CORNWALL INSIGHT
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Future of Renewables in Northern Ireland

Prepared for:

The Department for the Economy

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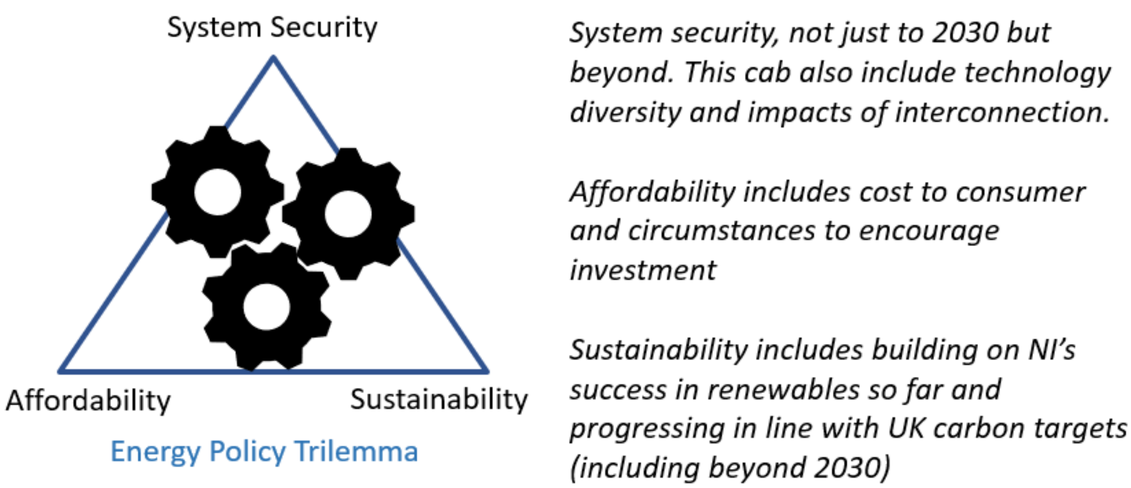
1 Executive Summary

Northern Ireland is on track to meet its 2020 targets with regards to electricity consumption from renewable energy sources (RES-E), which were set at 40%. The Department for the Economy (DfE) published statistics in 2019[1] indicating that over a 12 month period between July 2018 and June 2019, 44.0% of electricity consumption came from RES-E sources - exceeding the target of 40% by 2020, which was outlined in Northern Ireland's Strategic Energy Framework in 2010.

A new policy is required for the uptake of renewable electricity in Northern Ireland in the coming decades, in line with UK targets on climate change. The UK's fifth Carbon Budget targets an emissions decrease of at least 35% by 2030 against 1990 levels and, according to the Committee on Climate Change (CCC)[2] report published early in 2019, Northern Ireland's contribution will require a reduction of at least 35% on 1990 levels.

Much of Northern Ireland's emissions are produced in the agricultural, heat, transport and electricity sectors. The goal of this report is to provide a guide for the DfE when creating policy for the electricity sector in Northern Ireland post-2020. This report comprises extensive research from various sources and analysis based on policy scenarios and options potentially open to the DfE, taking into account the "energy policy trilemma" of system security, affordability and sustainability (Figure 1).

Figure 1. Energy Policy Trilemma for Northern Ireland



source: Cornwall Insight/Ionic Consulting

The methodology of the work based on the outcomes presented in this report is based on the following research and analysis activities:

- Extensive research of the electricity sector in Northern Ireland, based on government, industry and academic sources
- Multiple interviews with stakeholders including government, regulatory, non-government organisations and industry participants in the electricity sector
- Development of a high-level model to investigate various possible outcomes for different levels of renewable electricity policy ambition combined with possible system security considerations

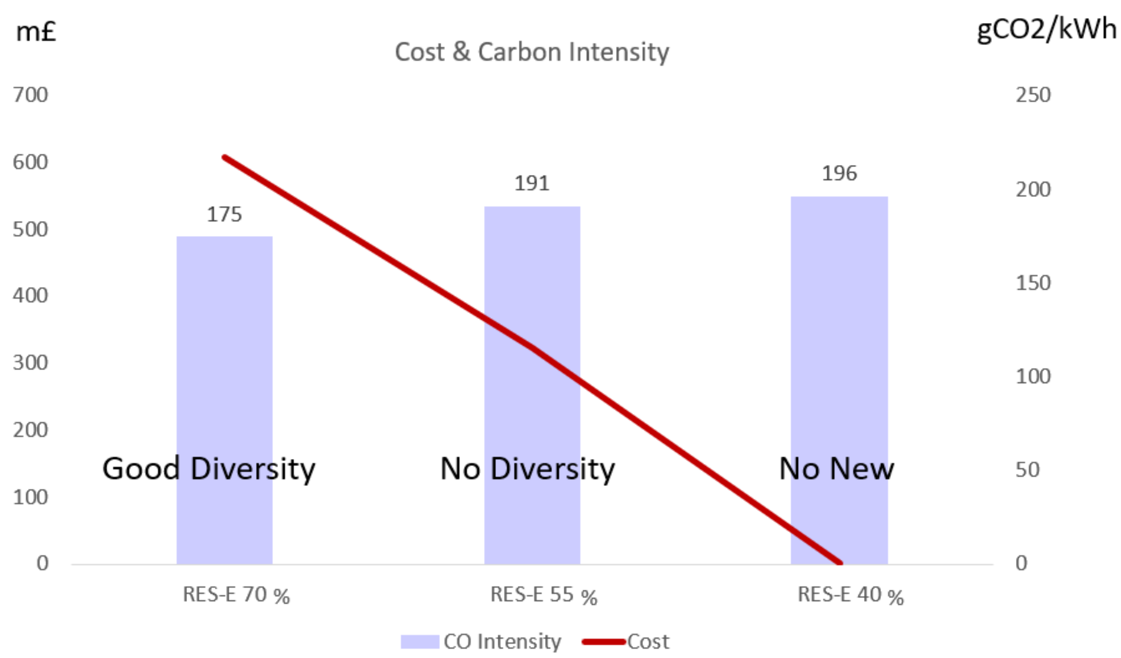
[1] https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Issue-12-Electricity-Consumption-and-Renewable-Generation-in-Northern%20Ireland-July-2018-to-June-2019.pdf
[2] https://www.theccc.org.uk/wp-content/uploads/2019/02/Reducing-emissions-in-Northern-Ireland-CCC.pdf

- An overview of policy options available to the DfE based on in-house industry knowledge, international best practise and case studies in other jurisdictions both inside and outside of Europe

The potential policy options open to the DfE have been considered from the perspective of the relative ambition of RES-E targets, compatibility with UK policy and State Aid Approval as well as compatibility with the Single Electricity Market (SEM) which Northern Ireland (NI) shares with the Republic of Ireland (ROI), and the likelihood of stimulating investment in renewable assets while considering the underlying cost to the consumer. In order to facilitate discussion of future policy, scenarios were developed based on different RES-E targets of 70%, 55% and 40% by 2030. These are referred to as “RES-E 70”, “RES-E 55” and “RES-E 40” respectively.

The reader should bear in mind that *the model is designed as a guide only* regarding possible outcomes of different policy options. The model is built in MS Excel and based on annual granularity and lacks the level of sophistication and analysis possible with, for example, a Plexos®[3] model or other more advanced tool. Therefore ***any values which emerge from the model are meant for comparison only and should not be taken as being absolute values.***

Figure 2. RES-E targets comparison between cost and technology diversity of new deployment and the carbon intensity of each scenario



Source: Cornwall Insight & Ionic Consulting

Figure 2 provides a comparison of the cost of the deployment of new generation assets for each of the scenarios from 2022 to 2030, as well as the carbon intensity for new and existing assets associated with each scenario. It should be noted that costs are not adjusted for expected changes in currency exchange for inflation. The model takes account of the existing available capacity forecasts and projected future demand figures as published by the System Operator Northern Ireland (SONI) in the 2018 Generation Capacity Statement[4]. In order to meet the requirements of system security and the renewable electricity target (sustainability) set by the user, the model recommends deployment of new renewable assets required for the lowest possible cost, in line with the requirements of the energy policy trilemma in Figure 1.

The results compare the carbon intensity, which is the amount of carbon produced from electricity generation in a given year as a function of demand, for each scenario. These values include carbon from existing assets as well as any new deployment. Figure 2 shows the carbon intensity for 2030 only and indicates that although the high RES-E 70% target has the highest cost, it is also the most efficient from a carbon minimisation perspective.

[3] https://energyexemplar.com/products/plexos-simulation-software/
[4] http://www.eirgridgroup.com/site-files/library/EirGrid/Generation_Capacity_Statement_2018.pdf

Investment in this scenario indicates the best return on meeting carbon targets out of the options examined, and it is in line with both UK and ROI commitments to climate change targets. This scenario deploys almost 1,200 MW of new renewables assets, of which 300 MW is offshore wind, and - when compared with RES-E 40 where there was virtually no deployment of any new generation - represents an 11% decrease in carbon intensity. When compared with the RES-E 55 scenario, the RES-E 70 scenarios represents an 8% decrease in carbon intensity, indicating that higher ambitions give relatively better rates of return on carbon intensity levels.

Costs in the model include those associated with running existing assets due to be in place after 2022 and any new assets which are deployed (which may include non-renewable technologies, such as new thermal gas plant). Networks costs and system actions such as curtailment are not included in the model. The cost output shown in Figure 2 is for new deployment only, but the model does not suggest how this cost should be recovered. This will ultimately be for the policy maker to decide and would most likely the recovered from a combination of public and private investment. This is discussed in more detail in Chapter 5. Although the cost for the RES-E 70 scenario is significantly higher than for RES-E 55, this is also reflective of the higher demand forecast based on SONI's "high demand" scenario.

Table 1. Table showing the projected Levelised Cost of Electricity (LCOE) for various technologies based on analysis by Cornwall Insight

Technology	2020 (£/MWh)	2030 (£/MWh)	% Drop (£/MWh)
Onshore wind	47.89	43.88	8%
Solar PV	52.91	44.86	15%
Offshore Wind	67.48	53.84	20%
Batteries	140.04	86.54	38%
Hydro	96.92	96.51	0%
AD	127.59	127.10	0%
Biomass	247.46	186.46	25%
EfW	163.41	147.51	10%
Tidal	162.93	151.16	7%
Gas Recip	102.36	126.26	-23%
CCGT	78.95	98.20	-24%
OCGT	88.77	105.88	-19%

source: Cornwall Insight

Additionally, any successful policy will aim to stimulate private investment as much as possible and - in doing so - the consumer may not bear the entirety of the costs from high target ambitions. In considering costs, system security must also be taken into account. Given the aging fleet of both conventional and renewable generation assets in NI, investment in new generation will be required towards the end of the 2020s and into the 2030s. The levelised cost of electricity (LCOE) gives an indication of likely future cost of different technologies and, based on our analysis summarised in Table 1 suggests that the cost of conventional plant will have increased significantly by 2030 whereas costs for virtually all the types of renewable technology under review will fall. This is also a consideration when comparing previous support schemes such as the Northern Ireland Renewables Obligation (NIRO) or the FiT scheme in GB. Costs have fallen considerably since those programmes were introduced, and so may not represent as high a cost to a consumer today as they might have 10 years ago.

As part of the analysis, a comparison was done based on the possible availability of offshore wind. Northern Ireland has not been included in the latest seabed leasing round by The Crown Estate as the area around Northern Ireland did not meet certain criteria. It is possible that policy changes could encourage Northern Ireland's inclusion in the next seabed lease round, enabling the potential addition of offshore wind to Northern Ireland's generation mix towards the end of the next decade. Offshore wind has become well established in GB and there is an expectation that it will also form a significant part of ROI's generation mix in the coming decade. Our analysis indicates that not having access to offshore wind could increase costs to new deployment by at least 10% to meet the RES-E 70 target.

The question of how to stimulate investment in deployment of new renewable electricity assets in Northern Ireland often fall into a few categories, based on the experience of both Cornwall Insight and Ionic Consulting. This has been supplemented by conversations with various industry stakeholders including the network operators, market participants and investors. Generally, investors are more comfortable accepting the risk associated with new projects in environments with long-term and stable policy and regulatory frameworks, predictable long-term revenue streams and clear routes to market. Traditionally subsidy schemes have been used to stimulate investment, and current policy thinking tends to consider finding a balance between providing enough support to stimulate investment while at the same time allowing the market to take much of the risk - - thus minimising costs to the consumer. In our experience, investors are less likely to consider investment in subsidy-free or merchant plant without being able to hedge some of their risk as is the case in subsidised projects. The current situation in Northern Ireland with respect to the closure of the NIRO means that there is a lack of subsidised (and hence lower risk) projects for investors. However, the feedback we have received from market participants is that investors are continuing to look to GB and ROI for opportunities for investment. That said, there is a belief amongst some industry and government representatives, that withdrawal of incentives forces developers to minimise costs in their projects by running them as leanly as possible such as using cheaper equipment (but with a lower lifespan or less controllability), not using external advisors etc.

It is important to bear in mind that costs for renewable electricity have come down considerably in the past decade and are set to decrease further. As such, analysis previously commissioned may not have considered this eventuality. It is also important to consider the barriers to investment and how this may impact cost recovery. A certain amount of realism is required by the policy maker with regards to the ability of purely merchant projects and/or corporate power purchase agreements to facilitate meeting Northern Ireland's carbon targets.

As part of our model analysis we also considered the implications of systems security - both from the perspective of interconnection and technology diversity. The lowest cost solution for new deployment tends to be onshore wind. However, there can be difficulties with facilitating such intermittent generation on the grid, even without the current saturation of capacity in many areas most suitable for onshore wind. This can lead to greater investment costs as well as curtailment risks, whereby wind assets are instructed to "turn off" due to there being more generation output from such assets than the network can physically accommodate. For this reason, it can be considered good practice to encourage diversity of technology, especially dispatchable plant such as anaerobic digestion or biomass.

The impact of the proposed 1500MW North-South interconnector with ROI was also analysed. Currently there is limited capacity for electricity flow between jurisdictions, which has contributed to price volatility in the SEM, as well as posing a potential system security issue for Northern Ireland as its aging and fossil fuel assets start to close. The assumption, which was confirmed by SONI, is that the North-South interconnector will be in place by 2024. However, its future is not certain as it has been subject to both ongoing public objection throughout consultation, as well as legal challenges. Our analysis indicates that should the North-South Interconnector not be in place, cost of new deployment will increase significantly and the commissioning of new fossil fuel plant such as OGCT may be required to meet Northern Ireland's demand requirements. A potential way of preventing such an eventuality would be to encourage investment in technologies such as batteries which could supplement system security without the need to deploy new, expensive fossil fuel plant. As recently reported[5], batteries are starting to replace gas peakers plant in some places, and this trend is likely to continue as costs come down and batteries become more efficient.

Electricity grid access and costs are an additional factor influencing investment in renewable energy in NI, and one which has been cited by several market participants as being a major barrier to investment in renewables in the region. A lack of grid capacity in the north-western region where the onshore best wind resources lie is of particular note. SONI's Ten Year Development Plan highlights a number of large transmission projects that would help alleviate some or all of the capacity constraints and permit the evacuation of power from the region to load centres in the east and south. More headroom exists in the eastern region to connect but again further investment will be needed at transmission level to facilitate large-scale connection of renewable projects. Distribution network capacity throughout NI is also limited albeit NIE Networks are currently working on a 'heat map' that clarifies where capacity to connect to the distribution system remains.

[5] https://www.greentechmedia.com/articles/read/california-clean-power-outlook-what-comes-after-shorter-duration-batteries

Figure 3. Socialise network cost analysis based on the different RES-E scenarios

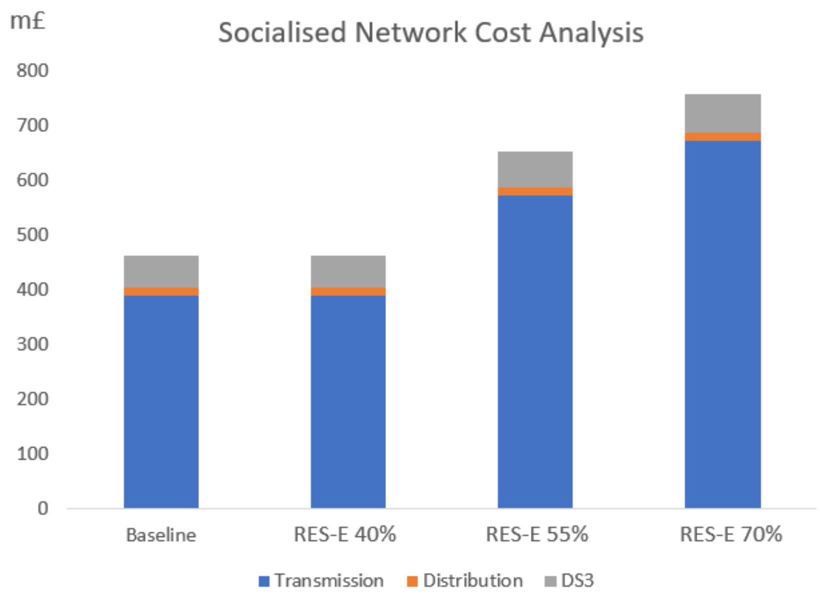


Figure 3 above provides a high-level estimate of grid-related investment costs associated with each scenario based on analysis done by Ionic Consulting. Whilst the majority of socialised investment is at transmission level, it is important to note that this is based on the assumption that the vast majority of investment at distribution level is allocated to project developers per their connection agreement as opposed to being socialised. The exception to this is where a project connects at the LV voltage level but triggers upgrades at the 33kV voltage level, the costs of which would be socialised per the current connection policy. The cost of network upgrades ranges from circa £460m to £757m between the Baseline/ RES-E 40 scenario and the RES-E 70 target, a difference of circa £300m. The significant cost relating to the Baseline/RES-E 40 scenarios is on the basis that all asset replacement projects, a number of security of supply related RES integration project and the North-South Interconnector will all go ahead regardless of future RES-E targets. The additional costs relating to the RES-E 55 and RES-E 70 targets primarily relate to new 275kV network projects, particularly in the NW of the region, which will be required to facilitate significant increases in onshore wind generation capacity. DS3[6]-related range from £57m to £73m and are assumed to scale in proportion to increases in renewable energy capacity on the NI system. Distribution costs are related only to those costs at 33kV that are not recouped via generators' connection agreements. In this regard it has been assumed that the level of such costs remain at circa £15m based on the level of generation exporting at LV being similar to that to-date. It should be noted that this does not account for distribution network costs relating to the IT and other infrastructure required to facilitate smart metering should this be rolled-out in NI. It is assumed such a scheme would require further cost-benefit analysis prior to proceeding.

Finally with regards to community energy schemes, as outlined in Chapter 8, there can be barriers in the form of funding access, project leadership, access to knowledge and expertise and concerns over routes to market and costs. Community Energy projects could benefit from a Renewable Energy Association (REA) to help assist communities with understanding their options, providing mentorship and guidance and advocate on their behalf. Investigations could also be made regarding access to UK funding for such projects or promoting enablers.

In this summary, we have attempted to indicate the choices facing policy makers based on renewable electricity ambitions with consideration of the interconnected facets of system security, affordability and sustainability. The mechanisms with which policy makers pursue these choices are outlined in Chapter 5 and will be guided by the trilemma, strategies to encourage investment and cost recovery. A factor in cost recovery concerns socialisation of costs, and Northern Ireland policy makers may wish to consider the possibility of joining the UK CfD scheme, developing an "all island" support scheme in conjunction with ROI or develop a Northern Ireland-only policy support mechanism. Feedback from across the stakeholder

[6] Delivering a Secure Sustainable Electricity System (DS3). Refer to http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/

interviews is that there is a desire for increased coordination between government departments, non-government organisations and communities in developing renewable electricity in Northern Ireland. Suggestions have been made of setting up working groups or associations and the establishment of the Steering Group formed as part of this project is seen as a positive step. There is considerable expertise and passion in Northern Ireland for renewable electricity which was clear from the many stakeholders involved in this study. This in combination with careful and progressive policy design, gives positive indications that Northern Ireland can continue to reach, and indeed exceed its targets in the coming decades.

2 Introduction

As part of Department for the Economy's (DfE) consideration around future renewables energy policy, Cornwall Insight in partnership with Ionic Consulting have been contracted to conduct research on renewable electricity and possible future policy in Northern Ireland. The outcome of this research is captured in this report, as well as views on policy options and recommendations on next actions.

This report forms a part of the process towards developing a New NI Energy Strategy which will serve to guide the Northern Ireland Executive on energy policy in the context of UK renewable energy guidelines.

The goal of this report is to provide an assessment of the current state of play for renewable electricity in Northern Ireland, including how the NIRO has contributed; an assessment of the technologies operating in the region and the potential for expanding deployment including emerging disruptive technologies; an assessment of grid capacity and the impacts on deploying renewables; the role that renewables can play in the SEM; the potential for community renewable energy schemes; the need for future incentivisation; and the policy options that should be considered going forward.

Based on the terms of reference, the outline of this report is as follows

1. **Executive Summary**
2. **Introduction** Introductory section outlining the basis for the work and summary of the report. This section also includes the research methodology for the report.
3. **Energy in Northern Ireland** including current policy, membership of the Single Electricity Market and the Northern Ireland electricity landscape
4. **Policy & Supports** including a NIRO Review, future policy options in the context of Northern Ireland, case studies from policy and support in other jurisdictions and considerations from an investor perspective
5. **Stakeholder Engagement** including views from various stakeholders including government, regulatory, non-government organisations and industry participants
6. **Modelled Scenarios** including description of the model, inputs and assumptions and analysis on model outputs
7. **Energy Sector & Technology Review** including various types of renewable energy technology from the perspective of costs, benefits and further developments. This section will include the impact of electric vehicle growth (EVs), future plant closure and renewables and storage, a technical review of renewable technology, a review of grid capacity and investment and an overview of the outputs of the scenarios model.
8. **Community Energy** including the context in Northern Ireland and case studies from other similar jurisdictions.

2.1 Methodology

This piece of work followed a methodology which combined extensive reviews of already existing research documents such as the Matrix Report[7], the Northern Ireland Affairs Committee report on the electricity sector in Northern Ireland[8], the Climate Change Committee (CCC)[9] report on NI, SONI's 2018 Generation Capacity Statement (GCS18)[4], the Strategic Energy Framework[10](SEF) as well as other government documents and those commissioned by lobby groups.

[7] https://matrixni.org/reports/2013-sustainable-energy-report/
[8] https://www.parliament.uk/business/committees/committees-a-z/commons-select/northern-ireland-affairs-committee/inquiries/parliament-2015/electricity-sector-northern-ireland/
[9] https://www.theccc.org.uk/publication/reducing-emissions-in-northern-ireland/
[10] https://www.economy-ni.gov.uk/articles/strategic-energy-framework-2010

Cornwall Insight and Ionic Consulting also undertook stakeholder engagement meetings with various participants in the Northern Ireland and UK energy industry including the Department for the Economy (DfE), Department for Business, Energy and Industrial Strategy (BEIS), the Utility Regulator (UR), Ofgem, System Operator Northern Ireland (SONI), Northern Ireland Electricity Networks (NIEN), the Crown Estate (TCE), the Department for Infrastructure (DfI) and various industry participants and lobby groups. Most of the meetings were face to face, including shared workshops, and individual meetings both in Northern Ireland and London. Others were teleconference calls or individual phone calls. Attempts were made to reach out to as many stakeholders as possible, and the views and information provided by each is collated and included in this report. A list of the stakeholders engaged with can be found in Appendix B.

In order to better understand the possible outcomes of different RES-E targets, Cornwall Insight - with input from Ionic Consulting - developed a high-level MS Excel model to test various scenarios based different possible renewable electricity targets in NI for the period from 2022 to 2030. The scenarios are based on the demand and generation figures from SONI's Generation Capacity Statement[4] (GCS18) which has figures available to 2027 which provided a framework for the scenario range. Data is included in the model for forecast Levelised Cost of Electricity (LCOE) which was compiled from an inhouse model developed by Cornwall Insight. The LCOE is defined as the unit cost of electricity over the lifetime of the asset and for renewable technologies is generally falling, whereas for fossil fuel plant is set to increase. Assumptions have also been made based on data from a number of sources including SONI, EirGrid, National Grid and NISRA on projected increases in heat pumps and EVs.

An extensive technology review is also presented in terms of existing and possible future options for NI which in turn informs forecasted deployments under each scenario. Each technology is reviewed from the perspective of technical and commercial maturity, expected technological and cost developments, and maximum feasible deployment in NI to 2030 given restrictions such as planning and available feedstocks in the region.

Finally as part of the terms of reference, the potential for community energy projects in NI has been examined. Community energy projects are typically defined as local power or heat generation facilities distributing energy to local users via public or private infrastructure, or local initiatives to reduce energy consumption. They are the result of collective action to reduce, purchase, manage or generate energy. Community energy projects have an emphasis on local engagement, local leadership and control, and the local community benefiting collectively from the outcomes.

3 Energy in Northern Ireland

Energy policy in Northern Ireland (NI) is largely devolved (with the exception of nuclear energy)[11] and is set by the Department for the Economy (DfE). As part of the UK, NI is included in UK renewable targets and overarching aspects of policy, while sharing its electricity market and grid with the Republic of Ireland (ROI) through the "all-island" Single Electricity Market (SEM). In this chapter we summarise the landscape of electricity in NI from the perspective of policy, electricity infrastructure and assets and the SEM. We also include a short section on implications of Brexit.

3.1 Energy Policy in NI

Although energy policy in NI is devolved, there exists UK-wide carbon emissions and renewables targets which take account of NI policies and developments. The UK government is expected to issue an Energy White Paper in 2019 that will set out more details on the direction of travel for policy for the next decade and beyond.

A speech by the Secretary of State, Greg Clarke, in November 2018 indicated that the cornerstone of UK energy policy will be enshrined in the four following principles:

- Market principle—Use market mechanisms wherever possible to take advantage of innovation and competition
- Insurance principle—Government must be prepared to intervene to provide insurance and preserve optionality
- Agility principle—Regulation must be agile and responsive to reap opportunities of a smart, digital economy
- No free-riding principle—Consumers of all types should pay a fair share of system costs

At this stage, the four principles are sufficiently high-level to enable NI policy to be designed without any apparent conflict and their compatibility with various policy options are explored in more detail in Chapter 7.

In NI, devolved energy policy is developed by the DfE and regulation of the energy sector in NI is managed by the Northern Ireland Authority for Utility Regulation (NIAUR or UR). The owner of both the distribution and transmission network is Northern Ireland Electricity Networks (NIEN). NIEN are also responsible for maintaining and developing the distribution network while System Operator Northern Ireland (SONI) runs the transmission system and in conjunction with EirGrid in ROI, the balancing and dispatch of the all-island system in the Single Electricity Market (SEM). Much of the data used in this report for demand and generation capability, as well as scenarios assumptions is based on data provided by SONI.

The population of NI is small compared to neighbouring markets with 1.8m people, which has a bearing on cost recovery considerations in terms of economy of scale for programme admin costs. It also (compared to GB) has low gas penetration, meaning more consumers, especially in rural areas use oil for heating. The economy of NI is relatively small compared to other liberalised energy markets, which is a factor in terms of the credible renewables capacity that could be deployed, and therefore the attractiveness to investors and competitive tension from prospective developers.

[11] Northern Ireland Act 1998 created the devolved institutions in Northern Ireland. This gives legislative control over certain matters (known as 'transferred matters') to the Assembly. The Assembly may also in principle legislate in respect of 'reserved' category matters (e.g. relating the foreshore and seabed). Areas which are not reserved or excepted in the Act is deemed to be devolved and the Assembly has full legislative competence.

Previous renewable energy policy included the Northern Ireland Renewables Obligation (NIRO) support which was successful in driving investment in renewable electricity in NI. Policy for the NIRO is set by the DfE (in alignment with GB) and the scheme is managed by NIAUR which has, through an Agency Services Agreement, secured Ofgem to carry out the day to day operation. NIRO is now closed to new projects.

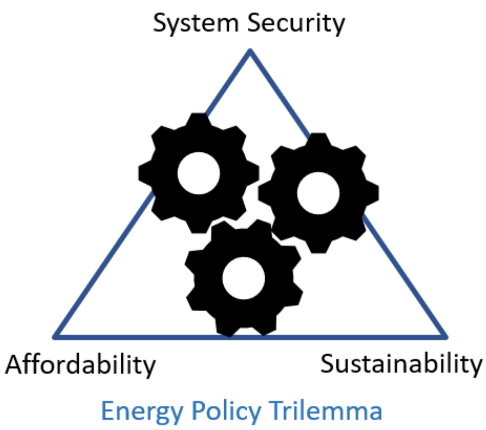
NI accounts for around 4% of all UK carbon emissions targets and much of the source is from agriculture. Due to policies such as the NIRO, NI in 2019 exceeded its 2020 RES-E target of 40% of electricity from renewables as outlined in the Strategic Energy Framework[10]. It is also assumed that any policy support scheme developed in NI must follow State Aid rules as outlined by the Competitions and Markets Authority (CMA). Statistics published by the DfE[1] show that over the 12 month period between July 2018 and June 2019, 44.0% of electricity consumption came from renewable electricity generated in NI.

GB developed the UK CfD scheme in 2014 to progress renewables policy and NI has opted not participate as inclusion would not guarantee deployment whilst leaving the NI customers exposed to the costs. ROI is due to launch the RESS auction scheme in late 2019, which would be similar to the UK CfD scheme. ROI has ambitious plans for meeting its EU renewables targets which as part of the SEM and the shared electricity grid could have an impact on NI.

NI is interconnected to GB through the Moyle Interconnector which connects Antrim and Scotland and has a highly constrained tie-line with ROI. There are future plans to build the North-South Interconnector with ROI which would create a 1500MW link between NI and the rest of the SEM and is due to be commissioned in 2024. It has faced several delays due to public objections, but should it be built, NI could in future also be linked to France via ROI through the yet to be built Celtic interconnector.

To facilitate greater intermittent generation on the network, the system operators both in NI (SONI) and ROI (EirGrid) have been increasing the tolerance for System Non-Synchronous Penetration (SNSP) on the grid, with ROI aiming 90% SNSP by 2030, up from 65% today. There could be implications for both jurisdictions as the grid is shared and impacts could include changes in expenditures on DS3 services in both regions and technical considerations around “min gen” levels when output from intermittent generation sources is high across both regions. There is a lack of clarity regarding alignment of SNSP targets between NI and ROI and as such the impact of diverging SNSP targets between NI and ROI should be carefully considered as part of policy development.

Figure 4. Energy trilemma - balancing security of supply, sustainability and cost



source: Cornwall Insight/Ionic Consulting

Strategic Energy Framework

In 2010 the DfE published the Strategic Energy Framework[10] (SEF 2010-2020) which has aims to “create the relevant conditions for an increase to 40% electricity consumption from renewable sources by 2020”;

and to “publish a Renewable Heat Route Map by March 2011 setting out key actions to achieve a 10% contribution from renewable heat by 2020”.

Renewable electricity policy is considered in the context of the electricity sector “trilemma” of balancing security of supply, sustainability and cost as shown in Figure 4. In terms of the SEF impact, the target to have 40% of consumed electricity coming from renewable sources, i.e. 40% RES-E (or Renewable Electricity Source – Electricity), has been successful. A sample list of documents and actions which have been issued since the publication of the Strategic Energy Framework can be found in Appendix A.

Since the publication of the SEF in 2010, the landscape of the renewable electricity sector has changed in the following ways:

- Levelised costs of electricity (LCOE) have fallen and in many cases are forecast to continue falling (see chapter 6).
- Policies supporting renewables have evolved as lessons have been gleaned from various approaches taken in European and US markets
- The scale of renewable generation required domestically and globally to meet carbon emissions goals remains very large.
- Almost all existing renewable generation will have come to the end of its operational life by the middle of this century, implying the level of required deployment over the coming decades will dwarf that already seen.
- In some cases, policies to encourage investment in new renewable electricity capacity have moved away from provision of direct subsidy. There is a new emphasis on the idea of “subsidy free” projects, especially for technologies such as onshore wind or solar where costs have fallen. Subsidy-free projects generally receive little or no direct financial support from subsidies, though as BEIS mentioned as part of the stakeholder engagement process, the definition of “subsidy-free” can be ambiguous. For some it means no intervention whatsoever, to others it means a small amount of support or non-financial support such as policies to remove barriers to entry. Governments can continue to have a key role to play in encouraging investment, even if subsidies are removed. Examples of this could be in facilitating routes to market (RtM) and will be discussed in Chapter 4
- Network considerations for increasing renewables on the systems will be discussed later in this report and will include maintenance of supply and demand challenges e.g. SNSP, the preferred location of renewables with regards to electricity networks infrastructure (or lack thereof) and public perception, the role of storage for managing differences in generation and demand patterns and additional future demand on the network due to electrification of transport and heat.

Post-SEF Policy

There is currently no energy policy in place to succeed the Strategic Energy Framework. This, and other connected issues, featured in the Northern Ireland Affairs Committee inquiry[8] into the NI electricity sector in April 2016 which focused on:

- Possible generation capacity shortfalls
- The relatively high electricity prices in NI
- Progress on greater interconnection with RoI and GB
- An assessment of difficulties for NI being in the SEM with regards to UK wide energy policy

The committee reported in April 2017 and made the following conclusions and recommendations:

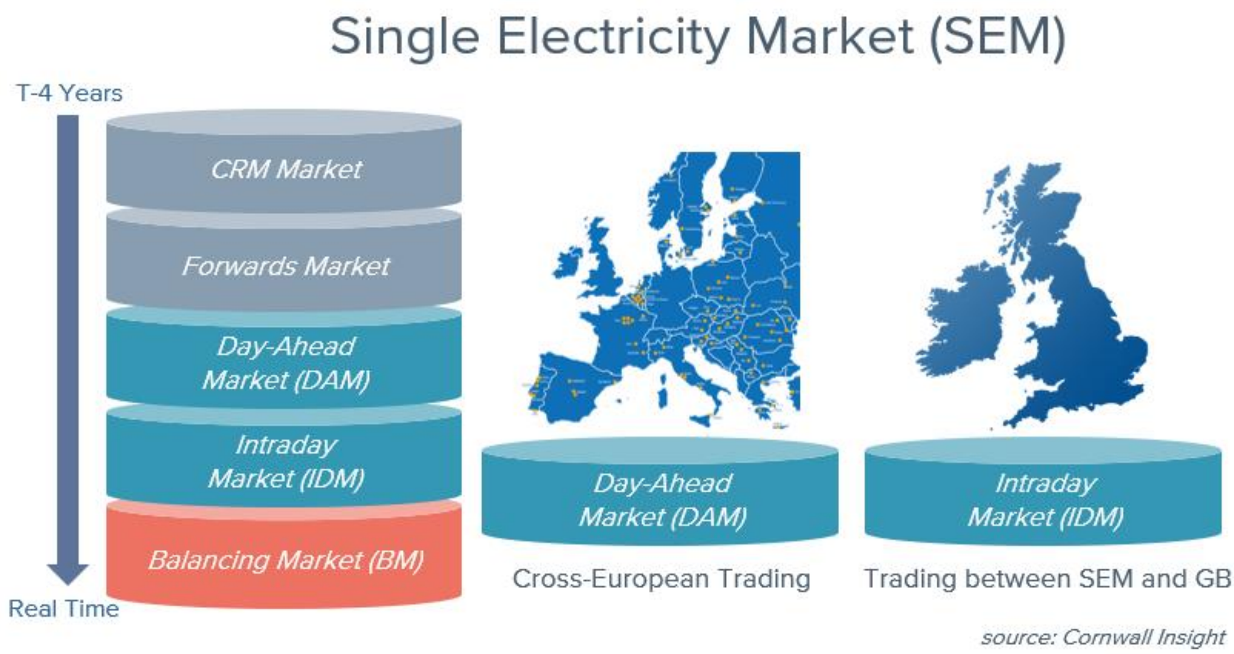
- Relatively high electricity prices for end users were a leading factor in the loss of major employers and difficulty with attracting new foreign investment from energy intensive industries
- Without greater interconnection with RoI’s electricity system by 2021, security of supply risks are exacerbated

- The UK government should be 'more alert' to the impact on NI of UK energy policies, given its participation in SEM. The Committee recommended a 'new, more robust consultative process for electricity policy'
- The Strategic Energy Framework needs to be updated as soon as practicable
- The NI Executive should create a permanent advisory body for electricity policy, with members including large energy users, generators, suppliers, network operators and domestic consumers
- To encourage investment in new generation capacity, to avoid a potential security of supply issue in the middle of the next decade, long-term policy clarity is required
- Further consideration should be given to how electricity network and policy costs fall on domestic and non-domestic consumers, recognising challenges with high levels of fuel poverty and energy intensive sector competitiveness

Points of relevance from the UK government's response to the report[12], issued December 2017, were:

- Reiteration that the UK government is 'committed to ensuring the devolved administrations are fully engaged in the process of planning for the UK's departure from the EU, including with regards to the electricity market in NI'
- Until the NI Executive is restored the Committee's recommendations with regards to updating existing energy policy, creating a long-term vision for policy, and establishing advisory bodies cannot occur, but the UK government will 'continue to advocate for NI's interest'

Figure 5. Markets making up the SEM



3.2 SEM Market

Northern Ireland has been a member of the Single Electricity Market (SEM) since 2007, the first cross-jurisdictional market of its kind in Europe. Additionally, NI shares much of its grid structure with ROI, though

[12] https://publications.parliament.uk/pa/cm201719/cmselect/cmniaf/51/51.pdf

is subject to a major cross-border physical constraint with regards to the network. Currently, electricity is transmitted between ROI across two distribution network cables known as the North-South tie-lines. Plans are in place to build a 1500 MW[13] transmission line from NI to ROI known as the North-South Interconnector which it is scheduled to be energised in 2024, which is discussed in more detail later in this report.

SEM Market and NI Market Competitiveness

On 1 Oct 2018, the SEM market changed from a pool-based structure which had been in place since 2007 to a new, traded market structure under the European Target Model (ETM) which aims to create a pan-European electricity market. The aim of the pan-European market is to create efficiencies on interconnector flows between jurisdictions and lower overall electricity costs for consumers by allowing for greater competition. The plan also aims to improve security of supply, increase transparency and provide cost drivers for system balancing.

The SEM consists of the following markets:

- Day Ahead Market (DAM)
- Intra Day Markets (IDM)
- Forwards market
- Balancing Market (BM)
- Capacity Renumeration Market (CRM)

In terms of NI's ability to compete on a European-wide level, the most relevant markets are the DAM and the IDM. The DAM is a cross-European market whereby generators (and suppliers), including renewables generators, can bid in to sell their power to the highest bidder (who could be a supplier or another generator).

All of these bids feed into the EU + Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA) which then calculates the optimal electricity flows across Europe for the lowest price. An additional cost benefit is an incentive for generators to establish a generation position before the balancing market opens, thus reducing imbalance volumes which ultimately should lead to lower balancing costs for the system.

In addition to the DAM, market participants can trade in the IDM which consist of two cross-border auctions - one SEM-only auction and continuous trading within SEM. At this time the SEM can trade only with GB in the cross-border IDM auctions though as part of the ETM, it is planned that this would eventually be opened up to Europe-wide trading.

The main restriction NI faces in trading competitively in the European markets (aside potentially from Brexit which is covered later in this section) is that NI is part of a market which is an island with only two interconnectors linking it to Europe (both of which are via GB). There are plans in place for two further interconnectors - Greenlink, which will connect Ireland to GB and is scheduled to be energised in 2023, and the Celtic Interconnector between RoI and France, due to be energised in or around 2026. This additional interconnection will allow the SEM to export excess renewable electricity at competitive prices while lowering costs associated with balancing and curtailment (when there is too much intermittent generation on the system). In association with the North-South interconnector, the Celtic Interconnector will create a direct route to Europe for NI's renewable electricity via RoI.

These developments mean that policy which encourages renewable energy development could see long term benefits both from meeting NI's commitments to the UK's climate change targets, as well as being able to trade its power directly into the European markets.

[13] http://www.eirgridgroup.com/site-files/library/EirGrid/North-South-Interconnector-Answering-Your-Questions-(Download).pdf

Physical Constraints in SEM

The North-South tie lines create a significant physical constraint on NI's ability to transfer electricity with ROI. At any one time, NI may only be able to import up to 200 MW across these lines, creating a large constraint in NI. Since the SEM's launch in late 2018, this has had an effect on SEM prices, most notably in the Balancing Market. The most extreme balancing price spike as a result of this was on 24 January 2019 when prices reached €3,774/MWh or £3,280/MWh. On this date, there was very little wind in NI and - as a result of the SEM Day Ahead Market (DAM) - NI was exporting on the Moyle Interconnector. During the day, there was also an unscheduled outage at one of NI's three thermal plant, and the price ended up being set by one of the other NI plant bidding in at a high price. The restrictions through the tie-lines meant that NI was unable to import the levels of power needed for security of supply and so the high bidding plant set the price.

Since this incident, the SEM Trading & Settlement Code (TSC) has been updated to remove locational constraints from the calculation of the balancing price which is intended to prevent a reoccurrence of this type of incident. There have been two particularly high price spikes in the Balancing Market since it went live on 1 Oct 2018, both due to plant trips in NI combined with import restrictions on the North-South tie lines. The new North-South Interconnector should alleviate many of these types of issues as well as allowing NI to benefit from renewable electricity in ROI. However, this project has been beset by delays due to coordinated public objections to the plan. For the purpose of this report, an assumption has been made for the scenarios that the North-South interconnector will be transmitting by 2024, based on validation with SONI. It should be noted that many of the industry participants we have interviewed are not confident that this will be in place by 2024. The North-South interconnector is of essential strategic value to NI, especially as NI has an aging fleet of both renewable energy assets and thermal assets and so should be considered carefully when designing policy.

Brexit Considerations in the SEM Market

The Electricity Target Model (ETM) was designed before the UK-wide vote to leave the EU in 2016, commonly referred to as "Brexit". As part of the UK's departure from the EU, certain goal posts have shifted with regards to the SEM market. There is an expectation that, under a Brexit deal, NI will remain in the SEM and the UK will continue to trade in the EU as before, without any additional tariffs. There is also an expectation that although the UK will leave the EU Emissions Trading Scheme (EU ETS), there will be a carbon price developed which will track the EU ETS prices. It is the preference of UK Government to "securing a linking agreement with the EU for a linked EU ETS", as articulated in the recently closed "Future of UK Carbon Pricing"[14] consultation. Were the UK to develop a carbon price which does not do this, there would be a risk of two carbon prices appearing in the SEM, one for ROI and one for NI. The risk of this is the reason that NI did not join the UK Carbon Price[15] floor scheme in 2013.

