SUSTAINABLE ENERGY AUTHORITY OF IRELAND

Poolbeg Sector Integration

Investigating synergies between the electricity, heat and hydrogen sectors

MullanGrid Consulting

Codema Dublin's Energy Agency

This report has been funded by the Sustainable Energy Authority of Ireland under the SEAI Research, Development & Demonstration Funding Programme 2021, Grant number 21/RDD/719.

Contents

1 Introduction 22

2 Key Insights from Literature Review 23

3 Poolbeg Modelling Scenarios 2030 and 2040 27

3.1 Introduction 27

3.2 Dispatch Down Analysis for 2030 and 2040 29

3.2.1 Oversupply and Curtailment Analysis 29

3.2.2 Constraint Estimates for Poolbeg Offshore Wind 34

3.3 District Heating and Thermal Storage 2030 and 2040 34

3.3.1 What is District Heating 34

3.3.2 District Heating in Dublin 36

3.3.3 The Dublin District Heating Scheme 38

3.3.4 Existing Electrically Heated DH Network in Dublin - Tallaght 39

3.3.5 District Heating & Thermal Storage Modelling Scenarios 41

3.3.6 District Heating & Thermal Store Results for 2030 Curtailment Scenario 43

3.3.7 District Heating & Thermal Store Results for 2040 Curtailment Scenario 45

3.3.8 District Heating & Thermal Store Results for DH Networks with Total Heat Demand of 2.7TWh 48

3.3.9 Electrolyser Waste Heat Assumptions 52

3.3.10 Thermal Energy Storage Comparison 52

3.4 Green Hydrogen 2030 and 2040 56

3.4.1 Green Hydrogen Production Scenarios 56

3.4.2 Green Hydrogen Production Model 67

3.4.3 Green Hydrogen 2030-2035 Analysis 72

3.4.4 Green Hydrogen 2040 Analysis 83

4 Future Hydrogen Markets in Dublin 93

4.1 Electricity Sector 94
4.1.1 Electricity Generation 94
4.1.2 Data Centres 98
4.2 Transport Sector 100
4.2.1 Passenger Car and Light Goods Vehicles 100
4.2.2 Urban Bus 101
4.2.3 Heavy Goods Vehicles 101
4.2.4 Aviation 102
4.2.5 Maritime 103
4.3 Industry Sector 104
4.4 Hydrogen Demand Spatial Analysis 105
4.5 Assessment of Hydrogen Applications in Dublin 108
5 Poolbeg: Hydrogen Production Case Study 116
6 Key Learnings 122
7 Further Research 133
1. Literature Review 135
a. EU Decarbonisation Targets, Strategies and Renewable Energy Directive 135
i. Fit for 55 package - European Green Deal 135
ii. EU Offshore Wind Strategy 136
iii. EU Energy System Integration Strategy 137
iv. EU Hydrogen Strategy 139
v. EU Revised Renewable Energy Directive (RED) II 140
vi. EU Taxonomy 144
vii. European Commission 145
viii. EU Aviation 145
ix. EU Maritime 146
x. REPowerEU Plan 147
b. Ireland’s Decarbonisation Targets and Strategy 149

i. Climate Action Plan 2023 149

ii. Offshore Wind 155

iii. Hydrogen 160

c. Decarbonisation Strategies in other Jurisdictions 160

i. Decarbonisation Strategies 160

ii. Offshore Wind 161

iii. Hydrogen Strategies 163

d. Roadmap to Achieving Net Zero Emissions by 2050 170

i. Global Roadmap to 2050 170

ii. Ireland's Roadmap to 2050 171

e. Ireland's Existing Energy System 178

i. Background 178

ii. Electricity 178

iii. Transport 206

iv. Heat 211

f. Levelised Cost of Hydrogen Production 219

g. Energy Security and Resilience 221

2. Appendix 226

a. Appendix A 226

i. Dispatch Down Modelling 2030 & 2040 226

b. Appendix B 227

i. Green Hydrogen 2030 & 2040 Curtailment Mitigation 227

c. Appendix C 234

i. Green Hydrogen 2030-2035 and 2040 Analysis 234

d. Appendix D 247

i. Dublin Existing and Future Gas Generation 247

e. Appendix E 248

i. Dublin Connected Electricity Generation 248

List of Tables

1 Introduction 22

2 Key Insights from Literature Review 23

3 Poolbeg Modelling Scenarios 2030 and 2040 27

3.1 Introduction 27

3.2 Dispatch Down Analysis for 2030 and 2040 29

3.2.1 Oversupply and Curtailment Analysis 29

Methodology 29

Scenarios 29

Model Input Assumptions 30

Oversupply and Curtailment Results 32

3.2.2 Constraint Estimates for Poolbeg Offshore Wind 34

3.3 District Heating and Thermal Storage 2030 and 2040 34

3.3.1 What is District Heating 34

3.3.2 District Heating in Dublin 36

3.3.3 The Dublin District Heating Scheme 38

3.3.4 Existing Electrically Heated DH Network in Dublin - Tallaght 39

3.3.5 District Heating & Thermal Storage Modelling Scenarios 41

3.3.6 District Heating & Thermal Store Results for 2030 Curtailment Scenario 43

3.3.7 District Heating & Thermal Store Results for 2040 Curtailment Scenario 45

3.3.8 District Heating & Thermal Store Results for DH Networks with Total Heat Demand of 2.7TWh 48

3.3.9 Electrolyser Waste Heat Assumptions 52

3.3.10 Thermal Energy Storage Comparison 52

3.4 Green Hydrogen 2030 and 2040 56

3.4.1 Green Hydrogen Production Scenarios 56

Grid Connected High RES-E 57

Offshore Wind Off Grid 59

System Wide VRES Curtailment 60

Offshore Wind Dispatch Down 62

Offshore Wind and Solar PPA 64

3.4.2 Green Hydrogen Production Model 67

Levelised Cost of Hydrogen Production 67

Internal Rate of Return 69

Model Input Data 71

3.4.3 Green Hydrogen 2030-2035 Analysis 72

Hydrogen as a Dispatch Down Mitigation 2030-2035 72

Hydrogen Production Modelling 2030-2035 76

Base Case 76

Sensitivity Analysis 80

Renewable Generation Sensitivity 80

Electricity Input Costs, CapEx, Waste Heat Tariff Sensitivity 82

3.4.4 Green Hydrogen 2040 Analysis 83

Hydrogen as a Dispatch Down Mitigation 2040 83

Hydrogen Production Modelling 2040 86

Base Case 86

Sensitivity Analysis 91

Electricity Input Costs, CapEx, Waste Heat Tariff Sensitivity 91

4 Future Hydrogen Markets in Dublin 93

4.1 Electricity Sector 94

4.1.1 Electricity Generation 94

4.1.2 Data Centres 98

4.2 Transport Sector 100

4.2.1 Passenger Car and Light Goods Vehicles 100

4.2.2 Urban Bus 101

4.2.3 Heavy Goods Vehicles 101

4.2.4 Aviation 102

4.2.5 Maritime 103

4.3 Industry Sector 104

4.4 Hydrogen Demand Spatial Analysis 105

4.5 Assessment of Hydrogen Applications in Dublin 108

5 Poolbeg: Hydrogen Production Case Study 116

6 Key Learnings 122

7 Further Research 133

1. Literature Review 135

a. EU Decarbonisation Targets, Strategies and Renewable Energy Directive 135

i. Fit for 55 package - European Green Deal 135

ii. EU Offshore Wind Strategy 136

iii. EU Energy System Integration Strategy 137

iv. EU Hydrogen Strategy 139

v. EU Revised Renewable Energy Directive (RED) II 140

Additionality Delegated Act 142

vi. EU Taxonomy 144

vii. European Commission 145

viii. EU Aviation 145

ix. EU Maritime 146

x. REPowerEU Plan 147

b. Ireland's Decarbonisation Targets and Strategy 149

i. Climate Action Plan 2023 149

Electricity 150

Built Environment 152

Transport 154

ii. Offshore Wind 155

Phase One 155

Phase Two 156

Phase Three 158

Enduring Regime 159

Offshore Renewable Energy Development Plan II 159

iii. Hydrogen 160

c. Decarbonisation Strategies in other Jurisdictions 160

i. Decarbonisation Strategies 160

ii. Offshore Wind 161

iii. Hydrogen Strategies 163

France 164

Germany 165

United Kingdom 167

Other Countries 169

d. Roadmap to Achieving Net Zero Emissions by 2050 170

i. Global Roadmap to 2050 170

ii. Ireland’s Roadmap to 2050 171

MaREI/UCC: Our Climate Neutral Future – Zero by 50 172

SEAI National Heat Study – Net Zero by 2050 174

e. Ireland’s Existing Energy System 178

i. Background 178

ii. Electricity 178

Existing Electricity Demand, Generation and Transmission Infrastructure 178

Dublin Transmission Network 182

Dublin Electricity Demand 182

Dublin Electricity Generation 183

Future Electricity Demand 184

New Demand Growth 184

Data Centres 185

Electrification of Heat and Transport 186

Demand Side Management 187

Dublin Electricity Demand Projections 187

Renewable Generation Pipeline 189

Offshore Wind Generation 189

Onshore Renewable Generation 189

Renewable Generation Dispatch Down 192

Oversupply Curtailment 192

System Curtailment 192

Constraint 192

Historical Dispatch Down Levels 194

Planned Transmission Infrastructure 195

EirGrid Transmission Development Plan 2021-2030 195

EirGrid Shaping Our Electricity Future Roadmap 199

EirGrid ECP-2.2 Constraint Reports 202

Electricity Prices 204

iii. Transport 206

Transport in Dublin 207

Low Emission Bus Trials 209

Dublin Port HGV Traffic 210

Dublin Maritime and Aviation Figures 210

iv. Heat 211

Ireland’s Gas Grid 214

Heat in Dublin 216

f. Levelised Cost of Hydrogen Production 219

g. Energy Security and Resilience 221

2. Appendix 226

a. Appendix A 226

i. Dispatch Down Modelling 2030 & 2040 226

b. Appendix B 227

i. Green Hydrogen 2030 & 2040 Curtailment Mitigation 227

c. Appendix C 234

i. Green Hydrogen 2030-2035 and 2040 Analysis 234

d. Appendix D 247

i. Dublin Existing and Future Gas Generation 247

e. Appendix E 248

i. Dublin Connected Electricity Generation 248

List of Figures

Figure 1 Oversupply and System Curtailment Analysis Results 24

Figure 2 Key Elements of District Heat Models. 26

Figure 3 Key Variables of District Heat Modelling. 27

Figure 4 2030 Heat Production Profile from Curtailed Electricity 28

Figure 5 2040 Heat Production Profile from Curtailed Electricity 31

Figure 6 National Heat Production Profile for 2.7TWh Demand, from 2030 Curtailed Electricity Profile 33

Figure 7 Hydrogen Production ‘Grid Connected High RES-E’ Scenario Schematic 41

Figure 8 Hydrogen Production ‘Grid Connected High RES-E’ Scenario Load Duration Curve 41

Figure 9 Hydrogen Production ‘Offshore Wind Off Grid’ Scenario Schematic 42

Figure 10 Hydrogen Production ‘Offshore Wind Off Grid’ Scenario Load Duration Curve 43

Figure 11 Hydrogen Production ‘System Wide VRES Curtailment’ Scenario Schematic 44

Figure 12 Hydrogen Production ‘System Wide VRES Curtailment’ Scenario Load Duration Curve 45

Figure 13 Hydrogen Production ‘Offshore Wind Dispatch Down’ Scenario Schematic 46

Figure 14 Hydrogen Production ‘Offshore Wind Dispatch Down’ Scenario Load Duration Curve 47

Figure 15 Hydrogen Production ‘Offshore Wind and Solar PPA’ Scenario Schematic 48

Figure 16 Hydrogen Production ‘Offshore Wind and Solar PPA’ Scenario Load Duration Curve 49

Figure 17 2030-2035 Electrolyser ‘Grid Connected High RES-E’ Scenario Curtailment Mitigation 55

Figure 18 2030-2035 Electrolyser ‘Offshore Wind Off Grid’ Utilisation 56

Figure 19 2030-2035 Electrolyser ‘System Wide VRES Curtailment’ Scenario Curtailment Mitigation 57

Figure 20 2030-2035 Electrolyser ‘Offshore Wind Dispatch Down’ Scenario Curtailment Mitigation 57

Figure 21 2030-2035 Electrolyser ‘Offshore Wind and Solar PPA’ Scenario Curtailment Mitigation 58

Figure 22 2030-2035 LCOHp All Production Scenarios 61

Figure 23 2040 Electrolyser ‘Grid Connected High RES-E’ Scenario Curtailment Mitigation 67

Figure 24 2040 Electrolyser ‘System Wide VRES Curtailment’ Scenario Curtailment Mitigation 67

Figure 25 2040 Electrolyser ‘Offshore Wind Dispatch Down’ Scenario Curtailment Mitigation 68

Figure 26 2040 Electrolyser ‘Offshore Wind and Solar PPA’ Scenario Curtailment Mitigation 68

Figure 27 2040 LCOHp All Production Scenarios 70

Figure 28 Liebreich Associates Hydrogen Ladder 75

Figure 29 Dublin Port RoRo and LoLo Routes 2022 85

Figure 30 Architecture of EU Green deal. 112

Figure 31 Today’s energy system and future EU integrated energy system models. 114

Figure 32 REPowerEU schematic. 121

Figure 33 Annual and cumulative offshore wind installation in Europe. 134

Figure 34 Technical potential of offshore wind in EU sea basins. 135

Figure 35 Comparison of electrolysis capacity targets for different EU countries by 2030 in absolute terms (blue) and on a per capita basis (orange). 137

Figure 36 IEA Net Zero by 2050 – A roadmap for the global energy sector. 143

Figure 37 IEA Net Zero by 2050 - Emissions reduction by mitigation measure. 144

Figure 38 Ireland’s energy System 2019 – MaREI Study. 145

Figure 39 Ireland’s electrification 2050 – MaREI Study. 147

Figure 40 National Heat Study: framework of reports. 147

Figure 41 SEAI National Heat Study: Annual related heat emissions by scenario 2020-2050. 149

Figure 42 SEAI National Heat Study: Electricity demand for heat sector 2020 to 2050. 150

Figure 43 Ireland’s electricity transmission infrastructure, with main cities highlighted. 152

Figure 44 Share of electricity consumption of each sector of the Irish economy, contrasting 2005 and 2020 values. 153

Figure 45 Ireland's electricity generation by fuel type in 2020. 154

Figure 46 Greater Dublin's electricity transmission network. 155

Figure 47 Growth Scenarios of the SEAI's National Heat Study. 157

Figure 48 Projection of the electricity required by data centres in Ireland. 158

Figure 49 Ireland Onshore Renewable Generation Pipeline. 163

Figure 50 Dublin Onshore Renewable Generation Pipeline. 163

Figure 51 EirGrid framework for grid development. 168

Figure 52 Reinforcement projects in and around Dublin. 169

Figure 53 EirGrid SOEF Roadmap: Study areas. 171

Figure 54 EirGrid SOEF Roadmap: Transmission system needs/thermal overloads in Dublin. 173

Figure 55 EirGrid SOEF Roadmap: Map of identified candidate reinforcements. 174

Figure 56 EirGrid ECP-2.2 Scenarios Modelled and corresponding RES-E Levels. 175

Figure 57 EirGrid ECP-2.2 Dispatch Down Modelling Results (System Wide Average). 175

Figure 58 Historical day ahead market prices during wind curtailment periods. 178

Figure 59 CO2 emissions by vehicle type for Dublin (excluding aviation and maritime). 180

Figure 60 Ireland's largest heat users, including power stations (red), emission trading sites (yellow) and other LIEN members (blue). 184

Figure 61 Total annual emissions (MtCO2/annum) from fuel use for heating, by sector. 185

Figure 62 Total annual heating demand (GWh/annum), by sector. 185

Figure 63 Sample of results of the spatial analysis of total heat demand. 186

Figure 64 The Irish gas pipeline map, with the existing biomethane injection point represented as a green circle. 187

Figure 65 Heat demand density in TJ/km² for each CSO small area in Dublin. 189

Figure 66 Breakdown of current heating technologies in Dublin. 189

Figure 67 Deloitte LCOH Analysis. 190

Figure 68 A generic resilience curve of an energy system. 192

Figure 69 Electricity supply resilience in Europe. 193

Figure 70 Average temperatures for the first two weeks of January 2021 in comparison to the historic average (above); as well as wind speeds for the same period and historical averages (below). 195

Glossary

BER	Building Energy Rating.
BEV	Battery Electric Vehicle.
BNEF	Bloomberg New Energy Finance.
BOP	Balance of plant costs are those associated with piping, pumps and electrical installations.
Capacity Factor	Amount of energy actually produced in a year relative to the maximum available output based on the nameplate capacity.
CapEx	Capital Expenditure.
CCGT	Combined cycle gas turbine.
CCUS	Carbon capture utilisation and storage.
CHP	Combined Heat and Power, plant designed to produce both heat and electrical power from a single source.
CNG	Compressed natural gas.
CO_2	Carbon Dioxide.
COP	Coefficient of Performance.
CRU	Commission for Regulation of Utilities.
CSO	Central statistics office, Ireland.
Data Centres	Large buildings used to store data.
DCCAE	Department of climate change action and environment, Ireland.
DCU	Dublin City University.
DDHS	Dublin District Heat Scheme.
DECC	Department of the Environment, Climate and Communications.
DH	District Heating
Dispatch Down	The level of reduction in output relative to available output requested by the system operator.
DWtE	Dublin Waste to Energy Plant.
ECP	Enduring Connection Policy

EirGrid	State-owned electricity transmission system operator in the Republic of Ireland; plans, develops and operates the electricity transmission system in the jurisdiction.
Electrolyser	A device used to split water into hydrogen via an electrical current.
ESB Networks	State owned operator of the distribution system. Asset owner of both transmission and distribution networks.
ETS	Emissions trading scheme.
EV	Electric vehicle, a vehicle that incorporates a battery to power an electric motor for propulsion.
FCEV	Fuel cell electric vehicle, zero emission vehicle powered by hydrogen.
Floor Price	The lowest preconceived price that a seller will accept.
GHG	Greenhouse Gas
GNI	Gas Networks Ireland builds, develops, and operates Ireland's gas infrastructure.
GoO	Guarantees of Origin, certificates which provide proof that electricity has been generated from renewable sources as defined in the renewable energy directive (RED).
GW	Gigawatt (1×10^9 watts).
H2	Hydrogen.
Heat Pump	A device that provides heat energy from a source of heat to a destination called a "heat sink".
HGV	Heavy Goods Vehicle.
HP	Heat pump.
HRS	Hydrogen refuelling station.
HVDC Interconnector	Connects the transmission system of one independently supplied transmission system to that of another using high voltage direct current cables.
Hydrogen Valley	A geographical area where several hydrogen applications are combined together into a hydrogen ecosystem that consumes a significant amount of hydrogen, improving the economics behind the project.
IEA	International Energy Agency.
IMF	International Monetary Fund.
IRENA	International Renewable Energy Agency.

IRR	Internal Rate of Return, measure of the rate of return expected from an investment.
I-SEM	Integrated Single Electricity Market, where electricity is traded on the island of Ireland.
kt	kilo tonnes.
ktoe	kilo tonnes oil equivalent.
kV	Kilovolt (1000 volts).
LCOE	Levelized cost of electricity, expressed in euro/MWh; represents the average price of electricity that each type of RES-e generator would have to earn in its lifetime at a given capacity factor in order to cover its capital costs and operating costs.
LCOHp	Levelized cost of hydrogen production, expressed in euro/kg; represents the average price of hydrogen that a hydrogen production plant would have to earn in its lifetime at a given capacity factor in order to cover its capital costs and operating costs.
LNG	Liquefied natural gas.
MaREI	Science Foundation Ireland Research Centre for Energy, Climate and Marine, coordinated by the Environmental Research Institute (ERI) at University College Cork.
MEC	Maximum export capacity, is the maximum capacity that a generator can export to the electricity distribution system.
Min Gen	Minimum conventional generation level to be running on the transmission system at all times, required by EirGrid/SONI.
$MtCO_2$	Metric tonnes of carbon dioxide.
Mtoe	Million tonnes oil equivalent, unit of measurement for fuel consumption.
MVA	Mega Volt Ampere; 1,000,000 Volt Amperes. Volt Ampere is the unit used for the measurement of ‘apparent power’ in an electrical circuit.
MW	Megawatt (1×10^6 watts).
MWh	Megawatt hours; 1,000,000-Watt Hours. Measure of energy over time.
NI	Northern Ireland.
NORA	National Oil Reserve Agency.
NPV	Net Present Value.

O&M	Operation & maintenance.
OpEx	Operational Expenditure.
ORESS	Offshore Renewable Energy Support Scheme
PEM	Proton Exchange Membrane.
PEM Electrolyser	Polymer Electrolyte Membrane, electrolyser device used to split water into hydrogen via an electrical current.
PHEV	Plug-in hybrid electric vehicle.
PPA	Power Purchase Agreement; contractual arrangement between electricity generators and purchasers (off takers).
Primary Energy	Energy in the form that it is first accounted for in a statistical energy balance, before any transformation to secondary or tertiary forms of energy.
PSO Levy	Public Service Obligation: a government subsidy charged to all electricity consumers in Ireland. The money collected is used to subsidise renewable energy generation.
RED	Renewable Energy Directive.
REFIT	Renewable Energy Feed in Tariff.
Renewable Constraint	The level of reduction in output relative to available output due to localised transmission network issues, requested by the system operator.
Renewable Curtailment	The level of reduction in output relative to available output due to electricity system technical limits such as Min Gen and SNSP, requested by the system operator.
RES	Renewable Energy Source: a clean form of energy production that is harnessed from natural resources.
RES-E	Renewable energy sources for electricity generation.
RESS	Renewable Electricity Support Scheme in Ireland.
RFNBO	Renewable fuel of non-biological origin.
ROI	Republic of Ireland.
SEAI	Sustainable Energy Authority Ireland.
SEM	Single Electricity Market.
SNSP	System Non-Synchronous Penetration, a technical limit placed on level of variable renewable generation allowed to be running on the transmission system by EirGrid/SONI.

SONI	Electricity Transmission System operator for Northern Ireland; plans, develops and operates the electricity transmission system in the jurisdiction.
TCO	Total Cost of Ownership.
TER	Total electricity requirement.
TLAF	Transmission Loss Adjustment Factors allocated to generators. These are calculations of the losses and are calculated jointly by EirGrid/SONI and approved by the Regulatory Authorities on an annual basis.
TSO	Transmission System Operator; responsibility of managing the bulk electricity supply in the jurisdiction.
TUoS	Transmission Use of System Charge is the system of charging for transporting power in bulk across the transmission system (110kV,220kV and 400kV network).
TWh	Terawatt hour (1×10^{12} watt hours).
UCC	University College Cork.
VRES	Variable renewable sources of energy, which include wind and solar.
WACC	Weighted Average Cost of Capital.
WEI	Wind Energy Ireland.

1 Introduction

During this research project Codema and MullanGrid undertook an assessment of the integration of renewable energy across the electricity, heat and transport sectors, with a focus on the Poolbeg area of Dublin. This project has been funded by the Sustainable Energy Authority of Ireland under the SEAI Research, Development & Demonstration Funding Programme 2021, Grant number 21/RDD/719.

The output of variable renewable electricity sources (VRES) can be restricted or often referred to as dispatched down due to the high availability of resource or technical limitations of the electricity system or networks. This project examines ways to maximise the use of renewable energy in Ireland, how to reduce inefficiencies in the electricity system and more specifically reduce the dispatch down of RES.

This report reviews the European Union (EU) and Irish Government policies and targets supporting decarbonisation and the development of renewable energy. Possible future pathways to net zero emissions by 2050 are examined in an international and Irish context.

The Irish Government's Climate Action Plan 2023 outlines a roadmap to 2030 and includes district heating and green hydrogen as technologies to help to deliver the necessary emission reductions. The project examines the potential benefits of these technologies to the electricity system as a mitigation measure for dispatch down electricity. The business case for deploying district heating and green hydrogen is discussed for a range of future scenarios for a highly renewable electricity system in Ireland. To understand the market for green hydrogen, a review of potential hydrogen applications is presented in this report. The assessment is based on Ireland's energy system with a specific case study carried out on the Poolbeg Peninsula.

2 Key Insights from Literature Review

The current climate emergency is one of the most threatening environmental and social problems of modern times. Ireland, as part of the European Union, faces ambitious climate and energy targets set by the EU and by the state itself, which add pressure towards a scenario of fast change in terms of emissions and energy generation.

For instance, the EU's 2030 Climate & Energy Framework sets a target of a 55% reduction in GHG emissions by 2030 compared to 1990 levels. The EU's 2050 Long-Term Strategy, in turn, is even more ambitious and proposes a climate-neutral society by 2050 (a European Union with net-zero GHG emissions), being further strengthened by the REPowerEU plan of reducing the EU's dependence on fossil fuels from Russia. Moreover, Ireland itself has committed to have net-zero emissions by 2050 and to a 51% reduction in emissions across all sectors by 2030, as stated in its 2021 Climate Action Bill.

Ireland's Climate Action Plan 2023 sets a roadmap to cut emissions by 51% by 2030 and reach net zero by at least 2050. Some key conclusions from reviewing the plan are:

- The electricity sector is critical to the decarbonisation of the energy sector and the plan aims to accelerate the build out of renewable generation with a target for 5GW offshore wind, plus 2GW offshore wind capacity for green hydrogen production, 8GW solar PV capacity and 9GW onshore wind capacity to deliver an 80% share of renewable electricity (RES-E). Although Climate Action Plan 2023 provides a detailed roadmap to 2030 and includes an action to carry out further studies to identify the investments and upgrades needed to facilitate 80% renewable electricity share (EL/23/21), there does not appear to be any actions to study the requirements of a net zero power system.
- Green hydrogen production from surplus renewable electricity by 2030, and green hydrogen production from 2GW offshore wind capacity by 2035.
- The built environment sector is required to reduce emissions to 4.34Mt CO_2 by 2030, the emissions in the sector for 2018 totalled 8.5Mt CO_2. In order to deliver the necessary emissions reductions, some key metrics listed include to; complete 500,000 retrofits to achieve a B2 building energy rating (BER), install 680,000 heat pumps in residential buildings (of which 400,000 will be retrofits in existing buildings), deploy zero carbon heating to meet the needs of 50,000 commercial buildings, deliver up to 2.7TWh of district heating, and provide 0.7TWh renewable gas for heating.
- In the transport sector, there are targets for 845,000 electric passenger cars, 95,000 commercial EVs, 3,500 low emission trucks and an expanded electrified rail network. Green hydrogen is considered in the roadmap in a post 2025 context with a role to play

in the decarbonisation of hard to abate sectors such HGVs, shipping and aviation. The Biofuels Obligation Scheme is under review to consider green hydrogen as a RFNBO.

Ireland's hydrogen strategy is due to be published in late Q2 2023. Many European countries have published hydrogen strategies and set out targets for green hydrogen production and technology development. Currently, Ireland does not have any clear pathway for green hydrogen production, storage, distribution, scale of market, as well as route to market in Ireland.

From a review of Irish and EU decarbonisation policies and research studies, three measures critical to achieving net zero carbon by 2050 appear to be:

1) Energy efficiency improvements.
2) Electrification of energy sectors, use of other renewable technologies such as green hydrogen where electrification is not feasible.
3) Deployment of market ready renewable electricity generation capacity.

SEAI and MaREI modelling indicates potential electricity demand growth up to c.187-198% for a net zero carbon energy system compared to 2019 demand levels. Electricity fuel use for heat alone could account for up to 26TWh of electricity demand in a net zero carbon system, this equates to c.90% of the 2019 electricity demand.

In recent years, Ireland has seized the opportunity to harvest its abundant wind resources to generate renewable electricity. EirGrid and ESB Networks have expanded the transmission and distribution networks to facilitate the connection of c.4.43GW onshore wind capacity, with renewable generation currently accounting for approximately 40% of the country's electricity.

Natural gas is the dominant source for electricity generation in Ireland. County Dublin alone has c.1.8GW of gas generation capacity connected on its electricity networks. These fossil fuel generators are dispatchable, whereby their output can be ramped up or down at the request of the system operator, this helps to ensure security of supply and also provides resilience to the system. EirGrid currently require 8 (5 in ROI, 3 in NI) dispatchable fossil fuel generators to be running on the electricity system at all times and two of the five generators in ROI are required to be located in Dublin due to the local system constraints of voltage and power flow control in the complex Dublin electricity network. While natural gas is critical to the electricity system today, it is vital that cleaner and more robust resilience mechanisms are put in place in a future where fossil fuels might be depleted, unavailable or simply not acceptable with carbon budgets or sectoral emissions ceilings.

Overall, as of 2019, only 12% of Ireland's gross final consumption is deemed renewable, further strengthening the need for acceleration in the country's efforts to decarbonise its energy system. Since 2022, Ireland has experienced volatile energy prices along with other EU countries. Ireland is heavily exposed to volatile pricing due to its reliance on imported fossil fuels, and currently imports two thirds of its energy requirement. Increasing energy storage capacity can help to reduce the volatility around energy pricing, and in the future increased long term electricity storage capacity will be critical as Ireland moves towards a net zero power system.

From a review of energy security and resilience, Ireland ranks well in terms of political stability, control of corruption and government effectiveness. However, some weaknesses and potential threats to the future of the resilience of Ireland's energy system were highlighted including reserves capacity which is the amount of power ready to be dispatched to cover supply shortages, insurance penetration which is the access to financial resources needed to rebuild a system and also the availability of engineers in the economy.

Ireland's ORESS 1 auction secured support for 3,074MW of Phase One offshore wind capacity. The c.890-1200MW of unsuccessful Phase One capacity may be financed via a corporate PPA, otherwise it may enter into Phase Two and compete in ORESS 2. Additional Phase Two Offshore Wind capacity will be connected from c.350-450MW off Cork and c.350-450MW off Waterford/Wexford and aims to deliver Ireland up to 5GW of offshore wind capacity by 2030. The timelines of achieving 5GW offshore wind capacity by 2030 are challenging considering potential issues around consenting for offshore wind projects and also for necessary grid reinforcements. Phase Three of Ireland's offshore wind development strategy aims to support the long-term potential for a floating offshore wind industry, including all elements of the necessary supply chain required for an industry of this type, in Ireland.

County Dublin has successfully attracted many large energy users. The county is also home to the country's largest airport and seaport. As Ireland's largest urban area, the city poses challenges and opportunities in terms of decarbonisation, presenting in an Irish context, a densely distributed population and a large vehicle fleet. Dublin is overall no more advanced than Ireland as a whole with regard to decarbonisation although the electrification of a part of public transport and even the launch of hydrogen-fuelled buses has been observed. The relative success of attracting data centre capacity compared to other countries has put a constrain on Dublin's electricity supply and EirGrid have introduced new data centre policy and started the powering up Dublin workstream to address the issues in a 2030 context, connecting Phase One offshore wind capacity in this timeline will also be crucial. Considering the Climate Action Plan 2023 ambitions for the electricity, transport and heat sectors, Dublin arguably has the greatest challenges to overcome to reduce emissions while enhancing energy efficiency, security and resilience.

EirGrid and ESB Networks will be critical to delivering net zero emissions for Ireland considering the projected electricity requirement from MaREI and SEAI for a net zero system. Currently, the necessary infrastructure upgrades to accommodate the future electricity demand, additional renewable generation capacity and dispatchable generation capacity are not yet understood for a net zero emissions energy system.

Considering off grid hydrogen production from offshore wind, the LCOHp is estimated to be as low as €3.7/kg in the North Sea according to Deloitte. Aurora analysis on hydrogen production in Ireland from a mix of offshore wind and solar capacity indicated an LCOHp as low as €3.5/kg. For grid connected hydrogen production, the LCOHp is estimated to be in the range of €3.8-4.9/kg based on electricity prices of €55-80/MWh. Some research on hydrogen production from curtailed electricity in Ireland estimated the LCOHp to be up to €18-20/kg for small scale electrolysis (1.5MW) located at an onshore wind farm, a curtailed energy price of €50-65/MWh and a capacity factor of approximately 20%.

3 Poolbeg Modelling Scenarios 2030 and 2040

3.1 Introduction

As part of this project, the potential oversupply, system curtailment and network constraint (at Poolbeg only) have been examined in a 2030-2035 and 2040 timeline. The projections for oversupply and system curtailment are based on MullanGrid's curtailment model, which is currently used by developers and investors to understand possible future curtailment levels and the associated risk. EirGrid's ECP-2.2 constraint reports are the basis for constraint projections in this study.

A number of possible renewable generation capacity build out scenarios were considered for these timelines to deliver at least 80% RES-E by 2030-2035. In 2040, the renewable generation capacities assumed deliver 100% RES-E. The modelling includes EirGrid demand projections from the tomorrow's energy scenarios workstream for the respective study years and it is possible that these demand projections are subject to change as EirGrid publish updates to this workstream in 2024.

Two mitigation options for dispatch down considered are thermal energy storage/district heating and green hydrogen. The effectiveness as a mitigation measure and business case for deploying these technologies as a curtailment mitigation measure is examined for 2030-2035 and 2040, with the operation of each technology based on hourly dispatch down profiles.

Codema developed an hourly heat demand and thermal storage model based on the proposed heat demand connected to the Dublin District Heating Scheme (DDHS) in both 2030 and 2040. This model considers both space heating and hot water demands as well as the impact building occupancy and ambient air temperatures on these demands e.g. space heating demand increases when external air temperatures are lower. The heat losses from the DH network (based on indicative best practice levels) and from the thermal storage (based on modelled energy loss) were also included in this model.

This model also incorporates the net production cost of heat in its operation strategy and pritirises the use of low-cost heat production in combination with thermal storage above higher cost heat production options. The graph below shows how heat produced during times when production cost are low are prioritised

A green hydrogen production model developed by MullanGrid was used to understand the business case for green hydrogen production in Ireland for a number of different electrolyser configurations of operation. The model captures the business case of an electrolyser that is grid connected on a high RES-E system, connected directly to an offshore wind farm, utilising system wide curtailed electricity, utilising offshore wind dispatched down electricity at Poolbeg and also models the business case of a grid connected electrolyser using offshore wind and solar PV.

3.2 Dispatch Down Analysis for 2030 and 2040

This section of the report estimates the potential oversupply, curtailment and constraints that could be experienced by offshore wind farms connected to Poolbeg, and all wind and solar farms on a system wide level in both 2030 and 2040. Oversupply, curtailment and constraint are collectively known as dispatch down and are described in more detail in section 'Renewable Generation Dispatch Down' of the literature review. A Microsoft Excel spreadsheet model of All-Island oversupply and curtailment developed by MullanGrid was utilised for this analysis. In the case of constraints, future projections for offshore wind connected to Poolbeg were obtained from EirGrid's ECP-2.2 Constraint Reports.

3.2.1 Oversupply and Curtailment Analysis

Methodology

At a high level, oversupply is a market-based dispatch which occurs when the availability of renewable generation exceeds system wide demand and interconnector exports, while curtailment is a non-market based redispatch which occurs when system wide limits are exceeded. MullanGrid's Microsoft Excel oversupply and curtailment model has been in use, and calibrated annually, since 2011, and takes account of the key variable factors (including the build-out of renewable generation, demand, interconnector flows, and operational constraints such as Min Gen and the SNSP limit which were discussed in more detail in section 'Renewable Generation Dispatch Down' of the literature review) in order to estimate potential future oversupply and curtailment for renewable generation for one 2030 scenario and two 2040 scenarios. <u>It is important to note that variations in the key factors outlined above would result in oversupply and curtailment levels being different from the estimates included in this study</u>.

Scenarios

For the period 2030-2035, multiple scenarios were considered. These are summarised in Table 1. The 'MullanGrid 2030 Base Case Scenario' considers at least 80% RES-E, '2030 Scenario 1' considers 92% RES-E and '2030 Scenario 2' considers 98% RES-E.

Table 1: 2030 Curtailment Scenarios Modelled

Scenario Description	MullanGrid 2030 Base Case Scenario	2030 Scenario 1	2030 Scenario 2
AI RES-E (%)	80%	90%	94%
ROI RES-E (%)	80%	92%	98%
NI RES-E (%)	80%	79%	77%
ROI Onshore Wind (MW)	8,200	8,000	8,000
ROI Offshore Wind (MW)	2,675	5,000	7,000
ROI Solar (MW)	3,500	5,500	5,500
NI Onshore Wind (MW)	2,430	2,542	2,542
NI Solar (MW)	600	600	600

2030 Base Case: MullanGrid 2030 80% RES-E Base Case Scenario, as of Q1 2023.

2030 Scenario 1: ROI wind as per 2021 Climate Action Plan. ROI solar as per Jul 22 update to 2021 Climate Action Plan. NI wind as per TES AA scenario. NI solar as per SOEF.

2030 Scenario 2: ROI onshore wind as per 2021 Climate Action Plan. ROI offshore wind & solar as per July 22 update to 2021 Climate Action Plan. NI wind as per TES AA scenario. NI solar as per SOEF.

Based on the information available in October 2022, "2030 Scenario 2" was selected as the appropriate 2030 scenario to apply to this study. At that point, it was understood that the Government were targeting 7GW of offshore wind in ROI. However, it has since been clarified that the target is 5GW of grid connected offshore wind and 2GW of off-grid offshore wind, which is associated with hydrogen. In hindsight, "2030 Scenario 1" may have been a more appropriate 2030 scenario to apply to the study. However, given the ambitious carbon related targets to be realised, it is expected that RES-E levels will need to be more than 80%, which is the case with "2030 Scenario 2". Furthermore, it is expected that the 2030 scenario considered in this study represents the worst-case scenario from the perspective of oversupply and curtailment.

With regards to the two 2040 scenarios in Table 2 selected for the study, the overarching assumption is that 100% RES-E will be reached. However, it is important to note that at this early-stage, other scenarios could also potentially be applicable to 2040.

Model Input Assumptions

Table 2 summarises the main input assumptions applied to the oversupply and curtailment analysis.

Table 2: Oversupply and Curtailment Analysis Input Assumptions

Input	2030 Scenario	2040 Scenario 1	2040 Scenario 2
ROI RES-E %	98%	100%	
NI RES-E %	77%	100%	
AI RES-E %	94%	100%	
ROI Demand	40.9TWh[1]	49.5TWh[2]	
NI Demand	8.7TWh	14.8TWh[3]	
ROI Onshore Wind	8,000MW[4]	8,950MW	
ROI Offshore Wind	7,000MW[5]	7,265MW[6]	6,655MW
NI Onshore Wind	2,542MW	2,762MW	
ROI Solar	5,500MW[83]	5,000MW[7]	7,000MW
NI Solar	600MW[8]	1,777MW	
Onshore Wind Generation Profiles	EirGrid 2008 Wind Profiles with 31% capacity factor[9]		
Offshore Wind Generation Profile	EirGrid 2008 Offshore Wind Profile scaled up to 45% capacity factor for new offshore wind		
Solar Generation Profile	2008 generation profile with a 10% capacity factor[10]		
Min Gen	519MW	0MW	
SNSP Limit	90%	100%	
Available Interconnector Export Capacity	EWIC: 397.5MW, Moyle: 300MW, Greenlink: 375MW, Celtic: 525MW	EWIC: 397.5MW, Moyle: 300MW, Greenlink: 375MW, Celtic: 525MW, and 2nr. additional interconnectors: 750MW	
Demand Flexibility	6%	23%	
Future 6-hour Energy Storage Capacity	550MW	1,100MW	

Oversupply and curtailment are currently allocated pro-rata among wind and solar generation, while there is also currently no distinction made by EirGrid/SONI between oversupply and

[1] Median demand projections from EirGrid 2021-2030 Generation Capacity Statement

[2] Figure relating to "Co-ordinated Action" scenario from EirGrid Tomorrow's Energy Scenarios 2019

[3] Figure relating to "Accelerated Action" scenario from SONI Tomorrow's Energy Scenarios 2020

[4] Climate Action Plan 2021

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

[6] ROI offshore wind capacity adjusted to calculate 100% RES-E in the MullanGrid model for two ROI solar scenarios

[7] MullanGrid Curtailment Analysis, 2022

[8] EirGrid Shaping Our Electricity Future Roadmap, 2021

[9] EirGrid; SONI, "EirGrid Wind Profiles." 2008

[10] MullanGrid, "MullanGrid Generator Database." 2020

curtailment. However, the EU Clean Energy Package[11], and in particular, Regulation EU 2019/943, will impact on how oversupply and curtailment is allocated going forward. The new EU legislation removes priority dispatch for new renewable generators connecting post July 4th, 2019 (with some leeway for some projects in development by that date). However, there is still a requirement to minimise the curtailment of renewables. The EU Clean Energy Package became EU law in 2019 and it now must be implemented by member states, with the aforementioned Regulation coming into force on 1st January 2020.

The SEM Committee consulted on how to differentiate between existing renewable generators with priority dispatch and new renewable generators without priority dispatch[12], and a decision on this matter was published on 4th November 2020[13]. It was decided in the consultation that projects maintaining priority would be defined as those either being connected, or having a REFIT/Corporate PPA in place ("Priority" generators), and all other future generators ("Non-Priority" generators) are allocated oversupply ahead of "Priority" generator. On this basis, it is assumed there would be 5,456MW and 529MW of "Priority" wind and solar generation respectively, and all additional wind (including future offshore wind connected to Poolbeg) and solar farms connected by 2030 and 2040 would be considered "Non-Priority" generation.

The wind and solar generation assumptions for ROI in the 2030 scenario are based on Government targets that were published in 2021 and 2022, and are estimated in the MullanGrid model to result in 98% RES-E in ROI. It is important to note that this RES-E level is far in excess of the Government's target of 80% RES-E in 2030. The overarching assumption in the two 2040 scenarios is that 100% RES-E will be reached in both ROI and NI, with two variations in the capacity of ROI solar generation assumed. In the case of offshore wind connected to Poolbeg, it is assumed 1.45GW is connected in 2030, and increasing to 2GW by 2040. It is also worth noting that there is considerable uncertainty regarding potential electricity demand levels that could exist in 2040. 2040 demand estimates, obtained from EirGrid and SONI with low to medium levels of growth, have been applied to this study. However, demand levels could be significantly higher (refer to Section 'Ireland's Roadmap to 2050' of literature review) depending on how much of the heat, transport, industrial and other sectors are electrified in the future.

Oversupply and Curtailment Results

Taking account of the methodology and input assumptions outlined in sections 'Methodology' and 'Model Input Assumptions', an analysis was undertaken to estimate the potential

[11] W. Lutsch, "Clean energy for all Europeans," *Euroheat Power (English Ed.*, vol. 14, no. 2, p. 3, 2017

[12] "Information Note on Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch."

[13] "Decision Paper on Eligibility for Priority Dispatch Pursuant to Regulation (EU) 2019/943," 2020.

oversupply and curtailment levels that could be experienced by wind (including Non-Priority offshore wind generation at Poolbeg) and solar generation in 2030 and 2040. For the purposes of this study, curtailment (which is a non-market based redispatch which occurs when system wide operational limits such as Min Gen and SNSP are exceeded) is referred to as "System Curtailment", and that system curtailment and oversupply are collectively referred to as "Total Curtailment". It is assumed for 2040 that the system wide operational limits such as Min Gen and SNSP will have been removed, which would result in no system curtailment. On that basis, it is assumed in 2040 that Non-Priority generation will experience oversupply only, while all renewable generation will not experience any system curtailment. The results of the oversupply and system curtailment analysis are presented graphically in Figure 1, and tabulated in Appendix A.

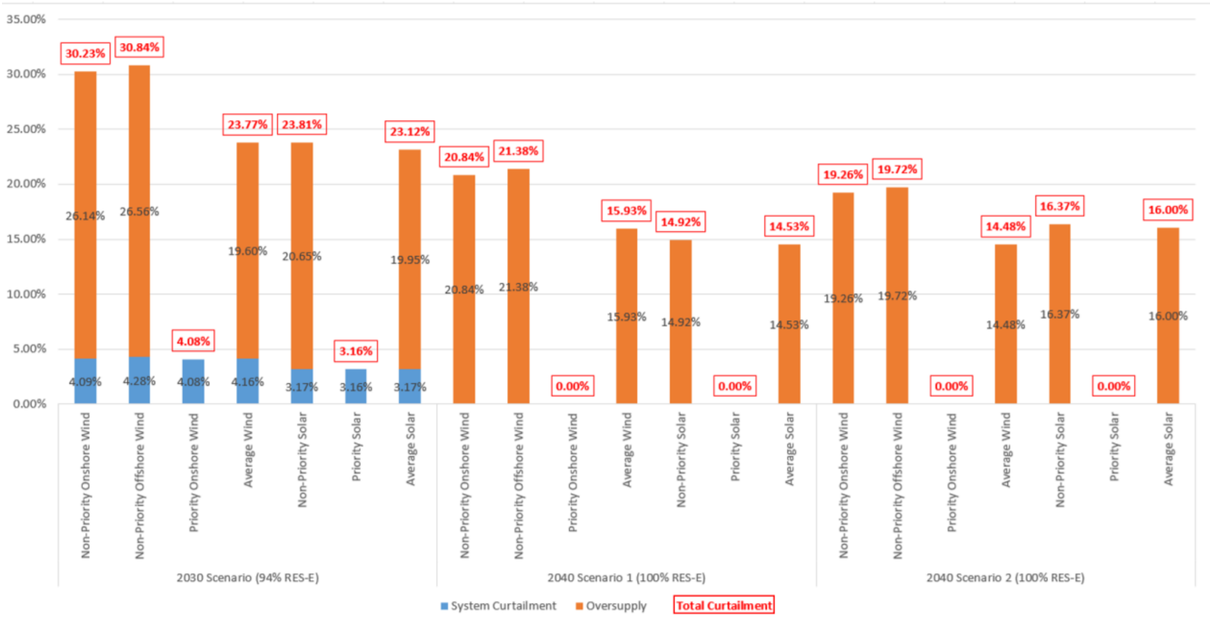


Figure 1: Oversupply and System Curtailment Analysis Results

Outlined as follows are some comments and observations on the oversupply and system curtailment estimates presented in Figure 1:

- Oversupply and system curtailment is estimated to be higher for wind generation compared to solar given that wind generation's capacity factor is approximately three times higher than solar;
- Oversupply and system curtailment levels for "Non-Priority Solar" and "Average Solar" are similar given that the vast majority of solar is "Non-Priority" with only 529MW being "Priority" solar;
- System curtailment is assumed to be removed for the two 2040 scenarios;

- Despite the two 2040 scenarios having higher RES-E levels compared to the 2030 scenario, oversupply is estimated to be lower in 2040 compared to 2030 mainly due to higher demand and additional interconnector exports assumed in 2040;
- Wind oversupply is estimated to be lower in 2040 Scenario 2 compared to 2040 Scenario 1, and vice versa in the case of solar. The reason for this is because there is less wind generation and more solar generation assumed in 2040 Scenario 2 compared to 2040 Scenario 1;
- Important to note that the 2030 and 2040 oversupply and system curtailment estimates presented in Figure 1 do not account for potential future long duration storage, which could take the form of green hydrogen. The potential benefits to oversupply and system curtailment of these two forms of energy storage are assessed in sections 3.3 and 3.4.

3.2.2 Constraint Estimates for Poolbeg Offshore Wind

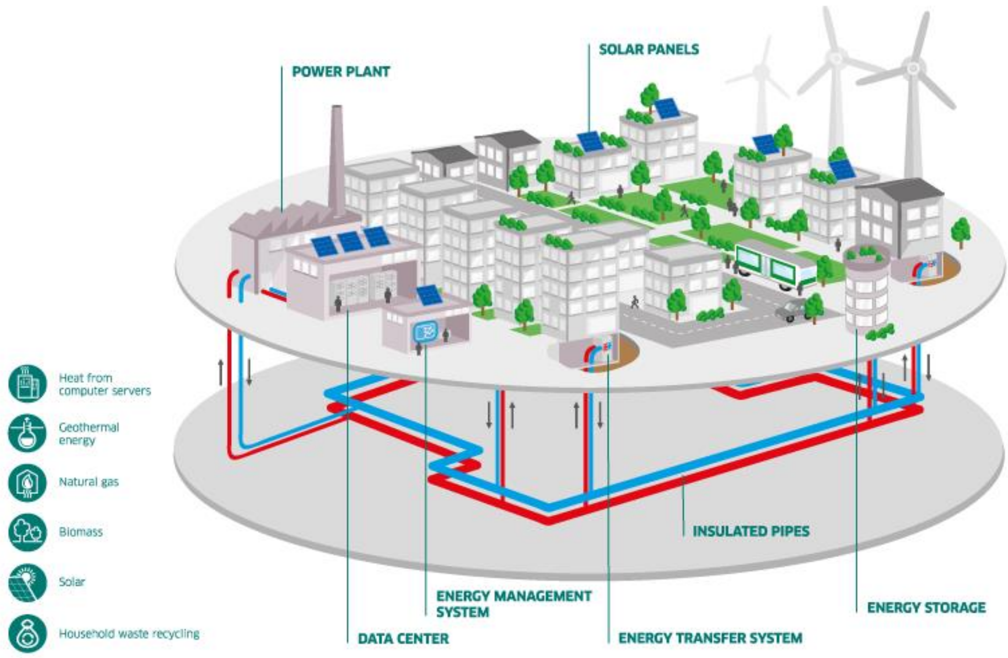
In addition to oversupply and system curtailment, this study has also taken account of potential transmission constraints that could be experienced by offshore wind connected to Poolbeg. At a high level, transmission constraints are a localised issue (unlike oversupply and system curtailment which are system wide issues) which occurs when the volume of available generation exceeds the capacity of the local transmission network.

In the absence of having access to a constraint analysis model, future projections for offshore wind connected to Poolbeg were obtained from EirGrid ECP-2.2 Constraint Reports, discussed in section . The EirGrid scenario '2027 ECP + 4.4GW Offshore Wind', which modelled a significant quantum of offshore wind without all planned transmission reinforcements, was selected. This estimated 10% transmission constraints for offshore wind connected to Poolbeg. This estimate of 10% transmission constraints was assumed to apply to the 2030 scenario in this study and given that EirGrid did not provide annual constraint profiles, it has been assumed for this study that constraints occur during the same periods when both oversupply and system curtailment occur. In the case of the two 2040 scenarios, it is assumed that EirGrid will have delivered sufficient transmission reinforcements in the Dublin region to result in zero transmission constraints for offshore wind connected to Poolbeg.

3.3 District Heating and Thermal Storage 2030 and 2040

3.3.1 What is District Heating

A district heating scheme consists of an insulated pipe network, which allows heat generated from a single or several larger centralised source(s) (energy centres) to be delivered to multiple buildings to provide space heating and hot water.



Indicative Diagram of a DH Netowrk (source: Engie)

DH networks benefit from economies of scale, the reduced coincidence of heat demand between different customers leading to lower capacity requirements (when compared with multiple building level units), increased efficiency of larger heat generation units and the reduction in maintenance costs of having a centralised plant. These benefits allow heat to be generated more efficiently and at a lower cost. Having fewer, larger heat generation units when compared with having an individual, building-level heating plant also allows for easier decarbonisation of heat in the long term, as it requires less individual heating units to be replaced when adopting newer technologies. These large-scale heating systems can also dramatically reduce the carbon emissions associated with heating without the need for significant retrofitting of buildings as they are capable of supplying heat at a high enough temperature to be a plug-in replacement for fossil fuel boilers.

District heating is technology agnostic and has the inherent flexibility to utilise multiple, diverse, locally available, renewable and low-carbon heat sources. This means customers are not dependent upon a single source of supply. This can help guarantee reliability, continuity of service and can introduce an element of competition into the supply chain, where desired. The use of these local resources also means that heat production is much less vulnerable to the price shocks experienced with imported fossil fuels. District heating can also allow waste heat (e.g. from electricity generation, industrial processes, etc.) which is often lost, to be captured and used to supply heat to homes and businesses, reducing the need to consume further fuel and significantly reducing carbon emissions and the cost of heat.

Greater utilisation of green electricity can also be achieved through the development of DH networks. For example, heat pumps or electric boilers can allow electricity to be converted into heat, which can be stored as thermal energy in the district heating network's pipes and thermal storage vessel, effectively acting as a large thermal battery. This is done at a fraction of the cost of other electrical storage methods (discussed in greater detail in section 3.3.10) and allows the electrical grid to be balanced during periods of low electrical demand. This off-peak demand allows intermittent, renewable generation technologies such as wind turbines to run during these periods, where previously they could not, and thereby increase the green contribution to the local energy system and prevent this renewable energy source from being curtailed. It is for these reasons that many of the most sustainable countries in the world have a large proportion of heat supplied by district heating systems. For example, DH plays a key role in the sustainability of cities like Copenhagen and Stockholm, where 98% and 90% of buildings are supplied by a DH network, respectively.

District heating is a low-carbon, low-cost method of supplying low-carbon heat to a community, district or region and aligns with the energy and climate change ambitions to decarbonise heat in Ireland. DH has not been widely implemented in Ireland but there is now an increased focus on DH with a target of 2.7TWh of heat to be supplied through DH networks by 2030 and 0.8TWh by 2025 set out in the Climate Action Plan 23.

3.3.2 District Heating in Dublin

District Heating represents the most cost-effective decarbonisation option for 70% (7.4TWh) and 87% (9.06TWh) of Dublin's heat demand by 2030 and 2050 respectively. The map below shows the areas where DH is most cost-effective in red and areas where individual heat pumps are most cost-effective in blue.

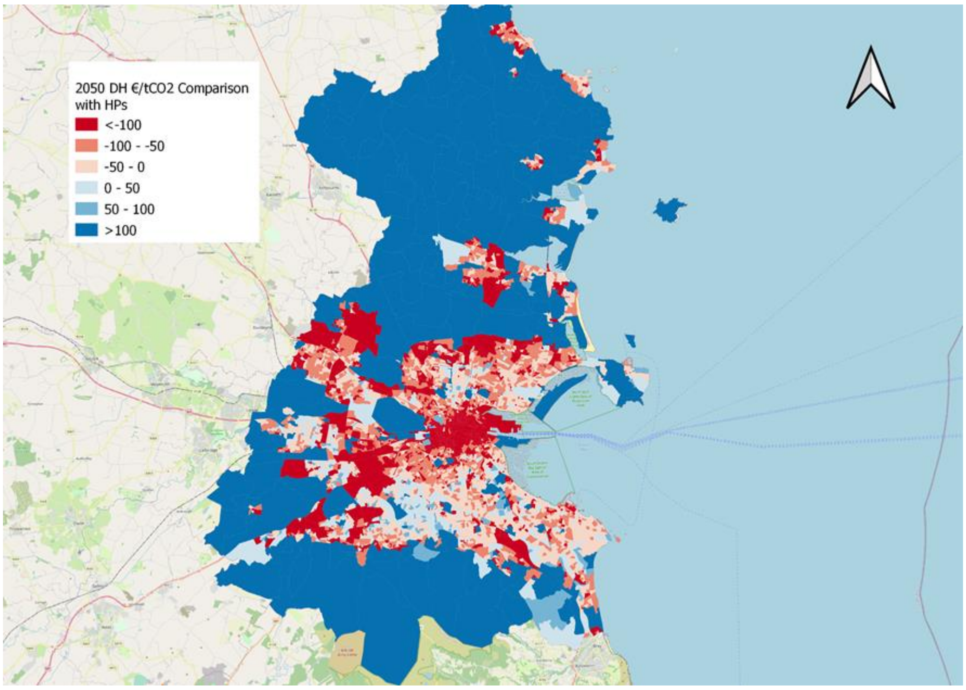
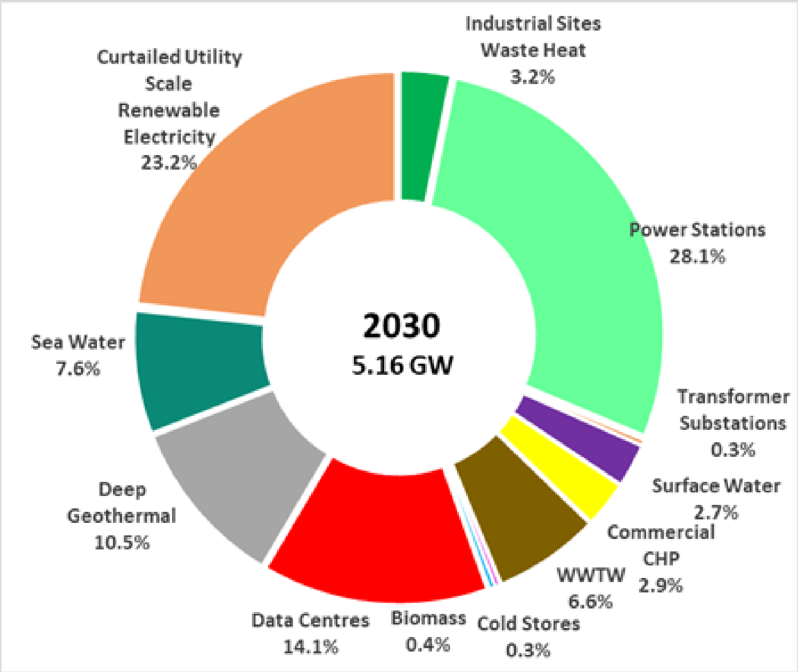


Figure 2: Heat Pump vs District Heating Map of Dublin (Source: Codema - Dublin Region Energy Masterplan)

The Dublin Region Energy Masterplan found that curtailed electricity represents a significant opportunity in terms of renewable heat supply for DH networks in Dublin from 2030 onwards due to plans for large offshore wind development, with projects such as Codling Wind Park and Dublin Array recently having successful applications to Irelands first offshore wind auction (ORESS 1)[14]. This is particularly true of the Dublin District Heating Scheme (DDHS) being developed in Poolbeg, due to its proximity to potential landing area for offshore wind power off the coast of Dublin.

14 **https://www.eirgridgroup.com/site-files/library/EirGrid/ORESS-1-Provisional-Auction-Results-2023-(OR1PAR).pdf**



Graph of heat source breakdown for Dublin in 2030 from DREM

3.3.3 The Dublin District Heating Scheme

The development of the DDHS network expected to go out to procurement in 2023 and as such represents a more realistic use of curtailed electricity when compared with highly uncertain uses such as production of green H2.

This network will initially utilise waste heat from the Dublin Waste-to-Energy plant as its primary heat source. Dublin City Council are in the process of procuring an Economic Operator (Consultant) to examine the strategies for managing, administering, developing and financing of the Dublin District Heating System (DDHS) and to progress the preferred strategy through tender stages to award of contract for the implementation of the System.

The initial phases of this network can be seen in the map below. This will serve buildings in the Poolbeg and Docklands areas of the city with potential to expand further across the city in the future. The heat demand used for the analysis in this report are based on data collected for the buildings located in the areas outlined below.

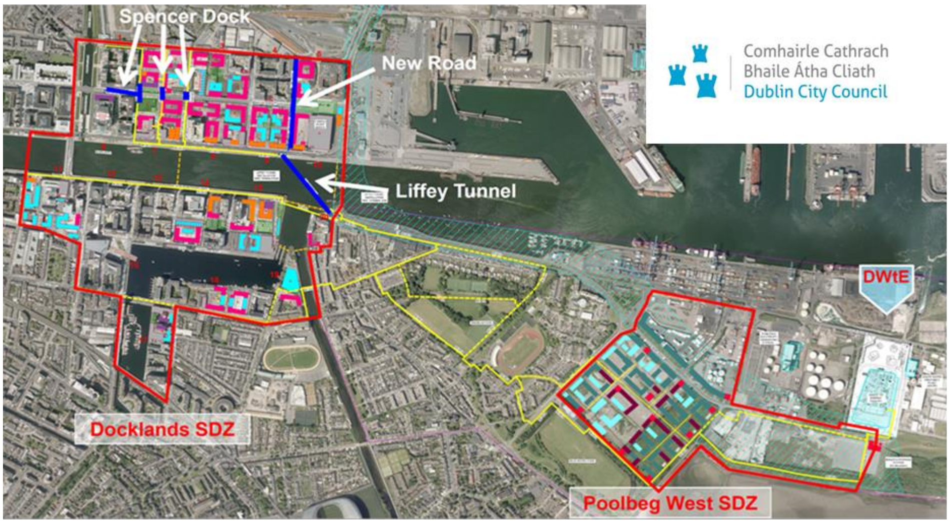


Figure 3: Map of Strategic Development Zones Connecting to Futureproofed for Connection to the Dublin District Heating Scheme (Source: Dublin City Council)

The estimated heat demand for the years 2030 and 2040 which were analysed in this study are set out below.

3.3.4 Existing Electrically Heated DH Network in Dublin - Tallaght

Electrically heating DH networks are already in operation in Dublin. The Tallaght DH network is the first large-scale DH network of its type in Ireland. It operates as Irelands first not-for-profit public utility. This network utilises data centre waste heat (waste heat from internet servers) to feed large-scale heat pumps (3MW) to supply heat and hot water to local buildings.

Figure 4: Energy Centre of Tallaght District Heating Scheme (HeatWorks) (Source: Codema)

Figure 5: Inside of Energy Centre of the Tallaght District Heating Scheme (Source: Codema)

The first phase of this project connects existing and new local authority buildings (council offices, library, innovation centre and affordable apartments) and the TU Dublin-Tallaght campus to this local district heating network. There is also potential for the new residential development at Belgard Gardens, which will be home to more than 3,000 people, and Tallaght Hospital among others to connect to the network at a later phase.

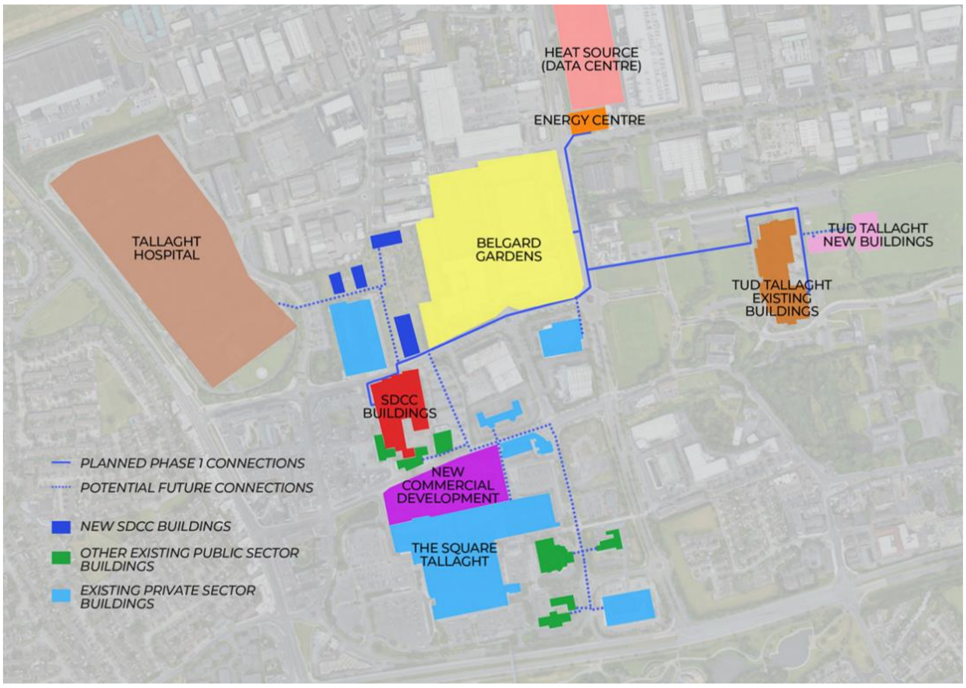


Figure 6: Map of TDHS Existing (solid blue line) and Planned (broken blue line) Network Route (Source: Codema)

3.3.5 District Heating & Thermal Storage Modelling Scenarios

This section of the report sets out the scenarios that were modelled to determine the optimal heat production method and sizing of the plant and thermal storage from the perspective of the DH network and to highlight the reductions to curtailment that can be made as a result. This analysis also considers practical constraints such as space availability.

Figure 7 outlines the various elements considered within these models. This includes the source of the electricity used to produce heat, whether this is directly from the offshore wind (behind the meter) or through the wider grid (in front of the meter). It should be noted that curtailment of electricity production from the Energy-from-Waste plant is assumed to be zero for the 2040 scenarios.

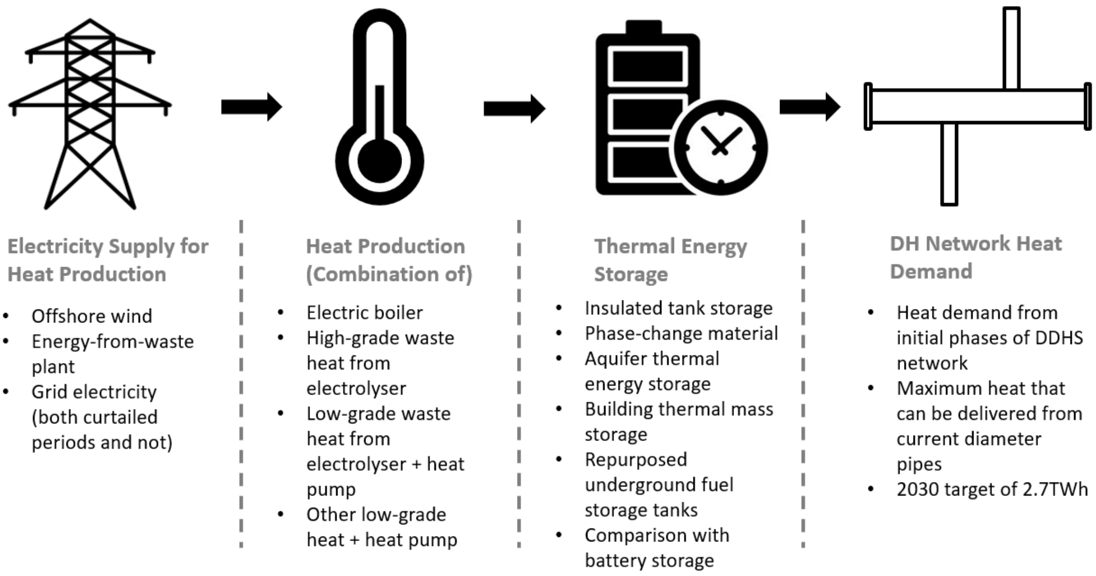


Figure 7: Key Elements of District Heat Models.

The differences in these considerations were captured using the variables outlined in Figure 8.

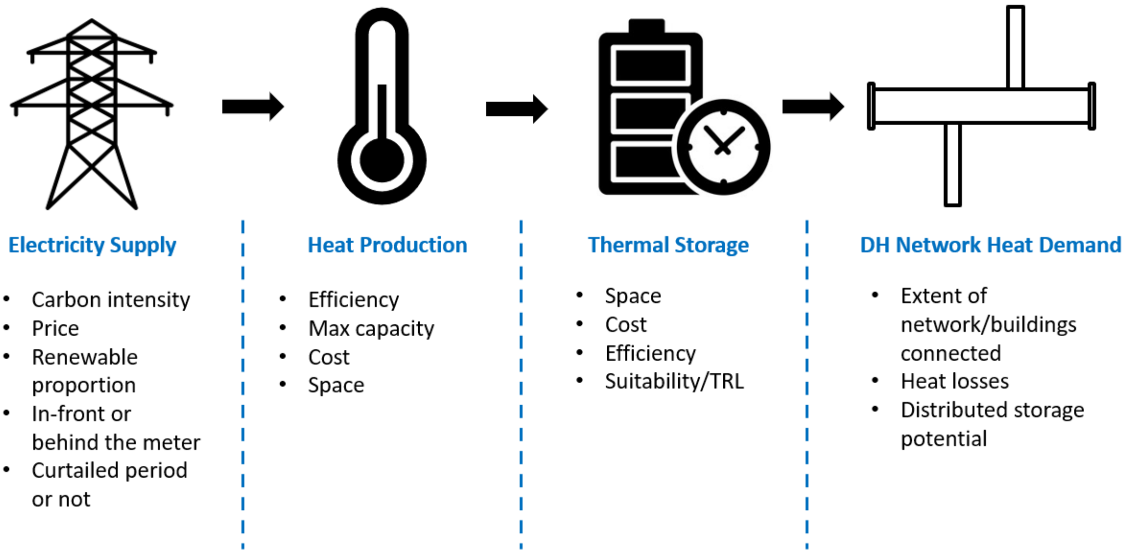


Figure 8: Key Variables of District Heat Modelling

For the curtailment scenarios modelled it was observed that if the heat production equipment to capture curtailed wind was connected in front of the meter i.e., taking its electricity from the wider grid, then the heat produced was not cost-competitive with the currently proposed main heat supply from the Dublin Waste-to-Energy plant. It should be noted that potential revenues from grid flexibility services were not included in this analysis.

When the heat production equipment was connected behind the meter i.e., directly connected to the offshore wind farm, then heat production was cost competitive with the currently proposed heat supply from the Dublin Waste-to-Energy plant. The heat production equipment was optimally sized to maximise the economic benefit to the DH network, assuming a discount rate of 4% and an investment lifespan of 30 years.

Two main heating technologies were considered for the production of heat. These were large-scale electric boilers and large-scale heat pumps. The assumptions used for modelling these are set out in the Table 3[15]. The thermal storage was modelled as large-scale tank storage to reflect the current thermal storage planned and based on the assessment of space efficiency,

[15] **Danish Energy Agency data with efficiencies corrected for Ireland**

technology readiness, lack of information on specific ground conditions, and cost-effectiveness at the scale required.

Table 3: Assumptions for Heat Production Technologies

	Elec Boiler 2030	ASHP 2030	LT Excess Heat HP 2030	WWTW HP 2030	Seawater HP 2030
Efficiency (annual average)	100%	320%	410%	380%	350%
Technical lifetime (years)	20	25	25	25	25
Space requirement (1,000m2/MW)	0.005	0.6	0.03	0.03	0.03
Allowable turndown (%)	5%	25%	25%	25%	25%
Total Investment (€M/MW)	0.06	0.76	0.57	0.57	0.38
Variable O&M (€/MWh)	1	1.69	2.01	2.01	1.51
Fixed O&M (Annual €/MW)	1,020	2,000	2,000	2,000	4,000

3.3.6 District Heating & Thermal Store Results for 2030 Curtailment Scenario

The heat production equipment was optimally sized to maximise the economic benefit to the DH network assuming a discount rate of 4% and an investment lifespan of 30 years. An hourly model was developed of the heat demand and the availability of curtailed electricity. The utilisation of this curtailed electricity for heat production is shown in green in Figure 9.

