Ireland Capacity Outlook 2022-2031

October 2022

EIRGRID SONI

Document Overview

This document contains two sections comprising of:

Part A – Capacity Summary for Ireland 2022-2031 - This outlines the purpose of the Generation Capacity Statement (GCS), the main messages from the GCS and the impact of the mitigation measures which are being progressed under the Commission for Regulation of Utilities (CRU) Security of Supply Work Programme supported by the Department of the Environment, Climate and Communications and EirGrid.

Part B – Generation Capacity Statement 2022-2031 - This is an all-island document and is a regulatory requirement for EirGrid and a licence requirement for SONI. This Generation Capacity Statement has been approved by the Utility Regulator in Northern Ireland, in accordance with the SONI licence requirement.

A data workbook containing all tables and figures from the GCS will be published separately alongside this document.

Part A:

Capacity Summary for Ireland 2022-2031

October 2022

EIRGRID SONI

What is the GCS?

The Generation Capacity Statement (GCS), is an annual report from EirGrid and System Operator Northern Ireland (SONI). Following a methodology set out by the energy regulators, the Utility Regulator (UR) in Northern Ireland and the Commission for the Regulation of Utilities (CRU) in Ireland, the GCS examines the balance between electricity demand and supply on the island of Ireland for the following 10 years.

When researching for the GCS EirGrid consider:

Demand - what Ireland needs –

- This incorporates the total electricity requirement including from electric vehicles and heat pumps; the winter peak; historic demand; and economic forecasts

Generation – what can be supplied to meet the demand?

- This includes conventional electricity generation plants
- What is coming through capacity and renewable energy auctions;
- The impact of forced (unplanned) and scheduled (planned maintenance) outages.

Adequacy – is there a gap?

- This is the likely surplus or deficit for each year.
- The CRU has set a standard of 8 hours called the Loss of Load Expectation. This means that the deficit should not exceed 8 hours of load shedding per year. If it does then the GCS signals to industry that further capacity is needed in the future.

To obtain the most relevant information, EirGrid and SONI engaged widely with industry participants and we use the most up-to-date information at the time of submission to regulators. We 'freeze' the date on which the calculations are measured to ensure that we are providing an accurate assessment.

1. Why do we have a GCS?

The GCS is a way for EirGrid and SONI to signal future needs and requirements to the all-island energy market, as well as to policy makers and regulators who may have to react.

GCS does not to set out the measures necessary to resolve any deficits identified by our analysis.

The GCS is published annually. This allows the document to identify changing scenarios and allows time for developers, policy makers and regulators to respond.

The ten-year outlook reflects the time required by the wider energy eco-system to build the necessary infrastructure that can address identified problems.

The GCS is a significant source of information for the Single Electricity Market (SEM) Capacity Auctions, which are run annually to meet electricity capacity needs for a specified year, typically four years later. These are known as "T-4" auctions and the most recent one was run in 2022 to source capacity for September 2025 to September 2026.

For Ireland, since 2016, EirGrid has warned via the GCS of an increasing tightness between supply and demand.

There is no question that the current outlook, based on the best information available, is serious. It is likely that in the coming years we will experience system alerts and will need to work proactively to mitigate the risk of more serious impacts.

This GCS report, while stark in its assessment, will allow the industry, government, regulators and other stakeholders to support us in securing the transition to renewable energy and support social and economic growth into the future while proactively managing the supply demand balance.

2. Overview of GCS 2022 – 2031 - stating the challenge

This year's GCS predicts a challenging outlook for Ireland with capacity deficits identified during the 10 years to 2031.

In the short term the deficits will increase due to the deteriorating availability of power plants, resulting in their unavailability ahead of intended retirement dates.

In later years the deficits are expected to reduce as new capacity comes forward through the SEM capacity auctions.

Our analysis for Ireland and Northern Ireland shows that further new electricity generation will be required to secure the transition to high levels of renewable electricity over the coming decades.

A balanced portfolio of new capacity is required and this includes the need for new cleaner gas fired generation plant which are renewable gas ready, especially at times when the wind and solar generation is low. This balanced portfolio is also crucial to ensuring Ireland meets its carbon budgets between now and 2030 for the electricity sector, which positions the electricity sector to achieve the zero net carbon target by 2050

Furthermore, by 2030 there will be significant new additional load from the heat and transport sectors as they are electrified, in line with government targets set out in the Climate Action Plan 2021.

3. Recent Developments impacting forecasts

Recent developments will affect the security of electricity supply over the coming years in Ireland.

Availability – Generator performance continues to be poor and this is reflected in our analysis. Furthermore, we have assumed that some generation capacity, due to close in September 2023, is not available for 2022 and 2023. This totals 590 MW of poor availability.

Failure of new generation to materialise – Since last year's GCS, 365 MW of previously awarded capacity has been withdrawn and the developers have paid termination charges. This is in addition to the previous 266 MW which terminated. This means that most new predictable capacity that was expected to come online over the coming years has now withdrawn.

Run Hour Restrictions – Two new Open Cycle Gas Turbines (OCGT) that came through previous capacity auctions may have limitations imposed on their run hours due to restrictions in their planning application or environmental permits. We have assumed these restrictions will be in place based on the latest available information.

Demand – Trends in the data centre sector show demand levels around 140 MW higher by 2030 than previous forecasts. The Climate Action Plan 2021 outlined specific targets for the electrification of heat and transport which are also included.

4. Meeting the challenges

Policy and regulation actions required to manage the shortfalls highlighted by the GCS by a combination of short-term measures and longer-term market based enduring solutions.

To address the challenge, the Commission for the Regulation of Utilities (CRU), incorporating some of the recommendations of EirGrid and in conjunction with the Department of Environment, Climate and Communications (DECC), has developed a programme of work[1] actions that will be delivered over the coming years. These include:

- The delivery, through the all-island capacity auctions, of over 2,000 MW of enduring flexible gas-fired generation capacity, which is renewable gas ready, by 2030.
- Procurement of 650 MW of temporary emergency generation capacity to remain available until the necessary replacement capacity has been secured. This capacity only be called upon in the event of a shortfall in capacity and where alerts on the system are likely.
- Extending the operation, on a temporary basis, of older generators to delay the loss of up to 1,200MW of capacity, to allow time for the enduring measures to be implemented.
- Actions to enhance the responsiveness of Demand Side Units and develop additional demand side capacity.

As shown in the figure below these temporary measures, if there are all fully implemented in time, help bring the adequacy position back to the standard set by the CRU. There are many risks associated with the deliverability of these measures and the CRU, Department of the Environment, Climate and Communications and EirGrid are all working closely to manage these. Finally note that an upcoming T-4 capacity auction for the October 2026 to September 2027 period will run in late 2022/early 2023 to procure permanent capacity to support us in meeting the future capacity deficits.

[1] CRU202264-Electricity-Security-of-Supply-Programme-of-Work-Update.pdf

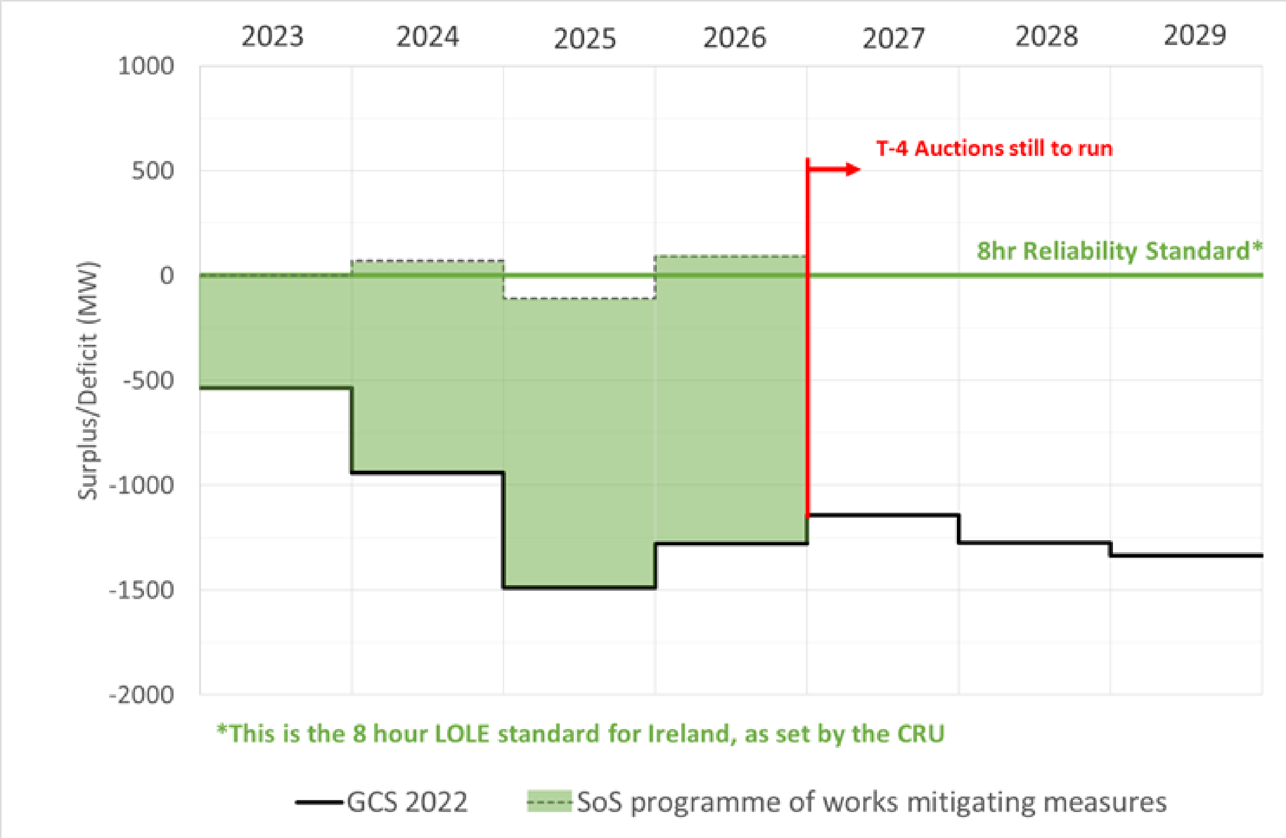

Figure 1 – Adequacy Results including SoS programme of works mitigating measures

The impact of some of these measures will be seen in future GCS reports, however some of these are temporary in nature and are not included in our analysis, as otherwise it would not send a clear signal to the energy eco-system that permanent capacity is needed.

Since the freeze date of the data that informed the GCS 2022-2031 there are a number of factors that have emerged that will influence the upcoming capacity year 2022/2023. Recent analysis for the Winter Outlook 2022 has identified a reduction of 124 MW on the median demand. This reduction is driven by lower than expected economic growth and the strong impacts of retail pricing/tariffing signals. For the capacity year 2022/2023, the overall electricity demand growth is trending between the median and low scenarios, with an envelope of credible forecasts between the low to high demand scenarios. This envelope covers outcomes such as weather conditions being unseasonably warm or an unexpected cold snap. In 2023, any enduring effects of demand reduction will complement mitigating measures identified in that year. The effects of the demand of this winter 2022 will provide new information that can be incorporated into our demand forecast cycle for the next GCS 2023-2032.

Furthermore, following on from the ACER's DECISION No 24/2020 on the methodology for the European Resource Adequacy Assessment (ERAA); EirGrid in collaboration with the CRU are currently reviewing the GCS methodologies to move to a new National Resource Adequacy Assessment (NRAA) as specified under Regulation (EU) 2019/943 Article 24. As part of this review of Ireland's reliability calculation, EirGrid will consider the impact of weather dependent renewable sources (for example: solar and wind), conventional generation, demand, operational requirements, interconnection, demand side response, storage and energy limited technologies.

5. Data Centres

A key driver for electricity demand in Ireland for the next number of years is the connection of data centres and new large energy users.

In Ireland, there is approximately 1,700 Megavolt Amperes (MVA) of demand capacity that is contracted to data centres and other new large energy users at the transmission level, and a further 600 MVA contracted at the distribution level.

The average load currently drawn by these customers is approximately 34% of their contracted capacity.

Demand from data centres and new large energy users is expected to continue to rise as these customers build out towards their contracted load. Almost all of this is in the Dublin region.

As part of the demand forecast process EirGrid examines the status of data centres and new large energy users using a range of factors. This process creates three credible low, median and high forecast scenarios.

There is very strong growth in this sector out to 2024, with continued growth towards the end of the decade.

This growth is from contracted projects only. As per the directive from the Commission for the Regulation of Utilities in November 2021, data centre projects that do not currently have connection agreements will be assessed on new criteria. Offers of new connections will be contingent upon the ability of the data centre applicant to bring onsite dispatchable generation (and/or storage) with a capacity equivalent to or greater than their demand. This does not constitute a moratorium for data centres but according to CRU's direction[2], EirGrid can 'determine whether a connection offer can be made within the system stability and reliability needs of the electricity network.' It also means that any new data centre demand must also bring equivalent capacity with it which would be intended to largely offset any further growth in data centre.

This makes new data centres "net-zero demand" from a GCS adequacy perspective.

Forecast Scenario	Additional data centre and new large energy user demand by 2031	Overall 2031 Demand in MVA
Low	425	1025
Median	891	1491
High	1395	1995

Table 1 - Data centre and new large energy users demand, additional to the 600 MVA assumed for 2022

6. Climate Action Plan

This year's GCS takes account of the targets from the Government's Climate Action Plan 2021 (CAP21), including increased electrification in the heat and transport sectors.

The median scenario assumes that 100% of the CAP21 targets will be met. The low scenario assumes 75% and the high scenario assumes 110%.

[2] https://www.cru.ie/wp-content/uploads/2021/11/CRU21124-EirGrid-Direction-1.pdf

The results below show a notable increase from last year's forecast. This is driven by increased economic activity in the short to medium term; more data centre demand; and higher levels of electrification in the heat and transport sectors.

In the median scenario, the energy demand is forecasted to increase 37% by 2031.

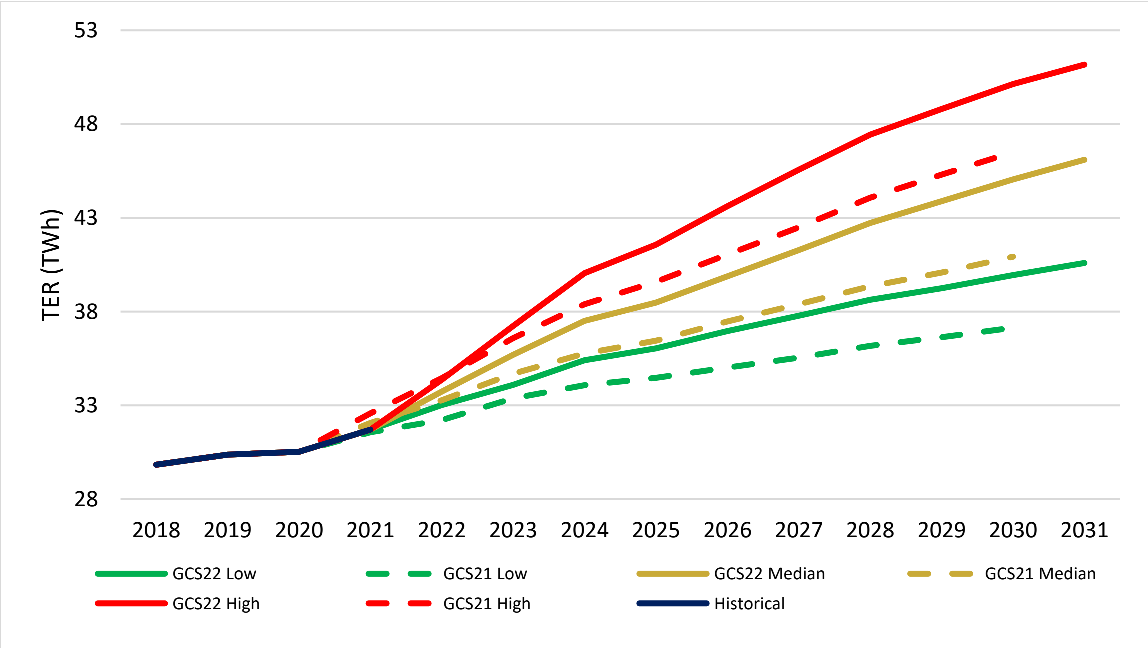

Figure 2 - Total Electricity Requirement forecast for Ireland 2021 – 2031

In the median scenario, the traditional residential, commercial and industry sectors remain relatively consistent across the decade.

The largest growth comes from the data centre and new large energy users, and an increased uptake of electric vehicles and heat pumps, particularly later in the decade.

By 2031, 28% of all electricity demand is expected to come from data centres and other new large energy users.

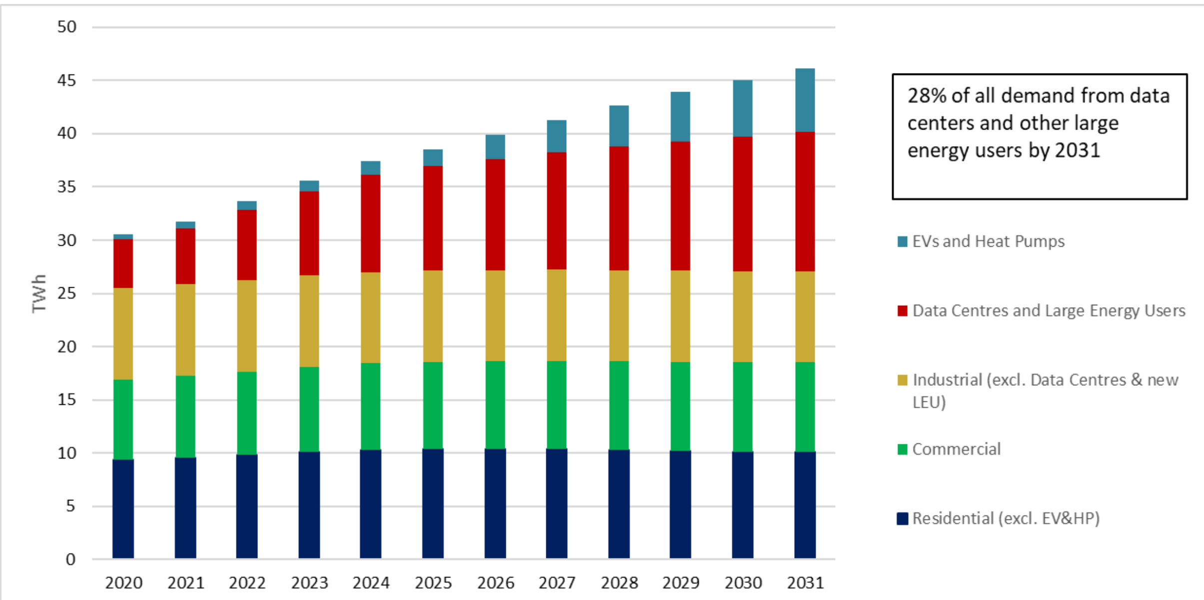

Figure 3 – Ireland Median demand scenario illustrating the approximate split into different sectors

7. Demand Scenarios

Analysis of temperature, economics, large energy user growth, energy efficiency as well as the electrification of heat and transport underpins the formulation of median, high and low demand forecasts for Northern Ireland.

Median Demand - The median demand forecast is based on an average temperature year. It includes assumptions on electrification of heat and transport, future energy efficiency in the electricity system, along with the application of a central economic growth rate factor. This is our best estimate of what might happen in the future.

Low Demand - The low demand forecast is based on a an above average temperature year (warm winter), lower levels of electrification of heat and transport with higher levels of energy efficiency and the pessimistic economic factor being applied.

High Demand - Conversely, the high demand forecast is based on a below average temperature year (cold winter), higher levels of electrification of heat and transport with lower levels of energy efficiency and the more optimistic economic factor being applied.

8. Conclusion

The electricity industry will have to find new ways to meet the increasing need for energy without relying mainly on burning fossil fuels.

Looking out to 2030 electricity demand is set to increase as consumers use electricity in new ways.

New government policies are expected to help guide us away from fossil fuels toward alternative heating methods, such as electric heat pumps, and cleaner modes of transport, such as electric vehicles.

This changing demand and generation supply landscape for the island will require coordinated management of both the volume and type of new capacity, alongside new ways of managing increasing demand to ensure security of supply.

To prepare for this change, EirGrid must make the electricity grid stronger and more flexible. Given the scale of change, there is a need to plan for a great deal of new grid infrastructure – such as underground cables, pylons and substations.

The Irish electricity ecosystem supported by EirGrid is at the vanguard of delivering a cleaner, affordable and secure supply of electricity for consumers in both jurisdictions. Mapping the island's electricity needs is an important feature of our work; it helps our governments, regulators and industry to prepare for the future.

Part B:

All-Island Generation Capacity Statement 2022-2031

October 2022

EIRGRID SONI

DISCLAIMER

EirGrid Plc and SONI Ltd have followed accepted industry practice in the collection and analysis of data available. While all reasonable care has been taken in the preparation of this data, EirGrid and SONI are not responsible for any loss that may be attributed to the use of this information. Prior to taking business decisions, interested parties are advised to seek separate and independent opinion in relation to the matters covered by this report and should not rely solely upon data and information contained herein. Information in this document does not amount to a recommendation in respect of any possible investment. This document does not purport to contain all the information that a prospective investor or participant in the Single Electricity Market (SEM) may need.

This document incorporates the Generation Capacity Report for Ireland and the Generation Capacity Statement for Northern Ireland.

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PREFACE

EirGrid Plc and SONI Ltd, as the Transmission System Operators (TSO) for Ireland and Northern Ireland respectively, have prepared the All-Island Generation Capacity Statement (GCS) 2022-2031. This statement outlines the expected electricity demand and the level of generation capacity that will be required on the island of Ireland over the next ten years to maintain security of electricity supply and support social and economic growth.

As part of the strategy to support sustainability and decarbonisation, the grid is undergoing a process of modernisation, with greater needs for flexible generation to ensure security of supply. We are working to ensure that everyone has electricity when they need it, at the most economic price possible while preparing the transmission grid to provide up to 80% of our power from renewable sources by 2030 in line with Government targets in both jurisdictions.

In last year's GCS 2021-2030 we communicated that the adequacy of the power system would reduce and we would anticipate more system alerts. These alerts indicate to industry market participants that capacity margins are tight and the loss of a generator could cause difficulty in meeting demand. During 2021/22 we continued to see several system alerts in Ireland and Northern Ireland. At all times our skilled and experienced workforce met supply without any customer disconnections, however we expect the number of system alerts to increase over the coming years as capacity exits and demand increases.

EirGrid currently forecasts capacity deficits in Ireland for the entire 10-year outlook of this statement. In the short term the deficits have increased due to deteriorating availability of existing generators, resulting in power plants becoming unavailable ahead of their intended retirement date. However, in later years the deficits may reduce as new capacity is expected to come forward through the Single Electricity Market (SEM) capacity auctions. Other measures outside the scope of this document will be needed to reduce the remaining capacity deficits and EirGrid continues to support the Commission for Regulation of Utilities (CRU) and the Department of the Environment, Climate and Communication (DECC) on this through the CRU's Security of Supply programme.

Since the publication of the GCS 2021-2030, the outlook for Northern Ireland has deteriorated generally, and specifically over the next four years. SONI recently obtained clarification from the plant operator on the running of existing near end of life coal plant. At present, the plant operates at a reduced generation capacity, following the expiration of the COVID-19 Regulatory Position Statement to manage and comply with their most recent environmental permit. Since the last GCS 2021-2030 statement, the change in running regime means a reduced contribution to capacity adequacy, therefore reducing Northern Ireland's short-term adequacy surplus.

Furthermore, SONI has recently received clarification from the developer of new capacity in Northern Ireland, that the permit they applied for and which was issued by the Northern Ireland Environment Agency means their Open Cycle Gas Turbines will have annual run hour limitations. This prevents them from running for more than 1500 hours on average per annum, until the expected conversion to a Combined Cycle Gas Turbine from 2026. The running restrictions on the new Open Cycle Gas Turbines mean the power system does not meet adequacy standard for Northern Ireland in 2024 and 2025. Once these restrictions are removed in 2026, the system is in surplus adequacy for the remaining years of the study. SONI is working with the Department for the Economy and the Utility Regulator in addressing these issues.

Our analysis of both jurisdictions clearly shows that further new capacity will be required to help serve us as we transition to high levels of renewable electricity over the coming decades. It is crucial that a balanced portfolio of new capacity is delivered, such as long duration storage, interconnection, demand side and renewable ready gas turbines. The new North South Interconnector remains critical for security of supply in both jurisdictions as its introduction will reduce the overall capacity deficit. The North South Interconnector, as with existing and new interconnection to Great Britain and the new Celtic interconnector to France, remains important for the medium to long-term security of supply on the island of Ireland. Together with the Single Electricity Market (SEM) capacity auctions, this will enable all consumers on the island of Ireland to realise the ambition of maximising the considerable efficiency benefits of an All-Island electricity system and market.

In 2021, EirGrid and SONI published a comprehensive plan called Shaping Our Electricity Future. This outlined the network, market and operational changes required to deliver on a power system where 70% of our electricity was sourced from renewable resources by 2030. The Ireland Climate Action Plan 2021 and the Northern Ireland Energy Strategy, complimented by the Climate Change Act (Northern Ireland) 2022, subsequently increased this ambition to target 80%[3] renewable electricity by 2030.

Currently, through our Shaping Our Electricity Future Roadmap, we have a plan to deliver at least 70% renewable electricity for the all-island power system. For this GCS 2022-2031, our forecast of renewable generation is aligned to 70% renewable electricity by 2030 for the median demand. Achieving 80% renewable electricity will require a seismic shift in thinking, as the scale of the task is unprecedented and there are significant challenges in terms of deliverability, technical scarcities and economic considerations. EirGrid and SONI are currently working on the next edition of Shaping our Electricity Future and aiming for publication ahead of the GCS 2023-2032. As part of the next Generation Capacity Statement, we will update our renewable assumptions when there is more clarity on what is required to deliver a power system with 80% renewable electricity.

The current Shaping our Electricity Future Roadmap outlines not only the volume and the type of capacity needed to solve our adequacy challenges but also what is required to solve the operational complexities of managing a power system with world leading levels of variable renewable generation.

It is clear the electricity industry will have to find new ways of meeting the increasing demand for energy without relying on mainly burning fossil fuels. Looking out to 2031, our electricity demand is set to increase as consumers use electricity in new ways. New government policies are expected to help guide us away from fossil fuels and instead towards alternative heating methods (such as electric heat pumps) and cleaner modes of transport (such as electric vehicles). This changing demand and generation supply landscape for the island will require coordinated management of both the volume and type of new capacity connecting, alongside new ways of managing increasing demand to ensure security of supply over this unprecedented period of change. To prepare for this change, EirGrid and SONI must make the electricity grid stronger and more flexible. The transmission grids in Ireland and Northern Ireland will need to carry more power, and most of this power will come from renewable generation that varies depending on the weather. EirGrid and SONI will use the existing grids to meet this goal where possible. However, given the scale of

3 The Climate Action Plan 2021 also introduced 5 yearly carbon budgets and a 2030 carbon ceiling.

change, there is a significant need to plan for a great deal of new grid infrastructure – such as underground cables, pylons and substations.

EirGrid and SONI are at the vanguard of delivering a clean, affordable and secure supply of electricity for consumers in both jurisdictions. Mapping the island's electricity needs is an important feature of our work as it helps our governments, regulators and industry prepare for the future. We hope you find the Generation Capacity Statement informative.

Mark Foley
EirGrid Group
Chief Executive

Alan Campbell
SONI
Managing Director

Contents

Document Structure

This document contains a Glossary of Terms section, an Executive Summary, four main sections and four appendices. The structure of the document is as follows:

The **Executive Summary** gives an overview of the main highlights of the document and presents the statement in summary terms.

Section 1 introduces our statutory and legal obligations. The purpose and context of the report is outlined.

Section 2 outlines the demand forecast methodology and presents estimates of demand over the next ten years.

Section 3 describes the assumptions in relation to electricity generation.

Adequacy assessments are presented in **Section 4**.

Five **Appendices** are included at the end of this report. They provide further detail on the data and methodology used in this study.

