ECP 2.1 Constraints Forecast Report

FAQ Document

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ECP 2.1 Constraints Analysis FAQs

The ECP 2.1 studies and analysis have led to a very large volume of queries, mainly focussed on a small number of questions. The purpose of this FAQ document is to help address the majority of these queries in a timely fashion and publish the responses for all interested parties in a fair and transparent way. This also allows the team to focus on preparing the ECP 2.2 studies.

Constraint Subgroups and EirGrid's Approach

Q: Some of the subgroups (e.g. North-West and Area J) are very large and have changed compared to ECP 1 reports. It would be good to understand the reasoning behind this and the binding constraints that are causing them?

A: The subgroup definition is based on the network topography. Typically the 110 kV network will provide rescue flows for other higher voltage circuits that are electrically in parallel. As part of network power flow analysis it is important that the network constraints are allocated appropriately. For the purposes of this analysis, sub-groups are identified and generation nodes are grouped together according to where the congestion bottleneck is located on the network.
For example: The Flagford - Louth 220 kV circuit has generation located in areas A, B, C and G North, these generators flow power from the 110 kV network up onto the higher voltage 220 kV network. Where there is low capacity on the 110 kV networks it becomes the limiting factor for the loss of Flagford - Louth 220 kV circuit. In a future year, an operational subgroup could be in place to ensure that a balanced dispatch down of generation is applied, i.e. on a pro rata basis, so that the generators contributing to the congestion are treated equally. In the modelling environment the tools that we use may unfairly dispatch down a wind farm. We use a subgrouping approach to prevent unfair allocation of constraints due to modelling limitations. We apply sub-grouping methodology consistent with that applied with today's operational wind dispatch tool, however the sub-groups will not be the same as we use the 2024 network and generation assumptions to develop the future sub-groups.
The subgroups are kept identical for all study years ensuring that the various scenario results are comparable.

SOEF – 80% RES-E

Q: The level of constraints in the future grid scenarios is concerning. How does this link to the development of Shaping our Electricity Future and plans to achieve 80% RES-E through increasing onshore wind?

A: The next iteration of Shaping Our Electricity Future will consider an 80% RES-E target. Any change in operational or network required to facilitate further RES integration will be evaluated within the next iteration of the Shaping Our Electricity Future process.
It is worth reminding the reader that the core ECP 2.1 study years are 2024 and 2026. ECP 2.1 provides an overview of total dispatch down for ECP 2.1 generators against the latest assumptions for a range of planned network reinforcements and changes to market and operational policies.

SOEF Reinforcements Included

Q: Have all reinforcements identified in SOEF been included in the future grid analysis? Noted that some reinforcements e.g. power flow controllers do not seem to be included.

A: Power flow controllers (PFC) are an operational tool. The PFCs are not currently modelled within the ECP 2.1 process, this aligns with the SOEF model. There is an opportunity to review PFC modelling within ECP 2.2, we will engage with the SOEF team on the subject. All other identified network updates in SOEF are included in the Future Grid study.

Maintenance Outages

Q: There is a need to understand EirGrid's approach to this and how they came up with the maintenance assumptions. Some areas are very badly impacted by the assumptions and how have outages been determined across subgroups.

A: Within ECP 2.1 Following ECP 1.0, we received a feedback from industry that including maintenance programme would be helpful; as part of ECP 2.1 this has now been included in the baseline models. The maintenance schedule was discussed with our internal operations team and it represents a typical outage programme for the network. However, every maintenance and outage season is different, and the results need to be interpreted with this in mind.
ECP 2.1 studies contain a "representative" transmission outage schedule. The outages included in this analysis represent a geographical spread of circuits across the system and are each configured for a 3-month period. This allows for a representation of outage impact in each geographical area. The impact of these outages is then averaged across the relevant subgroup in the post-processing step to give a sample outage impact for each area. In reality, each outage season may have up to a thousand outages of varying lengths and severities across the system, but this level of detail cannot be represented in the ECP studies and Plexos model.
It is important to note that the "representative" transmission outage schedule is not changed across the horizon (2024, 2026 and Future Grid), this stops dispatch down from being driven by differences in transmission outage schedules.
A more detailed overview of this topic is discussed in the Report Addendum found on the EirGrid website[1].

