In the interests of transparency, the Consultation Paper noted that centrally organised auctions would be desirable even in this option.

7.2.21 In the **reliability options (Options 5a and 5b),** all providers of reliability options have to make a payment equal to the difference between the reference price and the strike price (in all periods where the reference price is above the strike price). However, those providers delivering energy over that period (into the reference market) would have received the difference between the reference price and the strike price (and hence would make no net payment).

7.2.22 This incentivises delivery in the time frames in which the option is called, e.g. day ahead, as failure to deliver energy at these times leads to possible financial exposure. This means that the timing of when energy delivery is required and the penalty for non-delivery are market-based (with the potential for an additional administrative penalty if required).[38]

7.2.23 Effectively, the seller of the option is giving up the chance to earn additional income above the strike price in exchange for an advance option fee – i.e. swapping a volatile income for a more stable one. Similarly the 'buyer' of the option is paying an advance option fee to avoid exposure to prices above the strike price in the reference market.

7.2.24 If the reliability options remain purely financial, they need a reference price. The

[38] It is possible to include penalties for non-delivery into a reliability option schemes. However, to focus on the major differences between different types of CRMs, penalties were not assumed to be part of the reliability options presented in the Consultation Document.

choice would be between the coupled day ahead market price and an ex-post price, which would likely be a single imbalance price. An intraday price could be used to settle financial reliability options if intraday auctions were developed under the provisions in the draft Capacity Allocation and Congestion Management (CACM) Guidelines.

7.2.25 In the February 2014 Consultation Paper, we distinguished between centralised quantity-based approaches (Options 3 and 5a), and decentralised quantity approaches (Option 4 and Option 5b).

7.2.26 We noted that even in the decentralised approaches, there would be a centrally organised platform in Option 5b. Even in Option 4 it is seen as desirable to enforce centrally organised auctions for the capacity certificates/reliability options (e.g. with supporting liquidity measures as discussed for the energy trading arrangements , such as unit bidding etc.).

7.2.27 Notwithstanding these common central features across the designs, there are some key differences between Option 5a and 5b as proposed in the Consultation Paper. In this context, centralisation can refer to both the process of setting demand and the overall auction process. The former is the key difference between Options 5a and 5b.

7.2.28 With the decentralised approach a greater reliance is placed on the individual market participants having greater freedom for meeting their obligations and expressing their preferences for their desired level of reliability.

7.2.29 With the centralised approach under Option 5a, a greater reliance is placed on pooling liquidity through a transparent auction in providing all consumers with a level of reliability on equal terms.

7.3 QUANTITATIVE ASSESSMENT OF IMPLEMENTATION AND OPERATION COSTS

7.3.1 In this section, we set out initial estimates for the non-market costs of implementing and maintaining different forms of CRM in the I-SEM i.e. the cost that will be incurred to set up, run and participate in the CRM. For the avoidance of doubt, this does not cover generation costs.

7.3.2 Table 21 summarises the estimated costs faced by the three stakeholder groups, for each of the CRM options. These costs are annualised over a 14-year assessment period (2017-2030) using an assumed discount rate of 3.5%. This re reflects the discount rate recommended in the UK Treasury's Green Book (Appraisal and Evaluation in Central Government).[39] Further details of these cost estimates are available in Appendix 3.

[39] https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

7.3.3 We estimate the additional upfront and ongoing costs that could be incurred by market participants, the Market Operator and the TSO, and the Regulatory Authorities during the implementation and operation of the CRM.

7.3.4 In these cost estimates, we have not distinguished between centralised and decentralised versions of the quantity-based CRMs. We have also not estimated the implementation and ongoing costs for a Strategic Reserve mechanism, as that will depend on the particular nature of the Strategic Reserve and the frequency with which Strategic Reserve is used.

7.3.5 The absolute cost differences in Table 21 between the options are sensitive to the estimated additional costs to market participants (systems, staff and external advice) of participating in the quantity-based contract allocation process, both in the initial allocation and any subsequent re-trading required.

Table 21 – Annualised implementation and recurrent non-market costs (€ million/a for 2017-2030, real 2012 money, 3.5% discount rate)

	Market Participant	**Central Agency**	**Regulatory Authorities**	**Total**
LT price-based	<€1m/a	€2m/a	<€1m/a	**€2m/a**
ST price-based	<€1m/a	€2m/a	<€1m/a	**€2m/a**
Capacity Auction	€2m/a	€3m/a	<€1m/a	**€5m/a**
Reliability Option	€2m/a	€3m/a	<€1m/a	**€5m/a**

7.4 QUANTITATIVE ASSESSMENT OF WHOLESALE MARKET COSTS

7.4.1 This section reports the findings of our modelling of different CRM options under Base Case A, including an energy-only market as the reference case.

7.4.2 The reference case for the modelling has assumed a well-functioning energy-only market, which is assumed to be fully competitive, with perfect foresight of 'expected' future revenues. Although there is a price cap of €3000/MWh (to reflect the price cap in the NWE DAM), there is no restriction on price spikes up to that level.[40]

7.4.3 The modelling results of this well-functioning energy-only market are also used to provide the modelling results for reliability options. Reliability options are intended to help deliver the short-term price signals of a well-functioning energy-only market by addressing some of the recognised market failures of a pure energy-only market. For example, reliability options reduce the likelihood of regulatory intervention in response to price spikes and are expected to have a positive impact on financing costs by providing greater revenue certainty. This can then mitigate the perceived riskiness of the energy-only market.

[40] Although no investment in demand-side response happens in response to these short-run price signals.

7.4.4 We have modelled three other main forms of CRM set out in the Consultation Paper, i.e., a capacity auction (or obligation), a short-term price-based CRM, and a long-term price-based CRM.

7.4.5 In the capacity auction/obligation ('capacity auction'), an annual auction is held with the demand for capacity being set at a level that ensures the required security standard is met (8 hours a year LOLE). Both new entry and existing capacity can participate in the annual auctions, but there is no provision in the modelling for mothballing: closure is an irreversible decision. New entry is assumed not to 'lock in' a capacity payment for an extended contract length, because we are modelling snapshot years. However, as with the scarcity rent assumption in the energy-only market, the capacity price remains at new entry level once new entry is required.[41] Interconnected capacity is not eligible to participate, although the capacity requirement is reduced by a capacity contribution for interconnection.

7.4.6 In the short-term price-based CRM ('ST price-based'), the spot capacity price is paid to all available capacity in the particular hour. The spot capacity price is based on a scarcity function that reflects capacity margin tightness. This function is assumed to persist throughout the whole modelled period. There is no total pot and the total amount of capacity payments responds to the capacity margins throughout the year.

7.4.7 In the long-term price-based CRM ('LT price-based'), the CRM has the same format of the current capacity payment scheme in place in the SEM. The capacity payment is set at a level that provides a long-run signal through a regulated Best New Entrant price. The BNE is assumed to be a OCGT running on distillate. We assume a change in the distribution of the pot when compared with the current arrangements with a greater fraction of the overall pot being distributed based on the capacity margin to rebalance more of the pot to generation that has a greater contribution to system security.

7.4.8 The subsequent sections highlight the modelled results with respect to security of supply, wholesale market costs and cost to consumers. The modelling results should be interpreted in light of the modelling assumptions including:

- competitive and liquid markets for energy and capacity;
- no portfolio behaviour – i.e. all bidding into energy and capacity markets are designed to be optimal for an individual unit;
- no quantification of any differences in the cost of capital as result of a move to a CRM;
- plants have perfect foresight of expected energy and capacity revenues;
- fixed DS3 payments per technology, as set out in Appendix 1;and
- no additional deployment of demand-side response.

[41] This may result in an overestimate of consumer costs, compared with a situation where only the new entry receives the new entry cost for more than its year of entry.

SECURITY OF SUPPLY

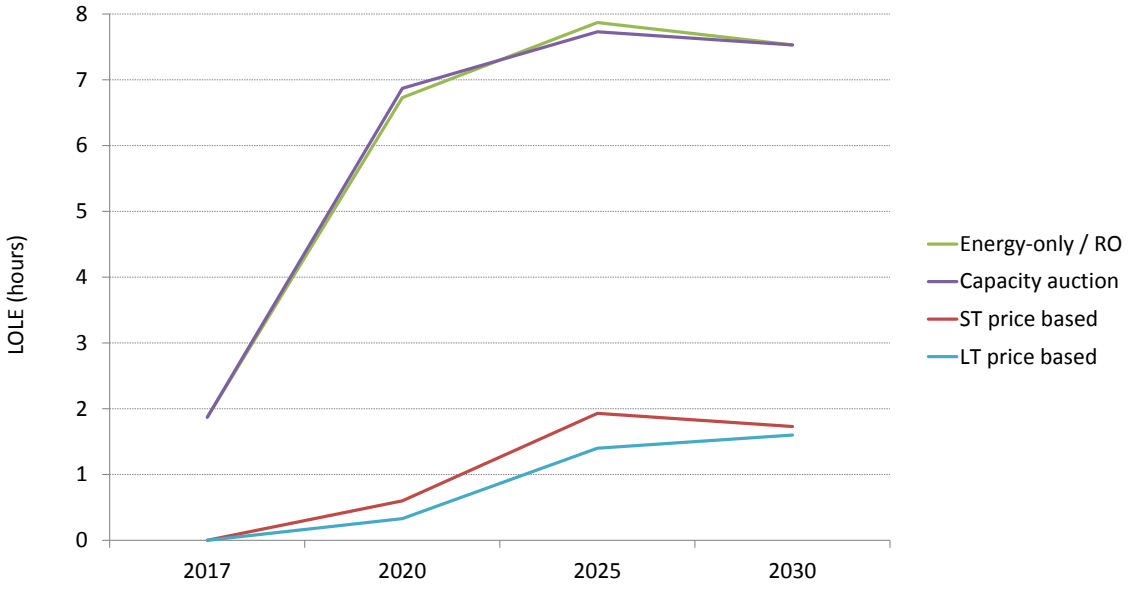
7.4.9 Figure 17 shows the projected LOLE for both the energy-only market and the modelled CRMs.

7.4.10 As described previously, the assumption of a well-functioning energy-only market (including with perfect foresight of expected revenues) means that the LOLE of 8 hours a year is (at least) met in all years. Similarly, the amount of the capacity procured in the quantity-based capacity auction is designed to ensure that the security standard of a LOLE of 8 hours a year LOLE is met. A similar result would be expected for other quantity-based schemes, such as the reliability options.

7.4.11 The well-functioning energy-only market/reliability options and the quantity-based capacity auctions deliver lower LOLE than the security standard in 2017 because of the assumption of perfect foresight of expected revenues means that some plants stay on the system even though they may make insufficient revenue in 2017 alone, because they are expecting to recover any losses in later years.

7.4.12 In the two price-based schemes, the LOLE stays below 2 hours for the whole period to 2030. This this means that more plants stay on the system than are needed to meet the security standard. The overshooting of the security standard in a price-based CRM reflects the absence of a strong exit signal in those types of arrangements. The LOLE would be expected to rise towards 8 hours once new entry is needed.

Figure 17 – LOLE for a well-functioning energy-only market and the different CRM schemes



7.4.13 One of the benefits of a CRM is to provide a longer-term hedge for capacity providers (and for energy retailers), which could become more valuable in a world of high deployment of variable renewable generation

7.4.14 Figure 18 shows the range in gross margins for each snapshot year for a 51% efficient (HHV) CCGT under the energy-only market, the two price-based CRMs, and capacity auctions.

7.4.15 As described earlier, the reliability options have been modelled effectively as a well-functioning energy-only market. In practice, the reliability options would offer a long-term hedge as illustrated in Figure 19. The impact of the reliability options on the range of the gross margin depends on the level of strike price assumed. The lower the strike price (SP), the smaller the range of gross margins. However, the expected gross margin does not change with different strike prices.

7.4.16 Figure 18 illustrates the widest range of gross margins is in the well-functioning energy-only market (top left chart). The average expected gross margin is towards the bottom of the shaded area. This means that there must be a small number of very good years denoted by the top of the range. In the well-functioning energy-only market, the assumption of perfect foresight of expected gross margins, and no dampening of price spikes (below the €3000/MWh cap) means that the wide range of gross margins has no impact on the entry/exit decision of plants.

7.4.17 In practice, though the potential variability in gross margins could then reduce the confidence of plants that they will be able to recover the costs of staying in the All-Island Market by capturing price spikes (without regulatory intervention) – even where the average expected gross margin is sufficient to cover their fixed costs.

7.4.18 The pattern of gross margins in the long-term price-based CRM (top right chart of Figure 18) shows how the commitment to capacity payments based on new entry costs in all years reduces significantly the downside risk for plant. This also discourages exit even when it is efficient.

7.4.19 In the capacity auction in 2017 and 2020 (bottom left chart of Figure 18), the capacity payment is low, reflecting the relatively comfortable supply-demand balance. The level of capacity payment increases (and stays high) once new entry is required in 2025. The higher capacity payment then significantly reduces the range of gross margins, compared with the energy-only market.

7.4.20 Finally, the short-term price-based CRM (bottom right chart of Figure 18) has relatively little impact on the downside for the gross margin for the CCGT. This means that it provides virtually no long-term hedge for the generator.