Executive Summary

This Generation Capacity Statement (GCS) covers both Ireland and Northern Ireland. It is produced on a joint basis by SONI and EirGrid[4].

In this GCS we examine the likely balance between electricity demand and supply during the years 2022 to 2031. The adequacy position for each year is then compared to the adequacy standard for each jurisdiction. This standard is called the Loss of Load Expectation (LOLE) and is the expected number of hours per year that a country's electricity production cannot meet its demand. The LOLE is set to 8 hours for Ireland and 4.9 hours for Northern Ireland. The respective standards are set by the Commission for Regulation of Utilities (CRU) in Ireland and by the Department for the Economy (DfE) in Northern Ireland.

The GCS sets out the demand and generation inputs used to determine the power system's adequacy position, however the purpose of this document is not to set out the measures necessary to resolve any deficits identified by the analysis. It is for this reason that capacity mitigating measures highlighted in the Capacity Summary for Ireland 2022-2031 are not included in the GCS 2022-2031 adequacy assessment.

The GCS is a means for EirGrid and SONI to signal future needs and requirements to the energy market as well as to policy makers, regulators and TSOs who may have to take action. The GCS is published yearly reflecting changing demand and capacity trends; its purpose is to highlight potential gaps in capacity without mitigating measures thereby sending signals and allowing time for developers, policy makers and regulators to respond. The ten-year outlook reflects the time required to provide the appropriate signals to support the build of new infrastructure needed to connect new generation.

The GCS is a significant input for the SEM Capacity Auctions which are run annually to meet capacity needs for the 'capacity year' in 4 years' time. This is known as a 'T-4'. The last T-4 was run in 2022 to source capacity for the capacity year October 2025 to September 2026. Intermediate auctions are also run e.g., a T-1 auction was run in 2021 for the capacity year October 2022 to September 2023. Other intermediate auctions are likely to be run to source new and enduring capacity to meet system needs. EirGrid and SONI are therefore cognisant of the overarching role of the capacity market and has been careful to set out, clearly and transparently, the generation requirements for the coming years. This will not include the other temporary measures required and implemented to manage the security of supply risks until such time as enduring market-based solutions are in place.

Over the next few years the general outlook is challenging for both jurisdictions, with capacity deficits identified across large parts of the study time horizon. This is due to a combination of external issues. EirGrid is engaging with the Department for the Environment, Climate and Communications (DECC), the Commission for Regulation of Utilities (CRU) and other relevant stakeholders in Ireland. SONI meanwhile is engaging with the Department for the Economy, the Utility Regulator (UR) and other relevant stakeholders in relation to the outlook for Northern Ireland.

This Executive Summary outlines the key areas which have driven changes in the adequacy position since the GCS 2021-2030 for Ireland, Northern Ireland and All-Island.

4 Where 'we' is used, it refers to both companies, unless otherwise stated.

Ireland

In response to challenges for Ireland identified in last year's GCS 2021-2030, the CRU published a proactive response "CRU Information Paper Security of Electricity Supply – Programme of Actions"[5] on 29 September 2021. This outlined a programme of work to address the forecasted increase in need for new generation capacity, through six overarching measures. These measures included securing enduring capacity through market measures, improving demand side response, and in the short-term, keeping units open or delivering generation on a temporary basis over the next four to five years as we transition from older power plants to new capacity. This programme of work, directed by the CRU, will provide additional stability and resilience to the Irish energy system.

The outputs from CRU's programme of actions and the impact are not reflected in this GCS 2022-2031 but will be reflected in future GCS reports. For example once contractual arrangements are in place for keeping existing units open, then these will be reflected in future iterations of the GCS.

As part of these actions the CRU has directed EirGrid to procure Temporary Emergency Generation to help mitigate the clear risks presented by the current security of supply challenges. This generation can only be used in emergency situations and therefore is not intended to be available to meet growing and enduring demand due to social or economic growth. It is therefore crucial that the capacity market delivers the type and volume of capacity needed to underpin the energy transition. The temporary generation will, however, provide critical insurance and will be called upon in the event of a shortfall in market-based capacity and where alerts on the system are likely. Alerts occur where the buffer between electricity supply and demand is tighter than is prudent to maintain a secure system.

The forecasting of the electricity demand of Data Centres and New Tech Loads in this GCS 2022-2031, is based on reasonable assumptions on how much power they will need, and the results lie well within what is currently committed in those customer contracts. There are several data centres which have contracts for energy that are not currently using power but are expected to ramp up how much energy they use in the coming years. It is worth noting that EirGrid's high demand forecast assumes not all this future contracted demand is fully used, and some attrition will occur.

The GCS 2022-2031 does not account for any new data centres or additional uncontracted demand from data centres i.e. a new 100 MW data centre, which does not have an existing connection agreement, will need to bring 100 MW of dispatchable capacity. EirGrid's approach to predicting the data centre demand forecast, is consistent with CRU Direction *(CRU/21/124)* given to EirGrid in November 2021. The CRU direction states that new connection of data centres is now contingent upon the ability of the data centre applicant to bring onsite dispatchable generation (and/or storage) with a capacity equivalent to or greater than their demand. This does not constitute a moratorium for data centres but according to CRU's direction[6], EirGrid can 'determine whether a connection offer can be made within the system stability and reliability needs of the electricity network.' It also means that any new data centre capacity must also bring equivalent

5 https://www.cru.ie/wp-content/uploads/2021/09/CRU21115-Security-of-Electricity-Supply-%E2%80%93-Programme-of-Actions-1.pdf
6 https://www.cru.ie/wp-content/uploads/2021/11/CRU21124-EirGrid-Direction-1.pdf

generation with it which would be intended to largely offset any further growth in data centre capacity.

For the GCS 2022–2031, EirGrid are seeing the continuing trend of deteriorating availability of existing plant and the resulting impact is increasing capacity deficits in 2022 through 2024. Since GCS 2021-2030, new capacity being awarded a contract through recent capacity auctions means that over the remainder of the decade we observe the capacity deficit reducing compared to last year's publication. A summary of the main drivers for change are:

Availability – Performance of existing generation capacity continues to be poor and this is again reflected in the analysis. Furthermore, over the last 12 months, some generation capacity, due to close in September 2023, has experienced technical issues and submitted notices that they will not be available throughout 2022 and 2023. This totals 590 MW (rated) of plant that will no longer be available.

Forecasted new generation failed to materialise – Since the GCS 2021-2030, a total of 364 MW of previously awarded capacity has terminated their capacity market contracts and accordingly paid their termination charges. This is in addition to the previous 266 MW which also terminated. This means that a large proportion of new capacity expected to come online has now been withdrawn by the developers.

Capacity Auctions – New capacity has come forward through the T-3 2024/25 and T-4 2025/26 capacity auctions. EirGrid has introduced enhanced deliverability reporting of these projects, which includes engagement with the developers and other state agencies to support a timely process. The output of this deliverability assessment has been used to determine a realistic view of whether this new capacity will deliver on time.

Annual Run Hour Limitations on New Units – EirGrid currently understand that two new Open Cycle Gas Turbines (OCGTs) coming through previous capacity auctions will have annual run hour limitations due to restrictions outlined in their planning applications. There is uncertainty around the application of run hour limitations, however in line with prudent planning we have assumed these units will have limitations based on the latest available information at the time of the data freeze. As new information regarding these units becomes available, subsequent GCS reports will be updated accordingly.

Demand – EirGrid include the latest social and economic growth projections and also the latest information on the growth of New Tech Load users and data centres within their contracted demand allowance. EirGrid observed trends in the data centre sector that showed demand levels around 140 MW higher by 2030, as the sector continues to grow towards their contracted demand levels. Growth of new data centres is an area of ongoing review by EirGrid, CRU and government. The Climate Action Plan 2021 outlined specific targets for the electrification of heat and transport. Full implementation of these targets is now a part of the central median scenario.

Operational Requirements – As part of the assessment EirGrid includes up to 875 MW of operational requirements by 2027. This is in line with the Transmission Planning and System Security Standards and Operating Security Standards, as approved by CRU in Ireland. It reflects the realities of operating a power system and is consistent with the capacity market volumes identified by EirGrid.

As noted above, EirGrid is actively engaging with the Department for the Environment, Climate and Communications, the CRU and other relevant stakeholders to resolve the capacity deficits over the coming decade.

Northern Ireland

The longer term outlook for Northern Ireland's generation adequacy is positive, the core median scenario highlights a surplus of generation from 2026 until 2031. However, SONI's core median scenario also shows there are adequacy challenges over the next four years.

Since the GCS 2021-2030 SONI has received clarifications on the impact of environmental regulations on the running of existing near end-of-life coal plant. The application of the regulations means the coal station must reduce its power output to reduce emissions, therefore reducing Northern Ireland's short-term adequacy surplus.

In addition, SONI recently received clarification from the developer of new capacity in Northern Ireland, that permitting rules implemented by the Northern Ireland Environment Agency will mean its Open Cycle Gas Turbines will have annual run hour limitations. This prevents them from running for more than 1500 hours on average per annum, until the expected conversion to a Combined Cycle Gas Turbine from 2026. The running restrictions on the new Open Cycle Gas Turbines mean the power system does not meet adequacy standard for Northern Ireland in 2024 and 2025. Once these restrictions are removed in 2026, the system is in surplus adequacy for the remaining years of the study. SONI is supporting the Department for the Economy and the Utility Regulator on addressing the issues identified up to 2026.

Since the GCS 2021-2030 the capacity adequacy outlook has deteriorated in the years 2022 to 2025, with the 4.9-hour LOLE standard breached in 2024 and 2025. In 2022 and 2023, whilst within standard, tightening margins mean that there is an acceptable level of risk whereby managed load shedding may occur. The main reasons for this adequacy position since the GCS 2021-2030 are:

Existing Plant Limitations – The existing coal fired units in Northern Ireland are due to close in September 2023. These are typically modelled at 175 MW on coal and 238 MW on oil. SONI was notified in December 2021 that, due to environment restrictions on certain fossil fuel plant, each unit would be significantly limited in their output. During 2022, the developer's coal-fired units have been undergoing testing to ascertain the maximum output of the units, while remaining compliant with their emissions permit. Subsequently, in this GCS 2022-2031, SONI has modelled each unit to operate at a maximum output of 130 MW on coal between now and when they close. If this position changes it will be updated in subsequent GCS reports.

Run Hour Restrictions on New Units – Two new Open Cycle Gas Turbines (OCGTs) at Kilroot were previously successful in capacity auctions. Both of these are assumed available from the beginning of 2024. In the GCS 2021-2030, it was noted that these new units were assumed to have no run hour restrictions based on information available at the time and that if any restrictions were in place that this in turn would have a negative impact on capacity adequacy. In December 2021, the developer formally notified SONI to confirm that these units would be restricted to approximately 1500 hours on average per annum due to the Best Available Techniques Directive. The impact of annual run hour restrictions means there are capacity shortfalls in 2024 and 2025 for Northern Ireland. The latest capacity offered at the Kilroot site cleared in the recent T-4 25/26 was classified as part of a Combined Cycle Gas Turbine (CCGT) arrangement. This arrangement would utilise waste heat from the new Open Cycle Gas Turbines. The developer is currently working through the design of the system, however, since the capacity was cleared as part of a CCGT arrangement SONI have assumed the new capacity is linked to the new Open Cycle Gas Turbines to enable the assessment of an unrestricted CCGT arrangement with no run hour restrictions from 2026. Therefore, the impact of Annual Run Hour Limitations (ARHL) are included in the core scenarios up until 2026. The removal of ARHL from 2026 results in a capacity surplus with LOLE close to zero hours for the remaining years of the study. It is important to note that any delays to the new capacity will negatively impact on security of supply in Northern Ireland.

Demand – The Department for the Economy published its new Energy Strategy in 2021. This included ambitious targets around the electrification of heat and transport. Although exact targets are not included, we have made an estimate of the expected numbers, and this drives an overall increase in demand. Furthermore we have also included a forecast of anticipated growth in New Tech Load for Northern Ireland.

Operational Requirements – as part of the adequacy assessment SONI now includes 200 MW of operational requirements, in line with the Transmission Planning and System Security Standards and Operating Security Standards as approved by UR in Northern Ireland. These are to reflect the realities of operating a power system and is consistent with the capacity market volumes identified by SONI.

As noted above SONI is actively engaging with the Department for the Economy, the Utility Regulator and other relevant stakeholders to address the capacity deficits over the coming years.

All–Island

In the Median scenario the All-Island system is in capacity deficit for the study horizon.

Since 2016 EirGrid and SONI via the GCS have warned of an increasing tightness between supply and demand. There is no question that the current outlook, based on the best information available, is very serious. It is likely that in the coming years we will experience a number of system alerts and will need to work proactively to mitigate the risk of a more serious impact across Ireland and Northern Ireland. This GCS 2022-2031 report, while stark in its assessment, will allow the industry, government, regulators and other stakeholders to support us in securing the transition to renewable energy and support social and economic growth into the future while proactively managing the supply demand balance.

The new North-South Interconnector is expected to be completed by end of 2025, therefore, we only provide an All-Island adequacy assessment for 2026 and beyond. Until this date we need to limit the support between both jurisdictions to ensure system stability and security. Once the new North-South interconnector is online, the ability for support is greatly increased. From our analysis it is clear that this new interconnector will support the overall security of supply outlook, along with other enduring market measures.

1. Introduction

This report seeks to inform market participants, regulatory authorities and policy makers of the likely generation capacity required to achieve an adequate supply and demand balance for electricity for the period up to 2031. It is a ten-year outlook to reflect the time required to allow market participants and generators the time to plan, develop and deliver the necessary infrastructure required to generate electricity.

Making a prediction of what the electricity adequacy position will be in the future is a multi-layered task for which EirGrid Plc and SONI Ltd consider a number of factors including:

Demand – *what is required* – including the total electricity requirement, the winter peak, historic demand, economic forecast (with the input of the ESRI and Oxford Economics), government targets, data centres and new tech loads forecasts.

Generation – *what can meet the demand* – changes in conventional plant, what is coming through capacity auctions, the capacity of renewable energy, and the impact of forced and scheduled outages.

Adequacy – *what is the gap* – standards of acceptable outages, hours of energy that is unserved, a probabilistic calculation

Generation Adequacy is a measure of the capability of the electricity system to balance supply and demand for each hour across a calendar year . Adequacy is determined using the Loss of Load Expectation (LOLE) standard, which is 8 hours in Ireland and 4.9 hours in Northern Ireland. This means that EirGrid and SONI are planning the system with the standard assumption that there will be insufficient generation to meet the system demand for 8 hours each year in Ireland and 4.9 hours each year in Northern Ireland. The development, planning and connection of new generation capacity to the transmission or distribution systems can involve long lead times and high capital investment. Consequently, this report provides information covering a ten-year timeframe to allow sufficient time for delivery of new generation.

EirGrid, the Transmission System Operator (TSO) in Ireland, is required to publish forecast information about the power system, as set out in Section 38 of the Electricity Regulation Act 1999 and Part 10 of S.I. No. 60 of 2005 European Communities (Internal Market in Electricity) Regulations.

SONI, the TSO in Northern Ireland, is required to produce an annual Generation Capacity Statement (GCS), in accordance with Condition 35 of the Licence to participate in the Transmission of Electricity granted to SONI by the Department for the Economy (DfE).

This Generation Capacity Statement covers the years 2022-2031 for both Northern Ireland and Ireland, and is produced jointly between SONI Ltd and EirGrid Plc. Where 'we' is used, it refers to both companies, unless otherwise stated. This report supersedes the joint EirGrid and SONI All-Island Generation Capacity Statement 2021-2030, published in September 2021. Input data assumptions have been reviewed and updated.

The GCS involves a detailed process completed over a period of approximately eight months. Steps in this process are outlined in Figure 1.1 and detail of the methodology is described in Appendix 5. We will continue to work with, the CRU in Ireland and the UR in Northern Ireland (jointly referred to as the Regulatory Authorities (RAs)), and other stakeholders to ensure that this document and the underlying methodologies remain relevant and useful.

In predicting the future of electricity generation supply in Ireland and Northern Ireland, we have endeavoured to use the most up-to-date information available at the time of the data freeze for this report (Demand Forecast: March 2022, Generation Forecast: May 2022).

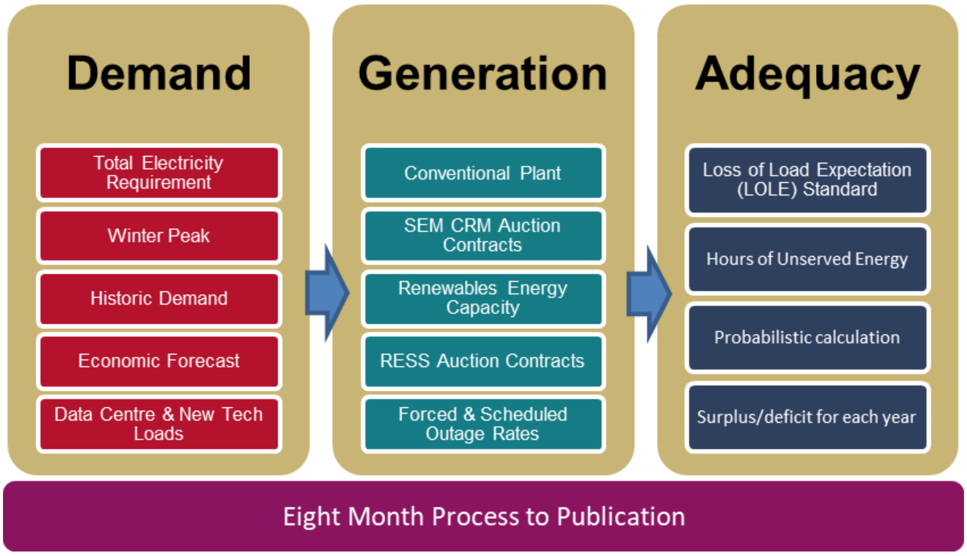


Figure 1.1 GCS Development Process

2. Demand Forecast

2.1 Introduction

Predicting future electricity demand is a complex task. A demand forecast is developed for each jurisdiction, and these are then combined to create a total demand forecast for All-Island studies.

For each jurisdiction, the starting point is the historical demand data. The initial part of the demand forecasting process explores the effect of weather on demand, for example correcting peak demand on a particularly cold or warm peak day to that of an average weather year.

The demand forecasting process takes into account the following factors that increase electricity demand: economic activity, electrification of heat and transport, and strong growth from sectors such as data centres and new technology loads[7]. We also look at factors that may decrease electricity peak demand such as the effect of 'smart' energy meters, smart charging of electric vehicles, and also efficiency improvements driven by consumers, like buying new white goods or changing to more efficient lighting e.g. halogen to LEDs.

Another aspect of historical demand analysis is calculating the level of self-consumption, i.e. electricity that is self-generated and used on-site, without being transmitted to the grid or metered. Examples would be a Combined Heat and Power (CHP) unit providing electricity and heat to an industrial user, or a home fitted with a roof-top solar PV panel.

The demand forecast outlined within this report is based on updated economic projections for both Ireland and Northern Ireland. These account for the impact of the Covid-19 recovery. At the time of writing, the long-term impact of the war in Ukraine remains uncertain, however this situation is being closely monitored by EirGrid and SONI.

In developing demand forecasts in Ireland, EirGrid has considered the impact of the Climate Action Plan 21, particularly on the electrification of the heat and transport sectors. SONI looks at the policy drivers and has considered the impact of the Northern Ireland Executive's Energy Strategy - The Path to Net Zero Energy[8] 2021 and the Climate Bill which, at the time of writing, is awaiting Royal Assent.

In order to cover a range of possible future outcomes, the GCS demand forecast is provided as three scenarios: low, median and high demand. The range of demand scenarios provides the reader with an understanding should certain growth factors fail to materialise or if stronger growth is realised.

As part of the SEM Capacity Market auction process, the GCS demand forecasts are used to derive the capacity requirement of upcoming auctions.

7 In this report, "new technology (or tech) load" refers to recent large scale, non-data centre growth in the technology sector that is considered separate from existing conventional (e.g. cement, pharma etc) industrial demand. Previously, GCS2021-2030 referred to this load as "new large energy users".
8 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf

2.2 Demand Forecast for Ireland

2.2.1 Methodology

The electricity forecast model for Ireland is a multiple year linear regression model which looks at current trends to predict electricity demand based on changes in economic parameters. Particular attention is given to the effects of data centres and new technology loads, electric vehicles and heat pumps. A spread of electricity forecasts covering the next ten years is produced. The key distinction between the scenarios is the assumed level of new data centres and new technology loads, and the level of electrification of heat and transport.

EirGrid has sought the advice of the Economic and Social Research Institute (ESRI) which has expertise in modelling the Irish economy[9]. The key economic parameters used in this study are Real Modified Gross National Income (Real GNI*) and Personal Consumption[10].

The demand forecast incorporates the roll-out of smart meters which has the effect of moderating growth in electricity demand; by 2030 EirGrid assumes up to an 8.8%[11] reduction from peak demand in domestic consumers (excluding heat pump and electric vehicles). Further demand reduction comes from energy efficiency improvements in the residential and commercial sectors, this is assumed to be a 1% per annum reduction. These efficiency assumptions, applied across all three demand scenarios (low, median, and high), have the effect of reducing the total electricity requirements in residential and commercials sectors by approximately 600 MW by 2031.

2.2.2 Historical data

Historical records of electricity generation and electricity sales are gathered from various sources including ESB Networks, SEAI (Sustainable Energy Authority of Ireland) and EirGrid. Transporting electricity from the generator to the customer invariably leads to electrical grid losses. Based on the comparison of historical sales to exported energy over the period 2008 to 2019, it is estimated that, on average, approximately 8% of power produced is lost as it passes through the electricity transmission and distribution systems to homes and businesses.

Historical weather data is obtained from Met Éireann, Ireland's National Meteorological Service. This data is used for the temperature correction as described in Peak Demand Forecasting – Temperature Correction.

2.2.3 Forecasting causal inputs

To predict future electricity demand, an energy model requires forecasts on economic activity. The economic input data is in the form of Real Modified Gross National Income (Real GNI*)[12]. Modified GNI is designed to exclude globalisation effects that disproportionally impact the measurement of the Irish economy's size. GNI* influences the forecast of Commercial and Industrial electricity demand, while Personal Consumption figures influence the forecast of residential electricity demand. These forecasts are provided by the ESRI[13] in their Quarterly Economic Commentary. Longer-term trends arise out of the ESRI's Median Term Review. Although there has been a slowdown in the economy in recent years due to Covid, current ESRI forecasts suggest strong post-Covid recovery over the next 2 years, however, the latest quarterly forecast has been adjusted to

9 http://www.esri.ie/irish-economy/
10 Personal Consumption of Goods and Services (PCGS) measures consumer spending on goods and services, including such items as food, drink, cars, holidays, etc.
11 https://www.cru.ie/wp-content/uploads/2011/07/cer11080ai.pdf
12 https://www.cso.ie/en/releasesandpublications/ep/p-nie/nie2019/mgni/
13 Economic Parameters obtained from ESRI on 28th March 2022

account for rising inflation which is influenced by the current situation in Ukraine. The figures listed in Table 2.1were used for GCS 2022-2031 studies.

	2021-2023	2024-2031
Real GNI*	6.7%	3.0%
Personal Consumption	5.2%	2.5%

Table 2.1 - Average annual growths for macroeconomic parameters, as advised by the ESRI

2.2.4 Forecasting Data Centres and New Technology Loads[14] in Ireland

A key driver for electricity demand in Ireland for the next number of years is the connection of data centres and other new tech loads.

In Ireland, there is presently approximately 1700 MVA of demand capacity that is contracted to data centres and other new tech loads at the transmission level, and approximately a further 600 MVA contracted at the distribution level. Demand from data centres and new tech loads is expected to continue to rise as these customers build out towards their contracted load. Almost all this extra load is contracted to materialise in the greater Dublin region.

GCS 2022-2031 considers over thirty projects for data centres that are in the connection process. As part of the demand forecast process EirGrid examines the status of data centres and new tech loads. This informs the future demand growth expected from these customers. EirGrid accounts for a range of factors that will drive growth from each site; these include historical demand growth rates from existing sites, contracted positions from companies and their growth potential, financial close, planning permission, etc. This process creates three credible scenarios that drive demand across the low, median and high forecast scenarios.

In GCS 2022-2031, apart from the delayed delivery of one new tech load project in 2022/2023, there is very strong growth in this sector out to 2024, with continued growth towards the end of the decade. Note this growth is from previously contracted projects. As per the recent directive from CRU in November 2021, any new data centre projects which do not currently have connection agreements, will be assessed on a number of criteria, including the "*ability of the data centre applicant to bring onsite dispatchable generation (and/or storage) equivalent to or greater than their demand*"[15]. EirGrid also notes that demand side flexibility of data centres is an area of ongoing development[16]. A small number of flexible demand sites have capacity that can be called on to prevent system alerts. For emergency situations, some sites will be required to curtail their demand requirements. These measures are assumed to be operational measures during a system Emergency State rather than contributing to system adequacy. Consequently, this has not been factored into the GCS 2022-2031 study.

In forecasting future demand, EirGrid assumes data centres have a flat demand profile across the year. This has been observed in real time data. From the result of this process, Table 2.2 outlines the breakdown of data centre and new tech load demand forecasted by 2031. Figure 2.1 shows the forecasted scenarios for growth in this sector. The graph shows the number of projects that are currently under contract (maximum possible build-out) and the three demand scenarios

14 In this report, "new technology (or tech) load" refers to recent large scale, non-data centre growth in the technology sector that is considered separate from existing industrial demand. Previously, GCS2021-2030 referred to this load as "new large energy users".

15 https://www.cru.ie/wp-content/uploads/2021/11/CRU21124-CRU-Direction-to-the-System-Operators-related-to-Data-Centre-grid-connection-processing.pdf

16 A recent Risk Preparedness Plan for Ireland, which outlines these measures, was published by CRU in May 2022. https://www.cru.ie/wp-content/uploads/2021/08/CRU202239-Risk-Preparedness-Plan-Ireland.pdf (estimated build-out projections). It is worth noting that EirGrid's high demand forecast assumes not all this future contracted demand is fully used, and some attrition will occur.

Forecast Scenario	Additional to 600 MVA of currently built data centre and new tech load by 2031 in MVA	Overall 2031 Demand in MVA
Low	425	1025
Median	891	1491
High	1395	1995

Table 2.2 - Forecasted data centre and new tech loads demand by 2031, which is additional to the 600 MVA of data centre and new tech load demand assumed for 2022

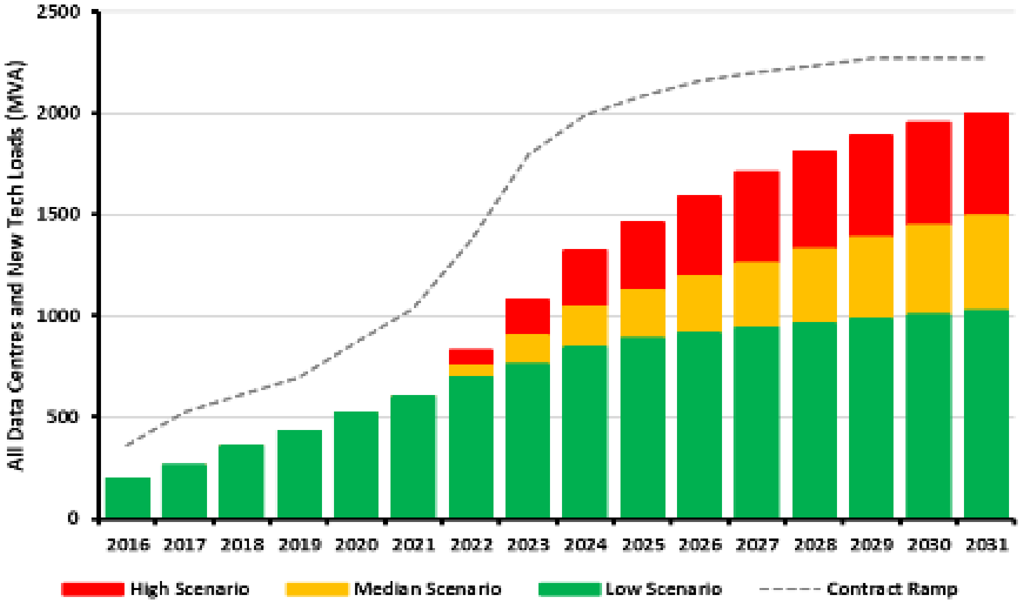


Figure 2.1 - Ireland demand expected from assumed build-out of data centres and new tech loads. EirGrid incorporate this demand into the low, median and high demand forecast scenarios for 2031

2.2.5 Forecast Scenarios and Climate Action Plan 2021

The GCS 2022-2031 takes account of the relevant targets from the Irish Government's Climate Action Plan 2021[17] (CAP21). This covers the higher electrification target in the heat and transport sector. These are ambitious targets which are required to keep Ireland on track for halving emissions by 2030. In this year's GCS 2022-2031, the median scenario assumes that by 2030, 100% of the CAP21 targets will be met. By 2030, the low scenario assumes 75% and the high scenario assumes 110%.