Difficulties could be created for NI in the SEM in the event of a "no-deal Brexit". BEIS has issued guidance that a new UK-wide carbon price would be created based on a fixed rate, and would not track the EU ETS. This risks creating two carbon prices within the SEM market, a reason as to why NI did not join the UK Carbon Price Floor in 2013. We strongly advise that the DfE clarifies this position with BEIS and considers what impact a dual-carbon price in the SEM could cause, especially as on 11 July 2019 BEIS has stated that any such carbon tax would be implemented on 4 Nov 2019[16] in the case of a no deal. That said the UK Government has stated it remains committed to maintaining the SEM on the island of Ireland and understand the importance of carbon pricing to this market. In a "no deal" scenario the UK will aim to ensure that carbon pricing does not hinder the effective operation of the system[17].

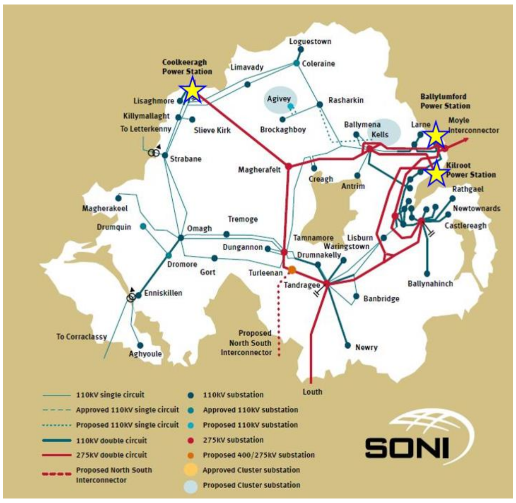
[14] https://www.gov.uk/government/consultations/the-future-of-uk-carbon-pricing
[15] https://www.gov.uk/government/publications/excise-notice-ccl16-a-guide-to-carbon-price-floor/excise-notice-ccl16-a-guide-to-carbon-price-floor
[16] https://www.gov.uk/government/publications/carbon-emissions-tax-technical-note
[17] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/790896/Carbon_Emissions_Tax_-_Technical_Note.pdf

Another consideration in a "no-deal Brexit" event regards tariffs on gas. Currently, ROI imports much of its natural gas from GB as part of the single market. However, should the UK revert to World Trade Organisation (WTO) rules, it is likely that tariffs would apply to ROI which do not apply to NI, again creating dual prices in the SEM market. Clarification on this from the relevant UK body on the likelihood of gas tariffs should be sought by the DfE.

3.3 NI Electricity Landscape

In this section we provide an introduction to the physical electrical infrastructure in NI including the grid and fossil fuel and renewable assets in terms of capacity and lifetime. Figure 6 shows SONI's map of the distribution and transmission network in NI as well as the location of significant generation assets on the system including the three plant pivotal to system security and inertia on NI's network, Coolkeeragh, Kilroot and Ballylumford (indicated with yellow stars on the figure).

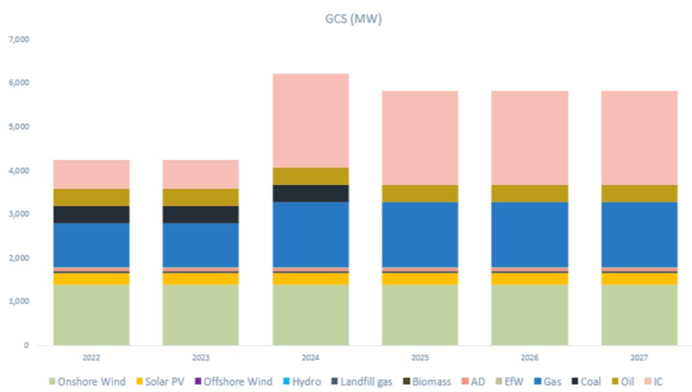
Figure 6. Northern Ireland transmission and distribution network map. The three main thermal plant are highlighted with yellow stars.



Per SONI's 2018 Generation and Capacity Statement (GCS18)[4], the capacity in 2022 of each of these plant under the median scenario are forecast as follows:

- Coolkeeragh (oil and gas units) ~ 460 MW
- Kilroot (coal and oil units) ~ 540 MW
- Ballylumford (oil and gas units) ~ 709 MW

Figure 7. Renewable energy generation mix per SONI's 2018 Generation Capacity Statement (18GCS).



source: SONI & Cornwall Insight

These plant would have a combined capacity of 1.7GW, approx. 1GW of which is gas. Note that the GCS gives the non-derated capacity which means that adjustments have not been made for plant availability over an annual period.

According to the GCS18, Kilroot coal is due to close in 2025 which will leave a combined capacity of 1.3 GW between the three plant. A new 480MW Combined Cycle Gas Turbine (CCGT), Belfast Harbour, has received planning approval and is due to be energised in the mid- 2020s (although the date is not yet confirmed we use the assumption for the model that this will be in 2024).

NI also has a 500 MW interconnector with GB and has limited interconnection with ROI. Plans are in place to build a new “North-South Interconnector” for better connectivity with ROI, which is discussed later in this section.

As part of the SEF targets, NI has been very successful in meeting its renewables obligations and in 2019 exceeded its 2020 target of 40% of electricity consumption to come from renewable generation sources. Statistics published by the DfE show that over a 12 month period between July 2018 and June 2019, 44.0% of electricity consumption came from renewable electricity generated in NI. Most of this renewable electricity in NI is currently provided by onshore wind, as indicated Figure 7.

The closure of the NIRO program in 2016 (see Chapter 4 for a review of the NIRO) without a successor means that the projected increase of renewables in the median scenarios of the GCS18 is minimal. The figures for renewable capacity stands at approx. ~1.8GW. Conventional generation is set to increase to ~2.3GW in 2024 due to the opening of Belfast Harbour, though with the closure of Kilroot’s coal capacity this would drop to 1.8GW in 2025. If the 1500GW North-South interconnector is energised in 2024, this will give a combined interconnector capacity of ~2.1GW.

A programme rolled out across the SEM market called DS3 aims to facilitate increased intermittent electricity on the grid. Management of the grid by the system operators has meant that the grid can now manage 65% system SNSP or non-synchronous penetration (i.e. intermittent generation) and it is expected to be able to manage 75% by 2020. Additionally, ROI has ambitions to increase this to 90% by 2030 and the system operator EirGrid is undertaking a series of initiatives under DS30[18] and Flextech[19] to deliver this target. Cornwall Insight and Ionic Consulting are not aware of discussions having taken place as yet by policy makers or system operators between both jurisdictions as to the impact of this ambition from a policy of system perspective.

Security of Supply

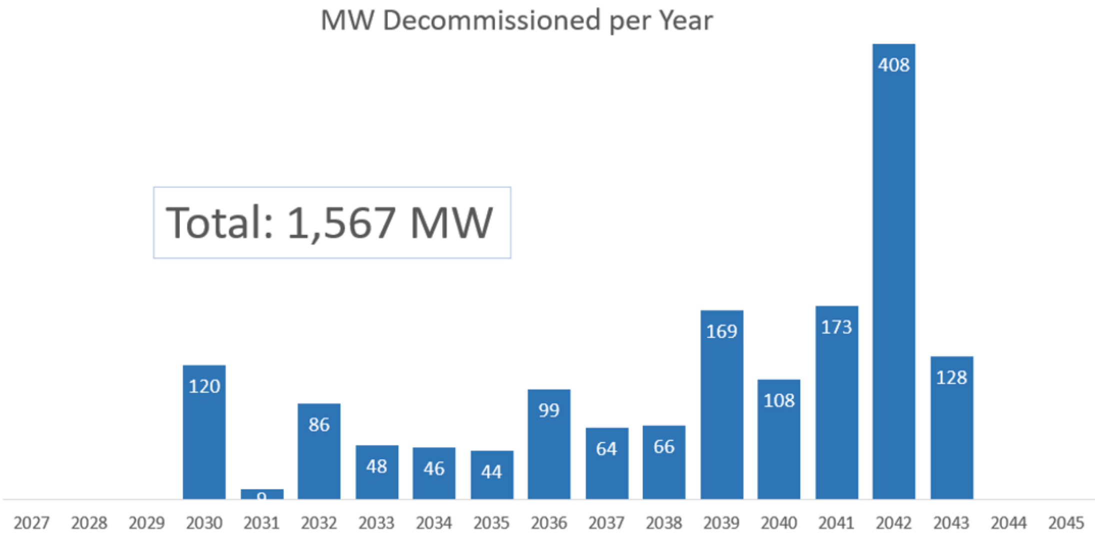
According to the median scenario in the GCS18 statement, the (non-derated) capacity of deployed renewables in 2027 will be 1,756 MW. Taking NIRO data from Ofgem and assuming a lifetime of 25 years from date of accreditation, the volumes of renewables due to be decommissioned were calculated as shown in Figure 8. These assets start to come to the end of their life in approximately 2030 and the total capacity of these NIRO projects decommissioned between 2030 and the mid-2040s is 1.6 GW. This represents 89% of the total renewable assets capacity in 2027 and approx. 40% of NI’s overall generation capacity (not including interconnectors or tie-lines).

This figure indicates that without significant investment, NI stands to lose a significant amount of renewable assets, which represents a considerable proportion of its generation assets overall. This could represent a serious security of supply issue, especially if the North-South interconnector is not built by 2030. Even with the interconnector, NI would be extremely dependent on interconnection in a way that may not be sustainable. Issues with security of supply could lead to emergency interventions on the part of the government such as commissioning new thermal plant which could lead to significant costs to consumers as well as moving in the opposite direction from UK carbon emissions policy.

Security of supply formulates one of the cornerstones of the energy “trilemma” (Figure 4) and it must be considered as to whether market forces alone can resolve this risk.

[18] DS30 refers to the programme and system services required to meet renewable integration targets to 2030.
[19] FlexTech is EirGrid/SONI’s Flexible Technology Integration Initiative is a platform to engage with industry with the objective of removing barriers to renewable integration (e.g. through use of DSM and battery storage).

Figure 8. Assuming a 25-year lifetime for renewables assets, dates and volumes of renewables due to be decommissioned



Source: Ofgem, Cornwall Insight

4 Policy and Supports

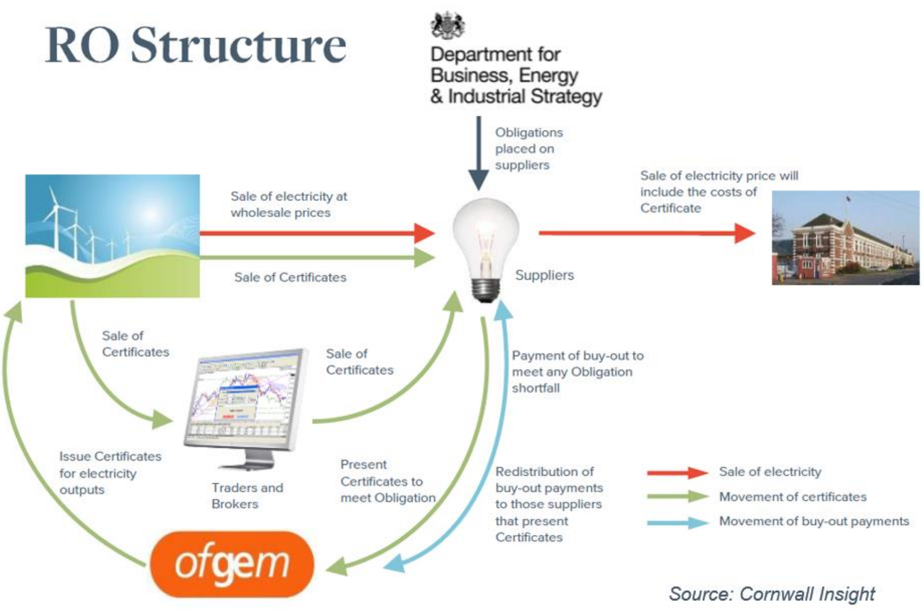
From the perspective of policy makers, driving investment in renewable electricity can be a balancing act between creating enough support to encourage investment while at the same time reflecting the lowest cost option to the consumer. Over the past few decades several different support types have been developed in Europe and elsewhere which have had different consequences with regards to the type and scale of renewables assets deployed and from which both positive and negative lessons can be learned. This chapter provides an overview of the main types of supports available (including no support) and the advantages and disadvantages for investors, policy makers, consumers and community energy projects with each. In exploring each of these supports, NI's position is considered taking into account UK policy, membership of the SEM and other factors such as cost to consumers and socialisation of those costs.

The chapter commences with a high-level review of the NIRO support and its impact on the deployment of renewables assets in NI. This is then followed by a discussion of some support and policy options open to the DfE and includes case studies of other small economy countries. There is also a discussion on the role of investors and what they look for when considering investment cases.

4.1 NIRO Review

The vast majority of renewable electricity projects in NI are supported under the Northern Ireland Renewables Obligation (NIRO). This scheme is classified as a Green Certificates scheme and follows the same structure and administration as all UK Renewables Obligation (RO) schemes. (England and Wales' version is the RO, Scotland is the ROS and Northern Ireland has the NIRO). ROs including the NIRO are structured as shown in Figure 9. NIRO policy is set by DfE and administered by Ofgem (on behalf of the Utility Regulator in NI).

Figure 9. Structure of UK Renewables Obligations (ROs)

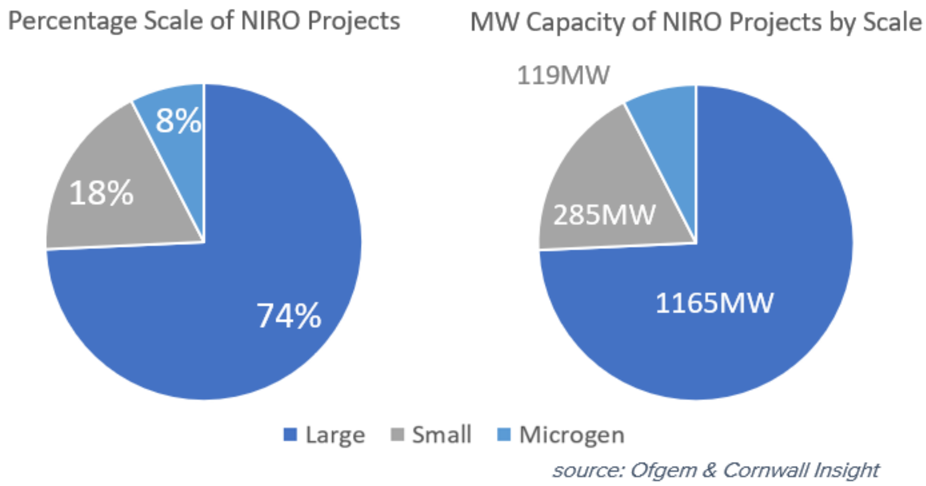


- The NIRO commenced in NI in 2005 and was closed to all technologies on 31 March 2017, with exceptions in the form of grace periods. The last grace period for the NIRO (for small scale onshore wind) ended on 31 March 2019 and projects are due to begin rolling off NIRO support from 2027 onwards.

- There was a high uptake of the NIRO by generators, including a large proportion of small (50kW to 5MW) generators and microgenerators (sub 50kW projects) since NI did not have a FiT scheme for small scale generation similar to that in GB.

Based on data from Ofgem[20] there are currently 1570MW of NIRO projects in NI. Figure 10 shows that 74% of these projects are large scale (projects greater than 5MW) and have a combined capacity of 1165MW. Small scale projects (with capacity less than or equal to 5MW but greater than 50kW) comprise 18% (285MW) of the projects and 8% (119MW) are microgeneration projects.

Figure 10. Proportion of NIRO projects by scale



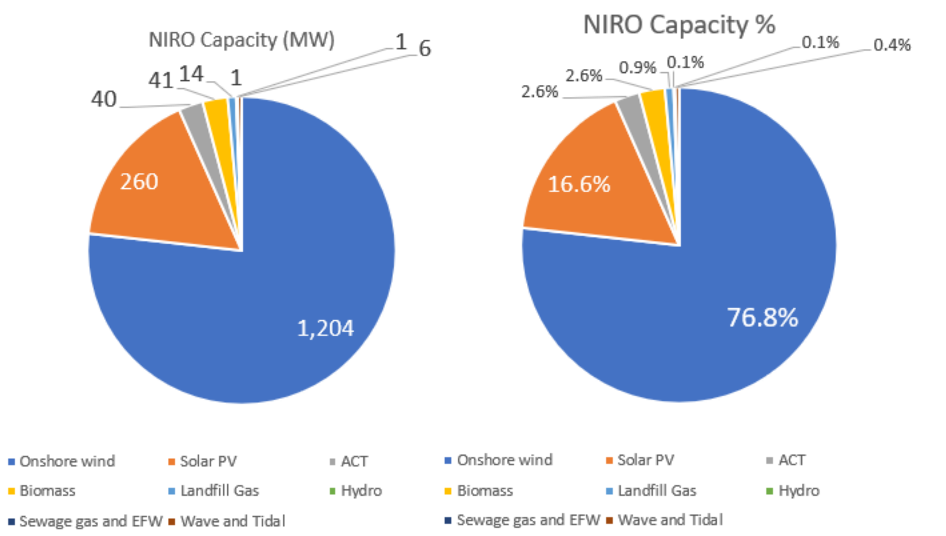
Technology Diversity & Scale

- The vast majority of developments were for onshore wind comprising 76.8% of projects as shown in Figure 11, followed by 16.6% for solar and ACT (ACT stands for Advance Conversion and in this analysis, AD is included with ACT) and biomass at 2.6%. As will be outlined in section 5.1 when discussing outcomes from the stakeholder meetings, onshore wind and AD are the technologies receiving the majority of public complaints, whereas solar has been more readily accepted. Part of this could be due to the relatively low deployment of solar to date compared to onshore wind but is probably also influenced by its low visible profile. Public acceptance is an important consideration for policy makers, and it is interesting to note the higher levels of deployment of solar relative to AD, but the greater levels of opposition to AD.
- The relatively low cost of onshore wind has been one reason for its higher levels of deployment in many European countries. As already explored in the Executive Summary the forecast LCOE of several technology types is set to decrease over the next decade and solar LCOE is set to converge with onshore wind by 2030 at a forecast price of £44.86/MWh (which represents a drop of 31% on today's costs)
- These factors suggest that onshore wind and solar will continue to dominate new renewables deployment in the coming decade which is something to be considered by policy makers who may wish to encourage diversity of projects with regards to technology type and scale. Onshore wind and solar are also the most likely contenders for viability as purely merchant projects and under these circumstances, large investors may have a competitive advantage in financing projects, which also could have implications on the scale and types of projects. Any policy decision (or no decision at all) will have an impact on the scale of projects being developed. In order to meet NI's renewables targets, large scale

[20] https://www.ofgem.gov.uk/data-portal/overview

projects would seem to be the most efficient, although there can be challenges regarding public acceptance of onshore wind, AD and potentially offshore wind.

Figure 11: NIRO projects by technology



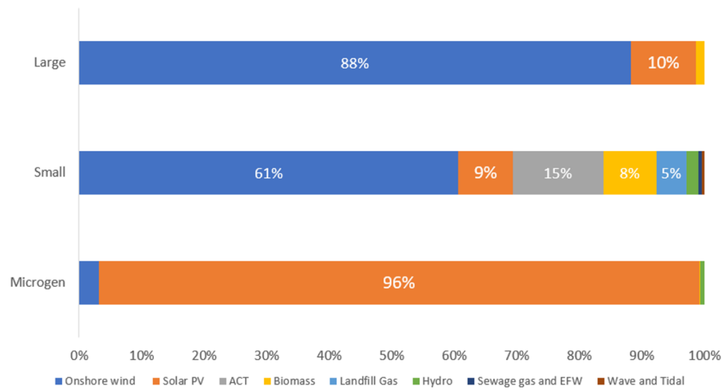
source: Ofgem & Cornwall Insight

- As indicated in Figure 12, large scale projects are dominated by onshore wind, and a large proportion of small scale projects are also onshore wind developments. Some council areas are indicating that they will start to restrict onshore wind in their jurisdiction as they feel they are saturated by small scale onshore wind developments.
- The vast majority of microgeneration projects are solar, as there was a large uptake of solar PV for residential homes under the NIRO. An unintended consequence of this was large levels of behind the meter intermittent generation[21] representing "invisible load" which creates difficulties from a system balancing perspective for the system operator.
- A consequence of NIRO has been the sporadic nature of small developments. Many of the stakeholders we spoke to mentioned that small scale onshore wind turbines appeared all over the countryside as a result of NIRO. Aside from the impact these renewable assets have on the landscape and local communities, it should be considered if smaller scale projects are likely to deliver enough renewable electricity capacity to meet the policy makers' targets.
- That said, large scale projects may be more effective, but consideration should be undertaken regarding location and grid accessibility. For example, establishing large scale onshore wind projects in the northwest region where the best wind resources are located may raise challenges due to the sparse grid infrastructure, as well as the presence of several Areas of Outstanding Natural Beauty (AONB). However, having such developments closer to urban areas could also create issues such as maintaining sufficient clearance to dwellings to avoid noise and shadow flicker impacts.
- Based on the stakeholder engagement process NIRO was considered very successful from the perspective of increasing renewables capacity and meeting NI's 2020 renewable electricity consumption targets. Commercial interests especially emphasised that having good policy creates investment in that space and that the renewable consumption targets outlined by the NI Executive drove the activity. The NIRO was due to close to all technologies on 1 April 2017 however the scheme closed to new onshore wind accreditations in 2016 to align with the early closure order for onshore wind under RO in the rest of

21 https://mie.umass.edu/sites/default/files/mie/faculty/baker/3.Unintended%20Consequences%20Electricity%20Journal.pdf

the UK. The main points of negative feedback from stakeholders we engaged with concerned this early discontinuation of the NIRO as some projects were left in limbo. There were grace periods for projects introduced to address the early closure but the situation created some investment uncertainty, especially for projects that did not meet grace period criteria. Additionally, the scale of projects had an impact on public perception and on managing the grid due the high levels of small and microgeneration. As policy makers formulate future energy strategy, there are lessons to be learned from NIRO regarding scale of projects, technology diversity and grid impacts.

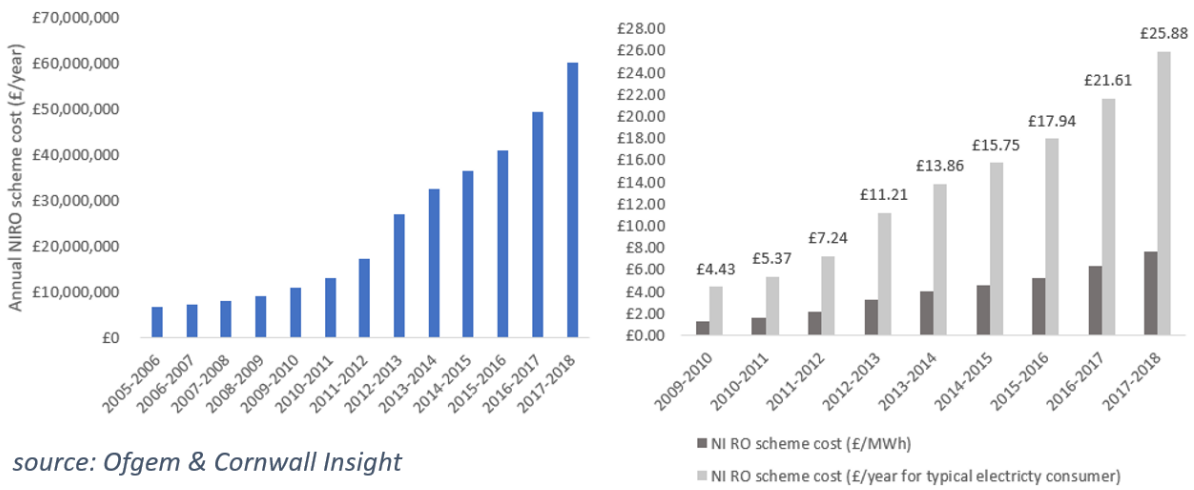
Figure 12. NIRO projects based on size and technology



source: Ofgem & Cornwall Insight

The costs of the NIRO scheme are socialised across all UK customers which means that the NI customer does not have to bear the cost on their own. Figure 13 shows the cost of the scheme per year since 2005. The cost to the Northern Ireland consumer is also shown in terms of the amount paid per MWh of renewable technology (£/MWh) as well as the overall cost per year for the typical electricity consumer.

Figure 13. Costs of NIRO to NI consumers



source: Ofgem & Cornwall Insight

The left-hand figure indicates the annual cost of the NIRO per period since the scheme was first launched in 2005. The right-hand figure shows the cost per MWh generated since 2009. The values in £/MWh are comprised from the average value of a ROC during that period, i.e. the buy-out price (£/ROC), times the ROCs/MWh which is the number of ROCs issued in a year.

4.2 Potential Investment Environment

Before going into detail of the different types of options open to policy makers it may be helpful at this stage to explore the potential investment environment from the perspective of investors. We start with an analysis on the way investors think when making a business case for development and the factors that they will be considering.

This is followed by a discussion of the route to investment for new projects under where no subsidy is provided, so called "subsidy-free" projects such as merchant build or under Corporate Power Purchase Agreements (PPAs).

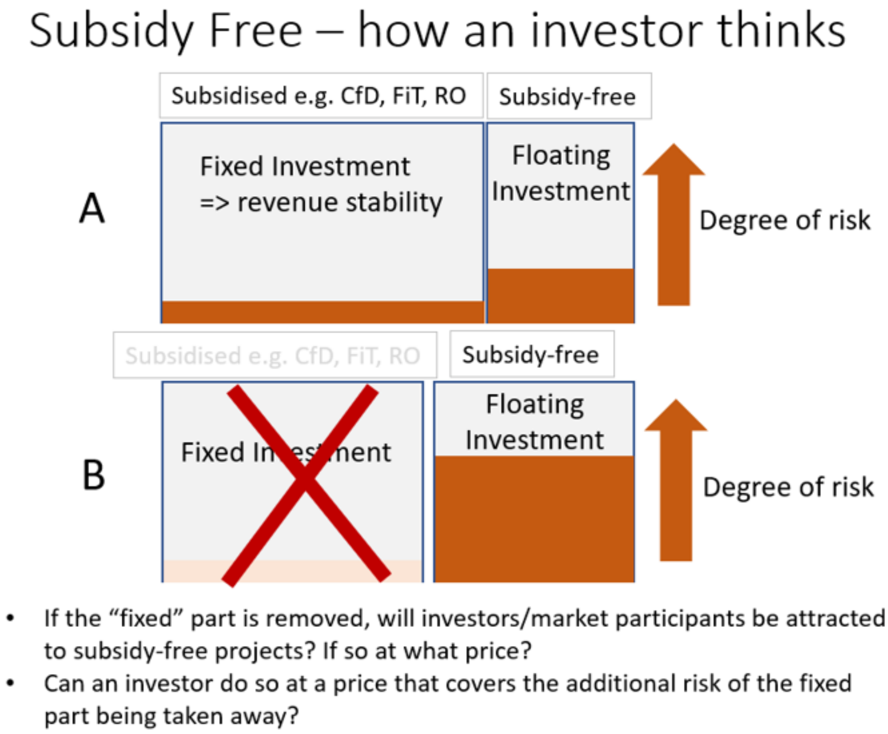
How an Investor thinks…

When an investor is considering development of a project, generally there are two main factors they consider. They have to consider the projected revenue stream of the project, and weigh that up against the risk of the project. There are many elements to consider with both of these factors, and what follows here a high-level walk through of some of these elements.

For making investment decisions, investors have the following considerations:

- Generally, investors prefer long-term certainty of revenue with lowest possible risk
    - Their appetite for risk can be based on many factors including access to credit and capital, the culture of the company, their already existing portfolio in a given jurisdiction and their understanding of the market
- Investors gain confidence in environments with long term, stable policies and regulatory frameworks, as well as stable market and political conditions
- Many renewables projects are invested in by financial institutions, such as banks and pensions funds who favour long-term low risk/yield projects
- On a global scale, NI is considered a relatively small market which could be considered a higher risk for smaller investors who cannot necessarily spread that risk across a large global portfolio. Therefore, it is likely that in the Baseline scenario, larger, rather than smaller investors would be funding any new developments
- Investors are more likely to be interested in shorter term revenues with higher risk/opportunity if they are able to stabilise a proportion of their revenues using a predictable, stable and low risk option (e.g. a government backed subsidy). This is similar to, for example, a blended mortgage whereby a customer may opt to fix 80% of their mortgage at a fixed rate of interest and float the other 20% at a variable rate in the hope that the risk on the variable can be covered by the stability of the fixed element
    - Figure 14 shows a high-level example of this concept. Option A outlines the case whereby an investor is considering a subsidy-free project in a jurisdiction whereby they already have assets under subsidy. In this case, the degree of risk associated with the subsidy-free or "floating investment" is spread across the existing subsidised or "fixed investment"
    - Option B indicates the case whereby there are no subsidised assets owned by the investor in the jurisdiction. Therefore the risk due to the subsidy free "floating investment" is much higher. New entrants to the NI market who do not already have a NIRO project, would come under category B, and would require large capital and credit reserves to consider such a project
- There is a view that withdrawing government support (creating a subsidy-free environment) allows for greater innovation from investors, thus allowing market forces to drive investment. This element will be considered in our analysis and what options and outcomes may be associated with it

Figure 14. High level schematic of investor mentality to risk in jurisdictions with and without subsidies



Source: Cornwall Insight

Investors and Policy Options – subsidy free

The options for developing projects in a subsidy-free environment involve pure merchant projects and corporate PPA projects. Although pure merchant projects are in existence both in the UK and Ireland, they are relatively rare, especially with regards to new build projects. Most merchant projects involve assets which have come out of subsidy support and have paid off much of their capital loans, allowing them to operate more competitively in the market than new build. Factors influencing purely merchant projects include:

- LCOE of renewables technology. The projected decrease in renewables cost in the coming years means that some projects may be more affordable without a subsidy. This may be especially true for solar, and to some extent for fixed-base offshore wind
- Projections of the impact of renewables on wholesale prices. Generally, renewables tend to put downward pressure on wholesale prices (price cannibalisation), which impacts the forecast revenue return from models. Although under the Baseline scenario there is not an expected increase in renewables in NI over the next decade, there is an expected increase in the SEM overall due to ROI's ambitious carbon targets. This could have an overall impact on the wholesale price, which is a key element under consideration by investors
- There is low investor certainty and a high amount of risk associated with subsidy free projects. Additionally, investors will be considering the risk of price volatility in the SEM, which - although expected to be mitigated to a degree by the new North-South interconnector (since the North-South constraint has driven much of the volatility) - is still a factor in their revenue models at present with the newness of the SEM market
- Direct consumer cost is lowered by subsidy-free schemes in that there is little or no direct levy applied to the customer to fund the scheme. That said, costs which are recovered the wholesale market can be passed onto customers indirectly in their electricity bills, especially in a situation whereby investment in

generation assets stagnates, leading to higher overall electricity costs. This needs to be considered under the different policy options, whereby taking no action on policy could create an environment in which consumers end up paying more than with a competitive auction process, for example, especially if the correct balance is not found between encouraging companies to innovate and discouraging investment in new deployment. In most European countries, subsidy-free projects are found alongside subsidised projects (as mentioned in the previous section) and may be developed in the following scenarios:

- Expiration of subsidy: Projects which had a subsidy but have now come out of that subsidy, e.g. NIRO after 20 years. Many of these projects will have their loans paid off and can continue as pure "merchant" projects until the end of operating life
- Repowered: Projects which are being repowered – often the loans on the initial project/connection costs are paid off, reducing the capital cost of the project, which may be able to operate subsidy free
- Pure merchant: High risk investors may see an opportunity to develop a pure merchant project without any government support
- CPPA: Some investors enter a corporate Power Purchase Agreement (CPPA) with a large energy user who wishes to procure "green energy" and an offtaker who provides a route to market for excess power generated or sources electricity from the market if there is a deficit (e.g. because the wind is not blowing). More detail on CPPAs in NI can be found in Appendix C.

4.3 Overview of Support Options

In this section we examine different types of support programmes to encourage investment in renewables generation, including no support in the context of Northern Ireland. The supports are considered against various criteria including competitiveness, type and scale of deployment, compatibility with UK policy and the SEM, cost to consumers, State Aid Approval and community developments and are summarised in Table 2.

Since electricity markets were privatised and retail market liberalised across Europe (and elsewhere), there have been many support schemes introduced to incentivise the deployment of renewables. Although each market jurisdiction where schemes have been introduced will have their own unique parameters, at a high-level there are a limited number of support scheme design structures. The key differences can be boiled down to the trade-off between scheme design introducing competitive tension when awarding support (ultimately to keep cost to consumers as low as possible) and scheme complexity (which impacts on set-up and administrative costs and level of deployment).

For well-established support mechanisms such as tradeable green certificates, tendered contracts and Feed-in-Tariffs and Contracts for Difference schemes, we consider the advantages and disadvantages of various types of support from the viewpoint of the investor, the policy maker, the consumer and community development. We also examine other options, which are not support (i.e. subsidy) programmes per se, but mechanisms that could reduce barriers to market and lowering of investment barriers.

The support schemes discussed here are:

- Tendered Contracts
- Feed-in-Tariffs
- Contract for Difference schemes
- Tradeable green certificates
- Routes to market/ Alternative Support
- No Policy Intervention

Table 2. Overview of policy options, advantages and disadvantages from the perspective of different industry participants

Support		Investor	Policy Maker	Consumer	Community Energy
Tendered Contracts	Pros	• Long term revenue • underwritten by consumer	• can target scale/tech • minimise costs • UK policy compatible • straightforward admin • compatible with State Aid	• long term cost certainty	• possible if process simple
	Cons	• risk of 'winners curse'	• challenges with SEM • challenges with UK policy • NI customer only pays	• cost could be higher due to wholesale price volatility • NI customer only pays	• could be complex
Feed-in-Tariff (FiT)	Pros	• long term revenue certainty • predictable changes to FiT rates/capacity caps • good for small projects	• UK policy compatible • can make case for State Aid approval • SEM compatible	• predictable long term costs	• accessible due to simplicity and payment guarantees
	Cons	• if only for SMG, not of interest to large investors	• risk of unchecked deployment • challenges with SEM • challenges with UK policy	• high costs though have reduced significantly in recent years	• could be complex
CfD Scheme	Pros	• Long term revenue certainty	• Can target scale/tech • UK policy compatible • SEM compatible • State Aid Approval compatible	• low costs compared with other schemes • predictable costs	
	Cons	• risk of 'winner's curse' • no guarantee of success • less accessible to small investors	• high admin costs • no guarantee of deployment (in UK/SEM wide scheme) • hard to compete with larger economies • would require legislation changes to set up e.g. LCCC type bodies	• NI specific version costly • no guarantee of deployment (in UK/SEM wide scheme)	• likely to be complex
Green Certificates	Pros	• long term support • straightforward accreditation	• SEM compatible • can adjust future costs	• high costs though have reduced significantly in recent years	• likely to be complex for small schemes
	Cons	• less revenue certainty than other schemes	• not competitive, though could make case for State Aid -risk of over-renumeration • risk of one size fits all approach • difficulty matching policy with rate of change of industry • high admin costs	• high costs if wholesale prices high • suppliers passing costs to consumers • high costs though have reduced significantly in recent years	
Route to market/Alternative Support	Pros	• depends on design • innovative offerings could have a competitive advantage	• depends on design (wide scope) • potentially lower cost --> market driven activity • potential for "quick wins"	• could be lower cost than formal supports	• depends on design
	Cons	• could be lack of revenue certainty to offset risks/market volatility	• may require legislative changes (e.g. grants, tax exemptions) • could require innovative thinking	• risk of low deployment	• could be inaccessible
No Intervention	Pros	• predictable	• low admin cost	• low direct cost to consumer	
	Cons	• full exposure to wholesale price risk	• risk of expensive intervention required for security of supply • not UK policy compatible • SEM challenges if mismatched ROI & NI renewables targets ' • security of supply risk	• risk of expensive intervention required for security of supply	• unclear path

Tendered Contracts

This support scheme design offers developers the opportunity to enter into a contract that guarantees an agreed payment for electricity generated. The contracts are offered on a competitive basis and specific renewables deployment could be targeted, for example by type of technology, capacity/ output and location (e.g. depending on local network considerations).

Contracts could be offered based on a volume (i.e. MWh/year) or capacity basis (MW) for specific renewables deployment, and typically pay-out on fixed price per kWh (which would be established via the competitive contract award process).

- Costs are typically recovered from consumers via a supplier obligation levy
- Community participation would be possible, provided that the process for applying is simple, or is being operated to specific scales of development (e.g. different 'lots' of contracts could be offered to community developers, with simpler award arrangements)
- An example of this kind of scheme is the Non-Fossil Fuel Obligation (NFFO) which operated across the UK in the 1990s. In NI, the NFFO was relatively small as it supported only 40MW and all costs were recovered via NIEN, as there was no competitive retail market at that time. The costs lapsed from the PSO in 2013/2014 and were applied to Power NI, given the change in market structure.

Advantages

- **Investor:**
  - Attractive as they provide long-term revenue certainty (typically) without exposure to volatile wholesale market prices
  - Support costs are underwritten by the consumer
- **Policy Maker:**
  - Specific technology/scale of deployment could be targeted
  - Competitive award of contracts should keep consumer costs to a minimum
  - Similar to the NFFO scheme, which has already operated in NI
  - Could be compatible with the UK "market principle" if payments to contract holders are referenced to wholesale market prices in some manner, but could undermine investor confidence (in revenue certainty)
  - Aside from reconciliation (outlined below), administration is relatively straight forward, but would be more complex where payments to contract holders is not a fixed/ known price.
  - Could most likely make a case for State Aid approval based on Northern Ireland's position regarding ability to recover costs from customers.

- Consumer:
  - Long-term certainty of support costs (and cost to the consumer)
- **Community**
  - Community participation would be possible, provided that the process for applying is simple, or is being operated to specific scales of development to avoid larger, well-resourced utilities crowding out smaller investors/ schemes.

Disadvantages

- **Investor**
  - "Winners curse" whereby in an attempt to win contracts, the developer bids lower than the value return on the asset. This could lead to lack of deployment. This was an issue with the NFFO,

however, the environment around technology costs and reliability and supply chains have improved since the 1990s - which should mitigate against this risk.

- **Policy Maker:**
  - Where payments to contract holders differed from SEM prices, financial reconciliation would be required which could create additional administrative burdens
  - Could conflict with the UK "market principle" if prices are fixed and not referenced with the underlying wholesale market prices
  - Costs likely to be recoverable from NI consumer base only.
- **Consumer:**
  - Costs to consumers could be higher than with other schemes, especially if wholesale prices are high and if costs cannot be socialised across the UK or SEM.
- **Community:**
  - Scheme design could potentially be too complex for community groups or favour larger developments due of economy of scale.

Feed-in-Tariff (FiT)

Feed-in-Tariffs (FiT) are a widespread form of renewable energy support. FiT schemes typically feature administered payments for generation and possibly export, based on technology and capacity. Although payment rates (a.k.a. the FiT) are usually set centrally, they are typically set at a level deemed necessary to make a reasonable rate of return. The traditional Feed-in-Tariff type scheme was designed for non-mature technologies and was not market linked. However in recent years they have evolved into a more sophisticated structure with a market price link and premium and are more competitive. Examples of these more sophisticated types of arrangements are the UK CfD and ROI's RESS. For clarification in this document, these newer structures shall be termed Feed-in-Tariff Premiums whereas traditional Feed-in-Tariffs such as the GB FiT and the ROI REFIT schemes will simply be referred to as Feed-in-Tariff schemes.

State Aid guidance now tends to rule out traditional FiT programmes as they lack competitive tension to reduce cost to consumers, but schemes aimed at smaller scale developments may be possible where the cost of introducing schemes that do create a competitive dynamic, are deemed to outweigh the benefits. It should be noted

Advantages

- **Investor**
  - Long-term revenue certainty with potential for no/ limited exposure to wholesale market volatility
  - Where scheme design allows for a degree of certainty regarding changes in FiT rates and capacity caps, this can reduce barriers to investment
  - For small scale projects which do not need to participate in the SEM Balancing Market, this could be an attractive route to the market for investors
- **Policy Maker**
  - Compatible with UK policy, since this approach would be similar to the small-scale FiT scheme introduced in GB in 2010, and from which valuable lessons could be learned. The GB FiT scheme closed in 2019, in part due to significant drops in the cost of solar which made the scheme financially less competitive and started to represent less value for money to consumers.
  - For small scale activities e.g. sub 10MW projects, case can be made for State Aid approval since small/ microgeneration (SMG) projects may not reasonably be expected to compete in the wholesale market
  - Because SMGs are exempt from participating in the SEM balancing market, setting the reference price could be relatively straightforward compared to, for example, the REFIT scheme in ROI

whereby balancing risk has to be incorporated. Linking the reference price to balancing increased costs to the generators, creating more difficulty with investment.

- **Consumer**
  - Predictable long-term cost to be recovered via the supplier
- **Community**
  - Readily accessible by community developers due to simplicity of scheme design and guarantee of payments

Disadvantages

- **Investor**
  - If scheme is only for SMG, then unlikely to be of interest to large investors

- **Policy Maker**
  - Unchecked deployment could create potential for higher than forecast levels of SMG onsite/behind the meter generation, resulting in undesired cost distribution aspects as well as encouraging "invisible load" issues. This could be dealt with by introducing scale or technology based "caps"
  - Could require financial reconciliation where FiT rates were different from SEM prices.
  - Could conflict with the UK "market principle" as prices would be set by government, but could be offset by scheme design parameters that adjust FiT rates in line with deployment rates
  - FiT schemes are not considered compatible with SEM, as generators receiving FiT are guaranteed a price for their output, which leaves them little incentive to respond to wholesale electricity prices.
  - If costs were only recoverable by NI customers, as would be the case in an NI only FiT scheme, this would be of concern to policy makers.
- **Consumer**
  - Although NI rejected joining the GB FiT scheme in 2010 due to there being no appropriate legislative vehicle and the costs being considered too high, technology costs have dropped considerably since then, e.g. GB FiT rates for household solar were approximately 45p/kWh in 2010, compared with less than 4.5p/kWh by the close of the GB FiT in 2019. An assessment could be considered to see if the costs in 2019 have decreased sufficiently to allow a re-evaluation of the viability of a FiT scheme in NI however with the closure of the GB FiT, it is likely the NI customer would have to bear the cost instead of it being socialised across the UK.
  - Fixed FiT schemes are considered to have high costs to consumers relative to other schemes due to support rates being set by government (or other central authority) without competitive pressure used to discover rates.
- **Community**
  - Scheme design could restrict deployment where application and/ or payment processes are complex.