Figure 18 –Gross margin[42] for a 51% efficient (HHV) CCGT under the energy-only market and different types of CRMs (Base Case A)

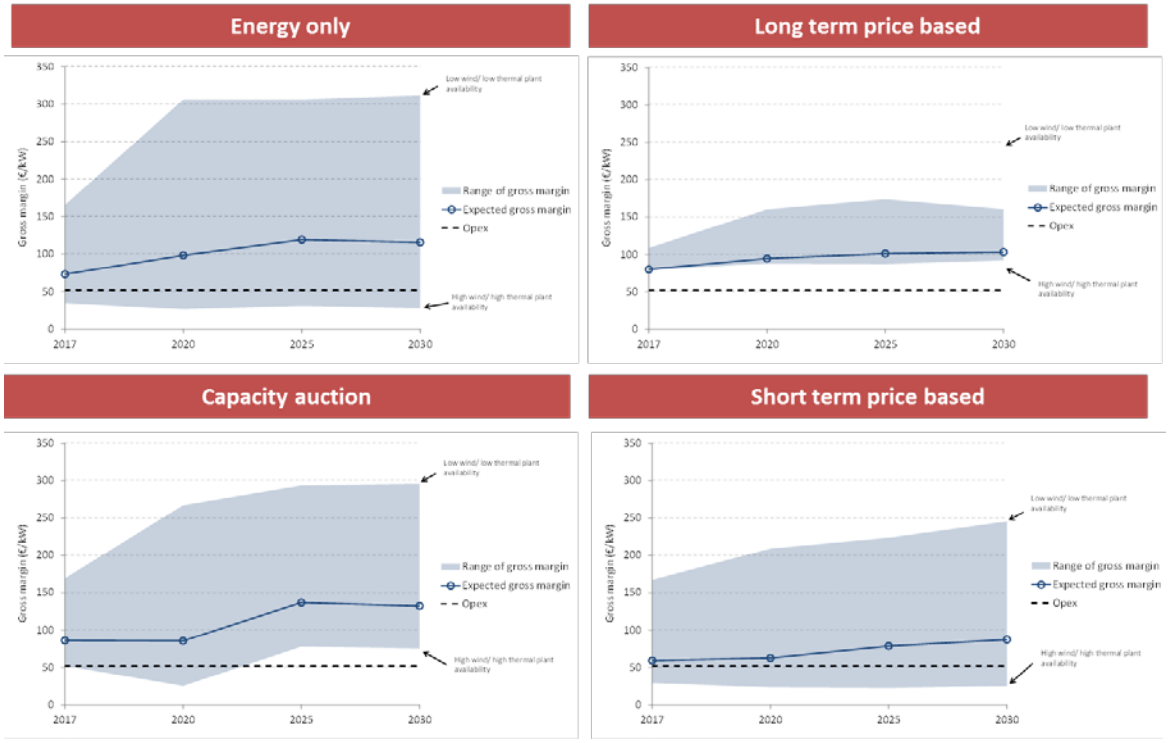
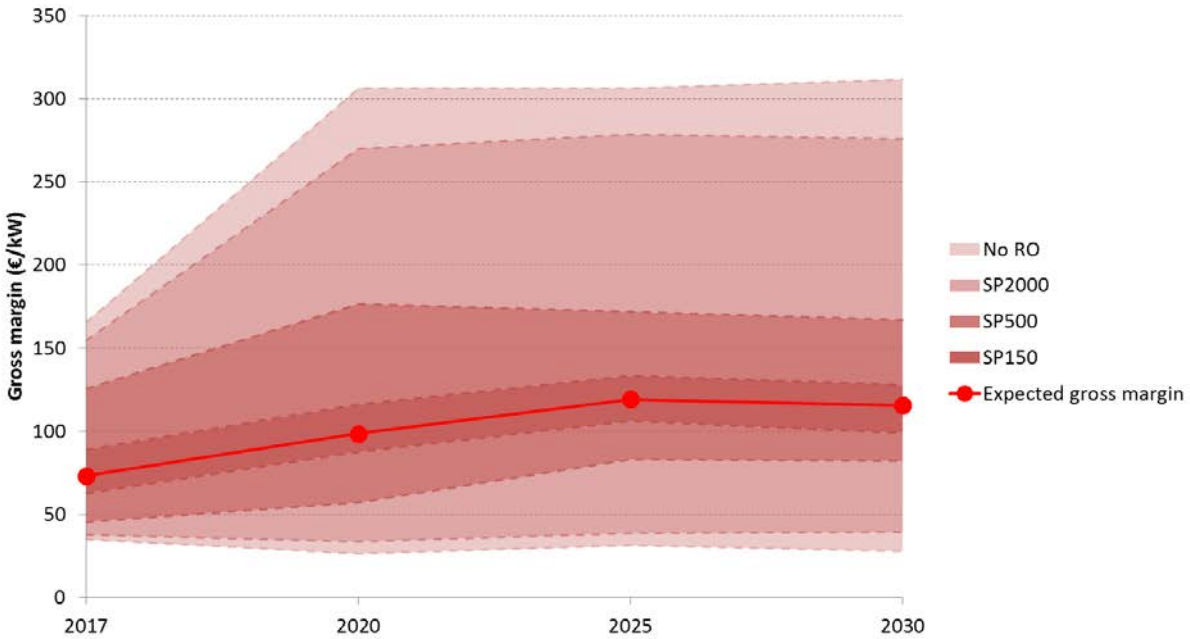


Figure 19 – Gross margins for a 51% efficient (HHV) CCGT under different strike prices for reliability options



42 Gross margin shown on this chart equals (wholesale electricity revenues + net DS3 revenue) minus variable fuel and operating costs

WHOLESALE MARKET COSTS

7.4.21 Compared with the LT price-based CRM, all of the other CRM designs show a reduction in overall wholesale market costs across the I-SEM and GB, as presented in Table 22. This does not include any benefits of lower financing costs under any CRM (including reliability options), and there is no allowance for cross-border participation in the capacity auction.

Table 22 – Difference in overall wholesale market costs (for the I-SEM and GB) between a long-term price-based CRM and alternative CRMs (Base Case A)

NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Change in overall wholesale market costs for I-SEM and GB (compared with LT price-based CRM)
Capacity Auction	-€110m
ST price-based	-€103m
Energy-only/RO	-€219m

7.4.22 Table 23 shows the change in wholesale market costs for the I-SEM alone (i.e. excluding GB) of moving from a long-term price-based scheme. Wholesale market costs are again lower for the capacity auction and short-term price based CRM than for the long-term price-based CRM. However, wholesale market costs actually increase for I-SEM alone when moving to the well-functioning energy-only market/reliability options.

Table 23 – Difference in overall wholesale market costs (for the I-SEM) between a long-term price-based CRM and alternative CRMs (Base Case A)

NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Change in overall wholesale market costs for the I-SEM (compared with LT price-based CRM)
Capacity Auction	-€64m
ST price-based	-€129m
Energy-only/RO	+€47m

7.4.23 Table 24 shows the breakdown of the different wholesale market cost elements. Annualised capital expenditure is lower in the two price-based CRMs as there is no need for new entry. Annual fixed costs, on the other hand, are significantly higher as more capacity remains on the system. This, however, delivers lower EEU (which is valued at VOLL).

7.4.24 A capacity auction delivers higher annualised capital expenditure but lower annual fixed costs as a result of different plant new entry in terms of technology type. Generation in the I-SEM is further favoured with the corresponding increase in variable production costs in the I-SEM and a similar decrease in the cost of net imports. However, as peak prices remain damped in both markets, there is a

reduced signal for new interconnection to be built assuming that interconnection does not receive capacity payments.

Table 24 - Components of wholesale market costs for the I-SEM compared with the long-term price-based CRM

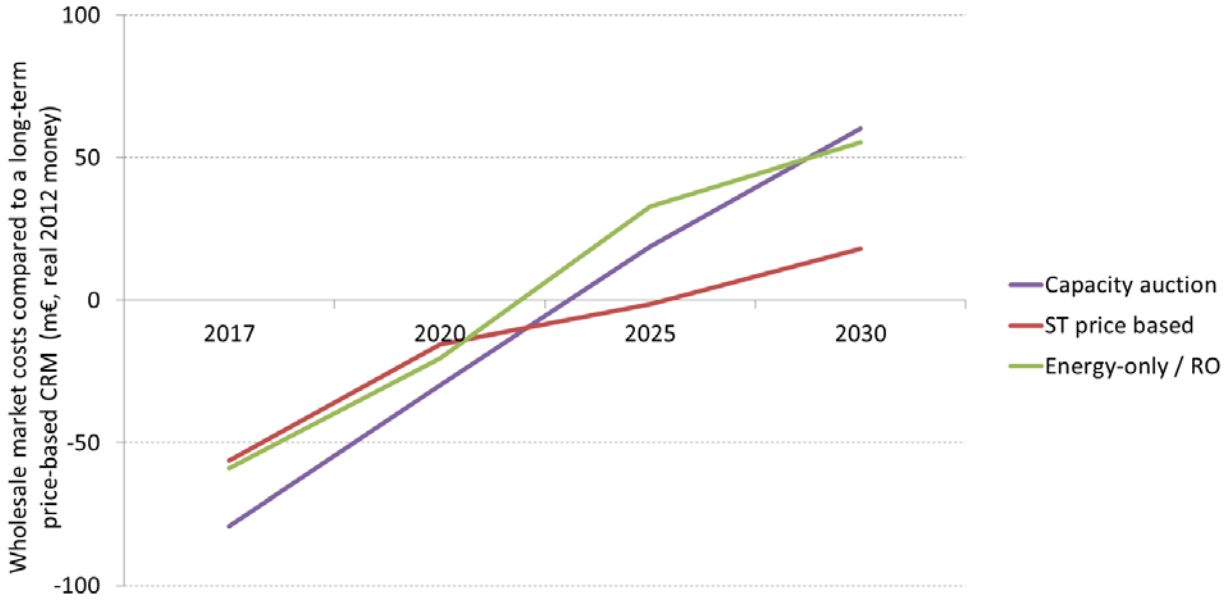
NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Capacity Auctions	ST price-based	Energy-only/reliability options
Annualised capex	+€203m	-€14m	+€108m
Annual fixed costs	-€547m	-€77m	-€659m
Variable production costs	+€2536m	+€2419m	+€1958m
Cost of EEU	+€277m	+€9m	+€401m
Cost of net imports	-€2533m	-€2466m	-€1762m
Total	**-€64m**	**-€129m**	**+€47m**

7.4.25 Figure 20 compares the annual wholesale market costs for the I-SEM under the long-term price-based CRM to the costs for each of the alternative CRMs. This shows that the long-term price-based CRM has much higher wholesale market costs in 2017 than the other CRMs. In 2020, it still has the highest wholesale market costs of any of the CRMs. However, in 2025, it has lower wholesale market costs than the quantity-based CRMs, and by 2030, it has the lowest wholesale market costs of all the CRMs.

7.4.26 This pattern of results is because a long-term price-based CRM encourages existing capacity to stay on the system.[43] Therefore, the higher wholesale market costs in 2017 and 2020 are driven by higher total fixed costs under the long-term price-based CRM as more plant stays on the system. By 2025, total fixed costs under the long-term price-based CRM start to fall as capacity retires because it reaches the end of its technical lifetime. At the same time, new entry in the well-functioning energy-only/reliability options market pushes up capital expenditure (and hence wholesale market costs) compared with the long-term price-based CRM. Lower levels of EEU in the price-based CRMs also help to reduce wholesale market costs compared with the quantity-based CRMs.

[43] A short-term price-based CRM also supports the retention of existing capacity, even though annual payments are low in 2017 and 2020 because of the high capacity margin.

Figure 20 – Difference in annual wholesale market costs (for the I-SEM) between a long-term price-based CRM and alternative CRMs (Base Case A)

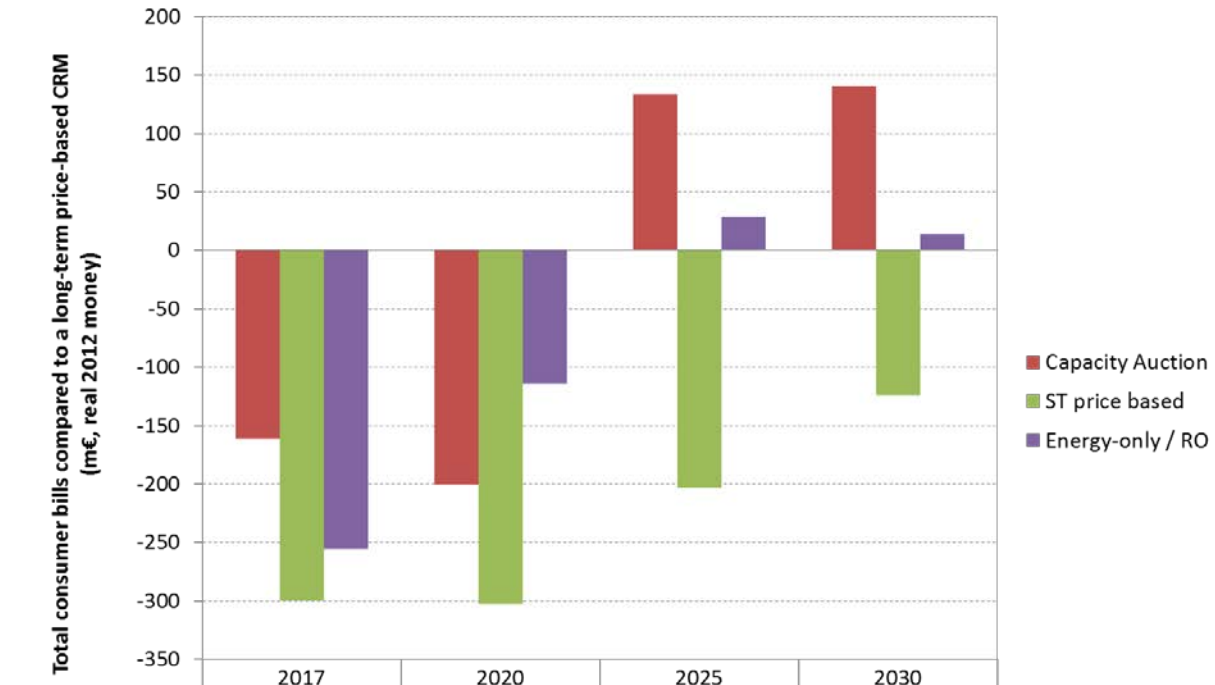


COSTS TO CONSUMERS

7.4.27 Figure 21 compares the annual consumer bills[44] under the long-term price-based CRM to the costs for each of the alternative CRMs.

