Single Electricity Market
(SEM)

Discussion Paper and Call for Evidence on Scarcity Pricing and Demand Response in the SEM

SEM-21-042

26 May 2021

EXECUTIVE SUMMARY

The TSOs have forecast tight capacity margins for the Winter of 2021/22 and the Regulatory Authorities (RAs) are working with the TSO's to investigate all potential options to mitigate these. This Discussion Paper and Call for Evidence focusses on the issue from the perspective of Administered Scarcity Pricing (ASP) and of demand side response, with a view to identifying measures that can be implemented on an interim basis, for Winter 2021/22, to encourage both the formation of appropriate price signals during times of scarcity and demand side response to those signals.

Over the 2020/21 period, there have been numerous system alerts, indicative of tight capacity margins. Market prices have rarely reflected this scarcity. In 2015 during the design of the capacity market, the SEM Committee recognised[1] that the market alone might not deliver appropriate price signals at times of scarcity and therefore included ASP in the design of the SEM. ASP is designed to ensure that in times of system need, generation and supply alike further respond to help address the system demand. However, ASP has not been triggered, despite the system alerts that have occurred over the 2020/21 period, or in previous years. The RAs are therefore reviewing the trigger for ASP and considering whether it should be made more sensitive and made to align more closely with the triggers for System Alerts, such that when a System Alert is issued it would be more likely that ASP would apply. The RAs are also considering whether the starting point of the Reserve Scarcity Price (RSP) curve should be changed so that the minimum price would be either higher or lower than the Reliability Option strike price, and additionally, whether the maximum price should be a higher percentage of the Value of Lost Load than it is currently. Feedback is sought from stakeholders on these considerations.

This Paper also discusses how to facilitate greater levels of implicit and explicit demand response for Winter 2021/22. Feedback is sought from stakeholders, consumers, suppliers and DSU's on both the effectiveness of existing incentives and the potential for increased incentives for demand side participation, as well as on the value of giving advance notice of tight capacity margins or the conditions which might lead to system alerts.

Responses are invited to this Discussion Paper and Call for Evidence until 7 July 2021 and can be sent to gkelly@cru.ie and kevin.baron@uregni.gov.uk.

[1] SEM-15-103

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1. Introduction

1.1 Purpose of this Paper

The purpose of this Discussion Paper and Call for Evidence is to inform and seek views from market participants on areas the Regulatory Authorities (RAs) are currently reviewing in relation to Administered Scarcity Pricing (ASP) and demand response in the SEM. The RAs are considering interim changes in these areas in order to encourage the formation of appropriate price signals and greater demand response during the periods of tight capacity margins that are expected over the 2021/22 Winter, in order to send appropriate signals to help mitigate adverse system states. This Paper is intended to help inform the next steps that will be taken by the RAs in this regard.

As of the date of publication of this Paper there have been three System Alerts (Amber) in the SEM in 2021 so far and there were nine System Alerts (Amber) in total in 2020. While the conditions for each Alert were unique (and are set out in Appendix 1 of this paper), in many cases they were driven by factors including the level of demand, coupled with scheduled and forced outages, leading to tight capacity margins. During the vast majority of these events however, prices have remained below the Reliability Option (RO) Strike Price. ASP was not triggered during any of these System Alerts.

ASP was implemented in the SEM in order to help ensure that prices rise appropriately in the balancing market to reflect scarcity. The first CRM Decision (SEM-15-103) states the following:

'*The SEM Committee is not convinced that prices will rise to reflect scarcity unless it is administratively introduced. This decision is based upon the experience of other markets where scarcity has not delivered high prices, and follows the model employed in a number of other markets'.*

This Paper therefore considers how ASP has been implemented in the SEM and whether changes to its functioning are warranted. The Call for Evidence questions for stakeholders, posed in this paper, look to establish whether ASP can appropriately reflect the level of scarcity associated with these System Alerts.

In addition, this Paper considers how to facilitate greater levels of implicit and explicit demand response in the SEM during periods of scarcity over the Winter 2021/22. Feedback is sought from interested stakeholders on both the effectiveness of existing incentives and the potential for increased incentives for demand side participation, as well as on the value of giving advance notice of tight capacity margins and conditions which may give rise to System Alerts.

In summary, the RAs are seeking feedback and proposals from stakeholders on interim changes that could be introduced in order to help mitigate tight capacity margins in Winter 2021/22 through amendments to ASP and incentives on demand response. Some changes could also be considered on an enduring basis following a further consultation with stakeholders. The RAs are continuing to work with the TSOs to investigate all possible options to manage the expected tight margins.

1.2 Overview of this Paper

This Discussion Paper first provides an overview of recent levels of forced outages in the SEM and of the conditions for System Alerts.

An overview of SEM Committee policy in relation to ASP is then set out in Section 2. This includes a discussion of how ASP has functioned in the SEM to date, before requesting feedback from interested stakeholders on potential changes to the scarcity pricing mechanism.

Section 3 of this paper considers both implicit and explicit demand response in the SEM, and the incentives on each to reduce demand during times of scarcity. Feedback is requested from stakeholders on the interaction between demand response and the potential changes to ASP, outlined in Section 2, along with any other opportunities to strengthen incentives for demand response in the short term. Feedback is also requested on the value of providing additional information on forecast tight capacity margins and expected system alerts.

The RAs welcome responses to this Discussion Paper and Call for Evidence and have set out a number of questions for interested stakeholders herein. Responses will be published unless marked as confidential and can be submitted to gkelly@cru.ie and kevin.baron@uregni.gov.uk by 7 July 2021.

