National Heat Study

Electricity Infrastructure

Costs for Scenario Modelling of Ireland's Heat Sector

seai SUSTAINABLE ENERGY AUTHORITY OF IRELAND

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Report 3 of the National Heat Study

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The National Heat Study and associated reports were commissioned by a project team across the SEAI Research and Policy Insights Directorate and developed with the assistance of Element Energy and Ricardo Energy and Environment.

Disclaimer

Sustainable Energy Authority of Ireland

SEAI is Ireland's national energy authority investing in, and delivering, appropriate, effective and sustainable solutions to help Ireland's transition to a clean energy future. We work with the public, businesses, communities and the Government to achieve this, through expertise, funding, educational programmes, policy advice, research and the development of new technologies.

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- ESB Networks
- EirGrid

This acknowledgement does not imply endorsement by the stakeholders listed, and this report is solely the work of Ricardo Energy and Environment, Element Energy and the Sustainable Energy Authority of Ireland.

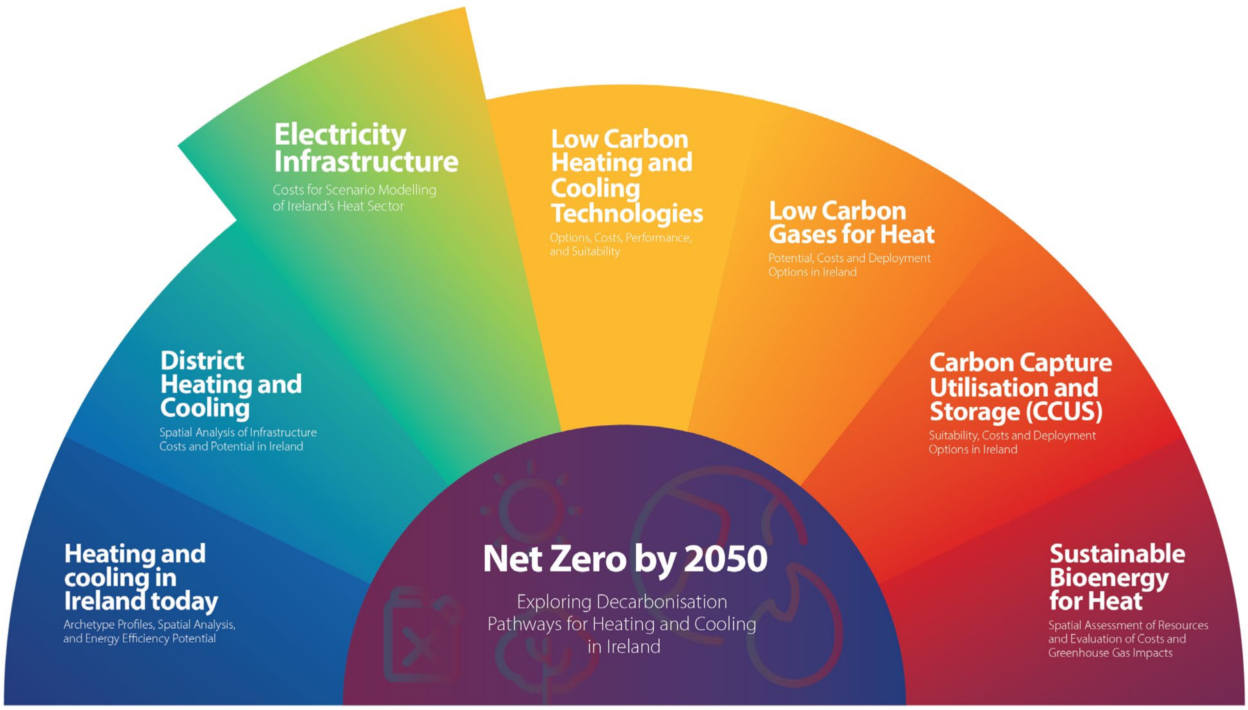
Contents

Introduction

Ireland's 2021 Climate Action and Low Carbon Development (Amendment) Act commits Ireland to reducing greenhouse gas emissions by 51% by 2030 and to achieving economy-wide carbon neutrality by 2050. This requires immediate emissions reductions in every sector. Energy used for heating and cooling accounts for 24% of Ireland's greenhouse gas emissions, but the current pace of decarbonisation falls short of the cuts required. Almost every sector of Ireland's economy uses heat energy, and decarbonisation efforts will need to be implemented by industry, businesses and households. This requires a comprehensive, robust and actionable evidence base, upon which policy makers and other stakeholders can use to make decisions.

To provide this evidence base, the Sustainable Energy Authority of Ireland (SEAI) commissioned Element Energy and Ricardo Energy and Environment to work with SEAI on the National Heat Study. The study evaluates the costs and benefits of various pathways that reach net zero by 2050. We based the evaluation on a comprehensive understanding of heating and cooling demand in Ireland and the deployment costs, potential and suitability of technologies, infrastructure and fuels to reduce emissions.

We have separated the insights and analysis from the study into eight reports (outlined in *Figure 1)*[1]. These reports provide a rigorous and comprehensive analysis of options for decarbonisation of heating and cooling in Ireland up to 2050. The findings support Ireland's second submission to the EU of a 'national comprehensive assessment of the potential for efficient heating and cooling', as required by Article 14 of the Energy Efficiency Directive[2]. There are seven major technical reports, each focusing on topics that form the overall analysis. The concluding report is *Net Zero by 2050*[3], which outlines the study's key insights across scenarios that achieve net-zero emissions from heating and cooling.



[1] All reports and supporting materials published as part of the National Heat Study are available from www.seai.ie/NationalHeatStudy/

[2] SEAI, 'Comprehensive Assessment of the Potential for Efficient Heating and Cooling in Ireland, report to the European Commission'. 2021 [Online]. Available: https://www.gov.ie/en/publication/e4332-introductory-text-for-publication-of-the-national-comprehensive-assessment-on-govie/#.

[3] SEAI, 'Net-Zero by 2050: Exploring Decarbonisation Pathways for Heating and Cooling in Ireland. 2022 [Online]. Available: www.seai.ie/publications/Net-Zero-by-2050.pdf.

Figure 1: Framework of reports

In this report, we set out to develop a simple and transparent framework to quantify the costs associated with maintaining and upgrading the electricity network in Ireland over the period to 2050, and the expected impact on these costs of changes in electricity demand and generation. In the report, we first produce an assessment of the electricity network costs in a 'base year' (set as 2020). This includes breaking down the total network costs into the underlying cost components. We then develop a methodology to project these cost components into the future, based on assumptions of how the costs are likely to depend on factors such as changes in electricity demand and generation, and changes in the size of the network asset base. Finally, we provide a worked example of the cost projection methodology, using scenarios from the literature.

We gathered data to inform this exercise through a comprehensive review of the literature, primarily the publications from the Commission for Regulation of Utilities (CRU) associated with the Price Review (PR) process, and a series of consultations with EirGrid and ESB Networks.

This is the first time, to our knowledge, that the change in cost associated with the electricity network due to electrification of heat and transport in Ireland has been modelled in detail using a bottom-up approach based on a projected increase in peak demand and generation capacity. This technical report describes the approach taken and assumptions made, the findings from the analysis, and the key uncertainties and limitations of the method used.

Base year electricity network costs

This section describes our approach to deriving a set of base year electricity network costs for 2020,[4] covering the electricity transmission and distribution networks.