[44] The consumer bill differences shown in this section are based on changes in wholesale market outcomes. They do not include the small differences in the implementation and operation costs, which are covered in a separate section.

Figure 21 – Difference in annual consumer bills[45] between a long-term price-based CRM and alternative CRMs (Base Case A)



	2017	2020	2025	2030
Capacity Auction	-161	-201	134	141
ST price based	-300	-302	-203	-124
Energy-only / RO	-255	-114	29	14

7.4.28 Under the long term price-based CRM the cost of electricity remains at much higher levels when compared with an energy-only/ reliability options market in the early years. This results in an estimated €255m and €114m additional cost in consumer bills in 2017 and 2020 respectively, when compared with the energy-only / reliability options market. In relative terms this equates to electricity bills that are 8% and 3% higher in those two years. In 2025 and 2030, however, the consumer costs of the long-term price-based and the energy-only market/reliability options are comparable, while a short term price based scheme is estimated to result in lower consumer costs than any of the other options.

7.4.29 A capacity auction on the other hand reduces the cost to consumers when there is more capacity on the system, unlike the long term price-based CRM. In the long term, as the capacity payments are towards all capacity (unlike scarcity rent captured in an energy-only market only when delivering energy) there is an additional transfer from the consumer to generation with existing capacity (with lower load factors) realising additional rents. The generation would have not captured these rents without the presence of a capacity market. This transfer may be avoided (and hence consumer costs reduced further) if there is a differentiation

[45] This covers costs of wholesale energy, capacity payments, additional renewable support payments, and DS3 payments. The figures shown in this chart do not include the impact of costs of operation and implementation.

of contract length for plants depending on whether they are new entrants or existing plant.

7.4.30 A short term price-based scheme delivers the lowest cost to consumers. It favours existing capacity and in particular generating units with low annual avoidable fixed costs. The capacity margin is more comfortable than in the energy-only market, which means that capacity payments reduce to a level sufficient to support low operating expenditure generation (GTs). At the same time, other thermal generation realises lower rents (such as coal and CCGTs) with a transfer of surplus from generators to consumers.[46]

Table 25 - Difference in overall consumer bills between a long-term price-based CRM and alternative CRMs (Base Case A)

NPV €m (2017-2030), real 2012 money, 3.5% discount rate	Change in overall consumer bills for I-SEM (compared with LT price-based CRM)
Capacity Auction	-€724m
ST price-based	--€2846m
Energy-only/RO	-€1074m

SUMMARY

7.4.31 A well-functioning energy-only market was modelled as a base case against which to compare the various CRM options under consideration. The effects of these various options on security of supply, total wholesale market costs (including the cost of expected energy unserved) and cost to consumers was calculated.

7.4.32 *Security of supply*: Unsurprisingly, all the options (energy-only market plus the CRM options) deliver the security standard of an LOLE of 8 hour a year. The well-functioning energy-only market, reliability options and the quantity-based capacity auctions deliver lower LOLE than the security standard in 2017. This is because some plants stay on the system, even though they may make insufficient revenue in the early years, because they are expecting to recover any losses in later years.

7.4.33 In the price-based schemes, the LOLE stays below 2 hours for the whole period to 2030. This means that more plants stay on the system than are needed to meet the security standard. The overshooting of the security standard in a price-based CRM reflects the absence of a strong exit signal in those types of arrangements. In the case of the long-term price-based CRM, this is because the commitment to capacity payments based on the cost of new entry in reduces significantly the downside revenue risks for plant on the system. This discourages exit even when it is efficient.

[46] This assumes that each individual generating unit stays on the system as long as it can recover its annual avoidable fixed costs. In reality, portfolio players may retire units to suppress capacity margins and increase capacity payments if that means higher overall profits.

7.4.34 *Wholesale market costs:* Wholesale market costs comprise annual fixed costs, annualised capital expenditure costs, variable generation costs (i.e., fuel and carbon and variable O&M) the cost of expected unserved energy (EEU) and the cost of net imports. Compared with a well-functioning energy only market, all the modelled CRM designs show an increase in overall wholesale market costs, taking the I-SEM and GB together. Reliability options are assumed to be indistinguishable from a well-functioning energy-only market for this purpose. But the differences are insignificant by comparison with the total combined annual turnover of the two generation markets, which is of the order of €70 billion.

7.4.35 For the I-SEM alone, wholesale market costs are lower than an energy only market or a market with reliability options for all three of the modelled CRM options. But again the differences are insignificant by comparison with the expected turnover of the I-SEM and well within the margin of error.

7.4.36 *Cost to consumers*: a long term price-based scheme, such as the existing CPM in the SEM, is estimated to result in electricity bills in 2017 and 2020 that are higher by €255 million and €114 million respectively than in a well-functioning energy only market or with a reliability option. This translates into an electricity bill that is on average €100 per customer lower in 2017 and €50 lower in 2020.

7.4.37 The difference between the CRM options narrows in later years as the capacity position tightens. However, a short term capacity price scheme is estimated to result in lower end-customer bills than in any of the other options, including an energy – only market and reliability options.

7.4.38 When interpreting the results of the cost-benefit analysis, it should be noted that it does not include the impact of unquantified factors covered by the qualitative assessment. These combined impact of these factors would be to strengthen the performance of the centralised reliability options compared with the modelled outcomes shown in the cost-benefit analysis.

7.4.39 These factors include:

- **Importance of hedging for capacity providers and energy retailers:** the quantity-based CRMs, and the long-term price-based CRM offer a hedge for market participants against short-term variability of energy prices and gross margins – the need for this hedge was identified as one of the main challenges for an energy-only market which supported the retention of a CRM. However, the benefits of the long-term hedge are not fully quantified in the modelling. In the modelling of the short-term price-based CRM, thermal plants stay in the market even if there are a number of years where gross margins are not sufficient to cover annual fixed costs (e.g. as a result of high renewable generation, and high plant availability). In practice, the impact of this could be greater exit from the market (if plants cannot sustain the losses) and/or increased financing costs – which would both be expected to push up costs to consumers in the short-term price-based CRM (and a pure energy-only market) compared with the modelled outcome.

- **Ability of quantity-based CRMs to differentiate between the duration of capacity price certainty needed by different types of capacity providers -** The modelling of the quantity-based CRMs (and the energy-only market) assumes that once new entry is required in one year, the combined capacity and energy price will then stay at new entry levels in all subsequent years. This assumption is driven by the modelling of snapshot years (at 5 yearly intervals). In practice, mechanisms can be put in place in the quantity-based CRMs that provide long-term capacity price certainty for new entrants (where large upfront investment is typically required) over a number of years whilst not paying that long-term price to existing plants in years when new entry is not required. This would still provide firm signals for efficient entry and exit whilst reducing the total payments by consumers under the quantity-based schemes, compared with the modelled estimate used in the cost-benefit analysis. For example, the quantity-based CRM being implemented in GB has this type of mechanism with 15 year contracts with a fixed capacity price for new entrants, and annual contracts with variable capacity prices for existing plant.
- **Competitive markets for energy and for capacity**: the modelling assumes competitive outcomes for energy and capacity, with no portfolio aspects to bidding behaviour. The qualitative assessment has identified particular concerns about the scope for gaming in the short-term price based CRM as the spot capacity price will be sensitive to the withdrawal of capacity on the day (particularly given the importance of the peakiness of the capacity price function to the overall reduction in consumer bills). Any such gaming could push up consumer bills compared with the modelled outcome. Effective market power mitigation measures may be needed in the quantity-based CRMs in the quantity-based CRMs to ensure that consumers benefit appropriately from the introduction of competition. These measures would be developed at the detailed design stage.
- **Impact of retaining efficient short-term price signals on incentives to invest in flexible resources:** the modelling does not include any scope for additional investment in flexible resources, such demand-side response, that could be delivered by efficient short-term price signals. The qualitative assessment identified that reliability options and short term price based CRMs are the CRM best able to deliver efficient short-term price signals.

7.5 QUALITATIVE ASSESSMENT AGAINST PRIMARY ASSESSMENT PRINCIPLES

7.5.1 This section assesses the seven CRM options against the following five primary criteria:

- The internal market in electricity: the market design should efficiently implement the EU Target Model and ensure efficient cross border trade;
- Security of supply: the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.
- Competition: the trading arrangements should promote competition between participants; incentivise appropriate investment and operation

within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner.

- Environmental: while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.
- Equity: the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner.

7.5.2 A subsequent section then looks briefly at the following secondary criteria:

- Stability: the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.
- Efficiency: market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant
- Practicality/Cost: the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.

The Internal Electricity Market

7.5.3 There are three aspects to this principle:

- The impact of the particular CRM on the effective implementation of the European Target Model for energy trading arrangements;
- The ability of cross-border capacity to participate in the CRM; and
- The compatibility with emerging capacity market designs in neighbouring European markets.

7.5.4 The February 2014 Consultation Paper made it clear that any CRM should be compatible with the requirements of the relevant EU State Aid Guidelines. As this is not a formal assessment of the CRM against the State Aid Guidelines, we do not explicitly test each scheme design against the full set of criteria. However, many of the State Aid criteria relate to good scheme design and overlap with our primary assessment principles – for example, the assessment principles of the internal energy market and competition (including entry and exit). [47][48]

EFFECTIVE IMPLEMENTATION OF THE TARGET MODEL

7.5.5 For price coupling, the assessment primarily depends on the impact of the CRM on

[47] The State Aid Guidelines refer to avoiding negative effects on the internal market and the CRM being open to participation from other Member States where physically possible.

[48] The State Aid Guidelines refer to a 'competitive bidding process', the fact that any CRM should be open to all with the same technical performance; the selection of beneficiaries should address the scheme objectives in most cost-effective manner; and that the CRM should not unduly strengthen market dominance.

short-term price signals produced in the DAM, IDM and balancing timeframes. [49]

7.5.6 A targeted contracting scheme, such as Strategic Reserve (Option 1), and reliability options (Options 5a and 5b) are designed explicitly to support efficient short-term energy price signals that would facilitate efficient market coupling.

7.5.7 Price based CPM schemes (including the current SEM design) attempt to create a real time scarcity price in each settlement period, and may apply this price to imports and exports. This would help to provide efficient short-term signals, provided that market prices reflect the true value of scarcity and are known (with reasonable certainty) at the time of trading. For cross-border flows, this means that the capacity price needs to be effectively known (or predictable) at the day-ahead stage, which conflicts with the need for prices to reflect actual scarcity conditions.

7.5.8 The short-term signal itself is expected to be stronger in a short-term price-based scheme (Option 2b) than a long-term price-based scheme (Option 2a). The impact of the long-term price-based scheme (Option 2a) on short-term price signals will depend on the design of the scheme and the degree to which the long term and short-term conditions differ. Where there is a significant discrepancy, the tendency is for the longer term designs to smooth the stream of payments, thereby over-rewarding plant which is available at times without real system stress, and under-rewarding plants which are available at the really critical periods. This feature of the current long-term price-based CRM in the SEM was identified as part of the CPM medium term review undertaken by the SEMC in 2009.

7.5.9 By carving out some part of the scarcity rent into a more stable capacity payment, the residual value of energy under the capacity auctions or obligations (Options 3 and 4) is unlikely to reveal extreme peak pricing. If the economic level of peak pricing could be achieved in an alternative design, then by comparison Options 3 and 4 risk distorting cross border energy trades, and also any real time energy prices revealed to customers.

7.5.10 In summary, reliability options perform well against this criterion because are designed explicitly to support efficient short-term energy price signals that would facilitate efficient day ahead and intraday market coupling; and interfere less with the formation of energy market prices than the other options.

EFFECTIVE CROSS-BORDER PARTICIPATION

7.5.11 Participation by out-of-zone resources is a major issue for the design of proposed CRMs in Europe. One respondent to the February 2014 Consultation Paper stated that the interconnectors could just be excluded from a CRM. However, this could

[49] There is currently a price cap of €3000/MWh in the NWE day-ahead market coupling arrangements, which provides an explicit limit on the price in the day ahead market.

unduly discriminate between national and cross border contracts.[50] The EC's emphasis on cross border participation in CRMs is reflected in its recent revised State Aid Guidelines on Energy and Environment.

7.5.12 Quantity-based schemes like Options 3 or 4 pose challenges to cross zonal participation given the definition of the requirement for physical availability or energy delivery into the system making the capacity payment[51]. However, proposals for participation by out-of-zone generation are now being developed for GB and for France.

