Irish electricity and gas demand to 2050 in the context of climate commitments

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ABOUT US

MaREI is the world-leading Science Foundation Ireland Research Centre for Energy, Climate and Marine, coordinated by the Environmental Research Institute (ERI) at University College Cork. MaREI has over 200 researchers across 13 partner institutes in Ireland working with 75 industry partners focussing on the energy transition, climate action and the blue economy. MaREI delivers excellent research with societal impact by supporting industry, informing policy and empowering society.

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SUMMARY

BACKGROUND AND MOTIVATION

Enshrining a legal basis for carbon budgets in 2021 put Ireland in a better position to meet national and international commitments to address climate change, and also set a generational challenge to rapidly transform its energy system. Meeting Sectoral Emissions Ceilings (SECs) in line with economy-wide carbon budgets this decade will require a rapid reduction in fossil fuel consumption across all energy sectors. Concurrently, with the Russian invasion of Ukraine, 2022 has seen skyrocketing natural gas prices and threats to security of energy supply in continental Europe, placing additional significance on rapidly accelerating Ireland's sustainable energy transition.

However, the electricity system faces multiple interconnected challenges: strong growth in electricity demand from data centres and carbon budget obligations will require the electricity system to both rapidly phase out fossil fuels while delivering far more electricity this decade. Electrifying heat and transport is also one of the most important options to reduce fossil fuels: any constraint on electrification will threaten the achievability of sectoral emissions ceilings.

This report critically examines the requirement for new gas-fired power generation capacity and future gas demand in the context of these challenges. The analysis focuses on the role of data centres as a driving force for gas-fired power generation and capacity, and the potential for alternative zero-carbon energy sources to meet electricity demand within the context of constrained carbon budgets this decade. The report also compares a carbon budget-consistent energy system with projections and forecasts of electricity and natural gas demand from network operators, EirGrid and Gas Networks Ireland.

Our analysis is based on a highly detailed, peer reviewed and open-source energy systems model, the TIMES Ireland Model (TIM). TIM is a model of the Irish energy system, which calculates the cost-optimal fuel and technology mix to meet future energy service

demands, while respecting constraints in Greenhouse Gas (GHG) emissions, primary energy resources, and feasible deployment rates[1].

KEY CONCLUSIONS AND RECOMMENDATIONS

To meet the national Carbon Budget Programme, as set out in the 2021 Climate Law, and long-term objective of a carbon-neutral economy by 2050 at the latest, cost-optimal pathways for the Irish energy system require demand for natural gas to fall by 40% this decade and a further 80% in the 2030s.

- ❖ Meeting the carbon budget programme means that, compared with 2020, natural gas demand in 2040 is reduced by 93% in the power sector, 85% in the residential sector and 67% in enterprise.

- ❖ Strong growth in data centre electricity demand, for example a trajectory aligned with the "High" or "Median" electricity demand forecasts set forth by EirGrid in its Generation Capacity Statement in 2022, would substantially increase the challenges for the achievement of Sectoral Emissions Ceilings in the power, transport and buildings sectors. To remain within emissions ceilings, data centre demand growth represented in EirGrid's "High" scenario – a 500% in growth in electricity demand from data centres this decade – would require deployment of renewable electricity capacity at implausibly rapid rates: a quadrupling of renewable electricity generation this decade.

- ❖ If significant growth in future renewable electricity generation is ultimately required mainly to serve strong data centre demand growth, this will further limit the potential for transport, buildings and industry sectors to meet their decarbonisation commitments. This is the case as replacing fossil fuels through electrification is also among the most cost-effective and achievable mitigation measures available in these other sectors.

[1] Balyk, O., Glynn, J., Aryanpur, V., Gaur, A., McGuire, J., Smith, A., Yue, X., and Daly, H.: TIM: modelling pathways to meet Ireland's long-term energy system challenges with the TIMES-Ireland Model (v1.0), Geosci. Model Dev., 15, 4991–5019, https://doi.org/10.5194/gmd-15-4991-2022, 2022.

Delivering on the legally-binding Sectoral Emissions Ceiling for the power sector to 2030 requires an immediate increase in natural gas capacity (largely to replace existing, more polluting capacity) but at the same time, meeting carbon budgets will require a strong decrease in the utilisation of natural gas-fired generation later this decade.

- New natural gas-fired power capacity is urgently necessary to meet climate commitments to replace older, more carbon-intensive generation capacity, but to meet carbon budgets, the annual power generation from natural gas plants (i.e. the actual operation of these plants annually) must fall by more than half by 2030. Around 2 GW of additional natural gas capacity must be deployed as quickly as possible. High data centre demand growth[2] necessitates an additional 0.2 GW of natural gas power generation capacity. Failure to ensure compliance with Sectoral Emissions Ceilings would risk higher investment in and operation of gas generation (and associated risk of emissions lock-in).

Any failure to rapidly deploy far greater renewable electricity capacity in parallel would lead to an increased utilisation rate of natural gas capacity, with consequent increase in emissions and risks to Sectoral Emissions Ceilings.

- While additional natural gas-fired power capacity is necessary in all scenarios, the share of time that natural gas capacity is used must be more than halved this decade for natural gas usage and CO_2 emissions to reduce in line with the Sectoral Emissions Ceiling. This cannot be achieved without a very rapid acceleration in renewable electricity capacity deployment – around 15 GW of new wind and solar capacity this decade – and this challenge is amplified with higher demand growth from data centres.

To adequately plan for the rapidly energy transition required to meet the national climate objective, and to avoid a lock-in to fossil fuel infrastructure, state agencies

[2] Consistent with EirGrid's "High Demand" scenario from the Generation Capacity Statement report, 2022

must make carbon budget planning explicit within energy projections and forecasting.

- EirGrid and Gas Networks Ireland (system operators of the electricity and gas networks) project future electricity generation capacity and natural gas demand without taking explicit account of Sectoral Carbon Budgets or the long-term net-zero commitment. The result is projections of demand which risk being misinterpreted by policy and industry as being compatible with legally-binding climate commitments. This provides poor policy messaging that does not factor in legally-mandated carbon budgets and risks locking in fossil fuel-intensive infrastructure and a CO_2 emissions pathway which exceeds legally-binding carbon budgets.

- It is necessary to shift focus from examining and addressing technology deployment only in terms of long-term targets to immediately reducing fossil fuel use in line with carbon budgets to 2025 and 2030. Delays in emissions cuts are likely to make the carbon budget programme infeasible.

ADDITIONAL CONCLUSIONS

To what extent could additional measures to reduce energy demand in the energy, heat and industry sectors heat reduce reliance on new gas plants while also reducing emissions?

This modelling analysis shows that around 2.4 GW of additional gas-fired power generation capacity is necessary to deliver security of electricity supply while displacing older, more carbon-intensive thermal generation capacity. However, the power sector can only remain within its Sectoral Emissions Ceiling if the operation of gas plants rapidly reduces, particularly from 2025 onwards. This cannot be achieved without a broad set of mitigation measures, including rapid deployment of onshore and offshore wind and solar PV at unprecedented rates in Ireland. Concurrently, reducing electricity demand growth from data centres and large energy users will reduce reliance on gas plants while enabling zero-carbon electricity to be directed at displacing fossil fuels in industry, heat and transport.

Energy demand reduction measures in other end-use sectors can further reduce the operation of new gas plants. For example, targeting a shift away from cars through more dense spatial planning, improving public transport and building safe walking and cycling infrastructure, rather than mainly on vehicle electrification in order to meet the transport Sectoral Emissions Ceiling would reduce electricity demand. However, even fully meeting the target of nearly one million EVs by 2030 would add around 5 TWh of electricity demand in 2030, around one-third of data centre demand in EirGrid's "Median" scenario in that year. Therefore, limiting the growth in electricity demand from data centres has a greater role to play in preventing gas generation.

Across all zero-carbon measures (renewables, energy storage, interconnection, hydrogen, energy efficiency and demand-side measures) which measures should be prioritised as having the biggest impact in supporting security and reducing reliance on fossil gas?

Renewable electricity will be the backbone of Ireland's clean energy transition: 80% (or more) of electricity generation must be from renewables by 2030, on the pathway to a zero-carbon grid in the 2030s. Such a penetration of renewable electricity will only be achieved with a transformation of the electricity grid, with long- and short- term electricity storage, interconnection and dynamic demand response necessary to align energy demand with renewable supply. At the same time, demand-side measures to reduce final energy demand will be necessary to deliver on both 2030 and 2050 goals. This can be achieved through stronger demand side management measures from large energy users, preventing further connections to the gas network, and a combination of structural changes in end-use energy sectors (such as a transformation in the transport sector towards non-car travel modes, or in enterprise towards low-carbon and low-energy intensity industries) and improving the efficiency of energy use (for example, through building retrofit and use of low-energy appliances). The pathway to delivering on 2030 targets in particular is so narrow that it is not possible to prioritise either renewable electricity deployment or demand reduction: both will be necessary, and concurrently will reduce reliance on natural gas imports.

Given that projected data centre connections require additional gas-fired generation, to what extent may this involve increased gas demand?

While electricity demand growth from data centres is not the primary driver of increased gas-fired generation capacity, it creates an upwards pressure on power generation, which will drive additional fossil fuel usage and associated CO_2 emissions until the power grid is fully decarbonised. All else being equal, EirGrid's "High" demand growth scenario would require a quadrupling of renewable electricity generation this decade – significantly beyond policy targets – and 31% more renewable energy generation than the "Low" demand growth scenario in 2030. However, even the "Low" growth scenario requires that 80% of electricity demand be derived from renewables in 2030.

What are the implications for energy security of gas demand scenarios which are not compatible with Sectoral Emissions Ceilings?

