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70 by 30

A 70% Renewable Electricity Vision for Ireland in 2030

October 2018

Version History

Version	Date	Description	Prepared by	Approved by
V8_0	20/09/2018	Final version	Mark Turner Yinfan Zhang	Oliver Rix

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Executive summary

In this study, Baringa has analysed two different scenarios for the energy sector on the island of Ireland in 2030:

- '**Renewable Energy**' is a scenario where the island of Ireland continues to be a world leader in renewable electricity and in wind and solar power in particular. Ireland achieves a renewable electricity target of 70% by 2030 in this scenario. Additional demand-side and supply-side flexibility is developed which help the successful integration of renewables in this scenario. Ireland's renewable electricity is also utilised for renewable heat and transport with the roll-out of heat pumps and electric vehicles, in line with EirGrid's Low Carbon Living forecasts[1].
- '**Fossil Fuel**' is a scenario where there is no further deployment of renewable generation after the 2020 target of 40% renewable electricity is met. In this scenario, Ireland still primarily relies on fossil fuels to generate electricity in 2030. Ireland will have a shortfall in renewable heat and transport in 2020 compared to the required targets. It is assumed that this shortfall is recovered by 2030 in this scenario, so there is 2% increase in overall renewable energy even though the renewable electricity share stays the same. This scenario provides a counterfactual against which we have measured the additional costs and benefits of the Renewable Energy scenario.

We have used our advanced in-house models of the Irish power market to analyse in detail the outcomes for the whole energy sector on the island of Ireland of these two scenarios. We have quantified the impact of the Renewable Energy scenario on end consumers, and have assessed the impact on decarbonisation in the heat and transport sectors, as well as electricity.

Table 1 provides a summary of the main scenario assumptions for 2020 and 2030 on an All-Island basis. Figure 1 presents a summary of our analysis of the total costs and benefits for end consumers of the Renewable Energy scenario versus the Fossil Fuel scenario over the period 2020-2030.

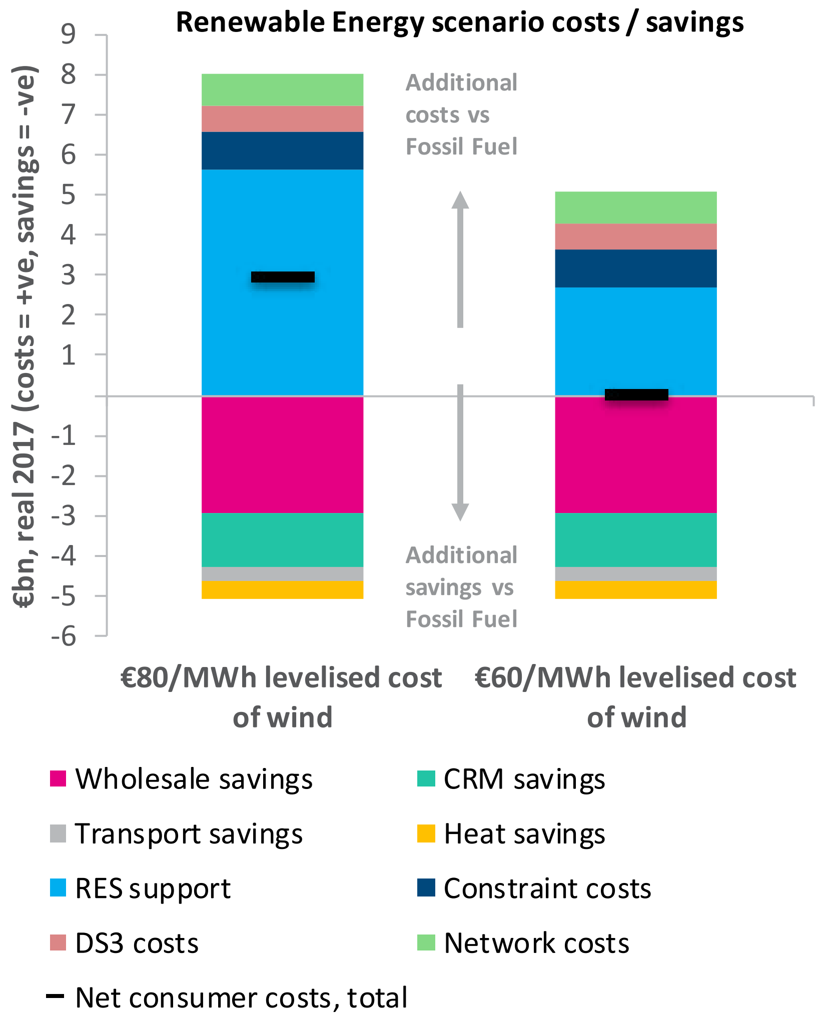
[1] http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Tomorrows-Energy-Scenarios-Report-2017.pdf

Table 1 Key scenario assumptions All-Island

	2020	Fossil Fuel 2030	Renewable Energy 2030
% RES-E	41%	37%	70%
% RES	13%	15%[2]	25%[3]
Total Electricity Demand (TWh)	40	46	49
Wind Power (MW)	5,400[4]	5,400	10,190
Solar Power (MW)	320	320	2,900
Interconnection (MW) – All Island	580	580	2,030
SNSP Limit – All Island	75%	75%	90%
Min Gen (MW) – All Island	1,000	1,000	700
Electric Vehicles (nr)	0	0	629,398
Heat Pumps (nr)	0	0	396,302
Small Scale Battery Storage (MW)	0	0	500
Large Scale Battery Storage (MW)	0	0	1,200

[2] There is a 2% increase in total RES under the Fossil Fuel scenario, primarily due to a growth in bioenergy in heat and transport based on SEAI assumptions.
[3] The 10% difference between the Fossil Fuel and Renewable Energy scenarios reflects the impact of the measures proposed in this study. Therefore, if there were no increase in bioenergy in heat and transport, the likely RES share in the 2030 Renewable Energy scenario would be 23% (i.e. an additional 10% to the 13% share in 2020).
[4] For modelling purposes, we have assumed an average availability of 35% for onshore wind in all years of the study. Actual onshore wind availability is currently lower than this, as the existing wind fleet was installed over a 25-year period. In order to match near term renewable energy generation accurately, we have modelled onshore wind installed capacity of 4,800 MW in 2020, at the higher assumed load factor of 35%.

Figure 1 **Summary of total Renewable Energy scenario costs and benefits relative to the Fossil Fuel scenario (2020-2030)**



Our analysis shows that the Renewable Energy scenario, while increasing end consumer costs in some areas, results in significant benefits and savings in others, compared with the Fossil Fuel scenario. As a starting point for technology costs, we used the the WSP|Parsons Brinckerhoff study[5] published by the Department for Communications, Climate Action and the Environment (DCCAE). This gives an average levelised cost of energy (LCOE) for onshore wind of around €80/MWh over the period of the study. The net result is a cost of just under €3bn for end consumers over the period 2020-30.

However, our analysis indicates that a reduction in these levelised costs to an average of €60/MWh for onshore wind, €70/MWh for offshore wind and €80/MWh for solar would result in delivering the Renewable Energy scenario at no additional cost to consumers versus the Fossil Fuel scenario. To put these levelised costs in context, we have already seen onshore wind delivered below €40/MWh in other European markets. Offshore wind and solar have cleared at €65/MWh and €70/MWh

[5] https://www.dccae.gov.ie/en-ie/energy/consultations/Documents/28/consultations/Renewable%20Technology%20Input%20Data.pdf

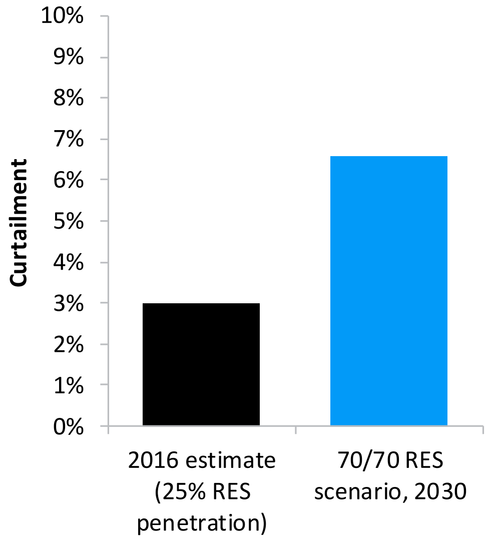
respectively – in jurisdictions with similar resources to Ireland. With an efficient policy framework in place on the island of Ireland, the levelised costs required for a cost neutral Renewable Energy scenario are achievable over the timeframe of this study.

If Ireland can match over the period 2020-2030 the renewable energy costs already achieved elsewhere in Europe, our analysis indicates that the Renewable Energy scenario could cost less for the end consumer than the Fossil Fuel scenario.

In the Renewable Energy scenario, the CO_2 emissions intensity of the power sector drops to around 100 gCO_2/kWh by 2030, from a 2020 level of around 300 gCO_2/kWh. In total, over the period 2020-30, the Renewable Energy scenario reduces the all-island power sector CO_2 emissions by 30% compared to the Fossil Fuel scenario, driven by a 30% reduction in fossil fuel consumption which is almost entirely natural gas.

Our modelling indicates that renewable curtailment levels remain in the range 5-7% in the Renewable Energy scenario, and our analysis of the benefits, costs and volume of renewables takes full account of this curtailment[6].

Figure 2 Projected renewable electricity curtailment for the Renewable Energy scenario



In implementing an increase from 40% RES-E to 70% RES-E, along with substantial electrification of heat and transport sectors, we have calculated that the Renewable Energy scenario would contribute almost 10% extra to Ireland's overall renewable energy target. It is anticipated that Ireland will reach a renewable energy share of approximately 13% in 2020, which grows to 15% by 2030 in the Fossil Fuel scenario, due to additional bioenergy in the heat and transport sectors (based on SEAI projections). By implementing the measures in the Renewable Energy scenario, we estimate that the overall renewable energy share increases by around 10% to reach 25% by 2030. While this is a significant contribution, the EU has recently set a renewable energy target of 32% for 2030, and therefore substantial additional measures would still be required in the heat and transport sectors if Ireland is to match the EU goal.

[6] We also analysed an additional scenario with less renewable electricity than the 70% All-Island RES-E penetration in the Renewable Energy scenario. The results indicated that, although curtailment increases in the Renewable Energy scenario, it is still cost-effective for end consumers due to the increase in positive benefits such as wholesale electricity cost savings.

1 Introduction

In this study, Baringa has analysed two different scenarios for the energy sector on the island of Ireland in 2030. 'Renewable Energy' is a scenario where the island of Ireland continues to be a world leader in renewable electricity and in wind and solar power in particular. Ireland achieves a renewable electricity target of 70% by 2030 in this scenario. 'Fossil Fuel' is a scenario where there is no further deployment of renewable generation after the 2020 target of 40% renewable electricity is met. In this scenario, Ireland still primarily relies on fossil fuels to generate electricity in 2030. Ireland will have a shortfall of renewable heat and transport in 2020 compared to the required targets. It is assumed that this shortfall is recovered by 2030 in the 'Fossil Fuel' scenario, so there is an increase in overall renewable energy even though the renewable electricity share stays the same.

We have used our advanced in-house models of the Irish power market, including an hourly power station dispatch model in PLEXOS, to analyse in detail the outcomes for the whole energy sector on the island of Ireland of these two scenarios. In particular, we have quantified the impact of the Renewable Energy scenario on end consumers, and have considered the impact on decarbonisation in the heat and transport sectors, as well as electricity.

As far as possible, the inputs for the study have been drawn from publicly available sources, and we set out in detail the assumptions and methodology for the study in this report, along with our findings.

The remainder of this report is structured as follows:

- **Section 2** presents the scenario input assumptions
- **Section 3** explains the methodology used in our analysis
- **Section 4** discusses the key results, and
- **Section 5** summarises the main conclusions of the study.

The Appendix includes further detail on the modelling approach and scenario assumptions.

All monetary values in this report are presented in real 2017 money, unless otherwise stated.

2 Scenario assumptions

2.1 Overview

The main assumptions for the two main scenarios, Fossil Fuel and Renewable Energy, in 2030 are summarised in the three tables below on an RoI, NI and All-Island basis, respectively. The assumptions for the scenarios were provided by IWEA and NIRIG. They are based largely on publically available sources. In the following sections, we step through each of the main assumptions in turn and explain the build-up of the two scenarios.

Table 2 Key scenario assumptions for the Republic of Ireland (RoI)

	2020 Assumptions	Fossil Fuel 2030	Renewable Energy 2030
% RES-E	41%	37%	70%
% RES	13%	15%	25%
Total Electricity Demand (TWh)	31.9	36.3	38.8
Wind Power (MW)	4,200[7]	4,200	8,000
Solar Power (MW)	50	50	2,500
Interconnection (MW) – All Island	580	580	2,030
SNSP Limit – All Island	75%	75%	90%
Min Gen (MW) – All Island	1,000	1,000	700
Electric Vehicles (nr)	0	0	426,000
Heat Pumps (nr)	0	0	279,000
Small Scale Battery Storage (MW)	0	0	400
Large Scale Battery Storage (MW)	0	0	960

[7] For modelling purposes, we have assumed an average availability of 35% for onshore wind in all years of the study. Actual onshore wind availability is currently lower than this, as the existing wind fleet was installed over a 25-year period. In order to match near term renewable energy generation accurately, we have modelled onshore wind installed capacity in ROI of 3,700 MW in 2020, at the higher assumed load factor of 35%.

Table 3 Key scenario assumptions for Northern Ireland (NI)

	2020 Assumptions	Fossil Fuel 2030	Renewable Energy 2030
% RES-E	49%	44%	70%
% RES	13%	15%	25%
Total Electricity Demand (TWh)	8.4	9.6	10.6
Wind Power (MW)	1,200[8]	1,200	2,190
Solar Power (MW)	270	270	400
Interconnection (MW) – All Island	580	580	2,030
SNSP Limit – All Island	75%	75%	90%
Min Gen (MW) – All Island	1,000	1,000	700
Electric Vehicles (nr)	0	0	203,398
Heat Pumps (nr)	0	0	117,302
Small Scale Battery Storage (MW)	0	0	100
Large Scale Battery Storage (MW)	0	0	240

Table 4 Key scenario assumptions All-Island

	2020 Assumptions	Fossil Fuel 2030	Renewable Energy 2030
% RES-E	41%	37%	70%
% RES	13%	15%	25%
Total Electricity Demand (TWh)	40	46	49
Wind Power (MW)	5,400[4]	5,400	10,190
Solar Power (MW)	320	320	2,900
Interconnection (MW) – All Island	580	580	2,030
SNSP Limit – All Island	75%	75%	90%
Min Gen (MW) – All Island	1,000	1,000	700
Electric Vehicles (nr)	0	0	629,398
Heat Pumps (nr)	0	0	396,302
Small Scale Battery Storage (MW)	0	0	500
Large Scale Battery Storage (MW)	0	0	1,200

[8] For modelling purposes, we have assumed an average availability of 35% for onshore wind in all years of the study. Actual onshore wind availability is currently lower than this, as the existing wind fleet was installed over a 25-year period. In order to match near term renewable energy generation accurately, we have modelled onshore wind installed capacity in NI of 1,100 MW in 2020, at the higher assumed load factor of 35%.