7.5.13 Where participation in the CRM scheme is based around access to the day-ahead energy market, the use of long-term transmission rights can provide cross-border access. This could be the case for both price-based schemes (Options 2a and 2b), and the reliability options (Options 5a and 5b).

7.5.14 Under the current proposals for the Target Model, long-term transmission rights effectively expire at the day-ahead stage. Therefore, holding long-term transmission rights would not allow participation in the CRM by out-of-zone generation if either the capacity price is finalised after the DAM (price-based schemes) or if the reliability options are referenced to other timeframes after the DAM. This would need to be taken into account in considering the reference price at the detailed design stage.

7.5.15 Under the Forward Capacity Allocation Network Code, these long-term transmission rights could be financial or physical. The proposed approach on energy trading arrangements in the I-SEM Draft Decision Paper is financial transmission rights, which are a better fit with centralised Reliability Options (Option 5a) as both rely on and engender liquid day ahead markets.

7.5.16 In summary, reliability options perform well in relation to cross border participation where the reference price is the DAM. While it might be difficult for cross border providers to purchase cross border transmission rights where the auction time lag is for example four years, they may choose to do so or they may request that multiannual transmission rights be issued. The secondary trading facility is likely to be a key advantage of reliability options as holders of cross border transmission rights will be able to purchased ROs if they are in a better position to meet the obligation that the original holder. Employing Financial Transmission Rights should be even more complimentary to cross border participation and reliability options.

COMPATIBILITY WITH NEIGHBOURING COUNTRIES

7.5.17 For the All-Island Market in particular, the assessment of the impact of the CRM on

[50] This would discourage investment in interconnection, distort flows and remove interconnection / interconnected capacity from capacity price formation.

[51] With physical delivery, this is difficult because the rules governing cross border access do not easily allow capacity to be withdrawn from the market through all timeframes to hold for physical delivery.

efficient interconnector flows is complicated by the fact that the closest neighbouring market (and other coupled markets) will be introducing a CRM.

7.5.18 For the centralised capacity auction (Option 3), the high-level similarities with the GB design may be seen as possibly mitigating some of the possible distortions to cross border flows (and also making it easier to possibly move to a common scheme in the future). However, this would rely on the detailed design of the auctions and the behavioural response in energy and capacity pricing also being similar. If that were not the case, the residual scarcity rent in the energy price could be quite different in the GB market and in the All-Island market, potentially distorting trade between the two markets, despite their similar CRM designs.

7.5.19 There is concern, particularly at a European level (e.g. ACER) about the impact of the proliferation of uncoordinated national CRM schemes.[52] However, the European Commission, in its staff working paper on generation adequacy in the internal electricity market, notes that long term capacity allocation rights could be used to make capacity mechanisms compatible with market coupling and could even work across several borders. [53]

> *With reliability options the incentive effect of the option should ensure that generators located in other Member States would anyway ensure they had sufficient interconnection capacity right'.*

7.5.20 The EC goes on to recommend that Member States should allow the participation of cross border capacity based on holding of (financial or physical) interconnection capacity rights, or alternatively implement reliability options which ensure that participants are incentivised to hold capacity rights.

SUMMARY

7.5.21 Reliability options are a market-based mechanism where regulatory intervention in the energy market and hence minimise long and short term distortions in cross border investment and trade. This is consistent with the objectives of the European Internal Market.

Security of Supply: the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.

7.5.22 The issues identified as needing to be addressed by a CRM against this criterion primarily relate to long-term security of supply, and specifically the risks of new entry and/or continued operation as a result of uncertainty about electricity

[52] 'European Energy Regulation: A Bridge to 2025. Public Consultation Paper. PC-2014-O-01', ACER, 29 April 2014.

[53] See http://ec.europa.eu/energy/gas_electricity/doc/com_2013_public_intervention_swd01_en.pdf

revenues and future load factors; and short term security of supply, which may be influenced directly by the CRM scheme or by retaining short-term energy price signals or both.

LONG-TERM SECURITY OF SUPPLY

7.5.23 As a form of a targeted contracting, Strategic Reserve is designed to address a specifically identified adequacy problem. However, the targeted nature of Strategic Reserve also means that it may only make a limited contribution (e.g. by time and/or location) to addressing the broader generation adequacy issues.

7.5.24 The detailed design of how the supported capacity can access other revenue streams will determine the impact of Strategic Reserve on the long-term security of supply signals in the market. Regulatory measures (such as allowing a low regulated return for the capacity) can help make the Strategic Reserve a relatively unattractive proposition, and hence a genuine measure of last resort.

7.5.25 Ultimately, if the Strategic Reserve undermines the incentives for investment and operation from other revenue streams (e.g. energy, ancillary services), then the so-called 'slippery slope' can set in, whereby further targeted intervention is required to maintain long term security of supply. If this happens, it could end up weakening long-term generation adequacy.

7.5.26 There is a perception that price-based mechanisms (Options 2a and 2b), capacity auctions (Option 3) and capacity obligations (Option 4) are better suited to address the 'missing money' problem than the reliability options (Options 5a and 5b). This perception, raised in consultation responses, is based on the logic that the advance option fee payment under a reliability option represents a 'risk-adjusted' estimate of the expected value of the payments (when the reference price is above the strike price), and any missing money in the energy market will translate into low option prices.

7.5.27 If the trading of the reliability options were entirely voluntary this might be true. However, if the purchase of reliability options to cover total system requirements is mandatory, then the option fee should also replace any 'missing money', together with the expected value of the stream of payments under the reliability option.

7.5.28 Quantity-based schemes have an advantage over price-base schemes in that the target (a required quantity of capacity) is directly under the control of the regulator, while the price of capacity is set by the market. As Cramton and Stoft put it:

> *'the regulator controls the level of capacity, but the market controls the price of capacity and the type and quality of capacity built. Hence the regulatory intervention has been strictly limited to the determination of the one factor*

about which the market has little information—the adequate level of capacity' [54]

7.5.29 In price-based schemes, by contrast, the price of capacity is determined by the regulator (based usually on an estimate of the cost of new entry) and generators (and the demand side) decide how much capacity to offer. Estimating the cost of new entry is not without its difficulties: it requires the choice of a technology, a series of hypotheticals about the costs of constructing new capacity, the net energy revenues that each type of new capacity would earn, and the rates of return required to encourage investors to sink capital into long-lived assets. And even if the cost of new entry can be estimated perfectly, price-based schemes run the risk of attracting either too much or too little capacity, given uncertainty about how much capacity will be forthcoming at the estimated cost of new entry.

SHORT-TERM SECURITY OF SUPPLY

Price Signals

7.5.30 The price-based schemes (Option 2) offer a mechanistic spot price for capacity, with the short-term price-based potentially offering the sharpest spot price signal. As discussed earlier, this spot price for capacity may need to be calculated at the day-ahead stage to be compatible with the current market coupling arrangements. This could reduce the ability of these schemes to incentivise delivery of more flexible resources.

7.5.31 Under the capacity auctions/obligations (Options 3 and 4), it is difficult to derive a capacity price for individual trading periods, even through secondary trading. This might adversely affect short term signals for flexibility and dynamic demand response, by comparison with the other options.

7.5.32 One of the attractions of a CRM based on reliability options (Option 5) is that its design is more compatible with retaining short-term energy price signals, whilst providing a long-term hedging instrument. This would allow energy market volatility to govern cross-zonal trading (through market coupling in the various timeframes) and should also deliver efficient short-term prices to producers and consumers.

Response Close to Real Time

7.5.33 Under a Strategic Reserve approach (Option 1), the strength of the requirement to respond close to real-time can be determined on a case-by-case basis to address the specific adequacy risk identified.

7.5.34 Under Options 3 and 4, the response time for eligibility can be defined closer to real

[54] Forward Reliability Markets: Less Risk, Less Market Power, More Efficiency, Cramton, P. and Stoft, S., Utilities Policy, 16, pp 194-201, 2008.

time. For example, the proposed GB scheme will have an administered signal of system stress 4 hours ahead of real time. This alone can provide additional incentives for flexible resources on top of the intraday and balancing energy markets. And, given the penalty regime, there are clear risks associated with selling firm capacity which cannot respond in 4 hours.

7.5.35 As pointed out earlier, the price-based CRMs (Option 2) would likely require capacity prices to be fixed at the day-ahead stage to minimise distortions of flows, and facilitate cross-border participation. This then means that the ability to move the capacity price signal closer to real-time will depend on how the intraday trading arrangements develop in the future.

7.5.36 Similarly, making the day ahead price the reference market for the reliability options helps with cross-border participation (and supports a liquid day ahead market). If there is a requirement for capacity to respond closer to real-time, then alternatives with delivery times falling at points intraday would need to be considered. Alternatively, since some market participants are sufficiently flexible to operate in the balancing market, and if there is a single balancing price, then this price could be used as a reference price for reliability options. However, even in a high wind world not all generation needs to be that flexible and setting the reference price on a real time price would place greater risks on less flexible capacity providers.

SUMMARY

7.5.37 There is a significant and growing body of evidence and international best practice (particularly in North and South America) showing that long-term auctions in the form of centralised reliability options have proved to be effective instruments to guarantee generation adequacy.[55] Reliability options provide a transparent and versatile mechanism for encouraging required new entry and sending efficient exit signals, whilst minimising interference with short term spot energy prices.

Competition: the trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner.

7.5.38 The consideration of competition with respect to CRMs has three dimensions: the scope for competition in the capacity market itself; the efficiency of entry and exit signals; and the impact on ability to exercise market power in the related markets

[55] See: Cramton and Stoft, ibid; Batlle, Michel Rivier, Ignacio J Perez-Arriaga *Security of Supply in the Dutch Electricity Market: the Role of Reliability Options;* Carlos Vazquez, Carlos; 2003 and Batlle, C., Rodilla, P., 2010. *A critical assessment of the different approaches aimed to secure* electricity generation supply. Energy Policy 38, 7169–7179.

(such as for energy).

COMPETITION IN THE CRM MARKET

7.5.39 Given that Strategic Reserve (Option 1) is intended to support capacity with specific characteristics, such as location, this may in general limit the scope for effective competition for the targeted contract.

7.5.40 With respect to short-term competition, the question for the price-based CRMs (Options 2a and 2B) is the extent to which capacity providers are able to affect the spot capacity price, e.g., by withdrawing capacity from the market.

7.5.41 This will be a bigger issue for a purely short-term price-based scheme (Option 2b) where the capacity price is very responsive to the short-term supply and demand conditions. Where interconnection can influence the short-term price signal, then this would help to reduce the ability of market participants to game the spot capacity price in a short-term price-based scheme.

7.5.42 For the long-term price-based scheme (Option 2a), the ability of market participants to game the short-term price signal will depend on the responsiveness of the spot price signal. However, the existence of a fixed pot means that capacity providers compete between themselves in the short term (in terms of reducing the payment received by each provider) but without the ability to increase or decrease the size of the pot and hence the cost to consumers.

7.5.43 For the quantity-based CRMs (Options 3, 4 and 5), the key area of competition is for the contract award in the form of the initial auction. Given the potential in a small market for anti-competitive behaviour, market power mitigation measures may be needed as part of the detailed auction design.

7.5.44 Market power mitigation measures are part of quantity-based CRMs in other markets, e.g. in the US and in the proposed GB scheme.[56] This can include bidding rules, which can relate to minimum offer prices to deter inefficient exit or maximum bids (e.g., for existing plant). These rules could also be targeted at a subset of the market where market power has been identified as a concern.

7.5.45 Crucially, centralised reliability options offer a transparent public auction that is held on behalf of all demand in the market so as to exploit economies of scale (though the concentration of liquidity) with the objective of increasing competition, and

[56] In New England, neither existing units nor new units have the freedom to bid whatever they want. Existing units, unless they wish to retire, have constraints on how high a price they can demand to withdraw from the capacity market. New units (which include any upgrades of existing units) have their bids screened by the market monitor to ensure that they are not, in effect, proxy bids placed by buyers to reduce the market price. In addition, there are caps and floors in the auction process to avoid rapid price changes.

creating a level playing field for market participants. International best practice and experience strongly argues for a centralised auction process on competition promotion and market power mitigation grounds. [57]

IMPACT ON ENTRY AND EXIT SIGNALS

7.5.46 The incentivisation of efficient levels of efficiency of market entry and exit of a CRM was an issue highlighted in the Proposed HLD for SEM.[58]

7.5.47 There are concerns about the efficiency of the exit-signal under a price-based mechanisms (Options 2a and 2b), particularly in the absence of significant performance penalties. This can depress the capacity price (by increasing the quantity of plant receiving the payment) and thereby deter new entry and/or refurbishment even when that may be efficient on performance grounds.

7.5.48 With respect to efficient entry signals, the capacity/energy value split under the capacity auction/obligations (Options 3 and 4) is to some extent arbitrary and hence uncertain. This means that entrants run the risk of committing for long term capacity with a market expectation of low-priced capacity and high priced energy, with the risk that during the contract term the market switches to high priced capacity (which is not available to those with long term contracts) and low priced energy[59].

7.5.49 However, the evidence suggests that quantity based schemes can be tailored better to address issues such as flexibility more easily than price based schemes. This is evidenced by the CPM in the current SEM in that many potential investors in new flexible plants have argued that the current uniform distribution of the capacity pot makes investment decision difficult and can keep older plants on the system which they believe should have retired.