EV		
	Passenger	Commercial
2025	175,000	20,000
2030	845,000	95,000

Heat Pump Installations		
Residential - New Builds	Residential - Retrofits	Commercial
100,000	100,000	15,000
250,000	400,000	50,000

Table 2.3: Climate Action Plan 2021 targets for EV and Heat Pumps

For this study, a linear uptake is assumed between interim years. The energy demand for EVs accounts for the number of vehicles, vehicle efficiency, and average distance per vehicle. The main types of EVs considered are Battery Electric Vehicles (BEVs) and Plug-in Hybrid Electric Vehicles (PHEVs) in the private sector, and the commercial sector assume the vehicles to be fully BEV. The energy demand of heat pumps takes into consideration factors such as number of installations, average dwelling heat demand, and coefficient of performance.

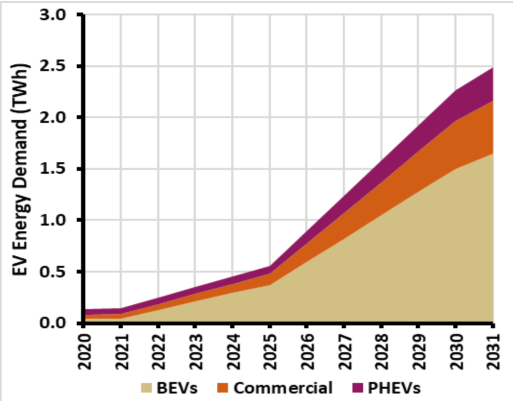


Figure 2.2 – EV Energy Demand – Median Scenario

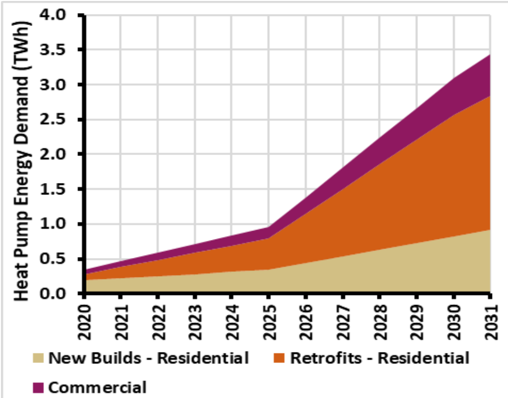


Figure 2.3 – Annual Heat Pump Energy Demand – Median Scenario

2.2.6 Total Electricity Requirement (TER)

The low, median, and high scenarios give an appropriate view of the range of possible demand growths facing Ireland. The results are shown in Figure 2.4 below. There is a notable increase from the GCS 2021-2030 forecast. This is driven primarily by increased economic activity in the short to medium term, increased build out from data centres and higher levels of electrification in the heat and transport sector to align with Climate Action Plan 2021 targets. In the median scenario, the energy demand is forecasted to increase 37% by 2031, from 2021 levels.

17 https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/

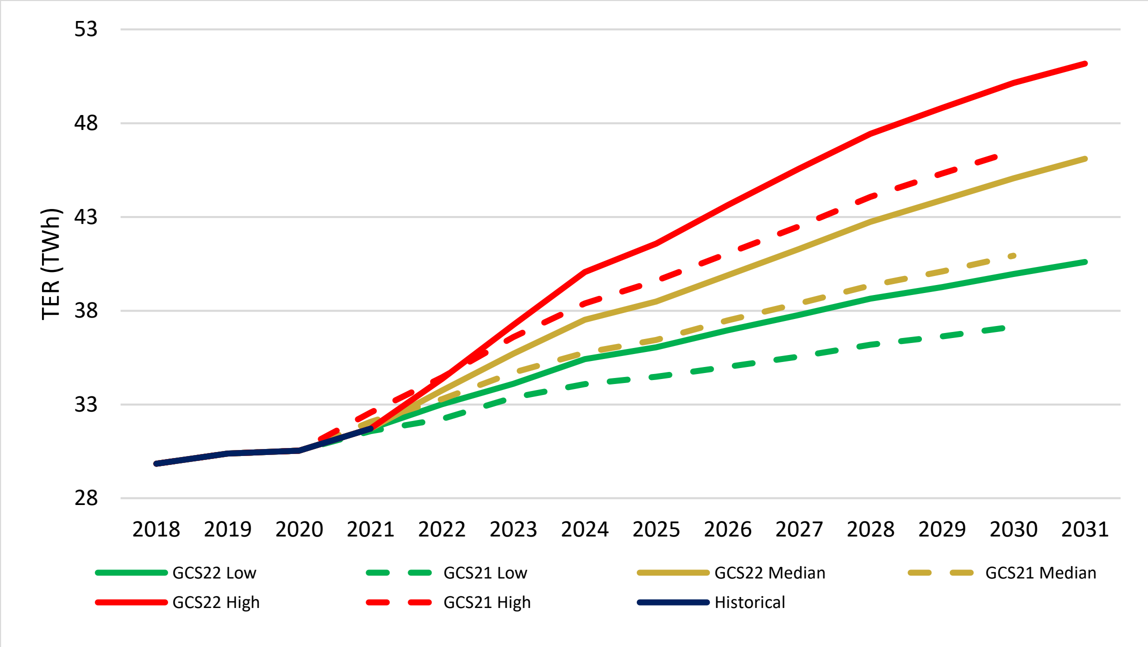


Figure 2.4- Total Electricity Requirement forecast for Ireland 2021 – 2031

Figure 2.5 shows the breakdown of results across different sectors in the median scenario. The residential (excluding EVs and head pumps), commercial and industry (excluding data centres and new tech loads) sectors remain relatively consistent across the decade. The largest growth comes from data centres and new tech load, and increased uptake of EVs and heat pumps, particularly later in the decade. Also notable is that by 2031, 28% of all electricity demand is expected to come from data centres and new tech loads.

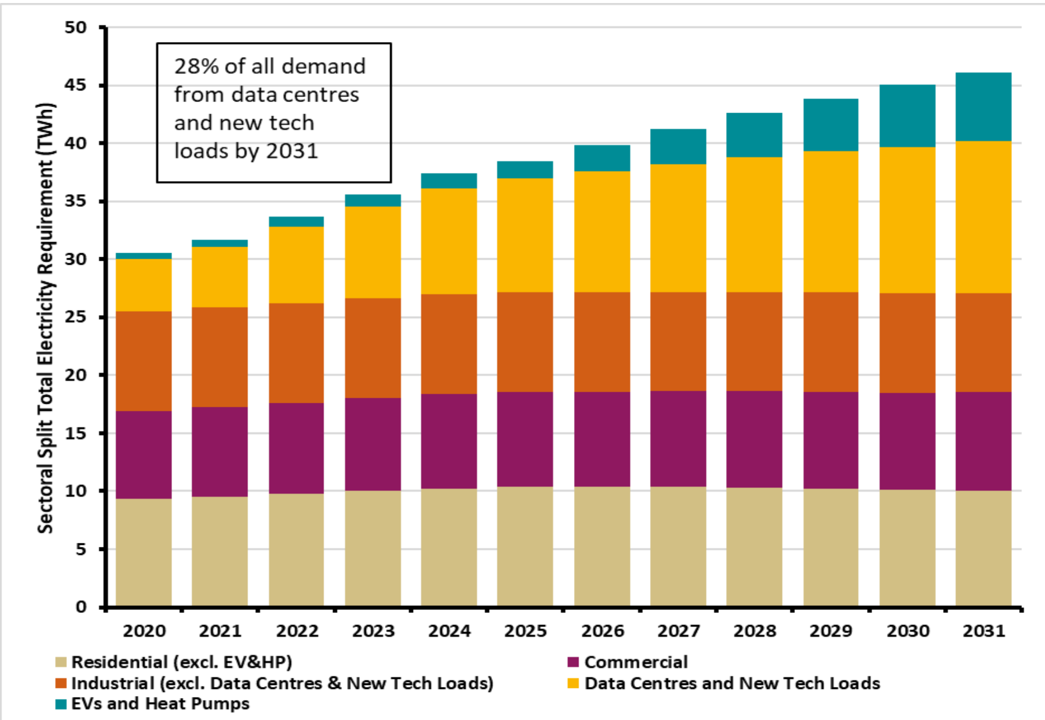


Figure 2.5 - For the Ireland median demand scenario, this illustrates the approximate split into different sectors. EirGrid estimate that 28% of total demand will come from data centres and new tech loads by 2031

The sectoral splits for 2031 are estimated as follows:

	2021 (%)	2031 (%)
Residential (excl. EV/HP)	30	22
Commercial	24	18
Industry (excl. DC + new tech loads)	27	19
DC + new tech loads	17	28
EV + Heat Pumps	2	13

Table 2.4 - Energy share per sector

2.2.7 Peak Demand Forecasting – Temperature Correction

The peak demand model is based on the historical relationship between the annual electricity consumption and winter peak demand. This relationship is defined by the Annual Load Factor (ALF), which is simply the average load divided by the peak load.

Temperature has a significant effect on electricity demand, particularly on the peak demand. Typically, every 1°C drop in temperature results in an electricity demand increase of approximately 50 MW[18]. This was particularly evident over the two severe winters of 2010 and 2011, when temperatures decreased dramatically, and demand increased to then record levels. Average Cold Spell (ACS) correction has the effect of 'smoothing out' the demand curve so that economic factors are the predominant remaining influences - see Figure 2.6. The temperature-corrected peak curve is used in the ALF model, which can then be modelled for the future using the previously determined energy forecasts.

To reflect different segments of demand, additional forecasts of industrial and data centre type demand is projected to grow separately, using a profile appropriate to its expected usage i.e., flat demand profile. Remaining additional demand is projected to grow proportionally using historical demand profiles.

For the high scenario, EirGrid has considered the risk that the winter might be severely cold and thus result in higher peaks. The high scenario assumes a peak correction based on either the severe winter impact, or the high data centre scenario, whichever is larger. Across the study horizon, the impact of the high data centre scenario exceeds that of the severe winter scenario.

18 https://www.eirgridgroup.com/site-files/library/EirGrid/Winter-Outlook-2021-2022.pdf

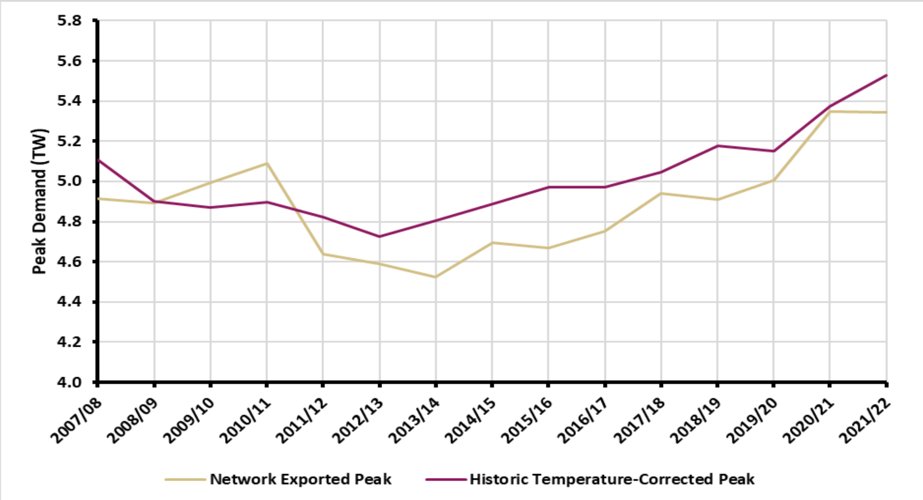


Figure 2.6 - Past values of recorded maximum demand in Ireland, and the ACS temperature-corrected values

2.2.8 Peak Demand Forecasting – Impact of 'Smartness'

Demand side measures and energy efficiency savings are a critical factor in understanding how future electricity consumers will contribute to peak demand and whenever there are opportunities to move demand when variable renewables are in surplus. For our forecast it is particularly important to allow for the effect of smart meters, as this acts to temper future forecasts of peak electricity demand. EirGrid, based on a study commissioned by CRU, assume by 2030 that smart meters could help reduce peak electricity demand by up to 8% for domestic users[19]. At present, residential demand is approximately 50% of peak electricity demand. Therefore, by 2030 it is assumed that a smart meter roll-out has the potential to reduce peak demand annually by 4%. This 'smartness' is included in our forecasts and it is assumed that the appropriate incentives are in place to ensure this 'smartness' materialises, otherwise additional capacity will be required.

An assumption on the variation of EV uptake across the demand scenarios is made to represent the range of possible rates of EV adoption. As quantities of electric vehicles grow, they will have an increasing impact on the electricity grid and on electricity markets. The scale of this impact will depend on a wide range of factors such as the quantity and types of electric vehicle, vehicle usage, types and locations of vehicle chargers and the charging patterns of vehicle owners. Vehicle charger technology has the potential to minimise the potential impact of electric vehicle demand on the electricity system, and on electricity markets. It is assumed that charger technology will evolve over time from simple chargers and patterns that are readily available today, to smart chargers with features such as programmable charge start times to smarter charging technology that optimises vehicle charging in line with dynamic electricity price signals. It is assumed that the appropriate policies and incentives are in place to ensure that smart vehicle charging technology is realised, otherwise additional capacity will be required.

As with the energy forecast, EirGrid has assumed an increase in the uptake of EVs and heat pumps, compared to the GCS 2021-2030; EirGrid assumes an uptake of 75% of CAP21 targets in the low scenario, 100% of CAP21 targets in the median scenario and 110% in the high scenario. In the high uptake scenario of electric vehicles, optimisation of charging demand is required to ensure that the need for grid development and additional generation capacity is minimised. In all three scenarios, the GCS 2022-2031 peak forecast incorporates the impact of smart metering and smart

19 https://www.cru.ie/wp-content/uploads/2011/07/cer11080ai.pdf

EV charging through the use of EV charging profiles which were previously developed as part of Tomorrow's Energy Scenarios 2019[20] study. The GCS 2022-2031 forecasts account for the effect of the 'smarter' charging profile developed in that study. This charging profile favours night-time charging, which reduces the need for 'peak time' charging.

Figure 2.7 shows the effect of smart metering and smart EV charging on the forecast peak day in 2030 in the median scenario. It can be seen here in this scenario that implementing 'smartness' has the effect of reducing the peak demand by approximately 600 MW. This significant effect has been incorporated into the final peak demand calculations.

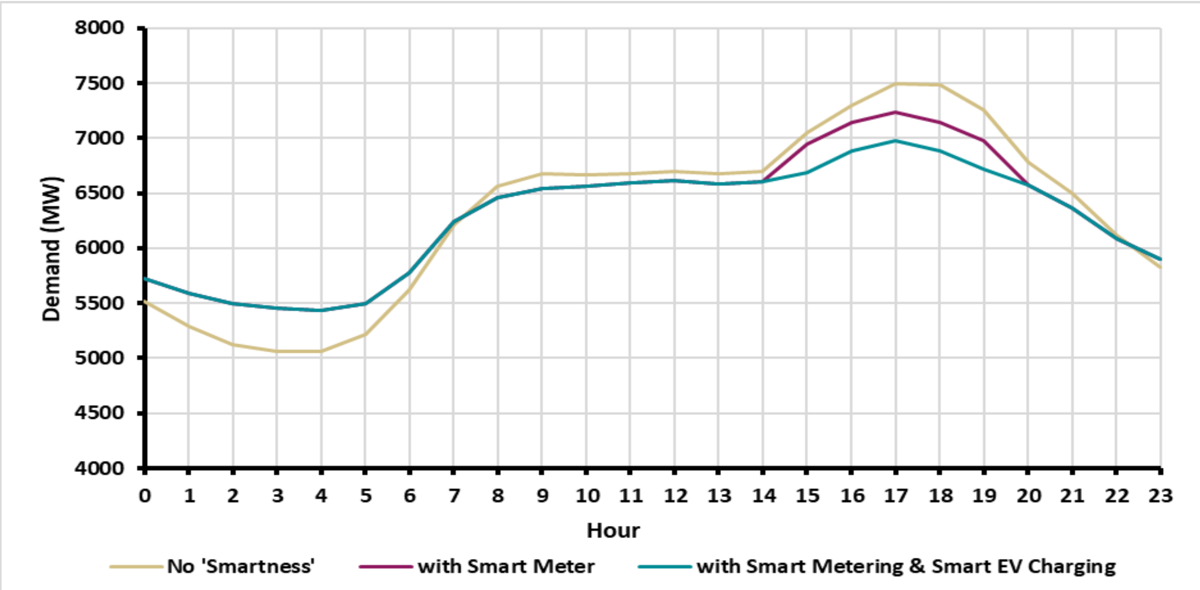


Figure 2.7 – The impact of Smart Metering and EV Smart Charging on the daily peak. The above graph is indicative of the peak day in the 2030 median scenario

Figure 2.8 shows the impact of smartness in the median scenario across the decade. There are greater gains in the latter part of the decade as the level of smart meters and electric vehicles increase annually.

20 *http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-TES-2019-Report.pdf*

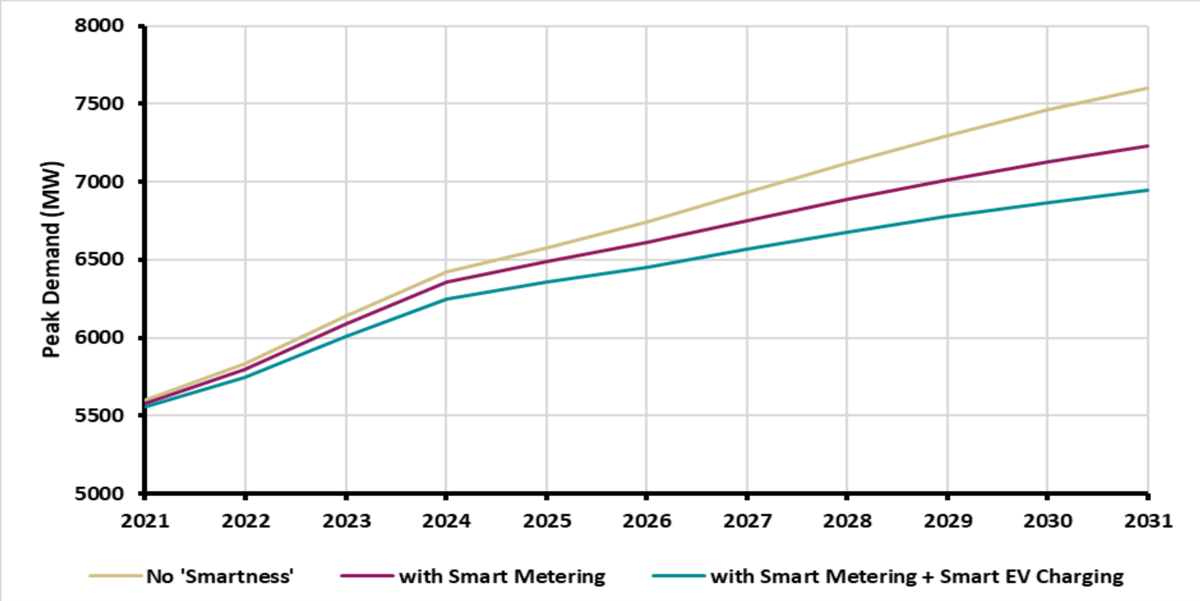


Figure 2.8 - Impact of Smartness in median Scenario across the decade

2.2.9 Peak Demand Forecasting – Overall

The overall peak demand forecast is shown in Figure 2.9. In the median scenario, the peak demand is forecasted to increase by 21% in 2031. Again, there is an increase from last year's forecast - this is driven by stronger post-Covid economic recovery, increased data centre growth and higher rates of electrification in the heat and transport sectors.

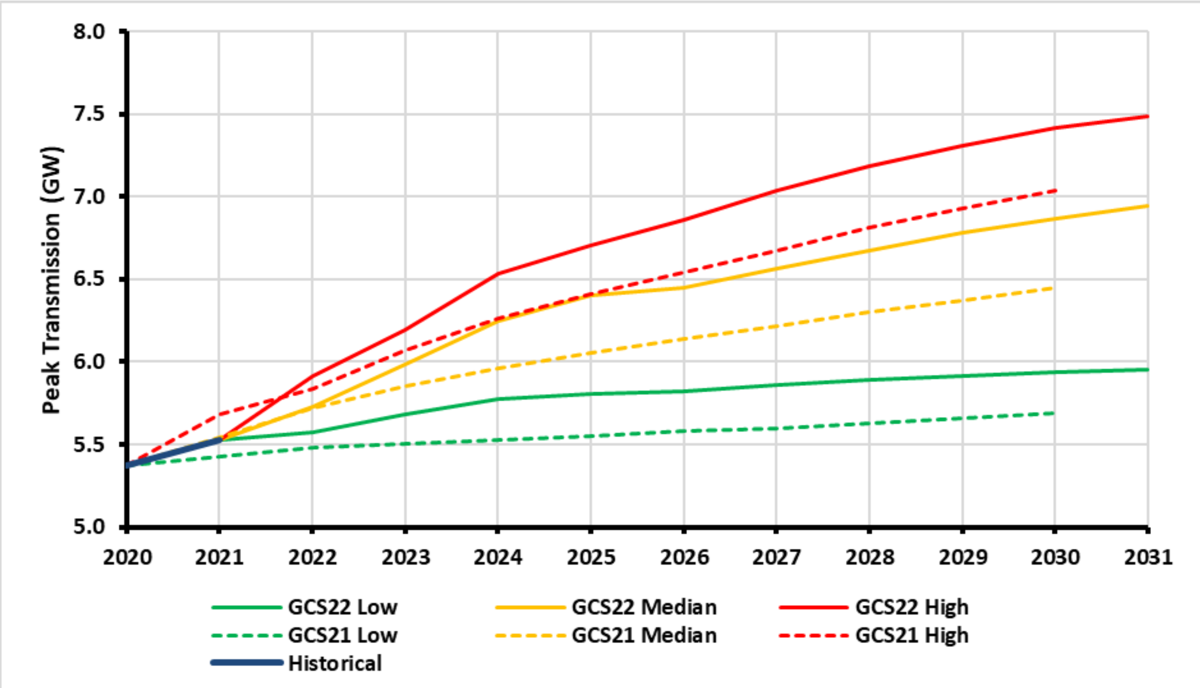


Figure 2.9 - Transmission peak forecast for Ireland

2.3 Demand Forecast for Northern Ireland

2.3.1 Methodology

The electricity forecast model is a multiple year linear regression model which looks at current trends in areas such as energy sales and economic parameters to predict electricity demand into the future. Particular attention is paid to the effects of energy efficiency measures and new tech loads. A spread of electricity forecasts is produced, covering the next ten years.

The TER forecast is carried out with reference to economic parameters, primarily Gross Value Added (GVA). The Northern Ireland economy was impacted significantly by Covid-19, reducing GVA in 2020 by approximately 10%[21]. The gradual removal of Covid-19 related restrictions led to GVA growth in 2021 of around 6%.

The consensus amongst economists is that there will be strong growth in Northern Ireland's economy in 2022 as remaining Covid-19 restrictions are lifted and normality returns, with modest growth forecast for years beyond 2022.

The Northern Ireland Executive's new Energy Strategy – The Path to Net Zero Energy[22] was published in December 2021. It outlines a roadmap to 2030 aiming to deliver a 56% reduction in energy-related emissions, on the pathway to deliver the 2050 vision of net zero carbon.

Following on from the new Energy Strategy the Department for the Economy (DfE) published The Path to Net Zero – Action Plan 2022[23]. This Action Plan 2022 is an integral part of delivering the overall energy strategy. These actions will be taken forward during 2022 by government and partners and will report in 2023 on the progress achieved against this 2022 Action Plan. In this report, the DfE has stated *'We intend that this closely managed approach to short term action planning and reporting will demonstrate government's commitment to the delivery of its agreed energy strategy over the longer-term.'*

Through its technical expertise and data, SONI is supporting the Northern Ireland Executive's Energy Strategy. The Energy Strategy points to an increase electricity demand from the heat and transport sectors.

2.3.2 Demand Scenarios

Given the degree of uncertainty in the future, SONI is of the view that it is prudent to consider three alternative scenarios to derive an estimate of energy production. Combining a range of factors including temperature, economics, data centre and new technology load growth, energy efficiency, as well as electrification of heat and transport, allows for the formulation of low, median, and high demand forecasts.

The median demand forecast is based on an average temperature year. It includes assumptions on electrification of heat and transport, future energy efficiency in the electricity system, along with the application of a central economic growth rate factor. This is our best estimate of what might happen in the future.

The low demand forecast is based on a relatively high temperature year, lower levels of electrification of heat and transport with higher levels of energy efficiency and the pessimistic

21 Based on data averaged across multiple sources including Danske Bank & EY
22 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf
23 https://www.economy-ni.gov.uk/sites/default/files/publications/economy/energy-strategy-path-to-net-zero-action-plan.pdf

economic factor being applied. Conversely, the high demand forecast is based on a relatively low temperature year, higher levels of electrification of heat and transport with lower levels of energy efficiency and the more optimistic economic factor being applied.

There have been applications from new tech loads and data centres seeking to connect in Northern Ireland. In order to capture the impact, SONI has based the demand forecast scenarios on different build-out scenarios. The low demand scenario assumes no new data centre or new technology load. The median demand scenario includes data centre and new technology load in the connection process. In addition to this, the high demand scenario contains potential additional load that may connect to the system within the ten-year study period. These three scenarios give an appropriate view of the range of possible demand growths and are based on applications for connection. These categories are similar to the approach for the demand scenarios in Ireland.

With the transition from fossil fuel sources, an increasing proportion of energy demand will be met from electricity. The demand forecast reflects higher electrification in the heat and transport sectors.

The air source heat pump is a low carbon solution that can help decarbonise Northern Ireland's heating demand, particularly oil dependent households. As part of the Path to Net Zero Energy Action Plan 2022 a review of permitted development legislation for low carbon heat installations is to be completed, primarily to address permitted development of heat pumps to align with modern standards and requirements. Factors impacting electricity demand of heat pumps include number of installations, dwelling heat demand and coefficient of performance.

Electricity demand in the transport sector is expected to increase with the growth in electric vehicle sales. The scale of this impact on electricity demand will depend on a wide range of factors such as the number and types of electric vehicle, vehicle usage and the charging patterns of vehicle owners. 'Smart' vehicle charger technology has the ability to reduce the impact of electric vehicle demand on peak electricity demand and is included in this demand forecast. It is assumed that the appropriate policies and incentives are in place to ensure that smart vehicle charging technology is realised otherwise additional capacity will be required.

The numbers of EVs and heat pumps included in the median, low and high demand forecast are detailed below with a linear uptake assumed in interim years. The number of EVs and heat pumps included in last year's median scenario are reflected in the low scenario of the GCS 2022-2031. This is in line with the assumptions used in Tomorrows Energy's Scenario Northern Ireland report[24].

24 https://www.soni.ltd.uk/media/documents/TESNI-2020.pdf

	Low		Median		High	
	Electric Vehicles	Heat Pump Installations	Electric Vehicles	Heat Pump Installations	Electric Vehicles	Heat Pump Installations
2025	35,000	16,000	64,000	42,000	86,000	42,000
2030	158,000	26,000	273,000	67,000	372,000	67,000

Table 2.5 - Number of EV and Heat Pump installations included in the low, median and high demand forecast

2.3.3 Self-Consumption

SONI has been working with Northern Ireland Electricity Networks (NIE Networks) and referencing the Renewable Obligation Certificate Register (ROC Register)[25] to establish the amount of embedded generation that is currently connected on the system and to predict what amounts will be connecting in the future. Examples of embedded generation include rooftop solar photo voltaic.