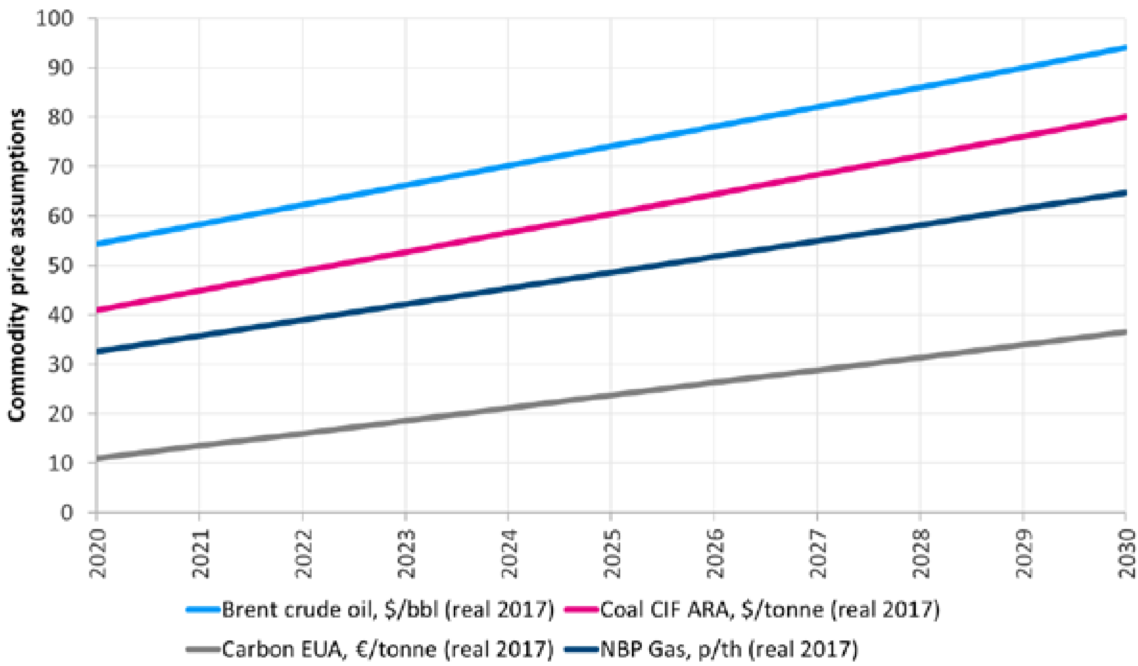
2.2 Commodity prices and exchange rates

The fuel and carbon prices used for this study are a blend of UK government, DCCAE and International Energy Agency (IEA) assumptions. The 2020 assumptions are taken from recent UK Department for Business, Energy and Industrial Strategy (BEIS) fossil fuel price projections[9]. The 2030 assumptions are based on the IEA World Energy Outlook (WEO) 2017 'New Policies' scenario. The 2020 carbon price was taken from the DCCAE's Public Spending Code[10], and the 2030 assumption was based on the IEA WEO 2017 'New Policies' scenario.

Fuel and carbon prices between 2020 and 2030 were derived using a simple linear interpolation. The assumptions are presented in Figure 3 and were used consistently across both the Fossil Fuel and Renewable Energy scenarios.

Commodity and carbon prices increase steadily between 2020 and 2030 in real terms, with NBP gas prices broadly doubling from around 33 p/th in 2020 to around 63 p/th in 2030. Carbon prices rise from around 11 €/tCO_2 in 2020 to reach around the IEA's forecasted price in the 2017 World Energy Outlook of 36 €/tCO_2 in 2030 (note: no price was provided for 2030 explicitly, so this is the average of the price provided across 2025 and 2040).

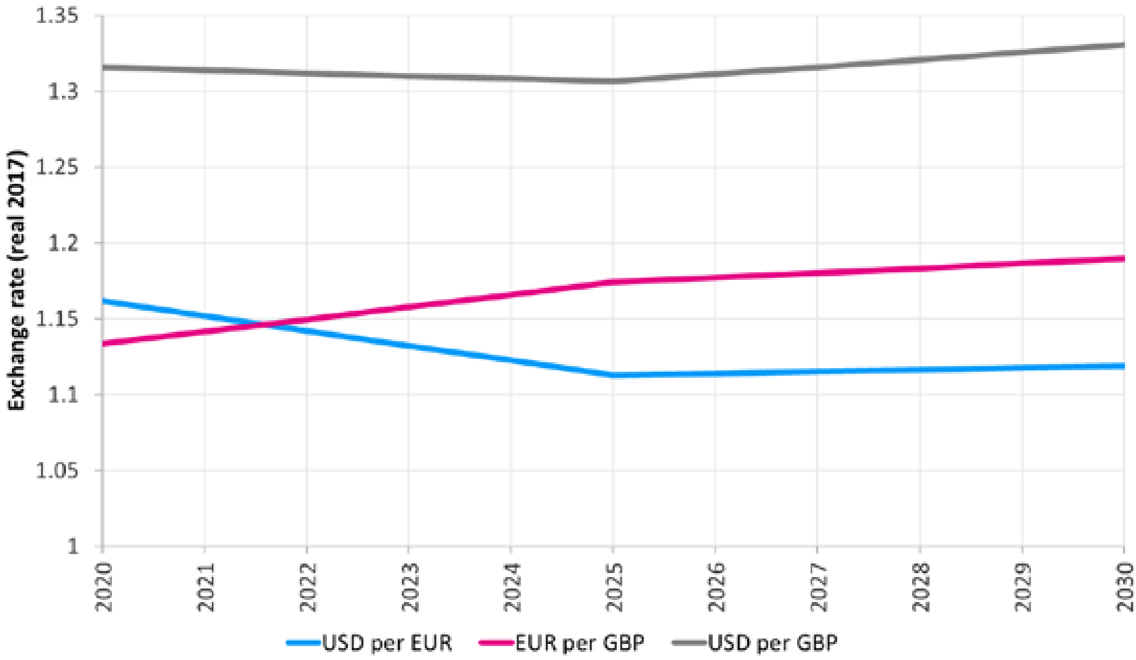
Figure 3 Commodity and carbon price assumptions



The exchange rate assumptions for this study are shown in Figure 4, which stay relatively flat in real terms over the study period.

[9] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/576542/BEIS_2016_Fossil_Fuel_Price_Assumptions.pdf
[10] https://publicspendingcode.per.gov.ie/wp-content/uploads/2015/09/E5.pdf

Figure 4 Exchange rate assumptions



Commodity price and exchange rate assumptions are tabulated in the Appendix.

2.3 Technology costs

With the exception of load factors, the levelised cost of energy (LCOE) assumptions for renewables used in this study are based on the WSP|Parsons Brinckerhoff study published by the Department for Communications, Climate Action and the Environment (DCCAE) alongside its September 2017 consultation paper on the design of a new Renewable Electricity Support Scheme (RESS) for Ireland[11]. We have aligned the load factor assumptions in the LCOE calculation with those used in our power market modelling of the two scenarios. For example, WSP|Parsons Brinckerhoff assumes a load factor of 32% for onshore wind whereas we model a load factor of 35%[12]. The main LCOE assumptions for wind and solar PV are presented in Table 5.

Under these assumptions, the LCOE of both wind and solar PV declines over time, driven mainly by capex reductions, but still remain at relatively high levels in the long term. For example, in 2030, the LCOE of large onshore wind is around €77/MWh. In comparison, pricing under the current REFIT scheme in Ireland is around €80/MWh, and recent renewables auctions in markets such as Germany and Spain have seen onshore wind projects clear below €40/MWh.

[11] https://www.dccae.gov.ie/en-ie/energy/consultations/Documents/28/consultations/Renewable%20Technology%20Input%20Data.pdf
[12] This is higher than the current average capacity factor in the all-island market and is intended to reflect future improvements driven by (i) repowering of existing sites, (ii) new more efficient turbine technology, and (iii) a focus on developing the best available sites under future RESS competitive auctions.

Table 5 Summary of LCOE assumptions for wind and solar PV

LCOE calculation	Units	2020	2025	2030
Onshore wind - large				
Capex	*€/kW*	*1,529*	*1,473*	*1,434*
Fixed Opex	*€/kW/year*	*53*	*51*	*50*
WACC (real, pre-tax)		*10.0%*	*10.0%*	*10.0%*
Total constr time	*years*	*2*	*2*	*2*
Economic life	*years*	*20*	*20*	*20*
Load factor		*35.0%*	*35.0%*	*35.0%*
LCOE	*€/MWh*	*81.63*	*78.62*	*76.66*
Offshore wind				
Capex	*€/kW*	*3,327*	*3,079*	*2,949*
Fixed Opex	*€/kW/year*	*105*	*97*	*93*
WACC (real, pre-tax)		*10.0%*	*10.0%*	*10.0%*
Total constr time	*years*	*3*	*3*	*3*
Economic life	*years*	*20*	*20*	*20*
Load factor		*45.0%*	*45.0%*	*45.0%*
LCOE	*€/MWh*	*146.60*	*135.56*	*129.82*
Solar - large				
Capex	*€/kW*	*882*	*787*	*732*
Fixed Opex	*€/kW/year*	*12*	*11*	*10*
WACC (real, pre-tax)		*10.0%*	*10.0%*	*10.0%*
Total constr time	*years*	*1.75*	*1.75*	*1.75*
Economic life	*years*	*25*	*25*	*25*
Load factor		*11.0%*	*11.0%*	*11.0%*
LCOE	*€/MWh*	*120.96*	*108.19*	*100.40*

We have used in-house cost assumptions for conventional thermal generation technologies, as well as battery storage technologies (see Appendix A.13).

2.4 Demand

In the Fossil Fuel scenario, the total annual demand for both ROI and NI through to 2026 is based on the Median scenario in EirGrid's 2017 Generation Capacity Statement (GCS)[13]. Demand in 2030 is then projected based on the annual average growth rate from 2021 to 2026. Demand rises linearly from 40.4 TWh in 2020 to 45.9 TWh in 2030 on an all-island basis. Demand in ROI rises from 31.9 TWh in 2020 to 36.3 TWh in 2030 (Figure 5), and in NI from 8.4 TWh to 9.6 TWh (Figure 6), over the same period. It is assumed that there is no deployment of electric vehicles (EVs) or heat pumps (HPs) by 2030 in the Fossil Fuel scenario.

[13] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf

In the Renewable Energy scenario, demand is higher in both NI and ROI due to the addition of EVs and HPs. They contribute an extra 2.5 TWh and 1.0 TWh to the total annual demand in ROI and NI respectively in 2030. This is equivalent to 19% of cars being EVs and 14% of homes being fitted with HPs in 2030 in this scenario across the whole island, which is in line with EirGrid's Low-Carbon Living forecasts in the Tomorrow Energy Scenarios publication (Figure 7)[14].

Figure 5 Renewable Energy scenario demand assumptions (ROI)