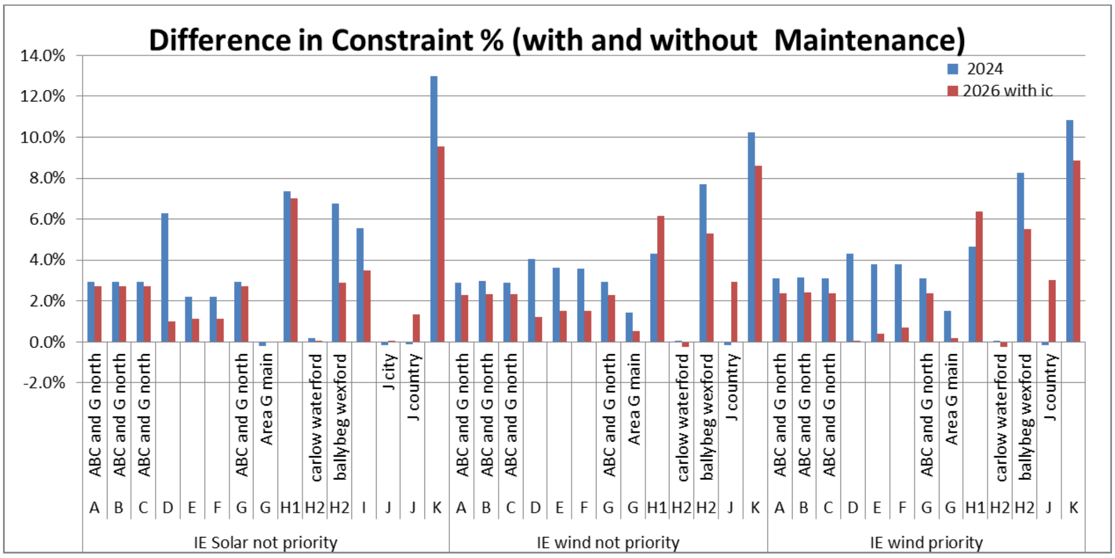
Q: Could EirGrid split out constraints per node so we can see what level of constraints is caused by maintenance/outages?

A: The current subgroup reporting approach is deemed appropriate as a nodal breakdown of the subgroup would report the same averaged results. A more detailed analysis may be considered for future ECP studies.

[1] https://www.eirgridgroup.com/customer-and-industry/general-customer-information/ecp-2.1-constraint-report-1/index.xml

Q: Can EirGrid undertake a sensitivity analysis of one of the scenarios, where the maintenance outages are removed?

A: The below graph shows area and subgroup results (% constraints difference) by comparing two studies one with maintenance and a second study without maintenance. The analysis was carried out for 2 study scenarios: “2024 ECP (All)” and “2026 with Greenlink ECP (All)”. Greater detail on this topic is available in the Report Addendum on the EirGrid website[2].



Binding Constraints

Q: Can EirGrid provide commentary of the most binding constraints in each of the reports, as was previously provided in the ECP 1 Constraint Reports.

A: This request will be completed by publishing a supplementary report on the EirGrid website[3].

Priority Dispatch Curtailment higher than Non-Priority Dispatch

Q: There are cases where curtailment is higher for wind farms with Priority compared to wind farms without Priority. Given that curtailment was allocated pro rata, can you please explain why there are differences in curtailment results?

A: The curtailment percentage is calculated based on initial available energy (before oversupply study). However, the pro-rata distribution of curtailment is based on the available energy in the curtailment study. This approach means that non-priority generator’s available energy, in the curtailment study, starts out less than that of priority generators. This means that at times of curtailed energy non-priority generators dispatch down percentage is lower compared to priority generators. Integrating oversupply modelling is a new step in ECP 2.1 compared to ECP 1. To provide clarity a sample calculation is given in Table 1.