This has enabled SONI to make an informed estimate of the amount of energy contributing to the total demand by self-consumption, which is then added to the energy which must be exported by generators to meet all demand, resulting in the TER.[26]

2.3.4 TER Forecast

The Total Electricity Requirement (TER) is the sum of electricity demand for the residential, tertiary, industrial and growing transport sectors. The tertiary sector comprises commercial activities such as retail, office and services. TER also includes power sector distribution and transmission system losses[27].

It can be seen that the new TER forecast (Figure 2.10) has increased when compared to the forecast published in the Generation Capacity Statement 2021-2030. This is primarily due to the assumptions made around growth in electrification of heat and transport. The range difference between median and high demand is based on several factors including the effect of temperature, economics, data centre and new tech load growth, energy efficiency as well as electrification of heat and transport.

25 https://www.renewablesandchp.ofgem.gov.uk/

26 Self-consumption in Northern Ireland currently represents approximately 3% of TER. This has grown over more than ten years with the installation of small-scale generation.

27 Losses describe the difference between the amount of energy entering a system and the amount of energy leaving it. For example, on the transmission grid, some energy provided by generators is lost, typically as heat and noise, as it travels across the grid to where it is needed.

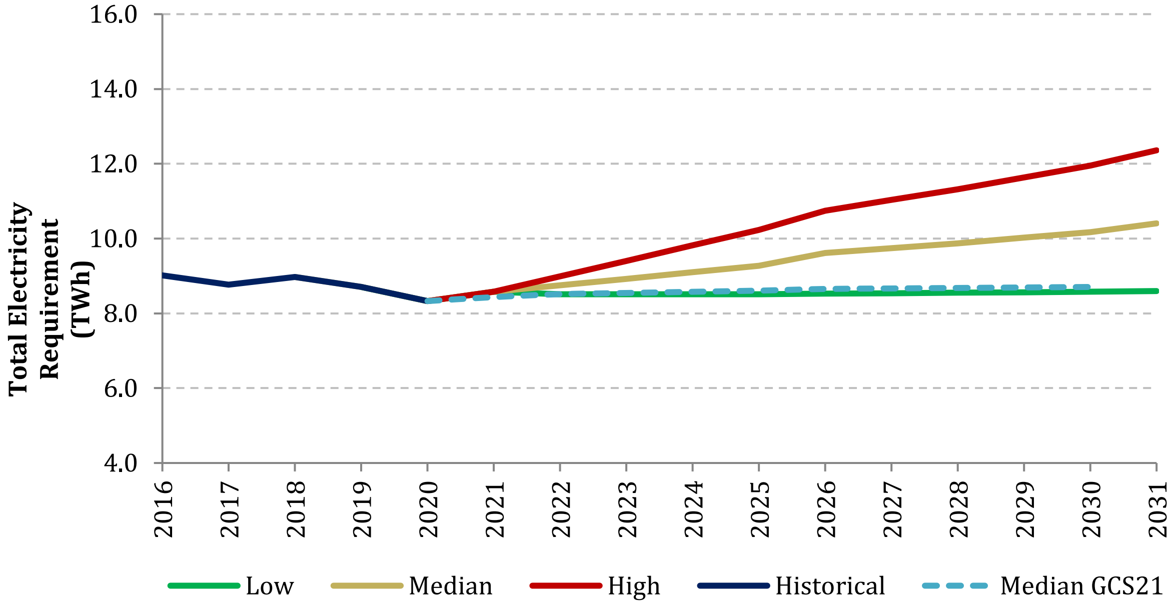


Figure 2.10 - Northern Ireland TER Forecast

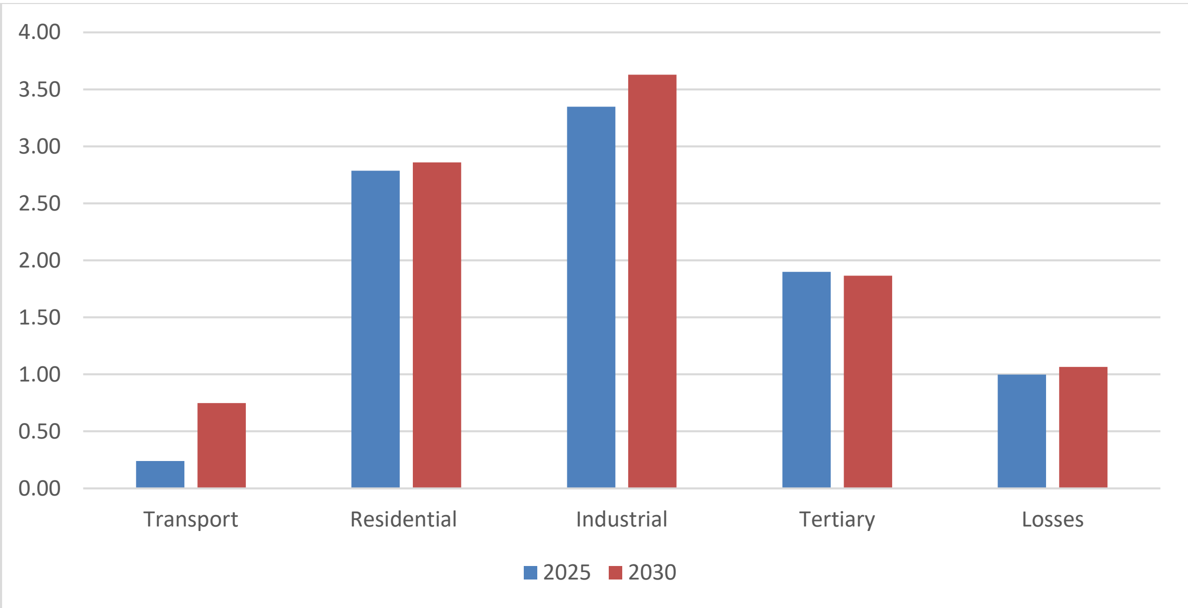


Figure 2.11 - Illustrates how the TER demand forecast is built up from the various demand components for the years 2025 and 2030. Growth in TER from 2025 is primarily driven by the electrification of heat and transport with government policies and incentives expected to drive growth.

2.3.5 Peak Demand Forecasting

The peak demand model is based on the historical relationship between the annual electricity consumption and winter peak demand. This relationship is defined by the Annual Load Factor (ALF), which is simply the average load divided by the peak load.

Temperature has a significant effect on electricity demand, particularly on Peak demand. This was particularly evident over the two severe winters of 2010 and 2011, when temperatures decreased dramatically, and demand increased to record levels. Average Cold Spell (ACS) correction has the effect of 'smoothing out' the demand curve so that economic factors are the predominant remaining influences. The temperature-corrected peak curve is used in the ALF model, which can then be modelled for the future using the previously determined energy forecasts.

The Northern Ireland 2020/21 sent out peak of 1599 MW occurred on Monday 7th December 2020 at 17:30. When ACS temperature correction is applied the Peak becomes 1618 MW.

As with the annual electricity demand forecast outlined in section 2.2(d), three peak forecast scenarios have been built.

Electricity demand in the heat and transport sector is expected to increase with the growth in heat pump and electric vehicle sales. It is assumed that appropriate policies and incentives will be in place to ensure that smart metering is realised, otherwise additional capacity will be required.[28]

In the early years of the ten-year peak demand forecast presented in this report, SONI used temperature variation to give a plausible range between the low and high peak forecasts, i.e., the low peak forecast is based on a mild winter, and the high scenario is based on a very cold winter. This has been based on historical records over the last ten years. While SONI does not expect an extremely warm or extremely cold winter every year, this range of scenarios is within the bounds of probability for the immediate years.

In later years of the ten-year peak demand forecast, variations caused by economic projections, data centre growth as well as electrification of heat and transport are more significant and are used instead.

The main difference between the forecasts of low, median and high peaks is the amount of load assumed from electrification of heat and transport as well as data centres. This forecast employs a similar methodology as that used in the TER forecast. Figure 2.12 shows the Transmission Peak forecast for Northern Ireland. The resulting forecast has increased compared to the GCS 2021-2030 median scenario.

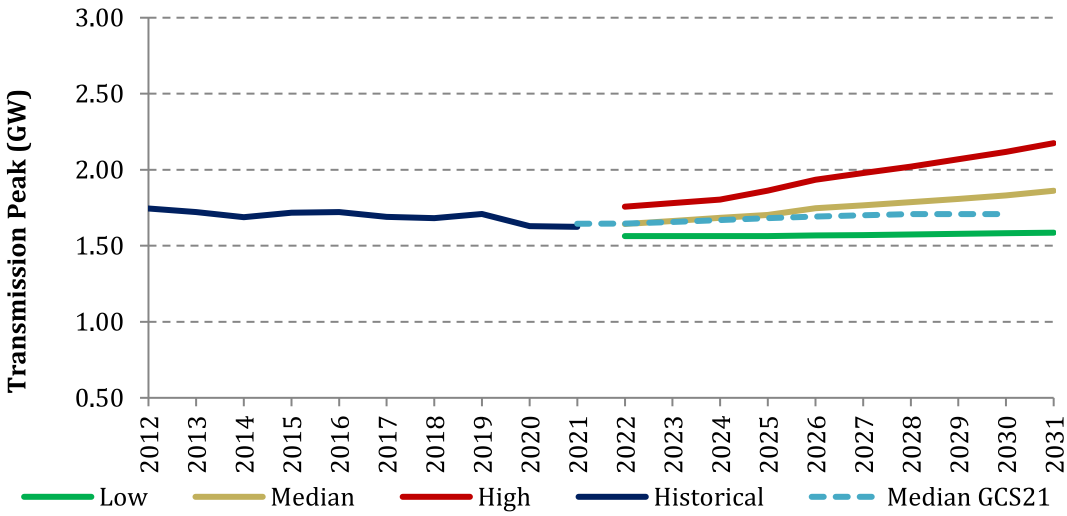


Figure 2.12 - ACS Transmission Peak forecasts for Northern Ireland

Appendix 1 lists the detailed energy and peak data out to 2031 including growth rates.

28 As part of the DfE Path to Net Zero Action Plan for 2022, a cost benefit analysis of electricity smart meters will be completed. The outcome of which will be incorporated into future studies

2.4 The Combined All-Island Forecast

In order to carry out combined studies for the All-Island system, we simply add the two jurisdictional forecasts together for the TER on a half-hourly basis to produce the new All-Island TER and Peak figures as shown in Figure 2.13 and Figure 2.14 below.

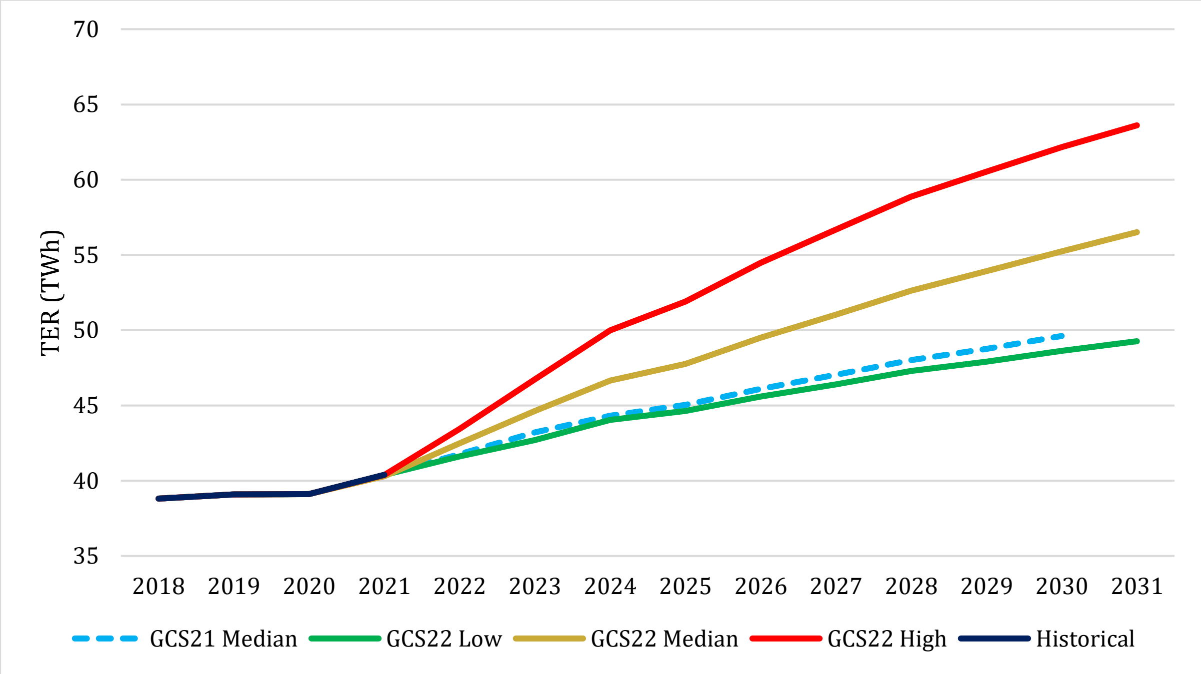


Figure 2.13 - Combined TER forecast for the All-Island system.

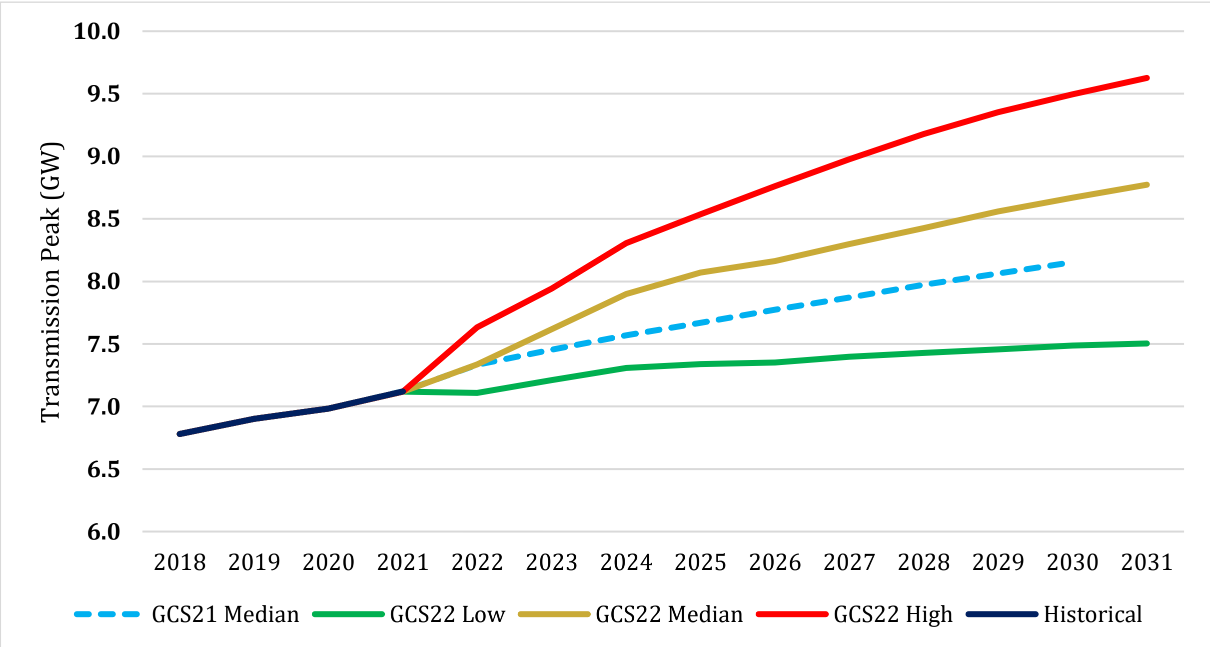


Figure 2.14 - Transmission Peak forecast for the combined All-Island forecast.

2.4.1 Annual Load Shape and Demand Profiles

To create future demand profiles for the adequacy studies, it is necessary to use an appropriate base year profile which provides a representative demand profile of both jurisdictions. This profile is then progressively scaled up using forecasts of energy peak and demand. Similar to the methodology employed in the Capacity Market auction calculations, we have used a number of base year profiles, carried out a number of adequacy studies separately, and then taken an average of the results. The profile year that gave the closest result to this average was then used for subsequent adequacy studies. This avoids any bias that might ensue if only one atypical year were used.

To reflect different segments of demand, additional forecast industrial and data-centre type demand is grown separately using a profile appropriate to its expected usage i.e. flat demand profile. Remaining additional demand is grown proportionally using historical demand profiles.

The choice for load profiling is a matter for continual review.

Electricity usage generally follows some predictable patterns. For example, the peak demand occurs during winter weekday evenings while minimum usage occurs during summer weekend night-time hours. Peak demand during summer months occurs much earlier in the day than it does in the winter period.

Figure 2.15 shows typical daily demand profiles for a winter weekday. Many factors impact on this electricity usage pattern throughout the year. Examples include weather, sporting or social events, holidays, and customer demand management.

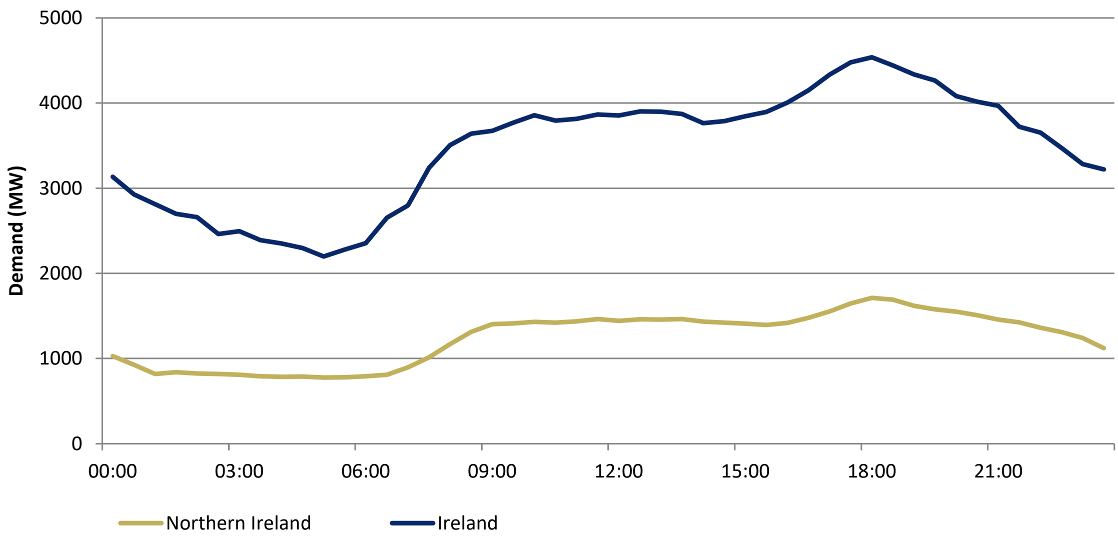


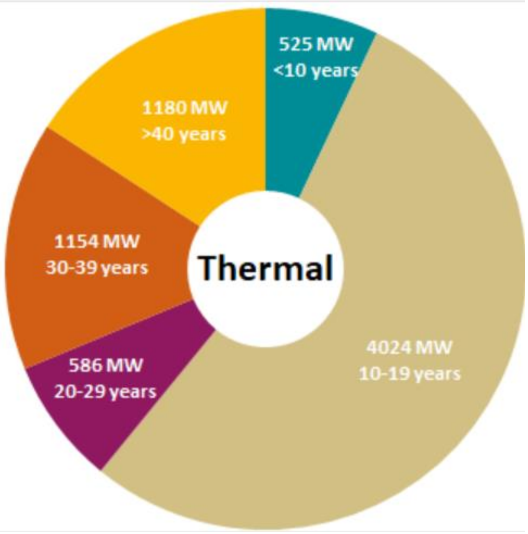
Figure 2.15 - Typical daily demand profile - winter weekday

3. Generation

3.1 Introduction

This section describes all significant sources of electricity generation connected to the electricity system in Ireland and Northern Ireland. The portfolio changes over time due to factors such as existing plant retiring and new capacity obtained via the Capacity Market in the Single Electricity Market (SEM), and performance of plant. Furthermore, a plant that does not receive capacity payments may seek to exit the market. Any changes to the portfolio are particularly significant to the operation of Ireland and Northern Ireland power systems, which has a high proportion of intermittent renewable generation.

For information, Figure 3.1 below illustrates the age of the dispatchable plant on the All-Island system (excluding demand side units). Notably approximately 30% of the thermal fleet is over 30 years of age.



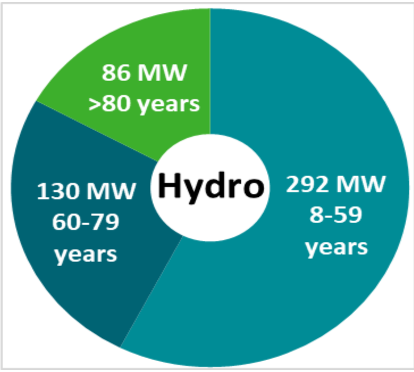


Figure 3.1 Age breakdown of dispatchable plant on the All-Island system

3.2 SEM Capacity Market Auction Results

The Single Electricity Market (SEM), established in 2007, is the wholesale electricity market operating in Ireland and Northern Ireland. It is designed to provide wholesale electricity at the lowest possible cost, ensuring that there is adequate supply to meet demand. The market design was revised since October 2018.

The SEM is designed and regulated by the Single Electricity Market Committee (SEM Committee) which is made up of representatives from regulators in Northern Ireland (the Utility Regulator) and Ireland (the Commission for Regulation of Utilities) and two independent members. The key aspect of the SEM are the energy market and the Capacity Auctions.

SONI and EirGrid operate the SEM, under the contractual joint venture, the Single Electricity Market Operator (SEMO).

Under the SEM, only generating units that are successful in the capacity auctions will receive capacity payments. The goal of the auction is to ensure that consumers do not pay for more capacity than is needed. Since 2017, there have been ten auctions, the total volumes procured for each auction are presented in Appendix 2.

The forecast generation portfolio has been updated to include the new entrant generation units that were successful in the following SEM CRM capacity auctions: T-1 2022/2023[29], T-3 2024/2025[30] and T-4 2025/2026[31].

These auctions have taken place since October 2021 and the results are publicly available.

To date, most renewable generation has not participated in the Capacity Auctions. In Ireland, renewable generation can receive support via a set of auctions called the Renewable Electricity Support Scheme (RESS). In Northern Ireland, there are plans to consult on a renewable electricity support scheme in 2022 for delivery in 2023 as detailed in the Northern Ireland Energy Strategy[32].

Figure 3.2 displays the new de-rated capacity (i.e. a unit's effective capacity when its operational availability is taken into consideration) which was successful in the recent capacity auctions.

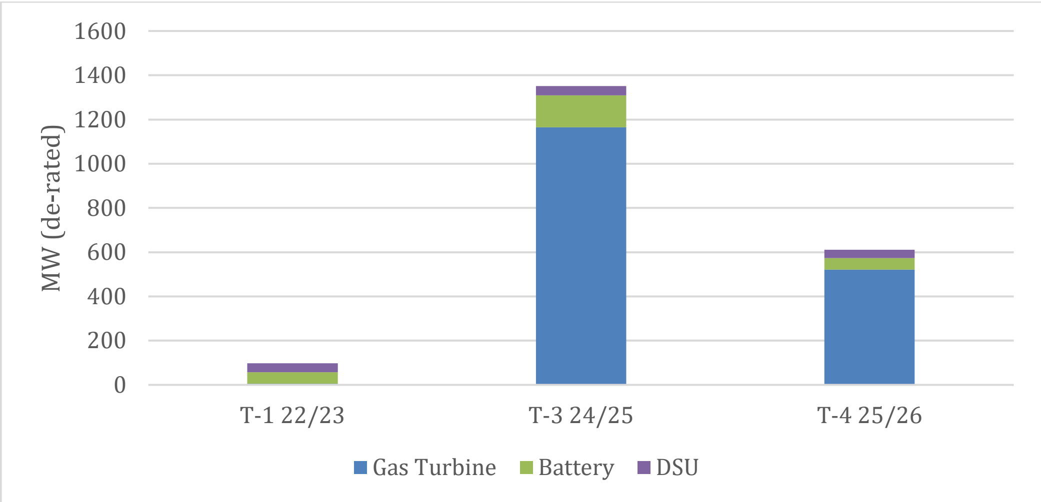


Figure 3.2 - Total All-Island de-rated awarded capacity from new units in recent auctions (T-1 2022/2023, T-3 2024/2025, and T-4 2025/2026)

Delivering new capacity of the volume required is a complex task for the developers and delays can take place due to issues outside of EirGrid's and SONI's control, such as planning permission, environmental consenting, and supply chain delays. Furthermore, in recent years, approximately 650 MW of new capacity units that were due to connect to the system have subsequently terminated their contracts (see Appendix 2 for a list of these units); with over 70% of this capacity having 10-year contracts in place. The Capacity Market Code makes provisions for an 18 month long stop date, which is built into 10-year capacity contracts. This means developers may connect up to 18 months after the 1st October of their first capacity contract year without being subject to termination charges. However, the duration of the 10-year contract does not extend.

Delivering new capacity is a constantly evolving process. To this end, both EirGrid and SONI have implemented enhanced monitoring of new capacity coming through the capacity auctions. Through this enhanced monitoring (which includes expert advice on power generation delivery) we are able to gain insights into the deliverability risks associated with the new projects as they progress

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29 https://www.sem-o.com/documents/general-publications/T-1-2022-2023-Final-Capacity-Auction-Results-Report.pdf
30 https://www.sem-o.com/documents/general-publications/T-3-2024-2025-Final-Capacity-Auction-Results-Report.pdf
31 https://www.sem-o.com/documents/general-publications/T-4-2025-26-Final-Capacity-Auction-Results-Report.pdf
32https://www.economy-ni.gov.uk/sites/default/files/publications/economy/energy-strategy-path-to-net-zero-action-plan.pdf (page 7)

through their implementation plans. This accounts for risk factors such as supply chain analysis, risks to planning permission and grid connection timescales.

It is EirGrid's and SONI's view, that based on the current deliverability assessment, not all of the recently awarded capacity can deliver for the 1st October of the capacity year. Additionally, it is our view that there are some projects which have significant technical and/or planning challenges that could mean non-delivery within the 18-month longstop period.

In 2017, the European Commission published a final decision on the Best Available Techniques[33] (BAT) for large combustion plants, which has applied new standards on emissions from August 2021. The latest BAT conclusions were published in February 2021[34]. For combustion plants, Emission Limit Values (ELVs) for Nitrous Oxide (NOx), Sulphur Dioxide (SO_2) and particulate levels have been tightened. As such, EirGrid and SONI have concerns that several new gas generating units will have annual run hour limitations (ARHL) based on our understanding of these BAT conclusions.

It should be noted that, at the completion of the latest T-4 2025/2026 auction, not all awarded new capacity have signed connection agreements. The GCS 2021-2030 and additional security of supply studies highlighted the negative impact to system adequacy from the risk of new capacity not becoming available on time. In the short term, failure to deliver new capacity for a given capacity year presents significant challenges to the adequacy position of the system. Further mitigating measures may be required if new capacity fails to deliver on time for a given capacity year.

The respective TSO risk adjusted view of new capacity is outlined in Table 3.1 for Ireland and Table 3.2 for Northern Ireland. Note, DSUs and battery projects are assumed to deliver on time. The total DSU and battery capacities are outlined in sections 3.8.1 Demand Side Units (DSUs) and 3.8(b), respectively.

Note, one of the new gas units in Ireland is expected to be subject to ARHL when they become available in 2026.

The two new gas units in Northern Ireland are expected to be subject to ARHL when they become available in 2024. There is an additional steam unit planned to become operational at this site in 2026, this unit is expected to remove any ARHL as the plant will have the ability to operate as a combined cycle gas turbine (CCGT).

[31] http://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1502972300769&uri=CELEX:32017D1442
[34] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32021D2326

Ireland	2023	2024	2025	2026	2027
Gas Turbine	0	120	190	790*[35]	140

Table 3.1– Ireland: Assumptions for new conventional plant capacities for adequacy studies (rated MW) from T-1 22/23, T-4 24/25, T-3 24/25 and T-4 25/26. Note values are rounded to nearest 10.