7.5.50 Quantity Based mechanisms and Reliability Options in particular provide strong entry and exit signals by coordinating new entry though a single and transparent auction and simultaneously sending efficient exit signals to inefficient generation by providing a market based mechanism that determines the price for the regulatory determined level of adequacy.

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[57] ' The international learning process has led to the conclusion that it is desirable to use centralised auctions for different reasons, among others, to benefit from economies of scale increasing competition ,to avoid vertical integrated companies taking advantage of obscure agreements' (Batlle, C., Rodilla, P., 2010)

[58] SEM – Proposed High Level Design (2005), The Single Electricity Market – Proposed High Level Design, SEM Committee, AIP/SEM/06/05, 31 March 2005, page 24.

[59] This concern may be overstated but it reflects the risk of separating total payments into different streams. The impact on consumers will depend on the extent to which it increases the risk (and hence financing) cost of participating in the capacity auctions/obligations.

IMPACT ON COMPETITION IN ENERGY TRADING

7.5.51 An intention of Strategic Reserve (and other forms of targeted contracting) would be to avoid impairing the competitive dynamics of energy and other markets. The ability of Strategic Reserve to do this in practice will depend on whether the supported capacity can access other revenue streams and under what terms.

7.5.52 An administered short-term price signal in the price-based schemes (Options 2a and 2b) could help to alleviate concerns about the exercise of market power in energy trading arrangements. This could then reduce the risk of regulatory/political intervention on short-term signals.[60] In addition, if the payments in the price-based mechanisms are linked to participation in the day ahead market, then this will help to support liquidity in that market (which is one of the market power mitigation measures proposed for energy trading arrangements).

7.5.53 By providing a long-term hedging instrument for generators and suppliers, reliability options (Options 5a and 5b) can be part of a strategy for market power mitigation and promotion of liquidity in the energy trading arrangements (as they support liquidity in the reference market). By reducing the value of price spikes to the sellers of the options, it mitigates market power directly.[61] They may also provide a risk-hedging mechanism that is particularly attractive to new entrant suppliers with uncertain quantity requirements, thereby enhancing competition at the retail level.

SUMMARY

7.5.54 In summary, centralised reliability options perform well against the competition criterion. They promote competition between licence holders that delivers appropriate investment in a transparent manner. Through providing transparent centralised auctions that are held on behalf of all demand they exploit economies of scale in the market with the objective of increasing competition, concentrating liquidity and creating a level playing field for market participants.

7.5.55 Regarding efficient entry and exit, quantity based mechanisms in general and centralised reliability options in particular provide strong entry and exit signals by coordinating new entry though a single and transparent auction and simultaneously sending efficient exit signals to inefficient generation. This should avoid the boom and bust problem that may emerge in an energy only market whilst also ensuring

[60] Ofgem is proposing to introduce an administered short-term scarcity pricing signal in the GB balancing arrangements, because the market is not expected to deliver an appropriate profile of prices at times of scarcity (because of the impact of strategic reserve procurement on offer prices into the Balancing Mechanism).

[61] At least over the duration of the options and for prices above the strike prices for the options. There might still be incentives for gaming over longer periods, to increase the price of the next round of options.

that consumers do not overpay for generation adequacy.

7.5.56 Reliability options based on a centralised auction (run by the TSO) also perform well in terms of their ability to reinforce market power mitigation measures in the energy market. They support cross-border participation more naturally than any of the other options, which helps to facilitate more competitive capacity price formation.

7.5.57 Market power mitigation measures may be required in the auction of reliability options, but this could equally apply to the alternative CRM schemes as well Depending on their detailed design.

Environmental: while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables**.**

7.5.58 Any CRM should allow the full participation of all technologies (including variable generation), to the extent that they can meet the required performance requirements. Moreover, the CRM should not be intended to address any (perceived or actual) failings in the renewable support schemes.

7.5.59 The challenges for generation adequacy discussed under the security of supply principles may present barriers to increasing levels of renewable deployment. Therefore, the extent to which the CRM design performs well in relation to security of supply may also determine its ability to facilitate higher levels of renewable deployment.

7.5.60 Within the I-SEM, the short-term price signals will also be important for helping to mitigate the risk of wind curtailment through the encouragement of flexible resources. However, the CRM design will have relatively little direct impact on this as the curtailment should only occur at times of low prices (and high capacity margins). Indeed, reduction of curtailment is not the concern of the CRM (compared with, say, the impact on wind curtailment of intraday energy trading and the DS3 programme).

7.5.61 In this respect, the most relevant impact of the CRM on wind curtailment will be the extent to which it encourages investment in resources that can increase demand at times of high wind, e.g. interconnection (therefore the cross-border participation element is important), storage and demand-side response (where this involves shifting demand from high-price to low-price periods).

7.5.62 The Strategic Reserve approach is unlikely to support additional investment in interconnection. There may be some scope for DSR to be facilitated under Strategic Reserve but this may be peak shaving more than load shifting (with the latter being more relevant for reducing curtailment).

7.5.63 Both price-based mechanisms (Options 2a and 2b) should be designed to allow cross-border participation which could facilitate increased investment in interconnection through increased demand for long-term transmission. They could also help the development of the demand-side (to the extent that short-term price signals are sufficiently sharp).

7.5.64 The signals for investment in interconnection under the capacity auctions / obligations (Options 3 and 4) depends on the ability to facilitate cross-border participation. This has proved difficult so far, particularly where the delivery requirements are determined close to real-time and after the expiry of explicit cross-zonal transmission rights. The detailed rules will determine the attractiveness of the scheme to DSR, particularly load-shifting DSR (which will be relevant for reducing curtailment). [62]

7.5.65 The reliability options (Options 5a and 5b) offer greater scope for cross-border participation. This should support demand for long-term transmission rights which in turn should support increased investment in interconnection and hence allow for increased penetration of variable renewable energy sources (for more on this see ESRI research has suggested that high penetration of wind should be accompanied by increased interconnection to neighbouring systems [63]). Where the reliability options are referenced to the day ahead market, this should provide a good signal for DSM with load-shifting (in addition to the encouragement provided by the retention of the short-term energy price signals).

SUMMARY

7.5.66 The facilitation of renewables by a CRM will depend mainly on the ability of the CRM to mitigate the risk of wind curtailment. It is unlikely to be able to do this directly through the encouragement of flexible resources, since curtailment should occur only at times of high capacity margins and low energy prices. A CRM might, however, indirectly reduce the need for curtailment by encouraging investment in resources that can increase demand at times of high wind, e.g. interconnection, storage and demand-side response.

[62] e.g., the duration of the requirement to deliver capacity in a stress event.

[63] See: DIFFNEY, S., J. FITZ GERALD, S. LYONS and L. MALAGUZZI VALERI, 2009. Investment in Electricity Infrastructure in a Small Isolated Market: the Case of Ireland, Oxford Review of Economic Policy, Vol. 25, No. 3, pp. 469-487. available at: http://oxrep.oxfordjournals.org/cgi/reprint/25/3/469. This study finds that for a small and relatively isolated market such as Ireland, a high penetration of wind is economically sound only if it is accompanied by an increase in interconnection to Great Britain

7.5.67 Reliability options perform well in this respect because they offer greater scope for cross-border participation and, through their direct connection with the day ahead market, the provision of good signals for demand side response and storage, thereby encouraging demand to shift from high priced to low priced periods.

Equity: the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner

7.5.68 One equity issue is the scope for double payments to providers. A revised CRM in Ireland and Northern Ireland must be closely interlinked with changes to the energy market and the ancillary services framework in order to reward flexibility and maintain an effective long term adequate capacity balance, while avoiding double payments for the provision of capacity.

7.5.69 For the quantity-based CRMs in general, including reliability options, competitive award of the capacity payments should encourage market participants to reduce the bids to reflect revenue from other sources (e.g. from system services). In addition, reliability options are effectively a one-way CfD that should directly address the risk of double payment between energy and capacity, at least for energy prices above the option strike price.

7.5.70 One-way CfDs (e.g. against energy revenues, constraint revenues, and/or system service revenues) can also be used in a targeted contracting mechanism to reduce the risk of double payments – e.g. through the use of a one-way CFD in the energy or DS3 markets. Examples of this are the reliability must-run contracts in US that system operators can sign with generation in constrained areas.

7.5.71 For a price-based mechanism, with an administratively set total pot, there may need to be an administrative correction mechanism to account for revenues from different sources (which may differ by generation technology), thereby increasing the complexity of the market arrangements. The administrative correction mechanism could apply to any of the different revenue streams (e.g. capacity or system services).

7.5.72 In terms of the degree of centralisation with quantity based mechanisms, centralised reliability options, where a centralised auction is run of the whole of system demand, ensures that all consumers pay the same price for generation adequacy which is consistent with public good attributes of reliability.

SUMMARY

7.5.73 In conclusion, quantity-based mechanisms, including reliability options, ensure that distributional and equity concerns are met by avoiding the potential double payments to producers at the expense of consumers, which are associated with

price-based mechanisms. Reliability options also provide a level playing field (insofar as is possible) between consumers and producers in different price zones.

7.5.74 Furthermore, in terms of quantity-based mechanisms, a centralised auction for the entire system demand would ensure transparency and a level playing field for new entrants as well as ensuring that all consumers effectively pay the same price for generation adequacy.

7.6 QUALITATIVE ASSESSMENT – SECONDARY ASSESSMENT PRINCIPLES

7.6.1 In terms of the secondary principles, the key issues for the HLD of the CRM are around stability, efficiency and practicality. The detailed design will determine the performance against the adaptability principle.

Stability: the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.

7.6.2 There are two aspects to stability of the HLD of the CRM: the need for continuing regulatory intervention; and the scope for pressure for major change in the future (from external or internal sources).

7.6.3 Some degree of regulatory involvement is needed in any CRM, with some decisions having to be made. In the market-wide based mechanisms, this will be about the key parameters of the scheme (including the demand curve), whereas for the Strategic Reserve option, this will be more about the grounds and subsequently the framework for the initiation of targeted contracting.

7.6.4 The major decisions in the price-based schemes (Option 2) are the fixing of the value of the scheme; whether this is the total pot in the long-term price-based scheme (and the mechanisms for over/under recovery) or the values determining the VOLL/LOLP calculation in the short-term price-based scheme.

7.6.5 One respondent to the February 2014 Consultation Paper noted that the distribution of payments between participants in a long-term price-based CRM can be sensitive to the detailed parameters of the scheme. This illustrates the scope for regulatory decisions on the details to lead to major changes in allocation of payments between participants, which could be seen as increasing the potential instability of the scheme.

7.6.6 In all the quantity-based schemes (Options 3, 4 and 5), there will be a need to determine the quantity of capacity to be procured. By being based around participation in a reference market (e.g., the day ahead market), the reliability options scheme may be simpler in terms of fewer regulatory parameters to determine, e.g., with respect to specific rules about the eligibility of demand,

interconnection and variable generation, since the capacity seller takes on delivery risk.

7.6.7 Similarly, the use of a market-based penalty under the reliability options could reduce the perception of regulatory risk compared with complete reliance on an administratively determined penalty (including the setting of VOLL).

7.6.8 The main pressures for changes to the CRM design over time are likely to come from:

- the effective inclusion of interconnector capacity, given the expectations of interconnection being increasingly important in a high-RES system;
- the compatibility with demand-side measures, given expected growth in potential for demand-side response; and
- greater harmonisation of European CRMs.

7.6.9 On the first two factors, the capacity auctions/obligations (Options 3 and 4) do less well than the other broad-based CRMs, particularly the reliability options approach.

7.6.10 On the third point, the CRMs currently being developed elsewhere in Europe are all quantity-based schemes of differing varieties, e.g. in France, Italy (reliability options), GB, with quantity-based alternatives also under consideration in Germany. So a quantity-based approach in the All-Island market would be more consistent with the high-level direction of travel amongst other European countries, why may reduce the risk of major changes in the future to meet a drive for greater harmonization at a European level. In addition, reliability options are directly referenced in the European Commission's guidance on Capacity Remuneration.[64]

7.6.11 In summary, the proposed I-SEM design is predicated on a liquid short term physical markets coupled and integrated with the European Internal Market with financial forward intra- and cross-zonal hedging instruments. This fits naturally with reliability options, which are financial in nature and dependent upon liquid short term reference markets. For this reason, reliability options offer the best choice for SEM consumers in terms of stability over the lifetime of the ISEM and beyond.

Efficiency: market design should, in so far as it is practical to do so, result in the most economic (i.e., least cost) dispatch of available plant.

7.6.12 This assessment principle is linked to the impact of the CRM on short-term wholesale market price signals and dispatch decisions.

7.6.13 In theory, the Strategic Reserve option (Option 1) should be capable of being designed not to distort the dispatch decision, so should perform well on this principle. It can do this by ensuring that the more efficient plant are all dispatched ahead of the plant with Strategic Reserve contracts.

64 http://ec.europa.eu/energy/gas_electricity/internal_market_en.htm

7.6.14 The price-based mechanisms (Options 2a and 2b) and the capacity auctions/obligations (Options 3 and 4) all have the scope to dampen short term energy price signals by comparison with what might otherwise have been the case. This is because, with a non-targeted CRM, less scarcity rent would need to be recovered from the wholesale price with the CRM than in the energy-only market (because the CRM payment would cover a portion of each eligible generator's costs). Whether directly or indirectly, this would then dampen wholesale price signals – both average prices and the variation around the average. This would reduce the efficiency of scarcity spot prices, with implications for demand side response and interconnector flows.[65]

7.6.15 This could change the dispatch for any plant not eligible for the CRM. In consequence, it is important that interconnector flows are exposed to the spot capacity price under the price-based mechanisms.