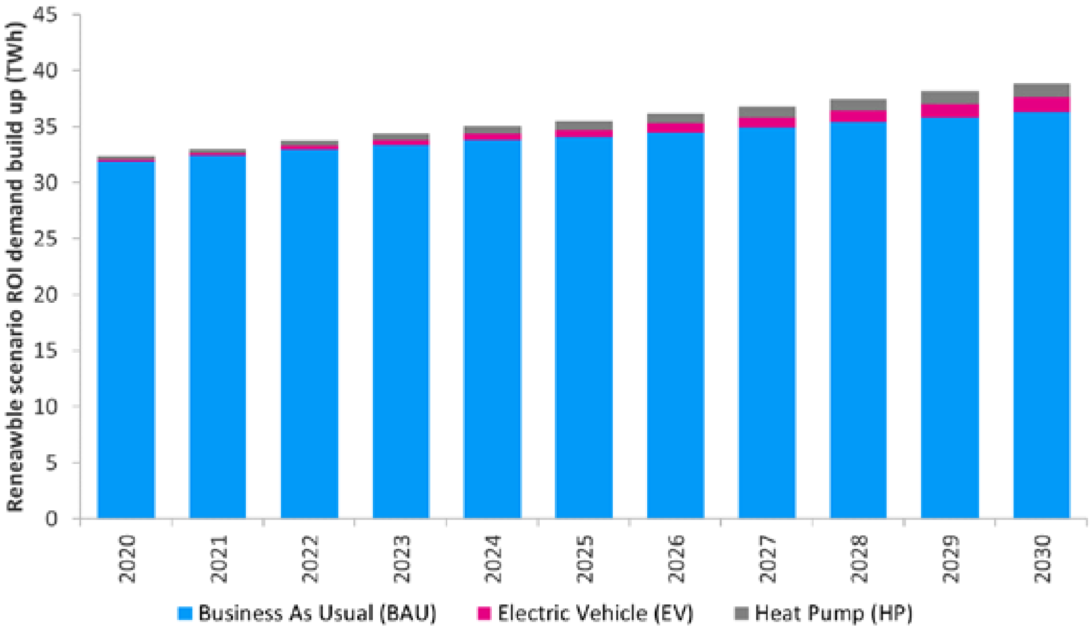
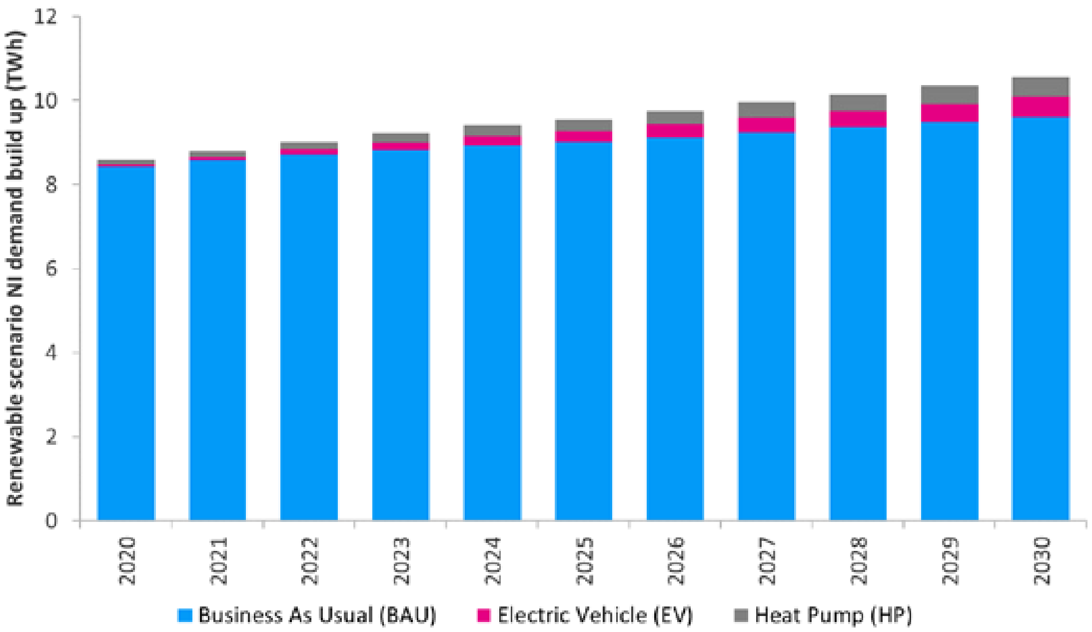
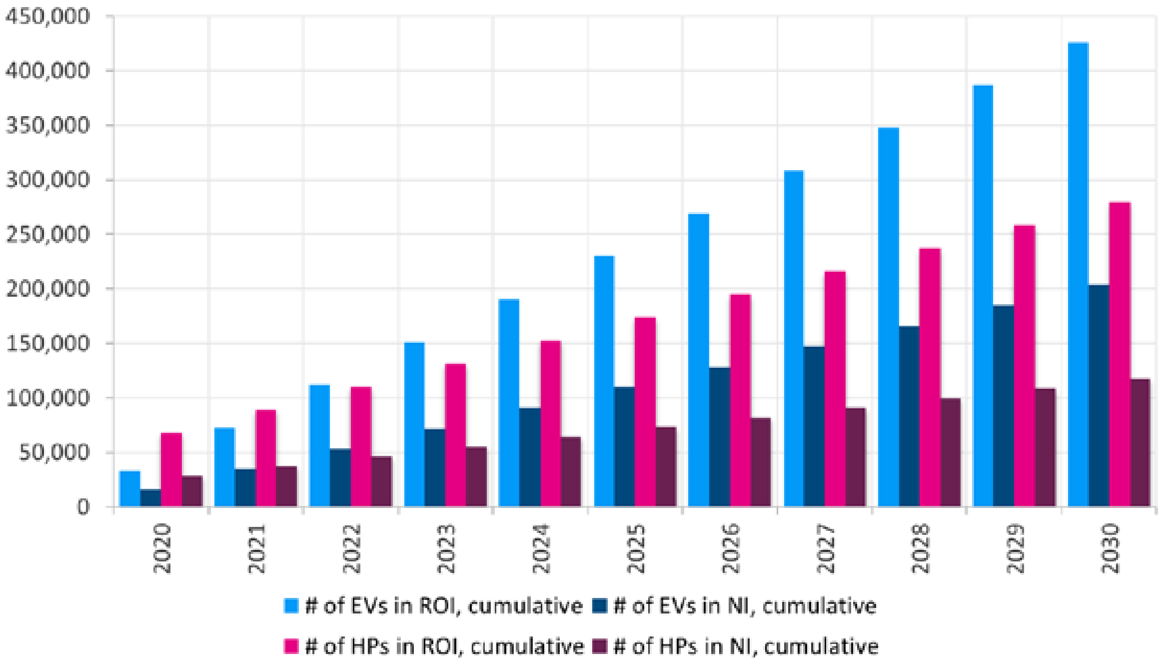


Figure 6 Renewable Energy scenario demand assumptions (NI)



[14] http://eirgridgroup.com/site-files/library/EirGrid/EirGrid-Tomorrows-Energy-Scenarios-Report-2017.pdf

Figure 7 Assumed deployment of electric vehicles (EVs) and heat pumps (HPs) in the Renewable Energy scenario



2.5 Generation capacity

We have generally aligned plant retirement decisions with the latest available Generation Capacity Statement that EirGrid published in 2017 covering the period 2017-2026.

In the Fossil Fuel scenario, no new wind or solar capacity is built beyond 2019. Instead around 2.9 GW of new thermal plants, in particular CCGTs and OCGTs, are built to fill the capacity gap that gradually develops because of rising demand and retirement of existing capacity. We use our in-house capacity market model to simulate the Capacity Remuneration Mechanism (CRM) auction under I-SEM, and new capacity is only built if it clears the CRM auction and wins a 10-year contract. The modelled installed capacity on an All-Island, ROI and NI basis is presented in Figure 8, Figure 9 and Figure 10 below.

Figure 8 Installed capacity in the Fossil Fuel scenario (All-Island)

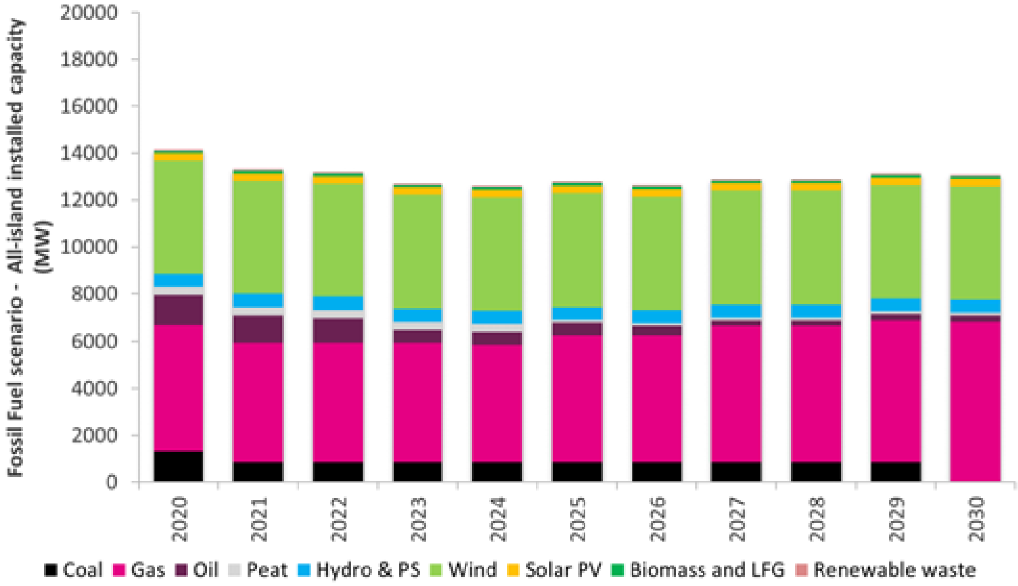


Figure 9 Installed capacity in the Fossil Fuel scenario (ROI)

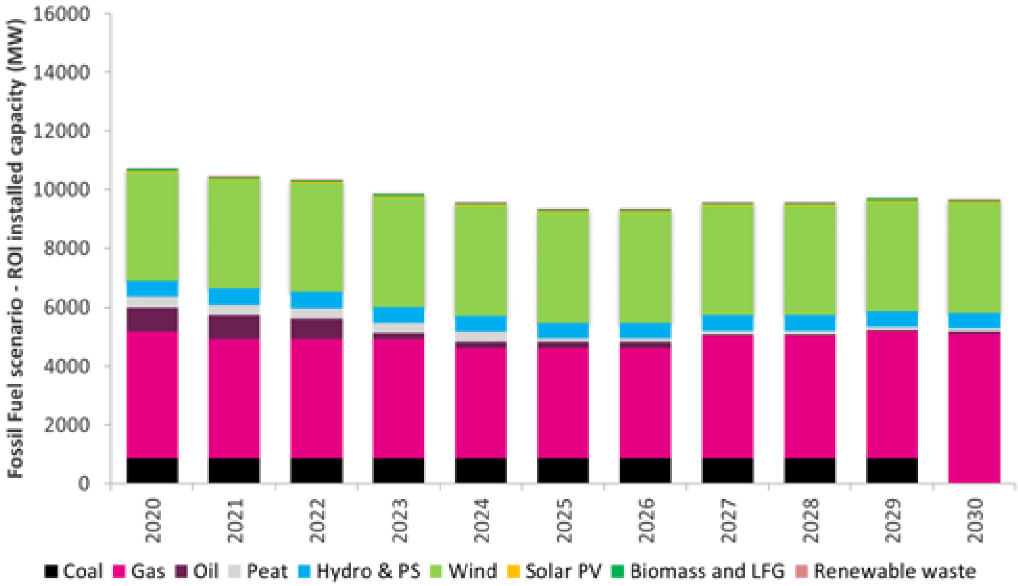
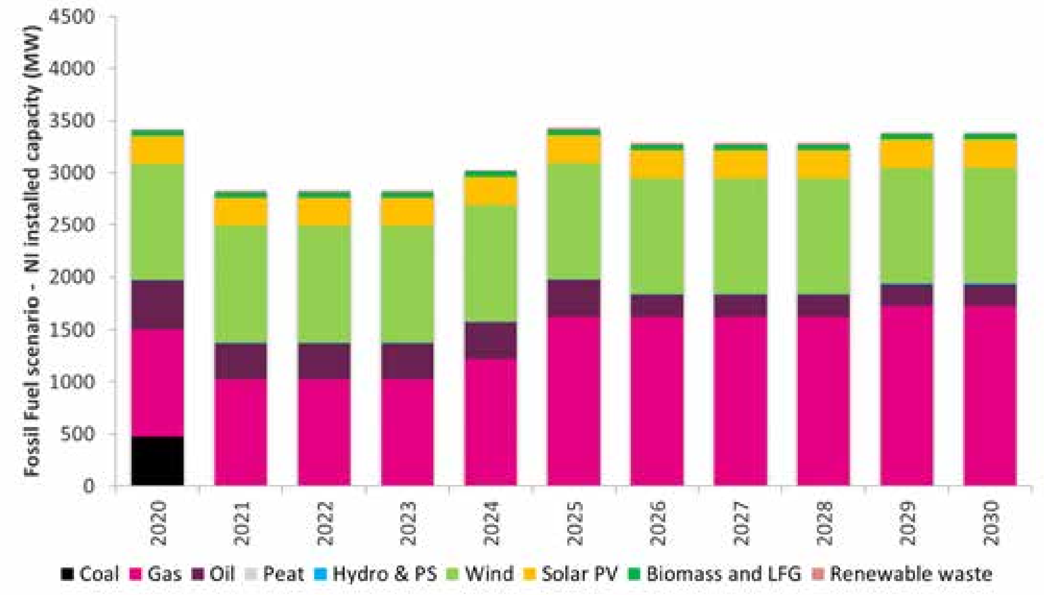


Figure 10 Installed capacity in the Fossil Fuel scenario (NI)



In the Renewable Energy scenario, wind and solar capacity is commissioned over the study period to reach a level in 2030 that is sufficient for the whole island to achieve 70% renewable electricity target, after any curtailment of renewables is taken into account (see Section 4.3). Although it is assumed that wind and solar do not participate in the CRM auction directly, their expected contribution to meeting peak demand is netted off the CRM procurement target[15] in accordance with their assumed auction de-rating factors[16]. The de-rating factor for wind is 10.75% and therefore on aggregate the additional wind build under the Renewable Energy scenario makes a material capacity contribution. Combined with additions of energy market battery storage (1.7 GW), interconnection (1.2 GW) and demand side flexibility (0.3 GW), this substantially reduces the requirement for new build thermal capacity in the Renewable Energy scenario to just 200 MW of OCGT capacity.

The modelled installed capacity for the Renewable Energy scenario on an All-Island, ROI and NI basis is presented in Figure 11, Figure 12 and Figure 13 below. The total additions and retirements of fossil fuelled and renewable capacity over the period of the study are shown in Figure 14.

[15] Capacity adequacy requirements are met by ensuring that there is sufficient de-rated capacity procured in the CRM auction to meet a target capacity margin of around 4-5%. There was no unserved demand in any modelled period in either the Renewable Energy or Fossil Fuel scenarios.

[16] We have aligned the CRM de-rating factors with those published in the final information pack for the first T-1 capacity auction held in December 2017. We note that actual de-rating factors may change over time.