Northern Ireland	2023	2024	2025	2026	2027
Gas Turbine	0	720*	0	0**[36]	0
Steam Turbine	0	0	0	310	0

Table 3.2 - Northern Ireland Assumptions for new conventional plant capacities for adequacy studies (rated MW) from T-1 22/23, T-4 24/25, T-3 24/25 and T-4 25/26. Note values are rounded to nearest 10

3.3 Changes to Conventional Generation in Ireland

This section describes changes in fully dispatchable-plant capacities in Ireland. Information on known plant additions and closures are documented.

Some of the older generators in Ireland have informed EirGrid of their intention to decommission, as detailed below in Table 3.3. A common reason for plant decommissioning is increasing restrictions due to Industrial Emissions Directive (IED) legislation.

Directive 2010/75/EU[37] of the European Parliament and the Council on industrial emissions (the Industrial Emissions Directive or IED) is the main EU instrument regulating pollutant emissions from industrial installations.

*35 * Denotes that there are units within this calendar year that are subject to ARHL.*
*36 ** ARHL removed as station converts to CCGT. This will increase the overall contribution to system adequacy*
37 https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN

Plant	Units	Export Capacity (MW)	Modelled as closing by the end of:	Comment
Aghada	AT1	90	2023	IED Limited Life-time Derogation. ESB has provided a closure notice for these units.
	AD2	449	Remains open for study horizon	Note AD2 has increased capacity from 431 MW to 449 MW
Tarbert	TB1	54	2021	SSE has previously provided a closure notice for this unit to close at end of 2023. TB1 has since been placed on outage until Dec 2023 so will be excluded from studies
	TB2	54	2021	SSE has previously provided a closure notice for this unit to close at end of 2023. TB2 has since been placed on outage until Dec 2023 so will be excluded from studies
	TB3	241	2023	SSE has provided a closure notice for this unit to close at end of 2023.
	TB4	243	2021	SSE has previously provided a closure notice for this unit to close at end of 2023. TB4 has since been placed on outage until end of March 2023. Will be excluded from studies
Moneypoint	MP1 MP2 MP3	285 250 285	2024	Moneypoint units could not qualify for the 2024/2025 T-4 Capacity Auction[38]. On this basis, these units will be excluded from end of 2024. EirGrid notes that ESB has not provided a closure notice for these units. The Grid Codes require 3 years notice to be provided prior to closure, therefore, a sensitivity is included in the results that assumes Moneypoint units remain available until the end of 2025. MP2 is now running on HFO with a capacity of 250 MW.
Edenderry	ED1	118	2030	The Bord na Móna plant ED1 was due to close at the end of 2023. Planning permission was recently awarded to keep this unit operating until 2030, running on 100% biomass from 2024.

Table 3.3 -Assumptions for conventional plant changes in Ireland

3.4 Changes to Conventional Generation in Northern Ireland

This section describes changes in fully-dispatchable plant capacities in Northern Ireland. Information on known plant unavailability, additions and closures are documented in Table 3.4 and Table 3.5.

38 The Clean Energy Package targets all generation to be under 550g/kWh by 2025 to be eligible to receive payment under a capacity mechanism

The forecast generation portfolio has been updated to include the new entrant generation units that were successful in the following SEM CRM capacity auctions: T-1 2022/2023, T-3 2024/2025 and T-4 2025/2026. The studies include cleared existing capacity and the new capacity awarded are either one or ten-year contracts.

Kilroot units KGT1, KGT2, KGT3 and KGT4 have an extended planned outage in 2025. They were not included in the T-4 2024/25 auction in January 2021 and this is reflected in our modelling with these units being unavailable in 2025 but available for all other years of the studies. This capacity is outlined in Table 3.4.

Plant	Export Capacity (MW)	Modelling Assumption:	Comment
KGT1	29	Unavailable in 2025	Did not qualify for inclusion in T-4 2024/25 auction
KGT2	29	Unavailable in 2025	Did not qualify for inclusion in T-4 2024/25 auction
KGT3	42	Unavailable in 2025	Did not qualify for inclusion in T-4 2024/25 auction
KGT4	42	Unavailable in 2025	Did not qualify for inclusion in T-4 2024/25 auction

Table 3.4 - Assumptions for Kilroot GT plant capacity

Kilroot ST1 and ST2 did not qualify for inclusion in the T-4 2023/24 auction in April 2020 and the developer subsequently issued a Closure Notice for ST1 and ST2 confirming its intention to close both units on 30th September 2023. This capacity is outlined in Table 3.5. The units each have HFO rating of 238MW, however the station has been declared unavailable for HFO operation for significant periods during 2021 and 2022.

SONI recently obtained clarification from the plant operator on the running of existing near end of life coal plant. At present, the plant operates at a reduced generation capacity following the expiration of the COVID-19 Regulatory Position Statement to manage and comply with their most recent environmental permit. Following engagement with DfE and NIEA, SONI are aware that a Direction under the Pollution Prevention Control (Industrial Emissions) Regulations was issued by DAERA to the Chief Inspector (the PPC(IE) Regulator) in April 2022[39]. The Direction instructs the PPC(IE) regulator not to enforce against exceedances on air emission limits where there is significant and imminent risk to the security of NI's electricity supply, as determined by the Department for Economy. Following receipt of the Direction issued by DAERA, the coal station operator has been written to, confirming that the PPC(IE) regulator has received the above Direction. The coal station's operator's current position is to run at reduced generation capacity and not invoke the use of the DAERA Direction.

The operator has informed SONI that each of these units are limited to a maximum of 175 MW when running on coal. Furthermore, to comply with their latest Environmental Permit the coal units are not operated as fully available at 175 MW, but at this output they are restricted by the operator to a limited number of periods across a typical day.

At the time of the GCS 2022-2031 data freeze, the developer has been carrying out operational testing to ascertain the levels at which emissions compliance can be maintained and this is

39 https://public-registers.daera-ni.gov.uk/pollution-prevention-control

currently estimated to be an average of 130 MW throughout the day. This limitation is reflected in our modelling.

Plant	Export Capacity (MW)	Modelled as closing by the end of:	Comment
Kilroot ST1	238	2023	EPUKI has provided a closure notice for this unit. Operation ceases 30th September 2023. The 238 MW is based on the HFO rating, however the station has been declared unavailable for HFO operation for significant periods during 2021 and 2022. Due to Environmental Permit Compliance Restrictions, the unit is assumed to be 130 MW for modelling purposes.
Kilroot ST2	238	2023	EPUKI has provided a closure notice for this unit. Operation ceases 30th September 2023. The 238 MW is based on the HFO rating, however the station has been declared unavailable for HFO operation for significant periods during 2021 and 2022. Due to Environmental Permit Compliance Restrictions, the unit is assumed to be 130 MW for modelling purposes.

Table 3.5 - Assumptions for plant changes in Northern Ireland

There are some uncertainties in Northern Ireland around new capacity becoming available for a given capacity year and risks around annual run hour limitations on existing plant and new capacity entering the market. The developer has informed SONI of annual run hour limitation on some new capacity awarded through several SEM T-4 auctions. Furthermore, SONI has identified operational risks if annual run hour limitations are applied to capacity connected to the system and operating in the market. Annual run hour limitations are due to legal requirements in relation to the application of the Industrial Emissions Directive (IED) BAT conclusions which provide guidance on the best available techniques to ensure combustion technologies comply with emissions levels including Carbon Dioxide, NOx and SOx.

It is SONI's view that careful consideration of annual run hour limitations is required and where possible technology should be designed and operated to maximise its availability while minimising the impact on system wide emissions, otherwise there may be a negative impact on security of supply and the environment.

In GCS 2021–2030 SONI noted that it was unclear if annual run hour limitations would apply to new capacity in Northern Ireland. The developer has subsequently confirmed that this new capacity would be run hour restricted. The latest capacity offered at the Kilroot site cleared in the recent T-4 25/26 was classified as part of a Combined Cycle Gas Turbine (CCGT) arrangement. This arrangement would utilise waste heat from the new KGT6 and KGT7 Open Cycle Gas Turbines. The developer is currently working through the design of the system and have confirmed that the capacity will be delivered as part of a CCGT arrangement. The new capacity is linked to KGT6 and

KGT7 to deliver an unrestricted CCGT arrangement with no annual run hour limitations from 2026. Therefore, the impact of Annual Run Hour Limitations (ARHL) is included in the core scenarios up until 2026.

In consideration of this GCS 2022-2031, SONI has coordinated with the Northern Ireland Gas TSOs and Northern Ireland Gas Market Operator (Mutual Energy GNI & GMO) to determine any future potential impacts on the Northern Ireland gas system as the result of new Open Cycle Gas Turbines (OCGT) at Kilroot commissioning in Northern Ireland. The preliminary results from this analysis indicate that the additional gas capacity, offtake profile and pressure requirements take the Northern Ireland Gas transmission network close to its physical capability. SONI will continue to work with the Northern Ireland Gas TSOs to understand how the electricity system will impact the infrastructure needs of the gas network.

Gas infrastructure is required to manage a scenario of low renewable generation and high output from Combined Cycle Gas Turbine (CCGT) and OCGT running during winter periods with net exports of electricity from Northern Ireland. This may result in Northern Ireland gas pressures falling below desired operational limits. Greater detail on this will feature in the upcoming 2022 Northern Ireland Gas Capacity Statement. While SONI is not the lead party in this area, gas limitations may mean there are additional complexities on scheduling and dispatch of generation. While SONI does have fuel switching arrangements in place, they are not intended for what SONI would consider as normal operating conditions that occur every winter. A fuel changeover introduces additional risks at a time the power system is experiencing high electricity demands.

3.5 Interconnection

Interconnection allows the transport of electrical power between two transmission systems. Interconnection with Great Britain over the East-West and Moyle interconnectors provides a significant capacity benefit. It also allows balancing market opportunities for direct trading between the system operators, known as counter-trading.

The existing North South Interconnector (between Louth and Tandragee), or the North South tie-line, plays a key role in system security and adequacy in both jurisdictions. Further transmission links between Ireland and Northern Ireland, including the second North South Interconnector would significantly enhance access to generation capacity in both jurisdictions.

Within the All-Island market, the tie-line between Ireland and Northern Ireland is an element of the transmission system, rather than an interconnector to facilitate cross-border market trading. For this reason, as an essential element of AC grid, it is treated differently to how the East-West (EWIC) and Moyle HVDC interconnectors are considered. These interconnectors are subject to cross-border trading obligations; eligible for participation in the Capacity Market and are therefore given capacity market de-rating factors.

3.5.1 North South Interconnector

The second high-capacity transmission link between Ireland and Northern Ireland is assumed to be commissioned by the end of 2025, and to become fully operational by 2026. It is assumed that All-Island generation adequacy assessments can be carried out from 2026 onwards. This All-Island assessment shows an increase in the security of supply for both jurisdictions, as the demand and generation portfolios for Northern Ireland and Ireland are aggregated to meet the combined demand.

Prior to the completion of this second North South Interconnector project, the existing tie line between the two regions creates a physical constraint affecting the level of support that can be provided between jurisdictions.

Generation adequacy assessments for each region are carried out with an assumed degree of capacity interdependence from the other region. This is an interim arrangement until the second North South Interconnector removes this physical constraint. This is due to the system outages and the region demand peak for each region occurring at different times. Therefore, some allowance for inter-regional supply can be estimated to balance supply across the island. The capacity reliance values used for the adequacy studies are shown in Table 3.6. This capacity reliance figure assumes that there is sufficient capacity from either jurisdiction to facilitate an exchange of power.

	North to South	South to North
Capacity Reliance	100 MW	200 MW

Table 3.6 - Capacity reliance at present on the existing North South Interconnector

SONI and EirGrid define the capacity reliance as the effective capacity adequacy benefit across a typical year. During real time operations, physical flows may be in excess of the stated capacity reliance.

3.5.2 Interconnection between the all-island system and Great Britain

When assessing the contribution of an interconnector to generation adequacy, consideration of the availability of generation at the other side is needed, as well as the availability of the interconnector itself.

The East-West interconnector connects the transmission systems of Ireland and Wales with a capacity of 500 MW in either direction. In Northern Ireland, the Moyle Interconnector is a dual monopole HVDC link with two coaxial undersea cables from Ballycronanmore (Islandmagee) to Auchencrosh (Ayrshire). The import capacity of the Moyle Interconnector is 450 MW.

It is difficult to predict whether imports for the full capacity will be available at all times. For the purposes of this adequacy study EirGrid and SONI assumes two existing HVDC interconnectors between the all-island system and Great Britain. We model this with two 500 MW_{rated} interconnectors, we apply a 60% External Market de-rating and use the relevant 2019 outage statistics for each interconnector as indicated in Table 3.8.

3.5.3 Further Interconnection

There are several proposed new interconnector projects seeking to connect to the Ireland and Northern Ireland transmission system. Table 3.7 summarises the projects that are assessed as part of the current European Ten-Year Network Development Plan[40]. For the purpose of the adequacy assessment, the Celtic Interconnector is assumed available from 2027, and it is assigned the external market de-rating factor of 60%[41] and average 2019 availability statistics. For the purposes of this adequacy as assessment we assume there is no additional adequacy

[40] *TYNDP 2020 is produced by the European Network of Transmission System Operators – Electricity (ENTSO-e), see https://eepublicdownloads.azureedge.net/tyndp-documents/TYNDP_2020_Joint_Scenario_Report_ENTSOG_ENTSOE_200629_Final.pdf*

[41] *Although this interconnector is from SEM to France we assume the 60% based on current Capacity Auction interconnector de-ratings for SEM to GB market. We expect the Ireland to France interconnector external market de-rating to be evaluated as part of T-4 26/27 Auction process.*

benefit from new SEM to GB market interconnection. For modelling purposes, we continue to model two 500 MW_{rated} interconnectors between SEM and GB, however, we acknowledge the fact that through the market adequacy benefit is shared between all interconnectors. We note the external SEM to GB market de-rating factors need to be re-evaluated as new interconnection comes online and as such, we will engage with the regulatory authorities on this.

Project	Description	Project Promoters Target Commissioning Year
Celtic Interconnector	Interconnector between Ireland and France (with PCI status[42])	2026
Greenlink Interconnector	Project providing interconnection to Great Britain [42]	2024
LirIC	Interconnector between Northern Ireland and Scotland	2028
MARES Connect	Interconnector between Ireland and Wales	2027

Table 3.7 - Future interconnection projects

There are further connection projects noted in ENTSOE's most recent Ten-Year Network Development Plan 2022. In Northern Ireland there is potential for new interconnection (LirIC) to Scotland, with one potential operator receiving an interconnector licence from Ofgem. In Ireland, there is a further interconnector project (MARES Connect) from Ireland to GB. Based on the early development status of these projects they are not included within any studies or tables in this report.

3.6 Wind Capacity and Renewable Targets

3.6.1 Wind Power in Ireland

In Ireland, the Department of Environment, Climate and Communications (DECC) launched a set of auctions called the Renewable Electricity Support Scheme (RESS). It can be assumed that Ireland's renewable targets will be achieved largely through the deployment of additional wind powered generation. There have been a number of grid access schemes to develop connection of renewable generation: Gate 3, Non-GPA and ECP-1. The current grid access scheme is called Enduring Connection Process-2 (ECP-2). EirGrid publishes a list of all transmission connected wind generation in Ireland[43], while ESB Networks publishes that which is distribution connected[44].

The Irish Government's updated Climate Action Plan 2021[45] has set an ambitious target to achieve up to 80% RES-E by 2030. This will require significant escalation in growth rates of renewables in the electricity sector. The current plan in Ireland includes delivering 5 GW of offshore wind by 2030. The level of renewables required to achieve 80% RES-E is currently a focus of the upcoming Shaping Our Electricity Future (SOEF) v1.1. For the purposes of these adequacy studies, the level of renewables is in line with government targets, as published in SOEF v1. The assumed build-out of renewables to reach 70% RES-E is shown in Figure 3.3. The impact of higher renewable roll-out will be considered as part of the next Generation Capacity Statement.

[42] *EC Project of Common Interest, see: fifth_pci_list_19_november_2021_annex.pdf (europa.eu)*
[43] *http://www.EirGridgroup.com/customer-and-industry/general-customer-information/connected-and-contracted-generators/*
[44] *https://www.esbnetworks.ie/new-connections/generator-connections/generator-connection-statistics*
[45] *https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/*

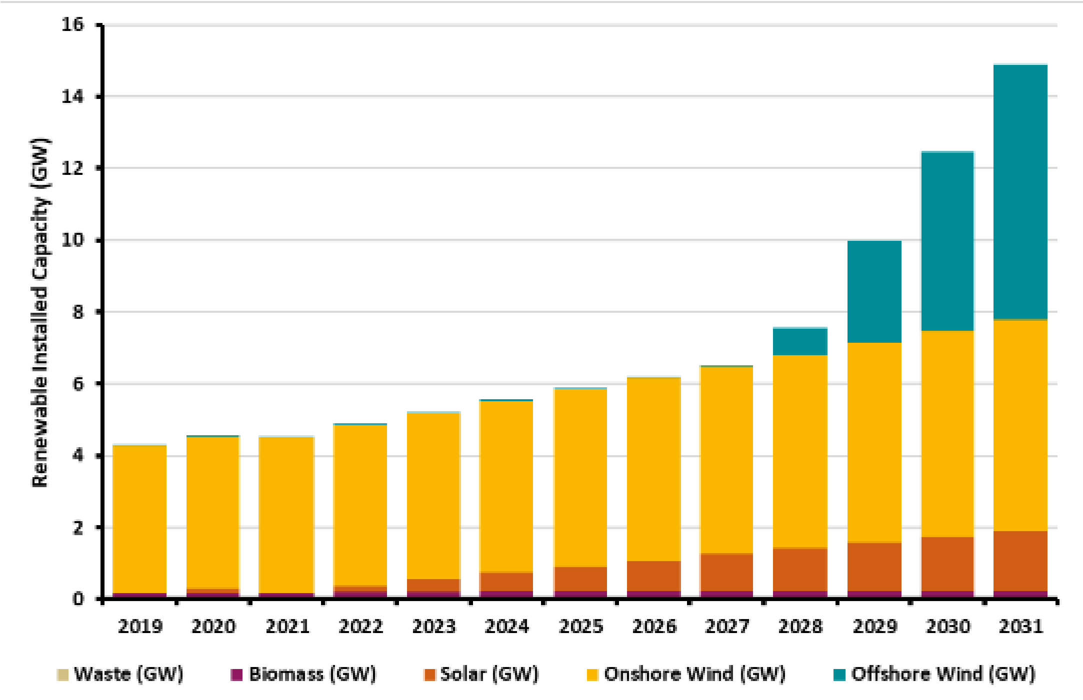

Figure 3.3 - Assumed Build-out of renewables

Installed capacity of wind generation has increased from 135 MW at the end of 2002 to 4.3 GW at the end of 2021. This value is set to increase to at least 12 GW between onshore and offshore capacity as Ireland endeavours to meet its renewable targets in 2030 and beyond.

Figure 3.4 shows the total wind generation, along with the capacity factor and normalised wind generation. To calculate the normalised wind generation, as per RES Directive (2009/28/EC)[46], the average capacity factor from the last five years is applied to the installed capacity. This normalised annual energy has grown from 4,122 GWh in 2012 to 10,500 GWh in 2021, accounting for constraints and curtailment. Last year saw a decrease in wind generation compared to 2020, primarily due to the lower levels of wind availability.

[46] https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32009L0028&from=EN

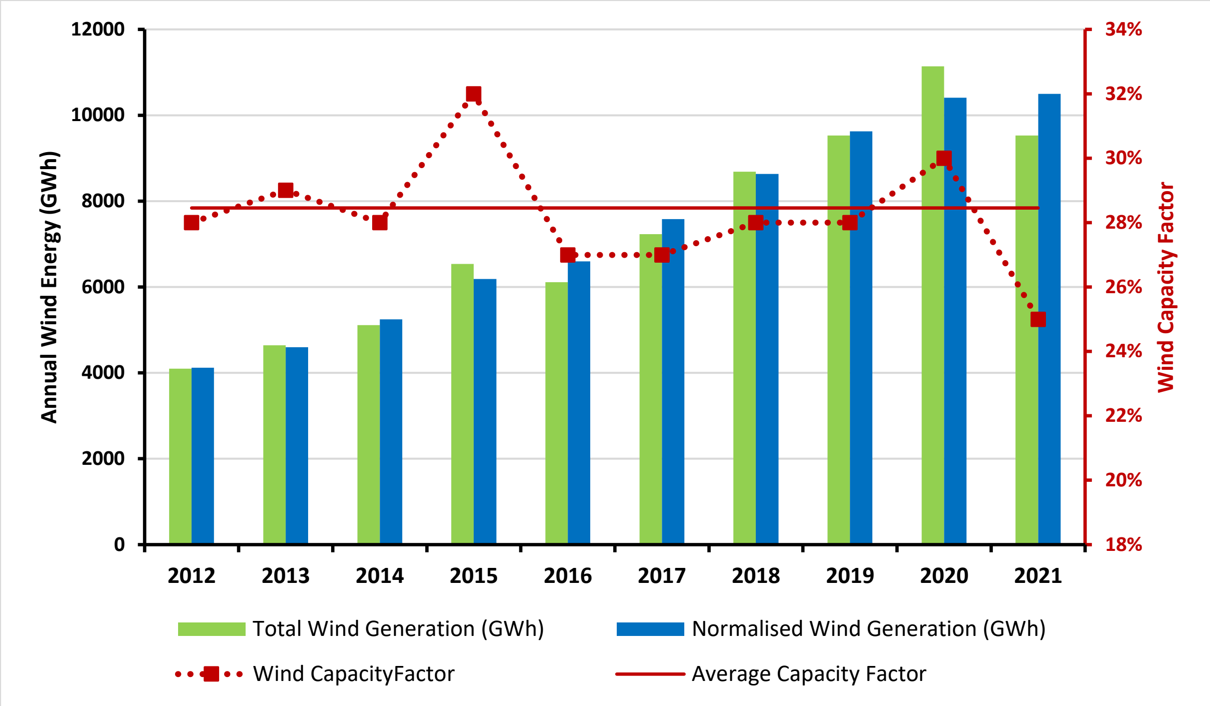

Figure 3.4 - The actual and normalised energy produced from wind power in Ireland over the last ten years

3.6.2 Wind Power in Northern Ireland

In June 2019, the UK became the first major economy to commit to a 100% reduction in greenhouse gas emissions by 2050. This 'net zero' target represents a significant step-change in the commitment to addressing the climate crisis.

More recently, the Northern Ireland Executive's new Energy Strategy – The Path to Net Zero Energy[47] was published in December 2021. It outlines a roadmap to 2030 that aims to deliver a 56% reduction in energy-related emissions, on the pathway to deliver the 2050 vision of net zero carbon.

Following on from the new Energy Strategy the Department for the Economy (DfE) published The Path to Net Zero – Action Plan 2022[48]. This Action Plan 2022 is an integral part of delivering the overall energy strategy. The plan lays out a range of actions that the government expects to take forward with other partners during 2022. The strategy includes a target of 'least 70% of electricity consumption from a diverse mix of renewable sources by 2030'. The renewable build out assumed for these studies is based on this 70% target.

Additionally, a new Climate Change Bill for Northern Ireland[49] has been introduced which sets a target of least 80% of electricity consumption from renewable sources by 2030. The level of renewables required to meet this target will be investigated as part of Shaping our Electricity Future Version 1.1 (SOEF v1.1).

For both targets, it is clear that significant investment will be required to deliver higher levels of new renewable and low carbon technologies. Whilst the SEM provides revenue streams for power generators irrespective of technology, the closure of the Northern Ireland Renewables Obligation (NIRO) in 2017 means that no support scheme designed to meet the specific needs of intermittent

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[47] *The Path to Net Zero Energy. Safe. Affordable. Clean. (economy-ni.gov.uk)*
[48] *https://www.economy-ni.gov.uk/sites/default/files/publications/economy/energy-strategy-path-to-net-zero-action-plan.pdf*
[49] *Climate Change (No. 2) Bill (niassembly.gov.uk)*

generation is available in Northern Ireland to encourage investment and reduce risk for investors. Both GB and Ireland have auction-style mechanisms in Contracts for Difference (CfD) and the Renewable Electricity Support Scheme (RESS). There are plans to consult on a renewable electricity support scheme in 2022 for delivery in 2023 as detailed in the Northern Ireland Energy Strategy.

In the medium term, onshore wind and solar PV are expected to be the most readily deployed technologies for Northern Ireland. Offshore renewables do offer a significant opportunity to develop additional large-scale renewable capacity. This is included in the NI Strategy Action Plan for 2022.

The Climate Change Committee, which advises UK central government and devolved administrations on emissions cuts and targets, has raised concerns about Northern Ireland's ability to fully contribute to wider UK targets[50].

In 2021, 36.7% of electricity came from renewable sources (based on sent out metering) in Northern Ireland, most of which was from wind power. It should be noted this is a reduction on the figure for 2020 and can be attributed to two factors: an increase in demand and reduction in generation output from renewable sources. Total and normalised wind generation for Northern Ireland is detailed in Figure 3.5. This normalised annual energy has grown from 1,125 GWh in 2012 to 2,508 GWh in 2021, accounting for constraints and curtailment. Last year saw a decrease in wind generation compared to 2020, primarily due to the lower levels of wind availability.

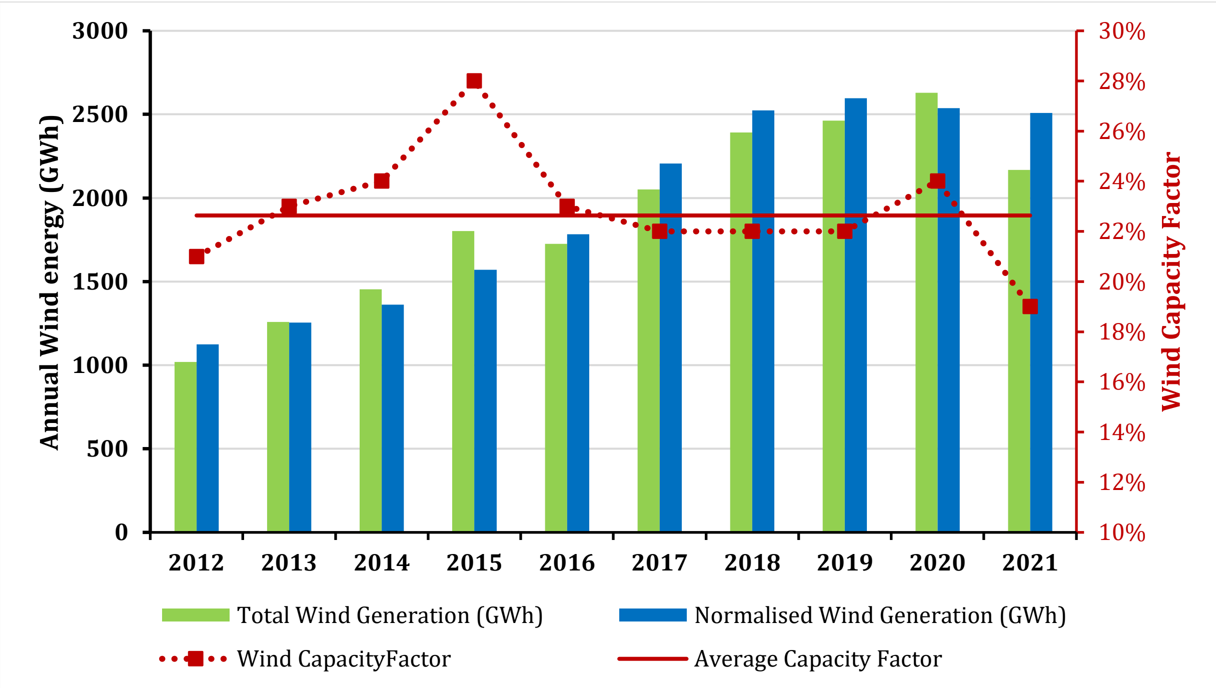

Figure 3.5 - The actual and normalised energy produced from wind power in Northern Ireland over the last ten years

SONI has based the future growth of renewable capacity on what would be required to achieve a 70% renewable ambition and aligns with government targets, as published in the SOEF v1[51] report.

