REGEN

Northern Ireland Electricity Networks

NIE Networks

Distribution network planning scenarios

Credible future scenarios for the electricity distribution network in Northern Ireland.

About NIE Networks

NIE Networks is the distribution network owner and distribution network operator for Northern Ireland. Electricity distribution involves the transfer of electricity from the high voltage transmission network and its delivery to consumers across a network of overhead lines and underground cables operating at 33kV, 11kV and lower voltages. These networks enable the delivery of electricity from generators to customers. NIE Networks also own the transmission network in Northern Ireland, operated by SONI (System Operator for Northern Ireland).

About Regen

Regen provides independent, evidence-led insight and advice in support of our mission to transform the UK's energy system for a net zero future. We focus on analysing the systemic challenges of decarbonising power, heat and transport. We know that a transformation of this scale will require engaging the whole of society in a just transition.

Acknowledgements

We would like to express our appreciation to stakeholders who contributed to the development of the distribution network planning scenarios detailed in this report.

This report was sponsored by	NIE Networks
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Approved by	Ray Arrell, Associate director
Version	V3 – 02/06/2025

Contents

Section 1:

Introduction

Scenario development context

1.1. **Background**

The distribution network planning scenarios detailed in this report outline credible future scenarios for new and expanded electricity loads connecting to the distribution network in Northern Ireland. Northern Ireland has set ambitious decarbonisation targets, including achieving 80% renewable electricity generation by 2030, as outlined in the Department for the Economy's Energy Strategy and legislated in the Climate Change Act (Northern Ireland) 2022[1,2]. This policy framework, combined with global reductions in clean energy technology costs, has already driven significant growth in renewable generation and initiated the electrification of transport, heat, and industry in Northern Ireland.

However, decarbonisation of demand in Northern Ireland has been slower than in other parts of the UK to date. Heat decarbonisation has been a particular challenge, with policies to encourage uptake of electric heating technologies yet to be introduced. This regional context is reflected in the scenarios with slower uptake in the short term.

As decarbonisation progresses, it is anticipated that the utilisation of the electricity distribution network will significantly increase. Historically, distribution networks have been designed to economically provide capacity for demand. In the context of energy for heat and transport, this has previously been provided by fossil fuels, rather than electricity. The Utility Regulator has emphasised the need for the energy system to adapt to accommodate low-carbon technologies[3]. In response to this challenge, NIE Networks has developed a business plan for the RP7 regulatory price control period covering April 2025 to March 2031. This plan details the network investments and strategies required to meet these evolving demands.

To further support long-term planning, NIE Networks has collaborated with Regen, an independent mission-based advisory organisation with extensive experience in developing future energy scenario projections for GB distribution network operators, to develop the distribution network planning scenarios detailed in this report [4] [5]. These scenarios combine a

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[1] Northern Ireland Energy Strategy 'Path to Net Zero Energy', 2021

[2] Climate Change Act (Northern Ireland) 2022

[3] Page 14, Delivering on decarbonisation, Utility Regulator Corporate Strategy, 2024-2029

[4] Distribution Future Energy Scenarios, National Grid Electricity Distribution

[5] Distribution Future Energy Scenarios, SSEN Distribution

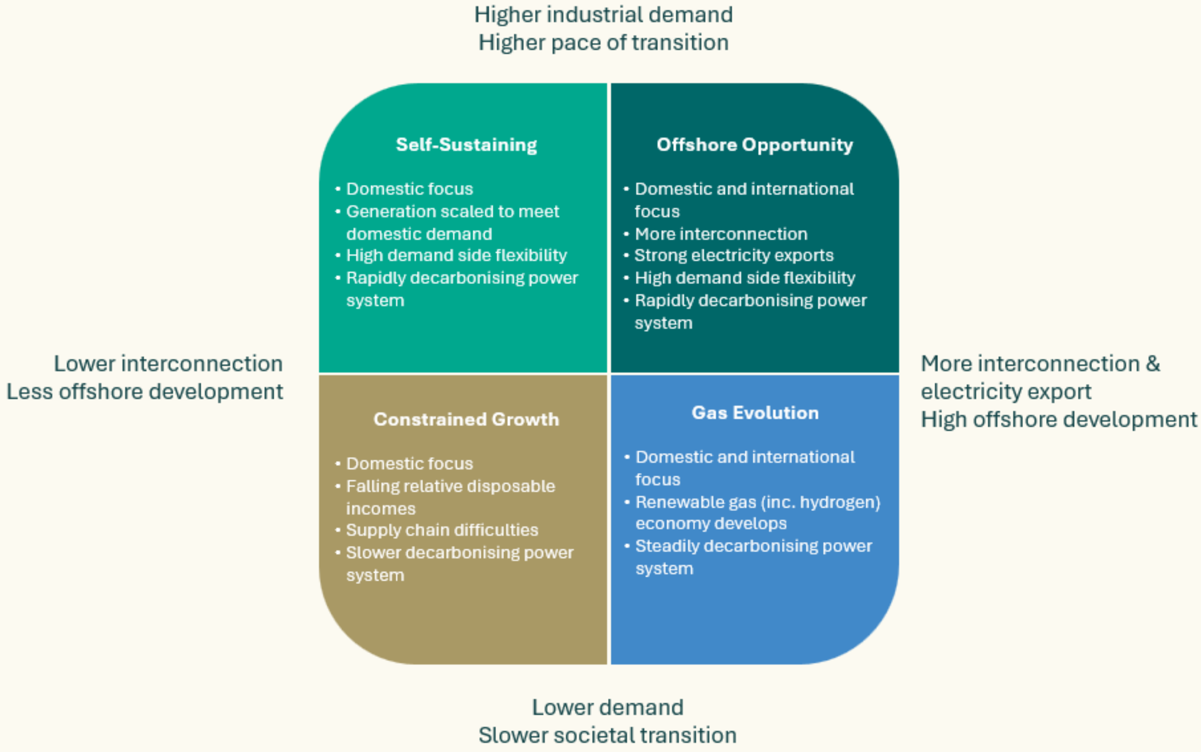
data, evidence and stakeholder-driven approach to assessing potential future electricity demand, generation and storage growth (or reduction) on the distribution network. This acts as an evidence base to demonstrate how the network could adapt to the evolving energy landscape and enable the delivery of Northern Ireland's decarbonisation targets, while maintaining a secure and reliable electricity supply to customers.

1.2. Scenario framework

The distribution network planning scenarios developed in this project make use of the TES 2023 as the overarching scenario framework, with the same national-level societal, technological and economic assumptions adopted.

For the near and medium terms, a bottom-up, evidence and data-driven analysis of the changing energy system has been carried out at the distribution network level. This reflects regional drivers for the uptake of renewable energy and low carbon technologies, and the reduction of legacy/fossil fuel technologies connected to the distribution network. In the longer term, the projections are modelled to align towards the TES 2023 projections for relevant technologies.

Figure 1



Regen has worked with the team at NIE Networks to develop a new methodology for Northern Ireland, to translate the national TES framework, energy policy, project pipelines, stakeholder input and market developments into distribution network scenario projections. The scenarios depict four different future worlds, as summarised in Table 1.

Table 1

Scenario	TES 2023 scenario description[6]	Implications for distribution network
Self-Sustaining	Self-Sustaining considers a future where there is a very high penetration of renewables across all technologies – onshore and offshore wind, large scale solar, rooftop solar, and grid-scale energy storage – and this clean energy attracts new industry and development to Ireland and Northern Ireland. There is also a very high penetration of electric vehicles, as well as residential and commercial heat pumps. This scenario results in a net zero power system from 2040 and an overall rapid pace of decarbonisation.	The rapid and sustained development of renewables and storage technologies in this scenario across all scales, results in a significant increase in distribution-connected capacity in response to supportive renewables policy measures. High levels of disposable income and strong consumer engagement in the transition, drive very rapid deployment of electric vehicles and low carbon heating technologies, requiring distribution network connections and capacity. A key differentiator between this scenario and the Offshore Opportunity scenario is its emphasis on domestic onshore renewables over offshore wind. This drives higher levels of distribution-connected generation, while heat pump adoption accelerates faster than in any other scenario as households seek to maximise bill savings by pairing rooftop solar with electric heating.
Offshore Opportunity	Offshore Opportunity is similar to Self-Sustaining, where it includes very high levels of offshore wind capacity and interconnection to Great Britain and continental Europe. In Offshore Opportunity, however, the buildout of offshore wind capacity is given a much higher priority and represents a greater opportunity for the whole island energy system. The large amount of clean electricity generated by offshore wind enables economic development, increasing energy exports and a portion of renewable generation is also used to create green hydrogen	Whilst the pace of transition towards a decarbonised power system is rapid in this scenario, the long-term increase in renewable generation and storage technologies on the distribution network is lower than the Self-Sustaining scenario. This corresponds to higher levels of transmission connected offshore wind development. High levels of disposable income, strong consumer engagement in the transition, and introduction of supportive policy measures drive higher sales of vehicles, with a rapidly increasing market share of EVs, and rapid installation of low-carbon heating

[6] Page 37, TES 2023 Full Report, SONI

Scenario	TES 2023 scenario description[6]	Implications for distribution network
	for power generation. Offshore Opportunity also features a rapid transition towards a net zero power system from 2040.	technologies. Higher levels of economic activity lead to higher annual vehicle sales and consequently an increase in the overall number of vehicles on Northern Ireland's roads.
Gas Evolution	Gas Evolution sees the energy transition being supplemented by a potential hydrogen economy. It features significant amounts of renewable power being converted, at scale, into green hydrogen. Due to more widespread use of hydrogen, the overall electricity demand on the transmission system is lower than under the previous scenarios. However, a portion of electricity demand will develop outside of the transmission system to produce green hydrogen. The pace of decarbonisation in Gas Evolution is steady, targeting net zero power system from 2045.	This scenario is characterised by an emphasis on transmission-scale generation to maximise energy exports, the development of renewable gas (including hydrogen), a steadily decarbonising power system and moderate levels of disposable income. For the distribution network, this means a slower pace of renewable generation deployment and a greater focus on transmission-connected generation sources. Adoption of low carbon demand technologies connecting to the distribution network is slightly slower in this scenario.
Constrained Growth	Constrained Growth reflects a future where the energy transition proceeds at a slower pace, and it takes longer to achieve climate targets for the power system and other sectors of demand. Under this scenario, offshore wind develops slowly, as does interconnection with other countries. Electric vehicle roll-out is also slower, and electrification of heat and other demand progresses more slowly. In Constrained Growth, the net zero power system target is 2050.	This scenario reflects a world where the energy transition in Northern Ireland has to overcome numerous challenges, including lower levels of economic activity and falling levels of disposable income. These challenges lead to delayed and lower EV uptake, and delayed uptake of electric heating technologies. Whilst this scenario has the slowest rate of decarbonisation overall, the focus on generation for domestic purposes, (rather than for export), involves more renewable capacity connecting at distribution level (over larger transmission generation) to meet increases in electricity demand from heat and transport electrification.

1.3. Stakeholder inputs

In addition to information and analysis provided to Regen by NIE Networks, these scenarios have been informed by a range of further inputs. Stakeholder engagement and regional and local input are cornerstones of Regen's approach to developing network planning scenarios.

While this analysis uses TES 2023 as the overriding framework, the scenario projections are directly informed by stakeholder engagement to reflect regional ambitions and the targets and policies of the Northern Ireland Executive. The views of other stakeholders, such as project developers, technology companies, trade associations and local authorities also influence the analysis.

Table 2

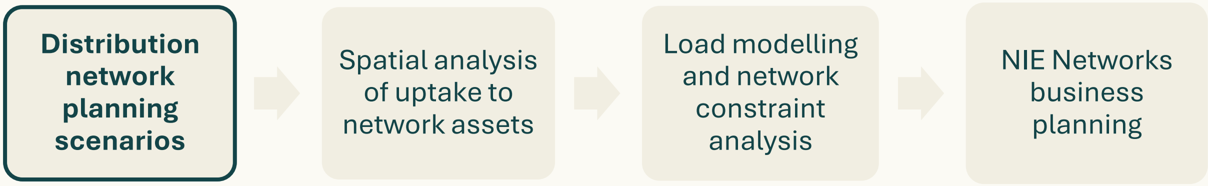
Stakeholder engagement approaches	
1	**Consultation webinar**: Interactive online webinar where a broad range of stakeholders were asked for their views on the future of energy technology sectors in Northern Ireland.
2	**Government departments workshop:** An online workshop with representatives from Northern Ireland Executive departments, exploring cross-departmental policies that could influence distribution network planning.
3	**SONI workshop:** An online workshop with the System Operator for Northern Ireland (SONI), exploring the development of the TES 2023 publication/data and integration with transmission network planning.
4	**Energy project developer engagement:** Informal interviews were conducted with technology, industry and sector-specific stakeholders, such as project developers and trade associations, to understand market trends, important policies, and key barriers to deployment/uptake.

A full list of organisations engaged throughout the project is provided in Section 4: Appendix.

1.4. **How these scenarios are used**

The scenarios developed in this project underpin a series of further analytical, network impact and business planning processes that enable NIE Networks to meet the evolving needs of their

Figure 2



customers throughout the energy transition. The licence area level load growth projections are the first input to a wider process that enables NIE Networks to model changes to future electricity flows across the network and subsequently assess where network interventions are needed, to ensure the capacity is available at the right time and place.

1.5. **Technology and sector scope**

The scenarios provide projections for electricity demand, generation and storage sectors:

- **Electricity demand** from electric vehicles and electric heating technologies
- **Electricity generation** such as solar, wind, fossil-fuelled generation and bioenergy
- **Electricity storage technologies** focusing on battery storage at various scales.

The full sector, technology and sub-technology scope is detailed below.

Table 3

Sector or technology	Subtechnology	Primary unit	Annual electricity demand unit
Electric vehicles	Cars (battery electric vehicles)	Number of vehicles	Annual consumption (GWh)
	Cars (plug-in hybrid electric vehicles)		
	LGVs (battery electric vehicles)		
	LGVs (plug-in hybrid electric vehicles)		
	HGVs		
	Buses and coaches		
	Motorcycles		
Electric vehicle chargepoints	Domestic	Number of properties	

Sector or technology	Subtechnology	Primary unit	Annual electricity demand unit
	Public slow chargepoints (below 50 kW)	Installed capacity (MW)	Annual consumption (GWh)
	Public rapid chargepoints (50 kW or over)		
	Workplace and fleet chargepoints		
Electric heat (domestic and non-domestic)	Air source heat pumps	Number of properties	Annual consumption (GWh)
	Ground source heat pumps		
	Hybrid heat pumps		
	Direct electric		
	Heat networks		
Other demand	Large demand projects	N/A	N/A
Generation technologies	Onshore wind	Installed capacity (MW)	N/A
	Thermal generation		
	Utility scale solar		
	Commercial solar		
	Domestic scale solar		
Electricity storage technologies	Utility scale storage	Installed capacity (MW)	N/A
	Commercial scale batteries		
	Domestic scale batteries		

Section 2:

Demand

Approach and modelling results

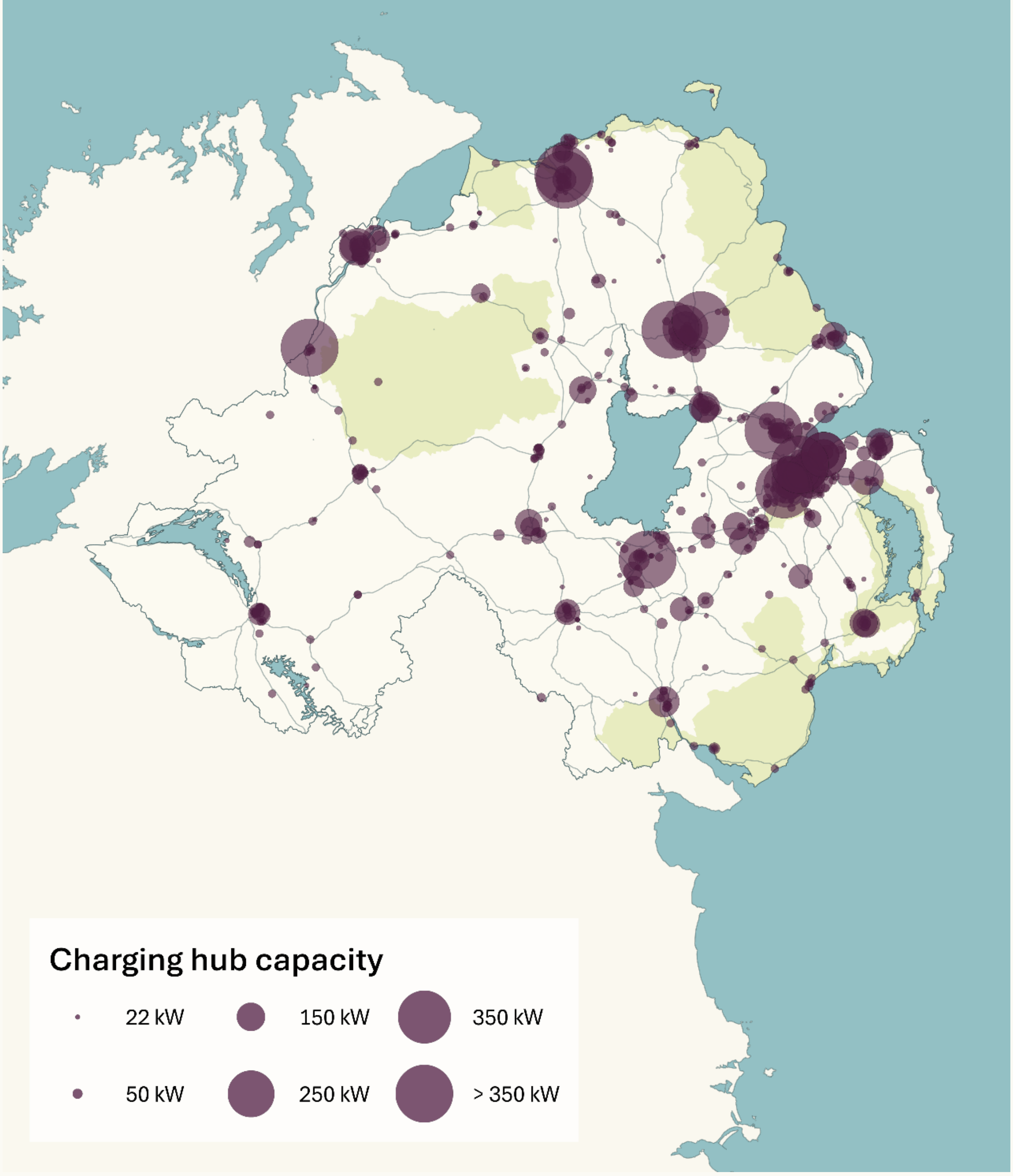
This section includes the approach and modelling results for the following demand-side technologies:

- Electric vehicles and EV chargepoints
- Electric heating technologies
- Other demand

Figure 3

EV Charging

Northern Ireland's charging infrastructure has expanded rapidly in recent years. The majority of chargepoints are located in and around Belfast. Outside Belfast, charging points are predominantly located along strategic trunk roads and near larger urban areas.



2.1. Electric vehicles and chargepoints

This analysis for electric road-transport is broken down into the following electric vehicle (EV) and electric vehicle chargepoint categories:

Table 4

Vehicle and charge point categories		
Vehicles	Cars	Battery and plug-in hybrid electric vehicles
	Light goods vehicles (LGVs)	Battery and plug-in hybrid electric vehicles
	Heavy goods vehicles (HGVs)	Battery electric vehicles
	Buses and coaches	Battery electric vehicles
	Motorbikes	Battery electric vehicles
EV chargepoints	Domestic	Homes where EV charging is taking place regularly via domestic electricity supply
	Public rapid	Public chargepoints 50 kW or over
	Public slow	Public chargepoints under 50 kW including car parks, destinations and on-street charge points.
	Workplace and fleets	Charging for commuters at places of work, as well as charging for vehicles that return to a depot for garaging.

2.1.1. Summary

Around 3% of vehicles in Northern Ireland are estimated to be battery electric or plug-in hybrid in 2024. This is anticipated to increase substantially under every scenario in the future, as the transport sector decarbonises through electrification in Northern Ireland.

The Zero Emission Vehicle mandate, introduced in Northern Ireland earlier in 2025 as part of the Vehicle Emissions Trading Schemes (VETS), is assumed to drive adoption of electric vehicles in all scenarios. UK government targets for electric vehicle sales are met or exceeded in two scenarios, Self-Sustaining and Offshore Opportunity.

A greater availability of low-carbon hydrogen under the Gas Evolution scenario results in harder-to-electrify vehicles, such as buses and HGVs, adopting hydrogen-fuelled alternatives in the late 2030s. This results in a slightly lower total EV uptake under this scenario.

The electrification of transport is slowest overall under the Constrained Growth scenario. However, the vast majority of vehicles are electrified by 2050.

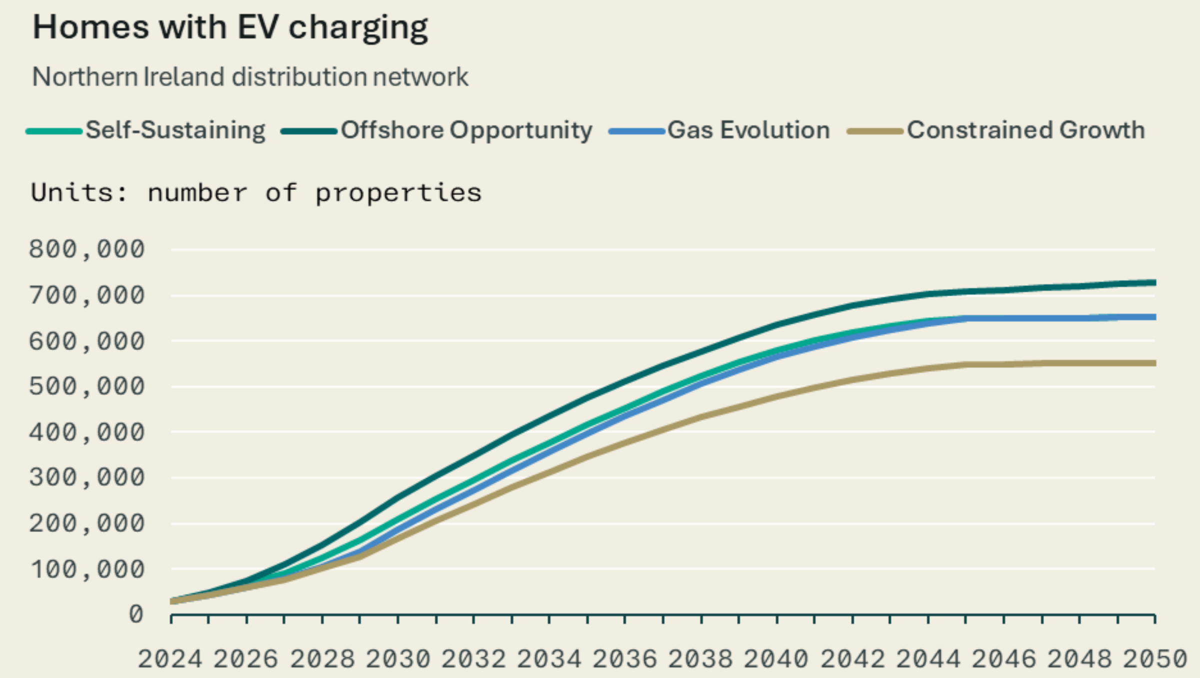
Regen's EV charging scenario model determines the charger capacity that is required to deliver electricity to the number of electric vehicles projected under each of the four scenarios. The future charging requirement is split across four categories:

- Domestic charging
- Public rapid chargepoints (over 50 kW)
- Public slow chargepoints (50 kW or under)
- Workplace and fleet chargepoints.

Regen's approach and modelling environment to develop scenario projections for EVs and EV chargepoints has been developed over almost a decade. This has enabled DNOs in Great Britain to estimate installed chargepoint capacities under different vehicle uptake scenarios, with feedback and updates to input parameters, modelling logic and assumptions in each iteration. For this analysis, the model inputs have been updated to reflect specific characteristics and market factors in Northern Ireland.

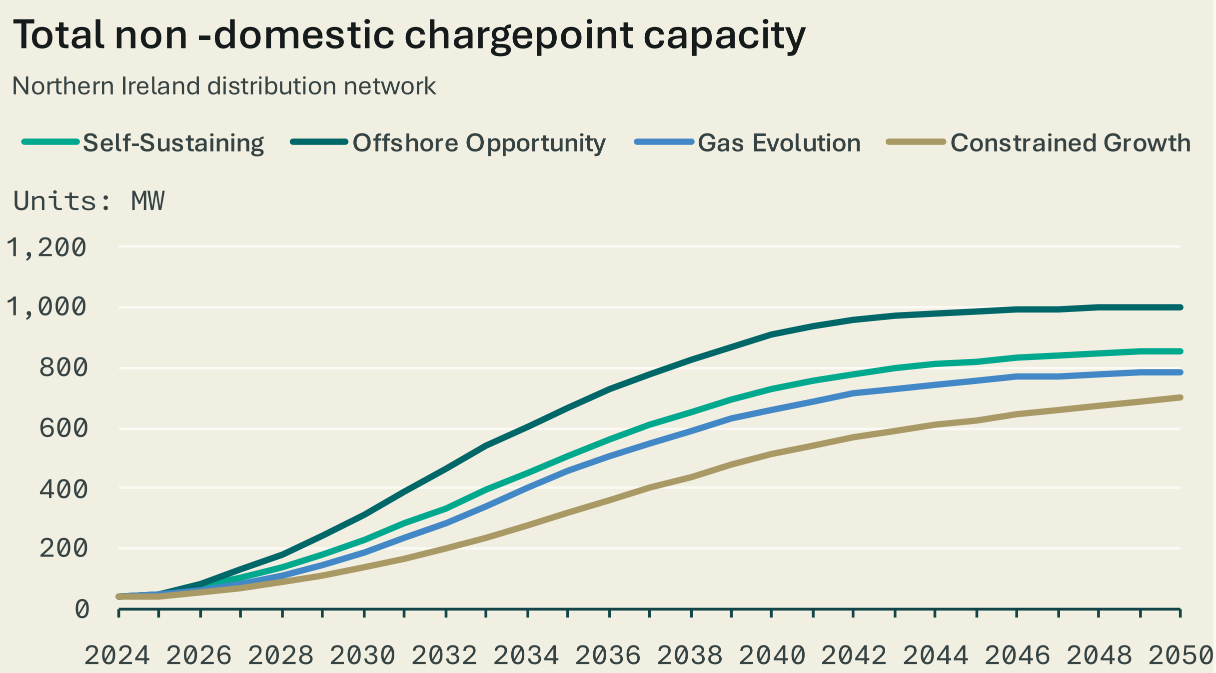
The near-term deployment of EV chargepoints contains an assumed build-out and connection of a pipeline of 35 MW commercial EV chargepoints that have an accepted connection offer with NIE Networks.

Figure 4



Note: includes properties with one or more electric cars and vans charging via a dedicated chargepoint or via a regular domestic socket.

Figure 5



Note: Comprises of both rapid and slow public chargepoints, as well as workplace and fleet chargers

2.1.2. Existing chargepoint capacity and development pipeline

Table 5

Chargepoint development status	Domestic chargepoints (MW)	Public slow (MW)	Public rapid (MW)	Workplace and fleet (MW)
Operational Source: NIE Networks connections data	146	11	8	23
In development Source: NIE Networks connections data	-	5	9	21

2.1.3. Scenario framework

The scenario analysis considers various potential EV adoption rates. This reflects the impact of each scenario's societal, policy and economic position driving the rate of EV uptake.

Table 6

Scenario	Description
Self-Sustaining	The Self-Sustaining scenario sees a rapid electrification across all demand sectors, including transport. EV adoption is expected to accelerate rapidly, driven by declining costs, increased consumer appetite for decarbonisation and policy measures that require manufacturers to increase sales of zero emission vehicles. The ZEV mandate, which requires an increasing share of cars and LGVs to be zero emission, is met in the period to 2030. After 2030, all cars and LGVs sold are either battery electric or plug-in hybrids. After 2035, all cars and LGVs are battery electric. The market share of battery electric HGVs, buses and coaches accelerates rapidly. After 2035, all of these vehicle types are battery electric. Annual registrations of cars and LGVs continue in line with average sales over the last decade of around 57,000 per year. By 2050 there are 1,071,600 electric cars and LGVs on the road in Northern Ireland.
Offshore Opportunity	The Offshore Opportunity scenario sees a rapid electrification across all demand sectors and EV adoption accelerates at the fastest pace of all four scenarios. As with the Self-Sustaining scenario, adoption of electric vehicles is driven by declining costs, increased consumer appetite for

Scenario	Description
	decarbonisation and policy requiring increasing sales of zero emission vehicles. In addition, the Offshore Opportunity scenario envisages greater levels of economic activity and higher disposable incomes. These factors lead to increased annual vehicle sales, driving EV uptake higher than the other scenarios. Annual registrations of cars and LGVs increase to 68,000 per year. By 2050, there are 1,278,400 electric cars and LGVs on the road in Northern Ireland, the highest of all four scenarios. In this scenario, the market share of battery electric cars and LGVs exceeds the requirement of the ZEV mandate in the period to 2030. After 2030, all cars are battery electric, while a small number of plug-in hybrid LGV sales continue to 2032. The market share of battery electric HGVs, buses and coaches accelerates rapidly. After 2035, all of these vehicle types are battery electric.
Gas Evolution	Gas Evolution reflects a slower delivery of the energy transition. This is reflected in a delayed acceleration of transport electrification. The ZEV mandate, which requires an increasing share of cars and LGVs to be zero emission, is not met in Northern Ireland in this scenario. It is important to note that this does not imply that the ZEV mandate is missed across the UK, but rather that manufacturers offset lower levels of zero emission vehicle purchases in Northern Ireland with higher levels elsewhere in the UK. Under this scenario, 60% of new car sales in 2030 are battery electric, missing the 80% ZEV mandate target. After 2035, all cars and LGVs are battery electric, with plug-in hybrid sales continuing until this year. In this scenario, annual vehicle registrations remain at current levels across vehicle types. Annual registrations of cars and LGVs continue in line with average sales over the last decade of around 57,000 per year. By 2050, there are 1,071,600 electric cars and LGVs on the road in Northern Ireland. The market share of battery electric HGVs, buses and coaches still accelerates rapidly under this scenario. However, ultimately the battery electric market share of these vehicles does not exceed 80%, as alternative renewable fuels, such as green hydrogen, are assumed to become available and adopted. However, this assumption under the Gas Evolution scenario can be considered as less likely as it contravenes advice from the Climate Change

Scenario	Description
	Committee, which has stated that there is "very little or potentially even no role for hydrogen in heavier vehicles".[7]
Constrained Growth	Constrained Growth sees the slowest delivery of the energy transition across the scenarios. This is reflected in a delayed acceleration of transport electrification. This scenario has the slowest rate of EV uptake, which is limited by falling disposable incomes, lower consumer appetite and a delayed implementation of wider decarbonisation policy. The ZEV mandate, which requires an increasing share of cars and LGVs to be zero emission, is not met in Northern Ireland in this scenario. It is important to note that this does not infer that the ZEV mandate is missed across the UK, but rather that manufacturers offset lower levels of ZEV purchases in Northern Ireland with higher levels elsewhere in the UK. 55% of new car sales in 2030 are battery electric, missing the 80% ZEV mandate target. After 2035, all cars and LGVs are battery electric, with plug-in hybrid sales continuing until then. In this scenario, lower disposable incomes and reduced levels of economic activity lead to lower numbers of annual vehicle registrations. Annual registrations of cars and LGVs decrease to 46,000 per year. By 2050, there are 864,800 electric cars and LGVs on the road in Northern Ireland, the lowest of all four scenarios. The uptake of battery electric HGVs, buses and coaches is initially delayed and then accelerates in the 2030s, as earlier deployment in other countries drives down costs of these vehicle models. Sales of diesel HGVs stop in 2040, in line with UK policy.

2.1.4. Stakeholder engagement

Table 7

Stakeholder organisation	Feedback provided
Electric Vehicle Association Northern Ireland (EVANI)	EVANI emphasised that the uptake of EVs in Northern Ireland is heavily influenced by imports from Great Britain, which are not captured by official data.
Cenex	Provided guidance for estimating an accurate number of electric vehicles in Northern Ireland. The Department for Transport has

[7] Page 146 (Section 7.1), The Seventh Carbon Budget, Climate Change Committee, 2025

Stakeholder organisation	Feedback provided
	highlighted that it is not currently possible to identify the location of leased EVs with public data.[8]
Consultation event	Responses from stakeholders indicated that car and LGV sales in Northern Ireland are likely to miss their share of the ZEV mandate. The consensus from stakeholders was also that moving to a shallower charging regime would improve the installation rates for business and public EV chargepoints. There was also an agreement that legislation requiring the installation of charge points at new-build domestic properties is likely to be implemented in Northern Ireland in the future.
Department for the Economy	Representatives from the Department confirmed that there is a likelihood for policy to shift to a shallower charging regime following an initial consultation.[9] A shallower charging regime would result in a lower connection cost for chargepoint developers, which was identified as a barrier to expanding the charger network.
Department of Finance	Representatives highlighted an ongoing consultation on a long-term strategy for building efficiency standards. This included a consideration for the installation of EV charge points.

2.1.5. Modelling approach

The modelling approach used to develop projections of EV chargepoint capacity is described in Table 8. A high-level overview of the approach is also shown in Figure 6.

Figure 6

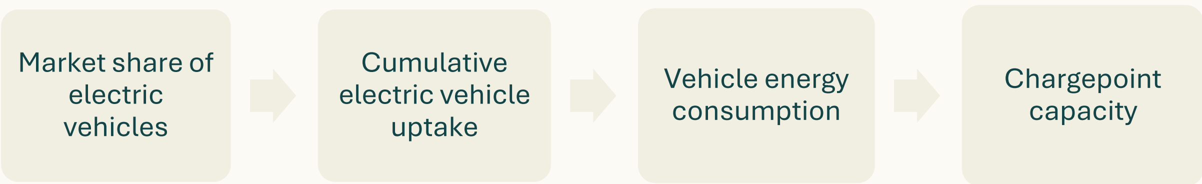


Table 8

Model factor	Description
Number of EVs	The number of EVs on the road in Northern Ireland is determined by an analysis of the EV market share of all new vehicle sales. These

[8] Identify the location of EVs by using commercially-held data about leased vehicles, Charging Ahead: Using location data to boost local EV chargepoint rollout, Department for Transport

[9] *Increased Socialisation of Connection Costs in the Electricity Distribution Network*, Department for the Economy

Model factor	Description
Source: ZEV mandate, DfT data, Regen analysis	market shares are defined according to the scenario framework (as detailed in Table 6). The number of existing EVs is informed by Regen analysis of Department for Transport (DfT) data. The uptake analysis also includes an estimate of vehicles leased or imported from GB, which are not present in the DfT registration data.[10]
Vehicle mileage Source: Regen analysis of Northern Ireland and UK mileage data	Vehicle mileage data is combined with energy efficiencies to calculate estimated energy consumption by each vehicle type. The average mileages below are used in the analysis: • Cars: 9,600 miles per year • LGVs: 16,175 miles per year • HGVs: 27,940 miles per year • Buses and coaches: 21,725 miles per year • Motorcycles: 4800 miles per year
Vehicle and charging efficiency Source: National Grid ESO FES 2022 data	Vehicle efficiency and charging losses are combined into one overall efficiency figure, taken from National Grid's Future Energy Scenarios 2022. These are projected to improve over time, as technology and battery performance improves. For example, HGVs are assumed to have a combined efficiency of 0.60 miles/kWh in 2024, and this is forecast to increase to 0.71 miles/kWh by 2050. The National Energy System Operator confirmed to Regen that these figures are used in FES 2024.
Charging patterns	Charging patterns are illustrated in Figure 6 and Figure 7. Access to domestic charging influences where cars, LGVs and motorbikes are likely to charge. Cars with access to domestic charging, either via off-street parking or using a pavement cable gulley if parked on-street, are assumed to charge mainly at home. Cars without access to domestic charging are assumed to split the majority of their charging between chargers located at workplaces and at public chargepoints. Owners of LGVs are also assumed to charge mainly at domestic supplies[11]. The majority of LGVs with access to off-street parking are assumed to split their charging between domestic supplies and workplace/fleet chargers. LGVs without access to domestic charging split their charging between public chargers (both rapid and slow) and workplace and fleet chargers. Motorbikes with access to domestic charging are assumed to mainly charge at domestic properties. Motorbikes without domestic

[10] Identify the location of EVs by using commercially-held data about leased vehicles, Charging Ahead: Using location data to boost local EV chargepoint rollout, Department for Transport
[11] Figure 5, EV smart chargepoint survey 2022, DESNZ

Model factor	Description
	charging access are assumed to charge mostly at public chargers (both rapid and slow). Electric HGVs, buses and coaches are assumed to mostly charge using public rapid chargers and fleet chargers located at depots or distribution centres.
Domestic charging	Charging via domestic electricity supplies can take several forms. The most common arrangement is a dedicated 7.36 kW chargepoint installed at homes with off-street parking. Others include: • On-street parking with a 7.36 kW chargepoint, such as those using pavement cable gullies • Charging without a dedicated chargepoint, either on- or off-street, using a 3 kW cable plugged into a standard domestic socket • A faster 22kW chargepoint via an upgraded domestic supply It is assumed that 83% of cars and 71% of LGVs have regular access to home charging of some kind based on survey data from DfT[12] and EVANI[13]. The number of properties with EV charging regularly taking place is modelled based on estimates of the numbers of single- and multiple-vehicle households sourced from Census 2021. (20% of households have no vehicle, 40% have one vehicle, and 40% have two or more[14]). To estimate the number of households with EVs, a binomial probability approach is applied. This assumes that each vehicle has an equal probability of being electric and calculates the number of 1 and 2+ vehicle households that have an electric vehicle. This method accounts for the likelihood of households having multiple electric vehicles that are charged at the same property.
New build properties	A projection of new build properties has been developed and used across multiple technologies in this analysis. New build property projections were developed to align with the Department for Communities (DfC) housebuilding target of 100,000 new homes between 2024 and 2039, as detailed in Appendix: New building developments. It is assumed that legislation requiring EV chargepoints to be installed in new build housing happens under every scenario. The year this requirement comes into law is varied between 2027 and 2030 by scenario, following similar policy introductions in England, Scotland and Wales [15].