As noted above, GNI gas demand scenarios, which forecast growth this decade, do not take account of legally-binding Sectoral Emissions Ceilings. Our analysis shows that gas demand must fall by around 30% this decade and a further 80% in the 2030s to limit GHG emissions in line with carbon budgets. This means that by 2040, gas demand needs to fall by around 85% relative to 2020 for compliance with the national climate objective. In particular, gas demand from the power sector must halve this decade to comply with its Sectoral Emissions Ceiling.

Basing future grid infrastructure and energy security policy on gas demand scenarios which do not factor in this need to reduce overall gas use on a trajectory to climate neutrality risks fossil fuel lock-in and/or stranded fossil fuel assets. Energy security policy and energy infrastructure planning should also take into account the importance and high potential of both energy demand reduction and accelerated renewables deployment as valuable energy security measures which complement, rather than conflict with, climate policy. It is important that the Government and the CRU analyses, before any decisions on new fossil fuel infrastructure, the potential for reduced gas usage in line with Sectoral Emissions Ceilings to result in lower demands for GB imports from the Moffat Entry Point in Scotland.

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1 INTRODUCTION

1.1 ENERGY AND CLIMATE POLICY

Ireland's 2021 Climate Law requires a reduction in overall national emissions by 51% by 2030 and reaching net-zero by 2050 at the latest. Five year national emissions ceilings (carbon budgets) have now been approved by the Oireachtas and the Government has allocating the bulk of those emissions between sectors. The target for the electricity sector is to reduce emissions by 75% between 2018 and 2030. The Government has already committed to reaching up to 80% renewables in the electricity system by 2030. The electricity system faces major challenges to meet this obligation, including the urgent phase-out of carbon-intensive peat and coal-fired generation.

In Europe, energy markets have undergone major disruption following the Russian invasion of Ukraine and interruptions to piped natural gas, which has contributed to skyrocketing energy prices. Ireland is not vulnerable to the same threat of gas supply interruptions as continental European countries, given that natural gas is produced domestically and imported via pipeline from Scotland from Britain, the bulk of which originates in the North Sea. Furthermore, Liquified Natural Gas (LNG) infrastructure is well developed in Britain, allowing Ireland access to this flexible supply of gas from the global market.

However, despite not being directly threatened by a disconnection from Russian gas, the operation of Ireland's electricity system is currently highly dependent on natural gas, and any physical interruption in supply would have major negative economic and social consequences.

Concurrently, the Government has commissioned a review of Ireland's energy security and has commissioned technical analysis of options to ensure security of gas supply[3], to identify and appraise options which could mitigate the impact of physical supply shocks to Ireland's electricity and gas systems.

[3] https://www.gov.ie/en/consultation/dbe14-review-of-the-security-of-energy-supply-of-irelands-electricity-and-natural-gas-systems/

However, future electricity and gas demand scenarios in that analysis are based on gas and electricity projections developed by Gas Networks Ireland and EirGrid, which do not factor in legally-binding carbon budgets and assume a growth in natural gas demand this decade.

Furthermore, public and policy discourse regarding energy security challenges has also focused on increasing gas-fired generation and import infrastructure, without adequate attention paid the important role that an acceleration of the energy transition can play in ensuring energy security, both through additional renewables deployment and reducing overall energy demand. It has also largely ignored fossil fuel lock-in risks and Ireland's climate and decarbonisation commitments.

1.2 Electricity demand drivers

Additional natural gas-fired power *capacity*[4] is required over the coming years for several reasons: in order to balance variable wind and solar generation, to displace older thermal power plant, and to serve growing electricity demands.

However, despite a requirement for additional natural gas capacity, these plants will need to be used less over time in order to meet greenhouse gas emissions budgets. For the power sector to remain within its carbon budget, the investment in and the actual generation of new gas-fired capacity depend on the absolute growth in electricity demand and the speed in the growth of alternative sources of power generation (such as solar PV and wind), as well as the potential alternative routes for energy decarbonisation (e.g., rollout of district heating).

Electricity demand has grown strongly and is projected by EirGrid to grow by a further 19-50% over the coming decade, mainly driven by large energy users, dominated by data centres.

Data centres are the largest recent and projected driver of electricity demand growth this decade. Metered electricity consumption is growing by 0.3-0.9 TWh each year and is accelerating[5]. Data centres currently account for around 14% of electricity generation, or 8

[4] Power generation capacity is the theoretical maximum electricity output of a generator at a specific point in time

[5] https://www.cso.ie/en/releasesandpublications/ep/p-dcmec/datacentresmeteredelectricityconsumption2021/keyfindings/

TWh annually. By contract, the European Commission has estimated that 2.7% of EU Member States electricity demand was from data centres in 2020, and projects this figure to grow to 3.2% by 2030[6].

As of July 2022, 75 data centres were in operation in Ireland, with an additional 11 under construction and 42 and 18 with planning approved and under assessment respectively (Table 1). Should all projects be completed, power demand capacity would triple. In addition, data centres are being built with on-site power generation capacity; however, Minister Eamon Ryan issued an instruction to Gas Networks Ireland to cease issuing any more connection contracts which would enable data centres to be mainly fuelled by on-site fossil fuel generation[7].

Existing data centres are reportedly only using 30% of their contracted capacity[8], therefore even in the absence of additional connections, demand growth from existing data centres could be substantial. Data centres have been building on-site thermal power generation capacity supported by gas network connections, but Minister Eamon Ryan has instructed Gas Networks Ireland to cease permitting new connections given government policy in relation to security of gas supply and climate targets.[9]

Earlier this year EirGrid announced a moratorium on new grid connections for data centres in the Dublin region until 2028 due to capacity constraints. New data centres both in and outside the Dublin region continue to gain planning permission[10].

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[6] https://digital-strategy.ec.europa.eu/en/library/energy-efficient-cloud-computing-technologies-and-policies-eco-friendly-cloud-market

[7] https://www.rte.ie/news/ireland/2022/1014/1329211-data-centres/

[8] https://www.businesspost.ie/news-focus/irelands-data-centre-dilemma-how-can-the-national-grid-cope-as-digital-demand-grows/

[9] https://www.rte.ie/documents/news/2022/10/eamon-ryan-letter-to-gni.pdf

[10] https://www.thejournal.ie/ennis-data-centre-granted-planning-permission-5837261-Aug2022/
https://www.independent.ie/irish-news/news/amazon-gets-planning-permission-for-two-new-data-centres-in-north-dublin-41911199.html

Table 1: Status of Data Centres operating or under planning or construction as of July 2022[11]

	Operational Data Centres	Under construction	Planning Approved	Planning Applications
Number	75	11	42	18
Maximum Design Power	1,060 MW	300 MW	1,300 MW	575 MW

In the past year, the Commission for the Regulation of Utilities (CRU) has issued a decision to limit new data centre grid connections based on location – whether they are in a constrained region of the electricity system – the ability of a data centre to bring onsite dispatchable generation or flexibility/demand response at times of system constraint[12]. This decision was in response to the growing challenge data centre demand growth poses to Ireland's electricity network and security of supply. The CRU did not impost a moratorium on new data centre connection at that time, but warned that this may become necessary in order to ensure uninterrupted power supply.

EirGrid's 2022 Generation Capacity Statement (Table 1) projects in its "Low" forecast scenario that data centres and other new large energy users will add around 0.5 TWh of electricity demand each year to 2030, growing to 1.4 TWh each year in a "High" scenario. In EirGrid's Median demand scenario, data centres and new large energy users are projected to account for 28% of all electricity demand by 2031 (Figure 1).

Table 2: Forecasted data centre and new large energy users energy demand in 2031, additional to 600 MVA assumed for 2022. Source: EirGrid Generation Capacity Statement, 2022-2031.

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

[11] https://bitpower.ie/index.php/dashboard Accessed: 24/10/2022
[12] https://www.cru.ie/document_group/data-centre-grid-connection/

Sectoral carbon budgets also have an overriding role in determining the power generation mix in the coming decade. This legally-binding commitment is not factored into either EirGrid or CRU analysis on future power system needs, which is a significant gap: increasing electricity demand will drive electricity generation from fossil fuels, unless the deployment of renewables accelerates enough to meet all electricity demand while displacing existing fossil fuel generation concurrently: to meet the sectoral carbon emissions ceiling for the power sector (which is consistent with a reduction in GHG emissions of 75% by 2030 relative to 2018), a strong reduction in fossil-fuel fired power generation is required, particularly from the most carbon-intensive sources, peat, coal and oil.

At the same time, new sources of electricity demand will also come from the electrification of heat, industry and transport as a key pathway for delivering sectoral emission targets during Carbon Budget 1 (2021-25) and Carbon Budget 2 (2026-30).