7.6.16 In the capacity auctions/obligation (Options 3 and 4), there is no spot capacity price which means that dispatch could be distorted, with implications for the demand-side and interconnection.

7.6.17 Under the reliability options, the short-term energy price signals could be retained (to a much larger extent than under the other options) which should help to deliver a more efficient dispatch outcome.

Practicality/Cost: the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.

7.6.18 The limited scope of the Strategic Reserve option could mean relatively low implementation and operation costs, compared with the broad-based mechanisms. However, the *ad hoc* process may need to be repeated and some continuing monitoring of the impact of the contracts on the wider market would be required, adding to the recurrent costs of the scheme.

7.6.19 For the quantity-based approaches, there is a need to determine the rules for allocating the capacity contracts, and for allocating the responsibility for paying for these contracts, as well as some means of facilitating secondary contract trading. This is because, if providers are asked to take on a physical commitment in advance with availability/non-delivery penalties, then they have to have a way of managing these risks closer to real time (e.g., to manage an unscheduled outage).

7.6.20 With reliability options, which are financial in nature, market participants may be

[65] Through the market expectations of scarcity energy prices, or through actual or the perceived threat of caps on spot prices when a separate CPM was in place.

able to make secondary trades without a need for central monitoring or notifications, subject to any liquidity and market power mitigation measures.

7.6.21 Centralised quantity-based auctions (Option 3) are perceived to be simpler and more straightforward to understand than reliability options (Options 5a and 5b). This is arguably deceptive since the implications are subtle, and implementation may be more complex than envisaged, as has been the case in the GB. This can include the separate exercise to define penalty arrangements which are central to the short-term availability signals and risks to potential providers under the scheme.

7.6.22 The use of market-based mechanisms to allocate capacity contracts in the quantity-based approach will also typically lead to higher participation costs for market participants who will need to define a bidding strategy, participate in the auction and maintain continuing mechanisms for managing risk of exposure to penalty payments. However, some of these costs would be incurred if there is secondary trading, irrespective of the initial auction/allocation process.

7.6.23 Our initial estimates of the total implementation and operation costs of different broad-based CRMs suggest that these costs would be higher - by about €3m/year - under a quantity-based scheme rather than a price-based scheme (see Section 7.3). However, this difference is small in the context of the likely level of payments under a CRM.

7.6.24 For the All-Island market, there are fewer of the implementation issues seen in other markets with respect to reliability options. For example, there are no legacy physical bilateral contracts (based on the right physically to nominate) which would affect the ability of possible providers to access a reference market.

7.6.25 The process of contract renegotiation for introducing Reliability Options in GB was estimated by DECC to be comparable to the costs of replacing the English and Welsh pool by NETA (for the CRM, this equated to over a cost of over £1 billion in NPV terms for a 20 year period). Given that there is not a similar legacy of legacy physical contracts in the All-Island Market, these changeover costs would not be faced by the I-SEM.

7.6.26 Also, the fact that the CRM design is happening in parallel with the energy trading arrangements (including for example the Balancing Mechanism) should help to ensure a consistent approach. For example, the uncertainty of the outcome of Ofgem's cash-out review was another one of the reasons DECC gave for not proceeding with reliability options. Their Impact Assessment noted that there could be a possible future move to reliability options if the imbalance pricing regime delivered sharper short-term price signals.

SUMMARY ASSESSMENT

7.6.27 In conclusions, the quantitative modelling backed by assessment against the I-SEM Objectives and international best practice provide strong evidence for the decision to implement a quantity based CRM based on centralised reliability options issued by a central party in the I-SEM (Option 5a in the Consultation Paper).

1 APPENDIX: REFERENCE SCENARIOS FOR MODELLING

1.1.1 We have developed two scenarios for quantifying the I-SEM wholesale market benefits and costs. These two scenarios do not cover the full range of all possible outcomes when it comes to fuel and carbon prices as well as evolution of demand and renewables deployment, but capture a plausible range to use in the cost-benefit analysis (CBA) and supporting quantitative analysis.

1.1.2 We have modelled I-SEM as an energy-only market under two reference cases (Base Case A and Base Case B). Both reference cases assume a security standard of 8 hours of LOLE for the All-Island system from 2020 onwards[66].

1.1.3 The electricity market modelling has been carried out with Poyry Management Consulting's power market model, BID3, which is capable of modelling the dispatch of all generation on the European network. BID3 simulates 8760 hours per year under (with multiple historical weather and/or availability patterns). It generates hourly prices and dispatch patterns for each pant in the modelled region(s).

1.1.4 BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plant and interconnectors on the system. At a high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour. However, the model does take into account for costs associated with start-up and part-loading as well as other technical limitations, such as minimum on and off times and minimum stable generation.

1.1.5 In the energy-only market, generators try to recover their capital expenditure ('Capex') and their annual avoidable fixed costs ('Opex') over 'tight' periods in the form of scarcity rent. When the capacity margin is 'wider', generators bid their SRMC in the market. We have assumed that investors have perfect foresight of the evolution of (average) future conditions (and hence expected future revenues and costs).

1.1.6 Each future year is modelled under a combination of historical weather (and demand) patterns and thermal plant availability profiles. Each future year is therefore modelled under 15 different 'paths' that are the combination of weather years 2006-2010 and three thermal plant availability profiles (High, Central and Low). This enables us to capture extreme conditions (for example a low wind period coupled with low thermal plant availability) ensuring that our scenarios are capacity

[66] For 2017 we assume that the North-South tie constraint is still in place and the security standard is different in Ireland and N. Ireland. The LOLE for Ireland and N. Ireland is 8 and 4.9 hours respectively.

adequate. This approach can be considered as pseudo-stochastic. In particular, such an approach allows us to:

- capture the expected plant gross margin under a suite of future conditions
- ensure sufficient capacity on the system to meet the security standard on average[67].

1.2 COMMON ASSUMPTIONS

ELECTRICITY DEMAND

1.2.1 Table 26 presents projected total annual demand for Ireland, N. Ireland and GB, whereas Table 27 shows the peak demand for both the All-Island system and GB.

1.2.2 We use the EirGrid Generation Capacity Statement 2014-2023 for projections of total annual demand for Ireland and Northern Ireland out to 2023[68]. After that, the annual demand grows in line with Poyry's own assumptions. GB demand projections come from the National Grid Gone Green scenario[69].

1.2.3 We model each future year under 5 different historical weather and demand patters (2006-2010). Peak demand is therefore based on the historical demand profiles.

Table 26 – Total annual demand

TWh	2017	2020	2025	2030
Ireland	27.7	28.9	30.9	33.0
N. Ireland	9.3	9.5	9.9	10.2
All-Island	37.0	38.5	40.8	43.2
GB	344.8	342.6	346.3	357.1

Table 27 – Annual peak demand

GW	2017	2020	2025	2030
All-Island	*6.7*	*7.0*	*7.4*	*7.8*
GB	*60.5*	*60.0*	*60.7*	*62.6*

DS3 REVENUE

1.2.4 Other revenue streams (outside of the energy market) have an impact on investment

[67] This means that under a combination of system conditions there can be a higher LOLE. On average, however, the LOLE is equal or less than 8 hours

[68] All-Island Generation Capacity Adequacy Statement 2014-2023, Eirgrid&SONI

[69] UK Future Energy Scenarios, National Grid; We have however included CHP generation as part of the total electricity demand.

decisions, the type of new technologies deployed and bidding in the energy market. It is still unclear what the level of payments will be for system services under the DS3 programme. The exact level of the revenue realised by market participants may (and most likely will) have an impact on the energy market.

1.2.5 The potential revenues for different types of technologies from the DS3 programme are indicative and may differ from the ones presented here. We have based the (net) revenues for different technologies on the payments from Scenario E (as described in the TSO recommendations paper) and the costs from the KEMA DNV study. For OCGTs, we use the current value of €4.5/kW assumed for ancillary services payments for the BNE for the entire modelled period.

1.2.6 DS3 revenues are treated as a fixed annual payment towards all generators. Table 28 presents our assumed DS3 revenues.

Table 28 – DS3 revenue

Technology type	Equivalent annual payment (€/kW)
CCGT	7.3
OCGT	4.5
Other thermal	12.1
CHP	25.6
Hydro	28.7
Interconnector	47.9

GENERATION COSTS

7.6.28 Table 29 shows the assumed generation costs (capital expenditure and operating expenditure), as well as other economic parameters for the main technologies, used in modeling the two scenarios and estimating related costs

Table 29 – Generation costs and economic parameters for main technologies

		CCGT (Ireland)	CCGT (N.Ireland)	OCGT (Ireland)	OCGT (N.Ireland)	Coal	Onshore	Offshore	Biomass
2017	Opex (€/kW)	58	46	32	27	63	37	145	105
	Capex (€/kW)	840	840	629	647	1700	1324	2495	2539
	Construction years	2.5	2.5	2	2	4	2	3	3
	Economic lifetime	20	20	20	20	20	20	20	20
	WACC	9.0%	9.0%	8.5%	8.5%	9.5%	7.9%	9.6%	12.5%
2020 -2030	Opex (€/kW)	58	46	32	27	63	37	129	105
	Capex (€/kW)	840	840	629	647	1700	1305	2179	2474
	Construction years	2.5	2.5	2	2	4	2	3	3
	Economic lifetime	20	20	20	20	20	20	20	20
	WACC	9.0%	9.0%	8.5%	8.5%	9.5%	7.9%	9.6%	12.5%

GB CRM

1.2.7 Under all scenarios and sensitivities we assume the introduction of a CRM in GB from 2018 onwards. This takes the form of a capacity auction. The auction format is PAC where each generating unit[70] is paid the clearing price of the auction. New entrants are assumed to lock in the price from the first auction in which they participate in for 10 years upon commissioning. From then on they are treated as existing plants receiving the annual level of the capacity payment. Existing plants act as price takers being allowed to bid in a low price in the auctions. Modelling of the GB CRM is in line with the modelling methodology adopted by DECC in its latest impact assessment.

DAY-AHEAD MARKET PRICE CAP

1.2.8 Euphemia, the Day-Ahead market coupling algorithm, currently has a 3000€/MWh price cap. We assume that this price remains in place throughout the entirety of the modelled period. Therefore, our electricity modelling assumes that generating units cannot bid above this price cap.

1.3 BASE CASE A

1.3.1 This uses the fuel and carbon price assumptions from the 'Current Policies' scenario (IEA WEO 2013[71]). Coal is more favourable to gas as a fuel for power generation. This comes as a result of depressed carbon prices and high gas prices (rising up to around 38 €/MWh in 2030). Decarbonisation is based primarily on RES with national schemes continuing to support RES throughout the entirety of the modelled period. Renewables targets are met in 2020 in both the All-Island Market and GB. By 2030, RES penetration in the All-Island market reaches 52%.

70 Excluding units that receive other forms of support, such as ROCs or CfDs.

71 World Energy Outlook 2013, International Energy Agency

1.3.2 Assumptions for low carbon technologies in GB come from the National Grid 'Gone Green' scenario[72].

1.3.3 Table 30 compares the variable (full load) cost of a typical CCGT and a typical coal plant. Coal plants run ahead of CCGTs throughout the entirety of the modelled period.

Table 30 – Variable cost of gas and coal generation in Base Case A

real 2012 money	2017	2020	2025	2030
Gas variable cost (€/MWh, 2012 money)	67.0	70.5	74.6	81.9
Coal variable cost (€/MWh, 2012 money)	40.9	45.9	50.8	55.1

1.4 BASE CASE B

1.4.1 This scenario uses the fuel and carbon price assumptions from the 450 scenario (IEA WEO 2013). Gas-fired generation becomes more favourable compared with coal-fired in the long-term. Decarbonisation is delivered through a stronger EU ETS price and is not based solely on explicit RES support. Renewables targets are met in 2020 in both the All-Island Market and GB in 2020. RES penetration however slows down, and reaches 45% by 2030.

1.4.2 Assumptions for low carbon technologies in GB come from the National Grid Gone Green scenario out 2020 and from then on follow the Slow Progression scenario out to 2030[73].

1.4.3 Table 31 compares the variable (full load) cost of a typical CCGT and a typical coal plant.

Table 31 – Variable cost of a gas and coal in Base Case B

real 2012 money	2017	2020	2025	2030
Gas variable cost (€/MWh, 2012 money)	67.2	71.4	77.3	81.6
Coal variable cost (€/MWh, 2012 money)	47.2	57.2	77.4	96.7

[72] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/fes/Documents/

[73] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/fes/Documents/

2 APPENDIX: IMPLEMENTATION AND OPERATION COSTS FOR ENERGY

2.1.1 We have reviewed international best practice to identify the costs associated with the introduction of a new energy market design. This review included first hand evidence gathered from recent system procurement processes, such as those in Turkey and Romania, alongside desk based research. This desk based research focused on the 2006 Cost-Benefit Study of the Single Electricity Market[74]; the Intra Day Proposed Costs and Estimated Benefits report[75] and the Assessment of the Costs and Cost Savings of NETA compared with the England and Wales Pool[76].

2.1.2 All staff costs are based on an average salary of €35k /year77 for each market participant plus an estimate of the additional costs faced by employers such as superannuation and national insurance contributions etc. We estimate these contributions to be in the region of 20% of the salary78. This gives a total staff cost of €42k per member of staff.