[12] Figure 5, EV Smart Chargepoint Survey 2022, Department for Energy Security and Net Zero
[13] Northern Ireland EV Drivers Survey 2024, EVANI
[14] Section 3.3, Statistics for Northern Ireland, Census 2021
[15] Infrastructure for charging electric vehicles, UK Government, 2021

Figure 7

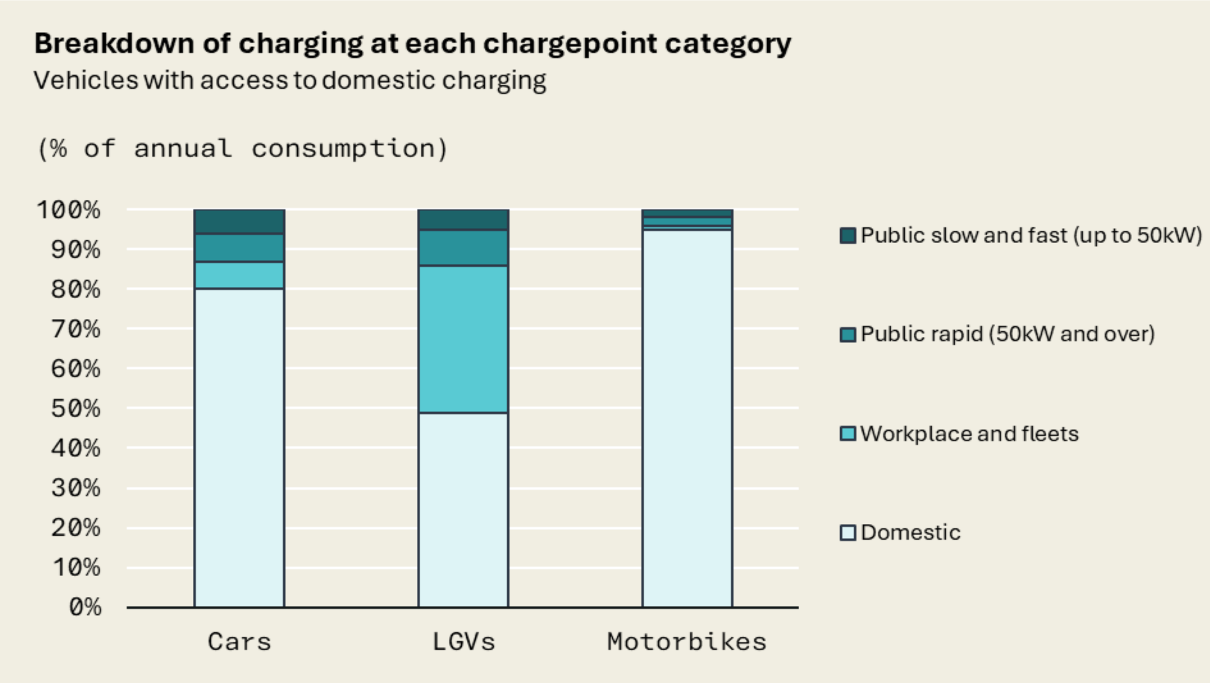
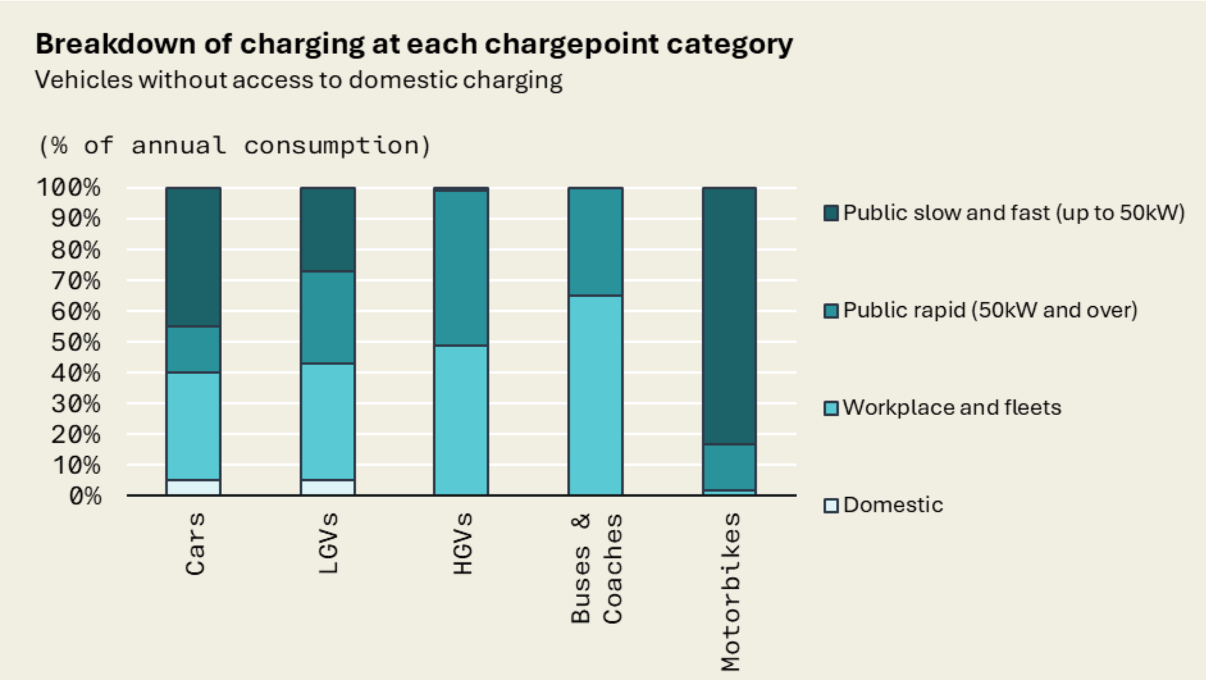
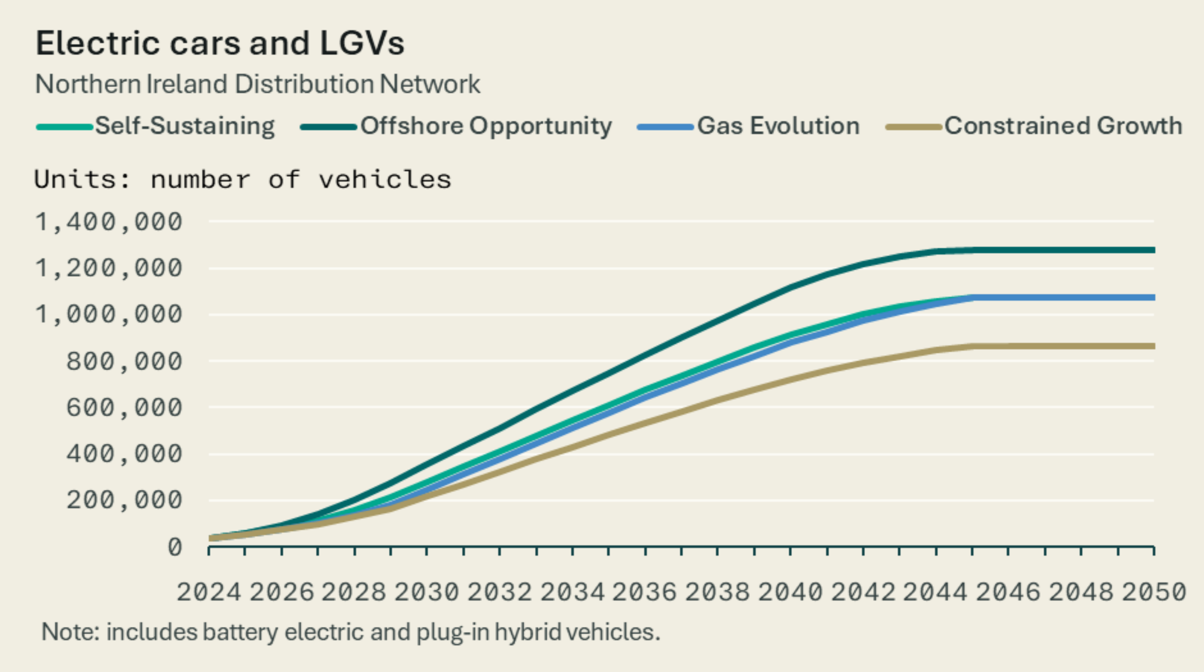


Figure 8



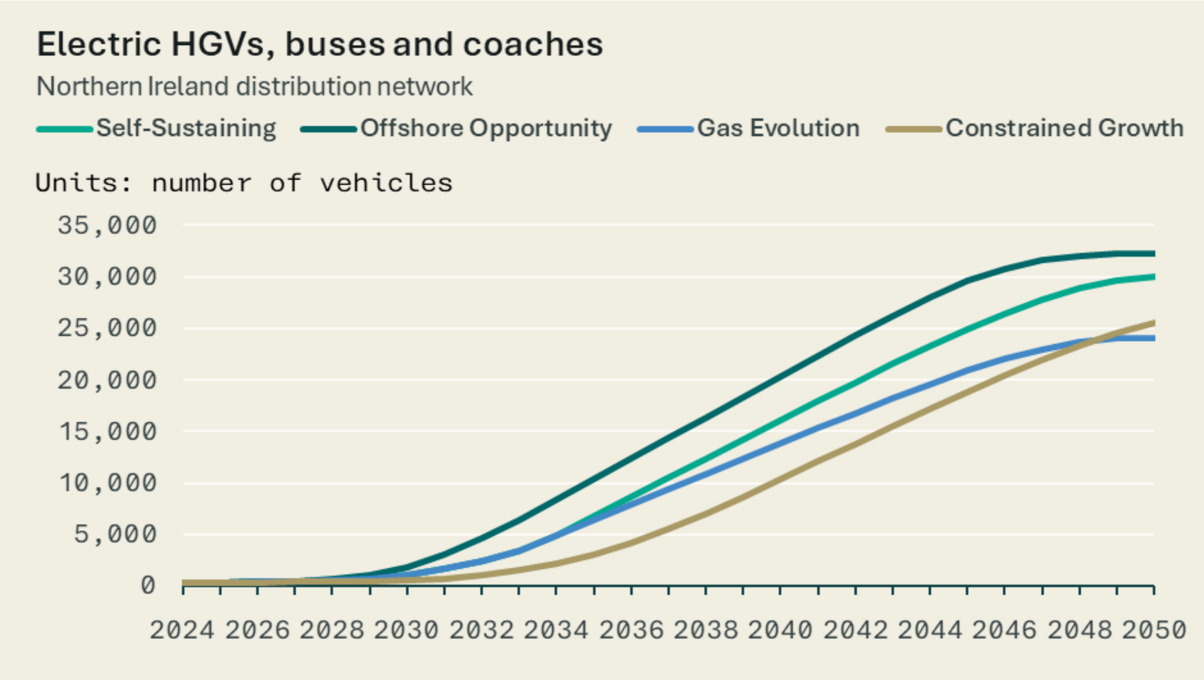
2.1.6. Electric vehicle uptake: detailed results

Figure 9



Battery electric powertrains increase in all scenarios until nearly all cars and LGVs on the road are electric. Sales of plug-in hybrids increase in the near-term and then decline to 2050.

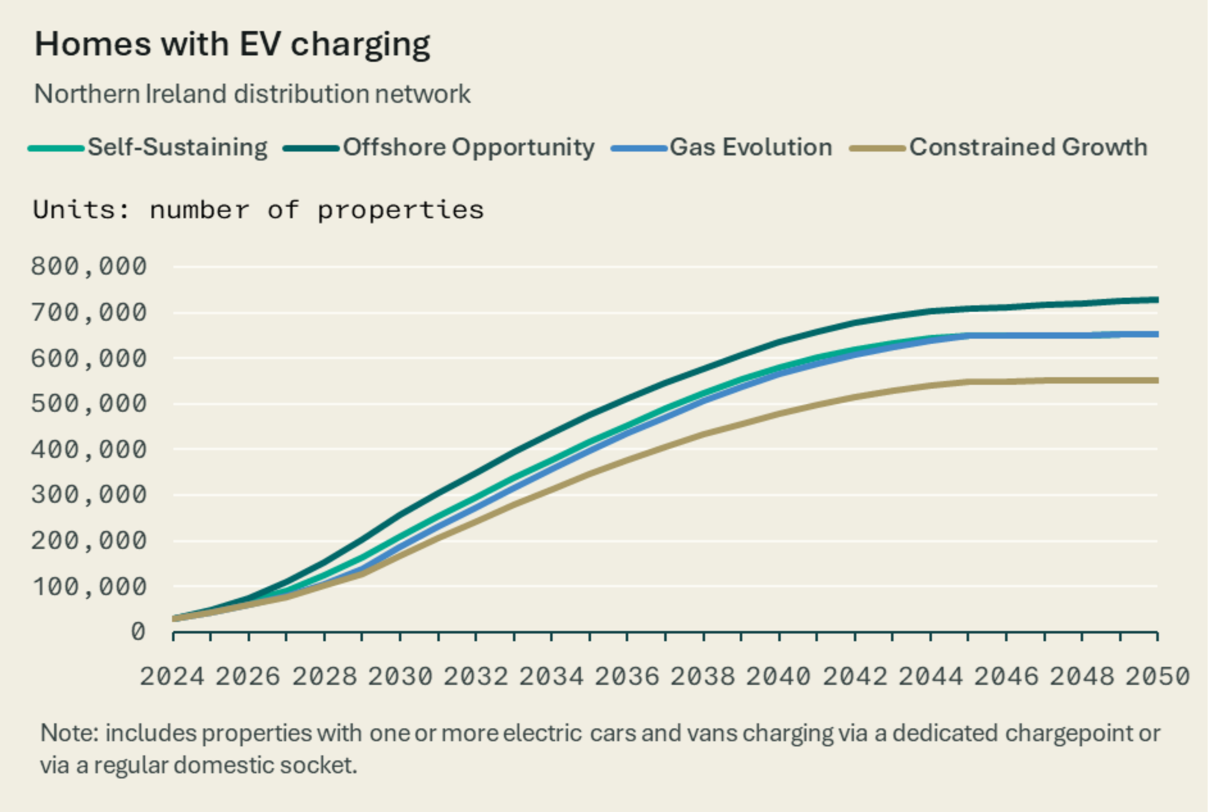
Figure 10



Offshore opportunity sees the fastest uptake of electric HGVs, buses and coaches, followed by Self-Sustaining. In Gas Evolution, a small share of these types of vehicles are assumed to use hydrogen powertrains in the long-term. Constrained Growth has the slowest overall rate of uptake, but results in more of these vehicles by 2050.

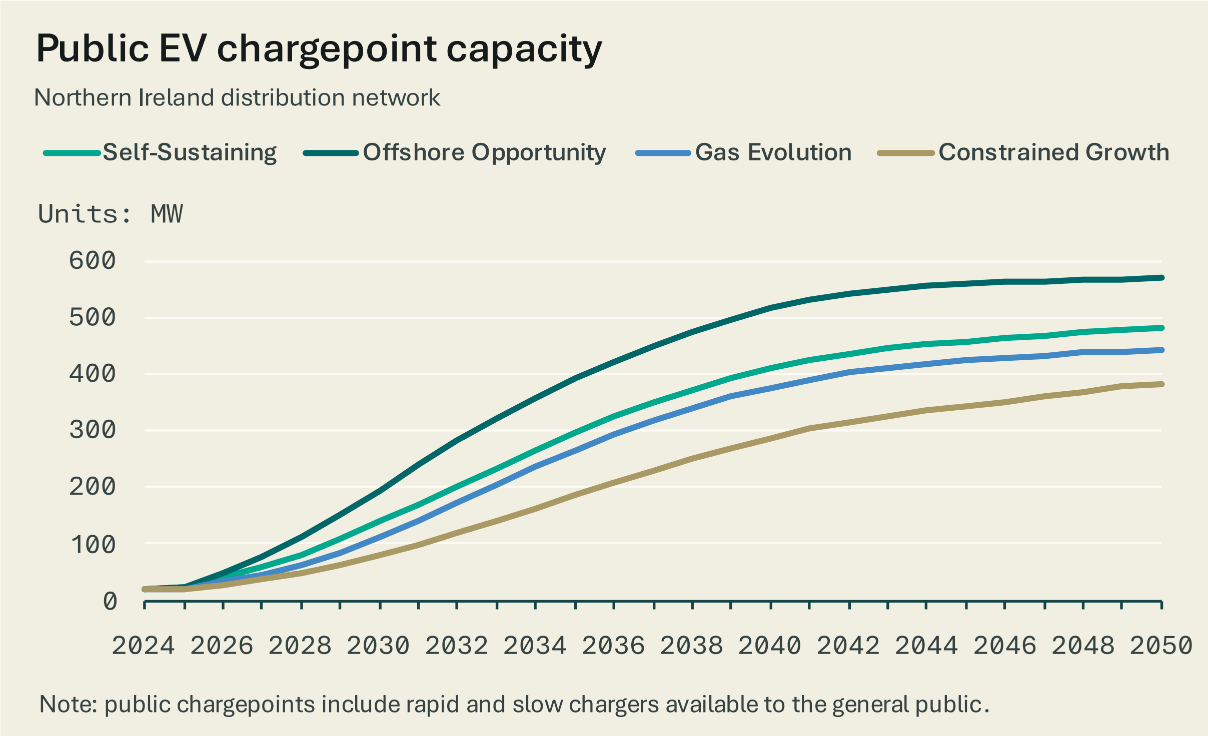
2.1.7. Electric vehicle charging: detailed results

Figure 11



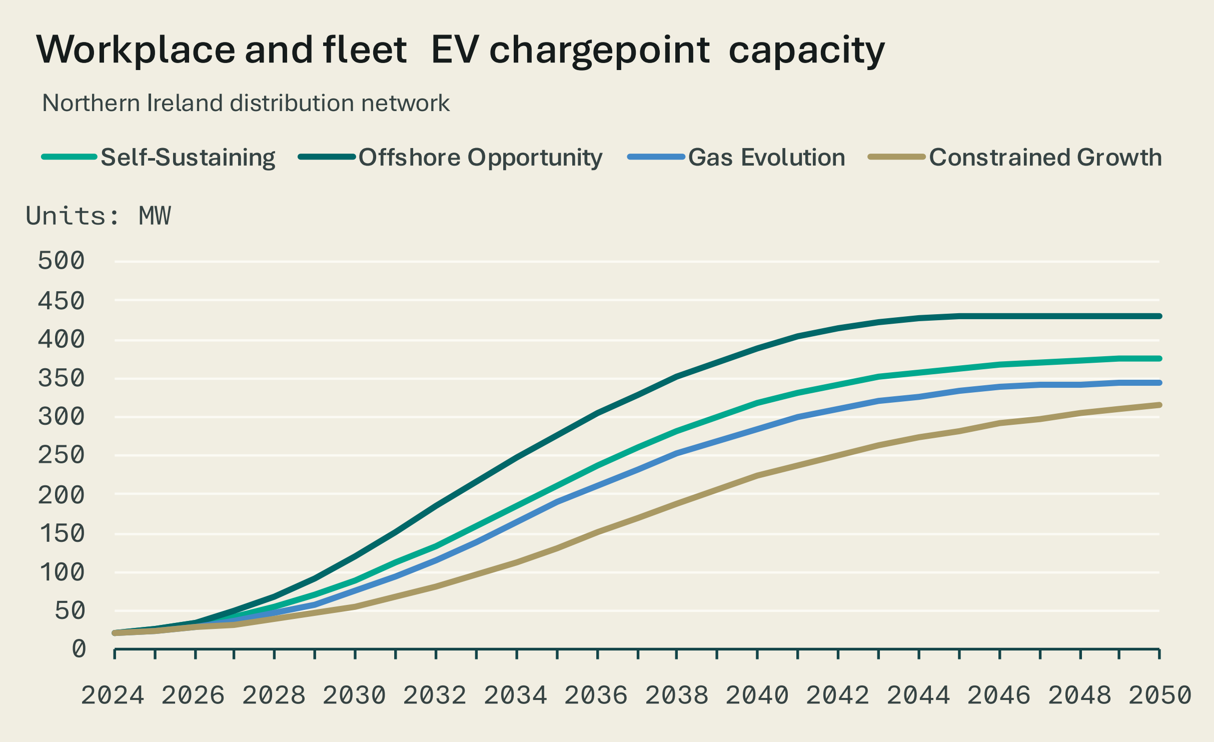
All four scenarios see a rapid growth in electric vehicle charging at domestic properties, driven by adoption of electric vehicles and the ability to access cheaper charging at home. As adoption progresses, additional EVs tend to be concentrated in households with two or more vehicles. The number of homes with EV charging installed is significantly lower than the number of vehicles that have access to EV charging. The method used to derive the projection of homes with EV charging can be found in Table 8.

Figure 12



Public capacity includes all chargepoints open to the general public at all ratings (including e-HGV chargers). Capacity under each scenario echoes the uptake of electric vehicles, with less capacity forecast in Gas Evolution as hydrogen fuelling becomes more popular.

Figure 13



The capacity of workplace and fleet chargepoints increases as fleets electrify and workplaces offer charging in all scenarios, except for in Gas Evolution, where some hydrogen HGVs, buses and coaches are used in the long-term.

2.1.8. Reconciliation to other projections

Uptake of electric vehicles has been compared between the distribution modelling, RP7 projections and SONI's Tomorrow's Energy Scenarios:

Table 9

Scenario	Year	SONI TES 2023 (millions of EVs, vehicle type not specified)	NIE Networks RP7 projections – Best View (millions of EVs, cars and LGVs)	NIE Networks Distribution Network Planning Scenarios (millions of EVs, cars and LGVs)
Baseline	2024			0.04
Self-Sustaining	2030	N/A	0.30	0.28
	2035	0.80	0.60	0.61
	2050	1.20	1.00	1.07
Offshore Opportunity	2030	N/A	0.30	0.35
	2035	0.90	0.60	0.75
	2050	1.20	1.00	1.28
Gas Evolution	2030	N/A	0.30	0.25
	2035	0.45	0.60	0.58
	2050	1.15	1.00	1.07
Constrained Growth	2030	N/A	0.30	0.22
	2035	0.35	0.60	0.48
	2050	1.04	1.00	0.86

The projections of EV uptake in 2050 in the SONI Tomorrow's Energy Scenarios fall within the range of the NIE Networks Distribution Network Planning Scenarios. Based on different economic landscapes envisaged in each scenario, the variation in electric vehicle uptake between different scenarios in the TES has been reflected in these scenarios with a slightly larger scenario envelope. The TES does not detail projected energy or grid capacity, so comparisons to numbers of vehicles have been made.

In the RP7 business plan, NIE Networks outlined low, best view and high scenarios for the volume of EVs to 2050. By 2030, the Offshore Opportunity exceeds the 0.3 million EVs projected in the RP7 Best View. All other scenarios are similar or slightly lower by 2030, with the lowest uptake in Constrained Growth reaching 0.22 million EVs by that date. In 2050, the RP7 Best View and High Scenario reach around 1 million EVs, slightly below the NIE Networks Planning Scenario forecast in Self Sustaining of 1.07 million. However, the NIE Networks Planning Scenarios model higher uptake in the other three scenarios, with Offshore Opportunity reaching just under 1.3 million.

Since the publication of the RP7 plan, there has been greater certainty in the ZEV mandate and a clearer political vision for the electrification of transport in Northern Ireland. However, this analysis highlights how different levels of total vehicle registrations and imports could significantly influence the number of electric vehicles on the road in Northern Ireland.

The Climate Change Committee has set out deployment rates for battery electric cars through to 2050 in their fourth carbon budget, measured in percentage of cars that are electric[16]. The adoption modelled in the CCC pathway is higher than all scenarios modelled here, apart from Offshore Opportunity[17].

Scenario	Year	Number of BEV cars (millions)
CCC	2030	0.248
	2035	0.547
Self-Sustaining	2030	0.198
	2035	0.482
Offshore Opportunity	2030	0.283
	2035	0.634
Gas Evolution	2030	0.156
	2035	0.426
Constrained Growth	2030	0.123
	2035	0.316

[16] Tab 3.4, Northern Ireland Fourth Carbon Budget advice - Charts and data, 2025
[17] The CCC publish the percentage of cars that are BEV; this has been converted to number of cars assuming that the total car fleet is 1,034,000 (per DfT table veh0101).

2.2. Heat

This analysis considers all forms of electric heating where electricity is the primary space heating and hot water source in domestic and non-domestic properties. This includes air source and ground source heat pumps, hybrid heat pump systems (where an air source heat pump is paired with another heating source), direct electric heating such as night storage heaters, and district heating primarily driven by large-scale heat pumps.

2.2.1. Summary

The vast majority of homes in Northern Ireland are currently heated by fossil fuels. Oil-fired central heating is installed in over half of homes across the country and electric heating is used in less than 2% of homes. This reflects the relatively high cost of electricity compared to fossil fuels and the high upfront cost of heat pumps, relative to replacement fossil fuel boilers.

While electric heating is not widespread today, it is anticipated under the scenarios used in this analysis for Northern Ireland that the main solution for space heat decarbonisation will be through electrification. In previous scenarios, alternative heat decarbonisation pathways have been developed that have included significant levels of hydrogen or bioenergy for heat in the 2040s to 2050. These options have not been included in this analysis, reflecting recent advice from the Climate Change Committee that hydrogen will have no role in providing heat for buildings and bioenergy should be prioritised for other applications with carbon capture where emissions reductions are greatest. [18] [19] The gas used by boilers connected to the gas network has not been modelled in this analysis – this could be a mix of fossil methane, biomethane or hydrogen.

The potential for space heat electrification has been modelled based on an analysis of the building stock in Northern Ireland and a specific analysis of two key factors:

1. **Heating system replacement cycles:** The likelihood of a property switching heating systems at the end of its operational life (ranging from 12 years for gas boilers to up to 18 years for oil and solid fuel boilers). These figures are based on desk research from a wide variety of sources, such as heating technology providers.[20] While there is a wide variety of heat system lifespans, especially with oil boilers where lifespans of up to 30 years are possible with regular boiler care and maintenance, this assumption reflects an average boiler age before continued operational and maintenance becomes less feasible compared to a replacement heating system. This propensity increases over time as Northern Ireland progresses toward carbon reduction goals and low-carbon heating

[18] Page 13, Northern Ireland's Fourth Carbon Budget, Climate Change Committee, 2025
[19] Figure 10.9, The Seventh Carbon Budget, Climate Change Committee, 2025
[20] Life expectancy of a heating oil boiler, Northern Energy, 2025. Regen's desk research combined several similar sources to inform the expected operational life of each modelled heating technology.

options become more appealing and accessible/affordable (including through support schemes).

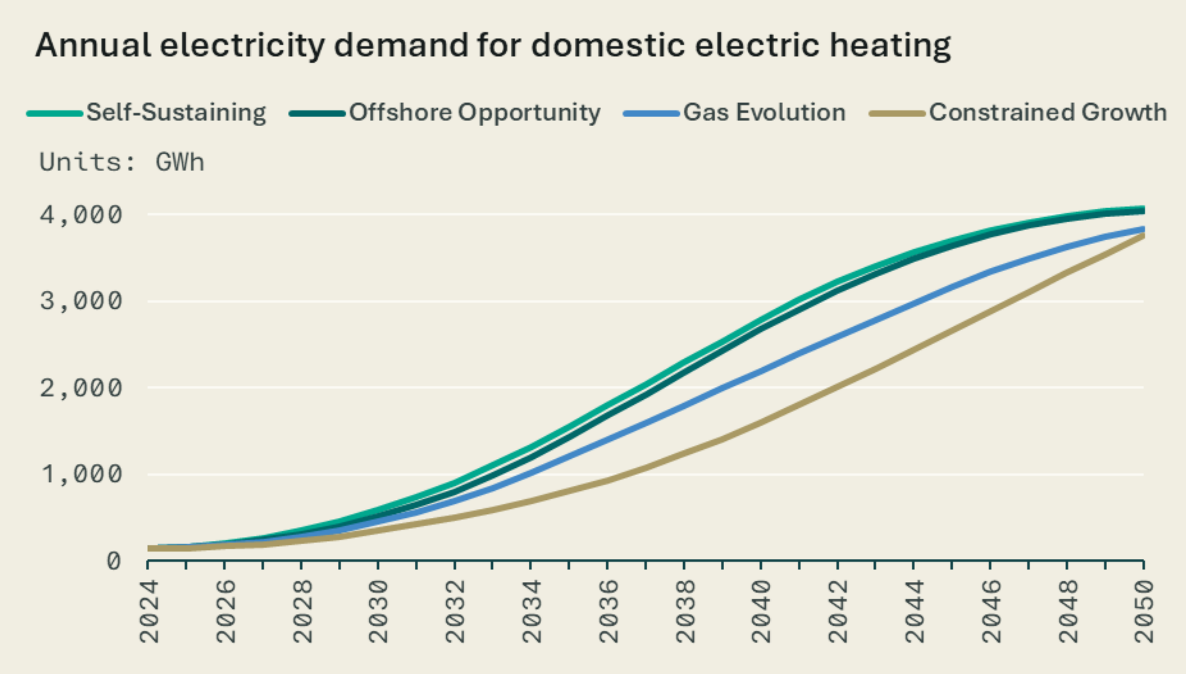
2. **Technology selection based on property characteristics:** Larger homes and new-build homes have been modelled as more likely to adopt hydronic air-source or ground-source heat pumps or hybrid systems due to fewer space constraints and higher energy demands. In contrast, smaller homes, such as flats, are more likely to adopt district heating (where available), air-to-air heat pumps, or direct electric heat. However, air-source heat pumps see high levels of uptake in all forms of property.

For non-domestic buildings, modelling has been less detailed due to limited data on Northern Ireland's non-domestic building stock. Heat technology adoption has been assumed to follow similar trends to domestic buildings, referencing existing heating types.

Annual energy consumption from electrified heating has resultantly been modelled to reflect both improvements in heat pump efficiency and increased building energy efficiency over time.

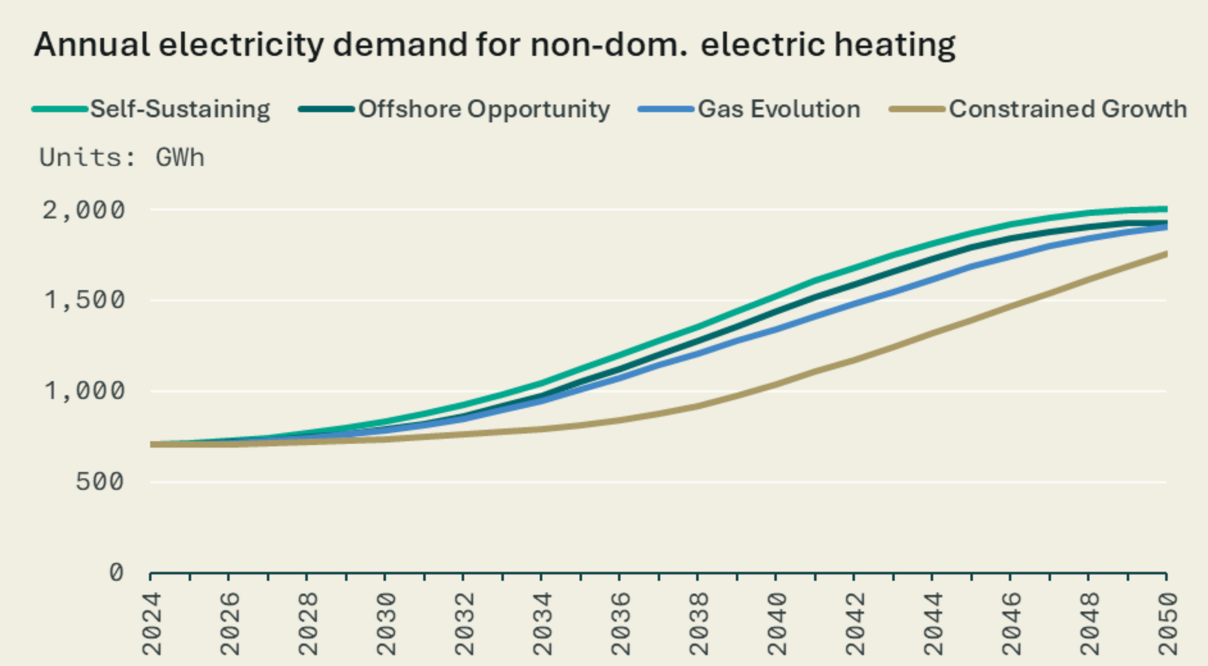
The scenario projections result in electricity demand for heating increasing from under 1,000 GWh/year in the baseline to 5,500-6,100 GWh in 2050, as the vast majority of homes upgrade to electric heating in all scenarios.

Figure 14



Note: includes air source and ground source heat pumps, hybrid heat pumps, direct electric and electric district heating.

Figure 15



Note: includes air source and ground source heat pumps, hybrid heat pumps, direct electric and electric district heating.

2.2.2. Existing heating systems

Table 10

Sector	Oil (thousand)	Mains gas (thousand)	Direct electric heating (thousand)	Heat pumps (thousand)	Other: biomass, LPG etc. (thousand)
Domestic Source: Census 2021, NIEN, Microgeneration Certification Scheme (MCS)	473	254	12	1	26
Non-domestic Source: DESNZ, MCS, NIEN	49	15	12	0*	2

* this does not include air-to-air heat pumps in non-domestic settings, as these are not discoverable in the baseline data against direct electric heating. Where air-to-air heat pumps are being used for space heating, this consumption will be reflected in the direct electric heating figures.