1.3 Background and Legislative Context

Scarcity pricing involves moving energy prices above the marginal cost of the marginal unit under conditions where the system is short on generation capacity and reserves, in order to incentivise demand response and generation capacity capable of providing reserves to the system. The Clean Energy Package includes provisions for the introduction of scarcity pricing as an option to address resource adequacy concerns, prior to the introduction of a capacity mechanism. Article 20(3) of Regulation 2019/943, in relation to resource adequacy, states:

'*Member States with identified resource adequacy concerns shall develop and publish an implementation plan with a timeline for adopting measures to eliminate any identified regulatory distortions or market failures as a part of the State aid process. When addressing resource adequacy concerns, the Member States shall in particular take into account the principles set out in Article 3 and shall consider:*
(c) introducing a shortage pricing function for balancing energy as referred to in Article 44(3) of Regulation 2017/2195;'

Article 22 (2(b)) in relation to the design of capacity mechanisms also notes that the market should, if necessary, reflect scarcity prices:

'*during imbalance settlement periods where resources in the strategic reserve are dispatched, imbalances in the market are to be settled at least at the value of lost load or at a higher value than the intraday technical price limit as referred in Article 10(1), whichever is higher*.'

Reference was also made to scarcity pricing in the European Commission's recent Opinions on the implementation plans submitted for Ireland and Northern Ireland pursuant to Article 20(5) of the new Electricity Regulation under the CEP (Regulation 2019/943)[2]. The Opinions noted the implementation of a scarcity pricing mechanism in the SEM as required under Article 20(3)(c) of the Electricity Regulation and stated:

'In the Commission's view, it is important that this mechanism is well designed so that it does not only provide incentives for short term flexibility but also sends appropriate signals for

[2] https://ec.europa.eu/energy/sites/ener/files/documents/adopted_opinion_ireland_en.pdf

https://ec.europa.eu/energy/sites/ener/files/documents/adopted_opinion_ni_en.pdf *investments to maintain system adequacy.'*

The Commission also noted that changes should be considered to the price floor applied through ASP (currently set at 25% of VoLL) to align with the full value of VoLL applied in the capacity mechanism.

The RAs recently published a Consultation Paper considering the compliance of the SEM market arrangements with the Electricity Balancing Guideline (EBGL) (Regulation 2017/2195). This Consultation, and the accompanying EirGrid and SONI paper analysing EBGL compliance, note the interaction of Administered Scarcity Pricing as implemented in the SEM with Article 55 of EBGL. In market conditions where the system is long and ASP is activated, there could potentially be an issue of non-compliance with the boundary conditions for imbalance pricing set out in Article 55. The RAs note that while this assessment has not concluded, this could lead to changes being required for ASP. This is being considered through the EBGL consultation process and is important context, however in this Discussion Paper the RAs are focusing on short term amendments under the existing design as outlined in Sections 1 and 2.

The CRM Detailed Design Decisions considered the interaction between scarcity pricing in the SEM and GB, given the fact that this could impact on cross border flows during periods of coincident scarcity. Administered Scarcity Pricing is also in place in GB and the Reserve Scarcity Price is calculated for each settlement period based on the product of a measure of system reliability called Loss of Load Probability (LoLP) and the Value of Lost Load (VoLL). The Reserve Scarcity Price in GB is currently being reviewed due to the fact that it has had less of an impact on System Prices than expected[3]. Between 2016 and 2020 there have been nine Settlement Periods where Reserve Scarcity Price repriced actions in GB have set the System Price. Six of these periods occurred in 2020[4].

Generation Outages in the SEM

The frequency of forced or unplanned outages has increased in recent years and unlike scheduled outages, which are optimised to take place at times of low system stress, these may occur with little notice and for extended periods. This means that availability has been

[3] https://www.elexon.co.uk/smg-issue/issue-92/
[4] https://www.elexon.co.uk/article/bsc-insight-why-the-reserve-scarcity-price-is-being-reviewed/

lower than forecast by the TSOs in recent years. This is particularly the case for ageing thermal plants.

As set out in the All-Island Transmission System Performance Report, the generation forced outage rate (FOR) is the capacity weighted percentage of the time during the day that generation units are unavailable due to unplanned outages. The latest report for 2019 showed an average FOR of 14.15%, compared to an average of 11.6% in 2018 and lower FORs in preceding years.

	2012	2013	2014	2015	2016	2017	2018	2019
Average FOR	6.74%	6.88%	8.49%	10.07%	6.4%	8.6%	11.6%	14.5%

Figure 1

In 2021 so far, there have been a number of forced generation outages. This is an important consideration in the context of the areas that are discussed by the RAs in this Paper. Information on expected generator and interconnector unit outages is updated weekly by EirGrid and SONI showing forced outages expected in the short term[5]. As of the Weekly All-Island Outage Plan published on 20 May, Huntstown (HN2) and Whitegate (WG1) for example are expected to be on forced outage for an extended period in 2021, representing 408MW and 444MW of unavailable capacity respectively. Based on the number of forced outages seen in 2020, it may also be expected that further forced outages could occur in 2021 and exacerbate tight capacity margins in Winter 2021/22.

System Alerts in the SEM

This section sets out the conditions under which System Alerts will be issued in Ireland and Northern Ireland. This is relevant to the discussion, that follows in Section 2, of the conditions under which ASP is triggered, and to the consideration of how to align the issuing of a System Alert and the triggering of ASP.

