DS3:
System Services Valuation
Further Analysis

Report to the SEM Committee

Contents

Executive Summary

The TSOs have completed an additional suite of financial analysis arising out of the proposal to introduce a new DS3 System Services remuneration mechanism. The studies seek to determine the benefit of enhanced system services, and consider a range of installed wind levels, a variety of operational scenarios emulating increasing system service capability and a number of updated assumptions. The analysis has been completed and is summarised in high level in this report. In parallel, detailed results have been provided as an annex to this paper.

The approaches used to estimate the benefit of enhanced system services were based on assessing the cost of operating the system with enhanced system services compared against a counterfactual (representing how the system might be operated without the enhanced services). The main counterfactual explored was based on an assumption that the Rate of Change of Frequency (RoCoF) standard had been increased to 1 Hz/s, and that the change in RoCoF standard would allow System Non-Synchronous Penetration (SNSP) levels to be raised to 60% (thereafter referred to as the "RoCoF resolved" scenario).

Two different approaches were examined to determine the value of enhanced system services. The first methodology utilised the production cost savings in the SEM, from operating with higher levels of wind, to value the benefit. The second methodology examined the change in wholesale market costs. This approach examines the difference in the total of the energy costs to energy consumers (system marginal price by demand) plus the dispatch balancing costs. This is equivalent to the sum of the dispatch production cost and the infra-marginal rent.

The analysis was carried out for a forecast 2020 Ireland and Northern Ireland system, with assumptions and inputs updated in line with the All Island Generation Capacity Statement 2014-2023. A range of wind capacities were considered. For the base case, it was assumed that in addition to the existing level of installed wind, 50% of the contracted/forecast wind generation would be connected by 2020. The resultant wind capacity (4.6 GW) is sufficient to meet the Governments' RES-E targets, provided the system can be operated up to a 75% SNSP level (EP 4600 Scenario). This level of wind is consistent with the figures in the Generation Capacity Statement (GCS) 2014-2023.

Full year market and dispatch schedules were modelled using Plexos, which allowed comparison of the cost of operating the system with enhanced system services (up to a 75% SNSP limit) against the counterfactual "RoCoF resolved" scenario (up to a 60% SNSP limit), for varying levels of installed wind. For the base case (4.6 GW installed wind, RR 4600 Scenario), the production cost difference between a 75% SNSP limit and "RoCoF resolved" is €98m.

However, the impact on wind curtailment levels should also be considered. For the enhanced operational capability scenario, wind curtailment is approximately 1.5% and the total renewable share is estimated at 40%. At the lower system capability level (only "RoCoF resolved"), wind curtailment is over 11% and the total renewable share is less than 37%. This is probably an unrealistic scenario as windfarms will be unlikely to build at this level of curtailment, at least without additional supports or other interventions.

To explore this issue further, different installed wind scenarios were examined. In particular, for the low wind scenario (3.5 GW installed, representing 25% of contracted/forecast wind), the "RoCoF resolved" scenario would result in curtailment levels of approximately 5%. However, in this case the level of annual renewable production only reaches 30% (RR 3500 Scenario). If this scenario is used as the counterfactual, then the production cost value is the difference between operating a system with 3.5 GW installed wind with only RoCoF resolved to one with 4.6 GW installed wind and an operating capability of 75% SNSP. This value is €241m (Figure 1). When the existing €60m is added to this for harmonised ancillary services (HAS), the total value of system services rises to €300m.

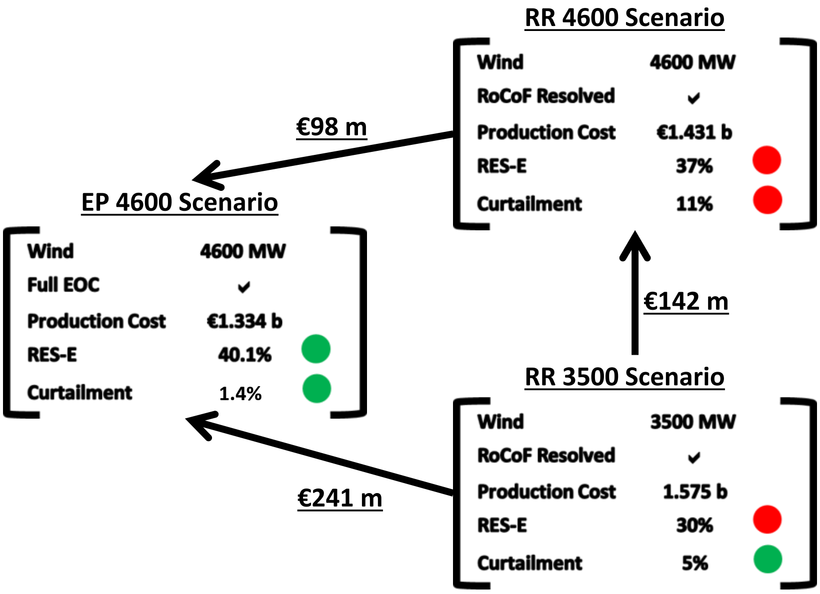

Figure 1 Overview of Starting Point and End point scenarios

In addition to the production costs, market prices, dispatch balancing costs and costs to the end consumers were calculated. The wholesale energy costs had not been included in the original analysis. This can be quite complex, due to the interaction between the SEM and GB, and the impact of curtailment on the market schedule. The consumer wholesale energy cost is the sum of SMP multiplied by demand added to the constraint costs, representing the market and dispatch elements.

The wholesale energy cost difference between the low wind counterfactual (3.5 GW with 60% SNSP) and the enhanced operational scenario for the base case is estimated at €178m. However, the TSOs have some concerns that there may be some modelling issues embedded in this answer which cannot be fully accounted for at this time. Specifically there are trends that appear to be non-intuitive with increasing levels of wind and could indicate some numerical issues in the price formation. However, it is also possible that the answers are a genuine outcome and arise from the non-linearity of the uplift formulation combined with the additional complexity introduced when trying to determine pricing volumes when wind is not paid for curtailed energy.

The €301m production value was used to calculate system service rates, volumes and ultimately revenue streams for all service providers. A detailed breakdown of System Services revenues based on this value is included in the report. Based on these revenues it would appear that if the full €300m was used to determine system service rates, the impact on the Capacity Payments Mechanism would be a reduction of €101m if the existing structures remain in place.

1. Introduction

EirGrid and SONI put in place a multi-year, multi-stakeholder programme of work, "Delivering a Secure Sustainable System" (DS3) to address the fundamental needs of the power system with increasing levels of renewable generation required to meet policy objectives by 2020. This eleven workstream programme aims to address the required and changing system performance characteristics while developing new operational policies to best manage and utilise this capability by implementing new control centre tools and practices.

The DS3 System Services Review is central to incentivising the appropriate investment in enhanced performance capability and is a key component of the DS3 programme. It has involved a multi-stage consultation process[1,2]. The objectives of the review were published and formed part of a preliminary consultation paper. This paper was followed by two further consultation papers, two rounds of bilateral meetings and a number of industry workshops. The consultation process culminated in a recommendations paper[3], which was submitted to the SEM Committee for its consideration.