Contract for Difference schemes (CfDs)

Contract for difference schemes (CfDs) attempt to blend the benefits of a FiT (e.g. revenue certainty) with competitive dynamics (to keep supports levels, and therefore consumer costs, as low as possible). They provide additional revenue (a premium) to generators above the wholesale market price where the latter is deemed insufficient to make projects viable. Most recent schemes will cap this premium at a level that ensures generators are not over-rewarded and consumers costs are no higher than necessary to make the investment viable.

Examples include the GB Contract for Difference and ROI's new RESS scheme. They are based on a two-way CfD between the generator and a counterparty, whereby the price received by the generator for their output will be topped up to a 'strike price' (which is determined through auctions and expressed as a payment for volumes generated) where the market reference price is below the strike prices. Where market reference prices exceed the strike price, the generator returns to the counterparty revenues above the strike price. In the GB CfD the counterparty is the Low Carbon Contracts Company (LCCC) who recover the premium paid to generators (or return payments when market reference prices are above strike prices) from licenced suppliers under government regulation. The expectation is that suppliers pass these costs on to their customers, although they are not compelled to do so. Therefore, there is no direct financial backing by the state.

These schemes are favoured as they provide revenue certainty to the generator as the developer can determine the strike price they require to make a reasonable return on investment, and provided they are competitively priced in the auction will receive the price for all units generated for a known period of time as determined by the contract with the counterparty. In turn, the revenue certainty is expected to allow for lower financing costs, which ultimately results in lower cost to the consumer compared to arrangements where the developer has less certainty of future revenues.

As CfD contract holders are paid a premium against a market reference price they have an incentive to trade their power in the wholesale markets to ensure revenues (traded power in the wholesale market and the 'top-up' premium) equals their strike price. The arrangements also help preserve the integrity of wholesale markets as CfD contract holders will engage with the wholesale market on similar terms to other generators.

Advantages

- **Investor**
  - High long-term revenue certainty which should reduce financing costs
  - Type of investor would be a function of the levels of capacity likely to be awarded under the CfD
  - Credit worthy counterparty (although the specifics are a function of the scheme design and views on costs being recovered from consumers in all instances)
- **Policy Maker**
  - Scope for design which can distinguish between technologies and scale and can be designed to delivery specific capacity (as is the case in ROI with RESS).
  - Compatible with UK policy as demonstrated by the GB CfD scheme and relies on auctions to discover strike prices
  - Compatible with SEM in that generators are incentivised to follow price signals and bid into the day ahead market to optimise their revenues, thus lowering system imbalance in the balancing market
  - Similar to the new RESS policy in ROI and scope for joining this scheme on an "all-island" basis could be explored
  - State Aid Approval application is straight forward
- **Consumer**
  - Cost to the consumer considered lower relative to a FiT scheme
  - Should result in lower cost development, and in sum (subsidy and wholesale market prices), the overall costs are predictable
  - LCOE reductions should mean lower costs for comparable capacity if implemented just a few years ago
  - BEIS spoke positively regarding the cost of the consumer for the GB CfD scheme as part of the stakeholder engagement process
- **Community**

  - Limited as the schemes are typically complex to access

Disadvantages

- **Investor**
  - Risk of "winner's curse" which could threaten deployment. Steps can be taken in auction design to mitigate against this
  - Significant resource/ expenditure to bid for CfDs which will not guarantee success
  - Less accessible to smaller, non-institutional investors
- **Policy Maker**
  - Cost for NI to establish, administer and oversee ongoing operation for such a scheme is high. For example, BEIS has a team of 15 people working on the CfD scheme, as well as having the LCCC as the counterparty for the CfDs themselves. NI would not be able to benefit from economies of scale for such a scheme.
  - NI could consider joining the UK CfD scheme. However, there would be no guarantee of deployment of renewables in NI, and the NI customer would still have to fund the scheme
  - If the scheme design favours larger, institutional investors, then the capacity/ budget envelope would have to be large enough to encourage desired competitive tension – the scale of the NI market should be put in context to other markets where international capital can compete for support
  - Legislation would be required to establish a NI version of LCCC and or EMRs Ltd. Given the current lack of an Executive, this could be a slow and resource heavy process.
- **Consumer**
  - An NI-specific CfD scheme would likely be costly (primarily in terms of set up and ongoing administration) for the NI customer, who would not be able to benefit from economies of scale as is the case in GB or ROI.
  - If joining a UK-wide or "all-island" scheme, the NI customer could end up funding the scheme without any guarantee that renewables would be deployed in NI.
- **Community**
  - Scheme parameters are likely to be complex, costly and require specialist skills to participate and manage ongoing arrangements.

Tradeable Green Certificates

Tradeable Green Certificates (TGC) schemes provide eligible generators with certificates that have value for an electricity supplier, who is under an obligation to demonstrate the volume of renewable electricity supplied to their customers. The generator receives payments for the TGCs (which forms the subsidy) from suppliers, who in turn submit them to the scheme administrator to demonstrate renewables supply to customers in a given period (typically a year).

The Northern Ireland Renewables Obligation (NIRO) is an example of a TGC scheme and was considered very successful by stakeholders in developing renewables capacity in NI from a volume perspective. In NI the obligation level is set lower than in GB, so suppliers have a lower amount of certificates to buy and therefore pass on less cost to the consumer. This is due to the smaller demand base in NI and with consideration to fuel poverty levels, indicating a degree of possible flexibility in policy design regarding TGCs. That said any future scheme would most likely not be socialised across the UK and thus may not result in a lower cost to the NI consumer than the NIRO.

Advantages

- **Investor**

    - Long term support, provided scheme design has sufficiently robust oversight to ensure market viability (i.e. overproduction of TGCs is not possible to "crash" the market)
    - Due to there being no competition to ensure support, accrediting for TGC is often relatively straight forward for companies with access to industry knowledge and/or consultants.
- **Policy Maker**
    - Would be compatible with SEM as generators would have to sell output into the market
    - Flexibility would allow adjustment of future costs via banding awards of TGC. However, a drawback mentioned by BEIS is that policy design may be unable to keep up with fast-paced changes in technology.
- **Consumer**
    - Had the NI customer alone been obliged to fund the NIRO, the cost would have been very prohibitive. However, costs have decreased significantly since 2005
- **Community**
    - Depending on the scheme design, could have a high likelihood of accreditation once the application is correctly submitted.

Disadvantages

- **Investor**
    - Revenue levels are less certain, as the TGC value in any given compliance period is a function of the overall target and the number of TGCs produced (which is largely weather dependent). The majority of revenue will also come from the wholesale market, which is volatile – increasing financing costs to reflect the revenue uncertainty

- **Policy Maker**
    - Not competitive. Although State Aid rules does not ban TGCs per se, they would be given much more scrutiny than other schemes.
    - Risk of over-remuneration of projects e.g. if wholesale prices are consistently high
    - Scheme needs to be designed using lessons learned from RO/NIRO. A “one size fits all” approach from the early days of the UK RO schemes did not work here in terms of having the same incentive for types of technology. A TGC scheme would need to reflect this experience and ensure that measures are in place to anticipate possible outcomes but with flexibility to make adjustments for technology developments as required throughout the policy.
    - Although policy review periods can be built in, this can drive undesirable activity from developers trying to get their projects in before the review.
    - Administration costs could be high as a market for the certificates would need to be created as well as an entity to run the scheme and monitor suppliers’ compliance
- **Consumer**
    - Potential for higher costs where wholesale market prices are high and result in a windfall for generators also awarded TGCs
    - Suppliers who do not meet their green certificate obligation can push the cost of that back on the consumer, as occurred under ROs (although the whole scheme cost remains the same).
    - Unlikely that costs would be socialised across the UK. However, as stated in the Advantages section, these costs could be considerably lower now than when the CfD scheme was originally incepted.
- **Community**

- Often seen as too complex for smaller schemes to join, unless a liquid and healthy market exists for the sale of TGCs.
- Medium/low - scheme complexity (accreditation and ongoing admin) and participation of scale gens will have an impact on local scheme participation.

Route to Market & Alternative Support

There is a view that governments can facilitate support for renewables by the removal of market or regulatory barriers, rather than explicit financial supports. This view has been considered in, for example, the Helm Review[22] where other options for support could be considered and governments intervene less directly in promoting renewables investment. BEIS, as part of the stakeholder engagement process gave examples of indirect support such as removing business rates, support of aggregators to take many smaller installations to market or removing barriers to smart meter rollout.

Examples of Route to Market Support

- Floor Price Guarantee: Cornwall Insight, in a letter to Minister Claire Perry, suggested a mechanism (though in the context of the CfD) whereby a top-up floor price could be introduced which would only be used if wholesale market prices dipped below a certain level. This would provide some revenue certainty for investors while representing low or no cost to the consumer base. This idea could be adapted as an alternative Route to Market scheme and investors could compete to receive this guarantee
- Innovations could be introduced by regulatory changes, such as smart, behind-the-meter technology or demand side interventions. For example, regulatory arrangements could be changed to encourage deployment of on-site renewables that enable access to DS3 revenues, avoided network costs and opportunities to arbitrage wholesale/ imbalance prices.
- Another option would be Virtual Power Plant (VPP) schemes such as the one set up recently in GB by Statkraft. A VPP usually aggregates multiple distributed generators often via cloud-based systems for the purposes of trading them in the market. Advantages of this would include decreases to network costs and reduced strain on the system. However, in NI this would be challenging without smart meters.
- Grants: A suggestion was made by Solar NI during the stakeholder engagement process to bring back capital grants. They argue it would be cheaper than NIRO or another green certificate and would allow for solar capacity with permitted development to be built out quickly. It was further suggested that options such as those put forward by Sustainable Energy Authority of Ireland (SEAI) could benefit the industry, especially in the short term between now and 2022. This could represent examples of “quick wins”
- Tax incentives: Renewables generation could be permitted to participate in the Enterprise Investment Scheme (EIS) or the Supported Employment Solutions (SES) scheme to help develop and maintain employment and support for renewables in NI.
- Some countries such as Lithuania have removed excise duties from all renewable electricity (see Section 4.5).
- Some stakeholders have claimed that VAT[23] is going to be increased on solar and battery installations, from 5% to 20% in October, creating more pressure on development. This is something which could also be examined.

[22] https://www.gov.uk/government/publications/cost-of-energy-independent-review
[23] https://www.theguardian.com/politics/2019/jun/24/hmrc-pushes-massive-vat-increase-for-new-solar-battery-systems

No major policy intervention

- The implications of no policy intervention and the risk of security of supply issues is outlined in section 3.3. Although investors would have a high level of certainty in that there is no policy to explicitly support renewables, they would be fully exposed to wholesale market prices, which reduces revenue certainty and increases financing costs for new projects. Consideration would have to be given to whether the LCOE costs and investment environment in NI would be enough to promote enough subsidy-free projects to meet NI's security of supply and renewables targets by 2030. This is considered in more detail in Section 4.2.
- Although there would be no subsidy for the consumer to finance, there could be indirect costs if emergency interventions were required for security of supply reasons or penalties arising from missed carbon reduction/ renewables targets (although at time of writing post Brexit, there do not appear to be financial penalties for missing UK emissions targets). NI is experiencing a challenging investment environment and as a result of the stakeholder engagement process, market participants have communicated that they feel lack of investment in renewables in NI is being driven by lack of policy, and the perception that GB and ROI have better investment environments
- It could be argued UK policy is not being met in the case of non-NI policy intervention, for example the following:
  - Insurance principle—Government must be prepared to intervene to provide insurance and preserve optionality
  - Agility principle—Regulation must be agile and responsive to reap opportunities of a smart, digital economy
  - As well as UK renewables targets
- Although innovation could facilitate some increase in renewables over the next decade it needs to be considered in the context of what the aim of those innovations are e.g. allow for more connection, or reduce reinforcement costs? An analysis of such options forms part of this report with contributions from SONI and NIEN in the absence of government policy, but the question remains will it be enough to both increase renewables on the system and prevent security of supply issues post 2030 (see Section 3.3 for further information).

4.4 Pricing Dynamics with Support Types

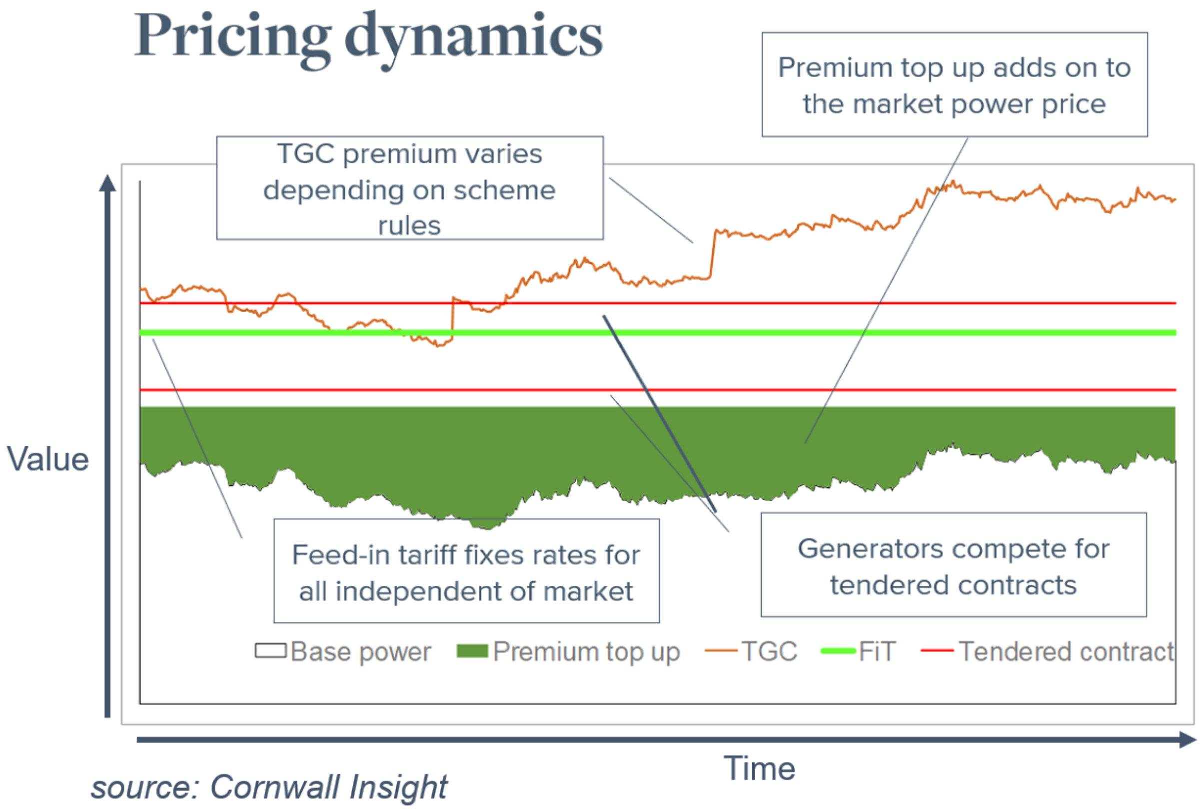
Figure 15 shows schematically the dynamics of different types of support from a pricing viewpoint, with the market price represented by "base power". This figure is design as a schematic representation illustrating the different movements of revenue, depending on the type of support and auction rules.

For example, the premium top-up illustrated here indicates a CfD-type structure whereby a strike price representing a cap is agreed (usually in an auction) and if the power price falls below that level, it is topped up to the agreed strike price. This differs from the FiT represented in the figure, which receives the same price regardless of the underlying power price. Depending on design, FiT schemes can be linked to the market prices (such as REFIT in ROI) or take the form of a fixed payment as demonstrated by the flat price in the figure.

The tendered contracts in this example receive a competitive "pay as bid" price which is indicated by two different red lines representing two different participants receiving their bid price.

The TGC in this example is an add-on to the power price and it changes over time due to scheme rules, an example of which may be the number of certs available. The TGC value can then vary based on different parameters such as there being multiple certs for a particular technology, how liquid the certificate market is and if the certs can be traded bilaterally or via a broker.

Figure 15. Schematic representation of pricing dynamics between different support types



source: Cornwall Insight

4.5 Policy Case Studies

This section provides an overview of relevant case studies on renewables support schemes and policies. Case studies have been chosen on the basis of their relevance to NI in terms of market size, maturity of renewables deployment and the potential to learn from the support schemes in place. Research also focussed on any comparable market issues relevant to NI, such as network constraints and fuel poverty considerations, to assess if these were dealt with in scheme design.

The 6 case study countries are:

- Republic of Ireland
- Scotland (within the GB CfD)
- Lithuania
- Finland
- Slovenia
- South Africa

All case studies have support schemes based around competitive auction or tender programmes. This is deliberate, as both European and International markets are conforming in the use of competitive schemes as they can provide numerous benefits in terms of price discovery and cost reductions, budgetary control and streamlined procurement processes.

The selected countries also had previous schemes before competitive auctions and provide an example for NI of how a transition to auctions can be made and the different approaches and auction designs to achieve this.

Table 3 provides an overview of the case studies and the key learnings for NI.

Table 3. Country Support Scheme Comparison

Country	Support scheme type	Key features	Lessons for NI
Republic of Ireland	Auction for CfD	Pay as clear auction Volume based CPPA tie ins and potential incentives Community ownership minima applied to ensure participation	Direct linkage to same SEM market and the potential for an "all-island CfD" Risks around payment for no delivery in NI i.e. if all RESS projects were to develop in ROI then NI consumers would have to pay towards this. But power access would be direct in the single electricity market which was not the case with the UK CfD
Scotland	Auction for CfD	Part of GB CfD - pay as clear Technology pots and budgets for established and less established technologies Budget based procurement with capacity caps	Favourable wind conditions help support development and limit risk of paying on only England and Wales wind farms – may not be the case in NI Grid issues managed through GB wholesale market – separate pricing impacts in NI with SEM would have different risks Remote Island Wind technology category added for latest auction which is dominated by small Scottish island projects. Similar dispensations may be worth exploring for parts of NI if it joined the CfD – although State Aid/CMA guidance an issue
Lithuania	Auction for Feed in tariff premium	Technology neutral and volume based 12-year Feed-in tariff premium price on top of stated market value price floor Set budgets over course of subsidy to limit spent	85% exemption on scheme costs for energy intensive industries to ensure they are not impacted by scheme cost changes Policy part of drive for energy independence on gas Volume based procurement potentially allows for clearer targets to be set for each auction against emissions or deployment targets. This could be utilised in NI on a separate scheme or under RESS which also has volume targets. Budget based procurement also face the risk of overspend and corrections as has occurred with the GB CfD where delivery has been delayed to the 2020s
Finland	Tender for Feed-in tariff premium	Technology neutral and volume based to meet 2030 emissions targets Feed-in tariff premium provided on top of market price which is updated quarterly and effectively sets floor for developers Regular tenders each year	Design allows for both debt providers and equity investors to get comfortable with the scheme as it provides a floor price and potential for upside when prices rise. NI financing structures under the previous NIRO scheme could potentially be applied to this design, making investors more comfortable and less concerned of "first of a kind" scheme risks Non-refundable application bonds as well as part refundable construction bonds. This could be utilised in an NI scheme to ensure only mature and creditworthy projects apply for support – but can also be a barrier to entry for small players The scheme costs are recovered through general taxation, potentially a more equitable way of recovering funds and would also limit uplifts in energy bills for the fuel poor in NI. However, the GB CfD scheme and planned ROI RESS scheme both pass on scheme costs to consumers through a direct levy

Slovenia	Tender for FiT	Tender for FiT tariff at flat level – no market linkage Incorporation of previous subsidy scheme into new one. Previous subsidy generators must "re-bid" under competitive conditions to be awarded a contract	Relatively unique example of a "re-tender" on existing FiT generators to try and reduce costs of existing scheme and procure new projects through a competitive process. Re-tender resulted in reductions for all existing sites and helped lower scheme costs on the consumer bill Interesting case study for NI with previous RO scheme, but unpopular with investors and likely to be to the detriment of existing renewable developers and generators
South Africa	Auction for FiT PPA	Move from FiT to a tender approach after previous low uptake Less developed market so award is for 20-year government backed PPA Technology specific budget pots Local criteria requirements on content of project	International example of a country moving from FiT to CfD style arrangements like ROI Local content approach has proved successful with 30% minima criteria on labour and equipment. This may prove harder to implement in NI due to State Aid/CMA competition rules Example of the negatives of tender/auction processes as severe delays on allocation rounds in 2014/15 led to no auctions being held. This severely dented investor confidence in the scheme. Any scheme in NI would need to be well resourced in order to ensure regular application windows and clear auction processes, a potential administrative burden

Republic of Ireland

Introduction

In 2018, the Department for Communications, Climate Action and Environment (DCCAE) issued their High Level Design (HLD) paper for ROI's new Renewable Energy Support Scheme (RESS).

Although the detailed design has yet to be published, the response to the HLD framework from market participants has been generally positive and it is seen as pivotal for ROI to reach its 2030 renewable energy targets. The scheme is designed to support 11-12 terrawatt-hours (TWh) of renewable energy through a series of auctions between 2019 and 2025.

The volume of subsidised output set out in the HLD is consistent with Ireland hitting a RES-E target of 55% by 2030 representing approximately one third of ROIs current annual electricity demand. The HLD was published with the assumption that ROI had a RES-E target of 55% renewable electricity by 2030. ROI has since announced a more ambitious overall RES-E target of 70% by 2030, although it is likely that the support scheme will still aim for 55%, with the rest to be made up by merchant projects and corporate PPAs.

Renewables Support Scheme

According to the high level design, RESS will consist of a CfD auction structure which will be delivered using two-way CfDs. So far, the department is minded to have all auctions technology neutral from a cost perspective, but to use "intervention levers" such as technology caps to mitigate against a dominance of any one form of technology, likely to be onshore wind.

There are planned to be 4 or 5 auctions, the first of which is due to occur in 2019 and is set to have a delivery date of 2020 (at time of writing the high level design and date of the first auctions is yet to be published). This most likely will favour solar due to eligibility criteria with regards to having planning permission and connections being in place, as well as bid bonds for delivery. The subsequent auctions are likely to be open to all types of technology including offshore wind. It should be noted that at time of writing, state aid approval was still outstanding.

A feature of ROI's scheme in comparison to the GB CfD is that the auctions are designed with a volume of output, rather than a budget target in mind, although budgetary caps may apply. This means that while there is a drive towards renewable capacity over a set financial budget, an argument exists that ensuring cost effective renewable capacity will itself benefit budgets[24].

A further feature of RESS regards community participation. For each auction after the first, there is planned a reserve of 5-15% of capacity for community-led projects with a specific policy objective of “community ownership of renewable electricity projects”. By industry standards, this is considered to be very ambitious, and it is unclear how this can be delivered. More details are expected to be available in the detailed design when it is published.

The detailed design may be quite bespoke to the different auctions. The HLD shows that DCCAE intends on retaining flexibility to amend the auction design over the lifetime of RESS in order to respond to changing circumstances such as declining costs or over/under delivery of capacity.

Technology

ROI’s renewable mix is currently dominated by onshore wind due to the success of the Renewable Energy Feed-in-Tariff (REFIT). The DCCAE have stated they are encouraging technology diversity in RESS, and as a part of this may use a single technology cap (from the second auction onwards). This is designed to limit the volumes within an auction which comes from a single technology, allowing other technology types to compete.

Without further detail beyond the HLD, it is difficult to state at present what type and scale of technology will benefit, aside from solar in the first instance. Many of the outcomes of the auctions will depend on the details of policy levers and auction design.

Cornwall Insight has noted considerable interest in RESS from various sectors of the market, including outside investors looking at market entry. Offshore wind is of particular interest, not least because of ROI’s potential in this regard[25].

Cost to Consumer

The RESS scheme will be funded by ROI’s Public Services Obligation (PSO) fund and the total estimated cost of the plan has not been published. It is expected to feature an Administrative Strike Price (ASP) as a budget control measure, whereby successful bidders with bid prices exceeding the ASP will only receive the ASP level. As a FiP scheme, the support would track the market price rather than being topped up to a set strike price as in a pure FiT, which should present lower costs to the consumer as generators still receive value via the wholesale market, rather than totally from a support payment.

The auctions are most likely to be technology neutral, with policy levers (more detail of which should be in the detailed design) as an attempt to keep costs for consumers down. However, there are concerns in the industry that this will promote only one type of technology, thus undermining the department’s commitment to a technology-diverse renewables mix.

Another risk concerns price cannibalisation[26] effects, which could depress wholesale prices leaving the consumer to cover the gap between a lower wholesale price and the support price. This effect can even cause negative prices as has been observed in the USA, Germany and GB, as well as occasionally in the new SEM since it went live in late 2018.

Although NI customers would not be funding the RESS scheme, cannibalisation effects would have an impact on SEM prices as a whole - regardless of NI policy - and should be considered carefully for any future policy or support.

One consideration for NI would be to join the RESS scheme or work with ROI to create an “all island” support scheme. However, as with the GB CfD scheme, the main difficulty here would be that the NI customer could end up financing assets which are not deployed in NI. The difference with a GB linked scheme is that any positive impacts of cheaper renewables projects on I-SEM market prices would be fed

[24] https://www.cornwall-insight.com/newsroom/all-news/the-case-for-a-floor-price-cfd
[25] https://www.cornwall-insight.com/insight-papers/a-great-leap-forward-offshore-wind-in-ireland
[26] https://www.cornwall-insight.com/insight-papers/wholesale-power-price-cannibalisation

directly through to NI consumers. Policy makers could consider an NI feed-in-tariff premium scheme though with a small customer base and no access to economies of scale this could prove to be expensive.

Other Considerations

There is potential for “winner’s curse” in RESS whereby projects bid in too low to win support but then cannot deliver the project. However, the inclusion of delivery bonds would mitigate against this possibility in that participants may price themselves just below the next most expensive alternative, rather than at their actual cost level. Both of these issues should be considered as part of any scheme and auction design.

Scotland

Introduction

Scotland is generally considered successful with regards to renewable energy with strong support for community projects and high levels of renewables capacity. As in Northern Ireland, Scotland developed much of its renewable electricity capacity under the Renewables Obligation scheme and this allowed Scotland to develop associated supply chains for renewable technologies. Constraints and grid connection issues are also a factor in the Scottish energy sector, especially in remote areas without good grid infrastructure where often the best wind is to be found. One of these areas is the Galloway Area which has high wind and significant grid constraints which also have an impact on the Moyle Interconnector with NI.

Renewables Support Scheme

Scotland is not considered a distinct market in GB in terms of market regulations and renewables policy. While national targets for carbon reduction, energy efficiency and some local heat and transport policy is devolved to the Scottish Parliament, electricity market rules still sit within national energy acts and legislation.

This also applies to renewables support schemes, with the Contracts for Difference (CfD) applicable to new renewables technologies in England, Wales and Scotland. The CfD provides a fixed strike price for generators over a 15-year time horizon, paying them the difference between the fixed strike price and a wholesale market reference value.

Generators bid strike prices into auction rounds, with a pay as clear approach providing strike prices for projects across delivery years i.e. generators receive the same strike price against the highest cleared valued in each delivery year. A cap is placed on uplifts to these strike prices, with technology specific Administrative Strike Prices (ASPs) placed on technologies based on Levelised Cost of Energy assessments. Generators must bid below these levels in an auction.

Importantly, awarded contracts are private law agreements between the generators and a government backed counterparty, the Low Carbon Contracts Company (LCCC). This provides greater certainty to investors regarding potential policy or change in law implications if the scheme or general energy policy were to change, as the contract is a private law agreement between the two parties (LCCC and the generator). This may be a consideration in NI for any scheme, as a private law counterparty may create lower risks for investors from a policy or regulatory angle.

Procurement is set against government budgets set aside for low carbon levies, which are now restricted out to 2025 to an additional £557mn for the CfD. The auctions procure on a MW capacity basis, with the potential to set capacity caps and minima or maxima spend by technology.

Technology

All typical renewables technologies are eligible for the scheme; however, the auction is not strictly technology neutral as auction budgets are split into pots. These pots are termed “established” (pot 1) and “less established” (pot 2). More mature technologies such as onshore wind and solar are in pot 1 while offshore wind, Anaerobic digestion, wave and tidal and remote island onshore wind amongst others are in pot 2. BEIS have the ability to set auction budgets for each pot and therefore can provide more or less to certain technologies. Only in the first auction in 2015 was money put into pot 1 for established technologies. Since then auction rounds 2 and 3 have only set auction budgets for pot2 less established technologies ”

Importantly for Scotland a new category has been added to Pot 2 going forwards for Remote Island Wind. This was originally designated as “Scottish Island Wind” but was amended to all remote islands to ensure State Aid approval. In upcoming auctions, several Scottish projects are expected to compete in this category and have received the designated status owing to their remote location and lack of mainland grid infrastructure links. This could be a consideration for any NI scheme around how remote areas with a lack of grid infrastructure, but favourable conditions for wind technology, could be integrated into a scheme.

Cost to Consumer

By 2025 the total scheme costs are forecast by government to be £2.5bn per annum (2012 money). These costs are shared across GB consumers via charges to suppliers, so that Scottish consumers pay the same unit £/MWh rate for the costs as customers in England and Wales. Despite the risk of Scottish consumers paying for projects outside Scotland, the reality of low land costs and high wind capacity factors in Scotland has favoured developments under the CfD there. Of the 57 projects currently in a CfD agreement, 12 are located in Scotland. This consists 3 offshore wind and 9 onshore wind projects. Beatrice 1 and 2 offshore wind farms, Moray East offshore wind, Neart Na Gaoithe offshore wind, Achlachan onshore wind farm, Bad a Cheo onshore wind farm, Coire Na Cloiche onshore wind farm, Doronell wind farm, Kype Muir onshore wind farm, Middle Muir onshore wind farm, Nan Clach onshore wind farm, Solway bank onshore wind farm and Tralorg wind farm,

Additionally, compared with NI, Scottish consumers receive more of a benefit of CfD development outside its borders and the risks are not identical with NI in terms of paying the costs. As an example developments in England under the CfD would benefit Scottish consumers directly if they lower power prices overall or provide cheaper renewables against alternative subsidies or the previous RO scheme. This is not directly the case in NI where power prices are in a different market and any savings from GB via imports are limited to the interconnector capacity.

The CfD scheme has one major exemption for customers with Energy Intensive Industries (EIIs) subject to an 85% exemption on their demand volumes which have to pay the CfD and other policy levies. This may be a consideration for any NI scheme in order to insulate the impacts of costs on industry, or another user group.

BEIS have frequently touted the CfD’s success in allowing price discovery for the price of new renewables. This is most clearly seen with offshore wind technology which has seen strike prices (2012 money) reduce from £119/MWh in the first auction in 2015 to £57.5/MWh for the 2017 auction. Despite adding costs to consumer bills overall, BEIS has argued that the counterfactual for further renewables development under the RO would have been more expensive owing to higher financing costs with market exposed wholesale revenue and the lack of competition in allocation vs the CfD.

Other Considerations

Based on conversations with stakeholders, Scotland has some significant differences with Northern Ireland. One difference is with regards to applying for grid connections. In Scotland a project does not need to have planning permission to apply for a grid connection, which is a difference with NI grid connection policy. The view from several stakeholders is that the NI policy of requiring local planning permission before being eligible for a grid connection represents significant risk to projects, even if there were supports providing a route to market. There is a belief that this feeds into funding issues for NIEN whereby they must apply for funding for network upgrades and reinforcement based on expressions of interest and numbers of grid connection applications. Due to risks with gaining planning permission and high costs for grid connections, many investors do not apply which then affects NIEN’s funding application and translates into higher connection costs thus perpetuating the issue. The Scottish transmission and network operators must also make a case to apply for funding but because projects can apply for grid connections without planning permission, the view is that the transmission and network operators are in a better position to apply for the necessary funding to facilitate the addition of additional renewable energy.

Public perception to renewable energy has been described as neutral or positive during the stakeholder engagement process. The public appears to have a preference for renewable electricity over nuclear energy and programmes run by companies such as Scottish Power have seen a generational shift in public perception with regards to how electricity is generated. The older generation still sees conventional plant as the standard on how electricity is generated whereas the younger generation would see for example solar PV or onshore and offshore wind as a normal way to generate. Additionally, Scotland has several successful community energy programmes which are discussed in more detail in Section 8.

In terms of the risk of the Scottish consumer paying for the CfD scheme without any deployment of assets, it seems that this was less of an issue in Scotland than in Northern Ireland. Part of this is due to the fact that Scotland had a high probability of winning contracts, especially in offshore wind. Additionally Scotland as part of the British Electricity Trading and Transmission Arrangements (BETTA) market with England and Wales is aligned both market and regulatory-wise with the rest of GB and there may be a view that benefits to one part of the market regarding renewables means benefits to the rest of the market.

Lithuania

Introduction

Lithuania, bordered by Russia (Kaliningrad Oblast), Belarus, Latvia and Poland, has a population of approximately 2.8mn and currently has just over 2 TWh of renewable electricity. Traditionally, Lithuania has been largely dependent on other countries for its energy needs, especially since the closure of their two nuclear plant in 2004 and 2009. Energy independence is commonly a major target when developing renewables policy, and Lithuania suffers from high levels of fuel poverty.

Renewables Support Scheme

A new renewables support scheme is being introduced in Lithuania, the first auction of which is expected to commence in July 2019. Aside from the overall energy independence goal, Lithuania is hoping the scheme will help reach a renewables goal of 38% by 2025 and an increase of 1 TWh of electricity a year. The scheme was awarded EU State Aid approval in 2019.

The new scheme is a competitive Feed-in-Tariff premium type scheme and will feature a series of technology neutral, volume-based targets. In this regard, the lowest cost technology will win a contract regardless of what type of technology it is. Auctions are due to be held every 6 months and subsidies will be awarded for 12 years. A unique aspect of the scheme is that other European countries will be eligible to bid in for support under a bilateral arrangement. This effectively means that new renewable energy projects that meet the same eligibility criteria in neighbouring interconnected markets can bid into the scheme. For instance, projects from Belarus or Latvia.

The previous scheme consisted of technology specific FiT auctions and winners were awarded 12-year subsidies. However, the funding for this ran out in 2016 and had not been replaced until its 2019 successor.

Technology

The auctions are open to all types of technology types and size and are technology neutral, which means the contract will be awarded to the project offering the lowest price.

In the context of Lithuania, this is likely to drive large scale onshore wind as this is considered the least cost technology for local conditions. As there is already a high penetration of onshore wind, the industry supply chain already exists. Additionally, it is likely that projects which can raise high amounts of debt-based capital will have a competitive advantage, these tending to be large scale projects with large international backing.

Offshore wind may feature for the first time in Lithuania. Although it will be allowed to apply, it is questionable whether it will be economically feasible. The state-owned energy company Lietuvos Energija sought an offshore wind developer earlier this year to partner – planning to add 3,000MW wind to its portfolio.

Some sources[19] are not expecting much solar to apply for the scheme, However, a 1.4MW array was installed behind the meter on a subsidy-free basis recently, so that remains a possibility. Additionally, there is significant existing bio-electricity production so more of this may be seen.

Cost to Consumer

The scheme is estimated to cost €385mn. Although Lithuania has high levels of fuel poverty, it has widespread district heating and government subsidies for heating to help lower costs to consumers. This means that consumer exposure to increasing renewables costs should be mitigated.

The scheme will be paid for by a levy on electricity consumption. However, energy intensive industries (electro-intensity rate of 20% or more) will be able to avoid 85% of the costs of this levy in an attempt to promote greater investment of energy intensive industry in Lithuania.

The use of technology neutral auctions is also likely to keep the costs down for consumers (this was a reason cited by the DCCAE for technology neutral auctions in RESS). However, this could further drive the development of large onshore wind (see Technology section). In the context of NI technology, this approach is something to be considered as part of the DfE's goals with regards to technology diversity and scale.

Additionally, there is strong public support for reducing Lithuania's energy dependence on Russia, which may factor into the public's wiliness to fund schemes and tolerate renewables assets such as larger wind turbines and associated network infrastructure. 103 out of 104 MPs voted for the scheme and the 104th abstained.

Network Considerations

At present, grid costs are borne by the network operator. However, this is set to change whereby those costs will be paid by the generators. Sources[27] state this is designed to decrease network costs overall, although it remains to be seen how effective this move will be.

Smart metering is not yet a feature in Lithuania, but it remains under trial and a widescale roll out is being investigated.

Other Considerations

Renewables electricity in Lithuania as well as Poland and Slovakia is exempt from excise duty, creating a further investment incentive. Perhaps this is could be something which could be considered for NI, however excise duty is not devolved and therefore the NI Executive would not be in a position to set excise duty exemptions. Additionally such a move if possible, would have to be carefully thought out in terms of implications for the SEM and State Aid rules. For example, would it be the end consumer who would benefit, or could it potentially create dual pricing in the SEM.

Finland

Introduction

The Finnish electricity wholesale market is part of the North European electricity market. Finland, Denmark, Norway, Sweden, Estonia, Lithuania and Latvia have integrated their wholesale electricity markets. The main part of the electricity wholesale trade takes place at the Nord Pool Spot[28] exchange.

Consumption has been broadly stable over the last decade and was 87TWh in 2018, 20TWh of this was imports from the neighbouring connected markets. The market has historically been dominated by fossil fuels, nuclear and wood fired biomass, currently 50% of the mix, with wind at 6.7% in 2018. Unlike NI, Finland's fuel poverty levels are relatively low and network constraints are not seen as a major issue. However, integration of new assets has caused some concerns of pass through costs to consumers. To mitigate this impact, new generators whose capacity exceeds 2 MW have to bear part of the costs of the connection works.

[27] https://www.roedl.com/insights/erneuerbare-energien/2018-08/renewable-energy-lithuania-new%20incentives-premium-model
[28] https://www.nordpoolgroup.com/ - Commercial trading exchange for use in trading power in various European countries. EPEX Spot is another example and the SEM Day Ahead market is traded on this exchange.

Renewables Support Scheme

After previous FiT style schemes and grants awarded to renewable technologies, Finland launched the tender based Feed-in tariff scheme in 2018. The first round opened in Autumn 2018 with a 6-week application window. Applicants for the first round are expected to be in operation by 2020.

The scheme is technology neutral with a premium effectively offered on the base market price, which is currently set at €30/MWh, up to a cap of a €53.5/MWh premium, effectively capping prices at €83.5/MWh overall. €30/MWh is guaranteed as a price floor, with generators bidding for a premium level on top of this with the lowest top-up levels winning under the competitive process.

The subsidy premium is paid for 12 years with market price being determined in quarterly assessments and the top-up is determined by the bid of each winning project. Payments are made up to each bidder set premium level in each tender. Importantly, no payments are made if market prices turn negative. Any earnings above the market plus premium are also not awarded payments, but projects do receive revenues through the market, therefore providing upside to generators which can prove attractive to equity developers.

For NI, any auction or tendered support scheme would need to consider whether a pay-as-bid or pay-as-clear[29] approach was used and how payments or caps where determined. The Finnish approach with pay as bid may result in lower prices for the most competitive projects and restrict uplift to the most expensive bid in the auction or tender. Additionally, the link to wider market prices and the opportunity for upside when prices rise can attract certain investors and also ensure generators are still responding to market signals i.e. generating when market prices rise.

As part of the application, prospective generators submit security deposits for both participation in the tender and on construction of the project. Participation fees are needed for access to the auction and are currently stated at €2,500 per bid. This is non-refundable. The tender also requires more “mature” eligibility requirements for applications, who must have grid connection offers and planning permissions already in place.

A bid bond set at €2/MWh valid for six months from the last day of the auction process has to be provided to the Energy Authority by the time of the submitting the bid. If the bidder is successful in the process, the security will be released immediately when the bidder grants a construction security at €16/MWh valid for three years and six months from the decision on the approval into the scheme. Failure to do this results in project termination.

If the energy producer has not fully completed the project, but has connected part of the project and is producing electricity within three years of the accepted bid, a proportionate part of the construction security deposit is deducted. Producers are also be obligated to pay sub capacity compensation if the producer is not able to produce the stated amount of electricity stated in their original bid.

This is a factor to consider for any scheme in NI, where a smaller pool of potential projects and developers exists than in ROI or GB. Asking for deposits can ensure only serious and creditworthy projects come forward for any future policy support. Although it can also be a barrier to entry for smaller players and may well be factored into bidding or top-up criteria to recoup spending regardless.

Technology

The scheme is technology neutral for new producers of electricity from wind, solar, biogas, biomass wood fuels and wave power and the tenders are procured on a volume basis with up to 1.4TWh annually.

The procurement-based approach is designed to align to Finland’s 2030 emissions reduction targets and each round is expected to be of similar TWh proportions. Importantly, eligible technologies must have an annual electricity production of 800MWh to apply. This is a relatively low level and would only exclude projects of around 250kW and below. The scheme also tries to mitigate against under delivery of projects against expected volumes through an “underproduction compensation mechanism”. For the purpose of this compensation, the 12-year support period has been split up into three sub-periods of four years each. The

[29] Pay-in-bid means that a winner in the auction receives the price they bid in at. Pay-as-clear means that a winner in the auction wins whatever the auction clearing prices is, which may be higher than the price they bid in at.

underproduction compensation becomes payable if the electricity produced annually by the relevant bidder is less than 75% of the aggregate electricity production volume offered in the first sub-period and/or (ii) 80% of the aggregate electricity production volume offered in the second and third sub-period respectively.

Volume based procurement is also expected in ROI under the RESS scheme and can be a more targeted approach to procurement compared to the GB CfD scheme, which bases CfD auctions around either budgetary levels or MW/GW capacity caps. The volume based approach for NI could provide a clearer pathway to emissions reductions targets, however Finland’s scheme shows how ensuring volumes can create added scheme complexity.

Cost to Consumer

The support system is financed by the state budget, i.e. through general taxation, and managed by the Ministry of Economic Affairs and Employment and is managed by the Energy Authority.

Results

Unlike RESS in Ireland and the new scheme in Lithuania, Finland’s tender premium has commenced with results in early 2019. Despite being technology neutral, the tender only attracted bids from onshore wind. Premiums sought by developers were very low, ranging from €1.27/MWh to €3.97/MWh in premium on top of the current €30/MWh set market price. The competitive price was due to the maturity of onshore wind technology in Finland and the security of the “floor price” effectively provided by the tender. Onshore wind was likely the only bidder technology due to the short lead times between tender rounds in late 2018 and the need to be commissioned by 2020. Potential incentives for other technologies may have produced other results, for instance if a minima for other technologies was set. However, doing this would have likely resulted in higher clearing prices and Feed-in premiums as in the neutral auction onshore wind was most competitive.