There were a number of System Alerts in Ireland and Northern Ireland in 2020 and 2021, corresponding to periods of tight capacity margin. These System Alerts occurred due to several factors including differences in forecast and actual wind availability, scheduled interconnector flows based on price differentials with GB, low plant availability, weather conditions and high levels of electricity demand. If, as is forecast[6], all-island demand

[5] http://www.eirgridgroup.com/customer-and-industry/general-customer-information/outage-information/
[6] https://www.eirgridgroup.com/site-files/library/EirGrid/All-Island-Generation-Capacity-Statement-2020-2029.pdf

increases, while older capacity exits the market, the number of System Alerts may increase in the short term.

An overview of the System Alerts in 2020 and 2021 is provided in Figure 2 below. While the RAs acknowledge that a number of System Alerts also occurred prior to 2020, the conditions and incentives during recent system events provide useful insight into potential short term changes to be considered. While the RAs acknowledge that other elements of the market, such as the imbalance volume, are important considerations, it is notable that the RO Strike Price has only been exceeded during 2 of these 11 events and in only one case where the System was in Alert State in both Ireland and Northern Ireland. ASP did not apply during any of these events.

Date	Duration	Location	System State	Max 5 Min BM Price	Max 30 Min BM Price
17/05/2021	10.26-15.33	ROI	Amber	€490.10	€283.22
08/01/2021	13.15-18:25	NI	Amber	€490.76	€444.36
06/01/2021	16:00-18.05	NI & ROI	Amber	€739.27	€520.87
09/12/2020	16.45-18.18	NI & ROI	Amber	€495.04	€494.63
26/11/2020	16.00-19.00	NI	Amber	€793.55	€691.57
24/11/2020	18.30-22.00	NI	Amber	€423.42	€290.71
19/11/2020	16.45-19.00	NI	Amber	€285.83	€206.85
05/11/2020	16.30-19.10	NI	Amber	€494.63	€491.75
15/09/2020	16.18-19.05	ROI	Amber	€490.10	€359.08
05/08/2020	10.50-15.00	ROI	Amber	€381.15	€101.27
11/03/2020	16.30-20.53	NI	Amber	€52.54	€51.54
21/01/2020	10.15-18.00	NI	Amber 2	€81.69	€65.46

Figure 2

Further detail on the system conditions leading up to and during each event is included in Appendix 1.

System Alerts in Ireland and Northern Ireland describe various system states, from normal to increasing levels of system stress starting at Alert (Amber), to Emergency (Red), to Blackout (Blue), and finally to a Restoration state which aims to return the power system to the normal state[7]. These categories are aligned to the requirements of the System Operation Guideline (Commission Regulation (EU) 2017/1485)[8].

As the North South tie-line is the only transmission connection between the Northern Ireland and Ireland systems, one system can be in Alert State while the other is not. At a high level as set out in the TSOs' business process for declaration of System Alerts referenced in the footnote below, any of the following events can trigger System Alert (Amber);

1. A Single Event would give rise to a reasonable possibility of failure to meet Power System Demand.
2. If frequency or voltage depart significantly from normal, or,
3. If multiple Events are probable due to prevailing weather conditions.

These requirements and the exact criteria for the System Alert (Amber) State are set out in greater detail in Appendix 2, illustrating also the slightly different criteria for the two jurisdictions.

In general, alerts should be cancelled only once system conditions have stabilised for at least one hour and there is only a very low probability of another alert being issued on the same day. When an alert is expected, a System Alert notification is issued to market participants by the Market Operator, SEMO.

The SEM Committee intended a degree of alignment between the triggering of a System Alert and the triggering of ASP. SEM-15-103 noted that it would be expected that an incident of full load shedding (when the Full Administered Scarcity Price applies) would correspond to EirGrid and SONI Red Alerts, and the reduced operating reserve threshold for Reserve Scarcity Pricing would be a reasonable approximation to events predicted by an Amber Level 2 Alert. The system state definitions have been updated since publication of SEM-15-103 to align with the requirements of SOGL, and as such, an Amber Level 2 Alert now corresponds simply to an "Alert (Amber)" rather than two level within this System State. Figure 4 shows the alignment between the old System States and new System States, with one System State for an Amber Alert as opposed to two.

ASP (either the Full Administered Scarcity Price or the Reserve Scarcity Price) has not been triggered since go-live of the I-SEM arrangements despite the numerous System Alerts that have occurred. The Full Administered Scarcity Price and the Reserve Scarcity Price will be discussed in further detail in the next section, but it is sufficient to note here that the intended

[7] https://www.sem-o.com/documents/general-publications/BP_SO_09.2-Declaration-of-System-Alerts.pdf
[8] The classification of system states is set out in Article 18 of the Guideline.

alignment between System Alerts and ASP has not been evident in the operation of the market thus far. This may be linked to the reclassification of system states illustrated in Figure 3.

Figure 3

2. Administered Scarcity Pricing

2.1 Background to Reserve Scarcity Price and Full Administered Scarcity Price

The background to Reserve Scarcity Price (RSP) and Full Administered Scarcity Price (FASP) implementation in the SEM is provided in this section. In this paper, the RAs refer to ASP in relation to general scarcity pricing as implemented in the SEM and RSP and FASP specifically in relation to the different triggers that apply to these elements of scarcity pricing. The triggers in place for each through the Trading and Settlement Code are discussed, as well as the RSP curve parameters.

As set out in SEM-15-103, the SEM Committee decided to introduce ASP to the balancing market in order to:

1. Remove the need for additional performance incentives to be introduced within the CRM by giving a strong incentive to capacity providers to be available at times of system stress.
2. Provide Suppliers with a strong incentive to provide demand side response and reduce consumption at times of system stress.