Following a review of these recommendations the SEM Committee (SEMC) has adopted a multi-stage approach to addressing the TSOs' proposals. The first stage focussed on the definitions of the proposed new products. A decision in principle (SEM-13-098) was published in December 2013. The second stage would focus on the contractual and financial aspects of System Services. The SEMC decided that further economic analysis was required to inform the decision. This economic analysis was to involve three elements:

i) "demand-side" analysis to determine the value of system services
ii) "supply-side" analysis to determine the revenues required to realise the necessary investment in system services
iii) assessment of options for procurement mechanisms

To facilitate the "demand-side" analysis, the TSOs have completed additional financial analysis, presented in this report, based on agreed assumptions with the regulatory authorities' project team.

1.1 SEM Committee objectives for further analysis

The reservations of the SEMC with respect to the financial analysis completed by the TSOs were discussed in a number of bilateral meetings between the TSOs' project team and the regulatory

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[1] System Services consultation process
http://www.eirgrid.com/operations/ds3/industryengagement/

[2] System Services review project plan
http://www.eirgrid.com/media/DS3%20System%20Services.pdf

[3] TSO Recommendations Paper
http://www.eirgrid.com/media/SS_May_2013_TSO_Recommendations_Paper.pdf

authorities, including their consultants, in October, November and December 2013. Through these meetings an agreed way forward was developed.

1.1.1 Counterfactual to assume RoCoF modifications approved and implemented

With respect to the work that the TSOs were to do, it was agreed that the core counterfactual that the SEMC wished to explore was to assume that the Rate of Change of Frequency (RoCoF) modifications as submitted by the TSOs in December 2012 were fully implemented. In this way there would be system operational benefits already accrued that would not be directly due to the DS3 System Services recommendation. This core counterfactual was to be examined through all the different scenarios.

1.1.2 Production Cost and Market Costs

The method of calculating the benefit from enhanced system services was a concern for the RAs. While it was accepted that production cost valuation was appropriate for the TSOs to consider, the SEMC have a duty to understand the final costs to the consumer. In this regard, in any new runs there would also be a need to calculate these. To this end it was agreed that production and market costs would be determined for all scenarios. Calculation of the production costs was based on Plexos modelling using the heat rate curves of the generators and the associated price of fuel (IEA World Energy Outlook 2013).

The determination of market costs was more problematic for a number of reasons:

- The calculation of system marginal price and uplift in Plexos compared to the core ABB market engine has always shown differences. Some of these arise out of the optimisation horizon and numerical algorithms employed. However, it is generally accepted that Plexos runs can be used in determining broadly appropriate market analysis.
- This approach was further complicated since wind curtailment will not be paid for post 2017; thus the curtailed volume was removed in determining market scheduled quantities and system marginal prices. This was implemented in Plexos by adding the curtailed volume to the demand, which then necessitated additional post-processing of results.
- The incorporation of priority dispatch was modelled as negatively priced generation with associated issues for aggregate generator revenues which needed to be post processed.
- The costs of the consumer will include the costs of supports to meet the RES-E targets in both jurisdictions and any potential penalties from Europe arising out of failing to meet the targets. These costs have not been included in the analysis.

In both benefit determination mechanisms it was assumed that revenues earned from System Service provision would not impact on the bid prices into the energy market.

1.1.3 General Modelling Assumptions

1.1.3.1 Installed Wind levels

Initially the modelling assumed installed wind levels consistent with the take up of offers in the Gate 3 process. These rates were applied on an all island basis. The preliminary runs based on this assumption (in all operational scenarios) showed that the level of renewable electricity greatly exceeded the target levels. However, revising the assumption iteratively it was determined that the base case to meet the 40% electricity (at 75% SNSP) from RES-E by 2020 was where a 50% take up rate for future wind generation[4] was applied. The base case therefore had an installed wind level of circa 4570 MW, combined with some small embedded RES. However, a range of different installed wind levels were examined to provide a broader context. Aggregated results are to be found in the appendix.

1.1.3.2 Interconnection

The modelling of interconnection in the original TSO recommendation had utilised a high arbitrage threshold (€13/MWh) to simulate the barriers present that restrict trading between the two market areas. The RAs and their consultants were concerned that this overly restricted the flows and, when combined with the fuel and carbon assumptions, unduly biased them to importing. In addition, given the introduction of intra-day trading in the SEM, the target model design (with implicit continuous auctions) and introduction of a high carbon price floor in Great Britain (GB), there should be an assumption of closer to real time trading, predominantly exports, particularly in high wind scenarios.

Exploring the implications of how this might be modelled it was agreed by the project teams that an arbitrage threshold should be lowered to €3/MWh and that a higher carbon price be used for GB generators. There was an examination of allowing the interconnector flow to be determined in the ex post market run rather than determining the flow in the ex ante run and fixing in the ex post run. This would simulate the ability of trading closer to real time but would have the drawback that it would make it difficult to disaggregate the benefits to the SEM from those in Great Britain. It was agreed that, provided the flows were predominantly exporting, it was appropriate to model the interconnector flows by fixing them from an ex ante run.

[4] For consistency, the same scaling factor was applied to future embedded generation

2. Plexos modelling – assumptions and methodology

The Plexos model developed for the system services review was used as the basis for the modelling. However, a number of revisions were made as more up-to-date information was available. A summary of the key assumptions is as follows.

Demand

The total demand is 38,691 GWh, corresponding to the median demand forecast in the Generation Capacity Statement (GCS) 2014–2023, scaled up for a full calendar year. Note that this is approximately a 10% reduction of the demand forecast used for the original modelling.

Installed Wind Capacity

Since the Gate 3 process has progressed significantly since the original modelling was carried out, the RAs initially suggested that the installed wind be based on the total connected and contracted wind. However, preliminary modelling indicated that when revised assumptions for demand were incorporated, by assuming that all contracted wind would construct, this would result in high levels of curtailment (up to 30%) and/or considerable overshoot of the renewables targets.

Thus, as explained in section 1.1.3.1, for the base case an assumed wind capacity of 4.57 GW was used. This represents all the currently connected wind generation and 50% of the contracted/forecast wind and is broadly in line with the installed wind generation figures in GCS 2014-2023. A range of other wind scenarios were also considered as shown in Table 1 below. Further details are in Appendix I.

Table 1: Installed Wind Capacities

Scenario	*Future wind uptake*	*Installed Wind (MW)*
Low wind	25%	3474
Base case	**50%**	**4572**
High wind	75%	5670
Very high wind	100%	6768

Generation portfolio capabilities

The generation portfolio is based on the GCS 2014-2023portfolio[5]. Further details are contained in Appendix A. Embedded generation (which is not centrally dispatched) is explicitly modelled in Plexos. This is also based on the GCS 2013. To ensure consistency with the wind capacity, a scaling factor is applied such that the amount of embedded generation modelled is all currently connected and 50% of the forecast increase.

