Response to SEM-22-030

Consultation on the Applicability of Reliability Option Non-performance Difference Charges to Available In-merit Units

EirGrid plc. and SONI Ltd. Response
31 August 2022

Executive Summary

EirGrid and SONI welcome the opportunity to participate in the SEM Committee's Consultation on the Applicability of Reliability Option Non-Performance Difference Charges to Available In-merit Units (SEM-22-030). This response is submitted by EirGrid and SONI in their capacities as TSOs and MOs for Ireland and Northern Ireland.

EirGrid and SONI note the broader context of capacity, including the Regulatory Authorities' deliberations, current and pending consultations, and proposed Trading and Settlement Code and Capacity Market Code modifications. All of which could potentially have significant impact and require substantial attention and consideration. EirGrid and SONI welcome expeditious resolution of matters which improve capacity margins and improve Security of Supply year on year.

EirGrid and SONI previously outlined to the SEM Committee concerns in relation to the effectiveness of the current implementation of the Reliability Option (RO) in the context of decreasing capacity margins. This response is intended to contribute to the discussion put forward by the SEM Committee in SEM-22-030 and to address the matters and specific questions raised in the consultation paper.

EirGrid and SONI address the questions posed by the Regulatory Authorities within the body of this response. An appendix describes the requested scenarios in *Question 1: When an available in-merit unit may not be dispatched to its availability.*

EirGrid and SONI wish to highlight the following summary points from our response:

- The current implementation of the Reliability Option may disincentivise new capacity investment due to the increasing frequency of 'RO Events[1]' on a system with capacity deficits. A redesign of the Reliability Option should be considered as soon as possible.
- EirGrid and SONI recognise the financial risk market participants may be exposed to in the application of Non-Performance Difference Charges in circumstances outside of their control.
- The Trading and Settlement Code has been designed and has evolved to reduce this risk e.g. flagging of interconnector actions which mitigate interconnector driven price spikes and excluding units that provide Replacement Reserve.
- Extending exemptions to units bound by operational constraints is appropriate however the implementation model would need to be considered carefully to address potential locational signals. This approach would not address all circumstances where units may be exposed to Non-Performance Difference Charges while available for dispatch.
- Exemption based on availability would be a change of approach and systematic implementation would have long lead-times. Any 'in-merit' test for exempting an available unit that is not dispatched is problematic to implement in real time and pricing timeframes i.e. through a flagging methodology. Achieving this approach may be effectively implementable in Settlement timeframes through manual re-work - subject to the availability of a clear set of criteria governing the 'in-merit' test.
- Should there be a change to the application of CDIFFCNP, options which do not require systems changes are preferable to implement within reasonable timeframes.

[1] As set out in SEM-22-030, the Regulatory Authorities define an 'RO Event' as when the RO creates an incentive to deliver energy by exposing Capacity Market Units to Difference Charges when energy prices exceed the Strike Price of the RO.

Introduction

EirGrid plc (EirGrid) holds licences as independent electricity Transmission System Operator (TSO) and Market Operator (MO) in the wholesale trading system in Ireland. SONI Ltd. (SONI) is the licensed TSO and MO in Northern Ireland.

Both EirGrid and SONI have been certified by the European Commission as independent TSOs. EirGrid also owns and operates the East West Interconnector, while SONI acts as Interconnector Administrator for both of the interconnectors that connect the island of Ireland and GB. The Single Electricity Market Operator (SEMO) is a contractual joint venture between EirGrid plc. and SONI Ltd. and operates the Single Electricity Market (SEM) on the island of Ireland.

EirGrid and SONI, both as TSOs and MOs, are committed to delivering high quality services to all customers, including generators, suppliers and consumers across the high voltage electricity system and via the efficient operation of the wholesale power market. EirGrid and SONI therefore have a keen interest in ensuring that the market design is workable, will facilitate security of supply and compliance with the duties mandated to us and will provide the optimum outcome for customers.

EirGrid and SONI have duties under licence to advise the CRU and UR respectively on matters relating to the current and expected future reliability of the electricity supply. We have also been allocated responsibility for administering the Capacity Market Code through our TSO licences.

This response is submitted on behalf of EirGrid and SONI in their respective capacities of TSOs and MOs for Ireland and Northern Ireland.