Data sources

Responsibility for the operation and management of Ireland's electricity network is split into three distinct roles:

- **Transmission System Operator (TSO) - EirGrid.** The TSO manages the physical operation of the transmission system in real time, including: the procurement of system services; the planning of extensions and reinforcements to the transmission network, and the associated interaction with the Transmission Asset Owner (TAO); and the offering of rights to connect to and make use of the transmission system.
- **Transmission Asset Owner (TAO) - ESB Networks.** The TAO owns and maintains the transmission network, and builds additional transmission infrastructure or replaces assets at their end of life as directed by the TSO.
- **Distribution System Operator and Asset Owner (DSO/DAO) - ESB Networks.** The DAO/DSO manages the physical operation of the distribution system; the planning and delivery of extensions, renewal and reinforcement of the distribution network; maintenance, repair and supply restoration of the existing network; and the offering of rights to connect to and make use of the distribution system.

We engaged with EirGrid and ESB Networks to identify the best sources of data available and to obtain guidance on the approach to modelling the capital and operating costs associated with the electricity networks.

The key source of cost data identified for this purpose is the set of reports published by CRU, the independent energy and water regulator in Ireland, relating to the PR process. The primary mechanism for ensuring the delivery of appropriate investment in the transmission and distribution network is through its PR process. Every five years, CRU carries out a PR, including an extensive consultation process with the

[4] Note that the derived base year costs correspond to the year including the last six months of 2020 and the first six months of 2021, but are taken to represent the calendar year of 2020 for simplicity of application in the wider National Heat Study modelling.

network companies, and sets out the CRU's decision on the network companies' revenues for that PR period. CRU also examines the cost and performance over the previous five years by comparing the projected costs of the preceding PR period with the actual costs. As such, the PR documents provide a comprehensive view of the costs incurred for each of the TSO, TAO and DSO. For this analysis, we have taken cost data relating to the CRU Price Review 4 (PR4) period (2016-2020), which is based on historical expenditure and the Price Review 5 (PR5) period (2021-2025) which is based on future projections. We have constructed the base year costs to reflect the average annual cost across the PR4 and PR5 Price Review periods, where possible, to reduce the impact of short-term variations in the costs from year to year, such as 'catch up' costs incurring in some years to address load growth in earlier years. We took the average cost across PR4 and PR5 as the base year cost for the DSO and TSO; for the TAO, we developed the base year cost on PR5 only due to data availability (see below).

Table 1 summarises the sources used for the cost data analysis. For PR5 projections, we extracted costs for the TSO, DSO and TAO from the relevant Revenue Model. For PR4, we took cost data from the PR5 documents that reviewed historical PR4 projections with PR4 actual costs.

Table 1: Base year cost data sources

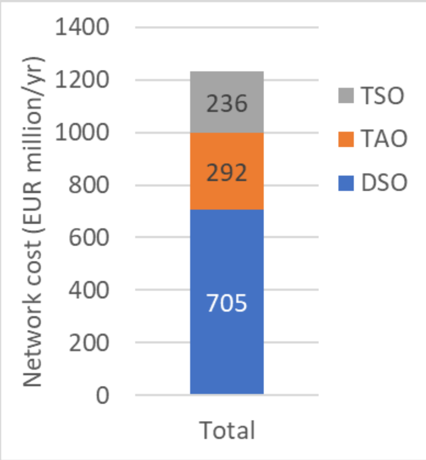
Source	Data extracted
CRU20157 DSO Revenue Model [1]	Projected PR5 cost data for the DSO
CRU20077 Distribution System Operator DSO Revenue for 2021-2025 [2]	Actual PR4 cost data for the DSO
CRU20156 TAO Revenue Model [3]	Projected PR5 cost data for the TAO
CRU20076 TSO and TAO Transmissions Revenue for 2021-2025 [4]	Actual PR4 cost data for the TSO and TAO
CRU20158 TSO Revenue Model [5]	Projected PR5 cost data for the TSO

Our review of the literature and engagement with ESB Networks and EirGrid also sought data sources that could provide a spatial element to the modelling of network costs, to understand whether and how the cost of maintaining and upgrading the networks varies significantly between different regions across Ireland. However, we did not identify any spatially resolved data. Therefore, we undertook the cost analysis using datasets which apply at the national level.

Results

Table 8, *Table 9* and *Table 10* in the Appendix present a detailed breakdown of the DSO, TAO and TSO costs respectively for PR4 and PR5 included within the scope of this analysis. We summarise the resulting base year cost in *Figure 2*, which amounts to €1,234 million per year, with €705 million associated with the DSO, € 292 million with the TAO and €236 million with the TSO.

Figure 2: Base year electricity network cost (2020)



We developed the electricity network cost in this work to be integrated into the wider modelling framework of the NEMF and included within the system-wide cost-benefit analysis of the future energy scenarios.

The infrastructure module of the NEMF captures the network cost as a component of the electricity unit cost to the end user, in cents/kWh. We have therefore translated the base year network cost into a cost per unit of electricity demand, in cents/kWh, for application within the NEMF. We will use this in the NEMF to derive the future network cost under various scenarios, according to the projection methodology described in the next section. *Table 2* summarises the data sources used for the annual electricity demand, and *Table 3* summarises the resulting network costs per unit of electricity demand.

Table 2: Base year electricity demand data sources

Source	Data extracted
CRU, Consultancy Support for Electricity Distribution Revenue Controls (2016-2025), Price Review 4 and 5 DSO Opex and Capex (2020) [6] [*Figures 3-17*]	Annual electricity demand associated with the DSO in PR4
EirGrid, System and Renewable Data Summary Report [7]	Annual electricity demand associated with the TAO and TSO in PR4
CRU20157 DSO Revenue Model [1]	Annual electricity demand associated with the DSO in PR5
CRU20158 TSO Revenue Model [5]	Annual electricity demand associated with the TAO and TSO in PR5

Table 3: Base year electricity network cost per unit of electricity demand

Category	Base year annual network cost (€ million/yr)	Base year annual electricity demand (TWh/yr)	Base year network cost per unit of electricity demand (cents/kWh)
DSO	705	26.0	2.7
TAO	292	32.9	0.9
TSO	236	30.4	0.8
Total	**1,234**		**4.4**

Future projections for electricity network costs

The scenarios under consideration in the National Heat Study cover a wide range of future energy system pathways, all compatible with net-zero carbon by 2050 (except for the baseline scenario). The scenarios include those with varying levels of electrification of heating and other end uses, and a range of electricity generation mixes, all with high levels of variable renewable generation, in some cases combined with thermal generation accompanied by carbon capture, utilisation and storage. Under some of these scenarios, the electricity networks need to meet a significantly larger peak demand and enable the supply of a substantially increased generation capacity.

The analysis described in this report aims to capture the impact of these future requirements on the cost of operating and upgrading the electricity networks under any given future scenario.

We considered some factors when capturing the evolution of the network costs as realistically and accurately as possible within a simple and transparent framework. First, the peak demand that the networks need to serve may not increase in line with annual demand; for example, due to the increasing share of electricity demand associated with heating, which is highly seasonal. This could lead to a more 'peaky' electricity demand profile, where peak load increases over time more quickly than annual demand. Conversely, it is possible that smarter operation of the electricity system, with greater flexibility on the demand side, could lead to the peak load increasing more slowly than annual demand. Each of these cases is in the wider National Heat Study, so we aimed to capture the impact of either of these outcomes on the network costs within the framework developed here. Second, an increasing share of variable renewable generation on the system may impact the cost of operating and upgrading the networks, for example if the increase in renewables leads to greater spatial distribution of energy generation, requiring additional network investment. We also aimed to capture the impact of this factor within our framework.