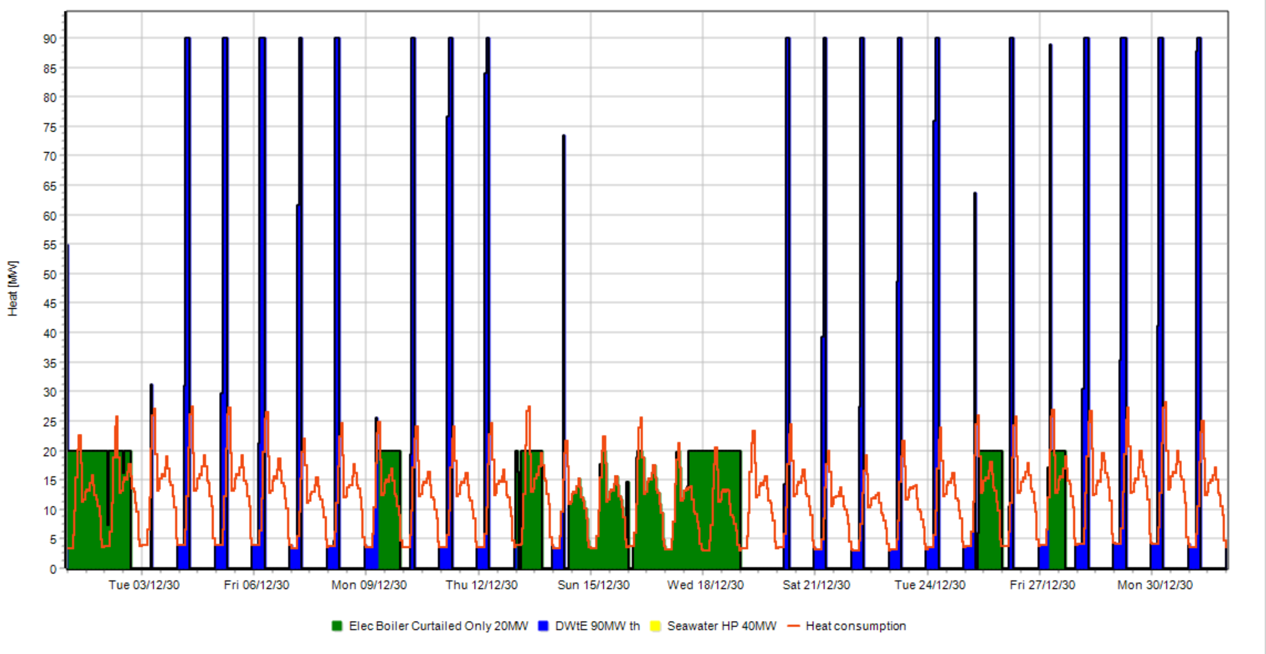


Figure 9: 2030 Heat Production Profile from Curtailed Electricity (green)

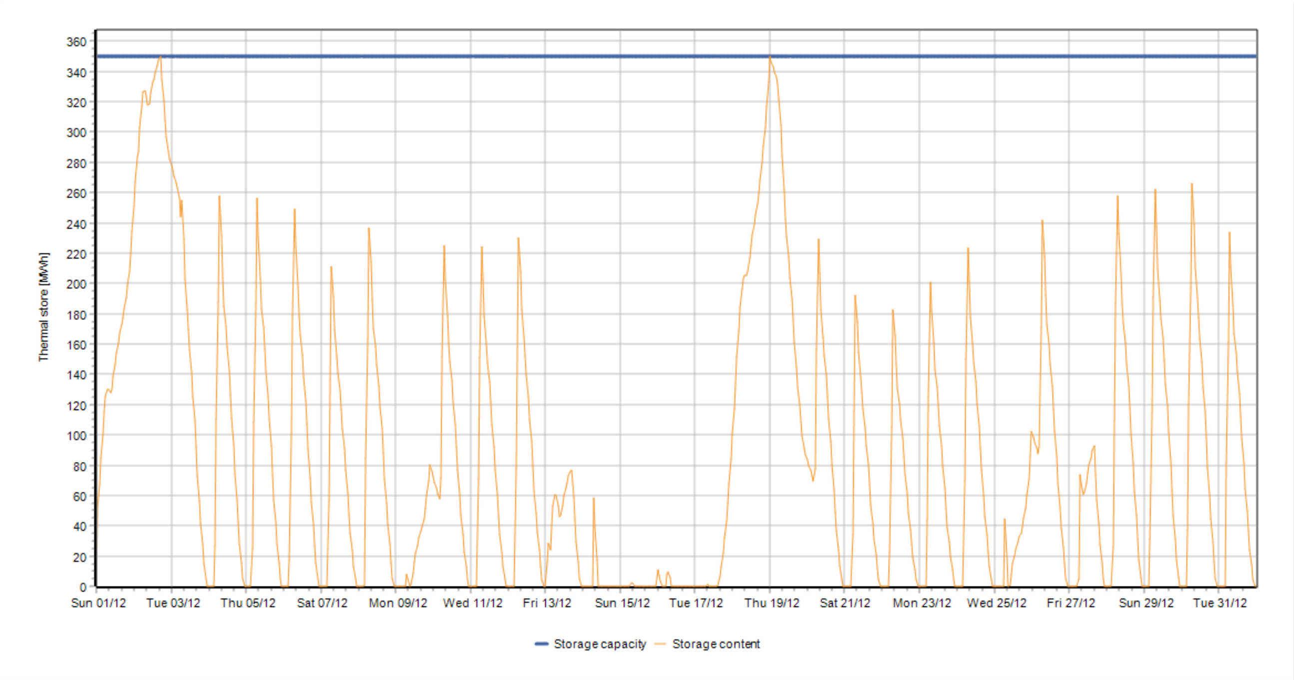


Figure 10: Hourly Energy Model showing Charging and Discharging of Thermal Store 2030

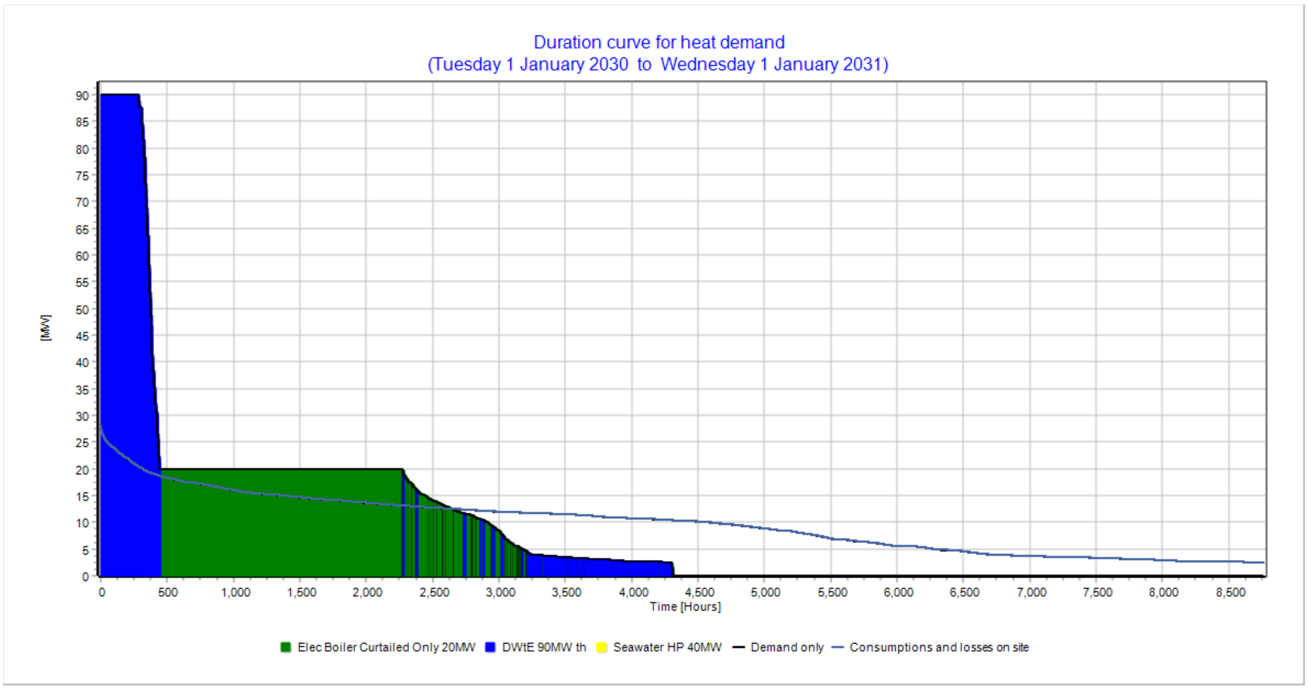


Figure 11: Heat Load Duration Curve from Hourly Model for 2030

For this 2030 curtailment scenario, it can be seen that if the heat production equipment to capture curtailed wind was connected in front of the meter i.e., taking its electricity from the wider grid, then the heat produced was not cost-competitive with the currently proposed main heat supply from the Dublin Waste-to-Energy plant. It should be noted that potential revenues from grid flexibility services were not included in this analysis.

When the heat production equipment was connected behind the meter i.e., directly connected to the offshore wind farm, then heat production was cost competitive with the currently proposed heat supply from the Dublin Waste-to-Energy plant.

Codema analysed 76 sizing scenarios to determine the optimal equipment size to maximise the net present value of the installation. The optimal heat generating and thermal storage combination for this scenario when this curtailed electricity is available for free is to have a 18MW electric boiler connected to 300MWh of thermal storage (this level of thermal storage will already be available on site as it will be initially used to increase the heat captured from the DWtE plant). With this size of plant, 53.2% of the heat demand on the DDHS network could be supplied from curtailed electricity feeding a boiler. This installation would also reduce the curtailed electricity by 2.1% (45.3GWh) in 2030.

Table 4 shows a sensitivity based on the price of the curtailed wind and the discount rate assumed for the cash flow.

Table 4: 2030 District Heat and Storage Analysis Curtailed Electricity Price Sensitivity

2030	**Curtailed Electricity Price (€/MWh)**		
Discount Rate	**0**	**5**	**10**
3%	20MW Boiler & 350MWh TES	12MW Boiler & 10MWh TES	Not Viable
4%	18MW Boiler & 300MWh TES	12MW Boiler & 10MWh TES	Not Viable
5%	14MW Boiler & 80MWh TES	12MW Boiler & 10MWh TES	Not Viable

3.3.7 District Heating & Thermal Store Results for 2040 Curtailment Scenario

The heat production equipment was optimally sized to maximise the economic benefit to the DH network assuming a discount rate of 4% and an investment lifespan of 30 years. An hourly model was developed of the heat demand and the availability of curtailed electricity for the '2040 Scenario 2' study year discussed in section 3.2.1. The utilisation of this curtailed electricity for heat production is shown in green in Figure 12.

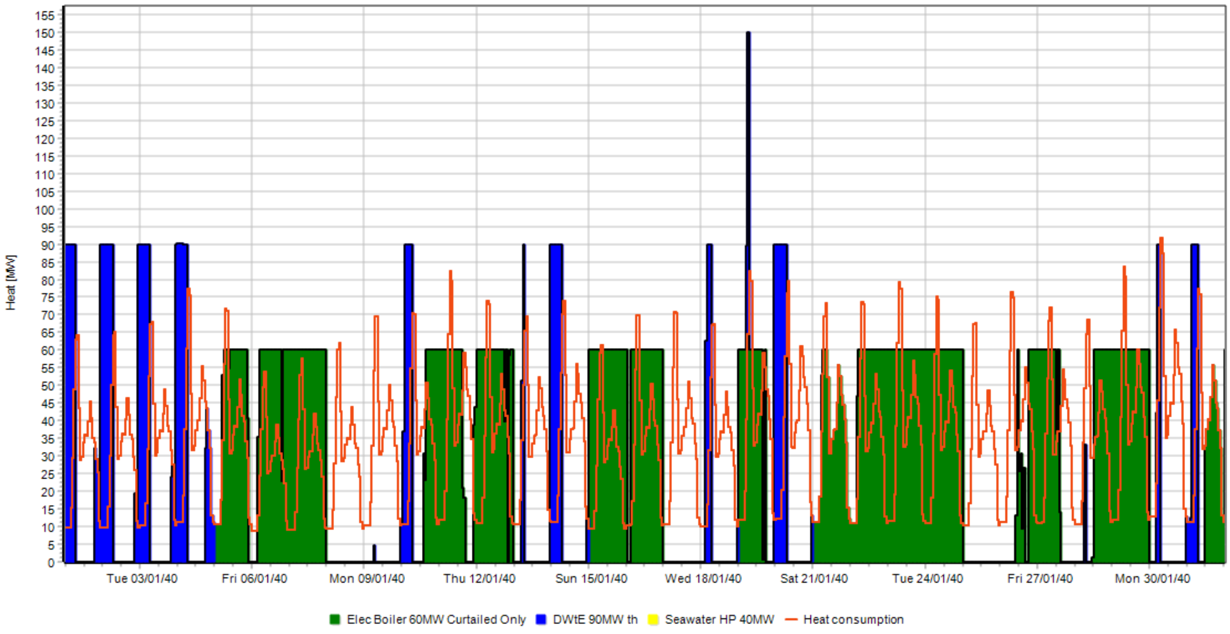


Figure 12: 2040 Heat Production Profile from Curtailed Electricity

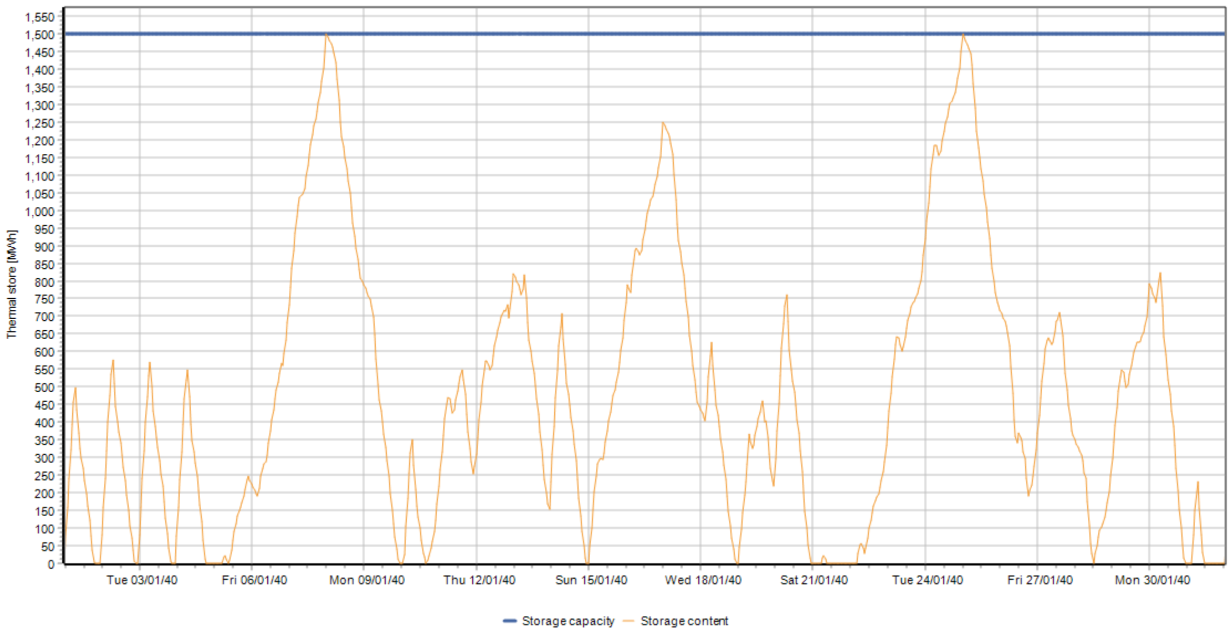


Figure 13: Hourly Energy Model showing Charging and Discharging of Thermal Store 2040

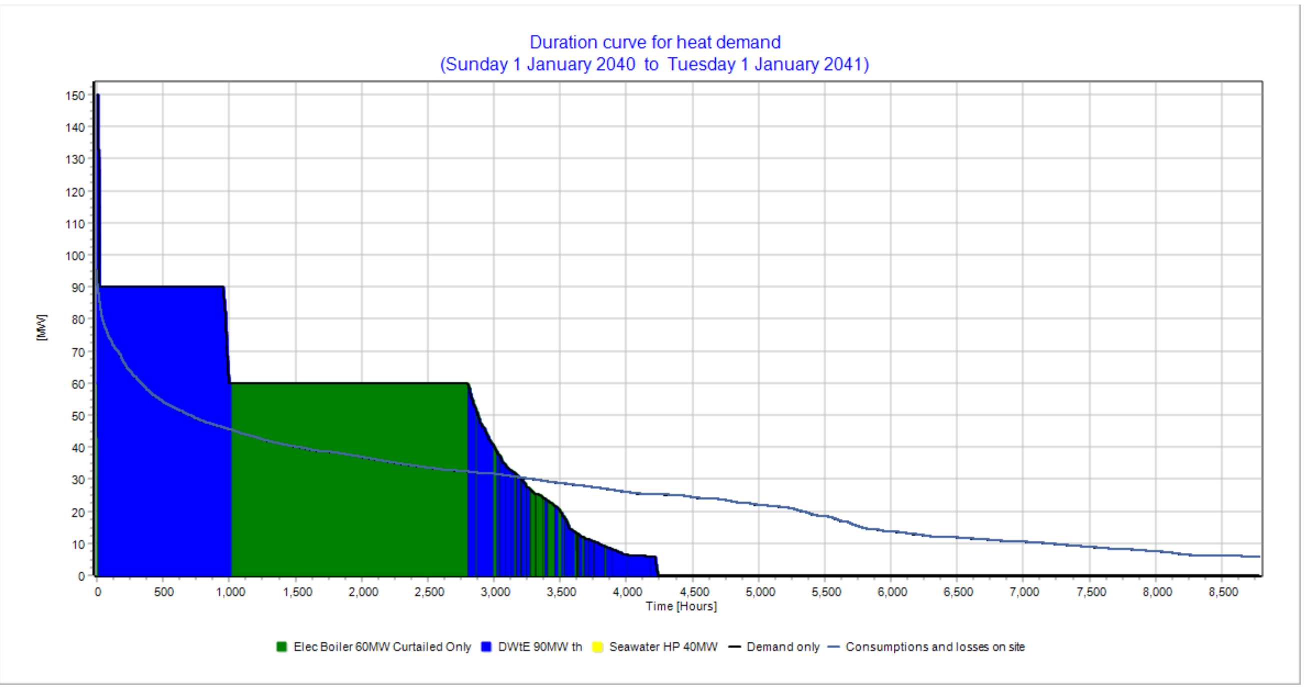


Figure 14: Heat Load Duration Curve from Hourly Model for 2040

For this 2040 (Scenario 2) curtailment scenario it can be seen that if the heat production equipment to capture curtailed wind was connected in front of the meter i.e., taking its electricity from the wider grid, then the heat produced was not cost-competitive with the currently proposed main heat supply from the Dublin Waste-to-Energy plant. It should be noted that potential revenues from grid flexibility services were not included in this analysis.

When the heat production equipment was connected behind the meter i.e., directly connected to the offshore wind farm, and was able to avail of very low electricity prices (see price ranges investigated in Table below) then heat production from either electric boilers or heat pumps was cost competitive with the currently proposed heat supply from the DWtE plant. If these heat production units were connected to the grid and using typical grid electricity prices their heat would not be competitive with heat coming from the DWtE plant and therefore are not considered a viable option as a significant heat supply where DWtE energy can cover the peak demand which is the case in both 2030 and 2040.

Codema analysed 30 sizing scenarios to determine the optimal equipment size to maximise the net present value of the installation based on a discount rate of 4%. The optimal heat generating and thermal storage combination for this scenario when this curtailed electricity is available for free is to have a 60MW electric boiler connected to 1,500MWh of thermal storage. This level of thermal storage was limited by the assumed land availability. With this size of plant, 58% of the heat demand on the DDHS network could be supplied from curtailed electricity feeding a boiler. This installation would also reduce the curtailed electricity by 8.6% (132.8GWh) in 2040.

Table 5 shows a sensitivity based on the price of the curtailed wind and the discount rate assumed for the cash flow.

Table 5: 2040 District Heat and Storage Analysis Curtailed Electricity Price Sensitivity

2040	**Curtailed Electricity Price (€/MWh)**		
Discount Rate	**0**	**5**	**10**
3%	60MW Boiler & 1500MWh TES	30MW Boiler & 100MWh TES	Not Viable
4%	60MW Boiler & 1500MWh TES	30MW Boiler & 100MWh TES	Not Viable
5%	50MW Boiler & 800MWh TES	30MW Boiler & 100MWh TES	Not Viable

3.3.8 District Heating & Thermal Store Results for DH Networks with Total Heat Demand of 2.7TWh

The heat production and storage equipment were sized using Codema's experience of sizing electrically heated DH networks for feasibility studies in the Dublin region. The thermal store was sized to utilise off-peak electricity rates. This model gives an indication of the national potential for curtailment of electricity using DH. An example scenario for the utilisation of this curtailed electricity for heat production (using the 2030 combined curtailment profile) is shown in green in Figure 15 and a summary of the contribution of 2.7TWh of DH to reducing curtailment for all curtailment scenarios can be seen in Table 6.

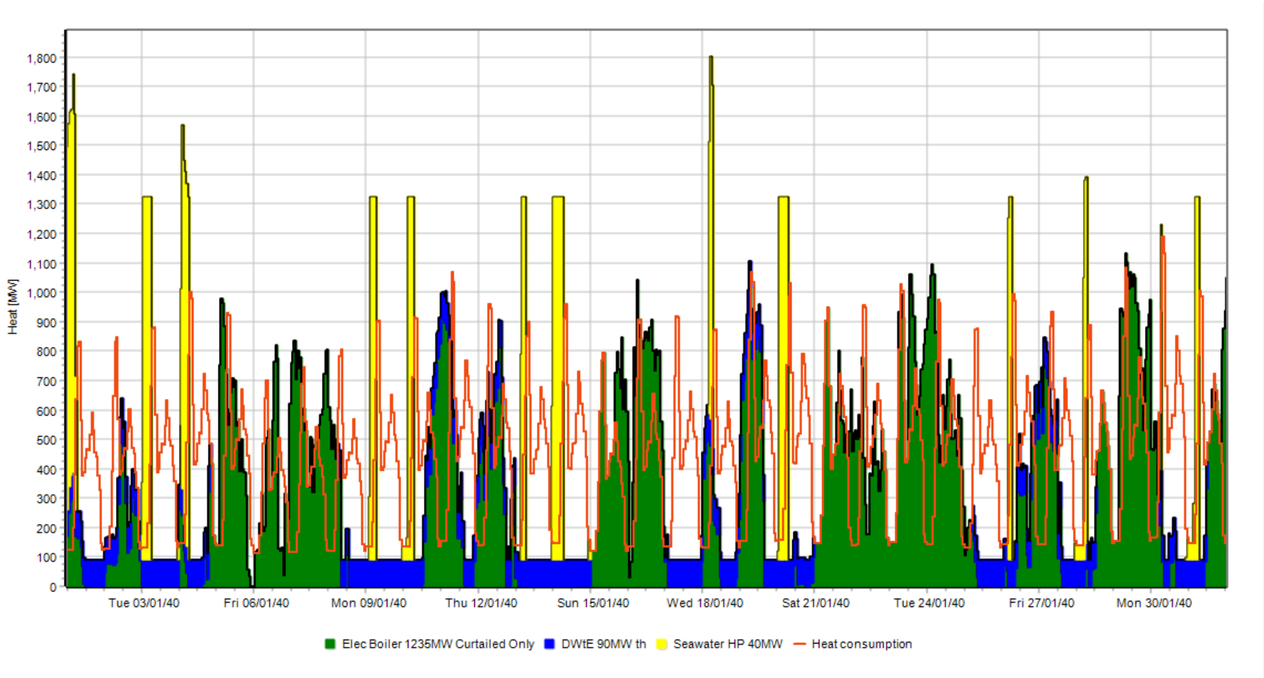


Figure 15: National Heat Production Profile for 2.7TWh Demand, from 2030 Curtailed Electricity Profile

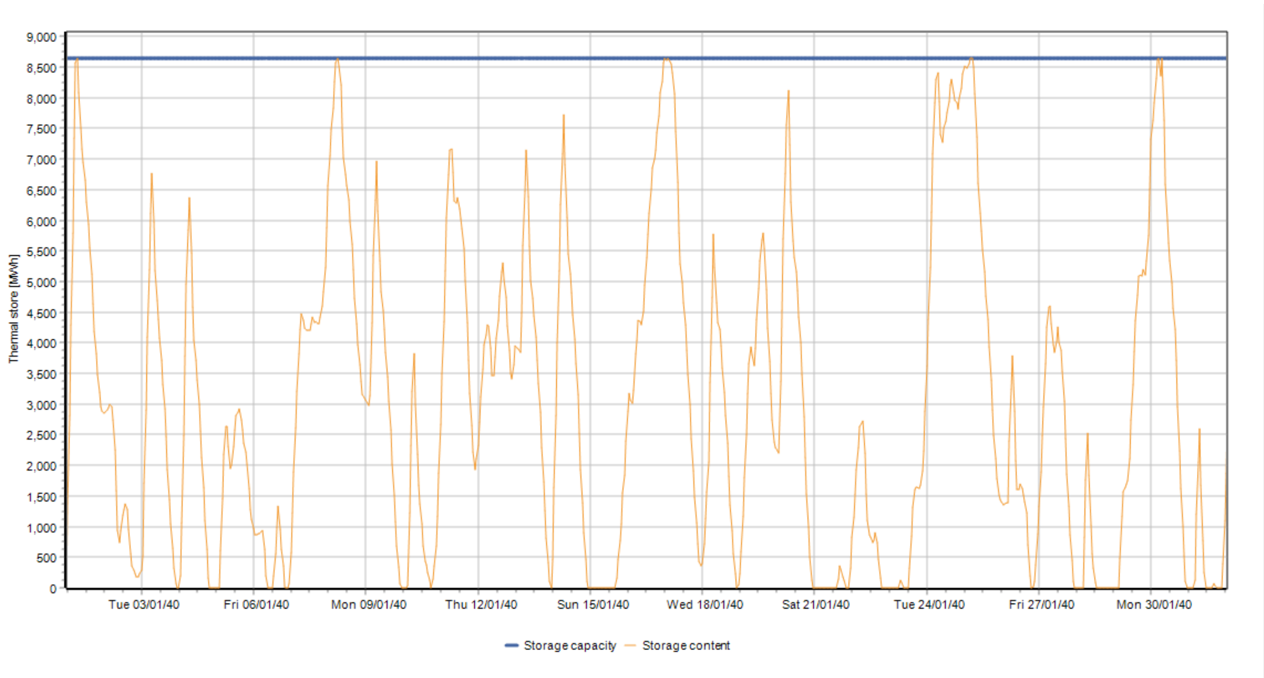


Figure 16: Charging and Discharging of Thermal Store for National DH Target of 2.7TWh in 2030 Scenario

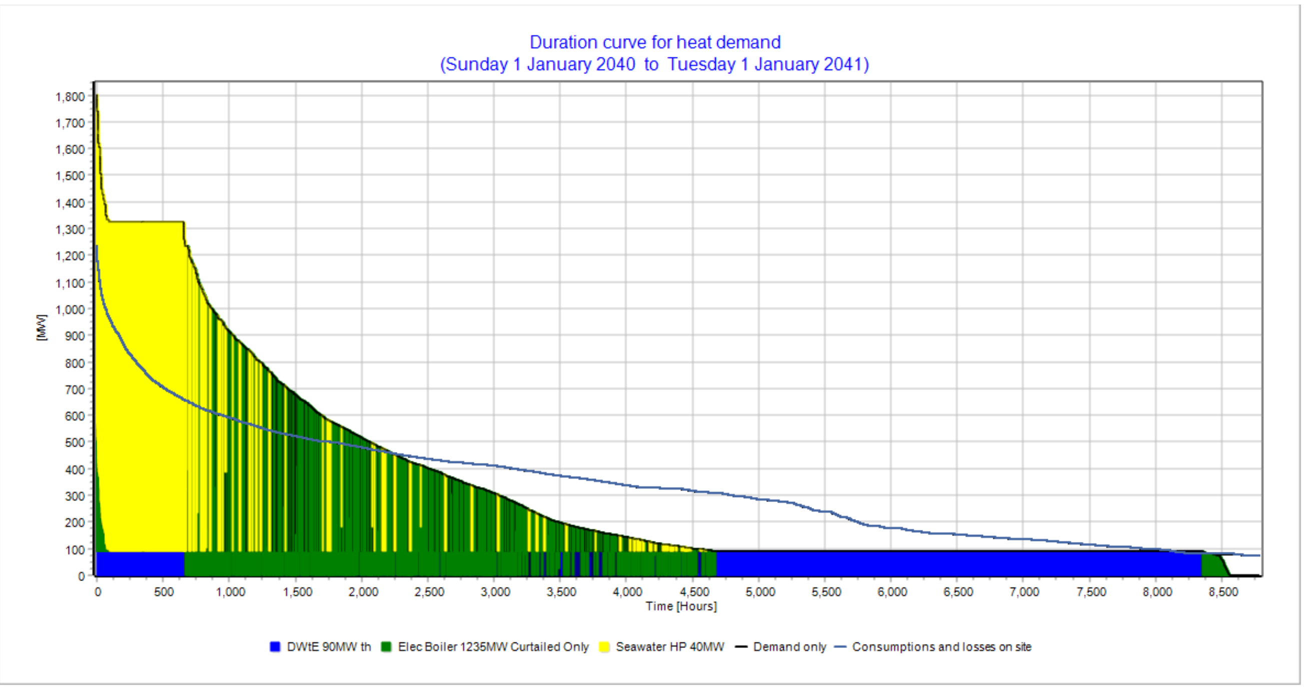


Figure 17: Heat Load Duration Curve for 2.7TWh DH Target in 2030

Table 6 shows that 2.7TWh of DH that has electric boilers could reduce curtailment by between 70% and 86%. This analysis assumes a very low electricity price within these periods that would make the heat production cost competitive with other forms of heat generation, specifically the waste heat from the DWtE plant.

Table 6: Impact of 2.7TWh District Heat Demand from Electric Boilers on Curtailment for 2030 and 2040

Curtailment Scenario	Curtailed Electricity (MWh)	Curtailed Electricity Absorbed by DH (MWh)	% Utilised
2030 Combined Oversupply & Constraint	2,150,164	1,501,865	70%
2030 S2	1,386,406	1,193,728	86%
2040 S1	1,675,727	1,217,861	73%
2040 S2	1,545,992	1,163,678	75%

If the DWtE plant and heat pumps were to be used (i.e. no electric boilers were installed) the following curtailment reductions of 24-34% may be achievable from 2.7TWh of DH, see Table 7. These results assume a heat pump COP of 3.5; this is based on the utilisation of a mixture of heat sources such as air, water, seawater, low-grade waste heat. It can be seen that the capacity to reduce curtailment is reduced in this scenario due to the higher efficiency of the HPs.

Table 7: Impact of 2.7TWh District Heat Demand from Heat Pumps & DWtE Waste Heat on Curtailment for 2030 and 2040

Curtailment Scenario	Curtailed Electricity (MWh)	Curtailed Electricity Absorbed by DH (MWh)	% Utilised
2030 Combined Oversupply & Constraint	2,150,164	526,569	24%
2030 S2	1,386,406	471,418	34%
2040 S1	1,675,727	430,058	26%
2040 S2	1,545,992	417,800	27%

3.3.9 Electrolyser Waste Heat Assumptions

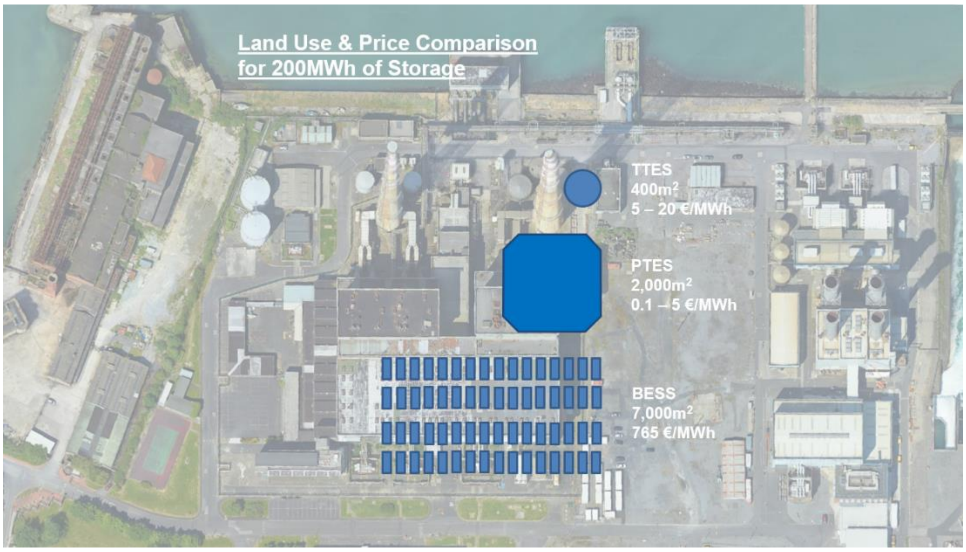
From research it was found that the stack temperature for Alkaline and PEM Electrolysers have ranges of 60-100°C and 50-90°C, respectively. For this analysis a specific Alkaline electrolyser was chosen, which was estimated to heat the cooling liquid to 74°C. Assuming that the DH network would be weather compensated (supply temperature requirement reduces with increases in ambient/outdoor temperature) no additional temperature lift would be required for the DH supply for 60% of the year. For the remaining hours of the year the average temperature required is 76.7°C (i.e., an average 2.7°C increase above the stack cooling liquid temperature).

3.3.10 Thermal Energy Storage Comparison

In this section of the report, eight forms of thermal energy storage were compared as part of this analysis. Details of typical utility scale Battery Energy Storage Systems were also included for comparison. This comparison can be seen in the table on the next page.

The main findings from this comparison are:

- Large-scale thermal storage of the size currently being developed in Dublin is in the range of 0.65% - 4.4% of the cost of equivalent size (MWh) utility scale battery energy storage systems.
- Thermal storage solutions have a much lower land take per kWh of storage provided compared with battery energy storage systems (BESS). This can be seen in the figure below where large-scale tank thermal energy storage (TTES), pit thermal energy storage (PTES) and large-scale batteries[16] are compared. Some of this is down to the shape of thermal storage compared with battery storage. TES being tall and narrow due to design advantages of having a height to diameter ratio of 1.5:1 or more. There may also be options for BESS to stack units to make better use of land, particularly in urban environments where space is at a premium.
- Thermal storage has a lifespan (up to 50 years+) that far exceeds battery storage systems (typically in the 5 -15 year range) and experiences comparatively little degradation over its life compared with batteries.



The table below provides a comparison of eight thermal storage systems and battery energy storage systems. It can be seen from this table that the battery systems are more expensive

[16] **Based on land take for 150MWh BESS system currently in planning in the Poolbeg area - https://epawebapp.epa.ie/licences/lic_eDMS/090151b2807aca75.pdf**

than thermal energy storage, require significantly less space, use less resources (specifically rare earth metals, metals, polymers, and chemical used as electrolyte) in their production (majority of TES being water which is reused within a close system), have a much longer lifespan and comparatively low levels of degradation over time. Thermal storage also provides storage over longer durations typically between seconds and days in terms of duration and seasonally in the case of pit, borehole or aquifer TES. The main advantage of battery storage is that the energy stored as electricity as opposed to heat and that in general it charges with a response time that is in the milliseconds as opposed to seconds for the thermal store to charge at full capacity (however the ramp down response is the same for both).

Table 8: Energy Storage Technology Comparison Table

w	Cost (€/kWh)	Assumed size for costing (MWh)	Land take (m2/MWh)	Response time	Storage durations suitability (s/h/d/m)	Efficiency (%)	Typical temperature / exergy level	Typical storage temp range	Lifespan (years)	Delivery complexity in Poolbeg	Pros	Cons
Large-scale tank storage	5 - 20	15 - 366	2 - 7	generally miliseconds load-off, seconds load-on (depends on plant & controls)	s - d	50 - 90	low	65 - 95	>50	low	- Highly reliable and well understood technology	
Phase-change material	10 - 50 (theoretical)	(Not available at scale)	1 - 2 (assuming same delta-T and height can be achieved as tank storage)	generally miliseconds load-off, seconds load-on (depends on plant & controls)	s - d	75 - 90	low	expected to be similar to tank storage	unknown	high	- Smaller volumetric size per kWh of storage when assuming the same delta-T can be achieved - Can be shaped in a rectangular footprint to make better use of land space	- Currently result in small dT making it less suitable for heating - Self-weight of spheres might limit height leading to higher land take - low TRL - Higher up front cost than other TES options
Building thermal mass & HW Cylinder	0	dependent on buildings connected	0 (no additional land take as using existing infrastructure)	generally miliseconds load-off, seconds load-on (depends on plant & controls)	s - h	Varies	low	<21	>50	med	- Low cost solution (only cost of controls) - No additional space requirement for storage from a DH perspective	- Lower efficiency when considering the volume to surface area ratio and uncertainty around how much of heat stored is usable heat - More individual controls required adding certain cost and complexity - Less stratification which can lead to lower efficiency - Smaller delta-T compared with large tanks so kWh/m3 is lower due to use of heating coils for heat transfer
Existing underground storage retrofit e.g. old large-scale underground oil tanks)	cost of diffuser only		0 (no additional land take as using existing infrastructure)	generally miliseconds load-off, seconds load-on (depends on plant & controls)	s - d	50 - 90	low	65 - 95	>50	low	- Low cost (uses existing structures/only requires diffusers) e.g. underground oil storage or caisson cooling water pump house & culvert structures of power plants	- Need to have existing structure in proximity of DH network
Aquifer thermal energy storage	1.3 - 2	500 - 5000	neglegible	generally miliseconds load-off, seconds load-on (depends on plant & controls)	s - m	50 - 90	low	5 - 20 (can go above 60)	>30	high	- Negligible land take - Can be used for seasonal storage	- Needs specific ground conditions (aquifer with clay cover)
Pit thermal energy storage	0.1 - 5	60 - 12,500	5 - 15 (assuming 10m deep for a 10,000m3 store, 10m wall thickness & slope, and reduced dT by 20C)	generally miliseconds load-off, seconds load-on (depends on plant & controls)	s - m	50 - 90	low	15 - 95	>50	high	- Allows for seasonal storage of energy - Very cost effective at large scale	- Generally requires temperature boost when using heat as stored at lower temp
Borehole thermal energy storage	1 - 2	300 - 600	neglegible for deep boreholes. Greater space required for shallow boreholes	generally miliseconds load-off, seconds load-on (depends on plant & controls)	s - m	50 - 90	low	15 - 90	>30	med/high	- Negligible land take - Can be used for seasonal storage	
Molten salt	10 - 100	unknown	unknown	generally miliseconds load-off, seconds load-on (depends on plant & controls)	s - d	40 - 93	med	200 - 800	unknown	high	- Stores at high temperature - Can be converted back into elelctricity	- Low TRL
Battery energy storage	765	100	35 - 45	miliseconds	s - d	80 - 96 (but degrades over time)	n/a	n/a	5 - 15	high	- Higher exergy (electricity stored as electricity)	- Degrades over time - High cost compared with thermal storage

Storage comparison table [17], [18], IF Technologies, Codema cost research

[17] https://tracer-h2020.eu/wp-content/uploads/2019/10/TRACER_D2.1-Heat-Storages.pdf

[18] https://www.sciencedirect.com/science/article/pii/S2352152X22017042

3.4 Green Hydrogen 2030 and 2040

3.4.1 Green Hydrogen Production Scenarios

The following sections of the report discuss the various hydrogen production scenarios modelled. Table 9 outlines the hydrogen production scenarios and the requirements and connection timelines based on the Additionality Delegated Act.

Table 9: Hydrogen Production Scenarios Description, Additionality Delegated Act Requirements

Scenario	Electricity Generation Source	Additionality Delegated Act		
		Configuration	Requirements	Timeline
Grid Connected High RES-E	System wide wind and solar generation	grid connection	>90% RES-E production hours determined by the share of RES-E.	2030+
Offshore Wind Off Grid	2GW offshore wind farm	direct line		Pre 2030
System Wide VRES Curtailment	System wide curtailed wind and solar generation	grid connection	renewable electricity consumed must be during an imbalance settlement evidence that hydrogen producer reduced the need for re-dispatching renewable generation downwards by a corresponding amount	Pre 2030
Offshore Wind Dispatch Down	Poolbeg connected dispatched down offshore wind generation.	grid connection	renewable electricity consumed for this scenario must be during an imbalance settlement evidence that hydrogen producer reduced the need for re-dispatching renewable generation downwards by a corresponding amount	Pre 2030
Offshore Wind and Solar PPA	Poolbeg connected offshore wind generation and a PPA solar capacity matching electrolyser capacity.	grid connection	The share of electricity on the Irish electricity system would need to be in excess of 90% RES-E and the number of production hours determined by the share of RES-E: OR Electricity produced under a renewable power purchasing agreement (PPA) and complies with 'temporal' and 'spatial' correlation requirements. The emission intensity of electricity system must also be lower than 18 g CO2eq/MJ.	2030+

Grid Connected High RES-E

Figure 18 presents a schematic of hydrogen production scenario 'Grid Connected High RES-E', which represents base load operation of the hydrogen production facility. All system wide offshore wind, onshore wind and solar generation was assumed to be available for hydrogen production.

The 'Grid Connected High RES-E' scenario falls under the 'grid connection' configuration of the Additionality Delegated Act discussed in section . To comply with the Delegated Act, the share of electricity on the Irish electricity system would need to be in excess of 90% RES-E and the number of production hours determined by the share of RES-E.

To operate the electrolyser with a 95% capacity factor, the share of renewable electricity in Ireland would be required to be at least 95%. Considering the current target of 80% RES-E in 2030, it appears unlikely that this scenario will align with the Additionality Delegated Act until after 2030 and only after Ireland has connected further renewable generation capacity from new onshore wind, solar and offshore wind capacity to move towards 100% RES-E. However, it is noted that the individual sectoral targets in the 2023 Climate Action Plan for offshore wind, onshore wind and solar cumulatively exceed 80%.

This scenario demonstrates the benefit of green hydrogen production to the wider electricity system in terms of curtailment mitigation and also the benefit to the electrolyser having a high-capacity factor (assumed to have access to all available offshore wind, onshore wind and solar generation connected onto the electricity system). This scenario does not account for local supply constraints on the electricity network in Poolbeg. At times of low renewable output, it is likely that there will be constraints on the electricity supply for the electrolyser considering the large existing industrial, commercial and residential sectors in the area that are fed from the local 110kV and 220kV networks. The electricity demand in Poolbeg and the wider Dublin area is likely to grow as electrification is rolled out in the heat and transport sectors. Constructing new substations and cables will likely be required to facilitate this demand growth but this could be particularly challenging in the Dublin urban area given the scale of the new infrastructure required and the existing congestion of utility services in roads.

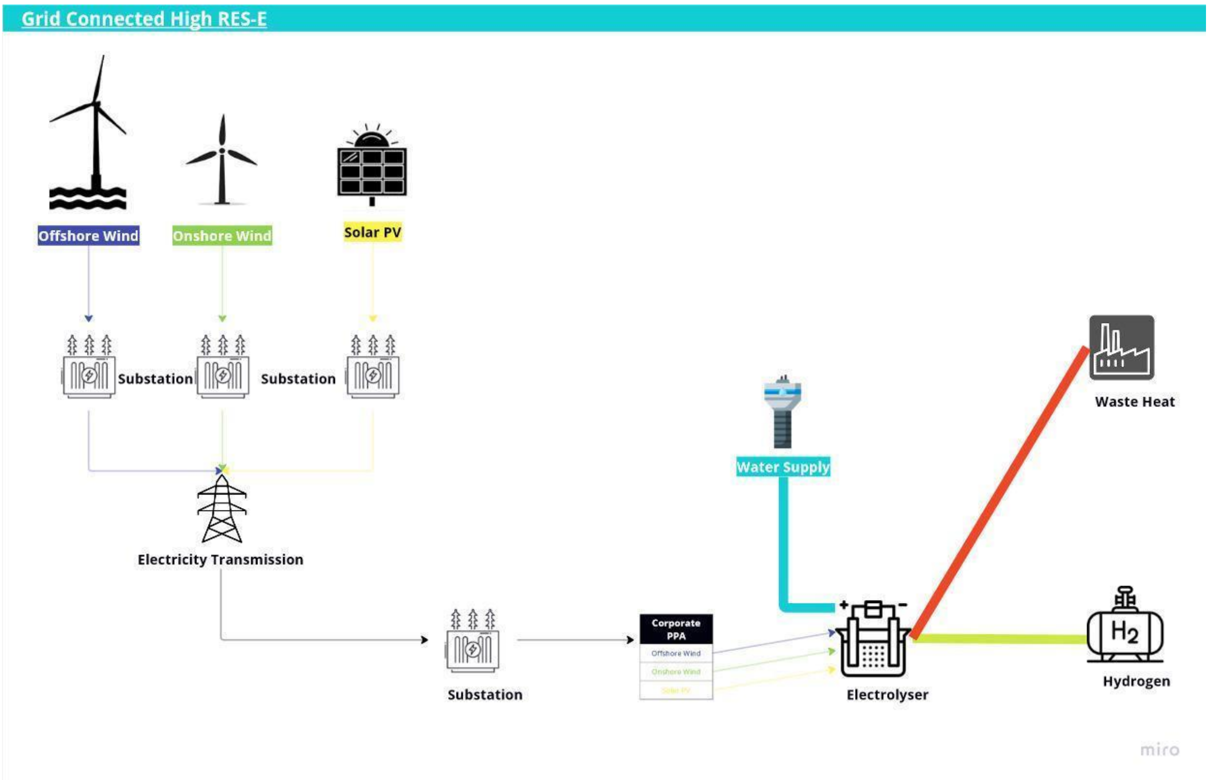


Figure 18: Hydrogen Production 'Grid Connected High RES-E' Scenario Schematic

The load duration curve associated with the 'Grid Connected High RES-E' configuration is presented in Figure 19 for the 2030 and 2040 hourly generation profiles. For all of the generation profiles modelled, the load duration curve indicated at least 2GW of renewable electricity available for around 90% of the year, with more than 400MW available for approximately 99% of the year.

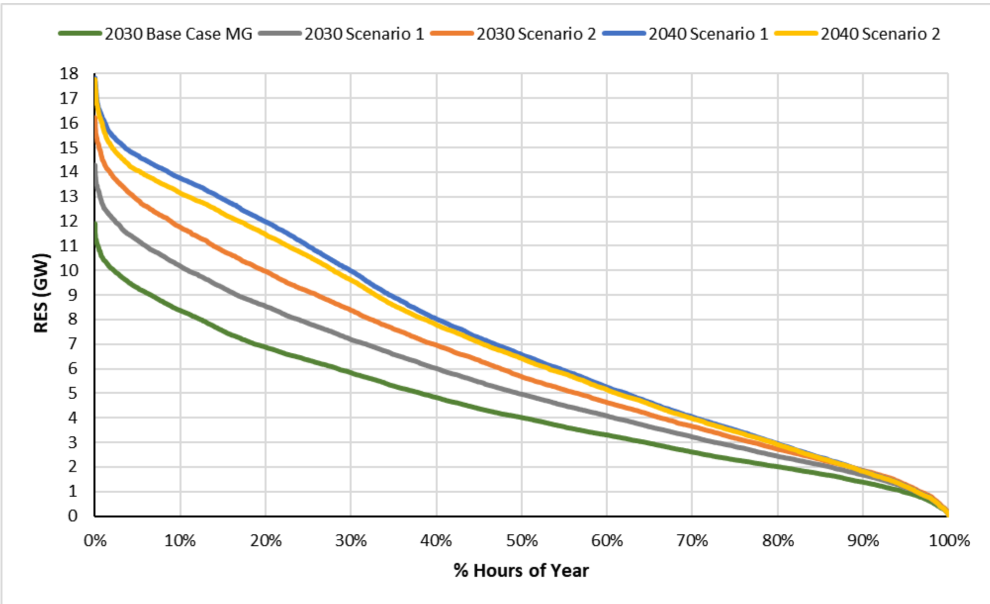


Figure 19: Hydrogen Production 'Grid Connected High RES-E' Scenario Load Duration Curve

Offshore Wind Off Grid

Figure 20 demonstrates hydrogen production scenario 'Offshore Wind Off Grid'. This scenario considers hydrogen production via a direct connection to an offshore wind farm without the need for a grid connection to the electricity system.

The 'Offshore Wind Off Grid' scenario aligns with the 'direct line' configuration from the Additionality Delegated Act discussed in section 1.a.v. This configuration could be implemented immediately but ultimately will be dependent on low-cost offshore wind capacity to provide a viable business case. This scenario could benefit an offshore wind farm that has limited available export capacity on the electricity grid and therefore requires an alternative route to market.

In addition, repetitive cold starts and dynamic operation from a wind farm may negatively impact stack lifetime for the electrolyser. For small scale electrolysers in the kW scale, there is a minimum power requirement of 10-20% of the nominal capacity. For larger scale electrolysers in the MW range, this percentage can reduce to 2% with modular MW stacks[19].

Current connection policy for offshore windfarms in Ireland is that the connection point is offshore and the transmission infrastructure from the offshore windfarm to the onshore point of connection onto the onshore transmission grid will be owned by EirGrid as the Offshore Transmission Asset Owner. The 'Offshore Wind Off Grid' production scenario assumes that the offshore windfarm is connected directly to the Electrolyser, behind any connection point. This could potentially be considered a private network, currently not allowed under Irish connection policy. Facilitating the direct connection of hydrogen electrolysis facilities, assuming an onshore location, may require the development of additional connection policy.

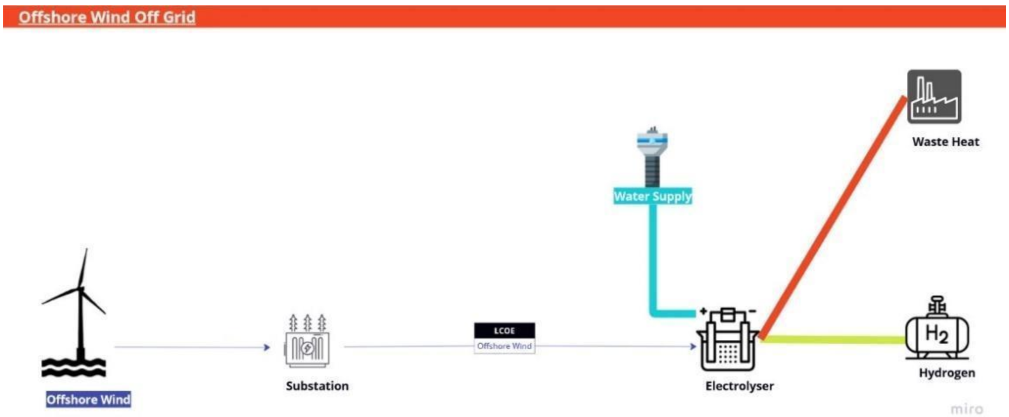


Figure 20: Hydrogen Production 'Offshore Wind Off Grid' Scenario Schematic

19 https://www.sciencedirect.com/science/article/pii/S0360319919319482

Figure 21 shows the load duration curve associated with the hourly generation profile modelled for the 'Offshore Wind Off Grid' production scenario. The graph indicates at least 1GW of renewable electricity available for around 40% of the year, with more than 400MW available for approximately 70% of the year.

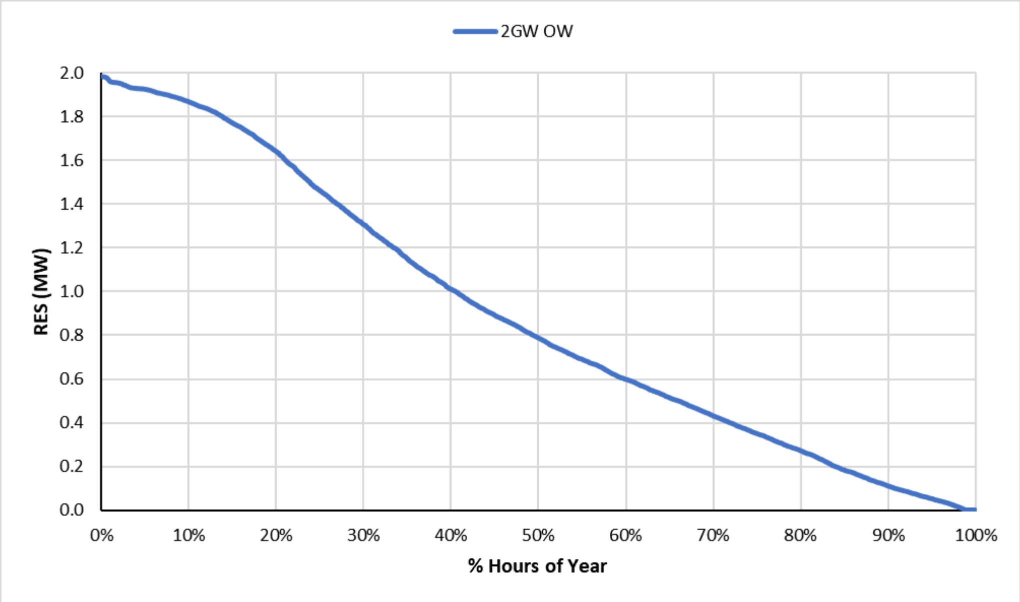


Figure 21: Hydrogen Production 'Offshore Wind Off Grid' Scenario Load Duration Curve

System Wide VRES Curtailment

Figure 22 illustrates hydrogen production scenario 'System Wide VRES Curtailment' where the electrolyser is fed from system wide curtailed wind and solar generation.

The 'System Wide VRES Curtailment' aligns with the 'grid connection' configuration from the Additionality Delegated Act discussed in the literature review section. The renewable electricity consumed for this scenario must be during an imbalance settlement where the fuel producer can demonstrate, based on evidence from the TSO that the hydrogen producer reduced the need for re-dispatching renewable generation downwards by a corresponding amount. This scenario could be applied immediately considering the EU rules and definitions.

This scenario demonstrates the benefit of green hydrogen production to the wider electricity system as a curtailment mitigation measure. The electrolyser is assumed to have access to all curtailed offshore wind, onshore wind and solar generation connected onto the electricity system and does not account for local supply constraints on the electricity network in Poolbeg and the wider Dublin area. The electrolyser would essentially become a large demand user and therefore compete for demand capacity in Dublin, on an increasingly constrained transmission and distribution network due to growing electricity demand.

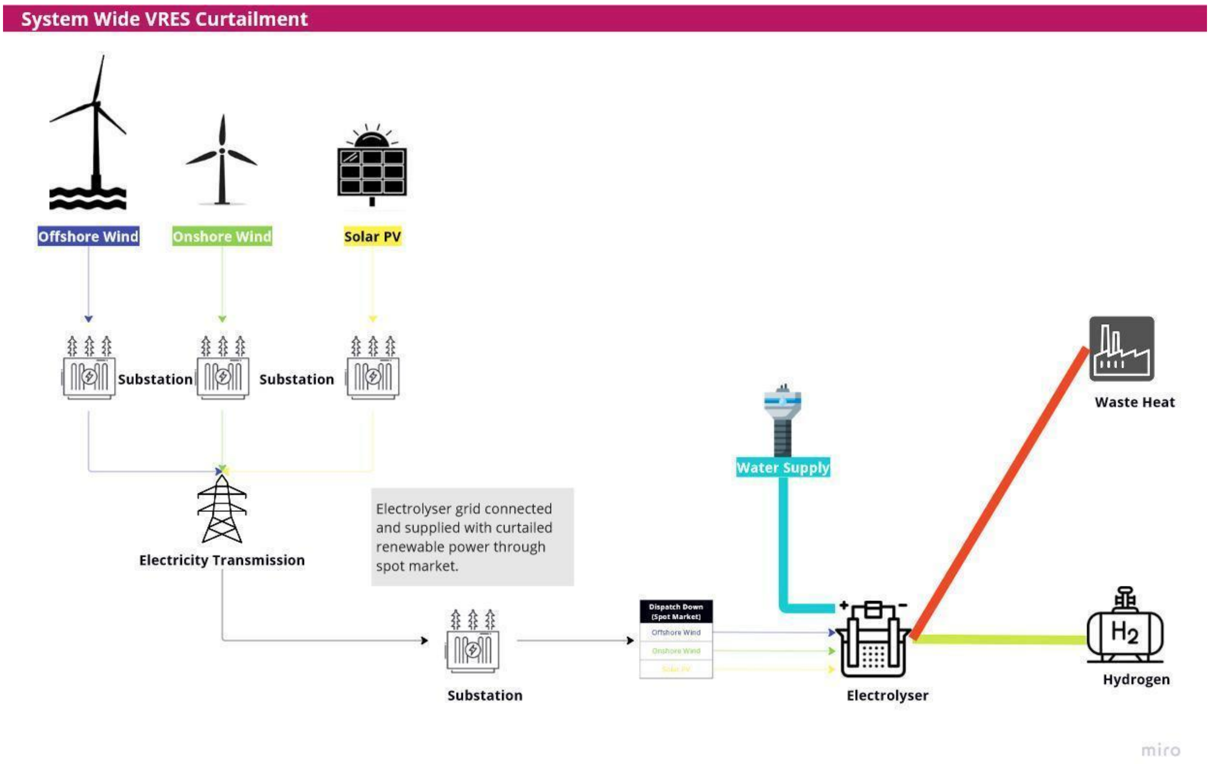


Figure 22: Hydrogen Production 'System Wide VRES Curtailment' Scenario Schematic

There is a large element of risk associated with a business model for a hydrogen production facility based on using curtailed electricity only. This is due to curtailment being extremely variable and difficult to predict year on year. The level of dispatch down available to the electrolyser is also dependent on a wide range of factors including the growth of demand, growth of renewables, the operation of interconnection, the delivery of system and network reinforcements and also potential competing dispatch down mitigation measures such as flexible demand. The aforementioned factors are outside the control of the developer of the hydrogen facility.

The load duration curves for the 2030 and 2040 hourly system wide curtailed generation profiles are shown in Figure 23. Analysing the graph, a significant variation may be observed in relation to the volume of renewable electricity available for the 2030 and 2040 scenarios. It appeared that at least 2GW was available across all of the 2030 and 2040 scenarios for 7-29% of the year. The highest frequency of time where at least 2GW curtailed electricity was available for hydrogen production was for '2030 Scenario 2'.

Taking 400MW capacity, it appeared that this capacity of renewable generation was available for 20-42% of the year. Similarly, the highest frequency for which at least 400MW curtailed electricity was available was for ‘2030 Scenario 2’.

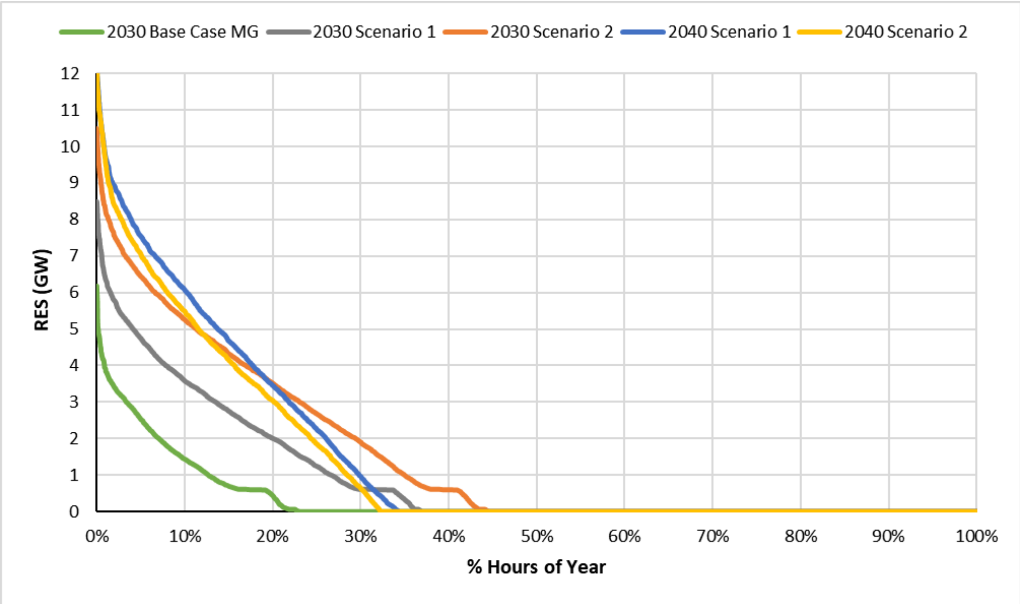


Figure 23: Hydrogen Production ‘System Wide VRES Curtailment’ Scenario Load Duration Curve

Offshore Wind Dispatch Down

Figure 24 shows hydrogen production scenario ‘Offshore Wind Dispatch Down’ where the electrolyser is fed from dispatched down (curtailed and constrained) offshore wind generation connected at Poolbeg.

The ‘Offshore Wind Dispatch Down’ scenario works under the ‘grid connection’ configuration from the Additionality Delegated Act discussed in the literature review section 1.a.v. The renewable electricity consumed for this scenario must be during an imbalance settlement where the fuel producer can demonstrate, based on evidence from the TSO that the hydrogen producer reduced the need for re-dispatching renewable generation downwards by a corresponding amount. This scenario could be applied immediately considering the EU rules and definitions.

This scenario demonstrates the benefit of green hydrogen production to the local electricity network in Poolbeg in terms of a dispatch down mitigation measure. This scenario accounts for the local conditions on the electricity network in Poolbeg.

Similar to the ‘System Wide VRES Curtailment’ scenario, there is a large element of risk associated with a business model for a hydrogen production facility based on using curtailed electricity only due to its variability by nature. In this scenario, the risk is higher as the volume of dispatched down electricity is much lower and only considers the offshore wind capacity planning to connect at Poolbeg.

The benefit of this configuration is that as both the offshore wind farm and the electrolyser are connected at Poolbeg, meaning there will be less network capacity constraints for other electricity demand customers in the Dublin area. Further engagement will be required with EirGrid and ESB networks on the connection method of the electrolyser in Poolbeg, but this will require further work to firstly determine the proposed scale and location of the electrolyser.

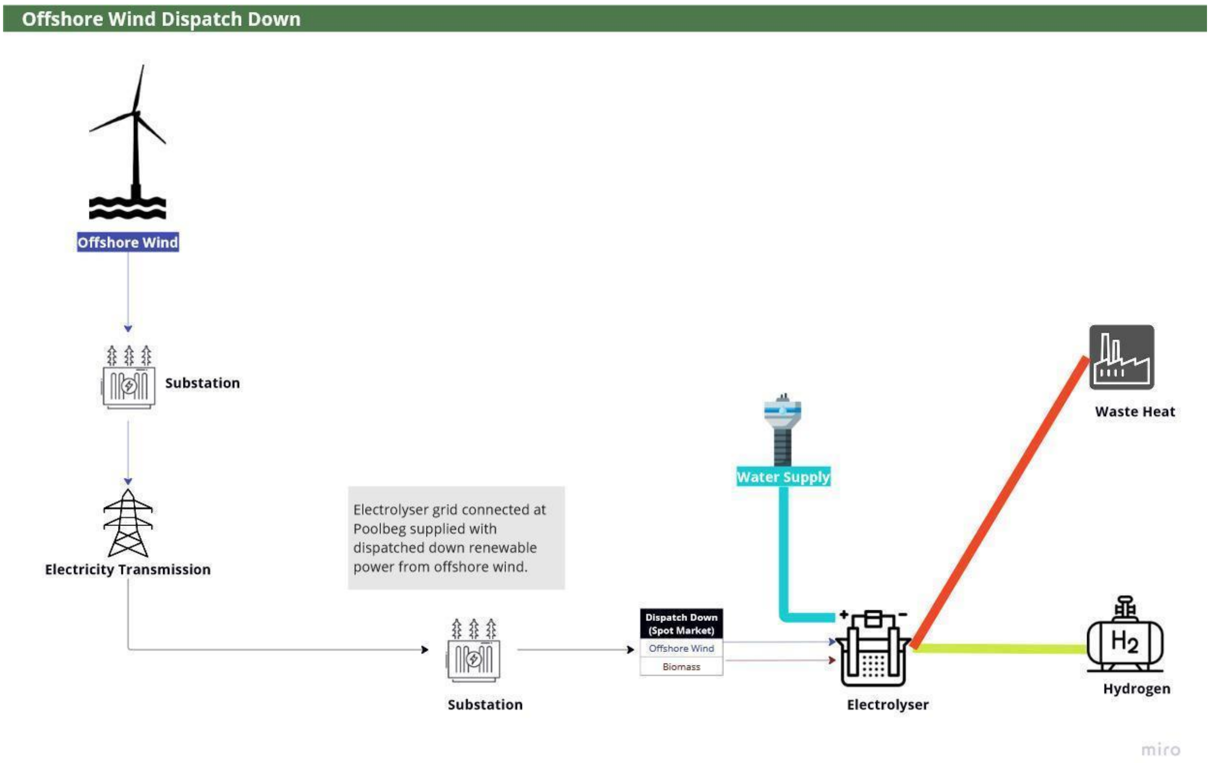


Figure 24: Hydrogen Production 'Offshore Wind Dispatch Down' Scenario Schematic

The load duration curves for the 2030 and 2040 Poolbeg dispatch down generation profiles are shown in Figure 25. As was the case for the 'System Wide VRES Curtailment' scenario, a significant variation may be observed in relation to the volume of renewable electricity available for the 2030 and 2040 scenarios. It appeared that at least 400MW was available across all of the 2030 and 2040 scenarios for 12-26% of the year. The highest frequency of time where at least 400MW curtailed electricity was available for hydrogen production was for '2030 Scenario 2'.

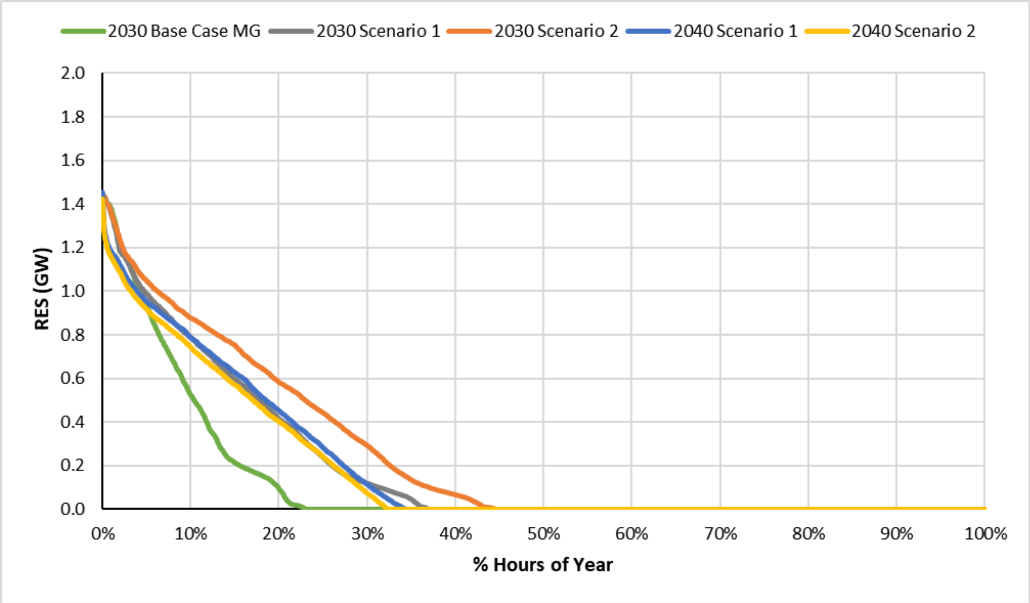


Figure 25: Hydrogen Production 'Offshore Wind Dispatch Down' Scenario Load Duration Curve

Offshore Wind and Solar PPA

Figure 26 presents hydrogen production scenario 'Offshore Wind and Solar PPA'. This scenario considers hydrogen production from all offshore wind electricity generated at Poolbeg and also from solar generation via a PPA with a grid connection to the wider transmission system. The capacity of the solar farm is matched with the electrolyser for this scenario.

In order to comply with the 'grid connection' configuration of the Additionality Delegated Act, then one of the following criteria must be complied with:

- The share of electricity on the Irish electricity system would need to be in excess of 90% RES-E and the number of production hours determined by the share of RES-E, or;
- Electricity produced under a renewable power purchasing agreement (PPA) and complies with 'temporal' and 'spatial' correlation requirements. The emission intensity of electricity system must also be lower than 18 g CO_2eq/MJ.

Therefore, the 'Offshore Wind and Solar PPA' scenario could potentially be deployed in 2030 provided the emission intensity of the Irish electricity system is less than 18 g CO_2eq/MJ, otherwise it would likely be deployed in a 2035-2040 timeframe when the share of renewable electricity is higher than 90%.

