DS3:
System Services Consultation
Finance Arrangements

Contents

Executive Summary

The power system of Ireland and Northern Ireland is in a period of transition driven by national and European policy, particularly with respect to renewable energy. This transition will result in a fundamental change to the power system generation portfolio, the operational characteristics of the system under both steady state and transient conditions and it will significantly transform the requirement for and composition of essential system services.

EirGrid and SONI have put in place a multi-year, multi-stakeholder programme of work, "Delivering a Secure Sustainable System" (DS3), to address these challenges. EirGrid and SONI also have licence and statutory obligations to ensure sufficient system services are available to enable efficient, reliable and secure power system operation. In earlier papers, the TSOs have established the need for system services through detailed studies and technical analysis, and also proposed new products which address the emerging challenges associated with achieving the governments' renewable energy policy objectives.

This consultation paper is the third part of a multi-stage consultation process within the DS3 Programme. The paper seeks views on a proposed methodology for determining the cumulative benefit of the required new system services to the electricity industry on the island of Ireland. It provides an indication of capital costs which may be incurred to provide these new services. Views are also sought on four methods, identified by the TSOs, by which the proposed System Services revenue might be allocated between each of the proposed system services products.

Using the methodology proposed by the TSOs over a range of portfolio investment, interconnection and fuel price sensitivities, the benefit from procuring the appropriate level of system services in 2020 to efficiently operate the power system with high instantaneous penetrations of wind is €295m per annum. For clarity, this is separate from the existing €60m currently paid for Harmonised Ancillary Services (HAS), which is subject to annual SEMC approval. The calculated benefit is based on an improved operational capability resulting from the new System Services which lowers curtailment levels on windfarms, reducing aggregate system dispatch balancing costs. In addition, there are associated benefits with lower energy production costs arising from increased installed wind because of the enhanced operational capability (and the resultant lower curtailment levels). The extent to which the calculated benefit of the new System Services is paid to the service providers is a SEM Committee decision.

There are, in addition, a range of external factors that could be considered in determining the value of System Services but would not be regarded as appropriate for the TSOs to include in the current benefit calculation, including, for example emissions trading benefits and potential reduced penalties for not meeting binding RES targets. These externalities will form part of the Regulators' final considerations before the new System Services structure is adopted.

The additional costs which may be incurred by potential providers include capital expenditure or impacts on the operational efficiency of the technology. The TSOs' view on these costs has been assisted by data provided by DNV KEMA. The total capital cost figures were estimated to be €535m for a generator investment scenario solution and €1,206m for a network investment scenario solution.

The TSOs' view is that the final figure allocated to service providers should lie between the cumulative benefit figure and the possible costs incurred taking into account factors such as the cost to the consumer, the financial risks associated with the implemented remuneration arrangements and the need for an incentive for potential providers.

In determining the method by which the proposed System Services revenue might be allocated between each of the proposed system services products, the TSOs express a preference for Option 3 which is based on calculating the relative value of the products. The relative values could then be used to weight the allocation of the system service money between the products.

In this paper the TSOs show, through the analysis conducted, why dispatch-dependent[1] payments (combined with rates fixed over a number of years) are recommended for most of the products. The TSOs consider that this represents the best compromise between providing the necessary certainty for investors, ensuring the efficacy of the incentive to manage the identified operational issues and minimising the final cost to the consumer. In particular, it minimises the impact on the Capacity Payment Mechanism (CPM), aids forecasting and protects consumers from excessive costs. An illustration is also presented which shows the money assigned to system services would come partly from a reduction in the total capacity pot and partly from a net cost increase to the consumer.

The TSOs also confirm that they will be recommending Bilateral Contracts to the SEM Committee (SEMC) for the new services, broadly similar to the existing Harmonised Ancillary Services contracts, with payments for new System Services based on Regulatory-approved rates. To balance predictability of income for providers with financial prudence in terms of costs borne by the end consumer, the TSOs will also recommend that these rates should be reviewed on a 3 to 5 year basis rather than the annual arrangements currently used for reviewing the existing Ancillary Services.

An updated section on the proposed new products which adds detail and takes account of points raised by the respondents to the previous papers is included at the end of the paper together with further examples provided in the Appendices.

While the TSOs are interested in views on all aspects of this consultation paper we specifically wish to collect views on the following questions:

1. Do you agree that the proposed value based approach to informing the amount of funding available for System Services is necessary and appropriate to deliver the required services to achieve the renewable targets?
2. Do you agree with the proposed methodology for determining the aggregate available pot for System Services?
3. To what extent, if any, should the capital costs inform the decision regarding future system services?
4. Which of the four methods outlined to allocate the funds between the System Services products would you prefer or is there another approach which should be considered?
5. Is the rationale for proposing dispatch-dependent payments clear?
6. Is there further justification, not included in earlier consultation responses, for adopting a more capability-based approach?
7. Are the proposed general contractual and payment arrangements clear?

All responses received to the current paper will be considered by the TSOs who will then develop and submit a set of recommendations to the Regulatory Authorities in Q1, 2013. The SEM Committee has indicated its intent to consult on a proposed decision following consideration of the suite of TSO recommendations.

[1] The previous consultation discussed capability, dispatch-dependent and utilisation based products

1 Introduction & Context

1.1 Traditional Power System Challenges

The evolution of electricity power systems has had a transformational impact on society in the 20th century. During this period, generators were based on three phase alternating current synchronous machines with steam and gas turbines, or more recently a mixture of both, as prime movers. These generators tended to be reliable, reasonably predictable and naturally provided many of the extra requirements (e.g. reactive power, inertia, fault current and controllable output) that are required to securely and efficiently generate and transmit electricity in a synchronous power system, while at the same time facilitating the resilience of the system.

In previously published technical reports and consultation papers – "Facilitation of Renewables" (FoR)[2], "Ensuring a Secure, Sustainable Power System"[3], "Delivering a Secure, Sustainable, System" (DS3) – Eirgrid and SONI (the TSOs) have shown that the behaviour of the power system in Ireland and Northern Ireland will significantly change with the significant increase in non-synchronous generators connected to the system along with the corresponding reduction in traditional types of generator. A significant technical step change in approach is essential if the government targets for substantial increases in volumes of renewable sources of energy in electricity (RES-E) is to be achieved without compromising the core system resilience. These studies identified four fundamentally new technical challenges to the system that are required to be effectively addressed:

- Management of Rate of Change of Frequency (RoCoF) following large energy imbalances in the power system;
- Management of steady state reactive power as on-line synchronous generation is replaced by non-synchronous generation, much of which is located in remote areas of the system, and half of which is connected to the distribution system;
- Management of increased variability and uncertainty over multiple time frames leading to increased system ramping requirements with an associated increase in need for these capabilities; and
- Management of system synchronicity at high levels of non-synchronous penetration.

These challenges are in addition to the traditional ones which include system black start capability and managing the minimum frequency following the loss of a credible maximum in-feed on the island of Ireland. One of the critical success factors in managing these challenges is to ensure that the entire system portfolio of generation and demand side have the necessary capabilities and are utilised in an appropriate manner.

1.2 Context

Government renewable policies are also impacting on the design and implementation of energy markets and associated regulation. At a European level there is considerable debate regarding how to design a competitive energy market which can deliver on the stated European RES-E targets. There is a general acceptance that considerable capital will be required to invest in the build out of the necessary RES-E and complementary plant. Mobilisation of investors and the need for appropriate levels of financial certainty has also been widely recognised as imperative. Most of the discussion on how to achieve these objectives is centred on how to pay for the necessary enhanced

[2] "Facilitation of Renewables", Work package 3, EirGrid-SONI, June 2010,ww.eirgrid.com/media/FacilitationRenewablesFinalStudyReport.pdf

[3] "Ensuring a Secure, Sustainable Power System", EirGrid-SONI, July 2011, www.eirgrid.com/media/Ensuring_a_Secure_Reliable_and_Efficient_Power_System_Report.pdf

system flexibility. There is, however, no clear consensus so far regarding how the financial certainty can be best achieved. Capacity Payments have been considered by several Member States[4]. This view appears to be primarily driven by existing conventional plant that see higher risks, more volatile pricing and a reduction in operating revenue going forward. In addition, there is discussion about the appropriateness of long term RES-E direct (financial and tariff) and indirect (priority dispatch and access) supports and when, if ever, to phase them out or alter them. It is in this international context that the TSOs are examining the way forward for system services.

This consultation paper is the third part of a multi-stage consultation process within the System Services Review workstream of the “Delivering a Secure Sustainable System” (DS3) Programme. The Programme was established to address the emerging power system challenges associated with achieving the government renewable energy policy objectives. EirGrid and SONI have licence and/or statutory obligations to ensure sufficient system services are available to enable efficient, reliable and secure power system operation.

Generators are obligated under the Grid Codes to provide certain levels of System Services. It could be argued that the provision of System Services should be a mandatory requirement for participation in the energy market, rather than being separately remunerated. However, mandatory only provision would be likely to result in only the minimum Grid Code required levels of service being provided without necessarily the requisite level of reliability. Another view would suggest that, in moving to a world where the System Services become short or scarce, it may be more efficient to develop mechanisms to reveal the cost of provision thus incentivising the efficient choice of alternative methods of provision.

As indicated by the studies carried out to date, greater capabilities than are defined in the current Grid Codes are required in order for the renewable targets to be achieved. At present, payments for System Services are small relative to other payment streams in the wholesale electricity market and have been loosely related to the cost of this basic service provision. As such, they do not provide a strong signal for future investment but they have proved to be adequate in maintaining levels of system services from the existing providers to meet the needs of the current system. The TSOs therefore consider that the existing approach will not be sufficient to ensure provision of the required level of new services to support the electricity system by 2020.

To achieve the government renewable energy policy objectives, a transformational change in plant portfolio and operational policies is required. Essentially through the detailed studies[2,3] conducted, a range of technical issues related to different operating regimes have been identified. To address these emerging operational deficiencies or “scarcities”, there may be merit in incentivising investment to address these issues. This can best be delivered by a combination of Grid Code changes and a paradigm shift in the way System Services payments are assessed. However, this should only be done, as stated by the Regulatory Authorities, if it is of benefit to the final consumer. In essence what quantifiable value do these System Services bring to the consumer?

Previous TSO papers have developed the need for and the design of products to incentivise the operational capability to manage the new challenges outlined. This paper will consider the remaining high level questions:

- How do you determine the benefit of provision of the necessary system services in an electricity industry context?
- What incremental costs are potentially incurred in delivering the necessary system services?

[4] At the time of writing there were discussions on going on Capacity Payments in France, Great Britain, Italy and Spain.

- How do you determine the allocation of this benefit between consumers and revenue for System Services Providers?
- How do you determine the allocation of this revenue between various products?

It should be noted that this paper does not address proposed levels of individual product rates for existing and new system services.

As part of the current consultation, the TSOs will offer to hold bilateral discussions with individual Service Providers, during the consultation period. Following a review of the responses to this third consultation, the TSOs will submit a set of final recommendations to the Regulatory Authorities. The SEM Committee has indicated its intent to consult on a proposed decision following consideration of the suite of TSO recommendations.

While views and comments are invited regarding all aspects of this document, the TSOs are particularly interested in your views on the proposed financial arrangements, the remuneration approach and contractual arrangements. Responses should be sent to:

DS3@eirgrid.com or DS3@soni.ltd.uk by Wednesday, 13th February 2013

It would be helpful if responses are not confidential. If confidentiality is required, this should be made clear in the response. Please note that, in any event, all responses will be shared with the Regulatory Authorities.

1.3 System Services Review: Responses to June 2012 System Services Consultation Paper[5]

The TSOs published the second System Services consultation paper in June 2012 as part of the DS3 System Services multi-stage consultation process. This was followed by an Industry Forum on the 4th July 2012 in Dundalk where the industry and other interested parties had the opportunity to learn about the proposals and seek clarity on any specific items.

After an eight-week consultation period, 26 responses were received. Most of these responses were from Generators or Generator affiliations. The remainder were from demand affiliations and academia.

Overall there was a very positive response to the need for the proposed new products. Most respondents indicated that the product descriptions were clear although some sought specific clarification, particularly regarding unusual aspects of their plant or equipment and how the products affected them. One respondent requested a check to see if the 8-hour ramping product could be better served by a negligible increase in scheduling costs as they considered that this may allow further incentivisation of the one hour and three hour ramping products. In addition, some respondents proposed product refinements and definition revisions that have been incorporated into the final proposed product designs.

A number of respondents made it very clear that while they were happy to respond regarding the new products and contractual arrangements they would withhold their final support until they had clarity regarding the financial arrangements supporting these new services. There was also a strong message from several companies expressing deep concern about the statements regarding funding arrangements in the SEM Committee Cover Note (SEM-12-035), which was issued at the same time as the consultation paper.

There was broad support for a remuneration approach related to the value to the system rather than a cost-plus basis. Most respondents agreed that bilateral contracts were the pragmatic way forward although a few expressed a strong support for a tender process. Payments based on Capability were favoured by many respondents as this was viewed as being much more helpful in making investment decisions. Most respondents indicated that the contracts should be long term and payment rates for services should be set for a period (many proposing at least 7 years) if the intention was to incentivise investment without incurring additional or excessive funding costs. There was also general acceptance that payments should be performance-related, but a range of views were expressed regarding how this should be achieved.

Other respondents' comments have been considered and influenced the drafting of sections 5-8 of this paper.

2 Value of System Services to the Electricity System

To date, under the "Harmonised Ancillary Services" (HAS) arrangements, the payments have been associated with the provision of the necessary services to enable the operation of a safe, secure and reliable power system. The basis of these payments has been loosely related to the cost of this basic service provision, estimated by the TSOs and recommended annually to the SEMC for approval. Many of these services have been inherently provided by the fundamental principles and design of three phase alternating current synchronous generators.

There is a common belief, reflected in the increasing focus in national, European and global energy policy, that accommodating increased renewable generation will benefit consumers and society. This scenario requires new products and system services as previously described but also requires that the current level of power system security is at least maintained. Many of the inherent services provided by synchronous generators unless strongly incentivised will not be available in the high wind generation scenario to maintain system security. As a consequence, there is a need to fundamentally review the valuation paradigm for system services. The key question is: how should you value these additional system services? In principle, the chosen mechanism should, at a minimum, ensure that any increased payments for system services are off-set by at least similar savings to the consumers. The recent SEM Committee cover note (SEM-12-035) clearly outlines that any increases in System Services levels need to be such that the consumer benefits.

The FoR[6] and subsequent studies have indicated that it will only be possible to securely operate the power system by addressing the four main challenges highlighted in Section 1.1. Several metrics were examined during the FoR to aggregate these issues into an all-encompassing, easily understandable metric. The most appropriate was found to be the System Non-Synchronous Penetration (SNSP) level. It was found that for the current system the prudent maximum SNSP level of 50% should be observed, but that if mitigation measures were put in place, a real time operational limit of 75% SNSP would be possible. Essentially, if the system evolved with the necessary system services then the system could be operated in a manner that could efficiently and securely meet the RES-E targets. The DS3 program has been put in place to facilitate this evolution.

New system services and an enhanced portfolio capability are an essential component of being able to move from the current maximum SNSP limit of 50% to a future limit of 75%. Previous studies[6] and the analysis presented in this paper indicates that moving to 75% SNSP results in reduced curtailment levels and lower dispatch balancing costs.

Based on this the TSOs initially considered two separate methodologies, described in section 2.1 below, that could be used to determine the benefit of System Services. This approach provides an upper limit of the value of System Services but does not indicate the allocation of these benefits between service providers and consumers which will ultimately be a decision for the SEM Committee.

- Do you agree that the proposed value based approach to informing the amount of funding available for System Services is necessary and appropriate to deliver the required services to achieve the renewable targets?

[6] http://www.eirgrid.com/renewables/facilitationofrenewables/

2.1 Methodology Overview

In the first valuation method considered, it is assumed that windfarms will only build and the Renewable targets will only be achieved if the industry is certain that the level of curtailment of RES-E, particularly windfarms, is low enough. Low curtailment levels are dependent on the adoption of new system services and the transition from 50% SNSP to 75% SNSP. To quantify the benefit of the system services to the electricity consumer in this method, a comparison is made between the total production costs for the case without any additional RES-E investment (and a 50% SNSP limit) and the case where assumed investment to meet the government targets is made (with a 75% SNSP limit).

The second valuation method assumes that the build of RES-E, particularly windfarms, will occur irrespective of the predicated level of curtailment and is fundamentally driven by externalities – direct (REFIT and ROCs) and indirect (priority dispatch and access) supports. The introduction of the additional system services facilitates increasing the SNSP limit from 50% to 75%, with a consequential reduction in dispatch balancing costs. In this case, the benefit to the electricity consumer is estimated by comparing the dispatch balancing costs for a 50% SNSP limit with those for a 75% SNSP limit.

Both methods have limitations with respect to determining a particular benefit of System Services. With the first method it could be argued that there is an element of overvaluation as the build of new RES-E will be in part due to the direct and indirect supports in place. In addition, some of the value that is derived is likely to be needed to offset the capital investment required for the RES-E build out in the first place. On the other hand the second valuation method underestimates the benefit of system services. This is because the build of new RES-E is completely disassociated with new System Services.