Slovenia

Introduction

Slovenia’s electricity market is still heavily state owned and operated, but a privatisation agenda is underway. The country has its own bilaterally traded electricity market and is directly coupled with the Italian, Croatia and Austrian electricity markets with significant interconnection.

Under the EU's Renewable Energy Directive, Slovenia has a renewable energy target of 25% by 2020. Currently the generation mix is broadly split three ways between nuclear, thermal coal and gas and hydro-electric dams. 17% of this mix was delivered through electricity imports, and the country is also reliant on Russia for much of its gas imports.

Electricity consumption has increased steadily over the last decade and stood at 14.5GWh for 2017. Around 10GWh of this is business consumption and 4.5GWh household consumption.

Renewables Support Scheme

Slovenia had its amended renewables support scheme approved by the European Commission in 2016. The previous scheme ran from 2009 to 2015. The amendments were based on ensuring existing and new schemes were more cost effective. The previous schemes included up to 50% grants for renewable project investments and a low interest loan scheme. With support scheme costs going directly to consumers, a sharp uptake under previous schemes led to a disproportionate rise in consumer costs and a policy re-think.

Under the amended scheme, the country has introduced a two-round tender process to determine who gets support and to set the level of support. The European Commission had stated this was in line with its guidelines requiring that from January 2017 State Aid for environmental protection and energy is granted on the basis of a transparent competitive bidding process open to all producers of renewable power.

Projects below 500 kW in Slovenia can continue to receive FiT. Operators of bigger systems will offer the produced power on the market and get a premium on top of the market price. This is effectively a Feed-in -tariff arrangement.

This was effectively a change in support scheme design and payment and should be noted for NI. Although this move can help control consumer costs, for instance in NI if the NIRO scheme was replaced by a bilateral CfD or premium tariff for all generators, it is usually disliked by investors and developers. This is because they will have banked on returns from support schemes over the lifetime of their financing arrangements and do not expect these to change over their duration. Additionally, investors would likely lose confidence in future support schemes and their certainty on financial support, adding a risk premium to these projects and ultimately leading to higher financing costs.

Slovenia's relaunched tender asked existing and new bidders to offer new €/MWh prices to secure contracts, the design was pay as bid with a limit on new entries determined by budget caps.

Technology

The scheme supports the generation of electricity from the following technologies; hydro energy, wind, solar energy, geothermal energy, biomass, biogas, energy from landfill gas and sewage treatment plants and energy from biodegradable waste.

The tender supports projects for new and predominantly new generating plants of all renewables technologies and CHP, which are connected after 22 September 2014, which will be included in the first round of selection, namely:

- Hydroelectric and photovoltaic power plants, and biogas installations using waste with a capacity up to 10 MW of rated power and wind power plants with a capacity not exceeding 50 MW,
- All renewables technologies and CHP generating plants whose operation is based on the purchase or production of fuels, raw materials for the production of biogas or the use of geothermal energy with a capacity up to 10 MW power, or up to 20 MW for CHP generating plants

In the second round of selection the following two groups could participate:

- Restored renewable and CHP generation plants, connected to the grid after 22 September 2014
- Wood biomass production plants which, by reason of their age, are no longer eligible for support and low electricity prices can not cover their operating costs,
- Renewable and CHP plants which did not succeed in competing groups during the first round

Cost to Consumer

In Slovenia, the end consumers bear the costs arising from the suppliers' obligation to pay for all electricity from renewable sources. The exact fees and obligations are set down in regulation and the level of payment depends on a customer's end-user classification according to the power voltage level, consumption level and end use.

During the first round of this tender €10million was offered with:

- €7 million for hydroelectric and photovoltaic power plants, and biogas installations using waste with a capacity up to 10 MW of rated power and wind power plants with a capacity not exceeding 50 MW
- €2 million for renewable and CHP generating plants whose operation is based on the purchase or production of fuels, raw materials for the production of biogas or the use of geothermal energy with a capacity up to 10 MW power, or up to 20 MW for CHP generating plants
- €1 million for restored renewable and CHP plants connected after 22 September 2014.

Results

Results from 2018 showed that on average tender prices had decreased tariffs by between 5% and 60%. With the Slovenian authorities stating the reason was both falling technology costs and the competitive dynamic in the tender, with limited budgets available for spending. Table 4 below details the price trends for the eligible technologies.

Table 4. Comparison of bid price in tender and previous support scheme values in Slovenian Tender (2018 tender)

Technology	New asset tender price (€/MWh)	Existing asset tender price (€/MWh)	Previous support price 2012 (€/MWh)	Previous support price 2010 (€/MWh)
Hydro	84.28	90.55	92.61	92.61
Solar	70.00	72.40	180.70	353.42
Wind	78.35	86.01	95.38	95.38
Wood biomass	134,24	173.67	246.29	225.74
Biogas and sewage gas	60.77	61.35	74.42	74.42
CHP with fossil fuel input	72.14	73.85	141.01	125.72

Source: Agen-RS

The results provide an interesting comparison to NI, where potential future support based around set budgets and competitive tendering could yield lower realised prices than alternatives such as a more simplistic FiT premium or traded certificate scheme.

South Africa

Introduction

Due to its fast growing economy, South Africa's electricity consumption has risen rapidly, outstripping capacity and, leading to a power supply crisis in 2007 and 2008. As a result, energy infrastructure has been seen as a priority investment.

In terms of liberalisation of the electricity sector, only the distribution has been fully unbundled. South Africa has a semi-decentralised power distribution sector, with about 180 distribution companies. Unbundling of generation and transmission has not yet taken place, since both activities are dominated by the public utility Eskom, which currently holds the monopoly in the market. Eskom generates more than 95% of all electricity and operates the entire national transmission grid.

Total demand in 2017 stood at 203TWh, around 60% of the size of the GB market.

Renewables Support Scheme

A REFIT style scheme was launched in 2008 to promote new investment but has since been replaced by a Renewable Energy Independent Power Producer Procurement (REIPPP) structure which resembles many of the tender and auction structures seen in Europe. This is an interesting consideration for NI, where a similar process is underway in ROI with a move from REFIT to RESS.

The style of this support scheme is effectively a competitive auction process to secure a FiT contract. The style of auction is similar to that in GB with the CfD and planned for RESS, but the resulting contract is different with a fixed FiT price rather than market-linked CfD.

The REIPPP scheme is aimed at above 5MW for the main element, with a 100MW reserve in each auction set aside for below 5MW project. This is effectively a minima to support small scale developments who would otherwise be uncompetitive in the auctions. All projects receive 20-year government backed PPAs with firm access to the market and guaranteed offtake.

Tender selection is a two-stage process, first bidders must meet minimum criteria on legal, financial and technical requirements and secondly must demonstrate economic development potential with a floor of 30% local (South African) content in the project.

This content element is interesting in trying to build local industries and supply chains and has been exceeded by many projects who have been able to source over 50% local content and still be price competitive. Whilst an interesting learning for NI, Cornwall Insight understands the stipulation on local content levels would be difficult to implement owing to current State Aid rules from the European Commission and expected competition rules after Brexit with the CMA. There are ways to promote local supply chains though, such as the supply chain plan used for 300MW and above projects under the CfD in GB.

Each year auctions are held on a capacity cap basis for each technology. In early auctions price caps were given to bidders and resulted in a lack of reduction from this level. In reaction, later auctions were amended to not reveal capped prices to bidders and also limit capacity caps to create higher levels of competition. This approach helped drive steep reductions in later tender round prices.

One negative area of the move to REIPP has been the delays in tender rounds and bidding. Under REFIT, application was effectively on a rolling basis with accreditation at any time. The move to a tender process did lead to more complication in organising and meeting stated tender timelines and some of these have been held back by delays in planning policy changes. As a result, investor confidence in the scheme has been hit and South Africa dropped down the Ernst and Young Renewables Country Attractiveness Index (RECAI) for successive years in 2014 and 2015 owing to this.

This is an important potential learning for NI in that offering tender contracts has proven to be beneficial for cost reductions but requires careful project planning and management to ensure stated tenders are delivered on time. If not, investors can quickly lose confidence in schemes.

Technologies

Procurement is technology specific across 6 auction tenders – wind, concentrated solar power (CSP), solar PV, Biomass/biogas/landfll gas, hydro and small project reserves.

Cost to consumer

Costs of the scheme are dealt with in general taxation management, with treasury budgets set aside for auctions out to 2020.

5 Stakeholder Engagement

As part of the research methodology for this report, Cornwall Insight and Ionic engaged with stakeholders from 18 different organisations including NI government departments, UK government representatives, regulators, non government organisations and industry participants. The meetings consisted of 9 face to face meetings with stakeholders external to the DfE and several teleconference meetings. A list of the meetings and stakeholders engage can be found in Appendix B.

The following section seeks to highlight many of the issues and concerns, as well as suggested solutions raised at these meetings. Broadly speaking the challenges with growth of renewables in Northern Ireland can be classified under policy, regulation, public perception, grid issues and innovation. Specific feedback from market participants suggests that the barriers to route to market for investment include factors such as lack of financial certainty, grid network issues and planning.

5.1 Policy, Regulation & Public Perception

The findings from the Northern Ireland Affairs Committee inquiry[30] were echoed by many of stakeholders interviewed in this process. There is a perception that there is a lack of coordination in terms of policy design and implementation across government departments. Another concern in terms of policy development is that the technology often moves faster than policy and so consideration needs to be given to expected technological advances when designing policy.

Examples of these issues are outlined in the following section.

Planning

- Regulation across departments
    - With regards to certain types of technology, such as AD plants, there is a lack of punitive commercial mechanisms for plant which breach the conditions of their planning permission. For example, operators may exceed the operational limits of their planning permission by sourcing additional feedstock from other parties resulting in excessive increases in public road usage.
    - There is a perception in planning that the penalty for violating the requirements of their planning permission is less than the incentive to violate them
        - A suggestion by planning for mitigating against this would be to link the receipt of any form of support with the development, so that if the developer violates the planning permission, they lose the support until steps are taken to resolve the issue. This however would require further discussion between the DfI and the DfE as to how such a plan could be implemented and who ultimately would be responsible for ensuring compliance.
- Policy design and consultation with planning
    - When the DfE commences with policy design, it was suggested by both the DfI and the local council representatives that there should be coordination with planning, allowing their experience and expertise to be used to develop good policy design and regulation. This could take the form of a coordinated government planning committee, for example.

[30] https://www.parliament.uk/business/committees/committees-a-z/commons-select/northern-ireland-affairs-committee/news-parliament-2015/electricity-sector-ni-launch-15-16/

- One suggestion on how developers could minimise planning-related issues is to engage with communities/planning authorities at an early stage to better align plans and to speed up the process. A difficulty with this viewpoint concerns commercial sensitivity, whereby developers may not be in a position to share their future plans outside their own organisation.

Renewables technology and scale considerations

The following section is based on a combination of the consultant's experience, the results of an extensive literature review and verbal evidence given by stakeholders including the client, planning councils, the DfI, other government departments, the Ulster Farmer's Union and renewables industry groups.

Most of the objections towards planning for renewable developments raised by stakeholders have been for onshore wind and anaerobic digestion (AD) plant, which partly reflects the prevalence of these types of technology in Northern Ireland. According to the planning authorities, in many cases, there are more objections to the associated transmission and distribution infrastructure such as power lines and clustered substations than for the renewable assets themselves, for example with the proposed North-South interconnector and with NIEN's "cluster-type" substations.

Wind

- Some stakeholders raised concerns regarding the visual impact of wind farms and in particular the large number of one-off wind turbines installed throughout NI. Whereas technologies such as AD create a limited visual impact due to the precedent that agricultural farms have barns and outhouses on site, reports suggest that the public perceive wind turbines as being outside the norm of what is normally expected in a rural environment.
- Members of the planning councils described situations where permission had been given to several individual onshore wind turbines in a particular area, which although were separate projects, created a relatively high density of wind turbines that seemed to some citizens to constitute a wind farm. The challenge in preventing this from happening in future from the planning authorities' perspective, is that if a precedent for planning has already been set, it can make it difficult to refuse additional projects in a given area. It was suggested that better coordination between the planning councils, DfI and the DfE could mitigate against further such situations. A suggestion was to form a working group to coordinate activities between the departments to discuss solutions to these and other issues outlined in this section.
- Some council areas such as Mid Ulster claim to have a higher penetration of certain technologies such as single turbine onshore wind, and there is a perception among some planning representatives that they are nearing saturation point from a political/public acceptability perspective. However Mid-Ulster were not present at any of the meetings with either the DfI or the planning councils.
- Regarding cumulative impact there is a view amongst some planning representatives that, should the public be given the choice between single onshore turbines spread across the country or designated zones for these types of developments, zones may be more readily accepted, especially in areas that run the risk of potential interactions with Areas of Outstanding Natural Beauty (AONB). The impact of having multiple small-scale wind turbines in a single area leading to a cumulative effect for local inhabitants was also raised by planning representatives although the extent of this issue was not evident. It should be noted that the cumulative effect of wind farms is clearly covered in PPS18 where it is incumbent on the local planning authority to take account of cumulative effects when granting permission for new developments[31].
- It has also been suggested that some AONBs could be considered "out of bounds" from a planning perspective, as is the case in some parts of ROI. Some of the Local Development Plans in preparation

[31] Refer to Section 3.2 of 'Wind Energy Development in Northern Ireland Landscapes - Supplementary Planning Guidance to Accompany Planning Policy Statement 18 'Renewable Energy' (August 2010)

look to restrict 'high structures' in particular areas which may impact on wind turbines and grid infrastructure in those regions.
- Offshore wind is most likely to cause objections if they are clearly visible from shore, interfere with maritime navigation, are large in size and number and/or have a lot of associated onshore infrastructure. Although the DfI may in principle approve onshore infrastructure for offshore wind, particularly if deemed strategically significant for a wider region, this could create problems with the public and/or politicians. There is more discussion on the future of offshore wind in Northern Ireland in Chapter 6.

AD plant
- The main complaints regarding AD plant have been due to increased traffic on the roads, smells, violation of planning, ammonia pollution[32] and the building of associated electricity infrastructure to facilitate the plant.
- Although the DfI have issued guidelines for AD plant on mitigating these impacts, these are not legally binding. As cited in the previous section, the penalties for such plant violating their planning permission do not seem to form a sufficient deterrent for doing so, and linking such actions to their receipt of any future support may improve that situation.
- One reason why ADs may violate their planning permission is that evolution of the technology has commonly moved faster than the applicable policy. Therefore, by the time the plant is commissioned, changes have been made by the developers from the original planning application. This echoes a view given by BEIS as part of the stakeholder process regarding policy trying to keep up with technology. Technology can evolve faster than policy can compensate for, which typically leads to policy intervention periods. A balance has to be sought between using policy interventions so that desirable outcomes of policy are encouraged without creating too much disruption or uncertainty to investors. For example, in the Renewables Obligation scheme, when developers knew a review on banding was imminent there was a push to get accredited before the review which meant that the change in policy applied to fewer projects than anticipated by the policy makers. This could have had a knock-on effect of requiring even more policy reviews which then creates a level of policy uncertainty from an investor's perspective.

Solar

- The planning authorities are of the view that the public is more open to alternative technologies, especially solar. Anecdotal evidence given by the planning councils indicates very few objections to solar farms, most likely in their view because of the relative lack of visual impact.
- Some councils state that they have not received many applications for solar, but should they get more they would be open to approving them. As part of the Policy Development work, potential for different types of technology or scale of technology should be assessed based on information from the planning authorities.

Other Technologies/Considerations
- There seems to be limited knowledge regarding the potential for geothermal energy amongst stakeholders including the planning authorities. However, planning representatives seemed to be receptive to the concept albeit further information would be required.
- Decommissioning of existing assets (especially onshore wind turbines) will increasingly be required as projects reach their end of life in the late-2020s. Some planning representatives raised concerns relating to lack of clarity on a process for decommissioning such as incentives or disincentives. Any future policy will need to take this carefully into consideration although it should be noted that the requirement for

[32] https://www.theguardian.com/environment/2019/jun/18/ammonia-pollution-damaging-uk-land-report

decommissioning commitments are covered in PPS18 and in other jurisdictions they are handled through decommissioning plans submitted at planning stage with the residual market (or scrap) value of equipment covering decommissioning costs.
- It was suggested by the planning council that efforts to demonstrate how renewables assets can enhance, rather than detract from the aesthetics of the countryside and general environment, could be a positive step to increasing public acceptance of renewables.
- Planning representatives queried whether brownfield sites could be used for different types of renewables technologies, such as EfW or AD, as opposed to placing in more visually and environmentally sensitive areas.

5.2 Grid related issues

Issues related to grid infrastructure and connections to it were cited by various stakeholders. The categories of issues can be briefly broken down as:

- Capacity
- Connections
- Curtailment
- Funding
- Other aspects

Capacity

- The capacity of the grid in north-west region of NI is nearing its maximum without further investment which will create issues for future connection of renewables and in particular onshore wind[33]. More capacity (in the region of 500MW) is available in the south and east at 275kV level but a heat map showing the location of this capacity at a distribution level is required and is currently under development by NIE Networks. The view from various stakeholders is that capital investment into both the transmission and distribution networks will be required to facilitate the addition of more renewables on the system, and delays caused by lack of grid investment creates an investment risk for developers of renewables projects.
- There are other issues described with regards to the network from stakeholders. One stakeholder involved in solar PV development stated that he could have developed 10-15 times the capacity of rooftop solar PV on a project but was blocked by NIEN, who cited fault levels on the network as the issue. This was felt to be overly restrictive and that solutions such as zero export connections may be viable approaches to resolving these issues.
- The 'clustering' approach whereby NIEN connect a number of generators to a single cluster substation has generally been seen by industry stakeholders as a relatively successful approach, but some developers stated that time frames for delivery have created problems for projects. Those developers stated they had to become directly involved with network to get projects over the line, resulting in additional time and cost and leading to impacts on the business case for some developments. ***Any policy support scheme needs to consider the interaction between network and project delivery timeframes from the perspective of attracting investment, especially if there is any kind of time-based criteria for eligibility.***
- Currently there is a perception that the development of the North-South interconnector by 2024 is not a foregone conclusion. Without that development, there is a serious risk to the energy sector in Northern Ireland from the perspective of security of supply, sustainability and keeping costs competitive for the NI

[33] EirGrid and SONI – Ten Year Transmission Forecast Statement 2017

customer. As has already occurred in the SEM market, this can create difficulties in balancing by driving up prices, even when there are periods of high wind on the rest of the island, which traditionally puts downward pressure on prices. Stakeholders believe that there needs to be a “Plan B” in place which could include upgrading/reinforcing the existing tie-lines between NI and ROI, and resolving issues with export on the Moyle interconnector (see below).

- Better utilisation of existing network capacity was also highlighted as a possible means to facilitate more renewables whilst also assisting in security of supply and curtailment / constraint related issues. SONI are already actively utilising measures such as high temperature conductors and dynamic line rating whilst NIE Networks are trialling technologies that will facilitate increased penetration of low carbon technologies. Additional measures such as prioritising hybrid or co-located projects (such as co-locating wind and battery energy storage) as well as investigating grid level storage for congestion management (for example, per EU internal electricity market rules, distribution system operators such as NIE Networks are not permitted to own storage capacity on the network except under certain conditions[34]) were also raised as possible means to address limited network capacity, in particular whilst waiting for build-out of new infrastructure in the northwest of NI.

Connections

- Difficulties with connections has been cited as a major risk for development. The cost of connection to the grid is perceived as being much higher than in other parts of the UK especially in areas where there has been a lack of investment in grid infrastructure. Often these areas are the ones with the best onshore wind potential.
- A possible solution would be to share the costs of connections. For example, subsequently compensating a developer who establishes a connection in an area which then benefits later developments. This was also raised for co-located projects where additional generation behind a connection point may trigger a major upgrade (such as a new transformer) in a local substation for which the developer carries the full cost making the project infeasible).
- Some industry stakeholders suggested that planning permission rules have a role to play. Under current grid connection rules, planning consent must be granted in order to apply for a connection. This process can take a long time and is perceived by investors as creating additional risks to a project, even for those with robust financing due in part to the lack of perceived investment in the grid. Developers therefore do not apply for grid connections which in terms undermines NIEN’s business case when applying for funding to finance upgrades and reinforcement. The next section outlines Scotland’s approach to grid connections (Connect and Manage) whereby planning consent is not required which industry stakeholders report has helped the investment cases in Scotland. ***Resolving capacity issues may allow projects to be initiated more quickly and allow for the development of renewables capability at a steady and speedy rate.***

Curtailment

- Curtailment is a factor which needs to be considered when designing policy. Too much intermittent generation on the grid may require the System Operator to curtail technologies such as onshore wind. Investment in non-intermittent renewables technology which are dispatchable and contribute to baseload electricity should be considered as part of taking pressure off the network. That said, the ***costs/kWh of such technologies such as Energy-from-Waste (EfW) or AD are much higher than for the***

[34] http://www.europarl.europa.eu/doceo/document/TA-8-2019-0226_EN.html

intermittent generation and as such may require careful policy design to encourage their development.

- Curtailment was also mentioned as a concern by some of the stakeholders we have talked to. If assets are curtailed and are not generating, they are not earning revenues and are not compensated. ***Curtailment is seen as a major risk factor for investment in new renewables assets. When creating financial models, investors would consider 5% to be a reasonable level of curtailment, however there is concern that curtailment levels in NI may increase in the absence of measures such as the N-S interconnector going ahead. As things stand the level is at 9.4% of the total available wind energy[35].***
- Another possible solution with regards to curtailment draws from Scotland's experience. For build-out of connections in remote areas, industry standard rules have been relaxed, allowing for cheaper connections (known as "Connect & Manage"). The compromise for developers is that they will be given non-firm access only. ***This has the purpose of lowering connection costs for developers thus encouraging investment.***
- Capacity and curtailment issues could be improved by having full use of export on the Moyle interconnector. Presently the interconnector is limited to 80MW (out of 500MW) export due to restrictions on the Scottish side of the interconnector. National Grid has created these restrictions due to curtailment and network capacity issues due to the levels of onshore wind in the Galloway area where some of Scotland's best wind resources lie.
- NIEN have tried to manage capacity on the grid by making non-firm offers for grid connections. This means that if projects are constrained down due to network issues, generators will not be compensated. This creates investment risk as there is no compensation for being constrained through no fault of their own.
- Some innovative solutions for resolving curtailment include diverting the curtailed electricity into heat, storage into batteries for DS3 services or for creating hydrogen. For example, Belfast Metropolitan College are running a project[36] (using EU funding) which uses an electrolyser to create hydrogen fuel for consumption by public transport.

Funding

- There is a view from industry stakeholders that NIEN have not received more funding because NI is on track to deliver on its 2020 renewables targets commitments. However, lack of further funding for building out infrastructure such as clusters and power lines, creates additional investment risk for developers. That said, funding is dependent on demand from developers for building projects, and so a cycle is developing which is hampering investment in renewables projects.
- NIEN follow the RAB model[37] and consult on various future development. However, it is unclear how they will deliver on these ideas without funding.

Other Aspects

- Some stakeholders pointed out that zero export is currently being considered to facilitate additional solar PV installations on the network. They believe that allowing this would solve many issues for NIEN

[35] http://www.eirgridgroup.com/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2018-V1.0.pdf
[36] http://www.nweurope.eu/projects/project-search/gencomm-generating-energy-secure-communities/?tab=&page=3
[37] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/825119/rab-model-for-nuclear-consultation.pdf see box 1 for definition

whereby developments could consume their own generation. This is something which could be considered if moving towards a “self-sufficiency” model as being promoted by the SEAI in ROI or a “prosumer model” as is occurring in GB. When coupled with household level DSR this could help reduce network demand, especially in times of peak consumption. For example, recent trials in the UK focused on domestic time-of-use and Demand Side Response (DSR) found that both allowed more demand capacity (in this case air-source heat pumps) to be placed on the distribution network[38].

- NIEN heat maps – a number of stakeholders indicated that the absence of up-to-date ‘heat maps’ showing capacity at network substations was preventing developers from progressing with project siting and planning. NIE Networks indicated that a new heat map is currently in development.
- There are plans by DfI for roll out of infrastructure to facilitate additional EVs. An early stage policy paper has been produced on charging infrastructure and any approach should be co-ordinated with other government departments such as DfE as part of a comprehensive energy policy.

5.3 Innovation & Development

Discussions arose about potential for innovation and development in improving NI’s energy infrastructure and in the context of meeting renewables and carbon targets. A willingness exists for innovation but feedback from the stakeholders is that risks are considered high without support which is likely to hamper investment in these areas. Some of the factors emerging from the discussions are as follows:

- Many public service initiatives can be curtailed by budget constraints. An example given during stakeholder engagement included an SIB project to roll out solar PV panels on a school, which was only possible because there was money left in the budget.
- Innovation can be hampered by a lack of access to data. The Landmark data set (an open source project by Google)[39] is not available beyond 2016. A government programme to make public data freely available in one source could help encourage innovation.
- Incentives could be created for innovation projects for small-scale batteries and solar in the private sector along the lines of the Fusion: Project Exempler programme[40] or in the form of tax break or upfront grants as is occurring in ROI[41]. Alternatively, tariffs such as Economy 7 could be used as an incentive to encourage batteries. Use of these mechanisms could allow for “quick wins” especially for technologies which already have permitted development.
- There is a concern that without policy to succeed the SEF, supply and skills of renewable technology such as solar is under threat. During the stakeholder engagement a renewables lobby group stated that much of the skills and labour are moving to ROI where there is more work and salaries are higher. The fear is that if this situation persists, Northern Ireland’s renewables technology industry will close down and it will be hard to get it back up in the future.
- Several stakeholders suggested setting up an entity similar to the SEAI in ROI. Some of the areas such an entity could target include:
    - Innovation solutions and grants
    - Low carbon buildings
    - Designated car parking spaces for EVs (e.g. one in 10)
    - Educate the public about Economy 7 and time of use style tariffs
    - Create tools for the public to calculate what grants are available to them and what savings they could make
    - Investigate aligning charging infrastructure with abundance of intermittent generation e.g. for solar charging at work while the sun is shining, charging at home at night while the wind is blowing
    - Innovation for district heating from council developments

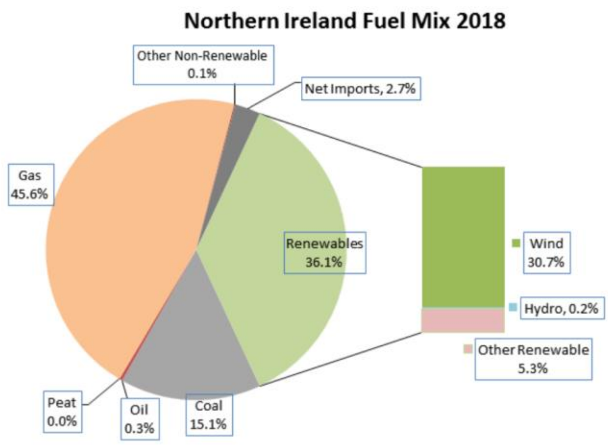
[38] CLNR Post Trial Analysis – Residential DSR for Powerflow Management (2015)
[39] https://ai.googleblog.com/2018/03/google-landmarks-new-dataset-and.html
[40] https://intertradeireland.com/innovation/fusion/fusion-project-exemplars/
[41] https://www.seai.ie/grants/home-energy-grants/solar-electricity-grant/

6 Technology Review

6.1 Current electricity generation technology in NI

Power generation in Northern Ireland is mainly through a mix of gas, coal, oil and renewable generation with onshore wind in turn accounting for some 80% of the contribution from renewable sources. The 480MW Moyle Interconnector also connects the system to the GB electricity grid with further interconnection being provided by two tie-in lines to the Republic of Ireland also providing a small amount of power transmission capability.

Figure 16 - NI Generation Fuel Mix in 2018[42]



<u>Existing thermal generation</u>

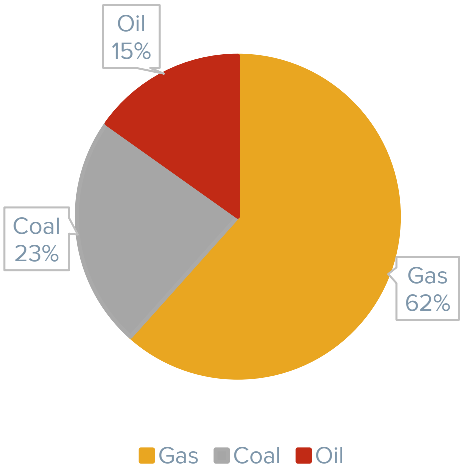
Thermal generation in NI is dominated by gas which comprises 1,263MW (circa 30%) of the installed capacity and nearly 46% of energy generated. Two plants at Ballylumford and Coolkeeragh account for the vast majority of this capacity with the former being converted from oil to gas in 1992 and the latter being a CCGT plant that became operational in 2005.

Two coal-fired units are in operation in Kilroot albeit they require further retrofit to meet requirements of the Transitional National Plan under the EU Industrial Emissions Directive to allow it to continue operation post-2020. It is assumed in the SONI Generation Capacity Statement that all coal-fired generation will cease in NI by 2024 in line with UK policy. Currently coal generation comprises 13% of installed capacity in NI.

All three of the above plants also have oil-fired generation capacity with Kilroot comprising 140MW of oil-fired gas turbines (albeit the main units can also be co-fired on oil[43]), Coolkeeragh having a single 53MW kerosene powered gas turbine and Ballylumford having two 58MW distillate fired aero-derivative gas turbines. These units primarily operate as peaking plant which is evidenced by the fact that although oil comprises 8% of overall installed capacity it accounts for only 0.3% of annual electricity generation.

[42] http://www.eirgridgroup.com/how-the-grid-works/renewables/
[43] Kilroot has primarily been fired on coal in recent years due to lower fuel costs

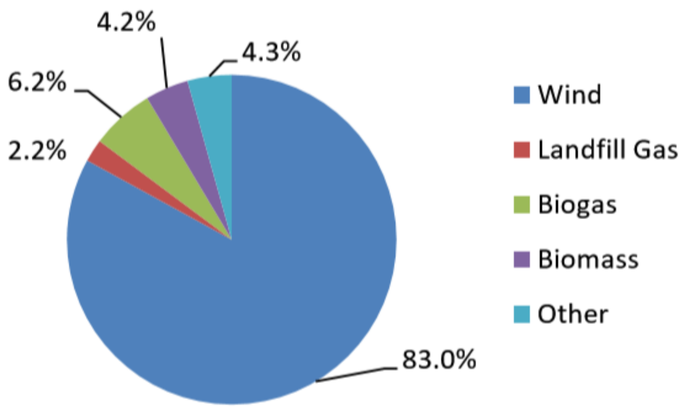
Figure 17 - NI generation fossil fuel installed capacity



Existing renewable generation

Renewable energy's contribution to the NI generation mix has grown to record levels in recent years. Figures published by the Department for the Economy show that renewable energy accounted for 38.6% of demand in the year to March 2019 from 8.1% in 2009[44]. Some 83% of that was generated by onshore wind with the remainder coming from a mix of renewables including hydro, biogas, biomass and solar PV per Figure 18.

Figure 18 – NI Renewable Electricity Generation by Type (Jan - Dec 2018)



Other includes Hydro, Tidal, Combined Heat & Power (CHP) and Photovoltaic (PV)

The breakdown of existing generation is shown in Table 5 below[45].

Table 5 - Breakdown of currently connected renewables projects

Scale	Capacity	Comments
Micro-generation (<11kW)	~83MW	Mainly G83 connected rooftop solar PV
Small-scale generation (<5MW)	~284MW	G59 connected uncontrollable

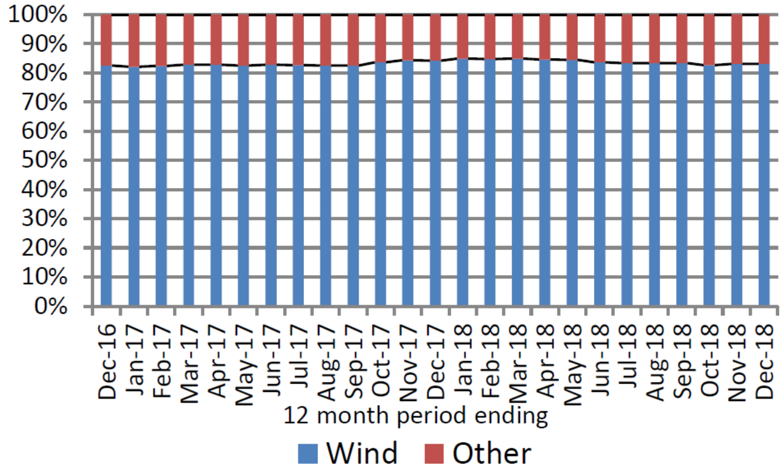
[44] DfE Electricity consumption and renewable generation in Northern Ireland – year ending December 2018
[45] SONI Connection Register March 2019

Scale	Capacity	Comments
		generation – mainly onshore wind and solar PV
Large-scale generation (>5MW)	~1,230MW	90% onshore wind 7% solar PV

The growth of non-onshore wind renewables in NI

Whilst onshore wind continues to dominate the renewable generation mix, other forms have also seen significant growth in the last few years, increasing 500% since 2013 and generally keeping pace with the roll-out of wind since 2016 per Figure 19[46].

Figure 19 - NI renewable generation split



6.2 Onshore wind

Onshore wind is by far the largest source of renewable electricity in NI both in terms of installed capacity and energy generated. It is also widely expected to play a dominant role in achieving any future decarbonisation of the NI electricity system. At the end of 2018 there was circa 1,283MW of onshore wind installed in NI per Table 6.

Table 6 - Onshore wind in NI

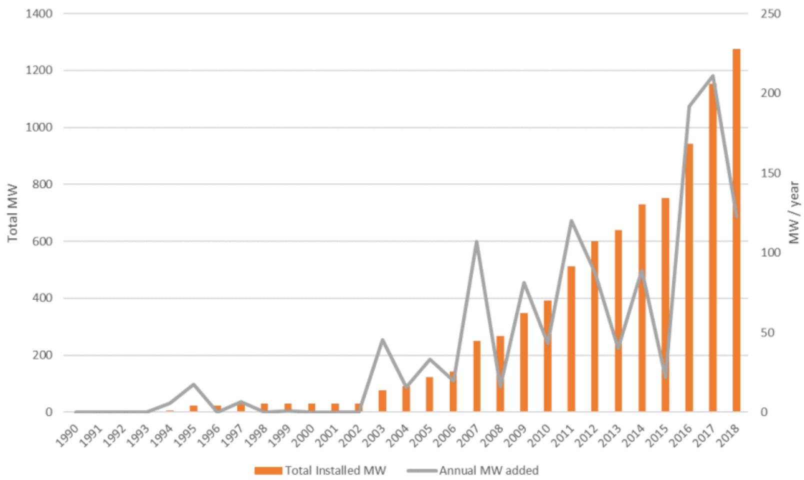
Category	Output
Large-scale (>5MW)	1,116MW
Small-scale (<5MW)	165MW
Micro-scale (<50kW)	~2MW

One of the effects of the NIRO support scheme was the construction of large numbers of one-off 250kW, or less wind turbines throughout the region driven by a banding level of 4 ROCs per MWh. This has drawn criticism from some stakeholders on the basis of their contribution to total renewable energy targets versus their cumulative visual impact.

[46] Refer to DfE Electricity consumption and renewable generation in Northern Ireland – year ending December 2018

Onshore wind penetration increased relatively steadily between 2008 and 2016 at approximately 67MW per year but surged to a 175MW yearly average between 2016 – 2018 as projects rushed to secure ROCs ahead of the closure of the NIRO.

Figure 20 - Onshore wind build-out in NI[47]



To date, development of large-scale onshore wind in NI has focused on prime sites to the north and west due to a combination of higher elevations and wind speeds, the availability of relatively remote sites and reasonable access to grid capacity. Small scale projects are distributed throughout NI.

Onshore wind's success in NI is based on a range of factors:

- A supportive policy regime and support scheme driven by an ambitious renewables target that provided attractive returns and investor certainty
- NI has one of the best wind resources in Europe – average speeds can be over 8.5m/s at hub height
- A supportive planning and grid connection process enabling connection of large quantities of renewables
- Low cost of capital due to its position as an increasingly mature technology
- Technology improvements leading to increased turbine size and output and decreased Levelised Cost of Electricity (LCOE) making marginal sites feasible
- A mature supply chain combined with experienced developers and contractors

Considering the quality of wind resource availability in NI it is widely expected that onshore wind will continue to be the primary source of renewable electricity in NI to 2030 and beyond with falling costs making it increasingly competitive with conventional generation sources including CCGT plants which will likely be the lowest cost fossil fuel generation in NI in that timeframe. NIEN already forecasts that an additional 134MW of onshore wind will connect by 2021, partly linked to its cluster substation build-out programme[48,49]. Given the recent announcement of NI's first subsidy-free wind farm there may be further, if limited, opportunities to deploy onshore wind in NI before 2022[50].

There are also currently circa 550MW of onshore wind projects in the pipeline per Table 7. This confirms the view of a number of key stakeholders that there is still a strong appetite for onshore wind development in NI despite uncertainty on the route to market for future projects.

[47] Based on information sourced from SONI and NIE Networks
[48] https://www.nienetworks.co.uk/documents/useful-resources/cluster-update-28-september-2018.aspx
[49] Based on NIE Networks RGLG Presentation, December 2018
[50] https://www.belfasttelegraph.co.uk/business/northern-ireland/renewable-energy-firm-res-sells-co-londonderry-wind-farm-for-37m-38072952.html

Table 7 - Onshore wind pipeline

Stage	No. of projects	MW
Pre-planning	2 (both for repowering)	55.8MW
Planning	76 (some co-located with storage)	404MW
Consented	455 (large number of 250kW units)	86MW
Construction	8 (7 are single-turbine 250kW units)	26.7MW

However, as seen in other jurisdictions, opposition to onshore wind has been growing with several projects experiencing delays after planning decisions were subjected to Judicial Review. Furthermore, as the electricity network in the region is nearing capacity, further development will likely require substantial capital investment to reinforce or expand the distribution and transmission system.

Onshore wind technology developments

Whilst onshore wind is a mature technology some further technology improvements and cost reductions are foreseen in the coming years, albeit not at the same rate as competitors such as offshore wind, solar PV and battery energy storage.

The main focus is expected to be on increasing rotor size thereby increasing the blade swept area and maximising capacity factor and energy capture. Historically increases in hub height have generally scaled linearly to increases in rotor diameter albeit with some scatter as manufacturers generally offer a number of tower configurations for each machine.

However, in recent times manufacturers have been responding to the need to drive down costs in competitive auction processes and cope with restrictive tip height restrictions by pushing the performance envelope of their machines and offering increasingly large rotor diameters often at relatively low hub heights. Previously mainstream rotor size offerings such as those in the 90m – 100m range are being phased out as manufacturers migrate to rotors typically in excess of 105m such as the Nordex N114, Vestas V105 and Siemens SWT114.

A 2016 International Energy Agency (IEA) / Berkley survey of 163 wind energy experts highlighted the expectation that onshore (and offshore) wind has plenty of scope to further reduce costs out to 2030 and beyond - notwithstanding project-specific elements are always a factor[51]. Key findings included:

- Experts expect onshore wind to remain lower cost than offshore but the gap between them to narrow
- Turbine sizes are expected to continue to grow leading to higher nameplate power and capacity factors
- Turbine reliability to further increase leading to lower costs and longer project life
- Capex reductions of 12% and opex reductions of 9% (from 2014 baseline)

In other parts of the UK, planning and government policy have been very favourable to the maximization of wind resources. For example, in Scotland planning has recently been granted for turbines with a tip height of up to 220m which will be suitable for machines with rotor diameters in excess of 150m[52]. Elsewhere, in ROI tip heights of 125m were typical but have now progressed to the 150m – 160m range. Furthermore, 170m tip heights are becoming increasingly common including on the first corporate PPA-based onshore wind project in the country.

Planning is therefore critical in the context of NI continuing to support a vibrant wind industry. During our consultation, concerns were raised that restrictive planning policies will end up limiting turbine dimensions

[51] https://www.nature.com/articles/nenergy2016135.epdf?author_access_token=xOjt15xAsgbwf-DTbC9umtRgN0jAjWel9jnR3ZoTv0Pm0tcEncNIRUyqt3vi2Zdm55gFQx3FMImKG0Gh8VsP0wqN8AeZekJAOtf6AfxskkGU8raC7OZ5Y_20S7qTMDRvAjSHfuoi9oAte8h3yQ3nDw==
[52] https://www.banksgroup.co.uk/projects/renewables/kype-muir-extension/

and locations so as to make maximizing available energy yield virtually impossible. In particular, reference was made to draft Local Development Plans that restricted structures based on height which has the potential to affect both wind turbine and grid infrastructure deployment. Whilst wind turbine manufacturers are reacting to such limitations by offering large blades on lower hub heights this is not always desirable, particularly in areas of high wind shear which places considerable additional stress on hardware leading to reduced performance and reliability.

If onshore wind is to be deployed at the lowest possible cost and play a significant role in meeting 2030 emissions targets then planning and energy policies will need careful alignment to best meet the requirements of stakeholders. There is significant risk that planning policy currently being developed may not facilitate the required renewables roll-out to 2030 in general in NI, and may significantly constrain onshore wind in particular.

Onshore wind growth in NI to 2030

If key elements such as a viable route to market, timely access to the electricity grid and supportive planning policies are in place, onshore wind capacity is in a position to grow strongly in NI to 2030 and beyond. As a number of projects will be exiting from the ROC scheme and approaching their end-of-life, onshore wind will likely enter an extensive period of repowering as we approach the late 2020s, likely resulting in existing sites being re-powered with fewer, larger turbines which will require new planning and may potentially face grid capacity issues if they are constrained by their original Maximum Export Capacity (MEC).

Onshore wind costs are expected to fall by circa 7% between 2022 and 2030 reaching £44/MWh. Whilst this is likely to make it the cheapest form of generation on the grid a large-scale deployment will require considerable investment in grid infrastructure coupled with innovative solutions such as hybrid projects.

In all scenarios onshore wind continues to be the dominant form of renewable energy in NI to 2030. The maximum level of deployment has been adjusted based on feedback from key stakeholders regarding transmission system capacity, particularly in the north-west of the country, and the desire for an increased spread of technologies.

6.3 Solar PV

Solar PV has enjoyed very strong growth in recent years having increased from 2MW in 2011 to 246MW in 2018[53,54]. This is in large part driven by a favourable support regime for micro-generation solar PV which resulted in the installation of over 22,000 systems through the region, with the vast majority of installations being microgeneration rooftop units[55]. The breakdown of solar PV installation is shown in Table 8.