We therefore separated the electricity network costs into three categories:

- **Fixed costs** we assume do not depend on the peak load or generation capacity.
- **Load-related costs** we assume will increase in line with increasing peak load.
- **Generation-related costs** we assume will increase in line with increasing generation capacity.

Allocation of fixed, load-related and generation-related costs

We have assigned the components of the base year costs associated with the DSO, TAO and TSO to these three cost categories, within the constraints of data granularity. Our approach to this allocation of the costs incorporates guidance provided by ESB Networks and EirGrid, which *Table 4* explains in more detail.

Table 4: Summary of assumptions on projections of cost components

Network stakeholder	Cost category	Summary of assumptions on cost projection
DSO	Operating expenditure (opex)	• We treat all opex as a fixed cost that does not increase in line with either load growth or generation capacity. These costs will not vary with different levels of electricity demand, and therefore will not vary with different levels of deployment of electrical heating technologies in particular. • Certain operating cost items are, however, likely to increase as the size of the asset base increases. This includes planned maintenance, fault maintenance and network rates, which we assume will increase by 2% each five-year PR period. These costs account for approximately €865 million of the forecast PR5 spend, corresponding to around 53% of all opex. • We assume all other opex stays constant over time.

Network stakeholder	Cost category	Summary of assumptions on cost projection
	Capital expenditure (capex)	• We treat capex as a mix of fixed, load-related and generation-related costs. • We base capital costs associated with network renewal on estimates provided directly by ESB Networks, with these costs increasing from approximately €440 million in PR5 to €585 million in PR6 and €780 million in PR7, staying constant beyond that. We assume that the network renewal costs are fixed, in that they do not vary with load growth or generation capacity (but do increase over time as noted above). Network renewal costs correspond to approximately 18% of the capex forecast in PR5. • The only cost component explicitly associated with the addition of new generation capacity is the cost of generation connections, which we treat as generation-related costs and assume scale in line with generation capacity connected at the distribution level. Generation connection costs correspond to approximately 8% of the capex forecast in PR5. • We assume that all costs relating to load-related capex, new business and re-inforcements (except for generation connections as noted above) are load-related costs and scale in line with load growth. These costs correspond to approximately 50% of the capex forecast in PR5. • We assume all other capex stays constant over time.
TAO	Operating expenditure (opex)	• We treat all opex as a fixed cost that does not increase in line with either load growth or generation capacity. • We assume all opex stays constant over time.
	Capital expenditure (capex)	• No TAO costs are explicitly associated with the addition of new generation capacity, and so we treat TAO costs as a mix of fixed- and load-related costs, not generation-related. • Capital costs associated with system reinforcements and new connections are treated as load-related, and assumed to increase in line with load growth. These costs correspond to 40% of the capital costs forecast for PR5. • We assume all other capex stays constant over time.
TSO	Operating expenditure (opex)	• We treat all opex as a fixed cost that does not increase in line with either load growth or generation capacity. • We assume all opex stays constant over time.
	Capital expenditure (capex)	• No TSO costs are explicitly associated with the addition of new generation capacity, and so we treat TSO costs as a mix of fixed and load-related costs, not generation-related. • We treat capital costs associated with network capex as load-related, assumed to increase in line with load growth. These costs correspond to 54% of the capital costs forecast for PR5. • We assume all other capex stays constant over time.

Results

We detail the resulting cost projections in *Table 8*, *Table 9* and *Table 10* in the Appendix.

Table 5 and *Figure 3* below summarise the share of the base year costs that we have allocated to the fixed, load-related and generation-related cost categories as described in *Table 4*. *Figure 3* shows that a majority of the costs (€894 million, 72%) are fixed costs, with load-related costs making up 25% of the total, and generation-related costs 3%. We note that the share of costs treated as generation-related costs is limited by the cost breakdown's granularity – the only cost component explicitly associated with the addition of new generation capacity is the cost of generation connections (DSO category), as described in *Table 4*.

Table 5: Allocation of base year electricity network costs to fixed, load-related and generation-related cost categories in units of € million (brackets show share of total electricity network costs)

Category	Fixed	Load-related	Generation-related	Total
DSO	471 (38%)	202 (16%)	32 (3%)	**705 (57%)**
TAO	202 (16%)	90 (7%)	0 (0%)	**292 (24%)**
TSO	221 (18%)	16 (1%)	0 (0%)	**236 (19%)**
Total	**894 (72%)**	**307 (25%)**	**32 (3%)**	**1,234 (100%)**

Figure 3: Full breakdown of base year electricity network costs

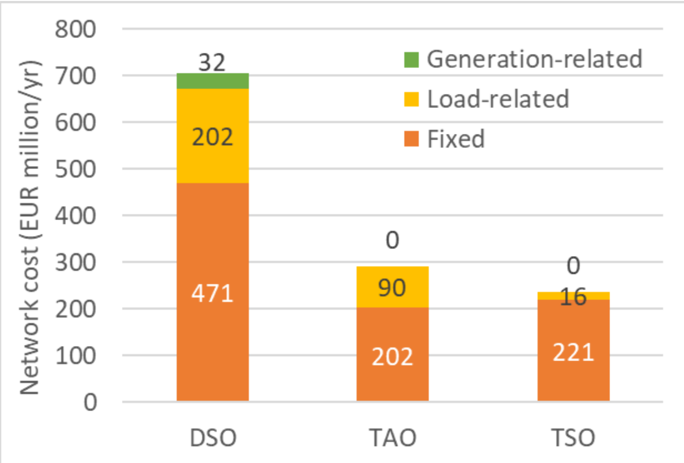


Table 6 presents the equivalent breakdown of the base year costs in terms of the cost per unit of electricity demand. This analysis finds that fixed costs correspond to 3.2 cents/kWh, with load-related costs contributing 1.1 cents/kWh and generation-related costs 0.1 cents/kWh.

Table 6: Base year network costs expressed per unit of electricity demand in cents/kWh

Category	Fixed	Load-related	Generation-related	Total
DSO	1.8	0.8	0.1	**2.7**
TAO	0.6	0.3	0.0	**0.9**
TSO	0.7	0.1	0.0	**0.8**
Total	**3.2**	**1.1**	**0.1**	**4.4**

Worked example and discussion of findings

The load-related and generation-related costs estimated for PR6 onwards will, within the framework set out above, vary according to deployment of electrical heating technologies in line with the change in load and generation capacity on the electricity network. To illustrate the application of the framework for network cost projections presented in this report, we present a worked example using scenarios taken from the literature, from EirGrid's Tomorrow's Energy Scenarios 2019 Ireland [8]. We focus on the Centralised Energy and Coordinated Action scenarios in that publication.

We derive the electricity network costs included in the scenarios developed as part of the National Heat Study, by using our own modelled estimates of the peak electrical load and generation capacity using the NEMF. We have presented the outputs of the National Heat Study scenario modelling in a separate report (*Net Zero by 2050*).