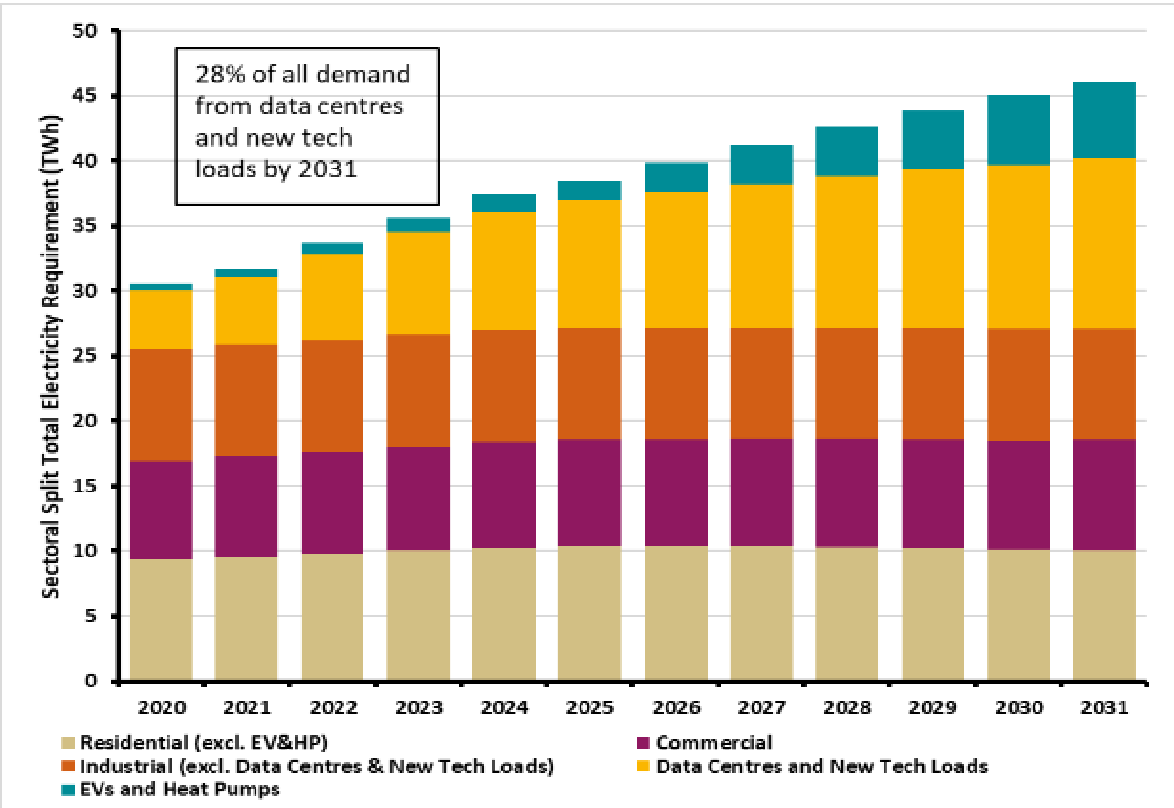


Figure 1: Projected electricity demand by sector by Eirgid in the "Median" demand scenario (EirGrid, 2022)

2 Power system pathways to 2030 consistent with Sectoral Emissions Ceilings

Greenhouse gas emissions from power generation grew by 18% in 2021, to nearly 10 Mt, mainly due to a resurgence in coal-fired power generation and steady growth in electricity demand. This constituted 24% of its sectoral emission ceiling for CB1 of 40 Mt.

Data on power generation from the Sustainable Energy Authority of Ireland[13] indicate that so far in 2022, GHG emissions in the sector are still on a growth trajectory: thermal generation rose by 8% in the year to August (mainly from natural gas), and total generation rose by around 3%. As a result, GHG emissions are on track to rise by around 5% this year, depending on how windy the remainder of 2022 will be, and how electricity demand will respond to rising prices.

The growth in emissions seen in 2021 and likely rise in 2022 will make meeting the sectoral emissions ceiling a significant challenge: the sector could be faced with emissions cuts of 20% each year in 2023, 2024 and 2025 if cuts start in 2023, or annual 40% cuts if emissions merely stabilise at 2022 levels in 2023, which would require emissions in the sector to fall to 4 Mt in 2025. By contrast, had emissions started to fall in 2022 already, in line with a steady trajectory, an annual cut of 10% in emissions would have been sufficient, with emissions in 2025 needing to fall to 6 Mt (Figure 2). To illustrate how infeasible annual emissions cuts of 40% in this sector is, the greatest annual cut in emissions in the power sector since 1990 was 11%, which was achieved in both 2018 and 2019, but emissions rebounded in 2021, growing by 19%.

[13] https://www.seai.ie/data-and-insights/seai-statistics/monthly-energy-data/electricity/

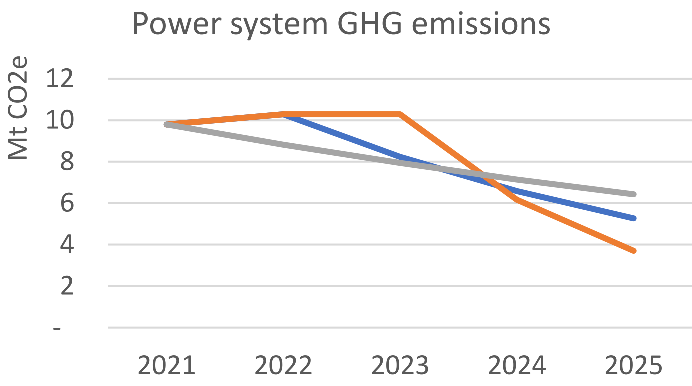


Figure 2: Trajectories for GHG emissions for electricity generation consistent with the Sectoral Emissions Ceiling for Carbon Budget 1 of 40 Mt CO2. Grey represents a peaking of GHG emissions in 2021 (requiring a 10% annual cut from 2022), blue a peaking in 2022, assuming GHG emissions are 5% higher in that year than in 2021, requiring a 20% cut in emissions from 2023, and orange represents a peaking in GHG emissions in 2023, requiring a 40% annual cut in emissions in 2024 and 2025.

Looking beyond the first carbon budget period to 2025, the SEC for the power sector in Carbon Budget 2, between 2026 and 2030, is 20 Mt CO_2. Figure 3 depicts representative pathways for all sectors (excluding LULUCF and "Other") to meet their SECs. Under this scenario, emissions from the power sector must fall to 3 Mt CO_2 by 2030.

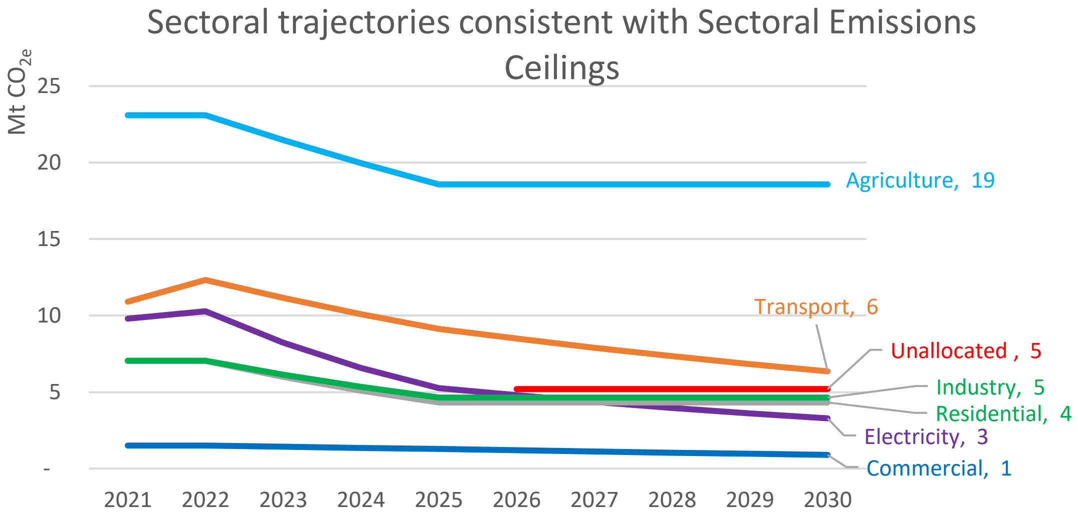


Figure 3: Trajectories for sectors (excluding LULUCF and "Other") consistent with Carbon Budgets 1 and 2. Scenario assumes transport & power sector GHG emissions are 13% & 5% higher in 2022 relative to 2021, respectively, and in all other sectors GHG emissions plateau in 2022, and annual reductions begin in 2023.

The sectoral emissions ceiling for the power sector sets a limit on the amount of electricity to be generated with fossil fuels, and assuming no peat, oil or coal in the generation mix from 2023, determines the maximum amount of electricity which can be generated with natural gas for the sector to stay within its SEC. Figure 4 charts one such scenario, assuming that electricity with natural gas is produced with an emissions intensity of 404 gCO_2/kWh. In this scenario, electricity from natural gas must fall from 14 TWh in 2021 to 13 TWh in 2025 and 8 TWh in 2030.

Should coal, oil or peat remain in the generation mix from 2023, or should gas-fired power generation be more CO_2-intensive than assumed, then the gas-fired power generation would need to be lower still, to remain under the sectoral emissions ceiling.

On the other hand, if the government does not rigidly impose the SECs for the power sector, this would likely lead to higher natural gas (or other fossil fuel) consumption in the sector this decade, and corresponding GHG emissions.

Similarly, should the carbon intensity of electricity from gas will be reduced – either through blending with biogas or green hydrogen, or through the potential for carbon capture and storage (CCS), the generation mix this decade would allow for a greater share of gas, while meeting the SECs. However, while the Government has established indicative targets for biogas and green hydrogen, there is as yet no policy framework in place to deliver significant deployment of these technologies. Furthermore, it is likely that, once biogas and green hydrogen are developed at scale, they are likely to be most effectively deployed for decarbonising industry and "hard to abate" sectors.

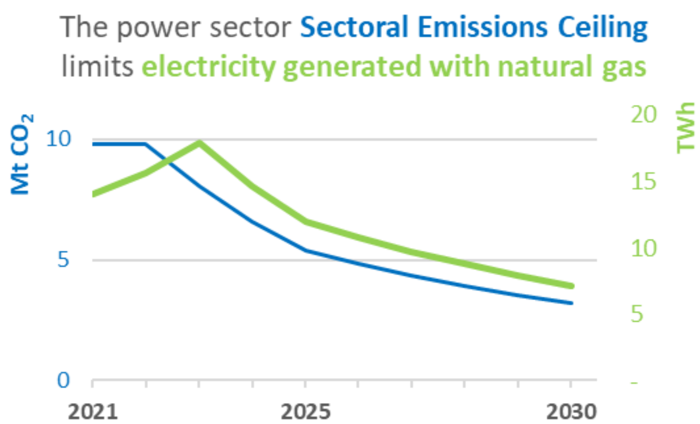


Figure 4: The Sectoral Emissions Ceilings limit overall CO2 emissions in Carbon Budgets 1 & 2. If natural gas remains the only fossil fuel in the generation mix from 2023, this requires a sharp fall in gas-fired power generation from 2024, halving gas use between 2021 and 2030

The level of electricity demand growth will play a strong role in determining the achievability of this scenario: With higher electricity demand, more zero-carbon energy sources will be necessary.