Figure 11 Installed capacity in the Renewable Energy scenario (All-Island)

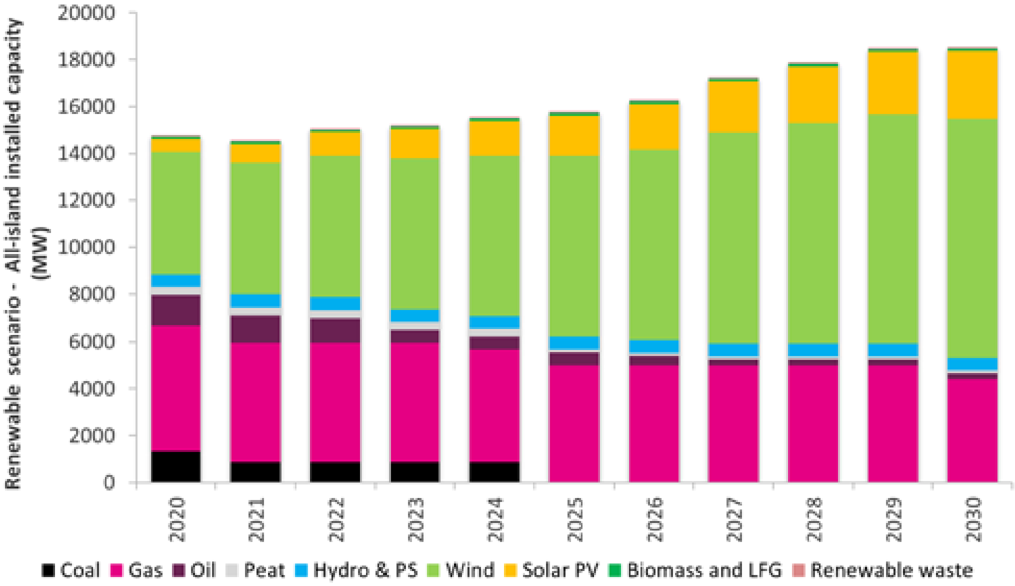


Figure 12 Installed capacity in the Renewable Energy scenario (ROI)

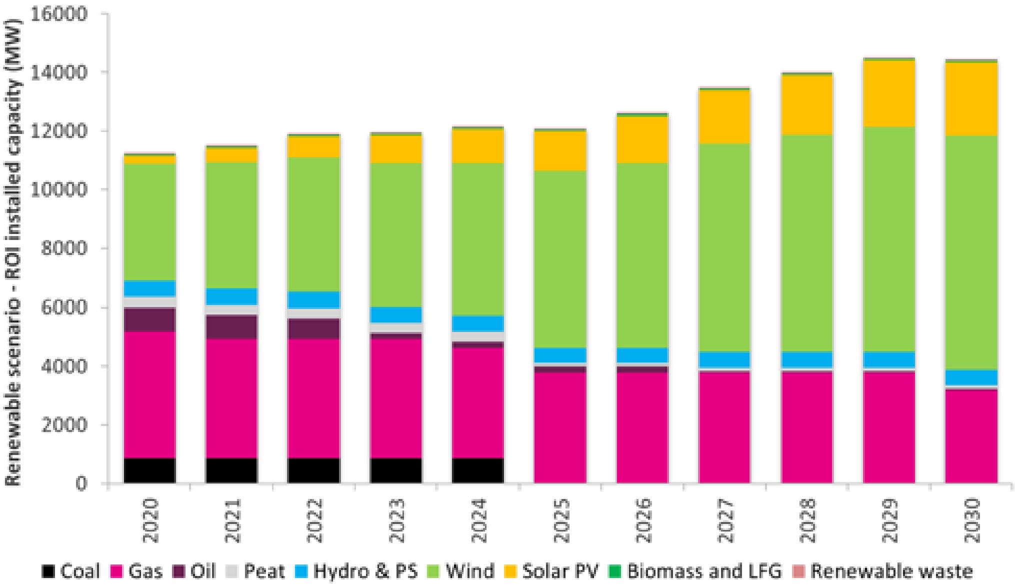


Figure 13 Installed capacity in the Renewable Energy scenario (NI)

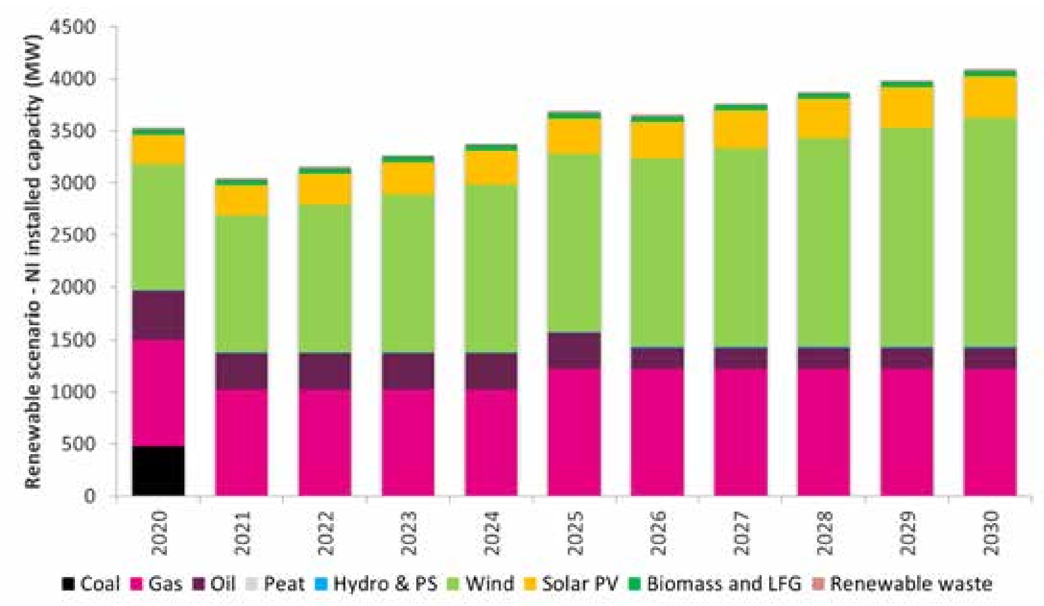
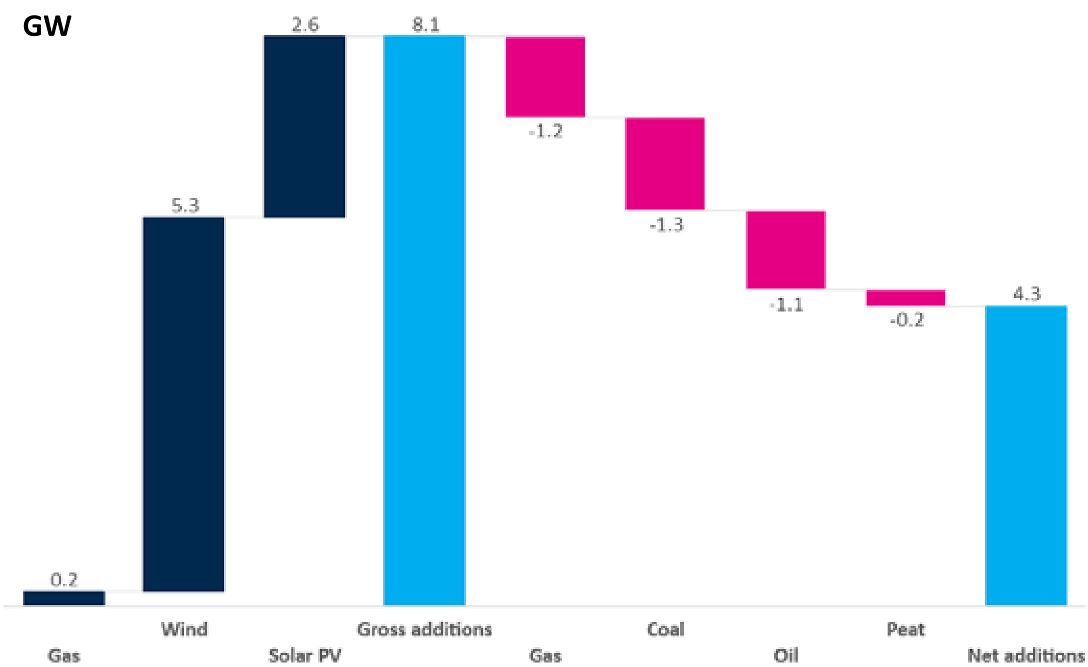


Figure 14 Summary of total additions and retirements of fossil fuel and renewable capacity over the period 2020-30 in the Renewable Energy scenario (All-Island)

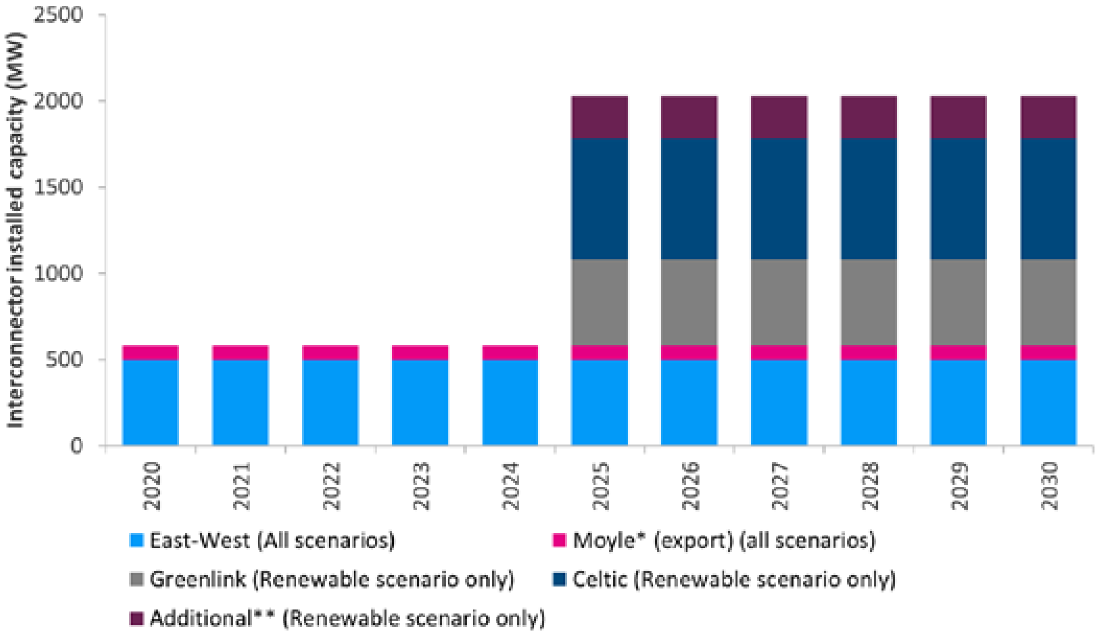


2.6 Interconnection and storage

The installed capacity of interconnectors assumed in the two scenarios is shown in Figure 15. In the Fossil Fuel scenario, we assume no new interconnectors are built. In the Renewable Energy scenario, two new interconnectors totalling 1450 MW of installed capacity are commissioned in 2025, in the form of Greenlink to GB and Celtic to France, again in line with EirGrid's Low-Carbon Living forecasts in the Tomorrow Energy Scenarios publication[17]. We also assume that the North-South interconnector between ROI and NI is commissioned in the 2020s in the two scenarios.

Interconnectors are typically private business ventures with costs recovered through cross-border wholesale power market arbitrage, capacity market revenues and ancillary service revenues, so they are self-funded. Unlike transmission or distribution network assets, the capital expenditure and maintenance costs of interconnectors are not recovered directly from consumers in the form of network charges. Based on the outcome of feasibility assessments of multiple interconnectors in Europe, in some of which Baringa was directly involved, we have assumed that the business cases for Greenlink and Celtic are sufficient under the Renewable Energy scenario to justify their development, without carrying out detailed verification. Furthermore, the import capacity of Moyle has been limited to 80 MW so expanding this is another option to increase the capacity of interconnection.

Figure 15 Interconnector capacity assumptions



* Moyle import capacity is assumed to be 450 MW for all scenarios.
** We assume an additional 250 MW of interconnector capacity brought online in 2025, either through an increase in Moyle's export capacity from 80 MW to 330 MW, or through Greenlink commissioned as an 750 MW link rather than 500 MW. This is in line with EirGrid's Low-Carbon Living forecasts in the Tomorrow Energy Scenarios publication[18].

Baringa has undertaken the modelling for this study using its pan-European wholesale electricity market model, which is described in Section 3. Interconnected markets have been co-optimised with the all-island market, and have been modelled at the same level of granularity (hourly), in order to capture the impact of cross-border flows and interactions in detail. Scenario assumptions for interconnected markets, including Great Britain and France, were based on the Baringa Reference Case[19]. Under the Reference Case, there is continued growth in renewable capacity across European markets. For example, in Great Britain:

[17] http://eirgridgroup.com/site-files/library/EirGrid/EirGrid-Tomorrows-Energy-Scenarios-Report-2017.pdf
[18] http://eirgridgroup.com/site-files/library/EirGrid/EirGrid-Tomorrows-Energy-Scenarios-Report-2017.pdf
[19] The Reference Case is Baringa's in-house 'central' market scenario

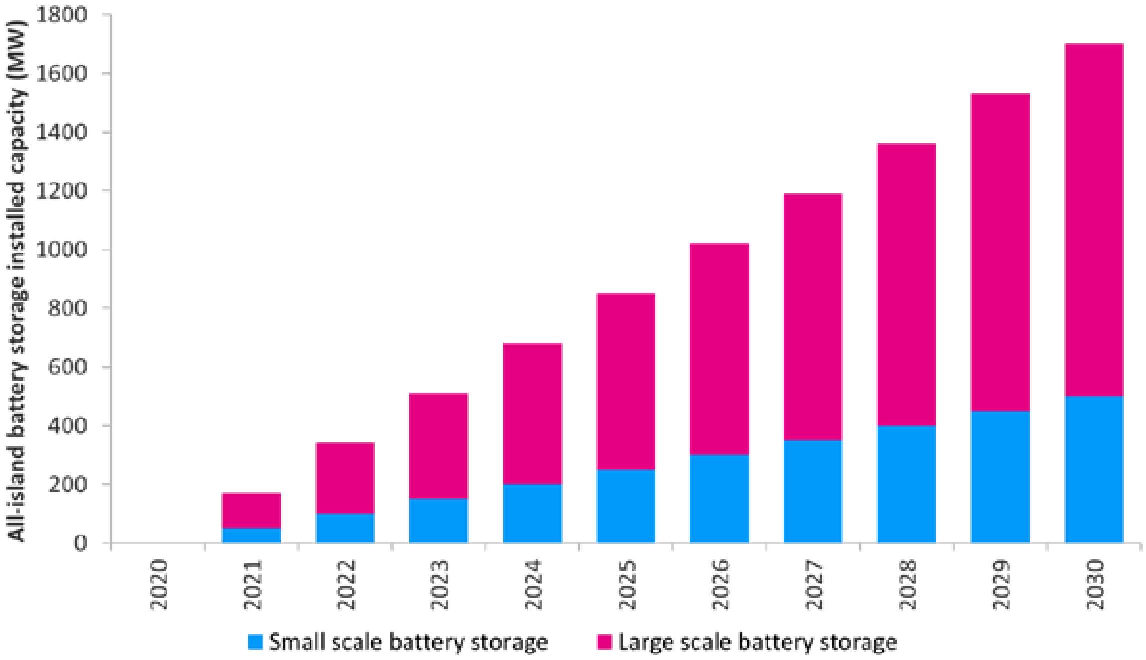
- onshore wind capacity increases from 13.1 GW in 2020 to 15.3 GW in 2030
- offshore wind capacity increases from 8 GW in 2020 to 15.5 GW in 2030, and
- solar PV capacity increases from 12.9 GW in 2020 to 17.9 GW in 2030.

Similarly, in France:

- onshore wind capacity increases from 18.0 GW in 2020 to 31.0 GW in 2030
- offshore wind capacity increases from 1.0 GW in 2020 to 4.2 GW in 2030, and
- solar PV capacity increases from 13.2 GW in 2020 to 36.0 GW in 2030.