Background

The implementation of the Reliability Option mechanism was, in part, intended to manage the risk of scarcity and to incentivise performance during scarcity driven 'RO Events'. Experience from the market shows that high prices have not always been correlated with shortages in capacity. Alternative approaches to the RO could directly incentivise good day-to-day practice which in turn places the system in a good position to deal with scarcity events.

In relation to the consultation, SEM-22-030, EirGrid and SONI support appropriate and effective targeting of Non-Performance Difference Charges ('CDIFFCNP') to incentivise economic delivery of contracted capacity for consumers. The consultation paper references a value of €10.7m with respect to the CDIFFCNP applied since 2018. It is perhaps worth noting this value in the context of capacity payments accrued over the same period (€1.33bn since 2018) when considering options for change in applicability.

Where there is scarcity (or imminent risk of scarcity) the Imbalance Price should reflect this - a central tenet of European Market regulations. While high prices are undesirable for the consumer, for the market to work efficiently and deliver benefits to end consumers including lower costs over the longer term, the price should be able to rise to reflect scarcity to provide the correct investment incentives and availability incentives during periods of likely and actual scarcity.

Consideration of the current applicability of CDIFFCNP and any change to the current approach should be considered in the context of significant Security of Supply concerns, the SEM Committee's deliberations on Administered Scarcity Pricing, the risk profile of new and existing capacity and how the CRM has and should evolve. An approach which would apply a broad test of performance against declared availability may not incentivise real availability or delivery.

Whilst CDIFFCNP arise and RO events are triggered when the Reference Price exceeds the Strike Price, the Reference Price may be driven upward by forces other than scarcity. Where prices reflect scarcity and exceed the Capacity Market Strike Price, participants should be incentivised to perform.

Aside from market design principles and operational implications, any change of approach which would require market systems changes would take a number of years to deliver and would need to be assessed and scheduled in the context of other policy implementation priorities over the same period and the cost / benefit of same.

Should there be a change to the application of CDIFFCNP it is therefore EirGrid and SONI's view that options which do not require systems changes are preferable and would deliver benefits within reasonable timeframes in the context of the lifespan of the current CRM.

APPROACHES TO APPLICATION OF NON-PERFORMANCE DIFFERENCE CHARGES

Consultation Questions:

"Under what circumstances, if any, beyond being flagged for providing Replacement Reserve, should units be exempt from Non-performance Difference Charges that would otherwise apply?"

Could these approaches introduce a detrimental locational signal into the Capacity Market (e.g. by exempting units bound by a Locational Constraint from Non-performance Difference Charges, could this send a signal to Capacity Market Units to locate behind a constraint)?

Is there any interaction with the incentives for units to trade in the ex-ante markets as a consequence of your preferred approach, or any of the approaches proposed?"

CURRENT APPROACH AND MOD_14_21

As outlined in the consultation paper, the current applicability of CDIFFCNP is limited to those RO units which do not achieve an ex-ante market position, exclusive of units which are dispatched or providing replacement reserve. Where a generator unit is bound by the replacement reserve operational constraint, the System Service Flag (FSS) is set to zero for that Imbalance Pricing Period and CDIFFCNP will not be charged.

MOD_14_21 proposes to extend the application of FSS to include units that are listed as providers of replacement reserve with reference to the contemporaneous TSO Operational Constraints Update and replacement reserve Transmission Constraint Group therein (Ref. S_REP_NI / S_MWMAX_NI_GT and S_REP_ROI / S_MWMAX_ROI_GT). The Modifications Committee has recommended for approval, in summary, to:

- Extend the application of the FSS to (generator) units listed by the TSOs in the Replacement Reserve Transmission Constraint Group subject to the unit's Incremental Price (PINC) being below the Strike Price (PSTR).

An impact assessment is ongoing with respect to the modification. Implementing the intention of the proposal in Settlement timeframes rather than through a flagging methodology may be possible for infrequent events if the necessary information (and criteria to apply) is available in those timeframes.

Mod_02_21 brought in flagging of interconnector actions in pricing, indirectly reducing the exposure of units to CDIFFCNP e.g. by flagging out System Operator trades above the Strike-Price. In the design of the SEM, SO interconnector trades were included in the imbalance price calculation to apply the same rules as to generator units – as SOs enter into SO Interconnector Trades to balance the system (for System Security).