The next section examines the requirements for future the electricity capacity and generation mix, including the requirement for new capacity, under alternative electricity demand scenarios.

3 Future power system pathways under alternative electricity demand scenarios

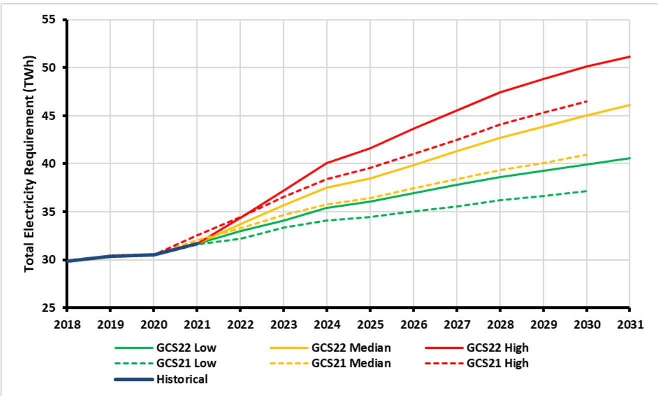
The previous section detailed the level of potential power generation from natural gas this decade, assuming that Sectoral Emissions Ceilings (SECs) are rigidly imposed by the government. The overall power generation mix, both in terms of additional generation capacity and overall fuel mix, will be strongly influenced by future electricity demand growth: All else being equal, greater electricity demand growth from data centres will require either more rapid and larger deployment of renewable electricity or electricity imports through the interconnector (which is limited), or else will require a cut in electricity consumption in other sectors.

This section examines each of these topics in turn.

- Firstly, in the next section, the absolute level and share of renewable electricity generation required to meet alternate projections for future electricity demand in EirGrid's Generation Capacity Statement (GCS) is quantified.
- Secondly, in following sections, a comprehensive and detailed modelling analysis of overall energy system pathways consistent with the carbon budget programme examines the outlooks for the power sector under alternative futures for data centre demand.

3.1 Future electricity mix under EirGrid Generation Capacity Statement outlooks for electricity demand

EirGrid's 2022 GCS median electricity demand projection sees power demand rising from 30 TWh in 2018 to 45 TWh in 2030, an upwards revision on last year's GCS (Figure 5, left). The growth relative to the previous year's GCS mainly comes from data centres and new large energy users, and an increased projected update in electric vehicles and heat pumps later in the decade. In EirGrid's "Median" electricity demand scenario, 28% of electricity demand is expected to come from data centres and other new large energy users by 2031, double the share in 2021. The difference between the GCS scenarios is largely driven by assumed future data centre and new large energy user scenarios (Figure 5, right). However, the GCS does not explicitly account for either total fossil fuel-fired electricity generation or resulting emissions, to enable an assessment of compliance of these scenarios with Sectoral Emissions Ceilings.



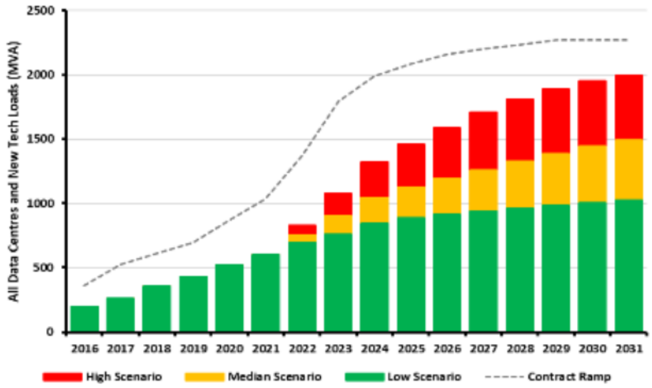


Figure 5: Total Electricity Requirement forecast for Ireland 2021 – 2031 (left) and demand expected from assumed build-out of data centres and new tech loads (right) (EirGrid GCS 2022)

Section 0 (Figure 6) demonstrated that under a constrained emissions ceiling for the power sector over the first two carbon budget periods, electricity generation from natural gas will need to fall to 8 TWh in 2030, from 14 TWh in 2021, in the absence of breakthrough technologies such as carbon capture and storage. The balance of electricity generation must come from zero-carbon sources, most likely wind (offshore and onshore) and solar PV. Greater electricity demand will require higher renewable energy generation and overall share in the generation mix.

Figure 6 shows the share of electricity that must come from renewables in 2025 and 2030, and the total renewable electricity generation, that is required to meet EirGrid's projected electricity demand scenarios. Even in the "Low" scenario, renewable electricity generation must double relative to 2021 by 2025, to 23 TWh, meeting a 63% share in the generation mix by 2025, rising to 80% by 2030.

Under "High" electricity demand growth, renewables must account for 68% of power generation by 2025 and 84% by 2030.

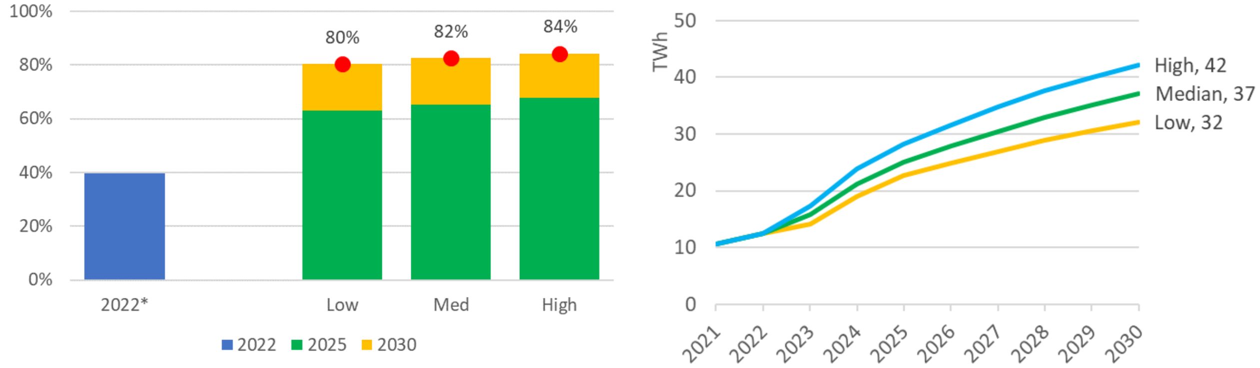


*Figure 6: RE share and total generation required to meet EirGrid GCS 2022 demand forecasts while remaining underneath sectoral carbon budget ceilings for CB1 and CB2. This assumes natural gas is the only fossil fuel un the generation mix from 2023, and the carbon intensity of gas-fired generation is 404 gCO_2/kWh. *2022 renewable generation is based on the first 6 months of 2022 and is based on SEAI monthly electricity generation data.*

In the “High” electricity demand scenario, the required renewable electricity generation in 2030 is 31% higher than in the “Low” scenario. This clearly has implications for the delivery of sectoral emissions ceilings: All else being equal, greater electricity demand from data centres must be met by renewable energy. Otherwise, other end-use sectors (transport, industry and buildings) may need to limit electricity demand, which is one of the main decarbonisation options available – this question is explored in later sections.

This analysis demonstrates that to meet the SECs, the power sector must rapidly and immediately deploy renewable electricity and concurrently manage electricity demand growth: high growth of electricity demand from data centres and large energy users puts the achievement of decarbonisation commitments under significant risk

It also demonstrates the necessity of considering the implications of alternative energy demand projections on the Climate Action Plan: given the barriers to renewable energy deployment, and the projected delays in offshore wind in particular, higher electricity demand makes delivering on Sectoral Emissions Ceilings more challenging. The key target for electricity in the 2021 Climate Action Plan is to achieve an 80% blend of renewable energy in the generation mix by 2030, which is only achieved in the “Low” data centre growth scenario.

This analysis assumes that electricity imports and exports through interconnectors are balanced. The potential for alternative electricity sources such as low-carbon gases or carbon capture and storage would change these results, increasing the allowable gas-fired generation. On the other hand, should other fossil fuels remain in the generation mix from 2023, it would decrease.

The following section outlines a comprehensive modelling exercise to quantify in more detail the requirement for new power generation capacity and climate mitigation pathways across all energy sectors to meet carbon budgets.

3.2 How is data centre demand growth driving the need for new natural gas capacity?

This section examines whether the need for new natural gas-fired power generation capacity is being driven minaly by the growth in electricity demand from data centres, or is mainly required to replace retiring older plant.

3.2.1 Modelling approach

The analysis is underpinned by the TIMES Ireland Model (TIM), which is an energy systems optimisation model that develops pathways for the Irish energy system to meet climate policy targets, given energy demands and technology deployment constraints at least cost (Figure 7). For a given scenario of energy demand dynamics, across all end-use sectors (transport, buildings and industry) and set of carbon budgets, the model determines the level of additional capacity investment in all energy technologies required.