In the Fossil Fuel scenario, we have assumed that no battery storage capacity is installed which participates in the energy market. The Renewable Energy scenario assumes a linear increase in energy market battery capacity from zero to 1.7 GW installed battery capacity from 2020 to 2030. This is shown in Figure 16. We have assumed that this battery storage has a two-hour storage duration. We assume that these batteries are self-funded and recover their costs through energy arbitrage, capacity market payment and ancillary service revenues. Based on Baringa's battery cost assumptions, we have verified that these batteries are commercially viable in the Renewable Energy scenario.

Figure 16 Battery storage capacity assumptions



3 Modelling methodology

3.1 General assumptions

Baringa carried out all the modelling in real 2017 money terms unless otherwise stated. When adding up the total costs or savings between 2020 and 2030, the time value of money has not been considered (i.e. a discount rate of zero was used) unless otherwise stated. This is in line with the methodology used by DCCAE in their recent Renewable Electricity Support Scheme (RESS) consultation[20].

The study period covers the 11 years between 2020 and 2030. We have aimed to model each individual year where it is practical to do so. The exception to this is wholesale electricity market modelling, where we have modelled 2020, 2025 and 2030 and used interpolation to approximate the results for the years in between.

3.2 Wholesale electricity market modelling

Baringa has developed in-house a Pan-EU power market model covering Ireland, Great Britain and most countries in Europe for the purpose of power market studies. The model sits within PLEXOS, a third-party commercial software that is widely used in the power and utilities industry for market price projections, asset dispatch modelling, network analysis and other purposes. The Baringa Pan-EU model takes key inputs and scenario assumptions such as hourly demand profile, commodity prices, plant build and retirement and hourly wind and solar profiles, and has detailed representations of generator technical parameters and interconnection between countries. The model engine carries out least cost optimisation to produce hourly dispatch for the generators and hourly prices for the markets taking full consideration of the operational constraints (ramp rates, start time, availability etc.).

The representation of Ireland in the model closely replicates the way in which the market operates under the I-SEM structure. Generators are dispatched based on their short run marginal cost, taking start fuel offtake, ramp rate, availability, minimum up and down time, heat rate variation, output capacity variation and other technical attributes into account. Two runs take place in the model. In the unconstrained run, no system constraints are in place and plants are dispatched on a merit-order basis. In the constrained run, two system constraints are modelled: a minimum generation constraint in Ireland and Northern Ireland respectively and a System Non-Synchronous Penetration (SNSP) constraint across the whole island.

In alignment with the I-SEM market arrangements, we take wholesale electricity price projections from the unconstrained run, and generator dispatch schedule from the constrained run. We have used our wholesale electricity price and demand projections to estimate the total annual wholesale electricity costs for end consumers in each scenario. The difference in this value between the Fossil Fuel scenario and the Renewable scenario represents the wholesale electricity saving/cost to Irish end consumers if a 70% renewable penetration in the electricity sector is adopted.

[20] https://dccae.gov.ie/en-ie/energy/consultations/Pages/Renewable-Electricity-Support-Scheme-Design-Consultation.aspx

3.3 Flexible demand modelling

We model in detail the dynamics of flexible demand in the system, such as electric vehicles (EVs) and heat pumps (HPs). Flexible demand can be optimised across the year, subject to operational and technical constraints such as assumed EV charging regimes and minimum range requirements.

The demand in each hour in the PLEXOS market model is the sum of the inflexible demand and the flexible demand in the system. The basis of the inflexible portion of demand varies by type:

- 'Business as Usual' (BAU) demand based on historical demand profiles.
- Transport – fixed load profiles for unmanaged charging of electric vehicles, based on standard weekday and weekend profiles.
- Heating – fixed load profiles for inflexible heat demand from heat pumps, based on seasonal standard profiles.

The basis for the flexible portion of demand is as follows:

- BAU demand – both load shifting (i.e. shifting load from periods with high prices to periods with lower prices) and load curtailment (i.e. curtailing some load if it is more economic to do so) are considered in our modelling. The potential of flexible BAU demand is assumed to increase over time in line with smart meter roll-outs in the residential sector and the increasing exploration of demand side flexibility in the industrial and commercial sectors. This refers to applications such as heating, ventilation and air conditioning of commercial buildings, refrigeration, dishwashers, laundry driers, washing machines and other residential applications, plus flexible loads in heavy industry.
- Transport – EVs plugged to the grid may be charged based on prevailing power price signals. The demand side flexibility provided by EVs, however, will be constrained by considerations such as timing, battery capacity, and the number of EVs that can be charged at the same time.
- Heating – flexible heating demand due to heat pump installations, subject to constraints such as storage and heat pump capacity, maximum withdrawal/injection rates, and efficiency losses. The model needs to meet a total amount of heat over a certain period but shifts flexible heating demand to ensure that this is generated in a price optimal manner.

For further details on the assumed number of HPs and EVs under the modelled scenarios, see Table 1.

3.4 Renewable support modelling

In the Fossil Fuel scenario, we assume that no additional renewable capacity will be developed post 2019, beyond the deadline for new capacity under REFIT. In the Renewable Energy scenario, we assume additional wind and solar capacity is built to meet a 70% RES-E target. The additional renewable capacity is assumed to have a 20-year economic life, and be supported by a 20-year CfD-type subsidy scheme, with the strike price fixed at the LCOE of the renewable technology in its commissioning year. The renewable technology is assumed to be topped-up to its strike price from the captured price it receives from the wholesale market. RES support is calculated as the total top-up payment to all wind and solar capacity built between 2020 and 2030.

3.5 Capacity remuneration mechanism (CRM) modelling

Baringa has developed an in-house CRM tool to simulate capacity market auctions. The tool is used in conjunction with our PLEXOS energy market model to project capacity evolution in the Irish electricity market. The PLEXOS energy market model projects plant generation and energy market revenues which feed into the CRM tool for calculating plant bids in the CRM auction. Unsuccessful plants in the CRM auctions are removed from the capacity mix in the next iteration of the PLEXOS energy market model. The process is repeated until a consistent set of capacity mix, energy market revenues and CRM clearing prices are produced. Typically, CRM clearing prices are high in years when new plants are commissioned, and low in years when existing plants set the price.

As we only did spot year modelling of the energy market (2020, 2025 and 2030) in this study, we were not able to carry out the iterative process described above fully. Instead, we made the following assumptions:

1. Thermal plants will be the price setters in the CRM auctions
2. The clearing price will be 70 €/kW if a new build thermal plants clears the CRM auction
3. The clearing price will be 35 €/kW if an existing thermal plants clears the CRM auction

These numbers are representative values for I-SEM, based on previous Baringa analyses. CRM cost in a given year is calculated as total CRM payment to eligible participants for that year.

3.6 DS3 cost estimate

We are experienced in undertaking detailed projections and assessment of the DS3 market in Ireland, and have an in-house DS3 model which we have deployed to project DS3 revenue and gross margin levels for various asset types, and to assess total DS3 spend and budgets.

We have not looked to undertake highly detailed modelling of the DS3 market in this assessment. However, based on our previous analysis, we would see a strong linkage between future system non-synchronous penetration (SNSP) levels, and the required spend for DS3 services. One of the key drivers for the DS3 programme is to enable the move to a 75% SNSP limit on the island of Ireland by 2020, and this is the basis for the current €235m per year budget cap.

We have taken a simple approach to estimate the potential additional DS3 costs under each of the two modelled scenarios. This is based on learnings from our previous analysis. We have projected under each scenario the hourly SNSP value, based on the output from our constrained model of I-SEM. This applies key constraints such as the SNSP limit and 'min gen' constraints, and is described in more detail in Section 4.3. We have estimated the potential additional DS3 costs under each scenario by a simple scaling of the budget spend in line with the average of the half-hourly SNSP values in each year. The 2020 annual budget cap for DS3 to accommodate a 75% SNSP and a 1000 MW 'min gen' level will be €235m/year. We estimate that this increases to an annual budget of €410m/year in 2030 in the Renewable Energy scenario, when a 90% SNSP and 700 MW min gen is reached.

3.7 Network cost estimate

We made a high-level estimate of the additional network cost incurred in the Renewable scenario compared with Fossil Fuel scenario due to deployment of additional wind and solar capacity. We studied the network capital expenditure by EirGrid between 2009 and 2018 and assume this cost to be associated with connecting the Gate 3 group of generators. We made a conservative assumption that this cost is entirely related to renewable capacity added during that period[21], and estimated the network expenditure required per MW of renewable capacity added.

Based on the renewable build profile over the study period, we calculated EirGrid's network expenditure each year, and assumed it to be recovered over a 40-year period at a discount rate of 4.95% based on allowed PR4 rate of return set by Commission for Regulation of Utilities (CRU). For example, network expenditure by EirGrid in 2025 will be a direct result of renewable capacity added in 2025, and will be recovered over 40 years from 2025 to 2064. The total network cost to consumers in that year will be the sum of the amount to be recovered in 2025 for network built between 2020 and 2025. In total, it is assumed that approximately €2.1 billion of additional investment is required in the electricity network to achieve a 70% RES-E penetration on the island of Ireland.

3.8 Electric vehicle savings

We assume that EVs will directly displace cars powered by internal combustion engines (ICEs) through new car sales on a one-to-one ratio. This allows us to estimate the additional capital expenditure incurred by consumers to switch to EVs in the Renewable Energy scenario.

Based on the average efficiency of typical electric vehicles (e.g. Nissan Leaf) and typical petrol engine vehicles (e.g. VW Polo) in the current market, the assumed EV annual demand during the study period, and assumed petrol price, we have calculated the fuel savings, CO_2 emission savings and fuel cost savings from EV switching in the Renewable Energy scenario. The assumptions used for conventional and electric vehicles are provided in Appendix A.10.

We have not assessed issues such as distribution network headroom, the requirement for distribution network reinforcement to accommodate EVs, or the cost of charging infrastructure, in this study. We have also assumed that there are substantive gains in internal combustion engine efficiency over the timeframe of the study. Equally, we have conservatively assumed that EV costs remain static, and have not factored in a learning curve or cost reduction over the period of the study.

3.9 Heat pump savings

We assume that HPs will directly displace oil-fired boilers through new sales on a one-to-one ratio. This allows us to estimate the additional capital expenditure incurred by consumers to switch to HPs in the Renewable scenario.

Based on the average efficiency of typical HPs and conventional oil heaters in the current market, the assumed HP annual demand during the study period, and assumed heating oil price, we have calculated the fuel savings, CO2 emission savings and fuel cost savings from switching to HPs in the

[21] In reality part of the capital expenditure would not be related to connecting the renewable capacity.

Renewable scenario. The specific assumptions for heat pumps and the counterfactual oil boilers are provided in Appendix A.9.

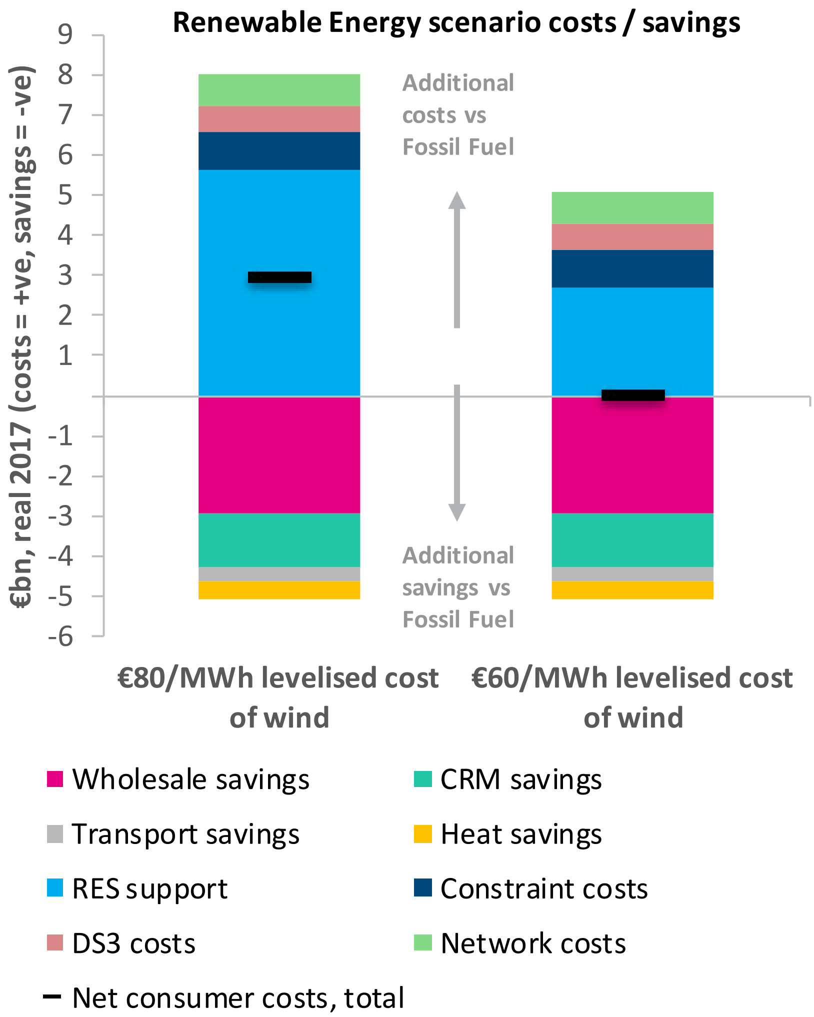
4 Results and discussion

4.1 End consumer costs and benefits

4.1.1 All-island

Figure 17 presents a summary of the total costs and benefits for end consumers of the Renewable Energy scenario versus the Fossil Fuel scenario over the period 2020-2030.

Figure 17 Summary of total Renewable Energy scenario costs and benefits relative to the Fossil Fuel scenario (2020-2030)



Our analysis shows that the Renewable Energy scenario, while increasing end consumer costs in some areas, results in significant benefits and savings in others, compared with the Fossil Fuel scenario. As a starting point for technology costs, we used the the WSP|Parsons Brinckerhoff study[22] published by the Department for Communications, Climate Action and the Environment (DCCAE). This gives an average levelised cost of energy (LCOE) for onshore wind of around €80/MWh over the period of the study. The net result is a cost of just under €3bn for end consumers over the period 2020-30.

However, our analysis indicates that a reduction in these levelised costs to an average of €60/MWh for onshore wind, €70/MWh for offshore wind and €80/MWh for solar would result in delivering the Renewable Energy scenario at no additional cost to consumers versus the Fossil Fuel scenario. To put these levelised costs in context, we have already seen onshore wind delivered below €40/MWh in other European markets. Offshore wind and solar have cleared at €65/MWh and €70/MWh respectively – in jurisdictions with similar resources to Ireland. With an efficient policy framework in place on the island of Ireland, the levelised costs required for a cost neutral Renewable Energy scenario are likely to be achievable over the timeframe of this study.