3. Reflect experience in other markets where scarcity has not delivered appropriate price signals.

The SEM Committee recognised that implementation of ASP increased risk on capacity providers and suppliers, along with other generators if they forward sold their power prior to scarcity and then had to buy it back (for example due to a forced outage) under conditions of scarcity. However, the SEM Committee noted the balance of risk and increased incentives to respond during scarcity events.

Trigger for RSP (Reserve Scarcity Price)

The RSP in the SEM applies as soon as available capacity is less than that required to cover electricity demand plus the associated operating reserve requirement. It is intended to provide capacity providers and suppliers with early incentives to react to scarcity, reducing the likelihood of further adverse events such as load shedding. As currently implemented within the Trading and Settlement Code, RSP therefore applies when the available Short Term Reserve Quantity (qSTR) is less than the Operating Reserve Requirement Quantity (qORR).

The calculation of RSP is set out in detail in Section E.4 of the Trading and Settlement Code, and the relevant excerpt is given in Appendix 3 of this Paper for reference.

The **Short Term Reserve Quantity** is defined in the TSC as the '*available reserves for Tertiary Operating Reserve Band 2*[9] *and Replacement Reserve*[10] *in the most recent Indicative Operations Schedule'*[11]*.*

The **Operating Reserve Requirement Quantity** is defined in the TSC as the "*operating reserve requirement for Tertiary Operating Reserve band 2 used to determine the most recent Indicative Operations Schedule in respect of an Imbalance Pricing Period*".

Therefore, for example, if the Operating Reserve Requirement Quantity is 450MW, and the available Short Term Reserve Quantity falls to 490MW, the RSP function does not impact prices, and prices will be market determined. The TSOs operate a common operating reserve

[9] Tertiary Operating Reserve Band 2 is defined as the additional MW Output (and/or reduction in Demand) required compared to the pre-incident output (or Demand) which is fully available and sustainable over the period from **5 minutes to 20 minutes** following an Event.

[10] Replacement Reserve is defined as the additional MW Output (and/or reduction in Demand) required compared to the pre-incident output (or Demand) which is fully available and sustainable over the period from **5 minutes to 4 hours** following an Event.

[11] Tertiary Operating Reserve and Replacement Reserve are both defined in the Grid Codes in terms of specific 'Events', which are '*an unscheduled or unplanned occurrence on, either the Transmission System or a User's System, including faults, incidents and breakdowns'*

requirement[12] across the island of Ireland. The requirement is primarily driven in practice by the size of the largest in-feed, which varies dynamically and could be around 500MW if the East-West interconnector is importing at full capacity or might be driven at other times by the size of one of the CCGTs or a Moneypoint unit (285MW).

The RAs are considering whether the trigger for RSP should be amended such that the qSTR would include only Tertiary Operating Reserve Band 2 and not Replacement Reserve, or whether another amendment could be made that would bring this trigger more into line with the triggers for System Alerts in the SEM (as set out in Appendix 2).

Trigger for FASP (Full Administered Scarcity Price)

SEM-16-022 set out the conditions for FASP to apply, which leads to a higher price applying immediately in comparison to an increasing price at different levels of reserve scarcity for the RSP. The FASP applies when, in addition to the conditions required for RSP to apply, instances of Demand Control involving automatic or manual involuntary load shedding or voltage control occur. FASP therefore applies when there is a system-wide scarcity event in both jurisdictions, in addition to a Demand Control/frequency event in either jurisdiction.

The conditions for Demand Control leading to the FASP being triggered are set out in Section E.4.3 of the Trading and Settlement Code[13] and the relevant excerpt is given in Appendix 3 of this Paper for reference. The FASP was implemented in this way, requiring system-wide scarcity in addition to jurisdictional Demand Control events, to ensure that it could only be triggered for system wide events rather than events in either jurisdiction. The FASP has been set to a value of 25% of the Value of Lost Load from the 2022/23 T-4 auction onwards.

The RAs are not at this point considering amending the trigger for FASP, as there has not been a Red Alert or Emergency System State since I-SEM go live, so there is no evidence that the triggers are misaligned. However, respondents' views are welcomed on this question.

Level of RSP and FASP

SEM-16-022 also set out that RSP would start from the RO Strike Price (currently €500/MWh) when short term reserve is 500MW, rising in a straight-line manner to the FASP when short

[12] Operating Reserve is defined in the Grid Codes as the '*additional MW Output required from Generation Units or Interconnector import or interconnector export adjustment or demand reduction which must be realisable in real time to contain and correct any potential Power System Frequency deviation to an acceptable level. It will include Primary Operating Reserve, Secondary Operating Reserve and Tertiary Operating Reserve*.'

[13] In addition to the process for Demand Control set out in BP_SO_09.1; https://www.sem-o.com/documents/general-publications/BP_SO_09.1-Demand-Control-Process.pdf Step 13 in this process involves triggering FASP within the MMS

term reserve is 0MW, with FASP based on VoLL. FASP has been set at 25% of VoLL in subsequent Capacity Auction Parameters Decisions.

The latest RSP curve is given in the table below and is set out in each Capacity Auction Parameters Decision for the relevant Capacity Year by the SEM Committee.

Short Term Reserve (MW)	Administered Scarcity Price (€/MWh)
Demand Control	25% of VOLL
0	25% of VOLL
500	RO Strike Price

Figure 4[14]

The anticipated final values for the FASP and RSP curve (with the actual €/MWh values corresponding to 25% VoLL and the RO Strike Price) are included in each Capacity Auction Information Pack published by the System Operators. These are anticipated as the TSC includes a provision in Section E.4.1.1 for the RAs to determine the values of the FASP and RSP curve from time to time along with the date on which they come into effect.