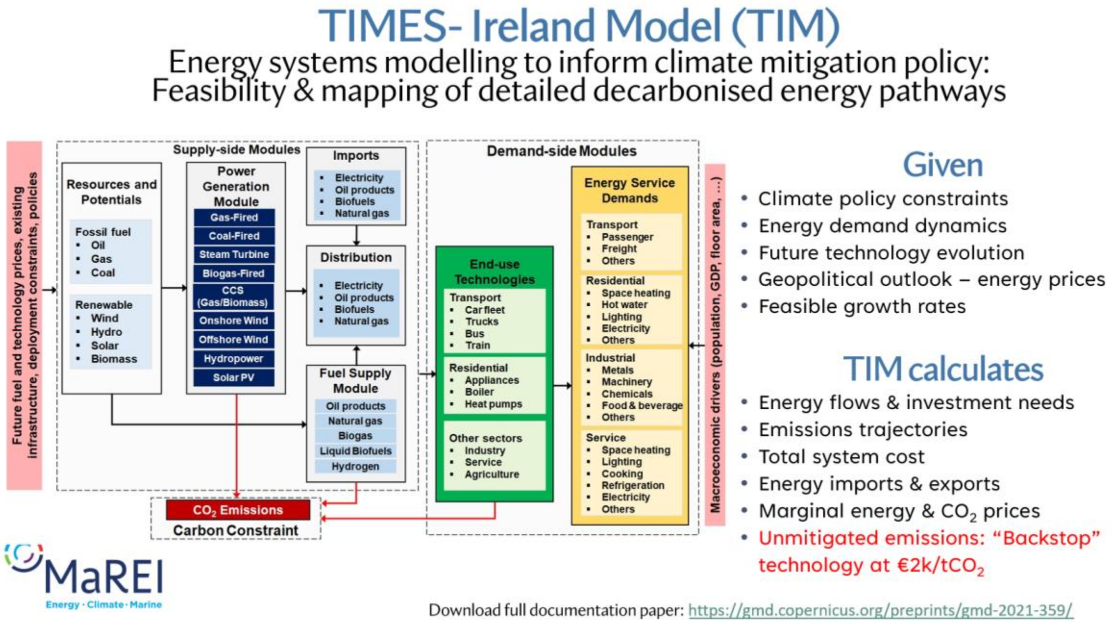


Figure 7: TIMES-Ireland Model[14]

TIM is open-source and peer-reviewed, and has been used to help inform national carbon budget ceilings through the Climate Change Advisory Council in 2021[15] and sectoral emissions ceilings in 2022[16]. A detailed description of the methodology is included in Section 5. *TIM is used to model the achievement of Ireland's announced sectoral carbon budget ceilings in the power sector and all energy-use sectors under four scenarios of data centre (DC) electricity demand growth, informed by scenarios depicted the EirGrid Generation Capacity Statement, 2022* *(Figure 8 and*

Table 3).

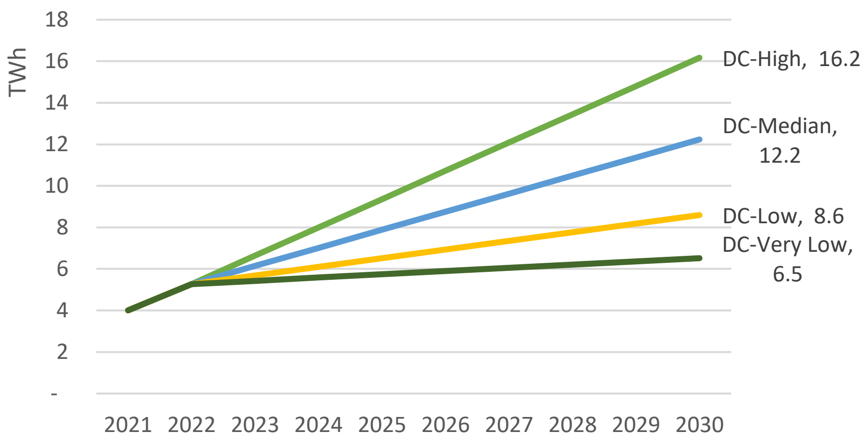


Figure 8: Scenarios for data centre electricity demand growth

[14] https://gmd.copernicus.org/articles/15/4991/2022/gmd-15-4991-2022.html
[15] https://www.climatecouncil.ie/carbonbudgets/technicalreport/
[16] https://www.gov.ie/en/publication/76864-sectoral-emissions-ceilings/

Table 3: Note that Data Centre electricity demand in 2020 was approximately 4 TWh[17]

Scenario	Overall DC electricity demand in 2030	Annual DC electricity demand growth
DC High	16.2 TWh	1.4 TWh/year
DC Medium	12.2 TWh	0.9 TWh/year
DC Low	8.6 TWh	0.5 TWh/year
DC Very Low	6.5 TWh	0.3 TWh/year

3.2.2 Additional natural gas capacity and generation

Given final energy demands across the entire energy system, SECs and the assumed feasible deployment of renewable electricity capacity, TIM calculates the level of investment and natural gas generation required to achieve each scenario while remaining within the power sector emission ceiling over carbon budgets 1 and 2.

Figure 9 (right) demonstrates that even under very low data centre demand growth, additional natural gas-fired power generation capacity is necessary, with 2 GW and 2.1 GW of additional capacity added in the “DC-Very Low” and “DC-Low” cases respectively. Relative to the “DC-Low” scenario, an additional 0.2 GW (200 MW) of natural gas capacity is necessary to meet electricity needs in the “DC-High” case. The majority of additional capacity investment in all cases is required to replace older and more carbon-intensive capacity, particularly in oil, coal and peat, and meet near-term capacity constraints in the electricity system. Of the additional capacity required, over 95% is required in 2023, according to the model.

However, Figure 9 (left) shows that despite the requirement for additional natural gas capacity, the actual operation of natural gas-fired power plants must fall in each scenario. This is particularly from 2025, for the power sector to remain within its Sectoral Carbon Budget (20 Mt CO_2 in Carbon Budget 2, from 2026 to 2030). Depending on the modelled scenario, electricity generation from natural gas must fall from 16 TWh in 2025, to between 4 and 9 TWh in 2030.

[17] https://www.cso.ie/en/releasesandpublications/ep/p-dcmec/datacentresmeteredelectricityconsumption2021/keyfindings/

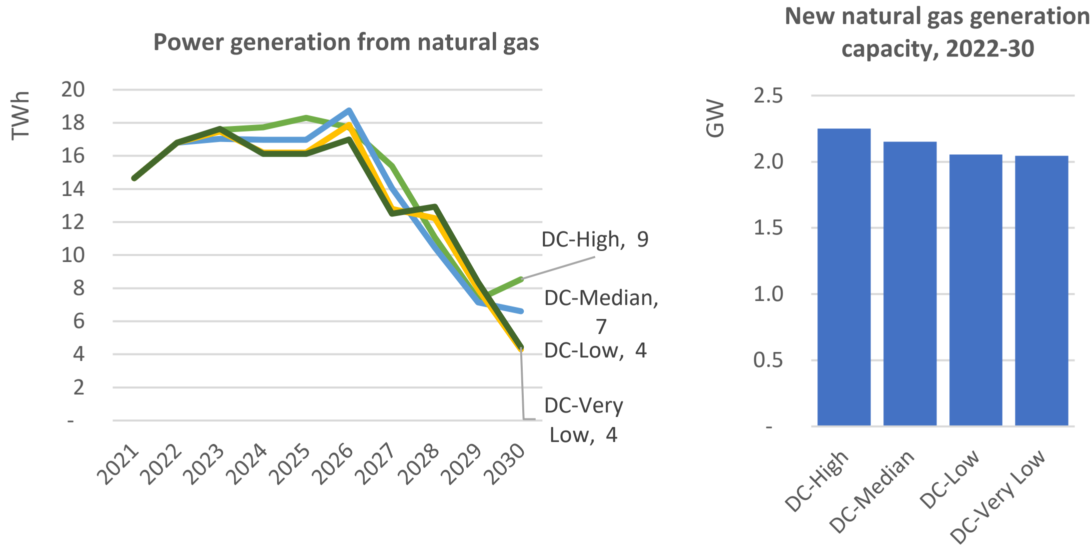


Figure 9: Natural gas-fired power generation (left) and new generation capacity (right) required to meet alternative scenarios for data centre electricity demand growth, 2021-30

As a result, in all scenarios, the share of time that existing natural gas generation capacity is used (its so-called capacity factor, or utilisation rate) declines from around 35% in 2021 to 8-15% in 2030 (Figure 10).

In particular, the gas capacity factor must halve during the second carbon budget period, otherwise (in the absence of breakthrough technologies such as carbon capture and storage), the sectoral emissions ceiling will be exceeded.

This decrease in utilisation is facilitated by more renewable electricity capacity in the system, which is explored in the next section.

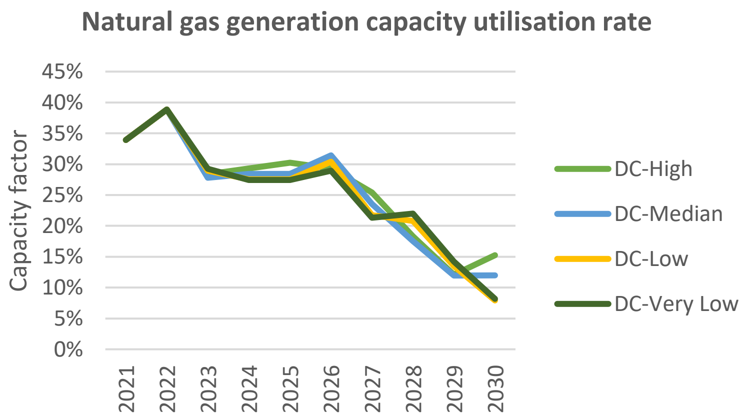


Figure 10: Capacity factor (utilisation rate) of natural gas power generation capacity

Delivering on the government-mandated SEC for the power sector requires an immediate increase in natural gas capacity (largely to replace existing, more polluting capacity) and at the same time, a decrease in its utilisation.

Unless this 2-2.2 GW of additional natural gas capacity is delivered in 2023, it is likely that more carbon-intensive fuel sources, largely from coal and oil, will remain in the generation mix beyond 2022. We do not explore this possibility in the model,

3.2.3 Additional renewable electricity generation and share

Figure 11 shows that across all scenarios, significant additional renewable electricity capacty is necessary: Around 5.5 GW of solar PV, 4.5 GW of onshore wind and 6.5-7.5 GW of offshore wind is necessary to meet electricity demand while allowing a phase-out of fossil fuel power generation, depicted in the previous section.