[5] Due to the urgency of this analysis, it was not possible to wait for the GCS 2014 portfolio to be finalised before commencing the Plexos modelling.

The current contracted capabilities and technical offer data for the generation portfolio were used as the base case assumption. An enhanced capability set was also developed and used in sensitivity studies for the enhanced operational capability scenarios (70% and 75% SNSP limits). The enhancements include reduced minimum stable generation levels, increased reserve capabilities and improved ramping capabilities (shorter start-up times for off-line generation), reflecting an assumption that payments for enhanced services are expected to deliver benefits in these capabilities.

2.1 Methodology

A three-stage process was used, with a Plexos run at each stage. The outputs from each stage form part of the inputs for the subsequent stages as shown in the Figure 2 and listed as follows:

1) Ex ante market (unconstrained) run – determines interconnector flows
2) Dispatch (constrained) run – replicates the actual dispatch based on the operational scenario
3) Ex post market run – determines SMPs and market quantities (wind curtailment removed)

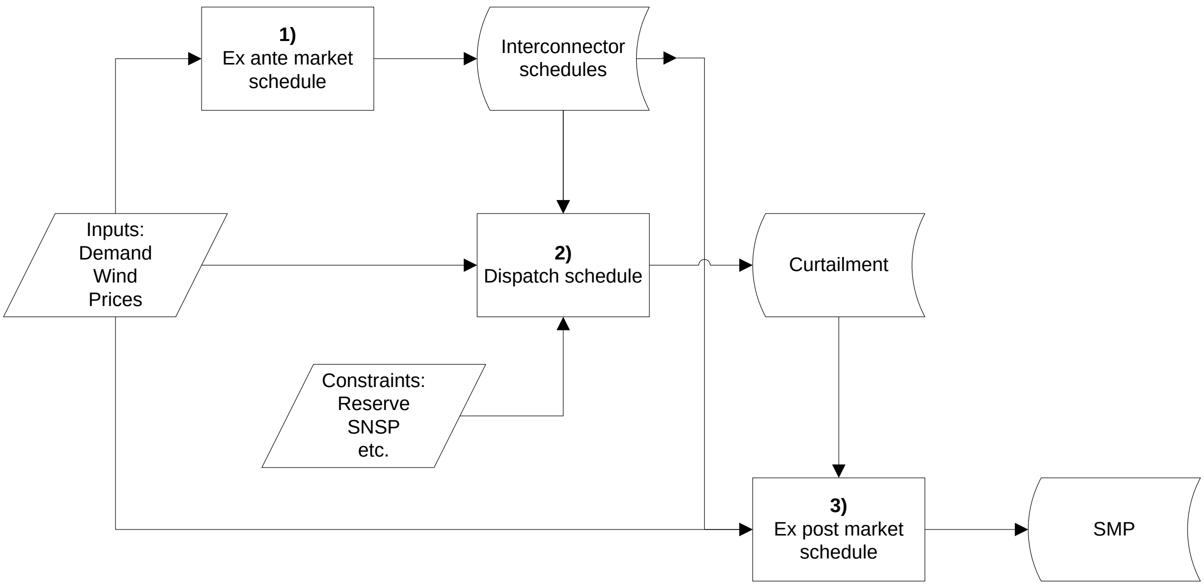

Figure 2 Plexos Modelling Methodology

The ex ante run is the least constrained and attempts to mimic the current ex ante market schedule. The key inputs are the demand, the wind profile and the generator prices.

The dispatch run includes operational constraints, which vary by scenario, to approximate the actual dispatch that would be expected. The interconnector flow determined in the ex ante market run is a fixed input for the dispatch run. The constraints are described in section 2.2 below.

The ex post market run has two input constraints in addition to those in the ex ante run:

a) Wind availability reduced by curtailment volume (output from dispatch run)
b) Interconnector flow fixed according to *ex ante* run

2.2 Operational constraints

For the original studies, the expected 2020 operational constraints were modelled as simply as possible by including an SNSP limit, an inertia limit and operating reserve requirements. This allowed the current operational constraints to be compared with relaxed constraints that would be expected to reflect a system with the proposed enhanced services.

This approach was appropriate for considering the two ends of the spectrum. However, since more operational regimes were to be considered, a more detailed approach to the operational constraints was required. In particular, for the new counterfactual it is assumed that the RoCoF standard has been increased to 1 Hz/s. This will allow some operational constraints to be relaxed (e.g. SNSP) but in the absence of the enhanced system service products, other constraints will become more binding and the full benefit will not be realisable.

For this updated analysis four operational scenarios were considered:

- Business as Usual (BAU): Current constraints
- Business as Usual (BAU): RoCoF resolved
- System Services Implemented: Partial Enhanced Operational Capability (EOC)
- System Services Implemented: Full Enhanced Operational Capability (EOC)

The operational constraints used in the four operational scenarios are detailed in Table 2. It should be noted that these constraints are indicative, based on the TSOs' judgement, as it was not possible to carry out detailed technical analysis within the timeline required for the Plexos studies. However, the evolution of the constraints is consistent with the findings of both the Facilitation of Renewables studies and the DS3 programme.

Table 2 Operational Constraints for four modelled operational scenarios

	Business as Usual		System Services Implemented	
	Current constraints	RoCoF resolved	Partial EOC	Full EOC
SNSP limit ***(%)***	50%	60%	70%	75%
Max RoCoF ***(Hz/s)***	0.5	1	1.0	-
Minimum Inertia ***(MW s)***	20,000	18,000	15,000	10,000
Minimum large generators	8	6	5	-
Operating Reserve ***(MW)***	*(current rules)*	Extra POR: +25% LSI	*(current rules)*	*(current rules)*
Wind Limit ***(MW)***	2,500	2,500	4,000	-

Further details on the operational constraints and their basis can be found in the Operating Security Standards[6] and the Operational Constraints Update[7] documents, both of which are published on the EirGrid website. A brief explanation of each is also provided here.

System Non-Synchronous Penetration (SNSP)
The SNSP limit has been developed based on the results of the Facilitation of Renewables (FoR) studies[8].

Maximum RoCoF
The maximum RoCoF is modelled in Plexos as a dynamic constraint that ensures that there is sufficient inertia relative to the size of the large infeeds and outfeeds such that the RoCoF limit will not be breached.

Minimum inertia and minimum number of generators
These constraints ensure that there is sufficient synchronous generation synchronised to ensure the transient, dynamic and voltage stability of the system following contingencies such as loss of generation and transmission faults.

Operating Reserve
In the original analysis, for simplicity, the operating reserve requirement was modelled as a fixed requirement. The reserve modelling has been enhanced: the requirement is now dynamic (time-varying) based on the largest infeed and there is a minimum spinning reserve floor, consistent with current operational policy. For the "RoCoF resolved" scenario, it is assumed that the system inertia will be lower (since the allowable RoCoF will be higher). The proposed enhanced system services are required to realise the full benefit of the higher RoCoF standard. In particular, faster reserves will be required. In the absence of the Fast Frequency Response product, it will be necessary to increase the primary reserve requirement so that a more rapidly falling frequency can be arrested before under-frequency load shedding is activated.