Data sources

The Tomorrow's Energy Scenarios publication contains, for each scenario, the following key metrics which we use in the worked example shown below:

- Peak demand (GW) (for 2020-2040)
- Generation capacity (GW) (for 2025-2040)
- Electricity demand (TWh) (for 2020-2040)

The peak demand and electricity demand relate to the transmission network. In this worked example, we assume that the corresponding metrics for the distribution network scale in the same way over time. The generation capacity, taken from Tomorrow's Energy Scenarios for 2025-2040 and from EirGrid's All Island Ten Year Transmission Forecast Statement 2019 [9] for 2020,[5] represents the total generation capacity connected to both the transmission and distribution networks. In our calculation of the projected electricity network costs, we need to separate the generation capacity connected to the distribution network from the capacity connected to the transmission network. We derived the share of the total generation capacity that is distribution-connected from two further sources. We took the distribution-connected share of generation capacity in 2020 from EirGrid's All Island Ten Year Transmission Forecast Statement 2019 (Table 4-1), as 2.2 GW of the total 12.2 GW of generation capacity. We estimated the distribution-connected share of generation capacity added in future years based on the EirGrid/SONI Annual Renewable Energy Constraint and Curtailment Report 2019 [10]. Table 1 in that publication provides the average distribution-connected share of wind generation during 2011-2019 as 53%. Here, we make the simplifying assumption that 53% of the generation capacity above that installed in 2020 is distribution-connected, besides the 2.2 GW of distribution-connected generation in 2020, since we do not detail the nature of retiring generation capacity in this example.

The resulting metrics for the Centralised Energy and Coordinated Action scenarios are in *Figure 4* and *Figure 5*.

[5] It can be seen that the generation capacity in *Figure 4* falls from 2020 to 2025. We assume this is related to the retirement of capacity in that period.

Figure 4: Key metrics derived for the Centralised Energy scenario

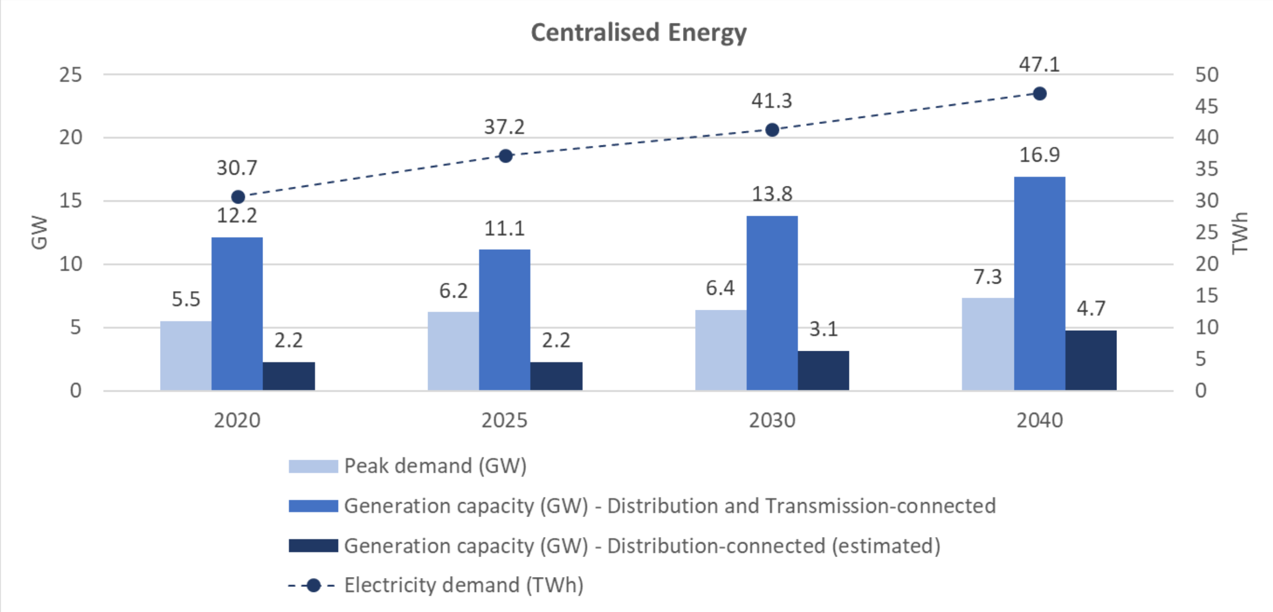
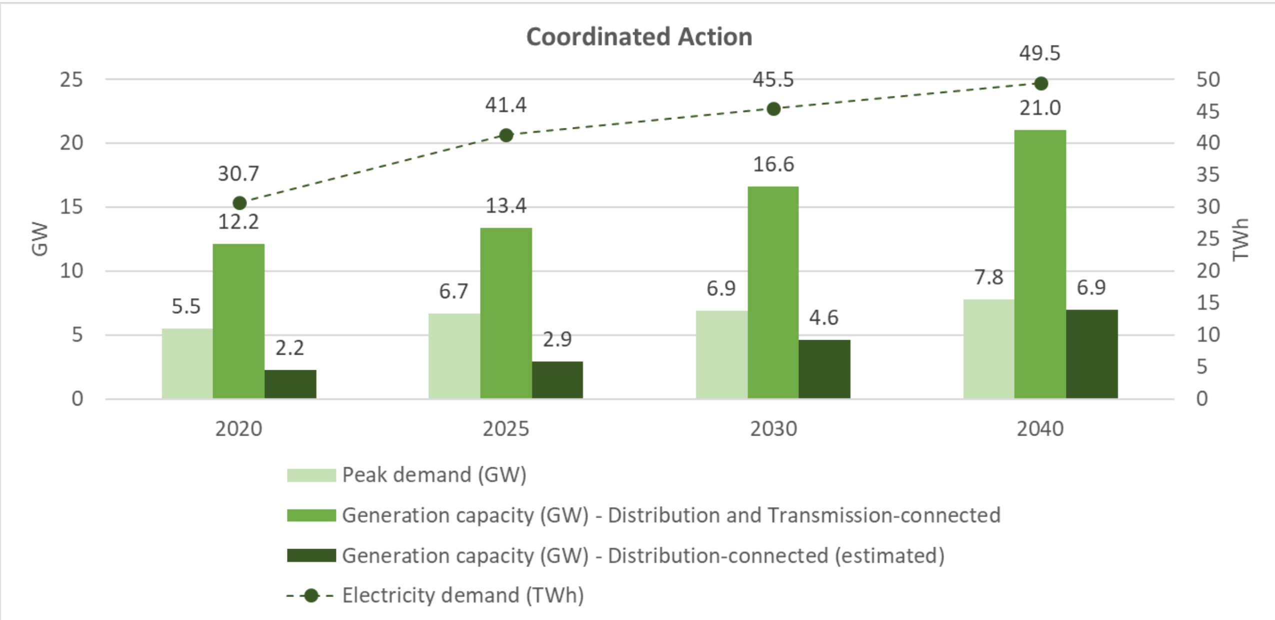


Figure 5: Key metrics derived for the Coordinated Action scenario



Results and discussion

Table 7 shows the future network costs derived by applying the framework developed in this study to the key metrics for the two scenarios. *Figure 6* and *Figure 7* present the costs graphically. As expected, given the increasing peak demand and the increasing generation capacity and the increasing fixed costs as described in *Table 4*, the network costs increase substantially in both scenarios, from €1,234 million in 2020 to €1,489-1,538 million in 2030 and €1,578-1,638 million in 2040. This represents a 28-33% increase between 2020 and 2040, associated with a significant investment in additional capacity to meet peak demand and accommodate additional generation capacity, and to operate and maintain an increasing asset base.