In practice, the benefit of system services lies somewhere between the values identified by the above two methods. Rather than considering these two methods independently, a combined approach is proposed by the TSOs that captures the direct Dispatch Balancing Costs savings associated with enhanced operational capability with the indirect effect of market cost savings due to higher levels of installed wind. It is assumed that, while curtailment levels remain low, a portion of the required RES-E will build due to external supports. The remaining RES-E build will be contingent on reduced curtailment levels that occur when new system services are in place and the SNSP limit can be raised to 75%. This combined approach, and the results of the analysis, are discussed further in section 3 below.

In following the above approach, the TSOs recognise that there are a number of external factors that might have been considered in determining the benefit of System Services but would not be regarded as appropriate for the TSO to include in the current value calculation. With delivery of new system services these other considerations could include the increased effectiveness of windfarm plant output as their capacity factor increase with reduced dispatch down levels. This could offset potential future RES penalties enforceable on Member States. There may also be an Emission Trading benefit with reduced carbon dioxide emissions.

3 Financial Modelling and Analysis approach

3.1 Modelling Description

The objective of the financial modelling was to understand the financial benefit which enhanced system services will deliver to the all-island power system in the future. The approach proposed here is to quantify the benefit, on an all-island basis, of increased levels of renewable generation by analysing production costs, dispatch balancing costs (DBC), and wind curtailment levels across a variety of scenarios.

A base case model for 2020 has been developed based on the All-Island Generation Capacity Statement 2011 – 2020 (GCS 2011). The Plexos production cost modelling tool has been used to simulate annual market schedules and dispatch schedules for 2020 over a range of generation portfolios, fuel prices, portfolio operational capabilities and operational constraint scenarios.

Key assumptions:

- Generation portfolio as per GCS 2011.
- Installed wind generation of 5,200 MW.
- Total demand of 42.8 TWh, as per median forecast in GCS 2011.
- All generators have firm access.
- No network has been modelled.
- Two interconnectors – Moyle and EWIC – between SEM and GB.
- GB modelled as a separate region with forecast demand and generation portfolio (based on an ENTSO-E model). This is used to determine market-based interconnector flows.
- Fuel and carbon prices based on the IEA World Energy Outlook (November 2011).

Installed wind capacity

The installed wind capacity for the base case is 5,200 MW, in line with the estimated capacity required to meet the 2020 40% RES-E target, based on the assumptions in the GCS 2011. To examine the effect that varying levels of wind have on market production costs, DBC and curtailment levels, a range of installed wind scenarios have been examined: 0, 2000, 3600, 5200, 6000 and 7,000 MW.

Market (unconstrained) Schedule

An unconstrained Plexos model is used to replicate the SEM rules and produce a market schedule. The only constraints included are: load balance (generation must equal load), generator technical characteristics and interconnector limits. The GB system is also modelled to determine interconnector flows, which arise whenever price arbitrage opportunities exist.

Dispatch (constrained) Schedule

To produce a representative dispatch schedule, additional constraints are included in the Plexos model. In practice, there can be a large number of operational constraints that influence the dispatch schedule. It is difficult to predict which constraints will apply in 2020. However, based on the most significant constraints in operation today and using the results of the FoR studies, four constraints have been developed and incorporated into the Plexos model as follows:

- Interconnector flow constraint: interconnector flows are determined by Plexos for the unconstrained run (market schedule) and this flow is a fixed input into the constrained run. This approach replicates the current SEM rules, whereby interconnector nominations are determined by the ex-ante market schedule.

- Operating Reserve constraint: operating reserve is required to manage system frequency in the event of the loss of a large in-feed. The requirements are based on current operational policy.
- SNSP limit: the System Non Synchronous Penetration limit accounts for a number of operational issues identified in the FoR studies. Limits ranging from 50% to 75% have been modelled.
- Synchronous Inertia constraint: Synchronous Inertia is a key determinant of the maximum rate of change of frequency (RoCoF) following a sudden power imbalance. A minimum level of 25,000 MWs is required to ensure the system can limit the RoCoF to a manageable level.

The key outputs from these two schedules are the market production costs and the total (dispatch) production cost. The difference between these two costs is the total constraint cost, which is the main component of Dispatch Balancing Costs.

As noted in the key assumptions above, the network has not been included in the Plexos model. It is assumed adequate transmission capacity has been built by 2020 to accommodate increased levels of wind on the system and negate any congestion in the current system. Therefore network limitations and localised constraints have not been modelled.

Two principal operational scenarios have been considered:

1) **Business As Usual (BAU):** this is a representation of current operational constraints. All of the above constraints are included with an SNSP limit of 50%.
2) **Enhanced Operational Capability (EOC):** this represents the possible operational constraints if enhanced system services are adopted. Interconnector and Operating Reserve constraints are included with an SNSP limit of 75%. No inertia constraint is included (i.e. assuming the RoCoF issue has been resolved).

3.2 Results and conclusions

By examining the unconstrained schedules, it can be seen from the range of installed wind capacity scenarios examined, that market[7] production costs decrease as the level of installed wind increases (see Figure 1). The decrease in production costs is approximately linear up to the levels of wind required to meet the 40% target; however, at higher levels of wind a flattening of the curve becomes evident, which indicates diminishing savings.

[7] It should be noted that for the modelling, the full GB system is included and therefore the production costs of both systems has to be considered. However, for simplicity, the SEM-only costs are represented by off-setting the total by the GB production cost.

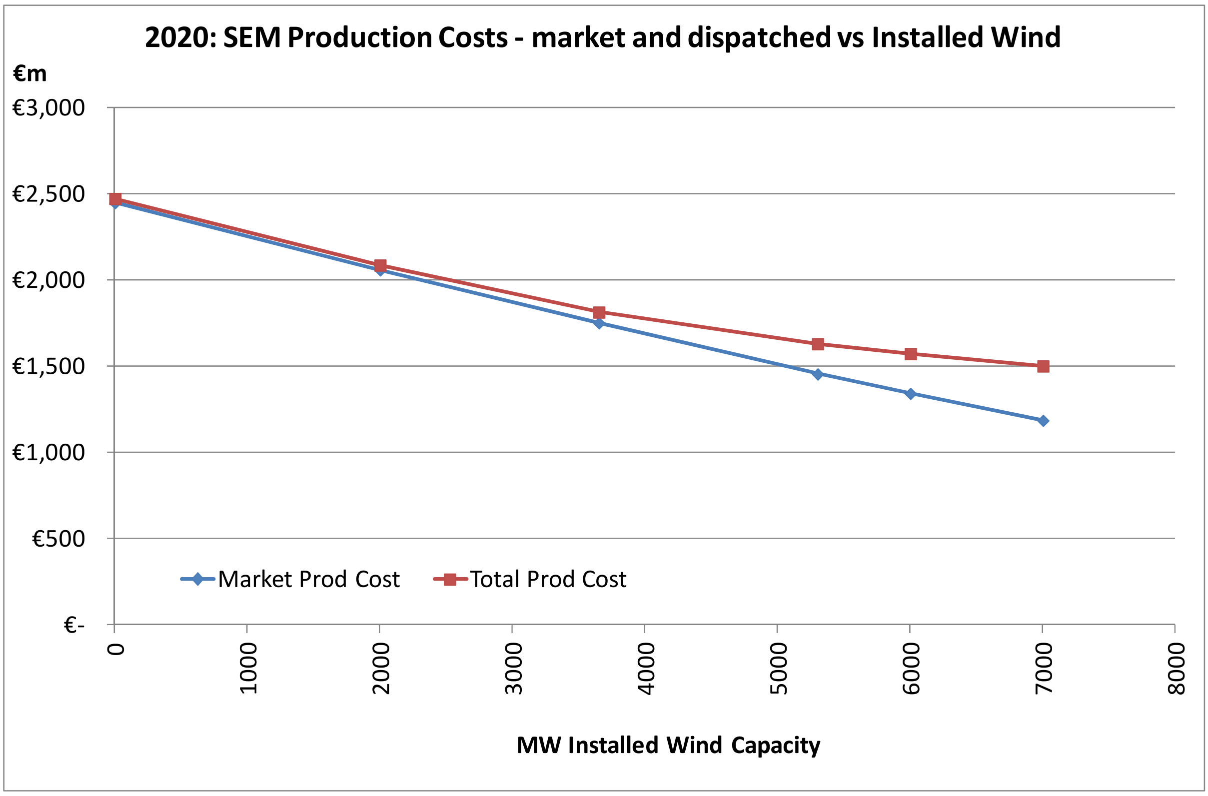


Figure 1: 2020 SEM production costs vs level of installed wind – market and dispatch (BAU) schedules

The set of system services and portfolio capabilities available to the system will determine the operational constraints that are applied to the dispatch schedule. As was shown in Figure 1, the constrained production costs also decrease in the BAU operational scenario as the level of installed wind increased. However, a divergence between the dispatch and market production costs is evident. This divergence represents an increase in constraint costs (and hence DBC). For example, for 5,200 MW installed wind, the DBC are €195m. This increase can be more clearly observed in Figure 2 below.

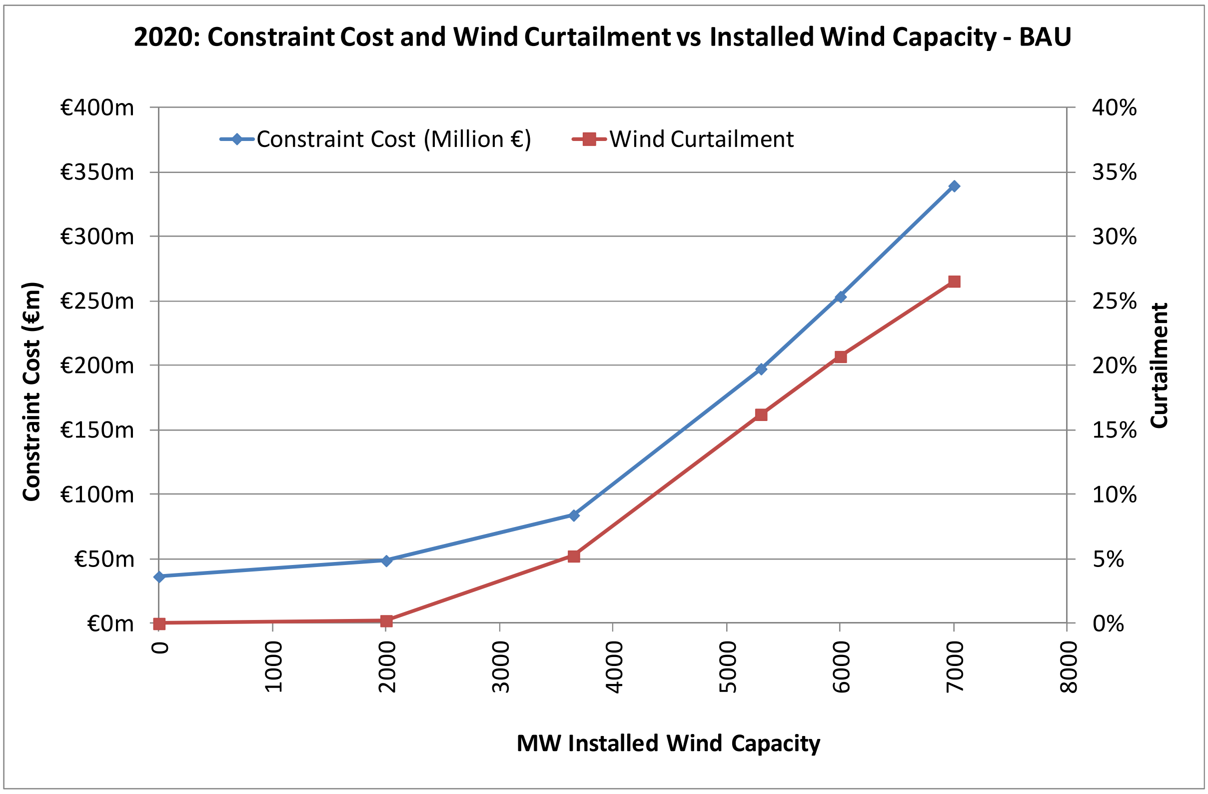


Figure 2: 2020 Dispatch Balancing Costs and wind curtailment vs installed wind capacity (BAU operational scenario – 50% SNSP limit)

Figure 2 also shows the increasing levels of curtailment, in the BAU scenario, as the installed wind capacity increases. It can be seen that for up to 3,600 MW of installed wind capacity the annual curtailment levels are below 5%; however above this capacity level, the rate of curtailment begins to rise significantly. At high levels of wind curtailment it is assumed that it becomes uneconomic for wind generation to build, both in terms of the impact of curtailment on the wind generator, and in terms of the DBC borne by the consumer. Therefore, as 3,600 MW represents a "knee-point" of the curtailment graph, it is used as a baseline for cost comparison.

With improved operational capabilities and enhanced system services, the system will be able to accommodate higher levels of wind generation without compromising system security. This is represented in the studies as the EOC operational scenario. Figure 3 below shows the impact that the EOC scenario has, both in terms of reducing curtailment levels and lowering DBC. For 3,600 MW of installed wind, the EOC scenario shows that curtailment falls to less than 1% and there is a reduction in DBC of approximately €26m (from €84m to €58m). At low levels of wind, the SNSP limit does not have a significant impact and therefore the DBC impact is small. However, at higher levels of installed wind, the increased SNSP limit results in a significant reduction in curtailment and a consequential reduction in DBC.

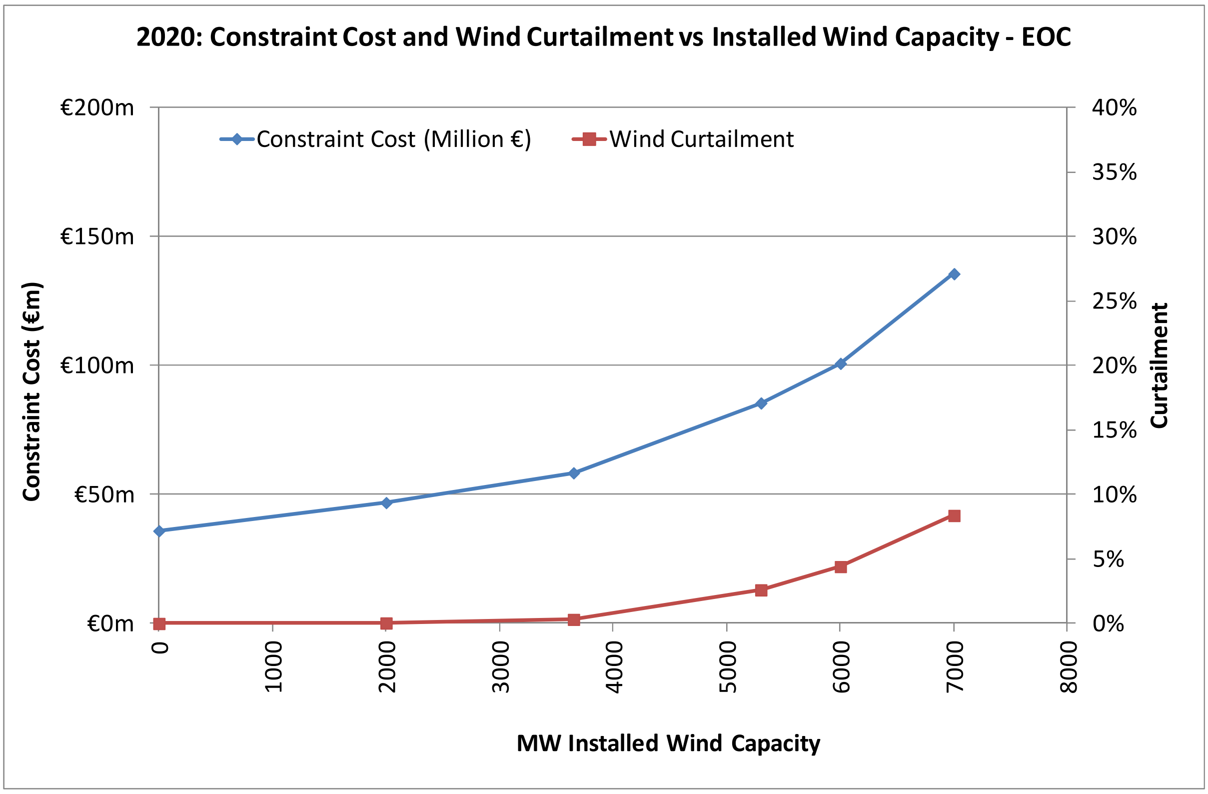


Figure 3: 2020 Dispatch Balancing Costs and wind curtailment vs installed wind capacity (EOC operational scenario – 75% SNSP limit)

For the EOC operational scenario, the reduced curtailment levels will enable the level of installed wind to increase to 5,200 MW, the level required to meet the 40% renewable target, without being uneconomic[8]. In addition, the increase in DBC with increasing wind is significantly reduced when compare to the BAU scenario. This can be seen in Figure 4 below, which shows the impact of increasing the SNSP limit to 75% on the total production cost for various wind levels.

[8] Based on discussions with windfarm developers, anecdotal evidence indicates that with curtailment levels regularly above 5% there is a significant risk of projects not being progressed.