Wind limit
Increasing the RoCoF standard to 1 Hz/s will address the problem of excessive RoCoF events caused by loss of a large infeed or outfeed. However, on its own, it will not address the problem of voltage-dip induced frequency dips which would arise at high wind penetration levels following a severe fault. The Fast Post-Fault Active Power Recovery and Dynamic Reactive Response products are specifically designed to mitigate this problem. If these services are not implemented, it will be necessary to manage the risk of a voltage dip induced high RoCoF event by imposing maximum security limits on wind generation in the affected areas, which will result in curtailment. Since the network is not modelled in Plexos, these regional limits are modelled as a single, system-wide wind generation limit. It is assumed that this limit will rise in the enhanced operational capability scenarios.

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[6] http://www.eirgrid.com/media/Operating%20Security%20Standards%20December%202011.pdf
[7] http://www.eirgrid.com/media/OperationalConstraintsUpdateDecember2013.pdf
[8] http://www.eirgrid.com/media/FacilitationRenewablesFinalStudyReport.pdf

It should be noted that between all the constraints there is a degree of overlap. This is normal. For example, the minimum number of units constraint may result in more synchronous inertia than the minimum requirement. However, each of the constraints is required to ensure that Plexos doesn't "cheat" – for example, by satisfying the SNSP constraint using low inertia generators resulting in an insecure system that is too low in inertia.

3. Results of modelling

The Plexos modelling including different wind levels and operational scenarios has been completed. For each run aggregate system information and individual unit hourly outputs have been determined for the full 2020 year. For the basecase (circa 4600 MW), low (circa 3500 MW) and high installed wind level (circa 5600 MW) scenarios, the aggregate system information for the interconnector flows (ex ante market run) is found in Table 1, production cost information is shown in Table 2, and market cost information is shown in Table 3. Further detailed aggregate information on additional scenarios is contained in the Annex to this report.

Table 3 Ex ante runs

			Interconnector flows			Market Production Costs			
Scenario	Wind connected (GW)	Description	Import (GWh)	Export (GWh)	Net (GWh)	SEM (€m)	GB (€m)	Total (€m)	Demand (TWh)
A	3.5	Low wind	1,723	-2,982	-1,259	1,482	11,062	12,544	38.7
B	4.6	Base case	1,477	-3,204	-1,728	1,304	11,042	12,346	38.7
C	5.7	High wind	1,292	-3,549	-2,257	1,123	11,022	12,145	38.7

The ex ante runs, which are unconstrained, show a predominant export flow on the interconnectors, consistent with the input assumptions. As expected, exports increase with increasing installed wind. Based on this, and as explained in section 1.1.3.2, the interconnector flows were fixed for the dispatch and *ex post* market runs. Also shown are the GB production costs, which since the interconnector flows are fixed, will not change across different dispatch scenarios (for a given level of installed wind).

Table 4 Dispatch runs (with high curtailment values highlighted)

			Dispatch			
Scenario ID	Wind connected (GW)	Dispatch	SEM Production Cost (€m)	Wind Curtailment (%)	Wind (%)	RES (%)
A_50	3.5	50% (current)	€ 1,557	8.5%	23.1%	29.2%
A_60		60% (RoCoF)	€ 1,575	4.8%	24.0%	30.1%
A_70		70% (Partial)	€ 1,525	1.5%	24.9%	31.0%
A_75		75% (Full)	€ 1,516	0.7%	25.1%	31.2%
B_50	4.6	50% (current)	€ 1,445	15.6%	28.0%	35.3%
B_60		60% (RoCoF)	€ 1,432	11.2%	29.5%	36.8%
B_70		70% (Partial)	€ 1,344	2.8%	32.3%	39.7%
B_75		75% (Full)	€ 1,334	1.4%	32.7%	40.1%
C_50	5.7	50% (current)	€ 1,367	23.0%	31.7%	40.5%
C_60		60% (RoCoF)	€ 1,338	18.8%	33.5%	42.3%
C_70		70% (Partial)	€ 1,194	6.0%	38.7%	47.6%
C_75		75% (Full)	€ 1,176	3.5%	39.7%	48.7%

Table 5 Market runs (ex post)

Scenario ID	Wind connected (GW)	Dispatch	Market: SEM Production Cost (€m)	Load weighted SMP (€/MWh)	Constraint costs (€m)	Consumer energy cost (€m)	Wholesale cost (€m)
A_50	3.5	50% (current)	€ 1,496	€ 73.02	€ 62	€ 2,826	€ 2,887
A_60		60% (RoCoF)	€ 1,479	€ 72.58	€ 96	€ 2,809	€ 2,904
A_70		70% (Partial)	€ 1,463	€ 71.68	€ 62	€ 2,774	€ 2,836
A_75		75% (Full)	€ 1,460	€ 71.52	€ 55	€ 2,767	€ 2,823
B_50	4.6	50% (current)	€ 1,374	€ 71.88	€ 70	€ 2,781	€ 2,852
B_60		60% (RoCoF)	€ 1,347	€ 71.28	€ 84	€ 2,758	€ 2,842
B_70		70% (Partial)	€ 1,281	€ 69.36	€ 64	€ 2,684	€ 2,747
B_75		75% (Full)	€ 1,274	€ 68.93	€ 59	€ 2,667	€ 2,727
C_50	5.7	50% (current)	€ 1,287	€ 73.01	€ 80	€ 2,825	€ 2,905
C_60		60% (RoCoF)	€ 1,255	€ 72.16	€ 83	€ 2,792	€ 2,875
C_70		70% (Partial)	€ 1,126	€ 70.04	€ 68	€ 2,710	€ 2,778
C_75		75% (Full)	€ 1,110	€ 69.62	€ 66	€ 2,694	€ 2,760

3.1 Feasibly Reaching the RES-E targets

The study results demonstrate and support a number of intuitive outcomes. From a RES-E perspective there are three trends that can be seen.

- In general, with increasing installed wind levels (and associated increase in embedded non-wind RES) there are increasing volumes of total energy from RES-E.
- For increasing installed wind within the same operational scenario, levels of curtailment increase.
- For a given level of wind, more enhanced system service capabilities result in lower levels of curtailment and higher volumes of total energy from RES-E.

However, the studies show that only a subset of scenarios reach the RES-E targets. In particular, in all the low installed wind scenarios (circa 3500 MW), irrespective of the operational scenario, the RES-E total only reaches a maximum of 32.1% (including the contribution from embedded RES).

On the other hand, as all the high installed wind scenarios exceeded the renewable policy targets (ranging from 40.5% to 48.7%), there is arguably an over-installation of renewable generation. These scenarios, particularly at 48.7% and 47.6% RES outputs, are not appropriate for valuing enhanced system services.