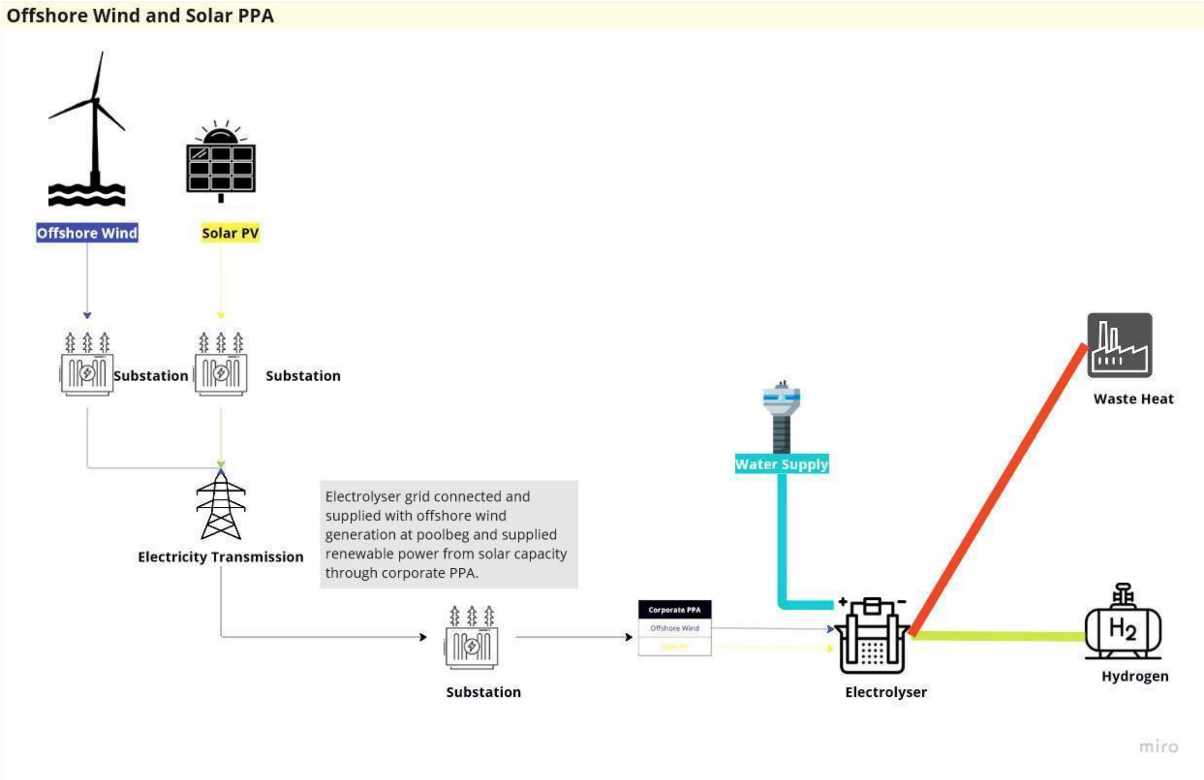


Figure 26: Hydrogen Production 'Offshore Wind and Solar PPA' Scenario Schematic

This scenario allows for a higher capacity factor on the hydrogen plant compared to the 'Offshore Wind Off Grid' production scenario. However, similar to the production configurations 'Grid Connected High RES-E' and 'System Wide VRES Curtailment', this scenario does not account for local supply constraints on the electricity network in Poolbeg and the wider Dublin area and it may not be technically feasible at times to import the solar generation through a PPA given the large existing electricity demand in the Dublin area.

The load duration curves for the 2030 and 2040 offshore wind and solar profiles are shown in Figure 27. The graph presents two profiles for 2030, one considering 1.45GW offshore wind and 400MW solar PV capacity and the other 2030 profile considered 1.45GW offshore wind and 2GW solar PV capacity. For 2040 profiles, the solar PV capacity assumed was the same but the offshore wind capacity at Poolbeg was assumed to increase to 2GW.

For the 2030 duration curves, it is observed that at least 400MW renewable generation was available for approximately 67% of the year considering the output of 1.45GW offshore wind capacity and 400MW solar PV capacity.

For 2040, it is observed that at least 400MW renewable generation was available for around 75% of the year considering the output of 2GW offshore wind capacity and 400MW solar PV capacity.

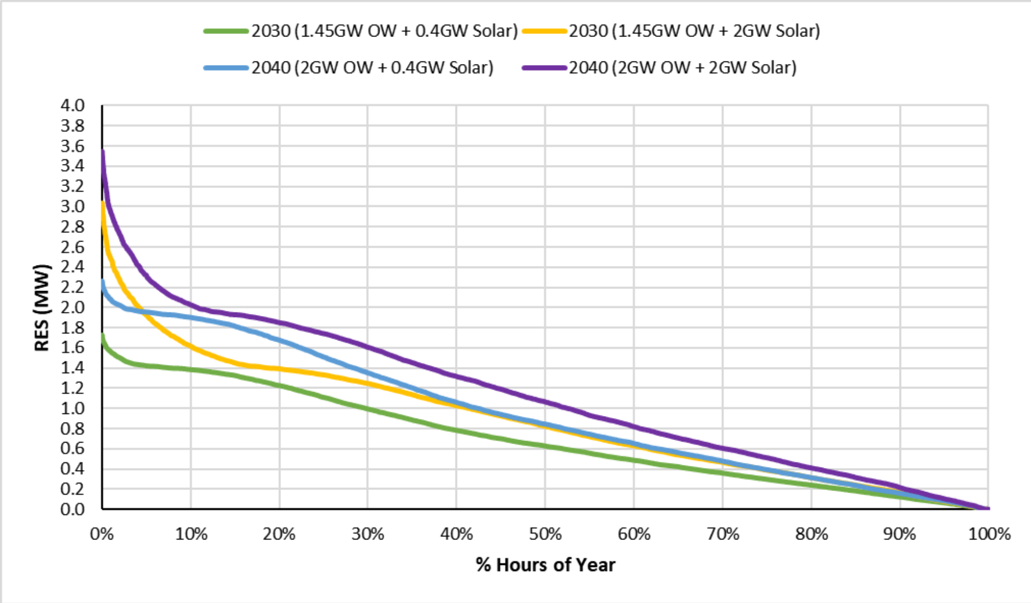


Figure 27: Hydrogen Production 'Offshore Wind and Solar PPA' Scenario Load Duration Curve

3.4.2 Green Hydrogen Production Model

The renewable hydrogen production model considers the main techno-economic drivers of CapEx and OpEx for the various components required for hydrogen production and compression. These components include the electrolyser system, compressors, and storage vessels. The model incorporates cost reduction projections sourced from literature for the system components. The 2030 and 2040 models both consider PEM electrolyser technology.

The model developed has the capability to analyse a number of connection and electricity supply arrangements for the production facility as presented earlier in Table 9.

The model considers electricity generation from renewable generation technologies including offshore wind, onshore wind and solar PV generation. The available generation from these renewable technologies follow hourly generation profiles in Ireland for the 2008 wind year. The model also utilises curtailment profiles output from MullanGrid's curtailment model and constraint models approximated from EirGrid modelling.

Electricity prices for the day ahead market and corporate power purchase agreements are inputted to the model.

The model was developed in Microsoft Excel 2016, which is low cost to setup, and the programming is not complex to learn or interpret. It can be easily checked against other similar models and can be open sourced, which also points towards the limitations of the model.

Levelised Cost of Hydrogen Production

A widely used approach to evaluate renewable hydrogen projects is the levelised cost of hydrogen production (LCOHp). The LCOHp usually is calculated as follows: the total project life-cycle cost divided by the total lifetime energy production. The LCOHp determines the cost of hydrogen production that will allow a project to break even.

Hydrogen production is based on hourly generation profiles, available grid imports and the electrolyser and compression capacity. The electrolyser system, compressor, and storage CapEx and OpEx values are input to the model to assess the total costs associated with the hydrogen production facility. See Table 10 for model assumptions.

To calculate the LCOHp, the NPV of the CapEx, OpEx and hydrogen produced are computed over the lifetime of the project using a desired discount rate. The energy costs associated with renewable generation is then input into the LCOHp calculation described by equation 1. The LCOHp is a metric used to define the costs of hydrogen production over the lifetime of the assets, similar to LCOE. The total hydrogen production investment costs, OpEx and energy costs are described by equation 2, 3 and 4 respectively. The discounted hydrogen production is calculated from equation 5. The costs for hydrogen distribution and long-term storage were not included in the model.

$$LCOH_p = \frac{NPV\ H_2\ \ Inv + NPV\ H_2\ OPEX + NPV\ H_2\ Energy\ Costs}{NPV\ H_2\ Production} \tag{1}$$

$$NPV\ H_2\ Inv = \sum_{T=0}^{T=L_H} \frac{C_H}{(1+r_H)^T} \tag{2}$$

$$NPV\ H_2\ OPEX = \sum_{T=0}^{T=L_H} \frac{O_H}{(1+r_H)^T} \tag{3}$$

$$NPV\ H_2\ Energy\ Costs = \sum_{T=0}^{T=L_H} \frac{O_E}{(1+r_H)^T} \tag{4}$$

$$NPV\ H_2\ Production = \sum_{T=0}^{T=L_H} \frac{M_{E,H}}{(1+r_H)^T} \tag{5}$$

The hydrogen production facility investment costs (C_H), calculated from equation 6, comprises costs for the electrolyser (C_E) and balance of plant ($C_{BOP,E}$), which are input in €/MW with the total electrolyser cost based on the installed capacity (P_E). The compressor unit costs (C_C), storage tank costs (C_S) and project development costs (C_D) are also included.

$$C_H = (C_E + C_{BOP,E})(P_E) + (C_C)(m) + (C_S)(S_H) + C_D \tag{6}$$

The hydrogen production facility OpEx (O_H) calculated from equation 7 accounts for the operation and maintenance costs for the electrolyser, compressor and storage systems ($O_{O\&M,H}$) which are calculated by equation 8. Insurance costs ($O_{I,H}$) and water costs (O_W) are also included.

$$O_H = O_{O\&M,H} + (O_{I,H})(P_E) + (O_W)(\rho_{W,E})(E_H) \tag{7}$$

$$O_{O\&M,H} = \left(O_{\%,C_E}\right)(C_E)(P_E) + \left(O_{\%,C_C}\right)(C_C)(m) + \left(O_{\%,C_S}\right)(C_S)(S_H) \tag{8}$$

The energy costs for hydrogen production (O_E) are calculated by equation 9. The energy costs are assumed to comprise the cost of energy for electricity dispatched to the electrolyser ($E_{EWF,H}$) from offshore wind. Energy costs for grid imported electricity are also included, these are based on the quantity of imported energy ($E_{G,H}$) and the market price of grid imported electricity (C_{GE}). The energy cost for a volume of dispatched down electricity ($E_{DD,H}$) is also included at an assumed dispatched down electricity price (C_{DDE}).

$$O_E = (E_{EWF,H})\left(C_{ORESS,1}\right) + \left(E_{G,H}\right)(C_{GE}) + (E_{DD,H})(C_{DDE}) \tag{9}$$

The total hydrogen production ($M_{E,H}$) is calculated from equation 10. The electrolyser capacity (P_E) and the capacity factor (λ_E) based on the available electricity and market demand for hydrogen are inputs to the calculation. The electrolyser electricity consumption per kg of hydrogen produced ($\rho_{E,E}$) is also required to estimate the hydrogen production volumes.

$$M_{E,H} = \frac{(P_E)(\lambda_E)(8760)}{\rho_{E,E}} \quad (10)$$

Internal Rate of Return

Another method identified to quantify the feasibility of the electrolyser investment is the financial indicator Internal Rate of Return (IRR). The IRR is a measure of the rate of return expected from an investment. Mathematically it is defined as the discount rate which, when applied to discount a series of cash outflows followed by cash inflows, returns a net present value (NPV) of zero. In other words, the IRR is the equivalent constant interest rate at which a given series of cash outflows must be invested for the investor to earn a given series of cash inflows as income.

The project is deemed to be viable if the project IRR is higher than or equal to the hurdle rate calculated from the debt/equity ratio, cost of equity and the cost of debt.

The model determines the hydrogen production price and if a subsidy is required on top of the sale price acceptable to the end user. This essentially estimates the viable sale price for hydrogen to achieve the desired IRR.

The IRR is iteratively calculated from Microsoft excel, equation 11 indicates the formula to derive the IRR from the net cash flow (C_t) for the time period (t) and also the initial investment costs (C_0). The project is deemed to be viable if the project IRR is higher than or equal to the weighted average cost of capital (WACC) shown in equation 12. The WACC is calculated from the debt ratio (r_d), cost of debt (D), equity ratio (r_e) and the cost of equity (E) and the corporate tax rate (T_c).

$$NPV = 0 = \sum_{t=1}^{T} \frac{C_t}{(1+IRR)^t} - C_H \quad (11)$$

$$WACC = (r_d \times D) + (r_e \times E \times (1 - T_c) \quad (12)$$

The net cash flow (C_t) from equation 13 accounts for the revenue (R_t) and operational costs for the wind farm and hydrogen production facility (O_t) over the lifetime of the project.

$$C_t = R_t + O_H \quad (13)$$

The revenue from the project is calculated from equation 14. The revenue streams include the hydrogen production volumes ($M_{E,H}$) sold at the market price for the desired use case (C_{H_2})

including the level of regulatory support (S_{H_2}). The waste heat from the electrolyser (WH_E) is also considered as a potential revenue stream with a waste heat tariff (C_{WH}) applied.

$$R_t = (M_{E,H})(C_H + S_H) + WH_E(C_{WH}) \tag{14}$$

The project operational costs are described by equation 15 and account for the hydrogen production facility operational costs (O_H) and the energy costs for hydrogen production (O_E).

$$O_t = O_H + O_E \tag{15}$$

The hydrogen production facility OpEx (O_H) calculated from equation 16 accounts for the operation and maintenance costs for the electrolyser, compressor and storage systems ($O_{O\&M,H}$) which are calculated by equation 17. Insurance costs ($O_{I,H}$) and water costs (O_W) are also included.

$$O_H = O_{O\&M,H} + (O_{I,H})(P_E) + (O_W)(\rho_{W,E})(E_H) \tag{16}$$

$$O_{O\&M,H} = \left(O_{\%,C_E}\right)(C_E)(P_E) + \left(O_{\%,C_C}\right)(C_C)(m) + \left(O_{\%,C_S}\right)(C_S)(S_H) \tag{17}$$

The energy costs for hydrogen production (O_E) are calculated by equation 18. Energy costs for grid imported electricity are included, these are based on the quantity of imported energy ($E_{G,H}$) and the day ahead market price (C_{GE}). The energy costs for offshore wind electricity are included, these are based on the quantity of imported energy ($E_{EWF,H}$) and the average ORESS 1 strike price ($C_{ORESS,1}$). The energy costs for dispatched down electricity ($E_{DD,H}$) are included with a price for dispatch down electricity (C_{DDE}) calculated from SEMO data.

$$O_E = (E_{EWF,H})\left(C_{ORESS,1}\right) + \left(E_{G,H}\right)(C_{GE}) + (E_{DD,H})(C_{DDE}) \tag{18}$$

Model Input Data

Table 10: Model Inputs 2030-2035 and 2040

Variable	Unit	2030-2035	2040	Description
P_E	MW	Dynamic		Electrolyser capacity
r_H	%	7.5%	7.5%	Discount rate for hydrogen production facility
r_d	-	0.7	0.7	Debt ratio
D	%	5.5%	5.5%	Cost of debt
r_e	-	0.3	0.3	Equity ratio
E	%	12%	12%	Cost of equity
T_c	%	12.5%	12.5%	Corporate tax rate
L_H	Yrs	25	25	Lifetime of hydrogen production plant
C_E	€/MW	515,000	360,000	Electrolyser cost per MW
$C_{BOP,E}$	€/MW	130,000	115,000	Electrolyser balance of plant cost per MW
C_C	€/kg/h	Not considered		Compression equipment cost per kg/h
m	kg/h	Dynamic		Storage filling rate, sized on electrolyser capacity
C_S	€/kg	430	415	Hydrogen storage @ 50 bar cost per kg
S_H	kg	3 x Production Capacity	3 x Production Capacity	50 bar hydrogen storage capacity onsite
C_D	€	1,000,000	1,000,000	Development costs associated with hydrogen production facility
$O_{I,H}$	€/MW	1,000	1,000	Insurance cost per MW for hydrogen production facility
O_W	€/l	3.7×10^{-3}	3.7×10^{-3}	Mains water cost per litre
$\rho_{W,E}$	L/kg	15	15	Electrolyser water consumption per kg of hydrogen produced
$O_{\%,CE}$	%	2	2	Electrolyser annual operational cost as a percentage of capital cost
$O_{\%,CS}$	%	2	2	Storage tanks annual operational cost as a percentage of capital cost
$E_{EWF,H}$	MWh	Dynamic		offshore wind electricity dispatched to hydrogen production facility, hourly profile input to model
$C_{ORESS,1}$	€/MWh	86.05	86.05	ORESS 1 average strike price
$E_{G,H}$	MWh	Dynamic		Electricity imported from the grid, based on RES profiles
C_{GE}	€/MWh	75	75	Day ahead market price
$E_{DD,H}$	MWh	Dynamic		Dispatched down electricity from utilised by hydrogen production facility, profiles input from curtailment model
C_{DDE}	€/MWh	35	35	Price of dispatched down electricity
λ_E	%	Dynamic		Annual electrolyser capacity factor
$\rho_{E,E}$	MWh/kg	47×10^{-3}	45×10^{-3}	Electrolyser electricity consumption per kg of hydrogen produced

3.4.3 Green Hydrogen 2030-2035 Analysis

Hydrogen as a Dispatch Down Mitigation 2030-2035

This section examines the benefit of deploying hydrogen as a curtailment mitigation option for 2030-2035. A worst-case oversupply and curtailment scenario referred to as '2030 Scenario 2' was modelled as a mitigation measure to understand the role of green hydrogen in a highly renewable electricity system. For the scenario, 7GW of offshore wind, 8GW onshore wind and 5.5GW solar capacity was modelled. Considering the Climate Action Plan 2023 generation targets, this level of renewable generation capacity may be more feasible closer to 2035.

Prior to the inclusion of the hydrogen electrolyser, it is noted that non-priority wind is estimated to experience 30.55% total curtailment (26.36% oversupply and 4.19% system curtailment) for the 2030-2035 scenario. This equates to 30.23% and 30.84% total curtailment for non-priority onshore and offshore wind respectively, while non-priority solar is estimated to experience 23.81% total curtailment (20.65% oversupply and 3.17% system curtailment).

Non-Priority offshore wind connected to Poolbeg is also assumed to experience 10% transmission constraints in 2030. Refer to section 3.2 for more background and detail on the estimated dispatch down figures.

Analysis of the results of the 'Grid Connected High RES-E' scenario (where the base load of the hydrogen electrolyser is fed by all wind and solar generation) are presented in Figure 28. The graph indicates substantial reductions in total curtailment as the capacity of the electrolyser increases, which has the subsequent impact of increasing RES-E in excess of 100%. This scenario is estimated to result in the electrolyser having a very high-capacity factor in the context of renewable energy.

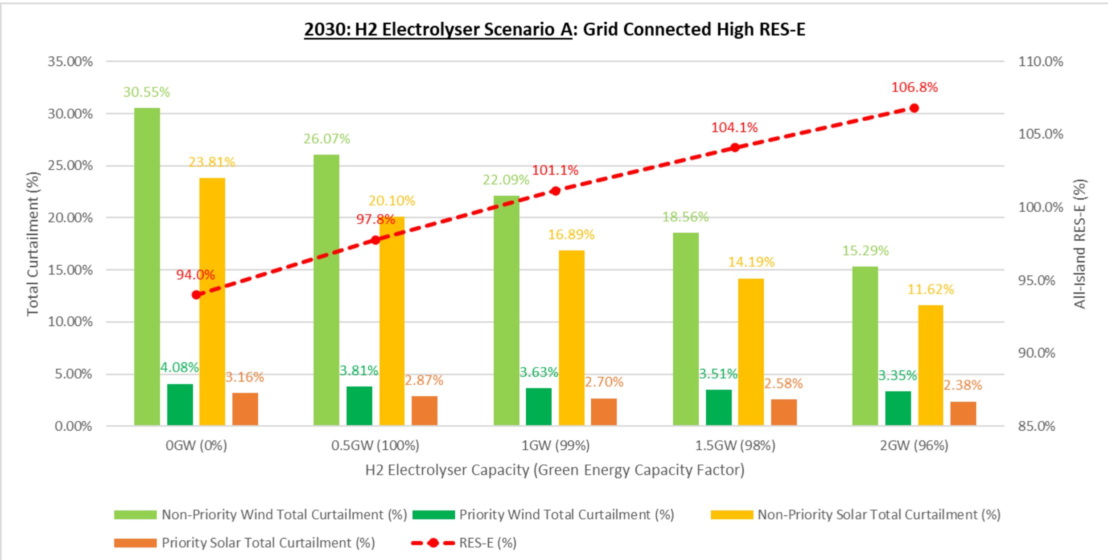


Figure 28: 2030-2035 Electrolyser 'Grid Connected High RES-E' Scenario Curtailment Mitigation

In the case of the 'Offshore Wind Off Grid' scenario (refer to Figure 29), the dispatch down of renewable generation is not a consideration as it is assumed that the electrolyser is off-grid and is fed by a 2GW offshore wind farm, which is also off-grid. For 2GW electrolyser capacity, all available electricity from the 2GW of offshore wind can be utilised. However, the electrolyser would have a capacity factor of only 45% (which is also the capacity factor of the offshore wind farm). The electrolyser's capacity factor increases as the capacity of the electrolyser reduces. However, this also results in an increase in unused offshore wind energy.

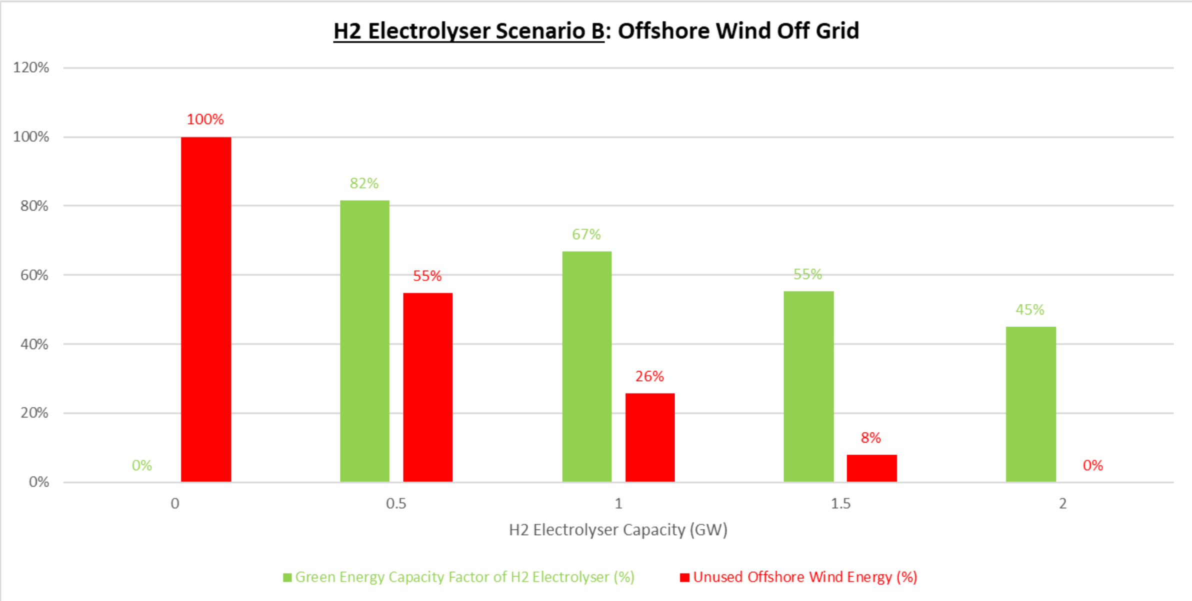


Figure 29: 2030-2035 Electrolyser 'Offshore Wind Off Grid' Utilisation

With regards to the 'System Wide VRES Curtailment' scenario, the total curtailment and RES-E percentages (refer to Figure 30) are the same as the 'Grid Connected High RES-E' scenario A (Figure 28). The reason for this is that in both scenarios the electrolyser is having the same impact on reducing total curtailment. The key difference between the two scenarios is that in the 'System Wide VRES Curtailment' scenario, the electrolyser is importing less wind and solar energy as it only has access to system wide curtailed electricity, and therefore has a significantly lower capacity factor.

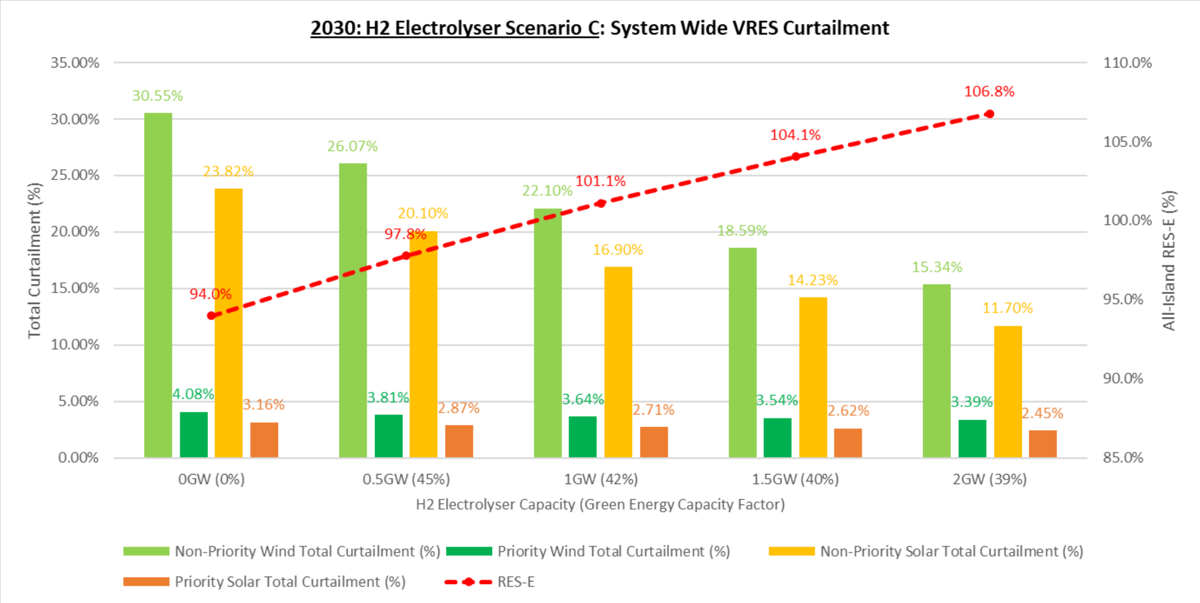


Figure 30: 2030-2035 Electrolyser 'System Wide VRES Curtailment' Scenario Curtailment Mitigation

In terms of the 'Offshore Wind Dispatch Down' production scenario where the electrolyser is fed from 1.45GW of Poolbeg offshore wind dispatched down energy, the results in Figure 31 indicate that from a dispatch down reduction perspective, there doesn't seem to be any merit in the capacity of the electrolyser exceeding approximately 1GW if it is fed by 1.45 GW of offshore wind. The electrolyser's green energy capacity factor is significantly lower than 'System Wide VRES Curtailment' because the electrolyser is being fed by significantly less renewable energy in the 'Offshore Wind Dispatch Down' scenario with only dispatch down energy from offshore wind connected in Poolbeg available for hydrogen production.

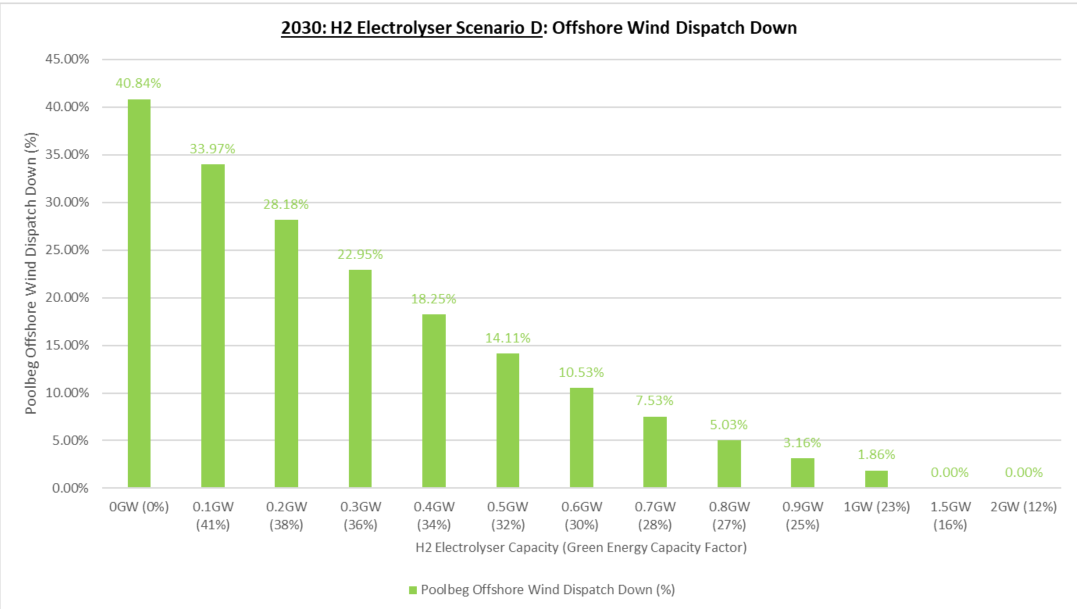


Figure 31: 2030-2035 Electrolyser 'Offshore Wind Dispatch Down' Scenario Curtailment Mitigation

In the case of the ‘Offshore Wind and Solar PPA’ scenario, the electrolyser is fed by all energy generated by offshore wind connected to Poolbeg, and is also fed by a solar farm that has the same capacity as the electrolyser. The results in Figure 32 indicate the levels in reduction of total curtailment for wind are very similar to ‘Offshore Wind Dispatch Down’ but are not quite as significant in this particular scenario, since the available electricity is from solar PV capacity. The differences between wind and solar total curtailment converge, and solar total curtailment exceeds wind beyond a certain point due to the fact that the capacity of the solar farm is increasing in line with each 100MW increment in the capacity of the electrolyser, while the capacity of wind remains fixed. The capacity factors are not as high as ‘Grid Connected High RES-E’, in which the electrolyser was absorbing energy from all wind and solar across the system, and not just at Poolbeg.

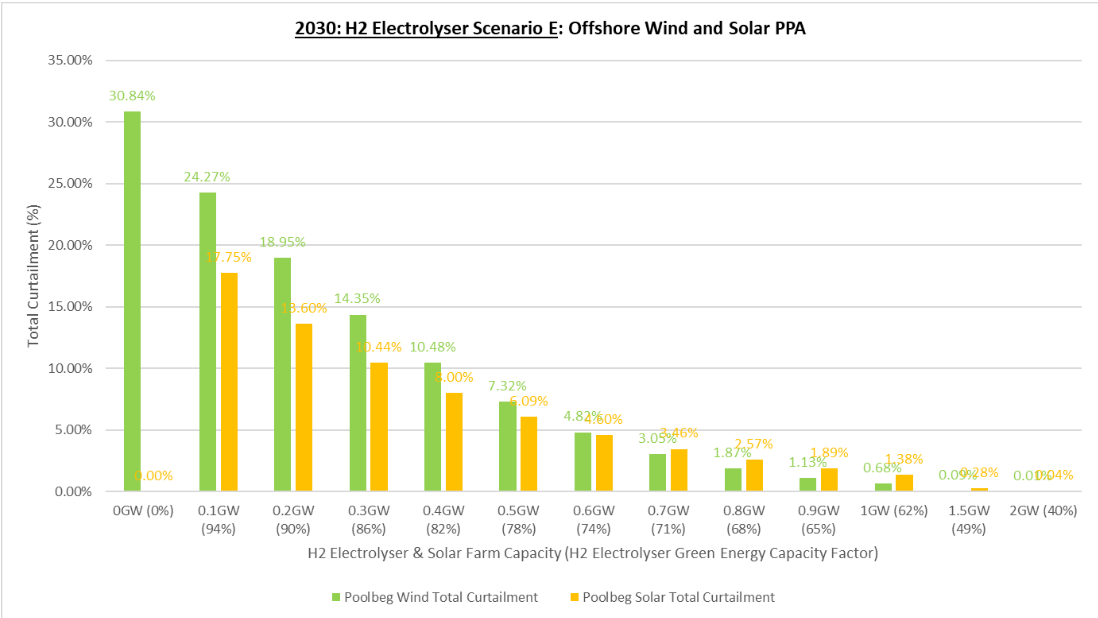


Figure 32: 2030-2035 Electrolyser ‘Offshore Wind and Solar PPA’ Scenario Curtailment Mitigation

In advance of, and in the absence of an economic analysis, two conclusions from this dispatch down focused analysis are:

1. Considering the availability of all system wide curtailed wind and solar electricity for 2GW of electrolyser capacity, the production scenarios ‘Grid Connected High RES-E’ and ‘System Wide VRES Curtailment’ appeared to provide a major benefit to the electricity system with a significant reduction of 50% for non-priority wind and solar total curtailment. Non- priority total wind curtailment was estimated to reduce from 30.6% to 15.3%, non-priority solar total wind curtailment was estimated to reduce from 23.8% to 11.7%.

2. If the hydrogen electrolyser is only operating on electricity from offshore wind connected to Poolbeg, there are greater benefits in terms of reducing dispatch down if it is only importing dispatched down energy, albeit with a much lower capacity factor. For the production scenario 'Offshore Wind Dispatch Down', it appeared there was no major benefit in sizing the electrolyser greater than 1GW.

Hydrogen Production Modelling 2030-2035

Base Case

In order for the hydrogen production scenario to comply with the Additionality Delegated Act presented in Table 8, a 94% RES-E scenario for the timeframe 2030-2035 (referred to as 2030 Scenario 2) was considered for the hydrogen production techno economic analysis.

To help minimise hydrogen production costs it is important to maximise the utilisation of a hydrogen production plant over its lifetime. CapEx and OpEx were also reported in the literature to impact significantly on the production costs.

Two electrolyser capacities of 400MW and 2GW have particular relevance for scenarios 'Offshore Wind Dispatch Down' and 'Offshore Wind Off Grid' respectively. The 2GW electrolyser capacity for 'Offshore Wind Off Grid' is based on the Climate Action Plan 2023 (2GW green hydrogen direct from offshore wind) and the 400MW electrolyser capacity for the 'Offshore Wind Dispatch Down' scenario is based on the 'review of the security of energy supply of Ireland's electricity and gas systems'[20] consultation, which included a 400MW electrolyser operating from dispatched down renewable electricity as a potential electricity supply mitigation option.

Figure 33 shows the modelled levelised cost of hydrogen production (LCOHp) for 2030-2035 with PEM electrolyser capacities ranging from 10MW to 2GW for all of the hydrogen production scenarios. The LCOHp is widely reported in the units of €/kg and is presented as such in this report. The optimal capacity was identified as the capacity which returned the lowest LCOHp while maximising the use of renewable energy.

From the LCOHp analysis it is noted that:

- **Grid Connected High RES-E:** electrolyser was assumed to have access to all system wide wind and solar generation at an assumed spot market price of 75 €/MWh. LCOHp is approximately €5/kg due to very high utilisation of the hydrogen production plant, where the estimated capacity factor was greater than 95% for all capacities assessed.

[20] https://www.gov.ie/pdf/?file=https://assets.gov.ie/234682/eafcea48-fd3f-4748-a9db-945c8e3e2c8f.pdf#page=null

These estimates are consistent with Deloitte's LCOHp analysis, which indicated an LCOHp of €4.90/kg for electricity prices of €80/MWh.

- **<u>Offshore Wind Off Grid:</u>** for 2GW electrolyser capacity directly connected to 2GW offshore wind capacity, the modelled LCOHp was €6.15/kg. The estimate assumed an offshore wind energy price of €86.05/MWh, based on the provisional average ORESS 1 auction strike price. This configuration provides a relatively modest utilisation of the [21]compared to the 'Grid Connected High RES-E' scenario, with an estimated capacity factor of 45%. The modelled LCOHp for this scenario appears to be considerably higher than Deloitte's estimate for the North Sea offshore wind of €3.7/kg and is likely due to the higher energy price assumed for offshore wind in Ireland.
- **<u>System Wide VRES Curtailment</u>**: with access to all system wide wind and solar curtailed electricity, the electrolyser benefits from the large volumes of relatively cheap curtailed electricity at €35/MWh. As more variable renewable generation is connected onto the electricity system, it is possible that the future price of electricity during curtailment will be lower than the historical value used in this analysis. Considering 2GW electrolyser capacity, the modelled LCOHp was €4.15/kg. The optimal LCOHp of approximately €3.80/kg appeared to be for an electrolyser capacity of c.400MW; this capacity was noted to decrease non-priority wind curtailment from c.30.6% to c.26.9% and decrease non-priority solar curtailment from c.23.8% to c.20.8%. The estimates for this scenario appear to be considerably lower than other estimates from literature that investigated hydrogen production from curtailed renewable electricity from onshore wind generation at a much smaller scale, with estimates of €18-20/kg based on 1.5MW of electrolyser capacity, curtailed electricity prices of €50-65/MWh and a capacity factor of approximately 20%.
- **<u>Offshore Wind Dispatch Down:</u>** electrolyser supplied only by curtailed and constrained electricity from 1.45GW offshore wind capacity connecting at Poolbeg. Considering 1.45GW electrolyser capacity to mitigate all dispatch down at Poolbeg, the modelled LCOHp was €7.10/kg and the estimated capacity factor was c.16.2%. It is noted the cost optimal LCOHp of approximately €4.20/kg appeared to be for an electrolyser capacity of c.400MW with a corresponding capacity factor of 34%. A 400MW electrolyser capacity was estimated to decrease the total dispatch down at Poolbeg from c.40.8% to c.18.3%. Compared to other LCOHp estimates from literature, the modelled LCOHp appears notably lower, possibly due to the large

[21]https://www.eirgridgroup.com/site-files/library/EirGrid/ORESS-1-Provisional-Auction-Results-2023-(OR1PAR).pdf

volume of curtailed electricity, scale of electrolyser and lower curtailed electricity price assumed.

- **<u>Offshore Wind and Solar PPA</u>:** electrolyser supplied by 1.45GW offshore wind capacity and solar capacity matching the electrolyser capacity. Considering c.1.45GW electrolyser capacity, the modelled LCOHp was approximately €5.32/kg and the corresponding capacity factor c.53%. The offshore wind electricity costs were assumed to be €86.05/MWh and costs for solar electricity through a PPA arrangement were assumed to be €75/MWh. The LCOHp estimate is relatively high compared to Aurora's estimate of €3.50/kg based on a 100MW electrolyser connected to 150MW offshore wind capacity and 20MW solar capacity in Ireland

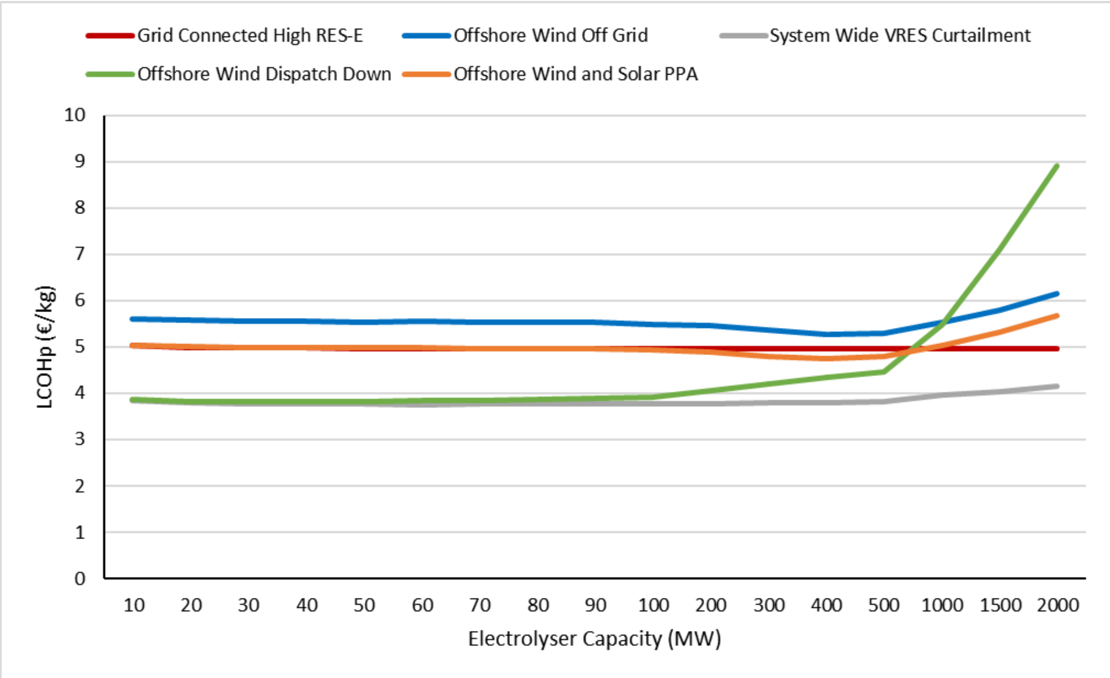


Figure 33: 2030-2035 LCOHp All Production Scenarios

The estimated viable sale prices for all of the production scenarios are presented in Table 11. The electrolyser capacity selected for each scenario was based on the capacity that maximised the use of renewable energy.

The viable sale price represents the price that will achieve an IRR/hurdle rate of 7.5% taking into account an assumed developer margin of 15%. The estimated viable sale price is presented in €/MWh, based on the lower heating value of hydrogen and includes:

- The cost of producing hydrogen, captured in model;
- The cost of distributing hydrogen via pipeline, assumed to be €15/MWh (€0.5/kg);
- The cost of storing hydrogen via salt cavern, assumed to be €45/MWh (€1.5/kg);

- The target sale price to the electricity sector (hydrogen gas turbines), assumed to be €75/MWh in line with historical 2019-2021 day ahead market prices;
- Regulatory support required on top of sale price to electricity sector.

There are a range of variables that may impact on the actual viable sale price; these include but are not limited to the capital cost for equipment, electricity input costs, financing arrangements (cost of debt, equity), annual inflation, hydrogen storage costs and hydrogen distribution costs. In addition, electrolyser technology in the GW scale is at an early development stage. Therefore, the estimates are provided to show the relative benefit of the various production configurations. From Table 11, it is observed that:

- The 'Grid Connected High RES-E' scenario had the cheapest viable sale price for hydrogen to the power sector at €230/MWh with regulatory support of approximately €155/MWh required. This highlights the benefit of maximising the utilisation of the production plant from all system wind and solar electricity at the day ahead market price of €75/MWh.
- The 'Offshore Wind Off Grid' scenario had a considerably higher viable sale price of hydrogen compared to 'Grid Connected High RES-E'. The estimated viable sale price was around €288/MWh and the level of required regulatory support was €213/MWh. This is due to the relatively modest capacity factor of 45% coupled with higher electricity input costs from offshore wind of €86.05/MWh.
- The 'System Wide VRES Curtailment' production scenario indicated a viable sale price of around €240/MWh and regulatory support of around €165/MWh. This appears to be the cheapest option after the 'Grid Connected High RES-E' scenario, benefitting from the large volume of system wide curtailed wind and solar assumed available at €35/MWh.
- 'Offshore Wind Dispatch Down' production scenario for Poolbeg indicated a viable sale price of approximately €397/MWh and regulatory support of around €322/MWh. This appears to be the most expensive configuration for hydrogen production, linked to it having the lowest capacity factor of 16%.
- 'Offshore Wind and Solar PPA' production scenario indicated a viable sale price of around €256/MWh and regulatory support of approximately €181/MWh. This appears to be more favourable configuration for hydrogen production than the 'Offshore Wind Off Grid' scenario, with Solar PV capacity increasing the capacity factor to 53% and reducing the level of regulatory support.

Table 11: 2030-2035 Comparison of LCOHp, Viable Sale Price and Regulatory Support Required

Parameter	Unit	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
Electrolyser Capacity	MW	2000	2000	2000	1450	1450
Electrolyser Capacity Factor	%	96%	45%	36%	16%	53%
LCOHp	€/kg	4.95	6.15	4.15	7.1	5.3
LCOHp MWh equivalent	€/MWh	148	184	124	213	159
Power Sector Target Price	€/MWh	75	75	75	75	75
Viable Sale Price	€/MWh	230	288	240	397	256
Production	€/MWh	170	228	180	338	196
Salt Cavern Storage	€/MWh	45	45	45	45	45
Distribution	€/MWh	15	15	15	15	15
Regulatory Support	€/MWh	155	213	165	322	181

Sensitivity Analysis

Renewable Generation Sensitivity

Sensitivity analysis was carried out on the level of renewable generation assumed for the 2030-2035 scenario. The base case scenario was a worst-case scenario for curtailment with very high levels of renewable generation assumed including 7GW offshore wind capacity. To understand the impact on the LCOHp and viable sale price of varying levels of RES-E and dispatch down, profiles for the 'Mullan Grid 2030 Base Case' (80% RES-E) scenario and '2030 Scenario 1' (90% RES-E) were input to the hydrogen production model. The comparison of the three 2030-35 generation profiles for production scenarios 'Grid Connected High RES-E', 'System Wide VRES Curtailment' and 'Offshore Wind Dispatch Down' is shown in Table 11. The comparison was based on the optimal electrolyser capacities identified in Table 11.

From Table 12, a major impact on the LCOHp, viable sale price and level of regulatory support can be observed with the different levels of RES-E assumed for 'System Wide VRES Curtailment' and 'Offshore Wind Dispatch Down' production scenario, for both of which the business model is based on dispatched down renewable energy. 'Grid Connected High RES-E' scenario was not impacted as significantly since it was assumed to have access to all system wide wind and solar generation.

Analysing the impact of different RES-E levels on 'System Wide VRES Curtailment' relative to the 2030-2035 Base Case scenario:

- the reduction in system curtailed electricity for '2030 Scenario 1' considering 90% RES-E resulted in the electrolyser capacity factor reducing by 8% to 28%. The resultant impact on LCOHp was an increase from €4.15/kg to €4.87/kg, and the estimated level of regulatory support increased from €165/MWh to €203/MWh;

- the reduction in curtailment for the 'MullanGrid 2030-2035 Base Case' 80% RES-E scenario significantly reduced the capacity factor of the electrolyser from 36% to 14%. This led to an increase in the LCOHp from €4.15/kg to €8.01/kg, and the estimated regulatory support required increased from €165/MWh to €371/MWh.

Analysing the impact for the 'Offshore Wind Dispatch Down' scenario relative to the 2030-2035 Base Case scenario:

- the reduction in Poolbeg dispatch down electricity for '2030 Scenario 1' considering 90% RES-E resulted in the electrolyser capacity factor reducing from 16% to 13%. The resultant impact on LCOHp was an increase from €7.1/kg to €8.5/kg, and the estimated level of regulatory support increased from €322/MWh to €397/MWh;
- the reduction in dispatch down at Poolbeg for the 'MullanGrid 2030-2035 Base Case' 80% RES-E scenario reduced the capacity factor of the electrolyser from 16% to 8%. This led to an increase in the LCOHp from €7.1/kg to €12.5/kg, and the estimated regulatory support required increased from €322/MWh to €608/MWh.

Table 12: Impact of Generation Profiles on 2030-2035 Scenarios A, B and C

Generation	Parameter	Unit	Grid Connected High RES-E		System Wide VRES Curtailment		Offshore Wind Dispatch Down	
	Electrolyser Capacity	MW	2000		2000		1500	
			Value	Difference to 2030-2035 Base Case	Value	Difference to 2030-2035 Base Case	Value	Difference to 2030-2035 Base Case
2030 Scenario 1 90% RES-E	Electrolyser Capacity Factor	%	95%	-1%	28%	-8%	13%	-3%
	LCOHp	€/kg	4.96	0.01	4.87	22	8.52	1.41
	Viable Sale Price	€/MWh	231	0	279	39	472	75
	Regulatory Support to Achieve WACC	€/MWh	156	1	203	39	397	75
MullanGrid 2030 Base Case 80% RES-E	Electrolyser Capacity Factor	%	93%	-3%	14%	-22%	8%	-8%
	LCOHp	€/kg	4.90	-0.05	8.01	3.86	12.46	5.35
	Viable Sale Price	€/MWh	229	-1	446	206	683	285
	Regulatory Support to Achieve WACC	€/MWh	154	-1	371	206	608	285

Electricity Input Costs, CapEx, Waste Heat Tariff Sensitivity

Sensitivity analysis was carried out on some of the key parameters that impact on the LCOHp which include the electricity costs and CapEx for the production plant, see Table 13 for analysis on the 2030 S2 generation year.

Looking at an electricity cost variation of 50% then the LCOHp may reduce or increase by up to c.33-39% for scenarios ‘Grid Connected High RES-E’, ‘Offshore Wind Off Grid’ and ‘Offshore Wind and Solar PPA’. The impact appears to be less significant for the dispatched down electricity production scenarios (‘System Wide VRES Curtailment’ and ‘Offshore Wind Dispatch Down’) and in the range of 12-20% where cheaper curtailed electricity was the electricity source and where the annual capacity factor was lowest.

The impact of increasing/decreasing CapEx costs by 25% was shown to have the largest impact on the dispatched down electricity scenarios and in the range of 6-8% where the annual capacity factor was lowest. With higher utilisation of equipment, the impact is reduced and in the range of 2-3% for scenarios ‘Grid Connected High RES-E’, ‘Offshore Wind Off Grid’ and ‘Offshore Wind and Solar PPA’.

Table 13: Impact of Electricity Costs and CapEx on LCOHp 2030-2035 Base Case

2030 S2	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
Base Case - LCOHp	4.95	6.15	4.15	7.11	5.32
Electricity Costs +50%	39%	33%	20%	12%	34%
Electricity Costs -50%	-39%	-33%	-20%	-12%	-34%
CapEx +25%	2%	3%	6%	8%	3%
CapEx -25%	-2%	-3%	-6%	-8%	-3%

Table 14 shows the impact of electricity costs, CapEx and Waste Heat tariff for a 90MW district heat scheme on the viable sale price for the 2030-2035 base case. The power sector market price is assumed to increase/decrease in parallel with electricity input costs.

A variation of 50% for the electricity input costs had the greatest impact on the viable sale price with a potential increase/decrease in the range of 6-25%. The impact was less pronounced for the scenarios where there was a lower capacity factor with only dispatched down energy assumed available to the electrolyser.

A CapEx variation of 25% appeared to have the potential to increase or decrease the viable sale price by 3-7%. The business models of using dispatched down electricity only appeared to be more sensitive to CapEx.

The Waste Heat tariff appeared to have the lowest impact due to the scale of the district heat scheme relative to the GW scale electrolysers assumed. With no revenue stream for waste heat, the percentage increase in the viable sale price was less than 0.5% for all scenarios. Assuming a tariff of 20 €/MWh, the reduction in viable sale price was less than 0.6% for all scenarios.

Table 14: Impact of Electricity Costs, CapEx and Waste Heat Tariff on Viable Sale Price 2030-2035 Base Case

2030 S2	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
Base Case – Viable Sale Price	230	288	240	397	256
Electricity Costs +50%	25%	21%	11%	6%	21%
Electricity Costs -50%	-25%	-21%	-10%	-6%	-21%
CapEx +25%	3%	4%	6%	7%	4%
CapEx -25%	-3%	-4%	-6%	-7%	-4%
Waste Heat - 0 €/MWh	0.4%	0.4%	0.5%	0.2%	0.6%
Waste Heat - 20 €/MWh	-0.4%	-0.5%	-0.2%	-0.6%	-0.6%

3.4.4 Green Hydrogen 2040 Analysis

Hydrogen as a Dispatch Down Mitigation 2040

Looking at 2040 scenario 2, non-priority onshore wind is estimated to experience oversupply levels of 19.26%, while non-priority offshore wind is estimated to experience oversupply levels of 19.72%. Non-priority solar is estimated to experience 16.37% oversupply. It is assumed that system curtailment will no longer exist in 2040, while it is also assumed that non-priority offshore wind connected to Poolbeg will not experience transmission constraints in 2040. Refer to section 3.2 for more background and detail on the estimated dispatch down figures.

Analysing the impact of Green Hydrogen as a curtailment mitigation in 2040, the trends are similar to those discussed in section 3.4.3.

Figure 34 shows the impact on curtailment for the 'Grid Connected High RES-E' scenario where the base load of the hydrogen electrolyser is fed by all wind and solar generation. With 2GW of electrolyser capacity, there is estimated to be substantial reductions in total curtailment with a c.50% reduction compared to when hydrogen was not deployed as a mitigation measure. RES-E levels also increased as a result and were in excess of 100%.

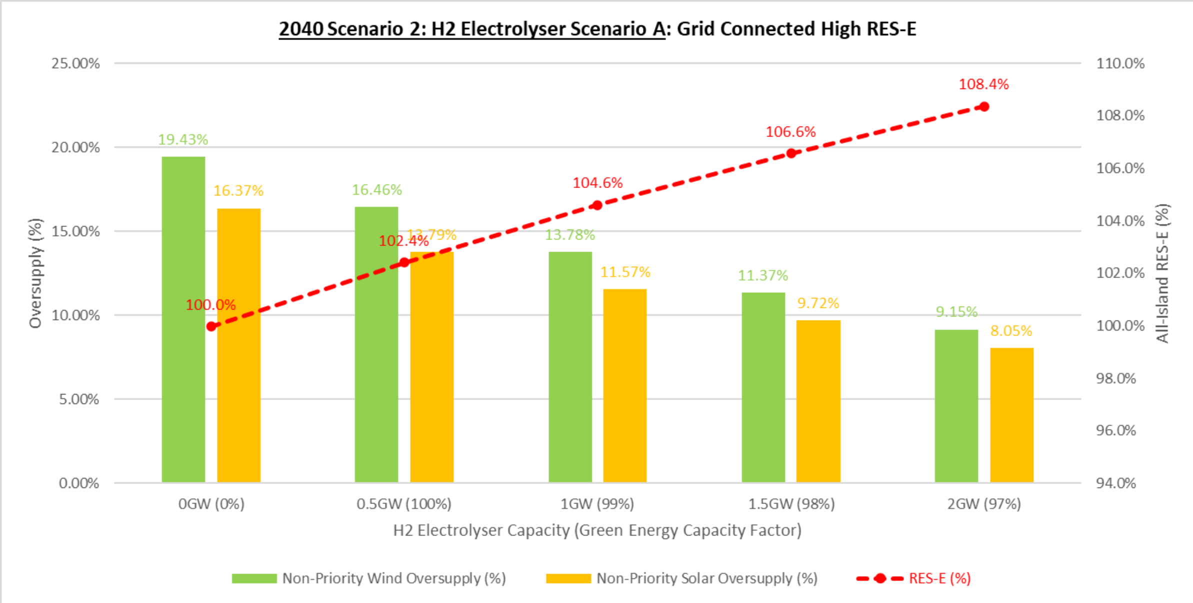


Figure 34: 2040 Electrolyser 'Grid Connected High RES-E' Scenario Curtailment Mitigation

The analysis for the 'System Wide VRES Curtailment' scenario where the electrolyser is fed from system wide oversupply and system curtailed energy from wind and solar is presented in Figure 35 for 2040. Similar to the 'Grid Connected High RES-E' scenario, there are major reductions in total curtailment.

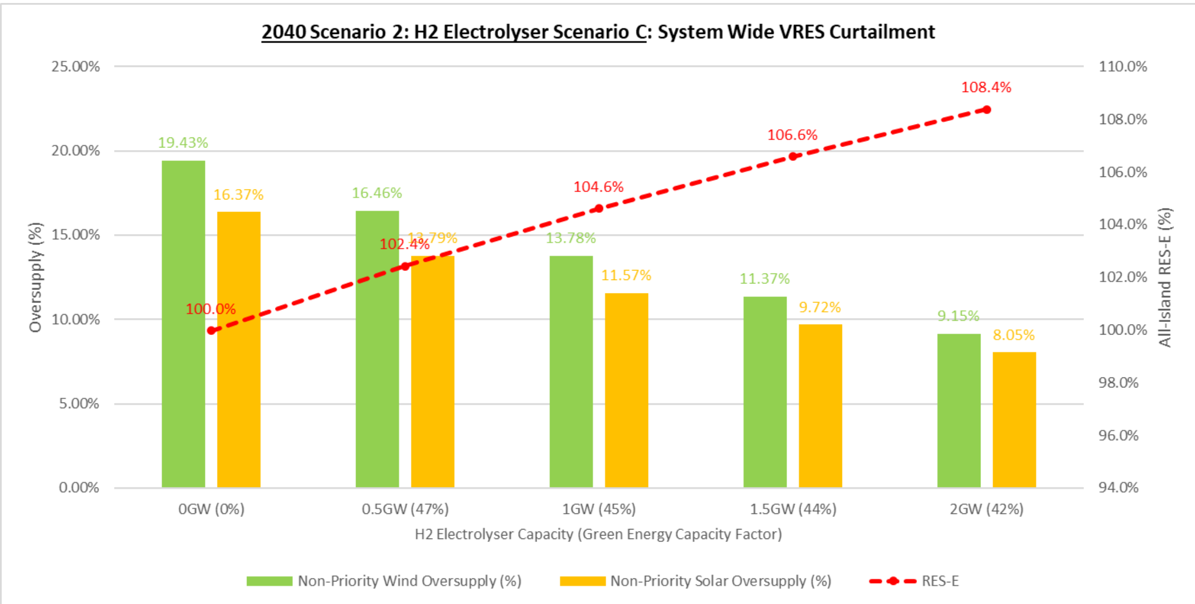


Figure 35: 2040 Electrolyser 'System Wide VRES Curtailment' Scenario Curtailment Mitigation

The results for the 'Offshore Wind Dispatch Down' scenario where the electrolyser is fed from dispatched down energy from 2GW offshore wind capacity connected to Poolbeg in 2040 are illustrated in Figure 36. There does not appear to be any major benefit to the electrolyser capacity exceeding approximately 1GW, if it is fed by 2GW of offshore wind. The electrolyser's capacity factor appears significantly lower than other scenarios with significantly less available renewable electricity.

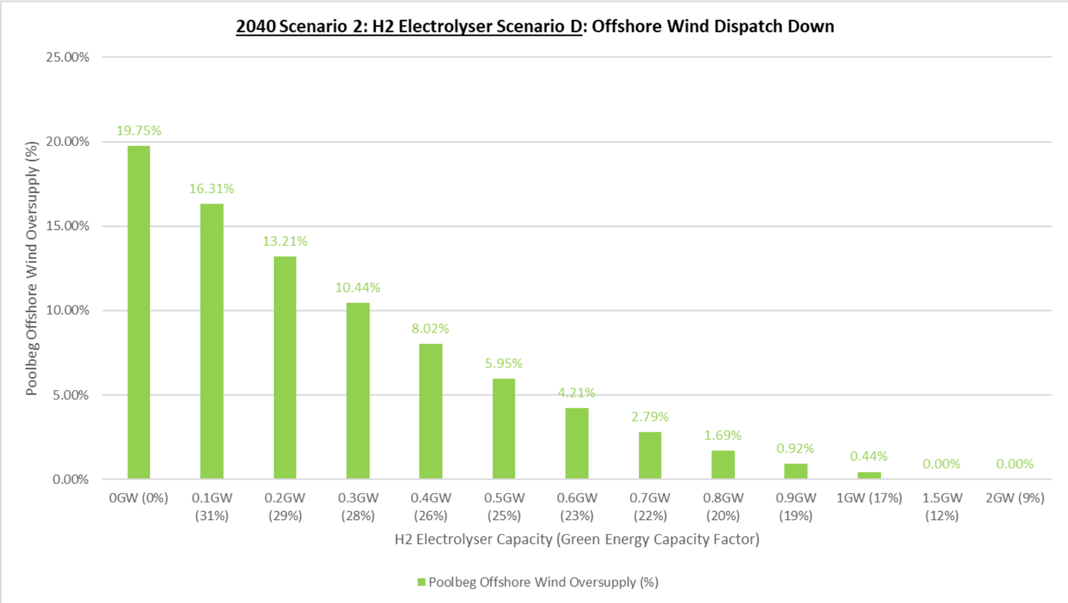


Figure 36: 2040 Electrolyser 'Offshore Wind Dispatch Down' Scenario Curtailment Mitigation

The impact of hydrogen as a curtailment mitigation in 2040 for the 'Offshore Wind and Solar PPA' scenario where the electrolyser is fed by all energy generated by offshore wind connected to Poolbeg, and also fed by a solar farm that has the same capacity as the electrolyser is presented in Figure 37. It appears that 2GW of electrolyser capacity significantly reduces wind and solar oversupply curtailment from 19.75% to less than 1%.

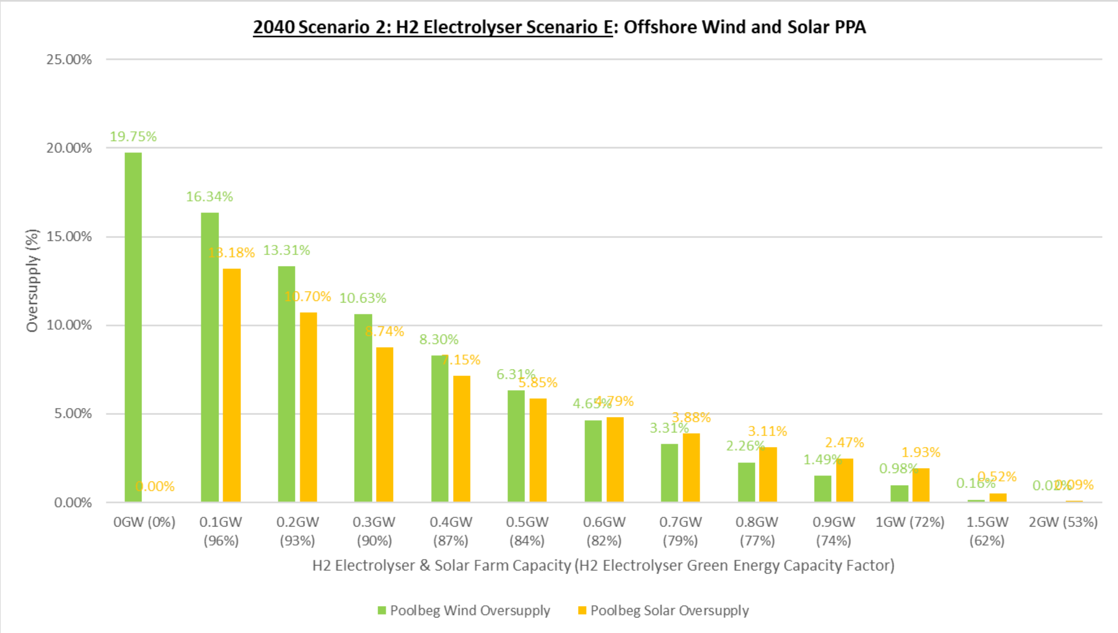


Figure 37: 2040 Electrolyser 'Offshore Wind and Solar PPA' Scenario Curtailment Mitigation

Hydrogen Production Modelling 2040

Base Case

For the 2040 study year, one potential scenario considered as the base case is '2040 Scenario 2' which includes a 6.7GW offshore wind, 8.95GW onshore wind and 7GW solar capacity build out to reach 100% RES-E. The electricity demand projection for this scenario was assumed to be c.49.5TWh based on EirGrid's 2019 Tomorrows Energy Scenarios analysis. It is possible that the level of demand and generation build will be higher in 2040 considering Ireland's net zero emissions targets for 2050. EirGrid is due to publish updates to its Tomorrows Energy Scenarios analysis in 2024, which could provide a more informed view of electricity demand in 2040 compared to their 2019 publication.

Comparing the key differences in input assumptions (Table 10, section 3.4.2) between the 2030-2035 and 2040 analysis, electrolyser efficiency improvements were assumed with the consumption per kg of hydrogen produced estimated to reduce from 47 to 45 kWh/kg. In addition, the CapEx for electrolysis was considered to reduce from c.515 €/kW to 360 €/kW.

Figure 38 presents the modelled LCOHp for the '2040 Scenario 2' study year for electrolyser capacities ranging from 10MW to 2GW for the various hydrogen production scenarios.

From the LCOHp analysis of the 2040 study year it is noted that:

- **Grid Connected High RES-E:** electrolyser was assumed to have access to all system wide wind and solar generation at an assumed spot market price of €75/MWh. The LCOHp was modelled to be €4.7/kg with very high utilisation of the hydrogen production plant, where the estimated capacity factor was greater than 95% for all capacities assessed.

- **Offshore Wind Off Grid:** for 2GW electrolyser capacity directly connected to 2GW offshore wind capacity, the modelled LCOHp was €5.6/kg. It was assumed offshore wind had energy price of €86.05/MWh, based on the provisional average ORESS 1 auction strike price[22]. The estimated capacity factor was 45%.
- **System Wide VRES Curtailment**: access to all system wide wind and solar curtailed electricity. The volumes of curtailed electricity available to the electrolyser at €35/MWh are reduced compared to the 2030-2035 scenario, therefore the capacity factor modelled was lower, and the LCOHp higher for the 2040 base case. Considering 2GW electrolyser capacity, the modelled LCOHp was €4.25/kg. The optimal LCOHp of €4/kg appeared to be for an electrolyser capacity of approximately 400MW, and this capacity was noted to decrease non-priority wind oversupply from around 19.4% to 17% and decrease non-priority solar oversupply from around 16.4% to 14.3%.
- **Offshore Wind Dispatch Down:** electrolyser supplied only by curtailed electricity from 2GW offshore wind capacity connecting at Poolbeg at a rate of €35/MWh. For 2040, constraints are assumed to be negligible at Poolbeg once the planned transmission network reinforcements are complete. Considering 2GW electrolyser capacity to mitigate all dispatch down at Poolbeg, the modelled LCOHp was €10.2/kg and the estimated capacity factor was 9%. It is noted the cost optimal LCOHp of €4/kg appeared to be for an electrolyser capacity of c.100MW with a corresponding capacity factor of 31%. A 100MW electrolyser capacity was estimated to decrease the total dispatch down at Poolbeg from 19.8% to 16.3%.
- **Offshore Wind and Solar PPA:** electrolyser supplied by 2GW offshore wind capacity and solar capacity matching the electrolyser capacity. Considering 2GW electrolyser capacity, the modelled LCOHp was €4.87/kg and the corresponding capacity factor approximately 55%. The offshore wind electricity costs were assumed to be €86.05/MWh and the energy price for solar electricity through a PPA arrangement assumed to be €75/MWh.

[22] https://www.eirgridgroup.com/site-files/library/EirGrid/ORESS-1-Provisional-Auction-Results-2023-(OR1PAR).pdf

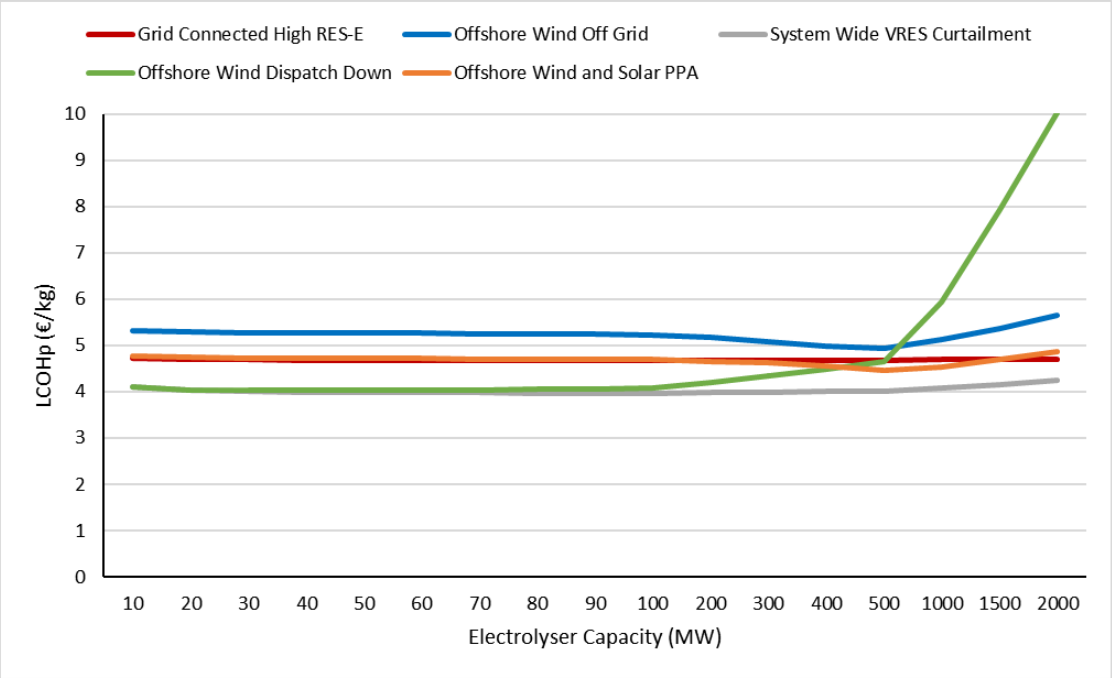


Figure 38: 2040 LCOHp All Production Scenarios

The viable sale price shown in Table 15 is modelled for the same IRR/hurdle rate of 7.5% and developer margin of 15%. The cost of distributing hydrogen was also assumed to be €15/MWh (€0.5/kg), and the cost of storing hydrogen was assumed to be €45/MWh (€1.5/kg) for each of the production scenarios. The target sale price for the power sector was assumed to be in line with projections for the 2030-2035 scenario and based on historical day ahead market prices for 2019-2021, where the average price was approximately €75/MWh.

Table 16 compares the LCOHp, viable sale price and regulatory support in the 2040 and 2030-2035 base case analysis. It is noted that:

- The 'Grid Connected High RES-E' scenario had the cheapest viable sale price for hydrogen to the power sector at €219/MWh with regulatory support of €144/MWh required. There appears to be a reduction compared to the 2030-2035 scenario due to the assumed reductions in CapEx and improvements in electrolyser efficiency based on the literature.
- The 'Offshore Wind Off Grid' scenario had an estimated viable sale price of €266/MWh with required regulatory support of €191/MWh. Compared to the 'Grid Connected High RES-E' scenario, the higher viable sale price appears to be due to a lower capacity factor of 45% coupled with higher electricity input costs from offshore wind of €86.05/MWh. It is possible that the energy prices for offshore wind will decrease in the future and follow a similar trend to the onshore renewable sector in Ireland where delivered energy prices decreased as the sector scaled up. To ensure competitive offshore wind energy prices compared to areas like the North Sea, the Irish

Government could set up a task force to help deliver reductions, similar to what was established in the UK[23]. Therefore, it is possible that the LCOHp may be lower in 2040 with lower energy prices for offshore wind.

- The 'System Wide VRES Curtailment' production scenario indicated a viable sale price of €246/MWh and regulatory support of €186/MWh. Even though CapEx and efficiency improvements were considered for 2040, the viable sale price estimated for the 'System Wide VRES Curtailment' production scenario in 2040 appears to be higher than the estimate for 2030-2035 due to the reduced capacity factor of 29% (36% for 2030-2035 base case). This highlights the variability of curtailment year on year and the potential impact on the business model of using dispatched down energy.