COSTS TO MARKET PARTICIPANTS

2.1.3 Market participants will face a number of costs relating to the implementation of new Energy Trading Arrangements. An overview of the central estimate of the total costs across market participants is presented in Table 32, where these costs are based on 40 market participants.

Table 32 –Implementation and operation costs for Market Participants

	ADM (Option 1)	MPNV (Option 2)	MCM (Option 3)	GPNS (Option 4)
One off implementation				
System	€600k	€1m	€600k	€1m
Change costs	€1m			
Ongoing costs (annual costs)				
Ongoing systems	€500k/a			
Staff costs	€8m/a			

2.1.4 We have assumed that system costs will be split in two parts, the first will be the one off system costs and the second will be the ongoing maintenance.

74 http://www.detini.gov.uk/year_cost_benefit_study_of_the_single_electricity_market_-_a_final_report_for_niaer_and_cer__december_2006_.pdf

75 http://www.allislandproject.org/en/TS_Decision_Documents.aspx?article=7bc8db07-0493-4ba6-aa04-c885a2826c23

76 http://www.nao.org.uk/wp-content/uploads/2003/05/0203624.pdf

77 Source: The Earnings and Labour Cost Statistics published by the Central Statistics Office.

78 This percentage estimate is based on the current national insurance contribution of 13.8% (http://www.hmrc.gov.uk/rates/nic.htm) in the UK, with an equivalent figure of 11% in Ireland e.g. PRSI Class A employers (http://www.welfare.ie/en/Pages/1896_Pay-Related-Social-Insurance.aspx). In addition we have included an average pension contribution of 5%. This is based on UK statistics (http://www.ons.gov.uk/ons/rel/fi/occupational-pension-schemes-survey/2012/stb-opss-2012.html). We do not have a figure for the Irish market but expect it to be in a similar range. We have then rounded the contribution to 20% to account for any additional costs.

2.1.5 We have assumed the current back-office IT systems for invoicing etc. required by market participants are adequate for the all the options. As a result there will be no additional costs, even though there will be new products that will be invoiced. As a result we assume no additional cost.

2.1.6 All the central market systems for Forward trading (Financial and Physical), DAM, IDM and Balancing will be delivered with a standard user interface (typically through a web interface) to manage participation in the various markets. As a basic requirement, this means that there will be no additional costs for this.

2.1.7 However, for a market participant to be able to participate in all market timeframes and keep track of its trading and open positions, there will be a need for additional back-office functions.

2.1.8 The sophistication of system required will depend on the complexity of the portfolio of assets a market participant has. Some participants might operate more conservatively in the various markets and be able to manage this manually without any additional IT costs. Alternatively, some of the bigger market participants would like to have a more sophisticated system. The estimate of the range of costs based on examples from these systems is from €5k for a simplified Excel-solution to €150k for a full-fledged energy risk management system[79]. Our central estimate for a standard solution tool is €15k.

2.1.9 For Options 2 and 4, there will be an additional complexity to administer quite different bidding formats for both the Pool, as well as the other markets. This is estimated to be an additional €10k per market participant for these two options. This is both to cover for the additional complexity and also the fact that this will be a specialised solution for I-SEM that cannot be procured from a standard solution.

2.1.10 Ongoing System costs will reflect the need to maintain and update the IT system on an annual basis. We have estimated this cost to be €12k per annum per market participant. These costs will be incurred every year from 2017 to 2030. We have assumed that these costs will be consistent across the four options.

2.1.11 There will also be additional Staff Costs incurred by companies participating in the IDM. This is due to the nature of the continuous trading in this market. Our estimate is that all market participants would require an additional 5 full-time members of staff to ensure that the trading desk is continually manned on 24/7 basis. This is linked to whether the market participants already have resources available to act on their behalf on a 24/7 basis– for instance if you have 24-hour shifts in a local "control center", they might have the potential to perform this role. At the same time, smaller market participants might decide to participate in some

[79] This is based on quotes and examples from commercial international vendors supplying similar systems to other European markets participants

hours of the day, but not 24 hours. In the central estimate of market participant costs, we have assumed that all of the relevant market participants seek to employ an additional 5 full-time members of staff. As a result this estimate can be seen as the upper end of our forecast.

2.1.12 Other costs incurred by Market participants will include additional consultancy support to help prepare their risk and bidding strategies for participation in the new markets. As all options will include participation in the Forward, Day-ahead and Intraday timeframes, the cost will be similar for all options. We have estimated this to a one off cost of €30k (on average per market participant) for the first year of operation, and no further costs in the following years.

2.1.13 Table 33 summarises the annualised total cost to market participants for each of the energy trading options. There is a large range depending on the assumed number of market participants.

2.1.14 The figure of €7m in Table 33 is based on the central estimate of 40 market participants, with the large range reflecting the impact of assuming that the costs are incurred by 17 or by 64 market participants.

2.1.15 This range of market participants is based on the number of registered units currently participating in the SEM[80]. The lower value of 17 takes account of the registered parties who own the major thermal generation, while the 64 includes parties with no thermal generation e.g. individual wind generation, and suppliers with no generation. For the central estimates provided in this assessment we have assumed 40 market participants.

2.1.16 This range reflects the uncertainty around degree of active market participation by small parties, particularly windfarms. This figure also reflects the uncertainty surrounding those participants who are content to operate only within the pool (Options 2 and 4), and do not wish to actively take part in the forward markets. The impact of market design on incentives and opportunities to participate in the ex-ante markets should therefore be an important consideration in detailed design process.

Table 33 – Annualised costs for market participants for each of the consultation options (€m/a over period 2017-2030, real 2012 money, discount rate of 3.5%)

	Market Participant costs	
	Central estimate	Range
ADM (Option 1)	**€7m/a**	€3m/a to €12m/a
MPNV (Option 2)	**€7m/a**	€3m/a to €12m/a
MCM (Option 3)	**€7m/a**	€3m/a to €12m/a
GPNS (Option 4)	**€7m/a**	€3m/a to €12m/a

[80] For our assessment we have grouped the registered units by party ownership.

2.1.17 We have not quantified the possible change in costs related to credit cover and collateral related to participation in different market timeframes (with different settlement practices).

2.1.18 The trading undertaken in the DA, IDM and Balancing market will be based on firm trades that can be settled the day after the trade. This means the Billing Period for the settlement of physical power (not including potential capacity payments) can be moved to become daily rather than weekly. In addition, the settlement can be done on the Trading day (i.e. there is no need to wait for metered values).

2.1.19 This will give savings on Credit cover from today´s position for Option 3 where all physical trading is in the organized ex-ante markets. There may also be cost savings for Options 1 and 2, depending on the extent of physical trading in the organized ex-ante markets that emerges in those options.

2.1.20 In summary, market participants could benefit from a reduction in the Credit Cover periods from seven Working Days (moving from weekly to daily settlement) and being able to settle at the Trading Day, (not when metered values are available).

TSO AND MARKET OPERATOR COSTS

2.1.21 In this section we present an assessment of the implementation costs associated with the Market Operator (MO) and the Transmission system operator (TSO) delivering the required trading systems in the various options.

2.1.22 An overview of these costs is presented in Table 34.

2.1.23 Importantly we assume that the Market Operator will not purchase additional systems to facilitate trading the forwards market. The cost of setting up a Clearing House to run a forward market is prohibitively expensive, with an estimate of upwards of €1 billion. As a result we assume the Market Operator will sign up with an existing Clearing House to facilitate the forward market.

Table 34 –Non Market costs to the TSO and MO

	ADM (Option 1)	MPNV (Option 2)	MCM (Option 3)	GPNS (Option 4)
One off implementation				
All systems	€16.5m	€29.5m	€16.5m	€11.5m
Other implementation	€10m	€10m	€10m	€10m
Ongoing costs (annual costs)				
Ongoing systems	€1.7m	€2.5m	€1.7m	€2.5m
Staff costs	€630k/a			
Other costs	€12k/a			

2.1.24 A major cost for the TSO/MO will be the IT costs, and again these will be split in two

parts, the first will be the one off system costs and the second will be the ongoing maintenance.

2.1.25 For all options, systems for the DAM and IDM will need to be procured. The cost for these will be the same for all of the options. There are some various options for how this can be procured. There are essentially three potential solutions that could be implemented:

- Procure all systems and services as part of SEMO;
- Procure IT services from others, but maintain the SEMO as the market operator;
- Outsource all market operations to another market operator.

2.1.26 As these costs will not vary between the various options, the estimates are based on the first option; i.e. that SEMO will be maintained as the operator of the All-Island market (the NEMO). This decision is assumed to be the same across the not be different between the various energy trading options. The choice of the NEMO is strictly not part of the HLD, but will have an effect on the detailed design and implementation phase.

2.1.27 The cost for the DAM and IDM systems is estimated to be€2.5m based on the results of two similar procurement processes in Turkey and Romania.

2.1.28 The cost for becoming part of the PCR project and therefore being part of the European DAM is set to a cost of €1m (based on current estimate of participation costs).

2.1.29 The cost of the Balancing Market will differ between the options. The implementation cost of the Balancing Market for option 1 and 3 is estimated at a cost of €13m based on the cost of upgrade of the central EMS and balancing systems at energinet.dk (the Danish TSO). These are indicative estimates for the cost of the balancing systems[81] and the real costs will be discovered as part of the procurement process as part of the implementation project and are highly dependent on the level of customisation that is required.

2.1.30 This results in overall upfront systems costs for Option 1 and Option 3 of €16.5m, consisting of:

- €2.5m for the DAM and IDM systems
- €1m for the costs of participating in the PCR; and
- €13m for the cost of the balancing mechanism systems.

[81] The reason for highlighting that these are estimates is due to the fact that all reference procurement processes for a balancing market in the relevant cases are part of a"bundled" procurement where the balancing market is part of a bigger solution that for instance in Denmark also included an upgrade of their EMS system; in Norway it included all market systems including the ancillary services procurement, settlement and other functions.

2.1.31 As Option 2 and Option 4 will retain the major functions of the current system, the costs will be the required adaptations to the current market systems.

2.1.32 The lowest implementation cost for balancing will be for option 4 as there will only be small changes needed to the existing system to cover the new functionality. The cost of the required changes is estimated to be €8m, mainly to cover for the Net Settlement process and the change in the management of interconnectors – this estimate is based on the estimated cost of implementing the Intraday modification in the current SEM systems[82] - however, it is uncertain how many rebidding windows would be needed, which could have a significant impact on the cost.

2.1.33 Therefore, the overall upfront system costs for Option 4 are €11.5m consisting of:

- €2.5m for the DAM and IDM systems;
- €1m for the costs of participating in the PCR; and
- €8m for the change to the pool-based systems.

2.1.34 Finally option 2 will require substantial changes to the current systems as essentially it will require changing the systems from being a Gross Pool to a Net Pool. These implementation costs are estimated to be in the order of two times greater than the cost of developing the balancing market. This cost forms part of the 'All systems' cost for the Mandatory ex-post Pool for Net Volumes and is estimated to be €26m. This results in total system costs for option 2 of €29.5m consisting of:

- €2.5m for the DAM and IDM systems
- €1m for the costs of participating in the PCR; and
- €13m for the introduction of a net pool mechanism.

2.1.35 A second major one-off cost impacting across all options relates to the contractual and consulting costs associated with setting up cost pre go-live. We estimate these costs to be in region of €10m.

2.1.36 Ongoing system costs include an estimated €500k per annum to maintain and operate the DAM and IDM for all energy trading options. The forward market is assumed to be operated by an existing market operator and therefore be of no cost for the markets.

2.1.37 In addition the ongoing system costs also include balancing. These costs will differ between the various options:

- For Option 1 and Option 3 these are estimated to be €1.2mper annum to maintain and operate the balancing market.
- For Option 4 this is estimated to be in line with the current system costs, €2m per annum[83].

[82] This estimate is based on the SEMO functional costs (€3.4m) plus the SEMO Hardware and Software Costs (€4.6m) as set out in the Proposed Costs and Estimation of Benefits of the Introduction of additional Intra Day Gate Closures in the SEM.

[83] As per the SEM price control, ref SEM-13-054

- For Option 2, the estimated cost will be the same as for the current system costs, i.e. €2m per annum.

2.1.38 The TSO/MO will also incur additional Opex costs associated with Payroll, facilities and insurance, professional fees, general and administration and corporate services. These costs (which are currently around €8m/year[84]) are assumed to be identical across all the four energy trading options. As such, these costs have not been included in this assessment.

2.1.39 The MO will require, on average, three operators on a 24/7 basis employed specifically in relation to the IDM. This means they will have a requirement for 15 new member of staff, on the assumption that 5 additional staff members are required to ensure one operator on a 24/7 basis.

2.1.40 Finally the 'Other' ongoing costs incurred by the Market Operator are estimated to be €12k per year. These costs cover a range of miscellaneous items such as additional consultancy costs. These costs are consistent across all energy trading options.

2.1.41 Table 35 shows the Market Operator costs annualised over a 14-year period (2017-2030) using an assumed discount rate of 3.5%. The majority of these costs relate to the design, capital and implementation of new IT systems to manage and deliver the new trading arrangements.

Table 35 – Annualised cost for the Market Operator for each of the energy trading options (€m/a over period 2017-2030, real 2012 money, discount rate of 3.5%)

	Market Operator costs
ADM (Option 1)	€4m/a
MPNV (Option 2)	€6m/a
MCM (Option 3)	€4m/a
GPNS (Option 4)	€4m/a

REGULATORY DESIGN AND ADMINISTRATION COSTS

2.1.42 The final set of costs relate to the regulatory design and administration costs incurred by the Regulatory Authorities (RAs). The design costs include any consultancy support used in the design of the project, while the administration costs include any additional costs of market monitoring and staffing.