In addition to reviewing the trigger for RSP, the RAs are also considering whether the minimum price on the RSP curve, corresponding to 500MW of short term reserve, should be set to a value other than the RO Strike Price, and whether the maximum value should be set to a higher percentage of VoLL.

2.2 Review of Administered Scarcity Pricing Implementation

Given that ASP (either at the level of RSP or FASP) has not yet been triggered in the SEM, the RAs are considering whether this sufficiently reflects the localised and all island scarcity events which have given rise to the System Alerts experienced since go-live of the new market arrangements. The RAs note that during these periods, the Strike Price has not regularly been exceeded in the market. This impacts on the delivery incentive created by exposure to difference charges when the imbalance price exceeds the Strike Price, which was designed for periods of system stress.

While the SEM Committee's decisions in relation to ASP were intended to ensure an appropriate balance between risks for Suppliers and Generators, RSP (as the first point on

[14] For example see the SEM Committee Decision in the 2024/25 Capacity Auction Parameters, SEM-20-034

the ASP curve) was also intended to act as an incentive to respond during times of scarcity in order to avoid any further reduction in reserve quantities. As noted above, the SEM Committee intended for RSP to apply under conditions expected during a System Alert (Amber) State (as redefined to align with SOGL). The SEM Committee also noted that the trigger for Administrative Scarcity should be objectively defined.

As explained previously, the RSP has been implemented within the TSC to reflect system wide scarcity where the available Short-Term Reserve (qSTR) is less than the operating reserve requirement (qORR) on an all-island basis. System Alerts (Amber), in comparison, are issued jurisdictionally so there may be a localised scarcity event without pricing incentives to encourage capacity providers to be available and for demand to respond appropriately.

While the Parameters used to define Short Term Reserve include both Replacement Reserve and Tertiary Operating Reserve Band 2, the Operating Reserve Requirement Quantity includes only Tertiary Operating Reserve Band 2, thus the conditions under which RSP might apply appear limited. The RAs are interested in stakeholder feedback on whether this appropriately reflects the incentives intended through the application of RSP during times of scarcity or whether the trigger for RSP should be more closely aligned to the System Alert triggers as classified in the SOGL. The RAs are also interested in feedback on whether this appropriately reflects the European Commission’s view described in Section 1 that ASP should provide incentives for short term flexibility and send appropriate signals for investments to maintain system adequacy.

In summary, the RAs are interested in feedback on whether changes should be made to ASP – including both RSP and FASP – in the SEM in order to better align scarcity pricing with System Alerts in anticipation of expected tight capacity margins for Winter 2021/22 and align with the intent for scarcity pricing set out in earlier SEM Committee Decisions.

Areas of Potential Change to ASP

There are two areas that the RAs have identified for potential change – the first relates to the trigger for RSP within Section E.4 of the Trading and Settlement Code in order to widen the circumstances under which RSP applies. The RAs acknowledge that short term changes in this area, particularly in 2021, may be limited by the ability of market systems to systemise these changes and therefore request that the TSOs and MO investigate appropriate options in response to this Paper. The RAs also recognise that these proposed changes may have interactions with the SONI and EirGrid Grid Codes.

The second area identified by the RAs for potential change is the Reserve Scarcity Curve, which is currently linked to the RO Strike Price and to 25% VoLL. This could consider, for example:

- Whether the RSP curve should begin at a point below the RO Strike Price, in order to encourage further demand response on the supply side before the Supplier Hedge begins to apply. This could potentially act as an incentive for demand response at lower prices if suppliers can reduce load and sell energy purchased in the ex-ante market back to the market at the Imbalance Price.
- Conversely, whether the RSP curve should begin at a point above the RO Strike Price and the effect this would have on incentives to be available during times of scarcity.
- Whether the FASP value should be increased to a level closer to 100% of VoLL rather than the current value of 25% of VoLL, as requested in the Commission's Opinion of the Implementation Plans submitted respectively for Ireland and Northern Ireland pursuant to Article 20(5) of the Electricity Regulation. SEM-18-028 considered options for the value of FASP being set at 50% of VoLL and 100% of VoLL in order to sharpen performance incentives and in its decision did not preclude a move to a higher value of FASP.

Call for Evidence Questions:

To help inform the RAs consideration of potential revisions to ASP, responses are invited to the following questions:

1. Do you have any views on the way in which RSP has been implemented in the TSC and the potential issues discussed in Section 2.2?

2. Section 2.2 has outlined a number of specific areas that could be considered further related to the trigger for RSP and the parameters that define the Reserve Scarcity Curve. The RAs are interested in respondents' view as to whether:

a) the trigger for RSP should be amended such that the qSTR would include only Tertiary Operating Reserve Band 2 and not Replacement Reserve, or whether another amendment could be made that would bring this trigger more into line with the triggers for System Alerts in the SEM.

b) the RSP curve should begin at a point above or below the RO Strike Price.

c) the FASP value should be increased to a level closer to 100% of VoLL.

3. Feedback is also sought in relation to alternative delivery incentives during times of system stress which have not been raised here, but which could be implemented in the short term.

3. Demand Response

3.1 Price Based and Implicit Demand Response

Demand side flexibility based on customer response to price signals is generally referred to as implicit demand response or 'price based' demand side flexibility. The barriers to uptake of this type of demand side flexibility and future opportunities for demand response at the domestic level are not the focus of this Paper. However, the RAs are interested in gathering feedback in this area, to inform options which could be implemented in the short term to encourage greater levels of implicit demand response prior to and during System Events. During the CRM design phase, the SEM Committee stated that stronger incentives were needed for suppliers to negotiate demand response agreements with a wider range of customers with half hourly metering, based on the limited amount of price sensitive industrial load in the SEM.