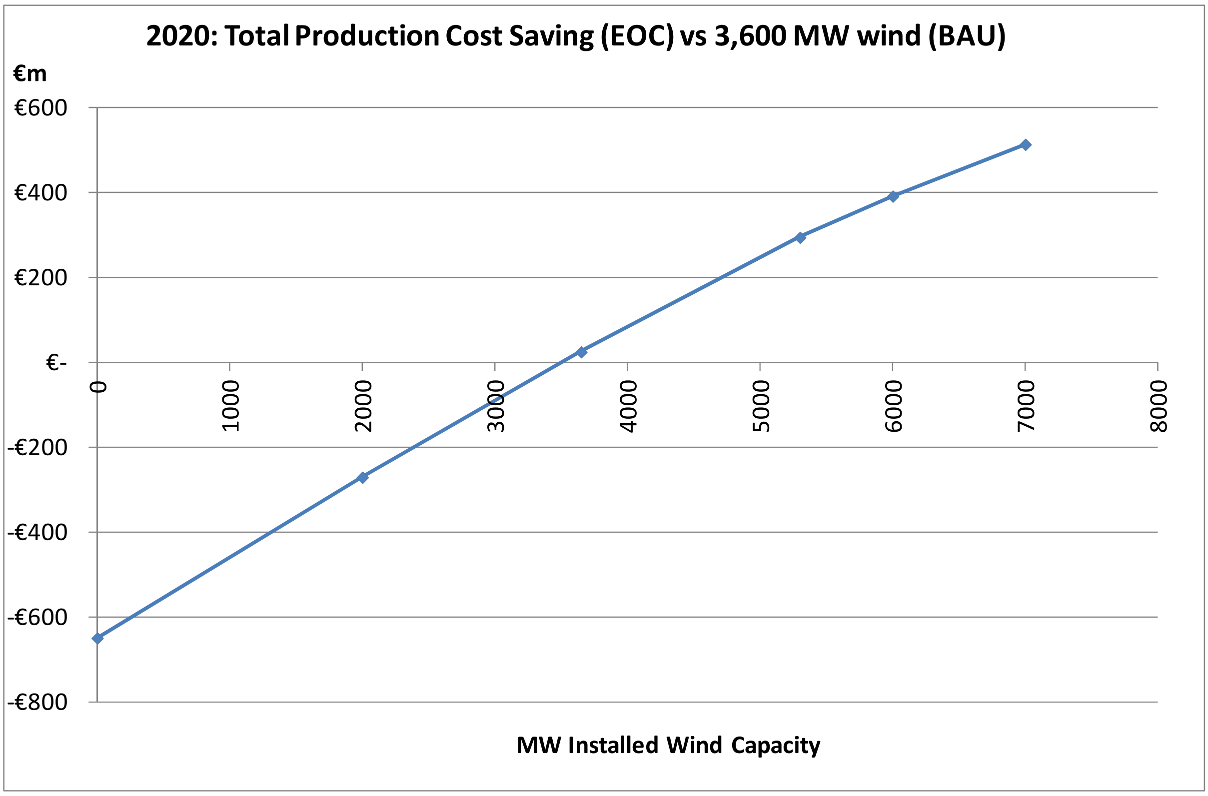


Figure 4: DBC reduction vs installed wind associated with increasing SNSP limit to 75%

The overall benefit of moving from 3,600 MW of wind with a 50% SNSP limit to 5,200 MW wind with a 75% SNSP limit can be quantified by comparing the total production costs for the BAU 3,600 MW wind case, with the EOC 5,200 MW wind case. The higher levels of installed wind capacity, combined with enhanced operational capabilities, lead to a reduction in market production costs and, through lower curtailment levels, a reduction in constrained production costs (which determine DBC). When these two reductions are combined to give the total production cost reduction, the annual net benefit to the all-island system is €295m. A table showing these results and a number of different Plexos studies are included in Appendix A. Table 1 below shows an extract from these results, with the total production costs for the 3,600 MW wind, 50% SNSP (BAU) scenario and the 5,200 MW wind, 75% SNSP (EOC) scenario highlighted in yellow; the difference between these two highlighted figures yields the €295 million benefit figure.

Table 1: Plexos results for GCS scenarios with 3600 MW and 5200 MW of installed wind

Scenario	Wind Connected (MW)	Dispatch	Production Costs (m) SEM	GB	Total	Constraint Cost (m)	Curtailment (%)
GCS: 3600 MW wind	3600	Unconstrained	€ 1,721	€ 12,824	€ 14,544		0.0%
		BAU	€ 1,779	€ 12,827	€ 14,606	€ 62.14	5.2%
		EOC	€ 1,753	€ 12,827	€ 14,581	€ 36.52	0.3%
GCS: 5200 MW wind	5200	Unconstrained	€ 1,457	€ 12,791	€ 14,248		0.3%
		BAU	€ 1,627	€ 12,796	€ 14,423	€ 175.72	16.2%
		EOC	€ 1,515	€ 12,796	€ 14,311	€ 63.66	2.6%

For clarity, the method analyses the benefits of procuring the additional services. There is also a need to at least maintain the existing levels of reserve, reactive power and black start. Therefore the total existing Harmonised Ancillary Services (HAS) payments (≈ €60m) should be added to the figure determined by the above approach. Thus the total potential payment for procuring the required new services and maintaining the existing System Services, based on the above methodology, is €355m. The TSOs consider that it would also be appropriate to include the existing HAS products in the same product revenue allocation method determined from those considered in Section 4 of this paper for the new SS products. Changes to the existing HAS financial arrangements would then be part of the Implementation phase of System Services development and subject to appropriate consultation processes at that time.

3.3 Cost of enhanced System Services

The System Service Review is predicated on previous studies, which showed that additional services are required, above and beyond what is procured today, to meet the needs of the system. These additional system services may require additional costs to be incurred – for example from capital expenditure or impacts on the operational efficiency of the providers. While the work outlined in previous sections has focused on the production cost benefits of obtaining these services, it is also appropriate to consider the potential costs that may be incurred in providing them.

In order to answer this question the TSOs have had to take a view of the potential changes to the portfolio that are required to solve the technical challenges of achieving the renewables targets. Any view of future developments contains inherent assumptions and is therefore open to challenge. To mitigate some of the risks associated with this the TSOs have approached answering this question by considering two alternative scenarios:

1. **Generation investment**: enhanced performance from existing and potential new plant; and
2. **Alternative investment:** no alteration to existing plant and no enhanced performance from new plant, necessitating alternative investment (e.g. network devices) to deliver the needed services.

Each of the two scenarios is considered from the perspective of the additional costs that are incurred. The benchmark, against which the additional costs will be determined, is a system without any investment; for this system, higher levels of renewables cannot be accommodated and therefore the production cost benefit of €295m described in section 3.2 is not achieved.

It should be noted that these scenarios are assumed to be adequate for meeting the system services requirements. This is based on the information and analysis performed in the Facilitation of Renewables studies and subsequent work. However, the analysis contained in these reports was based on a given network, assumed locations of service providers and it was necessary, at times, to examine the issues independently from one another. The scenarios below are an evolution of these earlier pieces of work and are based on the most recent Generation Capacity Statement. However, no optimisation or detailed technical studies have been completed on any of the scenarios envisaged below. Nevertheless the TSOs are of the view that these scenarios are sufficient for the purposes of providing an indication of costs incurred in delivering these system services.

A consultant – DNV KEMA – has been asked to estimate the level of capital costs that these enhancements may introduce. For information purposes, the DNV KEMA report is being published in conjunction with this consultation paper.

3.3.1 Methodology

For each of the scenarios, a level of investment in enhanced/improved technology has been assumed that will be adequate to enable the delivery of the needed system services in 2020. The TSOs' view on the possible ways of obtaining the services from different technologies has been informed in part by bilateral discussions on a range of issues with a variety of developers and manufactures particularly over the last 12 months. However, these discussions were high level and preliminary in nature and, as such, it is possible that not all the assumed enhancements will be technically feasible.

Each scenario has to be capable of resolving the four fundamental challenges identified, namely: inertia/RoCoF, ramping, reactive power and transient stability. In this regard, the TSOs have taken a view of possible sources of the required services from investment in different technologies.

3.3.2 Generation investment scenario

In this scenario, it is envisaged that most of the required services will be provided by generation sources. A number of assumptions have been made regarding the generation plant portfolio providing the services:

- Approximately 1,300 MW of windfarms connected to the system will have enhanced capabilities (i.e. will provide the Fast Post-Fault Active Power Recovery and Dynamic Reactive Response products described in section 8).
- A best in class 450 MW CCGT will connect to the system and provide lower minimum load, better ramping and better frequency response.
- A number of the existing CCGTs will also provide more flexible performance through shorter start up times, improved frequency response and improvement in min load.
- A number of new enhanced OCGTs will also connect to the system and provide Synchronous Compensation capability.
- A number of existing generators that are expected to retire will instead convert to Synchronous Compensators.
- Approximately 500 Mvar of dynamic reactive compensation (STATCOMs) is required to provide voltage control at high levels of SNSP.

Where enhanced performance is assumed, only the incremental capital cost has been used to determine the total cost figure.

Table 2: Additional capital cost requirement for the Generation Investment scenario

	Capital Cost *(€/MW or €/Mvar)*	**Volume** *(MW or Mvar)*	**Total cost** *(€m)*
Enhanced Wind (incremental cost)	€139,000	1300	€181m
Enhanced New CCGT	€30,000	450	€14m
Improve Existing CCGTs	€122,000	2000	€244m
Enhanced OCGT (incremental cost)	€74,000	400	€30m
Sync Comp conversion	€63,000	200	€13m
STATCOM (total cost)	€109,000	500	€55m
TOTAL			**€535m**

3.3.3 Alternative investment scenario

For the alternative investment scenario, it is assumed that there is no investment in enhanced performance by generation developers and as a consequence investment alternatives must be found that deliver the system capability to manage higher levels of renewables. It is therefore assumed that the majority of services are provided through the addition of new network devices distributed around the transmission system, with the remaining through the provision of Strategic Reserves (e.g. new OCGTs provided exclusively for System Operation purposes). The investment for this scenario includes:

- A number of dedicated Synchronous Compensators with flywheels to provide inertia and reactive support at various locations on the system.
- Approximately 400 MW of new OCGTs, which are required to provide ramping margin. It is assumed that these OCGTs will also be capable of operating in Synchronous Compensation mode.
- Batteries (50 MW) to provide fast frequency response services.
- A significant number of STATCOMs distributed around the system to provide voltage control.

The capital costs associated with these investments are shown in Table 3 below. Note that in this scenario, the full capital costs of the investment is included. Batteries have not been included since the flywheel / synch comp solution can provide the same frequency control services but at a lower capital cost.

Table 3: Total capital cost requirement for the Alternative Investment scenario

	Capital Cost *(€/MW or €/Mvar)*	**Volume** *(MW or Mvar)*	**Total cost** *(€m)*
Synch Comp / Flywheel	€766,000	840	€643m
Enhanced OCGTs - Strategic Reserve	€724,000	400	€320m
Batteries	€829,000	0	
STATCOM	€109,000	2,500	€303m
TOTAL			**€1,206m**

3.3.4 Summary

The total cost , based on the two scenarios above is as follows:-

Generation Investment €535m
Alternative Investment €1,206m

It should be noted that the costs described above represent the capital investment costs only. There may also be additional annual fixed costs, increased maintenance costs and higher operating costs associated with the two scenarios.

It should be noted at this point that while the TSOs have calculated total capital cost figures, based on the two scenarios above, determining the appropriate annualised cost based on such figures is a regulatory decision for the SEMC. In considering this subject, the TSOs suggest, however, that the SEMC should consider the financial risks to investors associated with future uncertainty regarding the level and duration of their return.

- **To what extent, if any, should the capital costs inform the decision regarding future system services?**

3.4 Impact on the all-island consumer

The valuation methodology proposed has quantified the benefit of system services in terms of the total production cost savings that arise due to the curtailment-lowering effect of enhanced system services and the consequential impact on the level of wind generation. These savings (principally due to a reduced all-island fuel bill) represent the maximum overall benefit to the all-island system based on the proposed methodology and assumptions made e.g. fuel costs.

The extent to which the total production costs savings result in lower energy costs to consumers is a rent allocation question. It is determined by the market design, which includes factors such as price-setting and the treatment of priority dispatch, and is therefore ultimately a matter for the SEM Committee. Nonetheless, some of the benefit will appear through lower dispatch balancing costs, some through lower SMP, while the remainder will appear though increased infra-marginal rents. It needs to be considered what level of the modelled benefit is necessary to be allocated to system service providers in order to ensure that the required system services are actually provided, such that the modelled benefits can be realised.

There is an interaction between payments for system services and the capacity payment mechanism. The impact of increased payments for system services on the end consumer may be lessened due to a reduction in capacity payments. This is discussed further in section 5.

The analysis carried out has quantified the benefit of system services in terms of total production cost only. Other costs and benefits have not been explicitly included, including fixed costs and capital repayment costs. In addition, there are external factors that could be considered in determining the overall value of System Services (e.g. RES penalties, an increase in the PSO level (REFIT) or cost to suppliers to procure sufficient ROCs, Emissions Trading benefit). The impacts of these on investor decisions are difficult to determine and lies outside the TSO core remit. However, when considering the value of System Services, it is important to be mindful of this wider context.

It is worthwhile noting at this point that while the TSOs can propose and recommend a methodology which results in a system services valuation figure; determination of how much of this valuation should be paid to the service providers is a SEMC matter. In considering this subject the TSOs suggest that the SEMC should consider the risks associated with future uncertainty, how these should be shared between the customers and the Service Providers and the possible consequences of their decision.

- **Do you agree with the proposed methodology for determining the aggregate available pot for System Services?**

4 Allocation of System Services Revenue

As well as determining the total benefit of the System Services, a regulatory decision has to be made regarding how much of this total benefit will be paid to service providers and then how best to allocate this money between the various products. Since there are varying degrees of interaction between the different products, and there is interaction between system service provision and energy provision, it is difficult to determine the appropriate allocation. The TSOs have identified four different methods for consideration by which the proposed System Services money might be allocated between the various products.

1) Equal division of the money between the products. Other than simplicity this has no other rationale to recommend it.

2) Allocate the money based on a set of rules determined by the TSOs using their operational experience of controlling the power system. The split created in this way would be set initially and not changed for a number of years to assist in certainty for service providers.

3) Calculate the relative value of the products, using a series of Plexos studies of the system in which each of the products removed. The outcome of the studies would be a number of constraint cost deltas which could then be used to weight the allocation of the system service money between the products.

4) A predetermined generation portfolio could be developed, which satisfies the needs of the power system and based on assumed required capital expenditure and weighted cost of capital determined by the Regulatory Authorities. Studies would then optimise the allocation of money to distinct System Services products to minimise the cost to the consumer while ensuring that sufficient revenues are rewarded to reliable performing units to invest in their plant. This optimisation could be completed over a range of fuel prices and could include, if required by the Regulatory Authorities, Capacity Payments. From this a set of tariffs could be determined that would be robust for a range of possible future scenarios. This option has been included for completeness, but given its complexity, the TSOs do not believe it could be implemented in any practical timeframe.

Each of the above allocation mechanisms has to be considered in terms of transparency, efficiency and appropriate levels of incentivisation. The simpler methods provide transparency. They can be well understood by participants and are likely to be appropriate where System Services are a small but necessary part of funding of investment. If, however, System Services are a significant part of the funding discussions it is likely that these simplified mechanisms will be less efficient. The fourth method, although the most complex, circumvents many of the issues as it is designed to ensure all the necessary capital funding is achieved for a given assumed portfolio. This method, however presupposes an outcome which may lead to longer term inefficiencies. In a market environment this approach needs considerable deliberation. There is precedent in this type of approach with the way in which Capacity Payments are structured. In addition the assumptions on the cost of capital and required expenditure may turn out to be insufficient and the subsequent system services may not deliver the intended outcomes.

On balance, the TSOs have a preference for the third method above but would welcome respondents views on all of the above methods and suggestions for a more effective and practical method. An illustration of the third method has been included as Appendix B to this paper.

Given the TSOs are proposing a valuation process for System Services with regulated tariffs that are reviewed every 3-5 years, there is a need to remove uncertainty in the allocation mechanism. In this regard, the TSOs consider that the allocation approach needs to be fixed for at least 8-12 years.

The TSOs have no plans to change the definitions of most of the existing HAS products other than Replacement Reserve and Static Reactive Power as part of the current DS3 Review. We do, however, consider that it would be sensible, given the increasing scarcity of these products, to include the HAS products in the same allocation methodology used for the new products. Changes to the existing HAS financial arrangements would then become part of the Implementation phase of System Services development and subject to appropriate consultation processes at that time.

- **Which of the four methods outlined to allocate the funds between the System Services products would you prefer or is there an alternative allocation method that should be considered?**

5 Remuneration Approach

The majority of generation respondents to the June 2012 consultation paper stated that they would prefer System Services payments based on capability in order to achieve greater financial certainty. They also stated that they do not want changes which would reduce the Capacity Payment Mechanism. There is, however, a direct link between System Service payments and the determination of the capacity pot. This link needs to be recognised in determining the appropriate payment mechanisms for System Services and the volumes of money involved. A balanced approach is required that recognises the conflicting considerations:

1) Capability type payments provide greater certainty to providers
2) Dispatch-dependent payments provide a more targeted incentive
3) The RAs have stated that increased System Services payments may reduce the CPM pot
4) The RAs have stated that increased payments for System Services should result in a net benefit to the all-island consumer
5) Respondents generally favour minimising change to CPM

5.1 Capability vs Dispatch-Dependent Payments

As set out in the previous System Services consultation paper in June 2012, payments for system services based solely on capability, availability or utilisation are valid remunerations mechanisms. The effectiveness and efficiency of the choice of mechanism to incentivise and mitigate system scarcity will depend on the nature of the service. More specifically, if significant new investment is required, remuneration mechanisms that are based on utilisation are riskier to the developer compared to capability payments. However, the corollary is that capability payments, as they provide greater certainty to the developer, may be at the expense of the consumer and this needs to be considered carefully.