2.2.3. Scenario framework

Table 11

Scenario	Description
Self-Sustaining	This scenario features the fastest uptake of heat pumps, as Northern Ireland achieves a rapid pace of decarbonisation across all sectors, including buildings. This results in almost 90,000 domestic heat pump installations by 2030, and the vast majority of buildings having non-hybrid ground or air source heat pumps or district heating by 2050. A rapid acceleration in the uptake of heat pumps is modelled in this scenario, relative to minimal current installation levels. This pace of adoption would likely require significant policy support similar to, or exceeding, the Boiler Upgrade Scheme grant available in Great Britain from the mid-2020s onward. The even greater levels of uptake seen in the 2030s and 2040s would also likely require coherent heat network zoning, planning and implementation, alongside a planned phase-out of fossil fuel heating systems in buildings. A key differentiator for this scenario is the very fast uptake of rooftop solar and domestic battery storage systems (see Figure 35 for domestic solar and 3.4.6 for storage). This is assumed to drive uptake of heat pumps, as households combine self-generation from rooftop solar and demand shifting to off-peak periods to achieve a reduction in their heating costs. The modelling of heating technologies in socially rented homes reflects draft plans shared by the Northern Ireland Housing Executive. These plans outline an approach to retrofit electric heating systems in socially rented properties from 2027/28. The uptake rates shared are directly reflected in this scenario. Total heat pump adoption is modelled to peak at just over 50,000 domestic installations per year in the late 2030s, in line with uptake rates in Northern Ireland's Fourth Carbon Budget. Direct electric heating is projected to remain stable throughout the scenario timeframe. Non-domestic HP uptake broadly mirrors domestic adoption under this scenario, due to a lack of specific data for non-domestic buildings in NI.
Offshore Opportunity	This scenario features a fast uptake of heat pumps, only slightly slower than the Self-Sustaining scenario. Like that scenario, this results in over 70,000 domestic heat pump installations by 2030 and the vast majority of buildings having non-hybrid heat pumps or district heating by 2050. A rapid acceleration in the uptake of heat pumps is modelled in this scenario, relative to minimal current installation levels. As with the Self-Sustaining scenario, this increased adoption would require significant policy support similar to, or exceeding, the Boiler Upgrade

Scenario	Description
	Scheme grant available in Great Britain from the mid-2020s onwards. In the later years, it would also likely require a coherent heat network zoning, planning and deployment approach, alongside a planned phase-out of fossil fuel heating systems in buildings. While heat pump uptake is very rapid in this scenario and represents a significant increase on current levels, it is not as fast as in the Self-Sustaining scenario. As this scenario focuses policy support on large-scale technologies, uptake of domestic solar and storage technologies is not as fast and this impacts the pace of heat electrification – as fewer households reap the cost reductions of combining a heat pump with rooftop solar and storage systems. The modelling of heating technologies in socially rented homes reflects draft plans shared by the Northern Ireland Housing Executive. These plans outline an approach to retrofit electric heating systems in socially rented properties from 2027/28. The uptake rates shared are directly reflected in this scenario. Total heat pump adoption is similarly modelled to peak at just over 50,000 domestic installations per year in the late 2030s, in line with uptake rates in Northern Ireland's Fourth Carbon Budget. Direct electric heating is projected to remain stable throughout the scenario timeframe. Non-domestic HP uptake broadly mirrors domestic adoption under this scenario, due to a lack of specific data for non-domestic buildings in NI.
Gas Evolution	This scenario features a moderate uptake of heat pumps, as the potential availability of biomethane moderates the demand for electric heating in the near term. Around 60,000 domestic heat pump installations are modelled by 2030, mostly in homes currently heated by oil. However, in line with the CCC's Seventh Carbon Budget recommendation, hydrogen for widespread home heating is discounted. As a result, this scenario still results in the vast majority of homes being heated by heat pumps and district heating, albeit with a greater proportion of homes on hybrid heat pumps compared to other scenarios. This is due to the greater availability of low carbon gas for heating under this scenario, resulting in hybrid heat pumps being more viable. The modelling of heating technologies in socially rented homes reflects draft plans shared by the Northern Ireland Housing Executive. These plans outline an approach to retrofit electric heating systems in socially rented properties starting from 2027/28 and ramping up over a five year period. This uptake rate is directly reflected in this scenario. Total heat pump adoption is modelled to peak at just over 40,000 domestic heat pump installations per year in the late 2030s and early

Scenario	Description
	2040s. Direct electric heating is projected to remain stable throughout the scenario timeframe. Non-domestic HP uptake broadly mirrors domestic adoption under this scenario, due to a lack of specific data for non-domestic buildings in NI.
Constrained Growth	This scenario reflects a continuation of the current low uptake of heat pumps in Northern Ireland out to the mid 2030s. After this, uptake ramps up in the later 2030s and 2040s in order for Northern Ireland to achieve net zero by 2050. Around 40,000 domestic heat pump installations are modelled by 2030, which is well below the uptake rate in other scenarios, but is still a major increase compared to current deployment levels. Standalone air source heat pumps and hybrid heat pumps play a larger role in this scenario compared to the others, as it is assumed that district heating is not prioritised as a solution, compared to individual property heating technology solutions. Total heat pump adoption is modelled to peak at around 50,000 domestic installations per year across the 2040s, as a lack of deployment earlier in the scenario timeframe results in a rapid deployment in the longer term in order to meet net zero by 2050. Direct electric heating is projected to remain stable throughout the scenario timeframe. Non-domestic HP uptake broadly mirrors domestic adoption under this scenario, due to a lack of specific data for non-domestic buildings in NI.

2.2.4. Stakeholder engagement

Table 12

Stakeholder organisation	Feedback provided
Northern Ireland Housing Executive	Shared draft plans outlining an electric heating system retrofit in properties from 2027/28.
Phoenix Energy	Highlighted focus around biomethane in Northern Ireland and hybrid heat systems. Informed understanding of gas network operator ambition for hydrogen, biomethane and fossil gas blending.
Consultation event	Highlighted the importance of housing standards and financial support to develop the Northern Irish heat pump market. Supported the idea that oil-heated homes are marginally more likely to adopt heat pumps earlier than gas-heated homes. This has been reflected in the near-term uptake of heat pumps in all scenarios, with a focus on uptake in oil-heated homes. However, as per the stakeholder feedback, gas-heated homes and homes

Stakeholder organisation	Feedback provided
	with other heating fuels have also been modelled to take up heat pumps in the near term. Indicated that social landlords and housing associations could lead the way for low carbon heating. This has been directly reflected in all scenarios through an accelerated uptake of heat pumps in social housing. Suggested towns in Northern Ireland that could see the development of heat networks. This has been cross-compared against heat pump opportunity areas to confirm the modelling aligns with stakeholder input.

2.2.5. Modelling approach

Table 13

Model factor	Description
Current heating technology Source: Census 2021, MCS installation records, DESNZ subnational gas and electricity statistics	The existing heating technology in homes and businesses influences the likelihood of a property switching its heating system at the end of its operational life, based on the costs of the heating system. Oil and solid fuel heating systems are assumed to be replaced more readily than mains gas heating systems, due to the often higher costs of heating associated with these technologies (though variability in oil and gas fuel prices has impacted these relative costs in recent years). This also reflects feedback from the stakeholder consultation event. Properties currently heated by a heat pump or direct electric heating are assumed to retain their current heating methods throughout the scenario timeframe. The current heating system also impacts the technology that properties are modelled to switch to, which varies by scenario. In Gas Evolution, mains gas heating is modelled to switch to hybrid heat pumps in up to 10% of properties. In all scenarios, the availability of mains gas is used as a proxy for potential district heating availability, based on the density of heat demand associated with mains gas buildings. This is combined with heat network opportunity areas, defined by UK government.[21]
Tenure (domestic only) Source: Census 2021	The current tenure of properties influences the likelihood of a property switching its heating system. Socially rented properties are modelled to switch at a faster rate, based on higher than average EPC ratings for socially rented properties in Northern Ireland and the influence of the Northern Ireland Housing Executive.[22]

[21] Opportunity areas for district heating networks in the UK, UK Government, 2021
[22] House Condition Survey, Northern Ireland Housing Executive, n.d.

Model factor	Description
	Privately rented properties are modelled to switch at a slower rate. This is based on overall lower levels of low carbon technology uptake in privately rented properties in Northern Ireland and the wider UK, especially in terms of heat pumps. Desktop research and stakeholder engagement suggested that this was down to differences between occupiers and owners of the building in terms of appetite to have low carbon heating solutions installed.
Building form (domestic only) Source: Census 2021	The building form (detached, semi-detached, terraced or flat) influences the technology that a heating system is modelled to switch to. Larger homes are modelled to be more likely to switch to hydronic air-source or ground-source heat pumps or hybrid systems, due to lower space constraints and higher energy demand, whereas smaller homes such as flats are modelled more likely to switch to district heating (where available), air-to-air heat pumps or direct electric heating. However, hydronic air-source heat pumps see high levels of uptake in all forms of building.
Size of property (domestic only) Source: Census 2021, Ofgem TDCVs	Heat demand by habitable room has been calculated based on Ofgem's Typical Domestic Consumption Values and scaled based on the number of rooms in each property.[23]
Heat demand served by heat pump (hybrid systems)	For hybrid heating systems, the heat pump component has been assumed to serve 84% of annual heat demand, in line with Pheonix Energy's hybrid heating trial, conducted on a property in Belfast.[24]
Heat pump performance	Heat pump Seasonal Performance Factors have been modelled to slightly increase between 2024 and 2030 based on the Sustainable Energy Authority of Ireland's Low Carbon Heating and Cooling Technologies report, in alignment with SONI's Tomorrow's Energy Scenarios methodology.[25] This reflects both technological improvements and increasing installation, operation and monitoring quality. The efficiency of heat pumps in hybrid heating systems is higher, as the heat pump component is utilised less during colder periods. Hybrid heat pump SPFs are based on Phoenix Energy's Belfast hybrid heating trial data.
New properties	New properties have been modelled in line with projections for new housing and non-domestic buildings used in the rooftop solar PV modelling. In accordance with anticipated uplifts to Northern Ireland Buildings Regulations concerning the energy efficiency of buildings, the

[23] Average gas and electricity usage, Ofgem, n.d.
[24] Hybrid heating trial 2024, Refresh NI & Phoenix energy, 2025
[25] *Low carbon heating and cooling technologies*, Sustainable Energy Authority of Ireland, 2022

Model factor	Description
	vast majority of new buildings are modelled to be built with heat pumps or district heating from 2030 onwards.
Hard-to-electrify properties	All scenarios reflect a small proportion of hard-to-electrify homes that do not take up electric heating, district heating or low carbon gas. These are primarily larger detached or semi-detached homes currently heated by oil or solid fuel. The modelling assumes that these homes would be heated by biofuel rather than electricity.

2.2.6. Domestic heat: detailed results

Figure 16

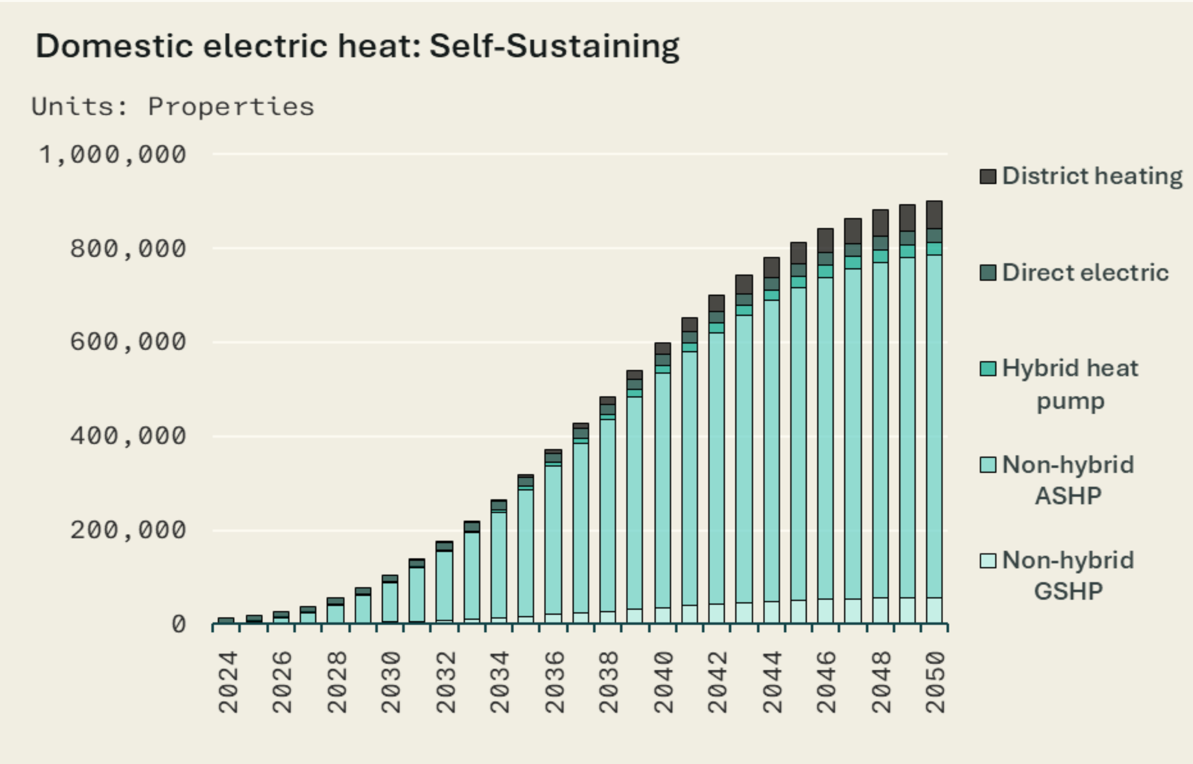


Figure 17

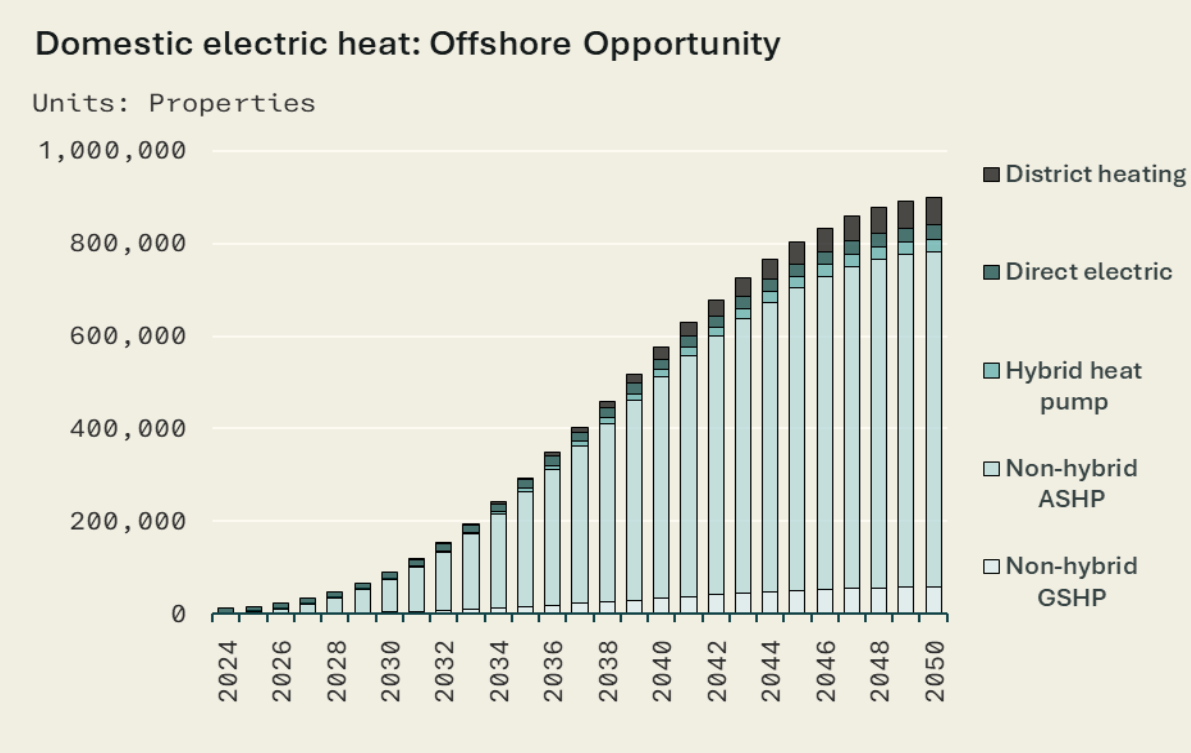


Figure 18

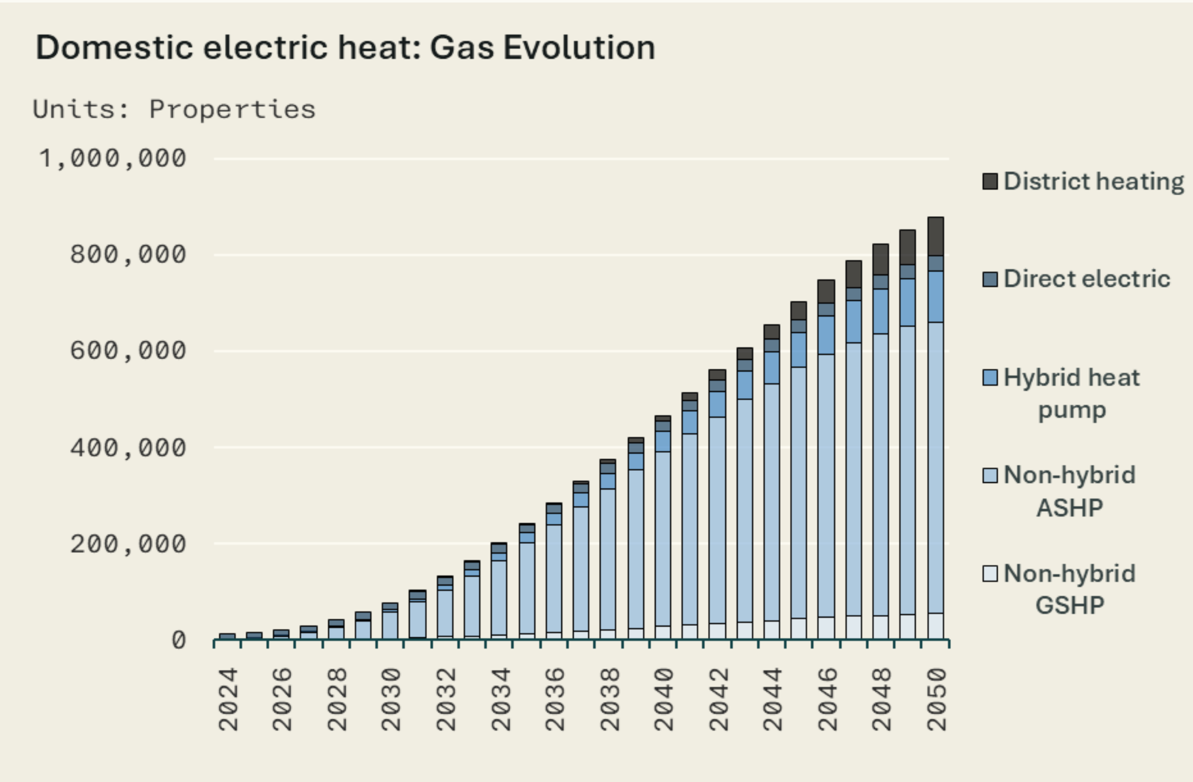
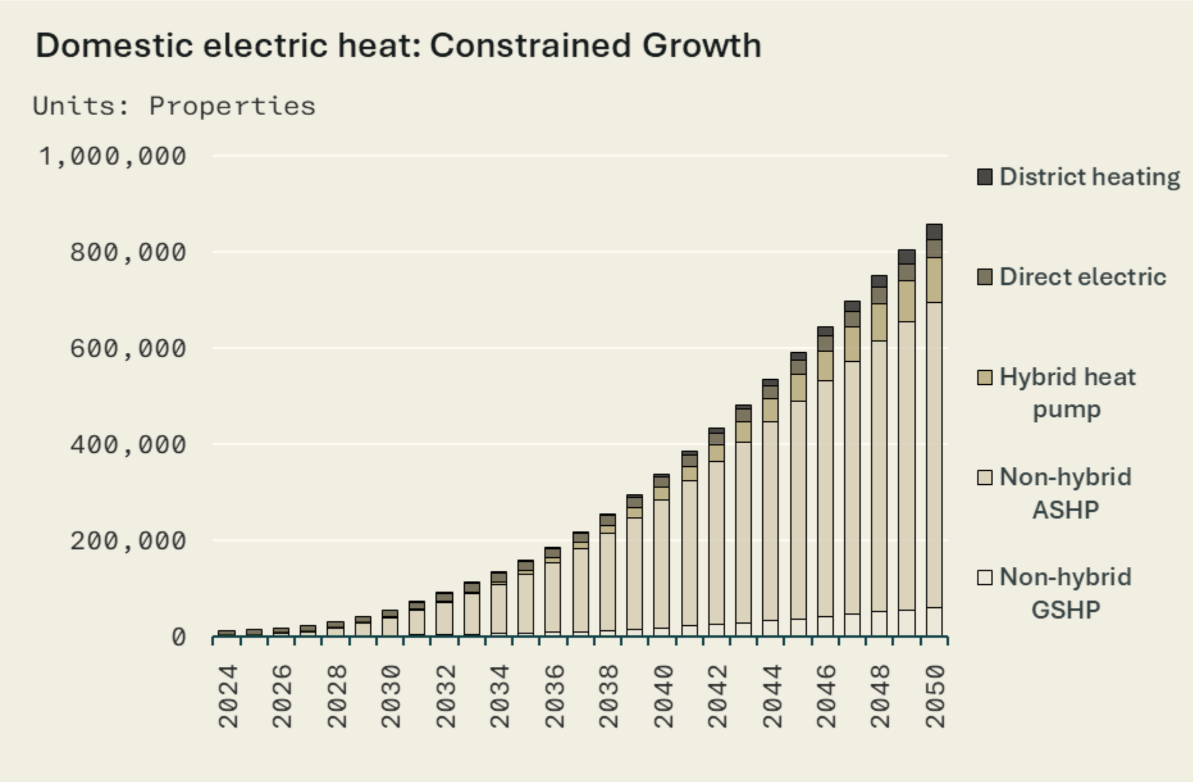


Figure 19



Domestic electric heat: Constrained Growth
Units: Properties
1,000,000
800,000
600,000
400,000
200,000
0
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
District heating
Direct electric
Hybrid heat pump
Non-hybrid ASHP
Non-hybrid GSHP

2.2.7. Non-domestic heat: detailed results

Figure 20

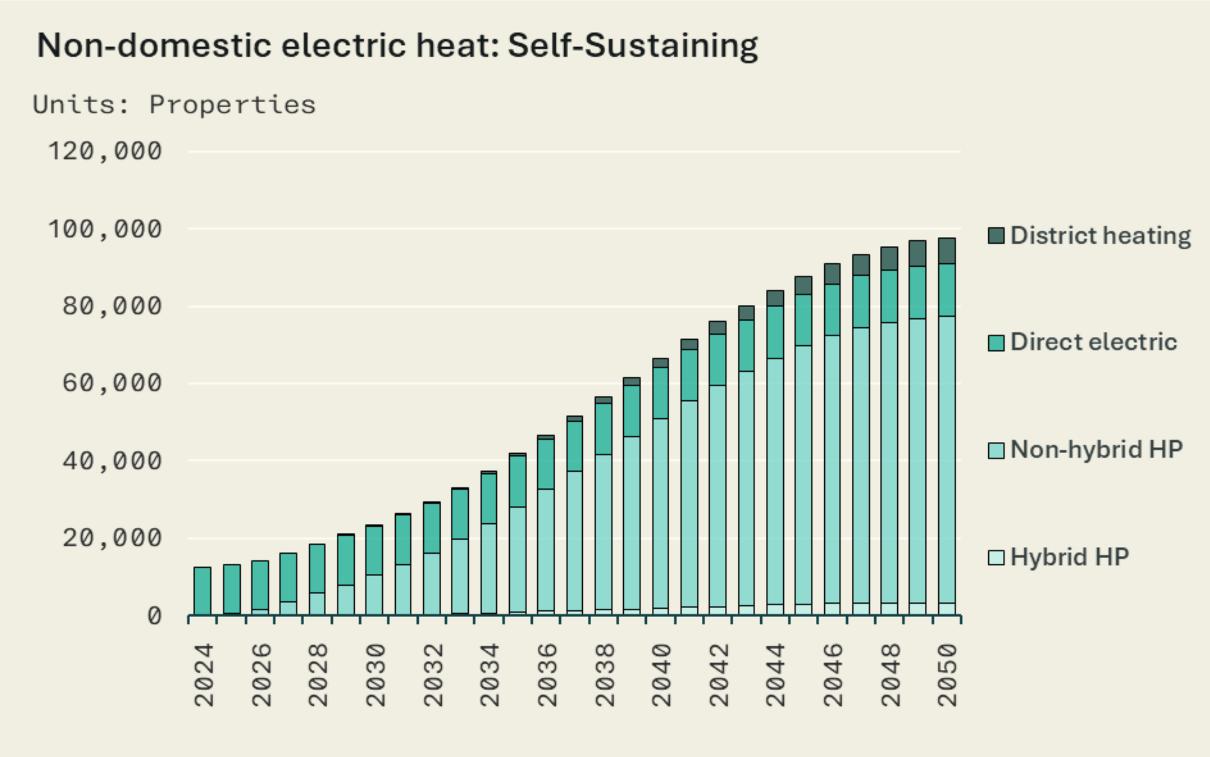


Figure 21

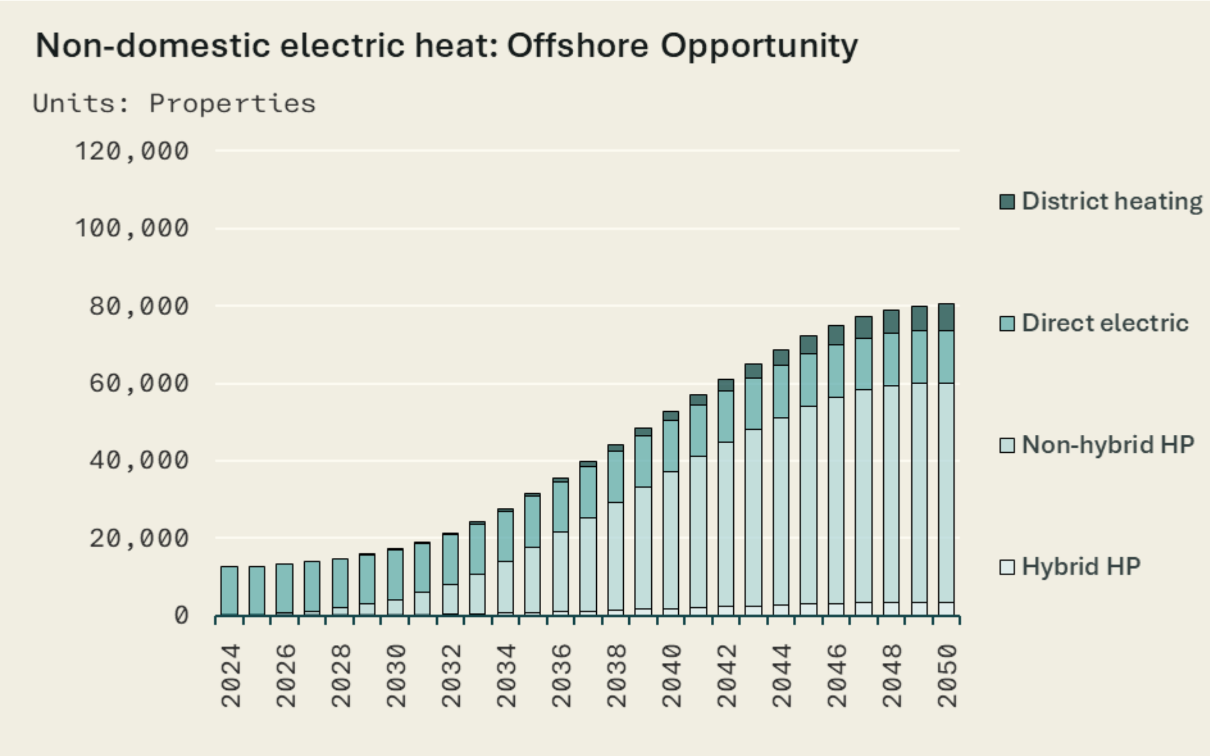


Figure 22

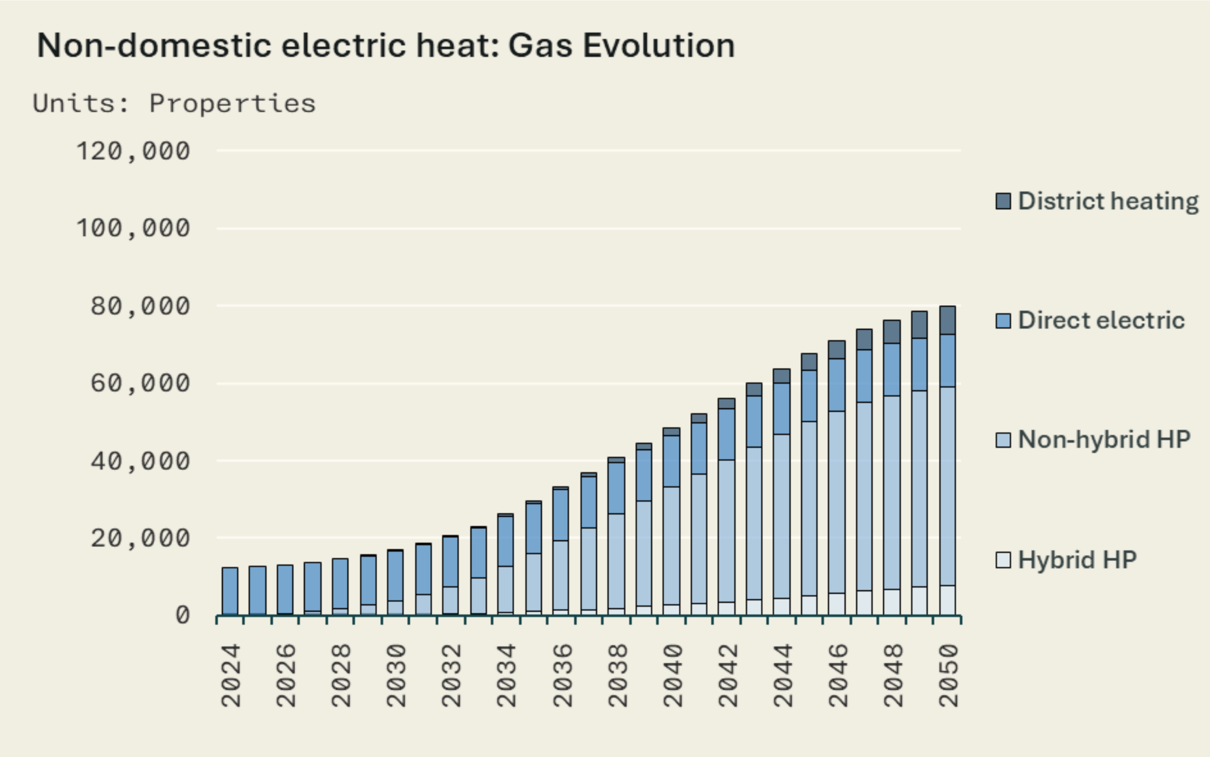
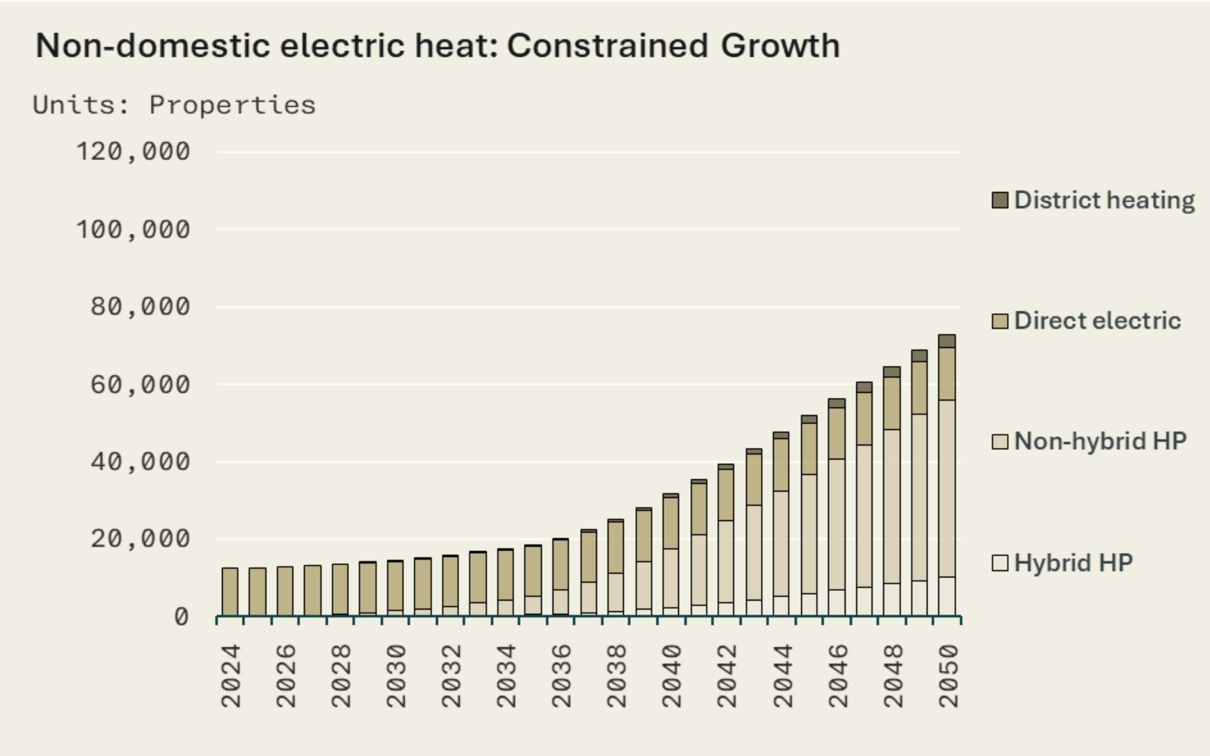


Figure 23



2.2.8. Reconciliation to other projections

Total heat pump annual electricity demand has been compared between the distribution modelling and SONI's Tomorrow's Energy Scenarios:

Table 14

Scenario	Year	SONI Tomorrow's Energy Scenarios 'Heat pump demand' (TWh)	NIE Distribution Network Planning Scenarios 'Heat pump demand' (TWh)
Self-Sustaining	2035	3.4	1.7
	2050	4.9	4.7
Offshore Opportunity	2035	2.8	1.5
	2050	4.8	4.6
Gas Evolution	2035	2.0	1.3
	2050	4.1	4.3
Constrained Growth	2035	1.9	0.7
	2050	4.2	4.3

The network planning projections reflect a slower uptake of heat pumps in the short term and therefore do not align with the TES in the period up to 2035. This is justified on the basis that the policies to drive heat electrification in Northern Ireland are not yet implemented and once implemented will take several years to drive uptake (as has been the case with the Boiler Upgrade Scheme in GB). There is, however, a stronger correlation with the TES 2050 outcomes in all scenarios.

The Self-Sustaining and Offshore Opportunity scenarios represent a very ambitious increase in annual heat pump deployment compared to current uptake levels. Although fossil fuel price increases will drive some growth, this would require significant policy interventions, including the availability of grant funding and measures to increase or mandate heat pump uptake in social housing and the private rental sectors. Even the Constrained Growth scenario would require a significant increase in heat pump installations over the period to 2035.

The TES also notes that a maximum of 7% of properties are connected to a district heat network by 2050, although the scenario is not specified. The planning scenarios developed in this analysis broadly align with this proportion, ranging from 3% to 9% of properties, depending on the scenario. The number of heat pumps was not published in the TES 2023, so comparison to annual electricity demand has been used.

The Climate Change Committee has set out deployment rates for domestic heat pumps through to 2050 in their fourth carbon budget[26]. The annual rate of heat pump deployment in the CCC scenarios is 20,000 per year in 2030 and 50,000 per year in 2035. The four scenarios developed

[26] Tab 3.4, Northern Ireland Fourth Carbon Budget advice - Charts and data, 2025

in this analysis illustrate a range of potential 2030 outcomes around the CCC's target of 20,000 installations per year, varying from 12,900 to 26,600 annually. The two most ambitious scenarios also reach the CCC's 2035 installation rate of 50,000 installations per year, with scenario outcomes ranging from 23,400 to 50,000 annually.

Given the relatively low rate of heat electrification currently, there is much more uncertainty around future rates of heat pump uptake than EV uptake. The pace of adoption in the near and medium term will be strongly influenced by upcoming policy decisions around financial support for low carbon heating systems.

2.3. Other demand

In addition to the electrification of transport and heat, detailed in the sections above, further economy-wide changes are anticipated in the use of electricity as the energy transition progresses. This section outlines a high-level review of the potential for clusters of new connections or sources of future disruptive electricity demand that may emerge on Northern Ireland's distribution network. This assessment looked at NIE Networks' demand connections data, to determine any trends in other demand growth, as well as a general future electrification outlook for a set of key sectors.

2.3.1. Data centres

The growing demand for digital services and recent advancements in artificial intelligence (AI), particularly in generative AI, has driven a global surge in computing power needs, associated cooling and an accelerated development of large-scale data centre sites.