However, given that 40.5% is reached in the "current constraints" case and 42.5% is reached in the "RoCoF resolved" case, it might be argued that these cases are suitable for valuing the benefit of DS3 system services. In these cases, wind curtailment levels are 22.9% and 18.8% respectively. This, on its own, suggests that these cases are unrealistic, at least without additional supports or other interventions. In addition, these scenarios would require an additional 1100 MW of wind to be installed along with the associated network build. For these reasons, these scenarios are not appropriate to be used as scenarios for the valuation of DS3 System Services.

What is a more probable scenario is a basecase level of installed wind of circa 4600 MW with full implementation of enhanced operating capability (Full EOC), which reaches a total RES-E of 40.1%

with a wind curtailment level of 1.5%. This level of installed wind just meets the policy objectives and has a credible level of wind curtailment. This is the end point scenario (EP Scenario).

Determining the most realistic counterfactual to estimate the benefit for enhanced DS3 System Services is more complicated. The basecase installed wind with only “RoCoF resolved” (RR 4600 Scenario) leads to 36.8% total RES-E but a wind curtailment level of 11.8%. In this scenario neither the overall RES target is achieved nor does the scenario have realistic wind curtailment levels. In the low installed wind scenario with only “RoCoF resolved” (RR 3500 Scenario), while the RES-E total is only 30%, wind curtailment levels have fallen to just under 5%. This suggests that this case is reflective of where the power system will reach with the existing RES support schemes in place and no investment in DS3 System Services except for “RoCoF resolved”. It is this scenario (RR 3500 Scenario) which is considered the appropriate starting point scenario (counterfactual) for valuing the DS3 system services.

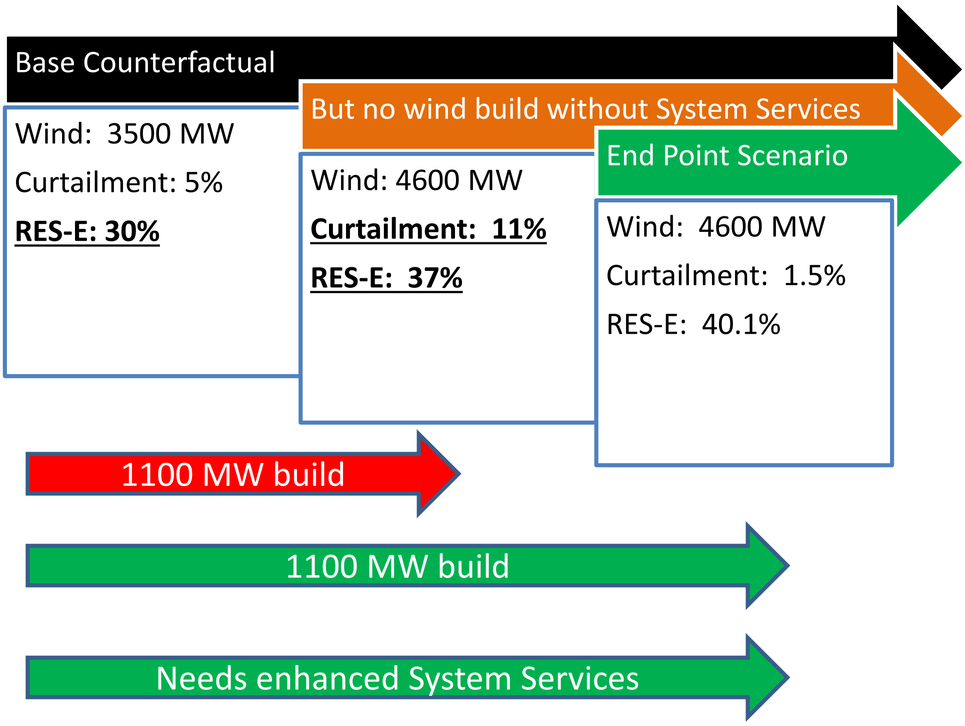

Figure 3: Establishing the counterfactual

3.2 Production Costs

In general, the trends that emerged with respect to levels of installed wind and operational scenarios for feasible RES scenarios also hold for production costs. As more and more wind is added to the portfolio, more and more fossil fuel generation is displaced and the total system production cost drops. In addition, for a given level of installed wind, increasing the capability of the system to better manage wind leads to reduced levels of production costs as more fossil fuelled generation can be displaced. The total production costs range from €1,175m to almost €1,600m. This represents an average production cost of between €30.40/MWh and €40.24/MWh.

For the EP 4600 Scenario the total production cost is €1,334m per annum. In this case there is an over two to one ratio of exports to imports with a net energy transfer from the SEM to Great Britain of 1.73 TWh. This is consistent with the reduced arbitrage on the interconnector and a carbon price floor in GB.

For the RR 4600 Scenario the total production cost is €1,431m, but, as discussed in section 3.1, this scenario has high levels of wind curtailment. However, the more appropriate starting point (RR 3500 Scenario) has a total production cost of €1,575m per annum. Therefore there is a total saving for having a system with the full enhanced operational capability of €241m per annum. This is illustrated in Figure 4 below.

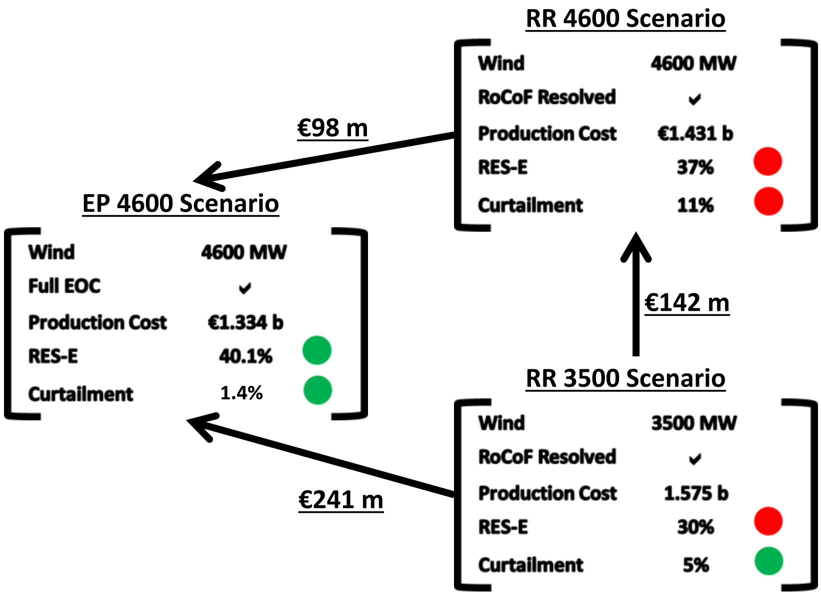

Figure 4: Basecase scenarios

For the RR 3500 scenario, the net interconnector exports are lower, at 1.26 TWh. The higher exports in the EP 4600 scenario means lower production costs for GB (as can be seen in Table 3), resulting in savings of €20m. How much of these savings accrue to GB and how much to the SEM will depend on a number of factors, including market rules and arbitrage risk. However, it could be argued that some of the savings should be included in the system services valuation.