The nature of scarcity in the system and how it will be best resolved should dictate whether payments are more capability-focused or utilisation-focused. The TSOs indicated previously that capability payments structures are likely to be more appropriate to provide the incentives for investment needed for the challenges facing the system although mechanisms to mitigate undue costs to the consumer need to be developed. Through the System Services consultation process, respondents have generally also expressed a preference for capability-type payments.

	PROs	**CONs**
Capability	• Based solely on contracted capability and declared availability and thus reduce revenue uncertainty for providers.	• Payment rates are lower as they are spread across more providers. • Consumers may pay for more services than are required. • Significant impact on capacity payments
Dispatch Dependent	• Focussed more specifically at the system needs. • Can be targeted to those providers that offer better value services. • Avoids payments to providers that are not required.	• Payment revenues are more difficult to predict

Utilisation	• May ensure existing investment capability is maintained at a high level of performance • Appropriate where there are material incremental operating costs in provision.	• Only paid when called upon so no payment for providing a service margin. • Payment revenues are more difficult for service providers to predict.

The TSOs on further reflection, however, now favour dispatch-dependent payments as they provide a more targeted incentive by focusing on providers that are "used" while avoiding payments to providers that are not required, thus protecting consumers from excessive costs. For a given "pot" of money, dispatch-dependent payments will result in higher rates than capability payments. In addition, dispatch-dependent payments generally have less impact on the CPM, as detailed further below.

Example

To illustrate the difference between these two payment types, a simulation has been carried out for the 2020 system with the following assumptions:

- Plexos run for the 2020 portfolio with 5,200 MW wind and EOC operational scenario
- Additional system service revenue is €1m
- Five new services – Synchronous Inertial Response, Fast Frequency Response, Ramping, Fast Post-Fault Active Power Recovery, and Dynamic Reactive Response, as defined in section 8
- Allocation option 1: system services revenue divided equally between five new services (i.e. €200,000 per service)
- 1,000 MW of windfarms provide enhanced services, including Fast Frequency Response, Fast Post-Fault Active Power Recovery and Dynamic Reactive Response
- Generator capabilities estimated based on current capabilities

Based on the availabilities and dispatched outputs, product volumes have been calculated for each provider for every hour in the year. Using this, annual payments have been calculated for each service provider. Table 4 below shows a selection of the resulting annual payments aggregated by provider type, normalised according to installed capacity (i.e. € per MW installed). A more detailed breakdown, showing payments by product type, is provided in Appendix C.

Table 4: Illustrative system service payments (per MW installed) for each €1m spent on System Services per year

Service Provider Type	Capability based (€/MW installed)	Dispatch-Dependent (€/MW installed)
CCGT	72	76
Coal	82	148
OCGT	144	73
Windfarm basic	14	0.28
Windfarm enhanced	45	64
Pumped Storage	264	328

This example illustrates the potential relative impact on provider types of a pro rata allocation for each additional €1m spent on system services. So for example, a typical 400 MW CCGT would earn €29k under the Capability-based approach while under a Dispatch-dependent approach it would earn €30k per €1m spent.

5.2 Relationship between payments for System Services and the CPM

The Annual Capacity Payments Sum (the capacity "pot") is determined based on the net annual cost of a BNE peaker and the Capacity Requirement. In determining the BNE peaker cost, the RAs determine the overall total annual cost of a BNE (including capital repayment costs and fixed annual costs), and deduct expected revenues from Infra-Marginal Rent and Ancillary Services.

The recent SEMC Decision Paper on Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for 2013 (AIP/SEM/12/078) states that while the RAs intend fixing the Ancillary Services deduction for three years, they reserve the option to review the Ancillary Services deduction if this System Services Review significantly impacts the system service revenue that the BNE would earn. If the BNE costs are reviewed taking into account the new System Service arrangements, the allocation of revenue between products and the payment type (capability or dispatch-dependent) will determine the impact on the capacity pot.

There is rarely a one for one relationship between spending €1m on System Services and the resulting reduction in the capacity pot. The impact on the capacity pot will depend on a number of factors, including: the proportion of the €1m that would be received by the BNE, total system generation availability, generator eligibility, if wind generation is eligible (and the relative difference between the actual capacity factor of wind and capacity credit attributed to wind in the CPM pot calculation).

- For a pure capability payment, that all generators receive based on availability, the cost of the system service will depend on the average system generation availability, whereas the impact on the CPM will depend on the annual capacity requirement. It is therefore likely, if the system has excess capacity, that the SS payment would be larger than the CPM reduction.
- For a dispatch-dependent payment that the BNE is unlikely to receive (e.g. dispatch-dependent SIR), there will be very limited impact on the CPM. The SS payment will therefore be larger than the CPM reduction.
- For a dispatch-dependent or capability payment that is BNE-centric (e.g. 1hr ramping), it is likely that the CPM reduction will significantly outweigh the SS payment.

Example

To illustrate the potential impact of System Services on the CPM, the example of system services payments in section 5.1 above has been applied to the BNE calculation. Using the assumptions for the BNE peaker as described in the 2013 decision (SEM/12/078), estimated annual payments to the BNE peaker for each €1m spent on system services are shown in Table 5, broken down by product type.

Table 5: Illustrative annual system service payments for the BNE peaker (192.5 MW) for each €1m spent on System Services

BNE Peaker	Capability based (€/year)	Dispatch-Dependent (€/year)
Synchronous Inertia	1,380	60
Fast Frequency Response	5,090	210
Ramping	9,870	13,890
Fast PF Active Power	4,390	230
Dynamic Reactive Response	3,980	160
Total	24,710	14,550

To estimate the impact that each payment approach would have on the CPM pot if the payments were deducted from the BNE annual costs, the annual payments have been scaled by the estimated capacity requirement for 2020 (based on demand growth). This is shown in Table 6 below.

Table 6: Illustrative impact on CPM pot for each €1m spent on System Services

	Capability	Dispatch-Dependent
Additional BNE peaker revenue (€/kW)	0.1284	0.0756
2020 Capacity Requirement	8,000 MW	8,000 MW
CPM pot reduction	€1.0m	€0.6m

It should be noted that the extent to which the new system services impact on the CPM pot is a matter for the SEM Committee to determine.

On reflection, having considered responses to the previous consultations, the relative merits of the different payment mechanisms and the impact on the CPM, the TSOs have concluded that Dispatch-dependent payments, with extended fixed rates (to aid forecasting), represent the best compromise between providing the necessary certainty for investors, ensuring the efficacy of the incentive to manage the identified operational issues and minimising the final cost to the consumer. . While they are less certain to investors than capability based services, the design of some of the new system services products are less dependent on MW output, allowing greater certainty than the existing ancillary services products. In addition, there is a significantly reduced impact on the capacity payment mechanism. It should also be noted that the future market integration project could impact on the current CPM and its design. This approach also has the additional benefit that, since dispatch-dependent payments provide a more targeted incentive, the interests of the consumer are better protected.

- **Is the rationale for proposing dispatch-dependent payments clear?**
- **Is there further justification, not included in earlier consultation responses, for adopting a more capability-based approach?**

6 Proposed Contractual Arrangements and Payments

6.1 Contractual arrangements

Respondents have made it clear that fixed term System Services contracts for periods less than 7 years will not provide the confidence to influence investment decisions. The TSOs therefore propose to recommend Bilateral Contracts which will not have a specific end date for the new services between the TSO and the Service Provider but will have a minimum contract period of 7 years. Specific circumstances under which the TSO or the Service Provider may terminate the contract will, however, be included in the document template.

The format of the bilateral contracts for these new System Services will be similar to the template of the existing HAS contracts[9] (available on TSO website). It may, however, be helpful to make a few changes and additions to clauses which could assist in the effectiveness of their operation (e.g. data substitution rules for alternative data and/or replacement times for equipment which result in extended periods of defective/missing data). It is envisaged that amendment of performance levels and contract terms will be by mutual agreement with a referral to an independent body or the Regulatory Authority where a failure to agree occurs. It is also proposed that settlement will be carried out on a monthly basis and that payments will be calculated on a half-hourly basis.

6.2 Generic Payment Structure

It is proposed that payments for system services will be calculated individually for each system service. The generic formulation for payment will be as follows:

$$Payment = Product\ Volume \times Product\ Scalar\ \times\ Product\ Rate \times Performance\ Scalar$$

Note that, for simplicity, the payment algebra presented in this paper assumes hourly payment to avoid the complexity of half-hourly scaling.

Product Volumes
Product volumes will be calculated based on a number of parameters:

- Contracted capability
- Declared availability (for MW and/or for service)
- *Dispatch Instructions – for dispatch-dependent payments only*

Details of how product volumes are calculated for each product are described in section 8 below.

Product Scalar
In general, the product scalar will be set to 1. For some services, where there is a distinct difference between the types of product offered by different providers, a scalar will be used to vary the payments. An example of this is the reactive power product under the existing HAS arrangements, which uses an AVR scalar to distinguish between reactive power provision with AVR action and reactive power provision without AVR action.

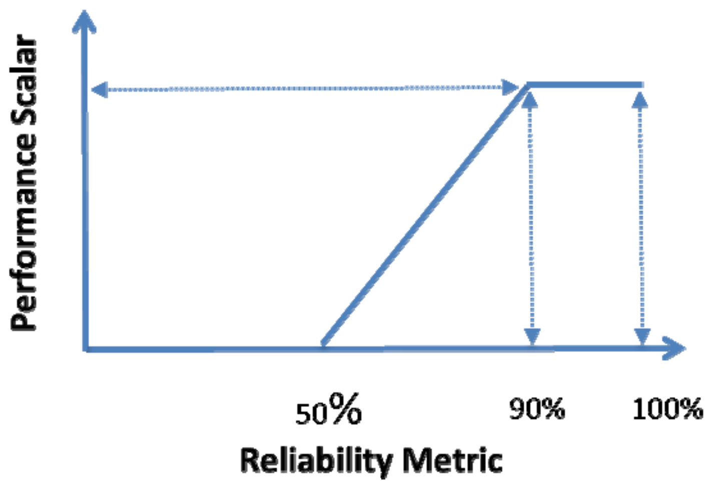
Product Rate
Payment rates for System Services could be fixed (time-invariant) or could vary by half-hour. Time-varying payment rates, such as those used in the CPM, have the advantage of enabling payments to be targeted towards specific periods where the need is greater or the value is higher. However, time-varying rates add significant complexity to the payment structure and are likely to be difficult

[9] www.eirgrid.com/media/Eirgrid%20Harmonised%20ASC_161209.pdf

for service providers to forecast. Fixed payments are simpler and more predictable, but they are less targeted. These issues are considered further in section 6.3 below.

Performance Scalar

Performance reliability is a key aspect of the proposed services. A unit that performs consistently when called to provide a service gives a greater degree of certainty to the system operators than a unit that performs sporadically. A sliding scale of reducing payment rates for performance below 90% but above 50% will be utilised. There should be no payment for performance below 50% as this is inherently unreliable service provision.



A performance monitoring process will be developed and documented as part of the DS3 Programme following the SEMC decision on the principles and approach proposed for System Services. Further details are provided in section 6.4 below.

6.3 Product Rates

In the recent System Services consultations, the TSOs have outlined an approach to system services valuation. At the heart of this approach is the need to reward for scarcity. For example, in order to meet the governments' RES-E policy objectives, the power system will experience more uncertainty and variability and have less synchronous torque available to it when significant volumes of generation are coming from non-synchronous resources. Therefore new products (e.g. ramping and dynamic reactive response) have been created to ensure there is some incentivisation to address the identified scarcity.

However, the pricing of the products has been presented to date as a simple rate, akin to the current Harmonised Ancillary Services (HAS) arrangements. The reality is that the scarcity of the system services is both a long and short term issue. In the long term, the necessary system plant portfolio needs to evolve in order that the system performance envelope is sufficient to meet the needs to achieve the governments RES-E policy. A regulated static tariff will, by design, provide a long-term signal but it will reward at all times, whether or not there is a real-time scarcity. Therefore, it is arguable that fixed rate would result in an over-payment in real-time when there is no scarcity.

To address this, it might be possible to design products that reflect the real-time scarcity more precisely. However, there are inherent links between these products, based on the nature of providers, their location, and the connecting network between all the generators, both RES-E and conventional. Therefore these interactions make real-time system service pricing mechanisms intrinsically more complicated than energy markets which focus only on one product. There is no generally accepted design for such multiple interacting system services real-time products. Some markets have previously attempted some efforts in this regard but with limited success (e.g. the Californian energy market). However, time-varying rates add significant complexity to the payment structure and are likely to be difficult for service providers to forecast, at least in the short-term.

There are a number of options for determining dynamic, time-varying rates. For example, it could be contended that, as the new system services products are intended to manage high wind situations, payment should only be offered to those providers that provide services at high system non-synchronous penetration levels. Effectively the price paid for the service would be related to the level of non-synchronous generation on the system. Other options for dynamic rate calculation mechanism could include:

- rate based on the level of service required
- rate based on the expected or actual surplus/deficit of the service
- rate based on the dispatch balancing costs arising from providing the service
- a clearing price or other market based mechanism.

Based on a consideration of the complexity and opaqueness of real time system services pricing, the TSOs consider that the best approach at this stage is for static tariffs, approved by the Regulatory Authorities. A current example of this is the existing tariff for Reactive Power under the HAS arrangements.

To balance predictability of income for providers with financial prudence in terms of costs borne by the end consumer, the TSOs believe that these tariffs should be reviewed on a 3 to 5 year basis rather than the annual arrangements used for reviewing the existing Harmonised Ancillary Services. This time period aligns with the recent decision on Capacity Payments and the Best New Entrant price determination[10]. It also allows appropriate review to ensure that the monies being paid out for the new system services products are delivering the benefits that they were designed to. In particular the basis of these payments has been calculated on two core outcomes:

- the need for the system services as installed windfarm build continues rise to meet the government targets and;
- The ability of the power system to be operated up to 75% from non-synchronous generation in real time.

6.4 Proposed Performance Monitoring Process

Details of a Performance Monitoring Process for System Services (e.g. Performance Level Expectation, Performance Review Period, Bad Data, Commissioning, etc) will be developed and documented as part of the DS3 Programme following the SEMC decision on the principles and approach proposed for System Services and will be included in subsequent consultation papers.

A process for handling situations where there are too few events to statistically ascertain performance levels would be developed as part of the implementation phase for new products. This process will also need to identify situations where a unit is commissioning, has been unavailable for a long period of time and/or the measuring equipment is unavailable.

It is envisaged that disturbance recorders will be required for fast acting products (Synchronous Inertial Response, Fast Frequency Response and Dynamic Reactive Response). It is further proposed that the service provider pays for the initial capital cost of these units, their installation and

[10] www.allislandproject.org/en/cp_current-consultations.aspx?article=75c548a7-34ee-497c-afd2-62f8aa0062df

commissioning at agreed locations. The TSO then takes ownership of the recorders after commissioning and provides the external communication links to their offices.

Ramping and Steady State Reactive products will utilise SEM data combined with EDIL dispatch instructions as data sources.

- **Are the proposed general contractual and payment arrangements clear?**

7 Interaction of System Services and Grid Code/Minimum Functional Requirements Proposals

There is an inherent interaction between the value ascribed to System Services and the capabilities required under other legislative instruments. The benefit of System Services determined using the proposed methodology set out earlier in this paper has been calculated based on the assumption that the Grid Code changes described below have been implemented and the remaining RoCoF issues have been resolved. If these are not delivered, the system will not be able to operate securely with high levels of wind penetration, meaning that curtailment levels will rise significantly and the targets for renewable energy will be unlikely to be achieved. In addition, if the enhanced Grid Code standards are not adopted, the costs as outlined in section 3.3 will most likely increase, as further investment will be required, e.g. in network devices.

There are a number of key proposals in the wider DS3 programme for changes to the minimum windfarm standards and the rate of change of frequency on all generators that have a direct influence on considerations here. To this end this section outlines the main capabilities being sought in the DS3 Grid Code and DS3 Rate of Change of Frequency (RoCoF) workstreams.

Grid Code modifications are being brought forward from issues identified in the FoR study. These modifications also influenced by the “Rules for Generators” and the Network Code requirements being drafted by ENTSO-E. This Network Code will, in the next five years, be legally binding across the 27 Member States of Europe. Where possible the TSOs (EirGrid and SONI) have not sought standards in excess of those allowed for in this draft European network code.

For windfarms, changes to standards are only being sought which the TSOs believe current turbines can fully meet with limited if any changes. These changes though are minimum standards and the TSOs are aware that a range of additional capabilities are available from a subset of the windfarm technology presently available. To this extent system service capabilities have been designed to try and incentivise this needed capability in excess of Grid Code minimum standards.

At the time of writing there were a number of areas in the draft code where Member States still had discretion. These areas include RoCoF standards for generators. Due to the nature of the island power system in Ireland and Northern Ireland, EirGrid and SONI have proposed a modification with a relatively high RoCoF value.

7.1 Windfarm Modifications

The purpose of the modifications is to clarify existing ambiguities in the current Grid Code/Minimum Functional Specifications and seek improved capabilities consistent with current windfarm technology capabilities and the identified challenges of the power system. Specifically the main changes sought are:

- Enhanced reactive power capability at lower active power outputs;
- Reduced times for post-fault active power recovery to no more than 500 ms for short duration faults; and
- Unambiguous standards for reactive current production during and post-fault disturbances with a rise time within 100 ms of fault inception.