[23] https://www.gov.uk/government/groups/offshore-wind-cost-reduction-task-force

- ‘Offshore Wind Dispatch Down’ production scenario indicated a viable sale price of €550/MWh and regulatory support of €475/MWh. Assuming transmission network reinforcements are complete to mitigate constraints at Poolbeg for the 2GW offshore wind capacity, then only curtailed electricity is available to the electrolyser to provide a capacity factor of c.9%. Similar to the 2030-2035 analysis, this configuration appears to be the most expensive hydrogen production option. Comparing the 2040 and 2030-2035 base case for the ‘Offshore Wind Dispatch Down’ production scenario, a major increase in the viable sale price was also observed. There appears to be a considerable risk associated with a business model using dispatched down energy.
- ‘Offshore Wind and Solar PPA’ production scenario indicated the lowest viable sale price of €236/MWh after the ‘Grid Connected High RES-E’ scenario, with regulatory support of €161/MWh. The higher offshore wind capacity and assumed cost reductions in electrolyser CapEx and efficiency improvements appear to improve the business model in 2040 compared to the 2030-2035 estimate.

Table 15: 2040 Comparison of LCOHp, Viable Sale Price and Regulatory Support Required

Parameter	Unit	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
Electrolyser Capacity	MW	2000	2000	2000	2000	2000
Electrolyser Capacity Factor	%	96%	45%	36%	16%	53%
LCOHp	€/kg	4.69	5.64	4.25	10.02	4.87
LCOHp MWh equivalent	€/MWh	140	169	127	300	146
Power Sector Target Price	€/MWh	75	75	75	75	75
Viable Sale Price	€/MWh	219	266	246	550	236
Production	€/MWh	159	206	186	491	176
Salt Cavern Storage	€/MWh	45	45	45	45	45
Distribution	€/MWh	15	15	15	15	15
Regulatory Support	€/MWh	144	191	171	475	161

Table 16: 2040 and 2030-2035 Base Case Comparison of LCOHp, Viable Sale Price and Regulatory Support Required

Generation	Parameter	Unit	Grid Connected High RES-E		System Wide VRES Curtailment		Offshore Wind Dispatch Down	
	Electrolyser Capacity	MW	2000		2000		2000	
			Value	Difference to 2030-2035 Base Case	Value	Difference to 2030-2035 Base Case	Value	Difference to 2030-2035 Base Case
2040 Scenario 2 100% RES-E	Electrolyser Capacity Factor	%	96%	-	29%	-8%	9%	-7%
	LCOHp	€/kg	4.7	-0.25	4.25	0.1	10	2.89
	Viable Sale Price	€/MWh	219	-11	246	6	550	153
	Regulatory Support to Achieve WACC	€/MWh	144	-11	171	6	476	153

Electrolyser capacity assumed to be 1,450MW for 'Offshore Wind Dispatch Down' in 2030-2035.

Sensitivity Analysis

Electricity Input Costs, CapEx, Waste Heat Tariff Sensitivity

Table 17 shows the impact of electricity costs and CapEx on the LCOHp for the '2040 Scenario 2' study year.

Looking at an electricity cost variation of 50% then the LCOHp may reduce or increase by up to c.37-40% for scenarios 'Grid Connected High RES-E', 'Offshore Wind Off Grid' and 'Offshore Wind and Solar PPA'. The impact appears to be less significant and in the range of 10-19% for scenarios 'System Wide VRES Curtailment' and 'Offshore Wind Dispatch Down' where cheaper curtailed electricity was the electricity source and where the annual capacity factor was lowest.

The impact of increasing/decreasing CapEx costs by 25% on LCOH was estimated to be c.2% for scenarios 'Grid Connected High RES-E', 'Offshore Wind Off Grid' and 'Offshore Wind and Solar PPA'. With lower utilisation of equipment, the impact is larger and in the range of 5-7% for scenarios 'System Wide VRES Curtailment' and 'Offshore Wind Dispatch Down'.

Table 17: Impact of Electricity Costs and CapEx on LCOHp 2040

2040 S2	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
Base Case	4.69	5.64	4.25	7.93	4.69
Electricity Costs +50%	40%	35%	19%	10%	37%
Electricity Costs -50%	-40%	-35%	-19%	-10%	-37%
CapEx +25%	2%	2%	5%	7%	2%
CapEx -25%	-2%	-2%	-5%	-7%	-2%

The impact of electricity costs, CapEx and Waste Heat tariff for a 90MW district heat scheme on the viable sale price for the 2040 base case is shown in Table 18. The power sector market price is assumed to increase/decrease in parallel with electricity input costs.

A variation of 50% for the electricity input costs had the greatest impact on the viable sale price with a potential increase/decrease in the range of 5-26%. The impact was less pronounced for the scenarios where there was a lower capacity factor with only dispatched down energy assumed available to the electrolyser.

A CapEx variation of 25% appeared to have the potential to increase or decrease the viable sale price by 2-6%. The business models of using dispatched down electricity only, appeared to be more sensitive to CapEx.

The Waste Heat tariff appeared to have the lowest impact due to the scale of the district heat scheme relative to the GW scale electrolysers assumed. With no revenue stream for waste heat, the percentage increase in the viable sale price was less than 0.5% for all scenarios. Assuming a tariff of €20/MWh, the reduction in viable sale price was less than 0.6% for all scenarios.

Table 18: Impact of Electricity Costs, CapEx and Waste Heat Tariff on Viable Sale Price 2040 Base Case

2040 S2	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
Base Case	219	266	246	442	226
Electricity Costs +50%	26%	22%	10%	5%	23%
Electricity Costs -50%	-26%	-22%	-10%	-5%	-23%
CapEx +25%	2%	3%	5%	6%	3%
CapEx -25%	-2%	-3%	-5%	-6%	-3%
Waste Heat - 0 €/MWh	0.3%	0.2%	0.4%	0.0%	0.5%
Waste Heat - 20 €/MWh	-0.4%	-0.6%	-0.1%	-0.5%	-0.5%

4 Future Hydrogen Markets in Dublin

Roles for hydrogen exist in a variety of applications, which can be divided into two broad categories: industrial applications, in which hydrogen is a valuable and versatile feedstock; and decarbonising applications, in which hydrogen acts as an energy vector to decarbonise energy systems. Ireland's existing hydrogen demand totals to less than 2,000 tonnes annually[24]. This report discusses these applications in an Irish and specifically county Dublin context.

To recognise the sectors that are more suitable to green hydrogen, there are a number of hydrogen 'ladders' or 'pyramids' that assess the potential sectors hydrogen could be part of in a net zero future. The Liebreich[25] associates hydrogen ladder in Figure 39 shows a wide range of applications for hydrogen in a net zero world, where applications that currently use grey hydrogen were considered to be unavoidable, and also some applications where hydrogen is not widely deployed were viewed as uncompetitive considering there are other more efficient and cost effective solutions from direct electrification.

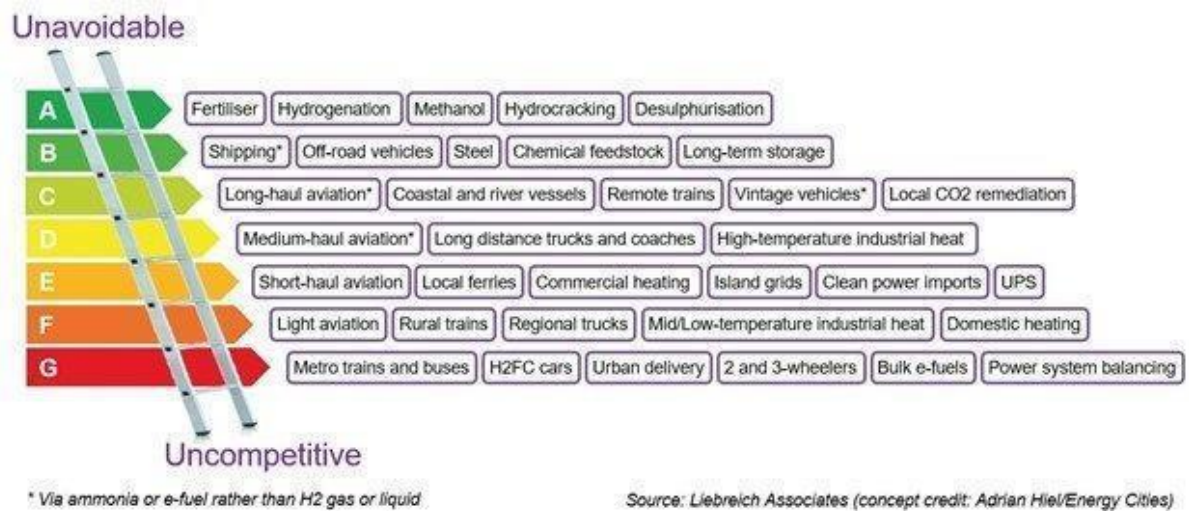


Figure 39: Liebreich Associates Hydrogen Ladder

Market opportunities for hydrogen are identified by ruling out sectors that do not exist in Ireland. At present there is no significant industry activity such as steel production or ammonia production in Ireland. Existing uses for hydrogen can be identified in Dublin for both industrial and decarbonising applications. The greater Dublin area is home to semiconductor manufacturers such as Intel, who need hydrogen to support chip fabrication processes;

[24] https://www.energyireland.ie/developing-irelands-hydrogen-potential/

[25] https://www.linkedin.com/pulse/clean-hydrogen-ladder-v40-michael-liebreich/

pharmaceutical giants such as Pfizer in Grange Castle, who perform hydrogenation; and glass manufacturers such as Diamond Glass, who employ hydrogen gas as a protective atmosphere. Many power stations such as Huntstown, Dublin Bay and Poolbeg, may also use hydrogen for cooling turbine power generators.

In the short to medium term, intercity public buses and heavy-duty trucks of the transport sector may potentially grow the market for hydrogen, albeit a modest demand. In the longer term, the hydrogen market could grow more significantly to meet the requirement for zero emission dispatchable generation with long term storage capabilities.

4.1 Electricity Sector

4.1.1 Electricity Generation

Currently today, Ireland's fleet of dispatchable fossil fuel electricity generation ensures security of supply and provides resilience to the energy system. EirGrid currently operates the electricity system with a requirement for 8 (5 in ROI, 3 in NI) large dispatchable conventional generators to be running on the all-island electricity system at all times. Two of the five generators in ROI are required to be located in Dublin due to the local system constraints of voltage and power flow control in the complex Dublin electricity network. EirGrid plans to reduce the requirement for the number of dispatchable units on the all-island system from 8 units to 3 (2 in ROI, 1 in NI) or less units by 2030.[26]

There is a substantial existing pipeline of gas generation in Dublin, see Table 45 from Appendix D for a list of generation from MullanGrid's generator database. As of Q1 2023, there is estimated to be c1,866MW of connected gas generation capacity in Dublin, with a further c.450MW contracted to connect. There is also c.96MW planned in ECP-2.1 and a further c.293MW of capacity in development with planning consent. It is noted that the pipeline estimated does not account for projects that are at an early development stage and have not yet entered the planning process. The total existing and future gas generation pipeline is estimated to be c.2,705MW.

Reviewing publicly available SEMO data, the half hourly metered output for gas generators in Dublin was analysed to understand how these plants operate during times of high renewable output and also during all periods throughout the years 2021 and 2022.

---

[26] https://www.eirgridgroup.com/site-files/library/EirGrid/TSO-Imperfections-and-Constraints-multi-year-plan-2023-2027-Consultation.pdf

Looking at Table 19, the combined total average output of the dispatchable plants was c.642MW during 2021 and c.802MW during 2022. In the context of an existing 2021 CSO metered demand of c.6.4TWh[27], it is estimated that this dispatchable generation capacity accounted for an 88% share of demand in 2021, highlighting the important existing role of dispatchable generation in Dublin and also the opportunity to connect offshore wind capacity in the region to increase the share of renewable electricity.

Table 19: Dublin Conventional Generation Operation 2021 and 2022

All Periods		2021		2022	
Generator	MEC (MW)	Total Metered Output (MWh)	Average Output (MW)	Total Metered Output (MWh)	Average Output (MW)
Dublin Bay	415	1,772,630	202	1,697,475	199
Huntstown 1	352	1,886,951	215	1,715,393	201
Huntstown 2	412	464,005	53	2,000,105	235
Poolbeg A	231.5	912,036	104	755,425	89
Poolbeg B	231.5	589,465	67	667,531	78
Dublin Total	**1,642**	**5,625,087**	**642**	**6,835,929**	**802**

Table 20 shows the historical operation of gas generation in Dublin during times of renewable curtailment in 2021 and 2022. The combined total average output of the dispatchable plants was estimated to be c.333MW during 2021 curtailment periods and c.345MW during 2022 curtailment periods. This illustrates how dispatchable generation is required on the electricity system today even at times of high variable renewable output, to satisfy the requirement for five conventional generators in Ireland to be on the system at any one time. It is noted that the requirement is planned to reduce to two units by 2030, however MullanGrid understands that it appears likely that the remaining two units will be required in Dublin due to the complexities and needs of operating the Dublin electricity network. Further investigation will be required to understand the technical limitations associated with removing dispatchable conventional generation from the electricity system, especially in the Dublin area.

[27] https://data.cso.ie/table/MEC03

Table 20: Dublin Conventional Generation Operation During Curtailment Periods 2021 and 2022

Curtailment Periods		2021		2022	
Generator	MEC (MW)	Total Metered Output (MWh)	Average Output (MW)	Total Metered Output (MWh)	Average Output (MW)
Dublin Bay	415	100,270	121	104,494	107
Huntstown 1	352	88,580	107	97,426	100
Huntstown 2	412	26,432	32	92,740	95
Poolbeg A	231.5	50,578	61	22,637	23
Poolbeg B	231.5	9,152	11	19,071	20
Dublin Total	**1,642**	**275,012**	**333**	**336,368**	**345**

Looking to a net zero emissions energy system, the gas grid will require zero emission gas. Green hydrogen may provide GNI with a new business model in the longer term (2040+) considering that Climate Action Plan 2023 (literature review section) appears to rule out using gas for heating buildings and instead use district heat or heat pumps.

An example of a new potential business model could involve supplying large energy users such as data centres and electricity generators with green hydrogen from a 100% hydrogen gas grid.

Based on current available information, it is difficult to quantify the future total electricity requirement for dispatchable generation. As outlined in the section on Ireland's Roadmap to 2050, MaREI/UCC estimate that c.8TWh of electricity could be generated by c.6GW of dispatchable hydrogen generation capacity. This study appeared to indicate that dispatchable generation may be required to operate on average at full output for 15% of the year.

In the absence of more detailed analysis, a high-level approach has been applied to estimating demand for hydrogen in the power sector in Dublin. For the purpose of this study, the potential hydrogen demand for the power sector was estimated by assuming the existing/future pipeline of 2,705MW gas generation in Dublin converts to run on 100% hydrogen and is required to operate on average at full output for 15% of the year, then c.3.56TWh of zero emission electricity could be supplied to the electricity sector (produced by c.6.45TWh of green hydrogen, with 59% CCGT efficiency). Assuming a round trip efficiency of c.36% (individual efficiencies shown in Table 21), there appears to be a requirement for c.9.95TWh of renewable electricity equivalent to c.2.5GW offshore wind capacity with a 45% capacity factor.

Table 21: Hydrogen for Electricity Sector Round Trip Efficiency Assumptions

Description	Individual Efficiency	Energy
Transformer to Electrolysis (AC-DC)	95%	Electricity
PEM Electrolysis	74%	Hydrogen
Electrolysis BOP	90%	Hydrogen
Hydrogen Pipeline: to Storage	99%[28]	Hydrogen
Hydrogen Storage	98%[29]	Hydrogen
Hydrogen Pipeline: Storage to CCGT	99%[30]	Hydrogen
Hydrogen CCGT	59%[31]	Electricity
Round Trip Efficiency	**36%**	

Given the large concentration of electricity demand in Dublin, there will likely be a more significant requirement for dispatchable generation capacity compared to other regions in Ireland, which have successfully connected large capacities of onshore renewable generation and have relatively modest electricity requirements compared to Dublin. In addition, connecting offshore wind capacity in Dublin will be vital to helping the county achieve net zero. It is currently estimated Dublin has a 8% share of renewable electricity based on the CSO 2021 metered electricity demand and the renewable generation capacity located in the county. However, it is noted Dublin does import renewable electricity from other regions of Ireland through the 220kV and 400kV networks. In the future, Dublin could potentially be supplied hydrogen from other counties in Ireland, particularly along the east coast given its proximity.

On the East Coast, it is noted that the HYSS project[32] is reviewing salt cavern storage near Kish Bank and it appears that there may be potential for c. 35TWh of storage capacity, assuming that 10% of c.270 caverns are developed. DCarbonX and ESB are also reviewing hydrogen aquifer storage off the East Coast[33].

28 https://www.mdpi.com/1996-1073/15/24/9370/pdf

29 https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf

30 https://www.mdpi.com/1996-1073/15/24/9370/pdf

31 https://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Study-3-Hydrogen-for-Power-Generation.pdf

32 https://hyss.ie/

33 https://esb.ie/media-centre-news/press-releases/article/2022/09/05/esb-and-dcarbonx-expand-irish-offshore-energy-storage-partnership

Going to a net zero energy system will drive significant electricity demand growth from c.29TWh in 2019 to c.84TWh in 2050 to meet electrification requirements, as discussed in section . The exact level of demand growth and investment required has not been studied by the electricity transmission or distribution network operators, EirGrid or ESB Networks, respectively. Challenges and timelines in building the grid for an 84TWh system could also create opportunities for technologies like green hydrogen that have an alternative approach for transporting energy via molecules opposed to relying on new electricity networks.

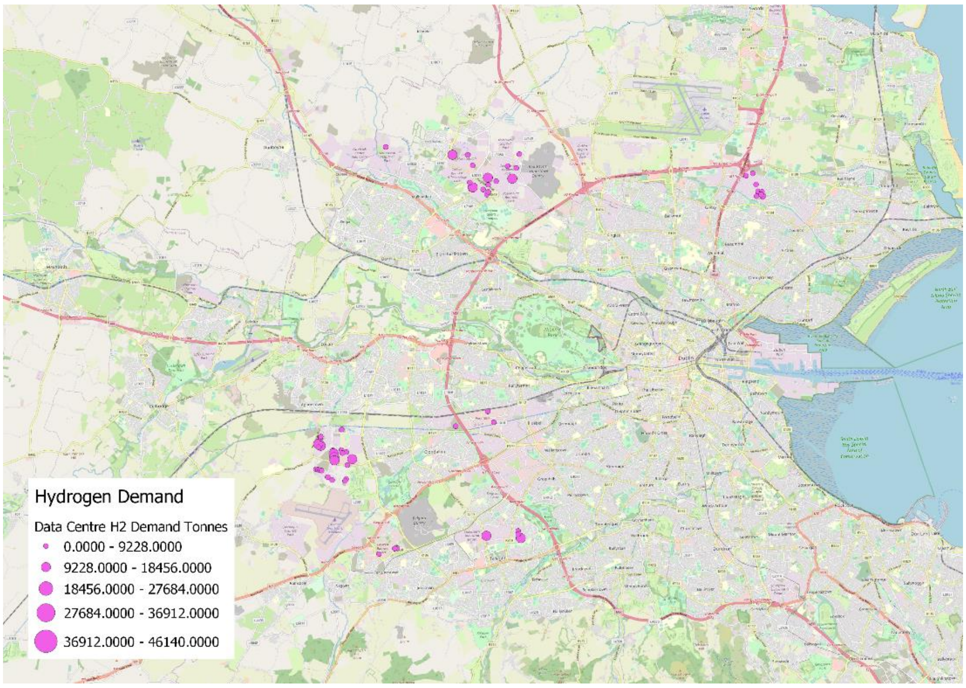
At times of low variable renewable output from wind and solar capacity, long term storage capacity and dispatchable generation will be important to ensure security of electricity supply and to provide added resilience to the electricity system. The future requirements for dispatchable generation and energy storage are not fully understood with a detailed technical assessment required for a net zero emissions system.

4.1.2 Data Centres

As outlined in section 4.1.1, a new potential business model could be for the gas grid to supply large energy users such as data centres and electricity generators with green hydrogen from a 100% hydrogen gas grid.

The literature review section 'Data Centres' indicated that there is c.1,884MVA of connected/contracted data centre capacity in the Greater Dublin region. Codema's 2021 'Dublin Region Energy Master Plan' estimated that data centres in Dublin require c.4.31TWh of electricity.

Unlike generator connections, EirGrid does not publish information on demand connections in Ireland. Therefore, by only using publicly available information, it is difficult to quantify the existing demand and associated maximum import capacity for data centres in Dublin. For the purpose of this study, the potential demand from data centres in Dublin has been estimated and the location of these large energy users has been mapped. This map assumes that the expected increase in electricity demand by 2030 will be provided by onsite generation due to limitations in grid capacity for providing bigger connections. This equates to an electricity demand of 4,000 GWh. It is assumed for the purpose of calculating H2 demand that this would be generated using onsite fuel cells with an efficiency of 50% based on the High Heat Value of hydrogen. This gives a potential hydrogen demand of approximately 202,800 tonnes.


Hydrogen Demand
Data Centre H2 Demand Tonnes
0.0000 - 9228.0000
9228.0000 - 18456.0000
18456.0000 - 27684.0000
27684.0000 - 36912.0000
36912.0000 - 46140.0000

4.2 Transport Sector

In Dublin, green hydrogen does appear to have significant potential in terms of electricity generation and also as a fuel source for data centres. In the shorter term (2030), the transport sector may help to grow the market for hydrogen, a potential decarbonising role appears to be for heavy goods vehicles. In the longer term (2040+), it appears hydrogen could support the decarbonisation of the maritime and aviation sectors.

In terms of heavy transport applications, fuel cell electric vehicles (FCEVs) and battery electric vehicles (BEVs) present possible options for decarbonising the fleet of trucks, buses and trains across Ireland. The upfront capital costs, ongoing operation/maintenance costs and availability of the respective FCEV or BEV option will ultimately help to decide the most suitable decarbonisation technology, there are also some operational requirements including operational long-range distances and weight requirements could shape the eventual uptake of the respective technologies. In the wider Dublin area, the availability of demand import capacity for charging infrastructure for the BEV option could provide some weighting in the decision on technology of choice.

4.2.1 Passenger Car and Light Goods Vehicles

It is not envisioned that hydrogen will play a significant role in the decarbonisation of the passenger car and light goods vehicles sectors. BEVs are seen as the optimal solution for these lighter vehicles, as the technological solution is already widely available and commercially proven. This is reflected in the rapidly growing range of models available on the market, and in the significant number of manufacturers who have committed to phasing out fossil fuel cars for the European market by 2030. The investment focus is now on battery production, with Europe projected to become the second largest battery producer globally by 2030[34]. In 2022, BEVs made up over 12% of EU car sales, despite being constrained by significant supply chain issues[35]. Purchase price parity between battery electric cars and vans and their fossil fuelled alternatives is expected to occur by the middle of this decade, while in many cases these vehicles are already competitive on a total cost of ownership basis. Hydrogen fuel cells or e-fuels are not projected to be able to compete with BEVs on this basis.

[34] **https://www.transportenvironment.org/discover/a-european-response-to-us-inflation-reduction-act/**

[35] **https://www.transportenvironment.org/discover/co2-targets-propel-european-ev-sales/**

4.2.2 Urban Bus

Dublin Bus, who operates a fleet of more than 1,000 vehicles, has already unveiled three FCEV buses, which currently operate routes in North Dublin[36]. In Dublin, buses alone currently account for 5% of the county's transport-related emissions.

The Phase Two report on the Low Emission Bus trials was published in 2022 and assessed the operation of two FCEV buses between November 2020 and August 2021 operating in county Dublin[37]. The report compared the findings of the FCEV buses with other bus technologies including BEV, diesel, hybrid and compressed natural gas. It was noted from the report, that FCEV buses were comparable to diesel hybrid buses for energy efficiency. On a primary energy basis, considering consumption, distribution, and conversion losses in transforming energy from one form to another, hydrogen was reported to rank below diesel-hybrid technology. Electric buses were indicated be the most energy efficient technology for urban bus fleets.

4.2.3 Heavy Goods Vehicles

County Dublin has a fleet of around 29,000 HGVs, which contribute to 15% of the county's transport-related emissions, with Dublin Port Tunnel alone experiencing around 10,000 HGVs every day. Dublin Port has plans to increase its annual throughput by approximately 40 million tonnes per year by 2040, which if all transported by truck, could result in over 1 million additional HGV movements per year at the port[38].

A survey performed by DCU in 2021 collected responses from 70 companies with a total fleet of 3,000 trucks and found that nearly half of them were willing to place an early order for hydrogen fuel cell electric trucks, with seven companies willing to take more than 20 trucks each[39].

---

[36] https://hydrogenireland.org/2022/08/08/one-year-of-the-hydrogen-bus-in-dublin-welcomed/

[37] https://www.gov.ie/pdf/?file=https://assets.gov.ie/224578/de98566c-8d6e-4201-996e-5f7f090ff4a0.pdf#page=null

[38] https://www.dublinport.ie/wp-content/uploads/2018/07/DPC_Masterplan_2040_Reviewed_2018.pdf

[39]https://reader.elsevier.com/reader/sd/pii/S0360319922026404?token=D1293E2A4517DA7E5E3F8F61D28C389F94F6F77BC8DE67F132D530E461F1BD398C017C6C8331B510175C5164C31EDA35&originRegion=eu-west-1&originCreation=20230510100107

4.2.4 Aviation

Dublin Airport was the 12th busiest airport in Europe in 2019, when almost 33 million passengers and 226,000 aircraft movements were recorded[40,41]. SEAI estimated jet fuel demand of 1,116 ktoe (1,062 kt) for international and domestic flights in 2019[42].

The Fit for 55 package includes a proposal to ensure a level playing field for sustainable air transport through the ReFuelEU aviation initiative. Parliament and Council negotiators agreed on a final text on 25 April 2023, which now is required to pass through both institutions for formal adoption. The final agreement sets ambitious targets for total SAF supply (70% in 2050) and for e-fuels, starting at 1.2% in 2030, increasing to 35% in 2050.

Aviation has more stringent technology and safety requirements than shipping[43]. A high gravimetric energy density is particularly important for aviation fuels as aeroplanes are more weight sensitive than other transport modes. Sustainable aviation fuels to substitute fossil fuels include e-kerosene and hydrogen.

E-kerosene appears to meet the specifications of conventional aviation fuel and is compatible with existing aircraft technology. Producing e-kerosene requires green hydrogen produced from renewable electrolysis and atmospheric CO_2, both of which are energy intensive processes.

Hydrogen aircraft are an emerging technology that could potentially replace conventional aircraft models and reduce fossil jet fuel use. Hydrogen has a gravimetric energy density three times higher than conventional kerosene. However, the weight of storage tanks reduces this weight advantage significantly. The market entry of hydrogen aircraft will be dependent on overcoming several technological challenges related to the properties of hydrogen, which differ from conventional aviation fuel and e-kerosene. In addition, using hydrogen in aviation may require significant investments at airports to transport and store hydrogen fuel.

Hydrogen Mobility Ireland reviewed the role of hydrogen derived e-fuels in aviation and maritime and the opportunities in Ireland[44] and estimated that Ireland could require up to 7-11kt hydrogen in 2030, reaching up to 230-330kt in 2050.

---

40 https://www.daa.ie/dublin-airport-welcomed-32-9m-passengers-in-2019/

41 https://assets.gov.ie/124190/658b19ef-240a-47fd-bedc-ba81e44ac628.pdf

42 https://www.seai.ie/publications/Energy-in-Ireland-2021_Final.pdf

43 https://www.itf-oecd.org/sites/default/files/docs/potential-efuels-decarbonise-ships-aircraft.pdf

44 https://h2mi.ie/wp-content/uploads/2023/05/HMI-eFuels-Report-May-2023.pdf

4.2.5 Maritime

According to a 2019 report by the IMDO there are approximately 20 vessels serving routes between the UK and Europe from Dublin and Rosslare[45]. This report suggested that an LNG refuelling terminal would not be feasible at Irish ports due to the small scale of Ireland's maritime industry. It was suggested that most ships would choose to refuel at larger ports, where fuel would be available cheaper.

SEAI estimate that the total domestic demand for marine fuel in Ireland in 2021 was 293 ktoe (303kt), with long-range international shipping representing close to 60% of the total.

In 2022, there were 7,473 arrivals at Dublin Port, representing a total throughput in gross tonnage of 36.7 million tonnes[46]. In 2021, approximately 52% of unitised (cargo) trade was on GB routes, with the remaining 48% on continental services. RoRo made up 74% of this, with LoLo accounting for the other 26%[47]. Continental LoLo routes are generally to Antwerp, Amsterdam or Rotterdam. GB LoLo route from Dublin is to Liverpool. Continental RoRo routes include Esbjerg, Leixoes, Rotterdam, Zeebrugge and Cherbourg. GB RoRo routes consist of Holyhead, Heysham and Liverpool[48]. See Figure 40.

The final FuelEU Maritime legislation includes an e-fuels sub-target of 2% of the EU's shipping fuels by 2034. Hydrogen Mobility Ireland analysed potential scenarios for e-methanol demand in the maritime sector out to 2050. The potential hydrogen supply required was estimated to be between 1-1.2kt for international and domestic shipping in 2030. Looking to 2050, the potential hydrogen supply required was estimated to be up to 48-61kt.

Hydrogen and ammonia are uncommon maritime fuels at present, but both are reported to be potential fuels that could support decarbonisation of the maritime sector. The main advantage of ammonia over hydrogen is its lower refuelling and on-board storage requirements. The use of hydrogen or ammonia in the shipping sector is still at a low stage of technology readiness and further pilot tests and research will likely be needed to better understand the feasibility of using these fuels. Even if technology is readily available for ships, challenges to introducing the refuelling infrastructure will need to be overcome.

---

[45] https://www.imdo.ie/Home/sites/default/files/IMDOFiles/13774%20IMDO%20Development%20of%20Alternative%20Fuel%20V6%20HR.PDF

[46] https://www.dublinport.ie/trade-statistics/

[47] https://www.dublinport.ie/wp-content/uploads/2022/07/DPC_Annual_Report_2021_English.pdf

[48] https://www.imdo.ie/Home/site-area/statistics/ports-operators/route-map

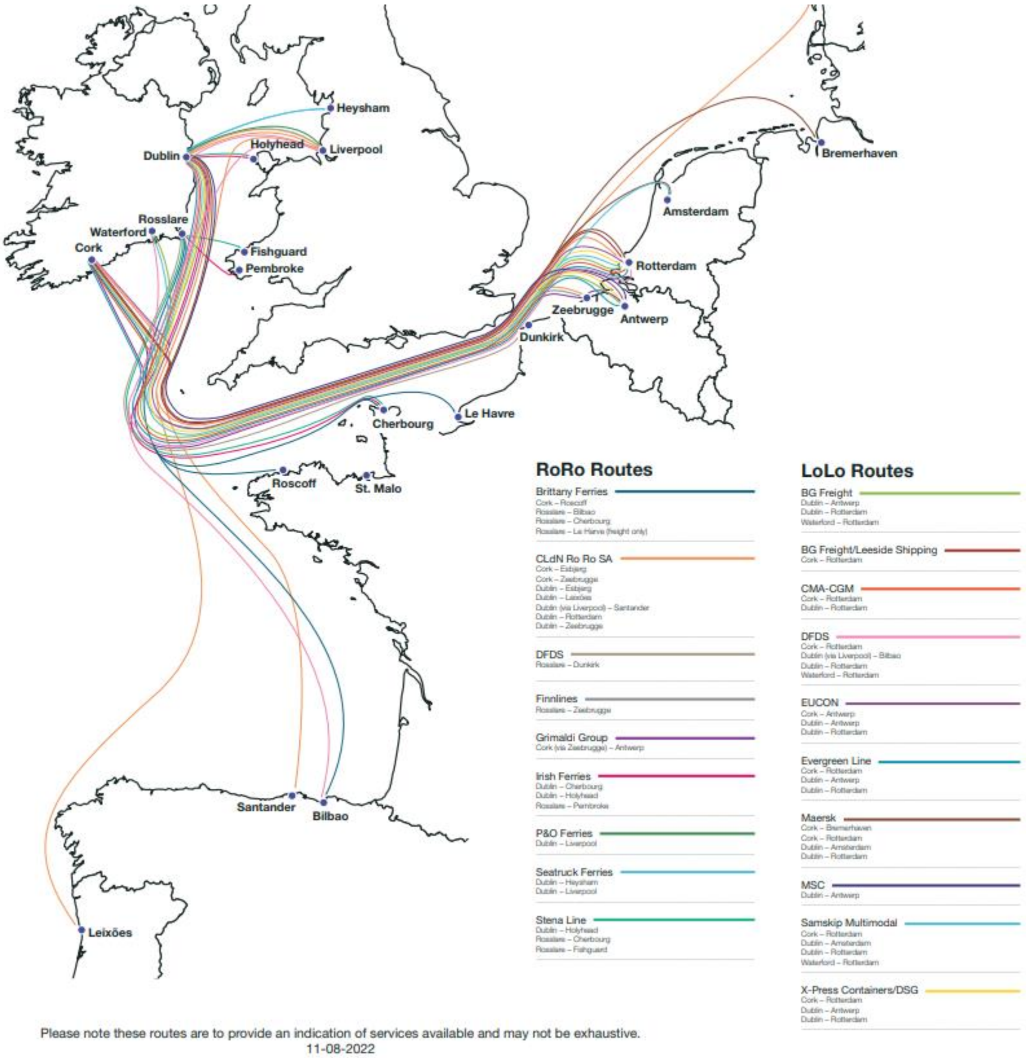


Figure 40: Dublin Port RoRo and LoLo Routes 2022

4.3 Industry Sector

As discussed earlier in section , it is noted from the Climate Action Plan 2023 that “All buildings will need to switch to heat pumps or district heating by 2050, meaning that the gas grid will no longer supply existing homes and commercial premises."

4.4 Hydrogen Demand Spatial Analysis

This section of the report maps the more likely hydrogen demands in the Dublin area. The location and estimated H2 demands for these sites have been mapped in the figure below. These maps can be used to indicate areas where H2 (or more cost-effective biomethane) could be utilised in the future and therefore where H2 consuming industries could be located in the future to reduce the need for maintaining a wider gas network to support these industries.

The main potential users identified as part of this study use hydrogen to generate electricity. It should be noted that the timeline. These are large-scale power generators who are assumed to use H2 in open-cycle gas turbines (OCGT) to provide firm power when renewable generation is low. For the purpose of this analysis the OCGT power generation efficiency is assumed to be 35%. The second potential user are data centres which due to increased stresses on the grid will be required to have on site generation which in the future does not use fossil fuels. The non-fossil fuels used for generating on-site power for data centres could be H2 but perhaps more likely could be biomethane due to the lower cost of biomethane. For the data centre site which use H2 it is assumed that fuel cells would be used for serving their electricity demand (demand over and above what is currently being served by the electricity grid). These fuel cells are assumed to be 50% efficient based on High Heat Value (HHV) of the Hydrogen.

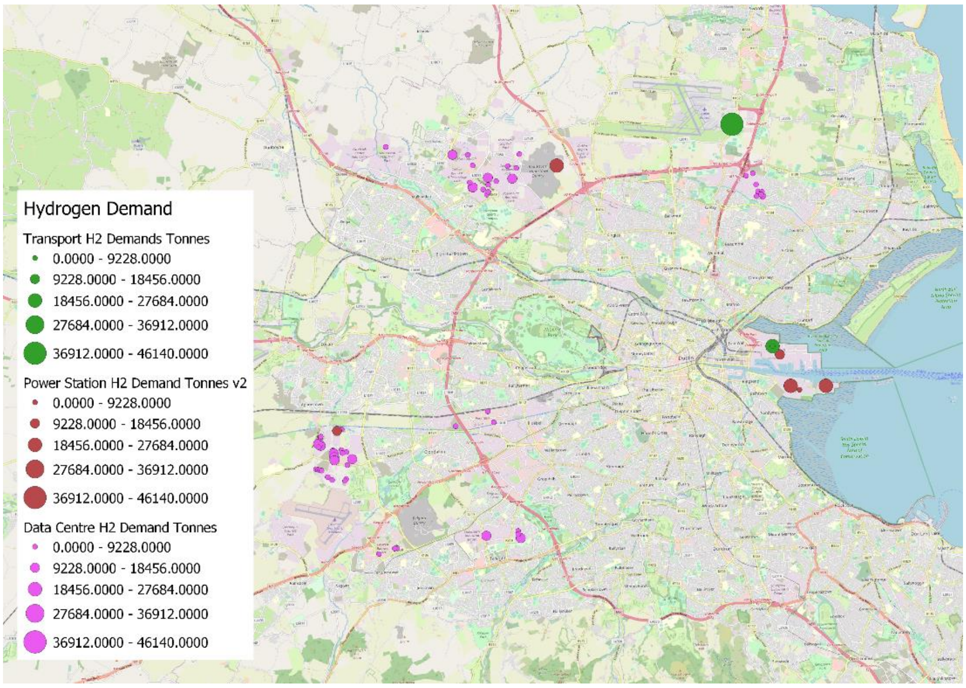


Figure 41: Potential Future Hydrogen Users (please note that there is a high degree of uncertainty around the business case for green hydrogen and lack of clarity around whether many of these potential users would create a market for H2 in Dublin)

The map below shows that concentration of potential hydrogen demand in the Dublin area. There are four areas where there could be potential for hydrogen consumption. These areas are the Dublin Airport area, the Ballycoolin-Huntstown area, the Grange Castle area and the Poolbeg-Dublin Port area.

If a green H2 is found to be viable in the future, these could also be the areas where future hydrogen users should be located in order to best utilise this infrastructure and reduce the need for a wider less cost-effective hydrogen supply network.

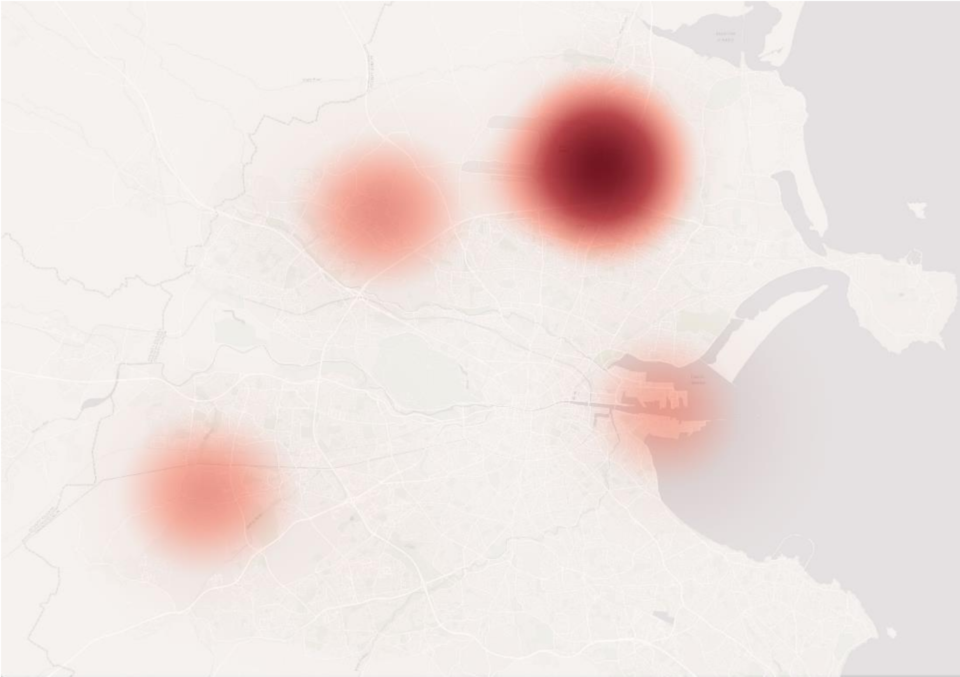


Figure 42: Hot Spots of Potential Future Green H2 Consumption in Dublin (please note that there is a high degree of uncertainty around the business case for green hydrogen and lack of clarity around whether many of these potential users would create a market for H2 in Dublin)

4.5 Assessment of Hydrogen Applications in Dublin

This section of the report qualitatively assesses the likelihood for hydrogen across electricity sector, transport sector and industry sector applications. The assessment takes into account the analysis of the various sectors presented in sections 4.1,4.2 and 4.3. For each sector and application, the maturity of technology or technology readiness level from the IEA ETP Clean Energy Technology Guide[49], the competing technologies and current policies for decarbonisation were also considered.

The assessment of potential uptake of green hydrogen in Dublin's electricity sector is presented in Table 22. It is noted that:

- **Dispatchable Generation:** Hydrogen gas turbines are at a commercial operation stage for a blend of natural gas and hydrogen mixtures, however operation from 100% hydrogen is still at a pre commercial demonstration stage. In the short-medium term it is possible that there may be some dispatchable power generation from a mix of natural gas and hydrogen in a 2030-35 timeline. There appears to be a higher likelihood for the deployment of 100% hydrogen in the longer term to 2040 considering the necessary phase out of fossil fuel generation. By 2040, it is also possible that the CCGT technology for 100% hydrogen operation may have reached greater maturity if the technology is widely deployed across other jurisdictions.
- **Data Centres:** There is a large connected/contracted capacity of data centres concentrated in the Greater Dublin region, there is an existing requirement for backup power generation for data centres to ensure security of supply. Current data centre connection policy does not facilitate connections in constrained areas of the electricity network in terms of demand capacity. Looking to 2030, there may be some deployment of hydrogen fuel cells at data centres in Ireland to replace diesel back up generation. In the longer term, there appears to be some potential for data centres to utilise hydrogen delivered via the gas grid as a replacement for natural gas. It appears that some data centres are already operating off the electricity grid and generating their own electricity onsite from natural gas. There are also some data centres with non-firm grid connections capacity that are required to operate their own onsite gas generation at times when the network and system are strained.

Table 23 shows the qualitative assessment of the potential hydrogen uptake across applications in Dublin's transport sector. From the assessment it appears that:

[49] https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide

- **Passenger Car/ Light Goods Vehicles:** Fully electric BEV passenger cars and light goods vehicles appear to be the cheaper and more efficient zero emissions option for decarbonisation compared to FCEVs. The scale up of BEV's has already commenced globally and in Ireland and the potential for FCEV uptake appears low.
- **Urban Bus:** Low Emission Bus trials indicate hydrogen ranks below diesel-hybrid technology in terms of efficiency on a primary energy basis. Electric buses were indicated be the most energy efficient technology for urban bus fleets. The likelihood of deployment appears low relative to fully electric buses. It is recommended that the charging infrastructure requirements for electric buses in Dublin is examined with consideration for demand growth in other sectors.
- **Heavy Goods Vehicles:** A DCU survey conducted in 2021 indicated that some haulage operators were considering FCEV trucks for their fleet. Although there appears to be challenges to the deployment including upfront capital costs and the availability of vehicles. The upfront costs of FCEVs are very high relative to the diesel option. Cost down curve projections indicate there may be greater parity from 2030 onwards. Based on the DCU study, the potential for FCEV deployment appears to be low-moderate in a 2030 timeline and moderate-high in a 2040 timeline assuming cost reductions and technology improvements. It is noted there may be advances in other technologies such as fully electric heavy-duty trucks by 2040 (or also electric roads) that may impact on the uptake of green hydrogen.
- **Aviation:** Dublin Airport was the 12th busiest airport in Europe in 2019. Sustainable aviation fuels to substitute fossil fuels and reduce emissions in the sector include e-kerosene and hydrogen. E-kerosene produced from hydrogen and atmospheric CO_2 appears to be a fuel that meets the specifications of conventional aviation fuel and is compatible with existing aircraft technology. Hydrogen aircraft are an emerging technology that could potentially replace conventional aircraft models and reduce fossil jet fuel use. In the future, there may be a significant requirement for green hydrogen as a sustainable aviation fuel in e-kerosene fuelled aircraft and/or hydrogen aircraft. Using hydrogen in aviation may require significant investments at airports to transport and store hydrogen fuel. Hydrogen Mobility Ireland reviewed the role of hydrogen derived e-fuels (e-kerosene) in aviation and estimated that Ireland could require up to 7-11kt hydrogen in 2030, reaching up to 230-330kt in 2050.
- **Maritime:** Hydrogen and ammonia are uncommon maritime fuels at present, but both are reported to be potential fuels that could support decarbonisation of the maritime sector. The use of hydrogen or ammonia in the shipping sector is still at a low stage of technology readiness and even if technology is readily available for ships, challenges to introducing the refuelling infrastructure will need to be overcome. According to a

2019 report by the IMDO there are approximately 20 vessels serving routes between the UK and Europe from Dublin and Rosslare, and it suggested that an LNG refuelling terminal would not be feasible at Irish ports due to the small scale of Ireland's maritime industry. It was suggested that most ships would choose to refuel at larger ports, where fuel would be available cheaper. Hydrogen Mobility Ireland analysed potential scenarios for e-methanol demand in the maritime sector out to 2050. The potential hydrogen supply required was estimated to be between 1-1.2kt for international and domestic shipping in 2030. Looking to 2050, the potential hydrogen supply required was estimated to be up to 48-61kt.

The potential for green hydrogen deployment in the industry sector in Dublin is presented in Table 24. From the assessment it appears that:

- **High Temperature Heat Processes:** Hydrogen steam boilers are already in commercial operation in other jurisdictions. High temperature requirements are reducing as steam is not always required which means heat pumps may be a more suitable option. Burning hydrogen provides less control than electricity methods. Discuss why low potential.
- **Low and Medium Temperature Heat Processes:** Hydrogen boilers are in commercial operation already. However more efficient, cheaper and proven technologies already exist so hydrogen appears to have low potential for heating buildings in Dublin. Climate Action Plan 23 also indicates that "All buildings will need to switch to heat pumps or district heating by 2050". The potential uptake for green hydrogen appears to be low.
- **Feedstock:** There is currently no ammonia or fertiliser production in Ireland however there may be potential in the longer term to develop some ammonia production plants with hydrogen as a feedstock to facilitate fertiliser production and ammonia exports. Ammonia is the main ingredient in synthetic fertilisers, of which Ireland is a major user, consuming 560,000 tonnes in 2020. Currently, fertiliser consumed in Ireland is manufactured across the EU using "grey" hydrogen. In the future fertiliser production could be from green hydrogen in Ireland. There may be more suitable locations for ammonia production in Ireland such as the Shannon Foynes Port in Limerick which is examining the potential for ammonia production from offshore wind[50], and it is noted

[50] https://www.sfpc.ie/wp-content/uploads/2022/11/SFPC-Vision-2041-Strategic-Review-Final-Report.pdf

that ESB have signed a Memorandum of Understanding (MOU) with the Shannon Foynes Port Company[51].

[51] https://esb.ie/media-centre-news/press-releases/article/2023/05/15/esb-and-shannon-foynes-port-to-deepen-partnership-as-transformation-of-shannon-estuary-into-international-green-energy-hub-gathers-pace

Table 22: Assessment of Potential Hydrogen Uptake in Electricity Sector

Sub Sector	Hydrogen Related Technology	Technology Readiness Level	2030 Likelihood	2040 Likelihood	Competing Technologies	Comments	Potential Demand (TWh)
Dispatchable Generation	Hydrogen fired gas turbine	(7-9) Pre commercial demonstration for 100% hydrogen, commercial operation for natural gas and hydrogen mixtures	Low-Moderate	Moderate to High	Natural Gas, Biogas	In the short-medium term it is possible that there may be some dispatchable power generation from a mix of natural gas and hydrogen in a 2030 timeline. There appears to be a higher likelihood for the deployment of 100% hydrogen longer term to 2040 considering the necessary phase out of fossil fuel generation. It is noted that the requirement for dispatchable power generation in a net zero electricity system is not yet understood for Dublin.	6.99 TWh
Data centres	High temperature fuel cell Ammonia fuelled turbine, Hydrogen fired gas turbine	(7-9) Pre commercial (4) Early prototype (7-9) Pre commercial for pure hydrogen, commercial operation for natural gas and hydrogen mixtures	Low-Moderate	Moderate to High	Biogas CHP, Hydrotreated Vegetable Oil	Considering the large capacity of data centres concentrated in the Dublin area, there is an existing requirement for backup power generation for data centres to ensure security of supply. Looking to 2030, there may be some deployment of hydrogen fuel cells at data centres in Ireland to replace diesel back up generation. In the longer term, there appears to be a high potential for data centres to utilise hydrogen delivered via the gas grid as a replacement for natural gas, particularly for the data centres off grid and non-firm grid connections.	N/A

Potential hydrogen demand for dispatchable generation based on existing/future pipeline of 2,705MW gas generation in Dublin converting to run on 100% hydrogen, operating on average at full output for 15% of the year, assuming delivered via hydrogen pipeline from offshore salt cavern storage, overall round trip efficiency assumed to be 36%.

Table 23: Assessment of Potential Hydrogen Uptake in Transport Sector

Sub Sector	Hydrogen Related Technology	Technology Readiness Level	2030 Likelihood	2040 Likelihood	Competing Technologies	Comments	Potential Demand (TWh)
Passenger car, Light goods vehicle	FCEV, hydrogen fuelled engine	(9) Commercial operation, (6) prototype at scale	Low	Low	BEV	Fully electric BEV passenger cars and light goods vehicles appear to be the cheaper and more efficient zero emissions option for decarbonisation compared to FCEVs.	N/A
Urban bus	FCEV, hydrogen fuelled engine	(9) Commercial operation, (6) prototype at scale	Low	Low	BEV	Based on the Low Emission Bus trials the likelihood of deployment appears low relative to fully electric buses. The charging infrastructure requirements for electric buses needs to be examined in Dublin with consideration for demand growth in other sectors.	N/A
Heavy Goods Vehicles	FCEV, hydrogen fuelled engine	(7-8) Pre-commercial demonstration, (6) full prototype at scale	Moderate	Moderate to High	BEV, Biofuels	A survey performed by DCU in 2021 indicated that some haulage operators were considering FCEV trucks for their fleet. Although there appears to be challenges to the deployment including the availability of vehicles. The upfront costs of FCEVs are very high relative to the diesel option. Cost down curve projections indicate there may be greater parity from 2030. Based on the DCU study, the potential for FCEV deployment appears to be moderate in a 2030 timeline and high in a 2040 timeline assuming cost reductions. There may be advances in other technologies such as fully electric trucks electric roads that may impact on the actual uptake. The hydrogen fuelled engine is currently still at a prototype stage and not in full commercial operation, in the longer term this may be an option for decarbonisation of the heavy goods vehicle sector.	0.07 TWh

Aviation	Hydrogen-fuelled engine	(3-4) Concept needs validation	Low	Moderate	Syntethic fuel, Biofuels, BEV	Sustainable aviation fuels to substitute fossil fuels and reduce emissions in the sector include e-kerosene and hydrogen. E-kerosene offers the commercial advantage of meeting the specifications of conventional aviation fuel and it is also compatible with existing aircraft technology. The hydrogen fuelled engine concept is at an early prototype stage and the weight of storage tanks appears to be an obstacle. Using hydrogen in aviation may require significant investments at airports to transport and store hydrogen fuel. Hydrogen appears to have some requirement as form of sustainable aviation fuel in the longer term to 2040.	**HMI nationwide projections[a]:** **2030** 0.23-0.37 TWh **2050** 7.68-11.02 TWh
Maritime	Ammonia fuelled engine, Hydrogen fuelled engine, FCEV	(4-5) early prototype, (4-5) early prototype, (7) Pre-commercial demonstration	Low	Moderate	BEV, Methanol, Biogas	Hydrogen and/or ammonia fuelled engines appear to have potential to reduce emissions in maritime sector although both are uncommon in the sector currently. Both technologies appear to be at a low stage of technology readiness and even if technology is readily available for ships, challenges to introducing the refuelling infrastructure will need to be overcome. According to a 2019 report by the IMDO there are approximately 20 vessels serving routes between the UK and Europe from Dublin and Rosslare, and it suggested that an LNG refuelling terminal would not be feasible at Irish ports due to the small scale of Ireland's maritime industry. It was suggested that most ships would choose to refuel at larger ports, where fuel would be available cheaper.	**HMI nationwide projections[a]:** **2030** 0.03-0.04 TWh **2050** 1.6-2.04 TWh

[a] Hydrogen Mobility Ireland projections converted to TWh using hydrogen lower heating value of 120.21 MJ/kg.

Table 24: Assessment of Potential Hydrogen Uptake in Industry Sector

Sub Sector	Hydrogen Related Technology	Technology Readiness Level	2030 Likelihood	2040 Likelihood	Competing Technologies	Comments	Potential Demand (TWh)
High temperature heat processes	Hydrogen boiler	(9) Commercial operation in relevant environment	Low	Low	Heat Pumps/Mechanical Vapour Recompression	Proven alternatives already exist for the lower range, high temperature requirements are reducing as steam is not always required which means heat pumps are a suitable option. These remaining demands can be mapped for Dublin. Burning hydrogen provides less control than electricity methods.	N/A
Low/medium temperature heat processes	Hydrogen boiler	(9) Commercial operation in relevant environment	N/A	N/A	Heat Pumps	More efficient, cheaper and proven technologies already exist so hydrogen is not likely to play a role here. Safety concerns over using hydrogen in less controlled environments (outside of industry) is also an issue.	N/A
Feedstock	Ammonia, Hydrogen	(11) Already used as feedstock in other jurisdictions	Moderate	Moderate	-	The Irving Oil refinery at Whitegate, Cork is currently the largest consumer of hydrogen in Ireland. There are plans to phase out fossil fuelled hydrogen production with renewable hydrogen production. There is currently no ammonia or fertiliser production in Ireland however there may be potential in the longer term to develop some ammonia production plants with hydrogen as a feedstock to facilitate fertiliser production and ammonia exports.	N/A

5 Poolbeg: Hydrogen Production Case Study

This section of the report presents a high-level feasibility assessment of hydrogen production at Poolbeg. The assessment takes into account the hydrogen production modelling discussed in section 3.4 and the review of future hydrogen markets from section 4.

The hydrogen production scenarios were qualitatively assessed with respect to the Additionality Delegated Act. The optimal electrolyser capacities (in terms of utilising available renewable energy) were considered for the various hydrogen production scenarios and the LCOHp and estimate viable sale price to the power sector compared. Considering land availability, the electrolyser capacity was limited to 400MW for the Poolbeg assessment.

Some key metrics considered to assess the potential deployment of the green hydrogen production scenarios in Poolbeg include:

- **Renewable Energy Source Available for Hydrogen Production**: it is important to consider Dublin's growing requirement for electricity and existing concentration of large energy users in the Greater Dublin region. Increasing the share of RES-E in Dublin from offshore wind will be critical to Dublin reaching net zero emissions in the electricity sector. The offshore wind connecting to Dublin should first be prioritised for the large electricity demand of Dublin.
- **Electricity Grid Demand Capacity**: with the rollout of electrification in heat and transport, there will likely be significant competition for demand capacity in Dublin on the transmission and distribution system. Considering EirGrid's data centre connection policy, it appears that there is already demand capacity constraints on Dublin's electricity network.
- **Land Availability**: the availability of land is a key consideration given the Poolbeg peninsula is home to Ireland's largest cluster of utilities with wastewater works, waste to energy electricity generation, natural gas generation, battery storage and the National Oil Reserve (NORA). Dublin Port is Ireland's premier port handling almost 50% of all trade in Ireland and the 3FM project plans to expand the port capacity by 2040. ESB are major landowner in the area that may have land available for a green hydrogen production facility. For example, there appears to be a ESB owned parcel of land available that could facilitate c.400MW of electrolyser capacity (based on land requirement of c.48m^2/MW electrolyser capacity for PEM technology and 3 days of onsite tanked storage).
- **Hydrogen Safety:** Poolbeg Peninsula is already home to a large number of utilities. However, it is recommended that further investigation is carried out on the safe

operation of hydrogen production via electrolysis. It is noted that the National Standards Authority of Ireland (NSAI) are preparing new standards for hydrogen.

- **Hydrogen Market:** there is a small existing demand for hydrogen in the Dublin area in the pharmaceutical sector. In the longer term, demand from hydrogen may grow with new demand from the power sector beyond a 2030 timeline as the electricity system moves towards 100% RES-E.
- **Hydrogen Storage:** currently there is no existing long term storage capacity for hydrogen in Ireland. A SEAI project referred to as HYSS is reviewing east coast salt cavern storage near Kish Bank, and it appears that there may be potential for c. 35TWh of storage capacity, based on the assumption that 10% of c.270 caverns are developed. DCarbonX and ESB are reviewing hydrogen aquifer storage off the East Coast.
- **Hydrogen Distribution:** Climate Action Plan 2023 details that “All buildings will need to switch to heat pumps or district heating by 2050, meaning that the gas grid will no longer supply existing homes and commercial premises." Therefore, the Gas Grid could potentially be repurposed to supply large energy users and electricity generators running on 100% hydrogen.
- **Water Availability:** the available Irish water capacity for a c.400MW electrolysis plant needs to be investigated further. Further research needs to be carried out on the possibility of desalination and the associated environmental parameters and economics.

The overall feasibility for each hydrogen production scenario at Poolbeg was classified as low, moderate or high potential. The development potential is summarised as:

- **Grid Connected High RES-E:** Low development potential, as there is limited demand capacity available in the Dublin region considering large existing demand and the need for electrification in the area. This configuration could have a higher development potential at other locations on the East Coast of Ireland where there is adequate renewable generation connected, greater capacity on the transmission system for increased demand and potential for hydrogen storage and distribution infrastructure.
- **Offshore Wind Off Grid:** Low to moderate development potential, the business model relies on offshore wind costs reducing in line with cost down curve projections. Given the competition for land in Poolbeg, the development potential for a 2GW hydrogen production facility appears to be low, however there appears to be low-moderate potential for a c.400MW capacity project. Further research could examine the potential for offshore electrolyser facilities considering competition for land in Dublin. A hybrid combination of a grid connection and electrolyser connection for 2GW offshore wind

capacity may improve the business case for the offshore wind facility, thus increasing the development potential.

- **System Wide VRES Curtailment:** Low development potential, this scenario is challenging to replicate in reality due to large volumes of dispatched down electricity considered on the electricity system. Identifying significant bottlenecks in exporting renewable electricity on the electricity network could point to a suitable location for an electrolyser for this configuration. Poolbeg is not an example of a bottleneck, as there is an existing large demand for electricity and a low capacity of renewable generation. For example, the West of Ireland has an existing large capacity of renewable generation capacity from mainly onshore wind. The North-West and West Galway currently experience significant constraints in exporting electricity to demand centres due to congestion on the local transmission networks at times of high renewable output. Some measures to address these constraints, include creating additional transmission network capacity and the co-location of demand. It is noted that there are projects exploring green hydrogen production in both of these areas, Mercury Renewables Firlough Wind Farm[52] in North Mayo and the Galway Hydrogen Hub[53].
- **Offshore Wind Dispatch Down:** Low development potential, the risk associated with using curtailed electricity at Poolbeg means this business model is viewed as low development potential. Curtailment is highly variable and is heavily influenced by the capacity of renewable generation, electricity demand, network operational measures and interconnector export capacity. Flexible demand and district heat could be more favourable measures for mitigating curtailed electricity in Poolbeg. The hierarchy of curtailment mitigation measures needs to be investigated further.
- **Offshore Wind and Solar PPA:** Low development potential, as there is limited demand capacity available in the Dublin region considering large existing demand and the need for electrification in the area. Similar to the 'Grid Connected High RES-E' scenario, this configuration could have a higher development potential at other locations on the East Coast of Ireland where there is adequate renewable generation connected, relatively low electricity demand and greater capacity on the transmission system for increased demand, and also hydrogen storage and distribution infrastructure.

[52] https://mercuryrenewables.ie/

[53] https://www.gh2.ie/

Table 25: Poolbeg: Hydrogen Production Case Study

Parameter	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
Scenario Description	Electrolyser utilising all system wide wind and solar electricity as required.	Electrolyser utilising electricity from 2GW offshore wind capacity.	Electrolyser utilising all system wide wind and solar curtailed electricity.	Electrolyser utilising Poolbeg connected curtailed offshore wind electricity.	Electrolyser utilising electricity from Poolbeg offshore wind capacity and PPA electricity from solar PV with capacity matched to electrolyser.
Additionality Delegated Act	2035+ or >90% RES-E.	Pre 2030	Pre 2030	Pre 2030	2035+
<u>Hydrogen Model Inputs/Outputs</u>					
Renewable Generation Capacity Modelled for Hydrogen Production in 2040	All RES from: 8.95GW Onshore Wind 7GW Offshore Wind 7GW Solar PV	All RES from: 2GW Offshore Wind	Curtailed RES from: 8.95GW Onshore Wind 7GW Offshore Wind 7GW Solar PV	Dispatched Down RES from: 2GW Offshore Wind	All RES from: 2GW Offshore Wind 100 to 2000MW Solar PV
Electrolyser Capacity (MW)	400	400	400	400	400
Capacity Factor (%) 2030-2035 and 2040	>95%	85%	21 – 43%	16 – 34%	83 – 87%
LCOHp (€/kg) 2030-2035 and 2040	4.7 – 5	5 – 5.3	3.8 – 5.9	4.3 – 7.1	4.6 – 4.8
Viable Sale Price (€/MWh) 2030-2035 and 2040	215 – 228	227 – 238	218 – 329	247 – 393	214 – 223
Regulatory Support(€/MWh) 2030-2035 and 2040	140 – 153	152 – 163	143 – 254	172 – 318	139 – 148

Parameter	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
Poolbeg Site					
Renewable Energy Source Available for Hydrogen Production	No	Yes (offshore wind planned off Dublin but may be required for electrification first, recommended to examine Dublin's future electricity requirements)	No (Not all system wide RES available)	Yes	No
Electricity Grid Demand Capacity	No	N/A	N/A	N/A	No
Land Availability	Limited land available in wider Dublin port area. ESB are a major landowner in the area and may have land available. Land requirement c.48m2/MW electrolyser capacity for PEM technology. Indicative site outline shows potential for c.400MW electrolyser capacity.				
Hydrogen Safety	Need to confirm if hydrogen plant can be safely operated in a built-up area and need to comply with COMAH regulations. Noted that NSAI are preparing new standards.				
Hydrogen Market	Appears to be potential for hydrogen uses in local/wider Dublin area. There is a small existing demand for hydrogen in the Dublin area in the pharmaceutical sector. In the longer term, demand from hydrogen may grow with new demand from the power sector beyond a 2030 timeline as the system moves towards 100% RES-E.				
Hydrogen Storage	HYSS (SEAI project) reviewing east coast salt cavern storage near Kish Bank. It appears that there may be potential for c. 35TWh of storage capacity, assuming 10% of c.270 caverns are developed. DCarbonX and ESB are reviewing hydrogen aquifer storage off the East Coast.				
Hydrogen Distribution	Climate Action Plan 2023, noted that "All buildings will need to switch to heat pumps or district heating by 2050, meaning that the gas grid will no longer supply existing homes and commercial premises." Therefore, the Gas Grid could potentially be repurposed to supply large energy users and electricity generators running on 100% hydrogen.				
Water Availability	Irish Water would need to confirm capacity. The possibility of desalination and the associated environmental parameters and economics need to be assessed.				

Parameter	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
<u>Poolbeg Site Development Potential</u>					
Estimated Development Potential	Low	Low-Moderate	Low	Low-Moderate	Low
Estimated Development Potential Comment	Low development potential. Limited demand capacity available in the Dublin region. Likely a large requirement for renewable electricity to meet electrification in heat and transport. Other locations on the East Coast of Ireland with lower electricity demand, large capacities of renewable generation could be explored. For example counties Louth, Wicklow and Wexford.	Low to moderate development potential. Dublin offshore wind capacity should possibly be prioritised for electrification. This needs to be examined further. Business model heavily impacted by offshore wind costs. Hybrid business model where windfarm can export electricity to grid and connect some capacity to an electrolyser could be investigated to improve the business case.	Low development potential. Challenging to replicate in reality due to system wide volumes of dispatched down electricity considered. Could be more suitable to bottlenecks in exporting renewable electricity on the transmission such as West Galway or the North-West. The location of hydrogen storage and demand needs to be considered in parallel. Dublin has a large existing demand for electricity. Flexible demand and district heat could be more favourable measures for mitigating curtailed electricity in Poolbeg. The hierarchy of curtailment measures should be examined further.	Low development potential. Curtailment is highly variable and is heavily influenced by the capacity of renewable generation, electricity demand, network operational measures and interconnector export capacity. Flexible demand and district heat could be more favourable measures for mitigating curtailed electricity in Poolbeg. The hierarchy of curtailment measures should be examined further.	Low development potential. Limited demand capacity available in the Dublin region. Likely a large requirement for renewable electricity to meet electrification in heat and transport. Other locations on the East Coast of Ireland with lower electricity demand and greater capacity on the transmission system for increased demand, large capacities of renewable generation could be explored. For example counties Louth, Wicklow and Wexford.

6 Key Learnings

- Thermal storage compares favourably with battery storage in terms of cost (typically 1% of the cost of battery energy storage systems per MWh), land use (typically requiring less than 10% of the land area per MWh of storage), degradation, length of lifespan and resource efficiency (use of materials). More details of the storage comparison carried out can be found in the Thermal Energy Storage section of this report.
- Electric boilers with thermal storage rather than electric heat pumps with storage represent the best option if this curtailed electricity is made available at a lower price. This represents a very cost-effective curtailment mitigation option when compared with battery energy storage systems.
- DH can potentially reduce curtailment by up to 70-86% if the national DH target of 2.7TWh in 2030 is achieved
- As shown in the table below the equipment sized optimally for DDHS can reduce curtailment by 2.1% and 8.6% in 2030 and 2040 respectively and can use this to provide 53.2% and 58% of the networks heat demand in these respective years.

DH & Curtailment Scenario	% Heat Supplied	Curtailment Reduction %
DDHS 2030 (CO&C)	53.2%	2.1%
DDHS 2040 (S2)	58.0%	8.6%
2.7TWh DH (CO&C)	55.6%	70.0%
2.7TWh DH (2030 S2)	44.2%	86.0%

- The optimal plant sizes for the DDHS scheme based on a curtailed electricity price of €0/MWh and a discount rate of 4% for each curtailment scenario is set out below.

2030	Curtailed Electricity Price (€/MWh)		
Discount Rate	**0**	**5**	**10**
3%	20MW Boiler & 350MWh TES	12MW Boiler & 10MWh TES	Not Viable
4%	18MW Boiler & 300MWh TES	12MW Boiler & 10MWh TES	Not Viable
5%	14MW Boiler & 80MWh TES	12MW Boiler & 10MWh TES	Not Viable

2040	Curtailed Electricity Price (€/MWh)		
Discount Rate	**0**	**5**	**10**
3%	60MW Boiler & 1500MWh TES	30MW Boiler & 100MWh TES	Not Viable
4%	60MW Boiler & 1500MWh TES	30MW Boiler & 100MWh TES	Not Viable
5%	50MW Boiler & 800MWh TES	30MW Boiler & 100MWh TES	Not Viable

- It should be noted that for the DDHS network that the curtailed electricity needs to be less than €10/MWh to be competitive with heat produced by the DWtE plant.
- Utilising the waste heat from the electrolyser producing green H2 can boost the overall efficiency from 60% – 70% up to 95%
- It is estimates that DDHS could pay up to €13/MWh for high-grade waste heat from an electrolyser which could reduce the cost of H2 production although the business case for green H2 is still uncertain even with this addition revenue stream. This price is estimated based on the assumed cost of heat generation from DWtE based on typical electricity prices and the plants z-factor (which represents the reduction in electricity generation due to extracting heat) and that the modest cost of heat recovery equipment would be borne by the green H2 producer as this cost would lkely be cost competitive with alternative heat rejection for the electrolyser.
- As the DDHS expands and the DWtE plant supply is not sufficient to cover the peak demand or comes to end of life the price paid for heat from the electrolyser (currently assumed at €13/MWh) could increase depending on the heat sources that it would be in competition with for supplying the DH network. This is also true of networks where alternative heat supply does not come from a high-grade waste heat source. In these cases the price paid for heat could be double what is assumed for the DDHS case.

Ireland, as part of the European Union, faces ambitious climate and energy targets set by the EU and by the Irish state. Three measures critical to achieving net zero carbon by 2050 appear to be (1) Energy efficiency improvements, (2) Electrification of energy sectors, use of other renewable technologies such as green hydrogen where electrification is not feasible and (3) Deployment of market ready renewable electricity generation capacity.

Climate Action Plan 2023 sets a roadmap to cut emissions by 51% by 2030 and reach net zero by at least 2050 in Ireland.

The electricity sector will be critical to the decarbonisation of Ireland's energy sector. Climate Action Plan 2023 aims to accelerate the build out of renewable generation with a target for 5GW offshore wind, plus 2GW offshore wind capacity for green hydrogen production, 8GW solar PV capacity and 9GW onshore wind capacity to deliver an 80% share of renewable electricity. Although Climate Action Plan 2023 provides a detailed roadmap to 2030 and includes an action to carry out further studies to identify the investments and upgrades needed to facilitate 80% renewable electricity share (EL/23/21), there does not appear to be any actions to study the requirements of a net zero power system.

The built environment sector in Ireland is required to reduce emissions to between 4.34Mt CO_2 by 2030, the emissions in the sector for 2018 totalled 8.5Mt CO2. In order to deliver the necessary emissions reductions, some necessary actions are to; complete 500,000 retrofits to achieve a B2 building energy rating (BER), install 680,000 heat pumps in residential buildings (of which 400,000 will be retrofits in existing buildings), deploy zero carbon heating to meet the needs of 50,000 commercial buildings, deliver up to 2.7TWh of district heating, and provide 0.7TWh renewable gas for heating.

Ireland's transport sector has targets for 845,000 electric passenger cars, 95,000 commercial EVs, 3,500 low emission trucks and an expanded electrified rail network.

The Irish Government have plans to develop green hydrogen production from surplus renewable electricity by 2030, and green hydrogen production from 2GW offshore wind capacity by 2035. Ireland's hydrogen strategy is due to be published in late Q2 2023. Many European countries have published hydrogen strategies and set out targets for green hydrogen production and technology development. Currently in the absence of a hydrogen strategy, Ireland does not have any clear pathway for green hydrogen production, storage, distribution, scale of market, as well as route to market in Ireland.