[50] *https://www.bbc.com/news/av/uk-northern-ireland-57601499*
[51] *https://www.eirgridgroup.com/site-files/library/EirGrid/Shaping_Our_Electricity_Future_Industry_Feedback_Summary.pdf*

These assumptions are detailed in Figure 3.6. The impact of higher renewable roll-out can be considered as part of the next Generation Capacity Statement.

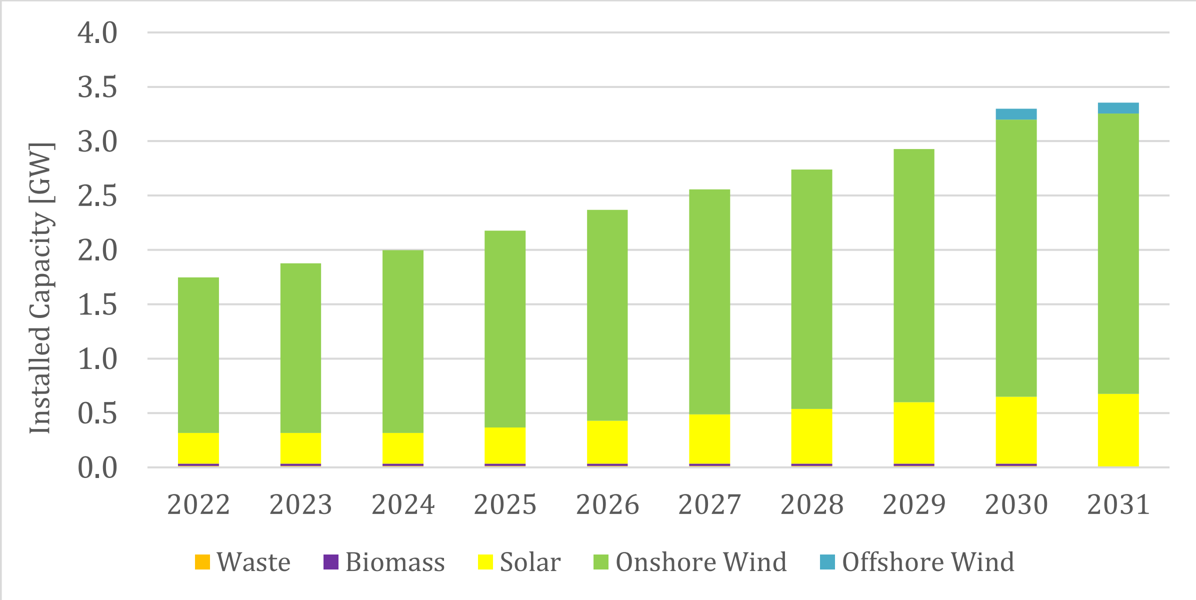

Figure 3.6 - Expected growth of renewable capacity installed in Northern Ireland.

3.7 Modelling of Non-Conventional Generation in Adequacy Studies

Wind, Solar and Interconnector modelling is based on a simplified methodology using de-rated capacity credits[52]. The de-rating factors are calculated as the average capacity adequacy value for a range of installed renewable capacities. EirGrid's and SONI's adequacy tool, AdCal, employs an efficient convolution model to build a generation probability distribution. It was developed mainly for power systems where the largest risk was the loss of a conventional plant. AdCal is best suited for assessing power systems that mainly consist of conventional power units complimented by a small number of simple storages like Turlough Hill.

AdCal allows for modelling a limited number of energy limited technologies, such as, battery storage or DSUs that help with peak shaving. As part of the Shaping Our Electricity Roadmap EirGrid and SONI identified a need to implement new modelling tools to address future adequacy needs in a power system with new risks not easily (if at all) modelled in AdCal.

For the purposes of interconnection in this adequacy study EirGrid and SONI assumes a 60% External Market de-rating and 2019 outage statistics as indicated in Table 3.8. The de-rating values used in AdCal studies are as follows:

Technology	De-rating value across 2022 - 2031
Wind	11% - 6%
Solar	13% - 5%

[52] *Half-hourly wind and solar generation profiles are developed for the forecast years; these are based on historical weather availability profiles and scaled to installed capacity for each forecast year. Adequacy calculations are carried on the portfolios with and without this generation. The capacity credit is selected as the difference in adequacy results. The reported capacity credits are calculated based on the total capacity of each technology*

Interconnectors	SEM <-> GB: 1000 MW_{rated} * EMDF* with Outage Statistics SEM <-> France: 700 MW_{rated} * EMDF *with Outage Statistics *Incorporates a 60% External Market De-Rating Factor (EMDF). See Table3.11 for outage statistics

Table 3.8 - De-rating values used in AdCal studies

3.8 Other Non-Conventional Generation

The assumed build-out of non-conventional generators is summarised in Appendix 3.

3.8.1 Demand Side Units (DSUs)

A DSU consists of one or more individual demand sites that can be dispatched as if it were a generator. An individual demand site is typically a medium to large industrial premises. A DSU Aggregator is able to contract with a number of individual demand sites and aggregate them together to operate as a single DSU. In the Capacity Market, DSUs typically are awarded 1-year contracts therefore the DSU capacity varies each year. Table 3.9 shows the DSU rated capacities assumed for the study horizon in Ireland and Northern Ireland. Note, the capacities from 2022 to 2026 are based on auction results. However, as auctions for the period 2027 onwards have yet to run, the studies use the 2026 value for the remainder of study horizon.

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ireland	604	639	589	727	662	662	662	662	662	662
Northern Ireland	143	136	165	225	234	234	234	234	234	234
Total	747	775	754	952	896	896	896	896	896	896

Table 3.9 - Ireland and Northern Ireland DSU Capacity (MW rated)

Industrial generation refers to generation usually powered by diesel engines, located on industrial or commercial premises, which act as on-site supply during peak demand and emergency periods. The condition and mode of operation of this plant is uncertain, as some of these units fall outside the control of the TSOs. Industrial generation has been ascribed a capacity of 9 MW in Ireland for the purposes of this report.

Dispatchable Aggregated Generating Units (AGU) operate in Northern Ireland, which consist of grouping together several individual diesel generators to make their combined capacity available to the market. In Northern Ireland, the total AGU capacity is 79 MW.

DSUs now form an increasing portion of the generation portfolio, therefore EirGrid and SONI will continue to engage with these capacity units in order to realise their full potential for contributing to system adequacy.

3.8.2 Energy Storage

There are two key revenue mechanisms by which battery projects are incentivised to connect to the SEM: SEM Capacity Auctions and DS3 System Services. These routes to market offer different but essential services to the power system on the island of Ireland.

The aim of DS3 System Services is to incentivise investments in all forms of generation that can provide all-island services that ensure the power system can operate securely with higher levels of non-synchronous renewable generation (up to 75% instantaneous penetration). In Ireland and Northern Ireland, the aim of the SEM Capacity Market is to ensure that sufficient existing and new capacity (including Storage, Demand Side Units, and Interconnector capacity) is delivered to balance demand and operational security requirement for the short-to-medium term. The Capacity Market procures capacity to meet the power system reliability standard. These mechanisms are designed to promote the interests of consumers of electricity across Ireland and Northern Ireland in respect of price, quality, reliability and security of supply of electricity.

Under the current DS3 System Services arrangements there are two means for batteries to contract, the Regulated Tariff (or Volume Uncapped) and the Volume Capped tariff. The Regulated Tariff under the current DS3 arrangements is available to any generator (including batteries) that passes testing for DS3 system services contracts. The Volume Capped tariff procurement process closed in 2019 and resulted in the award of fixed-term contracts to three battery projects totalling 110 MW for specific high availability reserve services. There are various batteries in different stages of development that are not under the Volume Capped or Capacity Market so are open to standard DS3 payments.

The following table provides a summary of the total assumed battery capacity that has been awarded contracts from the recent capacity auctions. Note all projects are offered either one or ten-year contracts, the table below takes this into consideration. Note, as auctions for the period 2027 onwards have yet to run, these studies use the 2026 value for the remainder of study horizon.

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ireland	31	264	261	621	737	737	737	737	737	737
Northern Ireland	192	192	124	166	166	166	166	166	166	166
Total	223	456	385	787	903	903	903	903	903	903

Table 3.10 - Total battery capacity successful in auctions (MW rated) for Ireland and Northern Ireland

3.8.3 Small scale CHP

Combined Heat and Power (CHP) uses generation plant to simultaneously create both electricity and useful heat. The overall efficiency of CHP plants is relatively high - often in excess of 80% - and its operation provides benefits in terms of reducing fossil fuel consumption and minimising CO_2 emissions.

There are approximately 160 MW of CHP units in Ireland, and these are included in the GCS 2022-2031 studies. These units are mostly gas-fired. For clarity, this small-scale CHP figure does not include 160 MW of centrally dispatched CHP plant operated by Aughinish Alumina.

In Northern Ireland, there is currently an estimated 9 MW of small-scale CHP connected to the distribution system (3 MW of which is renewable and 6 MW non-renewable). There is limited information available on future capacity. For the purpose of this statement, SONI assumes the current assumption on small-scale CHP capacity does not change over the next 10 years.

3.8.4 Biofuel

There are several different types of biofuel-powered generation plant on the island.

In Ireland, EirGrid currently estimates there is 24 MW of generation capacity powered by biofuel, biogas or landfill gas, with an additional 30 MW of biofuel units that are registered under DSU operators.

Bord Na Mona's Edenderry 118 MW unit is assumed to continue operation until 2030. This unit was recently awarded planning permission to operate as a 100% biomass unit from 2024. This unit is currently operating on a mix of peat and biomass. EirGrid assumes the unit uses a biomass percentage of 65% in 2022 and 2023, and 100% thereafter.

The Bord na Móna plant was due to close at the end of 2023. Planning permission was recently awarded to keep this unit operating until 2030, running on 100% biomass from 2024.

Currently in Northern Ireland, SONI estimates there is 46 MW of small-scale generation powered by biofuels, including biomass, biogas and landfill gas. For the purpose of this report, and in the absence of more detailed information, it is assumed this capacity will not change over the next 10 years.

In 2015, Lisahally Waste Project became operational in Northern Ireland. It is a wood-fuelled energy-from-waste/biomass combined heat and power plant with a capacity of approximately 18 MW. The plant is dispatchable and has been granted priority dispatch.

3.8.5 Large and Small-scale Hydro

EirGrid estimate there is currently 26 MW[53] of small-scale hydro capacity installed in rivers and streams across Ireland. This is a mature technology, however as there is the lack of suitable new locations, this factor limits future growth from hydro technologies. EirGrid assume there are no further increases in small hydro capacity over the 10 years of the study horizon. A large-scale hydro project, 360 MW Silvermines in County Tipperary, has been deemed a PCI project by the European Union[54]. This project has not been included in adequacy assessments, development of this project will be followed and included when appropriate.

In Northern Ireland, small-scale hydro capacity is around 6 MW. Northern Ireland's hydro capacity is generally derived from many small run-of-the-river projects. For the purpose of this report, SONI assumes this small-scale hydro capacity will not change across the 10 years.

3.8.6 Waste-to-energy

In Ireland, there are currently two waste-to-energy plants:

- Dublin Waste to Energy plant - 61 MW
- Indaver Waste to Energy plant - 17 MW

The GCS 2022-2031 assumes a 50% renewable content, thus contributing to our RES targets.

In Northern Ireland, there is currently one waste-to-energy plant:

- Full Circle Generation Waste to Energy plant at Bombardier - 15 MW.

3.8.7 Solar PV

In Ireland, EirGrid has assumed the amount of solar PV will grow linearly from 167 MW to reach 1.67 GW in 2031. This delivers 1.5 GW by 2030 in line with Shaping Our Electricity Future (SOEF) v1, which is based on Government targets contained within the Climate Action Plan 2019. A future 80% renewable share of electricity (RES-E) target is part of the Climate Action Plan 2021. The upcoming SOEF v1.1 report will provide insights on the renewable portfolio to reach the 80% RES-

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[53] *https://www.seai.ie/publications/2020-Renewable-Energy-in-Ireland-Report.pdf*
[54] *https://ec.europa.eu/energy/maps/pci_fiches/PciFiche_2.29.pdf*

E target. Subsequently, the impact of higher renewable roll-out can be considered as part of the next Generation Capacity Statement.

Northern Ireland has experienced a rapid growth in the capacity of Solar PV. SONI currently estimates Solar PV capacity at approximately 300 MW. For the purpose of this statement SONI has assumed capacity will grow to approximately 700 MW by 2031. SONI has based the future growth of renewable capacity on government targets as reported in SOEF v1, which targeted 70% RES-E.

Similar to the treatment of wind power, solar PV capacity is modelled in our adequacy assessments using a capacity credit, as discussed in Section 3.6.

3.8.8 Marine Energy

In Ireland, there is a high degree of uncertainty associated with this new emerging technology. EirGrid has taken the conservative approach and assumed there are no commercial marine developments within the study horizon of this statement.

In Northern Ireland, the Crown Estate awarded development rights for sites off the North Coast close to Torr Head and Fair Head. At present, there are no connection offers in place for tidal projects. Therefore, for this report, SONI has not included any marine capacity within our adequacy studies. SONI will continue to monitor its status with a view to incorporating it into future studies.

3.9 Plant Availability

Outage statistics for the SEM Capacity Market Requirement are determined at a technology class level using 5-year run hour weighted averages of forced outage, scheduled outage rates and availability data for all technology classes, excluding DSUs (which are given system-wide outage statistics) and pumped storage hydro (based on 10 years of data). 5-year run hour weighted averages per technology class are shown in Table 3.11.

Technology Category	Mean Forced Outage Probability (%)	Mean Scheduled Outage Rate (weeks)
DSU	7.8%	3
Gas Turbine	5.1%	2
Hydro	4.5%	6
Steam Turbine	14.2%	3
Pumped Storage	7.4%	3
System Wide	7.8%	3
Interconnector	7.5%	2

Table 3.11– Summary of availability parameters used in the T-4 2025/2026 Capacity Market auction

In 2021, EirGrid and SONI have observed a further decline in the All-Island system average availability of thermal plant compared with the GCS 2021-2030; where the observation of the downward trend in lower plant availability was also highlighted. DSU performance has remained largely consistent with previous reported values. For thermal plant in particular, forced plant outages of two high-capacity units brought the 365-day rolling capacity weighted system availability down to a low of 64% in the month of November 2021.

Figure 3.7 shows system-wide availability in Ireland and Northern Ireland which has been decreasing for the past number of years. This affects generation plant ability to provide maximum adequacy support to demand.

Historically, the adequacy calculation for the generation capacity statement has relied on 5-year run hour weighted technology class outage rates used in the most recent completed capacity auction. For all existing units (including interconnectors), this year's GCS 2022-2031 has used outage rates in line with EirGrid and SONI's security of supply studies which better reflect deteriorating plant and are based on the 2019 outage statistics. This year was chosen as 2020 and 2021 were deemed to be very unusual years for outages (i.e., due to Covid restrictions and two large unit outages occurring simultaneously in 2021). An updated methodology for calculating outage statistics is currently in review. New units use outage statistics as per auction parameters outlined in Table 3.11. Note, the specific outages for every unit are presented in the accompanying GCS 2022-2031 data workbook.

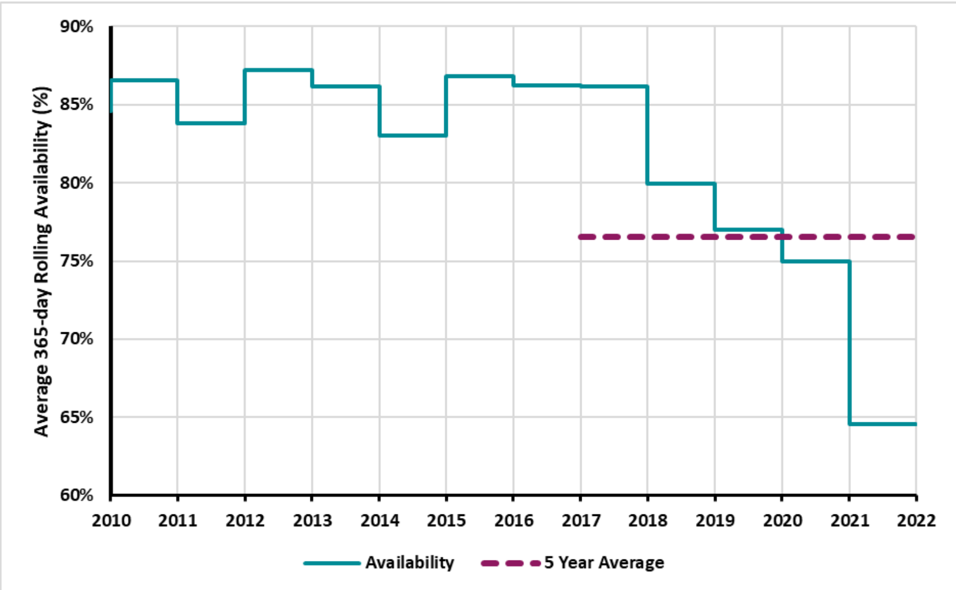

Figure 3.7 - The average 365-day annual system-wide availability in Ireland and Northern Ireland

Forced Outage Rates have been increasing over the past number of years, linked to the system availability falling. This is displayed in Figure 3.8.

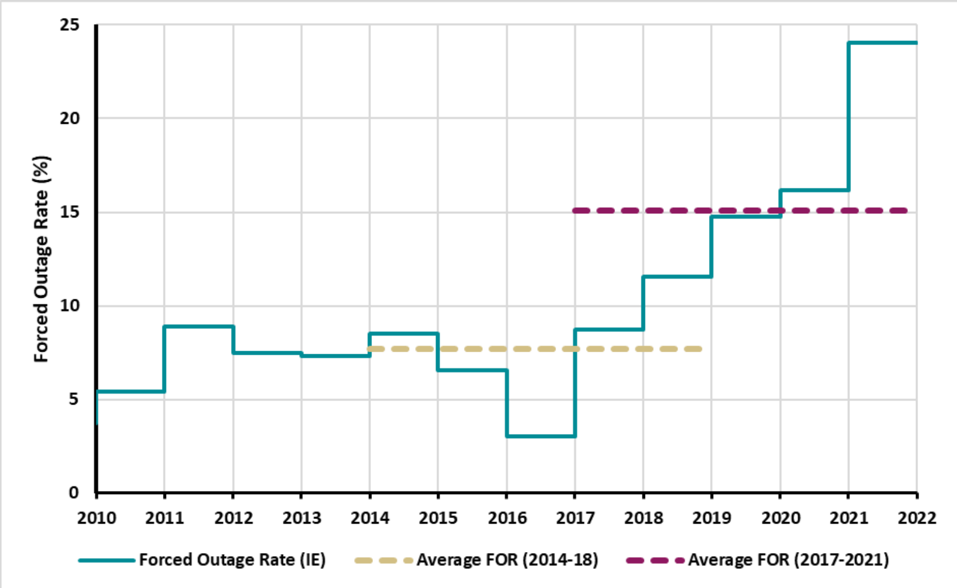

Figure 3.8 - Average annual system-wide Forced Outage Rates in Ireland for each of the past 13 years

For comparison, see the system-wide average Forced Outage Rates in Northern Ireland in Figure 3.9.

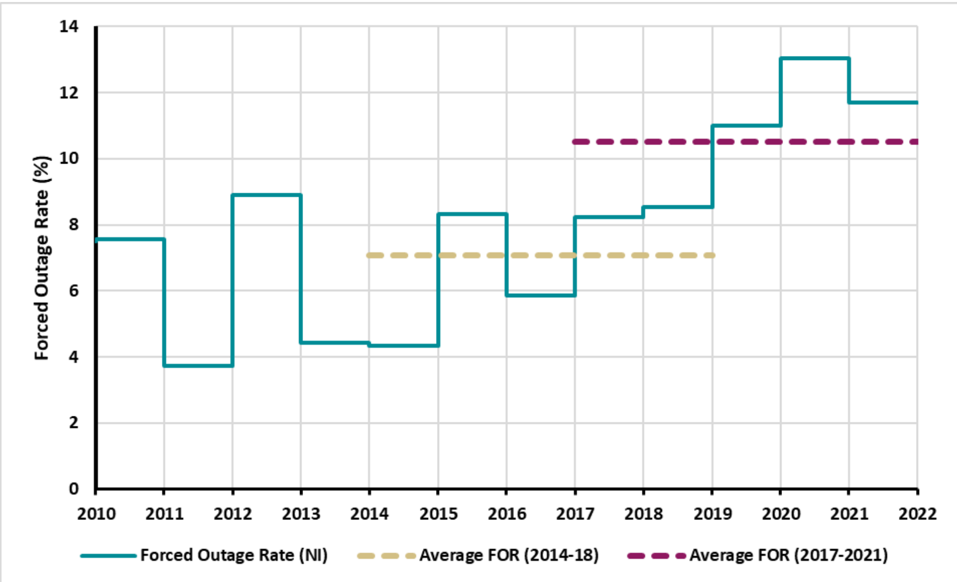

Figure 3.8 - Average annual system-wide FOR in Northern Ireland for each of the past 13 years

In Ireland and Northern Ireland, on average, there has been a deterioration of unit availability over the last number of years. EirGrid and SONI have both observed a continued deterioration of conventional plant unit availability and this was particularly acute in Ireland across 2021, where several large units were forced offline for extended periods of time. Figure 3.10. shows the deteriorating availability trends across the last 4 years for Ireland and Northern Ireland. Figure 3.8 also captures the very low availability of Ireland’s thermal units in 2021, the availability was adversely impacted due to several long duration outages from a number of large thermal units.

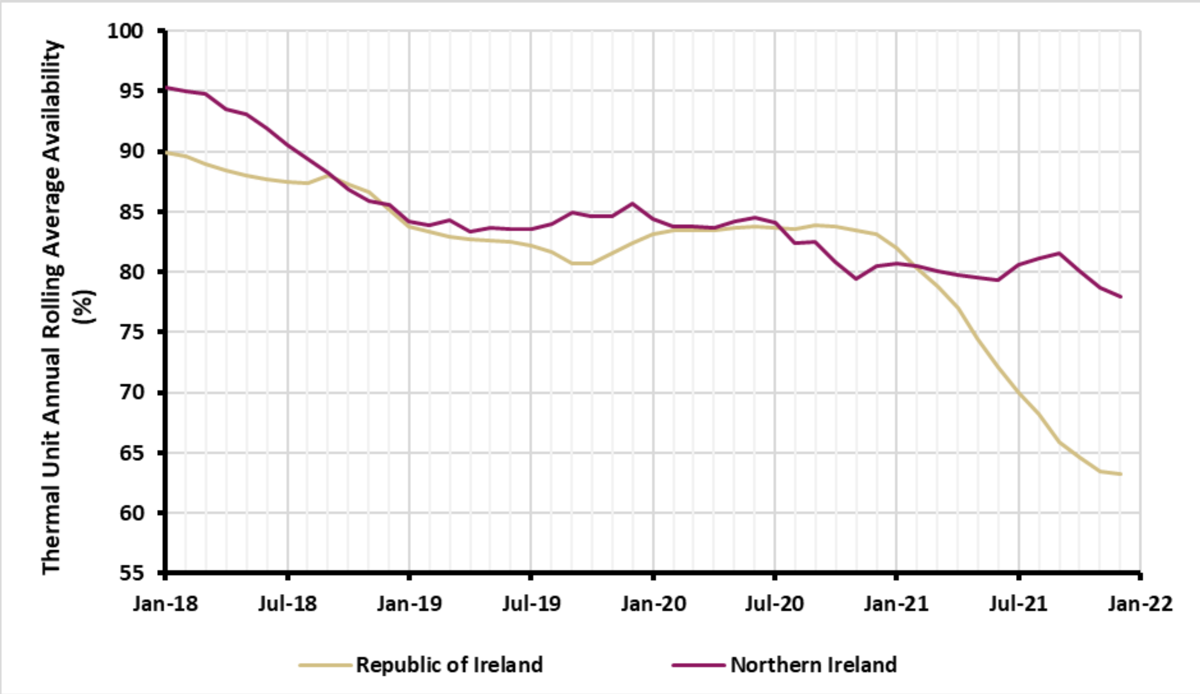

Figure 3.10- Ireland and Northern Ireland Conventional Unit Availability

4. Adequacy Assessments

4.1 Introduction

Security of supply is a high priority for EU Member States, Policy Makers within DECC and DfE, RAs and TSOs. Under current EU legislation[55] there is an obligation on each Member State to monitor the security of electricity supply within their territory over the medium to long-term and each member state is entitled to set and monitor the level of security of supply deemed appropriate for its own needs. EU Member states have the responsibility to comply with the requirements of the EU Target Model, which is designed around forward, intra-day and balancing markets. In Ireland[56] and Northern Ireland[57], the TSOs are required to report and advise on security of supply in electricity through adequate planning and operation of transmission capacity. This reporting is reviewed by the Regulatory Authorities in Ireland and Northern Ireland and approved by the Utility Regulator in Northern Ireland. The legislation continues to apply in Northern Ireland following the UK's departure from the European Union, as specified in Annex 4 of the Northern Ireland Protocol[58].

At present, the generation security standard is evaluated for the SEM as a whole, as well as separately for Ireland and Northern Ireland, using the following security standards:

- SEM: 8 hours LOLE
- Ireland: 8 hours LOLE
- Northern Ireland: 4.9 hours LOLE

We study generation adequacy in order to assess the balance of supply and demand in the future. The assumptions made in the last two chapters for supply and demand are now brought together in our adequacy assessments. Detail on the methodology we employ is given in Appendix 5.

Studies are carried out in three different ways:

- for Northern Ireland alone,
- for Ireland alone, and
- For both jurisdictions combined, i.e. on an All-Island basis.

In this section, we describe the setup of each scenario and present the results of the adequacy studies in graphical format. It is important to acknowledge the shifting nature of adequacy year-on-year. As a result, this document is updated annually.

The core scenarios of this year's GCS 2022-2031 take a more pragmatic view and considers factors such as current power plant availability (use of historical 2019 statistics), deliverability risks of new capacity becoming available on time, the impact of ARHL and need to ensure there is sufficient capacity to cover operational requirements. The core scenarios of this year's GCS 2022-2031 align with the assumptions of security of supply studies in GCS 2021-2030.

4.2 Assumptions

In our adequacy studies, we assume the following:

- The adequacy standard is set at 8 hours LOLE per year for Ireland and in the All-Island case. Ireland only study assumes a 100 MW capacity reliance on Northern Ireland.

[55] *Directive 2019/944 and Regulation (EU) 2019/941*
[56] *Statutory Instrument 60 of 2005*
[57] *https://www.uregni.gov.uk/files/uregni/documents/2022-01/2022-01-17-soni-tso-consolidated.pdf*
[58] *Part of the Withdrawal Agreement between the UK and the EU*

- For Northern Ireland, the standard is 4.9 hours LOLE and assumes a 200 MW capacity reliance from Ireland.
- Wind, Solar and Interconnector modelling is based on a methodology using de-rated capacity credit equivalent values, as approved by the SEM Committee[59].
- The portfolio excludes generation capacity that has notified us that they will not be available.
- AdCal was developed mainly for conventional plant and pumped storage units, such as Turlough Hill, and does not capture the variability of renewable energy sources or Interconnectors.
- AdCal looks at capacity adequacy and does not account for network related issues.
- The assessments were carried out for low, median and high demand core scenarios.
- The availability statistics for all existing units are based on historical 2019 data. New unit availability statistics matches those used in the Capacity Market auction, i.e. 5-year average values for each technology category unless otherwise stated for sensitivity study purposes.
- The adequacy results are given in MW as a surplus (+) or deficit (-) of perfect plant (plant that is 100% available).