There is agreement between EirGrid, SONI, ESB Networks and NIE that these changes will be applied on all controllable windfarms in Ireland and Northern Ireland. Some of these clauses may, however, cause issues for the security and safety on the distribution system and the utilisation of the capabilities will be subject to prior approval of the relevant DSO. At this stage all of these changes have been included in proposals being brought to the Ireland Grid Code. The dynamic reactive current production standard is not currently being consulted on in Northern Ireland as the windfarm settings schedule applies to both transmission and distribution connected windfarms and is the subject of further investigation.

These changes directly interact with the following proposed system service products:

1. Dynamic reactive current product which is clarified in this paper to be based on 40 ms rise time;
2. Post fault active power recovery which is clarified in this paper to be required within 250 ms of fault clearance.

7.2 RoCoF Modifications

As more non-synchronous generation connects to the system, the loss of the largest credible in-feed will result in higher rate of change of frequency events on the system. If units are unable to stay connected during these events the security of the power system would be compromised. The RoCoF modification is being brought to clarify and ensure that all generation is capable of staying connected during disturbances for a certain RoCoF.

Following studies and six months of discussion through a dedicated Joint Grid Code working group it is proposed that all generation in Ireland and Northern Ireland will be required to be capable of withstanding rates of change of frequency of up to 1 Hz/s averaged over 500 ms at the connection point. Until the second North-South interconnector is operational there will be a 2 Hz/s standard in Northern Ireland to cater for possible system separation events. At the time of writing the modification[11] is being taken through the necessary industry processes before submission to the Regulatory Authorities for approval. However, there are divided opinions in the industry on this issue and the approval of the modification is ultimately a matter for the CER and NIAUR respectively.

The need for large inertia machines at lower megawatt output will reduce if the following outcomes occur:

- The proposed Grid Code modification is approved and
- Generators find they are capable of riding through these frequency/RoCoF events and
- Associated protection settings on distribution protection relays are set appropriately.

The scarcity of inertia is diminished and consequently the value of the Synchronising Inertial Response product is reduced. Conversely if the modification is rejected then there is an increase in the requirement for and value of the Synchronising Inertial Response product.

7.3 Eligibility - Link between System Service Products and the Grid Code

As indicated in the 2nd System Services consultation it is proposed that the provider must be compliant with the relevant sections of the Grid Code in order to be eligible for remuneration for a system service product. Some respondents to the June consultation paper considered that derogated plant should be excluded from payment for system services if they were unable to achieve the Grid Code standard while others sought payment for lower product volumes and quality.

[11] The proposed modifications can be found on the DS3 section of the EirGrid website here: http://www.eirgrid.com/operations/ds3/communications/jointgridcodeworkinggroup/

To help clarify the proposed approach, the requirements of the Grid Code that apply to the proposed system services can be considered to have two aspects: volume and quality.

Volume
Where a provider is eligible and the minimum product volume is set out in the Grid Code then the TSOs are obliged to contract (e.g. existing HAS product 5% POR) for this volume. Where a provider has the capability to provide more than the Grid Code minimum, the TSOs have discretion in contracting for this additional capability, subject to the needs of the system.

Quality
For some services, where it is necessary to incentivise performance (quality) in excess of the Grid Code standard or where no clear Grid Code quality standard exists, the TSOs will only contract with those service providers who can demonstrate delivery according to this enhanced standard. Examples of this type of product include Dynamic Reactive Response and Synchronous Inertial Response.

8 Proposed System Services Products

8.1 Frequency Control

8.1.1 New product: Synchronous Inertial Response

Synchronous Inertial Response (SIR) is the response in terms of active power output and synchronising torque that a unit can provide following disturbances. It is a response that is immediately available from synchronous generators, synchronous condensers and some synchronous demand loads (when synchronised) because of the nature of synchronous machines and is a key determinant of the strength and stability of the power system. It has significant implications for rate of change of frequency (RoCoF) during power imbalances and for transmission protection devices and philosophy. With increasing non-synchronous generation this response becomes scarce and there is therefore a need to incentivise it. In particular, if synchronous inertial response can be provided at low MW outputs, the system can accommodate higher levels of non-synchronous generation.

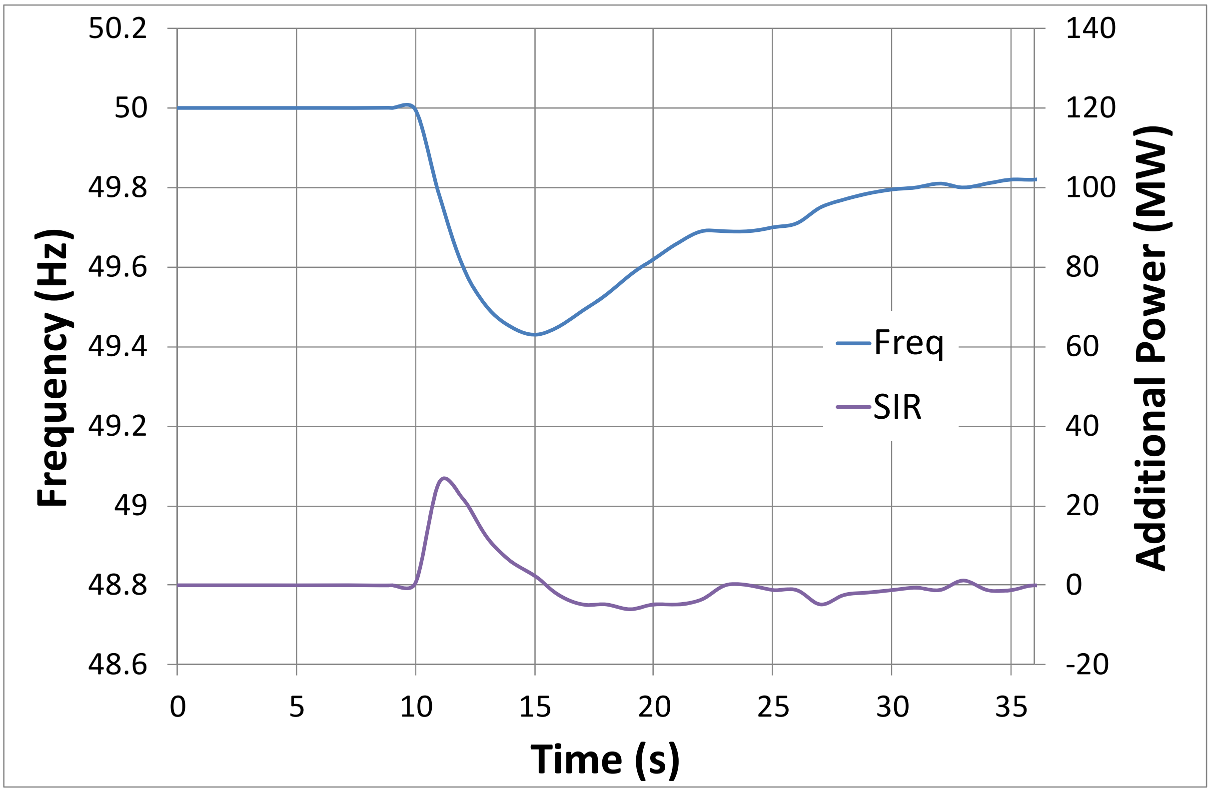


Figure 5: Illustration of typical inertial response

The proposed SIR product is defined as the kinetic energy (at nominal frequency) of a dispatchable synchronous generator, dispatchable synchronous condenser or dispatchable synchronous demand load multiplied by the SIR Factor (SIRF). The SIRF of a synchronous generator is the ratio of the kinetic energy to the lowest sustainable MW output at which the unit can operate at while providing reactive power control. It will be based on the commissioned design capability of the plant as determined through appropriate testing procedures. The SIRF will need to exceed a threshold of 15 s for the provider to be eligible for payment and payment will be capped at a SIRF of 45 s. The SIRF for a synchronous condenser or a synchronous demand load that can provide reactive power control is 45 s. Payments for SIR will be based on the SIR Volume:

SIR Volume = Stored Kinetic Energy × (SIRF – 15) × Unit Status

This product is dispatch-dependent. Plant will only receive payments when synchronised (i.e. when Unit Status = 1).

Product Volume	*SIR Volume*
Product Scalar	*2 if the provider is capable of providing operating reserve at the lowest sustainable MW output at which the unit can operate at while providing reactive power control* *1 otherwise*

Potential providers of these services include all synchronous generators (irrespective of generation technology), synchronous condensers and some synchronous demand loads.

Please see Appendix D.1 for examples.

8.1.2 New product: Fast Frequency Response

With appropriate control systems, both synchronous and non-synchronous generators can provide fast-acting response to changes in frequency that supplements any inherent inertial response. In particular, Fast Frequency Response (FFR) as defined below (MW response faster than the existing Primary Operating Reserve times) may, in the event of a sudden power imbalance, increase the time to reach the frequency nadir and mitigate the RoCoF in the same period, thus lessening the extent of the frequency transient. This product runs in conjunction with SIR so providers who can maintain or increase their outputs in these timeframes are eligible for both services. The analysis performed by the TSOs to date has indicated that a product in which output is decreased for high frequency events (i.e. Over Frequency Response) is not currently required.

Fast Frequency Response is defined as the additional increase in MW output from a generator or reduction in demand following a frequency event that is available within 2 seconds of the start of the event and is sustained for at least 8 seconds. The extra energy provided in the 2 to 10 second timeframe by the increase in MW output must be greater than any loss of energy in the 10 to 20 second timeframe due to a reduction in MW output below the initial MW output (i.e. the hatched blue area must be greater than the hatched green area in Figure 5).

Product Volume	*Additional MW Output that can be provided when connected*
Product Scalar	*1*

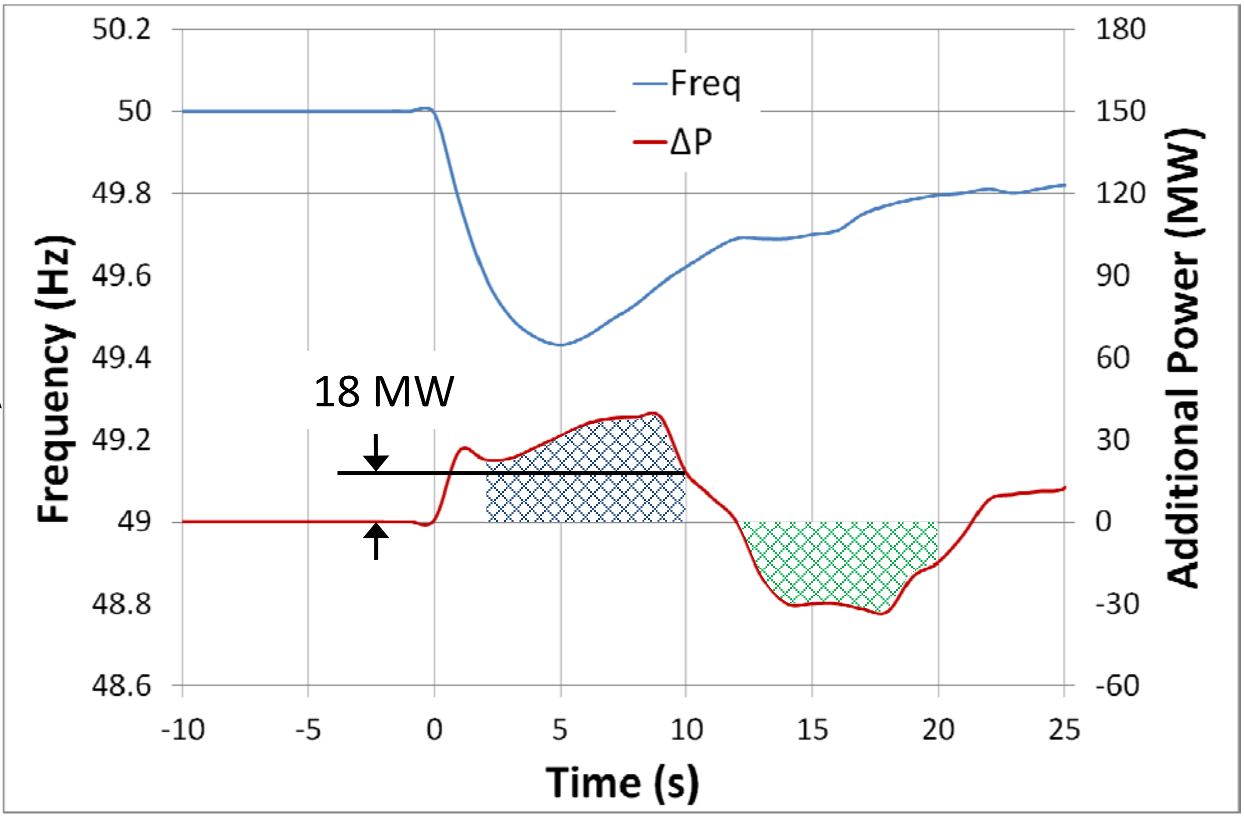


Figure 6: Fast Frequency Response Product

8.1.3 New product: Fast Post-fault Active Power Recovery

Units that can recover their MW output quickly following a voltage disturbance (including transmission faults) can mitigate the impact of such disturbances on the system frequency. If a large number of generators do not recover their MW output following a transmission fault, a significant power imbalance can occur, giving rise to a severe frequency transient. It is proposed to introduce a service that rewards generators that make a positive contribution to system security.

Fast Post-fault Active Power Recovery is defined as having been provided when a plant exporting active power to the system, recovers its active power to at least 90% of its pre-fault value within 250 ms of the voltage recovering to at least 90% of its pre-fault value for all fault disturbances cleared within 900 ms. The generator must remain connected to the system for at least 15 minutes following the fault.

Product Volume	*MW Output*
Product Scalar	*1*

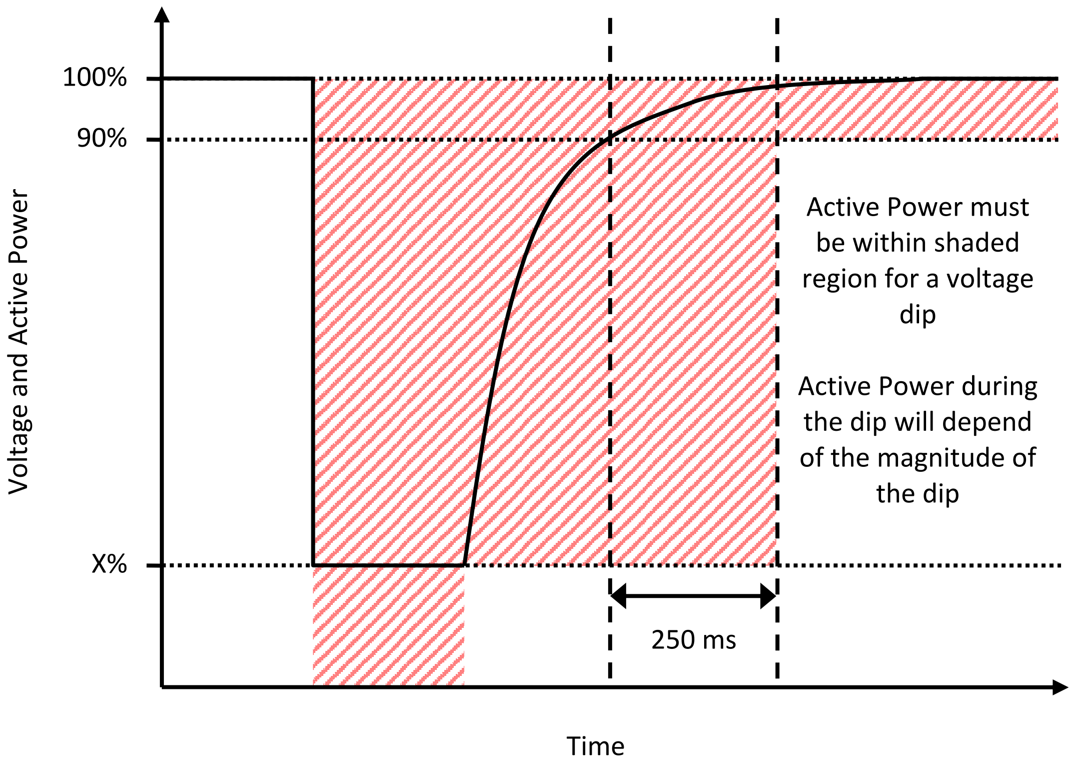


Figure 7: Fast Post-Fault Active Power Recovery Product

8.1.4 Existing product: Operating Reserve

As per current definitions – no changes to the definitions of the POR, SOR, TOR1 and TOR2 services are proposed.

8.1.5 Existing product: Replacement Reserve

It is proposed that, to avoid overlap with the 1 hour ramping product described below, the timings associated with the Replacement Reserve product are redefined.

Replacement Reserve is the additional MW output (and/or reduction in demand) provided compared to the pre-incident output (or demand) which is fully available and sustainable over the period from 20 minutes to 1 hour following an Event.

8.1.6 New product: Ramping Margin

The management of variability and uncertainty is critical to a power system with high levels of wind penetration. Detailed analysis has shown that portfolios that are capacity adequate are unlikely to be adequate in terms of ramping over all the necessary timeframes to efficiently and effectively manage the variable renewable sources and changes in interconnector flows while maintaining system security. The analysis has also indicated that a ramping-down product is not currently required.

To incentivise the portfolio to provide the necessary margins to securely operate the power system a new ramping-up product is being proposed over three distinct product time horizons.