SEAI and MaREI modelling indicates potential electricity demand growth up to c.187-198% for a net zero carbon energy system compared to 2019 demand levels. Electricity fuel use for heat alone could account for up to 26TWh of electricity demand in a net zero carbon system, this equates to c.90% of the 2019 electricity demand.

In recent years, Ireland has seized the opportunity to harvest its abundant wind resources to generate renewable electricity. EirGrid and ESB Networks have expanded the transmission and distribution networks to facilitate the connection of c.4.43GW onshore wind capacity, with renewable generation currently accounting for approximately 40% of the country's electricity.

Natural gas is the dominant source for electricity generation in Ireland. These fossil fuel generators are dispatchable, whereby their output can be ramped up or down at the request of the system operator, this helps to ensure security of supply and also provides resilience to the system. EirGrid currently require 8 (5 in ROI, 3 in NI) dispatchable fossil fuel generators to be running on the all-island electricity system at all times and two of the five generators in ROI are required to be located in Dublin due to the local system constraints of voltage and power flow control in the complex Dublin electricity network. While natural gas is critical to the electricity system today, it is vital that cleaner and more robust resilience mechanisms are put in place in a future where fossil fuels might be depleted, unavailable or simply not acceptable with carbon budgets or sectoral emissions ceilings.

Ireland has experienced volatile energy prices along with other EU countries and is heavily exposed to volatile pricing due to its reliance on imported fossil fuels. Ireland currently imports two thirds of its energy requirement. Increasing energy storage capacity and utilising indigenous resources can help to reduce the volatility around energy pricing, and in the future increased long term energy storage capacity will be critical as Ireland moves towards a net zero energy system.

In regard to energy security and resilience, Ireland ranks well in metrics such as political stability, control of corruption and government effectiveness. However, some weaknesses and potential threats to the future resilience of Ireland’s energy system include reserves capacity which is the amount of power ready to be dispatched to cover supply shortages, insurance penetration which is the access to financial resources needed to rebuild a system and also the availability of engineers in the economy. In Dublin City over 80% of heating is currently provided from imported fossil fuels.

County Dublin has successfully attracted many large energy users and as Ireland’s largest urban area, the city poses challenges and opportunities in terms of decarbonisation. The relative success of attracting data centre capacity compared to other countries has put a constrain on Dublin’s electricity supply and EirGrid have introduced new data centre policy and started the powering up Dublin workstream to address the issues in a 2030 context. Connecting Phase One offshore wind capacity in this timeline will also be crucial for contributing towards decarbonising Dublin’s electricity demand. Considering the Climate Action Plan 2023 ambitions for the electricity, transport and heat sectors, Dublin has significant challenges to overcome to reduce emissions while enhancing energy efficiency, security and resilience.

EirGrid and ESB Networks have expanded the electricity networks to successfully connect around 4.43GW of onshore wind capacity. This led to Ireland currently having one of the largest capacities of onshore wind per capita. However, with this relative success, the electricity system today can be considered inefficient at times of high wind speeds and low electricity demand, where wind farms are instructed to reduce their output, known as dispatched down. In 2020, the total average dispatch down for wind farms across Ireland was 11.4%, driven by local network constraints (arising from inadequate capacity or network outages) and curtailment (arising from system operational constraints that limit the output of non-dispatchable renewable generation and a requirement for dispatchable fossil fuel generation to be running on the system at all times). The acceleration in the build out of renewable capacity will no doubt intensify the challenges associated with efficiently integrating very high levels of renewable electricity including offshore wind, onshore wind and solar.

Renewable dispatch down, and specifically curtailment by its nature is highly variable and sensitive to renewable generation capacity, electricity demand, electricity system operational constraints and the level of export capacity from interconnectors. Curtailment may be classified as ‘oversupply’ or ‘system curtailment’. At a high level, oversupply is a market-based dispatch which occurs when the availability of renewable generation exceeds system wide demand and interconnector exports, while curtailment is a non-market based redispatch which occurs when technical system wide limits are exceeded.

For the period 2030-2035, there may be significant oversupply curtailment as Ireland increases its share of renewable generation above 80% RES-E. For a worst-case curtailment scenario for this period that considers an all island share of 94% renewable electricity, average total wind curtailment levels were estimated to be 23.8% and average total solar curtailment levels estimated to be 23.1%. Oversupply curtailment appeared to be the dominant form of curtailment with average system curtailment estimates of only 4.1% and 3.2% for wind and solar respectively.

EirGrid modelling from its ECP-2.2 Constraint Reports for the scenario ‘2027 ECP + 4.4GW Offshore Wind’ estimated 10% transmission constraints for offshore wind connected to Poolbeg. In 2040, it is likely that EirGrid will have delivered sufficient transmission reinforcements in the Dublin area, assuming these are complete then there may be minimal transmission constraints for offshore wind connected to Poolbeg.

The operation of very high levels of renewable capacity on the electricity system in 2040 has not yet been investigated in detail by EirGrid. By 2040, it is possible that EirGrid will have the capability to operate the electricity system without the need for the SNSP and Min Gen operational constraints which restrict the output of variable renewable generation at times. This report explored possible dispatch down levels in 2040 for a range of generation build out and demand assumptions, and also assuming the removal of the SNSP and Min Gen operational measures to effectively remove system curtailment. The 2040 analysis indicated average wind oversupply curtailment in the range of 14.5-15.9% and average solar oversupply curtailment in the range of 14.5-16%.

The EU Clean Energy Package (Regulation EU 2019/943) impacts on how oversupply and curtailment will be allocated going forward. The new EU legislation removes priority dispatch for new renewable generators connecting post July 4th, 2019 (with some leeway for some projects in development by that date). However, there is still a requirement to minimise the curtailment of renewables. The EU Clean Energy Package became EU law in 2019 and it now must be implemented by member states, with the aforementioned Regulation effective since 1st January 2020.

Five potential hydrogen production configurations were modelled to understand the benefit of green hydrogen to the electricity system as a curtailment mitigation measure. The possible deployment timelines and requirements for the production configurations were guided by the EU Additionality Delegated Act. The electrolyser configurations included:

- **Grid Connected High RES-E:** System wide wind and solar generation used to produce hydrogen. This may be implementable in a 2030-2035 timeline provided Ireland's share of RES-E is greater than 90%. The percentage of annual run hours of the electrolyser must not exceed the share of renewable electricity. The electrolyser location may be more favourable in a part of the electricity network that is not heavily constrained in terms of demand import capacity, therefore this is viewed as low development potential for Poolbeg, as there is limited demand capacity available on the transmission system in the Dublin region considering the large existing demand and the need for electrification in the area.
- **Offshore Wind Off Grid:** Direct line configuration with hydrogen production based on a 2GW offshore wind farm. This scenario could potentially be implemented by 2030. The development potential is viewed as low to moderate as the business model relies on offshore wind costs reducing in line with cost down curve projections. A hybrid combination of a grid connection and electrolyser connection for 2GW offshore wind capacity may improve the business case for the offshore wind facility, thus increasing the development potential.
- **System Wide VRES Curtailment:** System wide curtailed wind and solar generation used for hydrogen production. This scenario could potentially be implemented by 2030. The hydrogen producer would be required to provide evidence that it reduced the need for re-dispatching renewable generation downwards by a corresponding amount. This scenario may be difficult to replicate in reality given all system wide curtailed electricity was considered and the development potential is considered low for Poolbeg. Locating the electrolyser at bottlenecks in the transmission network such as West Galway or the North-West where there are significant transmission constraints due to a large capacity of renewable generation coupled with limited export capacity and electricity demand, could provide the best opportunity for utilising large volumes of dispatched down energy.
- **Offshore Wind Dispatch Down:** Hydrogen production from Poolbeg connected dispatched down offshore wind generation. This scenario could potentially be implemented by 2030. Similar to the 'System Wide VRES Curtailment' production scenario, the hydrogen producer would be required to provide evidence that it reduced the need for re-dispatching renewable generation downwards by a corresponding

amount. A more favourable electrolyser location could be where offshore wind capacity is locating in an area with a limited number of large energy users. In Poolbeg, it is possible that flexible demand, thermal energy storage and district heat will be in competition for dispatched down electricity. The development potential is viewed as low given the variable nature of curtailment and the alternative mitigation measures that might be more suitable to Poolbeg.

- **Offshore Wind and Solar PPA:** Poolbeg connected offshore wind generation and PPA solar capacity matching the electrolyser capacity. This scenario would require the PPA capacity to comply with 'temporal' and 'spatial' correlation requirements and the emission intensity of electricity system must also be lower than 18 g CO2eq/MJ.

From analysis of the dispatch down mitigation of the various hydrogen production configurations, it appeared that the 'Grid Connected High RES-E' and 'System Wide VRES Curtailment' provided the greatest curtailment reduction to the electricity system. The 2030-2035 analysis of 2GW electrolyser capacity indicated total curtailment reductions of approximately 50%, with non-priority wind total curtailment reducing from 30.6% to 15.3% and non-priority solar total curtailment reducing from 23.8% to 11.7%. The utilisation of this curtailed electricity appeared to increase the share of RES-E on the system from 94% to 106.8%. While the deployment of 2GW electrolyser capacity does appear to show significant benefits to the electricity system as a curtailment mitigation, careful consideration needs to be given to the location of electrolyser capacity as they can be considered a large energy user, and there are already locations across Ireland where electricity demand capacity is constrained such as the Greater Dublin Region.

Analysing the techno economics of hydrogen production for the various configurations, it is noted that:

- The 'Grid Connected High RES-E' configuration where all wind and solar generation was available for production indicated a high available capacity factor for the electrolyser (>95%) and a LCOHp in the range of €4.7-5/kg with electricity prices assumed to be €75/MWh. Deloitte estimate an LCOHp of €4.9/kg for a grid connected configuration with power prices of €80/MWh which aligns with the analysis carried out for this project.
- The direct line configuration with hydrogen production based on a 2GW offshore wind farm in scenario 'Offshore Wind Off Grid' indicated LCOHp estimates in the range of €5-5.3/kg for a 400MW electrolyser, and a capacity factor of 85% and a price of energy of €86.05/MWh from offshore wind. This estimate assumed the offshore wind generation not used for hydrogen production could be exported to the grid. When 2GW

of electrolyser capacity was modelled to be directly connected to the 2GW offshore wind farm, the LCOHp was in the range of €5.6-6.2/kg. With a reduction of 50% on the ORESS 1 energy price to €43.03/MWh, the LCOHp was modelled to reduce to €4.1/kg for 2030-2035 and €3.7/kg for 2040. Deloitte in 2022 estimated an LCOHp of €3.7/kg for North Sea offshore wind off grid electrolysis in 2030.

- 'System Wide VRES Curtailment' production scenario where all system wide curtailed wind and solar generation was available for hydrogen production, provided the cheapest LCOHp of €3.8/kg in 2030-2035, mainly due to a capacity factor of c.43% from the large volumes of oversupply curtailment from wind and solar assumed available at €35/MWh. Considering a range of curtailed electricity prices of €17.5-52.5/MWh, the LCOHp was modelled to be €3-4.7/kg. Comparing the results of a 94% RES-E system to those of an 80% RES-E system, the LCOHp increased to €5.9/kg with less curtailed energy available.
- Where the electrolyser operated on electricity from offshore wind connected to Poolbeg in scenario 'Offshore Wind Dispatch Down' in 2030-2035, it appeared there was no major benefit in sizing the electrolyser greater than 1GW for which total dispatch down levels were reduced from around 41% to 2%. The LCOHp analysis carried out on 400MW electrolyser capacity indicated an LCOHp of €4.3/kg for the 2030-2035 base case where dispatch down levels were 41% and the electrolyser had a capacity factor of 34% and reduced dispatch down to around 18%. Considering a range of curtailed electricity prices of €17.5-52.5/MWh, the LCOHp was modelled to be €3.5-5.2/kg. However, looking at an alternative generation build out scenario with 80% RES-E and lower volumes of dispatched down in 2030-2035 and a capacity factor of 16%, then the LCOHp was estimated to be €7.1/kg.
- For production scenario 'Offshore Wind and Solar PPA', with hydrogen production from Poolbeg connected offshore wind generation and 400MW PPA solar capacity matching the 400MW electrolyser capacity, the LCOHp was estimated to be in the range of €4.6-4.8/kg based on an energy price of €86.05/MWh for offshore wind and €75/MWh for PPA solar. With a reduction of 50% on the ORESS 1 energy price to €43.03/MWh and the solar PPA price to €37.5/MWh, the LCOHp was modelled to reduce to €2.95/kg for 2030-2035 and €2.8/kg for 2040. Aurora estimated an LCOHp €3.5/kg for Ireland with an 'optimal' mix of 150MW offshore wind and 20MW solar capacity for a 100MW electrolyser.

From a high-level IRR analysis, the range of regulatory support necessary for green hydrogen production for the power sector was estimated for a target sale price of €75/MWh, storage cost of €45/MWh and distribution cost of €15/MWh. The lowest level of regulatory support appeared to be for the configurations in production scenarios ‘Grid Connected High RES-E’ and ‘Offshore Wind and Solar PPA’ and in the range of €139-153/MWh, with the ‘Offshore Wind Off Grid’ scenario slightly more expensive and in the range of €152-163/MWh. The business models for scenarios ‘System Wide VRES Curtailment’ and ‘Offshore Wind Dispatch Down’ that both used dispatch down electricity only, appeared to be significantly more variable in terms of the range of regulatory support required, with €143-254/MWh required for ‘System Wide VRES Curtailment’ and €172-318/MWh required for ‘Offshore Wind Dispatch Down’.

The business case for green hydrogen production is very uncertain at present in Ireland. There is a relatively small existing market for hydrogen in Ireland compared to EU countries that require hydrogen for heavy industrial processes such as steel production. The potential end users of hydrogen in Ireland are not yet understood, although it is widely reported that hydrogen or a derivative could play an important role in the longer-term decarbonisation of energy intensive sectors such as maritime and aviation. Many commentators have mooted Ireland as having the potential to be a key producer of green hydrogen for the EU considering its wind resource, the form in which energy may be exported to EU hydrogen consumers is not clear at this stage. Hydrogen also appears to show significant potential for dispatchable electricity generation in the short-medium term with a potential blend of hydrogen and natural gas, with 100% hydrogen operation for hydrogen CCGT’s more likely to be in a 2040 timeframe. A shorter-term horizon application may exist in HGV’s refuelling. This study examined electrolyser capacities in the GW scale however it is noted the total global installed electrolyser capacity as of the end of 2022 was estimated to be only c.1.4GW. Ultimately, the deployment of GW scale electrolysis and the identification of hydrogen end users in Ireland will be heavily influenced by global developments, technology improvements, cost reductions and the availability of resources and skilled workers, and also critically the development of large-scale hydrogen storage facilities and transmission/distribution infrastructure.

County Dublin appears to be one of the counties in Ireland that may scale up the hydrogen market, assuming greater technology maturity, efficiency improvements and cost reductions in end user applications. Dispatchable electricity generation and data centres appear to show significant potential for the uptake of hydrogen given the requirement for zero emission dispatchable energy. In addition, Hydrogen or a derivative may be required to decarbonise Dublin Airport and Dublin Port in the longer term.

Locating hydrogen production facilities in Dublin may not be as favourable as other locations on the East Coast that may have less competition for land and renewable energy. Offshore wind capacity near Dublin may be prioritised to support electrification over hydrogen production. There is also a constraint on the available demand import capacity in the county which limits the potential for grid connected electrolysis configurations. The business model of producing hydrogen from dispatched down offshore wind capacity in Poolbeg appears very high risk and the most expensive production configuration, there may be more viable dispatch down mitigation measures in Poolbeg such as district heating/thermal energy storage and also flexible demand. There is also uncertainty over the availability of land in Poolbeg, and the Irish Water capacity may be another potential issue in Poolbeg, although the possibility of desalination could be explored to mitigate this. In terms of health and safety standards for hydrogen in Ireland, there is currently limited information, however the NSAI are in the process of preparing safety standards which may have a bearing on the location of hydrogen production via electrolysis facilities.

EirGrid and ESB Networks will be critical to delivering net zero emissions for Ireland considering the projected electricity requirement from MaREI and SEAI for a net zero system. Currently, the necessary infrastructure upgrades to accommodate the future electricity demand, additional renewable generation capacity and dispatchable generation capacity are not yet understood for a net zero emissions energy system. Understanding the challenges associated with electrification will help inform the identification of sectors where green hydrogen may be necessary.

7 Further Research

Some recommendations:

- Detailed Net zero roadmap carried out by Government or it's agencies to understand the scale of infrastructure investment required to meet net zero. This roadmap should consider maintaining high resilience of the energy system including long term storage technologies and dispatchable generation to meet security of supply requirements.
- Detailed infrastructure review of Dublin's existing and future energy system including electricity system and the requirements for net zero. With a focus on the future electricity demand projections, dispatchable generation requirements, additional network reinforcement and obstacles to electrification in the county, in particular in the electrification heat and transport sectors.
- Establish a hierarchy of dispatch down mitigation measures and their application across different geographical areas of Ireland. The hierarchy should consider the potential reduction in dispatch down, associated investment cost and business case of each technology.
- Investigate the feasibility of developing large scale hydrogen storage technologies both onshore and offshore including the East Coast of Ireland, addressing safety concerns, land requirements, costs and development timelines.
- Are there benefits to RES-E generators of reducing curtailment even if the price being paid for the electricity is low i.e. reduced wear and tear, faster ramp up when grid demand increases, etc.
- Typically DH networks use heat sources that are in close proximity to heat demand being serve by the network. However, in cases where high volumes of low-cost, high-grade heat (>70C) are available (as would be the case when using electric heat production supplied by low-cost curtailed electricity from large renewable electricity generators) it is not uncommon for heat sources to be located at substantial distances from the heat demand e.g. waste heat from power plants located outside towns are often the heat source serving DH networks. Further research into the allowable distances at which using heat generated from otherwise curtailed electricity or waste heat from electrolysers could provide further opportunities where offshore wind power comes ashore outside of urban centres.
- This study shows the high potential for DH networks with thermal storage to support the electricity grid (curtailment mitigation, constraint mitigation, grid balancing, flexibility, frequency response, etc.). Further work on how to enable DH network owners and operators, who are traditionally not active in the electricity sector, to fully

realise this sector integration potential is required. This could cover both technical and market requirements to engage in this market as well as raising awareness of the opportunity and potential revenue streams that are available to DH networks through providing these grid services.

1. Literature Review

a. EU Decarbonisation Targets, Strategies and Renewable Energy Directive

i. Fit for 55 package - European Green Deal

The European Commission adopted “Fit for 55” on July 14th 2021. “Fit for 55” is a set of policy proposals preparing the implementation of the European Green Deal[54]. The proposals combine: application of emissions trading to new sectors and a tightening of the existing EU Emissions Trading System; increased use of renewable energy; greater energy efficiency; a faster roll-out of low emission transport modes and the infrastructure and fuels to support them; an alignment of taxation policies with the European Green Deal objectives; measures to prevent carbon leakage; and tools to preserve and grow natural carbon sinks, see Figure 43.

Some key proposals of the package include:

- Reducing greenhouse gas emissions in the EU by at least 55% compared to 1990 levels by 2030;
- A target for 40% share of renewable energy in the EU for 2030;
- Energy efficiency target to achieve an overall reduction of 36-39% for final and primary energy consumption;
- More sustainable transport with a 55% reduction of emissions from cars and 50% reduction of emissions from vans by 2030, zero emissions from all new cars by 2035.

Energy efficiency, electrification, offshore renewable energy and hydrogen are some pivotal measures to realising the ambitions of the EU green deal.

[54] https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/delivering-european-green-deal_en

Figure 43: Architecture of EU Green deal

ii. EU Offshore Wind Strategy

In order to achieve the emissions reductions set out in the European Green Deal it will be required to ramp up renewable power generation and in particular the offshore wind industry. The EU Offshore Strategy[55] contains an objective to have an installed capacity of at least 60GW of offshore wind by 2030 with a view to reaching 300GW by 2050.

The EU policy proposals to scale up the deployment of offshore wind include a new approach to developing offshore wind and grid infrastructure. Most existing offshore wind farms have been deployed as national projects connected to the shore via radial links and this way of developing offshore wind is expected to continue in areas where the industry is only taking off.

[55] **https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2020:741:FIN&qid=1605792629666**

In parallel, the transmission system operators (TSOs) are also expected to continue to build cross-border interconnectors for electricity trading and security of supply.

Increasing the capacity of offshore wind in a cost efficient and sustainable manner will be necessary to develop a meshed electricity grid within the EU. The concept of an offshore hybrid project is relevant to this point where the meshed electricity grid has a role to play in combining interconnection between two or more member states, and the transportation of offshore renewable energy to its sites of consumption.

A lack of offshore grids or the risk of delay in grid development are major barriers to the scale up of offshore wind capacity. Offshore hydrogen production and hydrogen pipelines are another option to deliver energy onshore.

iii. EU Energy System Integration Strategy

The energy system is crucial to delivering on the European Green Deal[56]. Within this framework the primary objective of the EU Energy System Integration Strategy is to design a more efficient and integrated energy system that links different energy carriers, infrastructure and consumption sectors to support decarbonisation objectives by 2030 and climate neutrality by 2050. The current energy system that exists today is built on several parallel, vertical energy value chains that link specific energy resources with specific end use sectors. As an example, the transport sector predominantly uses petroleum products, and the electricity and heating sectors rely heavily on natural gas and coal. This diffused approach is economically and technically inefficient and as a consequence, substantial losses in the form of waste heat and low energy efficiency are realised. To achieve climate neutrality by 2050, energy system integration will be necessary whereby the energy system is operated as a whole across multiple energy carriers, infrastructures and consumption sectors. The idea of an integrated energy system is to connect missing links in order to achieve climate neutrality by 2050 in a cost-effective manner.

Three complementary and mutually reinforcing concepts are key to energy system integration:

1. **Energy efficiency**, a more circular energy system in which the least energy intensive choices are prioritised and unavoidable waste streams (such as waste heat or waste electricity) are reused for energy purposes (e.g. for heating through heat networks).
2. **Electrification**, the increasing renewable energy production capacity can service a growing share of energy demand. Heat pumps for space heating or low-temperature

[56] **https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0299&from=EN**

industrial processes and electric vehicles for transport are examples of how electrons can be used across multiple end-use sectors via the electricity grid infrastructure.

3. **Renewable and low carbon fuels including Hydrogen**, use of renewable fuels such as hydrogen to decarbonise end use sectors where electrification may not be feasible, efficient or may be considerably more expensive. Examples include producing renewable hydrogen for use in industrial processes, maritime transport, aviation and heavy-duty road and rail transport. The existing gas grid infrastructure may be utilised to facilitate the transport of hydrogen. However, it is noted that existing gas grids in the EU are limited on the blend of hydrogen that can be facilitated at present.

The integrated system aims to transform today's linear and parallel energy system to a more circular, flexible and interdependent system with improved efficiencies and less waste as shown in the Figure 44 below. These strategies define methods of developing an integrated system from renewable energy and low carbon technologies fit for climate neutrality. In addition, the strategy presents a new clean energy investment agenda to turn hydrogen into a viable solution to achieve the objectives of the EU Green Deal.

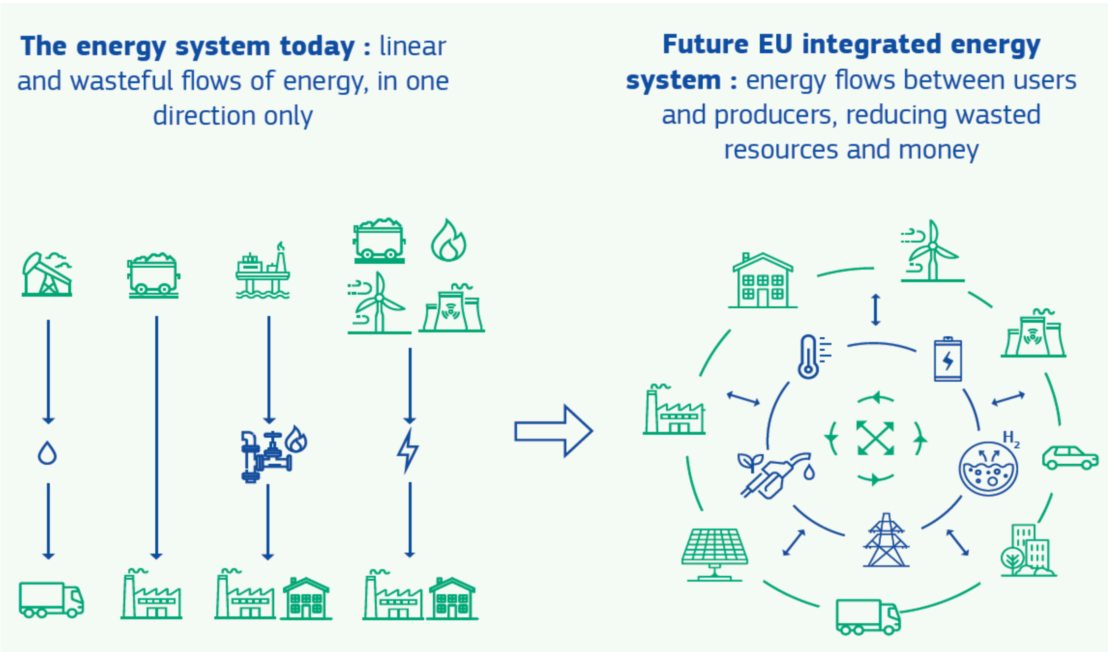


Figure 44: Today's energy system and future EU integrated energy system models

The integrated model will promote energy efficiency through utilisation of waste heat, primarily from data centres and industrial sites while producing sustainable biogas and biofuels from agricultural waste and residues. This will improve synergies between different energy infrastructures. The strategy aims to increase renewable electricity generation and expedite its use in industry, transport and building sectors which currently rely heavily on fossil fuels.

Not only does the strategy focus on renewables; it also spurs to promote use of low-carbon fuels including hydrogen, primarily for sectors like industry and transport, that are hard to decarbonise. This initiative also aims to unlock the potential of sustainable biofuels, biomass, synthetic fuels and green hydrogen. This will support fuel market uptake and transparency as different fuels are clearly defined and classified. This policy further focuses on adapting energy markets and infrastructure to a more complex and integrated energy system. Essentially, it will not only promote development of modern infrastructure which will make European Industry more sustainable and competitive but also aims to create jobs and provide clean energy for citizens.

iv. EU Hydrogen Strategy

In 2020, the EU Commission released the European Hydrogen Strategy[57], which provides a strategic roadmap for the development of green hydrogen in Europe, divided into three phases:

- First phase (2020 – 2024): This initial stage aims to achieve the installation of at least 6 GW of electrolysers for the production of 1 million tonnes of green hydrogen in the EU by 2024. An increase in the production of large electrolysers (<100 MW) and the deployment of more hydrogen refuelling stations are the main expected deliverables of this phase, as well as the retrofitting of existing fossil-based hydrogen production plants with carbon capture and storage technologies.
- Second phase (2025 – 2030): This stage aims to see hydrogen being integrated into the energy system as an intrinsic component and as a grid balancing mechanism. Green hydrogen is expected to become more cost-competitive and local hydrogen clusters – or hydrogen valleys – are to be developed, alongside a pan-European logistical infrastructure. By 2030, the EU is expected to install 40GW of electrolysers for the production of 10 million tonnes of green hydrogen.
- Third phase (2031 – 2050): The long-term aim of the Strategy is to see green hydrogen technologies achieve full maturity. By 2050, 25% of the EU's renewable electricity should be directed to the production of green hydrogen, which should be deployed within all hard-to-decarbonise sectors, from long-range transport to commercial buildings.

Although the European Hydrogen Strategy focuses on green hydrogen, it also recognises low-carbon hydrogen – fossil-based hydrogen with carbon capture, or blue hydrogen – as a valuable energy vector in the medium term. However, since the beginning of the conflict in

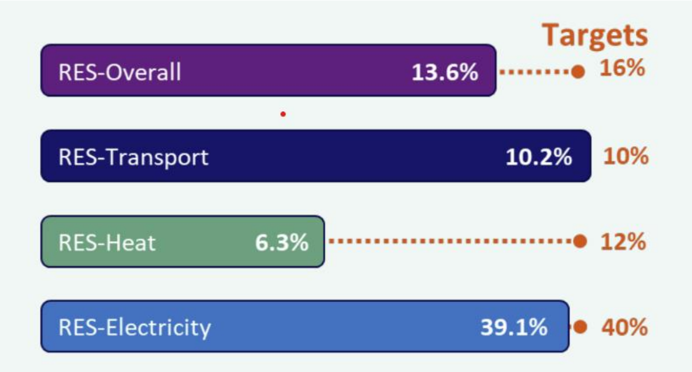
[57] https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

Eastern Europe and the Ukraine in 2022, fossil fuel prices have increased significantly to the extent that blue hydrogen production may not be economically viable. There are added concerns over energy security within the EU and importing natural gas for blue hydrogen production may not be favourable.

Furthermore, the strategy recognises the role of hydrogen in many industrial applications that are unrelated to decarbonisation, but which are of great importance in the context of a healthy economy, and which should be supplied with lower-carbon or green hydrogen.

v. EU Revised Renewable Energy Directive (RED) II

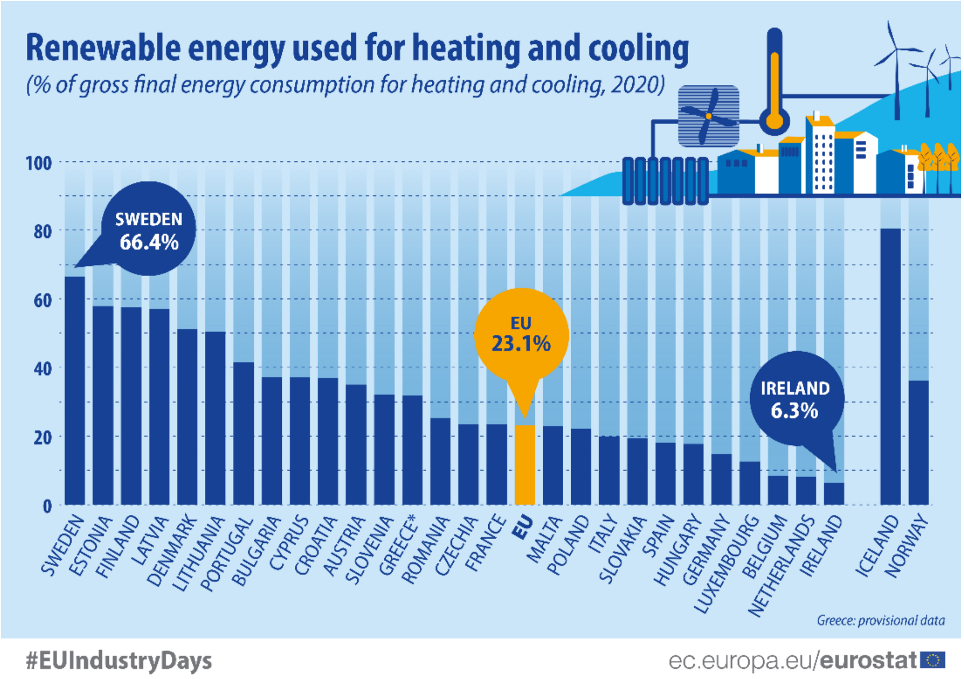
In 2009, the European Commission established the first Renewable Energy Directive (RED), setting a target of an overall share of renewable energy of at least 20% in the European Union by 2020, with individual member states having individual targets according to their specific circumstances. The overarching 20% target was achieved, with the EU reaching a 22% share of gross final energy consumption from renewable sources in 2020; however, not all countries achieved their individual targets: Ireland, for example, fell short of its 16% target and only delivered 13.6%[58]. Ireland also had individual sectoral targets for 2020. It can be seen in the graph below that the worst performing sector in terms of achieving the 2020 sectoral targets in Ireland is heat.



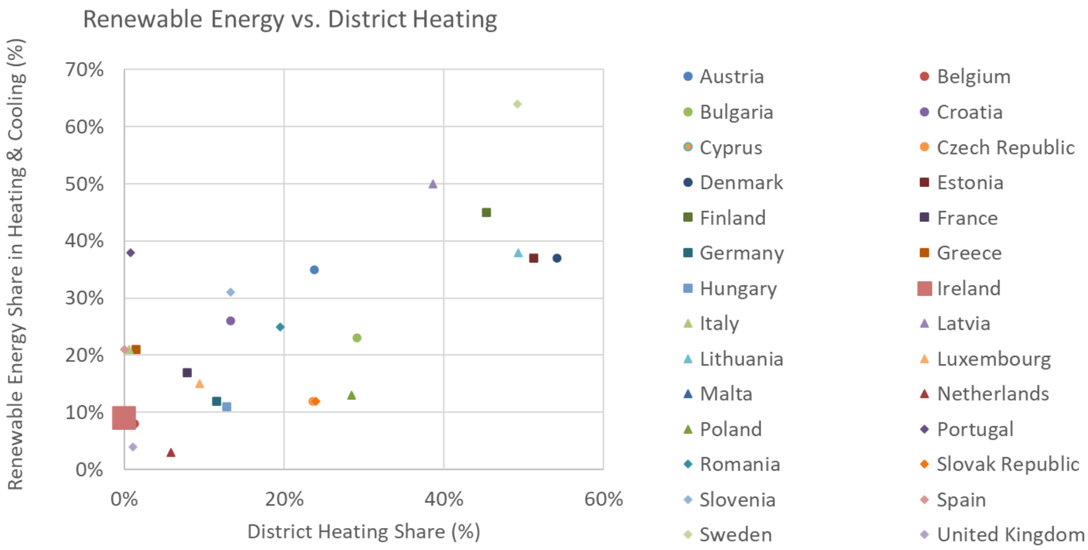
Ireland is also the worst performing country in the EU when it comes to its renewables share in heating (as shown in the graph below from Eurostat[59]). This makes heating a key sector when it comes to Irelands overall decarbonisation.

[58] https://www.seai.ie/publications/Renewable-Energy-in-Ireland-2020-Short-Note-FINAL.pdf

[59] https://ec.europa.eu/eurostat/web/products-eurostat-news/-/edn-20220211-1



Using waste renewable electricity, waste heat (as waste heat is treated on a par with renewable heat in the RED) or renewable heat sources through DH networks can make a significant contribution to Irelands renewable share in heating. This can be seen in the graph below, where the correlation between DH share and renewable share in heating can be seen (i.e. the countries with the highest share of DH also have the highest shares of renewables in heating).



In 2018, the Renewable Energy Directive was recast, establishing a new binding renewable energy target for the EU of at least 32% by 2030. This directive, commonly known as RED II, builds on the original RED targets and was later revised under the 'Fit-For-55' package. It was found that the original RED II target of 32% is not sufficient to deliver the 55% emissions reduction set out under the European Green Deal and therefore a revised target of 40% renewable energy was included in the revised RED II proposal[60]. Building on the hydrogen strategy, the proposal also introduces two binding sub-targets for the use of renewable hydrogen and its derivatives, with a target for 2.6% of fuels from renewable hydrogen in the transport sector and a 50% share of renewables in hydrogen consumption in industry. The revised RED II also extends the existing rules for certification and traceability to renewable fuels in all sectors and not only in the transport sector.

In addition to these requirements, the RED II includes a requirement that the use of RFNBO's contributes to at least a 70% reduction in greenhouse gas emissions.

Additionality Delegated Act

On February 2023, the EU commission adopted the Additionality Delegated Act[61] as required under article 27(3) of RED II. The Additionality Delegated Act defines when hydrogen, hydrogen-based fuels or other energy carriers can be considered as a renewable fuel of non-biological origin, or RFNBO. The rules are to ensure that these fuels can only be produced from "additional" renewable electricity generated at the same time and in the same area as their own production.

It is important to note that conditions set out in the Additionality Delegated Act apply to both domestic producers as well as producers from third countries that want to export renewable hydrogen – or other hydrogen-based fuels, such as renewable ammonia or renewable methanol – to the EU to count towards the EU renewables targets.

Where a production facility produces hydrogen/fuel from electricity, the share of RFNBO produced is equal to the average share of renewable electricity on the electricity network of the country in which the hydrogen/fuel production facility is located. By way of derogation from this default rule (under Article 27(3) of REDII), the hydrogen/fuel produced can be counted as fully renewable in two scenarios:

1. **The 'direct line' configuration**, where the hydrogen/fuel production facility is connected directly to a new renewable electricity installation and does not use grid

[60] https://eur-lex.europa.eu/resource.html?uri=cellar:dbb7eb9c-e575-11eb-a1a5-01aa75ed71a1.0001.02/DOC_1&format=PDF

[61] https://energy.ec.europa.eu/system/files/2023-02/C_2023_1087_1_EN_ACT_part1_v8.pdf

electricity. For the electricity produced under this setup to be fully renewable, the renewable electricity installation must (mainly) be connected via a direct line to the fuel production plant and have come into operation at most 36 months before the hydrogen/fuel production facility.

2. **The 'grid connection' configuration**, where the fuel/hydrogen production facility is connected to the grid but the electricity used is 'demonstrably' renewable. There are four scenarios under which grid electricity can be considered to use 'demonstrably' renewable electricity:
    1) Where the fuel/hydrogen production facility is located in a 'bidding zone' (geographical zone in which electricity is traded) containing a very high (90%+) level of renewables, and the number of production hours is capped at the same percentage of the year (i.e., 90%+ of the hours in a given calendar year).
    2) Where the fuel/hydrogen production facility is located in a bidding zone (outside scenario 1) in which the emission intensity of electricity is lower than 18 g CO2eq/MJ (i.e., a "low-carbon/nuclear bidding zone"), relies on electricity produced under a renewable power purchasing agreement (PPA) and complies with 'temporal' and 'spatial' correlation requirements. Additionality requirement does not apply in this instance.
    3) Where the fuel/hydrogen is produced with electricity consumed during an imbalance settlement where the fuel producer can demonstrate, based on evidence from the TSO that the hydrogen producer reduced the need for re-dispatching renewable generation downwards by a corresponding amount.
    4) Renewable electricity is (either produced on site or) procured via a renewable PPA, and 'additionality', 'temporal' correlation and 'spatial' correlation requirements are met.

The sets of requirements relevant for scenarios 2 and 4 under the grid connection setup are as follows:

- **PPA:** With respect to the PPA, the hydrogen/fuel producer must use renewable electricity by concluding one or more PPA(s) with one or more renewable electricity installation(s) for an amount that is at least equivalent to the amount of electricity used for the hydrogen/fuel production process.
- **Additionality:** For hydrogen facilities that come into operation as of 2028, the electricity generation installation(s) under the PPA must be 'new' – i.e., have come in operation not earlier than 36 months before the fuel/hydrogen facility – and be unsubsidised. Hydrogen/fuel production capacity that comes into operation before

2028 are exempted from these rules for 10 years, up until 1 January 2038. These requirements are never applicable in a low-carbon/nuclear bidding zone.

- **Temporal correlation:** the production of the hydrogen/fuel must either (i) use electricity taken from the grid during either the same one-hour period (or one-month period until 31 December 2029) as the renewable electricity production under PPA, or (ii) be produced during a one-hour period when the electricity price is below €20/MWh or below 36% of the EU carbon price, thus indicating that the electricity consumption would help with balancing the grid and would not involve fossil-based production. It is noted that the hourly correlation requirement is relaxed up to 31 December 2029 until when the correlation must in principle only be achieved on a monthly basis. However, Member States are allowed to impose the hourly correlation requirement from 1 July 2027 for RFNBOs produced in their territory.
- **Spatial correlation:** The renewable electricity installations under PPA must either be (i) located in the same bidding zone (or in an interconnected offshore bidding zone) as the hydrogen/fuel production facility, or (ii) in a neighbouring bidding zone where electricity prices are equal or higher than in the production facility's bidding zone. Member States are also allowed to introduce additional criteria concerning the spatial correlation requirements to "ensure compatibility of capacity additions with the national planning of the hydrogen and electricity grid", but without negatively impacting the functioning of the internal electricity market.

vi. EU Taxonomy

In June 2020, the EU published a framework to facilitate sustainable investment through the ‘Taxonomy Regulation’ and came into effect from July 2020[62]. The aim of the EU Taxonomy is to prevent greenwashing and help investors identify economic activities in line with the EU’s environmental and climate objectives. The Taxonomy Regulation establishes six environmental objectives:

1. Climate change mitigation
2. Climate change adaptation
3. The sustainable use and protection of water and marine resources
4. The transition to a circular economy
5. Pollution prevention and control
6. The protection and restoration of biodiversity and ecosystems

[62] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex:32020R0852

The Taxonomy Delegated Act[63] sets out technical screening criteria for economic activities having potential to contribute to climate change mitigation and adaptation in some sectors. Natural gas related activities have been recognised as contributing to the EU's climate and environmental objectives, in the transition to net zero emissions. The gas related activities include:

- Electricity generation from fossil gaseous fuels
- High-efficiency co-generation of heat/cool and power from fossil gaseous fuels
- Production of heat/cool from fossil gaseous fuels in an efficient district heating and cooling system

Each of the gas related activity is required to meet either of the following emission thresholds:

- lifecycle emissions are below 100gCO2e/kWh, or
- until 2030 (date of approval of construction permit), and where renewables are not available at sufficient scale, direct emissions are below 270gCO2e/kWh or, for the activity of electricity generation, their annual direct GHG emissions must not exceed an average of 550kgCO2e/kW of the facility's capacity over 20 years. In this case, the activity must meet a set of cumulative conditions: e.g. it replaces a facility using solid or liquid fossil fuels, the activity ensures a full switch to renewable or low-carbon gases by 2035, and a regular independent verification of compliance with the criteria is carried out.

vii. European Commission

viii. EU Aviation

Currently there are some policies that encourage the use of sustainable aviation fuels (SAF). The EU emissions trading system (EU ETS) provides an incentive for aircraft operators to use biomass-based SAF certified as compliant with the sustainability framework of RED II, by attributing them 'zero emissions' under the scheme; this means that airlines do not have to forego any emissions allowances when SAF is used instead of fossil jet fuel. RED II also allows Member States to count SAF towards the achievement of their national renewable energy targets, on the condition that they comply with the sustainability criteria listed in the directive. A specific multiplier of 1.2 is applied to the supplied quantity of non-food and feed based SAFs, meaning that they contribute 20% more of their energy content in accounting towards the renewable energy targets.

[63] https://eur-lex.europa.eu/resource.html?uri=cellar:8cee7f13-a162-11ec-83e1-01aa75ed71a1.0023.02/DOC_1&format=PDF

However the European Commission recognised that the regulatory framework for renewable energy and the EU ETS have not led to a sufficient increase in the uptake of SAF.

The Fit for 55 package includes a proposal to ensure a level playing field for sustainable air transport through the ReFuelEU aviation initiative[64]. Parliament and Council negotiators agreed on a final text on 25 April 2023[65], which now is required to pass through both institutions for formal adoption. The final agreement sets ambitious targets for total SAF supply (70% in 2050) and for e-fuels, starting at 1.2% in 2030, increasing to 35% in 2050.

The proposal also includes obligations on airlines to limit the uptake of jet fuel before departing from EU airports to what is needed for safe operation of flights, with the aim of ensuring a level playing field for airlines and airports, and avoiding additional emissions related to extra weight of aircraft carrying excessive amounts of fuel.

ix. EU Maritime

Depending on the policy scenarios assessed in the framework of the 2030 Climate Target Plan (CTP) and in support of the Sustainable and Smart Mobility Strategy, renewable and low carbon fuels should represent between 6-9% of the international maritime transport fuel mix in 2030. Looking forward to 2050, renewable and low carbon fuels should account for between 86-88% of the fuel mix[66]. This is necessary to achieve the EU economy-wide greenhouse gas emissions reduction targets.

The European Parliament and Council agreed on the final text of FuelEU Maritime on 23 March 2023[67], the EU's law that requires vessels trading within and to the EU to meet GHG emissions reduction targets starting in 2025. Fuel EU Maritime is intended to accelerate decarbonisation through the adoption of renewable and low carbon fuels and technologies in maritime transport with a goal-based approach. It sets a reduction target for the GHG intensity of energy used, with 2020 as the reference year and a reduction of 2% in 2025, increasing in steps to 80% by 2050. The regulation will apply to vessels greater than 5,000 gross tonnage (excluding inland vessels, fishing, naval and government vessels) calling at EU ports and

[64] https://www.europarl.europa.eu/thinktank/en/document/EPRS_BRI(2022)698900

[65] https://www.europarl.europa.eu/news/en/press-room/20230424IPR82023/fit-for-55-parliament-and-council-reach-deal-on-greener-aviation-fuels

[66] https://ec.europa.eu/info/sites/default/files/fueleu_maritime_-_green_european_maritime_space.pdf

[67] https://www.consilium.europa.eu/en/press/press-releases/2023/03/23/fueleu-maritime-initiative-provisional-agreement-to-decarbonise-the-maritime-sector/

covers all energy used for intra EU voyages, whilst at port in EU, as well as half of the energy used for voyages that start or end in the EU.

x. REPowerEU Plan

The REPowerEU[68] plan sets out a strategy to rapidly reduce the EU's dependence on Russian fossil fuels by fast forwarding the clean transition to achieve a more resilient energy system. The plan builds on the Fit for 55 package of proposals. Additional actions put forward in the REPowerEU plan include to save energy, diversify supplies, quickly substitute fossil fuels by accelerating Europe's clean energy transition and smartly combine investments and reforms, see Figure 45.

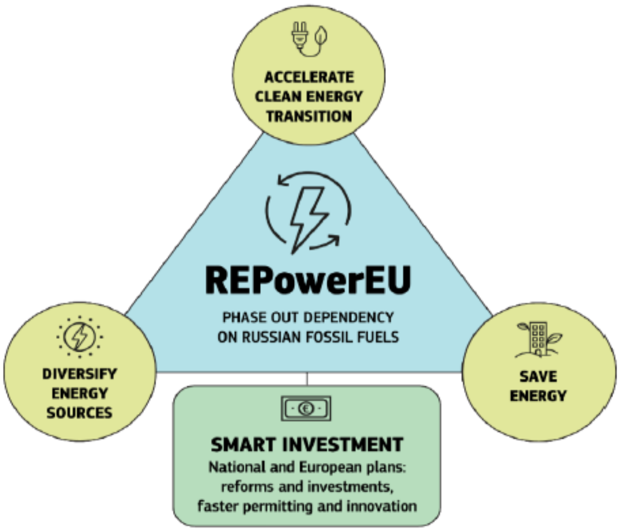


Figure 45: REPowerEU schematic

Accelerating the roll out of renewable energy in power generation, industry, buildings and transport is critical to the plan. The plan proposes to increase the target for renewables from 40% to 45% under the Fit for 55 package. By setting this overall increased ambition a framework for other initiatives will be created, where the initiatives include:

- A dedicated EU Solar Strategy to double solar photovoltaic capacity by 2025 and install 600GW by 2030.
- A Solar Rooftop Initiative with a phased-in legal obligation to install solar panels on new public and commercial buildings and new residential buildings.

[68] https://ec.europa.eu/commission/presscorner/detail/en/IP_22_3131

- Doubling of the rate of deployment of heat pumps, and measures to integrate geothermal and solar thermal energy in modernised district and communal heating systems.
- A Commission recommendation to tackle slow and complex permitting for major renewable projects, and a targeted amendment to the Renewable Energy Directive to recognise renewable energy as an overriding public interest. Dedicated 'go-to' areas for renewables should be put in place by Member States with shortened and simplified permitting processes in areas with lower environmental risks.
- Setting a target of 10 million tonnes of domestic renewable hydrogen production and 10 million tonnes of imports by 2030, to replace natural gas, coal and oil in hard-to-decarbonise industries and transport sectors. To accelerate the hydrogen market, increased sub-targets for specific sectors would need to be agreed by the co-legislators. The Commission is also publishing two Delegated Acts on the definition and production of renewable hydrogen to ensure that production leads to net decarbonisation. To accelerate hydrogen projects, additional funding of €200 million is set aside for research, and the Commission commits to complete the assessment of the first Important Projects of Common European Interest by the summer.
- A Biomethane Action Plan sets out tools including a new biomethane industrial partnership and financial incentives to increase production to 35bcm by 2030, including through the Common Agricultural Policy.

b. Ireland’s Decarbonisation Targets and Strategy

i. Climate Action Plan 2023

The Irish government published the Climate Action Plan 2023[69] in December 2022. The plan sets a roadmap to cut emissions by 51% by 2030 and reach net zero by at least 2050. The Climate Action Plan 2019 set an action for DECC to finalise Ireland’s long-term climate strategy in Q1 2022. In its approach to decarbonising, the EU has split greenhouse gas emissions into two categories, namely the Emissions Trading System (ETS) and the non-ETS. Emissions from electricity generation and large industry in the ETS are subject to EU-wide targets that require these sectors to achieve a reduction in emissions of 43% by 2030 relative to 2005 levels. The ETS facilitates participants to purchase allowances for every tonne of emissions, with the allowance amount due to decline over time to ensure the EU-wide target is achieved. The Climate Action Plan 2023 also advocates the need for a just transition and improving climate resilience for all communities and citizens.

The Renewable Heat Obligation (RHO) scheme aligns with these climate ambitions as its objective is to reduce GHG emissions in the energy sector by increasing sustainable renewable energy use, thus contributing to the Programme for Government’s target of a 51% reduction in emissions by 2030 and net zero emissions by 2050. In an attempt to achieve these targets, the scheme places an obligation on fuel suppliers of heat energy (including natural gas, oil, coal, liquid petroleum gas (LPG), and peat) to ensure a certain percentage of the fuel supplied is renewable. It also supports provision of up-front capital grant funding for low-carbon heating and ensures low-carbon district heating networks are eligible to earn credits under the proposed RHO.

Emissions from all other sectors including transport, agriculture, buildings and light industry are covered under the EU Effort Sharing Regulation which established binding annual greenhouse gas emission targets for member states for the period 2021-2030. Ireland is required to reduce its emissions from these sectors by 30% by 2030 relative to 2005 levels.

[69] https://www.gov.ie/pdf/?file=https://assets.gov.ie/249626/1c20a481-bb51-42d6-9bb9-08b9f728e4b5.pdf#page=null

Electricity

Climate Action Plan 2023 aims to accelerate the build out of renewable generation. Among the metrics listed to deliver the necessary emissions abatement in the electricity sector were a target for:

- Up to 80% share of renewable electricity (RES-E)
- 9GW of onshore wind capacity
- 8GW of solar PV capacity
- At least 5GW of offshore wind capacity (and an additional 2GW offshore wind capacity for green hydrogen production)

The plan also details a number of enabling targets to deliver and accelerate a flexible electricity system to support renewables while managing demand growth. Some of these targets include:

- c.2GW of new flexible gas-fired power generation;
- Phase out and end the use of coal and peat in electricity generation;
- System operators to transform the flexibility of the electricity system through changes to policies, standards, services, and tools, funded and incentivised through regulatory price controls;
- Establish the investment framework and competitive market arrangements needed to deliver zero carbon system services;
- Delivery of at least three new transmission grid connections or interconnectors;
- Explore further interconnection potential, including hybrid interconnectors
- Ensure that 15-20% of electricity system demand is flexible by 2025, increasing to 20-30% by 2030, to reduce peak demand and move to times of high renewable output;
- Deliver a demand side strategy that facilitates zero carbon demand, incentivises low carbon electricity consumption and aligns with the EU energy efficiency requirements, while facilitating electrification targets.

The key metrics to deliver abatement in electricity from Climate Action Plan 2023 for the years 2025 and 2030 are presented in Table 26. Some of the key performance indicators (KPI's) listed for 2030 relate to hydrogen and include:

- Green hydrogen production from surplus renewable electricity;
- Zero emission gas fired generation from biomethane and hydrogen commencing by 2030.

Table 26 also lists some measures between 2031-2035 necessary to deliver emission reductions. These include:

- Roadmap for a net zero power system;
- Green hydrogen production via 2GW offshore wind;
- Long duration storage technologies;
- Increase zero emission gas generation to enable a net zero power system.

Table 26: Key Metrics to Deliver Abatement in Electricity

Theme	2030 KPI	2030 abatement (vs 2018) MtCO2 eq.	2031-2035 measures
Accelerate Renewable Energy Generation	• 80% renewable electricity share of demand • 9 GW onshore wind capacity • At least 5 GW offshore wind capacity • 8 GW solar PV capacity including 2.5 GW of non- new grid solar • Green Hydrogen in production from surplus renewable electricity	8 .7	• Roadmap for a net-zero power system • Green Hydrogen Production via 2 GW Offshore Wind
Accelerate Flexibility	• Level of renewables at any one time on grid: 95-100% • Dispatch down (excluding oversupply) of renewables below 7% • Minimise oversupply • Required Long term storage (4 hour plus) in place • At least 2 GW of new flexible gas fired generation • Zero Emission gas fired generation from biomethane and hydrogen commencing by 2030		• Long Duration Storage technologies • Increased zero emission gas generation to enable a net zero power system
Demand Managemen t	• Demand Side Flexibility 20-30% • Zero carbon Demand growth	0.86	• Roadmap for a net-zero power system • Green Hydrogen Production via 2 GW Offshore Wind

There were a number of supporting measures listed to deliver Ireland's renewables acceleration programme, these included:

- EirGrid will carry out further grid, operational, and market studies, through an updated version of Shaping Our Electricity Future, due Q1 2023, and updated regularly thereafter, to assess additional supply and demand side measures, beyond current plans;

- Strengthen the electricity system by upgrading the network and building supporting infrastructure at key strategic locations;
- Having regard to the interaction between the planning and grid consenting systems and the overall timeframes for permitting, develop by Q1 2023, as an urgent priority, an electricity generation grid connection policy which facilitates timely connecting of sufficient volumes of renewable electricity generation and supporting flexible technologies aligned to required timelines for permitting renewable energy installations in EU Directives and Regulations;
- The CRU, EirGrid, and ESB Networks will enable hybrid technology grid connections, maximising the utilisation of existing grid infrastructure, to accelerate connection of new renewable generation and associated storage;
- Develop a policy on 'private wires' and, if necessary, pass any required facilitating legislation by end 2023.

Climate Action Plan 2023 provides a detailed roadmap to 2030 and includes an action to carry out further studies to identify the investments and upgrades needed to facilitate 80% renewable electricity share (EL/23/21). However there does not appear to be any actions to study the requirements of a net zero power system and it is noted that Climate Action Plan 2021 did include an action to carry out power system modelling required to meet renewable energy and electricity emissions targets and analysis to underpin a Net Zero Roadmap that was due to be published by Q2 2024 by EirGrid and ESBN, this was listed as action 127 in Climate Action Plan 2021.

Built Environment

The Climate Action Plan 2023 sets a roadmap to decarbonising Ireland's residential and commercial buildings so that they require less energy and use renewable energy sources to the maximum extent possible. The built environment sector is required to reduce emissions to 4.34Mt CO_2 by 2030, the emissions in the sector for 2018 totalled 8.5Mt CO_2. Meeting the level of emissions reduction, it will be necessary to:

- Complete 500,000 retrofits to achieve a B2 building energy rating (BER);
- Install 680,000 heat pumps in residential buildings (of which 400,000 will be retrofits in existing buildings);
- Deploy zero carbon heating to meet the needs of 50,000 commercial buildings;
- Deliver upto 2.7TWh of district heating;
- 0.7TWh renewable gas for heating.

It is also observed from Climate Action Plan 2023 that “All buildings will need to switch to heat pumps or district heating by 2050, meaning that the gas grid will no longer supply existing homes and commercial premises."

Transport

The transport sector emitted 12.2 $MtCO_2$ in 2018, which was approximately 20% of Ireland's greenhouse gas emissions. Climate Action Plan 2023 sets targets for 845,000 electric passenger cars, 95,000 commercial EVs, 3,500 low emission trucks and an expanded electrified rail network, as detailed in Table 27.

Green hydrogen is considered in the roadmap in a post 2025 context with a role to play in the decarbonisation of hard to abate sectors such HGVs, shipping and aviation. The Biofuels Obligation Scheme is under review to consider green hydrogen as a RFNBO.

Table 27: Transport targets set in Ireland's Climate Action Plan

Theme	2030 Abatement/KPI
Avoid	Total abatement -2.09 MtCO2eq.
Vehicle Kilometres	▪ 20% reduction in total vehicle kms 20% reduction in total car kms ▪ 20% reduction in 'commuting' car kms
Fuel Usage	▪ 50% reduction in fuel usage
Shift	Total abatement -2.09 MtCO2eq.
Sustainable Transport Trips	▪ 50% increase in daily active travel journeys ▪ 130% increase in daily public transport journeys. ▪ 25% reduction in daily car journeys.
Daily Journeys Modal Share	▪ Shift in Daily Mode Share 2018: 72% (car), 8% (PT), 20% (AT) ▪ 2030: 53% (car), 19% (PT), 28% (AT)
Escort to Education Journeys	30% shift of all E-to-E car journeys to sustainable modes
Improve	Total abatement –4.74 MtCO2eq.
Fleet Electrification	Private Car **Fleet** ▪ EV share of total passenger car fleet (30%) ▪ EV share of new registrations (100%) 845,000 Private EVs Commercial **Fleet** ▪ 20% EV share of total LGV fleet. 95,000 commercial EVs ▪ 30% ZE share of new heavy duty vehicle registrations ▪ 3,500 HGVs PT **Services** ▪ 1,500 EV buses in PSO bus fleet; ▪ Expansion of electrified rail services.
	Total abatement –1.08 MtCO2eq
Biofuels Blend Rate	E10:B20

ii. Offshore Wind

The 2020 programme for Government set a target for at least 5GW of grid connected offshore wind to be delivered in Ireland's maritime area by 2030. This target was affirmed in the updated 2023 Plan, that set a target for an 80% share of renewable electricity by 2030.

In 2021, the Government adopted the Policy Statement on the Framework for Ireland's Offshore Electricity Transmission System[70]. This document indicated that a plan-led offshore grid model would maximise societal benefits, avoid delaying offshore deployment, and also agreed to a three-phased pathway from the existing decentralised (developer-led) model towards a fully plan-led model over the course of this decade.

More recently, beyond the 5GW of offshore wind target by 2030, the Government has targeted an additional 2GW of floating offshore wind for the production of green hydrogen to create the necessary environment to develop a hydrogen industry. The exact details of how this objective will be achieved is expected to be contained within the hydrogen strategy due for publication by the end of Q2 2023.

These objectives will be achieved over three phases and these phases will also establish the building blocks for a long-term sustainable ORE industry in Ireland.

Phase One

Phase One consists of decentralised grid development with developers responsible for consenting and constructing offshore transmission assets, but to be handed over to EirGrid for operation. In March 2021, EirGrid issued an assessment of the potential grid connection options for the Offshore Phase 1 projects[71]. The indicative MEC's of the Phase 1 projects are presented in Table 28. Five of the six projects are located along the east coast with one project located off the west coast. Phase One aims to secure development of the largest proportion of Governments objective of 5GW offshore wind by 2030. The total combined existing Phase One capacity is c.4.4GW. It is noted that EirGrid in March 2021 issued an assessment of the potential grid Connection options for Phase One projects. Codling Wind Park was recommended to connect to substations on Poolbeg Peninsula.

---

[70] https://www.gov.ie/en/publication/5ec24-policy-statement-on-the-framework-for-irelands-offshore-electricity-transmission-system/

[71] https://www.cru.ie/wp-content/uploads/2021/10/CRU21112a-EirGrid-Offshore-Phase-1-Projects-Grid-Connections-Assessments-March21.pdf

Table 28: Phase One Offshore Wind Projects

Area	East Coast Projects	MEC Range	ORESS-1 Offer Quantity
East Coast	Oriel Wind Farm	370-400MW	0MW
East Coast	North Irish Sea Area (NISA)	500MW	500MW
East Coast	Dublin Array (Bray & Kish)	600-900MW	824MW
East Coast	Codling Wind Park 1 and 2	900-1500MW	1300MW
East Coast	Arklow Wind Park Phase 2	520-800MW	0MW
West Coast	Sceirde Rocks Wind Farm	350-450MW	450MW

The Government approved the Terms and Conditions for the first offshore RESS auction, ORESS 1, of which provisional auction results were published on May 11th 2023, with final auction results due to be published on June 14th 2023. The provisional results indicated 3074MW of successful ORESS 1 capacity. Oriel wind farm and Arklow Wind Park Phase 2 did not secure any capacity from ORESS 1 and alternative routes to market such as a corporate PPA can now be examined until August 2023, if an alternative route to market is not secured then Phase 1 capacity for these projects is recycled into Phase Two. Offshore wind projects were required to meet a number of milestones to be eligible to compete in ORESS 1, specifically, a project required a Maritime Area Consent (MAC) from the Minister for Environment, Climate and Communications, and a Grid Connection Assessment (GCA) from EirGrid. The outcome of the ORESS-1 auction and also the ability to secure development consent will determine the successful Phase One projects which will connect to the electricity grid.

Phase Two

The transition from Phase One to the longer enduring regime which incorporates the delivery of 5GW by 2030 is known as Phase Two. It is possible that a large proportion of the 5GW target will be delivered under Phase One. However, considering the combined 4.4GW capacity of Phase One projects and the prospect that some Phase One projects may fail to secure a route to market or development consent, additional offshore wind projects in Phase Two will be needed to meet 5GW by 2030. The main parameters of Phase Two include:

- **Alignment with available onshore grid capacity**: as outlined in EirGrid's Shaping Our Electricity Future. The analysis carried out by EirGrid has indicated c.700MW of available onshore grid capacity off the South Coast of Ireland, this capacity is based on the c.4.4GW of Phase One projects connecting to the electricity system. It appears that capacity up to 900MW is now being considered for phase 2 on the South Coast.

The available capacity indicates c.350-450MW off Cork and c.350-450MW off Waterford/Wexford[72]. Additional onshore grid capacity for connection of offshore projects under Phase Two may be identified by EirGrid following the outcome of ORESS 1. The geographical alignment of offshore wind projects developed under Phase Two with the availability of onshore grid capacity will further enable the TSO to optimise and expedite any onshore grid reinforcements that may be required to integrate Phase Two projects. This was designed to accelerate project delivery and minimise potential future grid constraints and/or curtailment.

- **Offshore Renewable Energy Designated Areas:** offshore capacity to be developed under Phase Two will be accelerated through the designation of maritime areas that have been specifically identified for the purpose of offshore energy production. This approach is consistent with EU policy and legislation, which aims to accelerate permitting procedures for renewable energy projects and associated grid infrastructure through designation of targeted specific renewable energy development zones.
- **Phase Two ORESS Auctions:** in a departure from Phase One, the auctions that take place under Phase Two on the South Coast will be explicitly targeting a pre-established benchmark volume of offshore wind capacity to be developed within specific ORE Designated Areas. It is noted that:
    - To ensure the optimum prospects for delivery by 2030, all ORE Designated Areas for Phase Two will be selected which facilitate offshore wind projects utilising technology that has been delivered at scale in other jurisdictions.
    - For the initial Phase Two auction, ORESS 2, participants will compete for supports to develop approximately 700-900MW of offshore wind capacity within one, or split evenly between two, ORE Designated Areas situated off Ireland's South coast.
    - Successful participants will connect into offshore substations developed by EirGrid, with arrays and transmission infrastructure to be situated within the ORE Designated Areas.
    - It is intended that the ORESS 2 will launch before the end of 2023. The auction and the development of the designated maritime area plans (DMAPs) will

[72] https://www.eirgridgroup.com/the-grid/offshore/Shaping-Our-Offshore-Energy-Future-April-2023-Brochure.pdf

determine whether this capacity will be split evenly between two 350 MW projects or allocated to a single 700 MW project.

  - The auction winner process may include inter alia weighting towards projects which can deliver additional non-grid connected capacity. Such considerations will be consulted upon following the publication of the ORESS 2 terms and conditions, to be consulted on in mid-2023. Further ORESS 2 design considerations may include weighting for co-location of flexible demand, overbuild, storage or other innovation that would maximise the greenhouse gas reductions in the state.
  - The number, regularity, size, and location of further Phase Two auctions will continue to be informed and determined by the availability of onshore grid capacity, including possible future identified capacity on the East or West coasts, marine forward spatial planning, as well as the outcome of ORESS 1.
- **Phase Two Offshore Grid Planning and Development:** EirGrid are to develop offshore grid transmission infrastructure for the South Coast Phase 2 projects that will compete in ORESS 2, including offshore substations and transmission lines connecting offshore substations to the onshore grid.

Successful participants in any subsequent Phase 2 ORESS auctions may be required to develop all offshore transmission assets, including offshore substations, as per Phase One, which will be subsequently transferred to EirGrid.

Phase Three

Phase Three aims to support the long-term potential for a floating offshore wind industry, including all elements of the necessary supply chain required for an industry of this type, in Ireland. The Irish Government has set an initial target of 2GW of floating offshore wind to be in development by 2030. This may include the development of projects devoted to production of green hydrogen, to create the necessary environment to develop an indigenous hydrogen industry, and projects devoted to other non-grid uses.

A Phase Three policy will be developed and published in Q1 2024. This will be informed by the in-development Offshore Renewable Energy Development Plan, which will be published in Q2 2023, and Hydrogen Strategy which will also be published by Government by the end of Q2 2023. This will aim to initiate a dedicated floating wind route to market in 2024 but further consideration and consultation will need to be given to route to market policy to ensure viable solutions with State protections.

Enduring Regime

The Enduring Regime will see greater state involvement in the sustainable development of the sector, in terms of where projects are developed, when they are developed, and where the energy generated will be used. This Plan Led approach will further provide for developing the onshore and offshore transmission infrastructure necessary to achieve a fully decarbonised energy system in Ireland, bolstering security of supply, and realising the economic opportunities associated with exporting offshore renewables to major regional demand centres in continental Europe and the United Kingdom. This will further act as an important signal for investment for renewable energy development.

The Government will assess Broad Areas of Interest for renewable energy production in the deeper areas of the Celtic Sea and off the West coast of Ireland leading to the designation of specific areas. More information on the proposed approach will be contained in the OREDP II, which will be informed by a public consultation which began in Q1 2023, and in Government's forthcoming Hydrogen Strategy and Electricity Interconnection Policy in Q2 2023. As with Phase Three, and upon completion of a route to market which is compliant with EU State Aid rules, Government intends to develop floating wind projects within these designated areas.

The Government propose that a move from a decentralised to plan-led model will ensure that development is managed in a planned, strategic, and sustainable way. Work is underway on developing this plan-led approach to future offshore renewables development, with this policy to be consulted upon this year, with a view to publication of an Enduring Regime for Offshore Wind policy in 2024.

Offshore Renewable Energy Development Plan II

The Offshore Renewable Energy Development Plan II (OREDP II) is a sectoral spatial strategy for ORE. In developing the plan, core principles within the National Marine Planning Framework are being centrally considered, namely the protection of the marine environment and biodiversity, while also recognising our seas are a shared space with potential for co-existence with other maritime activities. The outputs from the development of the OREDP II will inform how the State transitions to a more plan-led approach to the development of ORE. Together with an associated economic analysis, this will inform ORE ongoing policy development.

The OREDP II assessment encompasses the entire maritime area which extends to 200 nautical miles or 370 km off the coast. The plan will consider advances in wind, wave and tidal renewable energy technologies to assess the ORE potential in Irish waters. It will also provide an evidence base to facilitate the identification of areas most suitable for ORE using the latest data available on a range of themes including other maritime activities and marine biodiversity. An strategic environmental assessment (SEA) and appropriate assessment (AA) are being carried out to evaluate the potential impacts and inform the direction of the ORE.

iii. Hydrogen

At present, and in the absence of a Hydrogen Strategy which is due to be published by the end of Q2 2023, Ireland does not have any clear pathway for Green Hydrogen production, storage, distribution, scale of market, as well as route to market in Ireland. The Climate Action Plan 2023 does indicate that hydrogen could play a role in emissions abatement in Ireland, with a mention of green hydrogen production from surplus renewable electricity and zero emission gas fired generation from biomethane and hydrogen from 2030.

Going beyond 2030, some key measures listed necessary to deliver emission reductions included green hydrogen production via 2GW offshore wind, long duration storage technologies and increase zero emission gas generation to enable a net zero power system.

c. Decarbonisation Strategies in other Jurisdictions

i. Decarbonisation Strategies

Today, every developed country has considered and devised decarbonisation strategies of some kind, to some extent. While the overall objectives are the same - reduction of carbon emissions, alignment with international agreements, climate action - the contents of each strategy vary according to geographical, historical, political and social factors.

In the European Union, member states have published strategies, reports and roadmaps in recent years, aiming to plan and manage the decarbonisation of their economies and to meet binding targets set by the EU. Hydrogen is often an integral part of such strategies, especially in terms of decarbonising industry and transport, as well as energy storage and grid balancing.

Some member states, however, have a stronger focus on aspects such as electrification. Belgium's electricity system operator Elia released, in 2021, the group's "Roadmap to Net Zero" vision, highlighting above all the uncertainties about the most efficient path towards net zero. While "green molecules" such as hydrogen are mentioned, the vision emphasises that, in terms of energy storage, "the choice of technology does not need to occur today"[73].

---

[73] https://www.elia.be/en/news/press-releases/2021/11/20211119_elia-group-publishes-roadmap-to-net-zero

The following subsections detail the strategies of different EU countries in terms of offshore wind and, especially, hydrogen.

ii. Offshore Wind

As of 2020, Europe has over 5,400 grid-connected offshore wind turbines across 116 wind farms in 12 countries, totalling a 25 GW offshore wind capacity. Figure 46 shows the evolution of installed capacity between 2010 and 2020.