The exposure of units to CDIFFCNP in circumstances outside their control may have resulted in efforts to mitigate the risk of price spikes. EirGrid and SONI consider the price of balancing electricity should reflect the marginal cost of that energy. Where the difference charges can be targeted in a way that removes unintended exposure to units in circumstance which are beyond their control, this may provide the conditions to allow the imbalance price to fully reflect the marginal cost of balancing the system.

SYSTEM OPERATIONAL CONSTRAINTS APPROACH

In response to consultation SEM-19-024[2], EirGrid and SONI broadly supported the extension of exemptions to CDIFFCNP to units bound by an operational constraint which limits that unit's output.

As outlined in that response, with the current system implementation, this approach could only apply to those constraints which are included in System Operator Flagging under Imbalance Pricing. The FSS process relies on the System Operator Flag process being switched on in pricing in order to use the results of that process to also create the results for the FSS. To have a different implementation approach where System Operator Flags can be turned off for specific or all constraints, but would still create System Service Flags for them, would require a systems change with significant lead times.

It would be expected that this approach would result in a reduction in Difference Charges to meet Difference Payments, with a resultant downward pressure on the Socialisation Fund. However this option is less impactful in this regard than an approach based on availability. To date the Socialisation Fund, which stands at €20.2m[3], has tended to over-recover due to the differential between day-ahead (supplier volumes purchased ex-ante) and imbalance prices (generator exposure).

Extending the exemption of CDIFFCNP to units bound by an operational constraint will still leave units exposed, for example those with limited run hours or energy limited plant. However the capacity market design places the risk of non-delivery on the participant. A unit that cannot run at the level of their capacity obligations for the period of scarcity should be incentivised to perform to ensure that they can deliver to the level of their obligated capacity and /or invest in upgraded technology. A participant has the ability to nominate less qualified capacity if they consider that they cannot deliver for the full duration of the scarcity periods.

The operational constraints approach will also leave some units which are available, not energy or run hour limited and not bound by an operational constraint exposed to CDIFFCNP. As described in more detail in the response to SEM-19-024, when the constrained balancing market results in a unit's output being limited due to the North-South tie-line constraint, if the unit is System Service Flagged then they have potentially made the system situation worse in further driving network flows from Ireland into Northern Ireland, hitting the limits of these flows, whilst not being exposed to the outcome of this if the Imbalance Settlement Price rises above the Strike Price.

It needs to be carefully considered if the intention is to include a reduction in exposure due to locational network constraints, or only due to system service related constraints, which are not likely to have the same potential locational signal issue. It may be considered a balance that the removal of these constraints from System Operator Flagging reduces the potential for the high Imbalance Settlement Price events occurring, and therefore the need to include them in System Service Flagging may be reduced.

[2] SEM Committee Publication; EirGrid and SONI Response to SEM-19-024

[3] The Socialisation Fund includes €6.5m in termination fees.

Case Study

To provide an indication of the impact of a change of approach in the applicability of CDIFFCNP for this consultation a review of the 12th July 2022 RO Event was undertaken.

On this date the imbalance price exceeded the strike price for four settlement (half hour) periods.

In the review the application of CDIFFCNP was amended manually to remove the charges applied to units bound by an operational constraint and to remove units listed by the TSO as providers of replacement reserve per the published operational constraints update.

No ‘in-merit’ test or comparison between the unit’s price and the Strike Price was applied to the analysis i.e. the analysis does not reflect the full extent of modification Mod_14_21 which could result in some of the units being left exposed to CDIFFCNP due to their incremental price (PINC).

Result: The value of CDIFFCNP reduced by approximately 84%. The balance of CDIFFCNP was associated with units which were not available in this case.

AVAILABILITY APPROACH

Extending the exemption from CDIFFCNP to include an availability test is a move away from an approach designed to incentivise trading and delivering capacity obligations. Depending on the approach and implementation brought forward it could necessitate system changes with long lead-times among other significant programmes of work which deliver on policy priorities.

Availability is not physical (it amounts to a signal or declaration) and therefore not confirmed or measurable until dispatched. Metered delivered energy is a more robust test in measuring reliability. With an availability approach, participants could be incentivised to be available only to their obligated capacity quantity level, as this would ensure they are covered, and not available to higher levels they could operate at (although this is technically mandated in the Grid Codes). In this sense, it may be worth considering basing capacity payments on availability if the charges are to become much more linked with availability, to counter the potential downward pressure on availability.