Data centres are facilities that house computer systems, servers, networking equipment and cooling plant to store, process, and manage large amounts of digital data. Continuous operation of the servers and associated cooling leads to significant on-site electricity demand.

Data centres are already a significant contributor to energy demand in the Republic of Ireland and Great Britain (centred around telecoms infrastructure in Dublin and London). There are several existing data centres in Northern Ireland, and there is a strong potential for growth, due to relatively lower land costs, existing high levels of renewable electricity, and opportunities for demand to connect into cluster substation sites. With an increased need for AI services in businesses, the potential location and scale of data centre sites could become more distributed and less focused on proximity to existing telecoms hubs. In GB, due to significant grid connections and queue management reforms, some grid-scale battery storage developers are starting to pivot their business model towards developing data centres. This may begin to impact developers in Northern Ireland.

There are two existing data centres connected to the distribution network in Northern Ireland, with demand totalling over 25 MW. In the All-Island Resource Adequacy Assessment, annual electricity demand in Northern Ireland from "data centres and new tech loads" is projected to increase to 0.4 TWh by 2034, or around 4% of 11 TWh total annual demand. [27]

2.3.2. Industrial processes

Many commercial and industrial businesses will be developing and implementing a multi-stranded approach to their own decarbonisation, this will likely include:

- Electrifying their transport fleets
- Replacing fossil-fuel driven space and water heating in buildings with electric heating technologies

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[27] Figure 4.7, All-Island Resource Adequacy Assessment, SONI and EirGrid, 2025

- Deploying onsite renewable energy (e.g. rooftop solar PV, small-scale wind on land)
- Installing behind-the-meter battery storage for onsite energy management
- Replacing diesel or gas CHP generation plant with battery storage or low carbon alternatives

Each of these aspects of industrial decarbonisation are already considered in the technology scope of this assessment, where non-domestic buildings are one of the drivers of the uptake and deployment of renewable energy and low carbon technologies.

Alongside these core technologies, the electrification of industrial processes and industrial equipment are crucial components to reducing emissions for businesses, alongside carbon capture and storage, fuel switching (e.g. to hydrogen or bioenergy), and energy efficiency improvements.

Northern Ireland hosts several energy intensive industries including, but not limited to:

- Manufacturing, including aerospace and shipbuilding
- Food processing
- Breweries and distilleries
- Cement manufacturing
- Quarrying
- Pharmaceuticals and chemical manufacturing

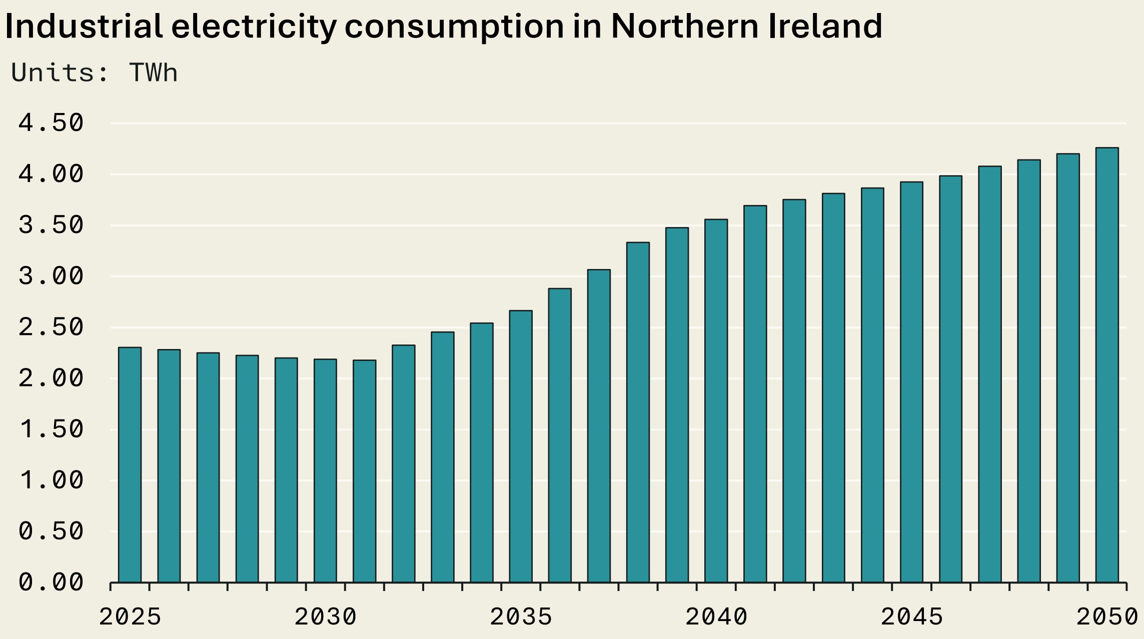
Whilst these industries create a wide range of end products and services, they all involve processes requiring a combination of heat and mechanical power. The utilisation of electricity to provide process heat can be summarised into four key approaches: heat pumps, resistive heating, electromagnetic radiation, and electric arc[28]. For mechanical power, electrification is enabled via electric motors, actuators and compressors.

The industrial sector in Northern Ireland already consumes significant amounts of electricity today and increases are anticipated in all decarbonisation scenarios. In the CCC's updated pathway for Northern Ireland, electricity demand from industry increases to 4.3 TWh in 2050 from 2.3 TWh in 2025. (See Figure 24).

Depending on the connection voltage tier of each customer, increases in demand may affect both transmission and distribution networks. Overall, it is likely that the growth of electricity demand from industrial processes will predominantly culminate in requests to increase import connection capacities from customers with existing connection agreements. This is in contrast to the development of generation and storage assets involving the construction of new sites and associated customer connection assets. This presents a risk for network operators, as the lead time for increases in demand may be relatively short. Changes to the connection charging regime, towards a shallower arrangement where the cost of upgrades are socialised, would likely help support industrial and commercial customers towards earlier electrification.

[28] Future Opportunities for Electrification to Decarbonise UK Industry, ERM, 2023

Figure 24



Source: CCC's Stretch Ambition pathway, presented in the Northern Ireland Target Advice.

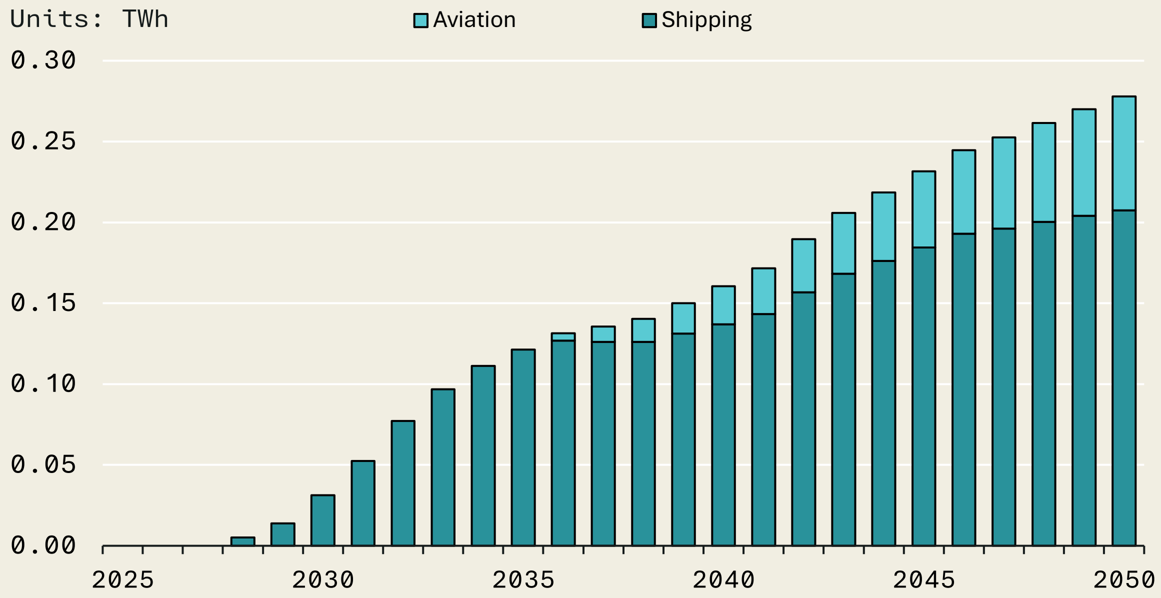
2.3.3. Non-road transport

Road transport is anticipated to contribute to the vast majority of transport related electricity demand by 2050. However, non-road transport (i.e. aviation, rail, shipping) operators are also likely to consider electrification as one of the solutions to enable decarbonisation. The degree to which electrification is a primary option will likely vary by non-road transport sector and by scale of asset that is currently using other fuel(s).

The CCC's Stretch Ambition pathway, published in 2024 as part of its Northern Ireland Target Advice, projects significant increases in annual electricity demand from both the aviation and shipping sectors. The electrification of rail is included in a wider surface transport aggregation.

Figure 25

Electricity consumption in Northern Ireland



Source: CCC's Stretch Ambition pathway, presented in the Northern Ireland Target Advice.

As the decarbonisation of Northern Ireland's economy progresses, increases in electricity demand are likely in maritime and shipping, aviation and rail sectors. Across several sectors, in particular agriculture and construction, use of electric non-road mobile machinery is likely.

Maritime and shipping:

There are three drivers of increased electricity demand at port locations:

- Shore power, also known as cold ironing, where ships temporarily connect to the local grid to power onboard systems when docked.
- Battery electrification of vessels, which is likely to enable decarbonisation of vessels operating shorter journeys, such as ferry routes and domestic freight. Electrification of

smaller vessels is likely to impact the distribution network, with demand distributed across over 40 marinas.
- The electrification of portside operations and machinery may also lead to demand increases at ports.

There are five commercial ports in Northern Ireland, with over two-thirds of seaborne trade handled through Belfast Harbour[29]. In addition to these commercial ports, the Northern Ireland Fishery Harbour Authority manages three fishery harbours and there are numerous smaller marinas spread across coastal areas.

Aviation:

There are a range of technological pathways to reduce aviation emissions, including biofuels, hydrogen or hydrogen-derived fuels, and electrification. In a similar way to maritime and ports, increased electricity demand at airports could have several drivers:

- Charging of battery electric aircraft (initially related to local and short-haul flights)
- Hydrogen liquefaction or compression
- Electrification of ground support, operational equipment and buildings

There are three major airports in Northern Ireland and a further 43 smaller airports and aerodromes that may see increased demand on the local distribution network.

Rail:

Northern Ireland's rail network is currently entirely diesel-powered. Whilst there are no public plans yet to electrify the network, the joint All-Island Strategic Rail Review (2024) identified a number of new and existing routes in Northern Ireland for electrification[30]. In 2023, Translink was provided with funding by the Department for Transport for a study on the cost, feasibility and value for money of electrifying the railway between Belfast and the Republic of Ireland[31].

Historically, electric rail networks have used overhead line electrification with transmission network connections. However, the development of battery electric trains is enabling the use of lower voltage distribution network connections[32].

Agricultural machinery:

The decarbonisation of the agricultural sector, and its resultant impact on the distribution network, is a potentially significant source of future demand for NIE Networks. Farm machinery and vehicles use fossil diesel as their primary fuel. In contrast to other sectors, the agriculture sector is exempt from fuel duty for its non-road mobile machinery.[33]

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[29] Gateways - sea ports, Department for Infrastructure
[30] All-Island Strategic Rail Review, Department for Infrastructure, 2024
[31] Options for improving rail links in Northern Ireland, Translink, 2023
[32] GWR FastCharge battery train trial, FirstGroup, 2024
[33] Reform of red diesel and other rebated fuels entitlement, HMRC

The electrification of agricultural machinery is still at a very early stage, especially for mobile machinery such as tractors and other larger farm vehicles, with very few registered electric vehicles to date. However, the CCC's 4th Carbon Budget report for Northern Ireland[34] highlights that the electrification of machinery is expected to be the primary solution to decarbonise agricultural machinery. The CCC's advice also suggests that some larger mobile machinery could switch to low carbon hydrogen. However, if electrified tractor/machine technology develops further, the full fleet of machinery could be electrified. Bioenergy/biofuels have also been referenced as a transitional fuel that is then phased out by 2040.

In terms of scale of potential future electricity demand, agriculture is one of the largest industries in Northern Ireland. As of June 2024, there are over 26,000 registered farms in Northern Ireland, employing over 50,000 farm workers, farming over 1 million hectares of land [35]. Many of these farms are small and are likely supplied by distribution network substations.

In addition to decarbonisation of mobile machinery, the electrification of on-site farm processes, (e.g. grain drying, livestock shed heating, dairy chilling etc.) was also highlighted as a significant source of potential future electricity demand by agricultural stakeholders in Regen's wider engagement that informed distribution network analysis for GB licence areas.

[34] Northern Ireland's Fourth Carbon Budget, Committee on Climate Change, March 2025
[35] The Agricultural Census in Northern Ireland, Department of Agriculture, Environment and Rural Affairs, June 2024

Section 3:

Generation and storage

Approach and modelling results

This section includes the approach and modelling results for the following generation and storage technologies connecting to the distribution network in Northern Ireland:

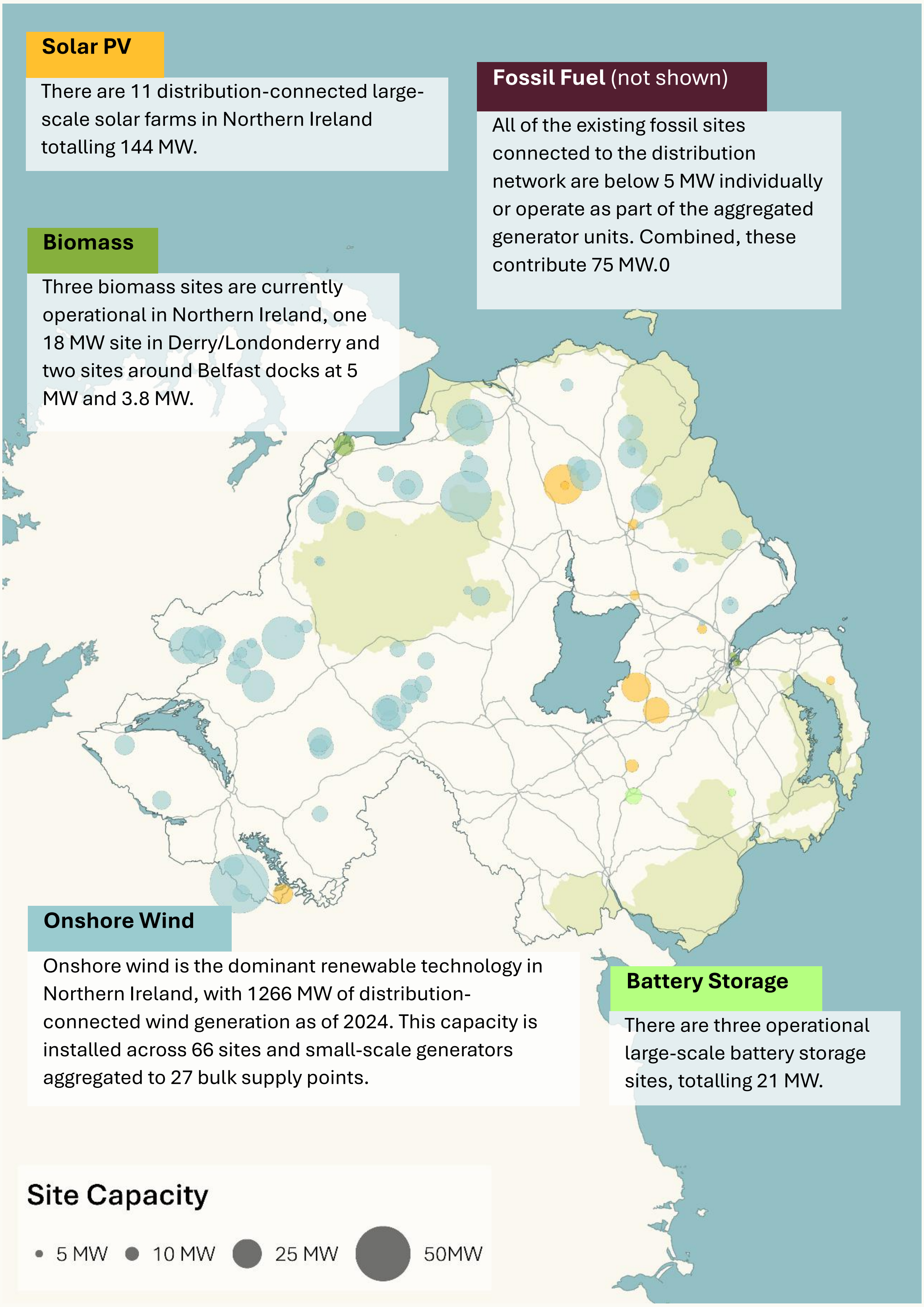
- Onshore wind (up to 47.5 MW, the assumed limit for distribution connections)
- Solar generation (large utility-scale, commercial-scale and domestic-scale)
- Thermal generation (diesel engines, biogas generation, fossil gas generation, biomass generation)
- Electricity storage (large utility-scale, commercial-scale and domestic-scale)

The development milestones set out in Table 15 have been used to categorise larger generation and storage projects.

Table 15

Milestone	Description
Connected	Generation and storage sites that are operational and connected to the distribution network by the end of 2024.
Contracted	Projects which have received and accepted a connection offer from the distribution network.
Prospective	Projects that have some evidence of development progress. This includes: • projects which have applied for a connection and are currently waiting for an offer • projects where developers are considering their connection offer • projects that have submitted a planning application or had a planning application approved • projects that are known to have begun development but have yet to reach any formal development milestones

Figure 26


Solar PV
There are 11 distribution-connected large-scale solar farms in Northern Ireland totalling 144 MW.
Fossil Fuel (not shown)
All of the existing fossil sites connected to the distribution network are below 5 MW individually or operate as part of the aggregated generator units. Combined, these contribute 75 MW.0
Biomass
Three biomass sites are currently operational in Northern Ireland, one 18 MW site in Derry/Londonderry and two sites around Belfast docks at 5 MW and 3.8 MW.
Onshore Wind
Onshore wind is the dominant renewable technology in Northern Ireland, with 1266 MW of distribution-connected wind generation as of 2024. This capacity is installed across 66 sites and small-scale generators aggregated to 27 bulk supply points.
Battery Storage
There are three operational large-scale battery storage sites, totalling 21 MW.
Site Capacity
5 MW
10 MW
25 MW
50MW

3.1. Onshore wind

This analysis accounts for onshore wind generation, ranging from small single-turbine installations up to multi-megawatt wind farms. Wind farms over 47.5 MW are not in the scope of this analysis, however, due to these sites connecting to the electricity transmission network.

3.1.1. Summary

Onshore wind is currently the most widely deployed low-carbon technology in Northern Ireland, which was home to some of the first wind energy sites in the UK. Financial support for onshore wind began in 2005 with the introduction of the Northern Ireland Renewables Obligation (NIRO), which remained in place until 2017. Despite the closure of NIRO and the absence of a support scheme for large-scale generation in the vein of the Contracts for Difference (CfD) scheme in GB, onshore wind farm development has continued. The forthcoming Renewable Energy Support Scheme aims to accelerate deployment.[36] Energy policies such as this have been considered directly in the pipeline analysis and to varying degrees under each scenario out to 2050.

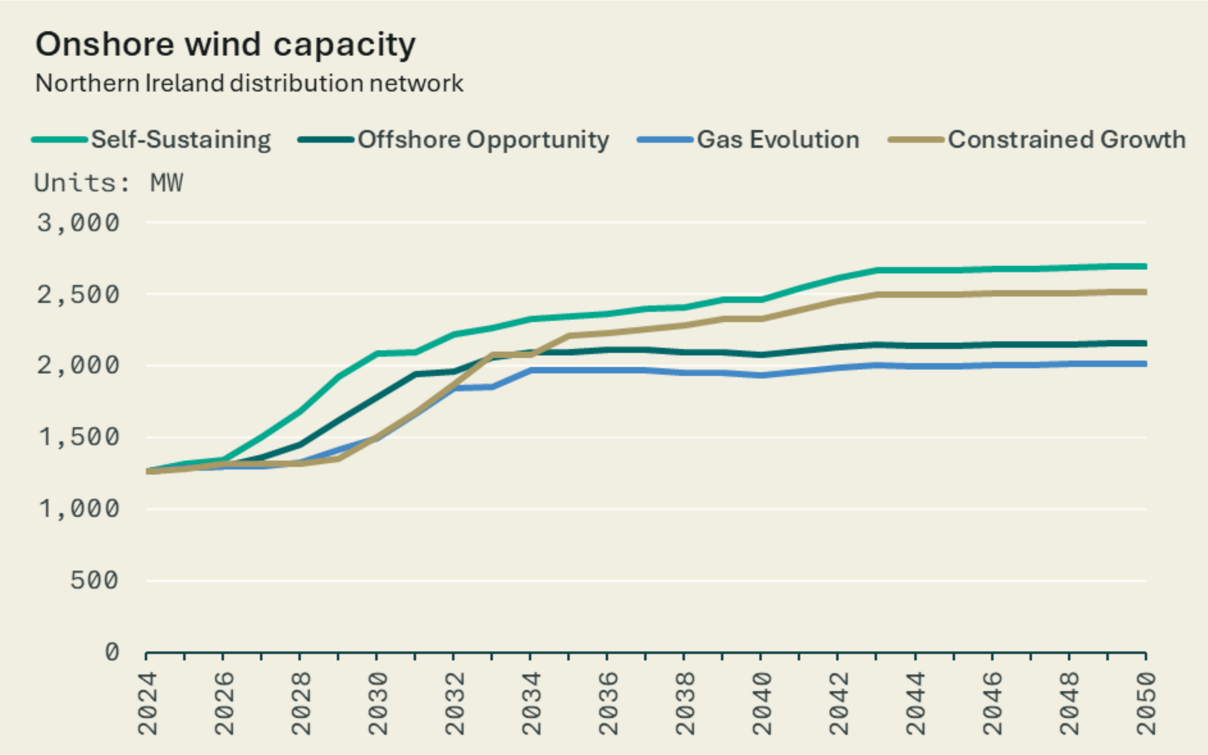
Future growth in the connected capacity of onshore wind has been modelled through:

- **Repowering potential** – assessing the opportunity to replace or upgrade turbines at existing operational sites as they reach the end of an assumed 25-year operational life.
- **Pipeline buildout** – evaluating the development potential and evidence of projects within the known pipeline.
- **Scenario alignment** – reconciling projected future capacity with TES 2023, considering both existing and anticipated grid connections.

Northern Ireland's current onshore wind capacity stands at 1.3 GW. By 2050, this is projected to grow to a range of between 2.2 GW (under the Gas Evolution scenario) and 2.7 GW (under the Self-Sustaining scenario).

[36] The Renewable Energy Support Scheme , Department for the Economy, 2023

Figure 27



3.1.2. Baseline distribution capacity and development pipeline

Table 16

Status	Capacity	Description
Operational	1,266 MW	Northern Ireland currently has 66 operational large-scale onshore wind projects on the distribution network, totalling 1,106 MW. Of these, 61 are large-scale sites with 5 MW or more capacity, while 5 sites range between 1 MW and 5 MW. The largest distribution-connected wind farm, Slieve Rushen 2 in County Fermanagh, has a capacity of 54 MW. A further 160 MW of capacity is made up of small-scale generators connected across 27 bulk supply points. Most operational projects were developed between 2007 and 2017 under the Northern Ireland Renewables Obligation (NIRO) scheme. However, deployment has continued, though at a slower pace, beyond the scheme's closure. Between 2018 and 2025, an additional 192 MW was installed, including 22.5 MW in 2024.
Contracted	281 MW	29 additional projects are currently contracted to connect to the network in the near term. There are 17 small-scale generation projects, 15 of which are less than 1 MW, which make up 9.2 MW of contracted projects. The remaining 12 large-scale projects account for

		272 MW of contracted capacity. These projects have secured planning permission and accepted their grid connection offer from NIE Networks. These contracted sites are modelled to be built out between 2028 and 2031 across all scenarios.
Prospective	707 MW	Like the rest of the UK, Northern Ireland has a significant number of projects in the connections queue, planning and pre-planning stages. Small-scale generation projects make up 33 MW of capacity in the connections queue across 42 sites. Two large-scale sites exist in the connections queue, which have a combined capacity of 28.5 MW. In contrast, onshore wind projects in the planning system or in pre-planning stages are all large-scale developments, often exceeding 20 MW individually. Most prospective projects are expected to be built out between 2028 and 2038 across all scenarios.

3.1.3. Scenario framework

Table 17

Scenario	Description
Self-Sustaining	The Self-Sustaining scenario is characterised by a faster pace of energy transition, backed by high levels of support from both domestic consumers and government. This results in the highest onshore wind capacity of any scenario. Existing operational sites over 1 MW are modelled to repower with an additional 50% capacity, reflecting the installation of new, larger and more efficient turbines at the end of operational life. Repowering adds a further 485 MW of capacity, bringing the capacity from existing connections up to 1.75 GW. The projected pipeline buildout adds a further 946 MW of capacity by 2050, which, when combined with the repowering capacity, contributes an additional 1,431 MW of new capacity. As a result, the distribution network onshore wind capacity in Northern Ireland reaches 2.7 GW by 2050 under this scenario.
Offshore Opportunity	Offshore Opportunity focuses primarily on developing larger-scale, predominantly offshore wind generation and exporting to international energy markets. So, whilst the pace of transition in Offshore Opportunity is rapid, the greater focus on offshore development results in lower levels of onshore wind deployment. Onshore wind sites over 1 MW are modelled to repower with an additional 25% capacity, reflecting fewer but more efficient turbines being installed at the end of project life. This results in a further 243 MW of onshore capacity by 2050. Decommissioning of small turbines that are no longer supported by revenue support

	schemes causes a reduction of 160 MW resulting in a net increase of 83 MW. By 2050, Offshore opportunity sees the buildout of 808 MW of the project pipeling. As a result, the deployment of onshore wind generation capacity in Offshore Opportunity will increase by 892 MW of capacity, totalling 2,157 MW in 2050.
Gas Evolution	Gas Evolution has a focus on leveraging international energy markets. It is also a scenario that considers the development of large-scale hydrogen-to-power plants, reducing the need for other distributed generation technologies. Gas Evolution targets net-zero emissions by 2045, resulting in a moderate pace of transition. In this scenario, the increased focus on hydrogen development results in lower support for repowering onshore wind projects. Projects over 1 MW repower with an additional 25%, resulting in an additional 243 MW capacity. The decommissioning of small turbines that are no longer supported by revenue support schemes causes a capacity reduction of 160 MW. Including a pipeline buildout of 665 MW, an additional 748 MW of capacity is installed under this scenario. Resulting in a total of 1,934 MW of onshore wind connected at the distribution network level by 2050.
Constrained Growth	Whilst Constrained Growth has the second-highest overall onshore wind capacity by 2050, under this scenario, delays to the development of policy support are assumed, including the in-development CfD scheme, resulting in the slowest pace of new renewable energy capacity buildout. The support for wind generation is reflected through the repowering of connected sites, where sites over 1 MW gain an additional 40% of their existing capacity once they reach the end of their operational life. As a result, repowering contributes an additional 388 MW of capacity by 2050 under this scenario, and the buildout of pipeline sites accounts for a further 863 MW. As a result, by 2050, an additional 1,251 MW will be installed, resulting in a total of 2,517 MW of onshore wind capacity connected to the distribution network.

3.1.4. Stakeholder engagement summary

Table 18

Stakeholder	Feedback provided
Consultation event	Responses helped confirm that there is a moderate likelihood of wind farms greater than 1 MW repowering with greater capacities. Repowering with additional capacity is less likely for smaller sites.

Stakeholder	Feedback provided
Developer engagement	Developer engagement revealed several new sites in planning and increased capacities at known sites. These indications of high ambition and desire to develop wind informed the high levels of onshore wind in the distribution scenarios as compared to the 2023 TES forecasts.
Invest NI	Invest NI emphasised the importance of grid reinforcement to integrate higher volumes of renewables onto the grid.
Renewable NI	Renewable NI have had sight of these projections and confirmed they reflect the scale of pipeline projects in development.

3.1.5. Modelling approach

Table 19

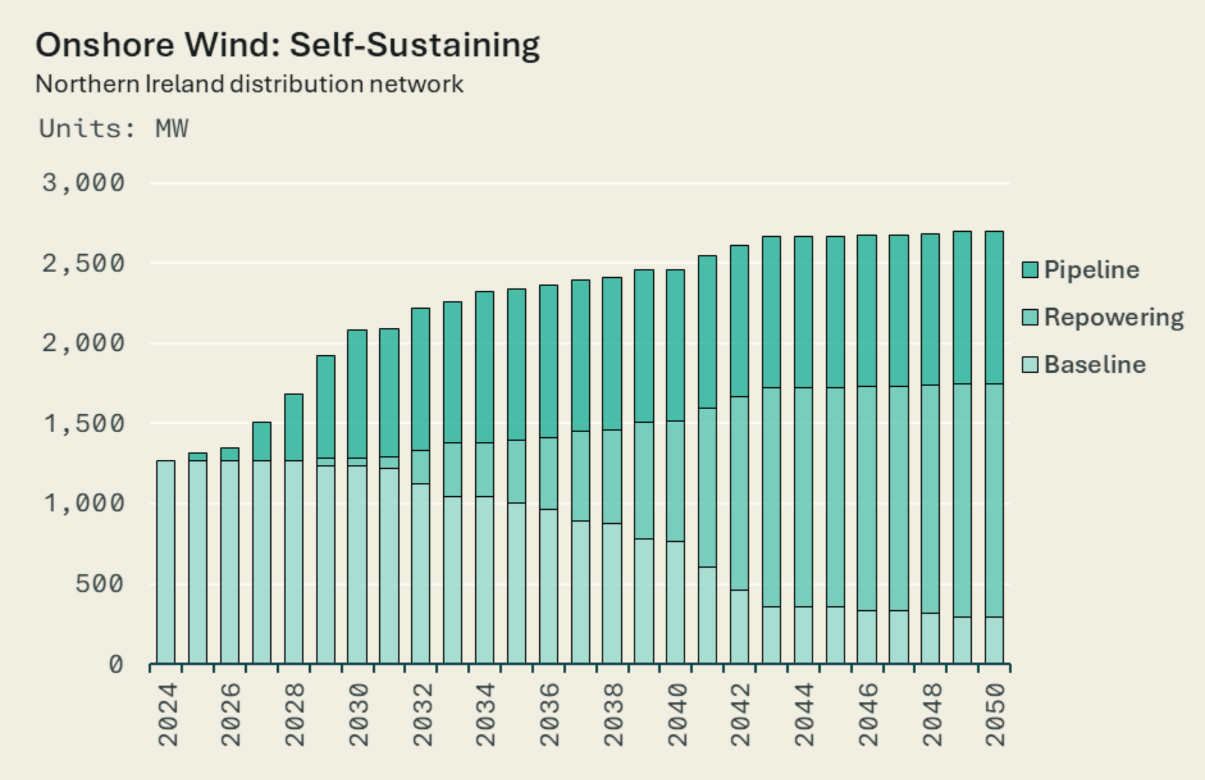
Model factor	Description
Repowering and decommissioning	The NIE Networks connection register provided a baseline of sites, indicating the years each site became operational. A project lifetime of 25 years was used to determine a repowering date. The repowering percentage and resultant capacity were varied by scenario, depending on the level of policy support for renewable energy generation under each scenario. In the most ambitious scenario, Self-Sustaining, projects over 1 MW repower with an additional 50% of their base capacity, reflecting a more supportive market and planning environment. In Offshore Opportunity and Gas Evolution, repowering only adds 25% capacity under a less ambitious policy framework. This is a conservative estimate relative to recent reports, which indicate that sites often repower at approximately 2.7 times their baseline capacity.[37] However, not all sites will repower or increase their capacity, therefore, it is assumed this is a suitable average capacity increase across all sites. A decommissioning curve was applied to sites of less than 1 MW, which are assumed to be operating under the NIRO scheme for Offshore Opportunity and Gas Evolution. In contrast, under the Self-Sustaining and Constrained Growth scenarios, support for small-scale sites is assumed, resulting in < 1 MW onshore wind sites repowering at their existing capacity at the end of their operating life. To prevent an overlap with repowering/additional capacity applications to NIE or in the planning system, sites which would have been repowered before 2029 were removed.
Project abandonment rates	Not all projects that enter the planning system or connections queue are modelled to build out under all scenarios. NIE Networks provided the abandonment rate of generation projects split between large (> 5

[37] *Repowering of wind farms*, Iberdrola, 2023

	MW) and small (< 5 MW) scale projects. These rates were interpreted and transcribed into each scenario to reflect a range of available policy support mechanisms and planning friendliness. Gas Evolution, the lowest ambition scenario for onshore wind, reflects the highest level of abandoned projects due to greater policy support and focus on hydrogen electrolysis and generation.
Contracted projects	Contracted projects are assumed to connect before those at earlier development stages in the grid connection process or spatial planning system. Grid connection application years are provided for six new onshore wind projects, totalling 85 MW. For these, a timeline of between 4 and 7 years from the project's grid application date is applied. This reflects analysis of project timelines in the renewable energy pipeline database. For projects without application years, the connection year was assumed to reflect the ambition of the scenario. For Self-Sustaining and Offshore Opportunity, which target net zero by 2040, contracted projects were modelled to build out in either 2028 or 2029, respectively.
Queue projects	Projects in the connection queue need to obtain planning permission within 120 days of receiving their connection offer. In the analysis, these projects connect alongside or after the contracted projects, but before projects that are solely in the planning pipeline.
Planning pipeline	Under the Self-Sustaining scenario, all projects were modelled to connect in line with the estimated completion dates held in NIE Networks' connection data. Under the Constrained Growth scenario, these projects were modelled to connect three years after the estimated dates. Project development delays under the scenarios are designed to reflect a weaker policy environment and less favourable market conditions for onshore wind development. Projects without estimated completion dates are assumed to be further behind in spatial planning processes and are therefore likely to move through to connect later. Under the Constrained Growth scenario specifically, this results in one project not connecting to the network until 2038.
Post-pipeline projections	Based on the development evidence identified for each of the pipeline sites, the projected capacity in the 2020s and 2030s is higher than the equivalent onshore wind capacity modelled under the TES analysis. The SONI TES considers additional transmission-connected wind capacity. As a result, the distribution scenarios do not model any additional capacity beyond the known pipeline and the repowering of existing sites.