Table 7: Network costs derived by applying the framework developed in this study to scenarios from EirGrid's Tomorrow's Energy Scenarios 2019

Cost category	Annual network costs (€ million/yr)							
	Centralised Energy				Coordinated Action			
	2020	2025	2030	2040	2020	2025	2030	2040
DSO	705	804	876	948	705	832	916	998
Fixed	471	544	596	611	471	544	596	611
Load-related	202	227	235	268	202	246	253	286
Generation-related	32	32	45	69	32	42	67	101
TAO	292	304	307	322	292	312	315	330
Fixed	202	202	202	202	202	202	202	202
Load-related	90	101	105	119	90	110	113	128
Generation-related	0	0	0	0	0	0	0	0
TSO	236	292	305	308	236	293	307	309
Fixed	221	274	287	287	221	274	287	287
Load-related	16	18	18	21	16	19	20	22
Generation-related	0	0	0	0	0	0	0	0
TOTAL	**1234**	**1399**	**1489**	**1578**	**1234**	**1437**	**1538**	**1638**
Fixed	894	1020	1086	1101	894	1020	1086	1101
Load-related	307	347	358	408	307	375	386	436
Generation-related	32	32	45	69	32	42	67	101

Figure 6: Total network costs derived for the Centralised Energy scenario

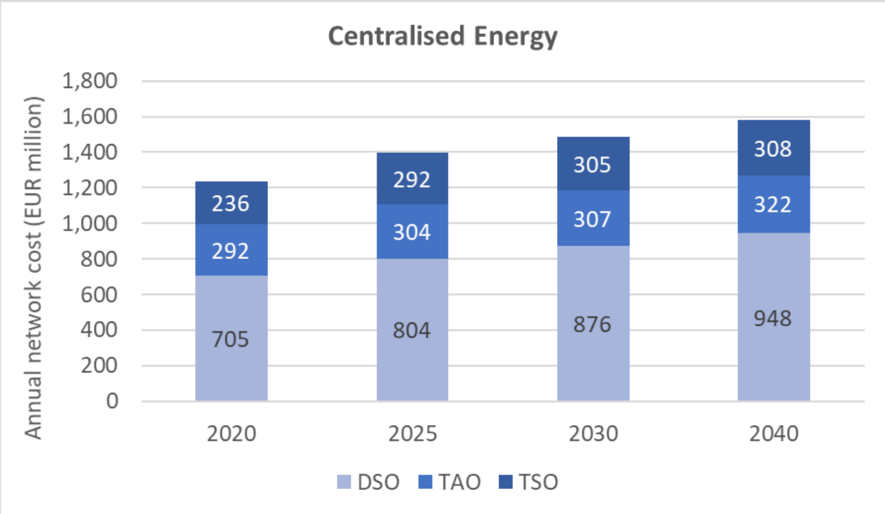


Figure 7: Total network costs derived for the Coordinated Action scenario

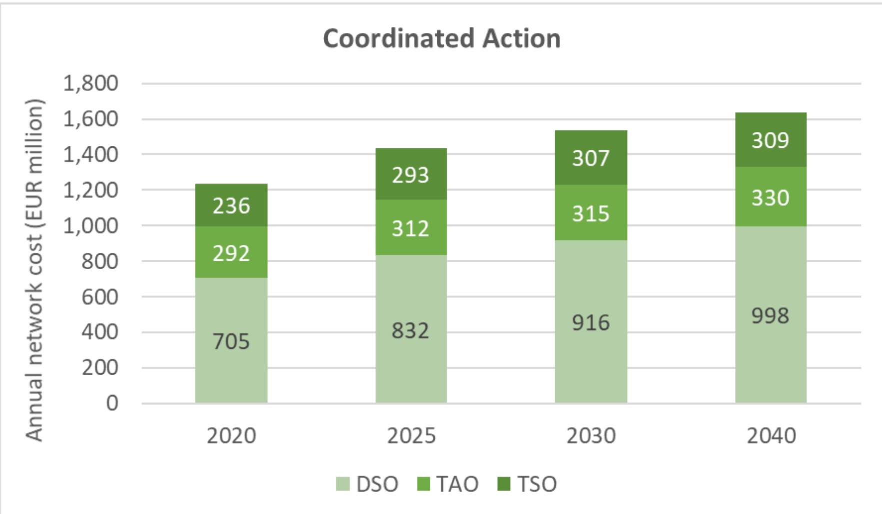


Figure 8 and *Figure 9* present the change in network cost per unit of electricity demand. This shows that, even as the total annual network costs increase, the cost per unit of electricity demand decreases in both scenarios - from 4.4 cents/kWh in 2020 to 3.7 cents/kWh by 2040 in the Centralised Energy scenario, and 3.6 cents/kWh in the Coordinated Action scenario.

Two factors largely explain the decrease in the network cost per unit of electricity demand. First, as shown in *Table 5*, we treat 72% of the base year costs as fixed costs and not scaled with increasing peak demand or generation capacity. As shown in *Table 7*, we assume the fixed costs will increase by 23% between 2020 and 2040 – from €894 million to €1,101 million. The electricity demand increases by a larger amount over the same period – a 53% increase from 30.7 TWh/yr to 47.1 TWh/yr in Centralised Energy (*Figure 4*) and a 61% increase from 30.7 TWh/yr to 49.5 TWh/yr in Coordinated Action (*Figure 5*). This means the fixed costs are spread over a larger demand base and so, even as the total annual network cost increases, the cost per unit of electricity sold decreases. Second, the increases between 2020 and 2040 in the peak demand – a 33% increase from 5.5 GW to 7.3 GW in Centralised Energy (*Figure 4*) and a 42% increase from 5.5 GW to 7.8 GW in Coordinated Action (*Figure 5*) – are lower than the increase in electricity demand (53% and 61% respectively, as noted above). So, even if all costs scaled in line with peak demand, with no fixed costs, the cost per unit of demand would decrease.

Note that the increases in distribution-connected generation capacity – a 114% increase from 2.2 GW to 4.7 GW in Centralised Energy (*Figure 4*) and a 214% increase from 2.2 GW to 6.9 GW in Coordinated Action (*Figure 5*) – are substantially larger than the increase in electricity demand, leading to large increases in this cost component. However, as shown in *Table 5*, we assume generation-related costs make up only 3% of the total network costs. As discussed further above, the small share of generation-related costs is partly due to limitations on the data available, with few of the cost components in the revenue models explicitly attributed to the addition of generation capacity. This means the framework does not capture the impact of generation-related factors, which may lead to different network cost outcomes, since the load-related costs and fixed costs drive the costs. For example, this methodology does not capture the impact on network costs of a highly decentralised, dispersed pattern of deployment of electrical generation versus a more centralised approach to generation, to meet the same electrical demand. This is a limitation of this work.

The factors described above mean that the network cost per unit of demand is likely to reduce over time in most scenarios, given that most scenarios are likely to involve a significant amount of electrification of heat and transport. This is an important finding as it suggests that, while a large amount of investment in the electricity network will need to serve an increase in peak demand and to connect new generation, the cost to the end user of upgrading and operating the network is likely to reduce on a per unit energy basis. This finding is largely due to the assumption that most the network costs do not scale with increasing peak demand or generation capacity (although some network cost components are assumed to increase over time with an increasing asset base, as described in *Table 4*). While we base this assumption on high-level guidance received from EirGrid and ESB Networks and therefore deemed relatively robust, it is clearly an important assumption to stress test in further work. Also, future analysis of network costs would provide a useful update to the evidence base in the coming years.