Ramping Margin is defined as the guaranteed margin that a unit provides to the system operator at a point in time for a specific horizon and duration. The TSOs are proposing horizons of one, three and eight hours with associated durations of two, five and eight hours respectively. The Ramping Margin products are called RM1, RM3 and RM8 respectively. The Ramping Margin for a unit at the starting point is the ramp-up capability of the unit in the horizon time limited by the lowest availability in ***both*** *the horizon and duration window (e.g. from 0 to 8 hours for RM3). Thus the Ramping Margin represents the increased MW output that can be delivered with a good degree of certainty by the product horizon time and sustained for the product duration window.*

Product Volume	*Ramping Margin*
Product Scalar	*1*

Please note the following points in relation to the Ramping Margin Product:

- The ramping-up capability of the plant will be based on Technical Offer Data submitted to the SEM and will include ramp rates, dwell times, break points, etc. as applicable.
- The measurement of this product will be based on half hour figures of MW output and availability.
- Performance metrics will be based on a consideration of performance against dispatch instructions, technical offer data and start reliability (e.g. failure to synchronise).
- The three proposed products are not mutually exclusive. Plant capable of providing all three products are eligible to receive payment for all three, similarly for two.
- Both synchronised and non-synchronised plant is eligible for payment.
- The TSOs do not currently propose to weight payments at times of scarcity.
- The TSOs acknowledge that further discussions will take place regarding plant constrained on/off in the implementation stage.

Potential providers of these services include conventional generators that are not dispatched to their maximum output, storage devices, demand side providers and wind farms that have been dispatched down. In the future with the potential for implicit continuous gate closures, interconnector participants with excess capacity for importing may also be able to provide this service.

Please see Appendix D.2 for examples.

8.2 Voltage Control

System voltage is a key performance metric of the power system. It must be maintained within prescribed ranges at every node on the power system to avoid damage to system users. This is achieved by balancing the generation and consumption of reactive power on the system. A number of voltage control services are needed to ensure that this balance is maintained in normal operation and in the event of a disturbance to the system, dynamic reactive power response is required to maintain system stability.

8.2.1 Existing product: Steady-state reactive power

The need for reliable steady state reactive power control is important for the control of system voltages and for the efficient transmission of power around the system. Both synchronous and non-synchronous sources can contribute to this requirement.

The need for reactive power varies as demand varies and as the sources of generation vary. Since reactive power is difficult to transmit over long distances (unlike active power), reactive sources are required to be distributed across the system. Thus there is not necessarily a strong link between the need for active power and reactive power from the same sources. It is therefore proposed that the reactive power product is re-structured in a way that incentivises reactive capability across the widest possible active power range (P_{range}).

The Reactive Power Capability product is defined for conventional generators as the dispatchable reactive power range in Mvar (Q_{range}) that can be provided across the full range of active power output (i.e. from minimum generation to maximum generation). For wind farms the Reactive Power Capability product is defined as the dispatchable reactive power range in Mvar (Q_{range}) that can be provided across the active power range from Registered Capacity down to at least 12% Registered Capacity. Payment for Reactive Power Capability will be scaled by the RP Scalar:

$$RP\ Scalar = \frac{Power\ Output\ range\ (P_{range})\ that\ Q_{range}\ can\ be\ provided}{Registered\ Capacity}$$

RP Scalar = 1 for dispatchable synchronous condensers and dispatchable loads.

This product is dispatch-dependent. Plant will only receive payments when they are able to provide reactive power.

Product Volume	*Q_{range} × RP Scalar, while able to provide reactive power*
Product Scalar	*2 if provider is operating under the control of an AVR* *1 otherwise*

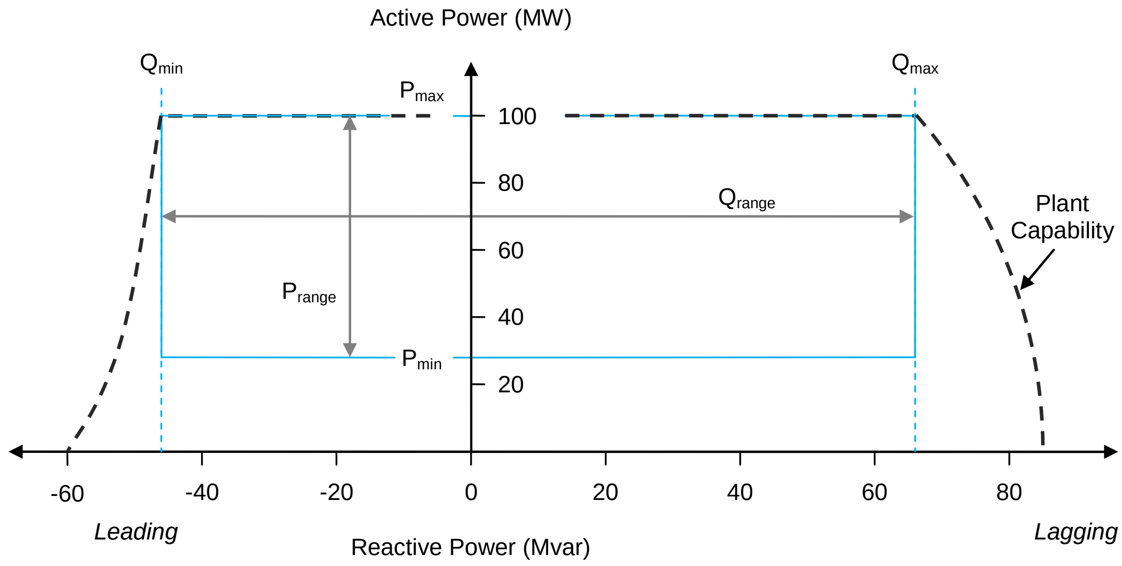


Figure 8: Illustration of Q_{range} and P_{range} for the Steady-State Reactive Power product

Please see Appendix D.3 for examples.

8.2.2 New product: Dynamic Reactive Response

At high levels of instantaneous penetration of non-synchronous generation there are relatively few conventional (synchronous) units left on the system and the electrical distance between these units is increased. The synchronous torque holding these units together as a single system is therefore weakened. This can be mitigated by an increase in the dynamic reactive response of wind farms during disturbances. Therefore, a new service is proposed to incentivise this type of response, which is particularly important at high levels of renewable non-synchronous generation. In line with the proposed changes to the Grid Codes, a Dynamic Reactive Response product is proposed.

The Dynamic Reactive Response product is defined as the ability of a unit when connected to deliver a Reactive Current response for voltage dips in excess of 30% that would achieve at least a Reactive Power in Mvar of 31% of the registered capacity at nominal voltage. The Reactive Current response shall be supplied with a Rise Time no greater than 40 ms and a Settling Time no greater than 300 ms.

Product Volume	*Registered Capacity when connected and capable of providing the required response*
Product Scalar	*1*

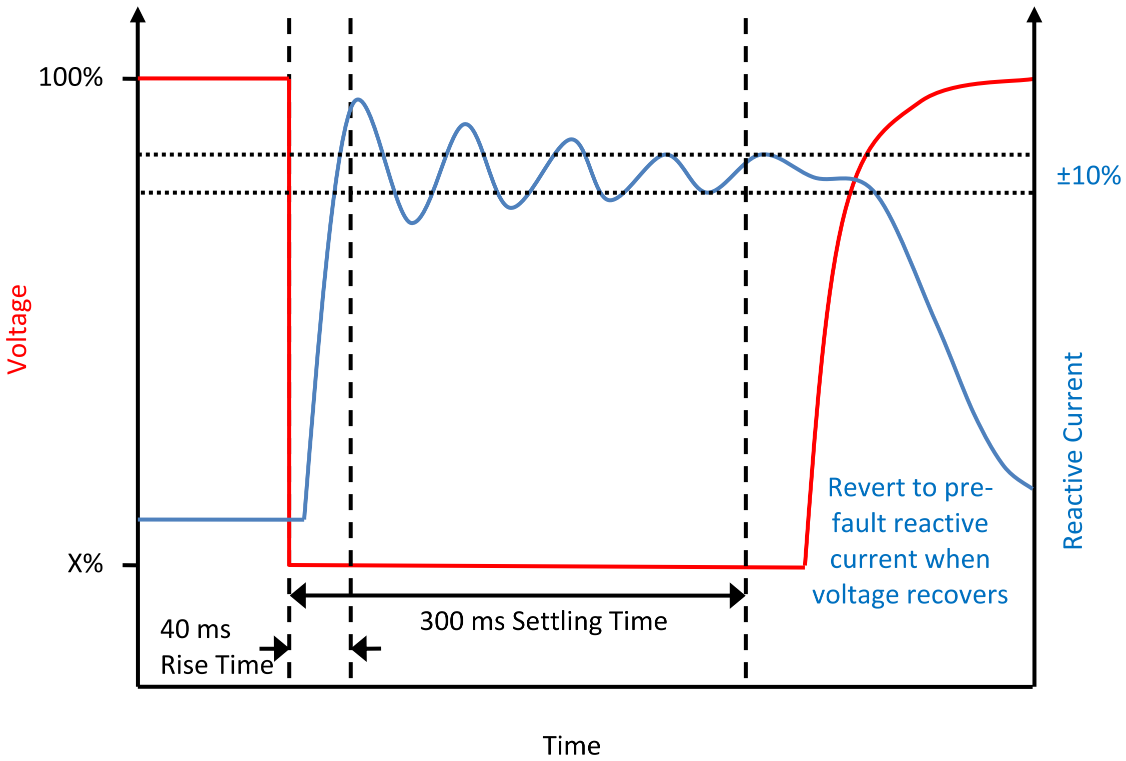


Figure 9: Dynamic Reactive Response product

The measurement of this product will require high quality phasor measurement units to be installed at the provider's site with appropriate communication and access arrangements agreed with the TSOs.

Any unit, synchronous or non-synchronous, who can provide this performance is eligible for the product. This includes conventional generators, storage devices and windfarms with advanced voltage controls.

Please see Appendix D.4 for an example.

9 Implementation and Funding Timetable

9.1.1 System Services Project Implement Timeline

Following any high level decision on System Services valuation approach there needs to be a detailed implementation plan developed with appropriate project resourcing. This plan will include appropriate consultation with the industry on topics such as:

- Development of the existing Harmonised Ancillary Services financial arrangements to align with those proposed for the new System Service products,
- The detailed approach to performance scalar determination including physical monitoring equipment,
- The development of a new standard system services contract template and
- The likely functional requirements of the settlement system.

It is currently estimated that approximately two years is required to complete implementation of the new arrangements following receipt of all necessary regulatory approvals.

As a consequence, 1st October 2015 appears to be likely start date for any new system services, subject to the approval of the SEM Committee. This allows time for full consideration to be made on the principles underlying the need for fundamental change in System Services and to allow for the design and implementation of all required systems. In addition this timing would also dovetail with the next pricing review for EirGrid-SONI and the next review for the CPM.

9.1.2 System Services Funding Requirements from 2015 to 2020

From a funding perspective if the decision is taken by the SEM Committee to adopt the value-based approach to System Services payments then three relevant factors should be considered when assessing when payments are likely to be needed to pay service providers.

- Given the performance scalar and the newness of the products it would seem sensible to assume that performance reliability would start at a lower level (resulting in lower performance scalar values) and rise to a higher level (greater than 90%) as service providers gain experience and tune their plant to the requirements. In essence performance reliability could be assumed to plateau by 2020.
- Some of the new system services products have been designed to improve on either existing conventional or windfarm plant design. Given that this will require investment there is likely to be more of this made by 2020 than 2015.
- With the growth in the installed RES-E plant expected to meet government targets by 2020 and as they have priority dispatch the dispatch levels for conventional plant are likely to reduce. Where dispatch based System Services products are used this will reduce System Services revenue as standard (Grid Code compliant) RES-E plant do not provide the same level of capability as standard conventional plant.

These considerations will mean that there is likely to be a rise in funding requirement from the introduction of the System Services up to 2020. This rise will be linked to the investment in the necessary system services capability and the level of RES-E, particularly windfarms.

10 Summary & Next Steps

- Policies regarding Renewable Energy are necessitating a fundamental change to the power system generation portfolio and operational characteristics which will transform the requirement for and composition of essential system services.

- This consultation paper, the third in a multi-stage consultation process, seeks views on a new methodology to determine the cumulative benefit of the required system services on the island of Ireland to facilitate the delivery of the renewable target.

- Using this methodology, the TSOs have calculated and propose a value of system services for consideration, in 2020, of €355m per annum, which includes the existing €60m for Harmonised Ancillary Services.

- The paper provides options and seeks views regarding the method by which the proposed System Services revenue might be allocated between each of the system services products.

- In this paper, the TSOs show why, through the analysis conducted, dispatch-dependent payments (combined with fixed rates over a number of years) are recommended for the products.

- The TSOs also confirm in this paper that they will be recommending Bilateral Contracts to the SEM Committee for the new services, broadly similar to the existing HAS Contracts with payments based on Regulatory approved rates. The TSOs will also recommend that these rates should be reviewed on a three to five year basis rather than the annual arrangements used for existing Ancillary Services.

- Finally, an updated section on the proposed new products, which adds detail and takes account of points raised by the respondents to the previous papers, is included at the end of the paper together with further numerical examples in the Appendices.

- As part of the current consultation, the TSOs will offer to hold bilateral discussions with individual Service Providers, during the consultation period.

- Following a review of the responses to this third consultation, the TSOs will submit a set of final recommendations to the Regulatory Authorities in Q1, 2013. The SEM Committee has indicated its intent to consult on a proposed decision following consideration of the suite of TSO recommendations.

11 Responding to the consultation

While views and comments are invited regarding all aspects of this document, the TSOs are particularly interested in your views on the proposed financial arrangements, the remuneration approach and contractual arrangements. Responses should be sent to:

DS3@eirgrid.com or DS3@soni.ltd.uk by Wednesday, 13th February 2013.

It would be helpful if responses are not confidential. If confidentiality is required, this should be made clear in the response. Please note that, in any event, all responses will be shared with the Regulatory Authorities.

Appendix A

A range of results from the Plexos studies are presented here. To assist in comparison, the following base case scenario for 2020 is shown in Table 7.

- Generation portfolio as per GCS 2011.
- Installed wind generation of 5,200 MW.
- Total demand of 42.8 TWh, as per median forecast in GCS 2011.
- Fuel and carbon prices based on the IEA World Energy Outlook (November 2011).
- Two interconnectors – Moyle and EWIC – between SEM and GB.
- GB modelled as a separate region with forecast demand and generation portfolio (based on an ENTSO-E model). This is used to determine market-based interconnector flows.
- Dispatch rules: Unconstrained, Business as Usual (BAU), Enhanced Operational Capability (EOC) as described in section 3.1.

For each Plexos run, the production costs are given as a total and broken down into SEM and GB costs. The constraint costs[12] are the difference between the constrained dispatch run and the associated unconstrained market run.

Table 7: Base Case Scenario (GCS 2020 portfolio, 5200 MW wind, fixed interconnector flows)

			Production Costs (m)				
Scenario	Wind Connected (MW)	Dispatch	SEM	GB	Total	Constraint Cost (m)	Wind Curtailment (%)
Base Case Scenario	5200	Unconstrained	€ 1,457	€ 12,791	€ 14,248	€ -	0.3%
		BAU	€ 1,627	€ 12,796	€ 14,423	€ 175.72	16.2%
		EOC	€ 1,515	€ 12,796	€ 14,311	€ 63.66	2.6%

Table 8 contains a range of sensitivity studies, with varying levels of installed wind generation. The rightmost two columns contain the difference between the total production costs and the constraint costs of the scenario with the equivalent scenario in the base case. For example, the 6000 MW case shows an unconstrained production cost saving of €112m compared to the base case. The difference between the two yellow highlighted cells is the €295m benefit described in section 3.2.

Table 8: Installed wind sensitivities (GCS portfolio)

			Production Costs (m)						
Scenario	Wind Connected (MW)	Dispatch	SEM	GB	Total	Constraint Cost (m)	Curtailment (%)	Prod. Cost Delta (m)	Const. Cost Delta (m)
GCS: 0 MW wind	0	Unconstrained	€ 2,367	€ 12,874	€ 15,241		0.0%	€ 993	
		BAU	€ 2,390	€ 12,875	€ 15,265	€ 24.20	0.0%	€ 842	-€ 152
		EOC	€ 2,390	€ 12,874	€ 15,265	€ 23.72	0.0%	€ 953	-€ 40
GCS: 2000 MW wind	2000	Unconstrained	€ 2,007	€ 12,845	€ 14,851		0.0%	€ 604	
		BAU	€ 2,032	€ 12,847	€ 14,880	€ 28.22	0.2%	€ 456	-€ 148
		EOC	€ 2,031	€ 12,847	€ 14,878	€ 26.27	0.0%	€ 566	-€ 37
GCS: 3600 MW wind	3600	Unconstrained	€ 1,721	€ 12,824	€ 14,544		0.0%	€ 297	
		BAU	€ 1,779	€ 12,827	€ 14,606	€ 62.14	5.2%	€ 183	-€ 114
		EOC	€ 1,753	€ 12,827	€ 14,581	€ 36.52	0.3%	€ 269	-€ 27
GCS: 5200 MW wind	5200	Unconstrained	€ 1,457	€ 12,791	€ 14,248		0.3%	€ -	
		BAU	€ 1,627	€ 12,796	€ 14,423	€ 175.72	16.2%	€ -	€ -
		EOC	€ 1,515	€ 12,796	€ 14,311	€ 63.66	2.6%	€ -	€ -
GCS: 6000 MW wind	6000	Unconstrained	€ 1,359	€ 12,776	€ 14,135		0.8%	-€ 112	
		BAU	€ 1,586	€ 12,779	€ 14,366	€ 230.71	20.7%	-€ 57	€ 55
		EOC	€ 1,434	€ 12,779	€ 14,213	€ 78.00	4.4%	-€ 98	€ 14
GCS: 7000 MW wind	7000	Unconstrained	€ 1,231	€ 12,748	€ 13,978		1.9%	-€ 269	
		BAU	€ 1,543	€ 12,751	€ 14,294	€ 315.77	26.6%	-€ 129	€ 140
		EOC	€ 1,338	€ 12,752	€ 14,090	€ 111.89	8.4%	-€ 221	€ 48

12 Note that the Dispatch Balancing Costs would contain additional elements to just the constraint costs.

Table 9 contains a number of additional sensitivity scenarios, where the assumptions in the base case are varied in turn.