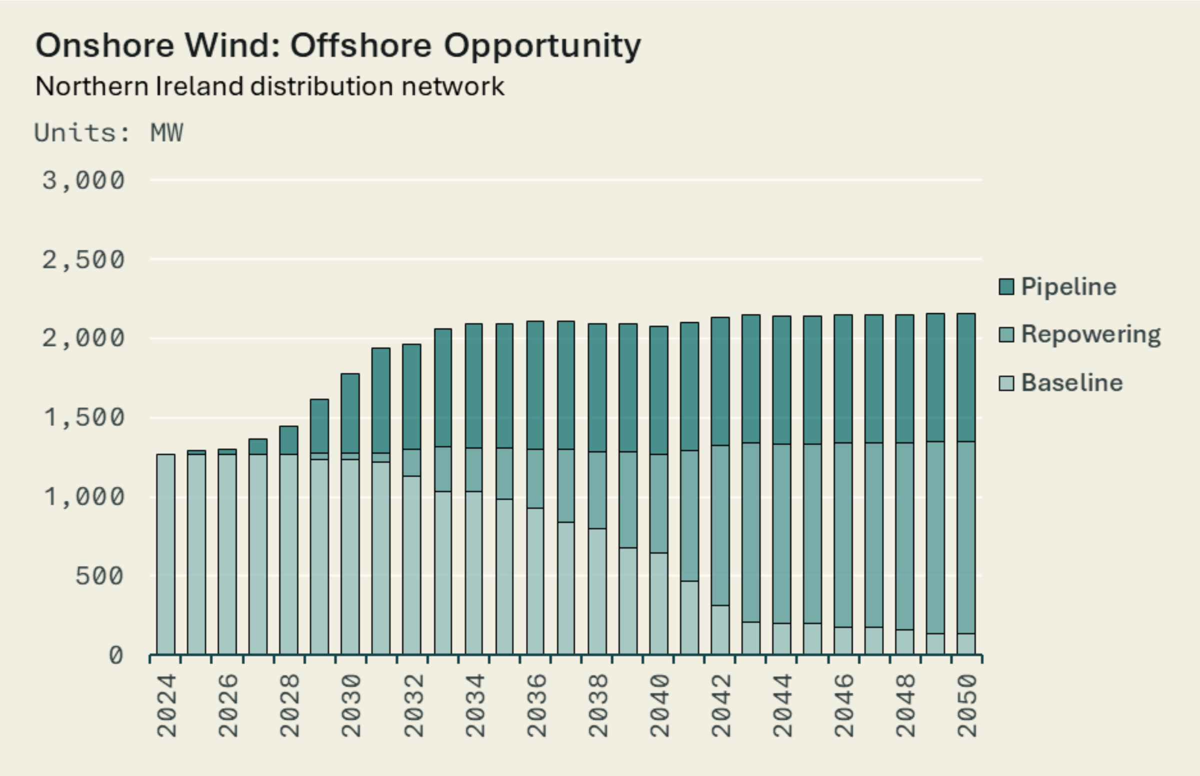
3.1.6. Detailed results

Figure 28



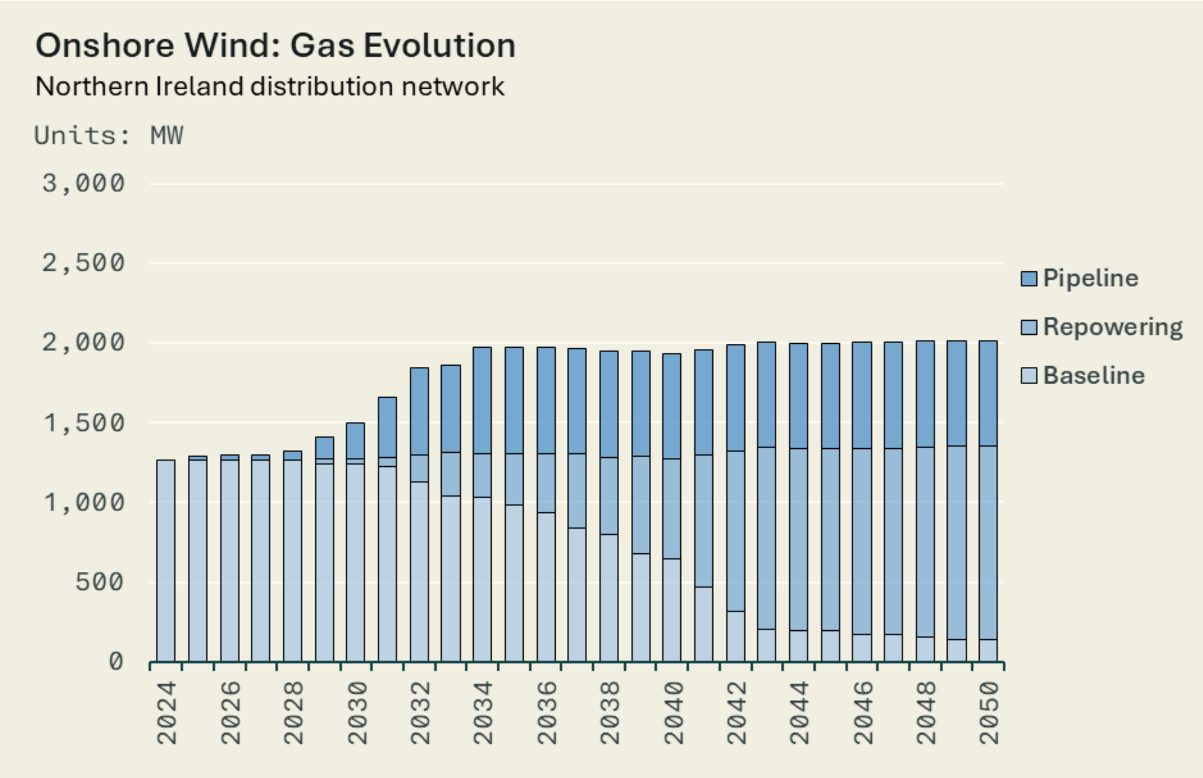
High ambition and a supportive policy environment result in the pipeline of projects connecting by 2034 in the Self-Sustaining scenario. The growth trajectory is kept up past this point with a favourable environment for repowering, resulting in steady growth to the early 2040s.

Figure 29



An ambitious target to reach net zero results in a rapid buildout of new capacity in Offshore Opportunity. The decommissioning of small-scale NIRO-supported turbines beginning in 2033 results in stunted growth after the buildout of new capacity, even causing a small decrease in installed capacity between 2037 and 2042.

Figure 30



Gas Evolution faces a slightly delayed rollout of support and new capacity for onshore wind, resulting in a delayed buildout of significant new capacity until the early 2030s. New capacity built out in the mid-2030s, as well as site repowering, mostly offsets the decommissioning of small-scale projects, though there are still small drops in installed capacity between 2036 and 2040.

Figure 31

Constrained Growth sees significant support given to onshore wind, though delays in implementation. Most of the pipeline in this scenario is built between 2031 and 2038, after which capacity growth results from the repowering of existing sites.

3.1.7. Reconciliation to other projections

The SONI TES projects a rapid uptake of new onshore wind development out to 2035, with all scenarios at, or very near, their 2050 capacities across both the transmission and distribution networks. The scenario projections in this study show similar results, with all scenarios seeing a flattening of installed capacity from 2035. This is due to almost all the pipeline being built by 2035, meaning the remaining capacity additions post-2035 are smaller repowering additions. In Offshore Opportunity and Gas Evolution, this is offset by the decommissioning of projects under 1 MW, resulting in almost no growth past 2035.

It was not possible to determine the distribution network proportion of the system-wide onshore wind capacity in the TES. The projections in this analysis are assumed to be in line with or moderately higher than the portion of distributed wind capacity that makes up the TES total. This assumption is backed up by existing transmission scale wind projects and 1.5 GW of projects in the pipeline of this scale. Due to the scale of potential transmission scale projects, all scenarios likely will reach higher overall capacities than in the TES, which was a view expressed during engagement with various stakeholders.

In the RP7 business plan, NIE networks anticipated that just under 2.5 GW of onshore wind is needed by 2030 to meet the Climate Change Act target of an 80% renewable energy supplied power system[38]. This projection is likely to be exceeded in Self-Sustaining, which reaches 2 GW of distribution-connected onshore wind capacity, assuming similar buildout rates of transmission-connected generation capacity. Under Constrained Growth and Gas Evolution modelled onshore wind capacity is likely to fall short of the RP7 2030 projection of 2.5 GW.

Table 20

Scenario	Year	SONI Tomorrow's Energy Scenarios (GW)	NIE Distribution Network Planning Scenarios (GW)
Self-Sustaining	2035	3.33	2.34
	2050	3.46	2.70
Offshore Opportunity	2035	2.46	2.10
	2050	2.46	2.16
Gas Evolution	2035	2.22	1.97
	2050	2.22	2.14
Constrained Growth	2035	2.75	2.21
	2050	2.90	2.52
Notes:		Transmission and distribution network connected capacity.	Distribution network connected capacity only.

[38] RP7 Scenario Forecasts, Northern Ireland Electricity Networks, 2022

3.2. Solar generation

This technology category includes all forms of solar photovoltaic electricity generation:

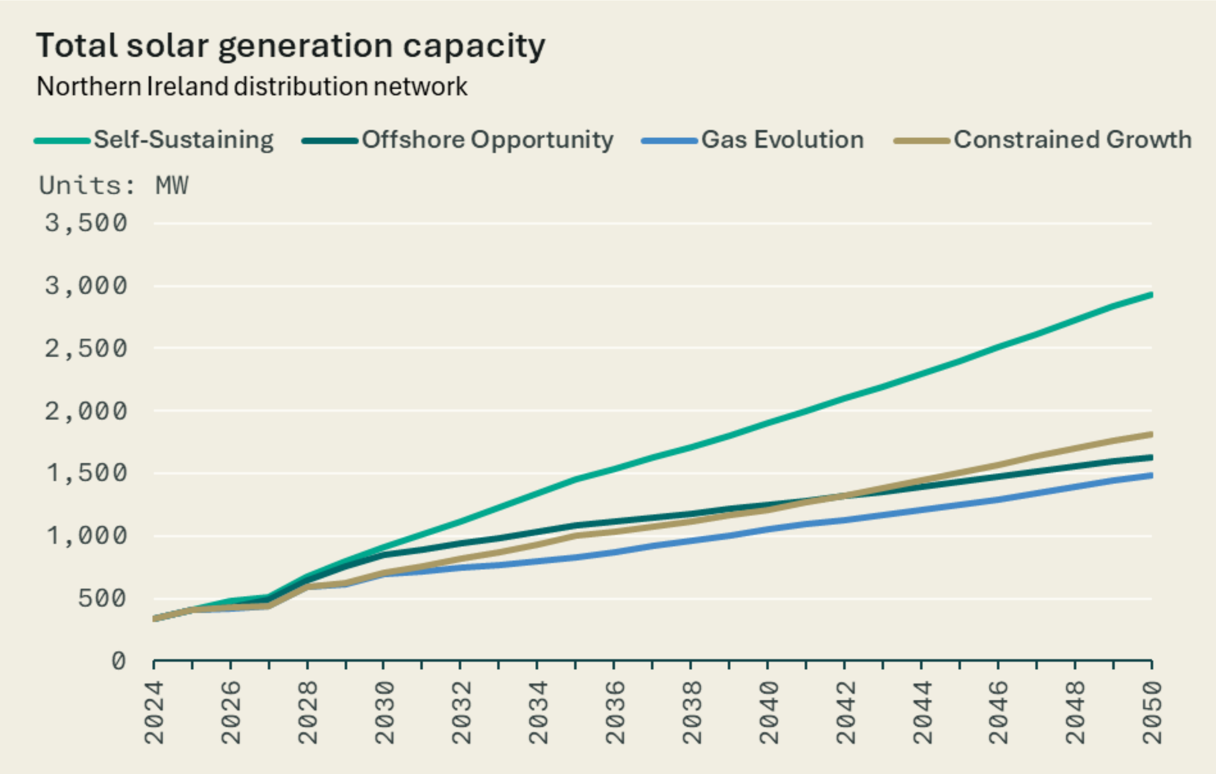
- Large utility-scale installations over 5 MW.
- Large warehouse rooftop and small ground mounted installations between 50 kW - 5 MW.
- Commercial-scale generation, typical for business premises, up to 50kW.
- Domestic rooftop generation, averaging 4kW.

3.2.1. Summary

Compared to onshore wind, solar generation has seen notably less deployment in Northern Ireland to date. This is likely to be a combination of limited solar irradiance levels and the market position for solar installations. There is, however, a notable pipeline of new solar projects currently in development and, with supportive policy and market structures, uptake of large and small-scale solar generation could increase significantly out to 2050.

Therefore, under all scenarios, installed solar capacity increases across all installation scales. However, this ranges notably across the scenarios, ranging from c.1.5 GW in Gas Evolution to c.2.9 GW by 2050 in Self-Sustaining.

Figure 32



3.2.2. Baseline capacity and development pipeline

Table 21

Status	Capacity	Description
Operational	308 MW	144 MW of large-scale solar generation capacity is currently deployed, comprising of 11 projects, each with capacities over 5 MW. Microgeneration Certification Scheme (MCS) data for commercial installations up to 50kW indicates that 49 MW is currently deployed in NI. The same data indicates that approximately 200 sites of this scale are currently deploying per year. Some further commercial-scale installations are captured by NIE Networks that have not been certified by MCS. NIEN connections data indicates that 103 MW of domestic solar generation is currently installed. Data published by the MCS foundation supports this and indicates that approximately 1,800 new domestic solar PV installations are currently being added per year[39].
Contracted	132 MW	The current capacity of solar generation sites that have contracted connection offers with NIE Networks totals 132 MW. Two large-scale projects in development, totalling around 45-50 MW each, compose two thirds of this capacity. If commissioned, these would become the largest solar projects in Northern Ireland. The remaining 40 MW of contracted capacity is commercial and domestic solar generation. This capacity has been modelled to commission in the near term under all scenarios, due to these smaller installations not requiring spatial planning consent and being likely to be installed quickly.
Prospective	288 MW	Another 45 solar generation sites have some evidence of development but are yet to secure a contracted connection offer with NIEN. Ten large-scale sites with an average capacity of 26 MW make up the majority of this prospective solar capacity. Evidence available on estimated commissioning dates has been used to model the future deployment of these sites, with less ambitious scenarios assuming less well progressed sites do not move through to deployment.

[39] MCS data dashboard, MCS, accessed March 2025

Status	Capacity	Description
		36 sites with capacities below 5 MW account for 22 MW of this prospective capacity. This has been modelled to connect by 2030 under all scenarios. Five sites with capacities greater than or equal to 47.5 MW have not been included in this assessment due to their likely connection at transmission level. This totals 315 MW of capacity.

3.2.3. Scenario framework

Table 22

Scenario	Description
Self-Sustaining	With a high degree of societal change and pace of decarbonisation, this scenario has the highest levels of solar deployment at all scales. All known large-scale sites in the pipeline build out, with additional capacity modelled between 2030 and 2035, reflecting a supportive policy and market conditions. The upcoming Renewables Support Scheme is successful in incentivising large-scale solar project deployment.[40] Reform to planning policies, currently identified as a key barrier, attracts further development.[41] A new incentive for small-scale solar generation is introduced, which results in annual installations increasing at a rate similar to that seen historically under the NIRO (Northern Ireland Renewables Obligation) scheme. In general, the increased demand from the electrification of heat and transport drives the continued uptake of solar on the distribution network under this scenario in the longer-term. As a result, total installed solar generation capacity reaches 2.9 GW by 2050.
Offshore Opportunity	A high pace of decarbonisation within this scenario means that all large-scale sites in the pipeline are modelled to build out. However, a long-term focus on large-scale transmission connected infrastructure and the export of excess electricity, means that utility-scale solar PV on the distribution network is deprioritised under this scenario, with no additional deployment seen beyond 2035. Similarly, the uptake of small-scale solar is high in the near term, thanks to supportive policy and market conditions, but post-2035

[40] Renewable Electricity Support Scheme, Department for the Economy, 2023
[41] Motion: The Green Energy Transition, NI Assembly, 2025

Scenario	Description
	deployment is significantly lower than under the Self-Sustaining scenario. As a result, 1.6 GW is deployed by 2050.
Gas Evolution	The Gas Evolution scenario is characterised by an overall slower pace of decarbonisation but also a greater focus on larger-scale, transmission connected generation projects. Large-scale solar generation is deployed but at a relatively low pace up to 2035. It is assumed under this scenario that larger transmission connected projects are prioritised over distributed generation, so solar generation deployment is moderate in the long-term. This scenario also does not see a near-term acceleration in the deployment of small-scale solar generation and has limited incentives for small-scale solar business models in the long term. This results in an overall lower level of solar PV deployment – at all scales – in Northern Ireland, resulting in 1.5 GW by 2050.
Constrained Growth	This scenario is characterised by an overall slower pace of decarbonisation, combined with a greater focus on generation to meet domestic demand, rather than for international export. Large-scale solar generation is deployed but at a relatively slower pace up to 2035, compared to other scenarios. However, without a long-term focus on larger transmission connected generation in this scenario, there is a greater reliance on distribution network connected solar to meet the demands of electrification of heat and transport. As a result, there is significant post-2035 growth in large-scale solar. With an assumption that no new small-scale renewable energy incentive scheme is introduced, alongside falling disposable incomes, this scenario sees limited near-term uptake in small scale solar installations. This continues out to 2050, reflecting no incentives for small-scale solar business models in the long term. The installed capacity of solar generation reaches 1.8 GW by 2050. This is the second highest total of all scenarios; a result of high post-2035 growth in large-scale deployment on the distribution network.

3.2.4. Stakeholder engagement summary

Table 23

Stakeholder	Feedback provided
Consultation event	Responses confirmed the view that there is no NI-wide policy in place or in development that requires all new properties to have solar installed. (However, Part F of existing building regulations in Northern Ireland has led to an increase in solar installation). This

	is reflected in the modelling of new build solar generation, low growth scenarios reflect the current policy environment, while high growth scenarios reflect the adoption of building regulations which lead to much higher rates of solar installation in new properties. This would follow the adoption of similar policy in other parts of the UK.[42]
Solar installer	Contact with a solar PV installer operating in NI indicated that the market for commercial scale PV is starting to pick up. They also agreed with the assumption, made within this assessment, that achieving high uptake rates of small scale solar is dependent on the introduction of a new small scale generation incentive scheme.
Developer engagement	Engagement with developers resulted in the inclusion of an additional 30 MW site in pre-planning, yet to apply for a grid connection.
Renewable NI	Renewable NI have had sight of these solar generation projections and have confirmed that they reflect the scale of pipeline projects in development.

3.2.5. Modelling approach

Table 24

Model factor	Description
Large utility-scale solar (5 MW – 50 MW)	NIEN connection data was used to evidence the current baseline and pipeline of large-scale solar sites. Pipeline sites are allocated a deployment year based on evidence including grid connection agreement status, planning status, and estimated connection dates. Developers were contacted to provide updated information on any sites in the pipeline over 5 MW. Contracted sites deploy ahead of non-contracted sites, sites, modelled to connect in line with estimated completion dates included in the connections data. Sites in pre-planning are not modelled to build out under the two least ambitious scenarios. A scenario specific growth factor was used to model post-pipeline deployment between 2030 and 2050.
Large commercial / small utility-scale solar (50 kW – 5 MW)	This scale of sites includes large warehouse rooftop installations, such as those deployed on logistics hubs, and small ground mounted sites. UK government data on the deployment of solar projects in Northern Ireland indicates that 11% of total capacity from all sites over 50 kW is contributed by sites under 5MW. This contribution is assumed to

[42] Update on the future homes standard, UK Government, 2024

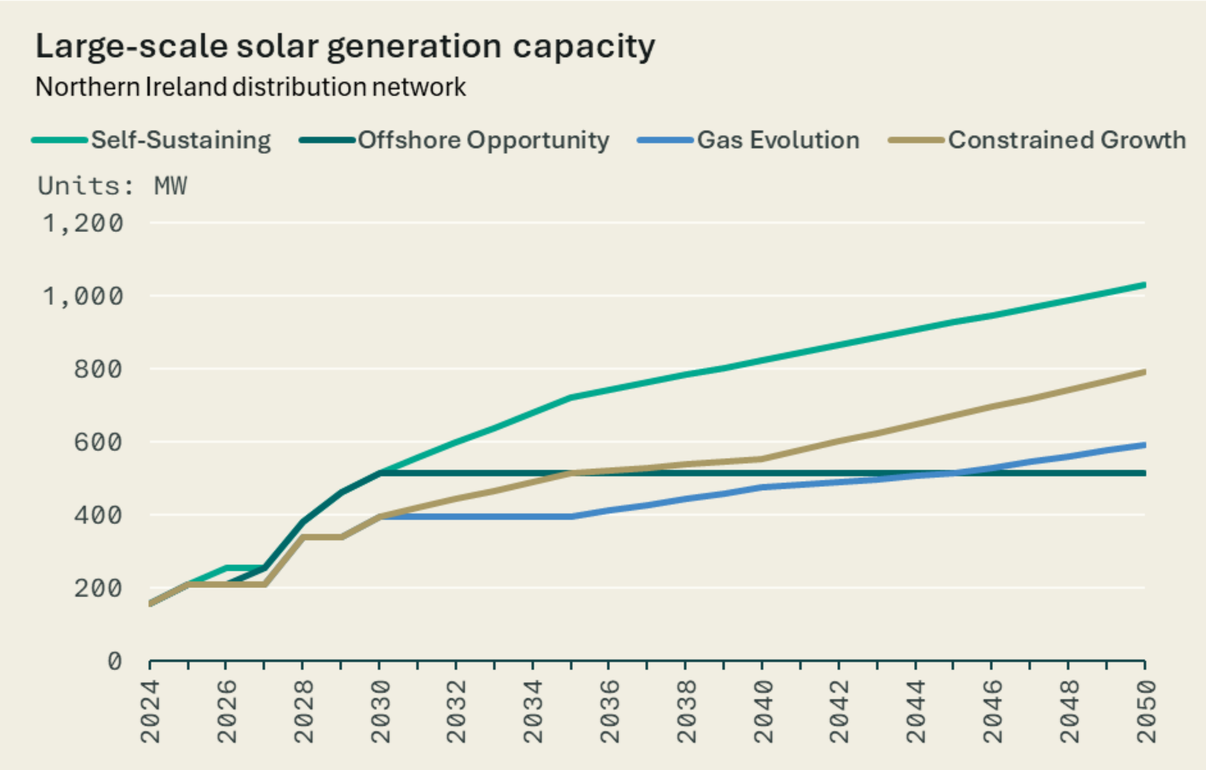
Model factor	Description
	remain in all scenarios and is assumed to be included within the utility-scale solar projections.[43]
Small-commercial scale (up to 50 kW)	Data from the MCS accreditation scheme was used alongside NIE Networks connections data to assess the current baseline of commercial solar installations and historic rates of deployment. To model deployment out to 2035, uptake curves for small commercial installations were created using historic trends. Under the most ambitious Self-Sustaining scenario, policy and market incentives are assumed to be present, which results in an increase from the current small commercial deployment rate of 4 MW per year, up to 22 MW per year by 2030. Post-2035 deployment is modelled by applying annual growth rates derived from the SONI TES projections. Specific growth rates for commercial rooftop solar are not clearly defined within the TES data, so domestic growth rates have been used as a proxy. Whilst there are differences between commercial and domestic scale installations, some of the core drivers for installation are shared across these two scales.
Domestic solar	Projections of domestic solar are driven by two components: 1. Retrofit installation on to existing buildings 2. Installation on to new build properties Data from the MCS accreditation scheme was used alongside NIE Networks' connections data to assess the currently deployed baseline of domestic sites and historic rates of deployment. To model future deployment to 2035, uptake curves for retrofit installations were created, using historic deployment data. The most ambitious Self-Sustaining scenario assumes a supportive policy and market incentive framework is present. This results in an increase from the current deployment rate of 1800 installations per year, up to 5000 installations per year by 2030. Post-2035 deployment is modelled by applying annual growth rates, derived from the SONI TES projections for domestic solar generation. To model the deployment of domestic solar on new builds, the projection for new build homes in NI, described in the appendix of this report, was paired with an assumption of the proportion of homes which are being built with rooftop solar. Research into existing new builds on the market indicates that this proportion is currently approximately 15%.[44] In higher adoption scenarios, it is assumed that policies to require solar installations in new builds are introduced that go beyond existing Part F building regulations. For example, in

[43] Northern Ireland solar deployment statistics, Department for Energy Security and Net Zero, 2024
[44] Desk based research of new builds available through the PropertyPal platform. This rate is lower than current estimates made for a UK wide rate by Solar Energy UK.

Model factor	Description
	the ambitious Self-Sustaining scenario half of new builds are constructed with rooftop solar in 2030, increasing to 90% of properties by 2050.

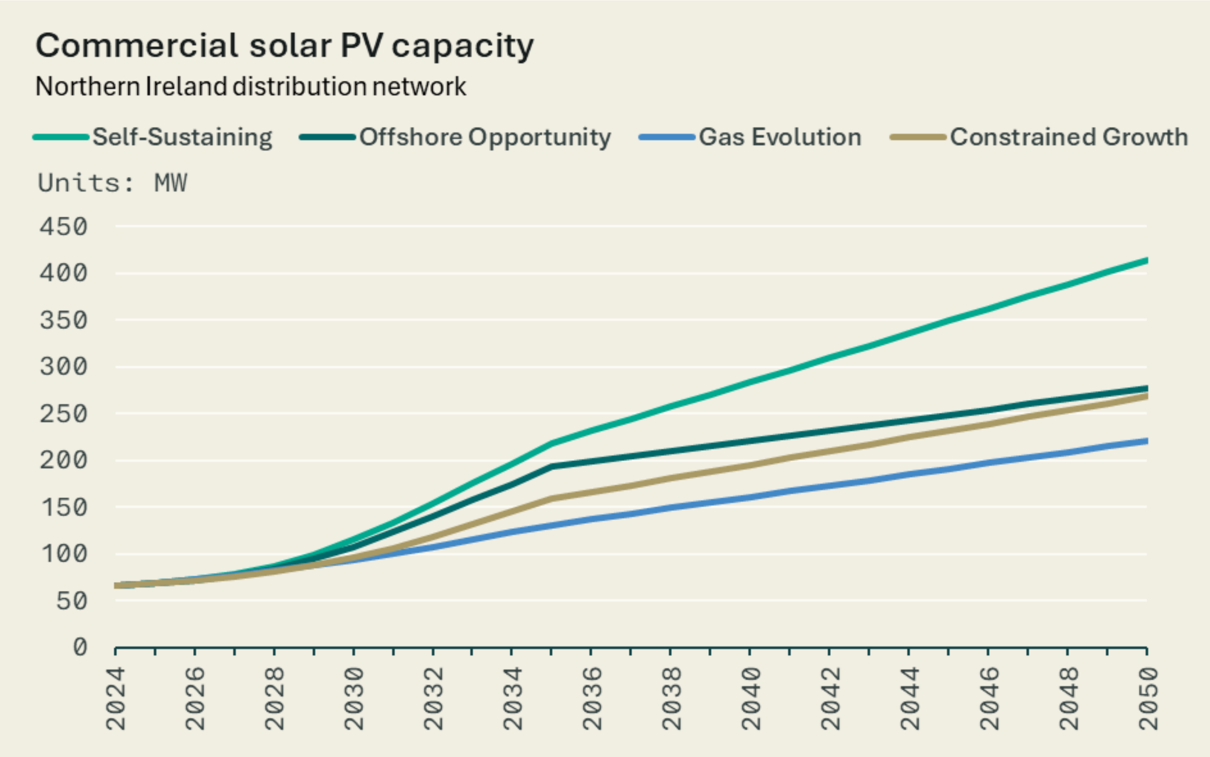
3.2.6. Detailed results

Figure 33



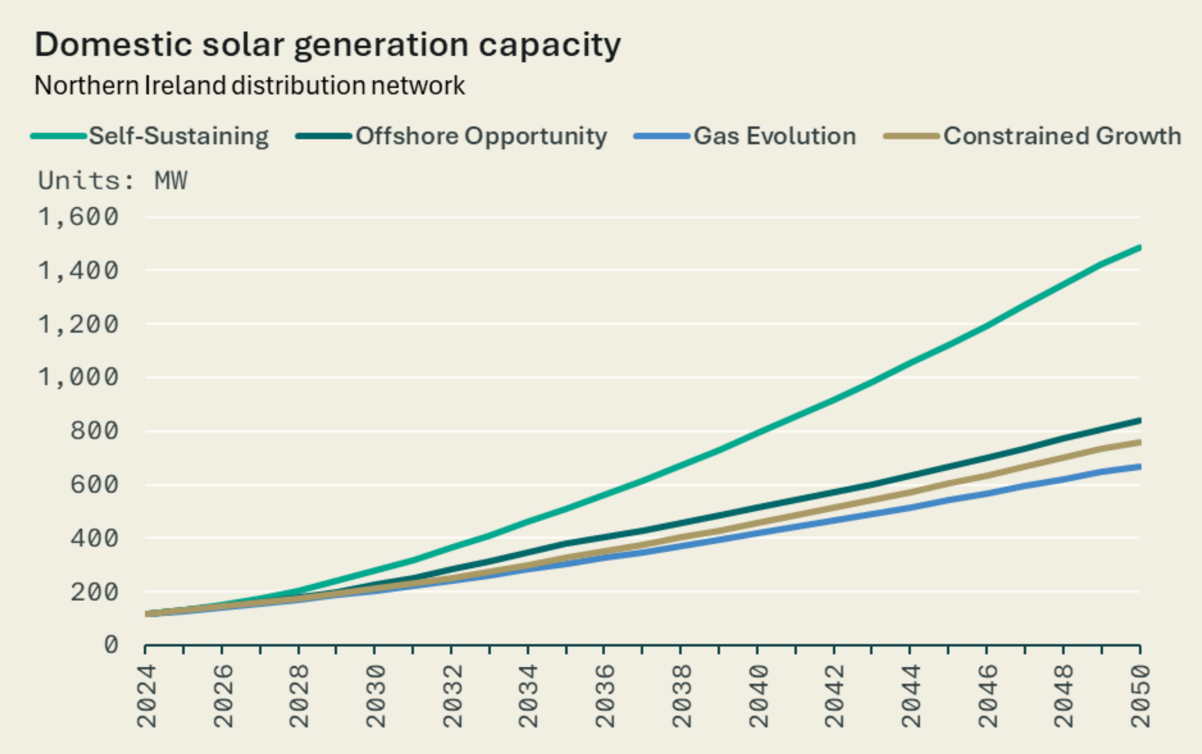
The pipeline of large-scale sites builds out by 2030, with an acceleration in the late 2020s as sites currently in planning or pre-planning connect. Higher post-pipeline growth is projected under the Self-Sustaining and Constrained Growth scenarios, with their greater focus on generation at the distribution network level.

Figure 34



With Self-Sustaining and Offshore Opportunity reflecting a higher pace of decarbonisation, policy and market incentives drive higher pre-2035 growth in commercial solar generation. These incentives are assumed to last through the 2030s and 2040s under Self-Sustaining. Gas Evolution and Constrained Growth reflect a lower growth in current commercial solar installation rates.

Figure 35



With the Self-Sustaining scenario reflecting a higher pace of decarbonisation and a higher degree of societal change, policy and market incentives are introduced which drive high growth in domestic solar generation. These incentives are assumed to last into the 2030s and 2040s. Other scenarios reflect less growth in current domestic solar installation rates.

Figure 36

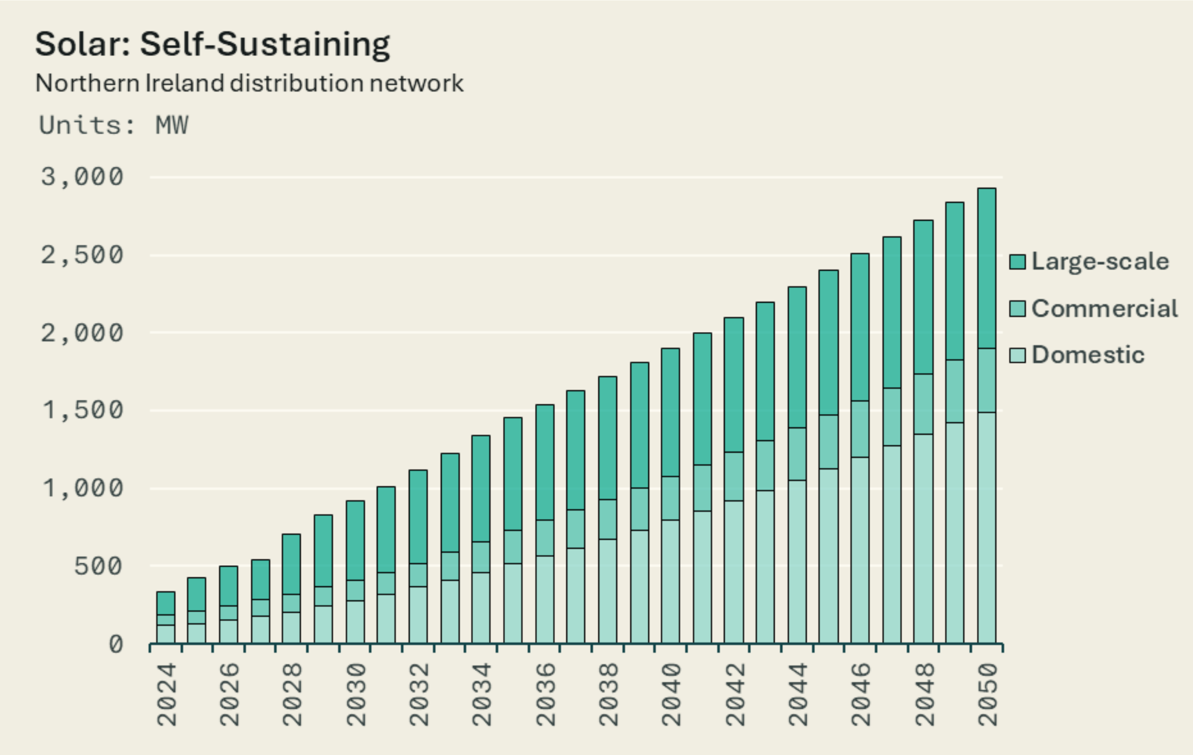


Figure 37

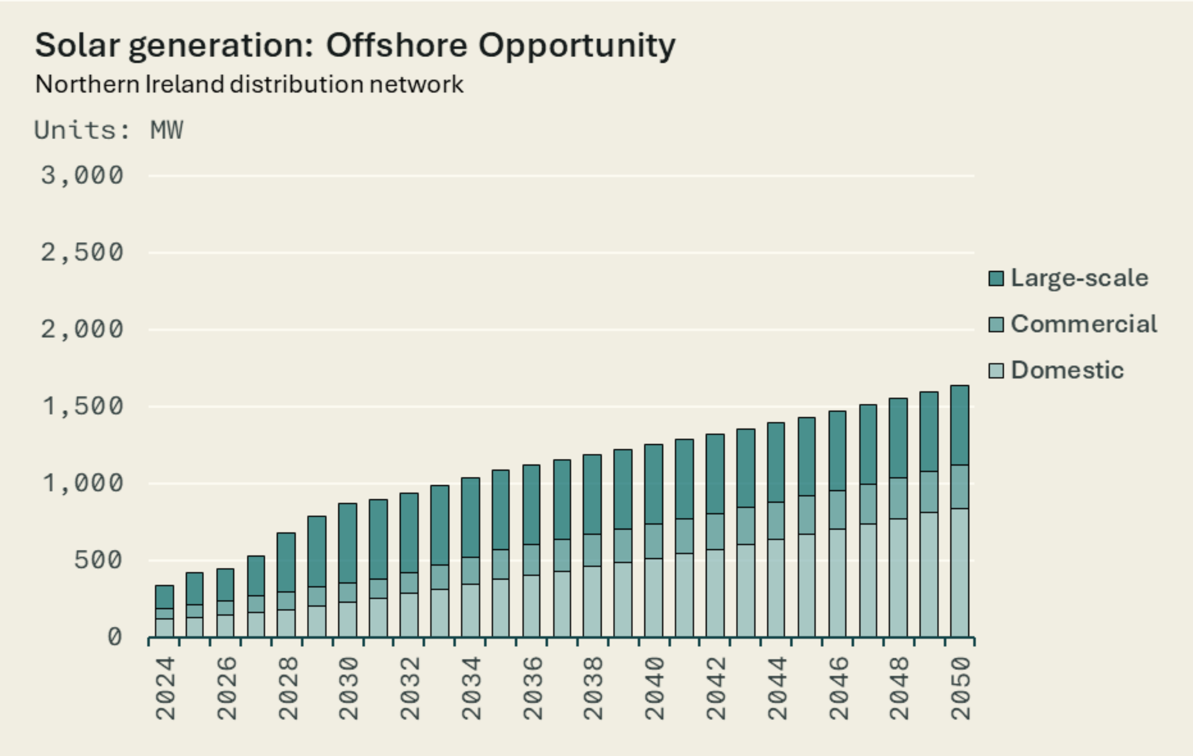


Figure 38

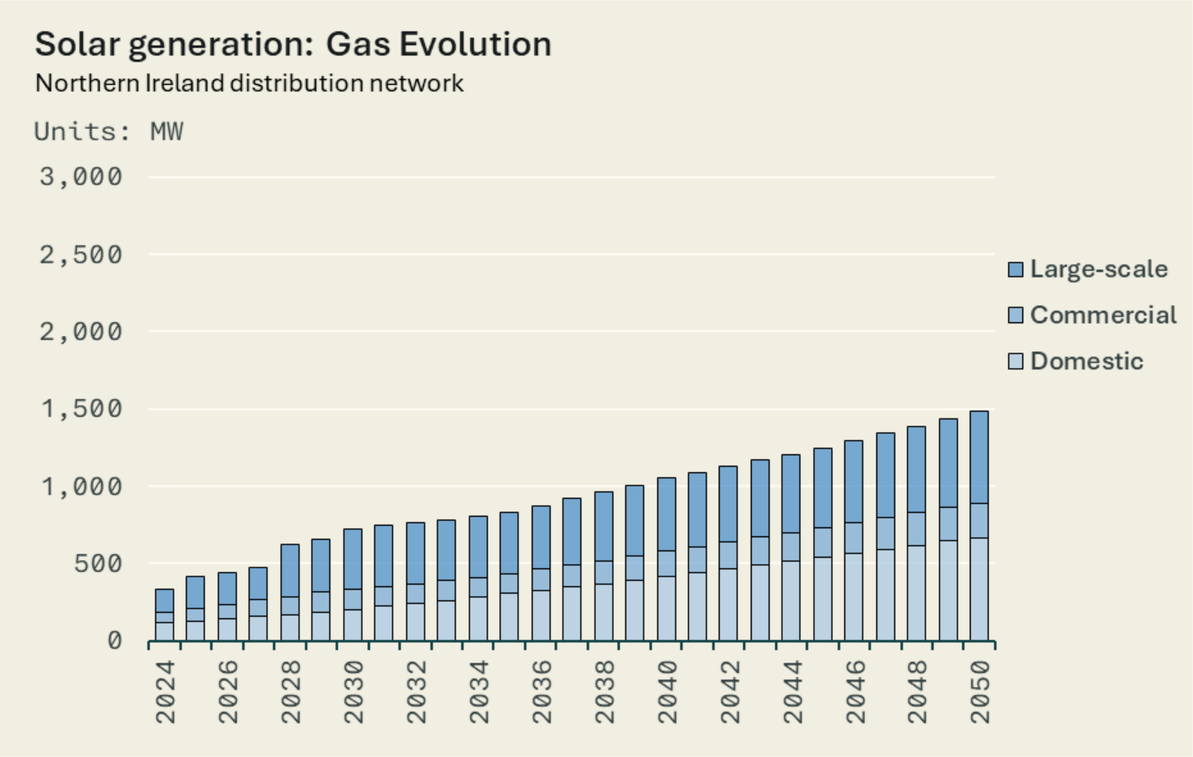
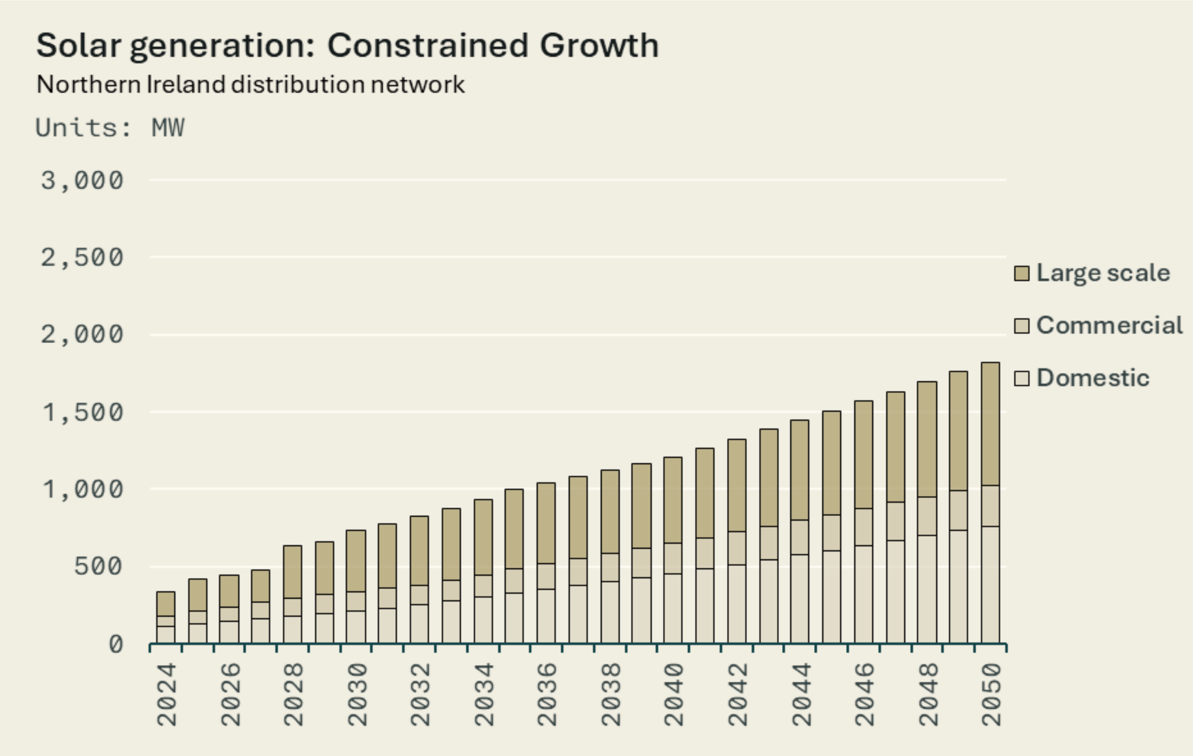


Figure 39



3.2.7. Reconciliation to other projections

Table 25

Scenario	Year	**SONI Tomorrow's Energy Scenarios** Micro-scale (GW)	**NIE Distribution Network Planning Scenarios** Domestic-scale, <10kW (GW)
Self-Sustaining	2035	0.71	0.51
	2050	1.35	1.49
Offshore Opportunity	2035	0.58	0.38
	2050	0.84	0.84
Gas Evolution	2035	0.26	0.30
	2050	0.44	0.67
Constrained Growth	2035	0.26	0.33
	2050	0.44	0.76

Table 25 demonstrates that for high-growth scenarios, Self-Sustaining and Offshore Opportunity, projected domestic solar capacity by 2035 is lower than the figure projected under TES. For low growth scenarios, Gas Evolution and Constrained Growth, domestic solar capacity by 2035 is higher than the total projected under the TES.