3.3 Market Costs

The determination of market costs shows the same trends as production costs. In the first instance the load weighted average price reduces with increased levels of installed wind or increased enhanced system service capability. The difference is approximately €1/MWh for each additional 1000 MW of wind installed. However there are some discrepancies in this trend. Particularly at the "current constraints" or "RoCoF resolved" the low and high wind cases have almost identical load weighted system marginal prices (SMP) ("Current Constraints": €73.02/MWh, €73.01/MWh and "RoCoF resolved", €72.58/MWh, €72.16/MWh respectively). Therefore for an increase in installed wind of over 2000 MW there is no significant change to the load weighted SMP. This appears non-intuitive.

However, when there is an appropriate investment in partial or full enhanced operational capability particularly with high levels of wind, the load weighted SMP falls considerably: €70.04/MWh, €69.82/MWh. In effect, the benefit of increased levels of installed wind on load weighted SMP is only realised if the system has the capability to effectively manage this increase.

In that sense, for the basecase level of wind it is important to note that at the "Partial EOC" and "Full EOC" the lowest load weighted SMPs are achieved (€69.36/MWh, €68.93/MWh respectively). This raises a potential outcome that there is a balance that needs to be struck between the level of wind installed in the system and the necessary complementary system service capability in order to achieve the greatest impact on load weighted SMP. The lowest outcomes appear to be achieved by holistically increasing the capability of the system in parallel with build in order to efficiently accommodate the necessary levels of wind to meet RES-E targets. This finding needs to be caveated with the general concerns the TSOs have raised regarding the pricing runs as described in Section 1.1.2.

However, the costs to consumers are not just those from the load weighted SMP, but also include, in the SEM, dispatch balancing costs. Another perspective is that the costs are the production costs of the portfolio plus the inframarginal rents that they earn[9]. In this regard, the total market costs reduction between the basecase counterfactual and the end point objective is €178m. This comes from a combination of reduced load weighted SMP as well as reduced dispatch balancing costs.

Nevertheless, when costs to consumers are being considered it can be difficult to determine what is relevant to include. Consideration of production cost does not concern itself with this issue, rather focuses on the benefits that directly accrue in fossil fuel savings. However, depending on legislation, regulation and cross-sectoral impacts, the TSOs recognise that there are a range of other factors that might be considered. These other benefits and costs include, but are not limited to, RES-E support costs, penalties for non-achievement of RES-E targets, increased security of supply and possible Emission Trading Scheme benefits. For a complete assessment of consumer costs these should be factored in at a minimum. In addition, the modelling assumes that there is no interaction between revenues earned through DS3 system services and the bid price into the energy market. It is possible that including this interaction could lead to greater consumer cost savings through lower SMP.

3.4 Sensitivity scenarios – other considerations

A range of sensitivities and altered input assumptions have been completed in an attempt to give a broader context and robustness to the benefit analysis completed. These sensitivities included examining the following:

- Impact arising from early implementation of windfarms before the installation of the second North-South interconnector
- Improved generator technical capabilities due to DS3 system services incentives
- Introducing a carbon floor in the SEM

[9] Generally correct but there are variations to account for interconnection flows and pumped storage in the SEM.

3.4.1 Impact arising from early implementation of installed wind level

The basis of the DS3 System Service valuation to date has implicitly assumed that all necessary network infrastructure is built in a parallel, consistent manner with the roll-out of necessary enhanced services and the required increases in installed renewable generation. To explore the impact if this were not the case, a specific case of early connection of windfarms prior to the build of the second North-South interconnector has been examined. This was modelled by including some additional jurisdictional constraints (minimum units, minimum reserve and maximum inter-jurisdictional flow) into the Plexos model. Table 6 below shows the production cost and curtailment impact of these constraints for the three principal scenarios considered in section 3.2. Further details are in the appendices.

Table 6: Comparison of the Early Implementation scenario (shaded) with the basecase

			Basecase Scenario		Early Implementation Scenario		Change	
Scenario	Wind connected (GW)	Dispatch	Dispatch Production Cost (€m)	Wind Curtailment (%)	Dispatch Production Cost (€m)	Wind Curtailment (%)	Delta Production Cost (€m)	Delta Wind Curtailment (%)
RR 3500	3.5	60% (RoCoF)	€ 1,575	4.8%	€ 1,596	5.3%	€ 21	0.5%
RR 4600	4.6	60% (RoCoF)	€ 1,432	11.2%	€ 1,459	11.8%	€ 28	0.6%
EP 4600		75% (Full)	€ 1,334	1.4%	€ 1,365	2.1%	€ 31	0.7%

In the EP 4600 scenario, with the full roll out of DS3 System Services, the early implementation assumptions result in an increase in the total production cost from €1,334m to €1,365m. This is an increase in production cost of €31m. In considering what impact, if any, this could have on the valuation of system services, this cost increase should be compared with the cost increase for the counterfactual (RR 3500), which is €21m.

3.4.2 Impact of improved technical capabilities

In this scenario, some of the enhanced system services performance is assumed to come from existing plant in the portfolio materially altering their technical offer data that is submitted to the SEM. Specifically lower minimum generation on a number of combined cycle gas turbines means that both in the dispatch and market runs there will be different running levels, which in theory should increase fossil fuel savings and reduce load weighted SMP.

Table 7: Comparison of the Improved Generator Capabilities scenario (shaded) with the basecase

			Basecase Scenario		Improved Generator Capabilities Scenario		Change	
Scenario	Wind connected (GW)	Dispatch	Dispatch Production Cost (€m)	Wind Curtailment (%)	Dispatch Production Cost (€m)	Wind Curtailment (%)	Delta Production Cost (€m)	Delta Wind Curtailment (%)
	4.6	50% (current)	€ 1,445	15.6%	n/a	n/a		
RR 4600		60% (RoCoF)	€ 1,432	11.2%	n/a	n/a		
		70% (Partial)	€ 1,344	2.8%	€ 1,315	2.2%	-€ 30	-0.7%
EP 4600		75% (Full)	€ 1,334	1.4%	€ 1,309	1.2%	-€ 25	-0.3%

In comparing the EP 4600 Scenario (€1,334m) against that of the Full EOC with improved Technical Offer Data (TOD) (€1,309m) there is a total production cost difference of €25m. The improved TOD reaps additional benefit and is possibly more appropriate to be used in the valuation of DS3 system services benefits, as some of these enhancements will likely be delivered in changes to the existing plant. The benefit between the same original base counterfactual (RR 3500 Scenario) and this case is €266m.

3.4.3 Introducing a Carbon Floor in SEM

With the recent publication of the Communication from the European Commission entitled "Policy framework for climate and energy in the period from 2020 to 2030", there is a clear move towards more aggressive carbon reduction. While the ramifications of this are unclear, a possible scenario is that a carbon price floor equivalent to that in Great Britain is introduced into the SEM. This scenario explores this option by simulating a carbon price of €20/tonne in both SEM and GB.