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2 https://www.eirgridgroup.com/customer-and-industry/general-customer-information/ecp-2.1-constraint-report-1/index.xml

3 https://www.eirgridgroup.com/customer-and-industry/general-customer-information/ecp-2.1-constraint-report-1/index.xml

Furthermore, variations in capacity factor, area wise renewable profiles and their correlations may lead to differences in dispatch down between different groups of generators.

Table 1: Oversupply and Curtailment Calculation Sample

	Available Energy (GWh) in each study				Generation (GWh) from each study			Dispatch Down (DD) Calculation			
Generator Name	Oversupply [A]	Curtailment wind non priority [B] Where, B = A * Sum(D1)/ Sum(A)	Curtailment wind priority [B] Where, B = A * Sum(D2)/ Sum(A)	Constraint [C] Where, C = B * (B - C)/Sum(B)	Oversupply wind non priority [D1]	Oversupply wind priority [D2]	Curtailment [F]	DD Oversupply (A - B)	DD Curtailment (B - C)	Oversupply % pro-rata (A-B)/A	Curtailment % pro-rata
Gen 1 wind non-priority	200	175		161	170		160	25	14	12.5%	7.0%
Gen 2 wind non-priority	200	175		161	180		165	25	14	12.5%	7.0%
Gen 3 wind priority	200		200	184		200	180	0	16	0.0%	8.0%
Gen 4 wind priority	200		200	184		200	185	0	16	0.0%	8.0%
Total	**800**	**350**	**400**	**690**	**350**	**400**	**690**				

Note:

- The available energy in curtailment study is calculated separately for priority and non-priority generators
- Sum (A) for available energy in curtailment study formula is for corresponding priority or non-priority generators

Circuit Ratings

Q: Please provide circuit ratings assumed for all new reinforcements – this information was provided in all previous EirGrid Constraint Reports.

A: The 2024 and 2026 circuit ratings have been published on the EirGrid website[4].

[4] https://www.eirgridgroup.com/customer-and-industry/general-customer-information/ecp-2.1-constraint-report-1/index.xml

RES-E Figures

Q: Please provide RES-E percentages for all scenarios, as was previously provided in the ECP 1 Constraint Reports.

The following table provides a summary of the out-turn percentage RES-E following completion of all three model runs, this means that oversupply, curtailment and constraint are accounted for in the RES-E % figures given in Table 2.
Note:
A study has not been carried where the cells are shaded grey.
The RES percentage are inclusive of large scale Wind, Solar, Hydro and Wave; these figures do not account for small scale renewable generation, storage, and peat or waste plants that may have a share of fuel which is accredited as being renewable.

Table 2: RES percentage in ECP 2.1 study cases

Row Labels	Initial	33%	66%	ECP	ECP + 1.7 GW Offshore	ECP + 3.9 GW Offshore
2024	44%	47%	49%	51%		
2026				53%	62%	
2026 ic	44%	48%	52%	54%	65%	
2026 two ic				56%	68%	
Future Grid				47%	59%	69%

SRCE Generators and Lines

Q: Please provide details of the individual generators and reinforcements associated with the "Site Related Connection Equipment", as was previously provided in the ECP 1 Constraint Reports.

A: The ECP 2.1 process uses the latest available information at the time of the data freeze. Further details on individual projects and their SRCE can be obtained from the Customer and Connections team.

Derryiron – Timahoe North – Maynooth

Q: In the case of Area J, the uprates to the Derryiron – Timahoe North – Maynooth 110 kV circuits are only assumed in the Future Grid scenario, and not in the 2024 and 2026 scenarios – can EirGrid please explain why this uprate was excluded from the 2024 and 2026 scenarios?