A number of larger energy customers with half hourly meters may have tailored tariffs which reflect the wholesale electricity price, entailing lower risk premiums for Suppliers versus flat rate tariffs. Such dynamic pricing can allow customers to respond to price signals by decreasing load during peak hours and shifting consumption to lower priced periods. However, the RAs understand that uptake of these types of variable tariffs may be limited in the SEM, because the ability of customers to adapt to price signals may be constrained by the nature of industrial processes for example, increasing price variance and risk. The RAs therefore invite feedback from relevant Suppliers in particular on the level of uptake of these types of tariffs in the market, as the RAs do not have any direct visibility of this through regular retail market monitoring.

Suppliers can also benefit from reducing load and selling energy purchased in the ex-ante market back to the market if Imbalance Prices are high. Although Suppliers' risk is capped by the RO Strike Price if they need to purchase additional power, Suppliers can still get the full marginal benefit of selling back any load reduction relative to their ex-ante purchase volume via the Balancing Market, if prices rise to reflect scarcity. This should act as a demand response incentive in the energy market.

To date, the RAs understand that this type of response has not been a significant feature of Supplier trading in the wholesale electricity market. The RAs are therefore seeking feedback as to the barriers and opportunities which, in Suppliers' views, impact on this interaction with the wholesale market. Responses will not be published where they are marked as confidential.

Call for Evidence Questions:

The Regulatory Authorities are requesting feedback from relevant stakeholders on:

(1) The response of large energy users to price signals in the wholesale market

(2) Supplier interaction with incentives for demand response in the wholesale market

(3) The extent to which suppliers and customers can be incentivised to reduce demand by prices above the RO Strike Price, given that the supplier hedge applies above this price

3.2 Explicit Demand Response

Explicit demand-side flexibility is related to dispatchable flexibility that can be traded in the energy and capacity markets. In the SEM, Demand Side Units consist of one or more demand sites that can reduce their demand when dispatched. Larger premises may operate as an individual DSU, or alternatively a DSU Aggregator may contract with the Individual Demand Sites and aggregate them together to operate as a single DSU. Dispatch instructions are issued by the TSO at an aggregate level and the DSU Aggregator then coordinates the reduction from the Individual Demand Sites. The Individual Demand Sites use a combination of on-site generation and plant shutdown to deliver the demand reduction.

Energy Payments

DSUs are expected to submit Physical Notifications (PNs), technical offer data (TOD) and commercial offer data (COD) to the TSOs for the purpose of settling imbalances. DSUs can also participate in the capacity market. The European Commission's State Aid Decision for the CRM noted that DSUs were initially exempt from the RO payback obligation where demand reduction is delivered, as DSUs could not receive energy payments for demand reduction in the SEM, with only suppliers remunerated for any reduction in demand. However, the RAs committed to end the exemption from the RO payback obligations for DSUs from

October 2020. This was the subject of a SEM Committee Decision on DSU State Aid Compliance (SEM-19-029). The Decision paper noted that an optimal solution would be to fully integrate DSUs into the market and calculate actual demand response in order to provide for energy payments for DSUs in the Balancing Market, but in the interim suggested a solution to be compliant with State Aid requirements by October 2020. This decision was implemented through TSC Mod_17_19 which introduced an interim approach for DSU State Aid Compliance to allow energy payments to be made to DSUs where there is an RO event in order to provide revenue for them to pay Difference Charges on the same basis as other capacity market units. This payment is included in the imperfections charge to suppliers.

If a DSU clears in the market at a price above the RO strike price in the market in which the strike price event occurs, there is an opportunity to earn additional revenue as DSUs can receive energy payments of €500/MWh for any volumes exposed to Difference Charges and also for non-exposed volumes traded in the same market, for example in the balancing market where;

- A units' bid price and the imbalance price are above the Strike Price;
- A units' bid price is above the Strike Price but the imbalance price is below the Strike Price.
- A units' bid price is below the Strike Price but the imbalance price is above the Strike Price.

This opportunity may increase if changes to the RSP discussed in Section 2.2 are introduced.

Feedback is requested on this point and the interaction between the proposals in Section 2.2 and current energy payment mechanisms in place for DSUs in advance of an enduring solution for such payments being developed. For the avoidance of doubt, the focus of this Discussion Paper is not on the enduring solution for DSU energy payments but on short term improvements and the interaction between the interim arrangements that have been put in place and the discussion in Section 2 of this paper.

Call for Evidence Questions:

The RAs are requesting feedback from relevant stakeholders on:

1. The strength of the existing incentives for DSU availability and the effect of the potential changes to ASP proposed in Section 2.2 on these incentives.

2. Additional short-term incentives which could encourage further DSU availability.

3.3 Advance Notification prior to Amber Alerts

When a System Alert is expected or in place, a notification is issued to market participants by the Market Operator, SEMO. The RAs are interested in feedback from stakeholders on any additional information that could be provided by the System Operators where there is a probability of tight margins. In the case of DSUs for example, this may help in providing more notice to customers when demand reduction or on-site generation may be required.

In the UK, information on the Loss of Load Probability (LoLP) and De-Rated Margin (DRM) is published a day in advance, which provides an information signal for periods of tight margin. This information is used extensively by market participants and in January 2021 was the 5th most viewed Balancing Mechanism Report. The LoLP is a value between zero and one, representing the likelihood that there will be insufficient electricity supply to meet demand. National Grid ESO calculates the Loss of Load Probability for every Settlement Period according to the principles set out the Loss of Load Probability Calculation Statement. The De-Rated Margin represents the difference between the forecast electricity generation and the forecast electricity demand.