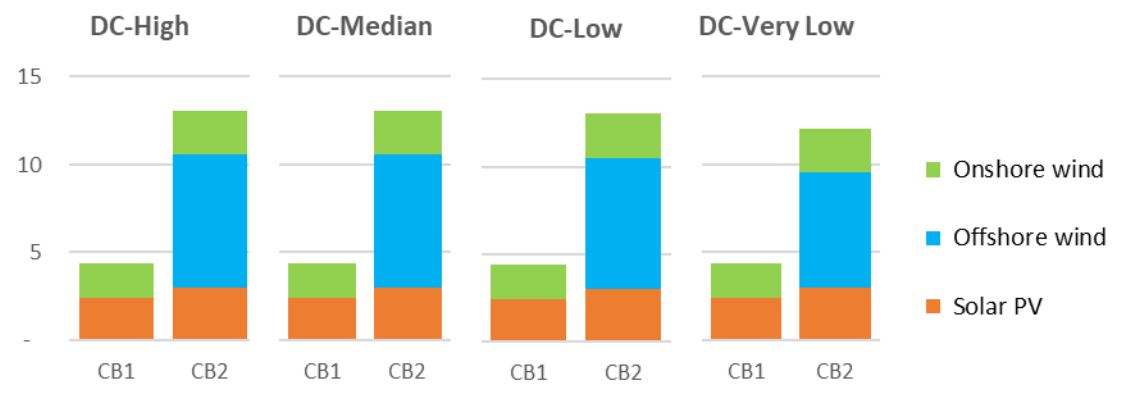


Figure 11: Additional renewable electricity generation capacity (GW) deployment required under alternate demand scenarios for carbon budget 1 (CB1, 2021-25) and carbon budget 2 (CB2, 2026-30).

The required annual deployment of renewable electricity generation capacity to fulfil these scenarios is unprecedented in Ireland for all scenarios. Onshore all-Island capacity additions over the period 2013-2020 averaged 400 MW per year, while delivering on carbon budget commitments requires this to increase to 560 MW each year each year in the period 2023 to 2030, while nearly 1 GW offshore wind and over 500 MW of solar PV additions are also required each year, from a practically zero starting point. Any failure to deliver on this capacity would lead to an increased utilisation rate of natural gas capacity, with consequent increase in emissions and risks to SECs.

This presents a very high risk for natural gas "lock in", whereby additional capacity would not be wound down as in Figure 10. One strategy to mitigate against this potential scenario is for mitigation strategies to not hinge solely on renewables deployment, but seek to maximise alternative mitigation options, including demand reduction, efficiency, district heating, green hydrogen, and carbon capture and storage (CCS).

3.2.4 Implications for cost and achievability of carbon budget programme

The previous sections demonstrated that high electricity demand from data centres is not the primary driving factor for new natural gas generation capacity, or renewable electricity capacity. However, higher data centre electricity demand makes delivery of several Sectoral Emissions Ceilings more costly and less feasible. This is because

Marginal Abatement Costs (MAC) is a key output of energy systems optimisation models. This metric represents the cost to the model of removing the most expensive tonne of CO_2 from the system and is a measure of how "achievable" or costly it is to deliver on CO_2 targets. Simplistically and theoretically, a MAC of €100 tonne of CO_2 (tCO_2) would be equivalent to the emissions reductions delivered by a carbon tax of the same amount, which is a policy target for Ireland in 2030.

Under "DC-High", there are no solutions available to the model for mitigating 1.2 $MtCO_2$ of the power sector's first overall sectoral carbon budget of 40 $MtCO_2$ at a cost of under €2000/tCO_2: this implies that this scenario is "infeasible" with high DC demand under the core model assumptions.

High DC electricity demand growth also increases the Marginal Abatement Cost of remaining within the SECs: Table 4 shows the average MAC across each Carbon Budget period by sector, and for the energy system as a whole. Of note in particular is the difference between the MAC in the power sector in CB2, which rises from €192/tCO_2 with "Very Low" DC growth, to €1227/tCO_2 with "High" DC growth. A similar but less strong pattern is reflected across all other sectors, with a higher average MAC observed in higher DC demand cases in CB2 across all sectors and the system.

Table 4: Average Marginal Abatement Cost (MAC, in €/tCO$_2$) in Carbon Budget 1 (CB1, 2023-25) and 2 (CB2, 2026-30) under alternative Data Centre demand trajectories.

	DC-Very Low		DC-Low		DC-Median		DC-High	
	CB1	**CB2**	**CB1**	**CB2**	**CB1**	**CB2**	**CB1**	**CB2**
Industry	1,924	1,852	1,924	1,852	1,924	1,852	1,924	1,852
Power	1,489	192	1,490	199	1,924	677	1,924	1,227
Services	1,924	1,095	1,924	1,115	1,924	1,769	1,924	1,882
Transport	1,924	1,852	1,924	1,852	1,924	1,852	1,924	1,852
Residential	1,270	450	1,270	444	1,453	677	1,460	952
Whole Energy System	**1,675**	**1,069**	**1,675**	**1,073**	**1,734**	**1,336**	**1,657**	**1,510**

The reason for this dynamic is that to remain within carbon budget, higher DC electricity demand limits the amount of electricity that can be consumed by other end-use sectors. Electrification is the most significant pathway for the decarbonisation of heat and transport, along with demand reduction and efficiency. Therefore, if additional electricity is not available to end-use sectors, more expensive options, including early phase-out of fossil fuel technologies, are necessary for individual sectors to meet their own SECs (Figure 12).

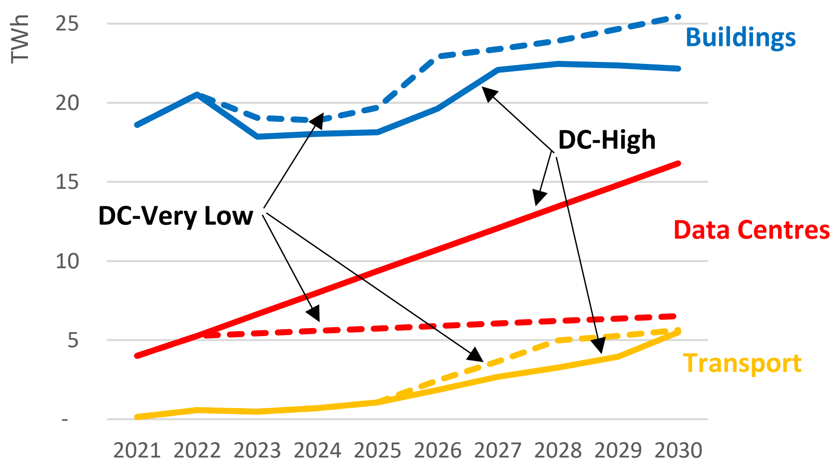


Figure 12: Electricity consumption by sector in "DC-High" (solid lines) and "DC-Very Low" (hatched lines).

This gap must be met by other mitigation options, such as demand reduction and efficiency or biofuels. In this analysis, energy demands are fixed and the model meets the mitigation gap with additional biofuels at significant additional cost. Figure 13 demonstrated that by 2030, the overall cumulative additional annualised cost of mitigation in the “DC-High” case relative to “DC-Very Low” amounts to €17 bn this decade, and €40bn in the period to 2050.

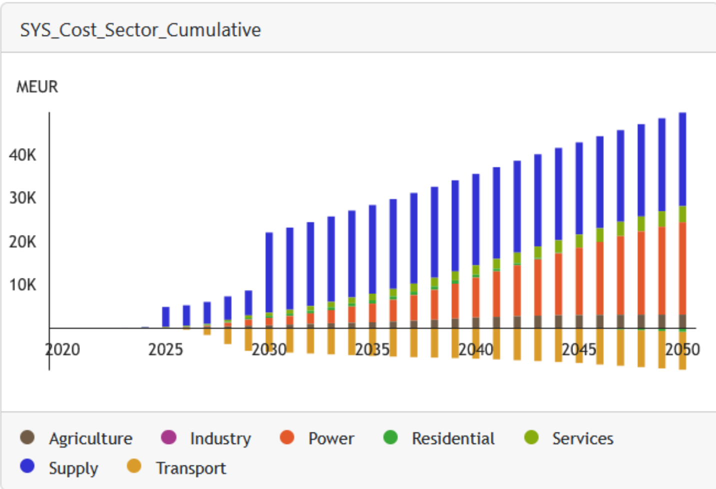


Figure 13: Additional cumulative annualised cost of mitigation in "DC-High" relative to "DC-Very Low", including investment, operational, fuel and fixed costs.

It is important to note that this analysis does not take account of “unallocated savings”, which are a gap between sectoral emissions ceilings and the economy-wide carbon budgets in the second period, from 2026-30. This will need to be allocated across sectors, and should savings be sought from the energy system, it will lower the allowable SECs in some or all sectors.