2050 projections for domestic solar capacity are aligned with the TES under Self-Sustaining and Offshore Opportunity. In Gas Evolution and Constrained Growth, higher domestic solar capacity is projected than under the TES; these projections assume annual domestic installation rates increase moderately in the near term, with annual deployment not exceeding the rate seen in the 2010s.

Table 26

Scenario	Year	**SONI Tomorrow's Energy Scenarios** non-'Micro-scale' (GW)	**NIE Distribution Network Planning Scenarios** Commercial and utility scale, >10kW (GW)
Self-Sustaining	2035	0.71	0.94
	2050	1.46	1.45
Offshore Opportunity	2035	0.41	0.70
	2050	0.41	0.79
Gas Evolution	2035	0.38	0.53
	2050	0.73	0.81
Constrained Growth	2035	0.53	0.67
	2050	1.28	1.06

Table 26 demonstrates alignment in the maximum growth potential of commercial and utility scale solar, under the Self-Sustaining scenario. Offshore Opportunity is the scenario with the greatest difference to the TES projection; it has been modelled to reflect a high speed of decarbonisation and so the entire 360 MW pipeline of utility-scale solar sites builds out by 2030. Less ambitious scenarios see 240 MW of this utility-scale pipeline connect by 2030.

In addition, the projections consider an acceleration in commercial scale deployment in response to supportive policy. The annual installation rates achieved are based on those already proven viable by historic data. Engagement with Renewable NI has helped validate these projections and ensure that they align with the ambitions of the solar industry in NI.

As referenced in NIE Networks' RP7 business plan, meeting the 2030 target of an 80% renewables electricity supply could include 1 GW of solar PV deployed[45]. This is slightly higher than the most ambitious Self-Sustaining scenario, which projects 900 MW by 2030.

[45] RP7 Scenario Forecasts, Northern Ireland Electricity Networks, 2022

3.3. Thermal generation

This technology category includes four main forms of thermal generation:

- **Diesel engines:** Generators using diesel fuel or biofuels such as biodiesel and hydrotreated vegetable oil (HVO). Some are used for back-up services at onsite commercial and industrial premises.
- **Networked gas generation:** Gas turbine or reciprocating engine sites fuelled from the gas network. Currently these sites operate on fossil methane blended with a small volume of biomethane.
- **Biogas generation:** Sites using biogas derived from anaerobic digestion to generate electricity. These can be part of combined heat and power (CHP) systems. Biogas can also be used to produce biomethane, which can supplant the use of fossil gas in the gas grid. In decarbonisation pathways, biomethane production for use in other applications is considered a higher value use of biogas than electricity generation in Northern Ireland. [46] [47]
- **Biomass generation:** Sites burning organic materials, such as wood or agricultural residues for electricity generation or CHP systems.
- **Energy from waste generation:** Sites using waste incineration, gasification or pyrolysis for electricity generation or CHP systems.

3.3.1. Summary

The electricity distribution network in Northern Ireland hosted the first Aggregated Generation Unit (AGU) in Ireland's single electricity market, the iPower AGU. An AGU is a grouping of smaller generation assets that can participate in electricity markets as a single unit. This has grown to become the fourth largest generator in Northern Ireland and is a key source of centrally dispatchable generation.

Thanks to a supportive policy framework though the Northern Ireland Renewables Obligation (NIRO) scheme, Northern Ireland has a significant existing deployment of biogas for electricity generation. Harnessing the region's abundant agricultural feedstocks, there is currently 84 MW of operational capacity distributed across 82 small-scale sites. The majority of these sites were deployed under the NIRO scheme between 2010 and 2017. These projects will continue to see financial support though this scheme until 2037 at the latest.

AGUs and biogas constitute the majority of thermal generation connected to the distribution network, with smaller contributions of networked gas and biomass generation.

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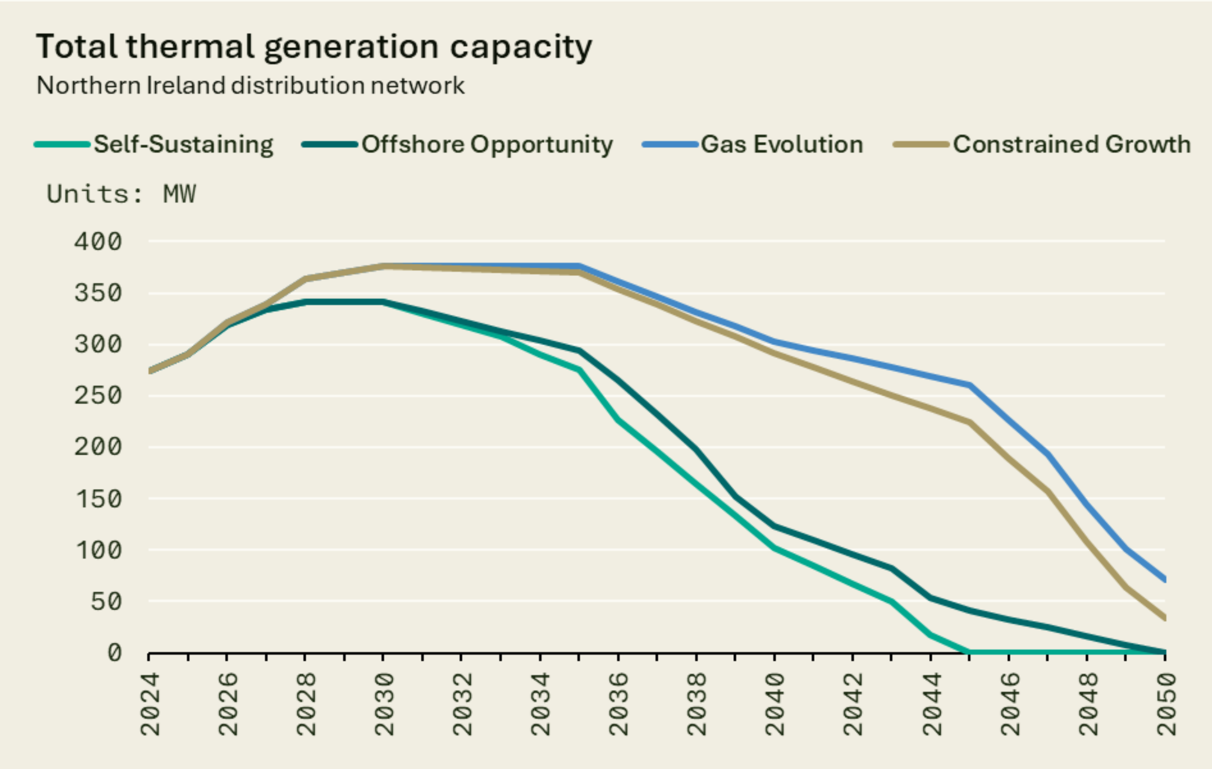
[46] Fig. 2.6, Advice Report: The path to a net zero Northern Ireland, Climate Change Committee, 2023.
[47] Developing biomethane production in Northern Ireland call for evidence , Department for the Economy, 2024

The growth in grid-scale electricity storage and a transition to biomethane production, means that, under net zero scenarios by 2050, thermal generation sites are operating at low utilisation using biofuels, have transitioned to biomethane production, or have fully decommissioned.

Figure 40



3.3.2. Baseline capacity and development pipeline

Table 27

Status	Capacity	Description
Operational	218 MW	There is currently 74 MW of installed diesel generation capacity, deployed at a number of small-scale diesel generators, primarily operating within AGUs. The largest of these AGUs has 62 MW installed across 112 sites. 14 MW of networked gas generation is also deployed across five units operating as AGUs. Alongside this fossil fuel generation, there is currently 84 MW of installed biogas generation capacity, distributed across 82 biogas generation sites in Northern Ireland. The majority of these sites were deployed between 2010 and 2017 under the NIRO scheme. These sites will continue to see support though this scheme until 2037 at the latest. There are also three operational biomass sites totalling 26 MW connected to the distribution network in Northern

Status	Capacity	Description
		Ireland. This includes the 17.6 MW Lisahally power station, commissioned in 2015. A single 15 MW energy from waste gasification plant has been operational in Belfast since 2018.
Contracted	68 MW	27 MW of diesel generation capacity, including a 5 MW biodiesel generation plant has secured contracted connection offers with NIE Networks. Alongside this, 40 MW of biogas generation capacity has a contracted connection agreement. These are modelled to build out under all scenarios by 2028.
Prospective	33 MW	12 MW of new diesel generation capacity has applied for a network connection agreement with NIE Networks. In addition to this, 14 biogas generation sites, totalling 19 MW and a single 1.5 MW biomass site have applied for a network connection agreement with NIE Networks. These prospective sites are all modelled to commission under only the Gas Evolution and Constrained Growth scenarios, with commissioning between 2028 and 2030.

3.3.3. Scenario framework

Table 28

	Self-Sustaining and **Offshore Opportunity**	**Gas Evolution** and **Constrained Growth**
Overview	These scenarios are characterised by a high pace of decarbonisation and net zero power generation being achieved by 2040.	These scenarios are characterised by a slower rate of decarbonisation and net zero power being achieved by 2045 (CG) and 2050 (GE).
Diesel: Fossil and biofuel	There is short term growth in installed diesel capacity under these scenarios, due to sites with connection agreements building out. However, from 2030 the dispatch of diesel generation is increasingly infrequent, as battery storage deploys at scale and market reforms are enacted to maximise the usage of low carbon flexibility and stability. By 2035, all diesel fuel has been fully substituted by biofuels. By 2050, all diesel variant generation sites have decommissioned.	Under these scenarios, the entire pipeline of diesel sites builds out, reflecting a slower buildout of energy storage and slower pace of market reform, leading to a prolonged reliance on fossil-fuel generation for grid services. By 2040, all diesel fuel has been fully substituted by biofuels. By 2050, some biodiesel generation remains connected, though primarily as reserve generators operating at very low capacity factors and resultantly very low annual emissions.

	Self-Sustaining and **Offshore Opportunity**	**Gas Evolution** and **Constrained Growth**
Networked gas generation	The small baseline of networked gas generators operating within AGUs continues to operate until being phased out between 2036 and 2040. After this, no fossil-gas generation is operating on the system.	The small baseline of networked gas generators operating within AGUs continues to operate until being phased out between 2046 and 2050. Under Gas Evolution, this capacity is also modelled to be repowered as hydrogen-fuelled generation, reflecting a market for low carbon hydrogen production and distribution.
Biogas generation	There is short term growth in biogas for electricity generation, where sites with connection agreements are built. However, the prioritisation of biomethane production and the expiration of NIRO contracts leads to a decrease in biogas fired generation through the 2030s. By 2045 all sites have transitioned to biomethane production or are decommissioned.	Due to a slower transition to biomethane production, the entire pipeline of biogas sites builds out. The expiration of NIRO contracts leads to a decrease in biogas fired generation through the 2030s. By 2050, all sites transition to biomethane production or are decommissioned.
Biomass generation	The two existing biomass sites connected to the distribution network continue operating until their feedstocks are diverted for use at alternative, larger scale sites where Bioenergy with Carbon Capture and Storage (BECCS) is viable. This conversion happens from 2033 under Self Sustaining and from 2036 under Offshore Opportunity. This is a reflection of the timeframes where BECCS becomes viable and available under the TES framework.	The two existing biomass sites on the distribution network continue operating until their feedstocks are diverted for use at alternative, larger scale sites where Bioenergy with Carbon Capture and Storage (BECCS) is viable. This happens in 2045 under the Constrained Growth scenario. Under Gas Evolution, biomass feedstock is diverted for use within other hard to decarbonise sectors and not reserved for power generation.
Energy from waste generation	The existing energy from waste gasification facility continues generating power until 2043, after which it transitions to synthetic fuel production.	The existing energy from waste gasification facility continues generating power until 2048, after which it transitions to synthetic fuel production.

3.3.4. Stakeholder engagement summary

Table 29

Stakeholder	Feedback provided
iPower	iPower were able to validate data on their 112 AGU sites. They also provided insight into their use of HVO fuel and typical dispatch patterns.
Consultation event	There was consensus among respondents at the NI stakeholder event that operation for fossil oil, diesel and gas was likely to decrease out to 2050. This is reflected in all scenarios to varying degrees. There was no strong consensus on future growth or decrease in biogas and biomass generation.

3.3.5. Modelling approach

Model factor	Description
Diesel: fossil and biofuel	Sites with connection agreements in place are modelled to deploy between 2025 and 2027 under all scenarios. Sites in earlier stages of development commission between 2028 and 2030, under the Constrained Growth and Gas Evolution scenarios only. The decommissioning of existing diesel plants is linked to the projected growth of electricity storage and demand side response (DSR) on the distribution network. With low marginal cost, storage and DSR undercut thermal generation within flexibility markets. It is assumed that market reforms are enacted to maximise deployment and use of energy storage of all durations. The dispatch of thermal generation becomes increasingly infrequent, though its system resilience role is maintained into the longer term. Scenarios with the fastest growth in battery storage capacity, Self-Sustaining and Offshore Opportunity, have faster declines in operational diesel capacity. It is currently assumed that half of the region's operational diesel generation capacity has transitioned to using biofuels.[48] Remaining diesel sites are assumed to transition to biofuel more quickly under the Self-Sustaining and Offshore Opportunity scenarios, being entirely biofuel from 2035. Under Constrained Growth and Gas Evolution, this happens by 2040. All generators between 1-5 MW will need to comply with emission standards set out in the Medium Combustion Plant Directive by 2030.[49] This may not be viable at all sites. The Climate Change Committee advise that biofuels should be prioritised for applications where they deliver highest emissions

[48] Engagement with iPower indicates a large portion is already running on biofuel. Awaiting further data.
[49] Medium combustion plant directive , DAERA, accessed Feb 2025

Model factor	Description
	savings. [50] In 2050, electricity generation with CCS is a high value use; however, it is unlikely that CCS will be viable for small thermal plants with low utilisation connected to the distribution network.[51] Therefore, by 2045 unabated biofuel generation has ceased under Self-Sustaining and by 2050 under Offshore Opportunity. The modelling of residual unabated biofuel generation beyond 2040 requires drawdowns from other sectors to comply with a 2040 net zero power system under Self-Sustaining and Offshore Opportunity. By 2050, no biofuel generation is modelled under these scenarios and the power system is net zero in isolation. Under Constrained Growth and Gas Evolution, net zero power is achieved by 2050. Residual unabated biodiesel generation past this date is assumed to be for grid resilience and security of supply services only and rarely dispatched.
Networked gas generation	The 14 MW of capacity which is deployed at gas generators operating in AGUs is modelled to decommission between 2036 and 2040 under Self-Sustaining and Offshore Opportunity, which is in line with achieving a decarbonised power system by 2040 under these scenarios. The rapid deployment of energy storage across a range of durations, as well as market reform to enable storage to become the main provider of grid services, is a key driver of this decommissioning. In Constrained Growth, these sites decommission, due to the development of other sources of gird services, but this happens later with sites being decommissioned between 2041 and 2045. In Gas Evolution, these gas generation sites are repowered to operate using low carbon hydrogen in the same period. This is this in line with achieving a decarbonised power system by 2045 and assumptions within the SONI TES framework around the transition to hydrogen. [52]
Biogas generation	Biogas sites with connection agreements currently in place are modelled to deploy between 2025 and 2027 under all scenarios. Sites in earlier stages of development commission between 2028 and 2030, under the Constrained Growth and Gas Evolution scenarios only. In the near-term, while the decarbonisation of heat remains a key challenge to net zero, a more efficient approach to emissions reductions could be achieved where biogas is used to produce biomethane and displace natural gas in the gas grid (grid injection). The Climate Change Committee recognise this opportunity in Northern Ireland, and the NI executive are consulting on a

[50] The seventh carbon budget , Climate Change Committee
[51] Cost of small-scale dispatchable CO2 capture, University of Sheffield, 2023
[52] Tomorrow's Energy Scenarios 2023 , SONI, 2023. Pg. 147

Model factor	Description
	biomethane production strategy.[46,47] It is assumed that a significant proportion of biogas generation sites transition to biomethane production under the Self-Sustaining and Offshore Opportunity scenarios, as part of the wider transition to net zero power by 2040 under these scenarios. In the long term, once network gas demand has fallen below supply due to the electrification of heat, the analysis has aligned to CCC advice, where any remaining biomethane should be used with CCS to either produce electricity or for produce low carbon hydrogen. These outcomes are considered to be a net-negative emission usage. The relative cost of CCS makes its application at small sites on the distribution network unlikely.[51] Through the 2030s, sites commissioned under the NIRO scheme will be reaching the end of their 20 year contracts and by 2037, no sites will be receiving NIRO certificates.[53] This is reflected in the projections, where higher rates of decommissioning happen between 2035 and 2040. Under all scenarios, no biogas fired electricity generation is modelled to be in operation by 2050. Residual use of biogas in CHP schemes may continue on farms, but it is assumed that this will likely be with no electricity grid export functionality.
Biomass generation	The analysis has aligned to CCC advice around the use of biomass being able to deliver more efficient decarbonisation when prioritised for use in hard-to-decarbonise sectors.[54] When paired with CCS, Biomass with Carbon Capture and Storage (BECCS) is a net negative electricity generation technology and therefore has an important role in enabling a net zero power system. In this role, it is best used at larger sites with very high load factors.[55] This, along with the high upfront cost of CCS, make BECCS for small biomass generation on the distribution network unlikely. As a result, the three operational biomass sites on the distribution network are modelled to decommission when BECCS becomes available and their feedstocks are diverted for use at larger transmission connected sites. In line with SONI TES 2023, this happens in 2033 under Self-Sustaining, 2036 under Offshore Opportunity and 2045 under Constrained Growth. In Gas Evolution, where BECCS does not become available, feedstocks divert to a hard to decarbonise sector.[54]
Energy from waste generation	Existing energy from waste generation capacity is deployed at a single 15 MW gasification plant. Through gasification, syngas is

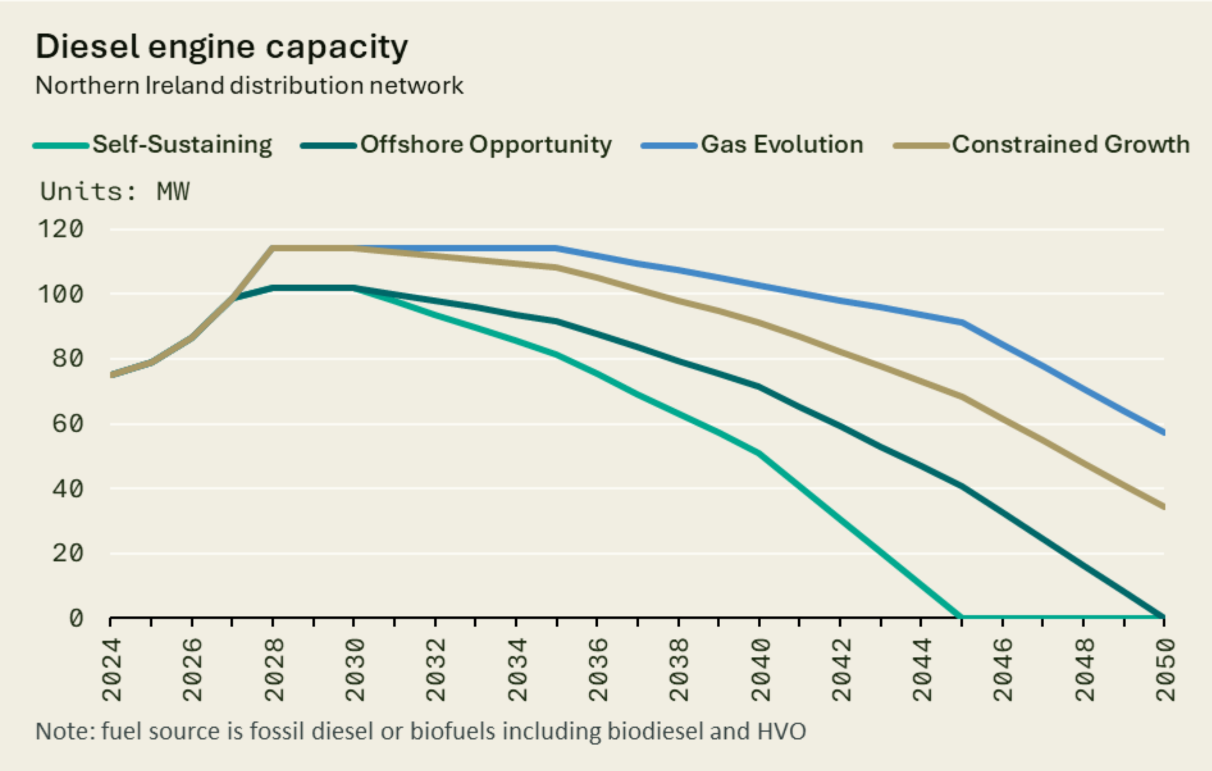
[53] Northern Ireland Renewables Obligation closure, Department for the Economy, accessed March 2025
[54] Biomass in a low carbon economy, Climate Change Committee, 2018.
[55] Tomorrow's Energy Scenarios 2023, SONI, 2023

Model factor	Description
	produced and combusted to drive a steam turbine. The CCC suggest a backstop date of 2050 for all energy from waste plants to employ CCS.[56] CCS is not assumed viable at sites of this scale within these scenarios, so combustion of syngas ceases at the plant. Syngas can also be used to produce syngas derived synthetic fuels or hydrogen. These can be used within hard to decarbonise sectors such as aviation and shipping. It is assumed that this use case is prioritised over electricity generation in all net zero scenarios. Under Self-Sustaining and Offshore Opportunity, the plant operates for 25 years as a power generation facility before transitioning to synthetic fuel production. Under Gas Evolution and Constrained Growth, the lifespan is 30 years.

[56] The Sixth Carbon Budget: Waste , Climate Change Committee, 2020

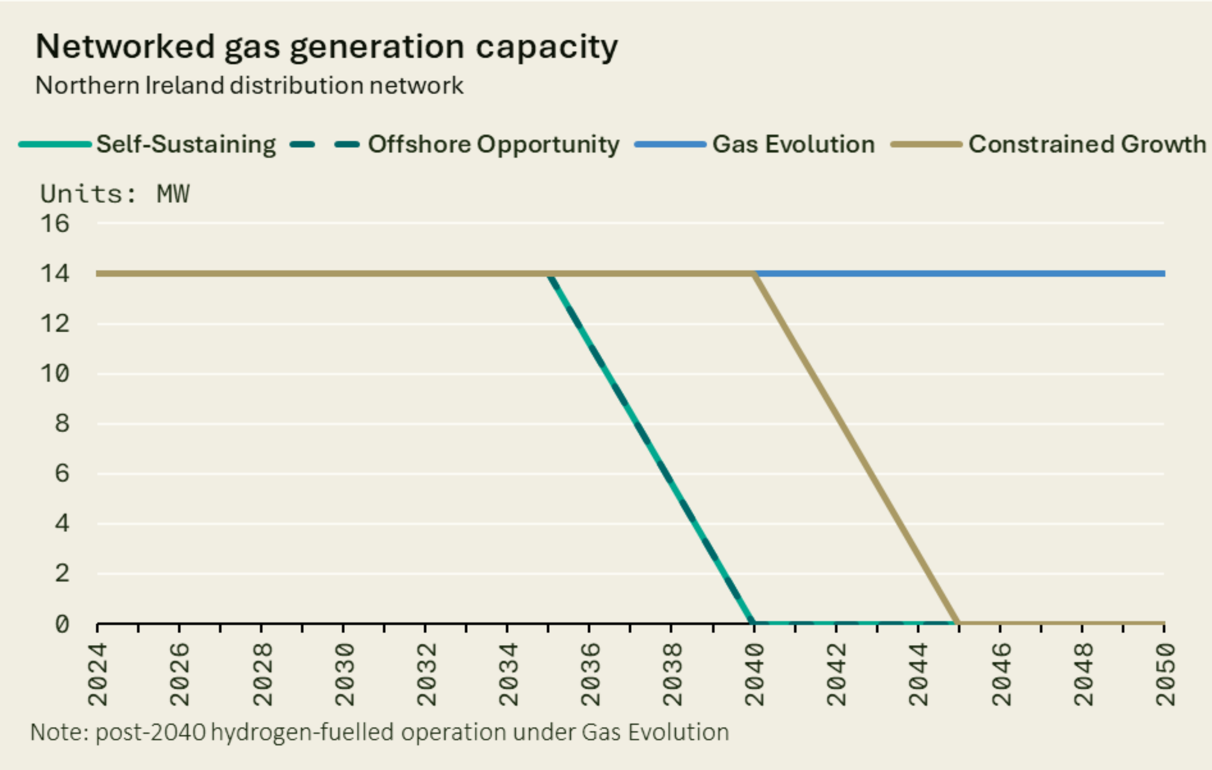
3.3.6. Detailed results

Figure 41



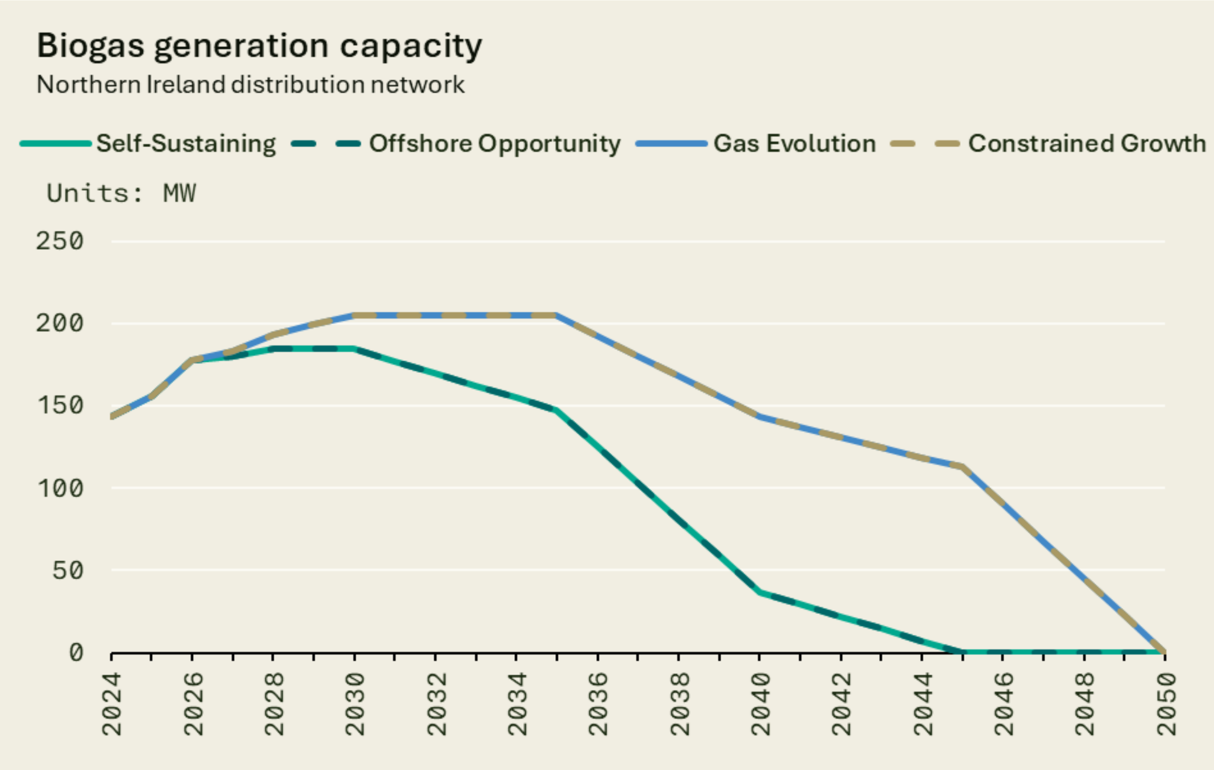
Diesel engine installed capacity increases before 2030 as the pipeline of sites builds out. Subsequent decommissioning of diesel generation capacity is modelled in all scenarios, due to the projected growth of electricity storage, which is able to provide low carbon grid services.

Figure 42



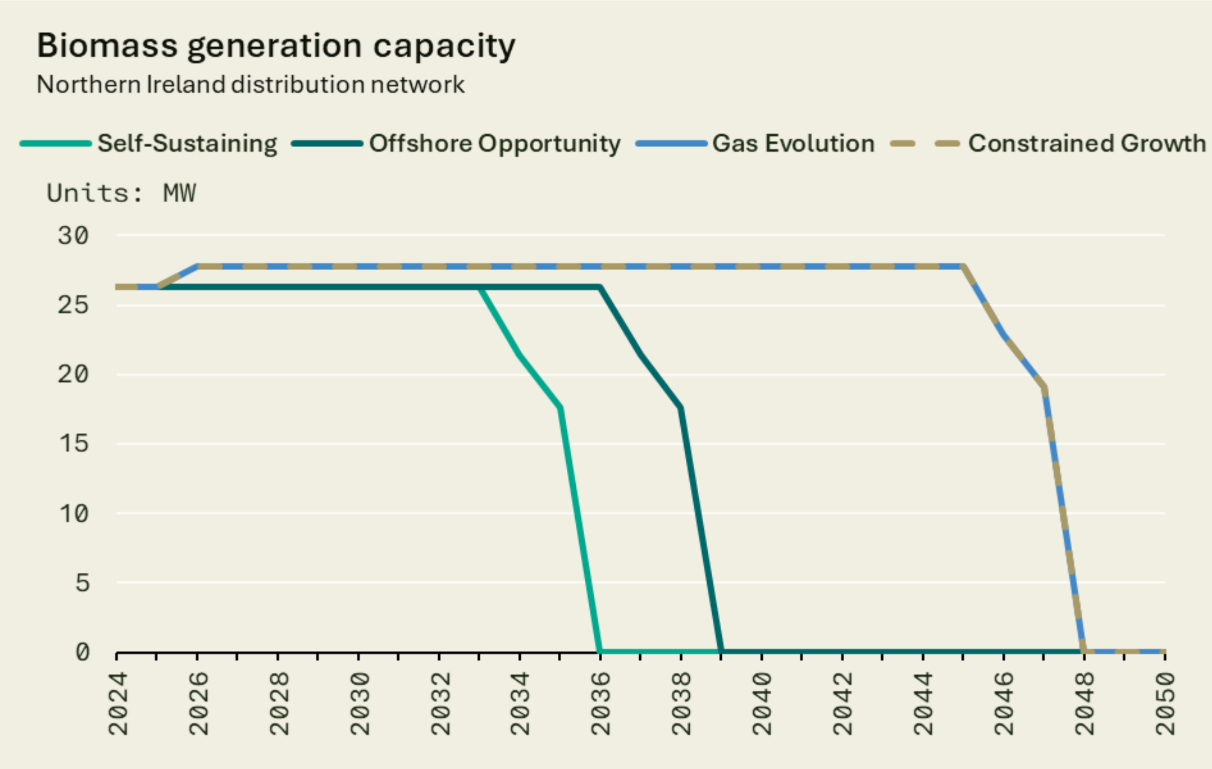
With no sites in development, there is no increase to the existing installed capacity of networked gas generation. These sites decommission or convert to hydrogen generation to meet net zero power under all scenarios.