Figure 8: Network costs per unit of demand derived for the Centralised Energy scenario

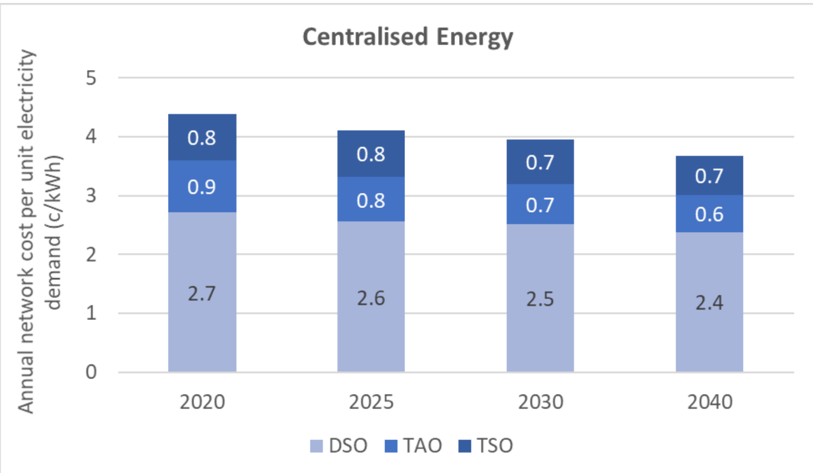
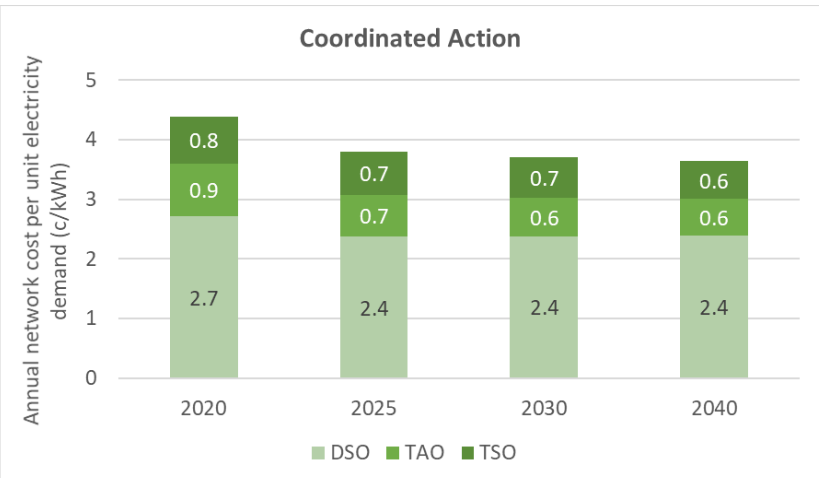


Figure 9: Network costs per unit of demand derived for the Coordinated Action scenario



Concluding remarks

In this work, we developed a simple and transparent framework to quantify the costs associated with maintaining and upgrading the electricity distribution and transmission networks in Ireland over the period to 2050, and how we expect changes in electricity demand and generation will affect these costs. We based our methodology on assumptions of how the future network costs are likely to depend on factors such as changes in electricity demand and generation, and changes in the size of the network asset base. This is the first time, to our knowledge, that the change in cost associated with the electricity network due to electrification of heat and transport in Ireland has been modelled in detail using this type of bottom-up approach based on projected increase in peak demand and generation capacity.

We have derived several important insights from this analysis. The analysis has shown that while some components of the cost of maintaining and upgrading the electricity networks strongly depend on the peak electrical load on the network, most costs are more appropriately considered 'fixed' and do not scale with peak load. Instead, most costs relate mainly to the size of the asset base (for example, the length of network and number of substations) and are independent of the peak or annual demand for electricity. We therefore find that in future scenarios with significant amounts of electrification, while the total cost of maintaining and upgrading the electricity networks increases substantially, this cost is likely to reduce in 'per unit of electricity sold' terms (i.e. in cents/kWh) due to the increased electricity demand base over which the network costs are spread.

We intend the worked examples shown in this report, based on scenarios from EirGrid's Tomorrow's Energy Scenarios [8], to be illustrative examples of applying this calculation methodology and the type of insights it can provide. This methodology was used to derive bespoke electricity network costs for the scenarios developed as part of the National Heat Study, the outputs of which are presented in a separate report (*Net Zero by 2050*).

While this framework has allowed a more accurate assessment of future electricity network costs in Ireland than previously, it has some limitations. In its present form, the calculation methodology does not distinguish between load growth on the distribution network and load growth on the transmission network. This means, for example, that all load growth due to deployment of heat pumps and electric vehicles, and any other electricity demand, is assumed to be 'seen' by both the distribution and transmission networks. A refinement to this would require the separation of electricity demand into distribution-connected and transmission-connected demand, which is not a feature of the NEMF (the model from which we developed this calculation methodology). However, we could implement this as a future update.

Due to limitations on the data available, which does not provide a detailed breakdown of the network costs relating to generation connections, the framework does not capture the impact of different configurations of deployment of generation (such as decentralised versus centralised, variable renewables versus fossil generation with carbon capture and storage, etc.) on the network costs. More generally, the framework does not have a spatial dimension, due to lack of spatially resolved data on network costs, and so cannot capture the impact of geographically varying scenarios for electricity demand (for example, some areas electrifying more deeply than others) or for electricity generation (for example, the location of renewable capacity). Also, future analysis of network costs would provide a useful update to the evidence base in the coming years.

Glossary

Term	Description
BAU	Business as usual
CORESO	Coreso is a Regional Security Coordinator, providing mandatory services to nationally regulated **TSOs**.
CRU	Commission for Regulation of Utilities – Ireland's independent energy and water regulator.
DAO	Distribution Asset Owner
DSO	Distribution System Operator
DUoS	Distribution Use of Systems
Electricity demand	The amount of electrical energy used to meet a demand (i.e. actual fuel used)
ENTSOE	European Network of Transmission System Operators for Electricity, an industry organisation which represents electricity transmission operators across Europe.
EWIC	East West Interconnector, a high-voltage direct current submarine and underground power cable linking the electricity transmission grids of Ireland and Great Britain.
GW	Gigawatt, a unit of power equivalent to 10^9 joules per second
HV	High voltage
IVADN	Integrated Vision of Active Distribution Networks, an innovation team within ESB Networks
kV	Kilovolt, a unit of electric potential equivalent to 1000 volts
LV	Low voltage
MRSO	Meter Registration System Operator
MV	Medium voltage
NEMF	National Energy Modelling Framework
QH data	Quarter Hour (metering) data
Price Review (PR)	Price Reviews, set by the **CRU**, limit the revenues that the relevant licensees, including the **TSO**, **TAO**, **DSO** and **DAO**, can recover from electricity customers to safely operate, develop and maintain the electricity networks. Price Reviews are set every five years, with the most recent Price Review ('PR4') covering the period 2016-2020 and the next Price Review ('PR5') covering the period 2021-2025.
Renew Prog	Renewal Programme
R&D	Research and Development
Revenue Model	Model produced as part of the Price Review process to estimate the revenues that the network companies may recover from customers during the relevant Price Review period.
SEAI	Sustainable Energy Authority of Ireland

TAO	Transmission Asset Owner
TSO	Transmission System Operator
TWh	Terawatt-hour, a unit of energy equivalent to 3.6 x 10^{15} joules