If Ireland can match over the period 2020-2030 the renewable energy costs already achieved elsewhere in Europe, our analysis indicates that the Renewable Energy scenario could cost less for the end consumer than the Fossil Fuel scenario.

Savings for the consumer in the Renewable Energy scenario

The savings for end consumers in the Renewable Energy scenario are as follows:

- **Wholesale energy cost savings** – this is a substantial benefit of the increased renewable build in the Renewable Energy scenario and our analysis indicates that savings of around €2.9bn are delivered over the period 2020-30. The main driver of this benefit is the effect of the low variable cost of renewables such as wind and solar in lowering the wholesale price of electricity. Wholesale electricity costs are a major component of end consumer retail electricity bills, and the saving would be realised through lower retail electricity tariffs for domestic consumers, and lower wholesale electricity pass through costs for larger industrial and commercial consumers.
- **CRM savings** – the driver for this benefit is the generation capacity contribution made by wind, other renewable generation such as biomass and hydro, and flexible capacity such as battery storage and interconnection. Under the I-SEM market design, capacity contracts are awarded to a defined volume of generation through a competitive auction process. The volume of capacity which is procured is determined centrally by the system operator and is set at a level which is sufficient to ensure that security of supply is maintained. In this calculation, all generators are assigned a 'de-rating factor' which scales down their installed capacity to reflect their 'expected' capacity contribution during periods when the system is likely to have the maximum need for capacity – in Ireland this is normally during winter evening periods. Wind capacity is assigned a de-rating factor like other generation technologies as it is expected to contribute to meeting peak demand. This means that additional renewable capacity build reduces the need for new fossil fuelled generation, alongside additional flexible capacity. This results in a substantial saving of around €1.3bn over the period 2020-30 through avoided new build capacity contracts for fossil-fuelled plant.

[22] https://www.dccae.gov.ie/en-ie/energy/consultations/Documents/28/consultations/Renewable%20Technology%20Input%20Data.pdf

- **Transport savings** – we have assumed the rollout of more EVs in the Renewable Energy scenario versus Fossil Fuel. This results in a displacement of the diesel and petrol fuel which would be required to complete the journeys that are now undertaken by EVs. The resulting cost saving to end consumers is around €370m over the period 2020-30 – this takes account of the assumed higher capital cost of EVs versus conventional vehicles, and the electricity costs for charging of EVs.
- **Heat savings** – we have assumed the rollout of more heat pumps in the Renewable Energy scenario versus Fossil Fuel. This results in the displacement of heating oil which would be required to fuel conventional oil-fired heating boilers that have been replaced by heat pumps. The resulting cost saving to end consumers is around €437m over the period 2020-30 – this takes account of the additional capital cost of heat pumps versus conventional boilers and the electricity to run these.

Costs for the consumer in the Renewable Energy scenario

The costs for end consumers in the Renewable Energy scenario are as follows:

- **Renewable support costs** – we have quantified the potential additional support costs for the Renewable Energy scenario versus Fossil Fuel. We have calculated the 'viability gap' between the revenues achieved by renewable generators from sales of wholesale electricity in the market and their levelised cost of electricity which is the price that we assume they would need to achieve per MWh generated. We have deliberately not modelled any specific renewable support scheme design, and have instead calculated the viability gap based on economic fundamentals. Our analysis shows that when the WSP|Parsons Brinckerhoff technology costs are used, the RES support costs are around €5.6bn over the period 2020-30. This is the most substantial additional cost in the Renewable Energy scenario. However, the WSP|Parsons Brinckerhoff levelised costs appear high in the context of historical renewable support levels, and recent European renewable auction results. For example, the average onshore wind levelised cost over the period 2020-30 under these assumptions is just under €80/MWh. This is commensurate with the support level under the REFIT scheme, which has applied since 2006. Evidence from recent European renewable auctions show wind routinely priced at levels below €50/MWh (in 15-year auctions). Our analysis shows that if renewables projects can be delivered in Ireland at a levelised cost over 20 years of around:
  - €60/MWh for onshore wind
  - €70/MWh for offshore wind, and
  - €80/MWh for solar PV

  on average over the period 2020-30, then support costs fall to €2.7bn and are fully offset by other end consumer benefits. This 'net neutral' position for end consumers can be achieved with a smaller reduction in levelised costs in NI, equivalent to delivering onshore wind at €67/MWh. If lower LCOEs are achieved, as they have been already in other European jurisdictions, then our analysis indicates that the Renewable Energy scenario could cost less for the consumer than the Fossil Fuel scenario.
- **Constraint costs** – we have analysed the potential additional constraint costs arising from the additional renewable build in the Renewable Energy scenario. Our analysis includes the key SNSP and 'min gen' constraints which are applied by the SO. We estimate additional costs over the period 2020-30 of around €950m.

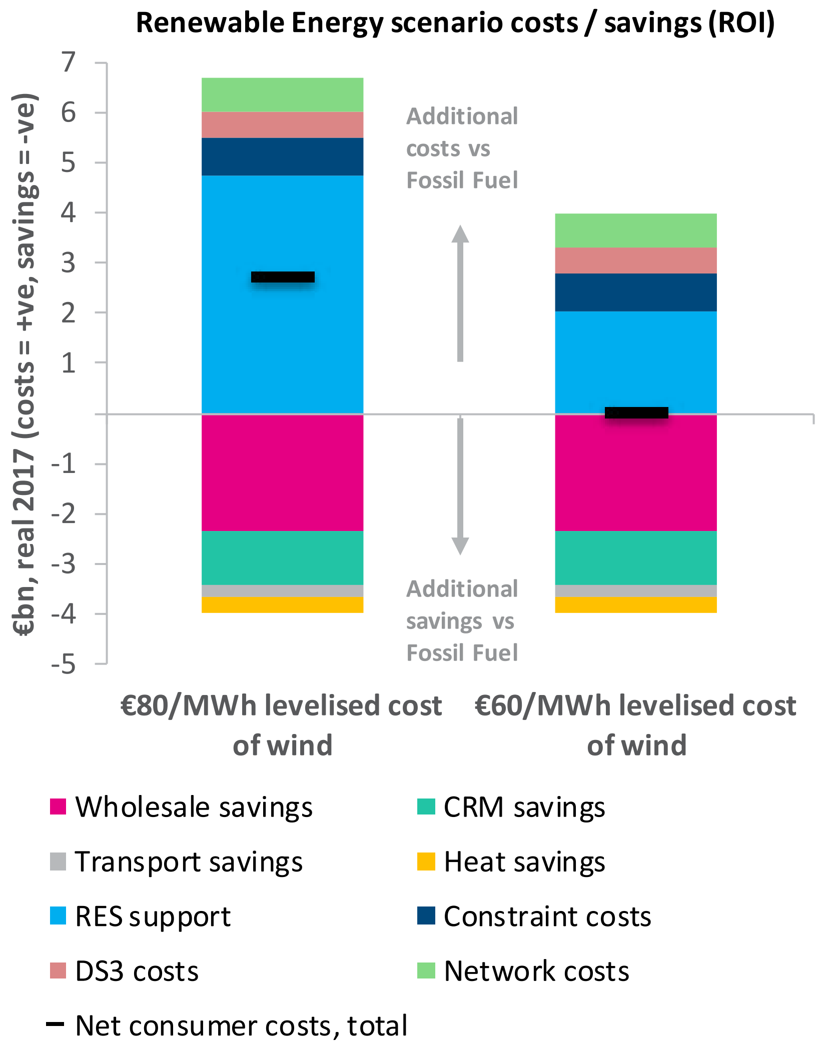
- **DS3 costs** – we have estimated the potential additional DS3 spend required in the Renewable Energy scenario by conservatively assuming that the budget scales in line with the average half-hourly SNSP level on the system. This results in additional costs of around €683m over the period 2020-30.
- **Network costs** – we have estimated the potential additional cost of network upgrades and reinforcements under the Renewable Energy scenario. These result in additional costs of around €756m over the period 2020-30 (see Section 3.6).

4.1.2 Republic of Ireland

We have analysed the Fossil Fuel and Renewable Energy scenario on an All-Island basis, and from the perspective of both the Republic of Ireland and Northern Ireland. We have assumed in our analysis that new build technology costs are consistent across the two jurisdictions. We have not modelled a specific renewable support scheme design, and so our analysis makes no assumptions on the potential form of future renewable support in either jurisdiction.

Figure 18 presents a summary of the total costs and benefits for ROI end consumers of the Renewable Energy scenario versus the Fossil Fuel scenario over the period 2020-2030.

Figure 18 Summary of total Renewable Energy scenario costs and benefits for the Republic of Ireland (ROI) relative to the Fossil Fuel scenario (2020-2030)



Our analysis shows that the Renewable Energy scenario, while increasing ROI end consumer costs in some areas, results in significant benefits and savings in others, compared with the Fossil Fuel scenario. Based on the starting point for technology costs, which was the WSP|Parsons Brinckerhoff study published by DCCAE, the net result over the ten year period of the study is a cost of around €2.7bn for ROI end consumers.

However, our analysis indicates that a reduction in these levelised costs to an average of €60/MWh for onshore wind, €70/MWh for offshore wind and €80/MWh for solar would result in delivering the Renewable Energy scenario at no additional cost to consumers versus the Fossil Fuel scenario. To put these levelised costs in context, we have already seen onshore wind delivered below €40/MWh in other European markets. Offshore wind and solar have cleared at €65/MWh and €70/MWh respectively – in jurisdictions with similar resources to Ireland. With an efficient policy framework in place on the island of Ireland, onshore wind levelised costs of less than €60/MWh are likely to be achievable over the timeframe of this study.

If Ireland can match over the period 2020-2030 the renewable energy costs already achieved elsewhere in Europe, our analysis indicates that the Renewable Energy scenario could cost less for the end consumer than the Fossil Fuel scenario.

The main costs and benefits and their relative magnitude are as described in Section 4.1.1. More detailed tables of results can be found in the Appendix of this report.

4.1.3 Northern Ireland

Figure 18 presents a summary of the total costs and benefits for NI end consumers of the Renewable Energy scenario versus the Fossil Fuel scenario over the period 2020-2030.

With the exception of renewable support costs which depend principally on the level of renewable deployment, technology costs and achieved wholesale electricity prices, most of the other costs and benefits covered in our analysis broadly scale with market size measured as total electricity demand.

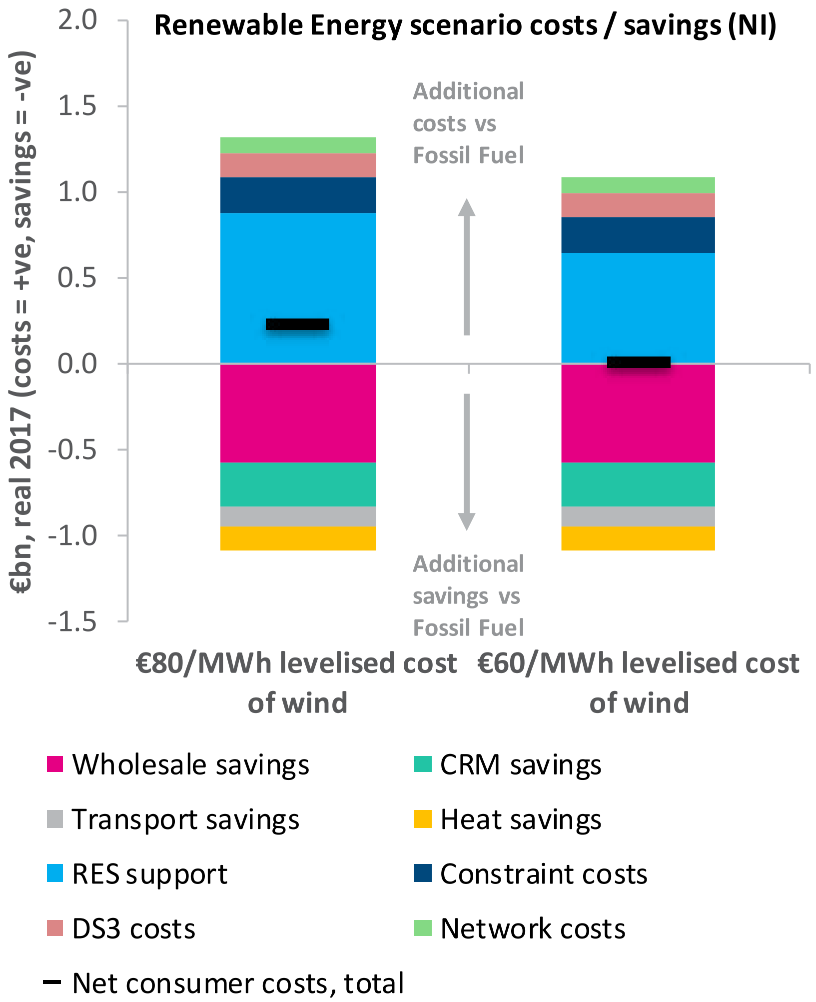
Our analysis shows that the Renewable Energy scenario, while increasing NI end consumer costs in some areas, results in significant benefits and savings in others, compared with the Fossil Fuel scenario. Based on the starting point for technology costs, which was the WSP|Parsons Brinckerhoff study published by DCCAE, the net result over the ten year period of the study is a cost of just over €230m for NI end consumers.

However, our analysis indicates that a reduction in these levelised costs to around €67/MWh for onshore wind and €93/MWh for solar would result in delivering the Renewable Energy scenario at no additional cost to NI consumers versus the Fossil Fuel scenario. To put these levelised costs in context, we have already seen onshore wind delivered below €40/MWh and solar at €70/MWh in other European markets with similar resources. With an efficient policy framework in place in Northern Ireland, onshore wind levelised costs of less than €67/MWh are likely to be achievable over the timeframe of this study.

The reduction in levelised cost of renewables required to make the Renewable Energy scenario cost-neutral for NI end consumers is significantly less than in ROI. This is because NI currently has a higher renewable electricity penetration than ROI, and therefore the relative level of additional deployment required to achieve a 70% RES-E level is lower, leading to lower additional renewable support costs.

The main costs and benefits are as described in Section 4.1.1. More detailed tables of results can be found in the Appendix of this report.