Key Assumption Updates for GCS 2022-2031:

- For the purposes of this adequacy study EirGrid and SONI assumes a 60% External Market de-rating plus 2019 forced and scheduled outage statistics for interconnectors between the All-Island system and Great Britain.
- Celtic Interconnector assumes a 420 MW capacity credit (60% External Market de-rating), plus appropriate forced and scheduled outage statistics.
- DSU and battery modelling uses AdCal's energy limited modelling functionality, which models the effect of peak shaving from these technology types.
- The portfolio excludes generation capacity that has a high likelihood of retirement based on an economic assessment of failing to qualify for a capacity auction.
- Annual run hour limitations (ARHL) are modelled on applicable[60] new plants that are expected to run in the market. ARHL is not modelled on Open Cycle Gas Turbines which are normally used for replacement reserve to the system.
- In this year's GCS 2022-2031, for the core scenarios we have included reserves and operational requirement across all study years for reasons set out below.
    - For Ireland, this amounts to 375 MW of reserve across all years, from 2025 EirGrid include an additional 350 MW transmission outage planning requirement; to facilitate outages needed to connect new generation and infrastructure to deliver on government 2030 renewable targets. In 2027 we assume the Celtic Interconnector becomes the largest single infeed resulting in a change to the reserve requirement increasing by 150 MW to 525MW.

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[59] https://www.semcommittee.com/sites/semc/files/media-files/SEM-18-030a%20Appendix%20A%20TSO%20Capacity%20Requirement%20and%20De-rating%20Factors%20Methodology%20June%202018.pdf

[60] *Kilroot KGT6 and KTG7 Open Cycle Gas Turbines limited to 1500 hours as advised by the developer. As of data freeze date, we are aware of a developer with an Open Cycle Gas Turbines limited to 200 hours per planning application, and another developer with an Open Cycle Gas Turbine limited to 1500 hours per planning application*

    - In Northern Ireland, SONI assumes an operational requirement of 200 MW across all years and this is now included as part of the assessment.
-

4.3 Changes Post Data Freeze Date

Ireland

As part of EirGrid's role in managing security of supply, EirGrid is continuously monitoring deliverability and progress of generation and new large demand projects. Since the data freeze, a number of items have changed including:

- one new tech load signing an updated connection agreement to ramp slower than originally contracted for;
- one generator will be delayed in delivery of their new capacity;
- recent engagement with one gas turbine developer has confirmed their units will have unrestricted running while remaining compliant with BAT conclusions and planning requirements.

These impacts were not captured in the GCS 2022-2031, however they are being monitored as part of the ongoing security of supply work with the Commission for Regulation of Utilities (CRU) and the Department for the Environment, Climate and Communications.

On 28th July 2022, the Irish government announced legally binding sectoral emissions ceilings*, setting Ireland on a pathway to turn the tide on climate change. To accelerate emissions reduction the agreement commits to additional resources for solar, offshore wind, green hydrogen, agro-forestry and anaerobic digestion. The Climate Action and Low Carbon Development (Amendment) Act 2021 make provision for the development of Sectoral Emission Ceilings and the introduction of Carbon Budgets. An assessment is required around how the future demand projections and renewable targets deliver on these carbon budgets and this is being assessed as part of Shaping our Electricity Future.

Northern Ireland

New capacity coming through the capacity auctions are required to provide Implementation Progress Reports (IPR) to the TSOs, as outlined in the Capacity Market Code. Following the GCS freeze date, the developer informed SONI of delays to this new capacity at Kilroot. SONI is currently engaging with the developer to understand the extent of the delay. As outlined in the adequacy assessments any delays to this new capacity will negatively impact on the adequacy position for Northern Ireland.

***https://www.gov.ie/en/press-release/dab6d-government-announces-sectoral-emissions-ceilings-setting-ireland-on-a-pathway-to-turn-the-tide-on-climate-change/**

4.4 Adequacy Results for Ireland

The adequacy assessment of Ireland system shows an initial deficit position in all of the core scenarios and remains in deficit over the study horizon.

The median demand scenario is a central scenario that EirGrid plans to. Taking this scenario as a reference we observe significant capacity deficits in 2024 and 2025. These shortfalls are driven by a number of existing generation plant leaving the system and strong demand growth which is forecast to be 180 MW/year up to 2025; this is 40 MW per year higher than the same forecast period in GCS 2021-2030. Across all scenarios, significant deficits exist for the remainder of the decade.

By 2026, we observe a forecast decrease in the deficit as new capacity units are expected to enter the system, but the deficit remains very significant. The benefit of this new capacity is somewhat tempered by the increasing demand (average of 90 MW/year in the median scenario between 2026-2031) and the impact of expected annual run hour limitations (ARHL) on some of the new capacity units. It should be noted that the new T-4 capacity auction will cover the period from October 2026 to September 2027 and this will run later in 2022. Further new capacity may come forward as part of this auction, which would further reduce the deficit.

In 2027, the energisation of the Celtic Interconnector reduces the deficit further. Beyond 2028, the deficits increase each year due to the increasing demand. The results are provided in Table 4.1. The core scenario trends can be seen in Figure 4.1.

For GCS 2022-2031, as part of the reliability assessment, EirGrid has factored in the realities in the operation of the transmission system to cater for operational requirements such as reserve. For Ireland this reserve requirement is 375 MW until the end of 2026 then increasing to 525 MW. A transmission outage planning requirement of 350 MW is included from 2025 across the remainder of the study period. For Ireland the total operational requirement by 2031 is 875 MW. As noted earlier, the median scenario provides a view of what is required to support Ireland's transition to low carbon economy and low emissions power sector. To this end, EirGrid has carried out a number of sensitivity studies on the median demand scenario.

The first sensitivity shows the impact of assuming no capacity support from Northern Ireland. Typically, this is assumed to be 100 MW in all scenarios. As the margins in both jurisdictions are becoming tighter, there is a possibility that this support through the existing North-South Interconnector may not be available.

Further sensitivities look at the impact of no ARHL on new capacity delivering in 2026 or assuming that there are no delays in new capacity delivering. It is worth stating that 10-year capacity contracts have an 18 month long stop which means that delivery can be up to 18 months after commencement of the capacity year. In the second scenario where no ARHL are assumed on new capacity delivering in 2026, EirGrid observe that deficit in the median scenario is reduced by 450 MW. The third scenario layers in an optimistic assumption that all capacity delivers on time. In this scenario it can be observed that deficits start to reduce a year earlier in 2024 starting with a reduction of 150 MW; this is reduced by 1000 MW by 2025. These sensitivities indicate either late delivery of capacity or the application of ARHL will require additional measures to reduce deficits. These measures are outside the scope of this report.

There is an EirGrid Grid Code requirement for generating units to provide the TSO with 3 years notice prior to closure. For this sensitivity we assume that ESB keeps Moneypoint open until the end of the 2025 calendar year, which would equate to 3 years notice. The last sensitivity provided highlights the forecast outcome of Moneypoint remaining open until 2025.

EirGrid also notes that the results presented here do not include any of the mitigating measures, such as temporary generation, demand side response or keeping existing units open, which are being investigated as part of the ongoing security of supply workstreams with CRU. The "CRU Information Paper Security of Electricity Supply – Programme of Actions"[61] published on 29 September 2021 captures the proactive response. As part of these actions the CRU has directed EirGrid to procure Temporary Emergency Generation to help mitigate the clear risks presented by the current security of supply challenges. This generation can only be used in emergency situations and therefore is not intended to be available to meet growing and enduring demand due to social or economic growth. It will, however, provide critical insurance and will be called upon in the event of a shortfall in market-based capacity and where alerts on the system are likely. Alerts occur where the buffer between electricity supply and demand is tighter than is prudent to maintain a secure system.

Core Scenarios	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Low Demand	-270	-300	-600	-1090	-900	-720	-790	-790	-810	-930
Median Demand	-380	-530	-940	-1490	-1280	-1140	-1280	-1340	-1420	-1600
High Demand	-510	-720	-1230	-1820	-1700	-1660	-1850	-1930	-2030	-2220
Sensitivities on Median Demand										
No NS Availability	-480	-630	-1040	-1590	-1380	-1240	-1380	-1440	-1520	-1700
No ARHL	-380	-530	-940	-1490	-850	-710	-840	-900	-980	-1170
No ARHL, No Capacity Delays or Terminations	-380	-530	-840	-470	-410	-360	-490	-540	-620	-830
MP Available in 2025	-380	-530	-940	-1110	-1280	-1140	-1280	-1340	-1420	-1600

Table 4.1 - Results of adequacy studies for Ireland, given in MW of surplus plant (+) or deficit (-)

61 *https://www.cru.ie/wp-content/uploads/2021/09/CRU21115-Security-of-Electricity-Supply-%E2%80%93-Programme-of-Actions-1.pdf*

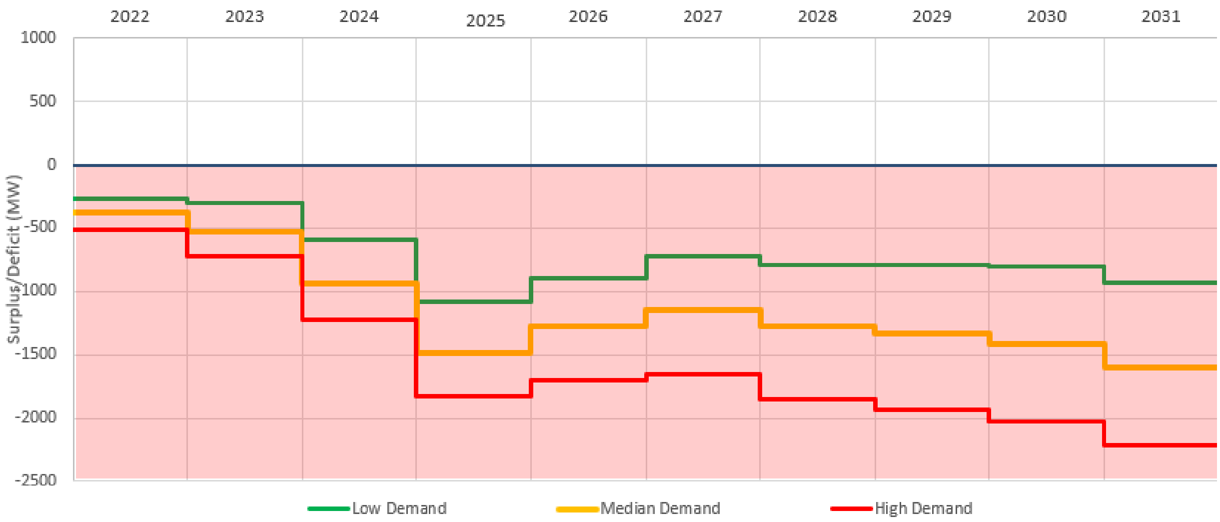

Figure 4.1 – Core scenario adequacy results for Ireland, in terms of surplus or deficit of plant.

As the system moves into adequacy deficits, there is a much greater loss of load expectation (LOLE). The LOLE for the median scenario is presented in Table 4.2. Note the results here do not give a sense of the scale or duration of the LOLE as this is calculated cumulatively across each hour of the year. A full description of the LOLE methodology is outlined in Appendix 5.

LOLE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Median	57	118	593	3,475	2,516	1,567	2,306	2,705	3,273	4,693

Table 4.2 - Loss of Load Expectation (LOLE) for Ireland in the median scenario

4.5 Adequacy Results for Northern Ireland

The adequacy assessment of the Northern Ireland system shows an initial slight surplus in the median scenario, before dropping to deficit for 2024 and 2025. From 2026 all the core scenarios are in surplus for the remainder of the study horizon. Figure 4.2 shows a graphical representation of the adequacy studies' results for Northern Ireland over the ten years of the study.

The median demand scenario is shown to be marginally in surplus against the 4.9 hour LOLE standard in the first two years. This is a reduction compared to the GCS 2021–2030 as the existing coal/oil fired capacity has a restriction on its output due to environmental licencing.

The capacity outlook drops into deficit in 2024 and 2025 as the existing coal/oil fired generation closes and the new OCGTs will have ARHL or 1500 hours on average per annum.

In 2026, the outlook returns to a surplus of approximately 500 MW for the remaining years of the study. This is because in the 2025/26 T-4 capacity auction a steam turbine was successful. Based on discussions with the developer this will be utilised as part of a CCGT arrangement whereby it would utilise waste heat from the new KGT6 and KGT7 Open Cycle Gas Turbines. The developer is currently working through the design of the system, however, since the capacity was cleared as part of a CCGT arrangement, SONI have assumed the new capacity will remove all ARHL associated with KGT6 and KGT7.

It should be noted that as part of the adequacy assessment SONI is assuming the timely delivery of the new capacity at KGT6 that was successful in the 2023/24 T-4 from the start of 2024. We also assume early delivery of the KGT7 which cleared in the 2024/25 T-4 capacity auctions from the start of 2024, as well as the generation that was successful in the 2025/26 T-4 capacity auction from the start of 2026. This is based on the latest available information from the developer at the time of the data freeze. Any delays to this new capacity will significantly impact negatively on capacity adequacy in Northern Ireland.

Furthermore, we assume once the CCGT is in place from 2025/26 that all run hour restrictions are removed. This is based on information from the developer. For GCS 2022-2031, as part of the reliability assessment, SONI has factored in the realities in the operation of the transmission system to cater for operational requirements such as reserve. For Northern Ireland this reserve requirement is 200 MW.

SONI has completed a range of adequacy scenarios studies to assess the risk to security of supply in Northern Ireland. The studies presented provide an indication of Northern Ireland's adequacy position based on a range of credible scenarios,

- Loss of tie-line support from Ireland. In this scenario the overall surplus is reduced by 200 MW. This is a credible operational risk given the capacity issues highlighted in the Ireland's security of supply studies. A scenario assuming loss of tie-line support from Ireland with the average annual 1500 running hour restriction on the new Kilroot capacity not removed in 2026. A scenario assuming new generation from the SEM CRM auctions is delayed by a one year period in the Median demand scenario.

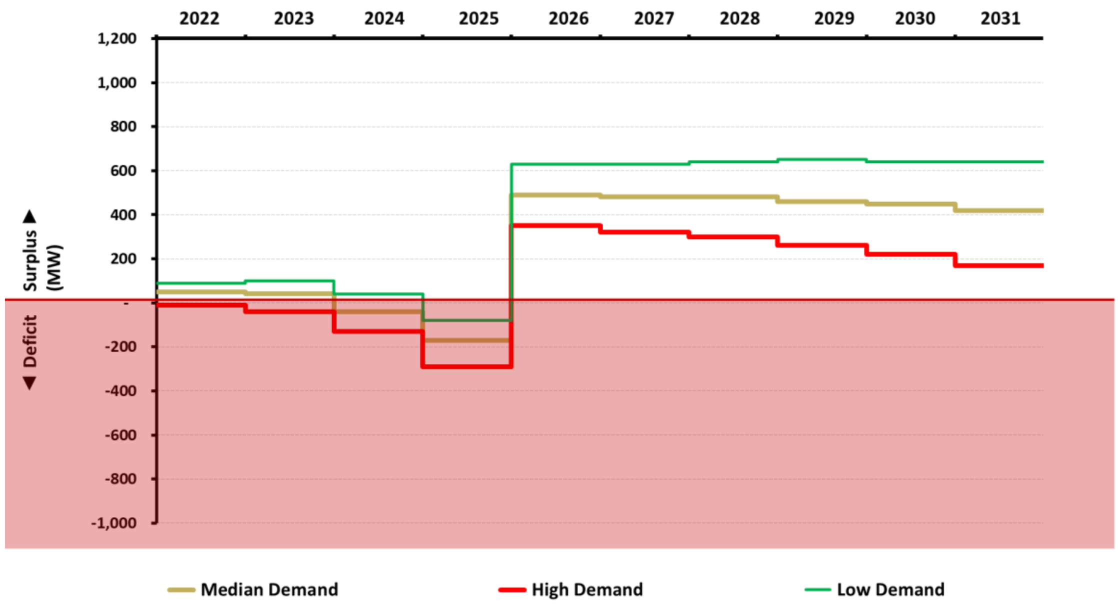

Figure 4.2 Adequacy results for Northern Ireland, in terms of surplus or deficit of plant (MW)

Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Low Demand	90	100	40	-80	630	630	640	650	640	640
Median Demand	50	40	-40	-170	490	480	480	460	450	420
High Demand	- 10	-40	-130	-290	350	320	300	260	220	170
Sensitivities on Median Demand										
No NS Reliance	-150	-160	-240	-370	290	280	280	260	250	220
No NS Reliance & ARHL from 2026	-150	-160	-240	-370	-250	-260	-270	-280	-300	-320
Late Delivery	50	40	-150	-170	-80	480	480	460	450	420

Table 4.3 - Results of adequacy studies for Northern Ireland, given in MW of surplus plant (+) or deficit (-)

LOLE	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Median Demand	2.9	3.1	7.8	31.1	0	0	0	0	0	0

Table 4.4 - Results of adequacy studies for Northern Ireland, given in Hrs of LOLE.

4.6 Adequacy Results for the All-Island System

Adequacy studies are carried out on an All-Island basis, which assumes that the second North-South Interconnector is available. The second North-South Interconnector is assumed to be commissioned by end of 2025 and become fully operational by 2026. The Celtic Interconnector is assumed to be operational from 2027.

In the All-Island case, the surplus for any particular year is greater than the sum of the two separate jurisdictional studies. This capacity benefit demonstrates some of the advantages of the second North-South Interconnector. Figure 4.3 and Table 4.5 show the All-Island adequacy results for the core scenarios. The median and high scenarios see a deficit from 2026 onwards. The low demand scenario sees a surplus across the study horizon. The benefit from the Celtic Interconnector is seen in 2027. From 2027 onwards, the changes in adequacy position are driven primarily by the demand changes. Table 4.6 shows the LOLE for the study horizon.

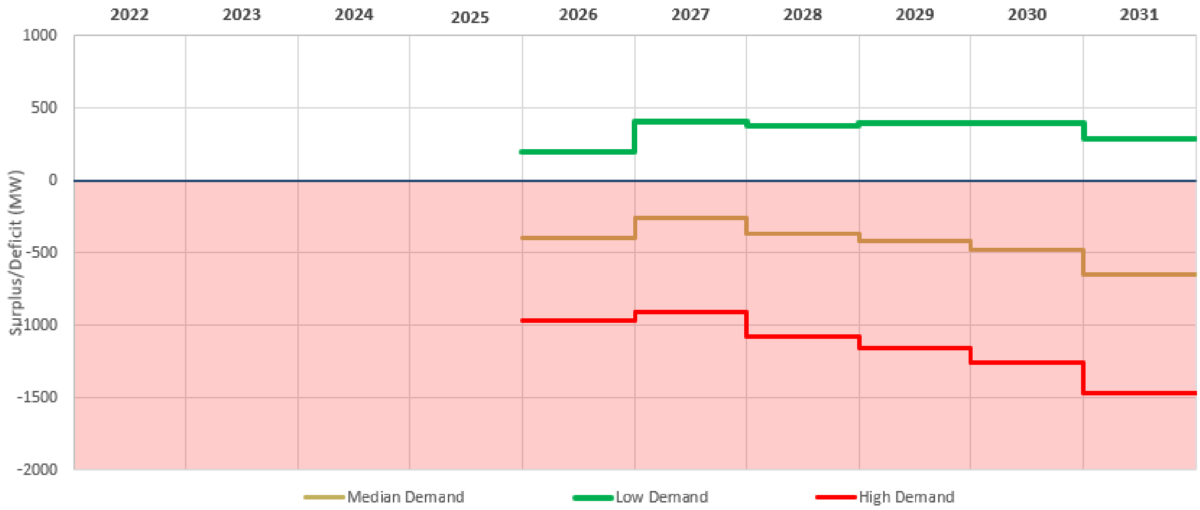

Figure 4.3 - Adequacy results for the All-Island system

Scenario	2026	2027	2028	2029	2030	2031
Low Demand	200	410	370	400	400	290
Median Demand	-400	-260	-370	-420	-470	-640
High Demand	-960	-900	-1080	-1160	-1260	-1460

Table 4.5 - Results of adequacy studies for the All-Island system (MW)

LOLE	2026	2027	2028	2029	2030	2031
Median Demand	60	30	49	62	79	164

Table 4.6 - Loss of Load Expectation (LOLE) for All-Island System (hours)

Appendix 1 Demand Scenarios

Table A-1 - The Median Demand Forecast, given in Calendar year format (including a correction to 366 days in each Leap year), for Total Electricity Requirement (TER). TER is the total electricity required by the region, i.e. it includes all electricity produced by large-scale, dispatchable generators, all small-scale exporting generators, and an estimate of electricity produced by self-consuming generators.

Median	Calendar year TER (TWh)						TER Peak (GW)			Transmission Peak (GW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
2021	31.7		8.58		40.3		5.65	1.66		5.53	1.62	
2022	33.7	6.4%	8.75	2.0%	42.5	5.5%	5.84	1.68	7.45	5.73	1.64	7.34
2023	35.7	5.8%	8.92	1.9%	44.6	4.9%	6.10	1.70	7.73	5.99	1.66	7.62
2024	37.5	5.1%	9.12	2.3%	46.6	4.5%	6.37	1.72	8.02	6.25	1.68	7.90
2025	38.5	2.6%	9.27	1.6%	47.8	2.6%	6.52	1.74	8.19	6.40	1.70	8.07
2026	39.9	3.6%	9.61	3.7%	49.5	3.6%	6.57	1.78	8.28	6.45	1.75	8.16
2027	41.3	3.5%	9.74	1.4%	51.0	3.0%	6.69	1.80	8.42	6.57	1.77	8.30
2028	42.7	3.5%	9.90	1.6%	52.6	3.1%	6.79	1.82	8.54	6.68	1.79	8.43
2029	43.9	2.7%	10.02	1.2%	53.9	2.5%	6.90	1.85	8.68	6.78	1.81	8.56
2030	45.1	2.7%	10.17	1.5%	55.2	2.4%	6.99	1.87	8.79	6.87	1.83	8.67
2031	46.1	2.3%	10.41	2.4%	56.5	2.4%	7.06	1.90	8.89	6.94	1.86	8.77

Table A1-1 Median Demand Forecast

Low	Calendar year TER (TWh)						TER Peak (GW)			Transmission Peak (GW)		
Year	**Ireland**		**Northern Ireland**		**All-Island**		**Ireland**	**Northern Ireland**	**All-Island**	**Ireland**	**Northern Ireland**	**All-Island**
2021	31.7		8.58		40.3		5.65	1.66		5.53	1.62	
2022	33.0	4.1%	8.51	-0.8%	41.5	3.0%	5.69	1.60	7.22	5.58	1.56	7.11
2023	34.1	3.3%	8.51	0.0%	42.6	2.7%	5.80	1.60	7.33	5.68	1.56	7.21
2024	35.4	3.9%	8.53	0.3%	44.0	3.3%	5.89	1.60	7.42	5.78	1.56	7.31
2025	36.0	1.8%	8.51	-0.3%	44.6	1.4%	5.93	1.60	7.46	5.81	1.56	7.34
2026	37.0	2.5%	8.53	0.2%	45.5	2.0%	5.94	1.60	7.47	5.82	1.57	7.35
2027	37.8	2.2%	8.54	0.1%	46.3	1.8%	5.97	1.61	7.51	5.86	1.57	7.40
2028	38.6	2.3%	8.57	0.4%	47.2	1.9%	6.01	1.61	7.55	5.89	1.57	7.43
2029	39.3	1.6%	8.57	0.0%	47.8	1.3%	6.03	1.61	7.57	5.92	1.58	7.46
2030	40.0	1.8%	8.58	0.1%	48.5	1.5%	6.06	1.62	7.60	5.94	1.58	7.49
2031	40.6	1.6%	8.59	0.1%	49.2	1.4%	6.07	1.62	7.62	5.95	1.59	7.50

Table A1-2 Low Demand Forecast

High	Calendar year TER (TWh)						TER Peak (GW)			Transmission Peak (GW)		
Year	**Ireland**		**Northern Ireland**		**All-Island**		**Ireland**	**Northern Ireland**	**All-Island**	**Ireland**	**Northern Ireland**	**All-Island**
2021	31.7		8.58		40.3		5.65	1.66		5.53	1.62	
2022	34.4	8.4%	8.99	4.8%	43.4	7.7%	6.03	1.79	7.75	5.91	1.76	7.63
2023	37.2	8.3%	9.40	4.6%	46.6	7.4%	6.31	1.82	8.06	6.19	1.78	7.94
2024	40.1	7.6%	9.85	4.8%	49.9	7.0%	6.65	1.84	8.42	6.54	1.80	8.31
2025	41.6	3.8%	10.23	3.9%	51.8	3.8%	6.82	1.90	8.65	6.71	1.86	8.54
2026	43.6	5.0%	10.75	5.1%	54.4	5.0%	6.98	1.97	8.88	6.86	1.93	8.76
2027	45.6	4.4%	11.03	2.6%	56.6	4.0%	7.15	2.01	9.09	7.04	1.98	8.98
2028	47.4	4.1%	11.35	2.9%	58.8	3.9%	7.30	2.06	9.29	7.19	2.02	9.18
2029	48.8	2.9%	11.63	2.5%	60.4	2.7%	7.43	2.11	9.47	7.31	2.07	9.35
2030	50.1	2.7%	11.95	2.8%	62.1	2.8%	7.53	2.15	9.61	7.42	2.12	9.50
2031	51.2	2.1%	12.36	3.4%	63.5	2.3%	7.60	2.21	9.74	7.49	2.17	9.63

Table A1-3 High Demand Forecast

Appendix 2 Auction Results

Table A2-1 outlines the results of the Capacity Market auctions since 2017.

Auction	Date	Awarded Capacity (De-Rated)
2018/2019 T-1	15/12/2017	7.774 GW[i]
2019/2020 T-1	13/12/2018	8.266 GW[ii]
2020/2021 T-1	26/11/2019	7.606 GW[iii]
2021/2022 T-2	5/12/2019	7.512 GW[iv]
2022/2023 T-4	28/03/2019	7.412 GW[v]
2023/2024 T-4	27/04/2020	7.322 GW[vi]
2024/2025 T-4	21/01/2021	6.168 GW[vii]
2022/2023 T-1	21/10/2021	1.121 GW[viii]
2024/2025 T-3	20/01/2022	1.471 GW[ix]
2025/2026 T-4	24/03/2022	6.484 GW[x]

Table A2-1 Capacity Market Auction Results

Auction Termination Notices

Since the GCS 2021-2030, a further 364 MW of de-rated capacity has terminated. This means that a total of approximately 650 MW has now terminated. The contracts listed below have issued termination notices since 2021 in addition to those identified in GCS 2021-2030. These contracts have been removed from the studies.