2.1.43 An overview of these costs is presented in Table 36.

[84] As per the SEM price control, ref SEM-13-054

Table 36 –Non Market costs to the Regulatory Authorities

	ADM (Option 1)	MPNV (Option 2)	MCM (Option 3)	GPNS (Option 4)
One off implementation				
Design Costs	€5m			
Ongoing costs (annual costs)				
External support	€200k/a			
Administrative costs	€96k/a			

2.1.44 Upfront design costs include the costs incurred by the RAs in obtaining consultancy in the design of I-SEM prior to go live. This includes the costs of the HLD process and the estimated costs off the detailed design phase. The costs are based on actual costs incurred during the development of the SEM. We estimate these costs to be €5m for each of options.

2.1.45 Ongoing external support will include the costs incurred by the RAs in obtaining consultancy advice from lawyers, economists, IT specialists etc., and including the costs of undertaking industry consultation. These costs will be incurred following go-live of I-SEM.

2.1.46 The estimate for the ongoing external support for all options is equivalent to €200k per annum. These also cover the cost incurred to cover participation in the European forums to represent the I-SEM. These costs will be consistent across all four options for the energy trading arrangements.

2.1.47 Administrative costs relate to the cost of market monitoring and surveillance of the energy trading in the new markets. We have estimated that the costs will be €96k per annum (e.g. 2 members of staff at €42k and €12k a year ongoing costs related to systems, legal, licensing and legislation).

2.1.48 We have assumed these costs will be consistent across all four energy trading options.

2.1.49 Table 37 shows the annualised RA costs over a 14-year period (2017-2030) using an assumed discount rate of 3.5%.

Table 37 – Annualised cost for the Regulatory Authorities for each of the energy trading options (€m/a over period 2017-2030, real 2012 money, discount rate of 3.5%)

	Regulatory Authorities
ADM (Option 1)	€1m/a
MPNV (Option 2)	€1m/a
MCM (Option 3)	€1m/a
GPNS (Option 4)	€1m/a

3 APPENDIX: IMPLEMENTATION AND OPERATION COSTS FOR CRM

3.1.1 This assessment is primarily informed by published figures from DECC (as part of their CRM Cost benefit Analysis process[85]) and Ofgem (as part of the Gas Significant Code Review[86], which looked at the costs of introducing a demand-side auction).

3.1.2 All staff costs are based on an average salary of €35k /year[87] for each market participant plus an estimate of the additional costs faced by employers such as superannuation and national insurance contributions etc. We estimate these contributions to be in the region of 20% of the salary[88]. This gives a total staff cost of €42k per member of staff.

COSTS TO MARKET PARTICIPANTS

3.1.3 We have assumed that a move to a quantity-based CRM would lead to additional ongoing costs for market participants, largely reflecting the fact that a need for greater active involvement (e.g. bidding for initial contract allocation and subsequent retrading) than under a price-based CRM (which is more administrative).

3.1.4 An overview of the estimated costs for market participants is presented in Table 38 We have assumed a range of 17 to 48 separate market participants. This range is based on the number of registered units currently participating in the SEM[89]. The lower value of 17 takes account of the registered parties who own the major thermal generation, while the 48 includes parties with no thermal generation e.g. wind farms. For the point estimates provided in this assessment, we have assumed 30 market participants.

3.1.5 This range reflects the uncertainty around degree of active market participation by small parties, particularly windfarms. The impact on participation should therefore be an important consideration in detailed design process.

85 https://www.gov.uk/government/uploads/system/uploads/yearttachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

86 https://www.ofgem.gov.uk/ofgem-publications/85990/poyrygasscrdsrcbafinalreportv20.pdf

87 Source: The Earnings and Labour Cost Statistics published by the Central Statistics Office.

88 This percentage estimate is based on the current national insurance contribution of 13.8% (http://www.hmrc.gov.uk/rates/nic.htm) in the UK, with an equivalent figure of 11% in Ireland e.g. PRSI Class A employers (http://www.welfare.ie/en/Pages/1896_Pay-Related-Social-Insurance.aspx). In addition we have included an average pension contribution of 5%. This is based on UK statistics (http://www.ons.gov.uk/ons/rel/fi/occupational-pension-schemes-survey/2012/stb-opss-2012.html). We do not have a figure for the Irish market but expect it to be in a similar range. We have then rounded the contribution to 20% to account for any additional costs.

89 Using registered units as a starting position, we first grouped the units by party ownership and secondly removed all the supplier units.

Table 38 – Implementation and operation costs for Market Participants (2017-2030)

	Long Term price-based	Short Term price-based	Capacity auctions	Reliability Option
One off implementation				
System	-	-	€720k	
Preparation of bids	-	-	€270k	
Ongoing (annual costs)				
Systems	€360k/a			
Staff costs	-	-	€2.5m/a	
External advice	-	-	€360k/a	

3.1.6 System costs will form a substantial proportion of the costs faced by market Participants. For example, these costs cover both the one off costs of implementing/upgrading IT systems when required, and the annual ongoing costs of supporting IT systems.

3.1.7 We assume there is no requirement for specific system upgrades for market participants under the price-based CRMs.

3.1.8 In the event of a move to a quantity-based CRM, we assume that new systems will be required to manage the new processes – e.g. submission of bids, retrading (retrading of capacity rights) etc. In this case we have assumed a one off implementation cost per market participants of €24k[90]. This figure is based on the estimated annual transaction costs (estimated at around £10k) of participating in an auction, calculated as part of the Ofgem Gas SCR Assessment[91]. In the first year we have assumed this cost will be doubled to take account of the one off implementation costs. This approach reflects the methodology outlines by DECC in its calculation of the administrative costs to business in its October 2013 impact assessment.

3.1.9 We have also included an upfront cost per participant for them to build the internal capability to participate in the quantity-based CRMs (e.g. staff training, external advice etc.). This estimate is based on the cost of employing a consultancy to provide the relevant training. We estimate that this training would be in the region of €9k. This is based on the external support element of the transaction costs estimated in the Ofgem Gas SCR Assessment[92].

3.1.10 Ongoing System costs will reflect the need to maintain and update the system on an annual basis. We have estimated this cost to be €12k per annum per market

[90] This is an estimate based on the costs calculated in the Ofgem Gas SCR impact assessment.

[91] This figure does not include any additional cost of retrading. This is because we are uncertain as to the magnitude of this cost.

[92] https://www.gov.uk/government/uploads/system/uploads/yearttachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

participant, which is assumed to stay constant in real terms over the period. The costs will be incurred across all four of the CRM options. This figure is based on the estimated average annual transaction costs (estimated at around £10k) of participating in an auction. This figure was calculated as part of the Ofgem Gas SCR Assessment[93], and is based on 50% of the one off system costs.

3.1.11 For the price-based schemes, **additional** staff costs are assumed to be zero as there is only a limited change to general interaction on administrative issues (and possible design changes) with the Central agency and RAs. We assume existing staff are able to adapt to the new price-based schemes.

3.1.12 For the quantity-based CRMs we assume that in addition to the general administrative workload, market participants will require on average one additional member of full time staff (across the year). These members of staff will be required to manage the additional processes such as submission of bids into initial contract allocation and any subsequent retrading.

3.1.13 Additional external advice costs will also be incurred by market participants in the quantity-based CRMs. This will include work and support to help prepare and submit bids etc. for the contract allocation, as well as help on contractual and legal arrangements, e.g. contracts and agreements between the market participant and the Central Agency and/or the Regulatory Authorities.

3.1.14 These costs are estimated at €12k/year per market participant. This figure is based on the estimated average annual transaction costs (estimated at around £10k) of participating in an auction. Again this is based on the Ofgem Gas SCR assessment.

3.1.15 Table 39 shows the central estimate of the annualised costs to market participants over a 14-year assessment period (2017-2030) using an assumed discount rate of 3.5%. The central estimate in Table 39 is based on 30 market participants. The range ishows the impact of using either end of the range of estimated number of market participants (i.e 17 participants or 48 participants).

Table 39 – Annualised cost for the Market Participants for each of the CRM options (€m/a over period 2017-2030, real 2012 money, discount rate of 3.5%)

	Market Participant costs	
	Central estimate	Range
Long Term price-based	**€<1m/a**	€0m/a to €1m/a
Short Term price-based	**€<1m/a**	€0m/a to €1m/a
Capacity auctions	**€2m/a**	€1m/a to €3m/a
Reliability Option	**€2m/a**	€1m/a to €3m/a

[93] This figure does not include any additional cost of retrading. This is because we are uncertain as to the magnitude of this cost.

CENTRAL AGENCY COSTS

3.1.16 In this section we present an assessment of the implementation costs associated with the Central Agency responsible for delivering and administering the CRM. An overview of these costs are presented in Table 40.

Table 40 – Non Market costs to the Central Agency (€m)

	Long Term price-based	Short Term price-based	Capacity auctions	Reliability Option
One off implementation				
Systems	-	-	€16m	
Ongoing (annual costs)				
Systems	€2m			
Staff costs	-	-	€100k/a	

3.1.17 A major cost for the central agency will be the systems costs, both the one off implementation and set-up costs and the ongoing maintenance.

3.1.18 In the event of a quantity-based CRM design being implemented we have assumed a completely new IT system and supporting infrastructure will be required. The estimated cost of setting up this IT system and the supporting infrastructure is €16m. This is consistent with DECC's estimate of the implementation costs for the proposed quantity-based CRM in GB[94]. For the price-based CRMs we have assumed the existing IT system will effectively be maintained.

3.1.19 We have assumed the current systems can be used under both priced based schemes and as a result no additional costs are incurred

3.1.20 Ongoing system costs are estimated to be €2.4m per annum for the central agency to maintain and operate the CRM. We assume these costs are constant across all the CRM options. Again this is based on DECC's estimate of the ongoing institutional costs for the proposed quantity-based CRM in GB[95]. These costs are consistent across all CRM options.

3.1.21 For the quantity-based schemes we have also assumed that the central agency will require, on average, two members of full time staff employed specifically in relation to the CRM.

3.1.22 For the price-based schemes, **additional** staff costs are assumed to be zero as there

[94] https://www.gov.uk/government/uploads/system/uploads/yearttachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

[95] https://www.gov.uk/government/uploads/system/uploads/yearttachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

is only a limited change to the current scheme. We assume existing staff are able to adapt to the new price-based schemes.

3.1.23 Table 41 shows the annualised costs for the Central Agency over a 14-year period (2017-2030) using an assumed discount rate of 3.5%. The majority of these costs relate to the costs of systems and supporting infrastructure to manage and deliver the CRM. The higher cost for the quantity-based scheme is driven by the need for new systems, represented as a large one-off implementation cost for the IT systems.

Table 41 – Annualised cost for the Central Agency for each of the CRMs (€m/a over period 2017-2030, real 2012 money, discount rate of 3.5%)

	Central Agency
Long Term price-based	€2m/a
Short Term price-based	€2m/a
Capacity auctions	€3m/a
Reliability Option	€3m/a

REGULATORY DESIGN AND ADMINISTRATION COSTS

3.1.24 The final set of costs relate to the regulatory design and administration costs incurred by the Regulatory Authorities (RAs). The design costs include any costs of external advice while the administration costs include staffing and any additional costs of market monitoring as a result of the CRM.

3.1.25 An overview of these costs are presented in Table 42.

Table 42 – Non Market costs to the Regulatory Authorities

	Long Term price-based	Short Term price-based	Capacity auctions	Reliability Option
One off implementation				
Regulatory Design	€2m		€4m	
Ongoing (annual costs)				
Design costs	€50k annually plus an additional €250k every 5 years			
Administrative costs			€42k/a	

3.1.26 We have estimated the upfront design costs of the CRMs. These costs will be incurred under all CRMs to different extents. Although, there would be a need to review the price-based schemes (e.g. to ensure compatibility with the Target Model amongst other things), the upfront design costs are expected to be larger in moving to a quantity-based scheme. We have assumed €2m for the price-based schemes and €4m for the quantity-based schemes. This is based on incurred costs during the HLD design and the anticipated costs of the detailed design process.

3.1.27 The ongoing design costs including the costs incurred by the RAs in obtaining consultancy advice from lawyers, economists, IT specialists etc., and including the costs of undertaking industry consultation. We estimate that this will be an annual cost of €50k. In addition, we have assumed that there will be a €250k study on the effectiveness of the scheme every 5 years. These costs are assumed to be the same for all of the schemes.

3.1.28 Administrative costs relate to the cost to the RAs of overseeing the operation of the CRM. For the quantity-based schemes, we have estimated that there will need to be one additional member of staff.

3.1.29 For the price-based schemes, **additional** staff costs are assumed to be zero as there is only a limited change to the current scheme. We assume existing staff are able to adapt to the new price-based schemes.

3.1.30 Table 43 shows the annualised costs for the RAs over a 14-year period (2017-2030) using an assumed discount rate of 3.5%.

Table 43 – Annualised cost for the Regulatory Authorities for each of the CRMs (€m/a over period 2017-2030, real 2012 money, discount rate of 3.5%)

	Regulatory Authorities
Long Term price-based	<€1m/a
Short Term price-based	<€1m/a
Capacity auctions	<€1m/a
Reliability Option	<€1m/a