Figure 19 Summary of total Renewable Energy scenario costs and benefits for Northern Ireland (NI) relative to the Fossil Fuel scenario (2020-2030)



4.1.4 Scenarios with lower NI renewables deployment

Alongside the core Renewable Energy scenario with 70% RES-E deployment on an all-island basis, we also analysed a scenario with lower deployment of renewables in Northern Ireland. This scenario had a 70% RES-E deployment in ROI and a 55% RES-E deployment in NI. However, our analysis indicated that net end consumer costs were *higher* under this scenario than in the 70% all-island case. This is because the additional end consumer benefits of greater RES-E deployment in NI outweighed the additional renewable support costs.

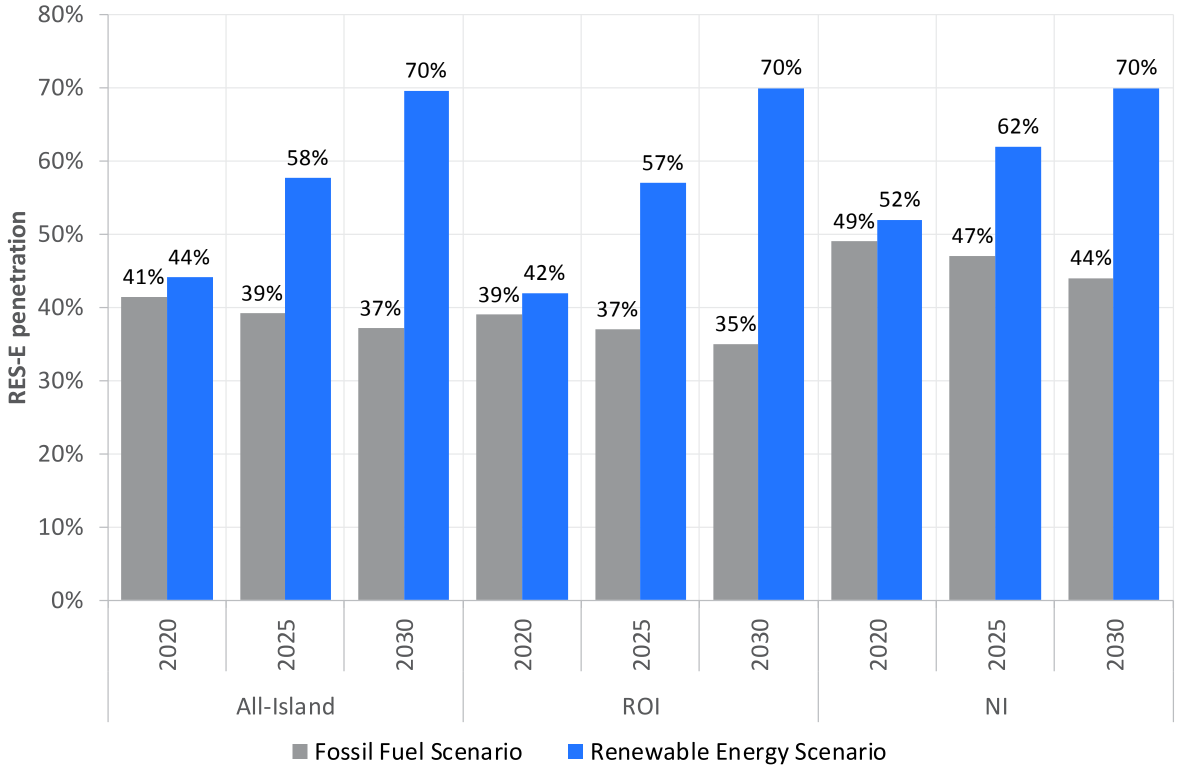
4.2 Renewable energy share

The Fossil Fuel scenario assumes no further growth in renewable generation beyond 2019. Although the 40% RES-E target for 2020 is almost met in this scenario, as demand grows over time, renewable penetration in the electricity sector declines. Between 2020 and 2030, RES-E penetration drops from

39% to 35% in the Republic of Ireland, from 49% to 44% in Northern Ireland and from 41% to 37% across the whole island.

In the Renewable Energy scenario, renewable generation increases over time through new-build wind and solar projects in the 2020s. Between 2020 and 2030, RES-E penetration increases from 44% to 70% across the whole island, with both the Republic and Northern Ireland achieving 70% RES-E target respectively. The RES-E % results for the two scenarios are presented in Figure 20.

Figure 20 Projected renewable share of electricity consumption



We have also estimated the overall renewable share of energy consumption in 2030, based on SEAI projections of 2030 final energy consumption and using EU methodology in the calculation[23]. Ireland is likely to reach a renewable energy share of around 13% in 2020. Our analysis indicates that the measures in the Renewable Energy scenario will contribute an additional 10% to the renewable energy share in 2030. Other measures which are beyond the scope of this work, primarily bioenergy in heat and transport, were recently forecasted by SEAI to contribute an additional 2% renewable energy share in 2030[24]. Combined with the electricity sector measures in the Renewable Energy, we estimate this would result in an overall renewable energy share in 2030 of 25%. For comparison, we estimate that in the Fossil Fuel scenario, the equivalent overall renewable share in final renewable energy consumption would be around 10 percentage points lower at 15%.

Our estimates imply that renewable electricity has the potential, under a scenario such as Renewable Energy, to make a substantial contribution to the overall penetration of renewable energy on the island of Ireland. Recently, the European Commission set a target of 32% renewable energy for the

[23] We have assumed that SEAI estimates are also applicable to Northern Ireland on a pro-rated basis.
[24] https://www.seai.ie/resources/seai-statistics/energy-data/

EU in 2030. This means that further progress is likely to be needed in renewable heat and transport if Ireland is to reach the average 32% RES benchmark that has been set at an EU level, and even more if a higher national target is set.

Critical to achieving substantive increases in the renewable share of both electricity and overall energy consumption, without additional cost to end consumers, is the successful integration of future renewable build. This involves:

- Ensuring that the output profile from renewables is matched as far as possible with the profile of power demand, in order to avoid extremes of low or high prices in the market, by means of additional generation or demand-side flexibility.
- Minimising curtailment of renewables as far as possible.

The greater loss of renewable output through curtailment, the greater the installed capacity required to achieve a given renewable penetration level. Our estimates of renewable shares of the electricity and energy sectors are based on our high resolution modelling of the power system, and take account of future projected curtailment of renewables. Our analysis suggests that if renewables are deployed alongside appropriate flexibility measures, such as flexible demand and interconnection, then curtailment can be kept at moderate levels in the Renewable Energy scenario. Our curtailment analysis and results are discussed in more detail in the following section.

4.3 Curtailment

Curtailment describes a situation when a generator is forced to reduce output below planned levels due to external system factors. In the Irish SEM, renewable generators can be instructed by the system operator (SO) to reduce output in physical dispatch in order to maintain system integrity. We term curtailment which is caused by system constraints as ‘technical curtailment’.

In addition, if wind / renewable output exceeds demand in a particular period, then generators could also achieve lower than planned levels of output in the market schedule. We term this ‘market curtailment’.

Either situation can negatively affect generator revenues by reducing energy market revenues, and support payments, which are typically made on the basis of metered generation. Curtailment increases the effective levelised cost of electricity for renewables, since costs must be recovered across a smaller generation volume.

For wind and solar generators, there are two key types of system constraint applied by the system operator which drive the majority of technical curtailment:

- The system non-synchronous penetration (SNSP) limit. For system stability reasons, the system operator currently imposes a limit on the maximum instantaneous amount of non-synchronous[25] generation as a proportion of total generation. If actual non-synchronous generation, including wind and solar, exceeds the threshold value then output is curtailed and regulated down. The SNSP limit is currently set at 65%, and EirGrid expects this to increase to 75% by 2020, and has indicated that further increases beyond this level are

[25] Non-synchronous generators are those which are not operating at the frequency of the system – typically this includes wind, solar and interconnection.

likely to be achievable in time. Increases in the SNSP limit are partly driven by improvements delivered under the DS3 ancillary services programme.

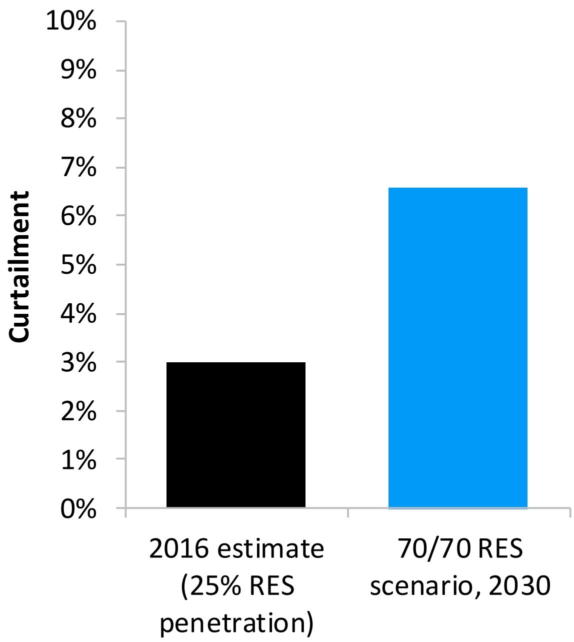
- 'Min gen' constraints. In order to enable secure and stable operation of the electricity system the TSO needs to apply certain operational constraints[26]. In addition to the SNSP constraint above, these include items such as inertia, voltage stability, and replacement reserve along with other technical limitations. The cumulative effect of these constraints is that a certain amount of conventional generation is constrained on, irrespective of whether they are 'in merit' in the wholesale market. This means that the 'window' of demand which is available to be met by the remaining plant, including wind and solar, is reduced, which can lead to curtailment. Finding alternative solutions to these technical operational constraints would facilitate greater renewable penetration and more efficient dispatch.

We have assumed under the Renewable Energy scenario that the SNSP limit increases over time to reach 90% in 2030, and that the 'min gen' constraint is reduced from the expected 2020 level, which requires around 1 GW of thermal capacity to be running, to around 700 MW in 2030.

We run a version of our power market model that includes these key system constraints in order to project the curtailment levels under a particular scenario.

Figure 21 presents our projections of renewable curtailment for the Renewable Energy scenario, and compares this against recent outturn curtailment levels. Table 6 provides a more detailed breakdown of market and technical curtailment for renewables through to 2030. All curtailment figures are presented on an all-island basis.

Figure 21 Projected renewable electricity curtailment for the Renewable Energy scenario



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[26] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_68_May_2018.pdf

Table 6 Projected all-island renewable electricity curtailment in the Renewable Energy scenario

Renewable energy		2020	2025	2030
Available energy	*GWh*	16,543	25,587	34,699
Generation - unconstrained[27]	*GWh*	16,367	25,066	33,484
Generation - constrained	*GWh*	15,895	23,804	32,412
Market curtailment	*% of available generation*	1.1%	2.0%	3.5%
Technical curtailment	*% of available generation*	2.9%	4.9%	3.1%
Total renewable curtailment	*% of available generation*	**3.9%**	**7.0%**	**6.6%**

In addition to improvements in the system constraints, increasing the levels of flexibility in the power market contributes to holding curtailment at manageable levels as RES-E penetration increases. In the Renewable Energy scenario, we project total renewable curtailment levels of around 6.6% in 2030, with a roughly equal split between 'market' and 'technical' components. This is a relatively moderate increase in curtailment over recent historical levels from 2016 of around 3%, despite the Renewable Energy scenario delivering a RES-E penetration of 70% – almost three times the level of 2016.

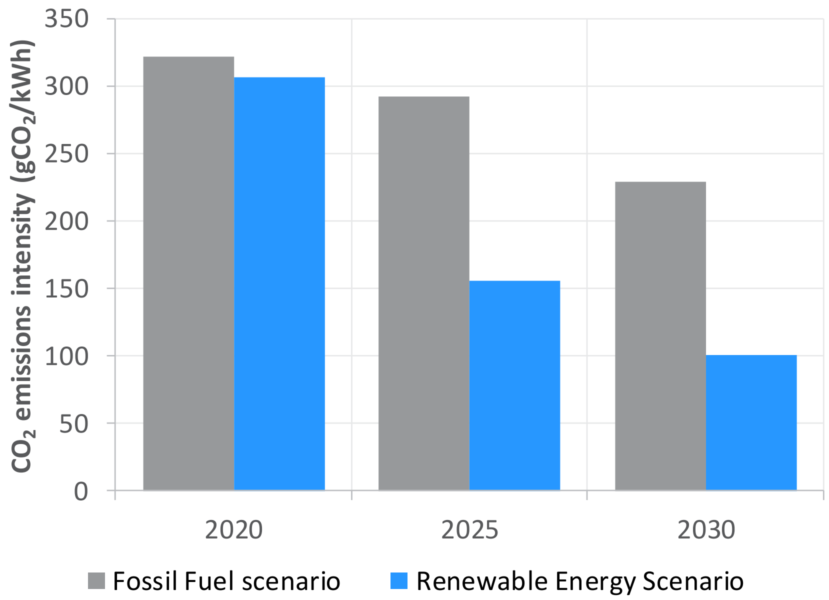
The Renewable Energy scenario assumes increases in interconnection, deployment of battery storage and increasing demand side flexibility via heat pumps and electric vehicles. These help to ensure a better match between renewable output and demand, significantly reducing the need for curtailment.

4.4 CO_2 emissions

We have calculated the CO_2 emissions intensity for the power sector on an all-island basis in both the Fossil Fuel scenario and the Renewable Energy scenario, and the results are presented in Figure 22.

[27] The difference between available energy and unconstrained generation is 'market curtailment' in periods where available renewable energy exceeds demand.

Figure 22 Power sector CO_2 emissions intensity



Under the Renewable Energy scenario the power sector emissions intensity falls from around 300 gCO_2/kWh in 2020 to around 100 gCO_2/kWh in 2030. In contrast, the reduction is much less under the Fossil Fuel scenario which remains at a level of around 230 gCO_2/kWh in 2030. The emissions intensity is calculated based on the physical dispatch of plant projected by our constrained model of the all-island market.

The main driver of this result is certainly the higher deployment of renewables in the Renewable Energy scenario. However, the additional flexibility measures in this scenario also play a role in allowing fossil fuel generation to operate in a more efficient manner – for example, by avoiding some plant starts and part-loading. The relatively moderate curtailment in the Renewable Energy scenario is also an important factor in avoiding as far as possible the 'shedding' of zero-emission renewable generation.