The RAs are interested in understanding the feasibility and usefulness of publication of additional information which might provide signals for generator availability and demand response where tight margins are expected.

Call for Evidence Questions: Feedback is requested from interested stakeholders on additional information that could be published to signal periods of scarcity in advance of alert notifications being issued by the Market Operator.

4. Next Steps

Responses are invited to this Discussion Paper until 7 July 2021 and all non-confidential responses will be published on the SEM Committee website. Responses can be sent to gkelly@cru.ie and kevin.baron@uregni.gov.uk.

Appendix 1 – Amber Alerts in 2020 and 2021

Information on system conditions in Ireland and Northern Ireland is presented in the tables below for each half hourly period in which the maximum 30-minute Balancing Market price occurred in each day. This is based on an average of each 5-minute scheduling period in RTD aligned to each of these 30-minute periods, shown in the sixth column.

For interconnector flows, a positive value means that the interconnector was importing into the SEM, while a negative value means it was exporting from the SEM. For the inter-area flow between IE and NI, a positive value means the direction of flow was from IE to NI, while a negative value means the direction of flow was from NI to IE. Fix Generation relates to embedded generation which is not registered in the market or otherwise represented explicitly in the scheduling.

Ireland System Conditions

Date	Time	Location	Type	Max 30 min BM Price	Scheduling Interval with Max BM Pice	Load (MW)	Non-Wind Generation (MW)	Fix Generation (MW)	Wind Availability (MW)	Wind Generation (MW)	Inter-area flow (MW)	FFR Req.	FFR Dynamic	FFR Asynchronous	POR Req.	POR Dynamic	POR Asynchronous	SOR Req.	SOR Actual	Interconnector Flow (MW)
08/01/2021	13.15-18:25	NI	Amber	444.36	16.00-16.30	4,458	3,860	86	656	656	143	0	0	45	110	117	120	110	317	-208
06/01/2021	16:00-18.05	All Island	Amber	520.87	17.00-17.30	5,105	5,050	25	138	137	107	0	0	45	110	112	120	110	265	0
09/12/2020	16.45-18.18	All Island	Amber	494.63	17.00-17.30	5,278	4,144	150	883	883	-101	0	0	45	110	105	120	110	239	-488
26/11/2020	16.00-19.00	NI	Amber	691.57	18.00-18.30	4,865	4,778	38	185	184	135	0	0	45	110	105	120	110	265	57
24/11/2020	18.30-22.00	NI	Amber	290.71	19.30-20.00	4,360	3,875	77	538	538	130	0	0	45	110	184	62	110	385	487
19/11/2020	16.45-19.00	NI	Amber	206.85	17.30-18.00	4,872	4,140	74	826	776	118	0	0	45	110	205	45	110	304	504
05/11/2020	16.30-19.10	NI	Amber	491.75	17.30-18.00	4,889	4,954	9	68	68	142	0	0	45	110	112	120	110	242	279
15/09/2020	16.18-19.05	Ireland	Amber	359.08	17.30-18.00	3,994	3,797	10	115	114	-73	0	0	45	110	115	120	110	245	0
05/08/2020	10.50-15.00	Ireland	Amber	101.27	13.00-13.30	3,798	3,061	89	797	786	139	0	0	23	133	133	98	133	324	350
11/03/2020	16.30-20.53	NI	Amber	51.54	18.30-19.00	4,698	1,951	314	2,696	2,612	180	0	0	23	133	124	91	133	272	-111
21/01/2020	10.15-18.00	NI	Amber 2	65.46	14.00-14.30	4,272	4,035	69	263	263	95	0	0	166	133	133	166	133	356	504

Northern Ireland System Conditions

Date	Time	Location	Type	Max 30 min BM Price	Scheduling Interval with Max BM Pice	Load (MW)	Non-Wind Generation (MW)	Fix Generation (MW)	Wind Availability (MW)	Wind Generation (MW)	Inter-area flow (MW)	FFR Req.	FFR Dynamic	FFR Asynchronous	POR Req.	POR Dynamic	POR Asynchronous	SOR Req.	SOR Actual	Interconnector Flow (MW)
08/01/2021	13.15-18:25	NI	Amber	444.36	16.00-16.30	1,262	1,066	13	39	39	143	0	0	15	50	77	90	50	167	-294
06/01/2021	16:00-18.05	All Island	Amber	520.87	17.00-17.30	1,536	1,386	9	34	34	107	0	0	15	50	86	90	50	159	-78
09/12/2020	16.45-18.18	All Island	Amber	494.63	17.00-17.30	1,545	1,187	50	440	409	-101	0	0	15	50	70	90	50	165	-300
26/11/2020	16.00-19.00	NI	Amber	691.57	18.00-18.30	1,406	1,166	7	98	98	135	0	0	15	50	47	90	50	138	74
24/11/2020	18.30-22.00	NI	Amber	290.71	19.30-20.00	1,236	975	16	115	115	130	0	0	15	50	114	15	50	129	440
19/11/2020	16.45-19.00	NI	Amber	206.85	17.30-18.00	1,448	1,191	18	121	121	118	0	0	15	50	107	15	50	128	440
05/11/2020	16.30-19.10	NI	Amber	491.75	17.30-18.00	1,441	1,264	15	20	20	142	0	0	15	50	60	90	50	151	276
15/09/2020	16.18-19.05	Ireland	Amber	359.08	17.30-18.00	1,138	1,144	21	46	46	-73	0	0	15	50	75	88	50	169	-52
05/08/2020	10.50-15.00	Ireland	Amber	101.27	13.00-13.30	1,059	867	13	40	40	139	0	0	12	48	49	85	48	134	-112
11/03/2020	16.30-20.53	NI	Amber	51.54	18.30-19.00	1,361	892	34	256	256	180	0	0	11	48	35	84	48	119	87
21/01/2020	10.15-18.00	NI	Amber 2	65.46	14.00-14.30	1,219	898	26	200	200	95	0	0	9	48	70	9	48	79	440