3.2.5 The potential for greater renewable electricity deployment

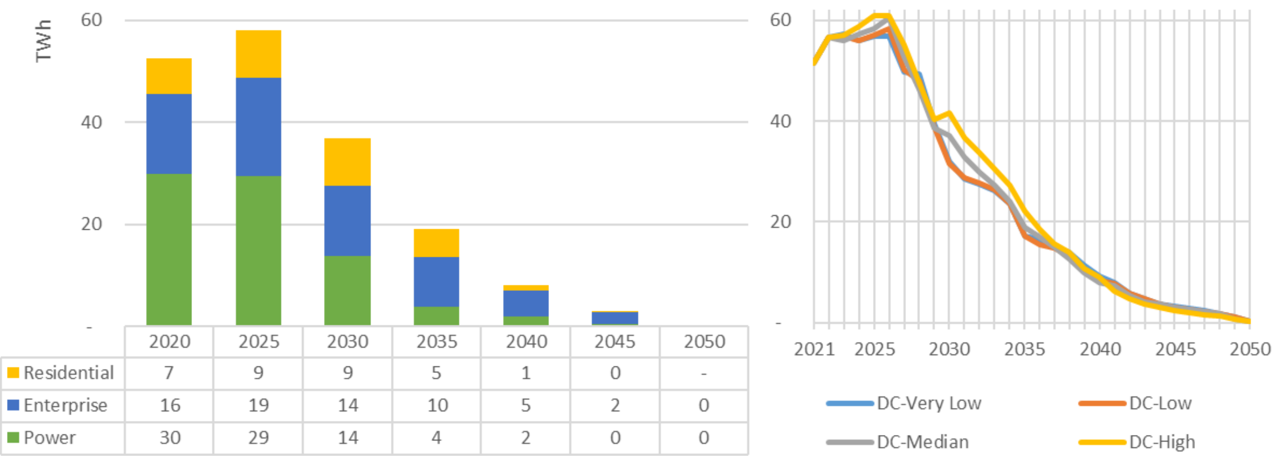
In addition to SECs and electricity demand scenarios, the required renewable electricity generation capacity for each scenario outlined in Section 3.2.3 is also determined by the assumed feasible rates of deployment of renewable electricity capacity, which is informed by industry and policy estimates. It is assumed, for example, that 0.5 GW of new onshore wind energy capacity can be delivered annually (reaching 8.3 GW by 2030), that offshore wind can be deployed from 2026 at 2 GW annually (reaching 7.5 GW by 2030), and that total solar PV capacity can reach 5.5 GW each year by 2030. In a scenario where the model can build renewable electricity capacity at even faster rates, the investment in new natural gas capacity in 2023 is not decreased, but the energy system can generate more electricity to enable faster decarbonisation of end-use sectors, lowers cost and increases the feasibility of the carbon budget programme.

4 THE FUTURE OF NATURAL GAS IN IRELAND'S ENERGY TRANSITION

This section examines the role of gas in the energy transition consistent with Ireland's carbon budgets over the period to 2030 and 2050, and analyses forecasts of natural gas demand from Gas Networks Ireland.

Achieving carbon budgets requires a rapid reduction in fossil fuel demand across all fuels and scenarios. For example, in the "DC-Median" case, overall natural gas primary energy demand falls by 30% between 2020 and 2030 in the TIM analysis (Figure 14), from 53 TWh to 37 TWh, and by a further 78% over the period 2030-2040 to 8 TWh.

A similar pattern is observed across all scenarios, with lower energy demand from data centres, natural gas demand reduces even further: Figure 14 (right) shows Total Primary Energy Demand (TPED) for natural gas (Right). The most notable difference across all demand scenarios is a 30% greater consumption of natural gas in "DC-High" in 2030 relative to "DC-Low" and "DC-Very Low".



	2020	2025	2030	2035	2040	2045	2050
Residential	7	9	9	5	1	0	-
Enterprise	16	19	14	10	5	2	0
Power	30	29	14	4	2	0	0

Figure 14: Natural gas demand by sector in "DC-Median" (Left) and natural gas Total Primary Energy Demand (TPED) (Right). "Enterprise" refers to Industry and Services (Commercial and Public).

In a scenario where we assume that renewable electricity capacity can be deployed at a faster rate than in the core scenarios, with total RE capacity reaching 25 GW in 2030 (compared with 21 GW in our core assumptions), natural gas demand falls even further in 2030, to 29 TWh, almost a halving of natural gas demand in the 2020s.

This scenario contrasts with projections for natural gas demand from Gas Networks Ireland (GNI) Network Development Plan, 2021 (Figure 15), where demand in 2030 is projected to remain equal or greater than in 2020, at 60-70 TWh, significantly higher than even the "DC-High" case in our analysis.

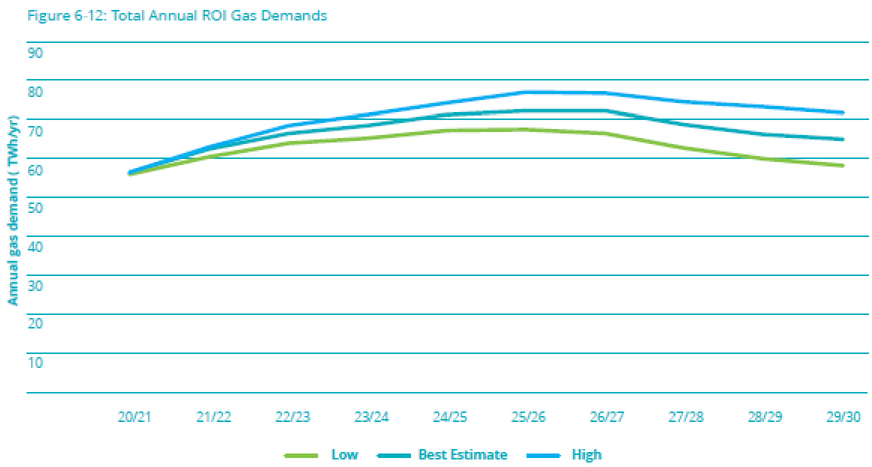


Figure 15: Total annual gas demand scenarios for Ireland, Gas Networks Ireland Network Development Plan 2021

The "Best Estimate" scenario in the GNI Networks Development Plan 2021 projects that natural gas demand grows to 65 TWh by 2030. Table 5 compares gas demand by sector in this section with that of the "DC-Median" scenario in TIM, which is consistent with Sectoral Emissions Ceilings. In TIM analysis, total primary gas demand falls to 37 TWh, 43% lower than GNI's "Best Estimate" scenario. The main difference is in the power sector, where TIM projects gas demand to be 60% (21 TWh) lower than GNI, and industrial and commercial sectors, where TIM projects demand at 34% (7 TWh) lower than GNI in 2030. By contrast, TIM projects 28% greater residential gas demand (2 TWh) in 2030.

Table 5: Comparison of natural gas demand in GNI and TIM scenarios in 2030

Sector	GNI "Best Estimate"	TIM "DC-Median"	Difference
Power	35 TWh	14 TWh	-60%
Industrial and commercial	21 TWh	14 TWh	-34%
Residential	7.3 TWh	9 TWh	+28%
Transport	0.6 TWh	0 TWh	-
Total	65 TWh	37 TWh	-43%

The primary difference between these analyses is that in the TIMES-Ireland Analysis, the model selects the cost-optimal and feasible energy fuel and technology mix in order to comply with SECs and incorporates a long-term trajectory to a zero-carbon energy system. GNI in its analysis does not take into account the new carbon budget programme and SECs, given that the analysis was undertaken before the Government decision and announcement. For GNI, gas demand is projected on the basis of the power sector delivering a 70% share of renewable electricity by 2030 and strong anticipated growth in the industry and commercial sectors driven by growth in the economy. It also assumes in the "Best Estimate" scenario that Daily Metered connections will be 16% higher – the modelling for this sector includes assumed efficiency improvements from the NEEAP4 measures, but not the potential for fuel switching. In the residential sector, TIM projects that in order to meet its SEC, homes heated with oil are the primary target for deep retrofit and electrification. However, if this is not borne out, gas demand in this sector will need to be substantially reduced, by more than is suggested in the TIM analysis.

5 ANNEX: METHODOLOGY

5.1 TIMES-IRELAND MODEL

The TIMES-Ireland Model produces energy system pathways for energy supply and demand in Ireland consistent with either a carbon budget or a decarbonisation target. It calculates the lowest cost configuration of energy fuels and technologies which meet future energy demands, while respecting technical, environmental, economic, social, and policy constraints (Figure 16). Key inputs and constraints include primary energy resource availability and costs, the technical and cost evolution of new mitigation options, and maximum feasible uptake rates of new technologies. Alternatively, TIM can be used to assess the implications of certain policies, namely regulatory or technology target setting (for example, biofuels blending obligation or the sales/stock share target for electric vehicles).

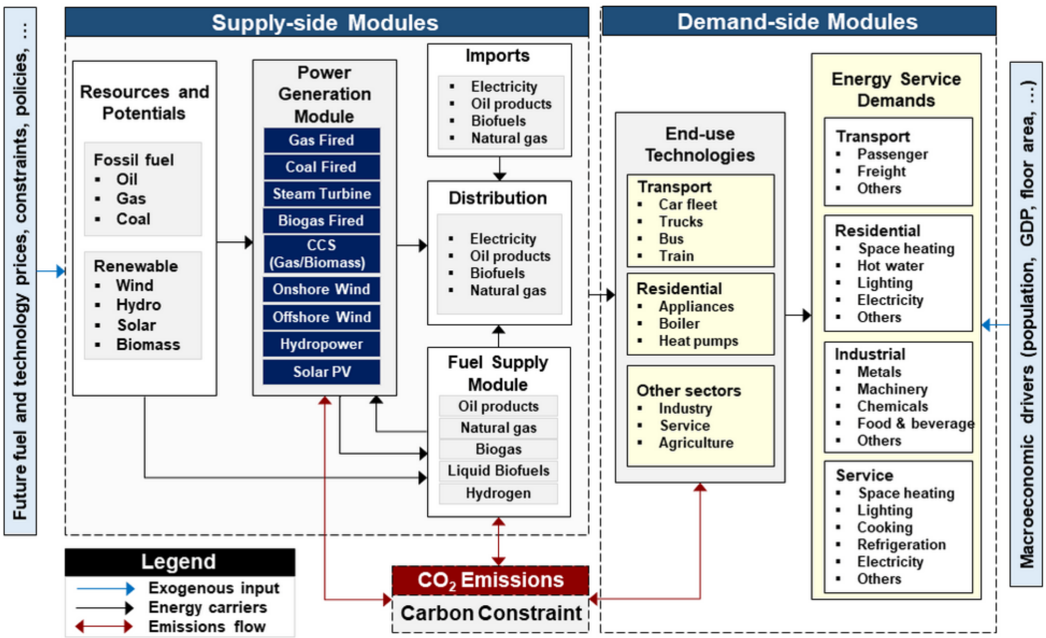


Figure 16: Simplified representation of reference energy system in TIM

TIMES (The Integrated MARKAL-EFOM System) is a bottom-up optimisation model generator for energy–environment systems analysis at various levels of spatial, temporal, and sectoral resolutions[18]. The TIMES code, written in GAMS and available under an open-

[18] https://iea-etsap.org/docs/Documentation_for_the_TIMES_Model-Part-I_July-2016.pdf

source licence, is developed and maintained by the Energy Technology Systems Analysis Programme (ETSAP[19]), a Technology Collaboration Programme (TCP) of the International Energy Agency (IEA), established in 1976. TIMES models can have single or several regions and are typically rich in technology detail, used for medium- to long-term energy system analysis and planning at a regional, national, or global scale.