Solar resource levels in NI are not particularly favourable being circa 900kWh/m^2/annum which is half that of southern Europe and 25% below those in southern England. Capacity factors are generally in the 9 – 11% range depending on location and whilst installations are spread throughout NI, the majority of the larger plants are installed in the east where solar irradiance is higher and network access is more straightforward. Despite these limitations a range of factors apart from the aforementioned support scheme contributed to a large-scale deployment throughout NI. These included a dramatic reduction in solar panel prices in the last 7 years, micro-scale solar PV being exempt from planning[56], substantially increased panel efficiencies and short construction durations.

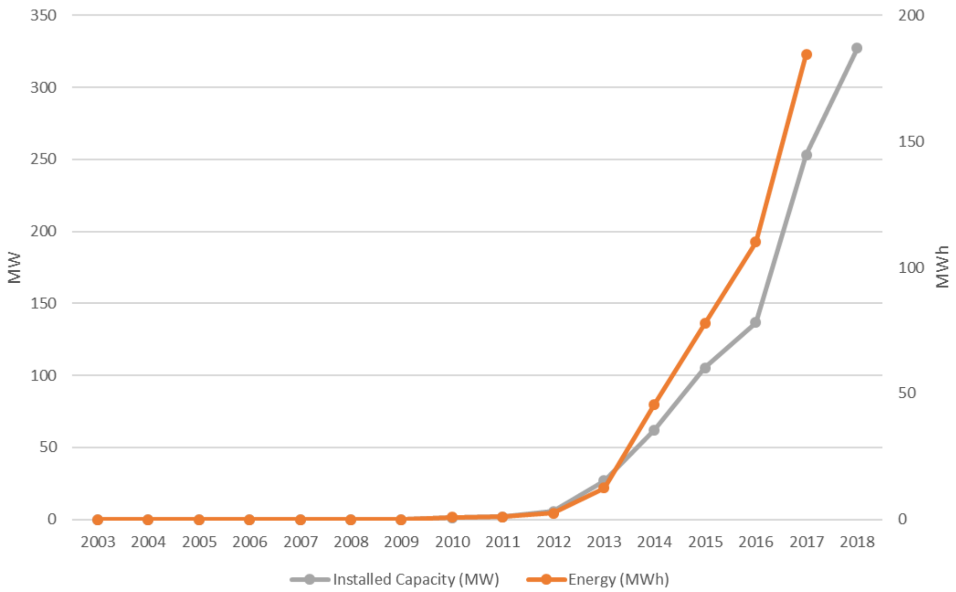
Table 8 - Solar PV installations in NI

Size	MW	No of installations	Comments
Large scale (above 5MW)	121MW	7	Range from 6MW to 36MW

53 Dept for Agriculture – Reducing emissions in Northern Ireland (2019)
54 Sourced from NIE Networks
55 The Electricity Journal - Unintended consequences of Northern Ireland’s renewable obligation policy
56 Micro-generation PV is classed as ‘Permitted Development’ in NI

Small scale (5MW or less)	22MW	31	Most projects are G59 connected and uncontrollable.
Micro scale (<50kW)	116MW	22,172	Mostly rooftop PV installations

Figure 21 - Solar PV penetration in NI[57]



Technology review

Solar PV is increasingly considered a proven and mature technology with close to 100GW installed globally in 2017 alone well ahead of any other generation technology. This brought global capacity to over 400GW with much of the growth centred in China. The future development of the technology will mainly be associated with advances in existing crystalline silicon technologies and thin film technologies with the latter being cheaper and requiring less silicon.

Solar PV forecast to 2030

While the capacity factor of solar PV is relatively low in comparison to other intermittent technologies such as onshore wind it has the advantage of being more predictable.

The 2013 MATRIX Report presented a relatively conservative view of the potential of solar PV in NI stating that they expected *"Limited activity in solar PV in the region. Few early demonstrators… but nothing significant beyond that. Geoclimate not ideal and developers have struggled to raise finance for large scale projects."*. This is unsurprising as solar prices were substantially higher at that time and were not expected to fall as steeply in the intervening years[58].

While most forecasts see solar PV forming an important part of the future energy mix in NI there are also some fundamental concerns including:

- The current absence of policy may lead to loss of skills and expertise for residential solar PV installation and this will be difficult to re-establish if new policy supports are approved

[57] https://www.gov.uk/government/statistics/regional-renewable-statistics
[58] According to IRENA (2019) the price of solar PV modules fell by 80% from 2009 to 2018 with LCOE falling by 75%

- Micro-generation rooftop solar PV (classed by NIE Networks as <11kW capacity as opposed to the 50kW threshold used by OFGEM) is typically not visible to or controllable by SONI, the system operator, and this may lead to system stability issues if a significant quantity is added to the network.
- Micro-generation can also cause issues for NIE Networks where it can lead to local issues on the distribution network and if not notified by the installer may cause safety issues where an undeclared unit feeds on to the local network where operatives believe to have been electrically isolated.
- This has led to NIE Networks placing limits on new solar PV installations due to distribution system capacity concerns in an area and may lead to issues with network stability should levels increase much further. NIE Networks have emphasised that any new micro-generation support scheme should ensure that they are notified as standard of new installations.

There is significant potential for deployment in a 2030 timeframe depending on the level of project supports provided. The continual fall in the price of solar PV is set to continue throughout the 2020s with costs forecast to fall as low as £45/MWh by 2030. This decrease combined with a relatively straightforward planning process and short construction durations of four to six months makes solar PV an attractive proposition for future deployment.

Other than the absence of a route to market, the primary concern for the further development of large-scale solar PV projects may be grid related with any further increase in curtailment and constraint negatively impacting solar PV projects in a similar fashion to onshore wind. With solar PV already carrying low capacity factors the prospect of such revenue uncertainty without any mechanism for compensation may make some projects non-viable.

6.4 Biomass

At 34MWe installed capacity, biomass generation accounts for circa 4.1% of renewable electricity generation in NI[59]. The largest plant is Evermore's 16MWe Lisahally CHP Plant which also provides 6MWth of heat to a local wood drying facility whilst burning approximately 110,000 tonnes of waste wood chippings per year that would otherwise be landfilled[60]. Other units range in size from sub-500kW to circa 6MW and are located throughout NI.

Whilst dedicated biomass for process heating has been a factor throughout NI, biomass for generation of electricity has principally been via CHP plants which requires the plant be built at facilities where there is an existing requirement for process heat and ready access to feedstock such as waste timber or animal waste renderings. Further biomass CHP growth has been limited by issues including a lack of established heat networks (an inherent limitation on CHP plant growth in NI in general), limited availability and guarantee of suitable feedstock such as wood chippings or fast rotation coppice and relatively high levelized costs compared with onshore wind and solar installations.

Electricity generation from biomass is widely regarded as a mature technology and accounted for over 2% of global generation in 2015. Whilst biomass generation is based on the traditional fossil fuel model its feedstock is generally less energy dense than fossil fuels with wood chips typically having 60% of the energy density per unit weight of coal. In recent years biomass has been used to supplement and part-decarbonize existing fossil fuel generation through co-firing or to replace it completely through biomass conversions such as at Drax Power Station where four of six units have been converted to burn wood pellets. We are not aware of any plans to utilize biomass for this purpose in NI.

Biomass feedstock for power generation includes:

- Energy crops – crops such as fast rotation coppice grown specifically as feedstock
- Forestry residues – residues from timber industry and forestry operations (incl. logging)
- Agricultural residues – straw and silage and food crops

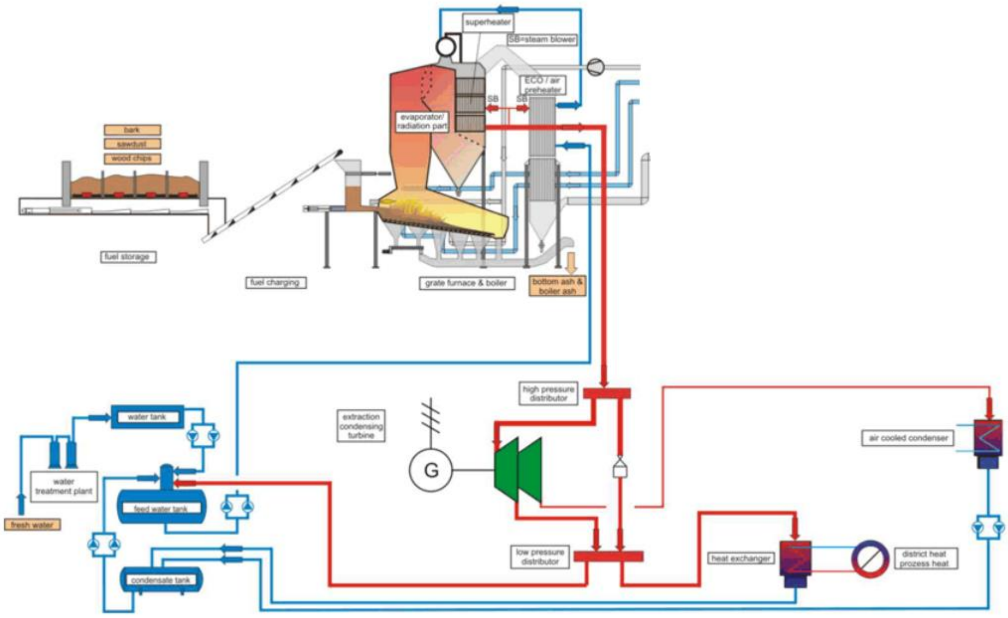
[59] Note that other CHP biomass generation may be listed by DfE under 'Other' and not included in the 4.1%
[60] www.evermoreenergy.com

- Organic wastes – wood waste, the organic fraction of municipal solid waste, manures, sewage sludge, tallow and used cooking oil

The predominant biomass fuel in NI is waste woodchips with the 16MW$_e$ Lisahally CHP plant utilizing 2M tonnes per annum. Most biomass-to-electricity plants in NI are smaller in scale and utilise fuel from their surrounding catchment areas which mirrors its development in other jurisdictions. However, recent years has also seen the development of large-scale biomass CHP plants in many parts of Western Europe including the rest of the UK, as well as in parts of Asia. Whilst biomass-to-electricity technology is well established, establishing a secure supply of suitable quality feedstock is perhaps most critical with the presence of credible fuel supply counterparties being key to the industry's development in a region.

The technology has advantages over intermittent sources of renewable energy such as wind and solar PV insofar as it typically has a high load factor (circa 80%), provides carbon-neutral back-up capacity and/or base load, and can provide ancillary services thereby supporting increased non-synchronous penetration on the system. Furthermore, as it is synchronous generation it is not subject to curtailment which is particularly valuable in NI where there are concerns that additional non-synchronous generation will drive curtailment to levels that impact projects' business cases.

Figure 22 - Typical CHP biomass plant layout



Whilst biomass has several advantages over other renewable technologies it also has a number of drawbacks. As mentioned previously fuel supply availability and quality control is a key risk to the business case of any biomass project but can be managed through contracting with reputable counterparties. The supply of feedstock in NI is relatively limited but with just 4% of the land under forest (far lower than the 12% average for the UK) there are options to increase supply in the region by moving to lower-carbon land use including fast rotation crops or coppice.

There has also been much debate about the true sustainability of biomass given practices such as importing large quantities of feedstock from other countries[61], transport impacts on local areas, the growing of biomass crops at the expense of food production or those that result in negative land-use change impacts. For example, a 300MW biomass-fired station uses approximately 2.4M tonnes of woodchips per year[62]. In response to these concerns the EU has issued non-binding guidance on biomass sustainability

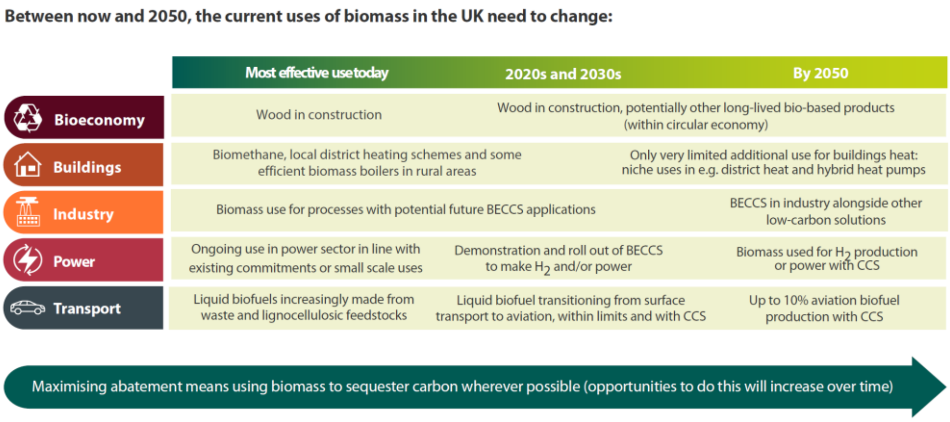
[61] Examples include transportation of wood pellets from North America to fuel four biomass-converted units at Drax Power Station

[62] See Renewable Energy Focus 2009

requirements including forbidding use of biomass from land converted from high carbon stock areas such as forest or from areas of high biodiversity[63].

In addition, a recent report by the UK Committee on Climate Change (CCC)[64] concluded that while *‘there is significant potential to increase domestic production of sustainable biomass to meet between 5% and 10% of energy demand from UK sources by 2050’,* the use of biomass for energy production without carbon capture and storage (CCS) must cease in the medium term if the UK is to achieve significant long term emissions reductions. This has the potential to limit the longer-term appeal of the technology for power generation in NI as the Committee has also stated that the region *“has limited access to CO_2 storage sites and does not appear to be best placed to locate BECCS plants[65]”*. Its recommendation suggests that generating power from existing biomass and adding some small-scale stations in future is optimal but ultimately sees the technology migrating to CCS-based plant only in the 2020s and 2030s.

Figure 23 - Recommendations from CCC report ‘Biomass in a Low Carbon Economy’ (2018)



6.5 Anaerobic Digestion (AD) and Landfill Gas (LFG)

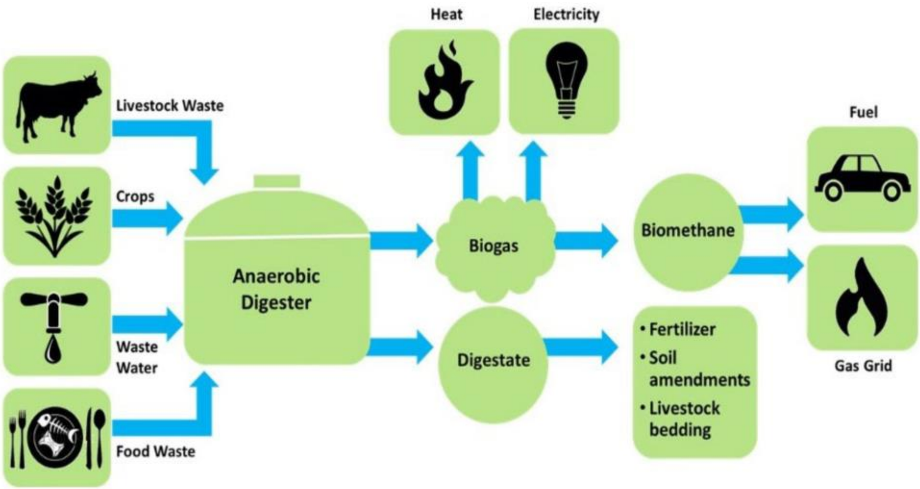
There are approximately 95 operational AD sites in NI with a total capacity of 84MW[66]. In addition, there is a further 16MW of LFG connected to the network. The majority of AD plants connected to the system are 500kW units which attracted 4 ROCs between 2010 and the closure of the scheme. Plants are typically farm-based and utilise organic residues such as cow or pig slurry, crop cuttings, food waste or chicken litter. AD plants are not location specific and are distributed throughout NI.

Anaerobic Digestion (AD) uses waste biomass materials to produce biogas by holding liquid biomass in a digester tank in the absence of oxygen causing broken down of the material producing biogas[67]. There are two types of AD process: mesophilic digestion where the digester is heated to between 30°C and 35°C and thermophilic digestion where the digester is heated to 55°C. Mesophilic digestion is cheaper but requires larger digestion tanks and sanitisation can be required. Thermophilic digestion offers higher biogas production in less time as well as having better pathogen and virus ‘kill’ capabilities. However, it is more expensive and requires more energy input due to higher temperatures.

The biogas produced in the digester is primarily composed of methane (approximately 60%) and carbon dioxide (approximately 40%), with traces of hydrogen sulphide and ammonia.

[63] See https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1410874845626&uri=CELEX:52010DC0011
[64] Committee on Climate Change - Biomass in a Low Carbon Economy (2018)
[65] BECCs stands for Bio-energy with Carbon Capture and Storage
[66] Renewable Energy Foundation website
[67] Ricardo-AEA - Envisioning the Future in NI to 2050 (Annexes)

Figure 24 - Typical AD layout[68]



The quantity of biogas produced is linked to the quality as well as the quantity of biomass that is used in the digester. AD installations are in widespread use in NI and indeed globally but have generally relied on supportive policies given LCOEs are relatively high at over £120/MWh.

The 2013 MATRIX report stated that *"Northern Ireland may have particular opportunity to develop and deploy anaerobic digestion technologies. However, although AD is considered likely to be an area of global growth, it will be a challenge for Northern Irish companies to compete against the long-established AD markets of countries such as Austria and Germany"*.

Landfill gas

There are currently 12 landfill gas plants located around NI totalling 16MW with the largest of which are outputting 2.8MW - 5MW. Gas produced through decomposition of organic waste is typically 50% methane and 50% CO2 which are highly potent GHGs and therefore not permitted to be released to atmosphere.

Typically, upon reaching capacity, landfill is capped and the biogas utilised to generate power via gas engines. Whilst output can vary the load factor is typically around 80% and sites can remain biologically active for several decades.

Whilst it is expected there will be ongoing requirements for further landfill sites in NI, the portion of organic matter being disposed in this manner has already decreased to around 35% of 1995 levels as mandated through the 2003 Landfill Act, considerably reducing the potential for any future roll-out of large-scale landfill gas generation in NI to 2030 or beyond.

[68] https://www.eesi.org/papers/view/fact-sheet-biogasconverting-waste-to-energy

Figure 25 - Landfill gas sites in NI[71]

Biomethane

An area raised by a number of stakeholders was development of biogas conversion to biomethane for injection into the natural gas grid[69]. Biomethane is formed by upgrading biogas through removal of CO_2, H_2S, water and other trace elements and can be achieved through a variety of processes including absorption, Pressure Swing Adsorption and membrane separation[70]. The Department for Agriculture, Environment and Rural Affairs (DAERA) 2019 report on reducing emissions in NI took a positive view on biomethane production stating that NI could produce 130 – 580 million m^3 of biomethane per year to generate up to 2,000GWh of power or heat annually. However, it also warned that biomethane injection into the gas network may prove difficult considering its limited coverage.

Whereas unrefined biogas can be utilised directly in CHP plant, further refinement into biomethane for injection into the gas grid was highlighted by a number of stakeholders as a potentially better use of AD than the generation of electricity and heat. However, this is likely case-dependent with developers who are remote from the gas network and/or with significant onsite heat and power requirements instead opting for dedicated heating or CHP plant. Overall, it is recommended that gas injection tariffs such as those in operation in GB should be considered as part of future energy policy development in NI, particularly given the planned expansion of the gas network.

AD and LFG forecast to 2030

While AD can contribute to the overall energy mix in NI there is likely a limited potential for deployment as large-scale electricity generation to 2030 depending on the level of project supports provided. However, it is expected that AD can play a role due to its flexibility, high (70%) capacity factor, scalability and adaptability from large facilities that treat sewage, sludge or municipal solid waste, to smaller plants that deal with waste from a specific farm or local community[71]. It is assumed that restrictions on landfilling of organic waste will continue to tighten limiting the future potential of landfill gas in NI.

6.6 Offshore wind

There is currently no offshore wind farm located in NI and it has not been included in The Crown Estate's (TCE) Round 4 leasing process. Approximately 90% of the prime area for offshore wind development in NI

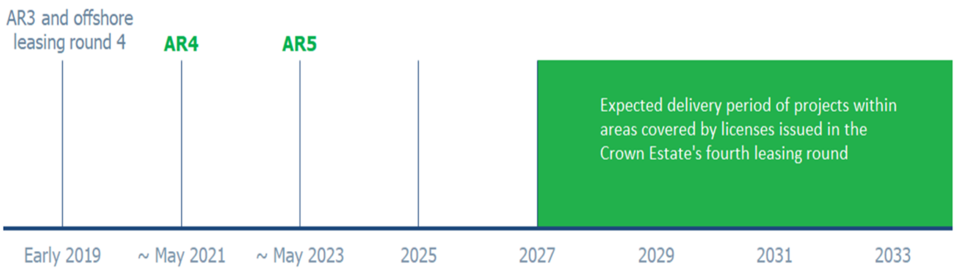
[69] 2013 MATRIX report
[70] Biogas: Developments and perspectives in Europe – Scarlat et al (2018)
[71] Landfill gas map based on number of sources including stakeholder engagement and desktop study

lies within 13km of the coast increasing the risk of receptor, navigational and environmental issues as well as conflict with marine activities such as commercial fishing when compared with other sites in the UK.

In March 2011 TCE launched two parallel leasing rounds for offshore wind and tidal energy in NI based on new policy aimed at creating an ocean energy sector in NI by 2020[72]. As a result, two 'Wind Resource Zones' were identified off the north-west coast and south-east coast with theoretical capacities of 600MW and 900MW respectively, based on technology and practices at the time. Zone 1 was not progressed due to relatively high receptor sensitivity and its situation in deeper waters than offshore technology was generally operating at the time whereas 600MW was allocated in Zone 2 to a single developer. The developer initially scaled back the project to 400MW to minimize impact on shipping and ultimately pulled out of the process in 2014 for commercial reasons. There has been no offshore development since that point.

Development timelines for offshore wind are typically longer than most other renewable technologies owing to the processes involved in seabed leasing, consenting and development. Cornwall Insight has calculated that for offshore wind in GB, successful projects have typically seen a 6 to 9-year lead time between being granted a lease and being awarded a contract under the CfD. An expected timeline for future GB development is shown below in Figure 26. It can therefore be assumed that even with a leasing round by TCE in Northern Ireland waters within the next few years, any physical development of offshore wind would be towards the end of the 2020's at the earliest.

Figure 26 – Expected offshore wind development timeline in GB



Source: Cornwall Insight

Offshore wind forecast to 2030

Since the launch of the NI Offshore Renewable Energy Strategic Action Plan (2012 – 2020) (ORESAP) the offshore wind industry has developed far more quickly than anyone had envisaged with LCOEs falling nearly 45% in the period to 2018[73]. For example, the ORESAP targeted auction prices of £100/MWh for offshore wind by 2020 whereas the price had already fallen to between £74.75 and £57.50 in the 2021 – 2022 and 2022 – 2023 UK CfD auctions which took place in 2017[74]. BEIS has set the target strike price for offshore wind at £56/MWh and £53/MWh for the 2023 – 2024 and 2024 – 2025 CfD allocation rounds respectively indicating that cost reductions are set to continue. Indeed, research by IRENA forecasts that offshore prices may drop by 35% by 2025[75].

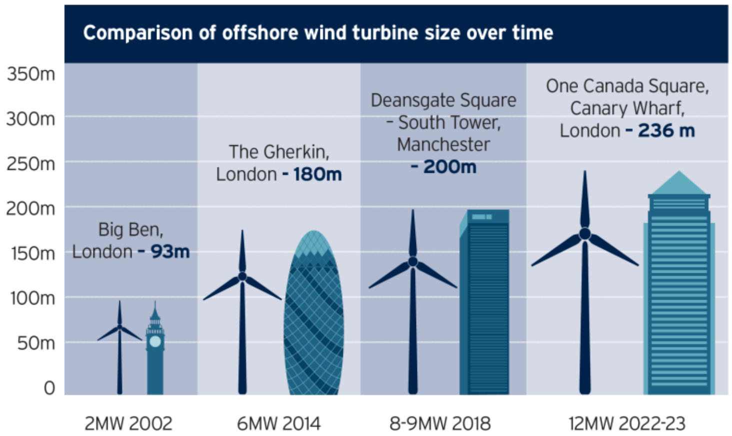
There are a number of factors driving the reduction of cost in offshore wind:

1. Reduced cost of capital – as investors' understanding of the level of risk associated with offshore wind development increases.
2. Increased turbine capacity – the capacity of offshore turbines grew by 16% annually between 2014 and 2018 and the average turbine size is in now excess of 6.5MW. This trend is expected to continue

[72] DETI – Offshore Wind and Marine Energy in Northern Ireland – Strategic Environmental Assessment (2009)
[73] https://www.windpoweroffshore.com/article/1525362/europes-offshore-wind-costs-falling-steeply
[74] https://www.carbonbrief.org/analysis-uk-auction-offshore-wind-cheaper-than-new-gas
[75] IRENA – The Power to Change: Solar and Wind Cost Reduction Potential to 2025

as 10MW – 12MW units currently in development come online per Figure 27. Some forecasts project turbine capacity increasing to 15MW by 2030 with a rotor size in excess of 230m.

Figure 27 – The increasing capacity of offshore wind turbines[76]



3. Other costs – These include turbine costs (circa 45%), installation costs (circa 19%), electrical and civil balance of plant costs including foundations (circa 22%) and grid connection costs (13%). The greatest opportunity for cost reduction was identified in innovative construction and installation approaches including moving some assembly and commissioning activities onshore, increasing the maximum permitted windspeed for turbine installation and increasing the size of installation vessels[77].

Discussions with SONI and NIE Networks indicated that integration of 200MW – 300MW of offshore wind would likely require considerable grid-related works depending on the location and connection method for offshore wind. Two approaches discussed were:

1. Direct transmission connection into existing substation on the network (e.g. Kells substation which is approximately 40km from shore). Such a connection could cost in the region of £100m - £150m, the majority of which is assumed to be borne by the developer.
2. Buildout of new 110kV or 275kV infrastructure along the north coast capable of incorporating offshore wind and tidal capacity as well as strengthening transmission capacity in the region also allowing onshore renewable generation and new load customers to connect. It would also have the benefit of reinforcing capacity in the north-west region facilitating connection of additional onshore renewable generation. This approach was originally considered during the RIDP process but has not progressed in light of headroom in the system to 2020 and the absence of any offshore development requiring access. Construction costs for this type of project may be significantly higher at over £250m.

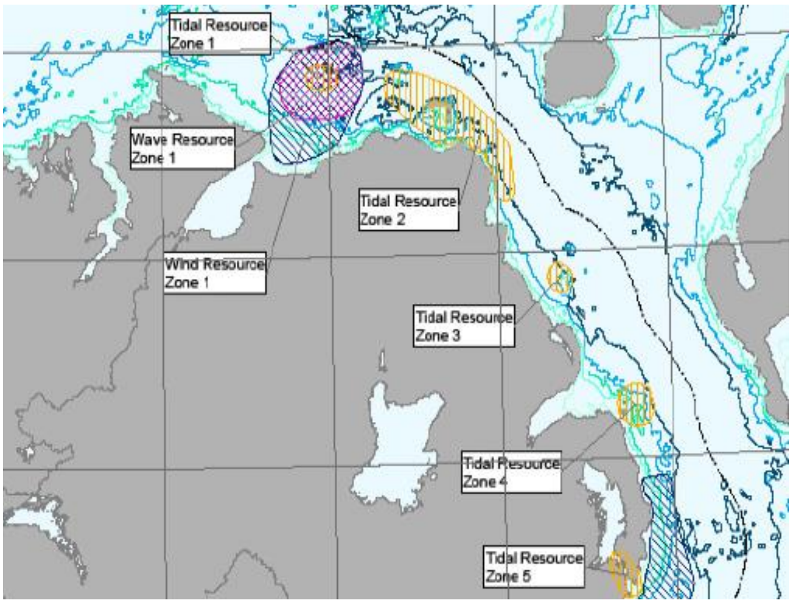
Offshore capacity is also contingent on distance from shore. Greater distances enable and necessitate larger projects due to decreased visual impacts, construction in deeper waters and higher grid-related costs. In the case of Zone 2 water depths are in the region of 20 – 60m. The original project was circa 8km from shore and it is assumed that any follow-on project would be similarly situated. Considering the availability of viable sites and the typical development timelines stated above it is assumed that up to 300MW of offshore wind may be operational by 2030.

[76] BEIS Industrial Strategy – Offshore Wind Sector Deal (2016)
[77] IRENA – The Power to Change: Solar and Wind Cost Reduction Potential to 2025

6.7 Tidal technology

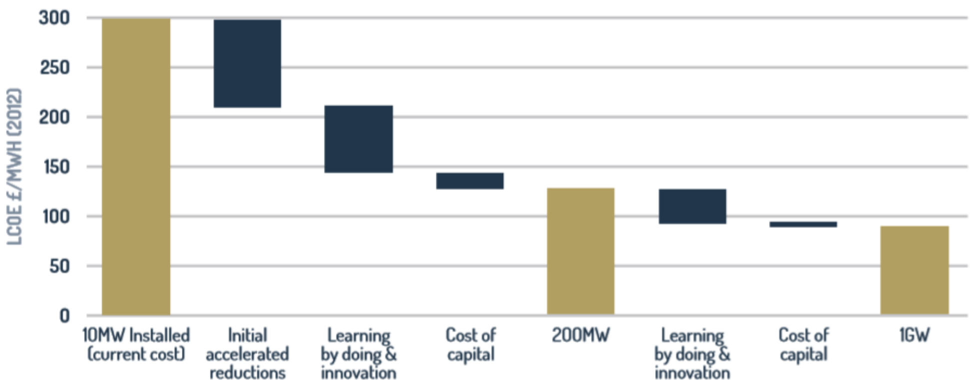
There have been several studies to date on the potential for the deployment of tidal technology in NI resulting in particular emphasis on deployment of tidal stream generators. The 2012 ORESAP study commissioned by DETI highlighted five regions of specific interest for tidal generation per Figure 28[78]. Three of these areas (Zones 3 – 5) at the Maiden Islands, the Copeland Islands and Strangford Lough, were considered to be of limited potential due to concerns about impact on the environment and marine users but suitable for small scale testing or demonstration projects. The two remaining sites at Fair Head and Torr Head (Zone 1 and 2) were considered to have the potential for deployment of up to 300MW of tidal generators.

Figure 28 - Areas for potential deployment of tidal technology in NI[78]



At that stage the Plan called for deployment of small-scale demonstration arrays in the 5 – 10MW range at a cost of circa £3m – £4.6m with a view that costs would reduce albeit remaining at over £200/MWh in 2020. Costs for tidal energy are unclear with a recent report by Catapult noting that whilst they currently stand at circa £300/MWh that they could reduce to £150/MWh after installation of 100MW and further to £90/MWh after installation of 1GW[79]. Other estimates fall either side of this estimate, sometimes by significant margins. Refer to Figure 29 for details of Catapult's forecast costs.

Figure 29 - LCOE forecast for tidal energy

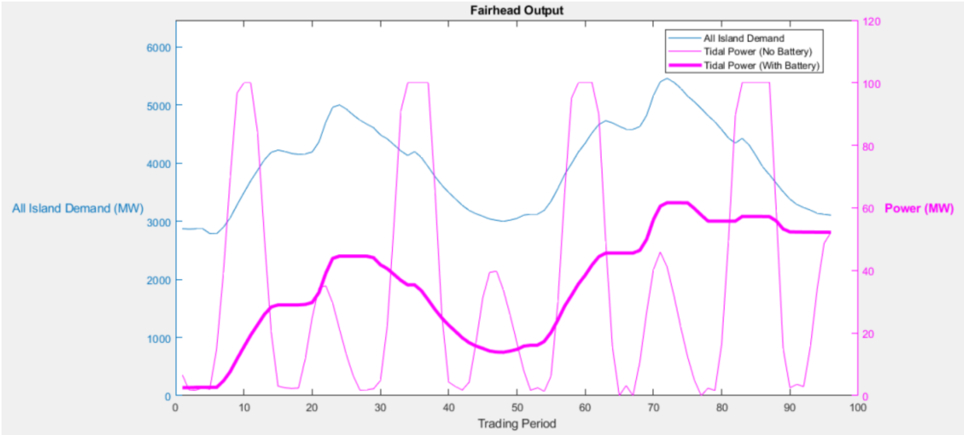


[78] DETI – NI Offshore Renewable Energy Strategic Action Plan (ORESAP) 2012
[79] Tidal Stream and Wave Energy Cost Reduction and Industrial Benefit - Catapult (2018)

Tidal energy has a number of key strengths when compared to other forms of intermittent renewables including:

- A predictable (intermittent) resource (refer to Figure 30)
- Water as a medium has a far higher density than air resulting in better power-to-weight characteristics
- Sites are generally located close to shore to avail of the strongest currents and ease of access
- Once commercially developed, deployment should be relatively straightforward, particularly in shallow waters

Figure 30 - Tidal resource predictability (with and without storage)[80]

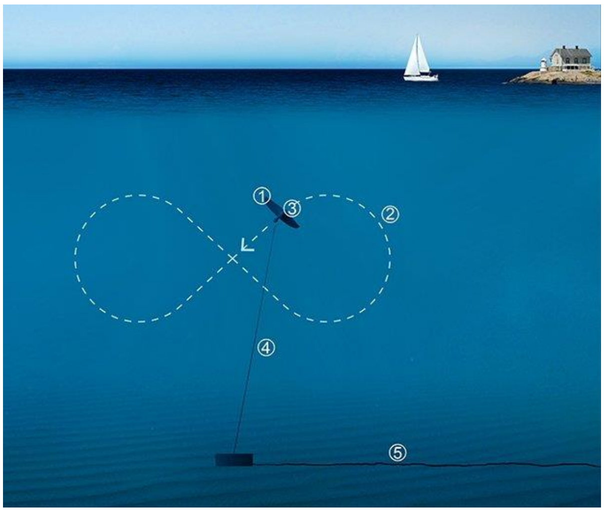


To date, the only large-scale grid connection of a tidal device has been the SeaGen demonstration project in Strangford lough. The project involved a piled, twin-rotor turbine with a maximum generation capacity of 1.2MW. The project was initiated in 2009 and was decommissioned in 2016. In general, the project is considered to have been a success in terms of proof of concept and small-scale demonstration.

More recent efforts to develop tidal technologies in NI waters include R&D testing by developer Minesto UK which has been deploying and testing of prototype-scale devices in the region since 2011[81]. It is also noted that in recent publications by the Crown Estate via their website that there is an intention to extend Minesto's existing lease at the site of its tidal project at Portaferry, Strangford Lough. Minesto are developing an underwater kite system which generates energy from lateral movement in a tidal stream and is deploying commercial-scale devices of 0.5MW at Holyhead, Wales.

[80] Typical example based on data received from Fair Head developer (DP Energy)
[81] https://minesto.com/our-technology

Figure 31 - Minesto's Deep Green kite system[82]



The European Marine Energy Centre (EMEC) in Scotland provides a list of 94 tidal technologies in development around the world[83] but the technology is still regarded as pre-commercial requiring further R&D and small-scale testing.

In respect of the larger scale developments in NI waters, it is noted that the Crown Estate granted lease agreements for two sites with the potential for up to 100MW each (subject to consents) off the coast of north Antrim. Agreements for lease were issued separately to two parties, with a site at Fair Head being allocated to a technology neutral developer in 2017 and the other at Torr Head to a joint venture partnership utilising a specific technology. With proposed grid connections at Ballycastle, the projects applied for consent to construct and operate 100MW tidal arrays in August 2015 and Feb 2017 for the Fair Head and Torr Head development areas respectively. However, one of the joint venture partners on the Torr head project filed for examinership in August 2018 which is expected to impact on the future development of the tidal array at that site.

Tidal barrages and lagoons, whilst well-established with capacities up to 250MW are in operation internationally there is no evidence that they have been considered in NI and therefore are not further considered.

Forecast tidal developments to 2030

The 2013 MATRIX report was cautiously optimistic for the potential of tidal (and wave) generation sectors stating that "Beyond 2035, marine, wave and tidal technologies are likely to play a greater role, particularly across Northern Europe, although they will still be dwarfed by the more established technologies[84]". In terms of the commercial viability of tidal technology, it is generally accepted that at the current stage of development, generation at sites with a significant resource in excess of eight knots is still significantly more expensive than other forms of renewable generation and would require substantial support to see commercial-scale deployment.

Outside the risks associated with deployment of the systems themselves, the grid connection for tidal arrays needs to be analysed given geographical constraints of tidal energy projects. Grid infrastructure in the areas zoned for tidal development is limited and any project approaching 100MW in scale would require a dedicated and potentially costly connection to a local transmission station. This risk may be further compounded if projects are deployed on a phased basis where a developer may need to pay for a grid connection that will be underutilised for a considerable period. However, the co-location of tidal energy with long and short-duration battery storage (as is being considered for the Fair Head site) as well as relatively

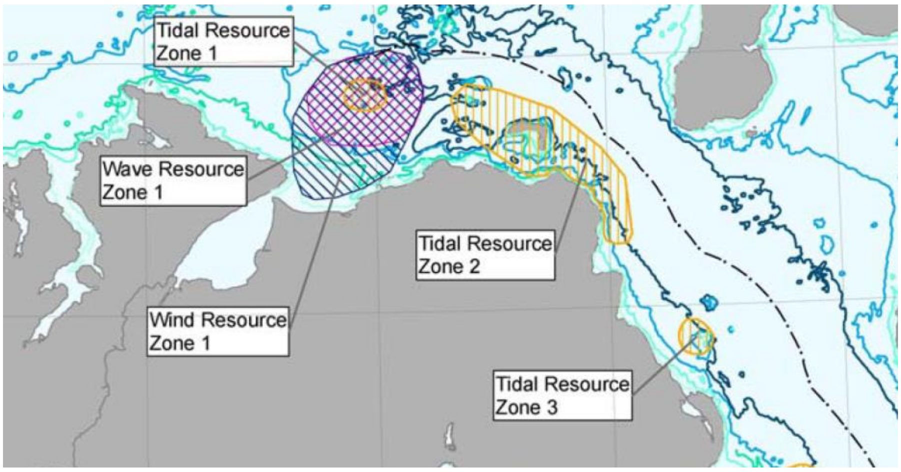
[82] https://minesto.com/our-technology
[83] http://www.emec.org.uk/marine-energy/tidal-developers/
[84] 2013 MATRIX report

close proximity to shore should assist in this regard and may allow the technology to be deployed pre-2030 assuming a supportive policy in enacted.

6.8 Wave energy

Studies of the available wave resource off the coast of NI have shown relatively limited opportunity for high-energy potential in areas readily accessible to shore. One study procured by DETI stated that *"Wave energy resources tend to be located in open seas where there is a large fetch (distance of open water over which wave area formed) and the largest waves are produced from the prevailing westerly winds"*[85]. This results in a limited area of territorial waters off the north coast of NI that meet these criteria per Figure 32. However, it also stated that while the resource appears geographically constrained this does not preclude future potential development in NI waters.

Figure 32 - Potential wave energy locations in NI



Wave energy devices are however still considered to be at a much earlier stage of development than other renewable technologies such as onshore wind, offshore wind and solar PV. Several wave energy technologies have been tested at reduced-scale and near-commercial scale levels at designated test sites in EMEC[86], Orkney Islands and small-scale testing of some devices have also taken place off the west coast of ROI[87]. The IEA's 2017 Tracking Clean Energy Progress report designated wave (and tidal) energy progression as 'Not on target' citing high development and demonstration costs and a requirement for public funding for deployment of sufficient scale demonstration projects as key barriers.

At present there are no commercial scale wave energy projects noted for development in NI waters nor have any areas for lease or significant expressions of interest been noted during any stakeholder meetings. Given the above and the apparently limited availability of commercial scale deployment sites close to the coastline suggests that any contribution from wave to NI's 2030 energy would be from small-scale demonstration R&D projects only, perhaps funded through a combination of UK and NI-specific innovation funding. Therefore, we have not considered wave energy in our projections for renewable electricity generation to 2030.

6.9 Geothermal energy

Considerable research has been carried out on geothermal energy resources on the island of Ireland. Whilst there are currently no operational plants in NI a number of areas with potential for geothermal power and heat generation have been identified. Geothermal energy can broadly be divided as shallow or deep per Table 9.

[85] Offshore wind and marine renewable energy in Northern Ireland – Strategic Environmental Assessment (2012)
[86] European Marine Energy Centre - http://www.emec.org.uk/
[87] Smart Bay - https://www.smartbay.ie/

Table 9 - Types of geothermal energy

Type	Depth	Energy source	Technology
Shallow	<15m	Mainly solar gain	Ground source heat pumps for low temperature heating
	100-500m	Geothermal plus solar gain at 15 - 25°C.	Borehole heat exchangers for low temperature heating, cooling and heat storage
Deep	1km – 3km	High temperature of 200 - 500°C. Related to volcanism and tectonism. Not the type of geothermal energy potential that exists in NI	"Flash" turbines for electricity production
Deep	1km – 4km	Low temperature of 70 - 160°C. Hydrothermal (deep, permeable, sedimentary aquifer)	Binary (Organic Rankine or Kalina Cycle) plants for electricity production. CHP plants an option.
Deep	3km – 6km	Engineered Geothermal Systems (EGS) in radiogenic granites, using natural fractures or hydrofracturing to produce water at 150 - 200°C.	Heat exchanger produces vapour to drive turbine.

Geothermal energy production involves extraction of thermal energy from the earth's crust, typically via techniques and technology used in the oil and gas extraction industry, in order to generate heat and/or electricity.

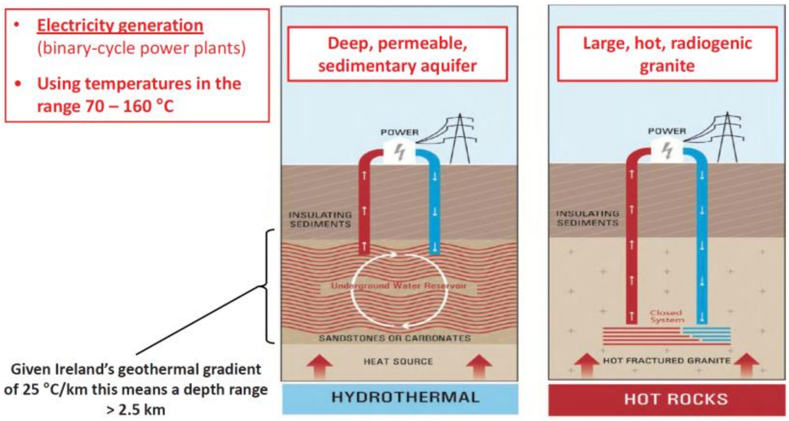
Heat flow through the earth's crust at an average rate of almost 59mW/m^2 due to two processes:

1. Upward convection and conduction of heat from the earth's mantle and core
2. Heat generated by the decay of naturally occurring radioactive elements such as isotopes of uranium, thorium and potassium

Thermal energy in the earth is generally stored in either solid rock (where conduction plays a major role) or in fluids (mainly water with dissolved salts but can be liquid-vapor or super-heated steam in some cases). The underlying geology of a region plays a major part in determining its suitability for geothermal energy production[88].