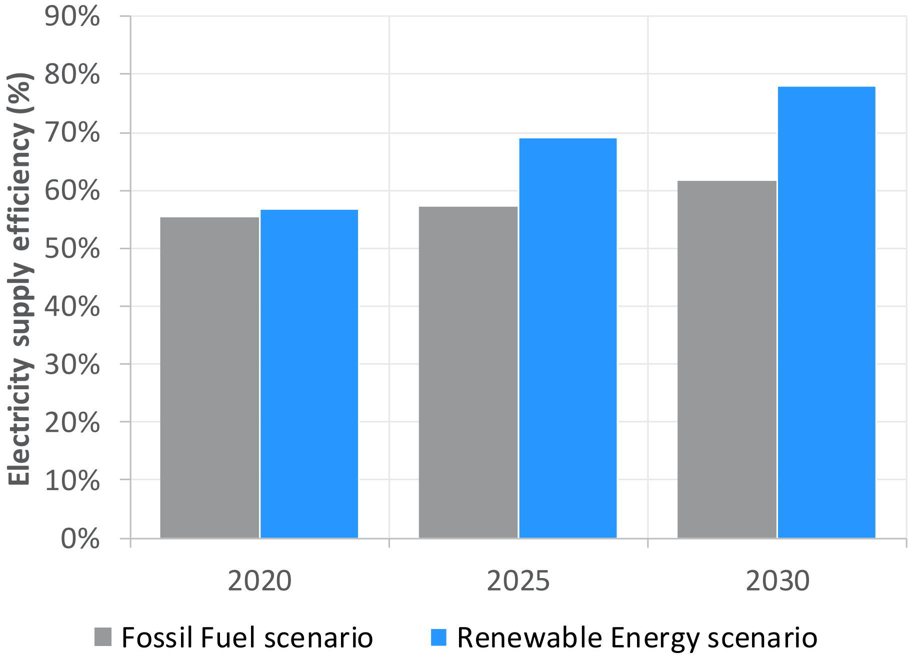
In total, over the period 2020-30, the Renewable Energy scenario achieves a reduction in all-island power sector CO_2 emissions of 37 $MtCO_2$ versus the Fossil Fuel scenario – this is a reduction of just under 30%. This is driven by around 145 TWh of avoided power sector fossil fuel burn under the Renewable Energy scenario over the period 2020-30, mainly natural gas, which represents a reduction of 30% on the Fossil Fuel scenario.

4.5 Electricity supply efficiency

We have calculated the electricity supply efficiency for each modelled scenario by dividing total power generation by total input fuel offtake. We have counted renewables such as wind and solar as 100% efficient in the calculation. The result, presented in Figure 23, shows that electricity supply efficiency in the Renewable Energy scenario increases from around 57% in 2020 to 78% in 2030 – mainly driven by the increasing renewable penetration in this scenario.

There is a more moderate increase in electricity supply efficiency in the Fossil Fuel scenario which reaches 62% by 2030. While renewable installed capacity is static in this scenario, over time older and less efficient fossil-fuelled generation is replaced by more efficient new build, which drives the slight increase in overall supply efficiency.

Figure 23 Electricity supply efficiency



Appendix A Input assumptions

A.1 Demand assumptions

Fossil Fuel scenario

Annual Demand Assumptions (All Island)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
All scenarios	*TWh*	40.4	41.0	41.6	42.2	42.7	43.1	43.6	44.2	44.7	45.3	45.9
ROI	*TWh*	31.9	32.4	32.9	33.4	33.8	34.0	34.5	34.9	35.4	35.8	36.3
NI	*TWh*	8.4	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.4	9.5	9.6

Renewable scenario

Annual Demand Assumptions (All Island)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
All scenarios	*TWh*	40.9	41.8	42.8	43.6	44.4	45.1	45.9	46.8	47.6	48.5	49.4
ROI	*TWh*	32.3	33.0	33.7	34.3	35.0	35.4	36.1	36.7	37.4	38.0	38.7
NI	*TWh*	8.6	8.8	9.1	9.3	9.5	9.6	9.8	10.0	10.3	10.5	10.7

A.2 Commodity price and FX assumptions

All scenarios		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Brent crude oil	$/bbl (real 2017)	54.3	58.3	62.3	66.2	70.2	74.2	78.1	82.1	86.1	90.0	94.0
Coal CIF ARA	$/tonne (real 2017)	41.0	44.9	48.8	52.7	56.6	60.5	64.4	68.3	72.2	76.1	80.0
Carbon EUA	€/tonne (real 2017)	11.0	13.5	16.1	18.6	21.2	23.7	26.3	28.8	31.4	33.9	36.5
NBP Gas	p/th (real 2017)	32.6	35.8	39.0	42.2	45.4	48.6	51.8	55.0	58.2	61.4	64.6

All scenarios	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
EUR/USD	1.162	1.152	1.142	1.132	1.122	1.113	1.114	1.115	1.116	1.117	1.119
GBP/EUR	1.133	1.141	1.150	1.158	1.166	1.174	1.177	1.180	1.183	1.186	1.189
GBP/USD	1.316	1.314	1.312	1.310	1.308	1.306	1.311	1.316	1.321	1.326	1.331

A.3 Interconnector assumptions

Fossil Fuel scenario	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Interconnector Capacity	*Total MW operational (export)*	580	580	580	580	580	580	580	580	580	580	580
East-West	*MW operational*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*
Moyle (import)	*MW operational*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*
Moyle (export)	*MW operational*	*80*	*80*	*80*	*80*	*80*	*80*	*80*	*80*	*80*	*80*	*80*
Greenlink	*MW operational*											
Celtic (France)	*MW operational*											

Renewable scenario	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Interconnector Capacity	*Total MW operational (export)*	950	950	950	950	950	2,150	2,150	2,150	2,150	2,150	2,030
East-West	*MW operational*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*
Moyle (import)	*MW operational*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*
Moyle (export)	*MW operational*	*80*	*80*	*80*	*80*	*80*	*80*	*80*	*80*	*80*	*80*	*80*
Greenlink	*MW operational*						*500*	*500*	*500*	*500*	*500*	*500*
Celtic (France)	*MW operational*						*700*	*700*	*700*	*700*	*700*	*700*
Additional GB interconnection[28]	*MW operational*						*250*	*250*	*250*	*250*	*250*	*250*

[28] We assume an additional 250 MW of interconnector capacity brought online in 2025, either through an increase in Moyle's export capacity from 80 MW to 330 MW, or for example by Greenlink commissioning as a 750 MW link rather than 500 MW.

A.4 Fossil Fuel scenario thermal capacity assumptions

Installed capacity: ROI	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	*MW*	855	855	855	855	855	855	855	855	855	855	-
Gas	*MW*	4,332	4,074	4,074	4,074	3,780	3,780	3,780	4,180	4,180	4,324	5,124
Oil	*MW*	810	810	694	208	208	208	208	52	52	52	52
Peat	*MW*	351	351	351	351	351	118	118	118	118	118	118
Hydro & PS	*MW*	530	530	530	530	530	530	530	530	530	530	530

Installed capacity: NI	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	*MW*	476	-	-	-	-	-	-	-	-	-	-
Gas	*MW*	1,022	1,022	1,022	1,022	1,222	1,622	1,622	1,622	1,622	1,722	1,722
Oil	*MW*	464	348	348	348	348	348	206	206	206	206	206
Peat	*MW*	-	-	-	-	-	-	-	-	-	-	-
Hydro & PS	*MW*	8	8	8	8	8	8	8	8	8	8	8

A.5 Renewable scenario thermal capacity assumptions

Installed capacity: ROI	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	*MW*	855	855	855	855	855	-	-	-	-	-	-
Gas	*MW*	4,332	4,074	4,074	4,074	3,780	3,780	3,780	3,780	3,780	3,780	3,181
Oil	*MW*	810	810	694	208	208	208	208	52	52	52	52
Peat	*MW*	351	351	351	351	351	118	118	118	118	118	118
Hydro & PS	*MW*	530	530	530	530	530	530	530	530	530	530	530

Installed capacity: NI	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	*MW*	476	-	-	-	-	-	-	-	-	-	-
Gas	*MW*	1,022	1,022	1,022	1,022	1,022	1,222	1,222	1,222	1,222	1,222	1,222
Oil	*MW*	464	348	348	348	348	348	206	206	206	206	206
Peat	*MW*	-	-	-	-	-	-	-	-	-	-	-
Hydro & PS	*MW*	8	8	8	8	8	8	8	8	8	8	8

A.6 Renewable capacity factor assumptions

Capacity Factors	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Onshore wind	%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Offshore wind	%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
Solar PV	%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%

A.7 Fossil Fuel scenario renewable capacity assumptions

Modelled installed capacity (Republic of Ireland)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	MW	3,710	3,710	3,710	3,710	3,710	3,710	3,710	3,710	3,710	3,710	3,710
Solar PV	MW	50	50	50	50	50	50	50	50	50	50	50
Hydro	MW	238	238	238	238	238	238	238	238	238	238	238
Biomass and LFG	MW	52	52	52	52	52	52	52	52	52	52	52
Renewable waste	MW	43	43	43	43	43	43	43	43	43	43	43

Modelled installed capacity (Northern Ireland)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	MW	1,112	1,112	1,112	1,112	1,112	1,112	1,112	1,112	1,112	1,112	1,112
Solar PV	MW	270	270	270	270	270	270	270	270	270	270	270
Hydro	MW	8	8	8	8	8	8	8	8	8	8	8
Biomass and LFG	MW	52	52	52	52	52	52	52	52	52	52	52
Renewable waste	MW	17	17	17	17	17	17	17	17	17	17	17

Modelled installed capacity (All Island)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	MW	4,822	4,822	4,822	4,822	4,822	4,822	4,822	4,822	4,822	4,822	4,822
Solar PV	MW	320	320	320	320	320	320	320	320	320	320	320
Hydro	MW	246	246	246	246	246	246	246	246	246	246	246
Biomass and LFG	MW	104	104	104	104	104	104	104	104	104	104	104
Renewable waste	MW	59	59	59	59	59	59	59	59	59	59	59

A.8 Renewable scenario renewable capacity assumptions

Modelled installed capacity (Republic of Ireland)	Units	2020	2025	2030
Wind	*MW*	4,006	5,985	7,965
Solar PV	*MW*	273	1,386	2,500
Hydro	*MW*	238	238	238
Biomass and LFG	*MW*	52	52	52
Renewable waste	*MW*	43	43	43

Modelled installed capacity (Northern Ireland)	Units	2020	2025	2030
Wind	*MW*	1,210	1,700	2,190
Solar PV	*MW*	282	341	400
Hydro	*MW*	8	8	8
Biomass and LFG	*MW*	52	52	52
Renewable waste	*MW*	17	17	17

Modelled installed capacity (All Island)	Units	2020	2025	2030
Wind	*MW*	5,216	7,685	10,155
Solar PV	*MW*	555	1,727	2,900
Hydro	*MW*	246	246	246
Biomass and LFG	*MW*	104	104	104
Renewable waste	*MW*	59	59	59

A.9 Heat pump assumptions

Key input assumptions	Units	2030
Conventional heating: Oil		
Upfront cost per unit	*€*	3,000
Power output per unit	*kW*	22
Efficiency	*%*	79%
Fuel cost	*€/GJ*	18.6
Other running cost: Distribution	*€/GJ*	4.1
FOM	*€/year*	270
HP		
Upfront cost per unit	*€*	10,000
Power output per unit	*kW*	10
Efficiency	*%*	260%
Fuel cost	*€/GJ*	Electricity Production & Distribution Is Modelled
Other running cost	*€/GJ*	
FOM	*€/year*	150

A.10 EV assumptions

Key input assumptions	Units	2030
Conventional vehicle: Average of Diesel/Petrol		
Upfront cost per vehicle	*€*	20,560
Fuel consumption	*GJ/km travelled*	0.00169
Fuel cost	*€/GJ*	41.8
FOM	*€/year*	842
EV		
Upfront cost per unit	*€*	27,777
Fuel consumption	*GJ/km travelled*	0
Fuel cost	*€/GJ*	Electricity Is Modelled
Other running cost	*€/GJ*	
FOM	*€/year*	614

A.11 Renewable scenario flexibility assumptions

Annual demand (Republic of Ireland)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electric vehicles (EVs)												
Fixed Demand	*GWh*	23	51	79	106	134	162	189	217	245	272	300
Flexible Demand	*GWh*	70	153	236	319	402	485	568	651	734	817	900
Electric heating (HP)												
Fixed Demand	*GWh*	73	96	118	141	164	186	209	232	255	277	300
Flexible Demand	*GWh*	218	287	355	423	491	559	627	696	764	832	900

Annual demand (Northern Ireland)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electric vehicles (EVs)												
Fixed Demand	*GWh*	11	24	38	51	64	77	90	104	117	130	143
Flexible Demand	*GWh*	33	73	113	152	192	232	271	311	350	390	430
Electric heating (HP)												
Fixed Demand	*GWh*	31	40	50	59	69	78	88	98	107	117	126
Flexible Demand	*GWh*	92	121	149	178	207	235	264	293	321	350	379

Annual demand and Battery Storage (All Island)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Battery storage												
Small scale battery storage	*MW*	0	50	100	150	200	250	300	350	400	450	500
Large scale battery storage	*MW*	0	120	240	360	480	600	720	840	960	1080	1200
Electric vehicles (EVs)												
Fixed Demand	*GWh*	34	75	116	157	198	239	280	321	361	402	443
Flexible Demand	*GWh*	103	226	349	471	594	717	839	962	1084	1207	1330
Electric heating (HP)												
Fixed Demand	*GWh*	103	136	168	200	233	265	297	329	362	394	426
Flexible Demand	*GWh*	310	407	504	601	698	795	891	988	1085	1182	1279

A.12 Constraint assumptions

SNSP Limit Assumptions		2020	2025	2030
Fossil Fuel	SNSP Limit (%)	75%	75%	75%
Renewable	SNSP Limit (%)	75%	75%	90%

Minimum Generation Assumptions		2020	2025	2030
Fossil Fuel	Min gen (MW)	1,000	1,000	1,000
Renewable	Min gen (MW)	700	700	700

A.13 Technology cost assumptions

Technology	Economic Life (years)	WACC	FOM (€/kW)	Overnight CAPEX (€/kW) 2020	Overnight CAPEX (€/kW) 2025	Overnight CAPEX (€/kW) 2030
CCGT	20	8.7%	32.0	653	627	597
OCGT Large	20	8.7%	20.0	386	367	349
Battery Storage 2hr	10	11.0%	10.0	618	449	380