An abstract availability approach could incentivise over-declaration of availability which could mask a deteriorating capacity situation over time. A holistic approach should incentivise declarations of availability to realistic, high levels and delivery to those levels when dispatched.

If an availability based approach is implemented it should be considered whether incentives to deliver when dispatched are adequate. Availability can change after dispatch - meaning a unit can appear available and ‘in-merit’ but after it is dispatched it declares down and is desynced. In this scenario it will appear available and in-merit but will and should be considered as neither performing nor delivering. An availability based approach should provide clarity on the applicability of CDIFFCNP in this scenario in order to avoid giving market participants a mechanism to avoid CDIFFCNP and in order to provide an adequate incentive to declare their availability accurately.

For the purposes of the consultation paper, ‘in-merit’ was defined ‘relative to the price in the Balancing Market’. There are circumstances where an available unit with a price higher than the imbalance price is not dispatched as it is providing Primary Operating Reserve. In this circumstance the unit would not be in-merit and would remain exposed to CDIFFCNP under the available and in-merit approach. Typically, ‘in-merit’ has referred to a unit that is dispatched and online. Therefore any merit order that is derived from the market schedule in RTPIMB (Real Time Imbalance Pricing) would be the correct merit order to use for this approach. However a unit will not appear in that merit order if not dispatched. This issue would need to be resolved in order to ascertain if a unit was in-merit.

In ascertaining if a unit is in-merit, the interactions of pricing and flagging would need to be considered. Higher price units may be dispatched and online but flagged out resulting in a lower price unit setting the imbalance price. In such a scenario the higher priced units which are dispatched and online are not ‘in-merit…relative to the price in the Balancing Market’.

Implementation of an ‘available and in-merit’ test would likely necessitate an ex-post solution in Settlement timeframes. Such a solution is likely to be more efficient and practically implementable than the introduction of a flagging process in real time or imbalance pricing timeframes for actions not taken. Flagging methods apply to actions which have been taken e.g. dispatch.

It would be expected that the availability approach would result in a reduction in Difference Charges to meet Difference Payments, the net effect being a downward pressure on the Socialisation Fund over time.

APPENDIX: Q1 TSO RESPONSE - DISPATCH BELOW AVAILABILITY WHEN IN-MERIT

The SEM Committee requests that the TSOs provide further information regarding all of the possible reasons why, in practice, units may not be dispatched when available and in-merit. This information is required as different scenarios may need to be considered differently in the context of the applicability of Non-performance Difference Charges.

1.	Primary Operating Reserve Requirements	Primary Operating Reserve (POR) is maintained in line with minimum requirements: 75% of Largest Single Infeed on an all-island basis subject to a minimum of 150 MW in Ireland and 50 MW in Northern Ireland. POR is typically provided by numerous online units. The POR provision of these units varies with their MW availability / output and would be zero at their maximum availability.
2.	Replacement Reserve Requirements	Replacement Reserve is the active power reserves available to restore or support the required level of exhausted Frequency Restoration Reserves (Tertiary Operating Reserves) after a frequency event in order to be prepared for additional system imbalances, including generation reserves. Replacement Reserve provision may include online and offline available in-merit units.
3.	Optimising Operating Reserve with the Largest Single Infeed	The All-Island requirement for Operating Reserve (Primary, Secondary, and Tertiary) ranges from 75% to 100% of the Largest Single Infeed. Reducing the Largest Single Infeed reduces the reserve requirement and associated cost.
4.	Transmission (Network) Constraints	A unit may be dispatched below its availability due to its direct contribution to risks associated with thermal constraints on the transmission network - either during intact networks conditions or as a result of a transmission contingency or outage (including transmission outages which prevent export entirely).
5.	Operational Constraints	A unit which is expensive with reference to the merit order may be started for non-energy reasons to satisfy Transmission Constraint Groups (TCG) e.g. voltage support, dynamic stability. While operating at minimum stable generation, a SO flag would bind. Subsequent incremental (energy) actions would remove this SO flag and could feed through to set the imbalance price while units with lower incremental prices are not used due to their start up costs.
6.	Voltage Support Capability	A generator unit may offer an increased level of voltage support (+/- MVAr) at a MW output level below full availability.
7.	Tie Line / Inter-Area Limitations	There is limited transmission capacity between Ireland and Northern Ireland. Further to this physical / thermal limitation there are system stability contingencies (hazards) which increase with power flows in either direction e.g. a fault on the tie-line with high flows would lead to system separation, potentially breaching the Operational Limit for Rate of Change of Frequency (RoCoF). As a result of these inter-area limitations an available unit which manages this contingency may be dispatched in preference for a unit which would exacerbate it.
8.	Conservation of Energy Storage	To conserve impounded energy stores over a period e.g. hydroelectric and pumped-hydroelectric generator unit stores held back in expectation of tighter margins.
9.	Hydroelectric Running Constraints	Environmental and hydrological constraints on hydroelectric facilities e.g. ramping limitations to ensure stability of reservoir structures, may result in hydro unit dispatch below availability.
10.	Observe Maximum On Time Limitations	When an online unit reaches its Maximum On Time (the maximum time that a unit can run following start up, per Technical Offer Data) it is shut down / de-committed while 'available'.