Appendix 2 – Conditions for System Alerts in Ireland and Northern Ireland

For Ireland, “Alert state” (Amber Alert) should be initiated by NCC when any one of the following criteria are satisfied:

a. *voltage and power flows are within operational security limits;* ***and***
b. *the All-Island reserve capacity is reduced by more than 20 % for longer than 30 minutes and there are no means to compensate for that reduction in real-time system operation; or*
c. *frequency meets the following criteria:*
    i. the absolute value of the steady state system frequency deviation from nominal has not continuously exceeded 500 mHz for a time period longer than one minute; and
    ii. the absolute value of the steady state system frequency deviation from nominal has continuously exceeded ± 200 mHz for a time period longer than 15 minutes; or
    iii. the absolute value of the steady state system frequency deviation from nominal has continuously exceeded ± 250 mHz for a time period longer than 10 minutes
d. *at least one contingency from the contingency list leads to a violation of operational security limits, even after the activation of remedial actions;*
e. *multiple contingencies are probable because of thunderstorm or high wind activity; or*
f. *the jurisdictional margin is such as the tripping of the largest set, would give rise to a reasonable possibility of failure to meet the System Demand*

Similarly for Northern Ireland, Alert State (Amber alert) should be initiated by CHCC when any one of the following criteria are satisfied:

a. *voltage and power flows are within operational security limits; and*
b. *the All-Island reserve capacity is reduced by more than 20 % for longer than 30 minutes and there are no means to compensate for that reduction in real-time system operation; or*
c. *frequency meets the following criteria:*

i. *the absolute value of the steady state system frequency deviation from nominal has not continuously exceeded 500 mHz for a time period longer than one minute; and*

ii. *the absolute value of the steady state system frequency deviation from nominal has continuously exceeded ± 200 mHz for a time period longer than 15 minutes; or*

iii. *the absolute value of the steady state system frequency deviation from nominal has continuously exceeded ± 250 mHz for a time period longer than 10 minutes*

d. *at least one contingency from the contingency list leads to a violation of operational security limits, even after the activation of remedial actions;*

e. *the jurisdictional margin (i.e. all the available plant, including wind, plus any guaranteed emergency assistance from interconnection less the predicted demand) pre fault in that period is less than the largest jurisdictional infeed but more than the primary spinning reserve requirement associated with this infeed*

Appendix 3 – Conditions under which the RSP and FASP apply in the TSC

Conditions under which the RSP applies

E.4.2.1 For each Imbalance Pricing Period, φ, the System Operator shall submit the Operating Reserve Requirement Quantity ($qORR_{φ}$) and Short Term Reserve Quantity ($qSTR_{φ}$) to the Market Operator in accordance with Appendix K "Other Market Data Transactions".

E.4.2.2 For each Imbalance Pricing Period, φ, the Market Operator shall calculate the Reserve Scarcity Price ($PRS_{φ}$) as follows:

(a) If $qSTR_{φ} < qORR_{φ}$, and $qSTR_{φ} \leq qRSC_{(Θ=N)}$, the Market Operator shall calculate the value of Θ that satisfies $qRSC_{Θ-1} \leq qSTR_{φ} \leq qRSC_{Θ}$ where $2 \leq Θ \leq N$ and then calculate,

$$PRS_{φ} = \left(\frac{PRSC_{Θ} - PRSC_{Θ-1}}{qRSC_{Θ} - qRSC_{Θ-1}}\right) \times (qSTR_{φ} - qRSC_{Θ-1}) + PRSC_{Θ-1}$$

where ($PRSC_{Θ}$, $qRSC_{Θ}$) is the Θth Reserve Scarcity Price Quantity Pair in the Reserve Scarcity Price Curve applying to the Capacity Year in which Imbalance Pricing Period φ falls and $qSTR_{φ}$ is the Short Term Reserve Quantity for Imbalance Pricing Period, φ;

(b) Otherwise, the Reserve Scarcity Price ($PRS_{φ}$) is set equal to PFLOOR.

Conditions under which the FASP applies

E.4.3 Determination of Demand Control Quantities

E.4.3.1 If during an Imbalance Pricing Period, φ:

(a) the Short Term Reserve Quantity ($qSTR_{φ}$) is less than the Operating Reserve Requirement Quantity ($qORR_{φ}$); and

(b) any of the following Demand Control events occurs:

(i) Customer Voltage Reduction in Northern Ireland, in accordance with section OC4.4.5 of the Northern Ireland Grid Code;

(ii) Emergency or Exceptional Voltage Control, in Ireland in accordance with OC4.4.6 of the Ireland Grid Code;

(iii) Automatic Load Shedding in Northern Ireland, in accordance with section OC4.4.8 of the Northern Ireland Grid Code;

(iv) Automatic Low Frequency Demand Disconnection in Ireland, in accordance with section OC5.5 of the Ireland Grid Code;

(v) Planned or Emergency Manual Disconnection in Northern Ireland, in accordance with section OC4.4.6 of the Northern Ireland Grid Code; or

(vi) Demand Control on the instructions of the TSO in Ireland, in accordance with section OC5.4 of the Ireland Grid Code.

then the relevant System Operator shall determine that the Imbalance Pricing Period, φ, is an Affected Imbalance Pricing Period.