Plant	Technology Type	SEM CRM Auction	Awarded New Capacity Terminated (MW)	Termination issued
ESB-FlexGen	Gas Turbine	T-4 22/23	192.36[xi]	2021
EnerNoc	DSU	T-4 22/23	60.70[xii]	2021
ESB	Gas Turbine	T-4 23/24	11.49[xiii]	2021
ESB	Gas Turbine	T-4 24/25	10.14[xiv]	2021
EnerNoc	DSU	T-2 21/22	2.64[xv]	2021
Statkraft	Gas Turbine	T-4 24/25	45.10[xvi]	2021
EnerNoc	DSU	T-2 21/22	1.51[xvii]	2021
Energia	Gas Turbine	T-4 23/24	17.64[xviii]	2022
EnerNOC	DSU	T-4 23/24	12.15[xix]	2022
Rhode Energy Storage	Battery	T-4 24/25	14.25[xx]	2022
	Total		**367.98**	

Table A2-2 - Units issued with Termination Notices since 2021 in addition to those identified in GCS 2021-2030

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[i] *https://www.sem-o.com/documents/general-publications/Capacity-Market-Final-Capacity-Auction-Results-Report_FCAR1819T-1.pdf*
[ii] *https://www.sem-o.com/documents/general-publications/T-1-2019-2020-Final-Capacity-Auction-Results-Report.pdf*
[iii] *https://www.sem-o.com/documents/general-publications/T-1-2020-2021-Final-Capacity-Auction-Results-Report.pdf*
[iv] *https://www.sem-o.com/documents/general-publications/T-2-2021-2022-Final-Capacity-Auction-Results-Report.pdf*
[v] *https://www.sem-o.com/documents/general-publications/T-4-2022-2023-Final-Capacity-Auction-Results-Report.pdf*
vi https://www.sem-o.com/documents/general-publications/T-4-2023-2024-Final-Capacity-Auction-Results-Report.pdf

vii https://www.sem-o.com/documents/general-publications/T-4-2024-2025-Final-Capacity-Auction-Results-Report.pdf
viii https://www.sem-o.com/documents/general-publications/T-1-2022-2023-Final-Capacity-Auction-Results-Report.pdf
ix https://www.sem-o.com/documents/general-publications/T-3-2024-2025-Final-Capacity-Auction-Results-Report.pdf
x https://www.sem-o.com/documents/general-publications/T-4-2025-26-Final-Capacity-Auction-Results-Report.pdf
xi https://www.sem-o.com/documents/general-publications/2223T-4-Capacity-Market_Capacity-Termination-Notice_PY_000030-ESB-(2).pdf
xii https://www.sem-o.com/documents/general-publications/2223T-4-Capacity-Market_Capacity-Termination-Notice_PY_000088-EnerNoc.pdf
xiii https://www.sem-o.com/documents/general-publications/2324T-4-Capacity-Market_Capacity-Termination-Notice_PY_000030-ESB.pdf
xiv https://www.sem-o.com/documents/general-publications/2425T-4-Capacity-Market_Capacity-Termination-Notice_PY_000030-ESB.pdf
xv https://www.sem-o.com/documents/general-publications/2122T-2-Capacity-Market_Capacity-Termination-Notice_PY_000088-EnerNoc.pdf
xvi https://www.sem-o.com/documents/general-publications/2425T-4-Capacity-Market_Capacity-Termination-Notice_PY_034058-Statkraft-Ireland.pdf
xvii https://www.sem-o.com/documents/general-publications/2122T-2-Capacity-Market-Termination-Notice_PY_000088-EnerNoc.pdf
xviii https://www.sem-o.com/documents/general-publications/2324T-4-Capacity-Market_Capacity-Termination-Notice_PY_000044.pdf
xix https://www.sem-o.com/documents/general-publications/2324T-4-Capacity-Market_Capacity-Termination-Notice_PY_000088.pdf
xx https://www.sem-o.com/documents/general-publications/2425T-3-Capacity-Market-Termination-Notice-PY_034111-Rhode-Energy-Storage.pdf

Appendix 3 Generation Plant Information

	ID	Fuel Type	Technology Category	2022	Comment
Aghada	AT1	Gas/DO	Gas Turbine	90	To close before end of 2023
	AT2	Gas/DO	Gas Turbine	90	
	AT4	Gas/DO	Gas Turbine	90	
	AD2	Gas/DO	Gas Turbine	449	Increased capacity from 431 MW
All DSU	DSU	DSU	DSU	604	
Ardnacrusha	AA1-4	Hydro	Hydro	86	
Dublin Bay	DB1	Gas/DO	Gas Turbine	415	
Dublin Waste	DW1	Waste	Steam Turbine	61	
Edenderry	ED1	Milled peat/ Biomass	Steam Turbine	118	Planning Permission was granted to extend operation to 2030. Will run exclusively on biomass from Jan 2024
	ED3	DO/Gas	Gas Turbine	58	Operating on gas from Oct 2025*
	ED5	DO/Gas	Gas Turbine	58	Operating on gas from Oct 2025*
Erne	ER1-4	Hydro	Hydro	65	
EWIC	EW1	DC Interconnector		500	
Great Island CCGT	GI4	Gas/DO	Gas Turbine	464	
Huntstown	HNC	Gas/DO	Gas Turbine	337	
	HN2	Gas/DO	Gas Turbine	408	
Indaver Waste	IW1	Waste	Steam Turbine	17	
Lee	LE1-4	Hydro	Hydro	27	
Liffey	LI1-4	Hydro	Hydro	38	
Moneypoint	MP1	Coal/HFO	Steam Turbine	285	Modelled as not available from October 2024
	MP2	HFO	Steam Turbine	250	Modelled as not available from October 2024
	MP3	Coal/HFO	Steam Turbine	285	Modelled as not available from October 2024
Poolbeg CC	PBA	Gas/DO	Gas Turbine	234	
	PBB		Gas Turbine	234	
Rhode	RP1	DO	Gas Turbine	52	
	RP2	DO	Gas Turbine	52	
Sealrock	SK3	Gas/DO	Gas Turbine	81	
	SK4	Gas/DO	Gas Turbine	81	
Tarbert	TB1	HFO	Steam Turbine	54	Unit has been placed on outage until Dec 2023. Scheduled to close thereafter
	TB2	HFO	Steam Turbine	54	Unit has been placed on outage until Dec 2023. Scheduled to close thereafter
	TB3	HFO	Steam Turbine	241	To close by end of 2023
	TB4	HFO	Steam Turbine	243	Unit has been placed on outage until March 2023. Scheduled to close by end 2023
Tawnaghmore	TP1	DO	Gas Turbine	52	
	TP3	DO	Gas Turbine	52	
Turlough Hill	TH1	Pumped storage	Storage	292	
Tynagh	TYC	Gas/DO	Gas Turbine	389	
Whitegate	WG1	Gas/DO	Gas Turbine	450	
Total Dispatchable including DSU				**7356**	

Table A3-1 Registered Capacity of dispatchable generation and interconnectors in Ireland in 2022 (MW)
DSU: Demand Side Unit; HFO: Heavy Fuel Oil; DO: Distillate Oil

* The original publication (issued 6th October 2022) incorrectly stated that ED3/5 was assumed to be operating on gas from October 2024, this has been corrected to October 2025

At year end:	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Wind Onshore*	4480	4630	4790	4940	5100	5250	5400	5550	5700	5850
Wind Offshore*	25	25	25	25	25	25	725	2865	5000	7140
Small Scale Hydro	26	26	26	26	26	26	26	26	26	26
Biomass and Biogas	24	24	24	24	24	24	24	24	24	24
Biomass CHP	30	30	30	30	30	30	30	30	30	30
Industrial	9	9	9	9	9	9	9	9	9	9
Conventional CHP	129	129	129	129	129	129	129	129	129	129
Solar PV	167	333	500	667	833	1000	1167	1333	1500	1667
Total	**4890**	**5206**	**5533**	**5850**	**6176**	**6493**	**7510**	**9966**	**12418**	**14875**

Table A3-2 Partially/Non-Dispatchable plant in Ireland (MW)

At year end:	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
All Wind*	4505	4655	4815	4965	5125	5275	6125	8415	10,700	12,990
All Hydro	242	242	242	242	242	242	242	242	242	242
Biomass/LFG (including those units registered in the Capacity Market and Biomass CHP)	24	24	24	24	24	24	24	24	24	24
Waste (Assume 50% renewable)	39	39	39	39	39	39	39	39	39	39
Peat Stations on Biomass	77	77	118	118	118	118	118	118	118	0
Solar	167	333	500	667	833	1000	1167	1333	1500	1667
Total RES	**5054**	**5370**	**5738**	**6055**	**6381**	**6698**	**7715**	**10171**	**12623**	**14962**

Table A3-3 All Renewable energy sources in Ireland (MW). We have assumed that the peat plant at Edenderry will be approximately 60% powered by biomass by 2021 and 100% biomass from 2024 onwards

	ID	Fuel Type	Technology Category	2022	Comment
Ballylumford	B31	Gas/Heavy Fuel Oil	Gas Turbine	246	
	B32	Gas/Heavy Fuel Oil	Gas Turbine	246	
	B10	Gas/Heavy Fuel Oil	Gas Turbine	101	
	GT7(GT1)	Distillate Oil	Gas Turbine	58	

	GT8(GT2)	Distillate Oil	Gas Turbine	58	
Kilroot	ST1	Heavy Fuel Oil/Coal	Steam Turbine	238	Ceases operation in 2023
	ST2	Heavy Fuel Oil/Coal	Steam Turbine	238	Ceases operation in 2023
	KGT1	Distillate Oil	Gas Turbine	29	
	KGT2	Distillate Oil	Gas Turbine	29	
	KGT3	Distillate Oil	Gas Turbine	42	
	KGT4	Distillate Oil	Gas Turbine	42	
Coolkeeragh	GT8	Distillate Oil	Gas Turbine	53	
	C30	Gas/Distillate Oil	Gas Turbine	408	
AGU	AGU	Distillate Oil	Gas Turbine	79	
DSU	DSU	Various	DSU	143	
Lisahally		Biomass		18	Not in Capacity Market, but assumed available for capacity requirement
Contour Global	CGA / CGC	Gas	Gas Turbine	12	
Moyle		DC Interconnector		450	
	Total Dispatchable plant:			**2490**	

Table A3-4 Registered Capacity of dispatchable generation and interconnectors in Northern Ireland in 2022 (MW).

At year end:	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Large Scale Wind*	1250	1380	1500	1630	1760	1890	2020	2150	2370	2500
Small Scale Wind	180	180	180	180	180	180	180	180	180	180
Solar PV	285	285	285	335	395	455	505	565	615	675
Small Scale Biogas	24	24	24	24	24	24	24	24	24	24
Landfill Gas	16	16	16	16	16	16	16	16	16	16
Small Scale Biomass	6	6	6	6	6	6	6	6	6	6
Renewable CHP	3	3	3	3	3	3	3	3	3	3
Other CHP	6	6	6	6	6	6	6	6	6	6
Small Scale Hydro	6	6	6	6	6	6	6	6	6	6
Waste-to-Energy	15	15	15	15	15	15	15	15	15	15
Total	**1791**	**1921**	**2041**	**2221**	**2411**	**2601**	**2781**	**2971**	**3241**	**3431**

Table A3-5 Partially/Non-Dispatchable plant in Northern Ireland (MW).

At year end:	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
All Wind*	1430	1560	1680	1810	1940	2070	2200	2330	2550	2680
Solar PV	285	285	285	335	395	455	505	565	615	675
All Biomass/Biogas/LFGas/WTE	79	79	79	79	79	79	79	79	79	79
Renewable CHP	3	3	3	3	3	3	3	3	3	3
Hydro	6	6	6	6	6	6	6	6	6	6
Total RES	1803	1933	2053	2233	2423	2613	2793	2983	3253	3443

Table A3-6 All Renewable energy sources in Northern Ireland (MW).

*Wind forecasts beyond 2022 are based on linear projections towards the government renewable target ambitions as outlined in the recent Shaping Our Electricity Future Roadmap. Note installed capacities may differ across horizon due to changes in demand or deliverability of renewable projects.

Appendix 4 Glossary of Terms

Acronym/ Abbreviation	Term	Explanation
ACS	Average Cold Spell	Average Cold Spell (ACS) correction has the effect of 'smoothing out' the demand curve so that economic factors are the predominant remaining influences.
AGU	Aggregated Generator Unit	A number of individual generators grouping together to make available their combined capacity.
ALF	Annual Load Factor	The ALF is the average load divided by the peak load. E.g. TER=42000 GWh, Peak = 7.3 GW (Median forecast for All-Island system in 2020) $\mathrm{ALF} = \frac{42000/8760}{7.3} = 66\%$ where 8760 = number of hours per year = 24*365
CF	Capacity Factor	$\text{Capacity Factor} = \frac{\text{Energy Output}}{\text{Hours per year} * \text{Installed Capacity}}$
CEP	Clean Energy Package	EU Commission package of measures to facilitate the clean energy transition. The EU has committed to cut CO_2 emissions by at least 40% by 2030 while modernising the EU's economy.
CCGT	Combined Cycle Gas Turbine	A type of thermal generator that typically uses natural gas as a fuel source. It is a collection of gas turbines and steam units; where waste heat from the gas turbines(s) is passed through a heat recovery boiler to generate steam for the steam turbines.
CHP	Combined Heat and Power	A highly efficient process that captures and utilises the heat that is a by-product of the electricity generation process.
	Demand	The amount of electrical power that is consumed by a customer and is measured in megawatts (MW). In a general sense, the amount of power that must be transported from generation stations to meet all customers' electricity requirements. This includes any losses (line or transformer).
DSU	Demand Side Unit	A Demand Side Unit (DSU) consists of one or more Individual Demand Sites that can be dispatched by the Transmission System Operator (TSO) as if it was a generator.

	Dispatchable Generation	Sources of electricity that can be used on demand and dispatched at the request of power grid operators, according to market needs. Does not include wind and solar generation which are non-dispatchable generation
	EU-SysFlex	Aiming to achieve a pan-European system with an efficient coordinated use of flexibilities for the integration of a large share of renewable energy sources. EU-SysFlex will come up with new types of services that will meet the needs of the system with more than 50% of renewable energy sources.
ECP-1	Enduring Connection Policy	A process to provide connection offers to facilitate 2GW of renewable generation in Ireland.
ENTSO-e	European Network of Transmission System Operators - Electricity	ENTSO-E, the European Network of Transmission System Operators, represents 43 electricity transmission system operators from 36 countries across Europe.
ESB Networks	Electricity Supply Board: Networks	A subsidiary within ESB Group, ESB Networks is the licensed operator of the electricity distribution system in the Republic of Ireland and owner of all transmission and distribution network infrastructure.
ESRI	Economic and Social Research Institute	The role of the Economic and Social Research Institute is to advance evidence-based policymaking that supports economic sustainability and social progress in Ireland.
EVs		Electric Vehicles
FOP	Forced Outage Probability	This is the statistical probability that a generation unit will be unable to produce electricity for non-scheduled reasons due to the failure of either the generation plant or supporting systems. Periods when the unit is on scheduled outage are not included in the determination of forced outage probability.
	Generation Adequacy	The ability of all the generation units connected to the electrical power system to meet the total demand imposed on them at all times. The demand includes transmission and distribution losses in addition to customer demand.
GWh	Gigawatt Hour	Unit of energy

		1 gigawatt hour = 1000000 kilowatt hours = 3.6 x 1012 joules
GNP	Gross National Product	The total value of goods produced and services provided by a country during one year, equal to the gross domestic product plus the net income from foreign investments.
GVA	Gross Value Added	In economics, GVA is the measure of the value of goods and services produced in an area, industry or sector of an economy. In national accounts GVA is output minus intermediate consumption; it is a balancing item of the national accounts' production account.
HVDC	High Voltage, Direct Current	A HVDC electric power transmission system uses direct current for the bulk transmission of electrical power.
IC	Interconnector	The electrical link, facilities and equipment that connect the transmission network of one country to another.
IED	Industrial Emissions Directive	Directive 2010/75/EU of the European Parliament and the Council on industrial emissions (the Industrial Emissions Directive or IED) is the main EU instrument regulating pollutant emissions from industrial installations.
LOLE	Loss of Load Expectation	The LOLE is the mathematical expectation of the number of hours in the year during which the available generation plant will be inadequate to meet the instantaneous demand.
MEC	Maximum Export Capacity	The maximum export value (MW) provided in accordance with a generator's connection agreement. The MEC is a contract value which the generator chooses as its maximum output and is used in the design of the Transmission System.
MVA	Mega Volt Ampere	Unit of apparent power. MVA ratings are often used for transformers, e.g. for customer connections.
MW	Megawatt	Unit of power 1 megawatt = 1000 kilowatts = 106 joules / second
	Non-GPA	Non-Group Processing Approach
NTL	New Technology Loads	Large high tech industrial demand customers primarily connected to the transmission system or new technologies required for the energy transition e.g. hydrogen production
NIE Networks	Northern Ireland Electricity Networks	NIE Networks owns the electricity transmission and distribution network and operates the electricity distribution

		network which transports electricity to customers in Northern Ireland.
RAs	Regulatory Authorities	Refers to both: Ireland: Commission for Regulation of Utilities (CRU) Northern Ireland: Utility Regulator for Electricity and Gas for Northern Ireland
	Reliability Options	The SEM CRM Capacity Auctions are a competitive process between qualified capacity providers to be awarded " reliability options" for the provision of capacity to the All-Island system.
RES	Renewable Energy Source	
RES-E		Renewable Electricity
RESS	Renewable Energy Support Scheme	Scheme will provide for a renewable electricity (RES-E) ambition of up to 70% by 2030 in Ireland, initially announced via the Government Climate Action Plan 2019. Subject to determining the cost effective level which will be set out in the National Energy and Climate Plan (NECP).
Annual Run Hour Limitations		Restrictions on availability of plant due to external factors for example environmental
SEAI		Sustainable Energy Authority of Ireland
SEM	Single Electricity Market	This is the wholesale market for the island of Ireland.
ENTSO-E TYNDP		European Network of Transmission System Operators - Electricity Ten Year National Development Plan
TWh	Terawatt Hour	Unit of energy 1 terawatt hour = 1000000000 kilowatt hours = 3.6 x 1015 joules
TER	Total Electricity Requirement	TER is the total amount of electricity required by a country. It includes all electricity exported by generating units, as well as that consumed on-site by self-consuming electricity producers, e.g. CHP.

	Transmission Losses	A small proportion of energy is lost as heat or light whilst transporting electricity on the transmission network. These losses are known as transmission losses.
	Transmission Peak	The peak demand that is transported on the transmission network. The transmission peak includes an estimate of transmission losses
TSO	Transmission System Operator	In the electrical power business, a transmission system operator is the licensed entity that is responsible for transmitting electrical power from generation plants to regional or local electricity distribution operators.

Appendix 5 Methodology

Generation Adequacy Standard

Generation adequacy is assessed by determining the likelihood of there being sufficient generation to meet customer demand. For these purposes customers include Distribution System Operators such as ESB and NIEN and some large users, such as data centres who connect directly to the grid. It does not necessarily take into account any limitations imposed by the transmission system, reserve requirements or the energy markets though often these considerations can be incorporated into adequacy calculations by making modifications to the input data-sets.

In practice, when there is not enough supply to meet load, the load must be reduced. This is achieved by cutting off electricity from customers. In adequacy calculations, if there is predicted to be a supply shortage at any time, there is a LOLE for that period. In reality, load shedding due to generation shortages is a very rare event.

LOLE can be used to set an adequacy standard. In Ireland the adequacy standard is 8 hours LOLE per annum and Northern Ireland it is 4.9 hours LOLE per annum. If this is exceeded in either jurisdiction, it indicates the system has a higher than acceptable level of risk. The adequacy standard used for All-Island calculations is 8 hours.

With any generator, there is always a risk that it may suddenly and unexpectedly be unable to generate electricity (due to equipment failure, for example). Such events are called forced outages, and the proportion of time a generator is out of action due to such an event gives its forced outage rate (FOR).

Forced outages mean that the available generation in a system at any future period is never certain. At any particular time, several units may fail simultaneously or there may be no such failures at all. There is therefore a probabilistic aspect to supply and to the LOLE.

The model used for these studies works out the probability of load loss for each half-hour period – it is these that are then summed to get the yearly LOLE, which is then compared to the adequacy standard. It is assumed that forced outages of generators are independent events and that one generator failing does not influence the failure of another.

As well as outages, adequacy calculations should consider other characteristics that restrict the ability of a generator to generate electricity when needed. This is the case for wind and solar generation whose ability to generate is determined by climatic conditions. Generators that are limited in the amount of time they can generate such as storage generators also need to be considered.

Loss of Load Expectation

AdCal software is used to calculate LOLE. The probability of supply not meeting demand is calculated for each hour of each study year. The annual LOLE is the sum of the contributions from each hour.

Consider now the simplest case of a single-system study, with a deterministic load model (that is, with only one value used for each load), and no scheduled maintenance, so that there is one generation availability distribution for the entire year.

If

$L_{h,d}$ =load at hour h on day d

G =generation plant available

H =number loads/day to be examined (i.e. 1, 24 or 48)

D =total number of days in year to be examined

Then the annual LOLE is given by

$$\text{LOLE} = \sum_{d=1,D} \sum_{h=1,H} \text{Prob.}(G < L_{h,d})$$

This equation is used in the following practical example.

Simplified Example of LOLE Calculation

Consider a system consisting of just three generation units, as in Table A5-1.

	Capacity (MW)	Forced outage probability	Probability of being available
Unit A	10	0.05	0.95
Unit B	20	0.08	0.92
Unit C	50	0.10	0.90
Total	**80**		

Table A5-1 System for LOLE example

If the load to be served in a particular hour is 55 MW, what is the probability of this load being met in this hour? To calculate this, the following steps are followed, see Table A5-2:

1) How many different states can the system be in, i.e. if all units are available, if one is forced out, if two are forced out, or all three?

2) How many megawatts are in service for each of these states?

3) What is the probability of each of these states occurring?

4) Add up the probabilities for the states where the load cannot be met.

5) Calculate expectation.

Only states 1, 2 and 3 are providing enough generation to meet the demand of 55 MW. The probabilities for the other five *failing* states are added up to give a total probability of 0.1036. So in this particular hour, there is a chance of approximately 10% that there will not be enough generation to meet the load.

It can be said that this hour is contributing about 6 minutes (10% of 1 hour) to the total LOLE for the year. This is then summed for each hour of the year.

State	Units in service	Capacity in service (MW)	Probability for (A*B*C)	Probability	Ability to meet 55 MW demand	Expectation of Failure (LOLE)
1	A, B, C	80	0.95*0.92*0.90 =	0.7866	Pass	0
2	B, C	70	0.05*0.92*0.90 =	0.0414	Pass	0
3	A, C	60	0.95*0.08*0.90 =	0.0684	Pass	0
4	C	50	0.05*0.08*0.90 =	0.0036	Fail	0.0036
5	A, B	30	0.95*0.92*0.10 =	0.0874	Fail	0.0874
6	B	20	0.05*0.92*0.10 =	0.0046	Fail	0.0046
7	A	10	0.95*0.08*0.10 =	0.0076	Fail	0.0076
8	none	0	0.05*0.08*0.10 =	0.0004	Fail	0.0004
Total				**1.0000**		**0.1036**

Table A5-2 Probability table

Interpretation of Results

While the use of LOLE allows a sophisticated, repeatable and technically accurate assessment of generation adequacy to be undertaken, understanding and interpreting the results may not be completely intuitive. If, for example, in a sample year, the analysis shows that there is a loss of load expectation of 16 hours, this does not mean that all customers will be without supply for 16 hours or that, if there is a supply shortage, it will last for 16 consecutive hours.

It does mean that if the sample year could be replayed many times and each unique outcome averaged, that demand could be expected to exceed supply for an annual average duration of 16 hours. If such circumstances arose, typically only a small number of customers would be affected for a short period. Normal practice would be to maintain supply to industry, and to use a rolling process to ensure that any burden is spread.

In addition, results expressed in LOLE terms do not give an intuitive feel for the scale of the plant shortage or surplus. This effect is accentuated by the fact that the relationship between LOLE and plant shortage/surplus is highly non-linear. In other words, it does not take twice as much plant to return a system to the 8 hour standard from 24 hours LOLE as it would from 16 hours.

The adequacy calculation assumes that forced outages are independent, and that if one generator trips it does not affect the likelihood of another generator tripping. In some situations, it is possible that a generator tripping can cause a system voltage disturbance that in turn could cause another generator to trip. Any such occurrences are a matter for system security, and therefore are outside the scope of these system adequacy studies.

As for common-mode failures, it is possible that more than one generating unit is affected at the same time by, for example, a computer virus or by extreme weather, etc. However, it could be considered the responsibility of each generator to put in place measures to militate against such known risks for their own units.

Surplus & Deficit

In order to assist understanding and interpretation of results, a further calculation is made which indicates the amount of plant required to return the system to standard. This effectively translates the gap between the LOLE projected for a given year and the standard into an equivalent plant capacity (in MW). If the system is in surplus, this value indicates how much plant can be removed from the system without breaching the LOLE standard. Conversely, if the system is in breach of the LOLE standard, the calculation indicates how much plant should be added to the system to maintain security.

The exact amount of plant that could be added or removed would depend on the particular size and availability of any new plant to be added. The amount of surplus or deficit plant is therefore given in terms of Perfect Plant. Perfect Plant may be thought of as a conventional generator with no outages. In reality, no plant is perfect, and the amount of real plant in surplus or deficit will always be higher.

It should be noted that actual loss of load as a result of a supply shortage does not represent a catastrophic failure of the power system[62]. In all probability such shortages, or loss of load, would not result in widespread interruptions to customers. Rather, it would likely take the form of supply outages to a small number of customers for a period in the order of an hour or two. This would be done in a controlled fashion, to ensure that critical services are not affected.

Value of Lost Load

The Value of Lost Load is becoming more and more important in current TSO's activities, especially regarding the generation adequacy issue. The Value of Lost Load can be used within capacity mechanisms and the cost-benefit analysis of system investments.

The Value of Lost Load is the monetary damage arising from the non-supply of a given amount of energy (in MWh for instance) due to a power outage. Costs can be significant as they imply the interruption of productive processes for industrials and businesses or the reduction of leisure activities. VoLL can vary per country depending on how much each country values the factors which affect the cost of lost load.

The revised Electricity Regulation, a part of the Clean Energy Package would require ENTSO-E, pursuant to Article 19.5 and Article 10, to develop a common VoLL methodology. ENTSO-E is working on developing a common VoLL methodology for member TSOs.[63]

The time of lost load is also significant. A power interruption during the night for 5 minutes does not have the same consequences as if it occurs during the peak hours for one hour. There is not a unique VoLL which can be applied for all types of outages. The VoLL should be fine-tuned to precisely consider interruptions characteristics and then real costs caused by an outage.

For defining generation adequacy standard, the VoLL should be assessed during peak hours only and should consider a several-hours pre-notification time.

The existing reliability standard is for an average LOLE. Two parameters feed into this reliability standard – the Net Cost of New Entry (CoNE) and the Value of Lost Load (VoLL). In Ireland the LOLE Standard is 8hr and in Northern Ireland the LOLE Standard is 4.9 hours.

In the SEM market, the VoLL and Net CoNE are set for each SEM Capacity Market which is used to calculate the value of contracts awarded to winning generators in each auction.

In essence, VOLL estimates the cost of not having enough supply to serve the load, while CONE evaluates the cost of having over-supply. In order to find the optimal balance between supply and demand, we can use VOLL and CONE to define the most appropriate LOLE standard

The most efficient number of hours of outage to allow (LOLE standard) is a function of the Value of Lost Load (VOLL) and the fixed and variable costs of a peaker (Cost of New Entry (CONE)).

The answer to the question "How many hours of lost load should I allow?" is derived from a straightforward cost analysis: In theory, load should be unserved in hours when the cost of serving it would exceed VOLL. [64]Put algebraically, outage makes sense as long as

VOLL * LOLE standard < CONE

[62] *In line with international practice, some risk of such supply shortages are accepted to avoid the unreasonably high cost associated with reducing this risk to a negligible level.*

[63] https://www.acer.europa.eu/Events/Workshop-on-the-estimation-of-the-cost-of-disruption-of-gas-supply-CoDG-and-the-value-of-lost-load-in-power-supply-systems-VoLL-in-Europe/Documents/CEPAPresentation_VoLLWorkshop.pdf

[64] *http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Hunt_Making_Competition_Work.pdf*

For example:

VOLL ~ [Cost of CONE] / [LOLE standard] = [€80,000/MW year] / [8 hours /year] = €10,000 /MWh

Figure A5-1 shows the point at which this balance point is found – marked by X between both graphs.

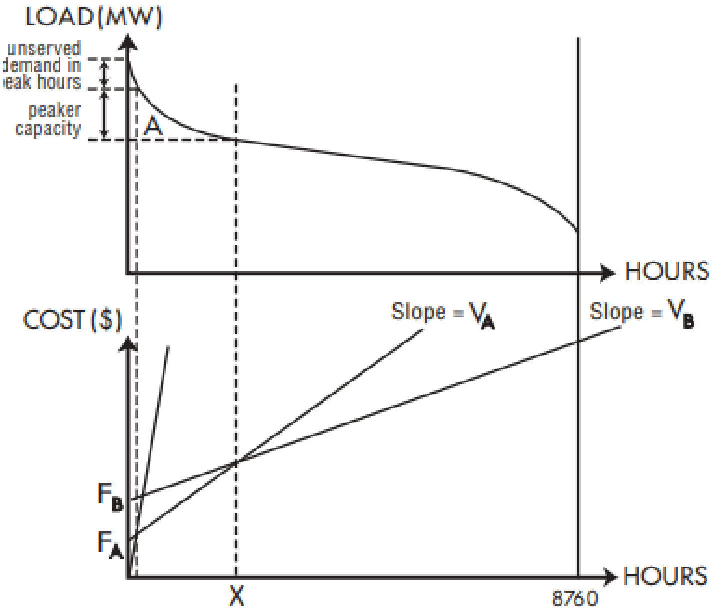

Figure A5-1 Balance point between the costs of a new entrant (CONE) to meet demand versus the cost impact of not meeting demand (VoLL) for a certain LOLE[65].

[65] *http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Hunt_Making_Competition_Work.pdf*