Table 8 Comparison of the Equal Carbon Price scenario (shaded) with the basecase

Sensitivity	Wind connected (GW)	Dispatch	I/C Import (GWh)	I/C Export (GWh)	Dispatch Production Cost (€m)	Wind Curtailment (%)	Δ Import (GWh)	Δ Export (GWh)	Δ Production Cost (€m)	Δ Wind Curtailment (%)
Base case	3.5	50% (current)	1,723	2,982	€ 1,557	8.5%	n/a			
		60% (RoCoF)			€ 1,575	4.8%				
		70% (Partial)			€ 1,525	1.5%				
		75% (Full)			€ 1,516	0.7%				
Base case	4.6	50% (current)	1,477	3,204	€ 1,445	15.6%				
		60% (RoCoF)			€ 1,432	11.2%				
		70% (Partial)			€ 1,344	2.8%				
		75% (Full)			€ 1,334	1.4%				
Equal CO_2 €20/t SEM and GB	3.5	50% (current)	4,472	413	€ 1,401	13.8%	2,749	-2,570	-€ 156	5.3%
		60% (RoCoF)			€ 1,436	7.0%			-€ 139	2.2%
		70% (Partial)			€ 1,339	2.5%			-€ 186	1.0%
		75% (Full)			€ 1,326	1.1%			-€ 190	0.4%
Equal CO_2 €20/t SEM and GB	4.6	50% (current)	3,899	774	€ 1,326	20.5%	2,423	-2,430	-€ 119	4.9%
		60% (RoCoF)			€ 1,303	13.3%			-€ 129	2.1%
		70% (Partial)			€ 1,186	4.0%			-€ 158	1.1%
		75% (Full)			€ 1,182	2.2%			-€ 152	0.8%

The introduction of equal carbon prices in SEM and GB reduces the tendency to export energy between the two. Because of this, there is an associated increase in curtailment levels (RR 4600, 11.2%, RR 4600 CO2, 13.3%) and a reduction in the fossil fuel production in the SEM. However, as some of this arises from increased generation in GB, it is not appropriate to directly compare the production costs between the equalised carbon floor price scenarios and the corresponding basecase scenarios.

However, were equivalent carbon prices in both markets realised, the equivalent scenarios to the RR 3500 and EP 4600 (highlighted in the table above) would result in a production cost difference of €254m, i.e. an increased benefit of €13m.

3.5 System Services Revenue

The production cost benefit between the RR 3500 Scenario and the EP 4600 Scenario is €241m. To better understand how this benefit plus the existing harmonised ancillary service value of €60m would be distributed as system services revenues, a range of additional calculations have been made. In the first instance new rates for each DS3 system service product have been determined.

These have been calculated by determining the pot of money available for each service and dividing by the volume of the system services expected in the scenario being examined.

To determine the product pot the relative weight of each was assumed from the original TSO recommendation. These relative weights are derived from a series of hypothetical operational studies on a product by product basis. Before final decision and implementation the TSOs recommend a full consultation and re-examination of these studies. However, the relative weights determined previously are deemed sufficient for exploring the allocation of the €301m (€241m plus €60m).

To determine the volume of System Services, the EP 4600 Scenario with enhanced technical capabilities (including wind reserve provision) was utilised to determine each service provider's hourly MW output. From this, the hourly product volume of each service provider was calculated, and then the total annual product volume could be determined. The rate was determined by the ratio of the product pot to the total annual product volume. It is important to note that only the TSOs' recommended split of capability and dispatch products (E) from the original analysis has been estimated here.

The calculated rates can be found in the following table.

Table 9 Product rates per €100m pot

Product	Rate for €100m System Services Pot
DRR	0.194727
FFR	4.928911
FPFAPR	0.394090
POR	3.545921
RM1	0.138370
RM3	0.284923
RM8	0.174247
RRD	0.092242
RRS	0.095273
SIR	0.000517
SOR	1.581099
SSRP	0.136009
TOR1	1.865658
TOR2	1.690429

From these rates and the product volumes system service revenues could be estimated for each service provider on an hourly basis. This was calculated for four operational scenarios (see Appendix B). The average annual payments per MW installed by technology type and fuel are shown in Figure 5 below.

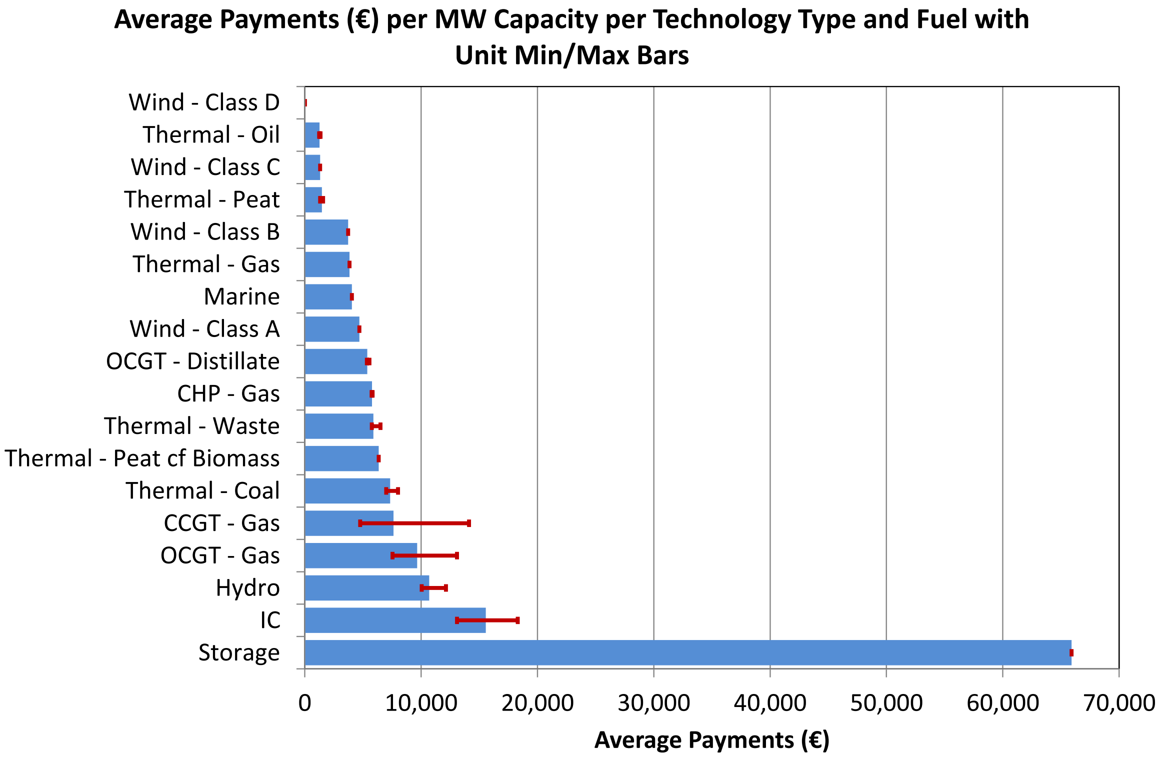

Figure 5: Average Payments (€) per MW Capacity per Technology Type and Fuel

3.6 Impact on Capacity Payments

The interaction of system service revenues with Capacity Payments is ultimately a matter for the SEMC. Nevertheless, the TSOs have estimated the impact that the proposed remuneration approach would have on the current Capacity Payments Mechanism, based on a number of key assumptions:

- Current approach of including AS revenues in determining CPM pot is retained
- System Services distribution and pot size
- System Services remuneration approach.