Figure 43



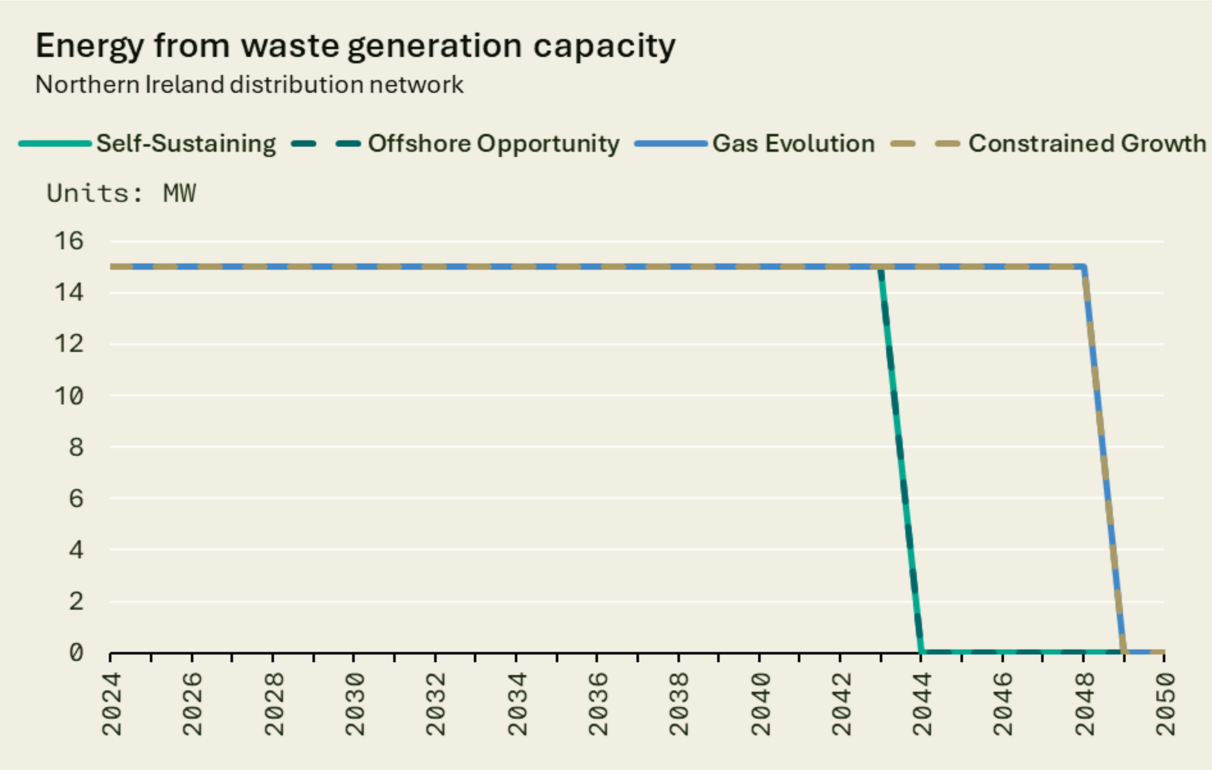
The significant capacity of installed biogas generation is added to by the pipeline of projects in development. However, biogas generation capacity decreases due to a transition to biomethane production and the expiry of NIRO contracts through the 2030s and 2040s.

Figure 44



Biomass generation is modelled to decommission as feedstocks are diverted for use in hard to decarbonise sectors or at larger scale generation sites, where CCS is more likely to be viable. A single small-scale (<5MW) pipeline site connects under Gas Evolution and Constrained Growth only.

Figure 45



Energy from waste generation capacity, located at a single 15 MW gasification site, is modelled to decommission as the site transitions to synthetic fuel production at the end of its 25 or 30 year lifespan.

Figure 46

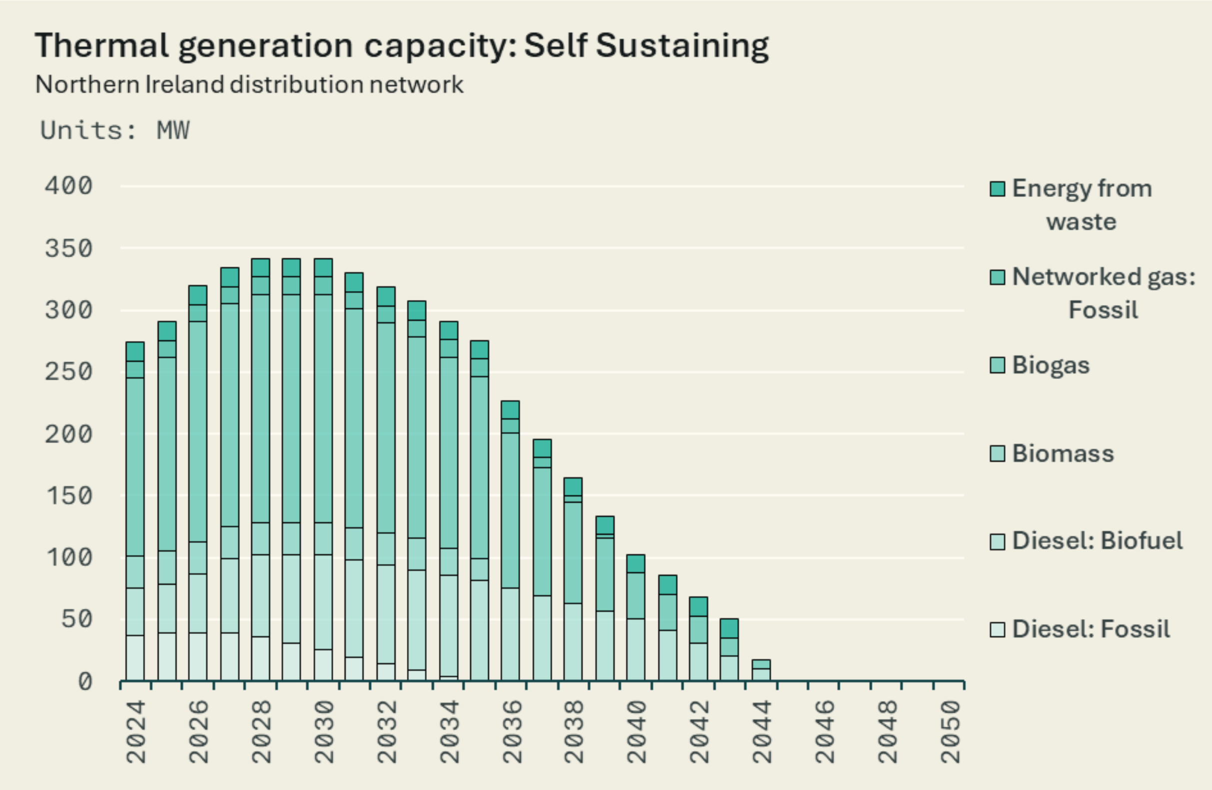
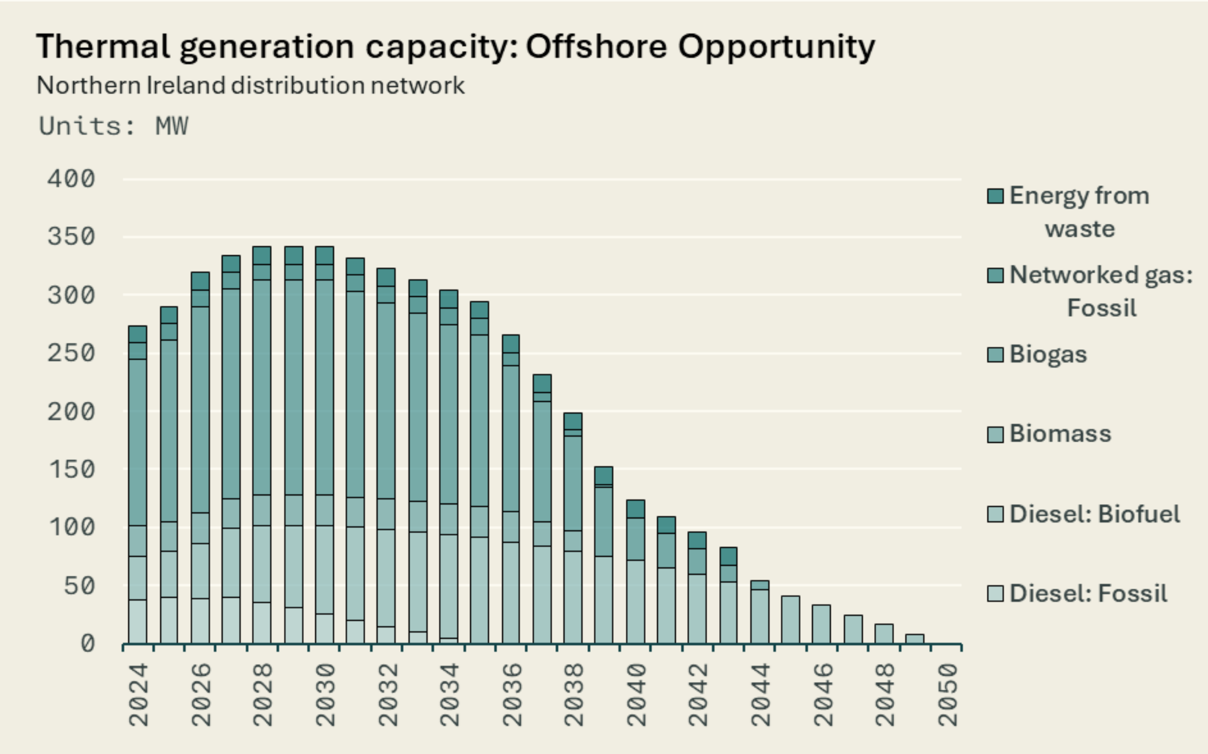


Figure 47



Under Self-Sustaining and Offshore Opportunity, net zero power is achieved by 2040. Residual use of unabated biogas and biofuel is for grid resilience services only, with very low load factors, and offset by negative emissions achieved in other sectors of the electricity network. By 2050, no unabated thermal generation is operational on the distribution network.

Figure 48

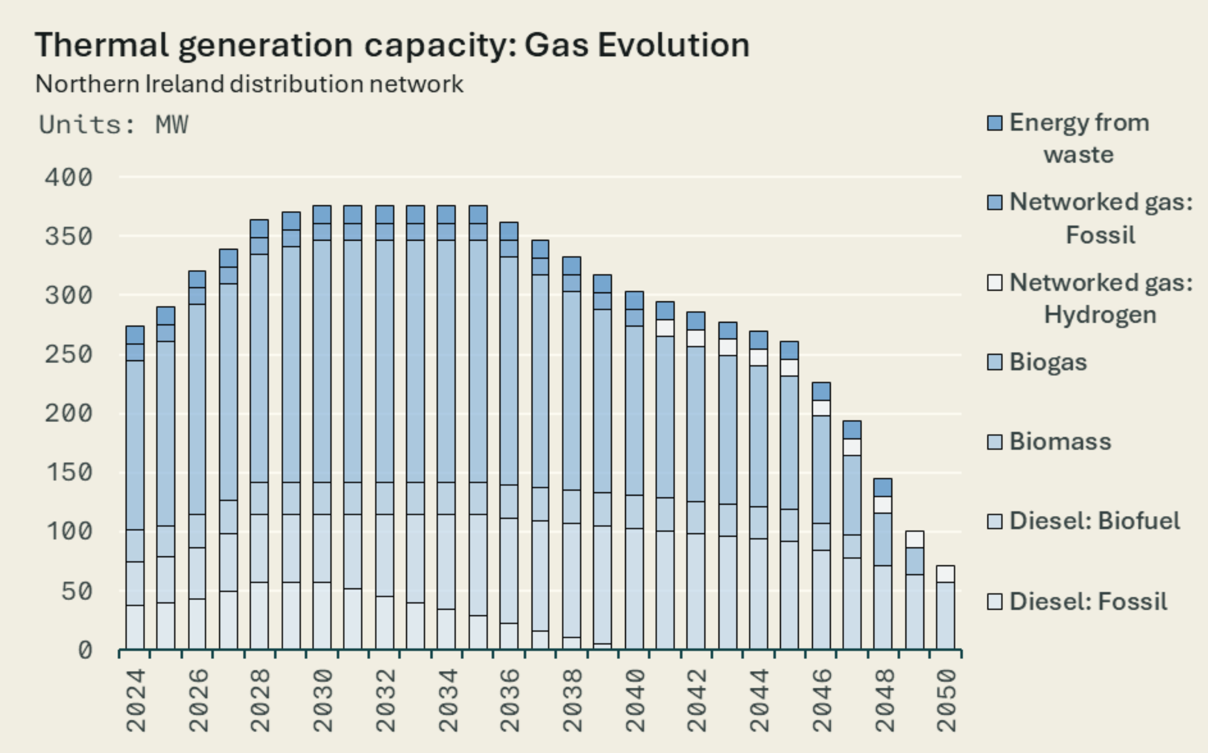
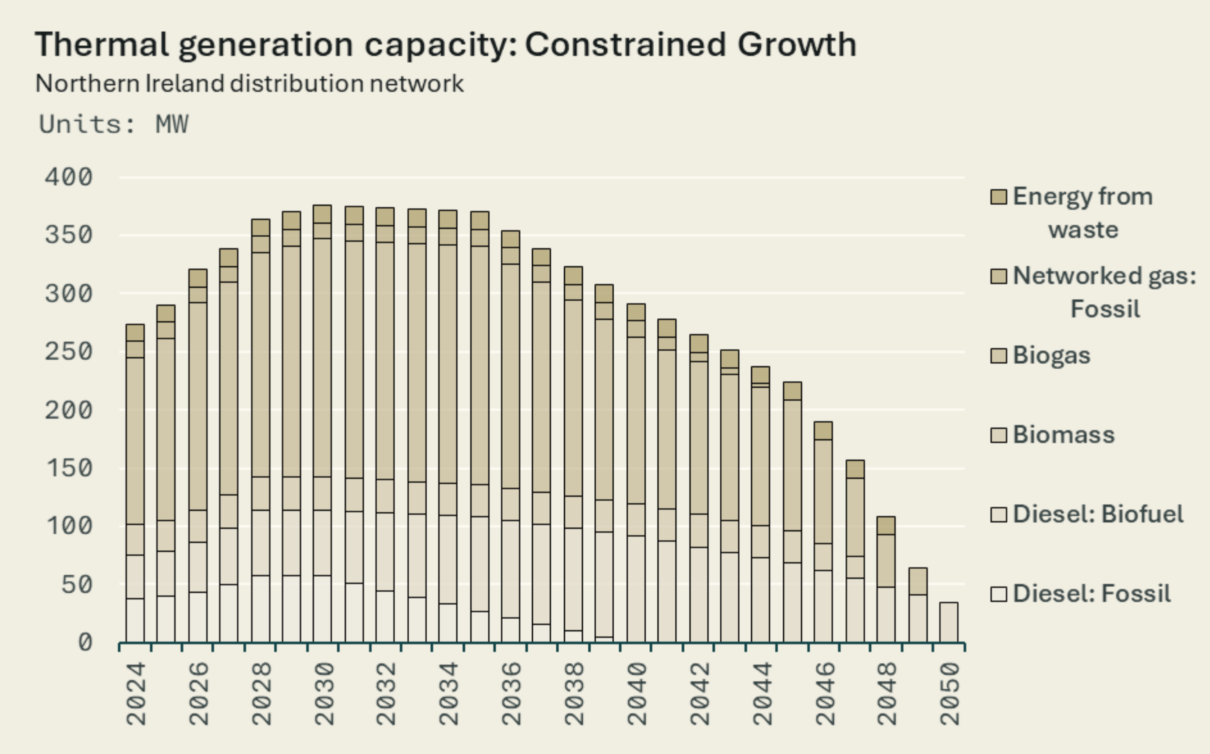


Figure 49



Under Gas Evolution and Constrained Growth, net zero power is achieved by 2045. Residual unabated biogas, biomass and biofuel generation is operated at very low load factors for grid resilience services and is offset by negative emissions from other sectors of the electricity network. This residual unabated capacity is still in service on the distribution network in 2050.

3.3.7. Reconciliation to other projections

Table 30

Scenarios	2050: SONI TES (inc. transmission network)	2050: NIE Networks scenario forecasts
Self-Sustaining **Offshore Opportunity** **Constrained Growth**	2.15 GW of fossil gas generation operational on entire electricity network. 0.52 GW of fossil gas with CCS operational in constrained growth.	No fossil gas generation on the distribution network, small existing capacity decommissions.
Gas Evolution	No fossil gas generation on the electricity network, replaced by hydrogen.	No fossil gas generation on the distribution network, small existing capacity repowers with hydrogen.

Table 31

Scenarios	2050: SONI TES (incl. transmission network)		2050: NIE Networks scenario forecasts
	BECCS	Unabated	
Self-Sustaining	100 MW	18 MW	No distribution network generation. Feedstocks are diverted for large-scale sites with BECCS or, in Gas Evolution, to hard-to-decarbonise sectors in line with CCC guidance.
Offshore Opportunity	50 MW		
Gas Evolution	0 MW		
Constrained Growth	24 MW		

3.4. Electricity storage

In Northern Ireland, Great Britain, and across Europe, battery storage systems are the highest growth electricity storage technology. Large portfolios of projects are under development that will deliver the vast majority of new near-term electricity storage capacity. While other electricity storage technologies, such as hydrogen electrolysis, flow batteries and liquid air energy storage are in development, they have not achieved commercialisation and are unlikely to be deployed at scale in the near term. As a result, this analysis has focussed on the impact of battery storage projects only, under three main categories:

- Utility scale installations up to 50 MW providing grid balancing services.
- Behind-the-meter commercial storage, typically 100-300 kW.
- Domestic battery storage, typically at around 5 -10 kW per installation.

3.4.1. Summary

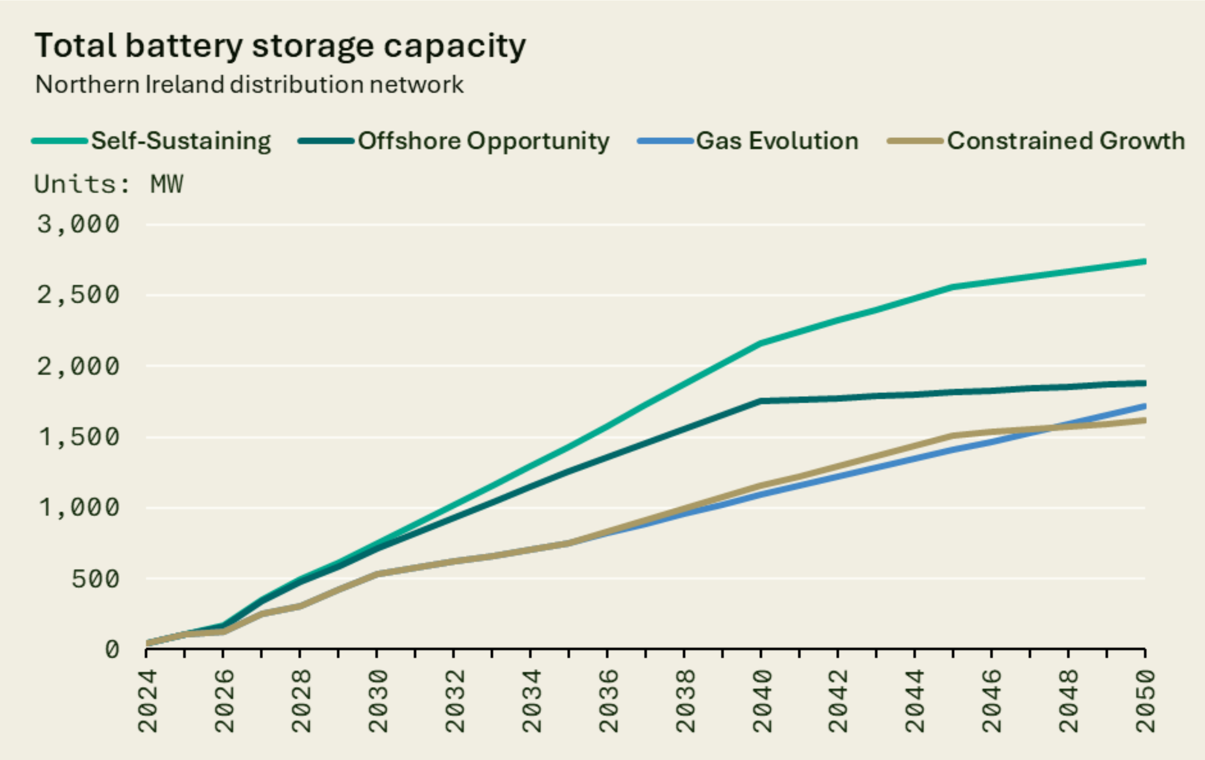
There has been significant sector growth and progressive cost reductions driving battery storage project development in the UK and internationally over the past 9-10 years. In GB, there are currently over 300 GW of speculative utility-scale battery storage projects seeking to connect to the network, at various voltage tiers. However, despite one of the first pioneering grid-scale battery storage installations being commissioned in Kilroot, battery storage project development has, to date, been extremely limited in Northern Ireland.

There are a number of factors driving this limited uptake, including:

- Lack of clarity around revenue streams and ancillary services procured by SONI and other market operators for flexibility and storage technologies to leverage.
- Grid constraints preventing the progression and connection of new projects.
- A challenging planning landscape and local opposition to battery storage projects.

With increased levels of renewable energy generation development, alongside the future electrification of heat and transport sectors, there will be an increasing need for flexibility services for Northern Ireland and the wider energy system. As a result, battery storage capacity connecting to the distribution network sees a notable increase under all scenarios out to 2050.

Figure 50



3.4.2. Baseline capacity and development pipeline

Table 32

Status	Capacity	Description
Operational	21 MW	Three battery storage sites are currently operational on the distribution network. This includes a 12.3 MW battery commissioned in July 2024 and a 4.1 MW site that has been identified as operational though developer engagement. This baseline is very low compared to the development of grid-scale battery storage projects seen in GB.
Contracted	48 MW	A number of prospective battery storage projects, totalling 48 MW, have secured contracts to connect to the distribution network.[57] Two utility scale sites make up the majority of this capacity, with a 20 MW site set to become the largest

[57] There is also a single c.500 kW synchronous condenser seeking to connect to the distribution network. While playing a role to support system inertia and reactive power, the deployment of these assets is likely to be limited and at specific locations. The scenario analysis, therefore, focuses on battery storage.

Status	Capacity	Description
		individual battery storage project in Northern Ireland when it comes online. These sites are modelled to deploy between 2025 and 2028 under Self-Sustaining and Offshore Opportunity, scenarios that are more supportive to flexibility technologies. These sites are modelled to connect later under Constrained Growth and Gas Evolution.
Prospective	829 MW	There is a large pipeline of battery storage projects in earlier stages of development. These are primarily utility scale sites with an average capacity of 20 MW.[58] Engagement with battery storage developers has resulted in the inclusion of four additional sites, totalling 105 MW, with pre-planning status, which were not present in NIE Networks connections data. Queue projects are modelled to deploy between 2027 and 2029. Sites that are waiting for a planning decision deploy between 2028 and 2030, with delays reflected in Constrained Growth and Gas Evolution. Sites in pre-planning are modelled to commission in 2030, under only the Self-Sustaining and Offshore Opportunity scenarios. Where provided within the data, estimated completion dates have been used. Fifteen prospective sites, totalling 40 MW of capacity, are comprised of small-scale battery storage sites with an element of generation co-location.

3.4.3. Scenario framework

Table 33

Scenario	Description
Self-Sustaining	With a high degree of societal change and pace of decarbonisation, this scenario has significant need for system flexibility and, as a result, sees the highest levels of distribution network battery storage at all scales. In this scenario, all utility scale sites currently in the pipeline are modelled to build out by 2030. This sees 900 MW of battery storage capacity connecting to the distribution network. It is assumed that a more favourable planning environment, market services and revenue opportunities exist for these projects, incentivising a renewed investment and sustained growth in the deployment of utility-scale battery storage across the 2030s. By

[58] Where capacity information was not available for 15 projects, a conservative estimate of 5 MW has been assumed per project. Updated data may be provided by RNI for final projection.

Scenario	Description
	2040, deployment slows as the market becomes saturated, with no growth in additional battery storage sites modelled to connect to the distribution network beyond 2045. The installation of domestic and commercial scale battery storage is modelled to continue through the entire period to 2050. Higher levels of installation under this scenario are driven by a high uptake of residential and commercial solar PV and assumed strong incentives for co-location with behind-the-meter storage, allowing businesses and consumers to reduce their energy costs. Under this scenario, from 2030, bi-directional EV charging dampens the market and use-cases for domestic battery storage, where consumers are maximising the use of EV batteries for home energy and cost management. By 2050, there is 2.7 GW of battery storage capacity on the distribution network under this scenario. This capacity is equivalent to 66% of the total distributed renewable generation capacity deployed by 2050.
Offshore Opportunity	All utility scale sites in the pipeline build out by 2030 due to the high pace of decarbonisation in this scenario. However, developers have stronger incentives to build utility scale battery storage sites on the transmission network. This results in a reduction in the connection of new battery storage projects to the distribution network deployment through the 2030s. By 2040, growth on the distribution network is modelled to flatline. Similarly, in this scenario, installation rates for commercial and domestic scale storage are initially high, driven by equally high levels of domestic and commercial scale solar installation. However, incentive schemes for small scale solar and storage are not maintained past the late 2030s and so deployment slows down. Under this scenario, from 2030, bi-directional EV charging dampens the market for domestic battery storage, where consumers are maximising the use of EV batteries for home energy and cost management. Total battery storage capacity on the distribution network under this scenario totals 1.8 GW by 2050. This capacity is equivalent to 66% of the total distributed renewable generation capacity deployed by 2050.
Gas Evolution	The Gas Evolution scenario is characterised by a slower pace of decarbonisation, with a greater focus on larger transmission connected generation projects. A less favourable planning policy and market environment means that fewer utility-scale battery storage projects are modelled to deploy on the distribution network. Beyond the known pipeline, additional deployment remains low throughout the 2030s, as

Scenario	Description
	developers are incentivised to build larger-scale projects on the transmission network. This priority for transmission level deployment and equivalent low growth on the distribution network continues out to 2050. Growth in small scale battery storage is similarly restricted under this scenario, reflecting homes and businesses not deploying onsite battery storage to support energy management as much as under other scenarios. In the long term, support for large-scale projects is prioritised over incentive schemes for small scale business models. This results in low overall uptake of battery storage in homes and businesses out to 2050. In total, 1.7 GW of battery storage capacity is deployed by 2050. This capacity is equivalent to 58% of the total distributed renewable generation capacity deployed by 2050.
Constrained Growth	This scenario is characterised by a low pace of decarbonisation, combined with greater focus on generation for domestic demand rather than for international export. This is reflected in a lower level of deployment for the existing pipeline of utility scale battery storage sites. Less favourable planning policy and market conditions means that fewer projects in the current development pipeline move through to commission, compared to other scenarios. Overall deployment remains low throughout the 2030s. However, without the long-term focus on larger transmission connected generation and flexibility under this scenario, there is a greater reliance on distribution network connected flexibility to meet demands of electrification of heat and transport. As a result, there is an acceleration in deployment from the mid-2030s into the 2040s. Constrained Growth sees lower overall levels of domestic and commercial scale battery storage deployment compared to other scenarios. This is driven by lower levels of small-scale solar market activity and deployment. Due to a high level of reliance on distribution network flexibility, there is some incentive for businesses to install storage at commercial premises in the longer term, resulting in moderate, steady deployment out to 2050. By 2050, 1.6 GW of battery storage is deployed across the distribution network under this scenario, equating to 43% of the total renewable generation deployment.

3.4.4. Stakeholder engagement summary

Table 34

Stakeholder	Feedback provided

Consultation event	Respondents suggested that grid constraints, unclear revenue streams/flexibility services, planning delays, local opposition and high upfront costs are the main reasons for limited development in Northern Ireland. Respondents indicated that project export capacity would be the primary determiner of connection voltage. This is reflected in the model; no pipeline sites above 50 MW are modelled to connect to the distribution network. Respondents indicated that battery storage systems are installed alongside 50% of all domestic solar installations. This contributed to the modelling of high domestic storage uptake in the near term.
Domestic solar installer	Contact with a domestic solar installer working in NI provided additional evidence that the majority of solar PV installs they carry out are now being paired with a battery storage system. They also agreed with the assumption, made within this assessment, that achieving high uptake rates of small-scale solar and storage is dependent on the introduction of a new small scale generation incentive scheme.
Renewable NI	Renewable NI have had sight of the electricity storage projections and have confirmed that the battery storage project pipeline presented in this report is aligned with the scale of their battery storage project database.
Developer input	Developers of utility-scale sites were contacted to provide updates on project data. This resulted in the inclusion of four additional sites in the pipeline, totalling 105 MW.

3.4.5. Modelling approach

Table 35

Model factor	Description
Utility scale battery storage	NIEN connection data was used to determine the current baseline and pipeline capacity of utility scale battery storage sites. Contracted sites are modelled to connect under all scenarios between 2025 and 2028. Queue projects are modelled to commission in 2027 and 2029 under all scenarios. Sites in planning are modelled to commission under all scenarios between 2028 and 2030, with delays reflected in Constrained Growth and Gas Evolution. Sites in pre-planning are modelled to commission in 2030 under only the Self-Sustaining and Offshore opportunity scenarios. Developers of pipeline projects over 5 MW were contacted to provide any updated information build-out plans for individual projects. This resulted in updates to the estimated commissioning dates for a small number of projects and the inclusion of four additional sites, totalling 105 MW. Scenario specific growth factors were applied to develop post-pipeline capacity growth in the years 2030-2035. This maintains the buildout rate of the project pipeline for high growth scenarios, while modelling a deceleration in deployment under low growth scenarios. Beyond 2035, annual growth rates were derived using the SONI TES projection for installed storage capacity. These scenario-specific rates were used to project additional capacity from 2035 to 2050.
Commercial scale battery storage	UK Government data on the total number of non-domestic meters in Northern Ireland was used to calculate the pool of customers who could operate a commercial battery for onsite energy management. Scenario specific assumptions around the total percentage of non-domestic customers with battery storage were developed and applied to determine commercial battery storage capacity growth out to 2050. This was informed/validated by responses collected during the consultation event, indicating that a quarter of commercial solar sites are currently co-located with battery storage. In all scenarios, by 2050, total commercial rooftop solar capacity is approximately matched to the deployment of commercial battery storage. This reflects a continued strong business case for behind the meter energy storage to maximise usage of onsite generation for commercial businesses.
Domestic battery storage	As is the case across Great Britain, the baseline of domestic battery storage is not well evidenced. This is due to most batteries being installed alongside rooftop solar generation, and only one technology type typically being recorded or formally registered. Where data from the MCS certification scheme provides insight into historic domestic solar installs, there is no equivalent national database for domestic battery installations.

A market assessment by SolarPower Europe estimated that 1.1 GWh of domestic battery energy storage capacity was installed across the UK at the end of 2023. Assuming that 1.1GWh of battery storage capacity is delivered by 1.1 GW of installed capacity, this suggests that 9% of UK domestic solar installs are currently paired with a domestic battery.[59] This figure has been used to estimate the baseline of domestic battery storage in Northern Ireland. This relies also on an assumption that homes with rooftop solar in NI and GB have seen similar drives towards battery installation, with similar additional upfront costs and availability of units and installers.

In this analysis, the deployment of domestic solar generation is the primary driver of deployment of domestic battery storage capacity. This approach has been validated though engagement with installers in NI and GB, which indicates that the majority of domestic retrofit solar installations these installers carry out are now coupled with a battery unit. In addition, responses collected during the consultation event suggested that half of all domestic rooftop solar installs are paired with a battery.

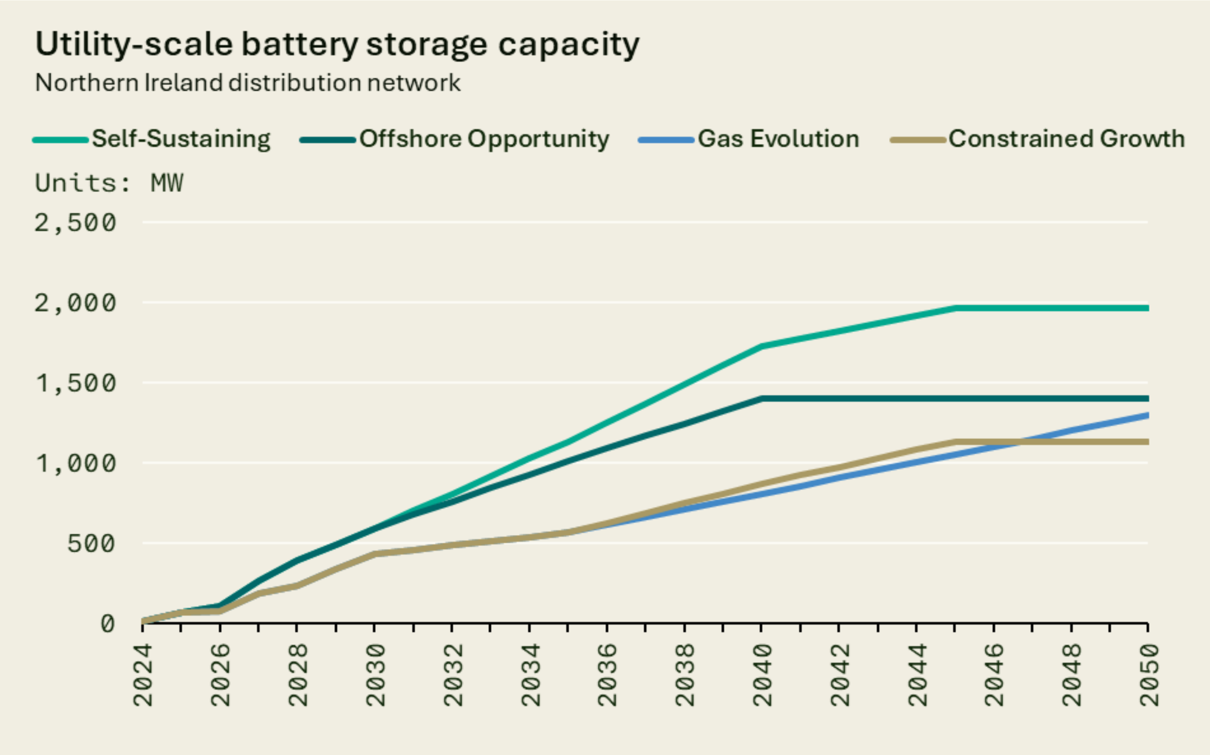
Scenario specific assumptions were applied around the percentage of retrofit domestic solar jobs also completing a battery storage installation. These percentages are modelled to be the highest in scenarios that are most ambitiously supportive towards domestic battery storage. Uptake is considered to decrease beyond 2030, as bi-directional EV charging becomes a competing form of domestic electricity storage/flexibility.

As a result of these assumptions, across all scenarios, domestic battery storage capacity totals approximately 20% of total domestic retrofit solar capacity by 2050.