11.	Commercial Offer Data and Production Costs	Complex Commercial Offer Data (start-up, no load and incremental/ decremental price quantity pairs) is used in the scheduling process to determine both unit commitment status and indicative MW output levels across the scheduling horizon. The incremental price of an offline unit may be cheaper than an online unit however the start-up cost may be prohibitive in the context of the scheduling horizon. Whereas Simple Commercial Offer Data (incremental/decremental price quantity pairs only) is used for balancing actions and Imbalance Pricing.
12.	Synchronisation and Ramping Limitations	Synchronisation dispatch instructions ('Notice to Synchronise') observe a unit's hot, warm and cold state and associated start up times. An available offline unit may not be technically capable of synchronizing 'immediately' following an unforeseen event such as a large generator trip. Further, following synchronization, the unit will ramp up to its maximum availability over a period of time (observing unit ramp rates).
13.	Generator Fuel Conservation	To maintain primary input fuel stocks (heavy fuel oil, distillate oil for 'peakers') e.g. if there are constraints on or risks to the supply of the input fuel.
14.	Displacement by 'Must Run' Unit	Security of supply 'must run' constraints may be applied to a generator unit for a period of time e.g. due to the risk of a subsequent forced outage should the unit be desynchronised during a period of tight generation margins. The dispatch of other available units may be impacted by this 'constrained on' unit.
15.	Displacement by Cross Zonal Actions	System Operator trading over the interconnectors is initiated ahead of time in order to manage forecast system security risks and to maximise priority dispatch generation. The volume and duration of the trades are fixed in a revised interconnector schedule. Real time system conditions may vary compared with forecast conditions however and the revised interconnector schedule could displace available generation.
16.	Conservation of Run Hours	Security of supply 'must not run' constraints may be applied to a generator unit(s) for a period of time e.g. due to limited run hours or starts remaining on a unit before a maintenance outage must occur. Conserving run hours during a period of low demand / high generation margins mitigates security of supply risks associated with periods of high demand / low generation margins.
17.	Generator Reliability	A generator which is less reliable in successfully synchronising or which may take a number of attempts to reach stability may be started before a unit which has performed more reliably.
18.	Environmental / Emissions License	Similar to the conservation of run hours for technical reasons, hours may be preserved due to emissions licence (e.g. SOx, NOx) limitations.
19.	National Gas Supply Emergency (Ireland)	Per the CRU's National Gas supply Emergency Plan 2018 -2022, EirGrid 'will decide during a gas supply emergency, which power stations if required should fuel switch, reduce output or come off load'. Gas Networks Ireland would issue an 'instruction to EirGrid to co-ordinate reductions in gas demand for the gas-fired power generation sector'.
20.	Non-Wind Priority Dispatch Plant	Non-wind Priority Dispatch units (hydro, peat, CHP) are generally dispatched to their Physical Notification (intended output and output level to which Priority Dispatch is applicable) and not above.
21.	Dispatch of Minor Availability Increments	There may at times be small (<5MW) availability on a unit which remains un-dispatched for a period e.g. when the real time availability of a unit increases.