TIMES is a linear optimisation, technoeconomic, partial equilibrium model generator which assumes perfectly competitive markets and perfect foresight. Model variants enable myopic foresight, general equilibrium, stochastic programming, and a variety of multi-objective function options. The standard objective function maximises the net total surplus (the sum of producers' and consumers' surpluses) which, in a perfect market with perfect foresight, equates to maximising the net present value (NPV) of the whole energy system, maximising societal welfare. Profits, taxes, and subsidies are internal transfers, i.e. occurring within the economy, that do not change the NPV (albeit that taxes and subsidies can be included to influence the optimisation). It calculates the energy system specification which minimises the discounted total energy system costs over the model time horizon, which is the sum of investments, fixed and variable costs, fuel import costs, and export revenues for all the modelled processes less the potential salvage values of investments for which the whole lifetime goes beyond the model time horizon.

The user inputs the following to the model generator:

- Reference energy system (RES), which is the process-flow architecture of economic sectors and energy flows (commodity) between processes (technology), which consume and produce energy, energy service demands, and/or other commodities such as environmental emissions (including greenhouse gases) and other materials. The base year energy flows are calibrated to national energy balances.
- Energy service demands are the physical services required by the economy and society for mobility, heat, communications, food, etc., which drive energy demand.
- Energy supply curves are the quantities of primary energy resources (e.g. wind power) or imported commodities (e.g. oil, gas, and bioenergy) available at specific costs points for differing quality and quantity of energy commodities.
- Technoeconomic parameters of existing and potential future energy technologies are economic parameters including current and projected future investment and fixed/variable costs and efficiencies of technologies for energy supply (e.g. solar PV

[19] https://iea-etsap.org/

panels, transmission and distribution infrastructure, biorefineries, and hydrogen production) and energy demand (e.g. electric vehicles, natural gas boilers, and carbon capture and storage). Technological parameters include the transformation efficiency, availability factor, capacity factor, and emissions factor.

- User constraints, which can be any combination of linear constraints (including fixed, maximum, or minimum bounds on growth, investment, or shares) on technologies or fuels. These are typically used to simulate real-world technology constraints or to simulate policy scenarios. A typical user constraint for decarbonisation analysis is limiting total annual or cumulative CO2 emissions to model energy system pathways that meet a national decarbonisation target.

TIMES outputs the optimal investment and operation level of all energy technologies which meet future energy service demands at least cost, while respecting user constraints. The model also produces corresponding energy flows, emissions, and marginal prices of energy and emissions flows.

TIM has been developed with the goal of achieving best-practice standards in software development and open modelling convention. A Git-centred model development process has been an integral part of the model development approach to enable version control and model management. Along with improvements in management, quality assurance, and transparency this brings, it also allows developers and researchers from different projects to branch research versions of the model to explore innovations and new developments, while keeping a secure and stable main version of the model for policy application. At the same time, individual projects and researchers can input their improvements and developments to the core model to enable continuous improvements.

TIM is freely available, which is a prerequisite for transparency, repeatable research, model maintenance, and enhancement and verification of results[20]. Internationally, TIMES models are used in a number of countries to understand and plan for long-term energy transitions, including in Denmark[21], and the United Kingdom[22]. An innovative web-based dashboard[23] have been extensively used in the model development process, both for internal model

[20] https://www.sciencedirect.com/science/article/pii/S2211467X17300809
[21] https://www.sciencedirect.com/science/article/pii/S2211467X18301044
[22] https://pubs.acs.org/doi/full/10.1021/acs.est.5b01020
[23] https://tim-review1.netlify.app/results/

diagnostics and for external engagement and review. The first TIM scenario results archive has also been made freely available[24]

5.2 Scenario specification

TIM underpins the energy systems analysis described in Section 3.2 and 4. Key assumptions underpinning any energy systems analysis, as outlined above, includes future energy demand growth, climate policies, technology costs and maximum new technology deployment rates.

Core assumptions and baseline data in this study are derived from previous published model documentation[25] with the addition of energy flows and GHG emissions calibrated for 2021, following the publication of Environmental Protection Agency (EPA) GHG inventories for that year. In addition, these scenarios meet climate targets without relying on negative emissions technologies (NETs) including Bioenergy with Carbon Capture and Storage (BECCS).

New scenarios were developed for this study. In each scenario, the energy system meets the Sectoral Emissions Ceilings for the power, transport, buildings and industry sectors, as set out in the Government decision on 28 July 2022 (

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[24] https://zenodo.org/record/5517363

[25] https://doi.org/10.5194/gmd-15-4991-2022

Figure 17)[26], and constrains total CO_2 emissions from the energy system between 2031-2050 to 109 $MtCO_2$.

	2018 Baseline (MtCO2eq.)[4]	Sectoral Emission Ceilings for each 5-year carbon budget period (MtCO2eq.)		Indicative Emissions in Final Year of 2021-2025 carbon budget period (MtCO2eq)	Indicative Reduction in Emissions in Final Year of 2021-2025 budget period compared to 2018	Emissions in final year of 2026-20230 carbon budget period (MtCO2eq)	Reduction in Emissions final year of 2026-2030 carbon budget period compared to 2018	Agreed CAP21 Ranges
Sector	2018	2021-2025	2026-2030	2025	2025	2030	2030	2030
Electricity	10	40	20	6	~40%	3	~75%	60 – 80%
Transport	12	54	37	10	~20%	6	~50%	40 – 50%
Built Environment - Residential	7	29	23	5	~20%	4	~40%	45 – 55%[5]
Built Environment - Commercial	2	7	5	1	~20%	1	~45%	
Industry	7	30	24	6	~20%	4	~35%	30 – 40%
Agriculture	23	106	96	20	~10%	17.25	~25%	20 – 30%
LULUCF[6]	5	XXX	XXX	XXX	XXX	XXX	XXX	40 – 60%
Other (F-Gases, Waste & Petroleum refining)	2	9	8	2	~25%	1	~50%	N/A
Unallocated Savings[7]			*-26*			*-5.25*		
TOTAL[8]	*68*	*XXX*	*XXX*	*XXX*	*XXX*	*XXX*	*XXX*	*N/A*
Legally binding Carbon Budgets and 2030 Emission Reduction Targets[9]	-	295	200	-	-	34	51%	-

Figure 17: Sectoral emissions ceilings

The 8 new scenarios show how the energy system can meet these carbon budgets under alternative assumptions for: i) Future data centre demand growth, and ii) maximum feasible deployment of renewable electricity capacity this decade.

[26] https://www.gov.ie/en/publication/76864-sectoral-emissions-ceilings/

i. **Future data centre demand growth**: Figure 18 depicts four future data centre electricity demand growth scenarios. High, Median and Low scenarios are based on EirGrid's 2022 Generation Capacity Statement and we include an additional "Very Low" growth scenario.

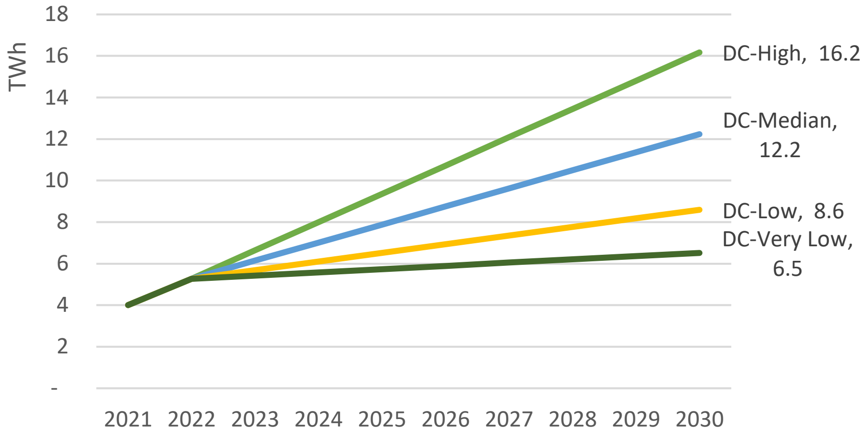

Figure 18: Scenarios for data centre electricity demand growth

ii. **Maximum feasible deployment of renewable electricity (RE) capacity:** Core mitigation scenarios assume the following maximum potential for future RE deployment in the 2020s.

TECHNOLOGY	CORE SCENARIOS	HIGH-RE SCENARIOS
ONSHORE WIND	0.5 GW annual additional capacity	0.5 GW annual additional capacity
OFFSHORE WIND	1 GW deployed in 2026, maximum 2 GW each year from 2027	1.5 GW deployed in 2026, maximum 3 GW each year from 2027
SOLAR PV	0.5 GW new capacity potential in 2023, with 20% per year annual growth potential	0.6 GW new capacity potential in 2023, with 30% per year annual growth potential

Full model inputs and outputs are archived and are available upon request from the authors.