[59] European market outlook for battery storage (page 21) , Solar Power Europe, June 2024

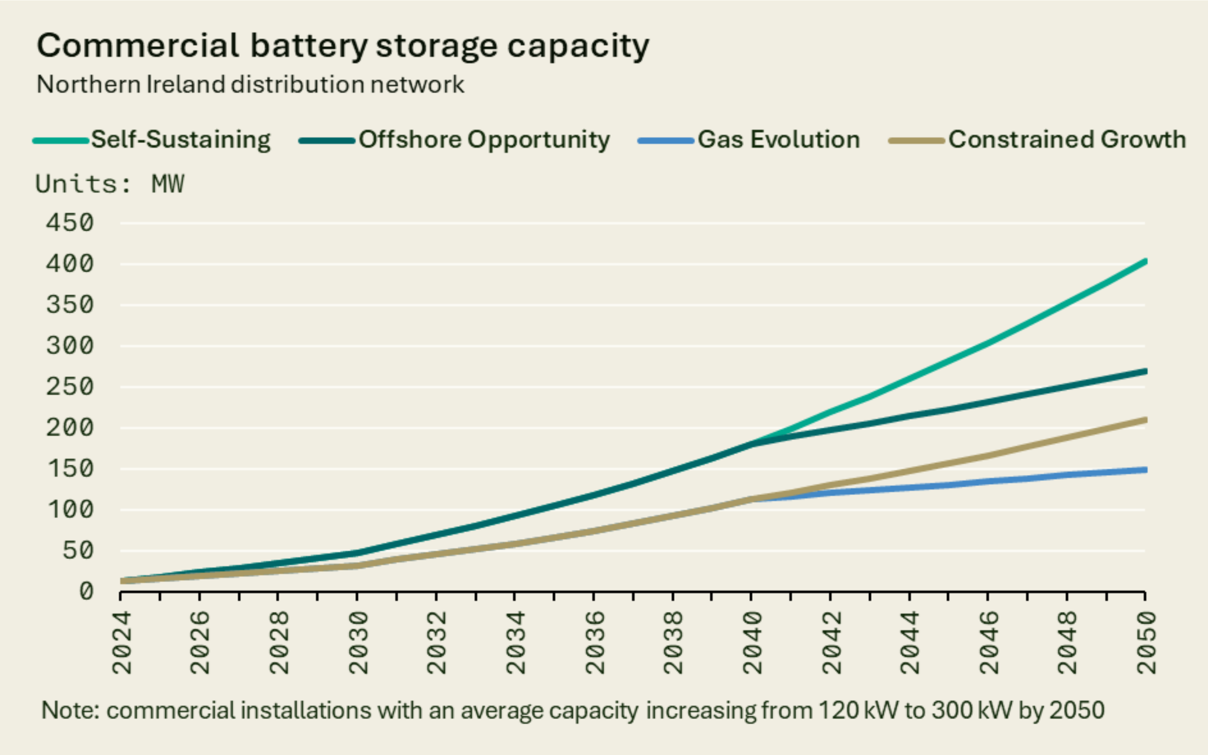
3.4.6. Detailed results

Figure 51



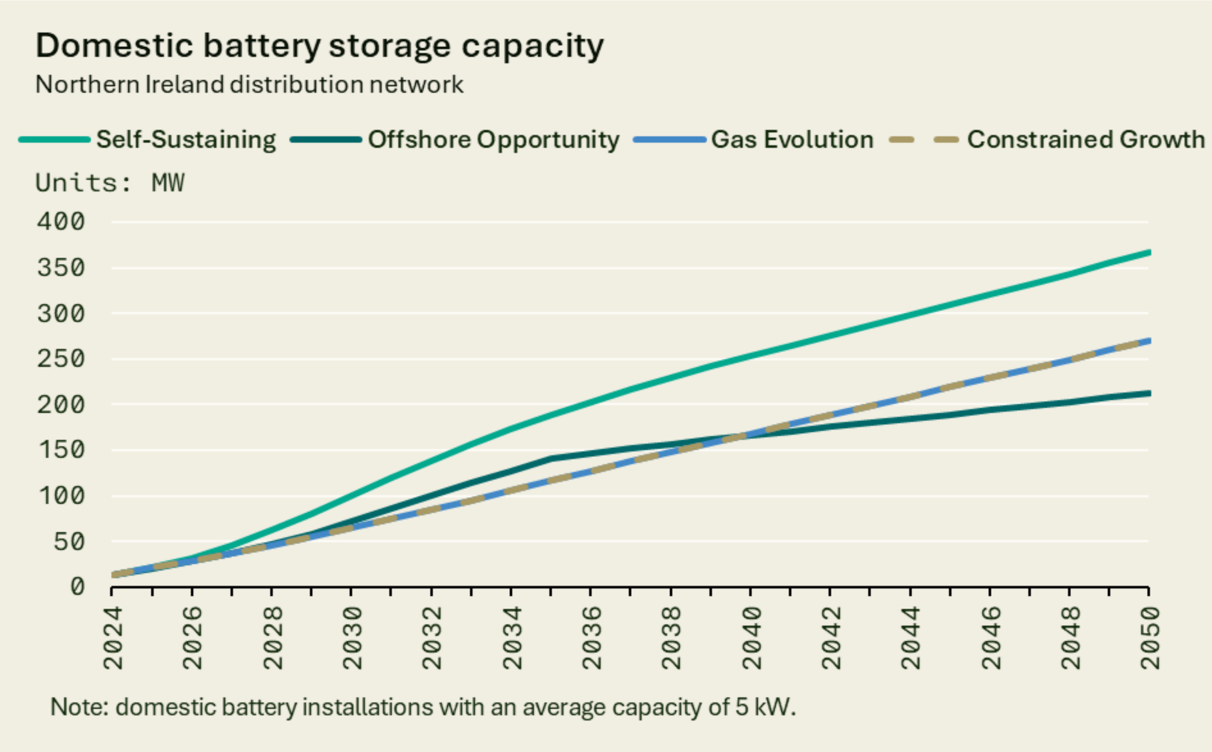
The pipeline of battery storage sites builds out by 2030, with higher project failure rates in Constrained Growth and Gas Evolution. Self-Sustaining and Offshore Opportunity maintain pipeline growth rates out to 2035. Constrained Growth and Self-Sustaining have higher 2035-2050 growth rates due to their greater focus on smaller scale, distribution connected flexibility.

Figure 52



Deployment of commercial scale battery storage grows alongside commercial scale solar generation. Under Self-Sustaining, policy and market incentives encourage greatest uptake. By 2050, under all scenarios, commercial scale battery storage capacity approximately matches commercial scale solar generation capacity.

Figure 53



Domestic battery storage deployment is driven by growth in the domestic solar generation market and high rates of co-location. A deceleration in growth is projected in Self-Sustaining and Offshore Opportunity in the mid-2030s; these are scenarios where bi-directional EV charging becomes an alternative form of flexibility.

Figure 54

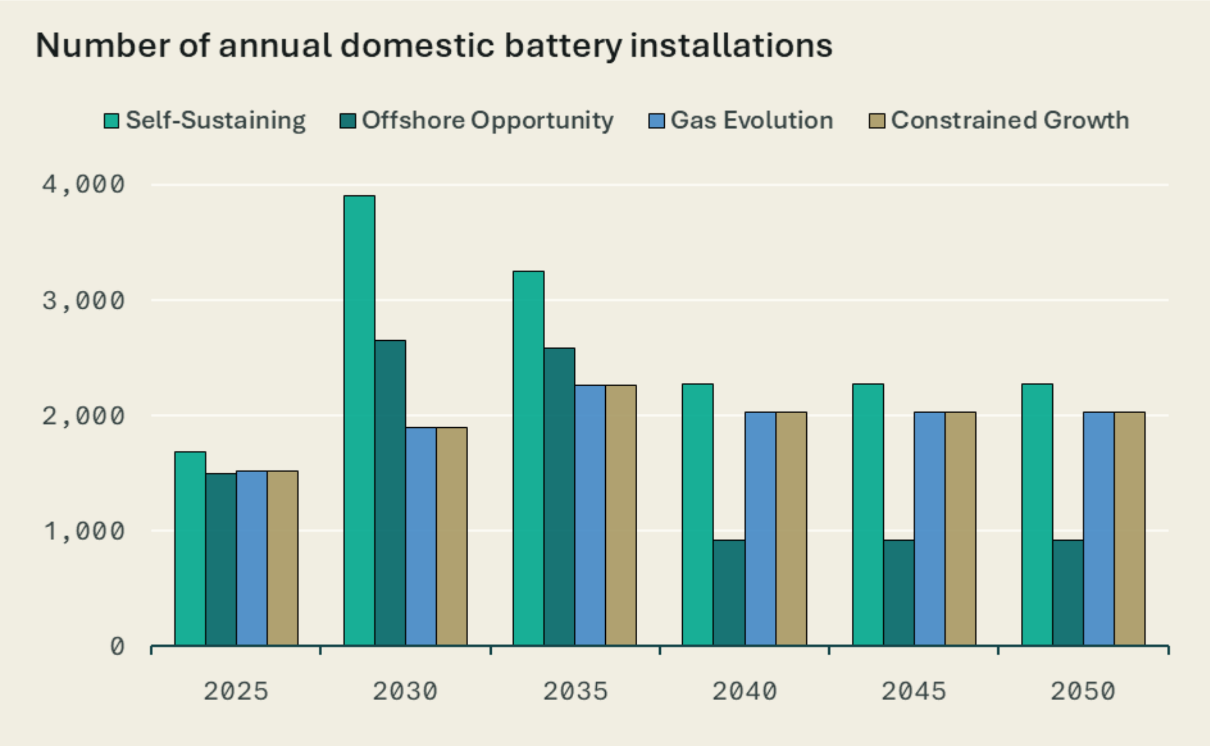


Figure 55

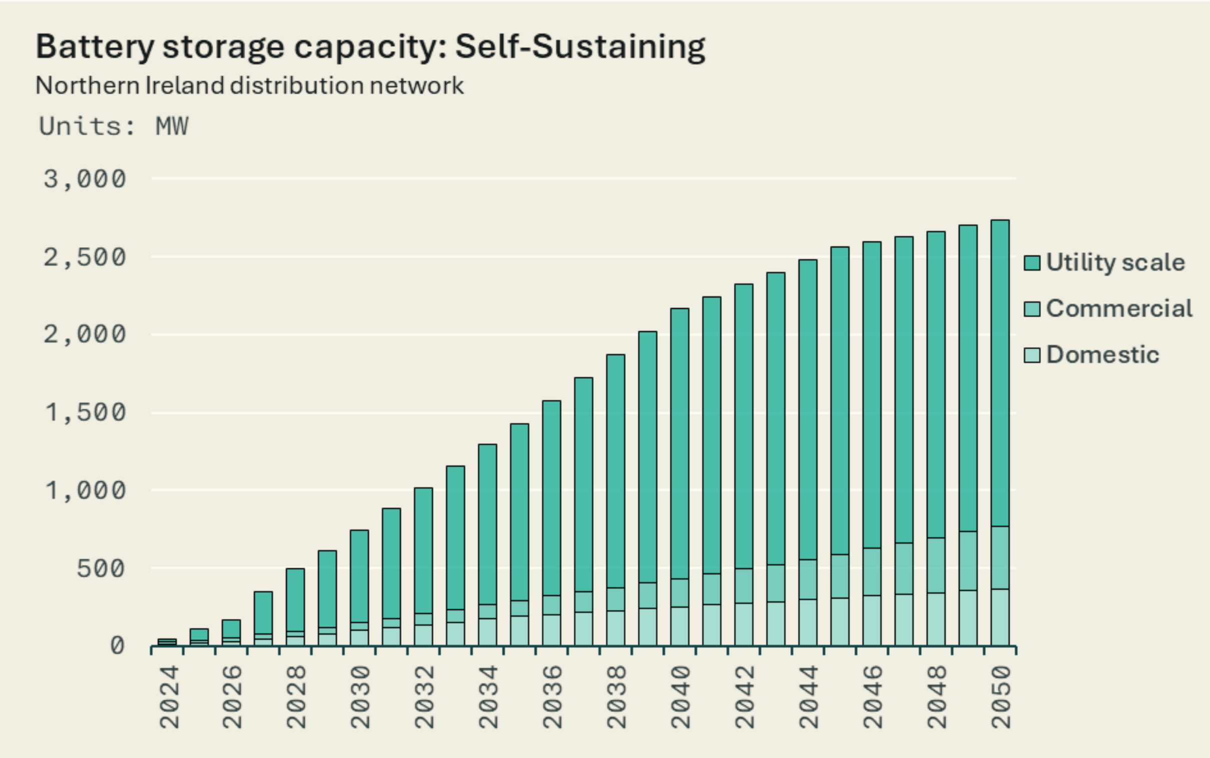


Figure 56

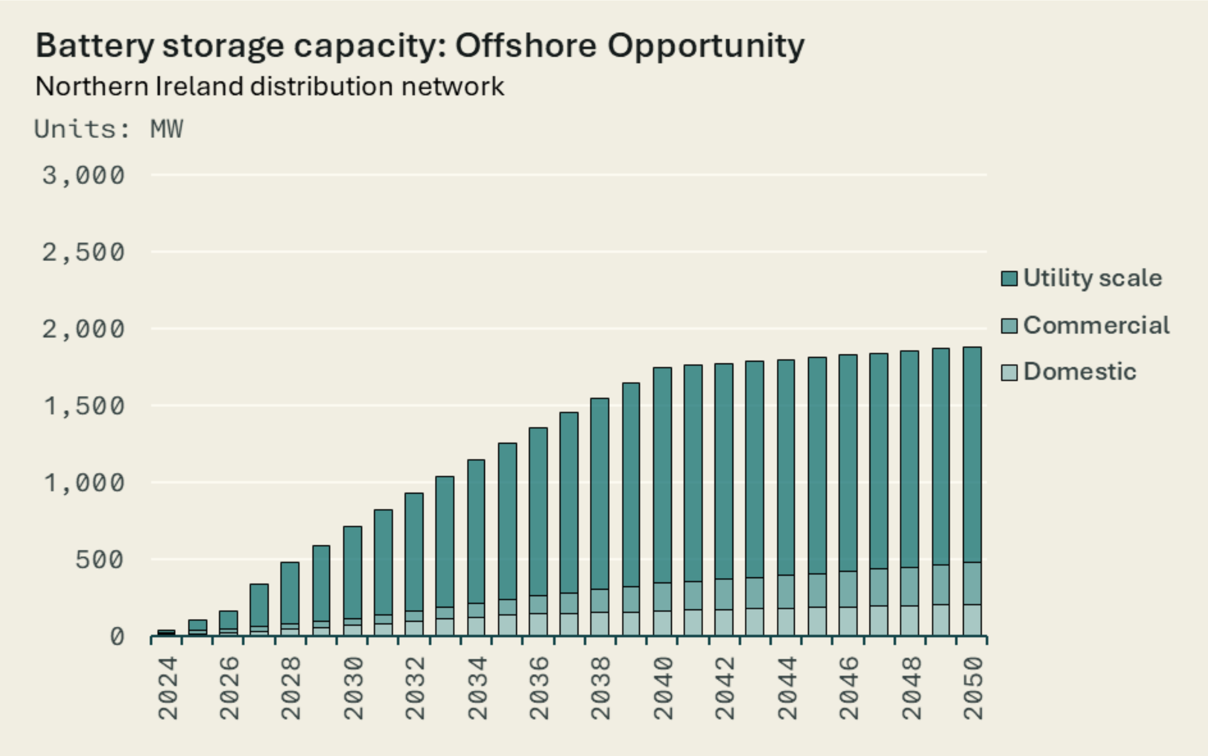


Figure 57

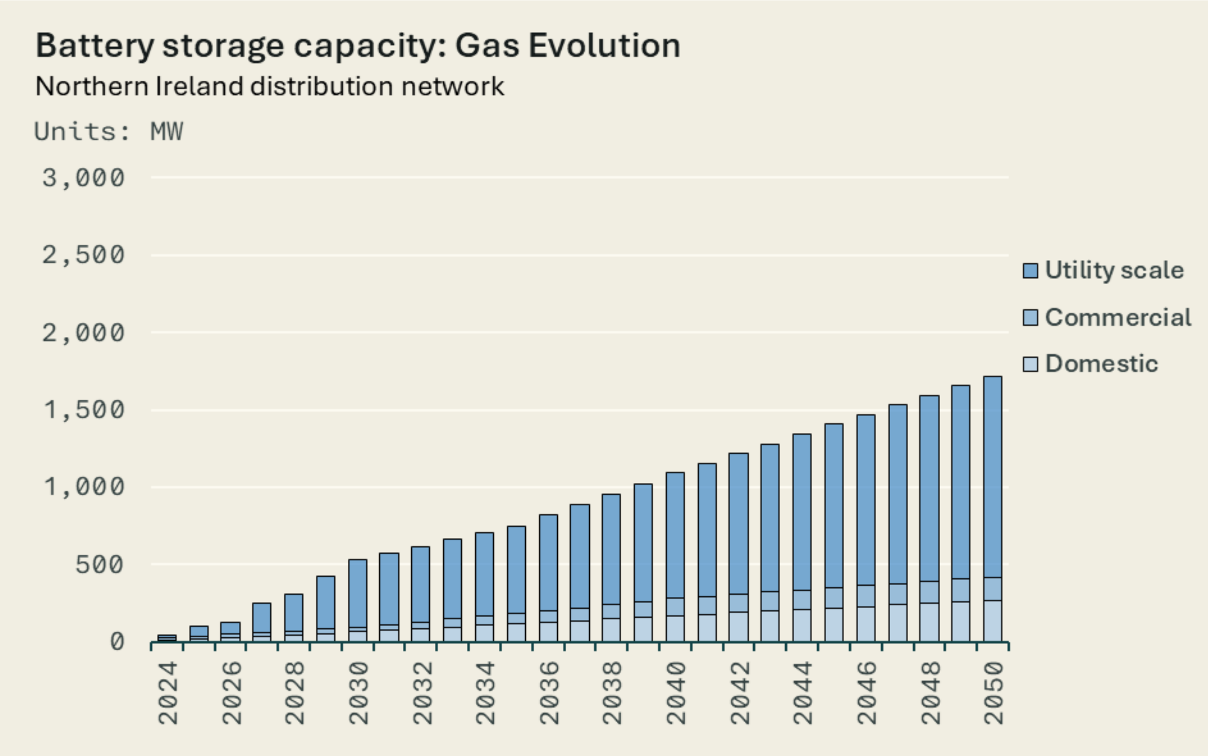
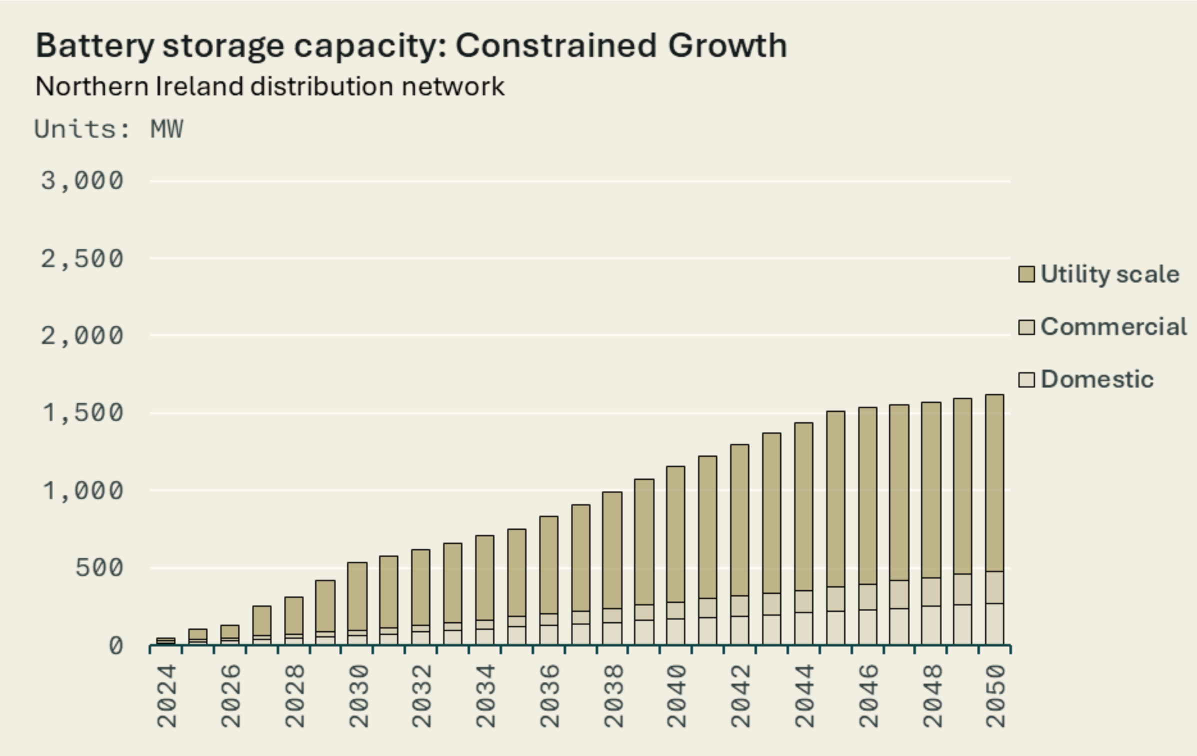


Figure 58



3.4.7. Reconciliation to other projections

TES projects total battery storage capacity in Northern Ireland in GWh. These projections have not included analysis on assumed duration of discharge of the battery fleet.

Currently, the majority of batteries deployed in GB have discharge durations of one hour. It is assumed that the majority of batteries deploying in the near term in NI will have similar one hour durations. In GB and across Europe, longer duration batteries are being developed; large numbers of two hour batteries populate the GB pipeline.[60] [61]

It is assumed that this trend will continue, prompted by new markets for long-duration battery storage. By 2035-2050, a working assumption is made that the average discharge duration of the battery fleet in NI is 3 hours. This figure has been used within the reconciliation presented in Table 36.

[60] MODO energy analysis, 2025
[61] European Market Monitor on Energy Storage, EASE, March 2025. Indicating an average pipeline duration of 2 hours.

Table 36

Scenario	Year	SONI Tomorrow's Energy Scenarios Assuming 3 hour duration average (GW)	NIE Networks Distribution Network Planning Scenarios (GW)
Self-Sustaining	2035	2.1	1.4
	2050	3.5	2.8
Offshore Opportunity	2035	1.6	1.2
	2050	2.2	1.9
Gas Evolution	2035	1.7	0.7
	2050	3.6	1.7
Constrained Growth	2035	1.2	0.7
	2050	2.4	1.6

No projections for battery storage have been made within NIE Networks Regulatory Period 7 plans.[62]

[62] RP7 Scenario Forecasts , Northern Ireland Electricity Networks, 2022

3.5. **Other generation**

Onshore wind, solar generation and thermal generation currently contribute 1.8 GW of generation capacity to the distribution network. In addition to this, there is a small capacity of sites with other operational generation technologies. This section summarises these other technologies in the context of the scenario analysis.

3.5.1. **Hydropower**

There is 6.5 MW of hydropower connected to the distribution network in Northern Ireland. This capacity is spread across 65 small sites, averaging 100 kW each. Most of these sites were built or refurbished in the 2000s, with some additional capacity coming online between 2012 and 2017. No new sites have been developed following the closure of the NIRO scheme in 2017.

All hydropower sites are assumed to continue operating out to 2050 under all scenarios, reflecting a feasible 50-year operational lifetime of hydropower sites.[63] Under the Self-Sustaining scenario, some additional hydropower capacity is assumed to be developed. In this scenario, 3.5 MW of additional hydropower capacity connects to the network, resulting in10 MW of capacity by 2050.

3.5.2. **Tidal power**

There is currently no tidal power capacity connected to the distribution network in Northern Ireland. The 1.2 MW SeaGen tidal site in Strangford Lough, the first major commercial project of its kind in the world, was brought online in 2008 and decommissioned in 2019. Since then, several new projects have been proposed or tested in Strangford Lough, but none have approached the same scale. Although the site may see future commercial development, any projects would likely be very small-scale, due to the narrowness of the strait.

The only major tidal project in active development in Northern Ireland is the 100 MW Fair Head Tidal Array. A project of this scale can be considered much more likely to connect to the higher voltage transmission network. Therefore, no tidal generation capacity has been projected to connect to the distribution network out to 2050, under any scenario.

[63] *How long do hydropower installations last*, Renewables First, n.d.

Section 4:

Appendix

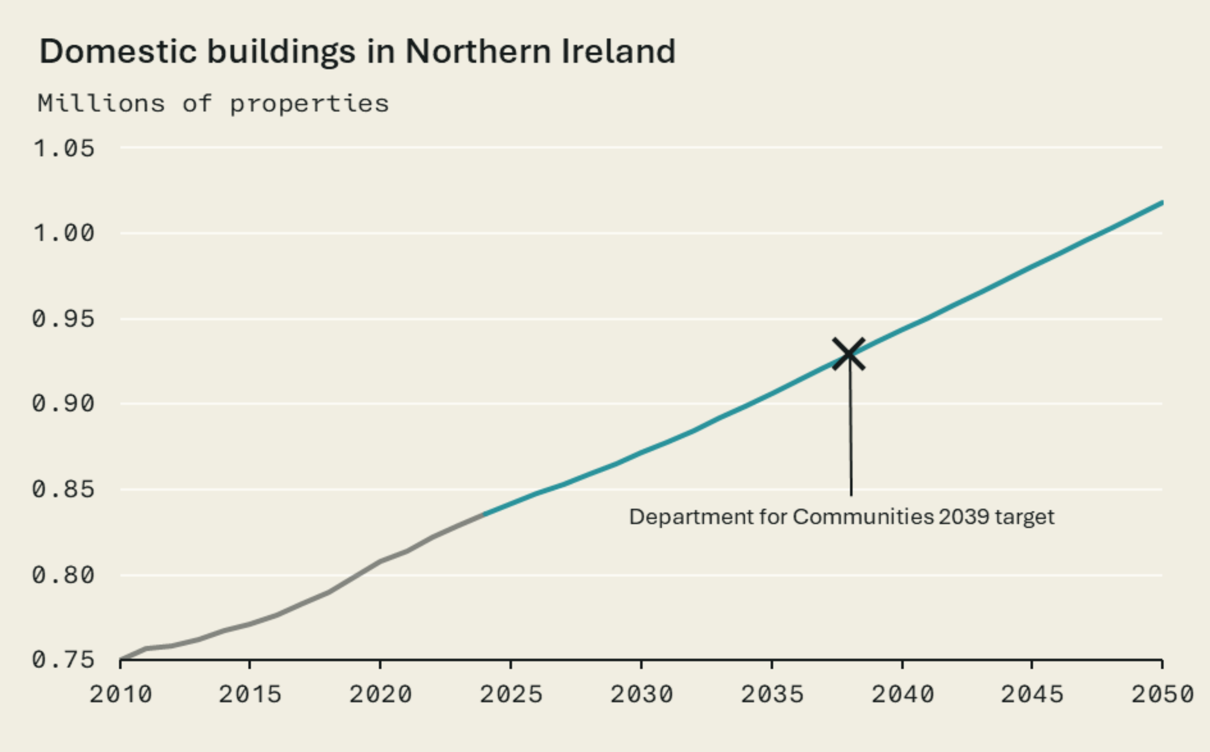
4.1. New building developments

New domestic and non-domestic building developments are an important driver of low carbon technology uptake on the distribution network in Northern Ireland. The table below illustrates which demand, generation and storage projections are influenced by development of new buildings.

Table 37

Sector or technology	Subtechnology	Domestic buildings	Non-domestic buildings
Electric vehicle chargepoints	Domestic off-street chargepoints	X	
	Workplace and fleet chargepoints		X
Electric heat (domestic and non-domestic)	Air source heat pumps	X	X
	Ground source heat pumps	X	X
	Hybrid heat pumps	X	X
	Direct electric	X	X
	Heat networks	X	X
Generation technologies	Commercial scale solar		X
	Domestic scale solar	X	
Storage technologies	Commercial scale batteries		X
	Domestic scale batteries	X	

Figure 59



New build projections were developed to align with the Department for Communities (DfC) housebuilding target, which aims for at least 100,000 new houses built between 2024 and 2039.[64] This target is equivalent to building c. 6,667 houses a year over the period.

Existing housing data was based on publicly available statistics from the Department of Finance (DoF), DfC, and connections data from NIE Networks.[65, 66] In the near term, build rates are constrained by the capacity of the sewerage system, which is assumed to be lifted by 2028, allowing the rate of new builds to increase to meet government targets. Post-target build rates are expected to remain steady.

A projection for non-domestic customers was developed using UK government historical data.[67] The annual growth in non-domestic meters seen over the past 8 years is projected forward to 2050.

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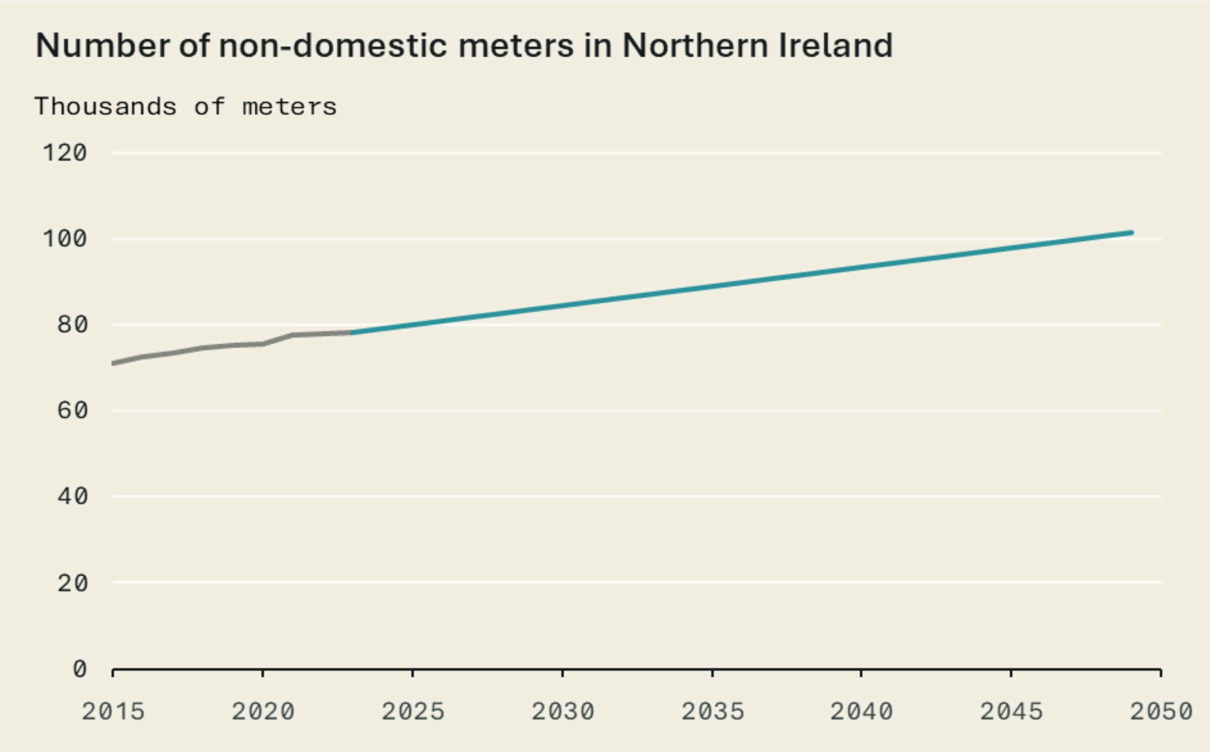
64 *Housing Supply Strategy*, Department for Communities, 2024
65 *Annual housing stock statistics*, Department of Finance, 2024
66 *Northern Ireland Housing Statistics*, Department for Communities, 2024
67 *DUKES: Subnational electricity consumption, Northern Ireland, 2015 - 2023*, UK Government, 2024

Figure 60



4.2. **Stakeholder engagement**

The following organisations registered to attend an online stakeholder consultation webinar on Thursday 6 March. In total over 120 individuals from 70 organisations attended the online event.

Interactive polling was used to provide an opportunity to feed into the assumptions used in the development of scenarios. The responses to the polling questions were used to inform and validate the modelling assumptions, market position and future potential uptake factors for the scenario projections.

Table 38

Registered stakeholder organisations			
1	ABO Energy	36	Lakeland Dairies
2	Action Renewables	37	Lidl
3	Anesco Ltd	38	M Donnelly Electrical
4	B4B Renewables	39	MCG Services
5	Belfast City Council	40	Mercedes Benz Truck and Van (NI)
6	Causeway Coast and Glens Borough Council	41	Mid and East Antrim Borough Council
7	CBI	42	Mott MacDonald
8	Consumer Council for Northern Ireland	43	Nemo Energy
9	Continu	44	NIE Networks
10	DAERA	45	Northern Ireland Civil Service
11	Department for Infrastructure	46	Northern Ireland Housing Executive
12	Department for the Economy	47	Northern Ireland Water
13	Department for the Economy, NICS	48	Orsted
14	Department of Finance	49	Phoenix Energy
15	Derry City and Strabane District Council	50	Plan Energy
16	Diageo	51	Power Capital Renewable Energy
17	DNV	52	PulseSolar Group
18	DRAI	53	Queen's University Belfast
19	Electric Vehicle Association NI	54	Saliis
20	Energia Group	55	ScottishPower Renewables
21	Energia Renewables	56	Solarfix NI
22	ESB	57	Solmatix
23	ESB - Generation and Trading	58	SONI
24	ESI	59	Statkraft Ireland
25	Evolve	60	TCI Renewables
26	Fermanagh and Omagh District Council	61	Tesla Ireland
27	FMK Electricity Consultant	62	The Maxol Group
28	FP McCann Ltd	63	The University of Manchester
29	GlenDimplex	64	Tri-power Environmental Energy
30	Heron Energy	65	Troup Bywaters and Anders
31	Invest Northern Ireland	66	Ulster Farmers Union
32	iPower	67	UrbanVolt
33	ISD	68	Utility Regulator NI
34	Joulen	69	Weev
35	Kelvatek		

4.3. **Summary tables**

4.3.1. Electric vehicles

Table 39

Technology	Units	Scenario	2025	2030	2035	2040	2045	2050
Electric vehicles	Number	Self-Sustaining	60,954	291,204	639,618	958,440	1,125,673	1,130,670
Electric vehicles	Number	Offshore Opportunity	62,569	367,746	784,713	1,169,061	1,339,943	1,342,640
Electric vehicles	Number	Gas Evolution	57,344	253,970	600,507	918,282	1,121,490	1,124,748
Electric vehicles	Number	Constrained Growth	57,232	223,987	500,067	752,600	907,511	916,656

Note: includes all plug-in vehicles (battery electric vehicles and plug-in hybrid electric vehicles)

4.3.2. Heat

Table 40

Technology	Units	Scenario	2025	2030	2035	2040	2045	2050
Domestic HPs	Number	Self-Sustaining	4,896	89,998	295,497	553,332	742,912	816,720
Domestic HPs	Number	Offshore Opportunity	4,166	74,697	271,558	529,392	730,881	812,819
Domestic HPs	Number	Gas Evolution	3,309	62,212	222,743	434,092	641,552	770,860
Domestic HPs	Number	Constrained Growth	2,422	41,437	138,333	311,409	546,870	792,336
Non-domestic HPs	Number	Self-Sustaining	489	10,452	28,608	51,804	70,794	78,453
Non-domestic HPs	Number	Offshore Opportunity	219	4,278	18,070	37,946	55,080	61,158
Non-domestic HPs	Number	Gas Evolution	202	3,925	16,318	33,812	50,913	60,059
Non-domestic HPs	Number	Constrained Growth	87	1,524	5,405	17,949	37,242	56,934

4.3.3. Generation

Table 41

Technology	Units	Scenario	2025	2030	2035	2040	2045	2050
Large-scale solar	MW	Self-Sustaining	209	515	722	974	1,227	1,480
Large-scale solar	MW	Offshore Opportunity	209	515	515	515	515	515
Large-scale solar	MW	Gas Evolution	209	395	395	448	605	762
Large-scale solar	MW	Constrained Growth	209	395	514	757	1,001	1,244
Micro and small solar	MW	Self-Sustaining	200	394	730	1,075	1,472	1,902
Micro and small solar	MW	Offshore Opportunity	198	333	572	733	915	1,116
Micro and small solar	MW	Gas Evolution	198	298	436	579	733	889
Micro and small solar	MW	Constrained Growth	198	308	484	652	836	1,026
Onshore wind	MW	Self-Sustaining	1,314	2,082	2,342	2,462	2,666	2,697
Onshore wind	MW	Offshore Opportunity	1,293	1,779	2,095	2,077	2,142	2,157
Onshore wind	MW	Gas Evolution	1,290	1,494	1,973	1,933	1,998	2,014
Onshore wind	MW	Constrained Growth	1,282	1,504	2,211	2,329	2,492	2,517
Thermal	MW	Self-Sustaining	290	341	276	103	0	0
Thermal	MW	Offshore Opportunity	290	341	294	123	41	0
Thermal	MW	Gas Evolution	290	376	376	303	261	71
Thermal	MW	Constrained Growth	290	376	370	291	224	34

4.3.4. Storage

Table 42

Technology	Units	Scenario	2025	2030	2035	2040	2045	2050
Domestic Storage	MW	Self-Sustaining	86	645	1,239	1,912	2,251	2,373
Domestic Storage	MW	Offshore Opportunity	86	645	1,120	1,583	1,625	1,672
Domestic Storage	MW	Gas Evolution	84	468	634	924	1,187	1,450
Domestic Storage	MW	Constrained Growth	84	468	634	985	1,293	1,346
Non-domestic storage	MW	Self-Sustaining	22	101	189	253	310	366
Non-domestic storage	MW	Offshore Opportunity	21	72	140	166	189	212
Non-domestic storage	MW	Gas Evolution	21	64	117	168	219	270
Non-domestic storage	MW	Constrained Growth	21	64	117	168	219	270

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