Table 9: Sensitivity scenarios

Optimised Interconnector flow (i.e. not fixed by market schedule)

Scenario	Wind Connected (MW)	Dispatch	Production Costs (m) SEM	Production Costs (m) GB	Production Costs (m) Total	Constraint Cost (m)	Curtailment (%)	Prod. Cost Delta (m)	Const. Cost Delta (m)
Optimised I/C flows	5200	Unconstrained	€ 1,457	€ 12,791	€ 14,248		0.3%	€ 0	€ -
		BAU	€ 1,676	€ 12,691	€ 14,367	€ 119.22	11.2%	-€ 56	-€ 56
		EOC	€ 1,527	€ 12,761	€ 14,289	€ 40.96	1.6%	-€ 23	-€ 23

Zero Interconnector flow

Scenario	Wind Connected (MW)	Dispatch	Production Costs (m) SEM	Production Costs (m) GB	Production Costs (m) Total	Constraint Cost (m)	Curtailment (%)	Prod. Cost Delta (m)	Const. Cost Delta (m)
GCS 2020 less new conventional	5200	Unconstrained	€ 1,490	€ 12,820	€ 14,310		2.7%	€ 63	€ -
		BAU	€ 1,678	€ 12,819	€ 14,497	€ 186.57	17.7%	€ 74	€ 11
		EOC	€ 1,583	€ 12,821	€ 14,404	€ 93.16	4.9%	€ 92	€ 30

Improved Generator Technical Characteristics (lower Min Gen and higher Reserve)

Scenario	Wind Connected (MW)	Dispatch	Production Costs (m) SEM	Production Costs (m) GB	Production Costs (m) Total	Constraint Cost (m)	Curtailment (%)	Prod. Cost Delta (m)	Const. Cost Delta (m)
Improved TOD	5200	Unconstrained	€ 1,455	€ 12,791	€ 14,246		0.3%	-€ 1	€ -
		BAU	€ 1,621	€ 12,794	€ 14,415	€ 168.66	16.2%	-€ 8	-€ 7
		EOC	€ 1,496	€ 12,794	€ 14,290	€ 43.57	2.6%	-€ 21	-€ 20

High Fuel Price Scenario (50% fuel price increase)

Scenario	Wind Connected (MW)	Dispatch	Production Costs (m) SEM	Production Costs (m) GB	Production Costs (m) Total	Constraint Cost (m)	Curtailment (%)	Prod. Cost Delta (m)	Const. Cost Delta (m)
High Fuel Price	5200	Unconstrained	€ 2,124	€ 18,366	€ 20,490		0.5%	€ 6,242	€ -
		BAU	€ 2,373	€ 18,371	€ 20,743	€ 253.86	15.6%	€ 6,320	€ 78
		EOC	€ 2,207	€ 18,372	€ 20,578	€ 88.71	2.2%	€ 6,267	€ 25

High Start Cost Scenario

Scenario	Wind Connected (MW)	Dispatch	Production Costs (m) SEM	Production Costs (m) GB	Production Costs (m) Total	Constraint Cost (m)	Curtailment (%)	Prod. Cost Delta (m)	Const. Cost Delta (m)
High Start Costs	5200	Unconstrained	€ 1,435	€ 12,835	€ 14,270		0.4%	€ 22	€ -
		BAU	€ 1,612	€ 12,837	€ 14,448	€ 178.58	16.4%	€ 25	€ 3
		EOC	€ 1,500	€ 12,838	€ 14,337	€ 67.59	2.6%	€ 26	€ 4

Deferred Conventional Investment (DCI) portfolio

Scenario	Wind Connected (MW)	Dispatch	Production Costs (m) SEM	Production Costs (m) GB	Production Costs (m) Total	Constraint Cost (m)	Curtailment (%)	Prod. Cost Delta (m)	Const. Cost Delta (m)
High Start Costs	5200	Unconstrained	€ 1,452	€ 12,801	€ 14,253		0.3%	€ 5	€ -
		BAU	€ 1,631	€ 12,804	€ 14,435	€ 182.16	16.3%	€ 12	€ 6
		EOC	€ 1,512	€ 12,804	€ 14,316	€ 63.29	2.6%	€ 5	-€ 0

Appendix B

As explained in section 4, the TSOs have a preference for allocation option 3, where the system service revenue is allocated between products based on their relative impact on Dispatch Balancing Costs. To illustrate how this option would work, a number of Plexos studies have been carried out to provide an example.

The Plexos model of the 2020 system with the GCS portfolio was used. To provide a baseline, a "relaxed" dispatch scenario was considered, where the only operational constraint was the 75% SNSP limit. Further sensitivity scenarios were examined, with constraints added as appropriate for each product (e.g. POR requirement for primary operating reserve, Inertia constraint for SIR product).

The results of the sensitivity studies are shown in the following table.

Product	Constraint cost impact (€m)
SIR	7
FFR	33
POR	32
SOR	20
TOR1	23
TOR2	22
RR	5
Reactive Power	31
Dynamic Reactive	29
FPFAPR	50
Ramping RM1	7
Ramping RM3	15
Ramping RM8	16

If applied to a total system service revenue of €355m, the "pot" size for each product is as follows:

Product	System Service Pot (€m)
SIR	8
FFR	41
POR	39
SOR	24
TOR1	29
TOR2	27
RR	6
Reactive Power	38
Dynamic Reactive	35
FPFAPR	62
Ramping RM1	9
Ramping RM3	18
Ramping RM8	19

Appendix C

In section 5.1, an example was presented to show the difference between dispatch-dependent and capability based payments, using allocation method 1 (*pro rata*). The payments by product and provider type are shown in the table below.

Table 10: Illustrative annual system service payments (per MW installed) for each €1m spent on System Services, broken down by product and provider type

Service Provider Type	Capability (€/MW installed)	Dispatch-Dependent (€/MW installed)
CCGT		
Synchronous Inertia	11	12
Fast Frequency Response	11	10
Fast PF Active Power	22	23
Dynamic Reactive Power	20	19
Ramping	7	13
Coal		
Synchronous Inertia	30	55
Fast Frequency Response	10	18
Fast PF Active Power	22	35
Dynamic Reactive Power	20	29
Ramping	-	10
OCGT		
Synchronous Inertia	14	1
Fast Frequency Response	41	3
Fast PF Active Power	22	1
Dynamic Reactive Power	20	2
Ramping	48	65
Windfarm Basic		
Synchronous Inertia	-	-
Fast Frequency Response	-	-
Fast PF Active Power	-	-
Dynamic Reactive Power	-	-
Ramping	14	0.28
Windfarm Enhanced		
Synchronous Inertia	-	-
Fast Frequency Response	9	17
Fast PF Active Power	7	19
Dynamic Reactive Power	15	27
Ramping	14	0
Pumped Storage		
Synchronous Inertia	96	132
Fast Frequency Response	71	87
Fast PF Active Power	23	6
Dynamic Reactive Power	22	26
Ramping	53	77

Appendix D.1

Example 1

Inertial H Constant	6 MW s/MVA
Rated MVA	500 MVA
Lowest sustainable MW output at which the unit can operate at while providing reactive power control	220 MW
Is the unit capable of providing operating reserve at the lowest sustainable MW output at which the unit can operate at while providing reactive power control	Yes

Stored Kinetic Energy = Inertial H Constant × Rated MVA
= 6 MW s/MVA × 500 MVA
= 3,000 MW s

SIRF = Stored Kinetic Energy / Lowest sustainable MW output
= 3,000 MW s / 220 MW
= 13.36 s

SIRF value is less than the required SIRF threshold of 15 s therefore this unit is not eligible for payment

Example 2

Inertial H Constant	7 MW s/MVA
Rated MVA	500 MVA
Lowest sustainable MW output at which the unit can operate at while providing reactive power control	160 MW
Is the unit capable of providing operating reserve at the lowest sustainable MW output at which the unit can operate at while providing reactive power control	Yes

Stored Kinetic Energy = Inertial H Constant × Rated MVA
= 7 MW s/MVA × 500 MVA
= 3500 MW s

SIRF = Stored Kinetic Energy / Lowest sustainable MW output
= 3500 MW s / 160 MW
= 21.88 s

SIR Scalar = Stored Kinetic Energy × (SIRF – 15 s)
= 3500 MW s × (21.88 s – 15 s)
= 24080 MWs^2

Product Scalar = 2

While the unit is synchronised:
Hourly Payment = Product Volume × Product Scalar × Product Rate × Performance Scalar
= 24080 × 2 × Product Rate × Performance Scalar
= 48160 × Product Rate × Performance Scalar

Example 3

Inertial H Constant	3 MW s/MVA
Rated MVA	100 MVA
Lowest sustainable MW output at which the unit can operate at while providing reactive power control	0 MW
Is the unit capable of providing operating reserve at the lowest sustainable MW output at which the unit can operate at while providing reactive power control	No

Stored Kinetic Energy = Inertial H Constant × Rated MVA
= 3 MW s/MVA × 100 MVA
= 300 MW s

SIRF = Stored Kinetic Energy / Lowest sustainable MW output
= 300 MW s / 0 MW
= Limited to 45 s

SIR Scalar = Stored Kinetic Energy × (SIRF – 15 s)
= 300 MW s × (45 s – 15 s)
= 9,000 MWs^2

Product Scalar = 1

While the unit is synchronised:
Hourly Payment = Product Volume × Product Scalar × Product Rate × Performance Scalar
= 9,000 × 1 × Product Rate × Performance Scalar
= 9,000 × Product Rate × Performance Scalar

Appendix D.2

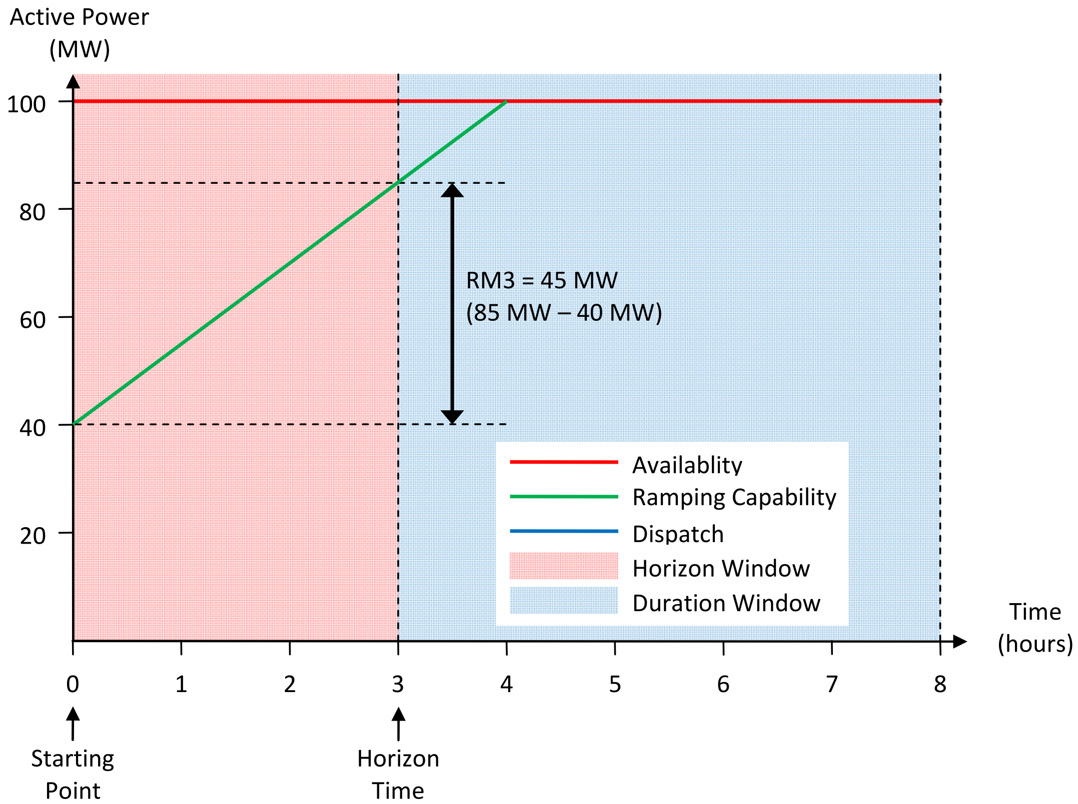


Figure 10: Example 1: Illustration of 3-hour ramping margin product with a 100 MW generator initially dispatched to 40 MW

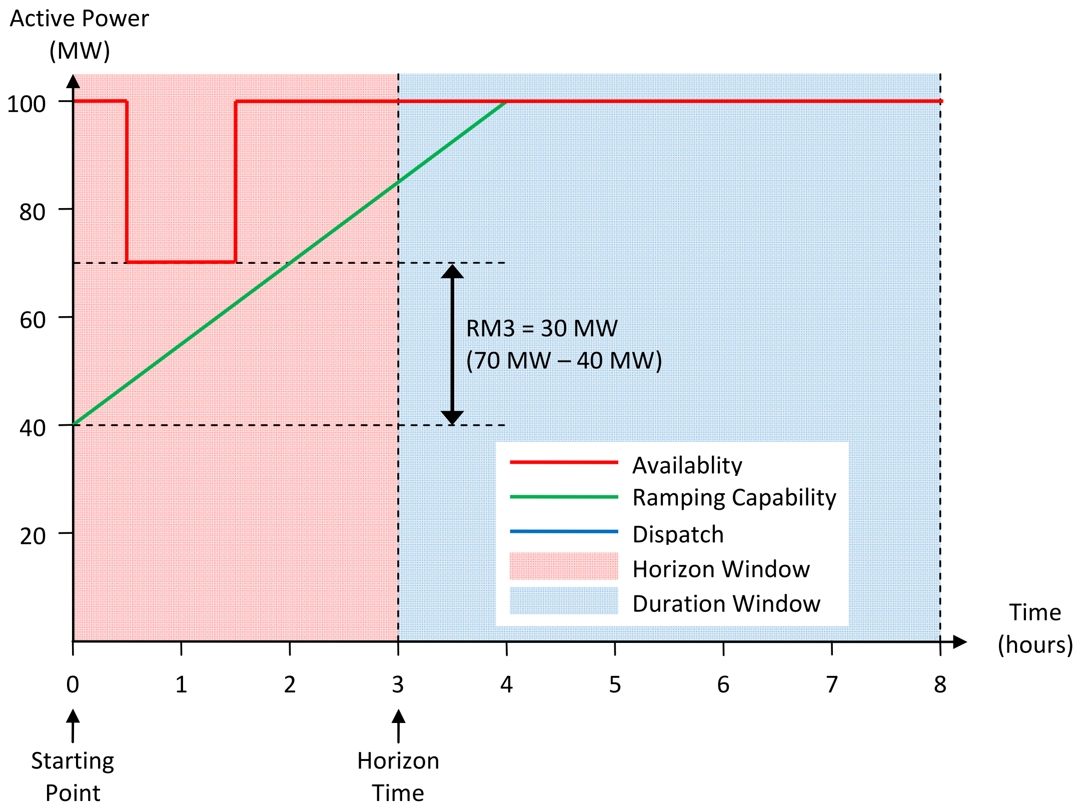


Figure 11: Example 2: Illustration of 3-hour ramping margin product with a 100 MW generator initially dispatched to 40 MW