From the estimates in Figure 5, the system service revenue for a best new entrant plant can be determined. This equates to €5.97/MW/year for a €100m pot. Given that it is assumed in the Capacity Payments Mechanism determination that a best new entrant requires €80.27/MW/yr to build, the system service revenue (for a €100m System Service pot) represents over 7% of the annual total revenue requirement. This reduces the total annual Capacity Payment pot by €11m per €100m DS3 System Services pot or €101m per €301m pot assuming a capacity requirement of 7,459 MW and when payment for the existing Harmonised Ancillary Services is accounted for.

Table 10: Best New Entrant Revenues and CPM Impact

A	**Pot Size (€)**	**100,000,000**	**301,000,000**
B	**Proposed System Services €/kw/yr Equivalent**	**5.97**	**17.97**
C	Existing Harmonised Ancillary Services €/kw/yr Equivalent	4.48	4.48
D	Capacity Requirement 2014 (MW) (SEM-13-056)	7049	7049
E	Load Growth*	5.82%	5.82%
F	Capacity Requirement 2020 (MW) (D x E)	7459	7459
G	BNE Peaker Cost 2014 (€/kW/yr) (SEM-13-056)	80.27	80.27
H	2020 CPM Pot @ current price (€) (F x G)	598,742,826	598,742,826
I	**CPM Saving (€) ((B – C) x H)**	**11,094,000**	**100,597,948**
J	2020 CPM Pot net of SS (€) (H – I)	587,648,826	498,144,878
K	**Net Cost (€) (A – I)**	**88,905,100**	**200,402,052**

4. Conclusions

A suite of revised financial analysis has been conducted on the benefits that the TSOs' DS3 System Services recommendations would bring if implemented. This suite of studies, which built on the analysis carried out for the original TSO recommendation, employed a revised set of assumptions and explored a different basecase counterfactual. In particular, the modelling was adapted to allow for increased use of the interconnectors between SEM and GB, appropriately modelling the carbon price floor in Great Britain and exploring a range of different installed wind levels. In addition, improved information surrounding demand growth and portfolio evolution were also utilised. The base case counterfactual to be examined was also changed to assume that the Rate of Change of Frequency modifications by the TSOs had been implemented.

A range of installed wind levels were modelled – 3500 MW, 4600 MW, 5700 MW and 6800 MW, consistent with 25%, 50%, 75% and 100% take up of Gate 3 offers respectively. These take up rates were pro-rated on an all-island basis. In addition, a range of operational scenarios were modelled to reflect the evolution of the system from the "Current Constraints" to one with the "Full Implementation of the Enhanced Operational Capability". Also included were a number of specific sensitivities and an estimate of the System Service revenues for relevant technologies which included an estimate of the impact on the Capacity Payments Mechanisms (CPM).

The primary findings from the studies are that:

- Increased wind levels reduce the production costs incurred in the SEM.
- Increased operational capability allows for better utilisation of the installed wind and lowers production costs.
- If the DS3 System Services are implemented, the scenario which meets the 40% renewable targets requires circa 4600 MW to be installed and represents a 50% uptake of Gate 3 offers.
- Without any additional investment in DS3 System Services, curtailment levels are high (11.2%) for 4600 MW of installed wind. The curtailment levels fall to acceptable levels (5%) if there is only 3500 MW of installed wind. At this lower level of wind there is a shortfall of 10% on the annual RES-E targets.
- The production cost difference of achieving the End Point 4600 scenario from the RoCoF resolved 3500 scenario is €241m.
- System Services revenues have been estimated for the allocation of €301m (€241m plus €60m from existing HAS). The impact on the CPM in this case is a reduction of €101m, assuming the current CPM methodology.

Appendix A – Portfolio Assumptions – Installed Capacity

Generator	ID	Type	MW
Aghada	AD1	Thermal	258
	AD2	CCGT	431
	AT1	OCGT	90
	AT2	OCGT	90
	AT4	OCGT	90
Ballylumford	B10	CCGT	97
	B31	CCGT	245
	B32	CCGT	245
	BGT1	OCGT	58
	BGT2	OCGT	58
Caulstown OCGT		OCGT	55
Coolkeeragh	C30	CCGT	402
	CGT8	OCGT	53
Cuileen OCGT		OCGT	98
Dublin Bay	DB1	CCGT	399
Dublin Waste		Waste	62
Edenderry	ED1	Peat	118
	ED3	OCGT	58
	ED5	OCGT	58
Great Island CCGT		CCGT	431
Huntstown	HN2	CCGT	395
	HNC	CCGT	337
Indaver	IW1	Waste	15
Kilroot	KGT1	OCGT	29
	KGT2	OCGT	29
	KGT3	OCGT	42
	KGT4	OCGT	42
	K1	Coal	198
	K2	Coal	198
Lough Ree	LR4	Peat	91

Generator	ID	Type	MW
Marina	MRT	OCGT	88
Moneypoint	MP1	Coal	285
	MP2	Coal	285
	MP3	Coal	285
Nore OCGT		OCGT	98
North Wall	NW5	OCGT	104
Poolbeg	PBC	CCGT	463
Rhode	RP1	OCGT	52
	RP2	OCGT	52
Sealrock	SK3	CHP	80
	SK4	CHP	81
Suir OCGT		OCGT	98
Tarbert	TB1	Thermal	54
	TB2	Thermal	54
	TB3	Thermal	241
	TB4	Thermal	243
Tawnaghmore	TP1	OCGT	52
	TP3	OCGT	52
Tynagh	TYC	CCGT	384
West Offaly	WO4	Peat	137
Whitegate	WG1	CCGT	442
Ardnacrusha	AA1-4	Hydro	86
Erne	ER1-4	Hydro	65
Lee	LE1-3	Hydro	27
Liffey	LI1-5	Hydro	38
Turlough Hill	TH1-4	Storage	292

Embedded Generation (non-dispatchable)

Embedded non-RES	IE	142
Embedded non-RES	NI	8

Renewable Generation

	Scenario	Low wind	Base case	High wind	V High wind
Renewables		**MW**	**MW**	**MW**	**MW**
Tidal	NI	105	105	105	105
Embedded RES	IE	106	142	178	214
Embedded RES	NI	69	93	116	140
Wind	IE	2820	3711	4602	5493
Wind	NI	654	861	1068	1275
Total Wind		**3474**	**4572**	**5670**	**6768**