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Appendix

Full breakdown of costs for DSO, TAO and TSO

Table 8: DSO costs

Item (costs in € million)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
OPERATING EXPENDITURE							
NETWORK OPERATIONS & MAINTENANCE		**574**					
System control	Assume fixed		91	91	91	91	91
Planned maintenance	Assume 2% increase for each 5-yr PR period		328	335	342	349	355
Fault maintenance	Assume 2% increase for each 5-yr PR period		207	211	216	220	224
ASSET MANAGEMENT		**82**					
Asset management	Assume fixed		83	83	83	83	83
Forestry and wayleaves	Assume fixed		25	25	25	25	25
METERING		**110**					
Meter reading	Assume fixed		29	29	29	29	29
QH data	Assume fixed		10	10	10	10	10
Data aggregation	Assume fixed		34	34	34	34	34
Customer meter operation	Assume fixed		14	14	14	14	14
Keypad/Token meter	Assume fixed		2	2	2	2	2
SMART METERING OPEX							
Smart metering opex	Assume fixed		59	59	59	59	59
CUSTOMER SERVICE		**89**					
Call centre	Assume fixed		33	33	33	33	33
Area operations	Assume fixed		56	56	56	56	56
Customer relations	Assume fixed		36	36	36	36	36
PROVISION OF INFORMATION		**57**					
Duos billing and accounts receivable	Assume fixed		4	4	4	4	4
MRSO	Assume fixed		10	10	10	10	10

Item (costs in € million)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
Market opening	Assume fixed		53	53	53	53	53
COMMERCIAL							
Third-party damages	Assume fixed		0	0	0	0	0
Supply repayable	Assume fixed		0	0	0	0	0
Other external repayable	Assume fixed		0	0	0	0	0
Other commercial	Assume fixed		0	0	0	0	0
SUSTAINABILITY and RESEARCH & DEVELOPMENT (R&D)							
R&D	Assume fixed	11	20	20	20	20	20
OTHER		**380**					
Network rates	Assume 2% increase for each 5-yr PR period		330	336	343	350	357
CER/CRU levy	Assume fixed		11	11	11	11	11
Reporting allowance	Assume fixed		1	1	1	1	1
Corporate charges and corporate affairs	Assume fixed	61	61	61	61	61	61
Insurance	Assume fixed		27	27	27	27	27
Legal	Assume fixed		16	16	16	16	16
Pension	Assume fixed		7	7	7	7	7
Environmental	Assume fixed		28	28	28	28	28
DSO transformation	Assume fixed		24	24	24	24	24
Health and safety	Assume fixed		40	40	40	40	40
Telecoms	Assume fixed	22	31	31	31	31	31
Flexible opex solutions	Assume fixed		0	0	0	0	0
Efficiency	Assume fixed		-35	-35	-35	-35	-35
Total (operating expenditure)		1,385	1,632	1,649	1,667	1,685	1,703
CAPITAL EXPENDITURE							
LOAD-RELATED CAPEX							
New housing schemes	Assume increases in line with load growth	90		172		Varies depending on	

Item (costs in € million)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
Non-scheme houses	Assume increases in line with load growth	164		144		load growth in scenario	
Commercial/industrial supplies	Assume increases in line with load growth	151		153			
Whole current metering	Assume increases in line with load growth	18		33			
NEW BUSINESS							
Transmission connection costs	Assume increases in line with load growth	0		0		Varies depending on load growth in scenario	
110 kV	Assume increases in line with load growth	70		136			
38 kV	Assume increases in line with load growth	98		106			
Medium-voltage (MV)/low-voltage (LV) system improvements	Assume increases in line with load growth	58		170			
20 kV conversion	Assume increases in line with load growth	11		119			
REINFORCEMENTS							
Generation connections	Assume increases in line with generation capacity	131		193		Varies depending on generation capacity in scenario	
Dismantling	Assume increases in line with load growth	0		0		Varies depending on load growth in scenario	
Non-repayable line diversions	Assume increases in line with load growth	100		96			
Repayable line diversions	Assume increases in line with load growth	62		55			
Wayleave payments	Assume increases in line with load growth			14			
NON-LOAD-RELATED CAPEX		**16**					
Renew prog – 110 kV and 38 kV lines	Estimated projections based on consultation with ESB Networks	33	33	44	59	59	59
Renew prog – 110 kV and 38 kV cables	Estimated projections based on consultation with ESB Networks	17	39	52	70	70	70

Item (costs in € million)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
Renew prog – High-voltage (HV) substation	Estimated projections based on consultation with ESB Networks	117	123	165	219	219	219
Renew prog – MV overhead lines	Estimated projections based on consultation with ESB Networks	101	141	188	251	251	251
Renew prog – MV cables	Estimated projections based on consultation with ESB Networks		0	0	0	0	0
Renew prog – MV substations	Estimated projections based on consultation with ESB Networks	42	42	55	74	74	74
Renew prog – Urban LV renewal	Estimated projections based on consultation with ESB Networks	11	4	5	7	7	7
Renew prog – Rural LV network	Estimated projections based on consultation with ESB Networks	2	39	52	69	69	69
Renew prog – LV cables and associated items	Estimated projections based on consultation with ESB Networks	13	17	23	30	30	30
Meters and time switches	Assume fixed	8	20	20	20	20	20
Renew prog – Cut-outs	Assume fixed	3	1	1	1	1	1
Continuity improvement	Assume fixed	14	39	39	39	39	39
Response capex	Assume fixed	74	27	27	27	27	27
System control	Assume fixed	23	169	169	169	169	169
New asset lives	Assume fixed		66	66	66	66	66
New asset lives adjustment	Assume fixed		-66	-66	-66	-66	-66
Protection (secondary asset)	Assume fixed		18	18	18	18	18
Protection adjustment	Assume fixed		-18	-18	-18	-18	-18
IVADN	Assume fixed	4	0	0	0	0	0
NON-NETWORK CAPEX							
New accommodation	Assume fixed	0	88	88	88	88	88
Accommodation refurbishment	Assume fixed	15	0	0	0	0	0
Fixture and fittings	Assume fixed	1	0	0	0	0	0
Office equipment	Assume fixed		0	0	0	0	0
Vehicles	Assume fixed	32	46	46	46	46	46
Tools	Assume fixed	31	28	28	28	28	28

Item (costs in € million)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
Distribution assets management	Assume fixed	29	75	75	75	75	75
Distribution control / operation	Assume fixed	3	0	0	0	0	0
IT infrastructure	Assume fixed	2	0	0	0	0	0
Enterprise applications	Assume fixed	50	0	0	0	0	0
Environment	Assume fixed	1	10	10	10	10	10
Telecomms and system control	Assume fixed	34	55	55	55	55	55
New customer experience capex	Assume fixed		19	19	19	19	19
SMART METERING							
Smart metering			Excluded				
Total (capital expenditure)		**1,627**		**2,407**		**Varies by scenario**	

Table 9: TAO costs

Item (costs in € million)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
OPERATING EXPENDITURE		**298**					
Operations allowance	Assume fixed		10	10	10	10	10
Maintenance allowance	Assume fixed		105	105	105	105	105
Wayleaves	Assume fixed		3	3	3	3	3
Telecoms	Assume fixed		9	9	9	9	9
Professional services fees	Assume fixed		13	13	13	13	13
Rates	Assume fixed		162	162	162	162	162
CRU levy	Assume fixed		6	6	6	6	6
Corporate	Assume fixed		18	18	18	18	18
Legal	Assume fixed		1	1	1	1	1
Insurance	Assume fixed		3	3	3	3	3
Pension administration	Assume fixed		2	2	2	2	2