A: In response to this query, the correct ratings were assumed in the analysis, however, reference to the network reinforcements were unintentionally omitted from Table A1 (Reinforcements in 2024) in Appendix A - this will be corrected in the near future.
The following table provides the correct information on the line ratings used in the ECP 2.1 models with respect to the lines in question.
The initial increase in line capacity for the Timahoe North – Maynooth from 74/83/91 MVA to 112/112/112 MVA, is driven by uprating of sub-station components. The second increase in line capacity from 112/112/112 MVA to 178/210 MVA is due to the full circuit uprate by a replacement conductor.

Table 3: Line Ratings in MVA

Line Ratings in MVA (summer/autumn/winter)			
Line	**2024**	**2026**	**Future Grid**
Derryiron - Timahoe North	103/132/156	103/132/156	178/210
Timahoe North - Maynooth	112/112/112	112/112/112	178/210

NI Generator Build Out

Q: Please explain the logic behind the NI generator assumptions applied for the 2024 and 2026 scenarios? The build out levels appears to be very high considering there is only a low on-going build out level at the moment.

A: Table B2 within the report outlines the generation in NI for the Future Grid scenario. The 'extra for 70pc' generation was only included in the Future Grid scenarios, this capacity was added to achieve at least 70% RES-E for Northern Ireland. The distribution of this capacity was aligned to the assumptions in Tomorrow's Energy Scenarios for Northern Ireland 2020 (TESNI 2020).
To clarify the Northern Ireland build out assumptions we have published additional tables outlining the generation build out for 2024, 2026 and the Future Grid scenario, these are available on the EirGrid website[5].

Area J Subgroup

Q: The constraint levels appear to be the same across all the nodes in the Area J Country subgroup in each of the scenarios.
Is it the case that all the network constraints experienced by the renewable generators in each hour of the modelling was average across all the renewable generators in the Area J rural (country) subgroup regardless of the location of the binding constraint?

A: Yes – see section 6.6.4 in the Area J constraints analysis report. These subgroups are selected on the basis that they share common transmission constraint bottlenecks.
Analysis of Area J identified two constraint subgroups for solar and wind generation; Area J City and Area J Country. The subgroup nodes are given in Table 6-5 (page 43 of Area J report). The constraints are shared on a pro-rata basis amongst the renewable subgroup generators.

Kinnegad Station Arrangement

Q: Was the busbar in Kinnegad assumed with N/O point on Mullingar cubicle or any other cubicle?

A: Yes – it is sectionalised (normally open).

[5] https://www.eirgridgroup.com/customer-and-industry/general-customer-information/ecp-2.1-constraint-report-1/index.xml

SRCE

Q: What was basis for assumptions that deemed projects energised by 2023 and included in 2024 analysis. Area J projects excluded in 2024 scenarios (157 MW solar, 270 MW wind).

A: The initial scenarios within the analysis included currently connected renewable generation plus all renewable generation expected to be connected by the end of 2023.
We used the latest information possible at the time of undertaking the study. Further details on individual projects and their SRCE can be obtained from the Customer and Connections team.
The 157 MW solar and 270 MW wind that was not included in the 2024 studies was SRCE (Site Related Connection Equipment) generation – this is generation that is not permitted to connect until certain system works are complete. These works may not be complete by 2024, hence this generation is not included in the 2024 studies.

Oversupply Allocation

Q: Why is there a difference in the oversupply figures from Area to Area (ranges from 13% to 17%) given that oversupply is applied pro-rata? Is this related to the capacity factor used in each area? If so what is the All-Ireland average wind farm and solar farm capacity factors used in the studies?

A: Yes – this is mainly due to the capacity factors and wind/solar profile time series correlation. Further detail on the calculation of oversupply and curtailment is given in Table 1.
The wind and solar time series used in the studies have been published on the EirGrid website.

Priority Unit Check

Q: Can EirGrid check if there are any priority projects incorrectly identified as non-priority in Area J?