[88] https://energy.mit.edu/wp-content/uploads/2006/11/MITEI-The-Future-of-Geothermal-Energy.pdf

Figure 33 – Principal of operation of binary-cycle geothermal energy plants[89]



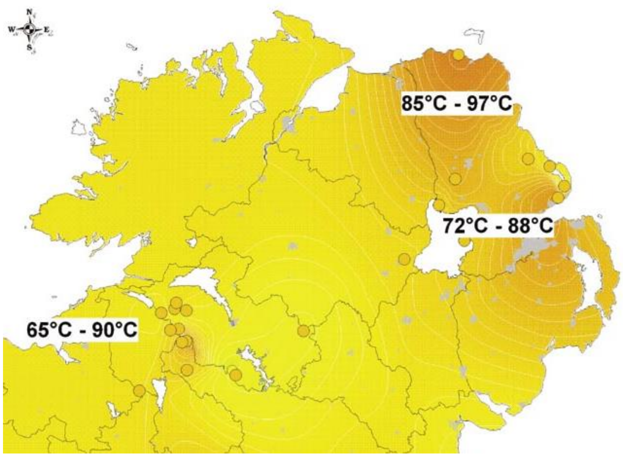
Geothermal energy is considered a mature technology having been deployed extensively in areas such as Italy and Iceland and more recently in Turkey where favourable geological conditions exist. However, the use of binary plants or EGS technology to generate electricity from low enthalpy geothermal resources in non-volcanic regions (such as NI) is a more recent development.

In 2009 the UK government posited that geothermal energy could supply up to 1.5GW of UK power needs by 2050 but warned that there was *“insufficient private sector appetite to de-risk the sector for power generation schemes”*.

Since then there has been limited exploitation of geothermal resources in the region but a project is currently underway in Cornwall that hopes to target rock at 190°C and power 3,000 homes in the area by drilling to a depth of 4.5km[90]. A second project for a 5 – 7 MWe power plant is planned for the Eden Project in Cornwall[91].

A number of regions in NI have also been highlighted as having potential for deployment of deep geothermal energy systems[92]. These include Ballycastle, Bushmills, Ballymoney, Ballymena, Larne, Antrim and the Mourne Mountains[93].

Figure 34 - Modelled and measured temperatures at 2500m depth[94]



[89] http://spatial.dcenr.gov.ie/GSI_DOWNLOAD/Geoenergy/Other/Deep_Geothermal_in_Ireland_Workshop_Sept2018.pdf
[90] https://www.uniteddownsgeothermal.co.uk/project-overview
[91] https://www.edenproject.com/eden-story/behind-the-scenes/eden-deep-geothermal-energy-project
[92] https://www.geothermal-energy.org/pdf/IGAstandard/WGC/2010/1625.pdf
[93] https://eurogeologists.eu/wp-content/uploads/2017/08/a_Magazine-May2010.pdf
[94] Refer to ‘Deep geothermal energy resource potential in Northern Ireland’ – Kelly and Reay (2010)

The main potential for deep geothermal energy in NI is associated with low enthalpy sedimentary aquifers where relatively low temperature water (<80°C) can be used for direct heating in heating networks rather than solely for electricity production. However, in the areas with the highest geothermal gradients, such as the Rathlin Basin where a bottom hole temperature of 99ºC was recorded at 2650m depth at Ballinlea, there may be potential for CHP using binary-cycle systems. Previous plans for Ballymena included the installation of a geothermal district heating system albeit supplemented by biomass for peak load and backup purposes. The geographical distribution of deep sedimentary aquifers restricts the potential location of plants and as NI does not have widespread district heating this is a further barrier that needs to be overcome. The granites of the Mourne Mountains are known to contain relatively high concentrations of heat-producing radiogenic elements and are associated with higher than average heat flows[95] and, although these are lower than those found in the granites of Cornwall, they may have some potential to generate electricity using EGS technology. However, it is unlikely that this potential would be realised by 2030.

The Business Committee in the NI Assembly discussed the prospects of deep geothermal and noted the following:

- Whilst there appears to be potential for geothermal in some areas of NI it *"will not happen unless DETI provides the necessary structure and incentive to kick-start that exciting sector"*
- Tariffs for deep geothermal (2 ROCs) should be separate from shallow geothermal as they were not adequate to spur investment in that technology. In particular, the high risk and cost associated with drilling was cited as a key barrier, with the IEA noting that drilling costs had actually increased in the past decade[96].
- Given the high costs there was some advocation for the state to take forward the exploration and exploitation of geothermal energy
- There was substantial debate around whether practices such as hydrofracturing of rock was akin to fracking. It should be noted that current practice is to target high permeability fault structures which differs from shale which is by its nature impermeable[97].

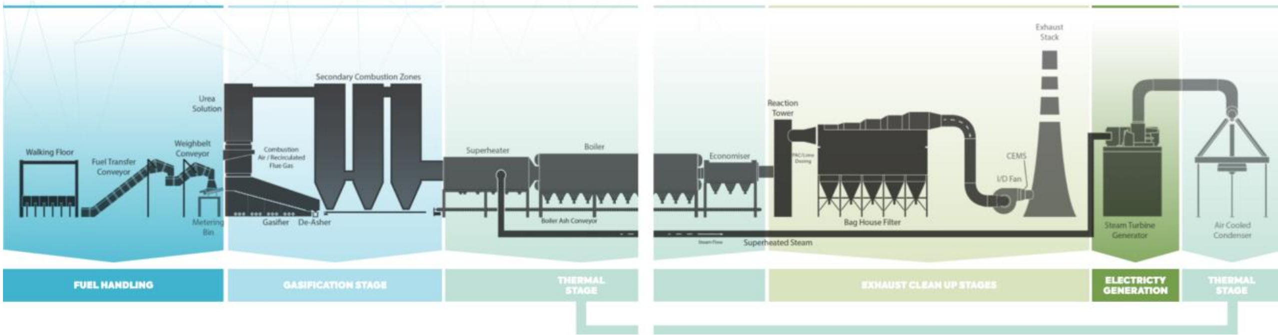
In its 2017 review the IEA saw limited scope for geothermal roll-out in Europe with only 3 – 4GW of capacity forecast to be installed in the region by 2030. However, the EGEC 2018 market review[98] reported that total installed capacity had reached more than 3GWe in 2018 and that this capacity had doubled in 6 years so there has been considerable expansion in some European countries, with new entrants in the sector such as Croatia[99] and France[100]. Nonetheless, considering the high risks and uncertainties associated with geothermal energy for electricity production in NI it is assumed that no large-scale plant will be installed during the period under consideration. There remains the potential for smaller distributed geothermal power systems to be developed using recent modular generating plant technology[101] but the greatest potential is for the use of deep geothermal energy for heating, as is the case for other Western European countries such as the Netherlands, Denmark, Belgium, France and Switzerland.

6.10 Waste-to-Energy

There is currently one waste-to-energy plant in operation in NI located next to Bombardier's wing production facility in Belfast. This plant, owned by Full Circle Generation, uses gasification technology to process up to 160,000 tonnes of waste per annum generating 14.6MW of electricity and process heat for Bombardier's operations. Waste material is secured via a long-term supply agreement and is sourced from throughout NI.

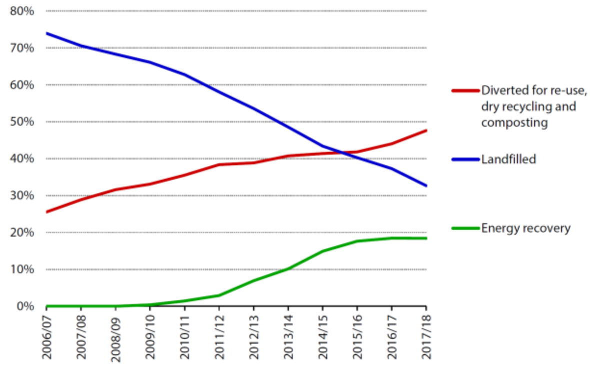
[95] www.skillsandgrowth.co.uk/wp-content/uploads/2018/03/Busby-2010.pdf
[96] IEA – Tracking Clean Energy Progress (2017)
[97] https://www.power-technology.com/features/could-cornish-granite-unlock-deep-geothermal-energy-in-england/
[98] https://www.egec.org/wp-content/uploads/2019/05/KeyFindings_MR-18.pdf
[99] http://www.thinkgeoenergy.com/the-17-5-mw-velika-ciglena-geothermal-power-plant-starts-operation-in-croatia/
[100] https://www.fonroche-geothermie.com/
[101] https://climeon.com/geothermal-plants/

Figure 35 – Full Circle Generation's waste-to-energy gasification process[102]



In response to the EU's 2005 Landfill Directive, NI implemented the Northern Ireland Landfill Allowance Scheme (NILAS)[103] which aims to reduce the level of material going to landfill in 2020 to 220,000 tonnes or 35% of 1995 levels.

Figure 36 - Destination of MSW collected by local authorities in NI (2006 – 2018)[104]



With increasing restrictions on the level of waste, and particularly organic material, going to landfill in NI there appears to be considerable scope for increasing the number of waste-to-energy plants in the region with the 2010 NI Regional Development Strategy stating that in order to meet the Landfill Directive targets that NI would require '*three 'energy from waste' plants. This includes both incineration and gasification plants, to deal with the residue from the MBT process'*[105]. The NIRO placed strict guidelines on what type of waste-to-energy plant are eligible for ROCs. These are:

- Biomass plants (where organic material must constitute at least 98% of the proposed fuel)
- Plants where advanced conversion technology such as gasification and pyrolysis is used to produce syngas, in which case biomass can be claimed for the biomass fraction of the fuel.

Plans to build a number of new facilities are underway including a new biogas facility located in Belfast which will utilise ROC approved gas engines to avail of existing supports and a new 14MW gasification facility being procured under the ARC21 umbrella comprising six local authorities in the region[106].

While the waste-to-energy process is proven there can be ongoing challenges including the reliability of fuel supply, strict emissions controls that are required during operation and negative public perception resulting in a challenging planning process.

[102] https://riverridge.co.uk/app/uploads/2017/03/FCG.pdf
[103] https://www.daera-ni.gov.uk/articles/northern-ireland-landfill-allowance-scheme-nilas
[104] Dept for Agriculture – Reducing emissions in Northern Ireland (2019)
[105] https://www.planningni.gov.uk/index/policy/rds2035.pdf
[106] https://www.indaver.com/ie-en/installations-and-processes/project-development-click-here-to-see-map/arc21-belfast/

It is assumed that there is potential for up to an additional 15MW of waste-to-energy plant will come online by the early 2020s.

6.11 Energy Storage

There is currently 153GW of energy storage globally with 97% being pumped hydro. The rest consists of a variety of technologies but is driven largely by lithium ion battery energy storage (Li-ion BES). The installed base of this alternative storage increased 300% between 2015 and 2018 and this is expected to accelerate in the coming years as battery prices continue to fall and their application become better understood[107]. NI has no pumped storage capacity and there is currently only one 10MW BES project located at Kilroot Power Station and is focused on the provision of system services under the DS3 programme.

With the increased penetration of intermittent renewable generation BES becomes increasingly important and can provide a mix of services as per Table 10[108].

Table 10 - Role of BES in providing flexible services

Area	Main functions	Status
Response	Frequency Response Reactive power and voltage support Other ancillary services	Primary route-to-market is via provision of DS3 services which provide long-term (6 year) contracts to service providers.
Reserve	Back-up Operating reserve Capacity reserve	Ranges from back-up capability to long and short-term capacity reserve.
Price / Time-shift	Price arbitrage Peak shaving Grid peak price avoidance / utilisation Aggregation Curtailment and constraint management	Demand customers can avoid peak prices whilst generators can take advantage of peak price periods. Intermittent generators with co-located storage or generators in area of locational constraint can reduce losses due to restricted output

The inherent flexibility and scalability of batteries (in terms of energy capacity, max. output, modularity and physical size) presents a wide array of deployment options. These include DS3-type grid support services, industrial and residential 'behind-the-meter' applications, grid management options including congestion management, stand-alone or co-location with new or existing renewable generation and energy trading options. It appears that both utility and small-scale storage capacity will play a major part with 45% of global battery capacity additions in 2017 being behind the meter.

The DS3 and Capacity markets currently provide batteries with a viable route to market in NI (and ROI) albeit in competition with other technologies. For DS3 services, the system operators are limiting the capacity of some services they are procuring (referred to as 'Volume Capped' services) which happen to be those most suited to energy storage (there are five such services comprising fast frequency response and several tranches of operating reserve). The first DS3 auction will run in September 2019 and will allocate between 91MW and 140MW of system services contracts to run over a 6-year period from 2021 – 2027.

[107] IEA – World Energy Outlook (2018)
[108] Based on presentation by Regen to Invest NI titled GB energy storage market update and supply chain opportunities (2017)

Participating BES is limited to 50MW in size. The recent T-4 capacity auction in ROI saw 212MW of de-rated capacity be allocated to BES. It is understood that this is primarily storage that has utilised the connection assets of retired generation thereby avoiding significant grid-related costs. This is an area that should be reviewed in NI in light of significant levels of thermal generation potentially reaching their end-of-life during the 2020s.

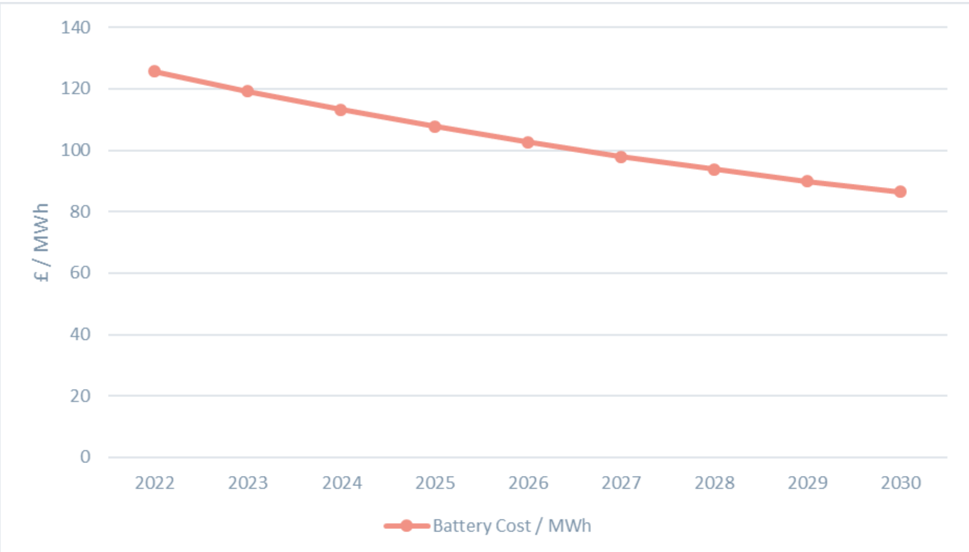
Unlike the all-island electricity market, GB does not offer long-term ancillary system services contracts which increases pressure on batteries to generate revenue from a variety of sources. Unlike volume-capped applicants in the SEM, batteries in GB can also access the capacity market which provides an additional potential revenue stream. However, recent changes in GB demonstrate how important market certainty is to participants with National Grid adding a de-rating factor for batteries that appears to favour larger storage capacities in response to the results of a consultation which found that 'stress events' on the GB system were typically 2 hours or longer[109]. This significantly reduces the revenue that can be earned by smaller installations such as those with 30 min capacity and this uncertainty has resulted in a 45% drop in the number of BES applications for the 2022 – 2023 T-4 capacity auctions.

The concept of 'revenue stacking' is an important element of making BES projects work. This involves combining revenues from a number of streams including ancillary services, the capacity market, intraday balancing and market operations (incl. price arbitrage). Whereas small independent BES developers often utilise aggregators to deploy efficiently in the market, larger market participants such as utilities with portfolios of intermittent renewable generation can also use BES to avoid exposure to the balancing market where prices can be unpredictable (for example when wind farm output is lower than forecast and does not meet supply obligations).

The price of Li-ion batteries is expected to drop substantially during the 2020s as shown in Figure 37 which should facilitate widespread deployment. Other key drivers include:

- The level of future ancillary services requirements including level of competition
- Level of grid congestion management and cost avoidance – capability of system operator to utilise batteries to manage network constraints or avoid/delay network investment
- Energy prices and the incentive for consumers to maximise self-consumption and avoid peak charging periods

Figure 37 - Cost projections for lithium ion batteries to 2030[110]



Whilst Li-Ion batteries are the main type expected to be deployed to 2030 other technologies reviewed included flywheel systems, CAES / LAES systems and flow batteries (including organic flow batteries). Flow batteries are of particular interest given they are already operational in other jurisdictions and have

109 https://www.energy-storage.news/news/uk-battery-project-numbers-fall-under-uncertain-future-for-capacity-market
110 Figures based on consultant's projections for li-ion battery costs to 2030

advantages over Li-Ion technology including longer life spans, higher number of recharge cycles and for large-scale storage of several hours, the cost per unit of energy can be lower Li-Ion batteries. Other technologies are currently earlier in their development cycle or are suited to one particular application (such as flywheel storage which is suited to short-duration ancillary services applications) and are not considered in this report for the NI market to 2030.

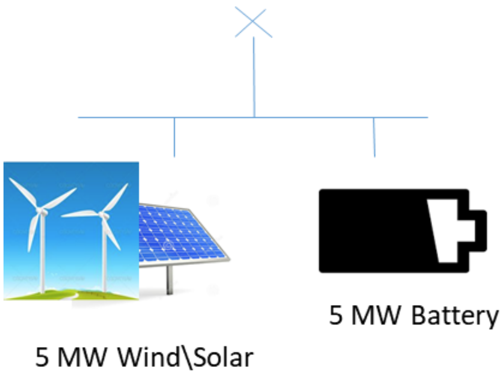
The thick salt beds beneath parts of east Antrim have significant potential for the construction of large engineered energy storage facilities. Feasibility studies, including deep drilling, have established that Permian salt bed is over 180 metres thick at depths of about 1500 metres below the Larne and Islandmagee area, and it is suitable for the construction of large storage caverns using solution mining. A 330MW part-EU funded Compressed Air Energy Storage (CAES) project located in Co. Antrim was previously in development in NI up to 2016 to store excess energy generated by wind in underground salt caverns but is not believed to have progressed further at this stage. However, a natural gas storage project in the same area has progressed to Front End Engineering Design studies for a facility of 7 – 9 storage caverns and the potential for CAES or hydrogen storage may be realised within the timescale of this review.

6.12 Co-location & hybrid systems

Hybrid or co-location projects where multiple renewable energy technologies and/or energy storage dynamically share a single grid connection are viewed as a means to maximizing the contribution of intermittent renewables such as wind and solar in NI. This is particularly important given the current limitations in available grid capacity and concern over increasing curtailment and constraint levels.

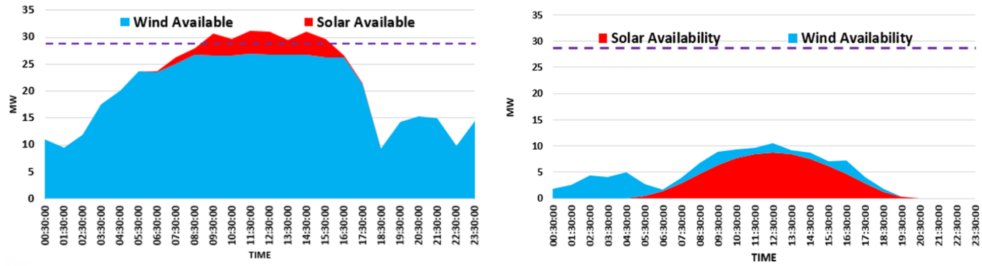
This approach enables these projects to optimize their grid connection capacity and balance mismatches in network supply and demand requirements which can occur at times of high wind and low electricity demand. Figure 39 shows a typical example where co-locating 28MW of wind generation and 10MW solar PV generation allows the grid capacity to be more fully utilised[111] and facilitates sharing of connection costs across an installation with a higher capacity factor thereby reducing the effective LCOE for the project. The same principle applies to other complimentary technologies such as energy storage.

Figure 38 - Hybrid renewable energy system[112]



[111] IWEA / NIRIG – Hybrid Sites Working Group Presentation
[112] IWEA / NIRIG – Hybrid Sites Working Group Presentation

Figure 39 - Examples of typical wind-solar generation balance in hybrid project



In this case co-location works for a number of reasons:

1. solar output is variable but relatively predictable
2. wind and solar are generally negatively correlated
3. there are very few periods where full MEC is utilised in a typical wind or solar project
4. both technologies are fully controllable and can be separately metered
5. internal constraints for such a project are expected to be in the low single digits

However, stakeholders raised a number of limitations that currently prevent hybrid projects from being deployed:

1. Market limitations including:
    a. under SEM rules units cannot dynamically share MEC and the market registration for a unit / technology is linked with a single MEC
    b. market requires visibility of output and availability of units at any time
    c. separate legal entities (e.g. separate SPVs for wind and solar projects) behind a single connection point
    d. Generators would have registered capacity in excess of MEC which can be problematic if it exceeds 120% of MEC
2. Technical limitations typically stemmed from a 'One customer, one connection point' policy including:
    a. Grid code compliance linked with a single unit / technology and MEC
    b. MEC duplication where the output of complementary technologies such as wind and solar are treated as cumulative (i.e. collocating a 5MW solar park with a 10MW wind farm requires a 15MW grid connection although output of both is generally not correlated and both technologies are fully controllable). This can lead to far higher connection costs and undermine otherwise sound business cases.
    c. MEC duplication also applies to storage even if its purpose is to supply DS3 services and will only be required for very short durations.

There are currently three wind / storage projects in the planning process and feedback from stakeholders indicates that hybrid projects have considerable potential to alleviate project constraint and curtailment in NI if the above issues are comprehensively addressed by decision makers in the policy, regulatory and technical areas.

6.13 Power-to-Gas (hydrogen)

Power-to-gas (P2G) provides an alternative means of utilising excess renewable generation at times of low demand by use of electrolysis to create hydrogen thereby acting as a form of chemical storage. Currently the majority of hydrogen is produced by the steam reforming of fossil fuels (usually natural gas) which is energy and CO_2 intensive though this can be addressed through use of carbon capture and storage where practical. It is used in a range of applications from industrial processes such as production of metals, glass and fertiliser to refining of crude oil into fuels to acting as a fuel itself.

Hydrogen can also be regarded as an energy carrier and has a number of distinct advantages as a form of storage over batteries or pumped storage:

- It is more energy dense and therefore superior for a number of applications including powering HGVs that are not suited to conventional battery solutions
- It can potentially be transported in existing gas networks (albeit this is contingent on factors)
- It can be converted into electricity (through fuel cells) or burned directly (in hydrogen turbines)

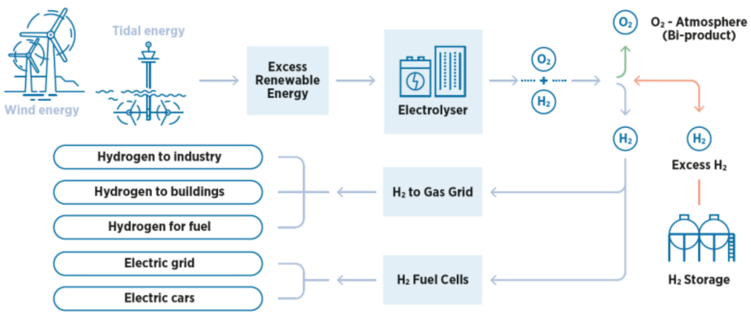
Currently the price of producing 'green hydrogen' through a combination of renewable resources and electrolysis is higher than that of reforming natural gas (being €3.50/kg of hydrogen vs €1.50/kg of hydrogen respectively)[113]. The two main cost elements are:

1. The cost of electrolysis itself due to limited global penetration though this is forecast to fall by 70% in the next 10 years.
2. The price of electricity from renewables which is also expected to fall considerably to 2030.

Some companies have targeted cost parity between grey hydrogen and green hydrogen by 2030. In NI there is currently a project in development looking to combine hydrogen production with wind energy with a view to providing it as fuel for transportation for a local bus fleet.

Other jurisdictions are also hosting innovative P2G projects. In the Orkney Islands off Scotland, the 'Surf 'n' Turf Initiative uses power generated from wind and tidal energy to produce hydrogen from a 500kW electrolyser per Figure 40[114]. The hydrogen is then shipped to either storage for use when renewable energy generation is low or use in the gas grid or electricity generation via fuel cells. The BIG HIT project in Kirwall (also in Orkney) is looking to utilise hydrogen generated via a 1MW electrolyser for a range of applications including heating and auxiliary power.

Figure 40 - Surf 'n' Turf power to hydrogen project in Orkney Islands



6.14 Carbon Capture, Usage & Storage

The decarbonisation of global electricity production through the use of renewables involving a high level of intermittent generation whilst also maintaining security of supply will require, in the medium term at least, a significant level of thermal generation on the system to meet minimum generation, back-up and system stability requirements. This is assumed to consist mainly of gas-fired generation in NI.

The use of CCUS has been proposed as a way to negate the GHG emissions of such plant but requires suitable storage sites which typically consist of depleted oil and gas fields and saline aquifers where porous and sedimentary rock is overlain by impermeable strata such as shale. The storage site must also be at sufficient depth to maintain the CO_2 in a sufficiently dense phase to maximise storage efficiency. CCUS is regarded as an effective means to store CO_2 with well managed storage sites expected to retain sequestered gas for more than 1,000 years[115]. There has been limited deployment of the technology to date

113 https://www.iea.org/newsroom/news/2019/april/the-clean-hydrogen-future-has-already-begun.html
114 IRENA – Innovation Landscape for a Renewable-Powered Future (2019)
115 https://ec.europa.eu/clima/policies/innovation-fund/ccs_en

and CO_2 injection has mainly been focused on enhanced oil recovery. However, industrial scale projects have been deployed with one in Norway reaching 20 years of CO_2 storage in 2016[116].

Like nuclear energy, CCUS policy is not devolved to the NI Assembly[117], which may impact on its development in the region. Currently there are no sites in operation in NI with the majority being located off the east and north-east coast of Britain. This is partly due to the extent of oil and gas exploration in the North Sea where suitable storage sites are well established.

Carbon capture technologies generally fall into one of three categories:

- Pre-combustion where input fuel is converted to CO_2 and hydrogen through processes such as gasification.
- Post-combustion where CO_2 is extracted from flue gases through processes such as absorbing it in a solvent before compressing it for transportation and storage
- Oxy-fuel combustion where oxygen is separated from combustion air before being used in combination of recycled flue gas to combust the fuel. This results in flue gases consisting mainly of CO_2 and water.

In its 2019 Reducing Emissions in Northern Ireland report, the CCC recommended that policy makers make preparations for deployment of CCUS in NI in the 2030s. Critical to this will be establishing sites where CCUS may be feasible and developing infrastructure to facilitate its transport to the site, particularly where they lie offshore[118]. Furthermore, the cost of capturing CO_2 is high, particularly for natural gas whose content is much lower than other fossil fuels.

A 2009 study identified a number of potential CO_2 storage sites in NI per Figure 41[119]. These were primarily saline aquifers in the Rathlin, Larne and Lough Neagh basins. Limited data availability meant that storage capacity estimates could only be made for two closures in the Lough Beg area whose capacity was estimated at 1,940Mt of CO_2. The lack of detailed knowledge about the subsurface geology and the likelihood of strong public opposition to the storage of CO_2 onshore means that these potential sites are unlikely to be utilised. A joint UK / ROI study into CO_2 storage on the island of Ireland considered the possibility of piping CO_2 emissions from Kilroot Power Station to a site in Porpatrick Basin off the east coast of NI[120]. It found that there was potential capacity to store a minimum of 10 and potentially 58 years of CO_2 emissions depending on the ultimate viability of the site with scope for further increases. The Peel Basin, between the County Down coast and the Isle of Man, was identified as having a very large storage capacity of the saline aquifer type but, owing to the lack of detailed analysis, this could only be categorised as theoretical. The depleted South Morecambe gas field has been the subject of several feasibility studies[121] and is estimated to have an effective/practical capacity about 30 times greater than that of the Portpatrick Basin. The study also estimated that adding CCS to a coal plant using pulverised coal would increase the LCOE of the plant by approximately €14/MWh over a equivalent non-CCS plant assuming a carbon price of €35/tonne. A large number of other potential sites were also identified but storage capacities could not be estimated due to a lack of data. Further geological analysis is required before an accurate estimate of potential CO_2 storage capacity can be made for NI.

[116] Progressing Development of UK's Strategic Carbon Dioxide Storage Resource (2016)
[117] Dept for Agriculture – Reducing emissions in Northern Ireland (2019)
[118]https://publications.parliament.uk/pa/cm201516/cmselect/cmenergy/692/69202.htm
[119] https://www.seai.ie/resources/publications/Assessment-of-the-Potential-for-Geological-Storage-of-CO2-for-the-Island-of-Ireland.pdf
[120] https://www.sciencedirect.com/science/article/pii/S1876610209006766
[121] http://www.zeroco2.no/projects/east-irish-sea-co2-storage-project

Figure 41 - Potential CO2 storage sites in NI

Whilst a number of forecasts predicted roll-out of thermal generation projects using CCUS in the UK by 2019/2020 with deployment accelerating in the 2020s, it now appears as though this will not be the case with delays of several years expected. Given this and the uncertain extent of suitable storage sites in NI, the deployment of CCUS before 2030 has not been assumed in any of the forecast scenarios.

7 Scenarios Outputs

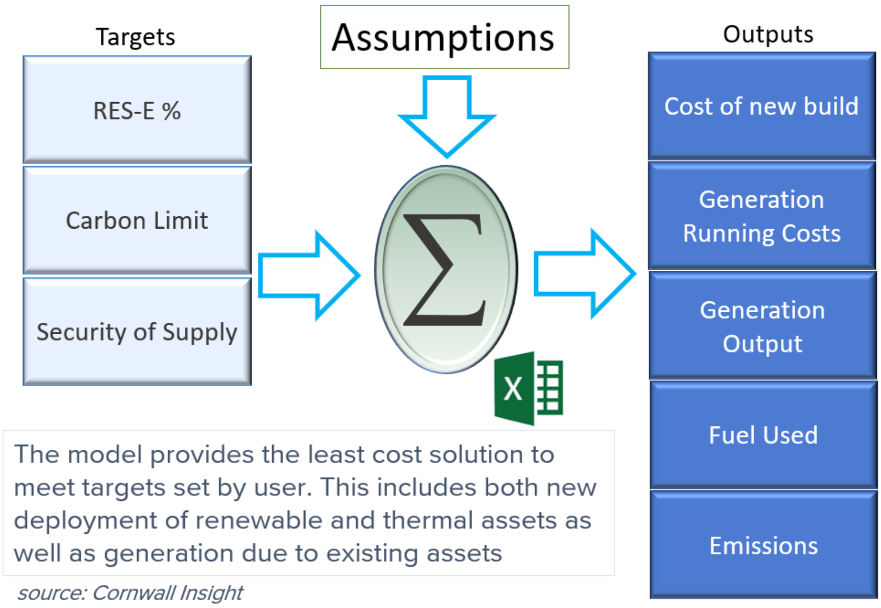
As part of this research we conducted scenario-based analysis based on different RES-E targets and with certain assumptions regarding available technologies and interconnection. The demand inputs are based on the different demand scenarios outlined in the GCS18[4] and the analysis is done using a bespoke Excel model, developed specifically for this report, which looks for the least-cost solution to maintain security of supply based on a year by year granularity.

The outputs of the model include the deployment of new thermal or renewable assets, costs associated with this deployment, cost of running existing generation assets, fuel used and emission generation. Figure 42 illustrates a high-level schematic of the model.

The inputs to the model include, but are not limited to the following:

- LCOE – Levelised cost of electricity. This value gives an indication of the costs for building new generation assets, normalised based on the cost per MWh for different types of technology. The values used in these scenarios will be available in the model and are calculated using Cornwall Insight's proprietary model which is based on values from UK and global sources.
- Capacity – both the de-rated and non-de-rated capacity is given in the model. For the calculation of the least cost solution, de-rated capacity is used. On a high level, derating means that the generation output of the plant/asset is adjusted for availability. Where possible, values were taken from SEMO's latest documentation for the T-4 Capacity Remuneration Mechanism (CRM) auctions for existing assets. For new assets, assumptions were based on derating factors using in-house data which will be available in the model
- Emissions for different technology types are calculated in the model based on data from both SEMO CRM data sources and from inhouse data and is available in the model.
- Load Factors – for new deployed assets load factors are provided based on inhouse values. These values are based on how often an asset is expected to generate. For example, a load factor of 30% for onshore wind indicates that the asset would be running 30% of the time. For dispatchable plant, the model as part of calculating the least cost solution "dispatches" the plant and thus calculates its load factor.

Figure 42. High level schematic of the scenarios model indicating inputs and outputs



source: Cornwall Insight

7.1 Model Inputs

Certain assumptions were made for the model which are listed as follows.

- The period under consideration runs from 2022-2030 in line with the earliest date a new policy could be expected to be implemented and the UK 2030 targets
- All conventional generation wins a contract in the CRM
- Data for demand and generation is from the 2018 SONI Generation Capacity Statement (GCS18)[4]. This only extends to 2027 so the data has been linearly extrapolated to 2030 and adjustments have been made for various levels of data centre build-out and expected uptake of EVs and heat pumps (see section 7.2)
- Kilroot Coal Power Station (400 MW) will close by 2024 as outlined in the GCS18
- North-South 2nd Interconnector (1500 MW) will be at full capacity by 2024
- Moyle Interconnector (450 MW) will be operating at full capacity in both directions by 2022
- The current renewables mix will be sustained and there will be no new renewables projects from 2022-2030 save what is deployed by the model
- The new Belfast Harbour CCGT (480 MW) will be energised by 2024
- There will be 40k new EVs – this represents 0.12 TWh of demand based on analysis done for this report
- There will be minimal deployment of heat pumps due to higher costs and lack of incentives

A baseline is assumed whereby there is no change in policy and no deployment of new renewables. The model was then run for RES-E targets of 70%, 55% and 40% and the demand forecast from the GCS18 was used as follows:

- RES-E 70% (aka Low Carbon scenario) - high demand scenario GCS18
- RES-E 55% (aka Sustainability scenario) - median demand scenario GCS18
- RES-E 40% (aka Efficiency scenario) - low demand scenario GCS18

The assumptions for each scenario are as follows:

- RES-E 70%

  - Uses higher demand forecast based on Median Demand Scenario in GCS18 adjusted for maximum data centre construction and maximum additional uptake of EVs and HPs
  - Key driver is achieving 70% RES-E by 2030
  - View towards 95% SNSP in line with ROI however this is not explicitly modelled
  - Maximum allowed deployed onshore wind = 200MW/year, solar = 15 MW/year. Note: these parameters can be changed in the model
- RES-E 55%
  - Uses median demand in GCS18 adjusted for additional EVs and HPs whilst maintaining existing forecast data centre construction.
  - Key driver is achieving UK electricity consumption target for 2030
  - Maximum allowed deployed onshore wind = 200MW/year, solar = 15 MW/year. Note: these parameters can be changed in the model
- RES-E 40%
  - Uses lower demand forecast based on Median demand scenario in GCS18 adjusted for low levels of EV and HP rollout and no new data centre construction.
  - No driver for uptake of renewables, any investment occurs without intervention
  - Maximum allowed deployed onshore wind = 200MW/year, solar = 15 MW/year. Note: these parameters can be changed in the model

The variation in demand takes into account forecast levels of electric vehicles (EVs), heat pumps and data centres. The analysis also includes high-potential renewable technology such as smart tech and energy efficiency (EE) as well as more conventional solutions such as Demand Side Management (DSM) and will draw where appropriate from the existing 2013 Matrix Sustainable Energy Horizon Panel[122] Report, which identified areas of strategic importance to the NI energy sector. Networks costs and upgrades are also analysed based on data provided by SONI and NIEN.

For each scenario the carbon intensity (carbon emissions as a function of demand), cost of running existing assets, cost of new deployment and a generation stack of new deployment was output from the model. New assets deployable in the model include onshore and offshore wind, solar PV, biomass, AD, Energy from Waste (EfW), tidal, hydro, landfill gas, battery storage, Open-Cycle Gas Turbines (OCGT) and Combined-Cycle Gas Turbines (CCGT). Existing renewable capacity is also included as are plant such as Kilroot, Coolkeeragh, Lisahally, Contour Global and Ballylumford. Demand side units (DSUs) and aggregated generation units (AGUs) as reported in the GCS18 are also included. Finally GB interconnectors flows over the Moyle interconnector are included as well as ROI flows over the North-South tie-line and proposed North-South interconnector. Please note that interconnectors are included to balance the supply and demand for the model only and there is no cost associated with them. Additionally the model does not always assume the interconnectors will be importing and will export power when supply exceeds demand.

The model is set to always seek the least cost solution to meet security of supply.

LCOE

Forecast levelised cost of electricity (LCOE) was modelled using Cornwall Insight's inhouse model. This model has forecast costs which have been incorporated into the bespoke model for this research report and is based on extensive market research into UK and global technology costs. LCOE is used in the electricity industry to determine the lowest overall cost of the system when optimising the building of new power plants or renewable electricity assets. In our LCOE model we incorporate technology specific capital costs, (e.g. civil and structural, mechanical equipment, electrical instrumentation and control costs, indirect costs such as contingency fees and owner costs such as development costs, permitting and planning) with research based on our own inhouse forecast and wider literature review.

[122] https://matrixni.org/reports/2013-sustainable-energy-report/

Table 11. LCOE between 2020 and 2030

Technology	2020 (£/MWh)	2030 (£/MWh)	% Drop (£/MWh)
Onshore wind	47.89	43.88	8%
Solar PV	52.91	44.86	15%
Offshore Wind	67.48	53.84	20%
Batteries	140.04	86.54	38%
Hydro	96.92	96.51	0%
AD	127.59	127.10	0%
Biomass	247.46	186.46	25%
EfW	163.41	147.51	10%
Tidal	162.93	151.16	7%
Gas Recip	102.36	126.26	-23%
CCGT	78.95	98.20	-24%
OCGT	88.77	105.88	-19%

source: Cornwall Insight

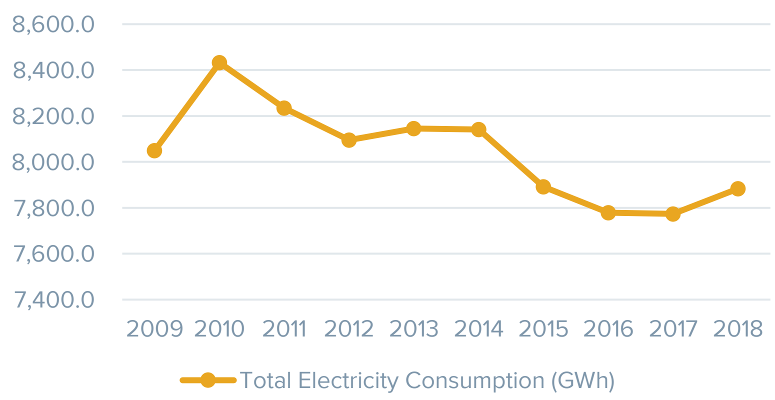
A comparison of forecast LCOE between 2020 and 2030 is outlined in Table 11. It is apparent that onshore wind and solar PV begin to converge by 2030. Costs of offshore wind also drop considerably in that time frame whereas thermal technologies such as CCGT and OCGT increase in cost over the time period. Battery technology is predicted to drop considerably also.

When considering policy, especially with regards to costs to consumers it is important to consider the potential changes in technology costs in the future. It should also be considered in the context of how cost have changed since the formation of the 2010 SEF and mechanisms which may have been considered too expensive 10 years ago, could be attractive options over the next 5 to 10 years.

7.2 Forecast electricity demand

Electricity demand in Northern Ireland has fallen since reaching a peak of 8,423GWh in 2010 to a recent low of 7,778GWh in 2017 due to a combination of factors including the effects of the global economic recession, the positive impacts of energy efficiency measures, changes in housing stock and switching of heating fuel to natural gas due to network expansion. 2018 saw a slight increase in demand and this is expected to continue in the coming years as increased sources of demand including electric vehicles, electric heat pumps and the electrification of industrial processes offset gains due to energy efficiency measures.

Figure 43 - NI historic electricity consumption[123]



Demand forecasts to 2030 generally expect organic demand growth in line with increased underlying economic activity as well as growth due to increased use of electric vehicles (EVs), electric heat pumps (HPs) for space heating and the potential for entry of Large Energy Users (LEUs) such as data centres into the market. Offsetting these increases are likely to:

- be continued gains in energy efficiency in the domestic and industrial sectors potentially aided by measures such as time-of-use charging at domestic level
- further increases in 'self-consumption' ranging from on-site industrial CHP plants to small- and micro-scale renewables such as rooftop solar PV

[123] Source: Energy in Northern Ireland 2018 and Electricity consumption and renewable generation in Northern Ireland – year ending December 2018 (both issued by the NI Dept. for the Economy)

- potentially the increased use of on-site battery storage to better match generation and consumption profiles and reduce spill of excess generation onto the grid thereby reducing 'public supply' requirements.

Electricity demand forecasts have been based on the median demand scenario in SONI's 2018 Generation Capacity Statement (GCS). Although the GCS outlines low, medium and high demand forecasts based on varying economic, discrete load growth projections and low and high temperature years (which impact on the level of heating demand), we have chosen to use median demand as it is SONI's best estimate of future demand growth.

As the 2018 GCS only runs until 2027 the information to 2030 has been extrapolated based on the average growth between 2021 and 2027 per Table 12.

Table 12 – Demand growth extrapolation 2027 to 2030

GCS Demand Scenario	% annual change 2027 - 2030
Median	+0.7%

We have also built upon the GCS median scenario as required to reflect demand in each of our forecast scenarios as outlined in Table 13.