Item (costs in € million)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
Company-wide costs	Assume fixed		0	0	0	0	0
Efficiency	Assume fixed		-5	-5	-5	-5	-5
Total (operating expenditure)		298	327	327	327	327	327
CAPITAL EXPENDITURE							
TAO NETWORK CAPEX		**803**					
Ongoing projects (€ million)	Assume fixed		431	431	431	431	431
System reinforcements	Assume increases in line with load growth				74	Varies depending on load growth in scenario	
New connections	Assume increases in line with load growth				376		
Asset refurbishment	Assume fixed		199	199	199	199	199
TAO adjustment	Assume fixed		25	25	25	25	25
DSO	Assume fixed		29	29	29	29	29
Generic projects	Assume fixed		1	1	1	1	1
Interest during construction	Assume fixed				Excluded		
Protection, telecoms and station security	Assume fixed		0	0	0	0	0
Total (capital expenditure)			**803**		**1,134**	**Varies by scenario**	

Table 10: TSO costs

Item (costs in €m)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
OPERATING EXPENDITURE							
INTERNAL OPEX							
Staff and staff-related costs	Assume fixed	139	177	177	177	177	177
Contractors	Assume fixed	7	8	8	8	8	8
Transport	Assume fixed		0	0	0	0	0
Telecommunications	Assume fixed	25	28	28	28	28	28
Premises	Assume fixed	26	29	29	29	29	29

Item (costs in €m)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
IT costs	Assume fixed	22	40	40	40	40	40
Insurance and compensation	Assume fixed	1	2	2	2	2	2
Selling and advertising	Assume fixed	9	14	14	14	14	14
Professional services	Assume fixed	20	21	21	21	21	21
Grid maintenance	Assume fixed	3	3	3	3	3	3
Provisions	Assume fixed		0	0	0	0	0
Rates	Assume fixed	2	3	3	3	3	3
Other	Assume fixed	1	0	0	0	0	0
PR5 reporting costs	Assume fixed		1	1	1	1	1
Promotion of research	Assume fixed	1	2	2	2	2	2
Intercompany charges	Assume fixed	-16	-16	-16	-16	-16	-16
Frontier shift	Assume fixed		-3	-3	-3	-3	-3
EXTERNAL OPEX		**499**					
Inter TSO compensation	Assume fixed		11	11	11	11	11
CORESO subscription	Assume fixed		3	3	3	3	3
Interconnector services	Assume fixed		4	4	4	4	4
CER levy	Assume fixed		5	5	5	5	5
Rolling retention	Assume fixed		2	2	2	2	2
DUoS charges	Assume fixed		16	16	16	16	16
Ancillary services	Assume fixed		919	919	919	919	919
ENTSOE fees	Assume fixed		0	0	0	0	0
EWIC support fees	Assume fixed		107	107	107	107	107
Total (operating expenditure)		**740**	**1,375**	**1,375**	**1,375**	**1,375**	**1,375**
CAPITAL EXPENDITURE							
NON-NETWORK CAPEX		**30**					
Sustainability and decarbonisation	Assume fixed		19	19	19	19	19

Item (costs in €m)	Assumption on development of costs beyond PR5	PR4	PR5	PR6	PR7	PR8	PR9
Operate, develop and enhance grid	Assume fixed		11	11	11	11	11
Engage in better outcomes for all	Assume fixed		1	1	1	1	1
BAU – IT asset replacement or upgrade	Assume fixed		32	32	32	32	32
BAU – Transition to cloud hosting	Assume fixed		0	0	0	0	0
BAU – IT operating model review	Assume fixed		0	0	0	0	0
BAU – Build resilience and manage market	Assume fixed		0	0	0	0	0
BAU – Maintaining baseline cyber defences	Assume fixed		0	0	0	0	0
Non-network capex deferred (PR4)	Assume fixed		-3	-3	-3	-3	-3
Real price effects	Assume fixed		0	0	0	0	0
Frontier shift	Assume fixed		0	0	0	0	0
NETWORK CAPEX	Assume increases in line with load growth		87		70	Varies depending on load growth in scenario	
Total (capital expenditure)			**117**		**131**	**Varies by scenario**	

Equations used in the calculation framework

Base year network costs:

$$\text{Base year DSO cost}\left(\frac{\text{€ million}}{\text{yr}}\right) = \frac{\text{Total DSO cost over PR4 and PR5 (€ million)}}{10\text{ yrs}}$$

$$\text{Base year TAO cost}\left(\frac{\text{€ million}}{\text{yr}}\right) = \frac{\text{Total TAO cost over PR5 (€ million)}}{5\text{ yrs}}$$

$$\text{Base year TSO cost}\left(\frac{\text{€ million}}{\text{yr}}\right) = \frac{\text{Total TSO cost over PR4 and PR5 (€ million)}}{10\text{ yrs}}$$

$$\text{Total base year network cost} = \text{Base year DSO cost} + \text{Base year TAO cost} + \text{Base year TSO cost}$$

Future network costs:

$$\begin{aligned}\text{DSO cost in year t (€ million)} \\ &= \text{Fixed DSO cost in year t (€ million)} \\ &+ \text{Load-related DSO cost in base year (€ million)} \times \frac{\text{Peak load in year t (GW)}}{\text{Peak load in base year (GW)}} \\ &+ \text{Gen. related DSO cost in base year (€ million)} \times \frac{\text{Distr. conn. gen capacity in year t (GW)}}{\text{Distr. conn. gen capacity in base year (GW)}}\end{aligned}$$

$$\begin{aligned}\text{TAO cost in year t (€ million)} \\ &= \text{Fixed TAO cost in year t (€ million)} \\ &+ \text{Load-related TAO cost in base year (€ million)} \times \frac{\text{Peak load in year t (GW)}}{\text{Peak load in base year (GW)}}\end{aligned}$$

$$\begin{aligned}\text{TSO cost in year t (€ million)} \\ &= \text{Fixed TSO cost in year t (€ million)} \\ &+ \text{Load-related TSO cost in base year (€ million)} \times \frac{\text{Peak load in year t (GW)}}{\text{Peak load in base year (GW)}}\end{aligned}$$

$$\text{Total network cost in year t} = \text{DSO cost in year t} + \text{TAO cost in year t} + \text{TSO cost in year t}$$

where:

Gen. related is 'generation-related'
Distr. conn. is 'distribution-connected'

Network cost per unit of electricity demand:

$$\text{DSO cost per unit of electricity demand in year t}\left(\frac{\text{cents}}{\text{kWh}}\right) = \frac{100 \times \text{DSO cost in year t (€ million)}}{\text{Annual electricity demand on DSO in year t (GWh)}}$$

$$\text{TAO cost per unit of electricity demand in year t}\left(\frac{\text{cents}}{\text{kWh}}\right) = \frac{100 \times \text{TAO cost in year t (€ million)}}{\text{Annual electricity demand on TAO in year t (GWh)}}$$

$$\text{TSO cost per unit of electricity demand in year t}\left(\frac{\text{cents}}{\text{kWh}}\right) = \frac{100 \times \text{TSO cost in year t (€ million)}}{\text{Annual electricity demand on TSO in year t (GWh)}}$$

$$\begin{aligned}\text{Total network cost per unit of electricity demand in year t} \\ &= \text{DSO cost per unit of electricity demand in year t} \\ &+ \text{TAO cost per unit of electricity demand in year t} \\ &+ \text{TSO cost per unit of electricity demand in year t}\end{aligned}$$

w: www.seai.ie
e: info@seai.ie
t: 01 8082100

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