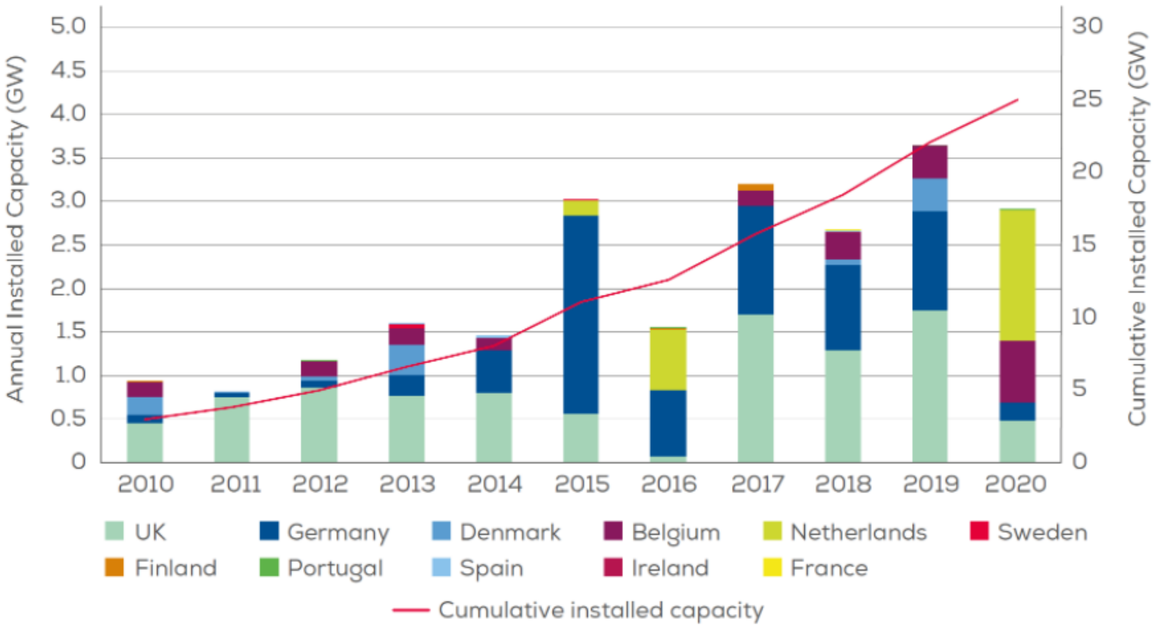


Figure 46: Annual and cumulative offshore wind installation in Europe

With 10.4 GW of installed capacity, the UK has more offshore installed wind capacity than any other country in the world. Given its strategic geography and abundance of potential offshore wind farm locations, the country considers offshore wind a major opportunity to meet its climate targets, and aims to increase its current capacity fivefold by 2030.

The European Commission released, in 2020, an EU-wide strategy for offshore wind[74], including vision and targets for the development of offshore wind within the economic bloc. Non-binding targets of 60 GW by 2030 and 300 GW by 2050 were established, and the need to adjust current policies to offer better conditions for investment in offshore wind was emphasised. The strategy provides an analysis of the EU's sea basins in terms of potential deployment of offshore renewables (Figure 47), highlighting different technologies and

[74] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0741&from=EN

opportunities in the North Sea, the Baltic Sea, the Mediterranean and the Black Sea, as well as in the Atlantic Ocean and EU islands.

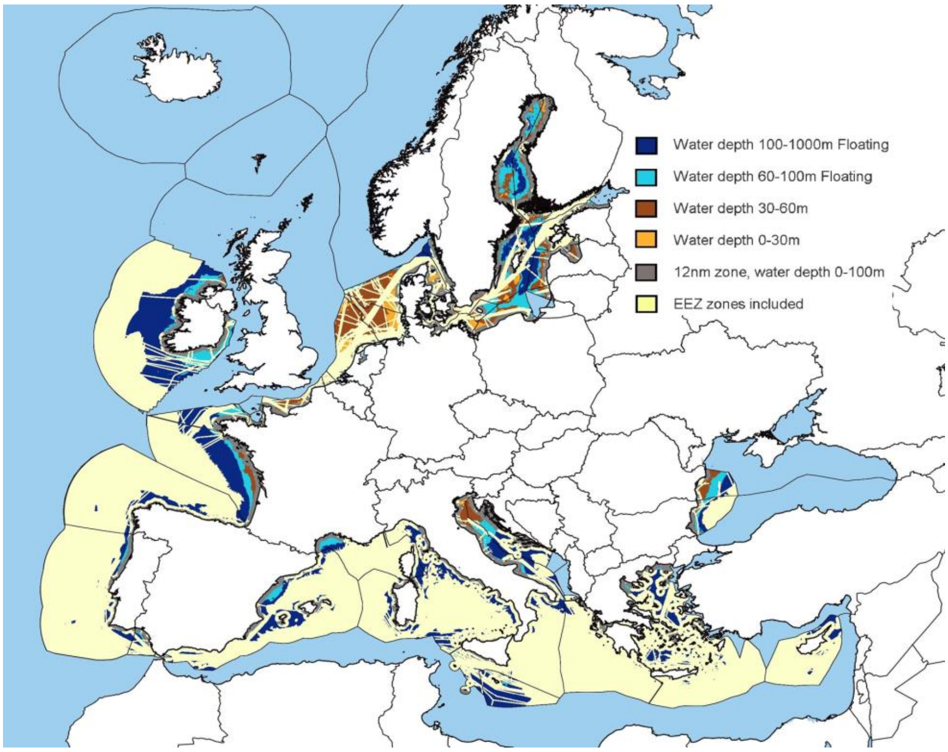


Figure 47: Technical potential of offshore wind in EU sea basins

The EU offshore wind strategy, above all, recognises the challenges involved in reaching its ambitious targets. It estimates that approximately €800 million, from both public and private investments, would be needed to reach 300 GW, with two-thirds of this budget allocated to infrastructure investments. Under the current framework, only 90 GW would be reached by 2050.

Major EU economies have also defined targets and strategies for the development of their offshore wind capacities. The French government has committed to build 50 offshore wind farms totalling 40 GW by 2050, under an agreement with France's wind industry. The country aims to quadruple offshore wind jobs from the current 5,000 positions to 20,000 direct and indirect jobs[75].

Meanwhile, Germany's offshore wind strategy focuses on partnerships with neighbouring countries such as Belgium and Denmark to increase connections between their grids and ensure a strategic approach when planning offshore projects. Germany aims to install 70 GW

[75] **https://www.evwind.es/2022/04/01/france-commits-to-40-gw-offshore-wind-power-by-2050/85431**

of offshore wind capacity by 2045, a plan that has not met unanimous agreement: while offshore wind power would inevitably have to be developed in the north of the country, Germany's largest load centres are located in the south. Therefore, it is important to ensure that the country's grid is robust enough to handle this north-south flow[76].

iii. Hydrogen Strategies

In addition to the European Hydrogen Strategy, many EU member states have released their own national hydrogen plans in recent years. There is a considerable degree of diversity between them and, while some countries have produced detailed hydrogen strategies and others still have not, almost all member states mention green hydrogen in their 2030 National Energy and Climate Plans (NECPs) – a mandatory document which outlines each country's climate and energy goals and policies between 2021 and 2030.

In this context, the opportunities of Power-to-Gas systems are widely recognised by EU member states, and some countries have set specific, tangible targets for the production and consumption of green hydrogen. Figure 48 shows the targets set by different jurisdictions in regard to installed electrolysis capacity by 2030 – the year that every member state has used as a medium-term reference. It also includes the 2 GW target set by Ireland.

France has the highest absolute target, aiming to install capacity to produce 6.5 GW of decarbonised hydrogen via electrolysis by 2030; while Sweden has the highest relative target, planning to have nearly 400 W per capita by then. Overall, the 11 countries of Figure 48 already plan a combined electrolysis capacity of 34.8 GW for 2030, which is equivalent to 87% of the overarching EU target of 40 GW set in the European Hydrogen Strategy.

[76] https://www.csis.org/analysis/germanys-offshore-wind-industrial-strategy

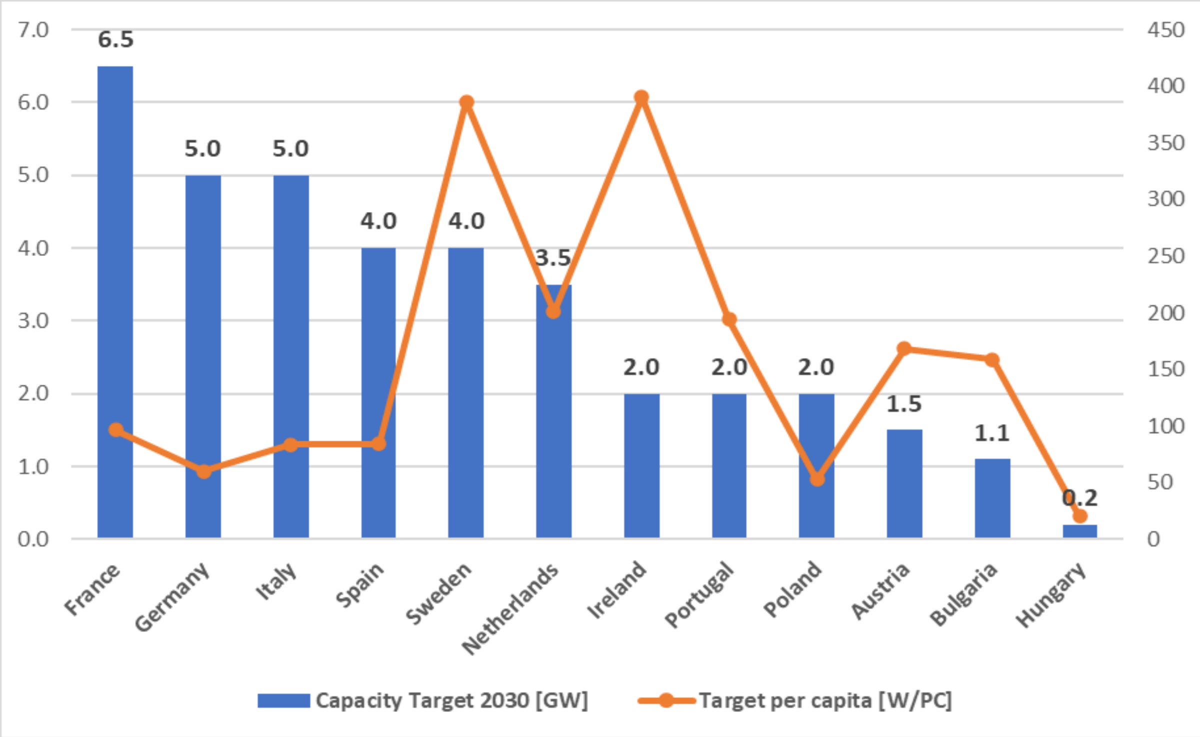


Figure 48: Comparison of electrolysis capacity targets for different EU countries by 2030 in absolute terms (blue) and on a per capita basis (orange)

The following subsections provide a more detailed analysis of hydrogen strategies published by major European countries over the last few years.

France

In 2018, France was one of the first nations to ever release a hydrogen plan. Two years later, the French low-carbon and renewable hydrogen strategy[77] was deployed, consisting of a €7 billion programme which highlights decarbonised hydrogen as a breakthrough technology that will be key in a lower-carbon future, and setting out three clear priorities:

1) **The development of an electrolysis sector**: this priority addresses the production of green hydrogen by aiming to have an installed electrolyser capacity of 6.5 GW in France by 2030, focusing on high-capacity projects. This section of the strategy recognises industrial processes, such as those performed by the petrochemical industry, as a key area where green hydrogen can displace fossil hydrogen, implying

---

[77] https://www.bdi.fr/wp-content/uploads/2020/03/PressKitProvisionalDraft-National-strategy-for-the-development-of-decarbonised-and-renewable-hydrogen-in-France.pdf

that a considerable amount of the added production capacity will be directed to the decarbonisation of industry.

2) **The development of clean mobility**: this priority addressed the role of hydrogen in the transport sector, with strong focus on heavy-duty mobility. Proposed types of transport to be converted to hydrogen technologies in France include light and heavy trucks, buses, trains, river shuttles and ships. In addition, the document recognises the prominence of certain French companies within this sector (such as Airbus) which will lead innovative projects such as hydrogen-powered aircraft over the next decade.
3) **The support for research, innovation and skills**: this priority addresses the need for a qualified workforce with the right skills to work in the future green hydrogen sector of France. Roles for hydrogen are highlighted in many areas, including in energy networks and in industry, and the importance of investment in research and development in the field of hydrogen is seen as a vital element to speed up the deployment of hydrogen technologies. The French government sets here a strategy to provide training on the operation, maintenance and safety of hydrogen technologies by developing job and qualifications campuses, and new courses in schools and colleges, as well as within companies in the sector.

In essence, the French Hydrogen Strategy covers the three main pillars of a future hydrogen economy (demand, use and professional skills), while proposing a clear plan with deliverables tailored to the country's local circumstances. Furthermore, France commits itself to a strong involvement in the EU's Clean Hydrogen Alliance to ensure that its national strategy is aligned and coordinated with the work carried out at European level. Hydrogen is thus seen as "a European matter", with France being a key player and an important stakeholder in the future European low-carbon economy.

Germany

Germany's National Hydrogen Strategy[78] was published in June 2020 and sets out the steps the country is aiming to take to become a leader and exporter of green hydrogen and its technologies. Similarly to the French Hydrogen Strategy, there is a strong focus on green (decarbonised) hydrogen, and the production of the gas from renewable electricity is seen as the only long-term sustainable option.

Germany is part of the world's hydrogen epicentre, being part of the "European cluster" of hydrogen production and consumption alongside countries such as the Netherlands and the

[78] https://www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.html

United Kingdom. The country has historically supported hydrogen research, having done so since the 1980's, and currently boasts an advanced and mature hydrogen research and innovation landscape. In this context, the German national strategy reflects the nation's commitment to achieving its climate goals, aligning with EU strategies and expanding considerably its investment in green hydrogen technologies in the future.

In addition to €2 billion which is being allocated to foster international partnerships, Germany is making available €7 billion for accelerating the market rollout of hydrogen technologies within the country. To do so, the first step is seen as the establishment of a domestic market for the production and use of hydrogen: Germany aims to establish 5 GW of green hydrogen generation capacity by 2030 and an additional 5 GW by 2035 or no later than 2040, with both onshore and offshore energy generation facilities needed. Admittedly, this capacity will be nowhere near enough to provide all of the nation's projected demand by 2030 (90 to 110 TWh), which, controversially, underlines Germany's plan to also import hydrogen.

The first phase of the German hydrogen strategy establishes an action plan of 38 measures to ramp-up the market by 2023, most notably:

- Measure 1, addressing the need for a better framework for the use of renewable electricity and a fair design of the energy price components, aiming to create a more favourable environment to produce decarbonised hydrogen;
- Measure 15, addressing the need to promote climate-friendly industrial processes and instituting a pilot programme named "Carbon Contracts for Difference", targeting the decarbonisation of the hydrogen consumed by the steel and chemical industries, for example;
- Measure 31, addressing the need to strengthen the investment in research and development of green hydrogen at EU level, focusing on the entire value and use chain of hydrogen (including transport and distribution).

As of 2022, the first phase of Germany's National Hydrogen Strategy is well underway, and work is being carried out to fulfil the above-mentioned 38 measures. From 2024, the second phase of the strategy is scheduled to start, focusing on stabilising the emerging domestic market as well as "moulding the European and international dimension of hydrogen". International cooperation and collaboration are key elements of the strategy, and Germany intends to assist other countries in their efforts to decarbonise and deploy hydrogen technologies. Creating such partnerships and engaging in joint projects is seen as beneficial on a global scale but also to Germany itself, given that partner nations may be potential hydrogen exporters in the future. Since 2020, Germany has signed agreements on hydrogen with many countries around the world, including Australia, Canada, Ukraine and Chile – an active effort to strengthen international bonds and secure Germany's future energy supply[79].

United Kingdom

The UK Hydrogen Strategy[80] was launched in 2021 and is considerably more detailed than those of other major European economic powers. The document contextualises the current state of hydrogen in the UK, highlighting the low volumes of green hydrogen currently being produced and making a case for the deployment of low-carbon hydrogen not only in England, but also in Scotland, Wales and Northern Ireland. The strategy also establishes a roadmap for the production and use of low-carbon hydrogen in the UK and addresses the economic benefits associated with that, such as the creation of new jobs and the upskilling of qualified workforce, as well as the opportunities for international investment and exports.

One of the most interesting aspects of the UK Hydrogen Strategy is the constant use of the term "low-carbon hydrogen" instead of "green" or "decarbonised" hydrogen. This is due to the fact that the UK, unlike countries such as France and Germany, strongly acknowledges blue hydrogen – produced from natural gas coupled with Carbon Capture and Storage (CCS) technologies – as well as electrolytic hydrogen as key elements of its strategy. This is referred to as a "twin track" approach to hydrogen production, which establishes CCS technology and infrastructure as important components of the UK hydrogen economy roadmap.

In this context, the main actions expected to arise from the development of a hydrogen economy in the UK are broken down into four phases:

- In the early 2020s (no later than 2024) the Net Zero Hydrogen Fund (NZHF) will kickstart investment in low-carbon hydrogen production by providing up to £240 million (€280 million) to support the deployment of new projects. This initial phase will see the finalisation of plans, standards and business models which will support the deployment of the strategy in the following years.
- In the mid-2020s (2025 to 2027) the UK is aiming for 1 GW of installed capacity to produce low-carbon hydrogen, as well as at least two Carbon Capture, Usage and Storage (CCUS) clusters. Strategic decisions are scheduled to be finalised and the trial of a "heat town" is expected for 2025.

---

79 https://www.globalcompliancenews.com/2021/10/18/germany-the-german-national-hydrogen-strategy-and-international-hydrogen-partnerships-06102021/

80 https://www.gov.uk/government/publications/uk-hydrogen-strategy

- In the late 2020s (no later than 2030) a production capacity of 5 GW and a minimum of 4 CCUS clusters are envisioned. The policy foresees a wide use of hydrogen in several applications and the pilot of a "hydrogen town" by 2030, as well as 40 GW of offshore wind capacity.
- Beyond 2030, it is expected that hydrogen production will continue to be increased and scaled up by different methods of production, such as nuclear power and biomass. A full range of end users will employ hydrogen, such as the shipping and aviation sectors, and a potential gas grid conversion is considered.

Furthermore, the UK government published its Energy Security Strategy[81] in April 2022 in light of the global energy crisis, which effectively doubles the 2030 target for the production of hydrogen to 10 GW. Plans to unlock £9 billion of investment to strengthen hydrogen's role in the UK's energy mix were also unveiled three months later.

The UK hydrogen economy roadmap is to be developed throughout all countries that constitute the United Kingdom. However, even before the UK Hydrogen Strategy was published, the Scottish government launched the Hydrogen Policy Statement of Scotland in 2020, which was followed by their own Hydrogen Action Plan[82] in 2021. This sets out actions to be taken over the next decade to ensure a "just transition" and decarbonise the Scottish energy system while developing a hydrogen economy. Scotland aims to have a minimum of 5 GW of low-carbon hydrogen production capacity by 2030, and at least 25 GW by 2045, which will be made possible through actions such as:

- A £100 million (€120 million) fund;
- The development of a domestic market with regional hubs of hydrogen production, storage and distribution;
- Seeking optimal locations for the installation of electrolysers;
- The dissemination of the opportunities in hydrogen markets to enable the transition of Scotland's supply chain;
- Establishing international partnerships with target countries in Europe and worldwide, aiming to produce a "Hydrogen Export Plan";
- Strengthening research and development by assigning 10% of the abovementioned fund for the support of innovation and research on hydrogen technologies.

[81] https://www.gov.uk/government/publications/british-energy-security-strategy

[82] https://www.gov.scot/publications/draft-hydrogen-action-plan/

Other Countries

Other European countries that have released National Hydrogen Strategies include:

→ **The Netherlands**[83], who aim to develop between 3 GW and 4 GW of electrolyser capacity by 2030, with a specific vision to produce green hydrogen from offshore wind, achieving 10 GW by 2040. The country recognises its strategic location and infrastructure, highlighting its extensive gas grid and existing storage capacity, and plans to continue to act as a European energy hub;

→ **Italy**[84], with the ambition to reach a 2% hydrogen penetration in the country's energy demand by 2030, increasing this target to 20% by 2050. To enable this, 5 GW of electrolysis installed capacity are expected to be in place by 2030, and an investment of up to €10 billion will be required by then;

→ **Norway**[85], which aims to establish five hydrogen hubs for maritime transport and a series of pilot projects by 2025, as well as a network of hydrogen hubs and the realisation of full-scale hydrogen industrial projects by 2030. The country aims to significantly strengthen the research, development and demonstration of hydrogen solutions, and to create the Centre for Environment-friendly Energy Research (FME);

→ **Spain**[86], with a phased plan to install at least 4 GW of electrolyser plants by 2030, setting a minimum green hydrogen contribution of 25% for the hydrogen consumed by industry in that year, and culminating with the decarbonisation of the Spanish society by 2050.

---

[83] https://www.fch.europa.eu/sites/default/files/file_attach/Brochure%20FCH%20Netherlands%20%28ID%209474122%29.pdf

[84] https://www.mise.gov.it/images/stories/documenti/Strategia_Nazionale_Idrogeno_Linee_guida_preliminari_nov20.pdf

[85] https://www.regjeringen.no/contentassets/8ffd54808d7e42e8bce81340b13b6b7d/hydrogenstrategien-engelsk.pdf

[86] https://energia.gob.es/es-es/Novedades/Documents/hoja_de_ruta_del_hidrogeno.pdf

d. Roadmap to Achieving Net Zero Emissions by 2050

i. Global Roadmap to 2050

The International Energy Agency (IEA) published a roadmap for the global energy sector to achieve net zero emissions by 2050[87]. Figure 49 presents a schematic of the roadmap and the key milestones between 2022 and 2050. The key pillars of decarbonisation underpinning the roadmap are: (1) energy efficiency, (2) behavioural change, (3) electrification, (4) renewables, (5) hydrogen, (6) bioenergy and (7) carbon capture, utilisation and storage (CCUS).

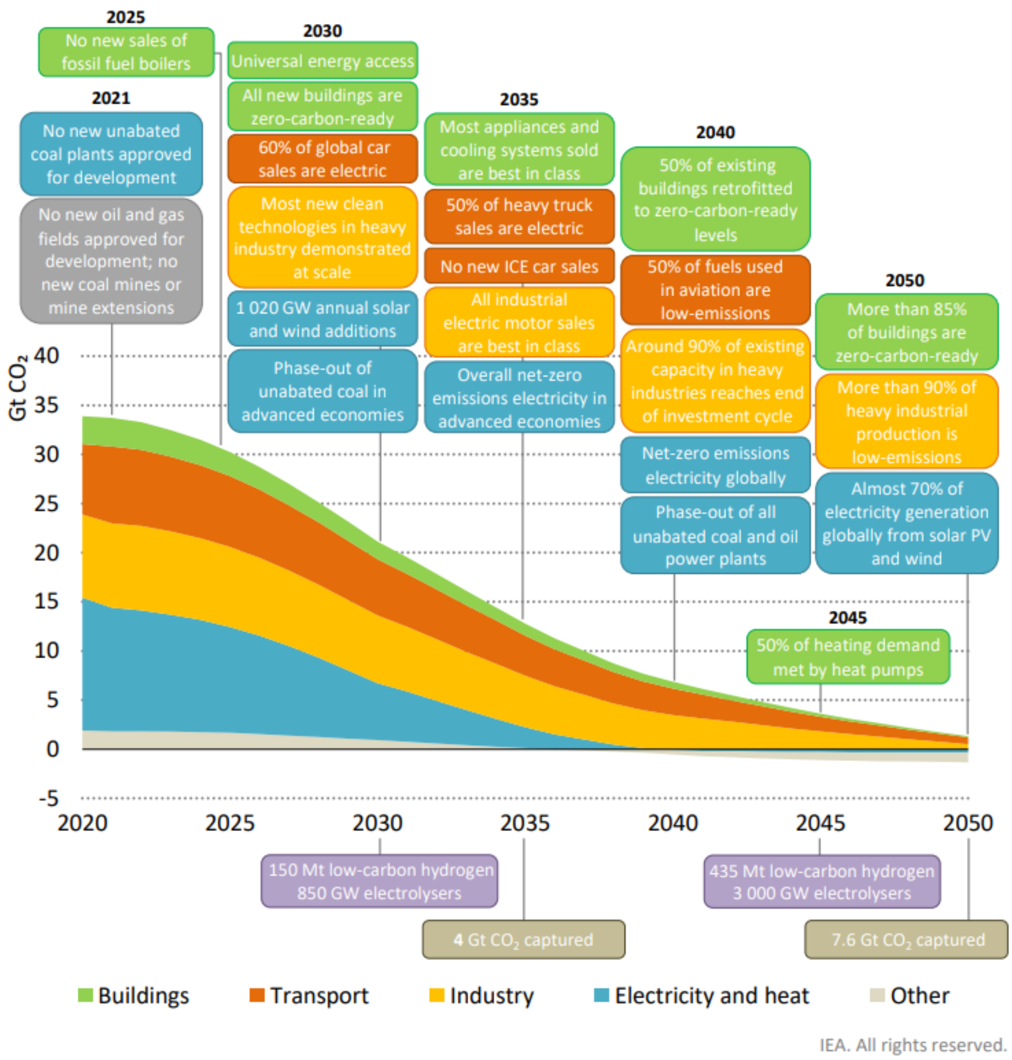


Figure 49: IEA Net Zero by 2050 – A roadmap for the global energy sector

87 https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf

The IEA assessed the impact of the decarbonisation mitigation measures on emissions reductions, as shown in Figure 50. Energy efficiency and building more renewable capacity such as wind and solar deliver close to half of the emissions reductions to 2030 in the net zero roadmap. From 2030 onwards increased electrification of the energy sector, renewable hydrogen and CCUS ensure net zero emissions by 2050.

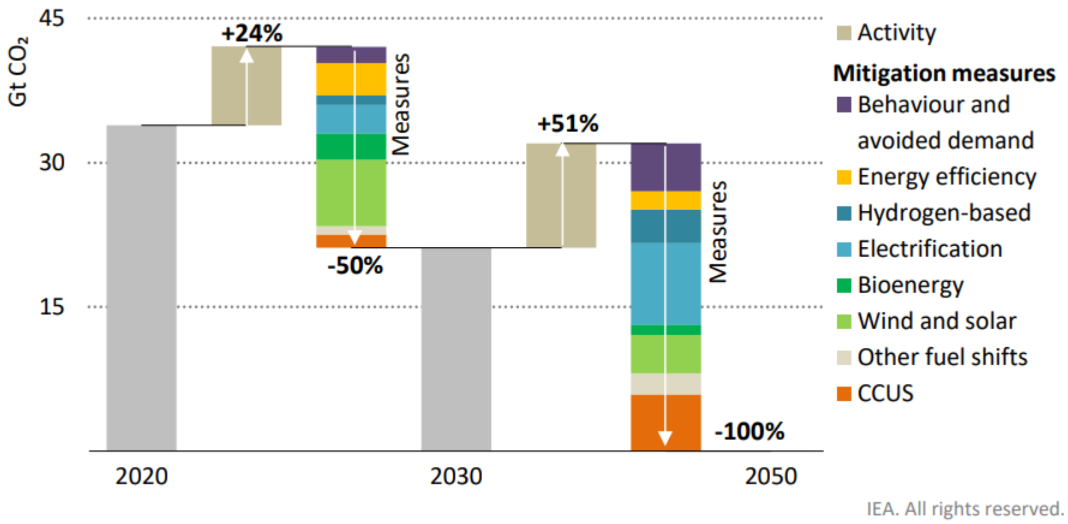


Figure 50: IEA Net Zero by 2050 - Emissions reduction by mitigation measure

Notes: Activity = energy service demand changes from economic and population growth. Behaviour = energy service demand changes from user decisions, e.g. changing heating temperatures. Avoided demand = energy service demand changes from technology developments, e.g. digitalisation. Other fuel shifts = switching from coal and oil to natural gas, nuclear, hydropower, geothermal, concentrating solar power or marine.

ii. Ireland's Roadmap to 2050

The Climate Action Plan 2023 sets out targets for Ireland's energy system for 2030 to ensure the country is on track to achieve net zero emissions by 2050. In general, there is no detailed information on the decarbonisation measures and energy infrastructure requirements in Ireland beyond 2030. It is noted the Climate Action Plan 2023 does list the development of a roadmap for net zero as a key measure for the electricity sector for 2031-2035.

EirGrid is due to update their Tomorrow Energy Scenario analysis, starting in Q3 2023, which may consider net zero scenarios.

MaREI/UCC: Our Climate Neutral Future – Zero by 50

In March 2021, Wind Energy Ireland (WEI) commissioned MaREI and UCC to carry out a study to determine a pathway to net zero emissions in 2050. The report ‘Our Climate Neutral Future – Zero by 50’[88] concluded that there are three “no regret options”, supported by international science to achieve net zero emissions: (1) energy efficiency (2) electrification and (3) deployment of market ready renewables.

The MaREI report reviewed the 2019 Irish energy system as shown in Figure 51. In this year, approximately 21% of Ireland’s energy consumption was electricity, with the remainder in the heating and transport sectors. Industry had a total energy demand of 25TWh in 2019 supplied from a mix of electricity, gas and oil. The transport and freight sectors accounted for 48TWh of energy demand and were primarily supplied by oil. The residential and commercial sectors had a total energy demand of 59TWh and were dependent on mainly oil, gas and electricity. In 2019, the electricity produced was approximately 37% renewable with the main renewable source being wind and the remainder of electricity coming from fossil fuel sources including gas, coal and peat.

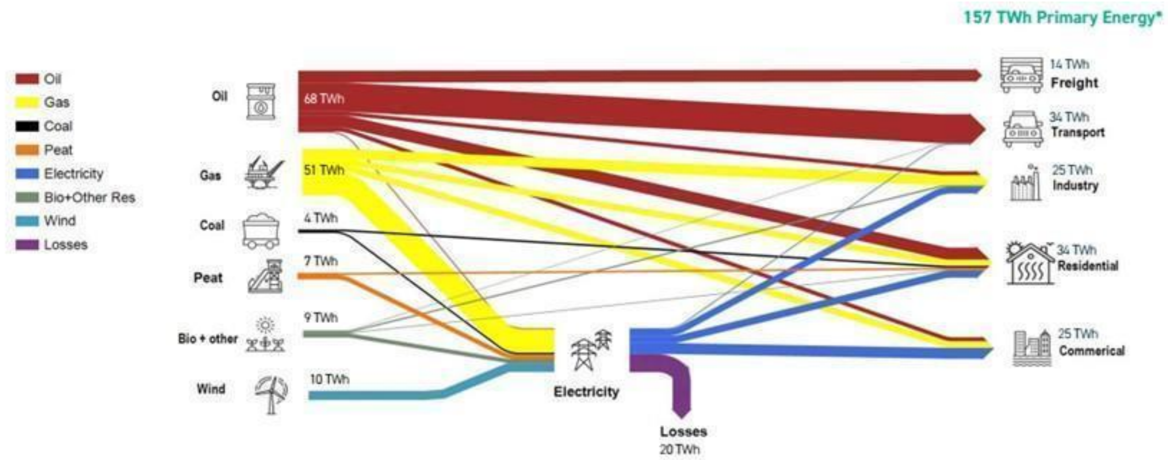


Figure 51: Ireland’s energy System 2019 – MaREI Study

The indicative energy system in 2050 modelled by MaREI is shown in Figure 52. The three no regret decarbonisation measures are evident from the schematic with reduced energy consumption and losses, increased electrification and additional renewable capacity. Some key observations on MaREI’s 2050 system include:

88 https://www.marei.ie/wp-content/uploads/2021/03/Our-Climate-Neutral-Future-Zero-by-50-Skillnet-Report-March-2021-Final-2.pdf

- The total primary energy requirement was modelled to reduce with improved energy efficiency by 22% from 157TWh to 122TWh.
- Almost all of the energy assumed is from renewable energy sources, with the export of some excess renewable energy helping to ensure net-zero carbon.
- There was a substantial increase in the use of electricity from 30TWh to 84TWh, a 180% increase compared to 2019.
- Electricity could change from providing approximately 20% of total energy to potentially around 65% in a net zero carbon system. To achieve this increase, it will be necessary to electrify to the highest extent possible the transport, industry, residential and commercial sectors.

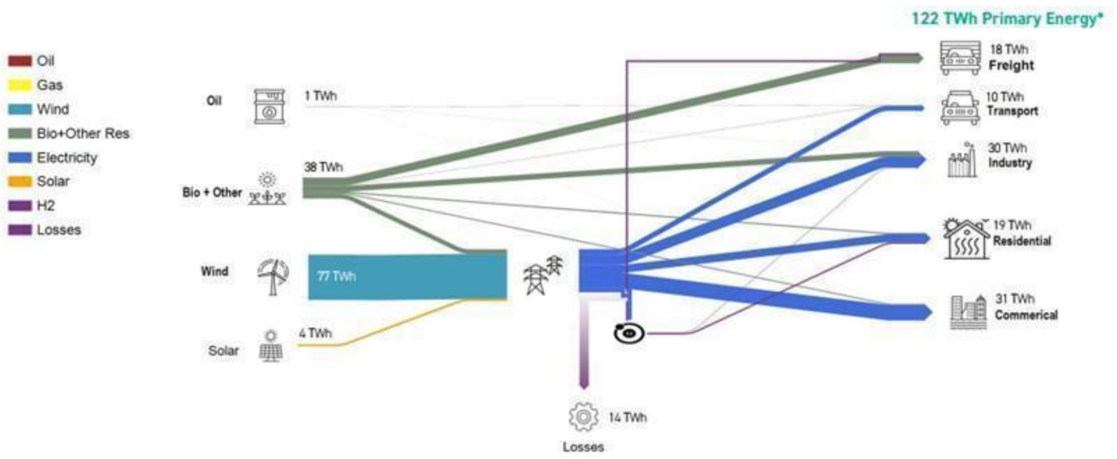


Figure 52: Ireland's energy system 2050 – MaREI Study

Figure 53 breaks down the electrification by sector in 2050. MaREI's analysis indicates that the electrification of the industry, commercial, residential and transport sectors could provide an additional 40TWh of electricity demand while the requirement for green hydrogen for dispatchable power plants could provide a further 14TWh of demand. MaREI estimated that the static electricity peak demand (ignoring flexible demand) could be 8.1GW in 2050, an increase of 55% on the existing 5.2GW peak demand. The report indicated the dynamic peak demand in 2050, including flexible demand at times of high renewables, could be 12.1GW, representing an increase of 130% on today's peak demand.

It is important to note that a major caveat of the study is that there was limited modelling of the distribution and the transmission network. To allow for the potential 180% growth in electricity usage and 55-130% growth in peak electricity demand there will be the need for substantial development of the transmission and distribution system. Considering the challenges and timelines to develop electricity infrastructure this could be a material impediment to achieving this level of electrification.

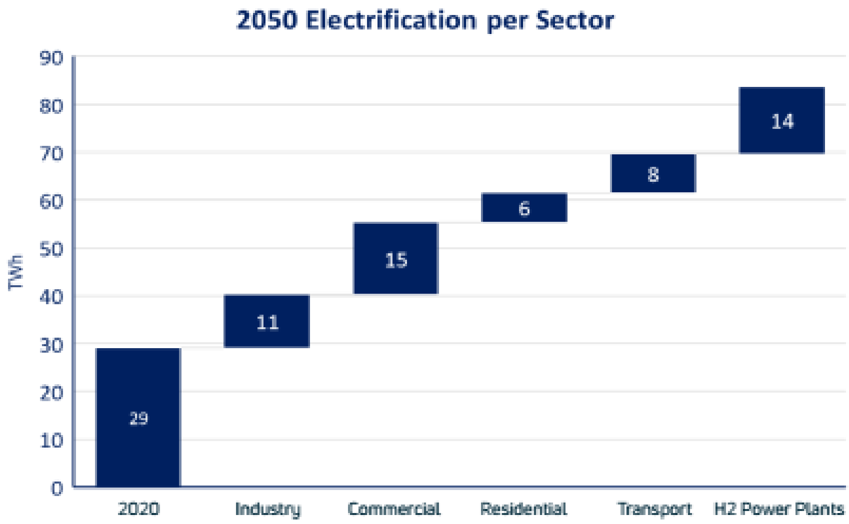


Figure 53: Ireland's electrification 2050 – MaREI Study

SEAI National Heat Study – Net Zero by 2050

The National Heat Study[89] was commissioned by a project team across the SEAI Research and Policy Insights directorate and developed with the assistance of energy consultants Element Energy and Ricardo Energy and Environment. The study explored pathways for heating and cooling decarbonisation in Ireland out to 2050. The study was designed to provide insight into the potential impacts for Government policy to 2030 and 2050. In total, there were eight reports produced as outputs from the study, see Figure 54.

[89] https://www.seai.ie/data-and-insights/national-heat-study/

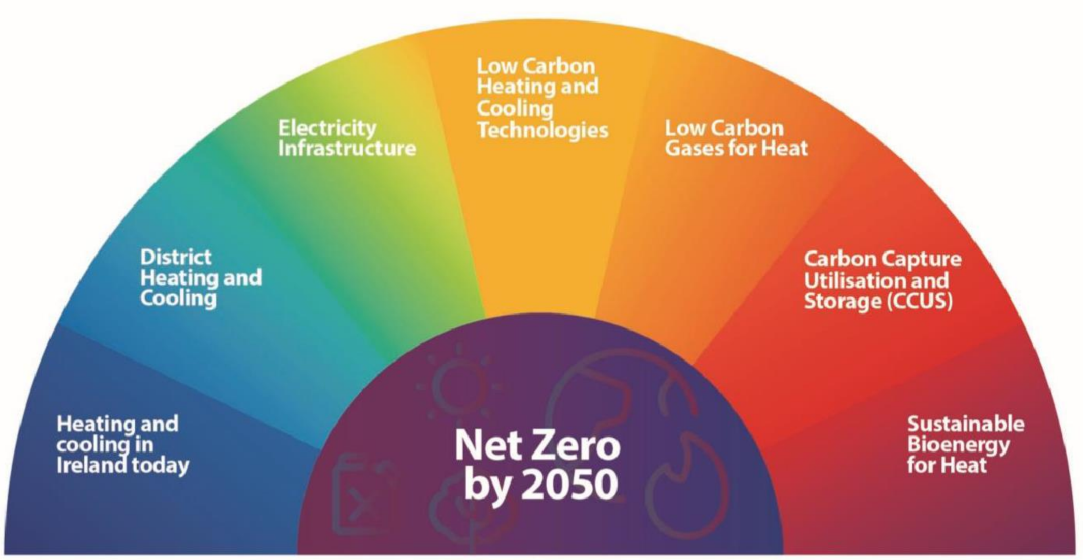


Figure 54: National Heat Study: framework of reports

The viable technologies and fuels considered for the study were: heat pumps, district heating, electricity use for heat, hydrogen, biomethane, solid biomass and other biogenic fuels and carbon capture, utilisation and storage (CCUS).

SEAI modelled five potential scenarios out to 2050, they included: (1) a baseline scenario where all sectors continue to use carbon intensive practices, (2) high electrification scenario with minimal bio-derived gases, CCUS and green hydrogen, (3) decarbonised gas scenario weighted towards green hydrogen use and CCUS infrastructure and bio-derived gases, (4) balanced scenario that progresses steadily and comprises a mix of low carbon heat solutions from electricity, green hydrogen and bio-derived gases, (5) rapid progress scenario where all low temperature heat applications are quickly electrified and bio-derived gases are prioritised for industry.

Figure 55 indicates the modelled CO_2 trajectories for the five scenarios. Excluding the baseline scenario, all the scenarios achieve net zero by 2050 in the heating sector. These scenarios include the phase out of fossil fuels in the various heat sectors before 2035, as shown in Table 29.

Table 29: SEAI National Heat Study: Fossil fuel phase out timelines

Sector	Baseline	Balanced, high electrification, decarbonised gas	Rapid progress
Public	No phase-out timeline	2031	2026
Residential		2032	2027
Commercial		2034	2029
Industry		2035	2030

Agriculture		2035	2030

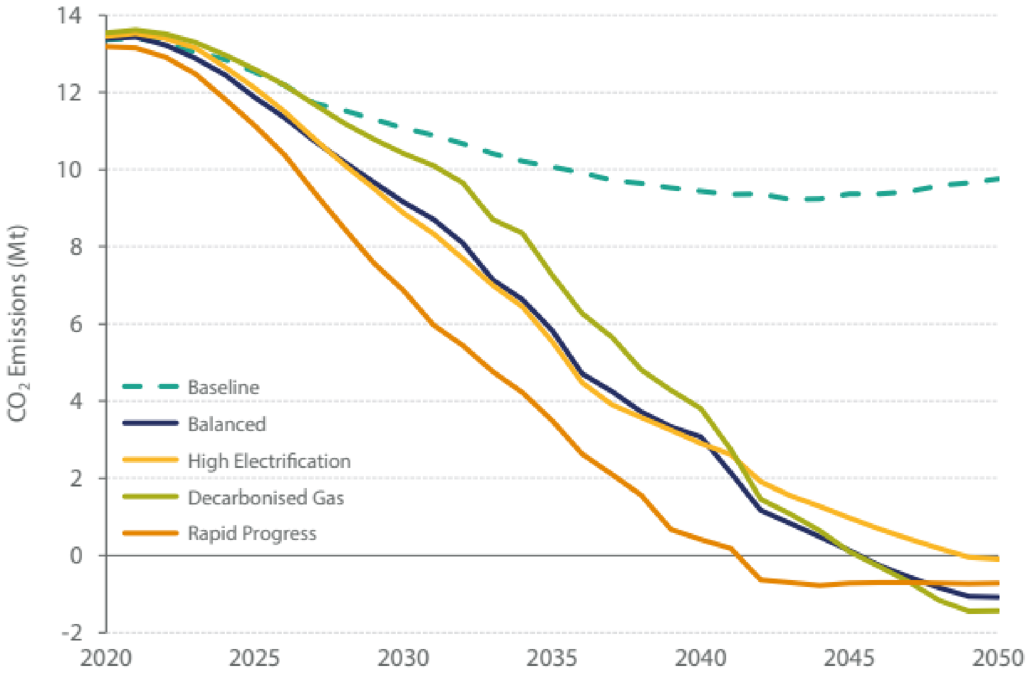


Figure 55: SEAI National Heat Study: Annual related heat emissions by scenario 2020-2050

Ireland's electricity demand was modelled to grow significantly for each of the four scenarios that achieve net zero emissions by 2050. Depending on the scenario, SEAI estimates that Ireland's total electricity demand could grow by 56-64% between 2020 and 2030, and a further 62-80% between 2030 and 2050.

Reviewing Figure 56, the electricity demand from the heat sector is expected to grow significantly out to 2050 for all the scenarios modelled. Heat pumps were modelled to account for 12-20% of heating demand in 2030 and 33-38% in 2050. The decarbonisation of the electricity sector appears to be imperative for the heat sector to achieve net zero emissions. This further highlights the requirement for the deployment of renewable generation, demand flexibility measures and the development of infrastructure for the electricity grid to facilitate demand and generation increases.

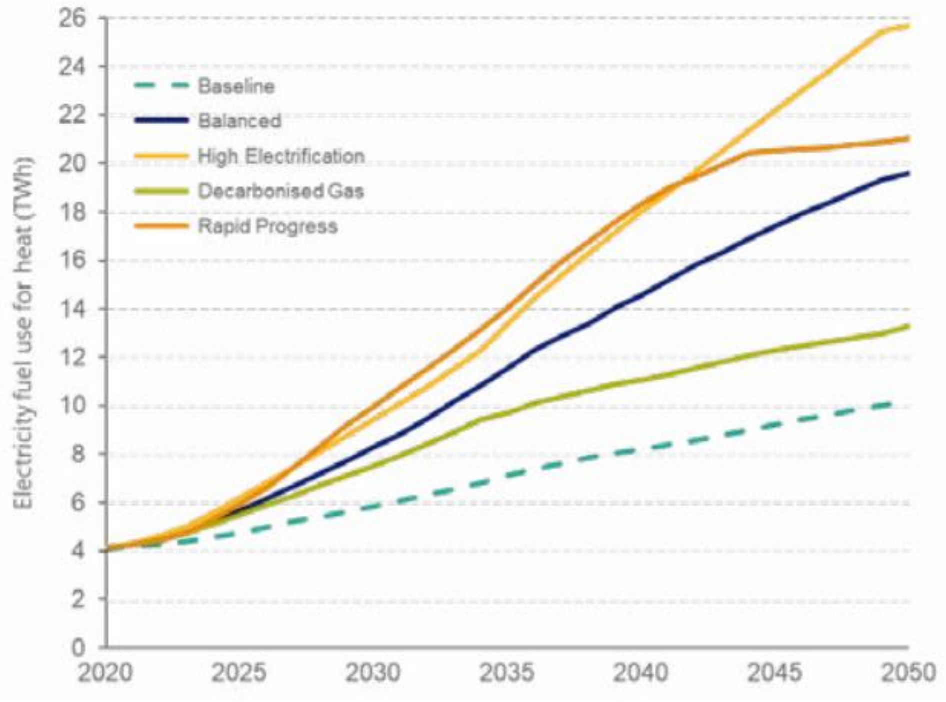


Figure 56: SEAI National Heat Study: Electricity demand for heat sector 2020 to 2050

The key insights highlighted in the National Heat Study report include:

- Ireland has a target of 51% emissions reductions by 2030, relative to 2018 levels. The measures outlined in the Climate Action Plan are highly unlikely to deliver required CO_2 reductions to meet a proportional share.
- Accelerate the deployment of district heating technology as it has the potential to meet approximately 50% of building heating demand in Ireland.
- Promoting evolving existing policy supports that encourage fossil fuels replacements in building as an effective and immediate mitigation strategy for emission reduction relative to a fabric-first approach.
- Accelerate the deployment of heat pumps at large scale as a prominent technology for rapid emission reduction.
- Decarbonising the electricity grid to reduce heat-related emissions.
- Investigating net-zero emission pathways with the lowest cumulative emissions use and more electric heating technologies including scenarios focused on a hydrogen gas grid which have more cumulative emissions.
- Carrying out a time-phased process to phase-out fossil fuel in all sectors as soon as possible to meet net zero target by 2050.

e. Ireland’s Existing Energy System

i. Background

Ireland has had a variable indigenous energy past, with 100% electricity requirements supplied by the Ardnacrusha hydroelectric station in 1929, indigenous natural gas fields allowing the development of a national gas grid, and peat combustion used up until 2020.

Today, Ireland is heavily reliant on imported fossil fuels in its entire energy sector, importing 67% of its energy requirement, including electricity and gas for heat and energy (domestic and industrial) and oil for its transport sector. The island is energetically interconnected to Europe via Great Britain with two natural gas pipelines, three cross-border cables and two DC subsea cables (DC interconnect cables isolate the electricity grid on the island of Ireland from Great Britain and Europe).

Ireland has experienced a dramatic increase in renewable wind energy capacity over the past two decades, growing its onshore wind capacity from negligible amounts in 2002 to over 4 GW of installed capacity in 2020. However, the decarbonisation process of the electricity sector has not been observed in heating and transport, with both sectors presenting considerably lower shares of renewable energy. Overall, as of 2019, only 12% of Ireland’s gross final consumption is deemed renewable.

The following subsections detail the current state of Ireland’s energy system in terms of electricity, heat and transport, also exploring the issue of energy security and resilience.

ii. Electricity

Existing Electricity Demand, Generation and Transmission Infrastructure

Ireland’s transmission system (Figure 57) is a network of 400kV, 220kV and 110kV high voltage lines and cables. It delivers large amounts of power from generator stations to demand bulk supply points where it connects to the distribution system to allow the power to be delivered to consumers. The distribution system operates at 38kV, 20kV, 10kV and 400V. The 400kV and 220kV networks are the backbone of the power system, connecting the large generator stations and large demand centres. The 110kV network reaches into all counties and traditionally supports the distribution system connecting all consumers to the electricity system. More recently, the 110kV system has been used for connecting and transmitting renewable power into the wider transmission system.

Renewable generation with its intermittent output and relatively low-capacity factors brings new challenges to operating and developing the transmission system compared with a system with just large conventional generation. The viability of medium to long term storage of electricity on a high wind generation system also drives the need for a robust transmission system to manage the times of generation high output relative to demand.

The transmission system is operated and developed by EirGrid in its role as the Transmission System Operator (TSO). The distribution system is operated by ESB Networks (ESBN). ESBN is also the owner of the transmission and distribution system assets.

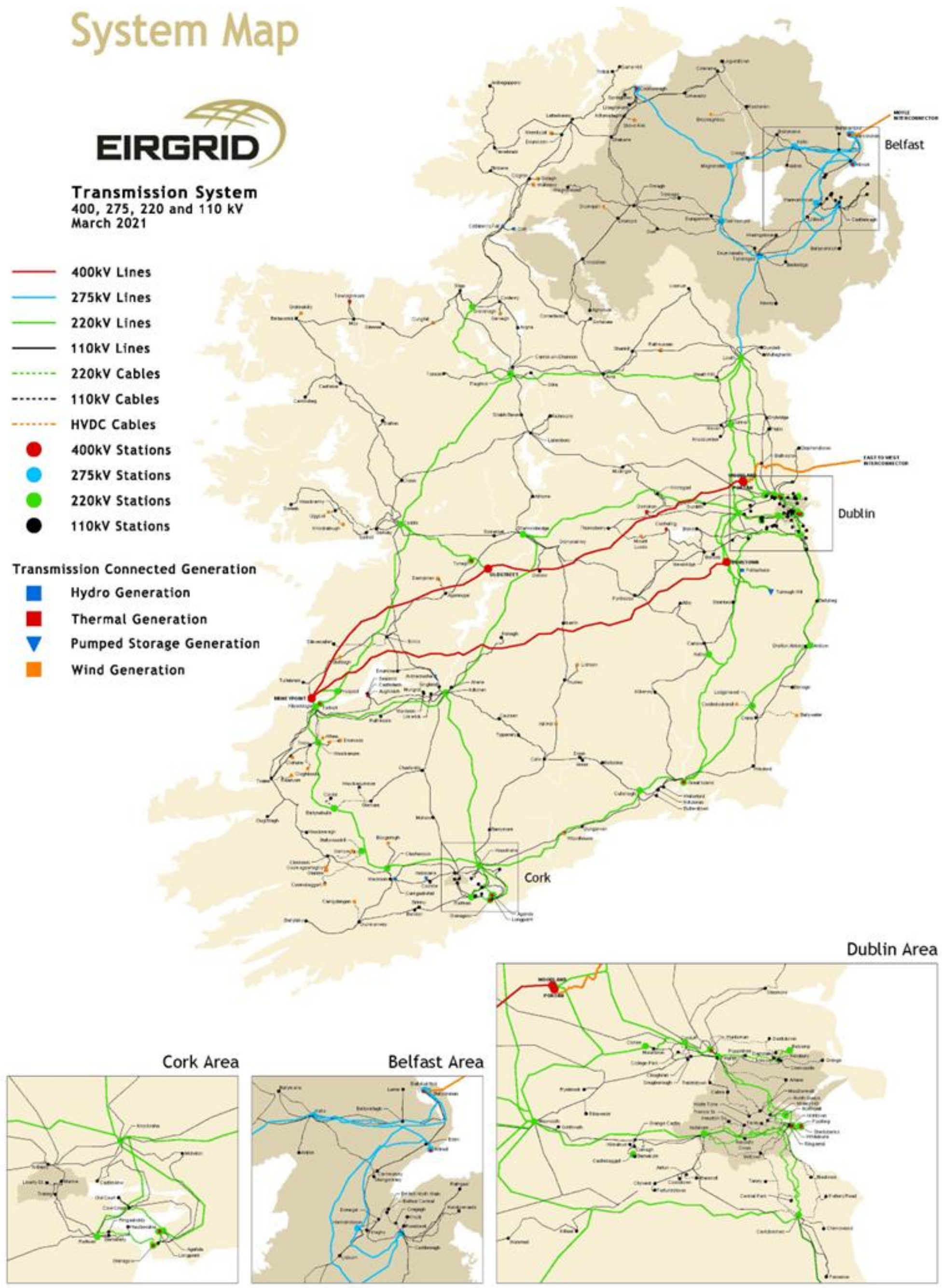


Figure 57: Ireland's electricity transmission infrastructure, with main cities highlighted[90].

[90] https://smartgriddashboard.com/assets/All-IslandTransmissionMap.pdf

Ireland's total electricity demand was over 29.08 TWh in 2019[91]. Based on CSO metered electricity demand data, the Greater Dublin Area counties of Dublin, Kildare, Meath and Wicklow were estimated to account for over 40% of Ireland's electricity demand in 2019[92].

Electricity in Ireland is mostly consumed by the residential, industrial and service sectors, as shown in Figure 58. The transport sector, encompassing the Dublin Area Rapid Transit (DART) rail system, the Luas light rail system, as well as electric vehicles on Irish roads, accounts for only 0.3% of the share of energy used. Since 2005, while the residential and transport sectors have experienced little change in terms of share of energy consumption, there has been a considerable increase in the share of services, accompanied by a corresponding decrease in the share of industry[93].

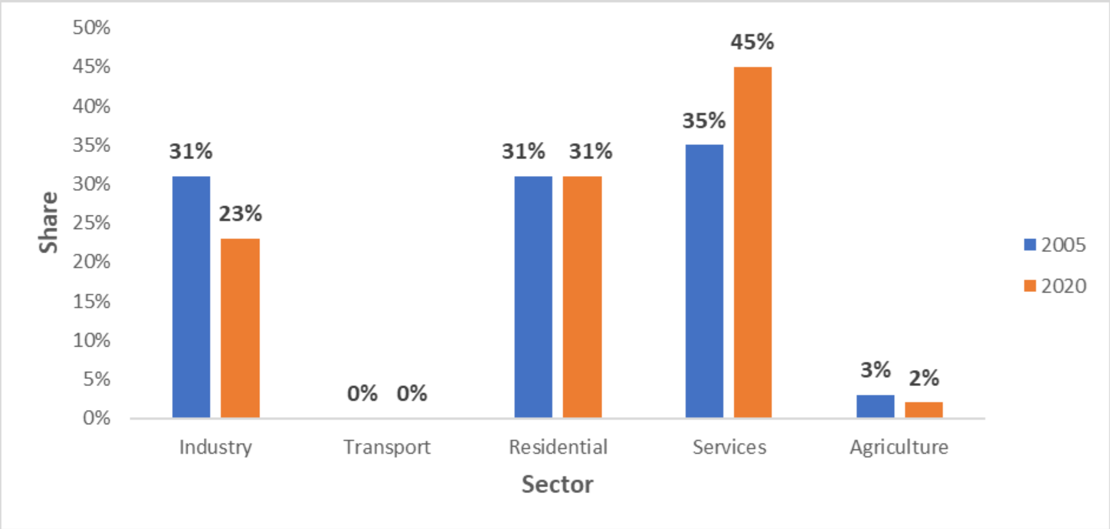


Figure 58: Share of electricity consumption of each sector of the Irish economy, contrasting 2005 and 2020 values

Ireland has an abundant wind resource with some of the highest average wind speeds in Europe. Over the past two decades, Ireland has significantly ramped up its onshore wind capacity with c.4,300 GW of capacity connected since the year 2000. The bulk of this capacity is connected along the western seaboard. The North-West (c.635 MW), West (c.694 MW) and South-West (c.1153 MW) regions have a total connected capacity of c.2,482 MW, which amounts to c.57% of Ireland's existing onshore wind capacity. The transmission network facilitates the flow of power from these regions to the Greater Dublin Area.

---

91 https://www.eirgridgroup.com/site-files/library/EirGrid/System-and-Renewable-Data-Summary-Report.xlsx

92 https://www.cso.ie/en/releasesandpublications/ep/p-mec/meteredelectricityconsumption2021/

93 https://www.seai.ie/publications/Energy-in-Ireland-2021_Final.pdf

Ireland is yet to realise its potential for offshore wind. There is only one offshore wind farm connected off the coast of Wicklow, namely the Arklow Bank 25.2 MW project that connected in 2004. However, the Programme for Government (see section 2.2.2) has signalled an intention to considerably increase the capacity of offshore wind in Irish waters.

Fossil fuels are still the dominant fuel source for electricity generation. In 2020, natural gas supplied just over half of Ireland's electricity requirement, and renewable generation accounted for c.42%, with wind generation alone contributing to c.36%. Figure 59 illustrates the Irish electricity generation mix.

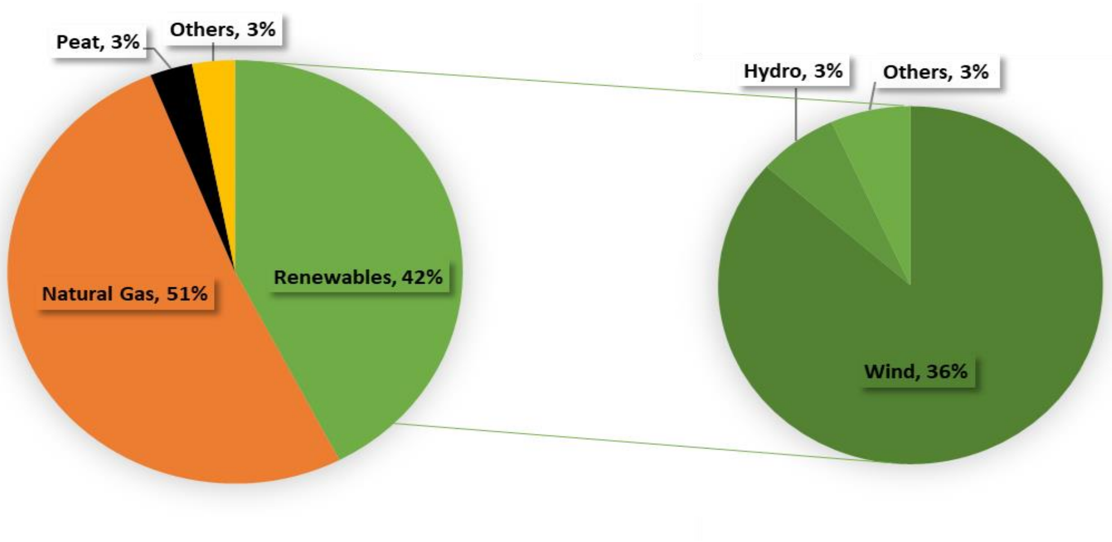


Figure 59: Ireland's electricity generation by fuel type in 2020

EirGrid currently operates the electricity system with a requirement for 8 (5 in ROI, 3 in NI) large dispatchable conventional generators to run on the all-island electricity system at all times. Two of the five generators in the ROI are required to be located in Dublin, due to the local system constraints of voltage and power flow control in the complex Dublin electricity network. EirGrid plans to reduce the requirement for the number of dispatchable units on the all-island system from 8 units to 3 (2 in the ROI, 1 in NI) or less units by 2030.[94] Dispatchable fossil fuel electricity generation helps to ensure security of supply and provides resilience to the energy system.

[94] https://www.eirgridgroup.com/site-files/library/EirGrid/TSO-Imperfections-and-Constraints-multi-year-plan-2023-2027-Consultation.pdf

Dublin Transmission Network

The transmission network in the Greater Dublin region, illustrated in Figure 60, consists of 110kV, 220kV and 400kV infrastructure. ESBN operates the 110kV network in Dublin, whereas EirGrid operates the 110kV network in the other counties of Ireland.

There are a number of underground cables in Dublin city that were installed between the 1950s and 1980s that are leaking oil and are due for replacement. The underground cables include:

- North Wall-Poolbeg
- Finglas-North Wall
- Poolbeg-Carrickmines
- 2 x Inchicore-Poolbeg

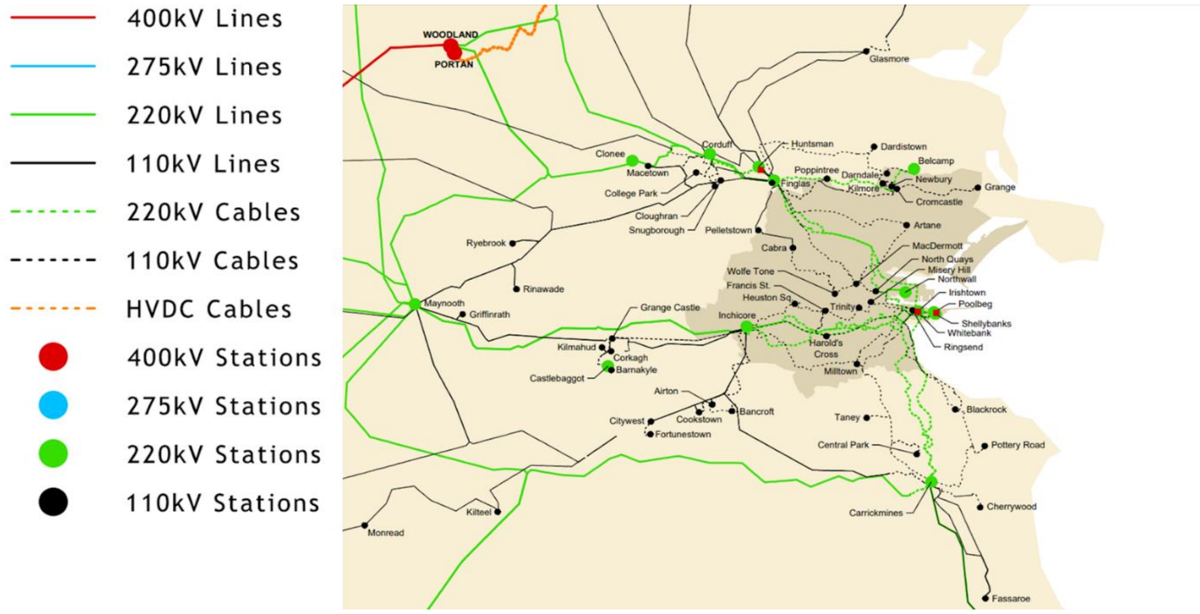


Figure 60: Greater Dublin's electricity transmission network

Dublin Electricity Demand

The electricity demand in county Dublin for 2019 was estimated to be c.9.46 TWh from the 'Dublin Region Energy Master Plan'[95]. Table 30 indicates the electricity requirement for the public, residential, commercial and industrial sectors and also from data centres. Currently, data centres are estimated to account for c.46% of Dublin's electricity demand.

[95] https://www.codema.ie/images/uploads/docs/Full_Report_-_Dublin_Region_Energy_Master_Plan.pdf

Table 30: Total electricity requirement in Co. Dublin in 2019 by sector

Sector	Electricity Demand [TWh]
Public Sector	0.56
Residential	2.94
Commercial	1.35
Industrial	0.30
Data Centres	4.31
Total	**9.46**

There is c.924 MVA of connected data centre capacity and a further 960 MVA of contracted capacity in the Greater Dublin region[96]. Considering the connected/contracted data centre capacity in Ireland, the Greater Dublin region accounts for c.97% of the total capacity.

CSO figures for 2021 indicated a total metered electricity demand from the residential and non-residential sectors of 6.4TWh[97].

Dublin Electricity Generation

Based on MullanGrid's generator database (see Table 46 in Appendix E), there is a relatively small connected capacity of renewable generation in county Dublin compared to other large demand hubs in Ireland such as Cork. In total, there is c.119 MW of solar PV, c.1.3 MW onshore wind, 0.2 MW hydro, 4 MW biogas, 72 MW biomass/waste to energy (WtE) and 17.8 MW of landfill gas (LFG) generation capacity. The 400 kV network connecting Moneypoint and the western seaboard to the Greater Dublin region facilitates the import of renewable energy to the region.

Applying typical capacity factors for onshore renewable generation, it is estimated that the fleet of renewable generation capacity in the county can generate up to c.484 GWh of renewable energy annually. This assumes that the 72 MW Dublin WtE plant output is 50% renewable. The existing level of RES-E in county Dublin is estimated to be c.8% based on the CSO metered electricity demand for 2021 and the renewable generation capacity located and connected in county Dublin.

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

[97] https://www.cso.ie/en/releasesandpublications/ep/p-mec/meteredelectricityconsumption2021/

County Dublin has a fleet of fossil fuel generators made up of c.1,881 MW natural gas and c.19.3 MW of diesel generation capacity. Applying typical capacity factors for gas generation facilities, it is estimated that natural gas could generate up to c.14,000 GWh of fossil fuel energy annually. In the future, some of this capacity could potentially be converted to run on renewable gas such as green hydrogen.

Future Electricity Demand

New Demand Growth

Ireland's electricity demand in 2019 was c.29.08 TWh. Demand in the Irish electricity system is forecast to increase significantly in the coming decade due to data centres and the electrification of the heat and transport sectors to achieve the 2023 Climate Action Plan targets for c.1 million electric vehicles and more than 680,000 heat-pumps. EirGrid's Shaping our Electricity Future Roadmap and SEAI's National Heat Study indicate the total electricity requirement could grow by c.60-65% out to 2030. Projections for 2050 for a net zero carbon system from both SEAI and MaREI indicate the total electricity requirement could increase by up to 187-198% compared to 2019.

SEAI's National Heat Study modelled the impact of data centres and the electrification of transport and heat in Ireland for 2020, 2030 and 2050, see Figure 61 for scenarios of the SEAI's National Heat Study. Data centres are the dominant form of growth between now and 2030, with electric vehicles also driving significant growth. SEAI assumes that heat sector electrification occurs later and by 2050, heat electrification is the dominant growth area in the electricity sector demand for all of the scenarios that achieve net zero emissions.

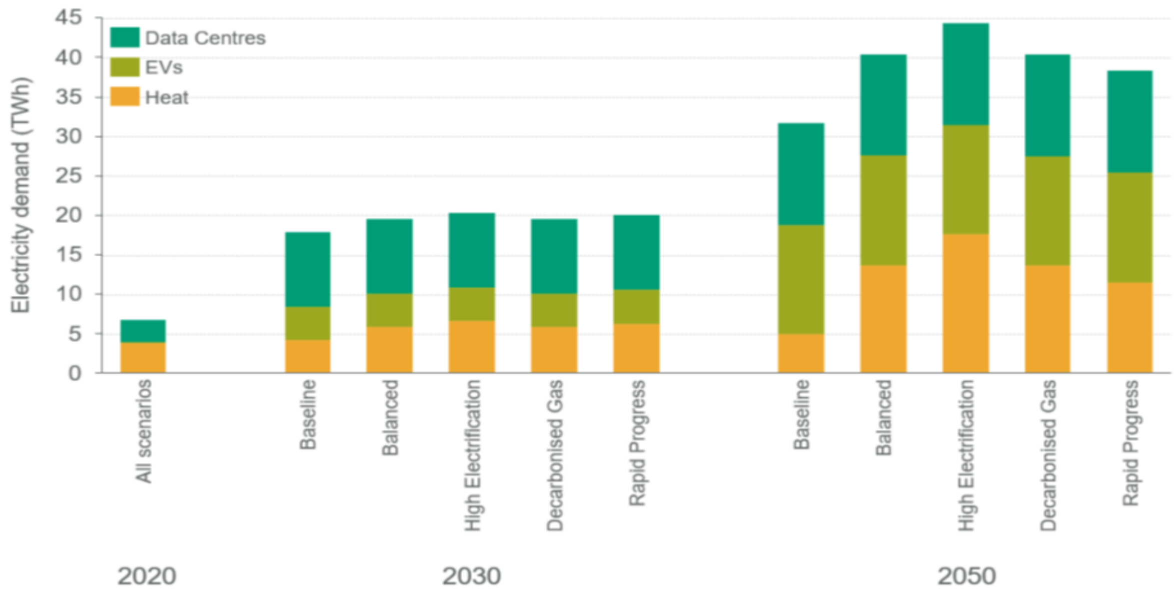


Figure 61: Growth Scenarios of the SEAI's National Heat Study

Data Centres

Alongside normal growth of the electricity demand, Ireland is currently experiencing high demand growth due to the relatively large capacity of new data centres located in Ireland, mainly in the Dublin area. The electricity requirement for data centres in Ireland is modelled to increase from c.2 TWh in 2019 to c.9.46 TWh in 2030, representing a 470% increase. The growth of data centre demand post 2030 should be viewed as indicative. In a scenario where there is uptake on data centres located outside of Dublin, there could be a higher requirement for electricity than indicated in Figure 62.

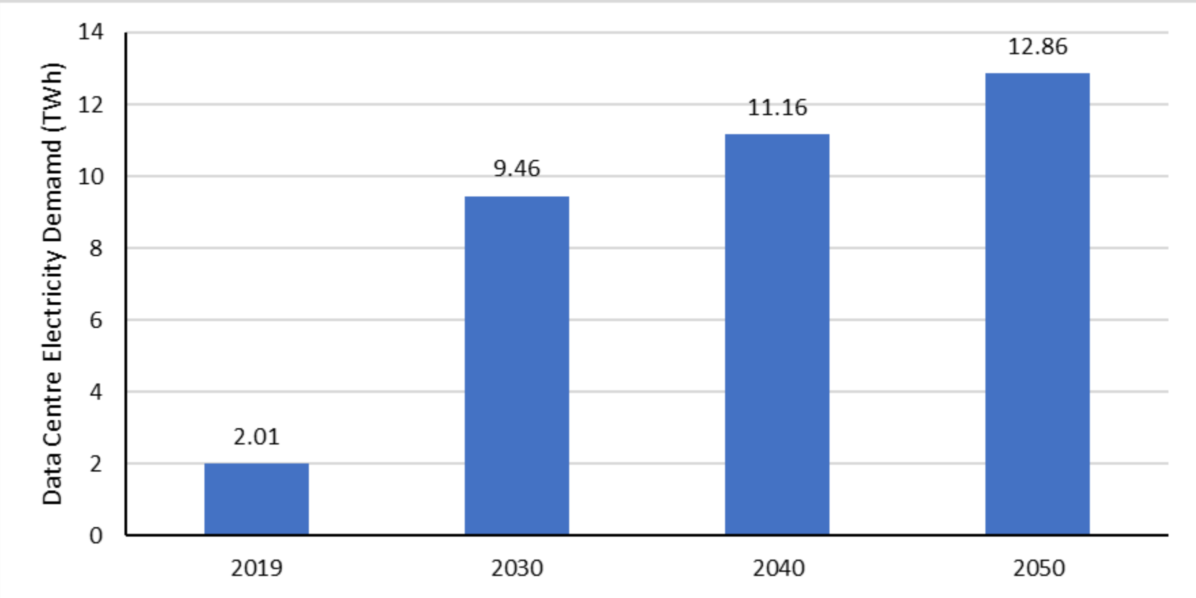


Figure 62: Projection of the electricity required by data centres in Ireland

The consistent ramping of data centre capacity in the Greater Dublin region in recent years means EirGrid is faced with the challenge of offering contracts for connection of data centres in the Greater Dublin region above the local transmission network capability. This has led to the CRU/EirGrid re-evaluating the strategy for new data centre connections in Ireland. In November 2021, the CRU published their decision paper[98] which gives direction to the system operators (EirGrid, ESBN) relating to data centre grid connection processing. This directs EirGrid and ESBN to prioritise processing data centre connection applications outside of a constrained region of the electricity system, in the context of demand connections (data centres) the Greater Dublin region is constrained. Essentially this places a moratorium on new data centre connections in Dublin excluding those already contracted to connect.