Table 13 - Alternations to Median Scenario

GCS Median Scenario	Changes
Temperature forecasts	Unchanged – GCS allows for average temperature year to 2027.
Economic Growth	Unchanged – GCS applies central estimate for economic growth to 2027.
Energy Efficiency	Unchanged – GCS applies 1% energy efficiency gain per year.
Electric Vehicles demand	Allowance for EVs has been made under each scenario as none is included in the GCS.
Heat pump (HP) demand	Allowance for HPs has been made under each scenario as none is included in the GCS.
Data centres	As the GCS Median Demand scenario allows for 100MVA of data centre load from 2022 no additional load has been assumed under the Efficiency and Sustainability scenarios. However, an additional 100MVA has been allowed from 2022 under the Low Carbon scenario in line with SONI's High Demand scenario.
Transmission losses	Unchanged - losses of 7 – 8% included in the GCS and assumed to 2030.

Breakdown of current demand

Analysing the source of demand shows that whilst domestic customers account for some 92% of connections they only account for circa 39% of consumption.

Table 14 shows the current composition of demand in NI and provides a breakdown between demand customers.

Table 14 - Split between NI demand customers[124]

Customer groups	Number of connections	% share of connections in market sector	Consumption (GWh)	% share of consumption in market sector
Domestic prepayment	359,262	44.5%	351.9	42.6%
Domestic credit	448,883	55.5%	472.9	57.3%
Total Domestic	**808,145**	**100%**	**824.8**	**100%**
I&C < 20 MWh	49,079	66.9%	92.2	7.2%
I&C 20 – 49 MWh	13,117	17.9%	114.2	8.9%
I&C 50 – 499 MWh	10,053	13.7%	350.3	27.3%
I&C 500 – 1,999 MWh	841	1.1%	209.2	16.3%
I&C 2,000 – 19,999 MWh	253	0.3%	336.4	26.2%
I&C ≥ 20,000 MWh	19	0.03%	181.0	14.1%
Total I&C	**73,362**	**100%**	**1,283.3**	**100%**
Total	**881,507**		**2,108.1**	

The data in turn shows that Industrial & Commercial (I&C) demand is dominated by a relatively small number of very large users with those consuming more than 2,000MWh per quarter year comprising 40.3% of non-domestic consumption but only 0.33% of I&C connections.

Electric Vehicles (EVs)

Significant growth in electric vehicle ownership is expected in each scenario. As of Q3 2018 there were over 2,300 plug-in EVs registered in NI, the vast majority of which were cars.

Table 15 - NI electric vehicle penetration at Q3 2018[125]

Vehicle Category	Cars '000	Motorcycles '000	LGVs '000	HGVs '000	Buses and coaches* '000	Other vehicles* '000	Total '000
Plug-in EVs (BEV and PHEV)	2.2	0.03	0.08	0	0	0	2.4
Breakdown between EVs	95.5%	1.1%	3.4%	0.1%	0.0%	0.0%	100.0 %
Total Vehicles	959.2	25.4	116.4	24.3	5.6	34.3	1.17
EVs as a % of total in each category	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.2%

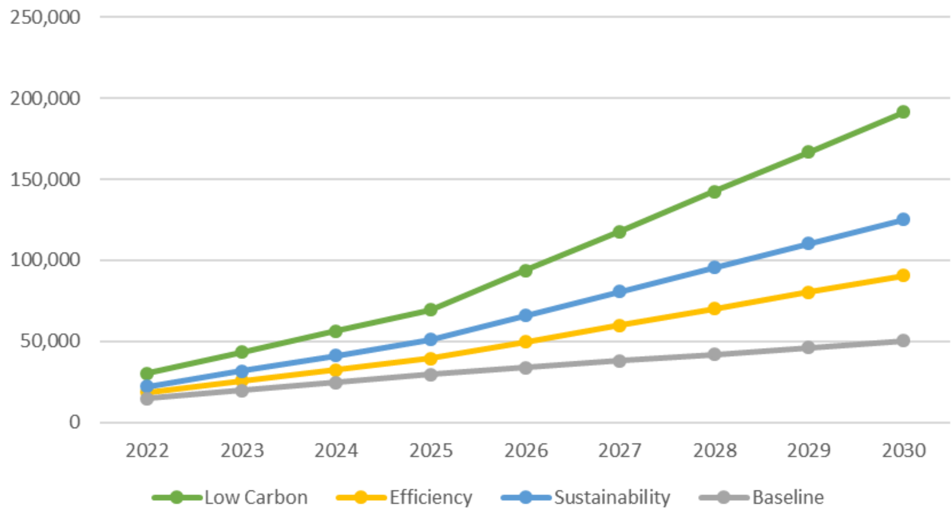
* Limited data was available for electrification of buses and coaches and other vehicles so they were assumed to be covered under HGVs

Whilst electrification of motorcycles, LGVs and HGVs is expected in future, it is generally forecast that up to 2030 cars will form the vast majority of future EV growth and therefore this analysis has focused on roll-out of plug-in cars when deriving demand forecasts to 2030. The assumed deployment of electric vehicles under each scenario is detailed in Table 15. It should be noted that the forecast deployment of electric vehicles varies considerably between studies so a reasonable view was adopted that balanced ambition with likely outcomes.

[124] https://www.uregni.gov.uk/sites/uregni/files/media-files/2019-02-28%20Transparency%20Report%20Q4%202018%20FINAL.pdf
[125] UK Department for Transport vehicle statistics https://www.gov.uk/government/collections/vehicles-statistics

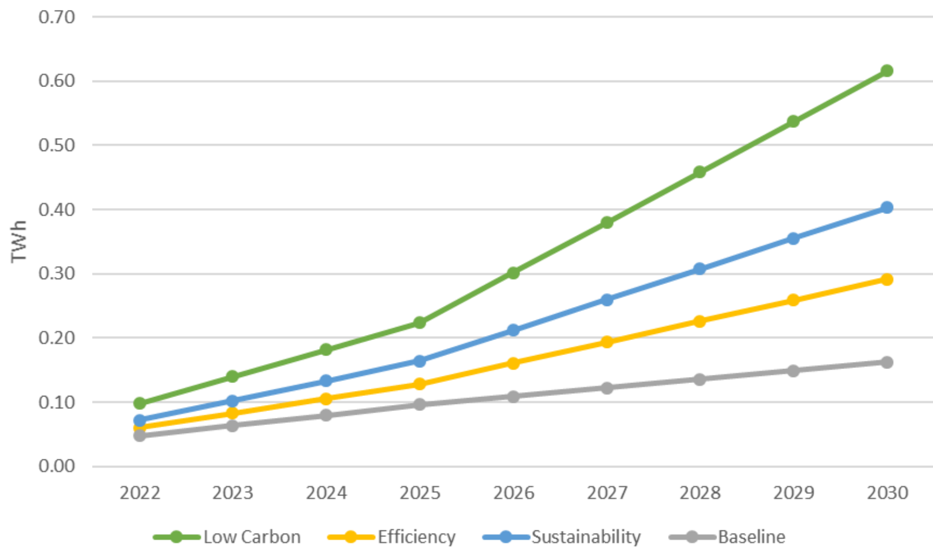
The Efficiency and Low Carbon EV deployment figures were based on those outlined in EirGrid's Tomorrow's Energy Scenarios report whereas the Sustainability figures were derived from NIE Network's Transform Model. This approach was taken to provide a reasonable spread of possible deployments in line with likely policy support as well as acknowledging that the median assumption for EV deployment in the Transform Model has already been exceeded, albeit numbers are too low at this point to infer any trend. EV deployment post-2025 accelerates as EVs prices are expected to be competitive with ICE vehicles from 2024[126].

Figure 44 - EV growth in NI to 2030



EVs demand was based on a demand of 0.32kWh per mile for an average EV passenger vehicle and an average 10,000 miles per annum. This is deemed quite conservative as it does not account for any increase in vehicle or battery efficiency to 2030. The EV demand profile to 2030 is shown in Figure 44. The forecast growth in EV demand varies considerably between studies and a balanced view was taken which seemed to provide a reasonable balance between ambition and likely outcomes.

Figure 45 - EV Demand Growth to 2030



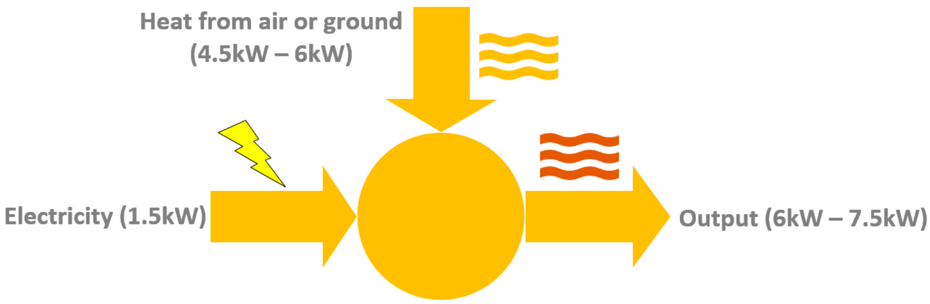
[126] BNEF Global EV Outlook 2017

Heat Pumps

Residential and commercial buildings in NI are responsible for approximately 15% of all GHG emissions with heating being the biggest component. Unlike the rest of the UK heating in NI is dominated by oil-fired central heating (68%), followed by gas (24%) and a mix of other technologies (8%) including direct electric and solid fuel systems[127]. With housing set to grow by 7% by 2030, resulting in an additional 52,000 dwellings, the electrification of heat through use of heat pumps is seen as key to decarbonising this sector of the economy. Of the 780,000 houses in NI, two-thirds were classed as urban with the remainder rural. Furthermore, some 22% of households were classed as 'fuel poor' meaning they spent more than 10% of household income on heating[128].

Electric heat pumps generally refer to air sourced (ASHP) or ground-sourced (GSHP). There is also a water source variety which draws heat from a nearby water body but these are not considered in this analysis. A key measure of the performance of a HP system is its coefficient of performance (COP) which is a measure of how much heat the system provides versus the electricity consumed. COPs of 3 for AHSPs and 4 for GSHPs are typical but ASHPs are particularly sensitive to changes in air temperatures with performance falling in colder weather. GSHPs tend to be more consistent as ground temperatures vary less from season to season.

Figure 46 - Coefficient of performance of HP



HPs tend to have substantially higher install costs relative to their fossil fuel counterparts but cost substantially less to run. The overall economics of their installation are dependent on the price of fossil fuels with low prices make them less attractive. The planned expansion of the natural gas network to the west also has the potential to make changing to HPs less attractive and offers less incentive given the relatively low cost of gas and the requirement to recoup the capital cost associated with such an expansion.

Given the high reliance on oil-fired heating in NI, and particularly in rural areas, stakeholders generally agreed that houses with oil-fired central heating are best suited for switching to heat pumps. Another suggested area of focus was new builds, albeit it was acknowledged that this will need to be supported by appropriate legislation requiring houses to meet higher energy standards including the installation of renewable heating which would remove the need for subsequent retrofitting of houses and ensure that the system is most effectively integrated.

Even if it is assumed that all new houses from 2022 are required to include HPs as standard this only accounts for some 38,000 dwellings[129]. Therefore, in order to reach penetration of HPs foreseen under the three lowest carbon scenarios will require their roll out in existing dwellings across NI.

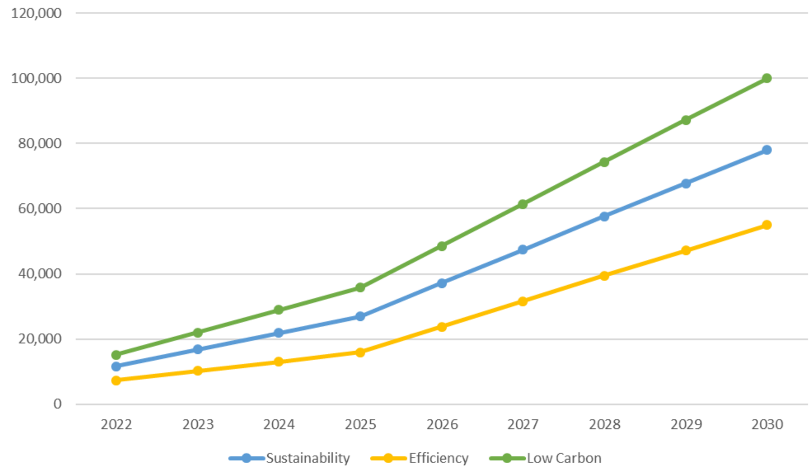
As 51% of the housing stock in NI currently has an EPC rating of D or lower this will require both the initial cost of deep retrofits to maximise thermal efficiency of the housing stock as well as the high upfront cost of

[127] Dept. for the Economy - Energy in Northern Ireland (2018)
[128] NI Housing Executive – 2016 House Condition Survey (2018)
[129] Taken from NISRA housing projections to 2030

HP installation to be addressed[130]. In order to drive such an increase in penetration, policy such as England's target of improving all housing to an EPC rating of C or greater by 2030, solutions such as ESCO financing of renewable heat and energy efficiency measures and updating of building regulations to drive increased thermal efficiency in new builds will be needed. NI has a number of schemes[131] in place to assist with retrofits and heating upgrades, particularly for fuel poor and low-income households, but critically none address renewable heat such as HPs in the absence of the RHI[132].

Roll-out of HPs was assessed against the above and in discussion with stakeholders including SONI based on their draft estimates for their upcoming Tomorrow's Energy Scenarios report. Whilst our forecasts were broadly aligned, HP uptake in their 'low carbon' equivalent scenario projection was considerably higher. However, given the assumption that any policy to encourage HP uptake will not be in place prior to 2022, our original high-uptake scenario of 100,000 HPs was maintained.

Figure 47 - NI forecast heat pump penetration to 2030[133]



Demand forecasts under each scenario

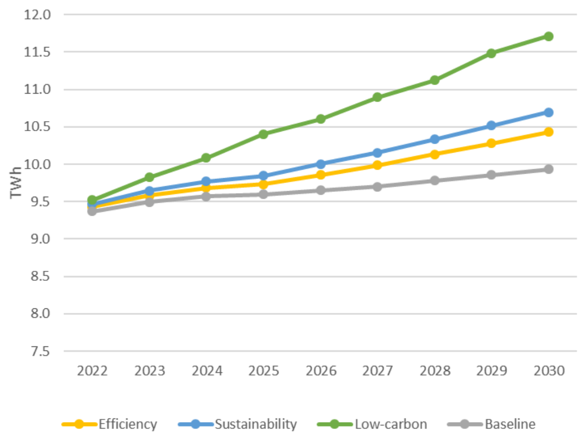
Figure 48 shows 2030 demand projects ranging between 9.5TWh and 11.8TWh per annum. It should be noted that these figures are defined as Total Energy Requirement (TER) in the GCS and consist of:

- Self-consumption due to autoproducers – approximately 3% of TER
- Transmission and distribution losses – between 7 and 8% of TER

These figures were compared with SONI's draft demand assumptions for production of their Tomorrow's Energy Scenarios report and matched well, ranging between 9.9TWh and 11.7TWh.

Figure 48 - Demand Forecasts to 2030

[130] NI Housing Executive – 2016 House Condition Survey (2018)
[131] Refer to list of Northern Ireland Sustainable Energy Programme schemes here
[132] Nearly 22% of the NI population is experiencing fuel poverty
[133] No HPs assumed for Baseline Scenario (there are circa 750 installed presently)



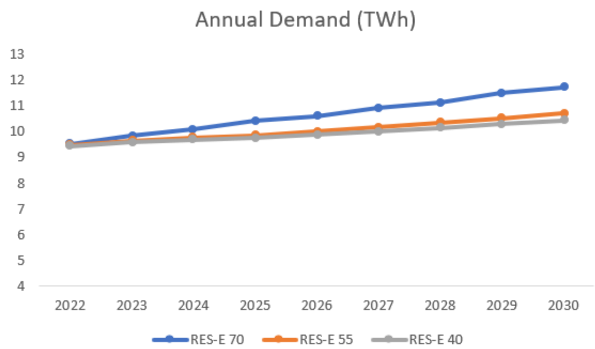
7.3 Results from Scenarios

The model was run with different parameters to investigate different outcomes of renewable deployment based on RES-E targets and on factors such as availability of offshore wind or the North-South interconnector. There were three sets of analysis conducted on the results which we outline in this section. The reader should bear in mind that *the model is designed as a guide only* regarding possible outcomes of different policy options. The model is built in MS Excel and based on annual granularity and lacks the level of sophistication and analysis possible with, for example, a Plexos®[134] model or other more advanced tool. Therefore ***any values which emerge from the model are meant for comparison only and should not be taken as being absolute values.***

Compare RES-E targets

The model was run with three different RES-E of 70%, 55% and 40%. Figure 49 shows the annual demand forecast for each RES-E target. The new deployment for RES-E 70 and 55 is compared in Figure 50. For RES-E 70 the model deployed a good diversity of technologies including lower cost technologies such as onshore wind and solar PV as well as offshore wind, batteries, hydro and biomass. For all three scenarios the maximum amount of onshore wind deployable is 200 MW/year and for solar is 40 MW/year based on realistic deployment of these technologies in the time frame.

Figure 49. Forecast demand for the three RES-E scenarios



source: Cornwall Insight, Ionic Consulting and SONI

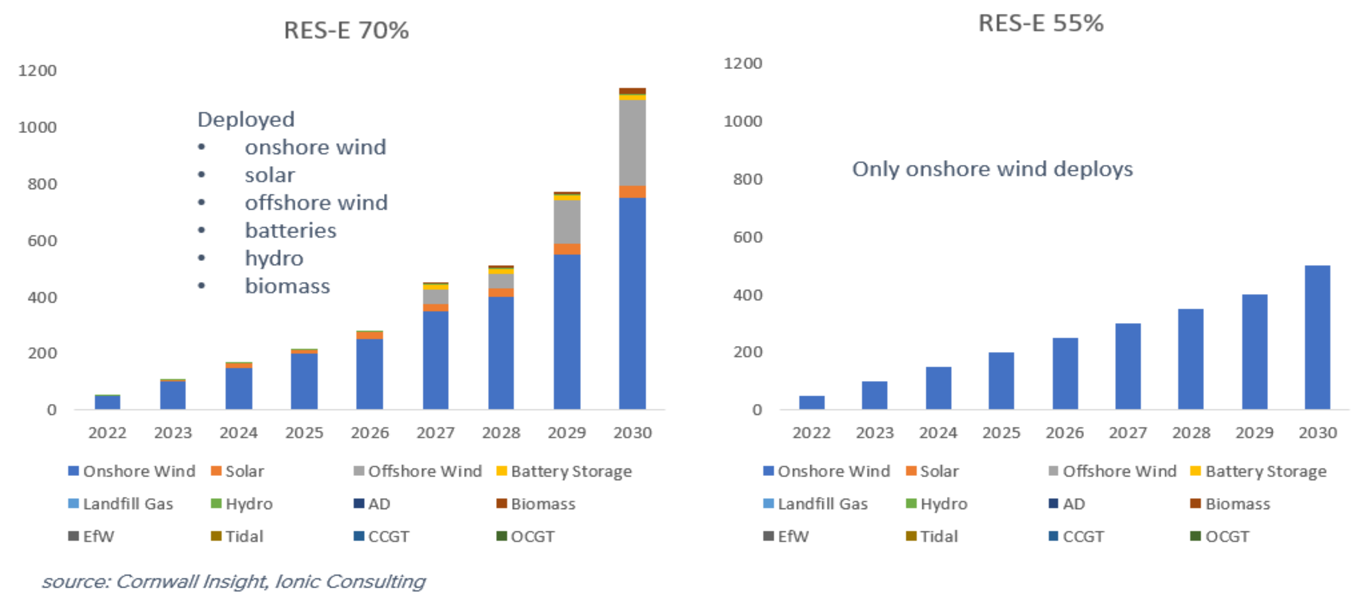
The RES-E 70 scenario assumes the highest demand from the GCS18[4] and the RES-E 55 scenario assumes the median demand. The RES-E 55 shows that using just onshore wind meets the demand for that requirement, however the higher demand associated with RES-E 70 requires deployment of other more expensive technologies.

In both scenarios it is assumed the earliest offshore wind would be available is 2027 and that the North-South Interconnector will be in energised in 2024. A considerable amount of the capacity for RES-E 70 is taken by offshore wind and the model deploys larger amounts in 2030 than 2027, when the cost will have

[134] https://energyexemplar.com/products/plexos-simulation-software/

come down further. It was assumed that the minimum capacity that would be deployed of offshore wind in one year would be 50MW as smaller projects than that would not be cost effective.

Figure 50. Comparison of RES-E 70 and 55



RES-E 40 deployed less than 10 MW of new renewables, mainly in 2030 when costs are lowest. It stands to reason that the lowest cost solution would not deploy new renewables since in 2019, NI already has a RES-E of ~39%. The low demand scenario from GCS18 indicates relatively low demand increase in the next decade.

Figure 51. Comparison of cost of new deployment and total carbon intensity of all generation

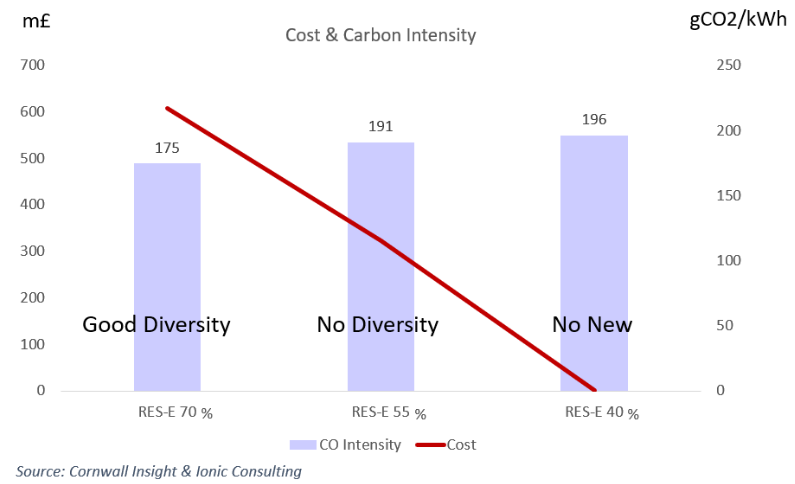
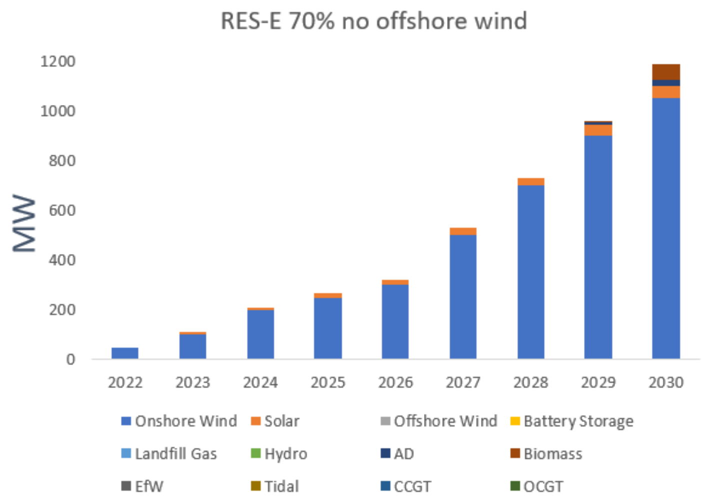


Figure 51 shows a comparison of the cost calculated by the model for new deployment only. It also shows the carbon intensity for all generating assets, both new and existing. The cost differential between RES-E 70 and 55 are significant, being £608m and £323m. Again much of this is being driven by the higher demand forecasts for each scenario, a point which is reflected in the relative carbon intensities of the scenarios. The carbon intensity for RES-E 70 is 11% lower than for RES-E 40 and 8% lower than for RES-E 55, indicating that the higher the RES-E target, the more carbon efficient the deployment is. However this should be caveated that this is assuming system security can be met without deploying fossil fuel plant, a point which will be revisited later in this section.

RES-E 70 and offshore wind

The RES-E 70 target was run again but this time offshore wind was made unavailable. In this situation only onshore wind, solar, AD and biomass were deployed at a cost of £735m, an increase of approx. £70m compared with when offshore wind was available. The reason for this increase is that less expensive technologies such as solar and onshore wind were not adequate to meet the peak demand for security of supply reasons (due to the maximum deployment levels defined in the model for those technologies as outlined in the previous section). Therefore, for system security the model deployed more expensive technologies such as biomass AD to meet the demand. The carbon intensity stayed the same. Although these cost figures may not represent actual costs, they provide a useful comparison as to the possible outcomes of different technologies for meeting demand.

Figure 52. New deployment for RES-E 70 where offshore wind is not available

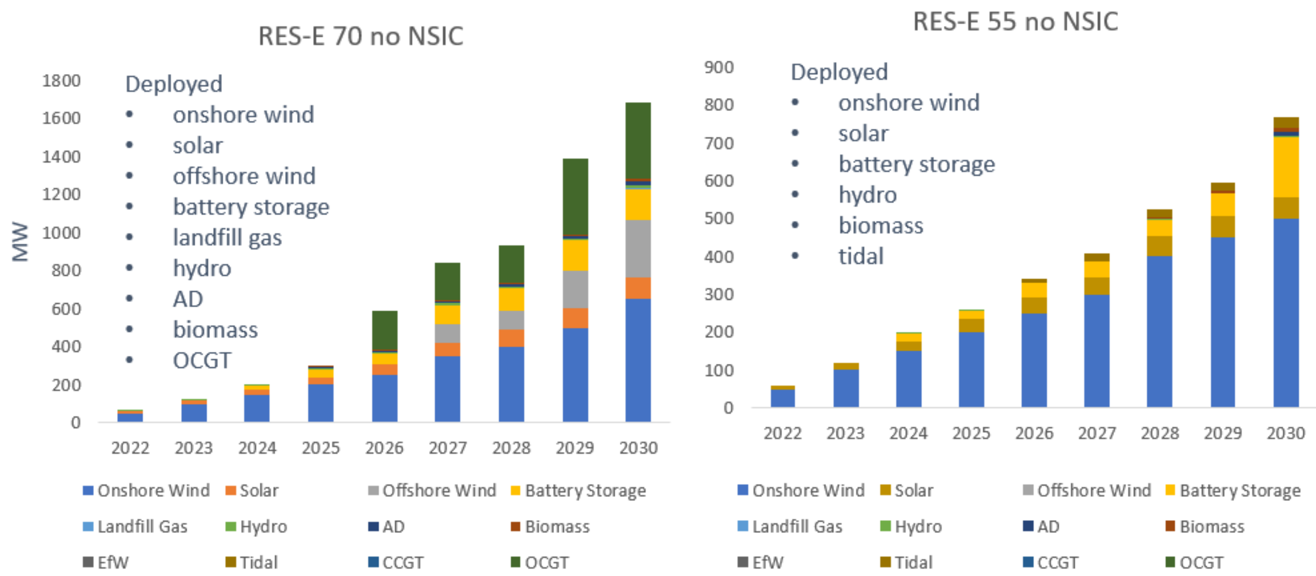


Source: Cornwall Insight & Ionic Consulting

What's notable is that the capacity not provided by offshore wind has been replaced by onshore wind in this case, suggesting that costs of offshore wind become competitive for Northern Ireland. The sector is growing in GB and is expected to grow in ROI in the next decade. The technology is discussed in more detail in the next chapter, but this analysis can hopefully provide the policy maker with some guidance as to the relative outcomes of encouraging certain technologies such as offshore wind.

North South Interconnector

Figure 53. Scenarios where the North South Interconnector is not available. Note: both charts are not to the same scale.



Source: Cornwall Insight & Ionic Consulting

The model was run for the RES-E 70 and RES-E 55 scenarios where the North-South interconnector was not available. Figure 53 shows the relative deployment of new capacity. Both targets encourage a broad diversity of technologies to deploy. Again, it should be noted that RES-E 70 is based on the higher demand scenario in the GCS18 and RES-E 55 is based on the median demand. Because of the restrictions on imported power from ROI, the generation capacity to meet this demand differs from when the North-South Interconnector is included, because as much power cannot be imported from ROI. This in combination with the maximum deployable onshore wind and solar as outlined previously, encourages greater technology diversity. Interestingly in order to meet the system security requirements of the RES-E 70 with high demand scenario, OCGT has been deployed as well as more battery storage than in the initial RES-E 70 results.

The costs between the RES-E 70 scenarios with and without the North South Interconnector by a significant 66% and carbon intensity has increased by 18%. The news is a little better for the RES-E 55 comparison whereby costs increased by 36% and carbon intensity by 2%. The RES-E 55 scenarios sees deployment of significant battery storage with hydro, biomass and tidal. The analysis gives a picture of how vital the North-South interconnector is to Northern Irelands interest, from the perspective of all sides of the trilemma. It hints towards a situation whereby Northern Ireland could find itself considering deploying more fossil fuel plant to meeting security needs, which would be considered regressive with regards to the UK's carbon targets. This in conjunction with the fact that NI has a generation fleet which will start coming out of subsidy and maybe out of operational use in the 2030 suggests that difficult, and potentially expensive decisions may have to be made towards the end of the 2030 should investment in new assets no occur in the next decade.

In times of stress like this, the diversity of technology deployed by the model raises an interesting consideration for policy makers. Diversity of technology as explained elsewhere is a good way of mitigating curtailment and network issues due to having a lot of intermittent generation on the system. It also appears to be a good way of protecting the electricity system from stress due to outages, lack of capacity etc. Even if the North-South interconnector goes ahead, by encourage diversity and technologies such as battery storage, policy makers could be protecting the grid not just over the next 10 years, but also beyond that time.

The DfE has a copy of the model used to run these scenarios. It is hoped that will allow policy makers to explore other options beyond those considered in this chapter.

7.4 Electricity network development

The rapid deployment of renewable energy up to 2019 has required significant investment in the grid network in NI at both transmission and distribution levels. Furthermore, the target to increase the level of intermittent renewables penetration to 75% has required the island-wide rollout of the DS3 Programme which involves network and non-network services to facilitate higher penetrations of intermittent non-synchronous generation[135].

NIE Networks has invested circa £78m in the distribution network to facilitate renewables which is deemed low considering the extent of renewables roll-out. For example, the 2012 Offshore Renewable Energy Strategic Action Plan (ORESAP)[136] estimated that network costs for integration of renewables to meet the 40% RES-E targets would amount to £1 billion. The lower-than-expected cost is understood to primarily be due to considerable existing headroom on the system and the allocation of the costs of connection and shallow works to project developers. The addition of further generation will likely necessitate a mixture of smart grid measures and trigger capital works such as network reinforcement and new builds.

The development of NI's electricity transmission and distribution networks are a key element in the roll-out of renewable energy to date and in future. Increased penetration of variable renewable generation to 2030 and beyond combined with the ongoing electrification of sectors such as transport and heating mean that ever increasing demand will be placed on the network in future. A conventional 'business as usual'

[135] The EirGrid/SONI DS3 Programme is at http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/
[136] https://www.economy-ni.gov.uk/sites/default/files/publications/deti/Offshore%20Renewable%20Energy%20Strategic%20Action%20Plan%202012-2020%20-%20First%20Year%20Progress%20Report_0.PDF

approach solely involving reinforcing existing lines and constructing new assets will likely result in considerable cost to the NI consumer. Therefore, an approach that utilises 'smart grid' technologies in order to avoid early large-scale investment is deemed the best approach in all scenarios.

Overview of current transmission & distribution network

The electricity network in NI broadly consists of the following elements:

Table 16 – NI Transmission & Distribution Assets

Transmission lines (275kV, 110kV)	2,200km
Distribution lines (33kV, 11kV, 6.6kV and 400/230V)	47,000km
Major Substations	300

SONI is the Transmission System Operator (TSO) whilst NIE Networks is the transmission and distribution system asset owner. As the electricity network is deemed a natural monopoly, NIE Networks operates under a price control mechanism where total expenditure relating to construction, operation and maintenance of the network is agreed for a 'Price Control Period' with the NI Utilities Regulator (UR) [137]. To date the UR has approved a budget of £1.2bn to spend on the transmission and distribution networks to 2024 although there are several re-openers whereby NIE can apply for additional funding where deemed appropriate.

Connection of non-synchronous renewable generation presents particular challenges for SONI and NIE Networks. Firstly, to meet the 40% RES-E target, grid capacity had to be made available for the connection of over 1,600 MW of renewable generation, predominately onshore wind. It was possible to provide this grid capacity at a relatively low socialized cost due to the headroom available on the transmission network at the time. This capacity headroom has now been used up particularly in the west of NI with little possibility of connecting additional wind generation in this area without significant grid infrastructure investment or applying high constraint levels to generators. There is some capacity for connection of generation in the east of Northern Ireland but the potential for construction of wind generation projects in this region is limited and any renewable generation here is more likely to be solar PV.

In addition to providing grid connection capacity NIE Networks and SONI have had to integrate non-synchronous generation onto a system that has traditionally been run on synchronous thermal generation plant while ensuring that curtailment is at levels that make renewable energy projects commercially viable.

SONI and EirGrid have implemented an all-Island DS3 Programme (Delivering a Secure, Sustainable Electricity System) to meet the challenges of operating the electricity system with increased amounts of variable non-synchronous renewable generation while achieving the NI and ROI 2020 renewable energy electricity targets. There are three pillars of the DS3 Programme - System Performance (including Grid Codes, System Services, RoCoF, etc), System Policies, and System Tools. Completion of the programme in 2020 will result in instantaneous system non-synchronous penetration (SNSP) levels of 75%. It is anticipated that further increases in SNSP levels will require an extension of this programme or implementation of further innovations. It should be noted that implementation of this programme on an all-Island basis was facilitated by both jurisdictions having the same renewable energy electricity targets.

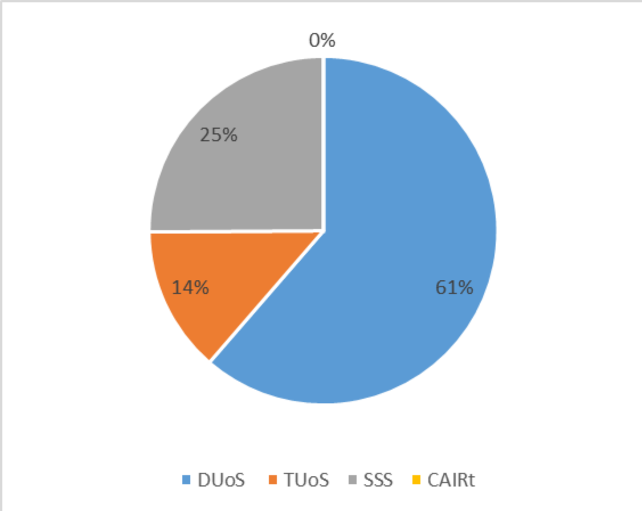
Network charges

Costs relating to the transmission and distribution networks generally fall under Transmission Use of System (TUoS), Distribution Use of System (DUoS) and System Support Services Charges (SSS) which incorporates both an allowance for SONI to recover costs relating to system operation and funding for DS3 service payments to generators. The Collection Agency Remuneration Requirement ($CAIR_t$) allowance[138] also permits the Moyle Interconnector to recover (from SONI) the balance of required revenues not collected through sale of capacity on the interconnector. It is not always needed when the Moyle interconnector can

[137] Currently in the RP6 price period which runs until 2024.
[138] http://www.soni.ltd.uk/customer-and-industry/general-customer-information/transmission-use-of-system-charges%20TUoS/collection-agency-income/

sell sufficient capacity to cover costs (such as in the 2018/2019 tariff period where no claw back is forecast), but with outages, increased competition from other interconnectors and increased bond payments it has needed additional support previously. Based on recent figures from UR, network costs form approximately 25% of customers' electricity bills and broadly consist of the elements in Figure 54.

Figure 54 - Electricity network cost breakdown for the 2018 / 2019 tariff period[139]



Future network development to accommodate renewable energy

Varying levels of network investment will be required depending on the extent of roll-out of renewable energy to 2030 with any investment being subject to the approval of the UR. NIE Network's current capital spend of £440m has been approved under RP6 to 2024[140] including up to £6.3m for innovative network solutions to accommodate increased penetration of renewables and low carbon demand such as heat pumps and EVs. Expenditure is nominally divided across the price control period as outlined in Table 17 but is subject to change based on actual expenditure for preceding periods.

Table 17 - Breakdown of RP6 expenditure[141]

Transmission & Distribution - '18/19 Price base	6 months to Mar-18 £m	2019 £m	2020 £m	2021 £m	2022 £m	2023 £m	2024 £m	RP6 £m
Direct capex	30.226	60.452	60.452	60.452	64.289	64.289	64.289	404.446
Renewables D5	1.425	8.716	17.432	15.842	8.223	8.223	0.000	59.860
Indirect & IMF&T	14.913	29.826	29.826	29.826	29.826	29.826	29.826	193.870
IT	4.576	3.850	4.204	2.591	2.024	1.201	2.598	21.044
Market Operations	8.772	13.990	10.093	9.194	8.507	8.580	9.408	68.544
RPEs and Productivity	-0.841	-2.377	-3.168	-3.876	-4.795	-5.522	-6.377	-26.955
Capex	**59.072**	**114.457**	**118.839**	**114.029**	**108.074**	**106.596**	**99.743**	**720.809**
Market Operations	6.617	12.992	12.822	12.688	12.576	12.465	12.345	82.505
Indirect & IMF&T	29.664	58.905	58.512	58.016	57.526	57.040	56.555	376.219
IT	0.247	0.329	0.219	0.219	0.219	0.219	0.219	1.672
Licence fees	0.822	1.645	1.645	1.645	1.645	1.645	1.645	10.689
Opex	**37.350**	**73.871**	**73.198**	**72.569**	**71.965**	**71.368**	**70.764**	**471.085**
Totex								**1191.894**

It should also be noted that an additional £200m was identified for possible inclusion if major transmission projects including the north-south interconnector are progressed by SONI during this timeframe[142]. SONI's

[139] $CAIR_t$ remuneration is not required for the 2018/2019 tariff period
[140] RP6 is the 6th NIE price control period and runs from 2017 – 2024. NIE have outlined their planned expenditure at https://www.nienetworks.co.uk/investment/investing-for-the-future
[141] Based on data received from NIE Networks
[142] SONI outline their major projects pipeline in their Transmission Development Plan 2018 – 2027 and are responsible for identifying and progressing projects for transfer to NIE Networks for development.

Transmission Development Plan shows that there are currently at least £531m worth of capital projects proposed of which £380m relate to new builds for integration of renewable generation, a large portion of which lies in the north-western region. It should be noted that the cost for the NW Reinforcement has not yet been defined and consists of an extensive list of new build and reinforcement options which SONI will consolidate in future development plans.

Assumptions on the extent of asset reinforcement and build-out under each scenario have been made in the absence of definitive data and applied to each scenario.

Transmission System Network Development

The extent of the transmission system development from 2020 to 2030 will depend on the following factors:

- NI's renewable energy electricity targets for 2030
- Connection method and location of renewable energy generation capacity required to meet the above targets
- Connection policy adopted for new renewable energy generation capacity.

These factors are considered in the various scenarios considered below.

It is assumed that there will smart grid technologies such as high temperature conductors, dynamic line ratings, STATCOMs and devices to regulate line characteristics utilised on the transmission network in the years 2020-2030, particularly to manage existing connections prior to large scale development. Some forms of these technologies have already been used on the NI transmission system with the implementation of special protection schemes which deliver some degree of dynamic line rating. However, new technologies will have to go through a qualification and type testing process by the transmission system owner and any significant implementation of these technologies is unlikely to happen until late in the period under consideration. For the purposes of this report it has been assumed that smart grid technologies will not contribute significantly to additional transmission system capacity in years 2020-2030.

Baseline Scenario

In the Baseline scenario no further renewable energy generation will be deployed so no significant transmission system projects for renewable integration purposes will be implemented. Demand growth is also low and it is assumed that no grid infrastructure upgrade will be required for this purpose.

This baseline scenario assumes that all asset replacement projects outlined in the SONI Draft Transmission Development Plan 2018-2027 will proceed at a total cost of £105.7m (£48.8m already approved by UR, £56.9m for projects outside RP6 mechanism). The SONI Draft Development Plan 2018-2027 was based on the NIE RP6 plan up to 2024. To take this plan up to 2030 it is assumed that additional asset replacement projects will be carried out and a cost of £58.5m has been assumed for these works based on the spend rate up to 2024. This scenario also assumes that a number of RES integration projects will proceed to ensure ongoing security of supply following achievement of 2020 targets.

It assumes that the major RES integration projects scheduled for completion post-2024 will not proceed in this timeline (for example the Coolkeeragh-Trillick 110kV line, Turleenan-Omagh South-Co. Donegal 275kV line and North West of NI Reinforcement).

It is assumed that the North-South Interconnector development will proceed and be operational by 2024. It is understood that the Coleraine, Omagh, and Tamnamore reactive compensation projects are no longer being progressed and an alternative more efficient solution is being considered. It is assumed that the Kells-Rasharkin 110kV circuit will be built to relieve congestion issues and address phase angle problems in the North-West. It is understood that SONI plan to continue investigating technology solutions to mitigate and minimize any remaining phase angle risks.

A summary of the projects assumed to progress by 2030 and total cost under the Baseline Scenario are outlined in Table 18 below.