A: This has been re-checked and we can confirm that the assumptions are correct based on the available data.

Refurbishment Projects

Q: Why are some TDP20 projects not listed as included – were they considered for Area J analysis? i.e. CP0873 Dunstown-Moneypoint refurb, CP0825 Oldstreet-Woodland refurb, CP0808 Maynooth station reconfiguration, CP1017 400kV voltage uprate trial & CP1021 East Meath / North Dublin reinforcement?

A: For the list of projects considered in each study, refurbishment projects are not included if there is no net impact to power flow due to changes in substation components or lines, particularly when their ratings remain unaffected.
CP1021 Woodland – Finglas 400kV circuit is included in the Future Grid study (candidate reinforcement of SOEF study).

ECP 1 and ECP 2.1

Q: ECP 2.1 analysis has more demand & more grid build out in initial case so why does it not align better with ECP 1 results?

A: The installed renewable generation capacity is higher in ECP 2.1 than ECP 1 along with increase in batteries. Also, the distribution of the generators has changed with updates to existing and new offers. Furthermore, ECP 2.1 introduces new operational assumptions, transmission maintenance outages, and includes a new methodology to account for oversupply. Additionally, the study horizons/years are different.

Interconnectors

Q: It is noted in Section 3.4.5 that the Moyle, EWIC and Greenlink interconnectors have been modelled with an ability to export at full capacity for 65% of the time. Can you please clarify what hours of the year you are assuming that the full export capacity is available? Furthermore, what export capacity was assumed to be available for the other 35% of the time?

A: The modelling of the interconnectors to Great Britain was based upon historical analysis. It was identified that during high wind availability (wind > 3 GW) that at 65% of the time the interconnector was exporting at its full capacity. While at 13% of time it was at 75% of its full capacity and at 7% of the time it was at 50% and 25% export capacity each. Using this information, the capacity of these IC's were assigned for the year.
The modelled flow on the interconnectors is affected by the marginal prices in SEM and the external GB market. Plexos calculates the marginal price in the Ireland region while the GB regional price is set using a marginal gas unit. This method provides a dynamic flow behaviour that captures some of the uncertainties in interconnector flows. This interconnector modelling change is an improvement over ECP 1's approach, where interconnectors could export at full capacity in all periods, this old approach could lead to a risk of understating dispatch down.
The interconnector modelling approach will once again be reviewed as part of the ECP 2.2 process. Interconnector hourly flows have been published online and are now available on the EirGrid website.

Q: Why have EirGrid modelled the Celtic Interconnector in a different way to the GB interconnectors. Celtic Interconnector de-rated to 80% whereas GB Interconnectors assumed to operate at full output 60% of the time?

A: Compared to the GB connecting interconnectors, the lack of historical interconnector flow data resulted in the assumption of de-rating the export capacity to 80%. This is a simplification for ECP 2.1, but it is intended to model future uncertainty in operational performance. The use of full interconnection capacity may lead to understating dispatch down levels. The interconnector modelling approach will once again be reviewed as part of the ECP 2.2 process.

Assumptions for Peat Unit

Q: What assumptions were made with respect to peat unit?

A: It is assumed that the peat unit has closed down in the model for 2024/2026 and Future Grid studies.

Reduction in Constraints Area J 2024 Case

Q: It is assumed that constraints reduce as generation increases in 2024 case in Area J, as it is being masked by increasing system curtailment and energy balancing. Please clarify if our understanding is incorrect

A: The 2024 Initial ECP 2.1 scenario assumes a demand of 35.8 TWh (IE), 6.2 GW (IE) of solar and onshore wind, this is in line with expectation for renewable deployment across the next 10 years. The ECP 2.1 2024 ECP (All) scenario includes additional 2.2 GW (IE) of solar and wind capacity not reliant on SRCEs. In this 2024 case there are no changes to the demand level, operational constraints or interconnection, so it reasonable to assume that system wide over-supply and curtailment could mask network related constraints.