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

Electrification of Heat and Transport

EirGrid published a future energy scenario analysis in 2019 that considered the potential changes to electricity demand out to 2030 and 2040[99]. The 'Coordinated Action' scenario aligns with the 2021 Climate Action Plan target for c.1,000,000 electric vehicles and 600,000 heat pump installations by 2030. The EirGrid modelling for this scenario indicated:

- an electricity requirement of 4.3TWh for electric vehicles by 2030, Dublin was estimated to account for 1.22TWh.
- an electricity requirement of 2.67TWh for heat pumps by 2030, Dublin was estimated to account for 0.95TWh.

The analysis to date on Ireland's potential electricity system in 2050 indicated a total electricity requirement of between c.8-13TWh for the transport sector. The heat sector was estimated to have an electricity requirement of up to 26TWh for 2050. From Figure in section , heat electrification is likely to be a significant driver of demand growth between 2030-2050, SEAI estimates up to an additional c.16TWh of demand for electric heating during this period. It is noted that there are no regional projections for electricity demand growth from the heat and transport sector for a net zero carbon system by 2050.

[99] http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-TES-2019-Report.pdf

Demand Side Management

Demand side management (DSM) may be defined as a situation where a consumer changes their consumption pattern to improve efficiency and operations in electrical energy systems. The change in consumption pattern stems from a financial incentive available to the consumer.

Large demand customers already provide important flexibility services to the electricity system. Industrial and commercial demand customers that can respond to EirGrid's requests for reduction or increases in demand are known as a Demand Side Unit (DSU). DSUs currently use a combination of on-site generation, plant shutdown or storage technology to deliver demand reduction or increases. They are paid by the electricity market for being available to provide these services. Currently the majority of DSUs are providing short term emergency capacity during the small number of times a year when there is a lack of available generation on the electricity system. There is only a small number of DSU units that are making more demand available at times of high renewables on the system.

Electric heating and transport have the potential advantage that it can provide the short-term service of being able to turn down or off the electric load when there is a lack of available generation on the electricity system and the longer terms service of being turned on when there are excess renewables on the electricity system, reducing the need to constrain and curtail renewable generation. The flexible demand can also be turned off if there are times when the local network is being overloaded due to excess demand. At times of high renewables there will also be the commercial opportunity for electricity heating to avail of very low or even negative electricity prices in the electricity market.

With the rollout of smart meters and devices in the residential sector, the future of demand side management may transition to households actively managing their demand to reduce their electricity bill. Smart electricity meters can record half hourly energy consumption data, providing pricing information and enable remote load control. Smart domestic appliances may use pricing information to identify the most cost-effective times to use energy.

Dublin Electricity Demand Projections

To date, based on a review of the literature, it does not appear that there have been any detailed studies carried out to assess the potential electricity demand and necessary electricity infrastructure reinforcement in Dublin for a net zero emissions system. It is recommended that a study of Dublin's future electricity, energy and infrastructure requirements for net zero emissions is carried out. The Dublin Region Energy Masterplan did explore the cost of grid reinforcement in response to increased demand based on high-level costs for upgraded connections provided by the ESB but did not look in detail of the requirements needed due to additional capacity of generation or at the requirements at transmission level..

Renewable Generation Pipeline

Offshore Wind Generation

The Climate Action Plan 2023 set a target for 5GW of offshore wind capacity to be delivered for 2030. The Phase 1 projects located along the east coast of Ireland may account for the majority of the 5GW target if they all connect successfully. NISA 500MW, Dublin Array 600-900MW and Codling 900-1500MW are all looking to connect in county Dublin. Two other projects, Oriel 400MW and Arklow 520-800MW, are looking to connect in Louth and Arklow, respectively. It is noted that some of these projects may fail to secure a route to market or development consent and therefore at this stage it is not clear whether all of the capacity will connect to the electricity system. Therefore, additional offshore wind projects in Phase Two will likely be needed to meet 5GW by 2030.

The Programme for Government indicated a strong ambition to ramp up Ireland's offshore wind capacity through at least 30GW of floating offshore wind. MRIA showed the potential for up to 50GW of floating offshore wind capacity in the Celtic Sea[100]. Off the West Coast, other commentators suggest there is potential to develop up to 75GW of floating offshore capacity[101].

Onshore Renewable Generation

There is a substantial pipeline of onshore renewable generation in development in Ireland.

To connect onto the electricity grid in Ireland, renewable projects must receive and accept a connection offer from EirGrid or ESBN. The CRU has the role of deciding the connection policy for the processing of connection applications for generators. In 2017, the CRU designed a new connection offer process known as the Enduring Connection Process (ECP).

The first batch of applications was ECP-1 and they have been processed already and are contracted to connect or have already connected. The second stage of the ECP process known as ECP-2 commenced in 2020 with one batch application window each September for four years starting from September 2020. The four batches for ECP-2 are referred to as ECP-2.1, ECP-2.2, ECP-2.3 and ECP-2.4. The successful applicants for ECP-2.1 have been processed and ECP-2.2 is currently being completed. The processing of ECP-2.3 will commence in Q3 2023 and application for ECP-2.3 will be accepted in Q4 2023.

---

[100] http://www.mria.ie/site/assets/files/1016/submission_to_decc_pt_1_dec_2020.pdf

[101] https://www.irishtimes.com/news/environment/ireland-could-supply-5-of-europe-s-electricity-with-offshore-wind-1.4194310

Figure 63 indicates the pipeline of onshore renewable generation in Ireland. The estimates are based on information presented in ESBN's connected and contracted generator list[102], EirGrid's connected and contracted generator list[103] and from EirGrid's ECP applicant lists for ECP-2.2[104] and ECP-2.3[105]. In addition, MullanGrid has considered renewable projects that are in the queue for future ECP batches by reviewing the county council planning databases for projects that are either in the planning process or have already achieved planning consent.

EirGrid's SOEF Roadmap contains a number of 'key strategic enablers' as being fundamental for infrastructure delivery between 2021-2030. Listed as a key strategic enabler and part of EirGrid's multi-year plan is to incentivise the location of generation and large energy users where grid capacity is available or where it will be available in the future; this may be of concern to onshore renewable developers, and it is currently unclear as to what implications it might have on ECP-3.

Onshore wind is currently the main source of renewable generation in Ireland. In addition to the c.4,430 MW of onshore wind capacity connected, there is c.4000 MW of onshore wind capacity in development across Ireland. There is also c.260MW of solar PV capacity connected and further of c.7,290 MW solar PV capacity in development in Ireland;, these estimates do not account for rooftop solar PV. It should be noted that there will likely be some attrition from this pipeline during the remainder of the development process. However, it is also likely there are further new renewable projects in development but these projects are still in the pre-planning stage and information on the projects is not yet in the public domain.

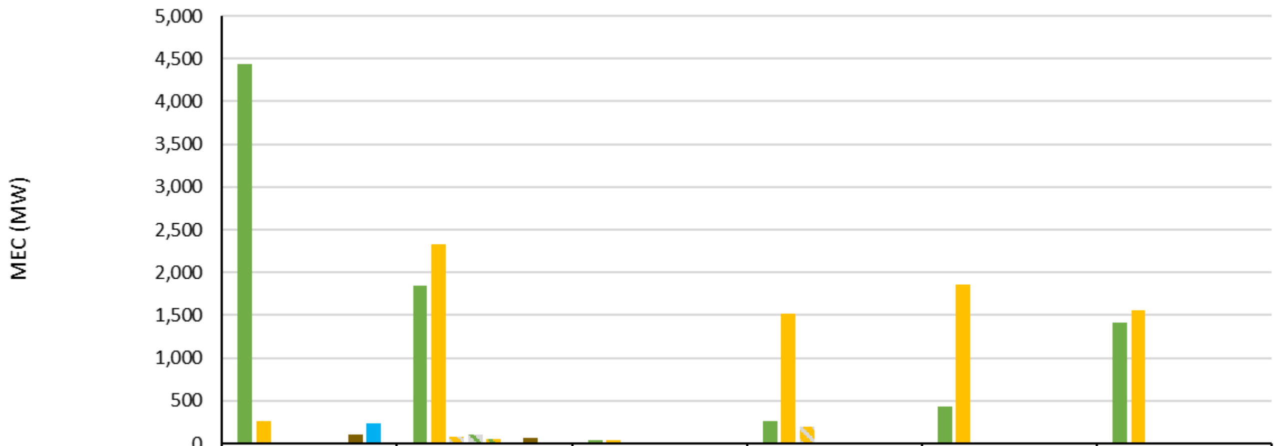
Considering new onshore renewable generation capacity in development in Dublin (Figure 64), there are a number of solar PV projects planning to connect beyond the c.119MW of connected solar PV capacity. In total, there is a pipeline of c.270 MW solar PV generation capacity (excluding rooftop solar PV). There may be further new renewable projects in development in Dublin that are not yet in the public domain.

[102] https://www.esbnetworks.ie/new-connections/generator-connections-group/generator-statistics

[103] https://www.eirgridgroup.com/customer-and-industry/general-customer-information/connected-and-contracted-generators/

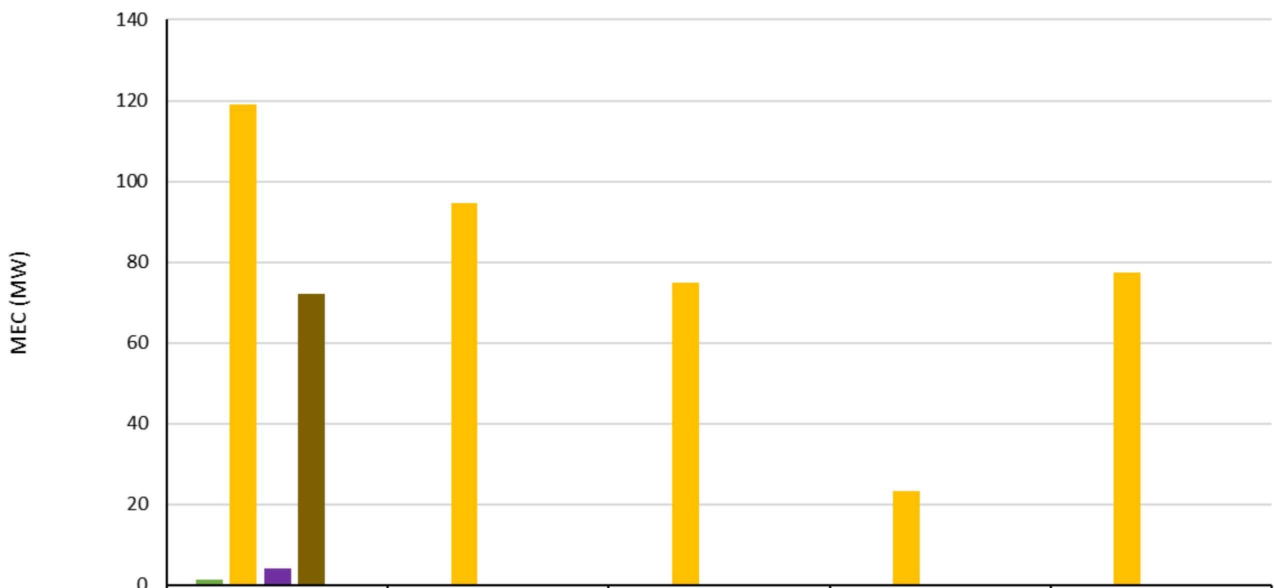
[104] https://www.eirgridgroup.com/customer-and-industry/becoming-a-customer/generator-connections/enduring-connection-polic/

[105] https://www.eirgridgroup.com/site-files/library/EirGrid/2022-Batch-(ECP-2.3)-Results-Joint-SO-Publication_November-2022_Final.pdf



	Connected	Contracted	ECP-2.1 Community	ECP-2.2	ECP-2.3	Queued for ECP
Onshore Wind	4,430	1,850	35	258	432	1,420
Solar	257	2,324	36	1,519	1,856	1,554
Hybrid Solar/Battery		77		200		
Hybrid Wind/Battery		106				
Hybrid Wind/Solar		55				
Biogas	17	6			8	
Biomass	103	72				4
Hydro	239	1				

Figure 63: Ireland Onshore Renewable Generation Pipeline



	Connected	Contracted	ECP-2.2	ECP-2.3	Queued for ECP
Onshore Wind	1				
Solar	119	94	75	23	78
Biogas	4				
Biomass	72				
Hydro	0				

Figure 64: Dublin Onshore Renewable Generation Pipeline

Renewable Generation Dispatch Down

EirGrid as the transmission System Operator controls the output of the majority of renewable generators. Current policy is that all wind farms and solar farms greater than 1 MW of capacity are controllable. To maintain the security of the electricity system and network, EirGrid turns down the output of renewable generators at times. This is known as dispatch down. To help explain the technical reasons for these dispatch down events they can generally be categorised as either curtailment or constraint events. With the introduction of the EU Clean Energy Package and the new T&Cs for the ORESS 1 and RESS 3 support schemes, there is now generally compensation for generators for dispatch down. With this compensation being paid to generators, there is now a greater incentive on the Government and its agencies, CRU and EirGrid, to bring in policies and mitigation measures to reduce dispatch down. There are two reasons for curtailment known as oversupply and system curtailment.

Oversupply Curtailment

Sometimes referred to as energy balancing curtailment, oversupply curtailment is the dispatch down of wind and solar where there is more generation (including interconnector export) than demand on the all-island electricity system.

System Curtailment

System Curtailment is dispatch-down when system technical limits require the redispatch of renewable generation by the System Operators to maintain system security. Operational policies and limits currently imposed by the TSO include a requirement for a minimum number of dispatchable fossil fuel generators on the system (Min Gen) at any given time, the system non-synchronous penetration (SNSP) limit, system inertia and rate of change of frequency (RoCoF) limitations[106].

It should be noted that these limits are set based on the physical capabilities of the system as it exists at a point in time, along with the operational and control capabilities of the TSO. As the system and capabilities evolve, it will be possible to maintain system stability while allowing more non-synchronous renewable generation to run.

Constraint

Constraint refers to changes of generator output due to overloading of transmission lines, cables and transformers. Constraint is location-specific and can be reduced by transmission

[106] https://www.eirgridgroup.com/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2021-V1.0.pdf

network reinforcements. The level of generation and the line ratings of the network in the local area are typical factors that influence constraints. In addition, outages required for network reinforcement works give rise to constraints.

Historical Dispatch Down Levels

Curtailment and constraint restrict zero carbon electricity entering the grid and effectively wastes zero marginal cost electricity that could otherwise be used. The lower the value of constraint and curtailment, then theoretically the lower the cost of electricity and a lower carbon footprint of the energy system.

As the portion of electricity from variable renewable sources grows to achieve EU targets and reduce emissions, grid balancing will become increasingly more difficult to maintain. Table 31 presents historical electricity demand, wind capacities, wind output, installed wind capacity factor and dispatch down levels from publicly available EirGrid data[107]. Between 2019-2022, controllable wind curtailment levels in Ireland fluctuated between 3.1% and 5.3%. At present, EirGrid reports on total curtailment and does not split curtailment into oversupply curtailment and system curtailment. Constraint levels were in the range of 4.5% to 6.1% for the same period. Total dispatch down levels for the period were in the range of 6.9% to 11.4%. These high levels of wasted renewable energy highlight some of the inefficiencies of Ireland's existing electricity system's ability to accommodate high capacities of variable renewable generation and also highlight the need for energy sector coupling and energy storage technologies.

Table 31: Historical wind: installed capacity, generation, capacity factor and dispatch down

Year	Electricity Demand (GWh)	Wind Installed Capacity (GW)	Available Wind (GWh)	Wind Capacity Factor (%)	Dispatch Down (%)	Constraints (%)	Curtailments (%)
2019	29,083	4.120	10,293	28.5%	6.9%	3.8%	3.1%
2020	29,331	4.300	12,656	33.6%	11.4%	6.1%	5.3%
2021	30,921	4.332	10,326	27.2%	7.3%	4.5%	2.8%
2022	31,622	4.527	11,934	30.1%	8.3%	4.8%	3.5%

[107] https://www.eirgridgroup.com/how-the-grid-works/renewables/

Planned Transmission Infrastructure

EirGrid Transmission Development Plan 2021-2030

EirGrid is responsible for the development of the transmission system. EirGrid consults on its Transmission Development Plan annually. The latest 2021-2030[108] plan was published for consultation in March 2022. This plan lists the projects that are at different stages of the EirGrid development process, from scoping to construction. The strategic objectives that inform investment in the Irish transmission network and are summarised as:

- Ensuring the security of electricity supply;
- Ensuring the competitiveness of the national economy; and
- Ensuring the long-term sustainability of electricity supply in the country.

To achieve the strategic objectives, EirGrid is required to invest in the development and maintenance of the electricity transmission network. The drivers of investment include:

- Securing transmission network supplies;
- Supporting market integration; and
- Supporting the integration of Renewable Energy Sources, complementary thermal generation and system services providers.

The TDP identifies three categories for reinforcement which are:

- New: asset newly developed to create additional capacity due to limitations in existing infrastructure or for the connection of a new demand/generation facility.
- Uprate/modify: asset replaced with higher rated equipment to cater for future needs.
- Refurbish/replace: where the asset condition is poor, assets are refurbished or replaced on a like-for-like basis.

Developing transmission assets can take considerable time to bring from concept to completion. Developing new 220kV or 400kV circuits should take approximately 7-10 years but due to opposition to the projects, they have been taking over 15 years to deliver, particularly for overhead line circuits. Similarly, new 110kV circuits should take 5-7 years to deliver but are often taking over 10 years to be complete. Upgrading existing assets would typically have timelines of less than 5 years and have a substantially lower delivery risk. Considering the long timelines to deliver new transmission infrastructure it is important to take a long-term view on the generation and demand needs of the region.

---

[108] https://www.cru.ie/wp-content/uploads/2022/03/CRU202222a-Draft-Transmission-Development-Plan-2021-2030.pdf

EirGrid has a six-step process for developing the reinforcements and engaging with stakeholders, as seen in Figure 65.

Figure 65: EirGrid framework for grid development

Table 32 lists the number of active reinforcement projects with capital approval (in Step 4 to 6 of EirGrid's grid development framework) by region and type from the TDP 2021-2030. The east of Ireland including the South-East, Mid-East and Dublin region appear to have the largest number of reinforcements planned with a total of 62 active projects.

Table 32: EirGrid TDP 2021-2030: Active projects by region

Project category	Border, Midlands, West	South- West, Mid- West	South- East, Mid-East, Dublin	Projects at multiple locations	Total
New Build	13	11	28	-	52
Uprate/ Modify	14	12	18	-	44
Refurbish/ Replace	13	14	15	4	46
Other	-	-	1	2	3
Total	**40**	**37**	**62**	**6**	**145**

Figure 66 is a map of the Dublin Area reinforcements with capital approval. In total, there are 20 projects with capital approval planned for the Dublin region, listed on Table 33. Major upgrades are required to replace ageing equipment in the area, to facilitate the planned Phase 1 offshore wind projects and the large demand growth from population increase, electrification and data centres.

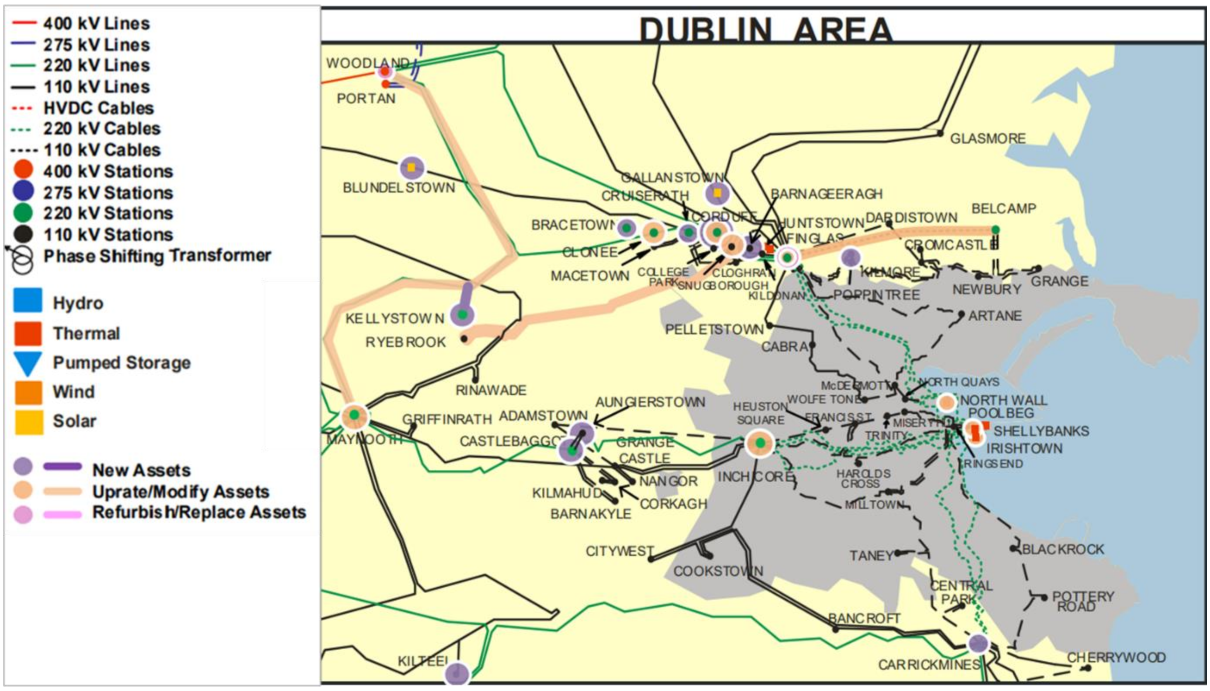


Figure 66: Reinforcement projects in and around Dublin

Table 33: EirGrid TDP 2021-2030: Active projects in Dublin

CP No.	Project Title	Type	km	Step	ECD
CP0984	Belcamp - Shellybanks 220 kV New Cable	New Build Capacity	10	6	2022
CP1113	Barnageeragh Deep Reinforcements	New Build Capacity	-	4	2023
CP0580	Carrickmines 220 - 110 kV Station GIS Development	New Build Capacity	-	6	TBC
CP0872	Castlebagot 220/ 110 kV New Station	New Build Connection	-	6	2021
CP1009	Cruiserath 220 kV New Station and two circuits to Corduff 220/110 kV station - Permanent Connection for Demand Customer	New Build Connection	-	6	2022
CP1051	Gallanstown 110 kV New Station and loop-in to Corduff – Platin 110 kV circuit – Solar farm connection	New Build Connection	-	6	2022
CP1093	Barnageeragh 110 kV Station	New Build Connection	-	6	2022
CP1102	Grangecastle South	New Build Connection	-	3	2022
CP1154	Belcamp Land Acquisition	Other	-	3	2021
CP0869	Maynooth - Woodland 220 kV Line Refurbishment and Uprate	Refurbish/Replace	22	6	2022
CP0646	Finglas 110 kV Station Redevelopment	Refurbish/Replace	-	6	2023
CP1064	Finglas 220 - 110 kV Station - Pantograph replacement	Refurbish/Replace	-	6	2024
CP1014	Snugborough 110 kV Station – Demand Connection Phase 2	Uprate/ Modify	-	6	2021
CP1025	Corduff 220 - 110 kV Station – Two New DSO Transformers for Demand	Uprate/ Modify	-	6	2021
CP0668	Corduff - Ryebrook 110 kV Line Uprate and Ryebrook 110 kV Station Busbar Uprate	Uprate/ Modify	14	6	2022
CP1105	Poolbeg BESS and FlexGen	Uprate/ Modify	-	3	2022
CP1103	Corduff FlexGen	Uprate/ Modify	-	3	2022
CP0792	Finglas 220 kV Station Upgrade	Uprate/ Modify	-	6	2023
CP1117	Irishtown FlexGen and BESS	Uprate/ Modify	-	6	2023
CP0692	Inchicore 220 kV Station Upgrade	Uprate/ Modify	-	6	2025

EirGrid Shaping Our Electricity Future Roadmap

In 2021, EirGrid published its Shaping Our Electricity Future (SOEF) roadmap[109] to deliver the Climate Action Plan 2019 target for 70% RES-E. EirGrid analysed the needs of the transmission system out to 2030 and identified a number of grid reinforcements required to facilitate the additional renewable capacity required to connect to the system to cater for the growth in demand from electrification of heat and transport and also from large energy users including data centres. EirGrid us currently in the process of updating the analysis to consider the needs of the transmission system for the Climate Action Plan 2021 target for 80% RES-E; the updated roadmap is expected to be published in June 2023.

EirGrid's analysis summarised the capacity available for new generation by study areas as shown in Figure 67. County Dublin is contained within EirGrid's study area J.

Figure 67: EirGrid SOEF Roadmap: Study areas

---

109 https://www.eirgridgroup.com/site-files/library/EirGrid/Shaping_Our_Electricity_Future_Roadmap.pdf

The EirGrid SOEF roadmap includes developing an additional 5GW of offshore wind, 1.3GW onshore wind and 1.5GW of solar PV (including 500MW rooftop solar) between 2021-2030 to deliver 70% RES-E in 2030 for the high demand forecast (46.5TWh) from the EirGrid Generation Capacity Statement 2021-2030. This does not align with the ambition of the Climate Action Plan 2023, which targets up to 80% RES-E in 2030 through a mix of at least 5GW offshore wind, up to c.4.4GW of additional onshore wind and up to 8GW of solar PV.

EirGrid included a number of grid development projects with capital approval in its assessment of the needs of the transmission network in 2030, referred to as 'Base Case Reinforcements'. These projects were listed in the TDP 2021-2030.

The needs of the network were identified by modelling the thermal overloads on the transmission network with the base case reinforcements in place, as seen in Figure 68. The modelling indicated a risk of heavy overloading on the transmission network in the Dublin city area. There appeared to be overloading on the following Dublin city circuits:

- Poolbeg-Inchicore 220kV circuit 1
- Poolbeg-Inchicore 220kV circuit 2
- Poolbeg-Northwall 220kV
- Poolbeg-Carrickmines 220kV
- Finglas-North Wall 220kV
- Inchicore-Carrickmines 220kV

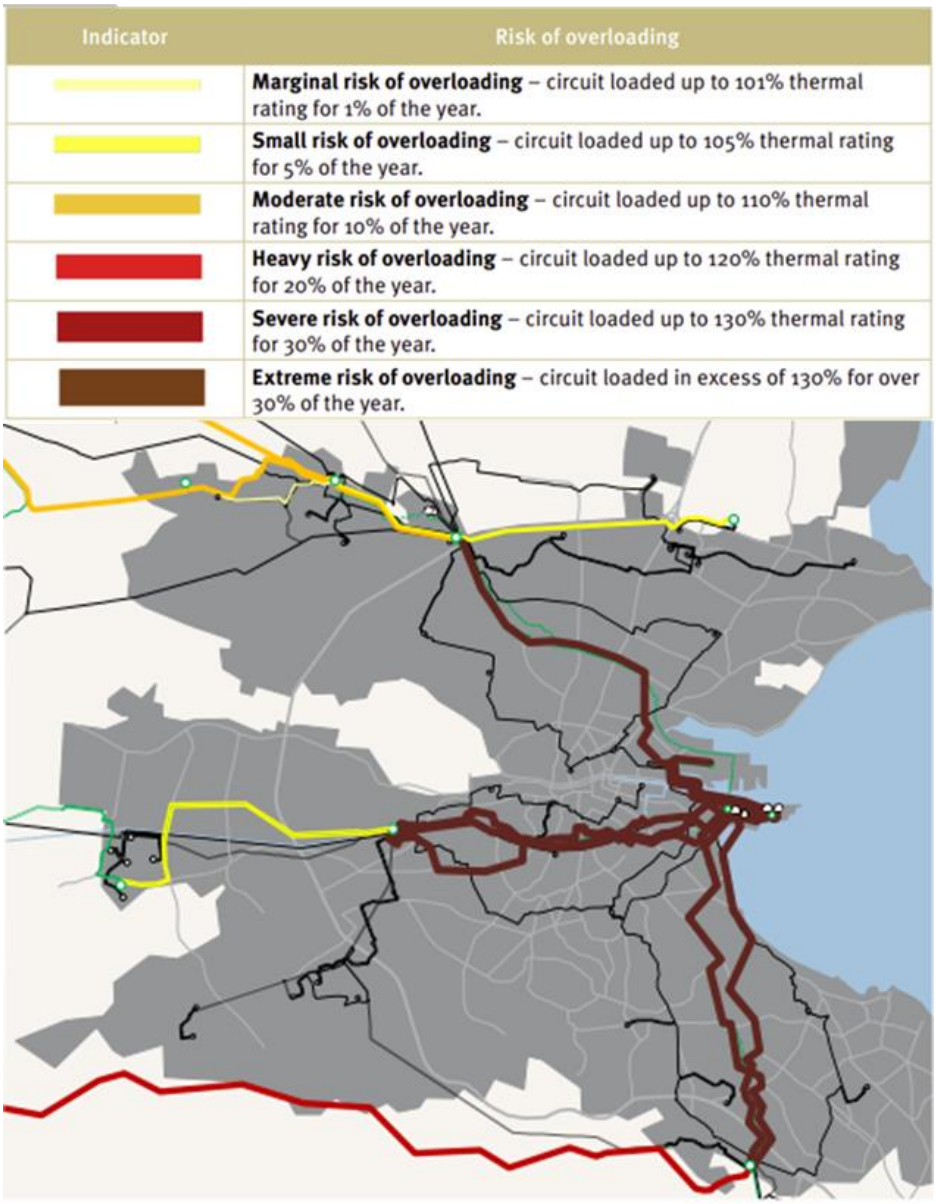


Figure 68: EirGrid SOEF Roadmap: Transmission system needs/thermal overloads in Dublin

From the SOEF analysis, EirGrid identified additional grid developments to address thermal overloading on the transmission network and were described as 'Candidate Reinforcements' (see Figure 69). It is expected that these new projects will be included in future iterations of EirGrid's Transmission Development Plan. Some candidate projects in the Dublin area include:

- A new 220kV circuit between Carrickmines and Inchicore
- A new 400kV circuit between Finglas and Woodland
- Uprating of Poolbeg-Inchicore 220kV circuit 1 & 2
- Uprating of Poolbeg-Carrickmines 220kV circuit

- Uprating of Poolbeg-North Wall 220kV circuit
- Uprating of Finglas-North Wall 220kV circuit

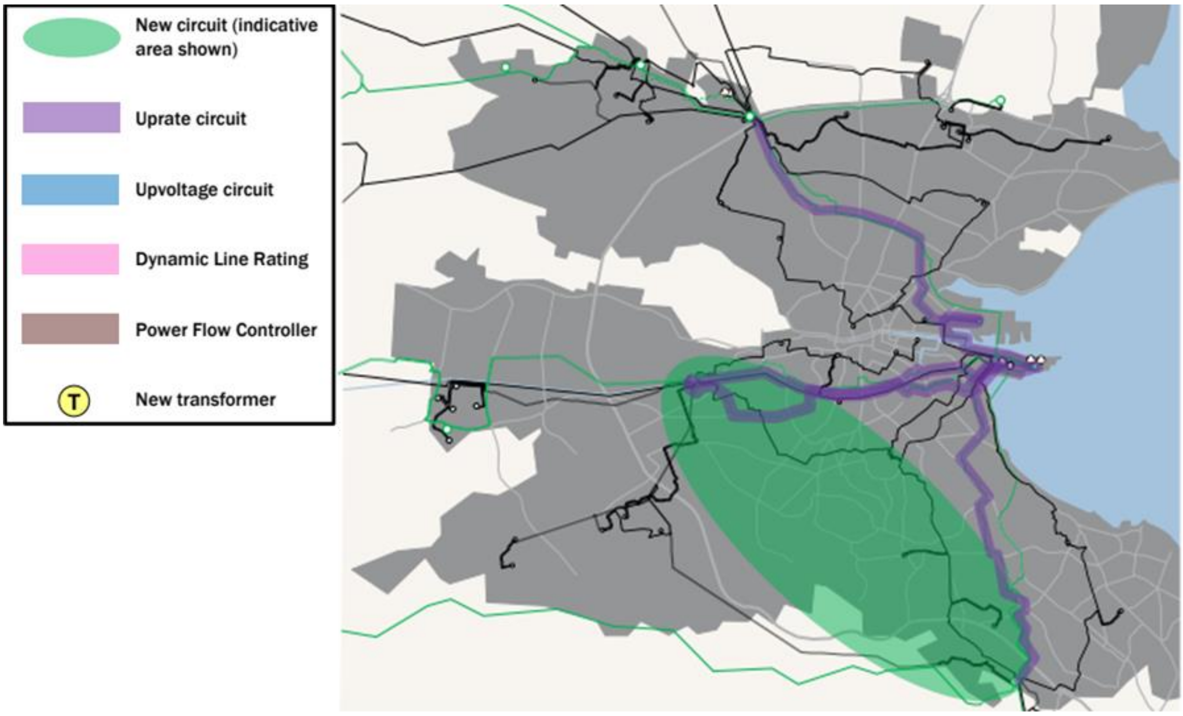


Figure 69: EirGrid SOEF Roadmap: Map of identified candidate reinforcements

EirGrid launched the 'Power Up Dublin'[110] project on the back of the SOEF roadmap. The project is currently at an early stage of development and planning.

EirGrid ECP-2.2 Constraint Reports

EirGrid in its 2022 constraint reports assessed potential levels of dispatch down for all renewable generation capacity that have been issued connection offers while accounting for new demand, new interconnection capacity and grid reinforcements planned for the study years of 2025, 2027 and 2030.

Figure 70 presents the capacity of renewable generation included in EirGrid's modelling and the corresponding RES-E levels based on annual capacity factors for renewable generation.

EirGrid's dispatch down modelling results for Ireland are presented in Figure 71. In general, a reduction in dispatch down is seen in later study years due to the benefits of network reinforcements, future interconnection, relaxation of operational constraints and increased

[110] https://www.eirgridgroup.com/__uuid/9fe9d891-469f-493b-8e60-eab2089c6f80/EirGrid-Powering-Up-Dublin-Web-Final.pdf

demand levels. An increase in dispatch down is observed for the offshore sensitivity studies, which is largely driven by oversupply.

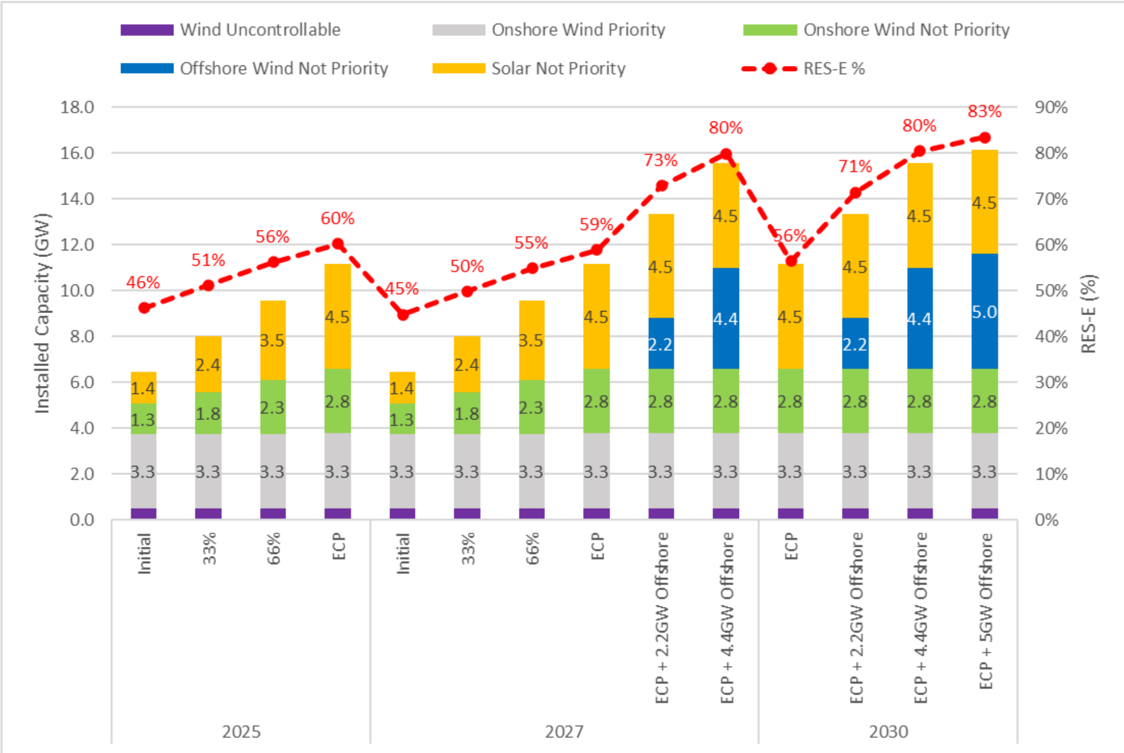


Figure 70: EirGrid ECP-2.2 Scenarios Modelled and corresponding RES-E Levels

Note: EirGrid's published % RES-E figures only accounted for wind and solar generation. Hence % RES-E figures above include an estimation of renewable energy delivered by hydro, waste to energy and biomass generation.

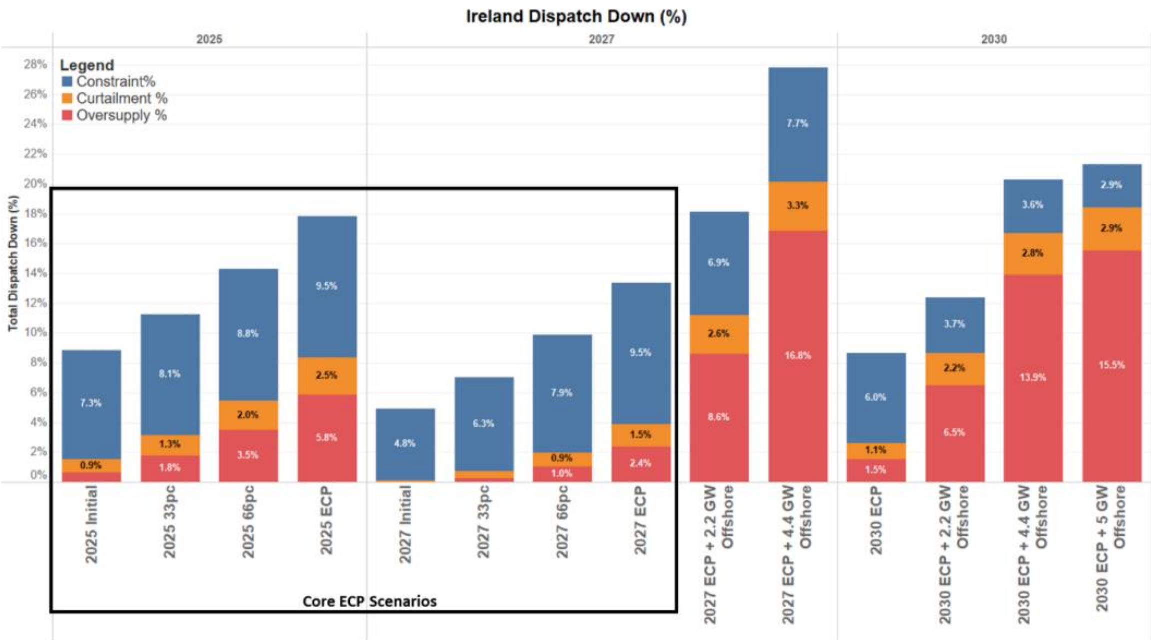


Figure 71: EirGrid ECP-2.2 Dispatch Down Modelling Results (System Wide Average)

The EU's Clean Energy Package[111] (Article 12 & 13) introduced new rules on how renewable generators are dispatched, with oversupply curtailment and network constraints to be allocated on a 'grandfathered' basis opposed to 'pro-rata' basis. It is noted that EirGrid in its analysis made assumptions on the implementation of EU Clean Energy Package that differ to SEM Committee (All-island Regulator Authorities) decision on the implementation of the Clean Energy Package. See Table 5. Considering the SEM Committee's final decision is different than the assumptions in the EirGrid ECP-2.2 dispatch down analysis, the actual dispatch down levels could be substantially different from those in the reports for some renewable generators.

Table 34: EirGrid ECP-2.2 Constraint Reports vs SEM Committee EU Clean Energy Package Decision

Type of Dispatch Down	Dispatch Allocation	
	EirGrid ECP-2.2 Reports	SEM Committee Decision
Oversupply/Energy Balancing	Grandfathered	Grandfathered
System Curtailment	Pro-rata	Pro-rata
Network Constraints	Pro-rata	Grandfathered

Electricity Prices

MullanGrid consulting perform monthly analysis for Irish wind farm asset owners/operators to understand the drivers of curtailment and constraint and the estimated lost revenue for wind farms. Historical electricity demand, wind capacities, wind output, installed wind capacity factor and dispatch down levels dispatch down levels were discussed earlier in the report in section ,'Historical Dispatch Down Levels'.

Figure 72 presents the historical day ahead market price for 2019 to 2022 for night and day periods, where day time = 07:00-23:00 and night time = 23:00-07:00. The day ahead market

111 https://op.europa.eu/en/publication-detail/-/publication/b4e46873-7528-11e9-9f05-01aa75ed71a1

is the where the bulk of electricity is traded, and the prices presented below represent the wholesale electricity price.

Table 35 indicates the Cumulative average historical day ahead market prices 2019-2022.

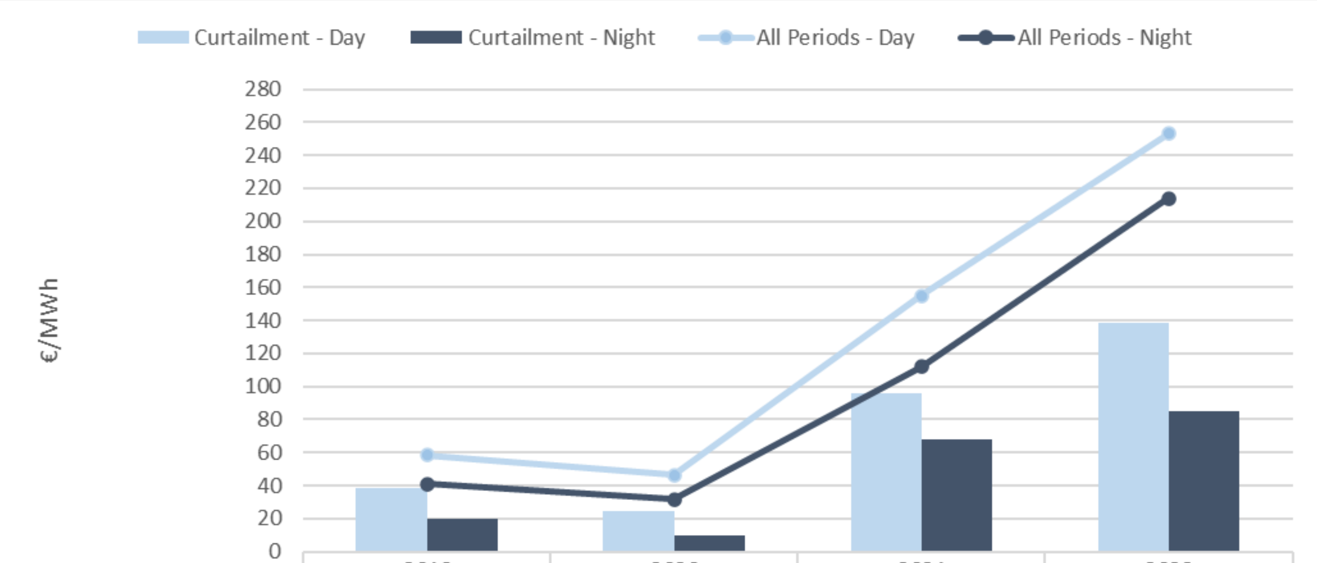
Curtailment periods were defined from half hourly data from the EirGrid dispatch down reports for a sample of over 100 wind farms provided to MullanGrid through the Wind Energy Ireland dispatch down working group.

Based on historical analysis of the day ahead market prices between 2019-2022 the following observations were made:

- The average day ahead market price was 53 €/MWh in 2019, the average price during curtailment was estimated to be 27 €/MWh. This year did not see excessive dispatch down levels (6.9%), with an average installed wind capacity factor of 28.5%.
- In 2020, electricity demand was lower than normal due to COVID 19 in Q1 & Q2, low electricity demand combined with a high average wind capacity factor of 33.6% drove record dispatch down levels of 11.4%. The average day ahead market price was 42 €/MWh and the average price during curtailment was estimated to be 16 €/MWh.
- In 2021, the average day ahead market price increased to 142 €/MWh. the average price during curtailment was estimated to be 78 €/MWh. It is noted that 2021 was a relatively low wind year with the average capacity factor at 27.2%.
- 2022 had significantly higher day ahead market prices due to the constraints on fossil fuels and in particular natural gas. The average day ahead market price for 2022 was 242 €/MWh and the average price during curtailment was estimated to be 103 €/MWh. Dispatch down levels were 8.3% on average with an average installed wind capacity factor of 30.1%.
- Not taking into account 2022 prices due to irregular constraints on energy supply and very high fossil fuel import costs arising from the Ukraine war, the average day ahead market price between 2019-2021 was 75 €/MWh. During curtailment periods between 2019-2021, it is estimated that the average day ahead market price was 35 €/MWh.

Table 35: Cumulative average historical day ahead market prices 2019-2022

Period	All Periods (€/MWh)	Curtailment (€/MWh)
2019	50	27
2019-2020	44	20
2019-2021	75	35
2019-2022	112	50



	2019	2020	2021	2022
Curtailment - Day	39	25	96	139
Curtailment - Night	20	10	68	85
All Periods - Day	58	46	155	253
All Periods - Night	41	32	112	214

Figure 72: Historical day ahead market prices during wind curtailment periods

iii. Transport

Transport is Ireland's largest energy-consuming sector, making up 42% of the energy that the country consumes, of which 96% is supplied by oil. Generally, as an island nation, Ireland presents an interesting scenario in the matter of means of transportation: previous to the COVID-19 pandemic, Dublin Airport alone experienced annual traffic of over 30 million passengers per year, with the Republic boasting the third-highest level of international air passengers per capita in the EU in 2016 – a figure only surpassed in Cyprus and Malta. Contrastingly, Ireland has the sixth-lowest rate of passenger cars per capita in the EU, with 439 cars per 1,000 inhabitants in 2016[112].

The Irish vehicle fleet, however, is largely fuelled by petrol and diesel: although annual electric car registrations experienced a tenfold increase between 2016 and 2020, they still accounted for only 5% of new car registrations in 2021[113]. Table 36 presents a breakdown of emissions

[112] https://www.cso.ie/en/releasesandpublications/ep/p-eii/eii18/

[113] https://www.cso.ie/en/releasesandpublications/er/vlftm/vehicleslicensedforthefirsttimedecemberandyear2021/

from transport by mode in Ireland, highlighting the carbon-intensity of sectors such as aviation and others, which include rail and shipping.

Table 36: Fleet size and emissions by mode of transport in Ireland in 2020. Adapted from CSO data

Mode of transport	Fleet size	% of total fleet	Emissions ($MtCO_2eq$)	% of transport emissions
Private Cars	2,215,127	77%	6.1	40%
Freight (HGVs)	39,922	1%	2.1	14%
Aviation	-	-	3.2	21%
Others	-	-	3.8	25%

In June 2022, the EU parliament voted to ban internal combustion engine cars by 2035, although the final law still needs approval from member states[114]. Ireland, in turn, has ambitious plans to decarbonise transport. A strategy has been set in the latest National Policy Framework on Alternative Fuels Infrastructure for Transport in Ireland, aiming to see all cars and vans sold in the country from 2030 to be zero emission capable. Furthermore, the framework envisages an increased penetration of hydrogen as a transport fuel across the Irish fleet from 2030[115].

Transport in Dublin

In Dublin, land-based transport has an annual energy demand of approximately 6.2 TWh. This represents 28% of the total annual energy demand in Dublin (excluding aviation and maritime). In terms of carbon emissions, this equates to almost 1.7 $MtCO_2eq$. Figure 73 and Table 37 show the current energy demand and emissions from the different transport modes in Dublin, as well as their projected Business-As-Usual (BAU) emissions by 2030 and 2050, assuming today's fuel mix remains the same for each vehicle type. This is based on modelling carried out by the NTA's East Regional Model and further developed in Codema's Dublin Region Energy Master Plan[116].

[114] https://www.bloomberg.com/news/articles/2022-06-08/eu-lawmakers-to-vote-on-banning-combustion-engine-cars

[115] https://www.gov.ie/en/publication/3cb2f6-national-policy-framework-on-alternative-fuels-infrastructure-for-tr/

[116] https://www.codema.ie/media/news/codema-study-shows-dublin-can-meet-emission-targets/

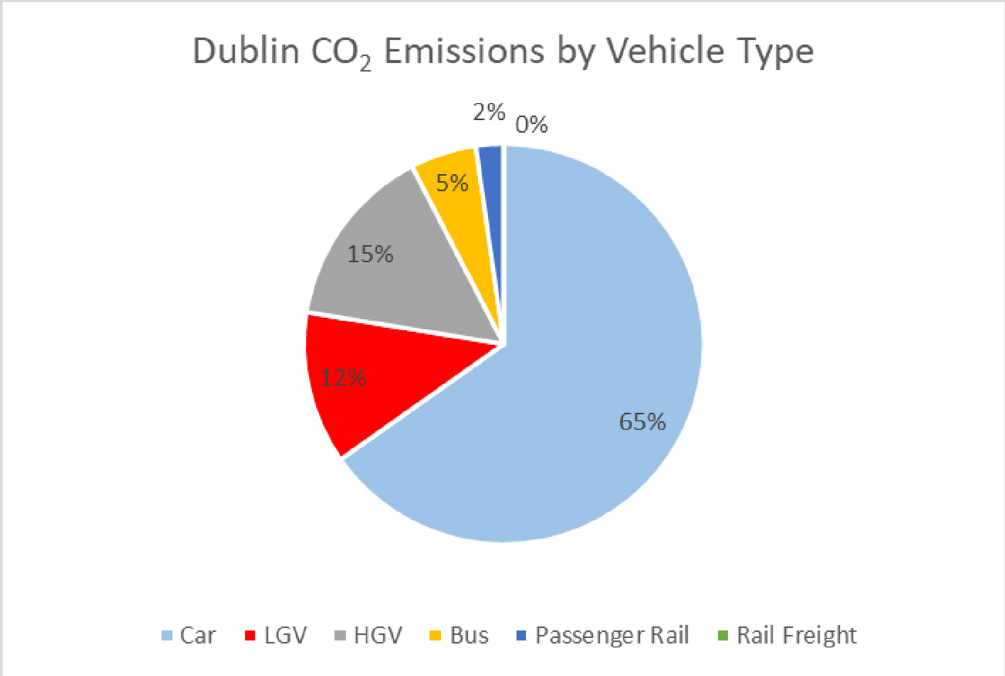


Figure 73: CO2 emissions by vehicle type for Dublin (excluding aviation and maritime)

Table 37: Current transport emissions in Dublin

Mode of transport	Fleet size	Energy Demand (TWh)	Emissions ($MtCO_2eq$)	% of transport emissions
Private Cars	554,470	4.02	1.09	65%
HGVs	29,000	0.92	0.25	15%
LGVs	49,000	0.77	0.21	12%
Bus	1,139	0.34	0.09	5%
Passenger rail	-	0.13	0.04	2%
Rail Freight	-	0.001	0.0004	0%

Cars make up by far the most significant proportion of transport energy demand in Dublin, at 65% of the total emissions or 4.0 TWh annually. As with the national picture, the vast majority of these cars are fuelled by diesel or petrol. In 2020, there were 554,470 private cars licensed in Dublin, with just 5,527 or 1% of this fleet being battery electric vehicles (BEVs). The average annual distance driven by these cars is typically 19% lower than the national average, at 9,576 km per year. In 2021, almost 10% of all new car registrations in Dublin were for BEVs, while a further 9% were plug-in hybrid electric vehicles (PHEVs). In the first 6 months of 2022, this had increased to almost 16% and 10% respectively, despite reports that sales of these vehicles have been suppressed due to global supply chain shortages.

Heavy goods vehicles make up the next largest proportion of transport energy demand in Dublin. In 2020, there were approximately 29,000 of these vehicles licensed in Dublin. Currently, almost all HGVs in this country are powered by diesel, with a very small number of

CNG and HVO fuelled vehicles in operation. The current annual energy demand from HGVs in Dublin is approximately 0.92 TWh, resulting in GHG emissions of 0.25 million tonnes CO2eq per year. By 2030, it is projected that energy demand for HGVs in Dublin will increase by 44% to 1.1 TWh due to steadily increasing vehicle kilometres.

A similar story is true for light goods vehicles, which currently account for 0.77 TWh of energy annually in Dublin and which are projected to see an increase in vehicle kilometres travelled of 44% by 2030. At present the vast majority of the vehicles licensed in Dublin are diesel, but a growing percentage of new sales are now BEVs. In 2021, this stood at 5% of new LGV sales.

Low Emission Bus Trials

The National Development Plan sets out that as of July 2019, no new diesel-only buses shall be purchased for urban fleets. Since 2018, the Department of Transport has been running low-emission bus trials to determine the most favourable technologies to shift Ireland's urban Public Service Obligation (PSO) bus fleet away from diesel. A Phase 1 report was published in December 2019, which compared a number of different technologies and fuel types, including CNG, bio-CNG, diesel hybrid, HVO hybrid and battery electric[117]. A double-deck hydrogen fuel cell bus was planned to be included in this analysis; however, this could not be accommodated at the time due to technical and logistical issues. The trial took place over a period of five months on two routes of roughly 20 km each in Cork and Dublin, which were seen as being representative of typical routes in each city. This Phase One report found that of the options analysed, electric buses were the most energy efficient option, and emitted the lowest tailpipe NOx. Battery electric was also found to come out on top in a cost benefit analysis of the various investment options.

A Phase Two report was published in May 2022, which updated the analysis to include findings from testing of two hydrogen fuel cell buses (one single-deck and one double-deck) in Dublin between November 2020 and August 2021[118]. The trial found that if 100% renewable electricity is used to generate the hydrogen, then hydrogen fuel-cell technology is comparable to diesel hybrid buses in terms of energy efficiency, but still significantly less efficient than battery electric. From a cost benefit analysis viewpoint, hydrogen fuel cell vehicles ranked poorly, based on their relatively high lifecycle GHG emissions, high capital cost and high fuel cost. However, it was noted that hydrogen fuel cells offer greater operational flexibility over electric buses, with a longer range and short refuelling times. In addition, hydrogen fuel cells vehicles are considered 'zero-duty heavy duty vehicles' as defined under the Clean Vehicles Directive, which cannot be said for alternatives such as HVO or bio-CNG. Furthermore, the potential for

[117] https://www.gov.ie/en/publication/7251e2-low-emission-bus-trials-report/
[118] https://www.gov.ie/en/publication/e2cd8-low-emission-bus-trial-final-report/

producing hydrogen from wind energy which would otherwise be curtailed was not considered in this analysis.

Dublin Port HGV Traffic

Significant volumes of road traffic enter and exit the Dublin Port area each day, some of which could potentially be fuelled by hydrogen. As part of the Dublin Port Masterplan 2040, a Strategic Transportation Study was carried out to assess the current and future traffic volumes for the area[119]. This included the Dublin Port lands on both the north and south sides of the Liffey estuary. This study, carried out in 2018, was based on traffic counts taken in 2014 for the Northern Lands and 2016 for the Southern Lands. Vehicles were classified using the industry standard vehicle classification system. As such, HGVs were broken down into two categories - "Other Goods Vehicle Type 1" (OGV1) for all rigid vehicles over 3.5 tonnes gross vehicle weight, and "Other Goods Vehicles Type 2" (OGV2) for all articulated vehicles. Bus and coach traffic was also counted under a separate "BUS" category.

For the Northern Lands, the study found average weekday one-way traffic volumes of 780 OGV1, 3,240 OGV2 and 244 BUS. On the Southern Lands, significantly lower weekday one-way traffic volumes of 66 OGV1 and 432 OGV2 were found. The study stated that Port throughput was expected to grow by 3.3% per annum out to 2040, and it was assumed that road traffic volumes would increase in line with this.

More recent video traffic count data from the Dublin Port Tunnel in 2017 found average annual daily traffic of approximately 26,700 vehicles per day using the tunnel (combined over both directions). Of this total, OGV1 accounted for 1,738 vehicles per day, OGV2 made up a significant proportion at 8,249 vehicles per day and buses and coaches made up 1,355 vehicles per day. While not all of this traffic was bound for Dublin Port, it shows that there may be a significant volume of non-port related traffic that could potentially avail of hydrogen refuelling facilities in this area of the city.

Dublin Maritime and Aviation Figures

In 2021, 7,251 ships arrived at Dublin Port. This number was somewhat lower than the peak figure of 7,860 reported for 2018[120], due to disruption related to the Covid-19 pandemic and Brexit. A recovery in the volume of freight passing through Dublin has been seen in the first

[119] https://www.dublinport.ie/wp-content/uploads/2018/07/DP-Mplan-Review-Strategic-Transport-Study-FINAL-2018-6-22.pdf
[120] https://www.cso.ie/en/releasesandpublications/er/spt/statisticsofporttrafficquarter4andyear2019/

half of 2022, with ship arrivals increasing by 150 to 3,694 compared to the same period in 2021[121].

Dublin Airport handled a total of 82,514 flights, including both departures and arrivals, in 2021. This represented 88% of all flights at Ireland's main airports. Over 8.2 million passengers passed through Dublin airport in 2021, as well as 144 kilo-tonnes of freight. These figures are still significantly suppressed from 2019 levels, when 229,143 flights were handled at Dublin Airport[122]. A new fuel storage facility was opened at Dublin airport in 2018, with the capacity to store 15 million litres of aviation fuel, or roughly enough fuel for 167 long-haul flights[123]. In 2019, Dublin airport reported GHG emissions of 387,853 tCO2eq. Scope 3 emissions generated by third party activities accounted for 93% of this total, with "aircraft landing and take-off cycle" accounting for 258,832 tCO2eq. This equates to almost two thirds of the airport's total GHG emissions[124]. Assuming emissions of 3.16 kg of CO2 per litre of aviation fuel[125], this would translate to a demand of approximately 82 million litres of aviation fuel per year.

iv. Heat

The 2021 National Heat Study report[126] shows that the total annual CO_2 emissions from fossil fuel consumption for heating of all buildings and industrial applications across all sectors in Ireland is approximately 14.t $MtCO_2$. This translates to 38% of the total energy related CO_2 emissions with 75% of these emissions coming from gas and oil. Similarly, the industrial and residential sector account for 82% of total heating fuel use. Figure 74 and Figure 75 show total emissions ($MtCO_2$) from the heating sector and heating demand (GWh) by fuel type.

[121] https://www.dublinport.ie/dublin-port-volumes-recover-strongly-in-the-first-half-of-2022-with-growth-of-10-1/
[122] https://www.cso.ie/en/releasesandpublications/er/as/aviationstatisticsquarter4andyear2019/
[123] https://www.dublinairport.com/latest-news/2019/05/31/dublin-airport's-new-fuel-farm-opens
[124] https://www.dublinairport.com/docs/default-source/sustainability-reports/dublin-airport-carbon-reduction-strategy.pdf
[125] https://www.offsetguide.org/understanding-carbon-offsets/air-travel-climate/climate-impacts-from-aviation/co2-emissions/
[126] https://www.seai.ie/publications/Heating-and-Cooling-in-Ireland-Today.pdf

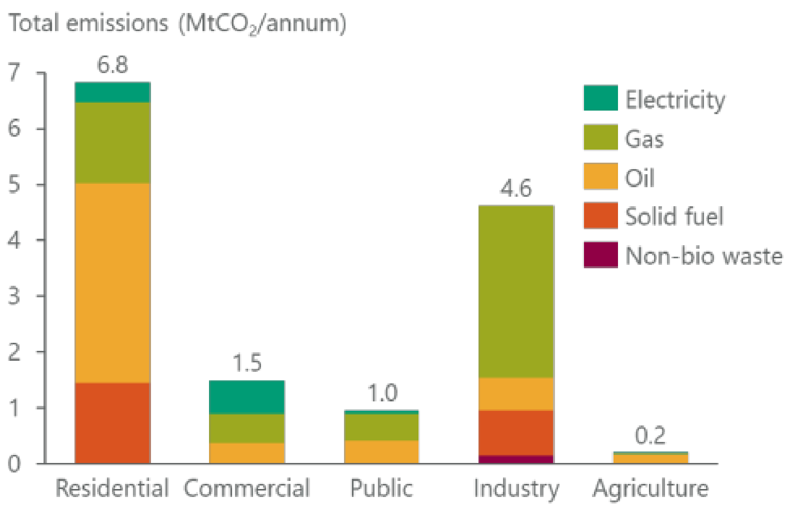


Figure 74: Total annual emissions (MtCO2/annum) from fuel use for heating, by sector

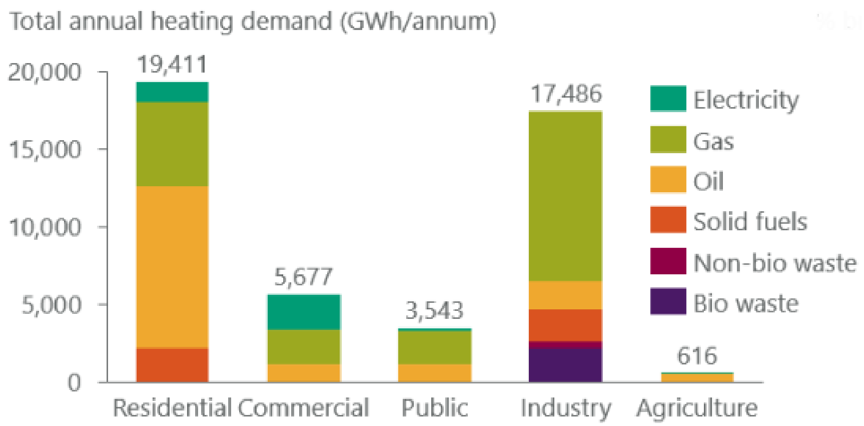


Figure 75: Total annual heating demand (GWh/annum), by sector

The National Heat Study report also outlines spatial analysis of heating and cooling demand with results used to produce a national map of heat demand. Potential heat sources including geothermal energy resources at different depths were analysed for each of the 18,641 small areas, and a sample is presented in Figure 76.

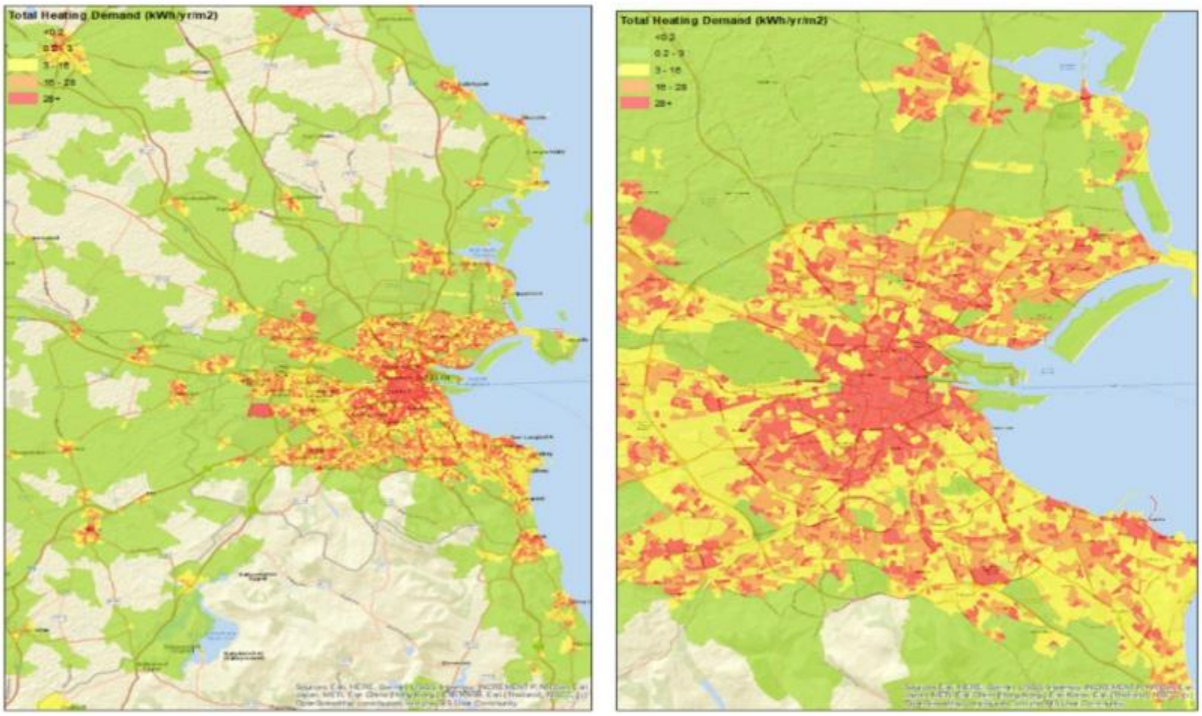


Figure 76: Sample of results of the spatial analysis of total heat demand

Ireland has relatively high industrial activity for a country of its size. The sector consumed 19.2 GWh of heat in 2019 – the equivalent of nearly 35% of the country's total heat consumption in that year – although only 6.3% of that heat came from renewable sources. Energy intensive organisations, with an annual energy spend of over € 1 million, are invited to be part of the Large Industry Energy Network (LIEN), a group of 199 members that together consume over a fifth of Ireland's entire primary energy requirement[127]. Figure 77 shows the locations of large heat users within the LIEN group, according to the Sustainable Energy Authority of Ireland (SEAI).

[127] **https://www.seai.ie/technologies/seai-maps/heat-demand-map/**

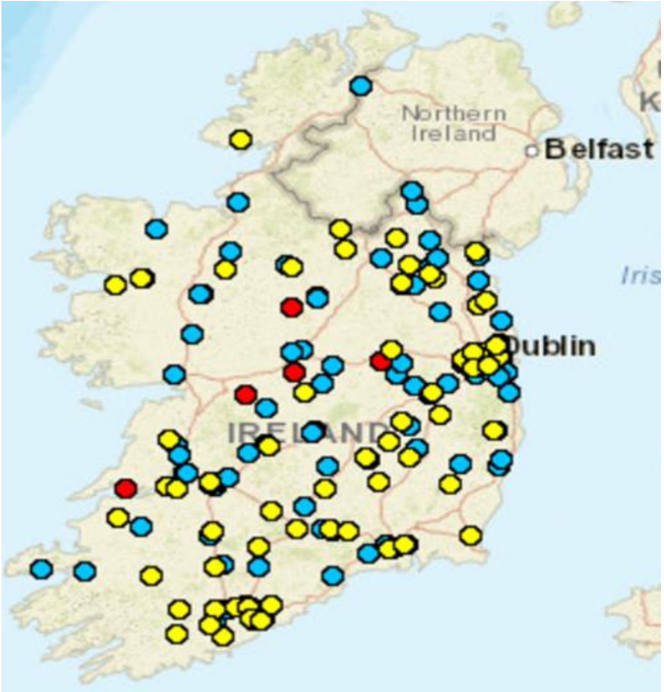


Figure 77: Ireland's largest heat users, including power stations (red), emission trading sites (yellow) and other LIEN members (blue)

With the vast majority of the Irish industrial heat being generated by oil and fossil natural gas, the sector presents ample opportunities for decarbonisation. Ireland's Climate Action Plan establishes the Support Scheme for Renewable Heat (SSRH), which aims to achieve 1.6 TWh of biomethane injection by 2030, 0.12 TWh of district heating by 2028, as well as heat pumps in new and existing buildings[128]. However, despite the goals of the SSRH, the action plan does not propose a specific strategy for decarbonising industrial heat, which comprises intensive practices such as water heating and direct supply for industrial processes, as opposed to the residential and commercial sectors, which require mostly space heating.

Ireland's Gas Grid

Ireland has a long history of gas use. In the late 18th century, coal was gasified to produce coal gas or "town gas", first for illumination, then for heating and cooking in towns and cities up to the 1980's. Interestingly, the coal gasification process employed to produce town gas produces syngas that contains up to 50% hydrogen. Following the discovery of the Kinsale Head gas field in the early 1970's, a significant amount of urban infrastructure was already in

[128] **https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/#**

place, and natural gas rapidly entered the market. Natural gas was phased into the Dublin area in the 1980's, eventually replacing town gas completely by 1986[129].

The gas network of Ireland, presented in Figure 78, has since been expanded and today extends to 14,521 km (2,477 km of high-pressure, >16 barg, transmission pipelines and 12,044 km of low-pressure, <16 barg, distribution pipelines), with most of the original cast-iron gas pipes replaced by modern polyethylene – which is hydrogen rated – making the Irish gas network one of the safest in the world. The national gas grid is linked to Northern Ireland operating a single energy market on the island of Ireland, and connected to Britain and European gas markets via Scotland and the Isle of Man. In addition to the international interconnectors, there is a single fossil gas injection point from the Corrib gas field at Co. Mayo, with two former fossil gas injection points at Co. Cork (Seven Heads and Kinsale Head, which are now depleted and undergoing decommissioning)[130].