Table 18 - Transmission System Projects Baseline Scenario

Project	Cost (m)	ECD
Creagh/Kells – Rasharkin	£23.1	2026
Limavady – Agivey 110kV Circuit	£30.0	2027
Tamnamore - Turleenan Upgrade	£2.28	2022
Omagh Main - Omagh South Upgrade	£4.2	2023
Reactive Compensation (single site)	£15.0	2023
110kV restring in North West (Omagh-Strabane-Coolkeeragh, plus Coolkeeragh-Limavady)	£10.0	2026
N-S Interconector	£109.00	2024
Enhancement to low frequency load disconnection scheme	£0.45	2021
Coolkeeragh Magherafelt 275kV Circuit Refurbishment	£27.40	2021
Ballymena Transformers 3 and 4 replacement	£1.89	2024
Enniskillen Main 1 and 2 Replacement	£1.89	2024
Strabane Main Refurbishment	£2.49	2024
Limavady Main Refurbishment	£1.43	2024
North West Special Protection Scheme	£0.34	2019
Coolkeeragh T1 Transformer Cabling Upgrade	£0.54	2020
Donegall Main Transformer Replacement	TBA	2018
Castlereagh Inter-bus Transformer replacement	£1.27	2018
Ballylumford Switchgear Replacement	£17.00	2020
Ballylumford Castlereagh Line Refurbisment	£12.50	2022
Banbridge Main Transformer 1,2,3,4 Replacement	£1.89	2024
Ballylumford Inter-bus transformer 1 and 2 cooler replacement	£0.27	2024
Glengormley main 110kV Replacement	£0.94	2024
Kells and Tandragee Shunt Reactor Replacement	£1.47	2027
Kells Remote Control	£0.37	2020
Tandragee 275kV Second Bus Coupling	£2.14	2021
Ballylumford Castlereagh 110kV Line Upgrade	£12.15	2022

Project	Cost (m)	ECD
Airport Main 110/33kV	£7.31	2022
Castlereagh 275kV Transformer	£8.06	2022
Shunt Reactors (4 no.)	£3.4	2024
Drumnakelly and Armagh Development Plan	£21.90	2027
Castlereagh and Tandragee 110kV Switchgear	£7.42	2021
Castlereagh – Knock 110kV Cable Upgrade	£1.22	2021
Cregagh Transformer B Switchgear Replacement	£0.29	2022
Asset Replacement Estimate RP6-2030	£58.5	2024-2030
Total	£388.11	

(Note: Limavady-Agivey Circuit is not detailed in plan but discussions with stakeholders suggest that this will proceed in Baseline Scenario. Budget figure is based on Kells-Rasharkin cost)

System services costs are assumed to continue at 2020 levels. The all-island DS3 system services spend has been capped at €235m (£205m). Assuming an expenditure split on ROI/NI population ratios (72%/28%), this would result in NI expenditure of **£57.4m**. Although this is considerably higher than the 2018/2019 anticipated NI spend of £41.4m the higher figure has been assumed for this Baseline Scenario as it allows for future volume capped contracts and additional services to be introduced before the end of 2020.

Efficiency Scenario

In the Efficiency Scenario limited additional renewable energy generation will be deployed which will not trigger any major 275kW transmission system upgrades. Demand growth is also relatively low with the main growth driver being an additional 40,000 EVs on NI roads by 2030. It is assumed that no grid infrastructure upgrade in excess of the Baseline Scenario will be required for this purpose. Expenditure on the transmission network for this scenario has therefore been assumed to be the same as that for the Baseline Scenario.

No additional system services beyond those developed as part of the DS3 programme will be required in this scenario resulting in an ongoing annual spend of **£57.4m** to 2030.

Sustainability Scenario

In the Sustainability Scenario demand growth and the requirement for additional renewable generation will drive the need for transmission system network upgrades. In this scenario it has been assumed that over 400MW additional renewable energy generation will be deployed. Over 300MW of this generation is assumed to be wind generation - the bulk of which will be sited in the west of NI. It is assumed, therefore, that reinforcement of the system at 275kV will be required and the cost of this reinforcement would be similar to that allowed for the proposed Turleenan-Omagh-Donegal 275kV Circuit project outlined in the SONI Draft Development Plan. This project is costed at £170m in the plan and it is assumed that this expenditure will be sufficient to deliver grid infrastructure for the generation to be connected in this scenario.

With additional generation likely to be connected on the distribution system the project to increase capacity at the transmission/distribution system interface identified in the SONI Draft Development Plan is assumed to proceed during the time period being considered.

Table 19 - Additional Transmission System Project Costs for Sustainability Scenario

Project	Cost (m)	ECD
New 275kV circuit in west of NI (assume cost of Turleenan - Omagh South - Donegal new 275kV line)	£170	Post-2025

Project	Cost (m)	ECD
Augmentation of Capacity at Transmission/Distribution Interface	£13.6	2024
Total Additional for Sustainability Scenario	£183.6	
Baseline Cost	£388.11	
Total Grid Costs (incl Baseline Costs)	£571.71	

In addition to the capital investment programme there will be integration costs associated with the additional renewable non-synchronous generation capacity. It is assumed that SNSP in this scenario could increase to 85% resulting in a pro-rata increase in system services cost to **£65.1m**

Low Carbon Scenario

The Low Carbon Scenario is based on the connection of circa 900MW of additional wind generation, 300MW of which will be offshore. As with the Sustainability Scenario it is assumed that most of the onshore wind generation will be constructed in the west of NI. The construction new 275kV circuits would provide grid infrastructure for an addition 500MW of wind generation. The offshore wind project would connect into one of the nodes in the east of NI with generation connection capacity.

It is assumed that further reinforcement of the grid in NI M-W would be required for additional renewable generation in this scenario. It is assumed that the project is similar in scale to the Turleenan-Omagh South Project and a provisional figure of £100m has been allowed for. Other options will also be considered in this scenario such as connecting some onshore wind into the eastern NI nodes or hybrid wind/solar connections in the west of NI.

Table 20 - Additional Transmission System Projects for Low Carbon Scenario

Project	Cost (m)	ECD
New 275kV circuit (cost based on Turleenan - Omagh South - Donegal new 275kV line)	£170	Post-2025
Augmentation of Capacity at Transmission/Distribution Interface	£13.6	2024
Additional Project for NI NW Grid Re-enforcement in LC Scenario	£100	
Total Additional for Sustainability Scenario	£283.6	
Baseline Costs	£388.11	
Total Grid Costs (incl Baseline Costs)	£671.71	

It is assumed that SNSP in this scenario could increase to 95% resulting in a pro-rata increase in system services cost to **£72.7m**

Distribution System Network Development

For the purposes of this report it has been assumed that generators other than small and micro-generators (<16A per phase at LV) connecting to the Distribution System will pay the full costs of any system upgrades required. Although large in number (c. 22,000), microgenerators make up a small percentage, estimated at circa 8%, of the overall renewable generation capacity in Northern Ireland. Generation installed at LV can trigger network upgrades at 33kV which are not chargeable to individual generators and the costs associated with these upgrades are recovered from electricity consumers. The costs associated with these upgrades up to 2020 have been estimated at £15m. It has been assumed that the percentage contribution of small-scale generation to future renewable generation capacity on the network will remain low. It is assumed that domestic generators will increasingly utilise battery technology to avoid exporting excess generation and network operators are concerned about large volumes of additional uncontrollable generation being connected to the distribution network.

Under the current price control mechanism NIEN are trialling a number of new technologies such as active network management, demand reduction through voltage conservation, facilitation of energy storage systems, demand side response, smart asset monitoring and management, voltage control through STATCOMs, and the development of nodal controllers to provide system voltage storage support. It is expected that these technologies will be utilised to varying degrees in the various scenarios under consideration particularly in helping to minimise network capital expenditure in scenarios with high levels of low carbon technologies.

Smart meters are not currently being trialled in NI but it is assumed that they will form part of the technology mix in scenarios with high levels of low carbon technologies.

RES-E 40 Efficiency Scenario (aka “Efficiency”)

In this scenario low growth in demand is assumed with a low take-up of low carbon technologies. It is assumed that any network investment costs will be borne by those connecting to the network or modifying their connection types.

RES-E 55 Scenario (aka “Sustainability”)

It is assumed that any network investment costs for large scale generation will be borne by those connecting to the network. There will be some costs associated with connecting microgeneration. Assuming a similar proportion of microgeneration to that installed in 2020 and scaling the costs associated with that capacity the cost for connecting this microgeneration is assumed to be £15m. It is assumed that innovative technologies and smart grid technologies will be utilized to minimise these costs.

RES-E 70 Scenario (aka “Low carbon”)

As with the Sustainability Scenario it is assumed that any network investment costs for large scale generation will be borne by those connecting to the network. There will be some costs associated with connecting micro-generation. Assuming a similar proportion of microgeneration to that installed in 2020 and scaling the costs associated with that capacity the cost for connecting this microgeneration is assumed to be £15m It is assumed that innovative technologies and smart grid technologies will be utilized to minimise these costs.

8 Community Energy

Community energy projects are typically defined as local power or heat generation facilities distributing energy to local users via public or private infrastructure, or local initiatives to reduce energy consumption. They are the result of collective action to reduce, purchase, manage or generate energy. Community energy projects have an emphasis on local engagement, local leadership and control, and the local community benefiting collectively from the outcomes.

The potential development of Community Energy Schemes forms a key part of the DfE's consideration with any new energy policy. In this section, we assess the potential for community energy schemes in Northern Ireland - as well as providing an overview of such schemes in other jurisdictions such as England and Wales, Scotland, Denmark, ROI and community energy groups in NI. The topics covered in this section include:

1. Drivers for communities to engage in projects
2. Enablers for supporting their development
3. Community energy projects types and goals
4. Creating engagement with policies
5. Case studies in other jurisdictions
6. Feedback from NI stakeholders as part of this process

Community energy projects are typically born of one or more driving factors that are reflected in the development and deployment of the scheme. These projects typically involve sufficient community support and buy-in, some capital investment and project management, and procurement and deployment of a number of subcontractors.

As such, community energy schemes, especially larger projects, can be costly and of long duration. An underlying theme or cause is typically essential for projects to transition from inception to commissioning. Some of the main factors that typically drive community energy projects are outlined in Table 21.

Feedback from stakeholder interviews revealed that reduced cost and potential revenues were widely accepted as the primary driver for community energy projects, with environmental benefits also listed as a strong drivers. Respondents noted that some locations have a very strong community presence that, when turned to energy, can drive the development of community energy projects. However, the lack of a strong sense of community universally means this driver is very location-specific.

Another driver noted in interview is the use of established models – respondents noted that communities are very good at imitating proven successful projects. Therefore a community that establishes both a replicable and scalable model can be a key driver for facilitating the development of further community energy projects in the vicinity or wider afield

Table 21. Drivers for community energy projects

Driver	Further information
Sustainability	Reduced production of greenhouse gas emissions, reduced pollution levels in the local environment
Ownership	Increased buy in and interest from the local community due to ownership structures and improved tangibility of energy

Reduced cost/ revenue	Financial benefits to individuals or the community through reduced costs or increased revenues
Management of energy challenges	Local energy generation effectively managing constraints and other issues, leading to better outcomes for the community
Innovation	Desire to do different and be a thought leader for others
Visual amenity	Local energy generation displacing traditional fossil fuel fired power generation

Enablers

While drivers reveal the main motivation behind the inception and delivery of a project, a number of "enablers" are required for the successful delivery of a community energy project. This is because projects can be delayed, or ultimately prevented, in developing from one stage to another. For example, a project will not progress from a feasibility study without funding, connection and a planning agreement, and a suitable route to market. Some of the main enablers are outlined below.

Table 22. Enablers for community energy projects

Enablers	Further information
Knowledge	Energy specific knowledge either in the community or available for free or a nominal fee. Knowledge of key risks and challenges in project.
Funding availability	Access to project funding and support through private capital or other.
Subsidy	Presence of easily available revenue streams for subsidising renewable power generation.
Route to market	Opportunities for selling power to an offtaker, ease of accessing offtakers, knowledge of offtakers, presence of standard contracts (e.g. Power Purchase Agreement), confidence in achieving a good deal.
Support (government and/ or regulator)	Support developing or delivering community energy projects, opportunities to engage with the regulator to explore innovative delivery
Supply chain availability	Knowledge of and access to engineering firms, cost-competitive new or refurbished generation assets, local labour and contracting fees.
Connections	Cost and timeliness of connections to the local distribution network. No/ minimal constraints once connected.
Planning	Ease of securing planning permission and/ or any environmental permits. NIMBY-ism or lack of local support hinders this.
Access to other community experience	In close proximity to other successful community developments making access to advice and benefitting from other experiences

Feedback from interviewees suggested that all of these enablers are in very short supply or entirely absent in Northern Ireland. Possible exceptions include:

- Routes to Market – one respondent said their community energy project had a few offtakers to choose from due to the expertise and range of skills present on their Board. In contrast another respondent claimed that Power NI is seen as an incumbent and was the only option available
- Connections – this (as might be appreciated) is very dependent on the experience of each of the individuals interviewed. A leader of a local energy project had no issues at all with their project, while a community energy consultant noted a range of projects with connection issues.
- Knowledge – very specific as the communities driving projects can be highly dependent on one or two knowledgeable individuals involved in the project. However all participants agreed it is difficult to access knowledge and there is no trade association or body that community energy groups can turn to in NI.

Respondents noted that a mentor or trusted advisor role is particularly important to support community energy groups with all enablers. Communities need a long-term relationship with a professional project manager in order to deliver these projects successfully, but such a role needs to be funded appropriately (potentially centrally or by local government to ensure neutrality). Respondents also suggested a body such as the Renewable Energy Association (REA) would be useful to facilitate information exchange and energy literacy.

Community energy project types

Community energy models fall into a number of broad types and categories depending on their primary goal, mode of delivery and the funding and governance models. Often, for community energy, the local physical environment and socio-demographic profile are important determinants in the type of community energy scheme being delivered.

The few community energy projects in NI were noted to be predominantly backed by government subsidy (the Renewable Obligation). Community energy projects would then share the benefits with farmers and local communities through education and fund raising, although the importance of this practice depending on ownership and goals for each of the community energy projects.

Policy engagement

Any policy developed to improve the delivery of community energy projects needs to understand:

- The primary drivers and motivations behind community energy in the jurisdiction;
- The main barriers preventing the successful deployment of community energy schemes;
- How motivations and barriers vary geographically; and
- The main types of community energy model that are likely to be deployed within the jurisdiction.

Existing community energy models

The following sections summarise the existing community energy models in a number of regionally comparable markets, including Great Britain, the Republic of Ireland and a number of European comparators.

Northern Ireland

As is the case in England and Wales, Rural Community Energy Fund (RCEF) support is still available, however challenges arise around the lack of policy regarding community energy. The community energy sector in Northern Ireland is now aided by the Fermanagh Trust and there is some 'self-support' provided by Northern Ireland Community Energy (NICE), the country's first community benefit society[143].

The community energy sector in Northern Ireland was only initiated in 2012, and as of June 2018, according to Community Energy England (CEE) [144] only one community owned energy project is listed – namely the Drumlin Energy Cooperative. This is an Energy4All supported co-operative, which now has six community owned and managed 250kW wind turbines across Northern Ireland.

Aside from what is listed in CEE, there is also a community solar enterprise being supported by the Northern Ireland Community Energy (NICE)[145]. NICE was established by members of the Northern Ireland community, including several who are involved in Drumlin Co-operative. NICE have supported 130kW of solar across 13 community groups since February 2015.

Note: The Rural Community Energy Fund (RCEF) is a £15mn programme, jointly funded by DEFRA and BEIS. It supports rural communities in England and Northern Ireland to develop renewable energy projects which provide economic and social benefits to the community. Has two stages:

Stage 1 - Feasibility study funding (up to £20,000)

Stage 2 - Planning applications and robust business case formation (up to £130,000)

In 2017, RCEF funded £40,000 to organisations.

Much of Northern Ireland's outlook up until now appears to have been focused on improving public acceptance of renewable energy through educational (schools) events, community funds and wider social benefits as outlined in the SEF[10].

Case Study: Drumlin Wind Energy Co-operative

Drumlin Wind Energy Co-operative aims to create self-sufficiency and switch to green power.

The co-operative has enabled members to invest in shares and earn annual interest. It's current share offer allows for investments of between £250-£30,000 with an earned interest rate of 4-5%. Its target is to raise £1,000,000 by 1 April 2019[1]. It raised £2.7mn in 2012 to build four turbines totalling 1MW of capacity in 2012[1]. Any profits from the turbines are channelled into a community fund.

Technology used

1.5MW wind turbines

Limitations

Remote developments have raised objection, are seen to be damaging to the landscape and 'intrusive'. In this instance, it may be harder to convert objectors' opinions through community funds or share offers.

Key stakeholders

933 active members, 8 directors, Energy4All, Drumlin Wind Energy Co-operative, local residents[145]

[143] https://communityshares.org.uk/resources/handbook/community-benefit-societies
[144] https://communityenergyengland.org/files/1530262460_CEE_StateoftheSectorReportv.1.51.pdf
[145] http://www.nicommunityenergy.org/

Scotland

Community energy constitutes a significant proportion of the Scottish energy mix, with 697MW of community-owned renewable energy capacity operation as of June 2018[146]. Enabling the development and deployment of locally-owned assets is seen as crucial to meet the government's original target of generating the equivalent of 100% of Scotland's gross annual electricity consumption from renewables by 2020[147]. Despite the likelihood of missing this target, with just over 68% of Scotland electricity consumption met in 2017, the community energy sector must still react to fulfilling this commitment as soon as possible. An interesting feature of Scotland's community schemes is that communities have been known to re-invest revenues earned from community projects into further renewables projects, as noted by Community Energy England (CEE) as an unexpected form of community energy funding in 2017. The Scottish Government has clear targets for local and community ownership of renewable energy[148]. They include:

- 1GW of community and locally-owned renewable energy by 2020
- 2GW of community and locally-owned renewable energy by 2030
- At least half of newly consented renewable energy projects to have an element of shared ownership by 2020

Case Study: Edinburgh Community Solar Co-operative (ECSC)

The project's key aims are to achieve self-sufficiency and reduce fuel poverty. ECSC acts to decarbonise the electricity generated in Edinburgh through installations on 25 public buildings such as schools, community centres and leisure facilities funded through a community share offer.[11]

A total of £1.5mn was raised by 541 members to fund community solar projects. Members are entitled to annual return of 5% on investment per annum and are also able to benefit from 30% tax relief.

Project linked to 'community benefit fund'. Funding made available to buildings with installations over first five years. After five years, funding allocated to 'common fund' to finance energy efficiency measures to alleviate fuel poverty.

Technology used

Installed technology is as follows:

- 1.5MW solar PV

Limitations

- Excludes those with insufficient capital to invest

Key stakeholders

Local residents and community investors, public entities with mounted installations

Local Energy Scotland is a Scottish government-funded organisation to benefit and encourage community energy. It is a consortium made up of the Energy Saving Trust, Changeworks, The Energy Agency, SCARF and The Wise Group. Its programmes include:

- Free support, advice and resources to developers.
- The Community and Renewable Energy Scheme (CARES)[149] loan offering, which provides up to £150,000 to community groups and rural businesses that want to generate renewable energy.

[146] https://www.energysavingtrust.org.uk/scotland/communities/community-renewables/community-energy-reports
[147] https://www2.gov.scot/Publications/2011/08/04110353/0
[148] Committee on Climate Change - Reducing emissions in Northern Ireland – February 2019
[149] https://www.localenergy.scot/funding/

- As part of the loan, good practice advice is given. For example, for onshore wind development, developers are advised to pay at least the equivalent of £5,000 per installed MW per year to local communities over a project lifetime. While not legislated, this is now expected as good practice.
- As of February 2019, the average payment for developments was £6,140 per MW
- The Local Energy Challenge Fund[150], which provided development and capital support to large scale demonstrator projects which show a local energy economy approach linking energy generation to energy use. This fund is now closed to the new applications.
- The Low Carbon Infrastructure Transition Programme (LCITP), which is aimed specifically at overcoming challenges within local supply, electrical grid constraints and energy storage. It is a Strategic Intervention supported by the European Structural and Investment Funds, and European match funding for the LCITP is guaranteed up until Autumn 2021. It is overseen by the Low Carbon Infrastructure Transition Programme Board, and awarded funding of more than £45mn in 2017151 to a total of 13 projects.
- Community Benefits of Civic Energy (COBEN), which focused on developing local energy plans across public and community stakeholders in four locations across the West and North of Scotland. The project is supported by the European Regional Development Fund and the Scottish Government's CARES scheme.

Case Study: Ealsburn Wind Farm, Fintry Scotland

Fintry residents explored options for local renewable energy installations with the idea of 'virtual ownership'[1], with an aim for funds to be utilised for fuel poverty. Local residents set up Fintry Renewable Energy Enterprise Limited (FREE) to be able to enter a joint venture agreement with Falck, the first partnership of its kind in the UK.

For the purpose of deciding what to do with the income generated, the community also established Fintry Development Trust (FDT) - a membership organization with charitable status, which is governed by a board of local residents. FREE is a trading subsidiary of FDT, which means the latter can legally control how profits should be spent.

FDT secured Scottish Government grant funding to commission a feasibility study that illustrated the financial viability for the initiative. After having explored different financing options, the community decided to take Falck Renewables up on their unique offer to provide up-front capital for the 15th turbine.

Over the first fifteen years, FREE will pay back the loan whilst generating an annual income of £30,000 - £50,000. After repayment, the residents are expected to receive £400,000 per annum. Electricity bills estimated to have decreased by £90,000 across 338 Fintry homes. Initial projects included £500 for energy efficiency measures or £1,000 if a household is deemed as being in fuel poverty.

Technology used

Installed technology is as follows:

- Fifteen 2.5MW wind turbines

Total capacity: 37.5MW

Limitations

- Initial repayment period limited short-term benefits

Key stakeholders

Fintry residents, Falck Renewables[1], EWEL (Falck Renewables subsidiary), RJ McLeod (main contractor) CII Holdco (more recently)

[150] https://www.localenergy.scot/funding/local-energy-challenge-fund/
[151] https://www.gov.scot/binaries/content/documents//govscot%3Adocument

Republic of Ireland

In RoI, there is currently one community wind farm, a number of bioenergy developments, two wind farms with community benefit aspects and a further five community owned developments that are currently in progress and are likely to be constructed over the coming years, pending grid connection and financing[152].

Case Study: Tipperary County Council Solar PV project

The project looks to decarbonise the public sector's electricity supply and help with energy efficiency.

It received 50% funding (€163,425) from the Better Energy Communities (BEC) grant by the Sustainable Energy Authority of Ireland (SEAI). The grant is available for those helping assist with energy efficiency community projects[1]. Electric Ireland contributed advice and financial support to the project and provided approximately 1.5% of the project costs.

Installation buildings included county council offices, libraries, fire stations and a leisure centre[1].

Technology used

Installed technology is as follows:

192kW solar PV

Limitations

There was a lack of involvement of the community with this development, which is seen widely as something that should come as part and parcel of decentralised developments to remove a lack of acceptance (especially wind turbines) and help to make involvement common practice. This is a common form in which the community aspect of low-carbon developments manifests in Ireland.

Key stakeholders

Tipperary County Council, Electric Ireland, local residents and building occupiers.

The new RESS scheme is due to feature a community scheme element, namely:

- All projects will be required to meet pre-qualification criteria, including offering the community to invest in and take ownership of a portion of renewable projects in their local area. Mechanisms may also include a Mandatory Community Benefit Fund and Register standardised across sector. It is proposed that this contribution is set at €2/MWh for all generation under RESS with the first auction due to take place in 2019.
- There's a proposal for ring-fenced 'community category for the RESS auction. It is proposed that this capacity would be limited to up to 10% of the second auction (around 300 GWh) which will be subject to review for future auctions. Projects would need to meet community-led criteria to qualify.
- The industry is still waiting on the detailed design for further details.
- Aside from RESS, Ireland-based co-operative Claremorris & Western Energy District created an initiative for community energy: The Community Renewable Energy Supply (CRES) is Ireland's first Community Owned Licenced Supply Company. It sells and purchases electricity generated from renewable energy sources which includes both wind and hydro projects. It works with a number of communities throughout Ireland who are actively engaged in creating sustainable energy futures for their local communities

[152] https://www.communitypower.eu/en/ireland.html

Denmark

In Denmark 90% of wind turbines and 50% of district heating are co-operatively owned[153]. It should be noted that in this country in particular, the general view from the community is that they have a right to own local generation. This has been born over time from its previous approach, and has created a stronger element of social enterprise than in other countries[154]. In the 1980s and 1990s the major part of wind turbines raised in Denmark were owned by local citizens organized in cooperatives. Today, only 20% of the local wind turbine projects are reserved for local citizens' ownership. This has been an important factor in the rising number of local protests.

Points to Note:

- In Denmark, the *Promotion of Renewable Energy Act*[155] requires developers to offer 20% of overall ownership shares of wind projects larger than 25m tall to eligible persons entitled to make an offer. The law provides a preferential right to residents within 4.5km of the site to buy the first 50 shares, and the remaining shares must then be offered to residents that reside in the local municipality. The law was brought forward following a fall in support for renewable energy developments in the early 2000s, when a number of large commercial renewable energy developers began to direct the renewables market in Denmark
- An important policy for promoting community-owned energy projects refers to a grid connection arrangement. This arrangement defines that turbine owners have to pay only for the connection to the closest technically feasible point of the grid[156]. Energy utilities are thus required to pay any necessary expansion of the grid and not the owners of the turbine.

Germany

In Germany, approximately 48% (30,250 MW) of total renewable energy is community owned. The German district of North Frisia has some 90% of installed wind capacity (700MW) that is community owned[157]. More generation is owned by the communities than by the four largest suppliers in Germany, with its largest supplier – E.ON – investing in more renewable assets in the UK than in Germany in the past 10 years[158]. Germany has over 1,000 energy co-operatives[159].The German government intends to generate 35% of its energy from renewables by 2020

Points to Note:

- Although this is not community focused, the government has put increasing pressure on its major energy suppliers with its decision to exit nuclear. The FiTs legislation, and the decision to give priority access for all renewables, gives communities a greater incentive to engage in renewable developments.
- In Germany, KfW Bank is popular in its affordable financing for community renewable schemes.
- Other countries define community projects as giving direct benefit to local communities, e.g. by supporting households improve their energy efficiency of their properties or supporting local charities. However, in Germany community investors are often different, commonly a group of farmers or community members but rather than the profits being used for community benefit activities, the profits are given to the investors. It is for this reason that community renewable energy projects pay German corporation and trade tax.

[153] https://www.communitypower.eu/images/Community_Energy_Policy_Position_Paper.pdf
[154] https://www.thebritishacademy.ac.uk//files/CoCE_International%20Case%20Studies_online_0.pdf
[155] https://ens.dk/sites/ens.dk/files/Vindenergi/promotion_of_renewable_energy_act_-_extract.pdf
[156] https://climatepolicyinfohub.eu/community-energy-projects-europes-pioneering-task
[157] https://www.communitypower.eu/images/Community_Energy_Policy_Position_Paper.pdf
[158] http://www.senedd.assembly.wales/documents/s34101/Paper%201.pdf
[159] https://www.theguardian.com/energy-cooperatives-uk-germany-denmark-community

9 Conclusion

As part of the development of a new Northern Ireland Energy Strategy, this report aims to guide the policy maker on the options and considerations to be taken into account in any such strategy. The report provides extensive research on the outcomes of past policy, the current landscape of electricity in Northern Ireland and feedback from various stakeholders including national and local government, regulators, industry bodies and non-government organisations.

Analysis was conducted on possible outcomes related to various possible electricity targets and from the perspective of the maintaining security of supply, cost considerations and sustainability. Although the model used in the analysis ran from only 2022 to 2030 based on lack of forecast data for beyond this time, the state of play of renewable generation was considered beyond that time.

The key messages for policy makers to consider when choosing the appropriate renewable electricity targets are as follows:

- From a purely cost perspective without subsidy support, onshore wind is the most likely technology to be deployed. In the absence of any support it is questionable whether onshore wind would meet either a RES-E 55% or a RES-E 70% target. It is the experience of Cornwall Insight that investors tend to be willing to take on riskier projects such as subsidy-free projects, alongside projects which are receiving a subsidy. With the closure of the NIRO, policy makers should consider realistically how much capacity is likely to be deployed as purely merchant or Corporate PPA projects.

- Without development of new generation assets in the 2020s, Northern Ireland could begin facing serious security of supply issues towards 2030 and beyond. Even assuming low electricity demand growth in the 2020s, renewable assets will begin to fall out of the NIRO subsidy and will require repowering or replacement in the 2030s. Should this not occur there potentially could be a generation shortfall beyond 2030. This situation could further be exacerbated if the North South interconnector is not developed as suggested by the model, leading to regressive actions from a climate policy perspective such as deployment of fossil fuel plant. With the LCOE of conventional generation rising, and uncertainty around future import fuel costs, these actions could also be considerably more expensive than pursing a renewable energy agenda. Developing a good pipeline of generation assets in the 2020s would help mitigate these risks and policy makers can consider how to do this from a low carbon perspective, which will help NI reach it's 2030 targets but also invest in the switching to a secure, low carbon future in the decades beyond.

- Diversity of technology is an important consideration from the perspective of both grid capacity and potentially for security of supply. Large amounts of intermittent generation such as wind and solar can create issues for the grid and increase curtailment costs. This creates risk for investors as well as requirements for expensive upgrades to the network. The model indicates that when the system is tight, it will deploy a diverse range of technologies, including battery storage. Costs for batteries are expected to decrease in the next decade and policy makers should consider how to encourage their uptake. Offshore wind is already present in GB and likely to become more prevalent in ROI in the next decade, and the model shows that deploying offshore wind can meet ambitious RES-E targets for less cost that having it unavailable. Presently NI is excluded from The Crown Estate's seabed leasing round and the DfE should liaise with The Crown Estate to see how policy may be able to increase NI's eligibility in the next round.

- The ambition of RES-E targets will have a material impact on the cost and extent of electricity grid build-out with forecast investment of between £388m and £672m required depending on scenario, albeit both figures include projects that will be constructed regardless for integration of existing renewables and security of supply reasons. The biggest and most pressing challenge from a grid infrastructure perspective will likely be the development and construction of large-scale transmission projects located primarily in the north and west of the region where remaining connection capacity is severely limited. As well as entailing significant costs they also bring significant programme uncertainty as is evident from the continual delays being experienced by the North-South Interconnector. Therefore, strong consideration should be given to formally identifying and advancing key strategic grid projects at transmission and distribution network levels to ensure that there is sufficient capacity available for projects to connect in a timely manner to meet the chosen 2030 targets.

- Chapter 5 has outlined some of the policy options open to the DfE for consideration. From a cost recovery perspective, should the DfE choose to initiate a subsidy scheme, recovery would have to come from either the UK customer (if NI joins the UK CfD scheme), the SEM customer (should NI join an “all-island” scheme with ROI) or the NI customer alone. Different schemes outlined in Chapter 5 have advantages and disadvantages associated with them from the perspective of consumers, policy makers, community energy and investors. Currently CfD schemes are gaining in popularity as governments move away from FiT schemes, as they are seen as being less burdensome for the consumer while still providing revenue certainty for the investor. For well-established technologies such as onshore wind they could be very suitable, however as covered in the previous point, the policy maker may wish to encourage less mature technologies, or different scales of technology for which the CfD may not be the most suitable, and a FiT or green certificate scheme may be more appropriate.

- There is potential benefit in more coordination between various government departments such as the DfI and the DfE in aligning on policy going forward. The Steering Group initiated for this project between the DfE, the DfI and the UR has been seen as a successful first step towards coordination and alignment. Consideration could be given to further liaising with the planning councils or with industry members. Many of the stakeholder we spoke to are passionate about the energy sector in Northern Ireland and have perspectives, ideas and experience to offer. This could be facilitated through the formation of working groups or a forum, where ideas could be exchanged and views listened to, which would allow alignment forming policy. Some participants suggested forming separate bodies similar to the SEAI to help deliver renewable energy policy in NI.

- With less than four months until the UK potentially leaves the European Union without a deal, we would urge the DfE to further liaise with BEIS regarding the eventuality of a hard Brexit, especially in the context of the carbon tax which would be implemented on the 4th of November. Statements from BEIS suggests this tax will apply to the whole of the UK, however NI’s unique position in a different market, means that there is a risk of there being two carbon prices in the SEM. This is the reason that NI did not join the Carbon Price Floor in 2013 and clarification should be sought from BEIS and the SEM Committee as to the implications of either NI no longer using the EU ETS, and/or being subject to the new carbon tax.

- Community Energy projects could benefit from a Renewable Energy Association (REA) to help assist communities with understanding their options, providing mentorship and guidance and advocate on their behalf. As mentioned by other stakeholders, challenges cited for community projects include access to supply chains, connections and routes to market. Community projects often replicate each other so a successful project may encourage further uptake of any supports available such as funding, subsidies or expertise.

10 Appendices

Appendix A

Date	Activity	Notes
November 2011	Memorandum of Understanding between the UK and ROI Governments on Offshore Renewables	Set out how governments of UK and RoI may arrange for the leasing, licensing, and operation of the seabed to facilitate the development of offshore renewable energy installations
March 2012	Offshore Renewable Energy Strategic Plan 2012-20	Aims to optimise the amount of renewable electricity sustainably generated from offshore wind and marine renewable resources in Northern Ireland's waters in order to enhance diversity and security of supply, reduce carbon emissions, contribute to the 40% renewable electricity target by 2020 and beyond and develop business and employment opportunities for NI companies. The associated development opportunity is for up to 900MW of offshore wind and 300MW from tidal resources in Northern Ireland waters by 2020.
May 2012	Sustainable Energy Action Plan	Brought into a single document all that the NI executive is doing to promote sustainable energy. Committed to the creation of a long-term vision, to 2050, for energy in NI
July 2013	Envisioning the Future: Considering Energy in Northern Ireland to 2050	A 'vision study' to inform thinking and further analysis of decisions and policy needed in NI to 2050. The focus of the study is on electricity, heat and transport. Two scenarios were developed, in which renewables provided at least half of all electricity generated against a backdrop of increased power demand for transport and heat
November 2013	Onshore Renewable Electricity Action Plan 2013-20	To maximise the amount of renewable electricity generated from onshore renewable sources in order to enhance diversity and security of supply, reduce carbon emissions, contribute to the 40% renewable electricity target by 2020 and beyond and develop business and employment opportunities for Northern Ireland companies
February 2014	Sustainable Energy Horizon Panel Report	Report commissioned to identify global sustainable energy technology market opportunities that could be realised by exploiting NI's science, research and technology capabilities. It recommended NI take a leadership role in the development of distributed energy solutions and their integration into Intelligent Energy Systems that will optimise efficiencies through the use of local resources and participation of multiple stakeholders; and to create an International Reference Site to demonstrate the commercial scalability of these solutions to the global market. If successful, "by 2023 Northern Ireland should have an active and intelligent energy network, with large scale integration of renewable generation (including onshore and offshore resources) and embedded energy storage"
January 2017	Industrial Strategy for NI—Consultation	This consultation set out the proposed strategy for the NI economy "to be a globally competitive economy that works for everyone". Within the document was the proposal to "develop a new Energy Strategy that will seek to address both our short to medium term needs and also position us to meet the longer

		term challenges out to 2030 and beyond". No response to the consultation has been issued.
February 2019	Reducing emissions in Northern Ireland—Committee on Climate Change	The Committee set out how NI can reduce its greenhouse gas emissions between now and 2030 in order to meet UK-wide climate change targets. It recommended: • Energy policy must enable an efficient, interconnected energy market to operate on both sides of the border • NI's contribution to the fifth UK carbon budget requires emissions reductions of at least 35% against 1990 levels by 2030—existing reserved and devolved policies in NI are not enough to deliver this • NI does not currently have any offshore wind capacity. The SONI and EirGrid capacity statement assumes that this will not have changed by 2027. Plans for the County Down offshore wind farm, which could have supplied up to 13% of Northern Ireland's electricity, were cancelled in 2014

Appendix B

Stakeholder	Location
Crown Estate	London
Ofgem	Teleconference
SONI	Belfast
DfE Statistics	Belfast
NIAUR	Belfast
NIEN	Belfast
BEIS	Teleconference
NIHE	Belfast (L2 workshop)
SIB	Belfast (L2 workshop)
Ulster Farmers Union	Belfast (L2 workshop)
Solar NI	Belfast (L2 workshop)
Viridian	Teleconference
NIRIG	Teleconference
DfI - transport	Belfast

DfE - Brexit team	Teleconference
Geological Survey NI	Teleconference
Drumlin Coop	Teleconference
Fermanagh Trust	Teleconference
Plan Energy	Teleconference

Appendix C

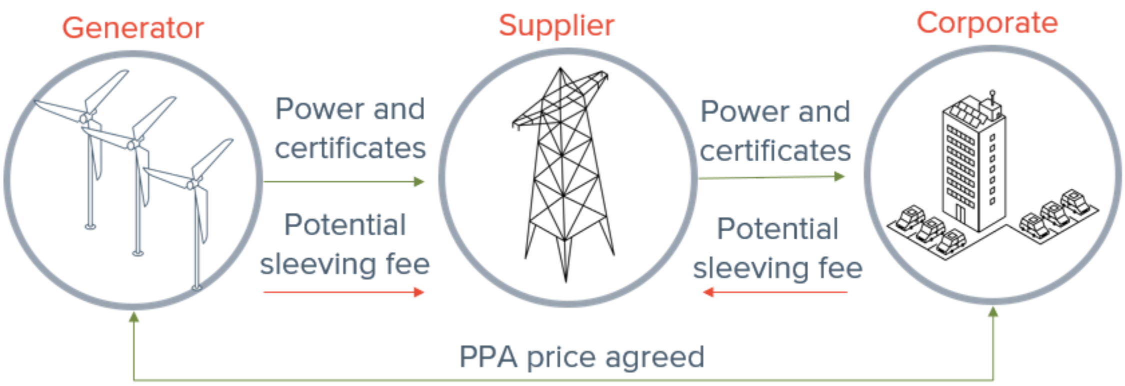
Corporate PPAs (CPPA)

Corporate PPAs are a tripartite agreement between an end user (known as the corporate), a renewables generator and an offtaker/supplier who tops up or spills energy produced by the generator.

- The corporate is (usually) a Large Energy User (LEU) such as a tech or pharma company and will have policy of trying to procure “green energy” for their industrial activities. Small and Medium Enterprises (SMEs) are often too small an offtaker to be involved in corporate deals and often lack a credit rating or significant backing to justify long-term deals
- The supplier/offtaker’s role in the CPPA is to top-up generation with green energy from the wholesale market in the case where the generator is not producing enough for the LEU’s activities, or to sell the generator’s excess power to the wholesale market where there is more electricity being generated than is required by the corporate
- If the generator is under a subsidy when entering a CPPA, it is often not considered a “pure” PPA - this structure representing most of the existing CPPAs in both the UK and Ireland. This is because the CPPA itself has not directly funded or underwritten the project, as this has been done by the subsidy payments. CPPAs in existence in NI include those for Bombardier and Belfast International Airport, amongst others.
- Examples of pure CPPAs in the UK have emerged quite recently (since 2017) with some solar, co-location (renewables with batteries) and onshore wind projects. Generally, these are with already existing projects, though Lightsource recently announced a new 100MW subsidy free development under a CPPA with Budweiser.
- CPPAs are more complex to negotiate than regular PPAs. Although some investors see this as a major disincentive, others believe that this will become easier as more of them are negotiated. At this time, it is hard to predict how this concern will develop in future.

- Sticking points for CPPAs tend to focus on the agreed price for power and the lengths of contracts. Generally, generators want to lock in long term contracts, but corporates are reluctant to do this, favouring 3-5 year contracts. This would be especially challenging for new build projects where there are long term capital loans involved, typically of 10 years or more in length.

Figure 55. Schematic showing Corporate PPA structure



Source: Cornwall Insight

- In GB, under the National Grid's[160] "Two Degrees" scenario, the scale of new build required is circa 90GWs with 40GWs coming from wind and solar.
  - Globally, it has taken 10 years to contract more than 40GWs of CPPAs.
  - In GB, it has taken 20 years of subsidy support to develop 50GWs of renewables
  - This has promoted questions as to how realistic it is that CPPAs will provide a large share of the capacity under this National Grid scenario, owing to their complexity and the currently small pipeline vs overall renewables capacity forecasts. Many developers and investors believe that CPPAs will form part of the renewables landscape, but are unlikely to close the gap materially between demand for renewables and expected deployment
- NI has several examples of corporate PPAs and some participants in the stakeholder engagement process have cited the lack of energy policy as driving this to a degree. There is a view that without a subsidy, developers have had to find a way to cut costs. This suggests a degree of market forces working to deliver renewable electricity however the policy maker should be mindful of how many developers will be willing to do this, versus developing elsewhere, and realistically how much volume of renewable electricity could be developed this way.
- In the case of a private corporate such as a tech company or pharma company, gaining permission from their parent company for a long-term arrangement can be a challenge. In the case of public entities such as hospitals, challenges arise due the year by year allocation of annual budgets, making it difficult for them to sign up to a long-term contract. Entities such as NI Water, who have stable long-term revenues, are much better placed to sign up as end-users for CPPAs. Therefore, the volume of possible CPPAs potentially available in NI will depend greatly on what kinds of funding potential end-users currently have.

[160] https://www.nationalgrideso.com/insights/future-energy-scenarios-fes

11 Glossary

Acronym	Definition
ACT	Advanced conversion technology
AD	Anaerobic Digester
AONB	Area of Outstanding Natural Beauty
BEIS	Department Business, Energy & Industrial Strategy (UK)
$CAIR_t$	Collection Agency Income Requirement
CRM	Capacity Remuneration Mechanism (SEM)
CMA	Competitions and Markets Authority
CfD	Contract for Difference
CPPA	Corporate power purchase agreement
DAERA	Department for Agriculture, Environment and Rural Affairs
DSM	Demand side management
DfI	Department for Infrastructure
DfE	Department for the Economy (NI)
DCCAE	Department of Communications, Climate Action and Environment
DS3	EirGrid / SONI programme titled 'Delivering a Secure Sustainable Electricity System' to integrate increased levels of renewable generation onto the power system
EV	electric vehicle
EE	Energy efficiency
EE	Energy efficiency
EFW	Energy from waste
ETM	European Target Model
FiT	Feed in tariff scheme operating in GB for sub 50kW renewables projects

GB	Great Britain: Scotland, Wales and England
GCS18	SONI/EirGrid Generation Capacity Statement 2018
GHG	Green House Gas
HP	Heat pump
IEA	International Energy Agency
LEU	Large energy user
LCOE	Levelised cost of electricity
LCCC	Low carbon contracts company
ORESAP	Offshore Renewable Energy Strategic Action Plan (2012 – 2020)
RAB	Model followed by NIEN
UR	NI energy regulator
SONI	NI System Operator (owned by EirGrid Group)
NIEN	NIE Networks
NFFO	Non-fossil fuel obligation
NI	Northern Ireland
NIAUR	Northern Ireland Authority for Utilities Regulation
NIRO	Northern Ireland Renewables Obligation
Ofgem	GB energy regulator
ONB	Outstanding natural beauty
PD	Permitted development
PPA	Power purchase agreement
RES-E	Renewable electricity targets
REFIT	Renewable energy feed-in-tariff (ROI)
RESS	Renewable Energy Support Scheme (ROI)

RO	Renewables obligation (not to be confused with reliability option)
RO	Reliability Option - a CfD used in the CRM for the SEM market
ROC	Renewables obligation certificate (not to be confused with reliability option)
ROI	Republic of Ireland
RES-E	Electricity from renewable energy sources
RESS	ROI's Renewable Energy Support Scheme
RtM	Route to market
SEM	Single Electricity Market
SMG	Small and microgeneration
SME	Small medium enterprise
SEF	Strategic Energy Framework
SIB	Strategic Investment Board
SNSP	System Non-Synchronous Penetration
TSC	Trading and settlement code SEM
VPP	Virtual power plant