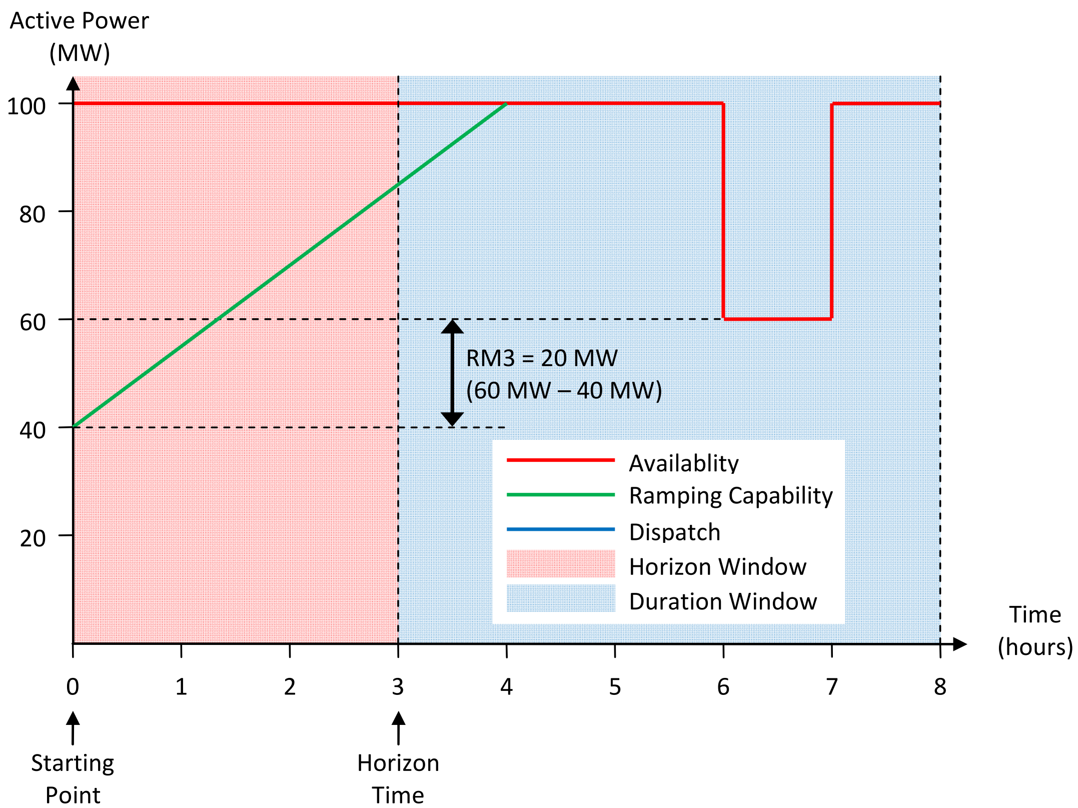


Figure 12: Example 3: Illustration of 3-hour ramping margin product with a 100 MW generator initially dispatched to 40 MW

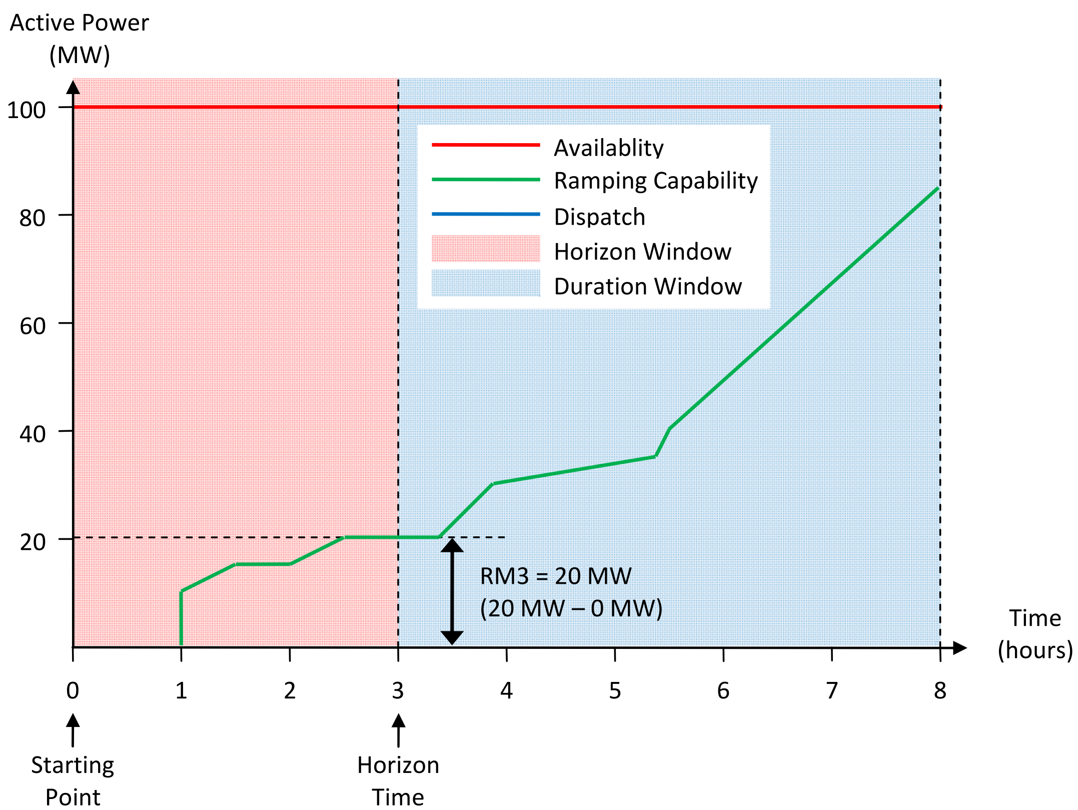


Figure 13: Example 4: Illustration of 3-hour ramping margin product with a 100 MW generator initially off

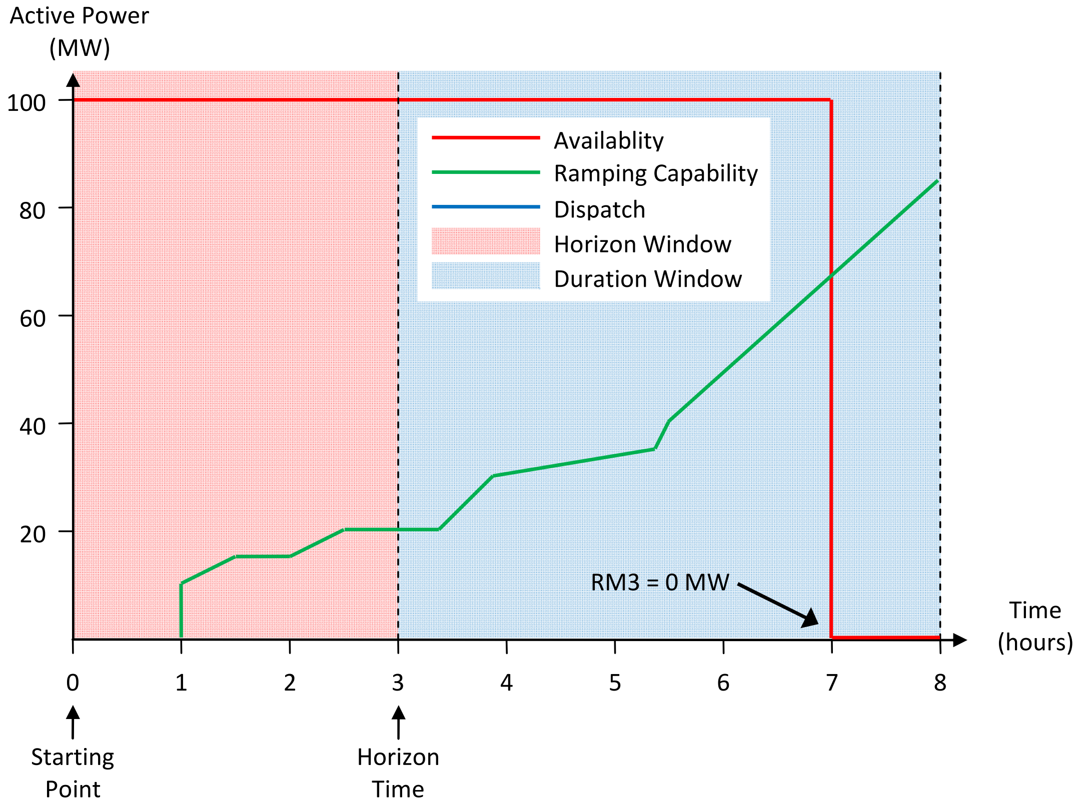


Figure 14: Example 5: Illustration of 3-hour ramping margin product with a 100 MW generator initially off

Appendix D.3

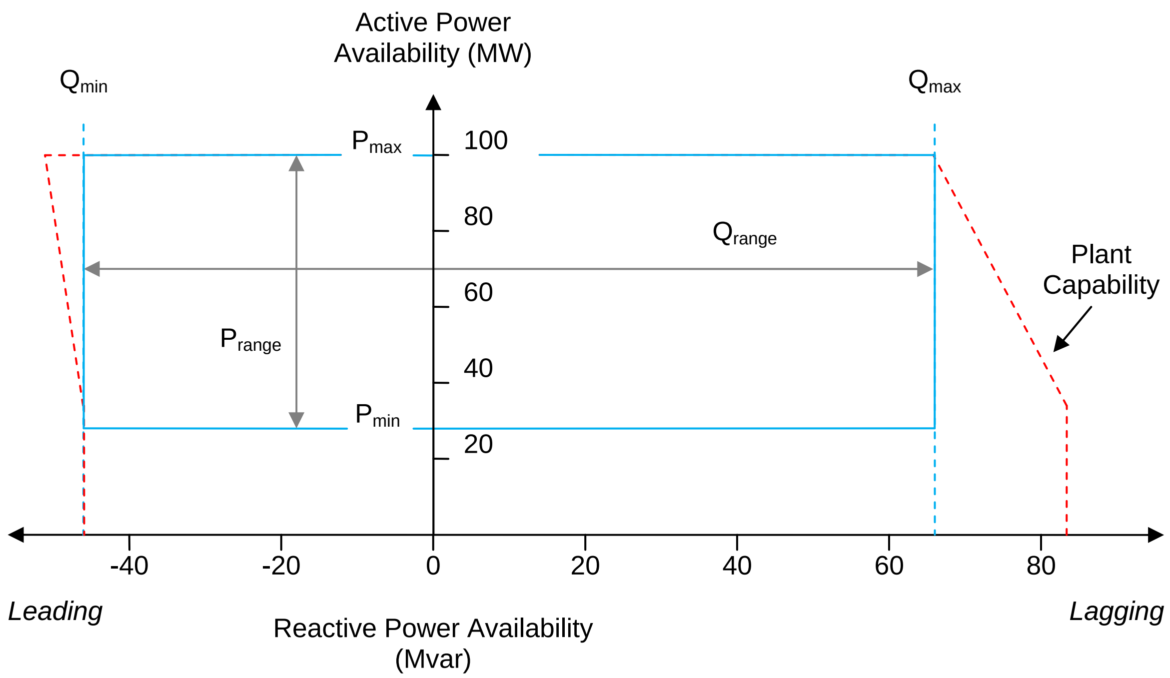


Figure 15: Illustration of Reactive Power product for a 100 MW generator

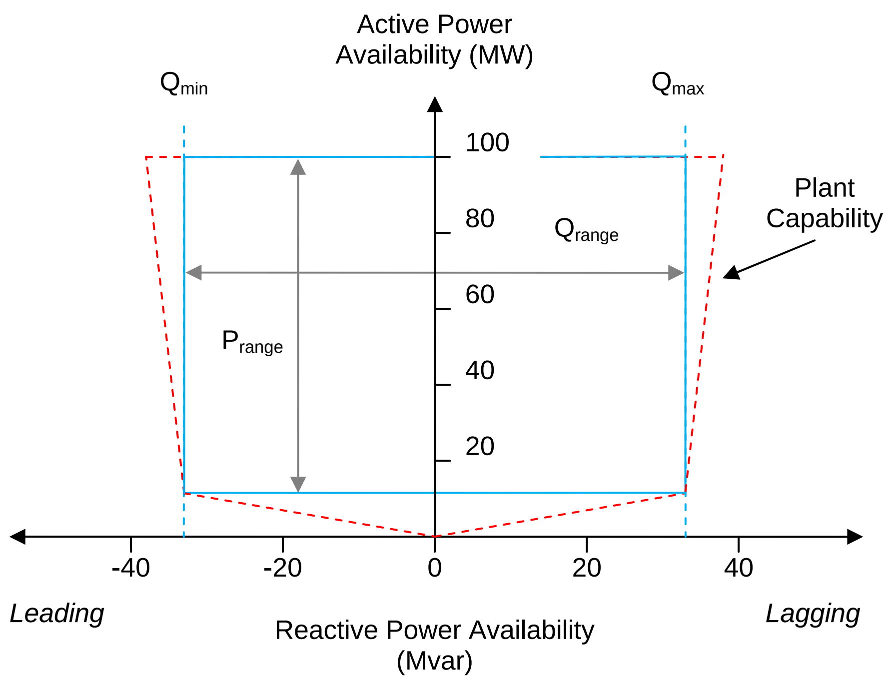


Figure 16: Illustration of Reactive Power product for a 100 MW wind farm. The wind farm will receive payment as long as it is generating above 12 MW.

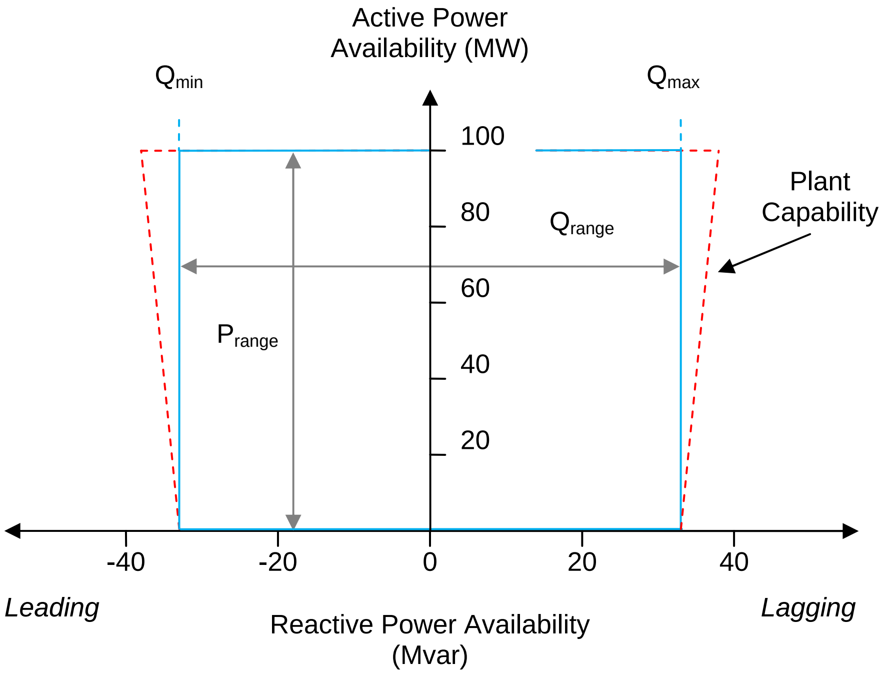


Figure 17: Illustration of Reactive Power product for a 100 MW wind farm with full reactive power control down to 0 MW. The wind farm will receive payments as long as it is available to provide reactive power.

Appendix D.4

Example

Unit Type	Wind Farm
Registered Capacity	100 MW
Output	50 MW
Nominal Voltage at Connection Point	110 kV
Voltage Dip	80%

At nominal voltage the unit should provide 31% of its registered capacity in Reactive Power i.e. 31 Mvar.

Therefore the reactive current required is 282 A (i.e. 31 Mvar / 110 kV)

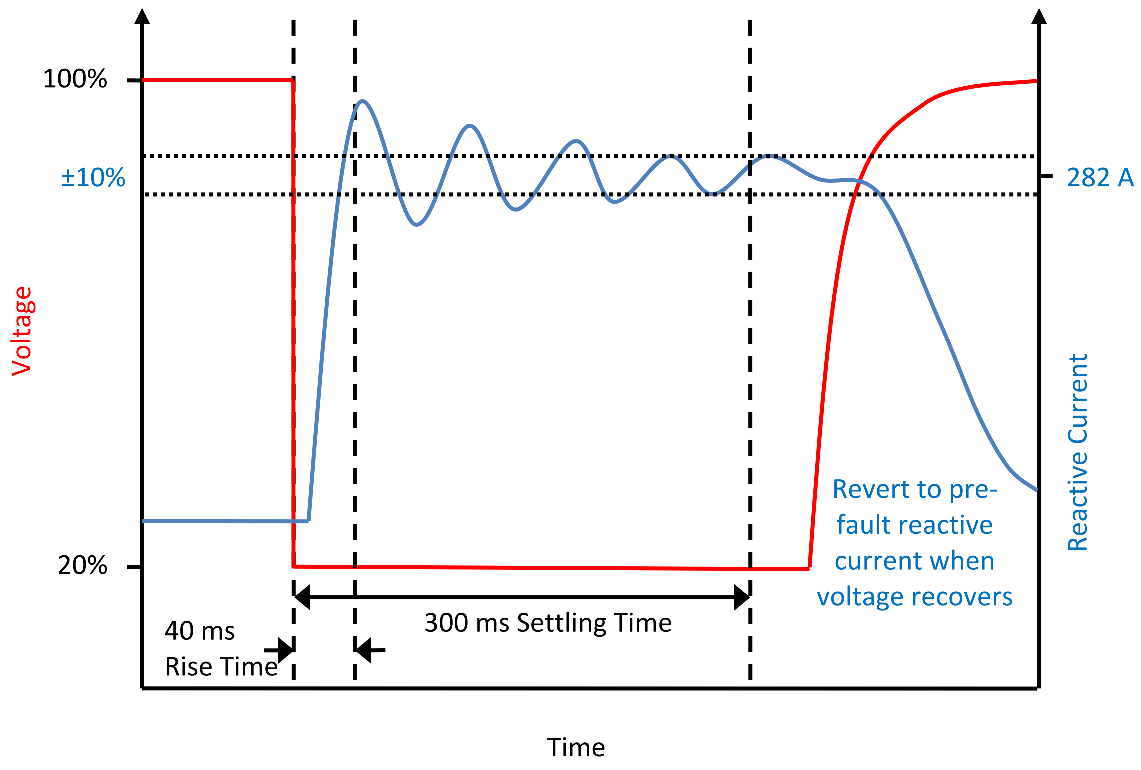


Figure 18: Dynamic Reactive Response product example with 100 MW wind farm exporting 50 MW