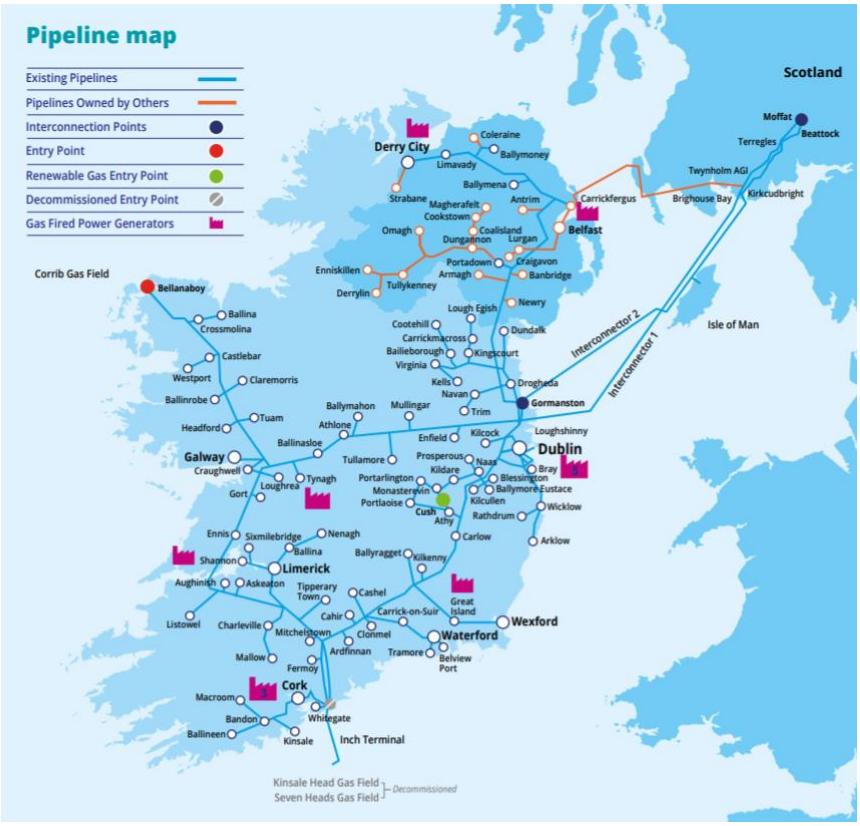


Figure 78: The Irish gas pipeline map, with the existing biomethane injection point represented as a green circle

---

[129] https://www.independent.ie/lifestyle/the-gasworks-26876013.html

[130] https://www.gasnetworks.ie/docs/corporate/gas-regulation/GNI-Systems-Performance-Report-2019.pdf

Furthermore, the first injection point dedicated exclusively to biomethane was inaugurated in Co. Kildare in 2020, with a second facility planned for Co. Cork. This renewable, biologically formed methane gas is produced by the natural breakdown of organic material such as food waste and animal slurry via anaerobic digestion, and is a direct replacement for fossil natural gas. Indeed, while the introduction of biogas to the Irish gas grid already indicates an important step towards the use of cleaner fuels, this is a step that could be followed by the injection of hydrogen, or even synthetic natural gas produced from green hydrogen, in the future.

The non-transportable renewable curtailed electricity could be used to generate hydrogen through Power to Hydrogen (P2H) process, a technology that uses electrolysis to produce hydrogen. The hydrogen can be stored externally and used directly in fuel cells or thermal batteries or alternatively injected into the natural gas network. The main benefit of P2G in RES is that it serves large-scale systems (larger than 1 MW), provides long term storage solutions and reduces curtailed renewable electricity[131]. The P2G technology can use existing gas infrastructure for long term transport of hydrogen gas and storage of natural gas. The natural gas can be converted back into electricity via conventional generators such as gas turbines.

Heat in Dublin

The heat analysis performed as part of the Dublin Region Energy Master Plan study looked at two main low-carbon heating options, district heating and heat pumps. The adoption of biomethane and limited quantities of green hydrogen (20% by volume which equates to 7% by energy content which can be accommodated within existing gas infrastructure) have been included in this analysis to produce future carbon emission factors for the gas grid. It should be noted that the use of these gases cannot deliver full decarbonisation of the entire heat sector (in the current quantities needed) and should be prioritised for high-exergy applications such as backup power generation or as a feedstock for specific industrial processes where needed rather than for low-exergy applications (space heating and hot water preparation).

Figure 79 shows the heat demand density in TJ/km^2 for each CSO small area in the county. This metric is one of the key indicators for DH suitability. The heat demand for Dublin has been calculated for each small area in the county from the Master Plan study. The map below shows the heat demand density (TJ/km^2) for the Dublin City region. This and further interactive heat demand maps for all local authority areas can be found on Codema's online map portal[132].

[131] https://www.mdpi.com/1996-1073/13/22/6047/pdf

[132] https://codema-dev.github.io/map/district-heating-viability-map-v2/

Furthermore, the graph[133] presented in Figure 80 shows that gas is the main heating fuel in Dublin, followed by direct electric and oil.

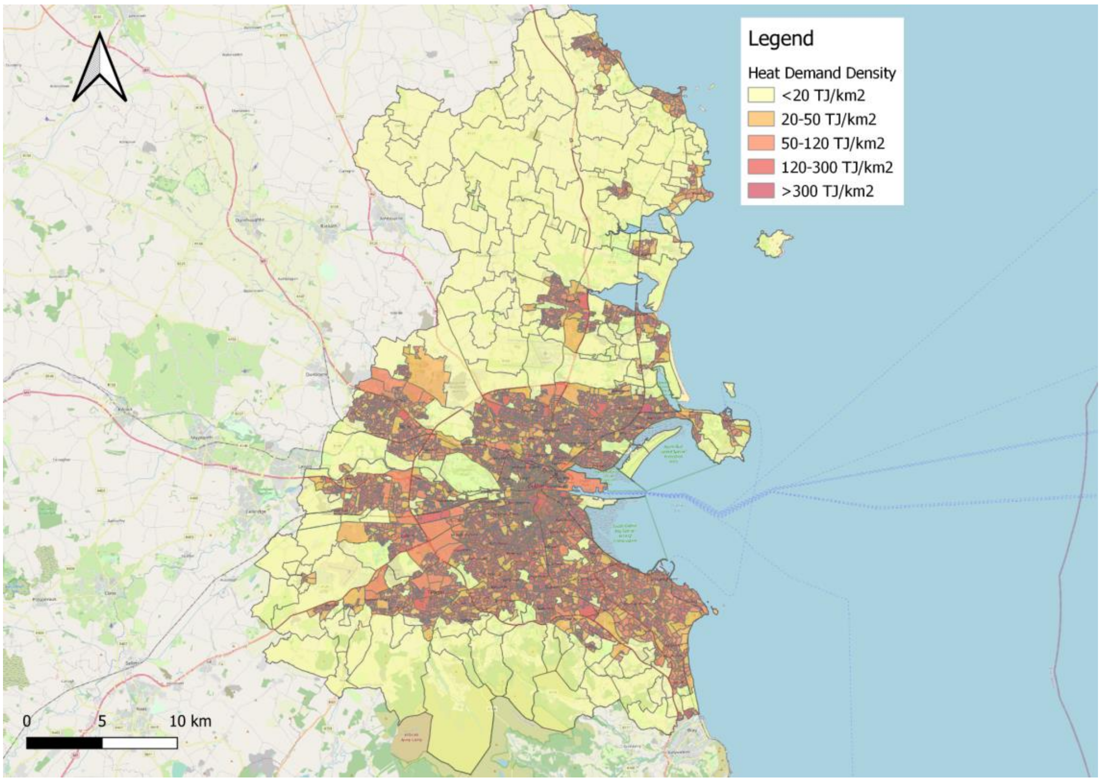


Figure 79: Heat demand density in TJ/km² for each CSO small area in Dublin

133 https://codema-dev.github.io/map/district-heating-viability-map-v2/

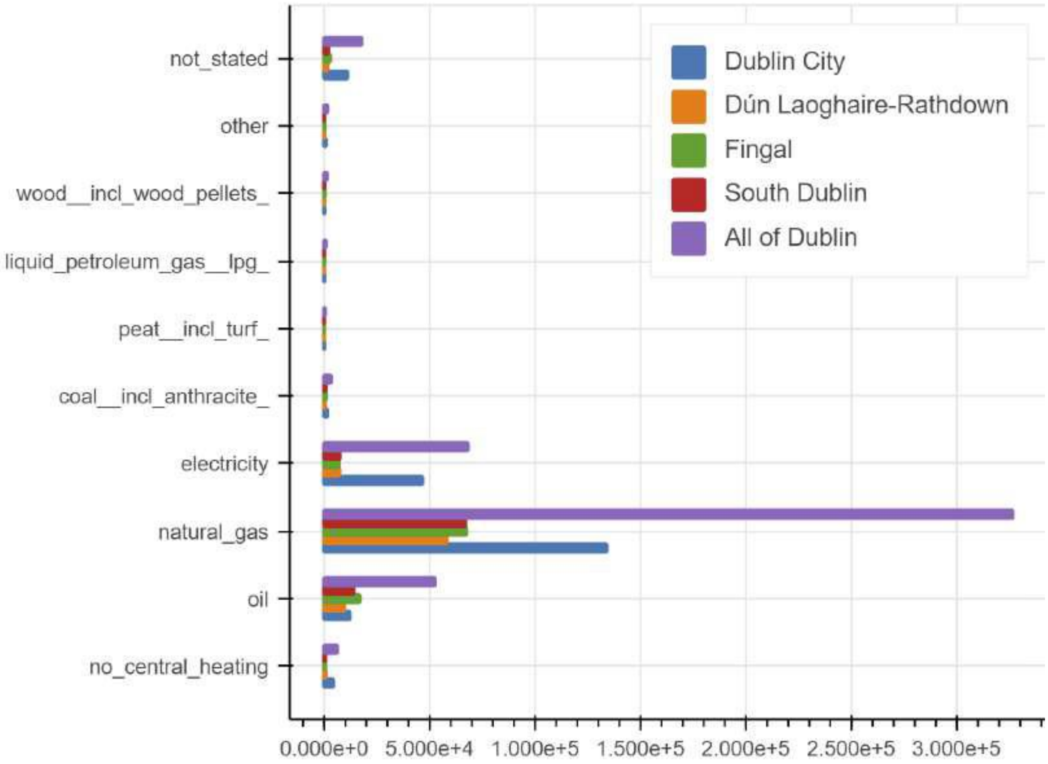


Figure 80: Breakdown of current heating technologies in Dublin

f. Levelised Cost of Hydrogen Production

Numerous studies have assessed the levelised cost of hydrogen production (LCOHp) in recent years. Deloitte carried out an outlook of the European hydrogen economy to 2030[134], where estimates of the LCOHp were provided for hydrogen production via offshore wind off grid electrolysis, solar PV off grid electrolysis and grid connected electrolysis. From Figure 81, the report indicated an LCOHp of 3.7 €/kg for off grid production via offshore wind. Solar PV off grid electrolysis LCOHp was estimated to be 5.3 €/kg. The LCOHp from grid electrolysis was estimated to be in the range of 3.8-4.9 €/kg assuming electricity prices in the range of 55-80 €/MWh. CapEx was found to be the main driver of LCOH for renewable hydrogen projects, with large variations across configurations. CapEx was not as sensitive to the grid connected configuration; however, the power price was highly sensitive.

[134] https://www2.deloitte.com/content/dam/Deloitte/fr/Documents/financial-advisory/European_hydrogen_economy_FINAL.pdf

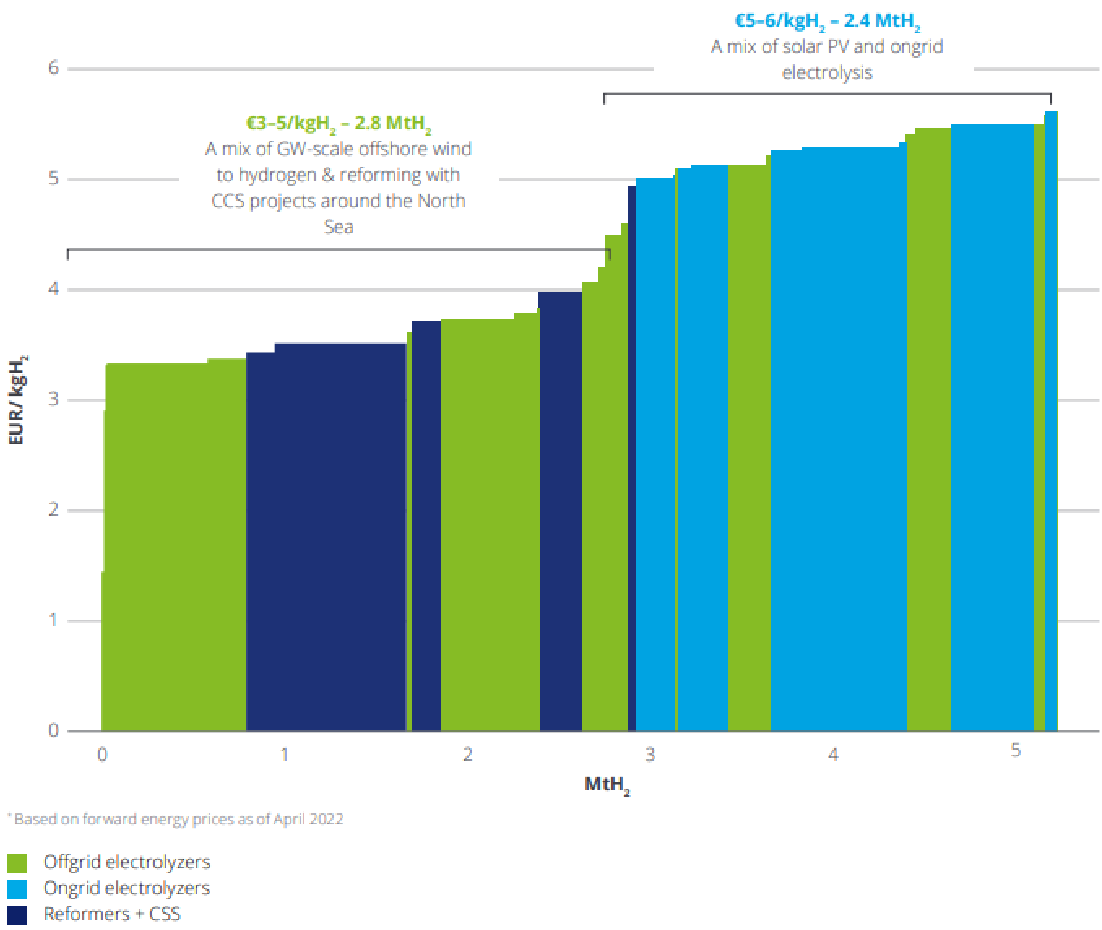


Figure 81: Deloitte LCOH Analysis

Aurora 2023 analysis[135] indicated Ireland could produce the cheapest green hydrogen at an LCOHp of 3.50 €/kg by 2030 under optimal conditions. The optimal conditions were reported as a 100MW electrolyser connected to 150MW of onshore wind and 20MW of solar photovoltaic generation, not connected to the all-island electricity transmission system, and located in Connacht.

Various research studies in Ireland have examined the LCOHp from curtailed electricity at onshore wind farms in Ireland. Gunuawan et al.[136] (2020) estimated the LCOHp to be in the range of €18-20/kg for a 1.5 MW electrolyser, a curtailed wind energy price in the range of €50-65/MWh and a electrolyser capacity factor of approximately 20%.

[135] https://auroraer.com/media/ireland-could-produce-cheapest-green-hydrogen-in-europe-by-2030/

[136] https://www.nweurope.eu/media/10081/arya-paper-8-april-2020-energies-13-01798-v2-1.pdf

g. Energy Security and Resilience

Energy system resilience – its ability to survive disruptions while recovering quickly afterwards – is a complex concept that has been receiving growing attention in the current energy transition process. In a world where societies require increasing amounts of energy, which in turn is being produced by non-synchronous, non-constant generation methods, resilience is a key element within risk management approaches of modern energy systems. Moreover, the increased incidence of weather-related threats driven by climate change, as well as digital threats such as cyber-attacks, add further layers of complexity as the demand for energy-based services continues to grow[137].

Robust, resilient energy systems are needed to support the decarbonisation of societies while providing energy security and reliability. While the issue has been widely discussed in academic literature, with some studies going as far as attempting to measure and quantify resilience, the overall consensus points towards an uncertain future of unexpected threats, ranging from natural phenomena to political instability and international conflicts. Figure 82 illustrates the concept of energy system resilience, showing the phases and different elements of a generic system disruption from start until a return to status quo.

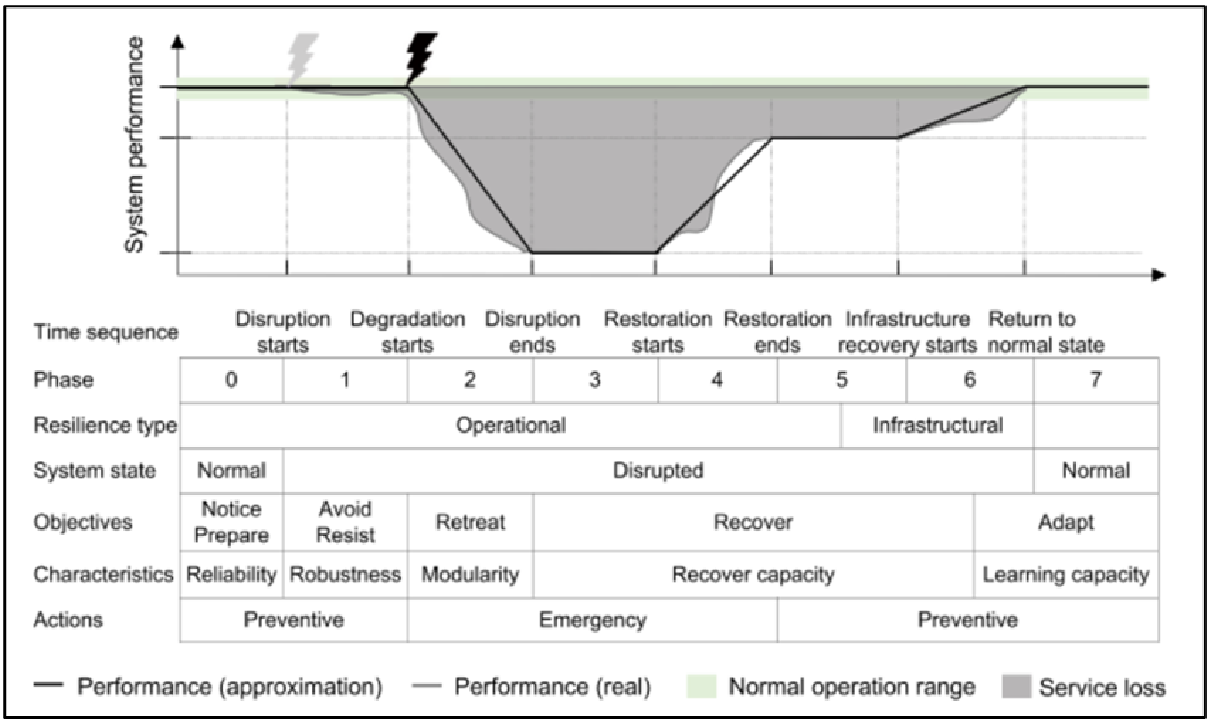


Figure 82: A generic resilience curve of an energy system

[137] https://doi.org/10.1016/j.rser.2021.111476

The concept of resilience of an energy system can be hard to quantify. In 2021, a comprehensive study from the Paul Scherrer Institute, in Switzerland, analysed 35 European countries in terms of different resilience dimensions, and developed a methodological framework to quantify the resilience of each country's electricity supply[138]. The criteria used in the analysis included factors such as political stability, electricity import dependency, reserves capacity, outage times and even the number of engineers in the economy. The study yielded a numerical score for each country analysed which allowed them to be ranked: Denmark, Switzerland and Iceland were the best-performing countries while Serbia, North Macedonia and Albania showed the worst resilience scores. Figure 83 illustrates the results.

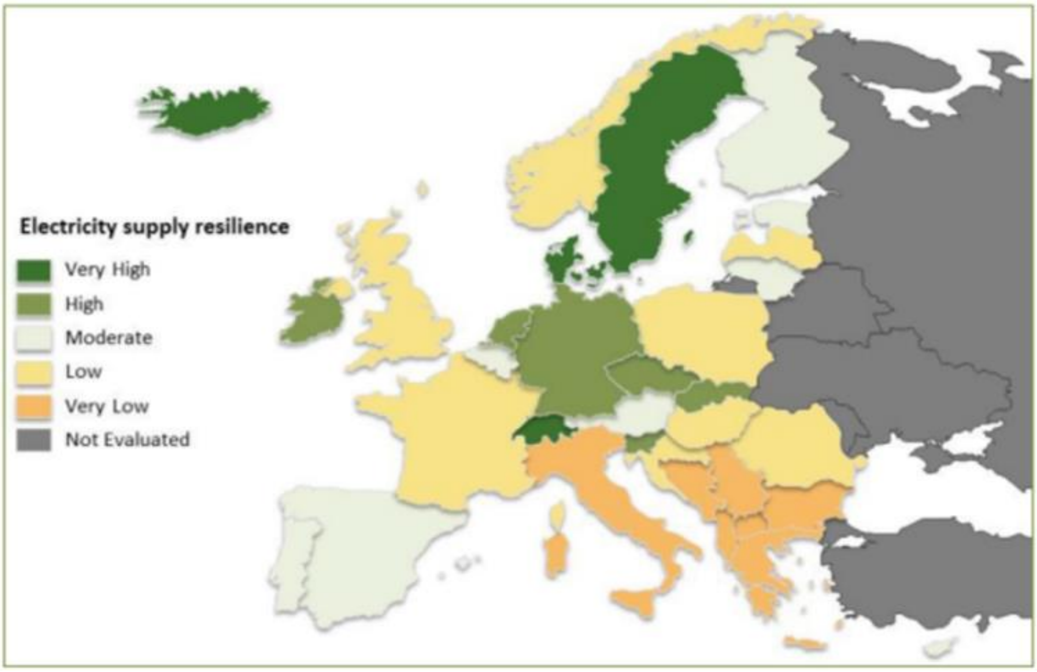


Figure 83: Electricity supply resilience in Europe

In the Paul Scherrer Institute's resilience study, Ireland achieved the 9th position, ahead of countries such as the Netherlands (10th), Belgium (18th) and the UK (23rd). Overall, Ireland obtained average to good scores for most of the criteria that were analysed, with particularly positive results for:

- **Political stability** and absence of violence/terrorism, with a score 68% higher than the 35-country average;
- **Control of corruption**, with a score 73% higher than the average;
- **Government effectiveness**, with a score 44% higher than the average.

[138] https://doi.org/10.1016/j.ejor.2021.07.026

However, some weaknesses and potential threats to the future of the resilience of Ireland's energy system were highlighted as some negative results were obtained for:

- **Reserves capacity**, or the amount of power ready to be dispatched to cover supply shortages, where Ireland's score was 64% lower than the 35-country average;
- **Insurance penetration**, or the access to financial resources needed to rebuild a system, where Ireland's score was 45% lower than the average;
- **Engineers in the economy**, where Ireland's share was 44% lower than the average.

The results of the study provide an interesting and comprehensive panorama of comparisons between Ireland and other European countries in terms of energy security, highlighting evident as well as unexpected strengths and weaknesses of the Irish energy system. However, the study is limited in the sense that 1) its scope does not include cyber-attacks, a minor but rapidly increasing concern, and 2) many of the indicators analysed are extremely volatile and change at a very fast pace, especially in the context of ongoing conflicts in Eastern Europe and their impacts on energy supply and security.

Another assessment of Ireland's energy system resilience was performed by the MaREI Centre in 2021, focusing on the role of natural gas as a backup[139]. The study analysed a period of two weeks in early January 2021 when the country experienced low incidence of wind and cold temperatures, a combination that saw the reduction of power generated from wind farms coupled with increased demand for electricity and heat (see Figure 84).

[139] https://www.marei.ie/irelands-energy-system-resilience/

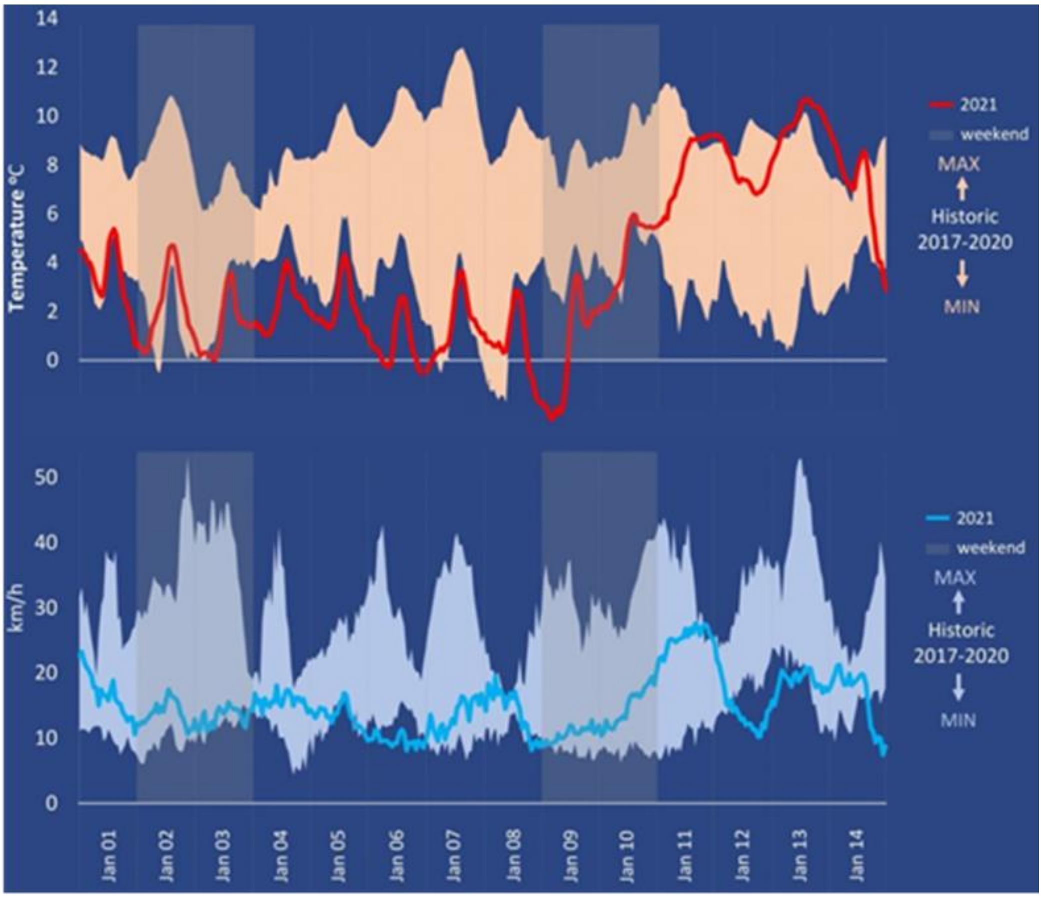


Figure 84: Average temperatures for the first two weeks of January 2021 in comparison to the historic average (above); as well as wind speeds for the same period and historical averages (below)

The situation provided an ideal case study to test the resilience of the energy system and the role that fossil fuels currently play in responding to disruptions and changes in weather conditions. The study concluded that fossil natural gas was the main source of power used to balance the system, providing resilience to meet electricity and heat demand requirements. Up to two-thirds of the all-island's daily electricity generation came from natural gas during that period.

However, the study also emphasised the "invisibility" of energy resilience, especially within the context of countries such as Ireland, which have a growing level of variable renewable energy and are experiencing the electrification of heat and transport. While natural gas is still a suitable backup today, it is vital that cleaner and more robust resilience mechanisms are put in place in a future where fossil fuels might be depleted, unavailable or simply not acceptable.

In May 2022, Ireland's Commission for Regulation of Utilities (CRU) published a draft risk preparedness plan setting up steps that must be taken by the Irish electricity sector to prevent, manage and prepare for emergency situations. The report, entitled "Electricity Crises: A Risk Preparedness Plan for Ireland"[140], includes:

- The identification of **26 crisis scenarios** grouped into **9 categories**: extreme weather, malicious attack, primary equipment failure, technical failure, natural disaster, primary energy shortage, human factors, market failure and infrastructure delivery deficit;
- The definition of **roles and responsibilities** of CRU and other stakeholders such as EirGrid and ESB;
- **Procedures and measures** that should be followed in the case of an electricity crisis, including emergency response as well as preventive and preparedness measures.

CRU's Risk Preparedness Plan establishes important strategies to ensure the resilience of the Irish electricity sector, ensuring these are communicated to the public and highlighting the importance of cooperation between the Republic of Ireland and Northern Ireland in the event of a crisis, in light of the Single Electricity Market operating on the island. The Plan follows EirGrid's most recent Generation Capacity Statement (GCS)[141], which has predicted a potential capacity shortfall of up to 1,850 MW by 2024 in Ireland if no action is taken. The 2021 GCS, however, was published prior to the development of conflicts in Eastern Europe, tensions with Russia and spiralling costs of energy, and thus an updated version of the GCS, taking these new challenges into account, is expected in 2022.

[140] https://www.cru.ie/wp-content/uploads/2021/08/CRU202239-Risk-Preparedness-Plan-Ireland.pdf

[141] http://www.eirgridgroup.com/site-files/library/EirGrid/208281-All-Island-Generation-Capacity-Statement-LR13A.pdf

2. Appendix

a. Appendix A

i. Dispatch Down Modelling 2030 & 2040

Table 38: 2030 and 2040 Total Curtailment Estimates

Scenario	Generator	Oversupply	System Curtailment	Total Curtailment
2030 (94% RES-E)	Non-Priority Onshore Wind	26.14%	4.09%	30.23%
	Non-Priority Offshore Wind	26.56%	4.28%	30.84%
	Priority Onshore Wind	0%	4.08%	4.08%
	Average Wind	19.60%	4.16%	23.77%
	Non-Priority Solar	20.65%	3.17%	23.81%
	Priority Solar	0%	3.16%	3.16%
	Average Solar	19.95%	3.17%	23.12%
2040 Scenario 1 (100% RES-E)	Non-Priority Onshore Wind	20.84%	0%	20.84%
	Non-Priority Offshore Wind	21.38%	0%	21.38%
	Priority Onshore Wind	0%	0%	0%
	Average Wind	15.93%	0%	15.93%
	Non-Priority Solar	14.92%	0%	14.92%
	Priority Solar	0%	0%	0%
	Average Solar	14.53%	0%	14.53%
2040 Scenario 2 (100% RES-E)	Non-Priority Onshore Wind	19.26%	0%	19.26%
	Non-Priority Offshore Wind	19.72%	0%	19.72%
	Priority Onshore Wind	0%	0%	0%
	Average Wind	14.48%	0%	14.48%
	Non-Priority Solar	16.37%	0%	16.37%
	Priority Solar	0%	0%	0%
	Average Solar	16.00%	0%	16.00%

b. Appendix B

i. Green Hydrogen 2030 & 2040 Curtailment Mitigation

Table 39: 'Grid Connected High RES-E' Analysis Results

Scenario	Electrolyser Capacity (MW)	Non-Priority Wind Total Curtailment after Electrolyser (%)	Priority Wind Total Curtailment after Electrolyser (%)	Non-Priority Solar Total Curtailment after Electrolyser (%)	Priority Solar Total Curtailment after Electrolyser (%)	Capacity Factor of Electrolyser (%)	RES-E
2030	0	30.55%	4.08%	23.81%	3.16%	0%	94.0%
	500	26.07%	3.81%	20.10%	2.87%	100%	97.8%
	1000	22.09%	3.63%	16.89%	2.70%	99%	101.1%
	1500	18.56%	3.51%	14.19%	2.58%	98%	104.1%
	2000	15.29%	3.35%	11.62%	2.38%	96%	106.8%
2040 Scenario 1	0	21.06%	0.00%	14.92%	0.00%	0%	100.0%
	500	18.04%	0.00%	12.62%	0.00%	100%	102.6%
	1000	15.32%	0.00%	10.65%	0.00%	99%	104.9%
	1500	12.91%	0.00%	9.04%	0.00%	98%	106.9%
	2000	10.67%	0.00%	7.59%	0.00%	98%	108.8%
2040 Scenario 2	0	19.43%	0.00%	16.37%	0.00%	0%	100.0%
	500	16.46%	0.00%	13.79%	0.00%	100%	102.4%
	1000	13.78%	0.00%	11.57%	0.00%	99%	104.6%
	1500	11.37%	0.00%	9.72%	0.00%	98%	106.6%
	2000	9.15%	0.00%	8.05%	0.00%	97%	108.4%

Table 40: 'Offshore Wind Off Grid' Analysis Results

Electrolyser Capacity (MW)	Capacity Factor of Electrolyser (%)	Unused Offshore Wind Energy (%)
0	0%	100%
500	82%	55%
1000	67%	26%
1500	55%	8%
2000	45%	0%

Table 41: System Wide VRES Curtailment' Analysis Results

Year	H2 Electrolyser Capacity (MW)	Non-Priority Wind Total Curtailment after Electrolyser (%)	Priority Wind Total Curtailment after Electrolyser (%)	Non-Priority Solar Total Curtailment after Electrolyser (%)	Priority Solar Total Curtailment after Electrolyser (%)	Non-Priority Wind Oversupply after Electrolyser (%)	Non-Priority Solar Oversupply after Electrolyser (%)	Average Wind System Curtailment after Electrolyser (%)	Average Solar System Curtailment after Electrolyser (%)	Capacity Factor of Electrolyser (%)	RES-E
2030	0	30.55%	4.08%	23.82%	3.16%	26.36%	20.65%	4.16%	3.17%	0%	94.0%
	500	26.07%	3.81%	20.10%	2.87%	22.16%	17.22%	3.88%	2.87%	45%	97.8%
	1000	22.10%	3.64%	16.90%	2.71%	18.37%	14.19%	3.71%	2.71%	42%	101.1%
	1500	18.59%	3.54%	14.23%	2.62%	14.95%	11.61%	3.61%	2.62%	40%	104.1%
	2000	15.34%	3.39%	11.70%	2.45%	11.87%	9.25%	3.45%	2.45%	39%	106.8%
2040 Scenario 1	0	21.06%	0.00%	14.92%	0.00%	21.06%	14.92%	0.00%	0.00%	0%	100.0%
	500	18.04%	0.00%	12.62%	0.00%	18.04%	12.62%	0.00%	0.00%	48%	102.6%
	1000	15.32%	0.00%	10.65%	0.00%	15.32%	10.65%	0.00%	0.00%	46%	104.9%
	1500	12.91%	0.00%	9.04%	0.00%	12.91%	9.04%	0.00%	0.00%	44%	106.9%
	2000	10.67%	0.00%	7.59%	0.00%	10.67%	7.59%	0.00%	0.00%	43%	108.8%
2040 Scenario 2	0	19.43%	0.00%	16.37%	0.00%	19.43%	16.37%	0.00%	0.00%	0%	100.0%
	500	16.46%	0.00%	13.79%	0.00%	16.46%	13.79%	0.00%	0.00%	47%	102.4%
	1000	13.78%	0.00%	11.57%	0.00%	13.78%	11.57%	0.00%	0.00%	45%	104.6%
	1500	11.37%	0.00%	9.72%	0.00%	11.37%	9.72%	0.00%	0.00%	44%	106.6%
	2000	9.15%	0.00%	8.05%	0.00%	9.15%	8.05%	0.00%	0.00%	42%	108.4%

Table 42: Offshore Wind Dispatch Down' Analysis Results

Scenario	Electrolyser Capacity (MW)	Poolbeg Offshore WF Oversupply after Electrolyser (%)	Poolbeg Offshore WF System Curtailment after Electrolyser (%)	Poolbeg Offshore WF Constraints after Electrolyser (%)	Poolbeg Offshore WF Dispatch Down after Electrolyser (%)	Capacity Factor of Electrolyser (%)
2030	0	26.56%	4.28%	10.00%	40.84%	0%
	100	20.74%	3.53%	9.70%	33.97%	41%
	200	15.64%	3.16%	9.38%	28.18%	38%
	300	11.30%	2.78%	8.86%	22.95%	36%
	400	7.73%	2.38%	8.14%	18.25%	34%
	500	4.88%	1.97%	7.25%	14.11%	32%
	600	2.78%	1.57%	6.18%	10.53%	30%
	700	1.44%	1.17%	4.92%	7.53%	28%
	800	0.69%	0.79%	3.55%	5.03%	27%
	900	0.29%	0.50%	2.37%	3.16%	25%
	1000	0.09%	0.30%	1.47%	1.86%	23%
	1500	0.00%	0.00%	0.00%	0.00%	16%
	2000	0.00%	0.00%	0.00%	0.00%	12%

2040 Scenario 1	0	21.41%	0.00%	0.00%	21.41%	0%
	100	17.79%	0.00%	0.00%	17.79%	32%
	200	14.57%	0.00%	0.00%	14.57%	31%
	300	11.67%	0.00%	0.00%	11.67%	29%
	400	9.09%	0.00%	0.00%	9.09%	28%
	500	6.85%	0.00%	0.00%	6.85%	26%
	600	4.92%	0.00%	0.00%	4.92%	25%
	700	3.32%	0.00%	0.00%	3.32%	23%
	800	2.07%	0.00%	0.00%	2.07%	22%
	900	1.15%	0.00%	0.00%	1.15%	20%
	1000	0.57%	0.00%	0.00%	0.57%	19%
	1500	0.00%	0.00%	0.00%	0.00%	13%
	2000	0.00%	0.00%	0.00%	0.00%	10%
2040 Scenario 2	0	19.75%	0.00%	0.00%	19.75%	0%
	100	16.31%	0.00%	0.00%	16.31%	31%
	200	13.21%	0.00%	0.00%	13.21%	29%
	300	10.44%	0.00%	0.00%	10.44%	28%
	400	8.02%	0.00%	0.00%	8.02%	26%
	500	5.95%	0.00%	0.00%	5.95%	25%
	600	4.21%	0.00%	0.00%	4.21%	23%
	700	2.79%	0.00%	0.00%	2.79%	22%
	800	1.69%	0.00%	0.00%	1.69%	20%
	900	0.92%	0.00%	0.00%	0.92%	19%
	1000	0.44%	0.00%	0.00%	0.44%	17%
	1500	0.00%	0.00%	0.00%	0.00%	12%
	2000	0.00%	0.00%	0.00%	0.00%	9%

Table 43: Offshore Wind and Solar PPA' Analysis Results

Scenario	H2 Electrolyser Capacity (MW)	Poolbeg Offshore WF Oversupply after H2 Electrolyser (%)	Poolbeg Offshore WF System Curtailment after H2 Electrolyser (%)	Poolbeg Offshore WF Total Curtailment after H2 Electrolyser (%)	Solar Farm Oversupply after H2 Electrolyser (%)	Solar Farm System Curtailment after H2 Electrolyser (%)	Solar Farm Total Curtailment after H2 Electrolyser (%)	Green Energy Capacity Factor of H2 Electrolyser (%)
2030	0	26.56%	4.28%	30.84%	0.00%	0.00%	0.00%	0%
	100	20.81%	3.46%	24.27%	15.46%	2.29%	17.75%	94%
	200	15.88%	3.07%	18.95%	11.68%	1.92%	13.60%	90%
	300	11.71%	2.64%	14.35%	8.84%	1.60%	10.44%	86%
	400	8.29%	2.18%	10.48%	6.67%	1.32%	8.00%	82%
	500	5.56%	1.77%	7.32%	4.99%	1.10%	6.09%	78%
	600	3.52%	1.30%	4.82%	3.70%	0.90%	4.60%	74%
	700	2.15%	0.90%	3.05%	2.71%	0.75%	3.46%	71%
	800	1.27%	0.60%	1.87%	1.95%	0.63%	2.57%	68%
	900	0.74%	0.39%	1.13%	1.38%	0.50%	1.89%	65%
	1000	0.43%	0.25%	0.68%	0.98%	0.40%	1.38%	62%
	1500	0.05%	0.04%	0.09%	0.15%	0.13%	0.28%	49%
	2000	0.01%	0.01%	0.01%	0.02%	0.02%	0.04%	40%

2040 Scenario 1	0	21.41%	0.00%	21.41%	0.00%	0.00%	0.00%	0%
	100	17.82%	0.00%	17.82%	12.06%	0.00%	12.06%	96%
	200	14.66%	0.00%	14.66%	9.84%	0.00%	9.84%	93%
	300	11.84%	0.00%	11.84%	8.06%	0.00%	8.06%	90%
	400	9.35%	0.00%	9.35%	6.61%	0.00%	6.61%	87%
	500	7.18%	0.00%	7.18%	5.40%	0.00%	5.40%	84%
	600	5.33%	0.00%	5.33%	4.41%	0.00%	4.41%	82%
	700	3.81%	0.00%	3.81%	3.56%	0.00%	3.56%	79%
	800	2.61%	0.00%	2.61%	2.82%	0.00%	2.82%	77%
	900	1.69%	0.00%	1.69%	2.20%	0.00%	2.20%	74%
	1000	1.08%	0.00%	1.08%	1.69%	0.00%	1.69%	72%
	1500	0.13%	0.00%	0.13%	0.37%	0.00%	0.37%	62%
	2000	0.01%	0.00%	0.01%	0.04%	0.00%	0.04%	53%
2040 Scenario 2	0	19.75%	0.00%	19.75%	0.00%	0.00%	0.00%	0%
	100	16.34%	0.00%	16.34%	13.18%	0.00%	13.18%	96%
	200	13.31%	0.00%	13.31%	10.70%	0.00%	10.70%	93%
	300	10.63%	0.00%	10.63%	8.74%	0.00%	8.74%	90%
	400	8.30%	0.00%	8.30%	7.15%	0.00%	7.15%	87%
	500	6.31%	0.00%	6.31%	5.85%	0.00%	5.85%	84%
	600	4.65%	0.00%	4.65%	4.79%	0.00%	4.79%	82%
	700	3.31%	0.00%	3.31%	3.88%	0.00%	3.88%	79%
	800	2.26%	0.00%	2.26%	3.11%	0.00%	3.11%	77%
	900	1.49%	0.00%	1.49%	2.47%	0.00%	2.47%	74%
	1000	0.98%	0.00%	0.98%	1.93%	0.00%	1.93%	72%
	1500	0.16%	0.00%	0.16%	0.52%	0.00%	0.52%	62%
	2000	0.02%	0.00%	0.02%	0.09%	0.00%	0.09%	53%

c. Appendix C

i. Green Hydrogen 2030-2035 and 2040 Analysis

Table 44: LCOHp Analysis 2030-2035 and 2040 including sensitivities

Sensitivity	Gen Year	Electrolyser Capacity (MW)	Grid Connected High RES-E	Offshore Wind Off Grid	System Wide VRES Curtailment	Offshore Wind Dispatch Down	Offshore Wind and Solar PPA
Base Case	2030 MG	10	5.02	5.60	5.76	5.79	5.03
Base Case	2030 MG	20	4.99	5.57	5.65	5.72	5.00
Base Case	2030 MG	30	4.98	5.56	5.63	5.75	4.99
Base Case	2030 MG	40	4.98	5.55	5.62	5.78	4.98
Base Case	2030 MG	50	4.97	5.54	5.61	5.81	4.98
Base Case	2030 MG	60	4.97	5.55	5.61	5.83	4.98
Base Case	2030 MG	70	4.97	5.52	5.62	5.85	4.96
Base Case	2030 MG	80	4.97	5.52	5.64	5.87	4.96
Base Case	2030 MG	90	4.97	5.53	5.65	5.89	4.96
Base Case	2030 MG	100	4.97	5.49	5.67	5.91	4.93
Base Case	2030 MG	200	4.96	5.47	5.77	6.21	4.88
Base Case	2030 MG	300	4.96	5.37	5.83	6.67	4.79
Base Case	2030 MG	400	4.96	5.26	5.88	7.06	4.74
Base Case	2030 MG	500	4.97	5.30	5.92	7.42	4.79
Base Case	2030 MG	1000	4.97	5.52	6.57	9.48	5.02
Base Case	2030 MG	1500	4.95	5.79	7.27	12.46	5.32
Base Case	2030 MG	2000	4.90	6.15	8.01	16.03	5.68
Base Case	2030 S1	10	5.02	5.60	4.25	4.26	5.03
Base Case	2030 S1	20	4.99	5.57	4.17	4.21	5.00
Base Case	2030 S1	30	4.98	5.56	4.15	4.20	4.99

Base Case	2030 S1	40	4.98	5.55	4.14	4.20	4.98
Base Case	2030 S1	50	4.97	5.54	4.13	4.20	4.98
Base Case	2030 S1	60	4.97	5.55	4.13	4.21	4.98
Base Case	2030 S1	70	4.97	5.52	4.13	4.23	4.96
Base Case	2030 S1	80	4.97	5.52	4.14	4.24	4.96
Base Case	2030 S1	90	4.97	5.53	4.14	4.26	4.96
Base Case	2030 S1	100	4.97	5.49	4.14	4.28	4.93
Base Case	2030 S1	200	4.96	5.47	4.16	4.53	4.88
Base Case	2030 S1	300	4.96	5.37	4.17	4.74	4.79
Base Case	2030 S1	400	4.96	5.26	4.19	4.93	4.74
Base Case	2030 S1	500	4.96	5.30	4.20	5.13	4.79
Base Case	2030 S1	1000	4.97	5.52	4.43	6.49	5.02
Base Case	2030 S1	1500	4.96	5.79	4.66	8.52	5.32
Base Case	2030 S1	2000	4.96	6.15	4.87	10.78	5.68
Base Case	2030 S2	10	5.02	5.60	3.85	3.86	5.03
Base Case	2030 S2	20	4.99	5.57	3.79	3.83	5.00
Base Case	2030 S2	30	4.98	5.56	3.77	3.82	4.99
Base Case	2030 S2	40	4.98	5.55	3.76	3.82	4.98
Base Case	2030 S2	50	4.97	5.54	3.76	3.83	4.98
Base Case	2030 S2	60	4.97	5.55	3.75	3.84	4.98
Base Case	2030 S2	70	4.97	5.52	3.76	3.85	4.96
Base Case	2030 S2	80	4.97	5.52	3.76	3.87	4.96
Base Case	2030 S2	90	4.97	5.53	3.76	3.89	4.96
Base Case	2030 S2	100	4.97	5.49	3.76	3.91	4.93
Base Case	2030 S2	200	4.96	5.47	3.78	4.05	4.88
Base Case	2030 S2	300	4.96	5.37	3.79	4.19	4.79
Base Case	2030 S2	400	4.96	5.26	3.80	4.33	4.74

Base Case	2030 S2	500	4.96	5.30	3.81	4.47	4.79
Base Case	2030 S2	1000	4.97	5.52	3.95	5.49	5.02
Base Case	2030 S2	1500	4.97	5.79	4.04	7.11	5.32
Base Case	2030 S2	2000	4.95	6.15	4.15	8.90	5.68
Base Case	2040 S1	10	4.72	5.32	3.96	3.97	4.76
Base Case	2040 S1	20	4.70	5.29	3.89	3.91	4.74
Base Case	2040 S1	30	4.69	5.28	3.86	3.90	4.73
Base Case	2040 S1	40	4.68	5.27	3.85	3.90	4.72
Base Case	2040 S1	50	4.68	5.27	3.85	3.91	4.72
Base Case	2040 S1	60	4.68	5.26	3.84	3.92	4.72
Base Case	2040 S1	70	4.68	5.24	3.84	3.93	4.71
Base Case	2040 S1	80	4.67	5.25	3.84	3.94	4.71
Base Case	2040 S1	90	4.67	5.25	3.84	3.95	4.69
Base Case	2040 S1	100	4.67	5.22	3.84	3.96	4.69
Base Case	2040 S1	200	4.67	5.17	3.85	4.08	4.65
Base Case	2040 S1	300	4.67	5.08	3.86	4.21	4.62
Base Case	2040 S1	400	4.67	4.98	3.88	4.35	4.56
Base Case	2040 S1	500	4.67	4.93	3.89	4.50	4.46
Base Case	2040 S1	1000	4.71	5.13	3.97	5.62	4.54
Base Case	2040 S1	1500	4.71	5.36	4.05	7.44	4.69
Base Case	2040 S1	2000	4.69	5.64	4.13	9.37	4.87
Base Case	2040 S2	10	4.72	5.32	4.10	4.11	4.76
Base Case	2040 S2	20	4.70	5.29	4.03	4.04	4.74
Base Case	2040 S2	30	4.69	5.28	4.00	4.03	4.73
Base Case	2040 S2	40	4.68	5.27	3.99	4.03	4.72
Base Case	2040 S2	50	4.68	5.27	3.98	4.03	4.72
Base Case	2040 S2	60	4.68	5.26	3.98	4.04	4.72

Base Case	2040 S2	70	4.68	5.24	3.98	4.04	4.71
Base Case	2040 S2	80	4.67	5.25	3.97	4.05	4.71
Base Case	2040 S2	90	4.67	5.25	3.97	4.06	4.69
Base Case	2040 S2	100	4.67	5.22	3.97	4.07	4.69
Base Case	2040 S2	200	4.67	5.17	3.98	4.19	4.65
Base Case	2040 S2	300	4.67	5.08	3.99	4.33	4.62
Base Case	2040 S2	400	4.67	4.98	4.00	4.48	4.56
Base Case	2040 S2	500	4.67	4.93	4.01	4.66	4.46
Base Case	2040 S2	1000	4.71	5.13	4.08	5.94	4.54
Base Case	2040 S2	1500	4.71	5.36	4.16	7.93	4.69
Base Case	2040 S2	2000	4.69	5.64	4.25	10.02	4.87
CapEx+25 %	2030 S2	10	5.13	5.71	4.06	4.08	5.14
CapEx+25 %	2030 S2	20	5.10	5.69	4.00	4.04	5.11
CapEx+25 %	2030 S2	30	5.09	5.67	3.98	4.04	5.10
CapEx+25 %	2030 S2	40	5.09	5.67	3.97	4.04	5.10
CapEx+25 %	2030 S2	50	5.08	5.66	3.97	4.05	5.09
CapEx+25 %	2030 S2	60	5.08	5.66	3.97	4.06	5.09
CapEx+25 %	2030 S2	70	5.08	5.64	3.97	4.08	5.07
CapEx+25 %	2030 S2	80	5.08	5.64	3.97	4.09	5.07
CapEx+25 %	2030 S2	90	5.08	5.64	3.97	4.12	5.08

CapEx+25 %	2030 S2	100	5.08	5.61	3.98	4.14	5.05
CapEx+25 %	2030 S2	200	5.08	5.59	4.00	4.30	5.00
CapEx+25 %	2030 S2	300	5.08	5.49	4.01	4.45	4.91
CapEx+25 %	2030 S2	400	5.08	5.38	4.02	4.60	4.86
CapEx+25 %	2030 S2	500	5.08	5.42	4.03	4.76	4.92
CapEx+25 %	2030 S2	1000	5.08	5.66	4.18	5.88	5.17
CapEx+25 %	2030 S2	1500	5.08	5.97	4.28	7.67	5.50
CapEx+25 %	2030 S2	2000	5.06	6.36	4.40	9.65	5.90
CapEx+25 %	2040 S1	10	4.80	5.40	4.14	4.15	4.84
CapEx+25 %	2040 S1	20	4.77	5.37	4.07	4.10	4.81
CapEx+25 %	2040 S1	30	4.76	5.36	4.04	4.09	4.81
CapEx+25 %	2040 S1	40	4.76	5.35	4.03	4.09	4.80
CapEx+25 %	2040 S1	50	4.76	5.35	4.03	4.10	4.79
CapEx+25 %	2040 S1	60	4.75	5.34	4.03	4.11	4.79
CapEx+25 %	2040 S1	70	4.75	5.32	4.02	4.12	4.79

CapEx+25 %	2040 S1	80	4.75	5.33	4.02	4.13	4.79
CapEx+25 %	2040 S1	90	4.75	5.33	4.02	4.14	4.77
CapEx+25 %	2040 S1	100	4.75	5.30	4.02	4.15	4.77
CapEx+25 %	2040 S1	200	4.75	5.25	4.03	4.29	4.74
CapEx+25 %	2040 S1	300	4.75	5.16	4.05	4.42	4.70
CapEx+25 %	2040 S1	400	4.75	5.06	4.07	4.57	4.64
CapEx+25 %	2040 S1	500	4.75	5.01	4.08	4.74	4.54
CapEx+25 %	2040 S1	1000	4.79	5.23	4.17	5.96	4.63
CapEx+25 %	2040 S1	1500	4.79	5.48	4.25	7.93	4.80
CapEx+25 %	2040 S1	2000	4.77	5.78	4.33	10.02	4.99
CapEx+25 %	2040 S2	10	4.80	5.40	4.30	4.31	4.84
CapEx+25 %	2040 S2	20	4.77	5.37	4.22	4.24	4.81
CapEx+25 %	2040 S2	30	4.76	5.36	4.20	4.22	4.81
CapEx+25 %	2040 S2	40	4.76	5.35	4.18	4.22	4.80
CapEx+25 %	2040 S2	50	4.76	5.35	4.18	4.23	4.79

CapEx+25 %	2040 S2	60	4.75	5.34	4.17	4.23	4.79
CapEx+25 %	2040 S2	70	4.75	5.32	4.17	4.24	4.79
CapEx+25 %	2040 S2	80	4.75	5.33	4.17	4.25	4.79
CapEx+25 %	2040 S2	90	4.75	5.33	4.17	4.27	4.77
CapEx+25 %	2040 S2	100	4.75	5.30	4.17	4.28	4.77
CapEx+25 %	2040 S2	200	4.75	5.25	4.17	4.41	4.74
CapEx+25 %	2040 S2	300	4.75	5.16	4.18	4.55	4.70
CapEx+25 %	2040 S2	400	4.75	5.06	4.20	4.72	4.64
CapEx+25 %	2040 S2	500	4.75	5.01	4.21	4.91	4.54
CapEx+25 %	2040 S2	1000	4.79	5.23	4.29	6.30	4.63
CapEx+25 %	2040 S2	1500	4.79	5.48	4.37	8.46	4.80
CapEx+25 %	2040 S2	2000	4.77	5.78	4.47	10.72	4.99
CapEx-25%	2030 S2	10	4.91	5.49	3.63	3.65	4.91
CapEx-25%	2030 S2	20	4.88	5.46	3.57	3.61	4.89
CapEx-25%	2030 S2	30	4.87	5.44	3.56	3.60	4.87
CapEx-25%	2030 S2	40	4.86	5.44	3.55	3.60	4.87
CapEx-25%	2030 S2	50	4.86	5.43	3.54	3.61	4.86
CapEx-25%	2030 S2	60	4.86	5.43	3.54	3.62	4.86

CapEx-25%	2030 S2	70	4.86	5.41	3.54	3.63	4.84
CapEx-25%	2030 S2	80	4.86	5.41	3.54	3.64	4.84
CapEx-25%	2030 S2	90	4.86	5.41	3.54	3.66	4.85
CapEx-25%	2030 S2	100	4.86	5.38	3.55	3.68	4.82
CapEx-25%	2030 S2	200	4.85	5.36	3.56	3.81	4.76
CapEx-25%	2030 S2	300	4.85	5.25	3.57	3.94	4.67
CapEx-25%	2030 S2	400	4.85	5.14	3.58	4.06	4.62
CapEx-25%	2030 S2	500	4.85	5.17	3.59	4.19	4.67
CapEx-25%	2030 S2	1000	4.86	5.37	3.71	5.10	4.88
CapEx-25%	2030 S2	1500	4.86	5.62	3.80	6.55	5.14
CapEx-25%	2030 S2	2000	4.83	5.94	3.90	8.15	5.47
CapEx-25%	2040 S1	10	4.65	5.24	3.78	3.79	4.69
CapEx-25%	2040 S1	20	4.62	5.22	3.70	3.73	4.66
CapEx-25%	2040 S1	30	4.61	5.20	3.68	3.72	4.65
CapEx-25%	2040 S1	40	4.60	5.20	3.67	3.72	4.64
CapEx-25%	2040 S1	50	4.60	5.19	3.66	3.72	4.64
CapEx-25%	2040 S1	60	4.60	5.19	3.66	3.73	4.64
CapEx-25%	2040 S1	70	4.60	5.17	3.66	3.74	4.63
CapEx-25%	2040 S1	80	4.60	5.17	3.66	3.75	4.63
CapEx-25%	2040 S1	90	4.60	5.17	3.66	3.76	4.61
CapEx-25%	2040 S1	100	4.60	5.14	3.66	3.77	4.61
CapEx-25%	2040 S1	200	4.59	5.09	3.66	3.88	4.57
CapEx-25%	2040 S1	300	4.59	5.00	3.68	3.99	4.54
CapEx-25%	2040 S1	400	4.59	4.89	3.69	4.12	4.48
CapEx-25%	2040 S1	500	4.59	4.85	3.71	4.26	4.38
CapEx-25%	2040 S1	1000	4.63	5.03	3.78	5.29	4.44
CapEx-25%	2040 S1	1500	4.63	5.24	3.85	6.95	4.59

CapEx-25%	2040 S1	2000	4.61	5.50	3.92	8.72	4.75
CapEx-25%	2040 S2	10	4.65	5.24	3.91	3.92	4.69
CapEx-25%	2040 S2	20	4.62	5.22	3.83	3.85	4.66
CapEx-25%	2040 S2	30	4.61	5.20	3.81	3.83	4.65
CapEx-25%	2040 S2	40	4.60	5.20	3.80	3.83	4.64
CapEx-25%	2040 S2	50	4.60	5.19	3.79	3.83	4.64
CapEx-25%	2040 S2	60	4.60	5.19	3.79	3.84	4.64
CapEx-25%	2040 S2	70	4.60	5.17	3.78	3.84	4.63
CapEx-25%	2040 S2	80	4.60	5.17	3.78	3.85	4.63
CapEx-25%	2040 S2	90	4.60	5.17	3.78	3.86	4.61
CapEx-25%	2040 S2	100	4.60	5.14	3.78	3.87	4.61
CapEx-25%	2040 S2	200	4.59	5.09	3.78	3.98	4.57
CapEx-25%	2040 S2	300	4.59	5.00	3.79	4.10	4.54
CapEx-25%	2040 S2	400	4.59	4.89	3.80	4.24	4.48
CapEx-25%	2040 S2	500	4.59	4.85	3.81	4.40	4.38
CapEx-25%	2040 S2	1000	4.63	5.03	3.88	5.58	4.44
CapEx-25%	2040 S2	1500	4.63	5.24	3.95	7.40	4.59
CapEx-25%	2040 S2	2000	4.61	5.50	4.03	9.31	4.75
Elec+50%	2030 S2	10	6.97	7.84	4.69	4.70	6.98
Elec+50%	2030 S2	20	6.94	7.81	4.63	4.67	6.95
Elec+50%	2030 S2	30	6.93	7.79	4.61	4.66	6.93
Elec+50%	2030 S2	40	6.93	7.79	4.60	4.66	6.93
Elec+50%	2030 S2	50	6.93	7.77	4.59	4.67	6.92
Elec+50%	2030 S2	60	6.93	7.77	4.59	4.68	6.92
Elec+50%	2030 S2	70	6.92	7.74	4.59	4.69	6.89
Elec+50%	2030 S2	80	6.92	7.74	4.60	4.71	6.89
Elec+50%	2030 S2	90	6.92	7.74	4.60	4.73	6.89

Elec+50%	2030 S2	100	6.92	7.69	4.60	4.75	6.85
Elec+50%	2030 S2	200	6.92	7.65	4.62	4.89	6.77
Elec+50%	2030 S2	300	6.92	7.49	4.63	5.03	6.62
Elec+50%	2030 S2	400	6.92	7.32	4.64	5.17	6.54
Elec+50%	2030 S2	500	6.92	7.36	4.65	5.31	6.59
Elec+50%	2030 S2	1000	6.92	7.58	4.78	6.33	6.82
Elec+50%	2030 S2	1500	6.92	7.85	4.88	7.95	7.12
Elec+50%	2030 S2	2000	6.88	8.21	4.99	9.74	7.48
Elec+50%	2040 S1	10	6.61	7.50	4.76	4.78	6.66
Elec+50%	2040 S1	20	6.58	7.47	4.69	4.71	6.63
Elec+50%	2040 S1	30	6.57	7.45	4.67	4.71	6.63
Elec+50%	2040 S1	40	6.57	7.44	4.66	4.71	6.61
Elec+50%	2040 S1	50	6.56	7.44	4.65	4.71	6.61
Elec+50%	2040 S1	60	6.56	7.43	4.65	4.72	6.61
Elec+50%	2040 S1	70	6.56	7.40	4.64	4.73	6.60
Elec+50%	2040 S1	80	6.56	7.40	4.64	4.74	6.60
Elec+50%	2040 S1	90	6.56	7.40	4.64	4.75	6.57
Elec+50%	2040 S1	100	6.56	7.36	4.64	4.76	6.57
Elec+50%	2040 S1	200	6.55	7.28	4.65	4.89	6.51
Elec+50%	2040 S1	300	6.55	7.15	4.67	5.01	6.45
Elec+50%	2040 S1	400	6.55	6.98	4.68	5.15	6.36
Elec+50%	2040 S1	500	6.55	6.91	4.70	5.30	6.21
Elec+50%	2040 S1	1000	6.61	7.10	4.77	6.43	6.26
Elec+50%	2040 S1	1500	6.60	7.33	4.85	8.25	6.41
Elec+50%	2040 S1	2000	6.57	7.62	4.93	10.17	6.59
Elec+50%	2040 S2	10	6.61	7.50	4.91	4.92	6.66
Elec+50%	2040 S2	20	6.58	7.47	4.83	4.85	6.63

Elec+50%	2040 S2	30	6.57	7.45	4.81	4.83	6.63
Elec+50%	2040 S2	40	6.57	7.44	4.79	4.83	6.61
Elec+50%	2040 S2	50	6.56	7.44	4.79	4.83	6.61
Elec+50%	2040 S2	60	6.56	7.43	4.78	4.84	6.61
Elec+50%	2040 S2	70	6.56	7.40	4.78	4.85	6.60
Elec+50%	2040 S2	80	6.56	7.40	4.78	4.86	6.60
Elec+50%	2040 S2	90	6.56	7.40	4.78	4.87	6.57
Elec+50%	2040 S2	100	6.56	7.36	4.78	4.88	6.57
Elec+50%	2040 S2	200	6.55	7.28	4.78	5.00	6.51
Elec+50%	2040 S2	300	6.55	7.15	4.79	5.13	6.45
Elec+50%	2040 S2	400	6.55	6.98	4.80	5.28	6.36
Elec+50%	2040 S2	500	6.55	6.91	4.81	5.46	6.21
Elec+50%	2040 S2	1000	6.61	7.10	4.89	6.74	6.26
Elec+50%	2040 S2	1500	6.60	7.33	4.97	8.73	6.41
Elec+50%	2040 S2	2000	6.57	7.62	5.05	10.82	6.59
Elec-50%	2030 S2	10	3.06	3.36	3.01	3.02	3.07
Elec-50%	2030 S2	20	3.04	3.34	2.95	2.99	3.05
Elec-50%	2030 S2	30	3.03	3.32	2.93	2.98	3.04
Elec-50%	2030 S2	40	3.02	3.32	2.92	2.98	3.04
Elec-50%	2030 S2	50	3.02	3.32	2.92	2.99	3.03
Elec-50%	2030 S2	60	3.02	3.32	2.91	3.00	3.03
Elec-50%	2030 S2	70	3.01	3.30	2.92	3.02	3.02
Elec-50%	2030 S2	80	3.01	3.31	2.92	3.03	3.03
Elec-50%	2030 S2	90	3.01	3.31	2.92	3.05	3.03
Elec-50%	2030 S2	100	3.01	3.29	2.92	3.07	3.01
Elec-50%	2030 S2	200	3.01	3.30	2.94	3.21	3.00
Elec-50%	2030 S2	300	3.01	3.25	2.95	3.35	2.96

Elec-50%	2030 S2	400	3.01	3.20	2.96	3.49	2.95
Elec-50%	2030 S2	500	3.01	3.23	2.97	3.64	2.99
Elec-50%	2030 S2	1000	3.02	3.46	3.11	4.65	3.23
Elec-50%	2030 S2	1500	3.02	3.73	3.20	6.27	3.52
Elec-50%	2030 S2	2000	3.02	4.09	3.31	8.06	3.89
Elec-50%	2040 S1	10	2.84	3.15	3.15	3.17	2.87
Elec-50%	2040 S1	20	2.81	3.12	3.08	3.11	2.84
Elec-50%	2040 S1	30	2.80	3.11	3.06	3.10	2.83
Elec-50%	2040 S1	40	2.80	3.10	3.05	3.10	2.82
Elec-50%	2040 S1	50	2.79	3.10	3.04	3.11	2.82
Elec-50%	2040 S1	60	2.79	3.10	3.04	3.11	2.82
Elec-50%	2040 S1	70	2.79	3.09	3.04	3.12	2.82
Elec-50%	2040 S1	80	2.79	3.09	3.04	3.13	2.82
Elec-50%	2040 S1	90	2.79	3.09	3.04	3.15	2.81
Elec-50%	2040 S1	100	2.79	3.08	3.04	3.16	2.81
Elec-50%	2040 S1	200	2.79	3.06	3.05	3.28	2.80
Elec-50%	2040 S1	300	2.79	3.02	3.06	3.40	2.78
Elec-50%	2040 S1	400	2.79	2.97	3.08	3.54	2.76
Elec-50%	2040 S1	500	2.79	2.96	3.09	3.69	2.71
Elec-50%	2040 S1	1000	2.81	3.15	3.17	4.82	2.81
Elec-50%	2040 S1	1500	2.81	3.39	3.24	6.64	2.97
Elec-50%	2040 S1	2000	2.81	3.67	3.32	8.57	3.15
Elec-50%	2040 S2	10	2.84	3.15	3.30	3.31	2.87
Elec-50%	2040 S2	20	2.81	3.12	3.22	3.24	2.84
Elec-50%	2040 S2	30	2.80	3.11	3.20	3.22	2.83
Elec-50%	2040 S2	40	2.80	3.10	3.19	3.22	2.82
Elec-50%	2040 S2	50	2.79	3.10	3.18	3.23	2.82

Elec-50%	2040 S2	60	2.79	3.10	3.18	3.23	2.82
Elec-50%	2040 S2	70	2.79	3.09	3.17	3.24	2.82
Elec-50%	2040 S2	80	2.79	3.09	3.17	3.25	2.82
Elec-50%	2040 S2	90	2.79	3.09	3.17	3.26	2.81
Elec-50%	2040 S2	100	2.79	3.08	3.17	3.27	2.81
Elec-50%	2040 S2	200	2.79	3.06	3.17	3.39	2.80
Elec-50%	2040 S2	300	2.79	3.02	3.18	3.52	2.78
Elec-50%	2040 S2	400	2.79	2.97	3.20	3.68	2.76
Elec-50%	2040 S2	500	2.79	2.96	3.21	3.85	2.71
Elec-50%	2040 S2	1000	2.81	3.15	3.28	5.13	2.81
Elec-50%	2040 S2	1500	2.81	3.39	3.36	7.13	2.97
Elec-50%	2040 S2	2000	2.81	3.67	3.45	9.21	3.15

d. Appendix D

i. Dublin Existing and Future Gas Generation

Table 45: Dublin Existing and Future Gas Generation, MullanGrid Database Q1 2023

Project Name	Status	Technology	MEC (MW)
Dublin Bay Power	Connected	Gas	415
Huntstown (2)	Connected	Gas	412
Huntstown (1)	Connected	Gas	352
Shellybanks Poolbeg (3)	Connected	Gas/HFO	242
North Wall CC	Connected	Gas/DO	118
North Wall (5)	Connected	Gas/DO	109
Shellybanks Poolbeg (1)	Connected	Gas/HFO	109
Shellybanks Poolbeg (2)	Connected	Gas/HFO	109
North Wall 4	Contracted	OCGT	120
Ballymakaily	Contracted	OCGT	115.2
Ringsend Flexgen	Contracted	OCGT	75
Corduff Flexible Generation	Contracted	OCGT	70
Poolbeg Flexgen	Contracted	OCGT	70
Echelon Dub10	ECP-2.1 Batch (A)	Gas	80
Poolbeg CCGT	ECP-2.1 Batch (A)	CCGT	16
Kilshane Energy Power Plant	Queued for ECP	OCGT	293
Total			**2,705**

e. Appendix E

i. Dublin Connected Electricity Generation

Table 46: Dublin Connected Generation, MullanGrid Database Q1 2023

Project Name	Technology	MEC	Associated Node
Gardnershill FGS	Battery	8.5	Stephenstown
Kylemore battery Energy Storage System	Battery	30	Inchicore
Huntstown Renewable Bioenergy Plant	Biogas	4	Poppintree
Tesco Cabra CHP	Biomass	0.2	Cabra
Dublin Waste to Energy Facility	Biomass / WtE	72	Ringsend
Arthurstown LFG & Diesel	Diesel	4.778	Kilteel
Data Electronics Services Ltd	Diesel	4	College Park
GE Super Abrasives (1)	Diesel	3.75	Kilmore
GE Super Abrasives (2)	Diesel	2.75	Kilmore
Pfizer Grange Castle DSO	Diesel	4	Grange Castle
Dublin Bay Power	Gas	415	Irishtown
Huntstown (1)	Gas	352	Huntstown
Huntstown (2)	Gas	412	Corduff
North Wall (5)	Gas/DO	109	North Wall
North Wall CC	Gas/DO	118	North Wall
Shellybanks Poolbeg (1)	Gas/HFO	109	Shellybanks
Shellybanks Poolbeg (2)	Gas/HFO	109	Shellybanks
Shellybanks Poolbeg (3)	Gas/HFO	242	Shellybanks
Arthurstown LFG & Diesel	LFG	4.992	Kilteel
Balleally LFG (1)	LFG	4.88	Glasmore
Ballyogan LFG (1)	LFG	1.955	Carrickmines
Dunsink LFG (1)	LFG	5	Finglas
Friarstown Landfill	LFG	1	Cookstown
Dublin Civic Offices CHP (1)	Nat. Gas	0.922	Ringsend
Elm Park Development 3	Nat. Gas	0.22	Blackrock

Guinness	Nat. Gas	8.075	Inchicore
Keelings CHP	Nat. Gas	1.7	Glasmore
Kilbush Nurseries CHP	Nat. Gas	1.6	Glasmore
Mater Hospital CHP (1)	Nat. Gas	1.5	Finglas
University College Dublin	Nat. Gas	1	Blackrock
Shackelton & Sons Hydro (1)	Small Hydro	0.075	Grange Castle
Woollen Mills	Small Hydro	0.104	Grange Castle
Gallanstown Solar	Solar	119	Gallanstown
Country Crest	Wind	0.5	Glasmore
Donaghmede Fr Collins Park	Wind	0.25	Grange (DR)
Shalvey Poultry WT	Wind	0.017	Shankill
Tesco Donabate	Wind	0.499	Glasmore